MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Historical Year, Bridge Period, and Projected Test Year Operations Resources
Electric Low Voltage Distribution (LVD) Workplan

Case No.: U-21870
Exhibit No.: A-178 (CMT-1)
Page: 1 of 1
Witness: CMTetrick
Date: June 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Description	2023 YE Actual	2024 YE Actual	2025 YE Projected 12 Mos Ending 12/31/2025	2026 YE Projected 12 Mos Ending 12/31/2026	2027 YE Projected 12 Mos Ending 12/31/2027	Bridge Period 16 Mos Ending 4/30/2026	Test Period 12 Mos Ending 4/30/2027
1	LVD Electric Operations Resource Requirement (FTEs)	1,104	1,155	1,229	1,537	1,742	1,537	1,742
2	LVD Consumers Energy Resources (FTEs)	981	1,017	1,091	1,306	1,481	1,306	1,481
3	LVD Consumers Energy Resources (percent change from prior year FTE)	15%	4%	7%	20%	13%	28%	36%
4	LVD Contractor Resources (FTEs)	123	138	138	231	261	231	261
5	LVD Contractor Resources (percent change from prior year FTE)	-	12%	0%	67%	13%	67%	13%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Historical Year, Bridge Period, and Projected Test Year Operations Resources
Electric High Voltage Distribution (HVD) Workplan

Case No.: U-21870
Exhibit No.: A-179 (CMT-2)
Page: 1 of 1
Witness: CMTetrick
Date: June 2025

Line No.	(a) Description	(b) 2023 YE Actual	(c) 2024 YE Actual	(d) 2025 YE Projected 12 Mos Ending 12/31/2025	(e) 2026 YE Projected 12 Mos Ending 12/31/2026	(f) 2027 YE Projected 12 Mos Ending 12/31/2027	(g) Bridge Period 16 Mos Ending 4/30/2026	(h) Test Period 12 Mos Ending 4/30/2027
1	HVD Electric Operations Resource Requirement (FTEs)	377	409	504	539	530	539	530
2	HVD Consumers Energy Resources (FTEs)	191	209	233	261	270	261	270
3	HVD Consumers Energy Resources (percent change from prior year FTE)	-2%	2%	11%	12%	3%	25%	29%
4	HVD Contractor Resources (FTEs)	186	200	271	278	260	278	260
5	HVD Contractor Resources (percent change from prior year FTE)	4%	8%	36%	3%	-6%	39%	-6%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the Property Tax Rate for the Test Year

Case No.: U-21870
Exhibit No.: A-180 (BJV-1)
Page: 1 of 3
Witness: BJVanBlarcum
Date: June 2025

Line No.	(a) Description	(b) Amount (millions)	(c) Amount (millions)	(d) Amount (millions)	(e) Source
1	Electric Property Taxes Paid - 2026 Estimate			$ 281.9	WP BJV-5, L-5
2	Electric Property Taxes on 2026 Plant Investment			33.6	Ex. A-180 (BJV-1), p.2, L-9
3	2027 Fossil Plant Valuation Tax Reduction			(0.1)	WP BJV-5, L-5
4	Electric Property Taxes on Real Property Taxable Value Increases			1.2	Ex. A-180 (BJV-1), p.3, L-4
5	Electric Property Taxes to be Paid - 2027			$ 316.6	
6	2026 Fiscal Year Property Taxes expensed in 2027			141.0	(Line 1 * 50.0%) [1]
7	2027 Property Taxes expensed in 2028			(158.3)	(Line 5 * 50.0%) [1]
8	Electric Property Tax Expense - 2027			$ 299.3	
9	Prorated Electric Property Tax Expense (May - December 2026)			183.7	WP BJV-5, L-10
10	Prorated Electric Property Tax Expense (January - April 2027)			96.8 [4]	
11	Prorated Electric Property Tax Expense			280.5	(L-10 + L-11)
12	2026 Estimated Year-End Plant-in-Service		$ 20,714.6 [2]		
13	2026 Estimated Construction Work-in-Progress	$ 595.2 [3]			
14	@ 50%	50.00%			
15	2026 Estimated Construction Work-in-Progress		$ 297.6		
16	Estimated Taxable Plant			$21,012.2	(L-13 + L-16)
17	Property Tax Rate			0.013349387	(L-12 / L-17)

Footnotes
[1] The 50.0% factor is from the 2024 CE Property Tax Fiscal Year Study
[2] Plant in Service Balance as of 12-31-2026; Plant Model U-21870; PIS (WP-PDD-21); Cell AH29 + JHC1&2 (WP-PDD-9), Cell AM18 + JHC3 (WP-PDD-9), Cell AM30
[3] Construction Work in Progress Balance as of 12-31-2026; Plant Model U-21870; CWIP (WP-PDD-24); Cell AI30
[4] Development of Estimated 2027 Prorated Property Tax Expense

2027 Estimated PT Expense	$ 299.3	Ex. A-180 (BJV-1), p. 1, L-9
Jan-Apr Expense Ratio	32.33%	Plant Model U-21870.xlsx; Input, Cells B215-E215
Prorated 2027 PT Expense	$ 96.8	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the 2027 Property Taxes
on 2026 Plant Investment

Case No.: U-21870
Exhibit No.: A-180 (BJV-1)
Page: 2 of 3
Witness: BJVanBlarcum
Date: June 2025

Line No.	(a) Description	(b) Amount (millions)		(c) Source
1	**Assessed Value of Personal Property (millions)**			
2	Year-end 2026 Estimated Taxable Closings less Retirements	$ 1,404.3	[1]	
3	First Year STC Multiplier	96.0%	[2]	
4	**True Cash Value of Personal Property (millions)**	$ 1,348.1		
5	Statutory Factor for Assessed Value	50%	[3]	
6	New Plant - Assessed Value	$ 674.1		
7	**Estimated Property Tax (millions)**			
8	Estimated Composite Millage Rate	49.7863	[4]	
9	Estimated 2027 Property Taxes Paid	$ 33.6		

Footnotes
[1] 2027 Electric Rate Case Property Tax Model
[2] Michigan Dept of Treasury Form 3589 - 1st year multiplier for Electric Distribution and Equipment
[3] Article IX, Section 3 of Constitution of Michigan of 1963
[4] CE Composite Millage Rate.xls

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the 2027 Estimated Electric Portion of
Real Property Taxable Value Increase

Case No.: U-21870
Exhibit No.: A-180 (BJV-1)
Page: 3 of 3
Witness: BJVanBlarcum
Date: June 2025

Line No.	(a) Description	(b) Amount (millions)	(c) Source
1	**2027 Estimated Electric Portion of Real Property Tax Increase (millions)**		
2	2027 Real Property Taxable Value - Estimated Electric Portion	$ 23.1 [1]	
3	2027 Estimated Composite Millage Rate	49.7863 [2]	
4	2027 Estimated Electric Portion of Real Property Taxable Value increase	$ 1.2	

Footnotes
[1] 2027 Electric Rate Case Property Tax Model
[2] CE Composite Millage Rate.xls

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Amortization of Excess Deferred Federal
Income Taxes for the Test Year

Case No.: U-21870
Exhibit No.: A-181 (BJV-2)
Page: 1 of 3
Witness: BJVanBlarcum
Date: June 2025

Line No.	(a) Description	(b) Projected Regulatory [1] Liability Amortization	(c) Projected Annual [2] Excess Deferred Tax	(d) Proration to Test Year
1	Protected Plant Balance - Subject to ARAM			
2	2026	(37,134,000)	(27,690,000)	(18,460,000)
3	2027	(39,904,000)	(29,756,000)	(9,919,000)
4				
5	**TCJA Amortization - ARAM**			(28,379,000)
6				
7				
8				
9	Non-Protected Plant Balance - 27 years			
10	2026	3,145,000	2,345,000	1,563,000
11	2027	3,145,000	2,345,000	782,000
12				
13				
14	Non-Protected Other Balance - 10 years			
15	2026	(8,708,000)	(6,493,000)	(4,329,000)
16	2027	(8,708,000)	(6,493,000)	(2,164,000)
17				
18	**TCJA Amortization - Non ARAM**			(4,148,000)
19				
20				
21				
22	**TCJA Regulatory Liability**	(10,603,566)	(7,907,000)	(7,907,000)
23				
24				
25	**Total Test Year Excess Deferred Taxes**			(40,434,000)

[1] Based on the Company's regulatory liability amortization schedule approved in Case No. U-20309.

[2] Adjustment to pre-tax based on 1.341056 gross-up factor used in Case No. U-20309.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No.: A-181 (BJV-2)
Page: 2 of 3
Witness: BJVanBlarcum
Date: June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CE Electric
Projected Tax Reform Regulatory Liability & Amortization
($000)

Case No.: U-20309
Exhibit No.: A-5 (SBM-3)
Page: 1 of 1
Witness: SBMcIntosh
Date: April 2019

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Plant Diff ***	**Oth Plant Diff *****	**All Other**	**Total Electric**
1	Amortization Period	ARAM	27	10	
2					
3	**Tax Reform Regulatory Asset (Liability) After Gross Up**	**$ (1,172,029)**	**$ 89,091**	**$ (87,076)**	**$ (1,170,013)**
4					
5	**Amortization Schedule**				
6	**2019	(8,953)	1,048	(2,903)	(10,807)
7	**2020	(28,209)	3,145	(8,708)	(33,771)
8	2021	(30,187)	3,145	(8,708)	(35,749)
9	2022	(31,436)	3,145	(8,708)	(36,998)
10	2023	(35,546)	3,145	(8,708)	(41,108)
11	2024	(36,898)	3,145	(8,708)	(42,460)
12	2025	(37,086)	3,145	(8,708)	(42,648)
13	2026	(37,134)	3,145	(8,708)	(42,697)
14	2027	(39,904)	3,145	(8,708)	(45,467)
15	2028	(42,747)	3,145	(8,708)	(48,309)
16	2029	(44,426)	3,145	(5,805)	(47,085)
17	2030	(45,859)	3,145	-	(42,713)
18	2031	(46,326)	3,145	-	(43,181)
19	2032	(47,316)	3,145	-	(44,170)
20	2033	(49,093)	3,145	-	(45,948)
21	2034	(51,089)	3,145	-	(47,944)
22	2035	(44,865)	3,145	-	(41,719)
23	2036	(42,334)	3,145	-	(39,189)
24	2037	(29,201)	3,145	-	(26,055)
25	2038	(26,019)	3,145	-	(22,874)
26	2039	(25,183)	3,145	-	(22,037)
27	2040	(24,370)	3,145	-	(21,225)
28	2041	(24,256)	3,145	-	(21,110)
29	2042	(24,259)	3,145	-	(21,114)
30	2043	(24,313)	3,145	-	(21,168)
31	2044	(24,345)	3,145	-	(21,199)
32	2045	(24,242)	3,145	-	(21,097)
33	2046	(24,063)	3,145	-	(20,918)
34	2047	(23,974)	3,120	-	(20,854)
35	2048 - 2056	(198,398)	-	-	(198,398)
36		**$ (1,172,029)**	**$ 89,091**	**$ (87,076)**	**$ (1,170,013)**

**** Subject to the normalization provisions of the Internal Revenue Code.***

***** Assumes Calculation C Interim Credit beginning September 2019 through December 2020.***

****** Includes a $4,168,278 beginning balance adjustment related to AFUDC approved by the Commission in U-21224.***

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No.: A-181 (BJV-2)
Page: 3 of 3
Witness: BJVanBlarcum
Date: June 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CE Electric
Tax Reform Regulatory Liability & Amortization

Case No.: U-20309
Date: March 2025

	(1) Beginning Balance [A]	(1-A) Rate Change Gross-up Adjustment [C]	(2) Amount Refunded	(3) Regulatory Asset (Liability)	(2-A) Regulatory Asset/(Liability) Refunded	(3-A) Remaining Regulatory Asset/ (Liability)	(4) Ending Balance
2019	$ (1,174,181,474)		$ 8,191,439	$ (6,240,769) [D]	$ 6,240,769	$ -	$ (1,159,749,266)
Beginning Balance Adj [B]	$ 4,168,278		$ -	$ -	$ -	$ -	$ (1,155,580,988)
2020	$ (1,155,580,988)		$ 33,772,000	$ (8,706,572) [E]	$ -	$ (8,706,572)	$ (1,113,102,416)
2021	$ (1,113,102,416)		$ 35,750,000	$ (5,569,763) [F]	$ -	$ (5,569,763)	$ (1,071,782,653)
2022	(1,071,782,653)		$ 36,999,000	$ (12,498,566)	$ 1,895,000 [A]	$ (10,603,566)	$ (1,022,285,087)
2023	(1,022,285,087)	2,381,350	$ 41,109,000	$ 2,821,501	$ -	$ 2,821,501	$ (981,616,238)
2024	(981,616,238)	-	$ 42,367,000	$ (1,723,356)	$ -	$ (1,723,356)	$ (937,525,882)

[A] Electric information contained herein includes amounts associated with transmission assets, which are subject to rate regulation by the Federal Energy Regulatory Commission ("FERC"). On September 13, 2022, FERC issued a final order in Docket #ER22-2597-000 requiring $1,895,000 of TCJA-related excess deferred federal income taxes associated with transmission assets be refunded to transmission customers. This amount is reflected in column 2-A and reduced the Regulatory Asset/(Liability) due to customers as it will be refunded subject to the FERC order.

[B] In its original U-20309 filing, the Company inadvertently included in its unprotected plant balance a remeasurement of excess deferred taxes associated with AFUDC timing differences. A subsequent reconcilation of the 2019 TCJA balance highlighted this discrepancy. The Company reflected this proposed change in Case No. U-21224 and the Commission subsequently approved the adjustment in it's January 19, 2023 order.

[C] Gross-up change to the regulatory liability balance due to a statutory or apportionment rate change.

[D] Included in Case No. U-21224.

[E] Included in Case No. U-21389

[F] Included in Case No. U-21585

Whole Home Optimization Demand Response Pilot

1. Pilot needs and goals detailed.

a. Need for the pilot and results of past pilots

The utility industry is rapidly adopting new technologies to engage customers in low-effort and minimally disruptive DR programming and the Company is seeking to collect field data on the potential for adoption of, and load shaping capabilities of, these technologies in Michigan. Major technology companies have developed the hardware and software necessary to administer these programs and are actively seeking utilities with whom to partner on feasibility testing and implementation.

To address these needs and opportunities, the Company is proposing a Whole Home Optimization Demand Response pilot that will test customer-owned smart home energy management systems, battery storage, and load management devices. A whole home optimization approach allows us to test how customers respond to and interact with energy usage and demand analytics, customer-controlled responses and behavior, and aggregation of resources within their home. The key technologies evaluated in this pilot are as follows:

Smart Home Energy Management System (SHEMS) – SHEMS platforms and software are advanced systems designed to monitor, analyze, and optimize energy consumption through a single device or application. These tools leverage data from various sources, including smart devices like thermostats, sensors, appliances, and intelligent assistants to provide actionable insights and control over energy usage.

Customers will benefit from real-time accurate energy data, which in addition to savings, can provide energy education and actionable insights, more readily available in-home automation, and energy optimization.

Battery Storage – Battery storage in the context of this pilot refers to a rechargeable home battery system that stores electrical energy for later use and could include electric vehicles if a feasible solution is determined. These systems typically consist of rechargeable batteries, an inverter, and a control system. The Company will seek out systems that come with advanced monitoring tools that allow customers to track energy consumption and storage in real time and can integrate with other distributed energy resources, smart home devices, and energy management systems – giving them control and autonomy in shifting energy use throughout the day. This allows for automated control of energy usage, such as charging the battery during off-peak hours and using stored energy during peak times.

Load Management Devices – Devices in this category can range from smart control panels to meter collars and are used to monitor and control the flow of electricity to ensure the electrical panel or grid doesn't become overloaded. Load Management Devices are often integrated with Smart Home Energy Management Systems to aid with load shaping according to homeowner preference, to control energy consumption, and to potentially eliminate utility service upgrades while enabling enhanced grid-edge capabilities. They provide a unique aggregated DR opportunity with the integration of electric vehicles and battery storage systems by acting as a whole

home DR platform using virtual service limit capabilities, with up to 10 times that of a single-point DR solution. Load Management Devices can also create a more cost-effective and faster electrification method of EV adoption, and it 'future-proofs' customer's homes for further electrification needs. These devices can benefit customers by helping them reduce energy use when it is most expensive, lowering their overall energy bill, and helping them participate in clean energy plans that still provide them with control over the decision to use energy when it is cleanest and use less energy when it is less ideal for the environment.

Past Pilots: Launched in 2020 as part of a settlement agreement, the Super-Efficient, All-Electric New Homes pilot aimed to decarbonize residential buildings and assess the potential of zero energy-ready homes in Michigan. This pilot incentivizes home-building partners to develop scalable production of affordable, high-performance single-family homes, evaluating energy bill impacts, heat pump performance, customer comfort, builder barriers, and cost-effectiveness. To date the pilot has 57 homes enrolled, each with a mix of energy efficient decarbonization and electrification measures. These measures include cold climate air-source heat pumps ("ccASHP") with energy recovery ventilators ("ERV"), heat pump water heaters ("HPWH"), comprehensive air sealing, premium insulations, high-efficiency windows, and ENERGY STAR appliances. A select number of projects were also eligible to receive rooftop solar arrays to understand conditions for achieving near-net zero energy and mitigate potentially higher utility costs associated with living in an all-electric home.

Additionally, six of the homes had submetering equipment installed to collect circuit level consumption data.

From this pilot, the Company learned that there are opportunities to test for DR through aggregation of resources with solar and battery storage, with use-cases identified for battery dispatching partnered with solar for testing resource aggregation. Customers also provided feedback on how demand response offerings could help them reach zero net energy and reduce energy costs. By deploying sub-metering equipment to collect circuit level data the Company learned that the average per home summer peak was 1.32 kW and average per home winter peak winter was 2.48 kW. This pilot indicated that DR offerings could impact whole home usage and that aggregated resources could work together to promote net zero energy.

b. Pilot goals and desired learnings

The Company is seeking to test this technology specifically with its residential customers given the past implementation of Time-of-Use ("TOU") rate structures (RSP_1001, RSH 1040, and RPM 1050), to quantify energy savings impacts, and to understand the barriers customers face with adopting distributed energy resources ("DER") in the home, including battery storage and electric vehicles, to shift energy off-peak. As more smart-ready devices become available, the Company must understand how customers interact with their energy usage via these devices. Currently, the Company does not have any active efforts to explore residential DR potential beyond current programming, limiting the impact the Company can have on residential peak demand and potentially jeopardizing

future DR cost-effectiveness. Additionally, incorporating EVs and other DERs into the DR portfolio has not been tested due to a limited understanding of how to best incentivize customers for participation in such programs and if there is a source of significant benefit to load management energy savings and grid benefits. The goal of the pilot would be to identify and quantify benefits from the perspective of load reduction and customer willingness-to-pay.

Research also shows that customers prioritize comfort and safety while also wanting to lower their energy bills and usage and we expect that this pilot will expand these learnings via recruitment of a larger sample and deeper exploration of customer attitudes and behaviors.

2. Design and evaluation plan

a. Pilot program design and evaluation plans

The Company will work with implementation contractors, third-party evaluators, and software and hardware vendors to install and test a variety of available technologies to assess cost-effectiveness, demand reduction, energy waste reduction, customer interest, and technical integration feasibility. Objective criteria for evaluating the success of the pilot include measuring the reduction in kilowatts per participant, assessing the cost-effectiveness of the pilot, and evaluating customer experience of and satisfaction with the

pilot technologies and programs through Customer Satisfaction ("CSAT") scores and the Customer Experience Index ("CXI").

b. Define target customer population, selection rationale (including those for location-driven programs), recruitment plans, and evaluation plans for customer adoption and satisfaction.

The Company will deploy a marketing and recruiting plan that supports enrolling approximately 500 residential electric or combination service territory customers that are single-family market rate, single-family low- to moderate-income, and multi-family units. Each residence will receive one or more of the tools for testing, depending on household needs and configuration. The Company will measure conversion and enrollment rates and will partner with a third-party evaluator to measure customer satisfaction and identify opportunities for improvement.

c. If statistical analysis will be conducted on pilot results, a statistically significant sample size must be selected, supported, and detailed. If a statistically significant sample size is not selected, justification must be provided.

The Company will engage with a third-party evaluator to validate if a statistically significant sample size is required and will build the recruitment plan to acquire the number of enrollments needed. The company will work with the third-party evaluator to build a comprehensive evaluation plan that includes pilot design and size, key testing assumptions, methodology for measuring impact on energy usage and peak demand reduction, and customer satisfaction.

d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.

See above.

e. If changes are required during implementation, pilot design, and evaluation impacts are shared.

The Company will provide updates on this pilot in its future electric rate cases and DR reconciliations and will notify MPSC Staff and other intervenors of significant changes from the approved plan during implementation or pilot design and will share the results of evaluation when complete, in accordance with the stakeholder engagement process outline below.

3. Pilot project costs detailed

a. Project costs detailed by source and amount for applicable periods

The project costs will be tracked internally and will include implementation costs, vendor costs, and administrative costs. The Company is seeking $750,000 capital and $250,000 O&M included in Exhibit A-XX (AMG-1) and Exhibit A-XX (AMG-2), respectively. The costs associated with testing these technologies include technology demonstrations for the various customer types. Load Management Devices will require an investment of $200,000, multifamily whole unit optimization will require $200,000, single-family whole home optimization will require $150,000, and smart analytics and aggregation through whole home smart optimization will require $200,000. Additionally, evaluation, incubation, and labor costs are estimated at $250,000.

b. Availability/pursuit of non-utility funding

The Company is not aware of outside funding available for this type of project but will seek learnings on how customers can stack incentives for technologies such as solar panels, batteries, EVs, etc. to decrease their overall out-of-pocket investment.

c. Anticipated cost-effectiveness and net benefits when deployed at scale

To be determined when evaluation work is completed. Leading indicators and confirmed findings will be shared during quarterly updates.

d. Proposed rate recovery approach

The funding requested for this project is identified in item (a) above and included in the revenue requirement for this case.

4. Project timeline

a. Proposed timeline for the pilot project and any related reports or evaluations

Phase 1 (May – August 2026) involves evaluating current assets to determine potential inclusion and securing third-party partner agreements. In Phase 2 (September 2026 – December 2026), we will geotarget customer populations and perform feasibility studies to properly test the consumer market for each use case. Phase 3 (January 2027 – April 2027) will involve scoping and launching each technology use case based on immediate feasibility. Finally, in Phase 4 (April 2027 – December 2028), we will finalize the evaluation and share a summary with stakeholders for scaling, sunsetting, or continual pilot recommendations.

5. Stakeholder engagement plan

a. Stakeholder engagement plan before, during, and after pilot takes place

Engaging stakeholders throughout the pilot is crucial for its success. We will work with interveners and interested parties in Phase 1 to finalize the scope and list of technologies to be tested.

b. Interim and final stakeholder reporting

Quarterly progress meetings will be held throughout the pilot to share updates with Commission Staff, and an annual in-depth review will be provided to third-party collaborators to gather more detailed feedback. Once the pilot concludes, final review meetings will be held to discuss outcomes and next steps.

c. Expected publicly available data from pilot shared under proper protections and privacy

Not applicable at this time.

6. Public interest

a. Public interest justification, including supporting the transition to clean, distributed energy resources; enhancing reliability, safety, affordability, or equity; or other related goals, and the pilot's expected impacts.

Based on customer research performed by the Company, it was determined that a significant population of customers believe they can make an impact on the environment by changing their behaviors and take into consideration the environmental impact of products/services they purchase. The work being done in this pilot looks to empower our

customers to become more aware of and readily reduce their energy use without significant impacts to comfort or convenience.

b. Any added benefits to ratepayers or the energy delivery system, either due to proposed site selection or through other pilot variables, especially if any system weaknesses or forecasted needs are addressed.

Demand response impacts energy delivery by encouraging customers to reduce or shift their electricity usage during peak demand periods, which improves grid stability, reduces the need for peaking power plants, and can lead to cost savings for customers. The technologies proposed for this pilot are designed to allow for increased customer involvement in DR via fuller and more nuanced customer control of energy usage.

c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills

By moderating energy usage during peak demand, DR programs like these can prevent grid overload, avoid usage of expensive power plants, and reduce the need to build new generation assets, leading to lower overall utility costs and customers' energy bills, as well as higher customer satisfaction.

d. Expected local or Michigan-based employment and business opportunities created by pilot

The pilot will require partners in implementation, manufacturers, and contractors and the Company will assess all opportunities available to use talent in Michigan and help support local economies. This will be assessed in line with cost, capabilities offered, delivery times, and expertise and maturity in the selected area.

e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations

Low- to moderate-income customers will be included in the pilot, allowing the Company to better understand the unique adoption barriers these customers face when considering implementing these technologies and identify new ways for them to participate in demand response. The Company will better understand the incentive structures that are most attractive and accessible to LMI customers, supporting the successful scaling of these technologies if appropriate.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Program-Field Device Asset Management
New Purchases Historical Acutal 2021 - 2024

Case No.: U-21870
Exhibit No.: A-183 (SHB-12)
Page: 1 of 2
Witness: SHBaker
Date: October 2025

Line No.	(a) Year	(b) Total Company New Purchases	(c) Reference*
1	2021	$ 1,207,651	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns f and h, line 48 and 49 plus 21% of lines 56 - 57 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
2	2022	$ 778,339	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, lines 64 and 66 plus 35% of lines 72 - 73 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
3	2023	$ 880,134	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, lines 52-54 plus 73% of lines 59 - 60 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
4	2024	$ 701,684	U-21870, Exhibit No. A-22 (SHB-7), page 5, columns e and g, lines 12, 14, 16, and 18.
5	Total Company Four-year Historical Average	$ 891,952	
6	Electric Allocation Four-year Historical Average	$ 611,611	

*Note: In 2021, 2022, and 2023 Field Device new purchases were a part of ARP-Workstation Asset Management and not ARP-FDAM.
See U21870-SA-CE-010 Worksheet for how Accessories and Shipping, etc. costs were allocated for new purchases for ARP-FDAM and ARP-WAM

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Program-Workstation Asset Management
New Purchases Historical Acutal 2021 - 2024

Case No.: U-21870
Exhibit No.: A-183 (SHB-12)
Page: 2 of 2
Witness: SHBaker
Date: October 2025

Line No.	(a) Year	(b) Total Company New Purchases	(c) Reference*
1	2021	$ 4,583,866	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns e and g, line 40 - 42, 44, 47, 50 - 51, and 53 - 57 plus 79% of lines 56 - 57 for ARP-WAM new purchases portion of accessories, shipping and handling, and other fees.
2	2022	$ 1,414,635	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, lines 48, 50, 52, 54, 56, 59, 62, 68, 70, 72, and 73 plus 65% of lines 72 - 73 for ARP-WAM new purchases portion of accessories, shipping and handling, and other fees.
3	2023	$ 318,694	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, lines 38, 39, 41, 43, 45, 47, 49, 55, 57, 59, and 60 plus 27% of lines 59 - 60 for ARP-WAM new purchases portion of accessories, shipping and handling, and other fees.
4	2024	$ 954,274	U-21870, Exhibit No. A-22 (SHB-7), page 15, columns e and g, lines 28 -34, and 36.
5	Four-year Historical Average	$ 1,817,867	
6	Electric Allocation Four-year Historical Average	$ 1,246,512	

*Note: In 2021, 2022, and 2023 Field Device new purchases were a part of ARP-Workstation Asset Management and not ARP-FDAM.

U21870-SA-CE-024
Requested By: Emma Zichi (EZ-1 - 19)
Respondent: Stacy H. Baker
Date of Response: 6/25/2025
Page **1** of **1**

Question:

19. Regarding the "ARP-FDAM" project:
a. In testimony on page 66, lines 12-13, it states the reason for a decrease in material costs related to new purchases. The reason being "current allocation factors that are updated annually" please explain what this means and how it decreased the spend on new purchases for this project.
b. When were the costs for the initial purchase of the devices, mentioned on lines 6-7 and 8-9 on page 67 of testimony, included in a rate case and subsequently approved?
c. Please explain the increased costs associated with labor and non-Labor other mentioned on line 13-14 on page 67 of testimony.

Response:

a. The Company updates the allocation factors for electric and gas annually. The cost of each common hardware asset is allocated between electric and gas based on the end users, such as employees and customers. Then the Company divides the sum of the electric allocation amounts by the total of all common hardware assets to calculate the electric allocation. In the previous Case No. U-21585, the 2025 electric allocation factor was 69.65% and, in this case, the 2025 allocation factor is 68.57%. This change resulted in $0.01 million decrease in the new purchases electric allocation.

b. The costs for the initial purchase of the devices discussed in my direct testimony on page 67, lines 6-7, were included in Case No. U-21224 as a part of the Corporate Capital and the case was settled on December 22, 2022 and approved on January 19, 2023. The first case the costs for the initial purchase of the devices in my direct testimony on page 67, lines 8-9, were included in was Case No. U21308, as a part of the Compression Digital Mobility project, and the case was settled on July 21, 2023 and approved on August 30, 2023.

c. The labor and non-labor other costs are associated with the increase in the number of field devices that are planned to be refreshed in 2026.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset refresh Program-Field Device Asset Management
For the replacements and new purchases for 2021, 2022, 2023, and 2024

Case No.: U-21870
Exhibit No.: A-185 (SHB-14)
Page: 1 of 1
Witness: SHBaker
Date: October 2025

ARP-Field Device Asset Mgmt

Line No.	(a) Units	(b) Avg. Unit Cost	(c) Total 2021 Units	(d) Total 2021 Dollars	(e) 2021 Electric Allocation Dollars	(f) Reference
	Replacements					
1	Field Devices CF33 w/acce	$4,201	235	$987,155	$690,910	U-21224, A-173 (JMW-8), page 2, line 6
2	Field Devices CF33 w/acce	$3,831	57	$218,348	$152,821	U-21224, A-173 (JMW-8), page 2, line 7
3	CF33 accessories			$111,888	$78,311	U-21224, A-173 (JMW-8), page 2, line 8
4	Software, labor, contractor and overhead and other costs			$8,057	$5,639	U-21224, A-173 (JMW-8), page 2, line 9
	New Purchases					
5	Rugged Devices(Semi Rugged devices - Toughbooks)	$2,857	45	$128,569	$89,985	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns f and h, line 48
6	Rugged Devices - Toughpads	$3,168	313	$991,513	$693,960	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns f and h, line 49
7	Add'l Accessories			$83,376	$58,355	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns f and h, 21% of line 56 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
8	Shipping and Handling, other fees			$4,193	$2,935	U-21224, Exhibit No. A-173 (JMW-8), page 8, columns f and h, 21% of line 57 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
9	**Total Electric Allocation**			**$2,533,099**	**$1,772,916**	

	Units	Avg. Unit Cost	Total 2022 Units	Total 2022 Dollars	2022 Electric Allocation Dollars	Reference
	Replacements					
10	Field Devices CF33 w/acce	$4,236	432	$1,829,952	$1,280,783	U-21389, A-182 (HNW-8), page 2, line 4
11	Accessories			$572,589	$400,755	U-21389, A-182 (HNW-8), page 2, line 6
12	Software, labor, contractor and overhead and other costs			($5,175)	($3,622)	U-21389, A-182 (HNW-8), page 2, line 7
	New Purchases					
13	Rugged Devices	$4,424.00	127	$561,848	$393,237	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, lines 64
14	Semi Rugged devices (Toughpads)	$3,312.00	33	$109,296	$76,496	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, lines 66
15	Accessories			$106,686	$74,670	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, 35% of lines 72 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
16	Shipping and Handling, other fees			$509	$356	U-21389, Exhibit No. A-182 (HNW-8), page 8, columns e and g, 35% of lines 73 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
17	Field Devices CF33 w/acce	$4,424.00	88	$389,312	$272,479	Field devices purchased for training as a part of Corporate Capital
18	Field Devices CF33 w/acce	$4,424.00	337	$1,490,888	$1,043,473	Field devices purchased as a part of Compression Digital Mobility project.
19	**Total Electric Allocation**			**$5,055,905**	**$3,538,628**	

	Units	Avg. Unit Cost	Total 2023 Units	Total 2023 Dollars	2023 Electric Allocation Dollars	Reference
	Replacements					
20	CF33 accessories	$10,655	1	$10,655	$7,237	U-21585, A-90 (SK-8), Page 2, line 8
21	Field Devices CF33 w/acce	$4,474	524	$2,344,418	$1,592,329	U-21585, A-90 (SK-8), Page 2, line 10
22	Field Devices Getac A140	$4,718	191	$901,149	$612,061	U-21585, A-90 (SK-8), Page 2, line 13
23	New Purchases					
24	Rugged Devices	$4,718	45	$212,313	$144,203	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, lines 52
25	Rugged Devices	$4,152	113	$469,140	$318,640	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, lines 53
26	Semi-Rugged Devices	$4,003	14	$56,046	$38,066	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, lines 54
27	Accessories			$133,135	$90,425	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, 73% of line 59 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
28	Shipping and Handling/other fees			$9,501	$6,453	U-21585, Exhibit No. A-90 (SK-8), page 9, columns e and g, line 60 for ARP-FDAM new purchases portion of accessories, shipping and handling, and other fees.
29	Software, labor, contractor and overhead and other costs			$17,618	$11,966	U-21585, A-90 (SK-8), Page 2, line 19
30	**Total Electric Allocation**			**$4,153,974**	**$2,821,379**	U-21585, A-90 (SK-8), Page 2, line 20

	Units	Avg. Unit Cost	Total 2024 Units	Total 2024 Dollars	2024 Electric Allocation Dollars	
	Replacements					
31	Field Devices CF33 w/accessories	$4,909	552	$2,709,520	$1,887,180	
32	Field Devices CF55 w/accessories	$3,652	80	$292,161	$203,490	
33	Field Devices Getac A140	$4,621	30	$138,616	$96,546	
	New Purchases					
34	Field Devices CF33	$4,909	109	$535,032	$372,650	
35	Field Devices FZ55	$3,652	20	$73,040	$50,872	
36	Field Devices Getac A140	$4,621	20	$92,411	$64,364	
37	Accessories			$1,201	$836	
38	Software, labor, contractor and overhead and other costs			$111,010	$77,319	
39	**Total Electric Allocation**			**$3,952,991**	**$2,753,258**	

U21870-SA-CE-080
Requested By: Brittney M. Klocke (BMK-3 - 1)
Respondent: Jessica R. Byrom
Date of Response: 7/17/2025
Page **1** of **2**

Question:

1. The following questions pertain to the Company's website:
a. What is the current status of the Company's website redesign?
b. If no progress has yet been made on redesigning the Company's website, when is the redesign projected to begin?
c. What areas of the Company's website are slated to be redesigned and why?

Response:

a. The Company has put the website redesign on hold due to extended support of the current on-premises Sitecore web content management system and the Company's SAP S/4HANA planned implementation.

b. The previous timing for the website redesign was developed with the expectation that the Company would need to migrate to the cloud/Software-as-a-Service (SaaS) version of the Sitecore system based on Sitecore's published product support lifecycle at that time. This would have been a major reason to initiate the website redesign. Since then, Sitecore has extended mainstream support for the on-premises version 10.4 to December 31, 2027, giving the Company more flexibility in its migration schedule. In addition, the Company's implementation of the SAP S/4HANA system will be a major undertaking, which will significantly impact the design of integration between the Company's website and SAP. The Company plans to complete the S/4HANA implementation before starting the website redesign.

c. The Company's full website is in scope for the redesign. The purpose of this initiative is to update the back-end architecture to more current methods and technology. This will provide:

   i. Flexibility: Enhances flexibility for future development initiatives.

   ii. Scalability: Allows for more efficient resource management and better performance under varying loads.

   iii. Performance and Security: Provides faster page load times and improves security measures.

   iv. Omnichannel Delivery: Delivers content seamlessly across multiple platforms.

   v. A full front-end redesign will also occur, resulting in:

   vi. Modern Visual Design: Creates a fresh, contemporary look and feel.

   vii. User-Friendly Navigation: Simplifies and makes navigation intuitive.

   viii. Enhanced Accessibility: Ensures the site is accessible to all users.

   ix. Interactive Features: Adds new interactive elements to engage users.

U21870-SA-CE-080
Requested By: Brittney M. Klocke (BMK-3 - 1)
Respondent: Jessica R. Byrom
Date of Response: 7/17/2025
Page **2** of **2**

x. Advanced Analytics: Enhances analytics capabilities to better monitor site performance.

xi. Content updates will be handled as follows:

1. Content Assessment: Pages will be assessed and all updated as needed.

2. Customer Flows: Customer flows will be evaluated and all redesigned as necessary.

xii. These improvements will significantly enhance the user experience and provide high-quality public services.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No.: A-187 (MRB-22)
Page: 1 of 1
Witness: MRBleckman
Date: October 2025

Company Revision to Staff's Exhibit S-4, Schedule D-1 Alternative

Consumers Energy Company (Electric Division)
Overall Capital Structure & Rate of Return
for the Test Year Ending April 30, 2027

Schedule D-1 Alternative

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line Description	Amount	Permanent Ratio	Total Capital Ratio	Cost Rate	Weighted Cost	Convrsn Factor	Pre-Tax Weighted Cost
1 Long Term Debt	$ 13,465,225,769	49.11%	41.55%	4.43%	1.84%	1.0000	1.84%
2 Preferred Stock	$37,315,000	0.14%	0.12%	4.50%	0.01%	1.3381	0.01%
3 Common Equity	$ 13,915,858,077	50.75%	42.94%	10.25%	4.40%	1.3381	5.89%
4 Total Permanent Capital	$27,418,398,846	100.00%					
5 Short Term Debt	$ 148,300,000		0.46%	4.92%	0.02%	1.0000	0.02%
6 Deferred FIT	$4,692,000,000		14.48%	0.00%	0.00%	1.0000	0.00%
7 Job Dev Invest Tax Credits	$148,000,000						
8 Def JDITC - Long Term Debt	$73,798,175		0.23%	4.43%	0.01%	1.0000	0.01%
9 Def JDITC - Preferred Stock	$201,260		0.00%	4.50%	0.00%	1.3381	0.00%
10 Def JDITC - Common Equity	$74,000,565		0.23%	10.25%	0.02%	1.3381	0.03%
11 Total JDITC	$148,000,000				0.03%		0.04%
12 Total Capitalization	$32,406,698,846		100.00%		6.30%		7.80%

Line Consumers Energy Adjustments

1, 8 Long-Term Debt balance changed from $13,682,687,000 to $13,465,225,769. See Exhibit A-14 (MRB-2) Schedule D-1a, page 2
Long-Term Debt cost rate changed from 4.37% to 4.43%. See Exhibit A-188 (MRB-23)

3, 10 Common Equity balance changed from $13,720,211,462 to $13,915,858,077. See Exhibit A-14 (MRB-2) Schedule D-1a, page 3
Common Equity cost rate changed from 9.75% to 10.25%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No.: A-188 (MRB-23)
Page: 1 of 1
Witness: MRBleckman
Date: October 2025

Company Revision to Staff's Exhibit S-4, Schedule D-2 Alternative

Consumers Energy Company (Electric Division)
Staff Long-Term Debt Balance and Cost Rate
for the Test Year Ending April 30, 2027

Schedule D-2 Alternative

Line	(a) Mortgage Bonds	(b) Original Issue Date	(c) Maturity Date	(d) Interest Rate	(e) Initial Amount (000)	(f) Cost Based On Net Proceeds	(g) Amount Outstanding (000)	(j) Annual Cost (000)	(k) Annual Cost (%)
1	5.800%	11-Aug-05	15-Sep-35	5.800%	175,000	5.888%	175,000	10,304	
2	6.170%	01-Sep-10	01-Sep-40	6.170%	50,000	6.243%	50,000	3,121	
3	4.970%	15-Oct-10	15-Oct-40	4.970%	50,000	5.005%	50,000	2,502	
4	3.390%	17-Dec-12	15-Dec-27	3.390%	35,500	3.436%	35,500	1,220	
5	4.310%	17-Dec-12	15-Dec-42	4.310%	263,000	4.342%	263,000	11,418	
6	3.950%	17-May-13	15-May-43	3.950%	425,000	4.019%	425,000	17,079	
7	4.350%	18-Aug-14	31-Aug-64	4.350%	250,000	4.443%	250,000	11,107	
8	4.100%	06-Nov-15	15-Nov-45	4.100%	250,000	4.167%	250,000	10,417	
9	3.250%	10-Aug-16	15-Aug-46	3.250%	450,000	3.347%	450,000	15,063	
10	3.950%	22-Feb-17	15-Jul-47	3.950%	350,000	4.035%	350,000	14,122	
11	3.18% (Private Placement)	28-Sep-17	28-Sep-32	3.180%	40,000	3.207%	40,000	1,283	
12	3.52% (Private Placement)	28-Sep-17	28-Sep-37	3.520%	125,000	3.550%	125,000	4,437	
13	3.86% (Private Placement)	28-Sep-17	28-Sep-52	3.860%	20,000	3.899%	20,000	780	
14	3.18% (Private Placement)	15-Nov-17	15-Nov-32	3.180%	60,000	3.207%	60,000	1,924	
15	3.52% (Private Placement)	15-Nov-17	15-Nov-37	3.520%	210,000	3.550%	210,000	7,454	
16	3.86% (Private Placement)	15-Nov-17	15-Nov-52	3.860%	30,000	3.899%	30,000	1,170	
17	4.050%	14-May-18	15-May-48	4.050%	550,000	4.170%	550,000	22,936	
18	3.68% (Private Placement)	01-Oct-18	01-Oct-27	3.680%	100,000	3.701%	100,000	3,701	
19	4.01% (Private Placement)	01-Oct-18	01-Oct-38	4.010%	215,000	4.041%	215,000	8,688	
20	4.28% (Private Placement)	01-Oct-18	01-Oct-57	4.280%	185,000	4.302%	185,000	7,959	
21	3.800%	13-Nov-18	15-Nov-28	3.800%	300,000	3.922%	300,000	11,765	
22	4.350%	13-Nov-18	15-Apr-49	4.350%	550,000	4.435%	550,000	24,390	
23	3.750%	28-May-19	15-Feb-50	3.750%	300,000	3.875%	300,000	11,625	
24	3.100%	03-Sep-19	15-Sep-50	3.100%	550,000	3.200%	550,000	17,600	
25	Floating Rate FMB	19-Sep-20	01-Sep-69	3.300%	75,650	3.760%	75,650	2,844	
26	3.500%	26-Mar-20	01-Aug-51	3.500%	575,000	3.550%	575,000	20,413	
27	2.500%	13-May-20	13-May-50	2.500%	525,000	2.534%	525,000	13,304	
28	Floating Rate FMB	20-May-20	20-May-70	3.300%	134,139	3.380%	134,349	4,541	
29	Floating Rate FMB	7-Oct-20	7-Oct-70	3.300%	126,497	3.760%	126,497	4,756	
30	2.650%	2-Aug-21	15-Aug-52	2.650%	300,000	2.703%	300,000	8,109	
31	3.600%	11-Aug-22	15-Aug-32	3.600%	350,000	3.670%	350,000	12,845	
32	4.200%	11-Aug-22	17-Aug-52	4.200%	450,000	4.268%	450,000	19,206	
33	4.650%	10-Jan-23	1-Mar-28	4.650%	425,000	4.868%	425,000	20,689	
34	4.625%	23-Feb-23	15-May-33	4.625%	700,000	4.730%	700,000	33,110	
35	5.24% (Private Placement)	15-May-23	15-May-26	5.240%	115,000	5.635%	8,845	498	
36	5.07% (Private Placement)	15-May-23	15-May-29	5.070%	50,000	5.281%	50,000	2,641	
37	5.17% (Private Placement)	15-May-23	15-May-32	5.170%	95,000	5.322%	95,000	5,056	
38	5.38% (Private Placement)	15-May-23	15-May-37	5.380%	140,000	5.491%	140,000	7,687	
39	4.90%	4-Aug-23	15-Feb-29	4.900%	500,000	5.060%	500,000	25,302	
40	4.60%	9-Jan-24	30-May-29	4.600%	600,000	4.798%	600,000	28,789	
41	4.70%	5-Aug-24	15-Jan-30	4.700%	700,000	4.898%	700,000	34,283	
42	4.500%*	2-May-25	15-Jan-31	4.500%	500,000	4.657%	500,000	23,285	
43	5.050%*	2-May-25	15-May-35	5.050%	625,000	5.208%	625,000	32,552	
44	New Debt Issue #3	1-May-26	1-Aug-56	6.260%	600,000	6.341%	553,846	35,117	
45	New Debt Issue #4	1-Aug-26	1-Aug-56	6.260%	725,000	6.341%	501,923	31,824	
46	Total Mortgage Bonds						$ 13,469,610	$ 588,916	
47	Other Long-Term Debt								
48	PCRB - MSF LORB - 19	01-Oct-19	01-Oct-49	3.350%	75,000	3.430%	75,000	$ 2,572	
49	PCRB - MSF LORB - 21	07-Oct-21	01-Apr-35	0.875%	35,000	0.994%	35,000	$ 348	
50	Total PCRB Debt						$ 110,000	$ 2,920	
51	Total All-Ecompassing Long-Term Debt						$ 13,579,610	$ 591,836	4.36%
52	Amortized Call Premium on reaquired debt							4,342	
53	Unamortized Debt Expense						$ (114,385)		
54	Long-Term Debt						$ 13,465,225	$ 596,178	4.43%
55	~~Ratemaking Long-term Debt (debt adjustment of plus $217,642,000)~~						~~$ 13,682,867~~		

Line ***Consumers Energy Adjustments***
44-45 Forecasted cost rate from 5.58% to 6.26%
55 Removed Long-term debt adjustment

	Staff Position	Consumers Energy Adjusted	
Projected 30-yr T-Bond Yield	4.58%	4.88%	Bloomberg 10/6/25
Credit Spread	1.00%	1.38%	Exhibit A-14 (MRB-4) Line 79
Cost Rate for 2026 Debt Issuances	5.58%	6.26%	

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **Consumers Energy Company** for authority to increase its rates for the generation and distribution of electricity and for other relief. /	Case No. **U-21870** **(e-file paperless)**

MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S ANSWER TO CONSUMERS ENERGY COMPANY'S FOURTH DISCOVERY REQUEST

Respectfully submitted,

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

Daniel E. Sonneveldt (P58222)
Nicholas Q. Taylor (81020)
Alena M. Clark (P73252)
Amit T. Singh (P75492)
Michael J. Orris (P51232)
Adam M. Cozort (P78363)
Assistant Attorneys General
Public Service Division
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917
Telephone: (517) 284-8140

DATED: October 8, 2025

MPSC Staff's Answer to the Consumers Energy Company's
4th Discovery Request
MPSC Case No. U-21870
October 8, 2025

Question:

21870-CE-ST-0009:

Refer to the box at the bottom of Mr. Megginson's Exhibit S-4, Schedule D-2 Alternative. Please provide all supporting data and citations to sources for the 2026 projected credit spread of 1.00%.

Response:

Staff's 1.00% credit spread noted at the bottom of Exhibit S-4, Schedule D-2 Alternative, is shaped by the credit spreads of the Company's most recent debt issuances in May 2025 and the Company's last 30-year debt issuance in August 2022. The 30-year debt issuance had a credit spread of 125 basis points. The Company's two May 2025 issuances had an average credit spread of 77 basis points. Thus, a reasonable 30-year credit spread for the Company's 2026 debt issuances is 1.00%. The Company's 1.38% credit spread is based on outdated and outlier data.

Respondents: Kirk Megginson

MPSC Case No.	**U-21870**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**3-CE-AG-5**

3-CE-AG-5
Refer to page 124 of Mr. Coppola's direct testimony which states that "Smaller utilities tend to have higher equity ratios to sustain them during potential volatility in their business, which larger utilities can better manage." Please provide all analyses, studies, or reports Mr. Coppola relied on in making this statement.

Response:

This same question was asked and answered in Case U-21806.

In establishing that smaller utilities tend to have higher equity ratios, Mr. Coppola relied on his knowledge and experience accumulated over the past nearly 50 years that he has been involved in the utility industry. Appendix A to Mr. Coppola's direct testimony shows his vast background as Chief Financial Officer, Treasurer, and financial manager involved in various aspects of financing and managing large and small utilities.

Mr. Coppola has also relied on research and a publication issued by financial expert, Dr. Roger A. Morin. The attached excerpt from Dr. Morin's book New Regulatory Finance provides supporting evidence on the higher business and financial risks faced by smaller utilities. See 3-CE-AG-5 Attach 1.

Date: 10/8/2025

MPSC Case No. **U-21870**
Responding Party: Attorney General
Respondent: Sebastian Coppola
Requestor: CECo
Question No.: **3-CE-AG-6**

3-CE-AG-6
On page 125 of his direct testimony, Mr. Coppola addresses Company witness Bleckman's Exhibit A-29 (MRB-10) – Peer Company Commission Authorized Equity Ratios. Mr. Coppola claims that the Company's analysis "excluded utility companies in the northeastern part of the United States where ROEs and equity ratios tend to be lower." Please provide all analyses, studies, or reports Mr. Coppola relied on in making this statement.

Response:

This same question was recently asked and answered in Case U-21806. The following table provides a list of utility companies in the northeastern part of the United States where ROEs and equity ratios tend to be lower than the list of utilities in Exhibit A-29. The ROEs for these utilities are also shown in Exhibit AG-40 and the equity ratios are from the respective year RRA reports to which the Company should have access.

Electric Company	Jurisdiction	& Order Date		ROE	Equity Ratio
Consolidated Edison of NY	NY	Jul. 20	2023	9.25%	48.0%
Green Mountain Power	VT	Aug. 23	2023	9.58%	49.9%
United Illuminating Group	CT	Aug. 25	2023	8.63%	50.0%
New York State Elec. & Gas	NY	Oct. 12	2023	9.20%	48.0%
Rochester Gas & Electric	NY	Oct. 12	2023	9.20%	48.0%
Atlantic City Electric	NJ	Nov. 17	2023	9.60%	50.2%
Jersey Central P & L	NJ	Feb. 14	2024	9.60%	52.0%
Delmarva Power	DE	Apr. 18	2024	9.60%	50.5%
Potomac Electric	MD	Jun. 10	2024	9.50%	50.5%
Fitchburg G & E	MA	Jun. 28	2024	9.40%	52.0%
Central Hudson G & E	NY	Jul. 18	2024	9.50%	48.0%
Massachusetts Electric	MA	Sep. 30	2024	9.35%	52.8%
Potomac Electric	DC	Nov. 25	2024	9.50%	50.5%
Versant Power	ME	Mar. 13	2025	9.35%	50.0%
Orange and Rockland	NY	Mar. 20	2025	9.75%	48.0%
Liberty Utilities	NH	Mar. 25	2025	9.10%	52.0%
Average				9.38%	50.0%

Date: 10/8/2025

PROOF OF SERVICE - U-21870

The undersigned certifies that a copy of the ***Attorney General's Response to Consumers Energy Company's Third Discovery Request*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 8th day of October 2025.

Celeste R. Gill Digitally signed by Celeste R. Gill Date: 2025.10.08 13:57:33 -04'00'

Celeste R. Gill

Consumers Energy Company:
Spencer Sattler
Mark Ruszkiewicz
Gary Gensch, Jr.
Evan Keimach
Bret Totoraitis
Anne Uitvlugt
Spencer.sattler@cmsenergy.com
Mark.ruszkiewicz@cmsenergy.com
Gary.genschjr@cmsenergy.com
Evan.keimach@cmsenergy.com
Bret.totoraitis@cmsenergy.com
Anne.uitvlugt@cmsenergy.com
Kelly.hall@cmsenergy.com
Mpsc.filings@cmsenergy.com

Attorney General of Michigan:
Celeste Gill
Lucas Wollenzien
Gillc1@michigan.gov
wollenzienl@michigan.gov
ag-enra-spec-lit@michigan.gov

Sebastian Coppola
sebcoppola@corplytics.com

GLREA:
Don Keskey
Brian Coyer
donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com

MPSC Staff:
Lori Mayabb
Daniel Sonneveldt
Amit Singh
Michael Orris
Nicholas Taylor
Alena Clark
Adam Cozort
mayabbl@michigan.gov
sonneveldtd@michigan.gov
singha9@michigan.gov
orrism@michigan.gov
taylorn10@michigan.gov
clarka55@michigan.gov
cozorta1@michigan.gov

ABATE:
James Dauphinais
Michael Pattwell
Stephen Campbell
Benjamin Holwerda
Christina Hildebrandt
Jessica York
jdauphinais@consultbai.com
mpattwell@clarkhill.com
scampbell@clarkhill.com
bholwerda@clarkhill.com
childebrandt@consultbai.com
jyork@consultbai.com

Customer A:
Valerie Brader
valerie@rivenoaklaw.com
ecf@rivenoaklaw.com

ELPC/EC/UCC:
Daniel Abrams
Katie Duckworth
Amanda Urban
Mark Templeton
Jacob Schuhardt
Emma Young
Alexandria Miskho
dabrams@elpc.org
kduckworth@elpc.org
aurbanlaw@gmail.com
templeton@uchicago.edu
jschuhardt@uchicago.edu
eyoung28@uchicago.edu
amiskho@uchicago.edu

METC:
Richard Aaron
Courtney Kissel
Olivia Flower
Hannah Buzolits
Josh Kluzak
raaron@dykema.com
ckissel@dykema.com
oflower@dykema.com
hbuzolits@dykema.com
jkluzak@dykema.com

MEIBC/IEI/AEU/EM/FAM:
Laura Chappelle
Timothy Lundgren
Justin Ooms
lachappelle@varnumlaw.com
tjlundgren@varnumlaw.com
jkooms@varnumlaw.com

MCTA:
Sean Gallagher
sgallagher@fraserlawfirm.com

Walmart, Inc.:
Melissa Horne
mhorne@hcc-law.com

The Kroger Co.:
Kurt Boehm
Jody Kyler Cohn
Michael Kurtz
Justin Bieber
kboehm@bkllawfirm.com
jkylercohn@bkllawfirm.com
mkurtz@bkllawfirm.com
jbieber@energystrat.com

MEC/CUB/SC/NRDC:
Tracy Jane Andrews
Christopher Bzdok
Holly Hillyer
Natasha Fowles
Jackson Neme
Tanya Stasio
Jordan Burt
Tyler Comings
Caroline Palmer
Julielyn Gibbons
Rick Bunch
Matt Bandyk
John Liskey
tjandrews@tropospherelegal.com
chris@tropospherelegal.com
holly@tropospherelegal.com
natasha@tropospherelegal.com
jackson@tropospherelegal.com
tanya.stasio@eaclinic.org
Jordan.burt@aeclinic.org
Tyler.comings@aeclinic.org
cpalmer@synapse-energy.com
jgibbons@5lakesenergy.com
rbunch@5lakesenergy.com
mbandyk@synapse-energy.com
john@liskeypllc.com

HSO/ST:
Jennifer Heston
jheston@potomaclaw.com

Covert Units 1 & 3 – LTSA Extra Work Scope Definition and Forecasted Cost

Prepared by: Paul Ohep

1. Purpose

This document outlines the scope of LTSA Extra Work anticipated for Cover Units 1 and 3, based on work completed during the 2025 outage at Unit 2. The intent is to provide clear definition and context for the types of activities that fall outside the base Long-Term Service Agreement (LTSA), explain why these activities are required to execute major outages, and present a forecasted cost based on recent historical data.

The scope and budget are based on detailed historical data from the Unit 2 outage in 2025, including actual execution costs, work scope breakdowns, and Extra Work Assignments (EWAs). These expenditures reflect Owner obligations under the LTSA and known outage requirements.

2. Background

The LTSA defines a division of responsibility between the Contractor (Mitsubishi) and the Owner. While the Contractor performs defined inspection and maintenance services, the Owner is responsible for:

- Enabling infrastructure and field support
- Supplying consumable and condition-based replacement parts
- Funding and managing any repairs or services resulting from inspections

These responsibilities are documented in the LTSA's Division of Responsibility (Attachment 5) and confirmed by prior outage experience.

During the 2025 Unit 2 outage, total LTSA Extra Work cost approximately $12.7 million, including both large pre-scoped work and smaller, necessary tasks that emerged during execution (documented as EWAs). This scope is representative of what will be required for Units 1 and 3.

3. Justification for LTSA Extra Work

A. Site Infrastructure & Logistics (Owner-Furnished)

These services are critical for OEM work execution but fall under the Owner's scope. For Unit 2, examples included:

- - Crane rentals
  - Office, restroom, and sanitation trailers
  - Potable water and safety stations
  - Laydown space prep and rigging
  - Building wall removal for generator access
  - Scaffolding, insulation, and electrical testing
  - Equipment/tool transport from offsite locations

B. Consumable & Condition-Based Parts

The LTSA does not cover routine outage consumables and condition-dependent replacements. For Unit 2, this included:

- - Gaskets, seals, thrust shims, and valve assemblies
  - HP valve rebuild kits
  - Turbine packing and alignment hardware
  - Small parts discovered as damaged or worn after disassembly

All such items are procured and installed by the Owner as part of standard outage execution.

C. Repairs Identified During Inspection

While inspections are covered under the LTSA, any resulting repairs are considered Extra Work. For Unit 2, this included:

- - Diaphragm and rotor machining
  - Bearing refurbishments
  - Hydrogen seal and steam shell repairs
  - Collector ring machining
  - Compressor hook fit machining
  - Oil deflector repairs

D. Extra Work Assignments (EWAs)

EWAs are smaller task-based scopes that arise during the outage and are not defined in the base plan. Examples from Unit 2 included:

- - Labor for valve disassembly and reassembly
  - Transport of tools and heavy equipment
  - Seal and bearing inspection and rebuild

- Field machining and turbine alignment services
- Miscellaneous parts procurement during outage execution

Together, these EWAs totaled approximately $500,000. Mitsubishi executes this work on a time-and-materials (T&M) basis, and charges are bundled by category, not individual activity.

4. Contractor Cost Structure Limitations

A critical constraint to note is that Mitsubishi does not provide a fully itemized breakdown of costs for each activity within the LTSA Extra scope. While they may offer pre-outage estimates, actual billing is based on T&M rates and grouped into summary-level invoices (e.g., 'EWAs' or 'extra parts/labor').

This means the Owner cannot precisely forecast or post-audit individual line-item costs. Instead, budgeting is based on:

- Historical outage records (e.g., Unit 2 actuals)
- OEM outage patterns and typical inspection findings
- Prior EWA structure and cost groupings

This dynamic makes proactive funding of LTSA Extra Work essential, even if some scopes are not explicitly known in advance.

5. Financial Summary- Planned LTSA Owner obligations (former LTSA extras)

The figures below represent forecasted costs for LTSA Extra Work based on historical outage practices, known contract obligations, and typical work scopes required to support major outages at Covert.

Unit	2026	2027
Unit 1	$8,176,300	$5,550,000
Unit 3	$12,726,000	$200,000

6. Conclusion

LTSA Extra Work is a required and recurring element of major turbine-generator outages at Covert. While not included in the base LTSA scope, these activities-ranging from enabling infrastructure to condition-based parts and repairs-are necessary to execute the defined work scopes and return units to safe, reliable operations.

Due to Mitsubishi's T&M billing approach and lack of granular invoicing, the Owner must

rely on historicals, outage experience, and OEM expectations to estimate scope and funding needs.

The $12.7 million per-unit request reflects actual Unit 2 experience and contract-defined Owner responsibilities. This document formalizes the budget authorization needed to support outage execution for Covert Units 1 and 3.

Concept Approval

Ludington Pumped Storage Dike Load Center replacement.

Date: 6/10/2024

Prepared by: Paul Ohep

Figure 1. Ludington pumped storage station.

Executive Summary

Consumers Energy is undertaking a critical infrastructure upgrade at the Ludington Pumped Storage Station to replace aging and deteriorating Dike Load Centers (DLCs). These upgrades are essential for maintaining the operational efficiency, safety, and reliability of this vital energy facility. The project focuses on replacing the high-priority DLCs that are at significant risk of failure, ensuring continued support for the station's critical functions.

Current Equipment Issues:

The original Dike Load Centers were installed in the early 1970s and have been considered obsolete since the 1990s. Prolonged operational use and environmental exposure have led to significant corrosion and deterioration. Recent failures, including the replacement of DLC14 and DLC16 transformers, highlight the urgent need for this upgrade. Additionally, parts from the replaced DLC1 and DLC2 have been used for repairs, and a new transformer has been ordered to manage future defects.

Priority Assessment and Replacement Strategy:

Plant and dam safety engineers have categorized the DLCs into high, medium, and low priority for replacement. High-priority DLCs are those that are highly likely to become inoperable within five years and provide electricity to pumps that run frequently to maintain adequate drainage of the dike's asphalt liner. This project will replace 10 high-priority DLCs identified as critical for safe and reliable operation.

Financial and Operational Impact:

Failure to replace the high-priority DLCs could result in significant operational disruptions and extended downtimes, with estimated shutdowns potentially lasting up to a year due to obsolescence issues. The estimated financial impact ranges from $24 million up $55 million for Net Energy Value losses and $101.5 Million for potential capacity losses.

Conclusion:

The replacement of the outdated and deteriorating Dike Load Centers is crucial for preventing extensive damages and operational interruptions at the Ludington Pumped Storage Station. This targeted approach ensures that the most critical components are addressed promptly, supporting the facility's long-term operational efficiency and safety. By investing in this strategic upgrade, Consumers Energy is committed to maintaining the reliability of Michigan's energy infrastructure while mitigating potential financial and operational risks.

Financial Summary

Funding Type:	Capital
Initial approved cost:	51% dollars - $4,555,000. 100% dollars – $8,931,372
New revised cost:	51% dollars - $**10,286,051.** 100% dollars - $**20,168,728**

Proposed Start Implementation Year and span

2019, 8-year span.

Problem Description

The Ludington Pumped Storage facility, crucial for Michigan's energy infrastructure, includes twenty 480-volt Dike Load Centers and one 4160-volt Switchgear. These units power one hundred ninety-three dike pumps and additional support equipment critical to the facility's operations. Failure of a Dike Load Center would result in an area of the reservoir where the asphalt liner is inadequately drained, potentially leading to an increase in pore water pressure both on the upstream face and at the downstream toe of the dike.

Issues with Current Equipment:

- **Age and Obsolescence:** The original Dike Load Center equipment was installed in the early 1970s and has been considered obsolete since the 1990s.
- **Corrosion and Deterioration:** Prolonged operational use and environmental exposure have led to significant corrosion and deterioration.

Recent Failures:

- Dike Load Center 14 (DLC14) transformer failed and replaced in 2023.
- Dike Load Center 16 (DLC16) transformer failed and replaced in 2024.
- Other repairs have utilized parts from the old DLC1 and DLC2 load centers, which were replaced last year.
- Due to the lack of spares and long lead times, the current strategy to manage the existing risk involves ordering a new transformer to replace any future defects in the remaining 18 DLCs. This approach will bridge the gap until DLC3 is replaced at the end of next year as part of this project.

Risks Posed by Equipment Failure:

- **Operational Impact:** The Centers are essential for distributing power to the dike drain pumps and pumping relief wells that maintain the structural integrity and safety of the reservoir. For these reasons, Dike pumps are required to be operational.

Critical Functions of the Dike Load Centers:

- **Dike Drain Pumps:** They maintain the drained condition of the dike's upstream face, protecting the asphalt liner from pressure-induced damage.
- **Pumping Relief Wells:** These wells manage groundwater levels, maintaining them at preconstruction levels to prevent dike stability issues.

Consequences of Potential Failure:

- **Study Findings:** An engineering study completed in 2020 indicated that the Dike Load Centers are in poor condition, leading to operational hesitancy in cycling them due to potential recovery failures.

- **Operational Disruption:** Failure would lead to insufficient drainage in parts of the reservoir, increasing the risk of structural failures by elevating pore water pressure upstream and downstream.

Priority Assessment by Plant and Dam Safety Engineers:

- **Priority Categorization:** Plant engineers, along with dam safety engineers, have categorized the Dike Load Centers (DLCs) into high, medium, and low priority for replacement. High priority DLCs provide electricity to pumps that are in service for many hours due to the inherent drainage features of the dike itself. These pumps are critical for providing adequate drainage to the asphalt liner, a vital part of the dike's structural integrity. Therefore, the load centers that supply electricity to these frequently running pumps need to remain operational.
- **High Priority DLCs:** Out of the 20 DLCs, 10 have been identified as high priority based on the aforementioned criteria. This project is focused on replacing these 10 high-priority DLCs to ensure the continued safe and reliable operation of the Ludington Pumped Storage facility.

Conclusion: The necessity to replace the outdated and deteriorating Dike Load Centers is critical, not only for maintenance but also to ensure the facility's operational efficiency and safety. This replacement is needed to prevent possible extensive damages and operational interruptions, with a focused approach on the 10 high-priority DLCs identified by plant and dam safety engineers. The list of high, medium, and low priority DLCs is displayed in Figure 2.

Alternative Solutions/Alternatives Considered

1. Do Nothing - $101.5M in potential capacity losses + minimum $24M in Net Energy Value losses

This option involves not replacing the outdated and deteriorating 480-volt Dike Load Centers and the 4160-volt Switchgear at the Ludington Pumped Storage facility.

Immediate Implications:

- **Continued Deterioration:** The Dike Load Centers and Switchgear, already in a state of significant corrosion and obsolescence, will continue to degrade without any intervention.
- **Operational Reluctance:** As noted, the Operations Department is currently hesitant to cycle the Dike Load Centers due to concerns over their reliability and the potential inability to recover them if they fail.

Long-term Consequences:

- **Increased Risk of Failure:** Ongoing deterioration will likely lead to the eventual failure of the Dike Load Centers, which are critical for the operation of the dike pumps and related infrastructure.
- **Inadequate Reservoir Drainage:** Failure of the Dike Load Centers would result in inadequate drainage of the reservoir's asphalt liner. This can increase pore water pressure both on the upstream face and at the downstream toe of the dike, leading to structural vulnerabilities.

Impact on Facility Operations:

- **Operational Shutdown:** The most severe impact of this option is the potential complete loss of operational capability at the Ludington Pumped Storage Station. Due to obsolescence issues with the high-priority Dike Load Centers, there is no quick way to obtain replacement parts, which are essential for safe operation. Without these crucial components readily available, the pond/reservoir would not be safe for continued operation, resulting in an estimated downtime of a full year.
- **Extended Downtime and potential Capacity Losses**: The unplanned downtime not only involves higher direct repair costs but also results in significant operational and revenue losses due to the plant's inability to generate power during the period of inactivity. Given the obsolescence issues, the assumed shutdown would extend to a full year. From a capacity position, a forced outage would necessitate replacing the lost capacity to avoid future accreditation impacts. The potential capacity loss cost, based on capacity replacement costs valued at 75% of CONE (Cost of New Entry), would be substantial. With CONE set at $127K/MW-year, 75% of CONE equals $95K. Considering the average Zonal Resource Credits (ZRCs) for all Ludington units is 178, if all 6 units were lost for a year, the cost would be:

  178 ZRCs * 6 units * $95K = $101.5 million.

- **Net Energy Value (NEV) and Locational Marginal Prices (LMPs)**: In the event of a forced outage of all six units at the Ludington Pumped Storage Station for a full year, the financial impact can be assessed using Locational Marginal Prices (LMPs). LMP is the cost of supplying the next increment of electricity demand at a specific location in the grid, reflecting supply and demand balance, transmission constraints, and generation availability. The analysis compared similar high and low load days to estimate the impact on LMPs during the outage.
    - Analysis Details:

      During a recent outage period (9/27/23-10/13/23), the average LMP was $33.63/MWh, compared to an annual average of $30.65/MWh.

      Day-Ahead LMP Comparison:
        - Lower Load Days:
            - 29-Sep: $34.96/MWh (Delta: $3.65/MWh)
            - 5-Oct: $32.88/MWh (Delta: $1.57/MWh)
        - Higher Load Days:
            - 3-Oct: $47.02/MWh (Delta: $16.37/MWh)
            - 4-Oct: $39.64/MWh (Delta: $10.11/MWh)
        - The deltas represent the difference between the specific day's LMP and the average LMP for similar days based on load and weather profiles.

    - Financial Impact:

        - It is estimated by our internal economics forecast models that the net energy value (NEV) loss for this scenario would be a minimum of **$24 million** for one year. That estimate is based upon normal conditions. Based on load variability we can expect LMPs to increase by between $3/MWh and $16/MWh which will impact the NEV forecast.

        - At $3/MWh annual average increase in LMPs due to the loss of Ludington, the $24 million net energy loss would increase to **$30 million.**
        - At $16/MWh annual average increase in LMPs due to the loss of Ludington, the $24 million net energy loss would increase to **$55 million.**

Conclusion:

- The 'Do Nothing' option, while avoiding immediate expenditure, poses significant long-term risks including the potential for operational halt as well as significant costs for capacity and energy losses should the site be forced to shut down. The failure to replace the critical Dike Load Centers could lead to irreversible damages and operational challenges, making this approach highly inadvisable.

2. Replace as needed – Internal Estimated Cost of $28,236,219

Description of the Approach:

- **Reactive Replacement:** This alternative involves replacing individual Dike Load Centers at the Ludington Pumped Storage facility only as they fail. While this reactive approach has been previously applied to cabling, where failures were addressed on a case-by-case basis, it's important to note that cabling replacements are significantly simpler. In contrast, replacing Dike Load Centers involves a more complex process. Since the replacements are not like-for-like due to updates in technology and regulation, several additional steps, including system integration and infrastructure modifications, are necessary to facilitate these replacements.

Current State of Equipment:

- **Dike Load Center Maintenance:** Over the years, specific breakers within the Dike Load Centers have been maintained to extend their operational life without replacing entire units. However, this approach is increasingly becoming non-viable due to the growing obsolescence of the parts involved.

Risks and Challenges:

- **Increased Frequency of Failures:** Given the structural deterioration of the Dike Load Centers, failures are expected to become more frequent.
- **Risk of Operational Disruption:** The lengthy lead times required for the design, procurement, and installation of replacement units introduce significant risks. Should multiple Dike Load Centers fail simultaneously, the facility could experience substantial operational disruptions. The complex engineering planning necessary for each unplanned replacement extends these lead times further.
- **Inconsistency in Installations:** Replacing components on a piecemeal basis as they fail leads to non-standard, one-off installations. This inconsistency can complicate maintenance procedures, escalate costs, and diminish overall system efficiency.

Long-term Implications:

- **Continued Reliability Issues:** The approach does not address the underlying issue of aging and obsolescence across all Dike Load Centers but rather postpones comprehensive solutions.
- **Operational Inefficiency:** As more components are replaced on an as-needed basis, the system may become a patchwork of old and new technology, potentially decreasing operational efficiency and increasing maintenance complexity.

Financial Impact:

- **Cost Escalation:** Due to the inefficiencies of this option and the complexities involved in engineering planning and procurement of components, the cost estimates for replacing the high priority DLCs are escalated by an estimated 40%. These increased costs are attributed to the emergency nature of unplanned replacements, which require rapid response and often premium pricing for expedited services.

- **Estimated Project Cost:** Consequently, the total estimated project cost for this approach, factoring in all associated inefficiencies and complexities, is estimated at $28,236,219 in 100% dollars. This figure reflects the significant financial burden imposed by the ad hoc replacement strategy under conditions of urgency and operational necessity.

Conclusion:

- While this option allows for spreading out expenditures over time and addressing issues as they arise, it carries significant risks of unplanned operational halts and safety concerns. The piecemeal approach might also lead to increased costs over time due to emergency replacements and the inefficiencies of managing a non-standardized system. Therefore, this option, though seemingly less capital intensive initially, will lead to higher overall costs and operational challenges.

3. Option 3 - Staged Phased replacement of high priority DLCs only - Initial internal estimate of $8,931,372 (100% dollars), new revised internal estimate $20,168,728 (100% dollars)

This option proposes a structured and phased replacement of the ten most critical Dike Load Centers at the Ludington Pumped Storage facility. This plan is designed to prioritize the replacement of units that are most problematic first, with subsequent phases targeting units that are currently less prone to failure. The other 10 DLCs will be considered under a different project once the data suggests that replacement is warranted.

Planned Phases of Implementation:

- **Priority-Based Replacement:** The initial phase targets the Dike Load Centers that are in the worst condition or that have shown the most frequent issues. This approach mitigates the most immediate risks to facility operations.
- **Subsequent Phases:** Following the initial replacements, the remaining Dike Load Centers would be replaced in a planned sequence over the next six years, based on their assessed condition and risk of failure.

Benefits of the Staged Approach:

- **Risk Management:** By prioritizing the most critical replacements first, this plan not only effectively manages the risk of sudden failures that could disrupt operations but also ensures that the remaining Dike Load Centers continue to operate reliably for several years. The strategy includes utilizing parts from the DLCs that are being decommissioned to stock an inventory of spare and refurbished parts. This approach will provide a robust support system for the Dike Load Centers that are not scheduled for immediate replacement, thereby extending their operational lifespan and enhancing overall plant resilience.

- **Operational Continuity:** A phased approach ensures that replacements are done systematically, minimizing the impact on daily operations and allowing for better planning and resource allocation.
- **Equipment Compatibility:** Implementing a uniform replacement strategy across all units ensures that the new equipment is compatible, avoiding the complications associated with non-standard, one-off installations.

Long-term Strategic Advantages:

- **Enhanced System Reliability:** With new and compatible equipment installed in a phased manner, the overall reliability of the Dike Load Centers is greatly improved, ensuring stable operations for the foreseeable future.
- **Cost Efficiency:** Although this approach requires upfront planning and investment, it is more cost-effective in the long term compared to emergency replacements or piecemeal upgrades. It allows for budget predictability and can leverage bulk procurement discounts.

Option 4 – Full replacement of all 20 DLCs. Internal Estimated Cost - $37,827,823.(100% dollars)

Option 4 proposes a comprehensive replacement strategy for all 20 Dike Load Centers (DLCs) at the Ludington Pumped Storage facility. This option extends beyond the high-priority DLCs addressed in Option 3 to include the remaining 10 DLCs, which have exhibited significantly fewer failures and operational issues over the past five years.

Rationale for Exclusion from High Priority List:

- **Lower Failure Rates:** The 10 DLCs not included in the high-priority list have shown considerably lower failure rates. These units primarily consist of DLCs with dry wells where the pumps have not been operating frequently.
- **Operational Observations:** Due to the minimal operational demand on these DLCs, the wear and stress on components have been substantially less, leading to a decreased likelihood of immediate failures.

Financial Considerations:

- **Cost of Full Replacement:** The total cost for implementing Option 4, which entails replacing all 20 DLCs, is estimated at $37,827,823 (100% dollars). This figure represents a significant increase from the initial estimates made five years ago, which did not account for the escalated costs due to inflation, increased material costs, and more comprehensive engineering requirements now deemed necessary.
- **Comparison to Reduced Scope:** While Option 4 ensures that all components are uniformly modernized and potentially reduces future disparate maintenance schedules, the additional cost compared to Option 3 is considerable. Given the lower risk associated with the 10 non-high-priority DLCs, the additional expenditure does not proportionately increase the value or return on investment when compared to the focused scope of replacing only the high-priority units.

Conclusion: Option 4, while offering a uniform upgrade across all DLCs and potentially simplifying future maintenance, does not present a significantly higher value over Option 3 given the substantial additional costs involved. The decision by subject matter experts in engineering to prioritize Option 3 over Option 4 is based on a strategic assessment of risk, operational need, and financial efficiency. The comprehensive replacement of all 20 DLCs under Option 4 does not align sufficiently with the incremental benefits when weighed against the additional financial investment required.

Recommended Alternative: Option 3 - Staged Phased replacement of high priority DLCs only - Initial internal estimate of $8,931,372 (100% dollars), new revised internal estimate $20,168,728 (100% dollars)

In evaluating the options for addressing the critical condition of the Dike Load Centers at the Ludington Pumped Storage facility, a comprehensive analysis of operational, financial, and technical factors has been conducted. The following section outlines the justification for selecting Option 3, the staged phased replacement plan.

1. **Risk Mitigation:**
    - **Immediate Risk Reduction:** By prioritizing the replacement of the most deteriorated Dike Load Centers, this plan directly addresses the highest risk components within the system. This proactive measure prevents potential failures that could lead to significant operational disruptions or safety concerns.
    - **Controlled Risk Exposure:** The phased approach reduces the likelihood of encountering multiple failures simultaneously, a critical factor considering the long lead times required for designing, procuring, and installing new equipment.
2. **Operational Continuity and Efficiency:**
    - **Minimized Operational Disruption:** Staging the replacements ensures that the facility remains operational without significant downtime. Replacing equipment in a controlled, planned manner prevents the sudden loss of capacity that could result from emergency replacements following unexpected failures.
    - **System Uniformity and Standardization:** As replacements are made systematically, the new installations will be uniform and standardized, which significantly simplifies maintenance and operation. This uniformity ensures all components communicate and function optimally within the system, enhancing overall operational efficiency.
3. **Cost Management and Budget Planning:**
    - **Predictable Expenditure:** A phased plan allows for better financial planning and resource allocation. Budget impacts are spread over several years, which can be

accommodated more easily within annual capital budgets, avoiding the financial strain of unplanned, large-scale expenditures.

- **Economies of Scale in Procurement:** Purchasing equipment in planned stages rather than as one-off replacements can reduce costs through bulk buying and potentially negotiating more favorable terms with suppliers.

4. **Long-term Strategic Benefits:**

- **Enhanced Longevity and Reliability:** Systematically upgrading the Dike Load Centers ensures that all components are modern, robust, and capable of meeting the operational demands of the facility. This not only extends the life of the infrastructure but also boosts its reliability and performance.

Conclusion:

The selection of Option 3, a staged phased replacement plan, is justified based on its comprehensive approach to managing the inherent risks associated with the Ludington Pumped Storage facility's Dike Load Centers. This option balances the need for immediate action on the most critical components with the practicalities of budget, operational continuity, and long-term reliability.

Budget Revision Justification

The initial budget for the replacement of the Dike Load Centers (DLCs) at the Ludington Pumped Storage facility was set over five years ago, based on a 'like-for-like' replacement strategy. Since then, the project estimate has more than doubled, primarily due to significant changes in the technical requirements of the replacement units. The detailed analysis of these changes highlights several key factors contributing to the increased cost:

1. Changes in Size and Design Requirements:

- **Increased Physical Size:** The replacement DLCs are now 2.5 to 3 times larger than the original units. This size increase is mainly due to current industry standards and regulatory requirements not in place or anticipated during the initial budgeting.
- **Foundation Modifications:** The larger size of the new DLCs necessitates the demolition of the existing foundations and the construction of significantly larger ones. This requirement was not included in the original plan, which had assumed the new units would fit the existing foundations.

2. Infrastructure and Installation Adjustments:

- **Conduit and Wiring Changes:** The original project plan assumed that the new DLCs could use the existing pathways for wiring and cabling. However, due to the changed positioning and increased size of the new units, this is no longer feasible. Additional conduit installation is now necessary, along with more extensive wiring than previously planned.

- **Junction Box Installation:** The new layout and increased complexity of the electrical connections require the installation of additional junction boxes. These elements are essential to safely manage and distribute the electrical loads from the larger DLCs, further adding to the project cost.

3. Unforeseen Technical Challenges:

- **Engineering and Design Revisions:** The significant alterations in the project's scope, necessitated by the larger size and different configuration of the replacement DLCs, have required additional engineering and design work. This revision process has introduced delays and increased costs associated with specialized labor and technical expertise.

Conclusion:

The substantial increase in the budget estimate for the Dike Load Center replacement project at the Ludington Pumped Storage facility is a direct result of changes in the physical size of the units, enhanced regulatory requirements, and the complexities involved in retrofitting new technology into an existing infrastructure. These factors were not fully anticipated in the initial budget, resulting in the need for a revised financial plan that reflects the current project realities.

Scope of work

This scope of work details a revised strategy focusing specifically on the replacement of high-priority Dike Load Centers (DLCs) at the Ludington Pumped Storage facility. This initiative spans a four-year timeline and is designed to address the most critical DLCs that have experienced multiple failures over the past five years, ensuring reliable and safe operation of the plant.

Project Details:

High-Priority DLC Replacement:

- **Objective:** Implement a phased replacement of the ten most critical 480 Volt Dike Load Centers based on an assessment by the environmental and dam safety teams.
- **Tasks:**
    - Demolish existing structures and construct new foundations as needed for the modern DLCs.
    - Install new Dike Load Centers that comply with current regulatory standards and operational requirements.

Utilization of Existing Equipment:

- **Objective:** Efficiently utilize existing resources by repurposing used and recently replaced dry transformers and electrical equipment as spares for the remaining lower-priority DLCs.

Phased Implementation Schedule:

- **2023:** Complete the replacement of DLCs 1 & 2 (completed).
- **2025:** Replace DLCs 3 & 4, focusing on critical components and integration with existing plant systems.
- **2026:** Address DLCs 17 & 16, incorporating lessons learned and feedback from previous installations.
- **2027:** Update DLCs 15 & 5, ensuring continuity and system integrity.
- **2028:** Finalize replacements with DLCs 12 & 11, completing the priority updates.

This targeted approach allows for a focused upgrade of the most critical components within the facility, aligning resource allocation with the most immediate needs for reliability and safety. By prioritizing high-risk DLCs and strategically scheduling their replacement, the project ensures ongoing compliance with safety and operational standards while optimizing the use of existing resources. This phased strategy minimizes disruption and maximizes the efficacy of the upgrades, ensuring the long-term sustainability of the Ludington Pumped Storage facility's operations.

Funding and Timing

- Funding that has been previously committed for this project: $4,278,409 (51% dollars)
- A Scheduled outage is required for this project.
- Desired implementation year: first year spend 2019 with installation and closeout finishing 2029.
- System Engineer: Tarik Butrus

Conceptual Estimate

Year	Loaded Cost	Description
2019	**$43,747**	51% dollars. Engineering and planning
2020	**$668,263**	51% dollars. Engineering and planning
2021	**$1,013,244**	51% dollars. Engineering and planning. Procurement and preparation for installation
2022	**$1,665,599**	51% dollars. Engineering and planning. Procurement and preparation for installation
2023	**$887,558**	51% dollars. Engineering and planning. Installation of DLC 1 & 2
2024	**$679,492**	51% dollars. Engineering and planning.
2025	**$1,186,497**	51% dollars. Installation of DLC 3 & 4
2026	**$1,309,572**	51% dollars. Installation of DLC 17 & 16
2027	**$1,308,113**	51% dollars. Installation of DLC 15 & 5
2028	**$1,421,968**	51% dollars. Installation of DLC 12 & 11
2029	**$102,000**	Monitoring, Post Maintenance testing, Documentation and Closeout

Total Cost: 51% dollars - $10,286,052 100% dollars – $20,168,728

Asset Strategy Approval Comments

Asset Strategy endorses the reduced scope approach of Option 3, focusing exclusively on replacing high-priority Dike Load Centers at the Ludington Pumped Storage facility. This decision is based on a detailed risk assessment and cost-benefit analysis performed by our engineering experts, who recommend prioritizing replacements where they are most needed due to repeated failures in the last five years. By concentrating resources on the most critical areas, we ensure a cost-effective allocation of capital while maintaining operational reliability and safety.

This investment **is** included in the current electric rate case.

Amount set for Bridge year: $990,000

Amount set for test period: $852,000

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric supply		

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

Consumers Energy Count on Us®

Concept Approval

Ludington Pumped Storage Oil Water Separator

Date: 12/11/2023

Prepared by: Paul Ohep

Figure 1. Ludington pumped storage station.

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

Executive Summary

The Ludington Pumped Storage (LPS) Plant, co-operated by Consumers Energy Company (CEC) and DTE Energy, is a significant hydroelectric facility located on Lake Michigan. The plant, which began operations in 1973, plays a crucial role in energy production. Central to its operations is the Oil/Water Separator (OWS), tasked with removing oil and grease (O&G) from process water before discharge into Lake Michigan. The OWS's importance is underlined by its regulation under a National Pollutant Discharge Elimination System (NPDES) permit, which mandates specific limits on O&G levels in discharged water.

Recent incidents have raised concerns about the efficacy of the current OWS. These incidents occurred in the fourth quarter of 2021 and the first quarter of 2022 and were attributed to OWS upset conditions. Despite these releases, O&G levels have generally been non-detectable in effluent samples, indicating a need to address specific failure points rather than overall process inefficiency.

The primary objective of this project is to identify and implement a solution that ensures compliance with environmental standards through 2069. This requires modifications to the existing infrastructure.

Three main options were considered:

1. **Do Nothing**: Continuing with the current system, risking further environmental compliance violations.
2. **Enhance OWS & Modernize System**: Involving the installation of new equipment to make the OWS system efficient, modernized control systems, and necessary modifications to the existing infrastructure.
3. **Modify Existing OWS**: Entailing significant modifications to the current OWS, which poses challenges in meeting national rating requirements and necessitates extended outage times.

After a comprehensive evaluation, Option 2 - Enhance OWS & Modernize System - is recommended. This option not only addresses immediate compliance issues but also ensures the plant's operational readiness and environmental responsibility through the projected facility lifecycle. The investment in this option, estimated at $5,228,422 (100% dollars), is justified by the long-term benefits of improved environmental performance and compliance with evolving regulatory standards.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	51% dollars - $2,666,495. 100% dollars – $5,228,422

Proposed Start Implementation Year and span

2023, 3 year span.

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

Problem Description

The Ludington Pumped Storage (LPS) Plant is currently grappling with maintaining environmental compliance with its existing Oil Water Separator (OWS) system. The OWS, a critical component of the plant since its inception in 1973, is responsible for removing oil and grease (O&G) from process water before its discharge into Lake Michigan. This discharge, regulated under a National Pollutant Discharge Elimination System (NPDES) permit, is subject to stringent limits of 6.5 million gallons per day (MGD) and a maximum of 15 milligrams per liter (mg/L) of O&G in monthly grab samples. Moreover, the discharge must adhere to a narrative standard prohibiting turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits in unnatural quantities that may harm designated uses of the receiving water.

With six turbines and associated wicket gates contributing oil and grease to the Station Drainage Sump (SDS), and a noted increase in SDS discharge since 2019, there is a pressing need for a robust solution. The plant aims to evaluate and implement new processes or retrofit the existing system to eliminate violations of the narrative standard. This objective is essential for the plant's compliance with its NPDES permit and the protection of Lake Michigan’s ecosystem.

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

Alternative Solutions/Alternatives Considered

1. Do Nothing

The "Do Nothing" alternative involves maintaining the current status quo of the Oil Water Separator (OWS) system at the Ludington Pumped Storage (LPS) Plant without implementing any upgrades or modifications.

Key Points of Consideration:

1. **Continued Compliance Challenges:**
   - Under this approach, the plant would continue to operate with the existing OWS system, which has already shown inadequacies in handling hydraulic oil releases, as evidenced by two reportable incidents in December 2021 and January 2022 due to an observed oil sheen.
   - Persisting with the existing system could result in repeated non-compliance with the stringent NPDES permit requirements, particularly the narrative standard.
   - The plant risks facing regulatory penalties, enforcement actions, and potential legal challenges due to continued environmental compliance failures.
2. **Environmental Implications:**
   - Discharge of inadequately treated process water could have detrimental effects on the aquatic ecosystem of Lake Michigan, potentially harming the water quality and the diverse aquatic life.
   - The plant's environmental stewardship reputation could be compromised, leading to public concern and scrutiny.
3. **Operational Efficiency:**
   - Without improvements or upgrades, the existing OWS system may become increasingly inefficient as flow rates increase due to the wear of existing wicket gates.
   - This inefficiency might lead to higher operational costs, increased maintenance requirements, and potential unplanned downtimes.
4. **Financial Considerations:**
   - Although this option avoids the immediate capital expenditure required for upgrading the OWS system, it could result in higher long-term costs due to potential fines, legal fees, and increased maintenance expenses.
   - The plant might also incur financial losses due to unplanned shutdowns or reduced operational capacity as a result of compliance issues.

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

Conclusion: The "Do Nothing" alternative, while avoiding immediate investment, poses significant risks in terms of regulatory compliance, environmental protection, operational efficiency, financial liability, and public perception. It fails to address the underlying issues with the OWS system and could result in more serious consequences for the LPS Plant and its stakeholders in the long term.

2. Enhance OWS & Modernize System for Facility Lifecycle – Internal estimate of $5,228,422 (100% Dollars)

Option 2 proposes a comprehensive approach to address the inefficiencies of the current Oil Water Separator (OWS) system at the Ludington Pumped Storage (LPS) Plant. This option involves making enhancements to the existing OWS and modernizing the system to align with the facility's lifecycle requirements.

Key Points of Consideration:

1. **System Replacement and Modernization:**
   - The existing OWS system, which has been prone to reportable releases, will be enhanced to address the flow rate and provide additional oil removal equipment.
   - The new system will be designed to meet the current and future operational demands of the plant, considering factors like increased flow rates due to wicket gate wear.
2. **Enhanced Compliance with NPDES Permit:**
   - The modernized system will aim to effectively eliminate any violations of the NPDES narrative standard.
3. **Environmental Benefits:**
   - Upgrading to a more efficient system will significantly reduce the risk of pollutants entering Lake Michigan, thereby protecting the aquatic ecosystem.
   - It demonstrates the plant's commitment to environmental stewardship and sustainable operations.
4. **Operational Efficiency and Reliability:**
   - It will enhance the reliability of the plant's operations, ensuring consistent power generation without interruptions due to compliance issues.
5. **Financial Considerations:**
   - The initial investment of $5,228,422 will cover the costs of purchasing and installing enhancements to the OWS system.
   - While this option requires a significant upfront capital expenditure, it could potentially save costs in the long term by avoiding regulatory fines, reducing maintenance expenses, and minimizing the risk of operational disruptions.

Conclusion: Option 2, with its focus on enhancing and modernizing the OWS system, presents a comprehensive and proactive solution to the current challenges faced by the LPS Plant. Despite the substantial initial investment, this option offers long-term benefits

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

in terms of regulatory compliance, environmental protection, operational efficiency, and stakeholder relations.

3. Modify Existing OWS – internal estimate of $4,000,000 (100% dollars)

Option 3 proposes substantial modifications to the Ludington Pumped Storage (LPS) Plant's current Oil Water Separator (OWS). This plan focuses on retrofitting the existing system to enhance its oil and grease separation capabilities while addressing environmental compliance challenges.

Key Points of Consideration:

1. **Extensive Modification Requirements:**
    - Significant alterations to the current OWS are needed, which may include the integration of advanced technology and materials.
    - These modifications could necessitate extensive testing to ensure compliance with national standards, adding complexity to the project.
2. **Operational Challenges and Outage Duration:**
    - The OWS is integral to the plant's operations; hence, modifications mean prolonged outage periods.
    - The necessary downtime for these modifications could be considerably longer than other options, potentially impacting the plant's availability and power generation schedule.
3. **Limitations in Achieving Compliance:**
    - Despite the modifications, there is uncertainty regarding the modified system's ability to fully satisfy NPDES permit requirements, specifically the prevention of oil sheens at Outfall 007.
    - The risk of not fully addressing the regulatory concerns remains a significant consideration.
4. **Lack of Backup Functionality:**
    - Unlike Option 2, which proposes a system providing backup functionality, modifying the existing OWS does not offer this advantage.
    - In the event of system failure or maintenance, there would be no alternative system to ensure continuous compliance.
5. **Cost and Investment Efficiency:**
    - The estimated investment of $4,000,000 primarily funds the modifications without providing additional operational benefits like backup functionality.

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

- When weighed against the potential for prolonged outages and uncertain compliance achievement, the cost-effectiveness of this option may be less favorable compared to others.

Conclusion: Option 3, involving the modification of the existing OWS, presents several challenges, including extended outage times, uncertainty in meeting compliance standards, and lack of backup functionality. Although it leverages existing infrastructure, the limitations and risks associated with this option, particularly in terms of operational disruption and regulatory compliance, make it a less favorable choice compared to a complete system replacement.

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

Recommended Alternative: #2 Enhance OWS & Modernize System for Facility Lifecycle - $5,228,422 (100% dollars)

Rationale for Selection:

1. **Reliability and Compliance:**
    - The new system is designed to meet the National Pollutant Discharge Elimination System (NPDES) requirements. This aligns with Consumers Energy Company's (CEC) objective to eliminate violations of the narrative standard and ensures adherence to environmental regulations.
2. **Backup Functionality:**
    - Unlike modifying the existing OWS, this enhancement offers backup functionality. In the event of maintenance or unforeseen system failures, the plant's operation can continue unhindered, ensuring continuous compliance with environmental standards.
3. **Operational Efficiency:**
    - The enhancement and modernization of the OWS are expected to streamline operations at the Ludington Pumped Storage (LPS) Plant.
4. **Reduced Outage Time:**
    - Installation of a new system is more predictable and can be planned to minimize operational disruptions. This contrasts with the extensive outage times required for retrofitting the existing system as proposed in Option 3.
5. **Long-Term Cost-Effectiveness:**
    - While the upfront cost is significant, the long-term benefits such as reduced maintenance costs, enhanced operational reliability, and avoidance of potential fines for environmental non-compliance make this a cost-effective solution.
6. **Risk Mitigation:**
    - This option significantly reduces the risk of future NPDES reportable releases, thus protecting the integrity of Lake Michigan's ecosystem and maintaining the plant's compliance track record.

Conclusion: Given the critical need to address the environmental compliance issues at the LPS Plant, Option 2 stands out as the most viable and strategically sound choice. It offers a comprehensive solution that not only enhances operational efficiency and reliability but also aligns with CEC's commitment to environmental responsibility and regulatory compliance. The investment is justified by the long-term operational and environmental benefits it provides, making it the recommended alternative for the project.

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

Scope of Work

1. **Installation of Advanced Skimming and Contaminant Capture System:**

   This system will enhance the initial treatment of process water, effectively removing oil, grease, and other pollutants before they enter the main OWS.

2. **Installation of Parallel Tank Organic Clay Pretreatment System:**

   This system will serve as an additional layer of treatment, targeting specific contaminants and enhancing the overall efficiency of the water purification process.

3. **Installation of Baffle/Divider System in the Collection Sump:**

   This addition will aid in the effective removal of fats, oils, and grease (FOG) contaminants from the water.

4. **Enhanced Instrumentation and Monitoring for Collection Pit and Pretreatment System:**

   This upgrade will provide real-time data and analytics, crucial for monitoring system performance and ensuring compliance with environmental standards.

5. **Installation of Isolation Valves in Transformer Secondary Containment Discharge Lines:**

   These valves will offer greater control over the flow and treatment of discharged water, enhancing safety and operational efficiency.

6. **Monitoring of Existing Plant OWS:**

   This will facilitate continuous assessment and management of the OWS's performance, ensuring that it meets the required environmental regulations and operates at optimal efficiency.

Funding and Timing

- Funding that has been previously committed for this project: $1,147,500
- A Scheduled outage is required for this project.
- Desired implementation year: 2024
- System Engineer: Steven Morris

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

Conceptual Estimate

Year	Loaded Cost	Description
2023	**$** 1,147,500	51% dollars. Engineering and planning
2024	**$** 892,500	51% dollars. Procurement and preparation for installation
2025	**$**626,495	51% dollars. Monitoring, Post Maintenance testing, Documentation and Closeout

Total Cost: 51% dollars - $2,666,495. 100% dollars – $5,228,422

Asset Strategy Approval Comments

Asset Strategy recommends approval Based on regulatory requirement.

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

Approvals

Title	Approver Name	Date
Generation Planning Manager	George L. Mckenzie II DocuSigned by: George L. Mckenzie II C3EF301E4E4F4F0...	12/21/2023 | 10:37 AM EST
Director of Generation Asset Strategy	Scott Hugo DocuSigned by: Scott Hugo F1C1A2B7C3F34C8...	12/21/2023 | 10:36 AM EST
Exec Director of Electric Planning	Richard T. Blumenstock DocuSigned by: Richard T. Blumenstock C3E2F5B0B2A449B...	12/23/2023 | 9:39 AM EST
VP of Electric Grid Integration	Srikanth Maddipati DocuSigned by: Srikanth Maddipati 67DA622787D2488...	2/1/2024 | 4:58 PM EST

DocuSign Envelope ID: 8F9478A4-9504-48FB-A451-037B21B21AEA

References

1. WSP USA Inc. "Alternatives Evaluation for Oil-Water Separation at the Ludington Pumped Storage Plant." 27 June 2023. Prepared for Consumers Energy Company (CEC) and DTE Energy.

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy Company
LPS Corrective Work Project

Concept Approval

Pony Motor Rotor Cracking and Fretting

PH-00119-BSD-002

Revision 0.0

Circulated for Approval: 9/27/2024

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

1 Revision History

Revision	Date	Reason For Revision	By	Checked	Generation Planning	Legal
0.0	9/27/2024	Initial Release	KCG	DET	SAM	EJH

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

Consumers Energy Count on Us®

Approvals

On approval, this document authorizes the EPM LPS Corrective Work Project to execute the work according to the budgeted Long Term Financial Plan or Change Log processes.

Approvals:

Approvals according to the Total Project Value listed below.

Title	Reviewer/Approver	Approval Limit	Signature	Date
Project Engineer - Ludington	Kyle Grassmid	Preparer	Signed by: Kyle Grassmid 24BCC7D2AF5C4F0...	9/27/2024 | 8:39 AM EDT
Gen Planning	Steven Morris	$100k	Signed by: Steven A. Morris 89F850CADAEC448...	9/27/2024 | 8:55 AM EDT
Project Manager	Kristopher Koster	EPM Reviewer	Signed by: Kristopher Koster DC10DD6B8392473...	9/27/2024 | 10:00 AM EDT
Sr Manager Plant Operations - LPS	Jason Durand	Site Reviewer	Signed by: Jason Durand 2C1456FD230B409...	9/27/2024 | 12:40 PM EDT
Assoc General Counsel	Emerson Hilton	Legal Reviewer	Signed by: Emerson Hilton E48267A0BA9F473...	9/30/2024 | 9:19 AM EDT
Dir Generation Engineering	David Thornock	$2,000k	DocuSigned by: David E Thornock 31C4AFE905164D3...	9/30/2024 | 10:13 AM EDT
Dir Generation Asset Strategy	Scott Hugo	$250k	DocuSigned by: Scott Hugo 31EC7A87F8F34C6...	9/30/2024 | 1:39 PM EDT
Exec Director Electric Supply Eng	Richard Blumenstock	2,000k	Signed by: Richard Blumenstock C3E2F0B9920949B...	9/30/2024 | 4:35 PM EDT
VP Electric Supply	Sri Maddipati	$8,000k	Signed by: Srikanth Maddipati 67DA622787D2488...	10/2/2024 | 10:20 AM EDT

Additional Supporting Information:
Though the work covered under this Concept Approval is intended to be executed in conjunction with the LPS Corrective Work Project, and the Company has outstanding claims against Toshiba in connection with failing to evaluate certain related issues at an earlier time, the work covered here was not initially within the scope of the LPS Overhaul Project and therefore is not considered repair of defective work.

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

General Information			
Project Title:	PH-00119 – LPS Corrective Work Project		
Generating Site / Plant:	Ludington Pumped Storage Facility	Unit(s):	1 & 6
Project Sub-Part Title:	Pony Motor Rotor Cracking and Fretting		
Budgetary Scoping Document (BSD) ID Reference:	BSD-002		
LPS System ID Reference:	Pony Motor		
Plant Asset ID: (Enter "NEW" as applicable)	Retirement Unit N/A		

System Description and Problem Statement:

The Ludington Pumped Storage Plant has six units that can be used to generate electricity, or by turning the units in the reverse direction, can pump water into a reservoir to be used later to generate electricity. To start in pump mode, a lead unit (either unit 1 or unit 6) operating in generator mode must be electrically coupled to the desired unit to be started. Pump starting is done with power provided from the lead unit until it is ready to be synchronized with the grid. As the units are started, the last unit remaining to start in pump mode is the lead unit. (unit 1 or unit 6). In order to start the last unit in pump mode, the unit needs to be spun up to speed using another motor, a pony motor. The pony motors are directly attached to the rotor shafts of units 1 and 6. These pony motors are large, and they cannot be started by simply closing a breaker. The technology installed in the 1970s to control large motor starts was a liquid rheostat. The liquid rheostat provides a variable resistance to the motor power supply, controlling the motor starting speed.

Since the pony motor is directly coupled to the main shaft, it rotates with the unit whenever the unit is in operation. Even when the motor is not being used to start the units, it spins up and down with every other unit start when acting as the lead unit.

During a Non-Destructive Examination (NDE) test performed on Unit 1's pony motor structure, linear indications, aka cracks, were noted in high stress locations. The indications have been monitored periodically since they were first discovered. Prior to re-assembly after the major overhaul, the linear indications were repaired. Subsequent inspections after being returned to service note the indications returned, and the indications continued to grow with use of the pony motor. Unit 1's pony motor was subsequently removed from service and the indications continue to be tracked with regular inspections. Since the pony motor is no longer used to start the unit in pump mode, the indications have not grown, nor have new indications been noted. However, an analysis has shown that the rotor material is beyond its fatigue life limit.

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

Project Description / Scope:

Project will remove and replace the existing Pony Motor rotors with new rotors that will provide another 50 years of service. It is assumed that the stators on both units can be reused, and that the new rotor will be designed to work with the existing stator and liquid rheostat. The new rotor will be redesigned to ensure that fatigue is no longer an issue for the remaining life of the plant.

Project Justification:

Project Justification: (Enter text for all areas of justification that are applicable. Place an X to the left of the justification that is driving the change. Only mark one field.)		
Safety:		
	If safety-driven, provide specific safety requirements (MIOSHA, etc.).	
Regulatory:		
	If regulatory-driven, provide specific requirements (EPA, EGLE, etc.).	
Compliance:		
	If compliance-driven, provide specific CEC compliance requirement.	
Economic: For economic projects provide inputs needed in the economic evaluation.		
	% ROR Reduction:	
	O&M and / or PSCR cost changes:	PSCR Cost Savings $90k per year 1.1M/year starting after 8 years
	Changes in periodic factor:	
	Heat Rate Improvements:	
Other: Provide basis.		
X	Broke/Fix	Unit 1's pony motor rotor structure has cracks that prohibit it from being used as a motor for pumping. It so far has been safe for the unit to operate normally as long as the pony motor is not used. Unit 6's pony motor is 50 years old and is not expected to last through the remaining life of the plant
	Condition-Based	
	Infrastructure, Facilities	
	Strategic, etc.	

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

NOTE: All costs are in 100% dollars.

Alternatives Considered:

- Do Nothing

  This option continues to utilize the one pony motor that is in operation, while not repairing the other. It is expected that over time, 8-10 years, the operational pony motor would develop similar indications in the rotor and would then also be removed from service. Once both pony motors are out of service, the site would only be capable of pumping with a maximum of 5 pumps. Normal unit maintenance and operation require units to be taken off line. Today, any time Unit 6 is off line the site is down two pumping units.

  Today, Unit 1's pony motor has significant indications in the rotor support structure. These indications are monitored quarterly to ensure safe operation. Currently indication growth is not occurring. If more growth occurs, the team will have to evaluate whether to take the unit out of service for both pump and generate. An in service failure could catastrophically damage the unit.

  Lead time to design, build and install a new pony motor is a minimum of 3 years. Funds must be secured, a bidding process must be completed with qualified vendors, the new rotor must be designed, manufactured, and installed. If the unit is unavailable for this amount of time in pump or generate, the cost impacts will be significant.

  A 3 year outage is expected to incur replacement power costs of 10M and lost capacity cost of $102M. The cost of executing a pony motor replacement as a standalone project is estimated to be $50M compared to $15M when executed during the upcoming LPS Corrective Work project. The differences in costs are due to shared engineering, supervision, and fabrication windows.

  Regular inspections for 30 years – $485k

  2022 annual replacement power cost for 1 Unit OOS - $3.3M or $10M for 3 years
  Cost for unplanned replacement - $37M + project costs + replacement power + capacity = $170M

- Alternative 1 – Replace One Pony Motor Rotor

  This option consists of engineering a new rotor to work with the existing stator. This would require a significant outage duration to remove the collector rings and brush rigging for both the generator and the pony motor. Then remove the air cover and upper bearing bracket to remove the existing rotor and then install a new rotor. Minimum unit outage duration of 200 days. This is planned to be completed in conjunction with the planned Unit 1 BOP overhaul corrective work, saving both outage costs and project implementation costs. The second motor is not expected to last for another 30+ years and therefore would need to be replaced at a later date.

  Capital Cost - $11.8M + Project costs = $23M

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Future Outage Replacement Power cost = $2M
Future replacement of Unit 6 pony motor rotor - $68M (project cost only)

- Alternative 2 – Replace Both Pony Motor Rotors

  This option would replace the pony motor rotors for both Unit 1 and Unit 6. The pony motor for Unit 1 is beyond end of life, the pony motor for Unit 6 has an estimated 8-10 years of life left. The next scheduled outage that could support this work would be in 2029-30. By 2029, the expected remaining life of the Unit 6 pony motor rotor will be 3-5 years. To execute a project at that time, in conjunction with the existing projects will cost $15M. To wait until the estimated end of life, the project would need to be executed as a standalone project, costing $50M plus the addition of another 200 day outage to perform the replacement. As shown in Alternative 1, while there is an existing project that can support the engineering and management the cost of installing the second pony motor is greatly reduced.

  Replacement of both pony motors - $11.8M + $11.8M + project costs =$46M

- Alternative 3 – Repair the existing rotor

  This option would attempt to repair the 31 indications that are currently being tracked. Per an American Welding Society standard, the cracks would need to be excavated to the end plus 2 inches. The indications range from 1/16th inch to 2-5/8th inches. Repairs were made to Pony Motor #1 during the overhaul, but the indications returned within 2 years. The proposed repairs would not bring pony motor #1 to usable condition, as welds from previous weld repairs have failed in service after a relatively short time. True repair is not practical due to the material being at the end of it's fatigue life for the service conditions. This also does not prevent Pony Motor #2 from the assumed failure in 8-10 years.

  This option was reviewed to assess whether repairing Pony Motor #1 rotor is worth repairing to reduce the inspection costs, NOT as a viable solution to the problem at hand.

- Alternative 4 – Remove Pony Motor and use SFC to start last pump

  This option would remove the need for the pony motor itself and replace the 1970s technology with new technology. The Liquid Rheostat would be removed, the pony motor would be removed and a Static Frequency Converter (SFC) would be installed. The SFC would energize the main generator as a motor. The SFC would require two new transformers and a large building to house the power electronics. The space required is not available. From a technical perspective, the generator was not designed to be used with a SFC and would require modifications to account for the harmonics created by the SFC.

  Based on the space and technical requirements this is NOT a viable option.

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

	Do Nothing	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Scope	Operate with one less pump	Replace One Pony Motor Rotor	Replace Both Pony Motors	Repair Pony Motor Rotor	SFC
Risk	Indications start to grow causing unit removed from service	Future replacement of 2nd pony motor will cost more		Alternative is not viable N/A	Alternative is not viable N/A
Costs					
Estimate Class	3	3	3		
O&M	485k			N/A	N/A
Capital		$15M	$46M	N/A	N/A
PSCR	$1.1M/year or $3.3M/year (future failure)	$2M			
Future Capacity Impact	$102M				
Future Project	$68M	$68M			
Total	$170M	$85M	$46M	N/A	N/A

Alternative Selected (Detail which option was selected and why)**:**

Alternative 2 was selected to replace both Pony Motor Rotors for the following reasons:

- Lowest long term costs
- Leverages on site existing engineering / contractor support
- Increases unit reliability
- Minimizes risk to the plant
- Returns the plant to original operational condition through the current license period
- Avoids future major outage and avoids lost capacity costs

Project Benefits (Include IRR, if applicable)**:**

- Reduced Replacement Power costs

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

- Pumping capacity redundancy during unit 1 & 6 outages
- Decreasing operational risk
- Reduces risk for catastrophic disassembly
- Replacement conducted during planned outage rather than forced outage.

Present Need (Describe current condition)**:**

Unable to use the pony motor #1 to start the last pump. Mitigate pony motor rotor structural fatigue and end of life damage for both pony motor rotors

Timing Impact – Is an outage required?

Outage Information	
Estimated Outage Duration, if needed:	200 days (two outages)
Desired implementation year:	2028-29 & 2029-30
Specify the impact if the recommended implementation year is changed:	1.1M/year

COST ESTIMATION

Engineering and Conceptual Development (Provide the status of engineering and conceptual development. Is additional engineering required to provide adequate cost/benefit information to fully evaluate the project? **NO**

Cost Summary (100% Dollars) (subject to change with input from 3rd parties) Preliminary and Subject to Change	
Estimate Class (DOE 413.3 Definition)	Class 3 (-%20/+%30)
Total Estimated Project cost (100%; Whole dollars)	$46M Capital
Identify funding that has already been spent or committed, if any. (Whole dollars)	$900K
Contingency included in the Total Estimated Project Cost above (Whole dollars)	$1.3M
• Was the estimate developed based on a previous project of similar size and scope? No • Was a formal estimate completed based on detailed engineering? No • Was a formal estimate completed based on a conceptual engineering design? Yes • Was an informal estimate done based on the recommended project concept? No • If an informal estimate was done, please identify the basis for having confidence in this estimated cost.	

Cash Flow Forecast (100%; whole dollar values): Preliminary and Subject to Change	
Year	Dollar Value

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

2024	$0.5M
2025	$4M
2026	$5M
2027	$11M
2028(Fall 2028 installation Unit 1)	$14M
2029 (Fall 2029 Installation Unit 6)	$7M
2030	$3M

51% CE Share Calculation:

Cash Flow Forecast (51% project total; whole dollar values):	Preliminary and Subject to Change
Year	51% Dollar Value
2024	$ 0.25M Capital
2025	$2M Capital
2026	$2.5M
2027	$5.5M
2028	$7M
2029	$3.5M
2030	$2.25M

Priority Code	
• Select a recommended project priority code and provide a basis.	
• Priority code table provided below	
Priority Code	**Basis**
5	The present situation impacts replacement power costs with $90k per year with a high potential to impact at $1.1M/yr and a maximum potential impact of $37.3M/yr

Priority Basis Chart		
Rank	Title	Definitions

Docusign Envelope ID: 7F9BD271-EDC9-4D33-89E8-DE0D30E311E1

Consumers Energy – PH-00119 – LPS Corrective Work Project
Project Sub Part: Pony Motor Cracking and Fretting

Priority Basis Chart		
1	Legal, Regulatory	These are the items that CEC is required to do without flexibility.
2	Safety	Safety items that must be addressed within one year due to hazard to employees.
3	Strategic	These are board approved projects, submitted outside the standard budget and LTFP processes. This work instruction does not apply to these items.
4	Critical Reliability	Deferral has a high likelihood of significantly impacting asset reliability in the near term. This category also includes spending to address long-standing safety issues and regulatory commitments that have some flexibility with respect to implementation.
5	Important Reliability	Deferral has a high probability of impacting asset reliability. Projects that will significantly improve unit performance, key performance indicators will generally be in this category.
6	Desired Reliability	Repeated deferrals will impact long term reliability. One time short term deferral, while undesirable, is unlikely to impact reliability in a significant way. In general, items that are in this category in future years are good candidates for the up levers list.
7	Reliability and Performance Improvement	Spending that, while desirable, is a lower priority. These items will be the primary candidates for the capital and major maintenance down levers lists.

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

Concept Approval

Consumers Energy
Electric Supply
PROJECT INITIATION & CONCEPT APPROVAL
Generation Planning
Capital

Generation Type: Hydro
Site: Ludington
Unit: 1-6
Date Created: 2/23/2022
Proposed Start Implementation Year: 2024
Project Span Whole Years: 6
Project Title: Ludington 1-6 DCS Control Relay Replacement CA

Problem Description (Section 1-Initial Information):

Ludington Pumped Storage (LPS) units are currently controlled and protected by the original (1970's technology) hardwired electromechanical relay control system, going forward referred to as "the system". The system is comprised of relays mainly in the auxiliary relay room and operator control handles located on the Main Control Board (MCB). The system has outlived its useful life and is failing. The system is not fail-safe in design; does not provide fault tolerance; and the redundancy is inadequate. There are gaps in the system protection scheme. The system is presenting plant operations and maintenance with problems. The Uninterruptable Power Supply (UPS) system is not currently segregated by unit pairs and presents a common point of failure for the plant.

The system is based on electromechanical devices (relays and operator control handles) that wear and have become less reliable over time. The relay contacts wear, and increased resistance has caused intermittent failures. The operator control handles are in a similar state of wear and age and have also experienced intermittent failures. The system will not last until End of Life (EOL) of the units.

The plant was designed using the control and protection methodologies available in the 1970's. Many of the relays in the system fail to a non-protective state. A small subset of examples is as follow:

Emergency Stop Relays (5E) – Each unit has an emergency stop relay. The relay is configured to energize to trip. A failure of this relay results in the unit not being shut down by the relay. There are fourteen legs in the design which energize this relay to trip the unit. A few of them are as follow:

- Turbine Overspeed (125%)
- 345 KV Bus Fault while pumping
- Upper reservoir water level high (Overtopping protection)
- Intake gate closed

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

Many portions of the protective scheme are not fault tolerant. Fault tolerance refers to the ability of a system to continue operating without interruption when one or more of its components fail. As an example, master shutdown relays (5) do not provide fault tolerance. While there are five master shutdown relays for each unit they are not implemented in a redundant fashion. There are five of these relays because when the emergency shutdown function is asked for by the protection scheme there are so many different actions taken that one relay cannot implement them all. Thus, each of the five relays shut down different portions of the process. A failure of any one of the relays will directly affect only the portions of the process tied to that relay. This means that a portion of the equipment (a subset) can inadvertently be tripped while the balance remains in service.

Many critical trip inputs from the relays are not redundant. Redundancy is a system design principle that introduces duplicate components to provide fault tolerance. When a component fails, a backup takes over to ensure the system still performs as designed. A small subset of examples where we rely on one device to provide unit protections is as follow:

- Overspeed switch and aux relay (12X) – One relay contact energizes the emergency stop relay. If the relay fails, we will not shut the unit down as prescribed.
- High draft tube water level (71DWHX) – One relay contact energizes the emergency stop relay. If the relay fails, we will not shut the unit down as prescribed.
- Governor oil tank level low (71GTL) – One relay contact energizes the emergency stop relay. If the relay fails, we will not shut the unit down as prescribed.

Challenges for plant Operations and Maintenance

- The main control board switches are wearing. Even with lubrication and maintenance a number of these switches have the interface with their key or handle worn excessively. Many of our larger main control board switches are no longer in production. There are minimal spares available. Replacement for the more complex switches that have many contacts are no longer readily available and obsolete. We are reliant on custom assemblies for replacements and must commission custom builds. These custom builds also present a problem in long lead times. If failure is observed unit(s) and portions of the plant may remain out of service for extended durations

- The Relay Room is so densely populated with relays that just walking around has caused issues when relays get bumped. As part of the process of routine relays checks the covers are removed and replaced which has caused inadvertent circuit changes.

- Changing a relay(s) can affect multiple circuits and even other units (starting bus, Main Transformer Banks (MTB)) due to their common neutrals. Direct Current (DC) bus grounds can be difficult to find when there is no indication on cause (i.e., alarming).

- Intermittent issues can take months to find and correct. This is due to the lack of active monitoring/measurement that allows for troubleshooting to be performed timely. For each occurrence custom recordings must be setup with ad-hoc hardware to assess what the controls are executing and experiencing.

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

- The system does not provide the proper diagnostic and troubleshooting capabilities.

- During the startup and shutdown process plant operations cannot see the operational state of the unit. Functionality and troubleshooting during start/stop sequences cannot be observed other than by individually observing and testing scenarios with personnel and recording devices (multimeters or digital recorders for electrical signals).

- Start permissives have limited visibility. Critical valve positions are not individually observable as they come to single relay collectively to provide the start permissive. Troubleshooting requires additional effort and resources.

- Several current manual processes cannot be automated preventing the removal of human error potential during startup, shutdown, and other equipment configurations.

- Any updates of equipment and systems that need to be integrated with the unit operation are difficult and expensive to integrate into the hardwired relay logic.

- Automation efforts prove to be difficult if at all even possible with the hardwired relay logic. Changes to operating criteria are difficult to implement, test and verify and costly and time-consuming.

- Training for Operations is limited to studying procedures as the system does not provide a testing and simulation environment.

- The unit overtopping protection needs improvements that can't easily, and cost efficiently be implemented into the current legacy relay-based control system (pump start lockout above 932’ reservoir elevation, overtopping protection and system control of how many units are allowed to pump above 940’ and 941’ respectively).

As a result of the system failing the unit can come off-line, become unavailable, or experience derates. In addition, as these devices also serve to provide equipment protection their failure can result in significant equipment damage up to and including destroying significant parts of the unit and/or plant potentially rendering the unit(s) and/or the entire plant unavailable for years. The potential costs of such repairs could easily rise to hundreds of millions of dollars. In addition, there are significant gaps in the original protection design. Consumers Energy is exposed to substantial risk due to the state of the system.

LPS will become more important to the stability of the grid as renewable generation (solar and wind) sources increase and as fossil generation (gas and coal) is decommissioned. LPS provides the Midcontinent Independent System Operator (MISO) grid support by delivering frequency and voltage support (reactive load generation) that replaces the support that will be lost when our gas and coal units are decommissioned. Providing grid stability in conjunction to our generation realignment is an important aspect to our corporate strategy.

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

Alternative Solutions/Alternatives Considered

Alternative Solutions (Section 2):

Alternative #1 - Do nothing (20-Year Payback)

Total Cost of doing nothing: $29.6M (51% dollars)

The costs associated with doing nothing include costs associated with the damage occurring as a result of system failure(s) and the units not being available to run and support our renewable strategy. There are other costs related to doing nothing such as maintaining the plant and operational issues that can make the units unavailable for relatively short periods of time, however the major impacts are derived from system vulnerabilities with respect to their protection functions.

DAMAGE
The system provides the basis for personal and equipment protection. If we do nothing, we will continue to experience failures of the system. The frequency of errors is progressively getting worse as system components continue to age. Eventually a failure or combination of failures could result in catastrophic damage to a unit or the entire plant rending it unavailable for up to a year or more. This would cause significant impacts to our ability to serve our customers.

Relay fault probability used is based on data from the Overtopping Fault Tree analysis report. In the report the Savanna component fault probability database was consulted, and the component fault relay probability used as part of the overtopping fault tree analysis was 0.001 failures per day.

ALREADY OCCURED
Recently the plant experienced an incident where unit 4 entered shutdown as it went into pumping mode before the generator breaker was closed and the unit synchronized. As mentioned in the problem statement there are gaps in the logic, a pumping mode should not be permitted until unit 4 had been synchronized. In addition, as part of the event the cross trip to unit 1 did not take place and the unit 4 motor was operated synchronously (as its exciter had been taken offline when unit 4 went into shutdown). Damage to the unit 4 generator field along with other equipment may/could have occurred. The plant is still looking into the incident; however, it is difficult to ascertain what truly happened with the current system in that the protections are not all contained in one system. Portions of the protection are in the system relays and portions are in the protection relays. This event is indicative of the system risks. Damages for this event can easily reach $60M and make a unit unavailable for months which would cost another $15M depending on Local Marginal Price (LMP) and market demands. The total cost for an event of this nature could reach $75M (100% dollars).

POTENTIAL EVENTS
The following provides a description of three other scenarios that provide significant system failure(s) risk to the operation using the old technology. The three scenarios below are a small subset of the control system vulnerabilities. It should be noted that these are all low probability

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

and high cost/consequence events. Based on data from the Overtopping Fault Tree analysis report the fault probability database was consulted and the relay fault probability of 0.001 failures per day was used.

Scenario 1: Turbine Overspeed Switch and Aux Relay (12X)
The system provides unit overspeed protection through a relay which is energized to trip. If the relay fails when needed during an overspeed event the damage associated with an overspeed event could be to damage the rotor bearings and the rotor itself. This would make the unit unavailable for years of time and costly repairs. It is estimated the repair cost could reach up to $160M and the loss of the unit for years another $70M for a total of $230M. Based on data from the Overtopping Fault Tree analysis report the fault probability database was consulted and the fault probability of a relay is 0.001 failures per day; the fault probability of the wicket gates failing to close is 0.0002 per day. This results in a total probability of failure of 2E-7 per day, which is 7.3E-5 per year.

7.3 E-5 x $230M = $16,790/year x 20 years = $336K x 6 units = $2M (100% dollars)

Scenario 2: Upper Reservoir Water Level High (Overtopping Protection)
As a FERC regulated facility, dam safety is of the utmost importance. Consumers Energy is under constant scrutiny by regulators to provide safe reliable operations. Overtopping protection is very high on the priority list. Proving the effectiveness and reliability of dam safety protection schemes for overtopping protection is a must do. The overtopping protection protects corporate and public, life and property. The current plant overtopping protection scheme has 4 levels of protection. A breach of the overtopping protection schemes would require disclosure to our regulators which could trigger a requirement to install an emergency spillway, which may cost in excess of $150M (100% dollars).

No cost with regard to this scenario has been placed into the cost of this solution as the probability is negligible, however this scenario demonstrates the magnitude of cost were the event to occur.

Scenario 3: Loss of the starting bus
As the system provides protection for the plant starting bus, a failure in its protection would leave the plant without many if not all of its units for years depending on the severity of the event. This estimate uses a loss of three units for 1 year It is estimated that the replacement of the starting bus would cost around $100M and losses in revenue of $25M (100% dollars).

No cost with regard to this scenario has been placed into the cost of this solution as the probability is negligible, however this scenario demonstrates the magnitude of cost were the event to occur.

HIGHER FUTURE PROJECT INTEGRATION COSTS
There are many projects being executed at the plant. The costs for these projects to integrate with the system is higher and costs projects an additional $70,000 per year. In total that amounts to $1.4M over the 20-year payback period.

The cost for the 20-year payback period is $1.4M (100% dollars) or $.7M (51% dollars).

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

PLANT OPERATION AND MAINTENENCE COSTS

The operation and maintenance costs of maintaining and working with the system are estimated to be $100,000 per year per unit. This includes but is not limited to the extra time it takes to troubleshoot issues; the cost to maintain the system as best as possible; and the extra overhead related to operations. Over the period of 20 years the total is $12M (100% dollars).

The cost for the 20-year payback period is $12M (100% dollars) or $6.1M (51% dollars).

FORCED OUTAGES

Increased Random Outage Rates (ROR) due to continued failures of the system may cause unit outages and/or derates.

Using NERC Generating Availability Data System (GADS) data and supplemental knowledge of plant management that the units are worth $5M – $6M in the high season (July – September) and the expected forced outages based on past events it is estimated that there will be revenue loss of $1.75M (100% dollars) in the future year. It was then assumed that there will be a rise in forced outages due to the relays at the rate of approximately 3% per year. Projecting this out over a 20-year timeframe (the period that choice 2 & 3 would be expected to be in service before further action) would result in a cost of $42.9M in lost revenue.

Total cost breaks down for the 20-year payback period to:

Damage:	$2M (100% dollars) or $1M (51% dollars)
Project Integration:	$1.4M (100% dollars) or $.7M (51% dollars)
Operation & Maintenance:	$12M (100% dollars) or $6.1M (51% dollars)
Forced Outages:	$42.9M (100% dollars) or $21.8M (51% dollars)

The cost for the 20-year payback period is $29.6M (51% dollars).

Alternative #2 - Replace hardwire relay control system with Distributed Control System (DCS) and segregate the UPS (20-year payback)

Total cost of putting in a DCS: $13.4M (51%dollars)

Installing a modern Distributed Control System (DCS) will allow a system that will be able to be used and maintained for the life of the unit. It will increase site availability by reducing failures caused by aging relays and allowing better diagnostic tools such as historian trends, live logic viewing, alarm messages and related operator responses, and common Human-Machine Interface (HMI) control for all the plant equipment in a central system. A modern control system also allows for additional process automation further reducing error potential during operations and associated impacts.

The DCS Control Relay Replacement Study project (PH-20106) evaluated the detailed scope, budget, and schedule to replace the existing hardwired controls at the Ludington Pumped Storage (LPS) facility with full Emerson Ovation Distributed Control System (DCS) control. The study included the following scope:

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

Modernization of the control room including removal of many of the operator control handles on the Main Control Board (MCB) to be implemented in the DCS as well as optimization of the layout of the control board for operational efficiency. In addition, the operator control console would be replaced with a modernized console with dedicated alarm displays and alarm response aids. The central alarming function the DCS provides enhances reliability of the units. As an example, DC bus grounds will be brought into the DCS for diagnostic and troubleshooting purposes.

A high fidelity DCS simulator will be provided for the project. The simulator will provide operator training capabilities prior to implementation of DCS control and monitoring at the plant. The simulator will be capable of replicating all logic and control schemes for all six (6) units. The simulator will allow testing of logic changes before they are implemented on the "actual" units which will enhance reliability. Simulation will be a primary means to test and verify logic operation before the implementation outages for each unit. This will help reduce risks during this project.

Turbine Supervisory Panels - Remote control functions associated with the turbine datalink will be migrated to hardwired DCS control as part of this project to replicate the existing plant hardwired controls from the MCB panels.

Pony motor control and monitoring will be migrated to the DCS.

The existing UPS system at the plant has a rating of 20KVA and provides 120VAC power to equipment for all six (6) units. This UPS system has reached its maximum capacity and requires an upgrade to support future loading requirements. The new DCS hardware installed as part of this project requires reliable and redundant power distribution for plant operations. An evaluation of the UPS system was performed. The results determined that a full upgrade of the UPS system is required to support the project and maintain sufficient spare capacity for future projects. Three (3) separate 20KVA UPS systems will be installed to allow unit pair separation (Unit 1 & 2, Unit 3 & 4, and Unit 5 & 6) to provide reliable and redundant power distribution throughout the plant.

The cost for the 20-year payback period is $13.4M (51% dollars)

Alternative #3 - Replace all Control Relays and a portion of the operator control handles with new ones and replace and segregate UPS (20-year payback)

Total cost of replacing the relays: $22.7M (51% dollars)

A complete replacement of all control relays to reach end-of-life (EOL) of the plant would require an immense undertaking to de-terminate the wiring on close to a thousand relays, replace the relay and rewire to the previous state. The system would require a complete recommissioning of the control system and post maintenance testing. Validity of the testing would be difficult. The amount of time required to do this work would require the work to be performed over multiple outages and would be difficult to perform without complete site outages. There would be increased risk of possible unit trips if attempted to perform under individual unit outages due to common systems and interrelated control signals.

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

This option does not provide benefits to resolve all the issues mentioned in the problem definition. Trouble shooting issues are still limited by the lack of tools available as compared to a modern control system. Many of the problems that occur over time are the result of the system itself being comprised of hundreds of electro-mechanical relays that eventually wear out and fail. Common operator interface of a DCS, along with operating events and alarms brought into a system-wide historian and allowing full historic trending of the process leading up to the issue, is not available with the relay-based control system.

The cost of replacing the relays will also include the following costs as they are not mitigated by the solution as in reality there is no alternative that will do what a DCS does. The following items are detailed in the cost of doing nothing choice and have been scaled as to their associated costs with this choice.

Damage:	$2M (100% dollars) or $1M (51% dollars)	(Scale Factor 1)
Project Integration:	$1.4M (100% dollars) or $.7M (51% dollars)	(Scale Factor 1)
Operation & Maintenance:	$10.8M (100% dollars) or $5.5M (51% dollars)	(Scale Factor .9)
Forced Outages:	$21.5M (100% dollars) or $10.9M (51% dollars)	(Scale Factor .5)
Cost to replace relays:	$9.0M (100% dollars) or $4.6M (51% dollars)	(Scale Factor 1)

The cost for the 20-year payback period is $22.7M (51% dollars).

Recommended Alternative Benefits/Objectives (Section 3):

Recommended Alternative #: 2
Recommended Alternative: Replace hardwire relay control system with Distributed Control System (DCS)

Why was this Alternative chosen?

A DCS is recommended for full control of the units at Ludington Pumped Storage. This solution provides a reliable and sustainable method to control and operate the six units at LPS for the remainder of the life of the plant. The DCS solution mitigates gaps in the plant protection scheme. The DCS solution will therefore mitigate the potential of damage at the plant. The DCS will make integration with future projects less expensive. The DCS will reduce the plant operation and maintenance costs.

The architecture of a DCS allows the reduction of electromechanical relays and timers and replacement with electronic input/output (I/O) modules that do not rely on mechanical movements and physical contacts to control the equipment. The DCS can program the sequencing of the equipment using control logic sheets (SAMA - (Scientific Apparatus Makers Association) control functional diagrams) that represents the functionality of hardwired series and parallel relay circuits. The number of physical components that can fail is significantly reduced. Operation sequences can be changed and updated with greater ease and new equipment can be added to the DCS control with less effort and full integration into the system. A DCS also provides appropriate control and trip redundancy that currently does not exist.

The modern DCS provides a complete control solution. HMI graphics provide the operator with easy to use "mouse-click" control of the plant equipment. Process sequences can be automatically

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

controlled to reduce and eliminate operator intervention. Troubleshooting tools such as live logic display, trending and historical review, and alarm with alarm responses improve the diagnostic capabilities and reduces the time required to resolve problems. The DCS can also improve efficiencies and performance by providing more accurate control and monitoring of equipment and processes. Integration of other equipment control systems can be brought into the DCS to provide a single user interface for the operators to monitor and control all equipment with a common alarm system.

There have been several engineering studies performed in the last 15 years to determine the best options for the extended operating life of Ludington Pumped Storage Facility. In 2007 a study was prepared by Devine Tarbell & Associates, Inc. (DTA) (DTA was acquired by HDR in 2009). The study was a condition assessment and life extension study along with a technology upgrade study report.

In 2019-2021 the Data Acquisition System was upgraded to Ovation DCS, also annunciator panels and the sequence of events (SOE) recorder were implemented into the DCS. These upgrades were implemented in three projects which resulted in a fully functional DCS (no equipment control) at the plant.

The recommended project is the natural next step in the migration to full control in the DCS.

Another engineering study was performed in 2021 and established a detailed scope, schedule, and budget to execute a project to expand the DCS to fully control the plant.

Project Benefits/Objectives

- Reduce the risk of potential damage due to the state of the current system.
- Replacement and elimination of worn and less reliable control relays and control board switches with new electronic input/output modules and new relays where needed.
- Future projects that have controls impact at Ludington will cost less
- The number of hardware control relays will be reduced due to the "control" being performed in logic instead of "hardwired" circuits. This will increase reliability and reduce outages and derates.
- Common control and monitoring of system equipment allows operation of the equipment from the HMI graphics and keeps the operator focused on one system instead of monitoring several the systems from several areas of the control room on different devices.
- Alarms are located in one alarm system with alarm management and responses based on International Society of Automation (ISA) 18.2 standards. Integration of external systems will be brought into the DCS for common operator experience.
- Automation of sequences can be programmed to reduce operator interface and improve on efficiency and performance of unit operation.
- Operational efficiencies and performance increases may be achieved by modern process control loops with Proportional Integral Derivative (PID) algorithms.
- Diagnostic and troubleshooting capabilities are greatly enhanced with the use of real-time control logic viewing, historian archive capability of process variables and operating parameters, trending graphs of process variables, start permissives, and logging of system messages.

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

- Additional redundancy for critical trip controls for reservoir overtopping and equipment protections.
- A DCS will provide the long-term path to support the LPS units into the future and through operation towards their End-of-Life (EOL) dates.

Scope of Work

An engineering study was performed in 2021 to provide a detailed scope of work, schedule and budget to complete this project. The document was completed by Worley Energy and lists the scope in detail for the following items: Please refer to the attached engineering study for full details.

- Control Room -Consoles
- Control Room - MCB Panels (move existing Main Control Board devices to DCS graphics control and monitoring)
- Auxiliary Relay Room (relays replaced with DCS controller drops and I/O modules)
- UPS (Uninterruptible Power Supply replacement and reconfiguration for better redundancy and duration and backup of control systems)

Systems included:

- Creep Detector and Brake Control
- Depression Air Compressors 1 and 2 (common to all six (6) units)
- Electrical System (Unit 1 and Unit 2 common electrical equipment listed below, Unit 3 & 4 and Unit 5 & 6 are similar)
    - Station Power Transformer 1 4KV Breaker 1136
    - 4KV Bus No. 1 to Transfer Bus Tie Breaker 1135
    - 4KV Bus No. 1 to Station Power Transformer 11 Breaker 1199
    - 4KV Switchgear 1 Monitoring
    - 4KV Intake Breaker Feeder 1
    - Station Power Transformer 11 to 480V Bus No. 11 Breaker 1166
    - 480V Bus No. 11 Tie Breaker 1165
    - 480V Bus No. 11 Tie Breaker 1160
    - Standby Transformer No. 10 Breaker 1066
    - Generate/Pump Breaker 116
- Exciter
- Generator Motor Heater
- Governor Cabinet Interface
- HP Oil Pumps
- Intake Gate
- Load Break Switches
    - Load Break Switch 115
    - Load Break Switch 116
- Lockout & Protection Relays
- Miscellaneous Solenoid Control
- MT-1 Transformer (common between Unit 1 & 2, Unit 3 & 4 and Unit 5 & 6 are similar)
- Pony Motor (only applicable for Unit 1 and Unit 6)
- Steering Logic
    - All field inputs interfacing with existing control relays in the MCB and Auxiliary Relay Panels
- Water Depression

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

- Engineering and Design and drawings
- DCS hardware, software and logic and engineering and commissioning
- Data links
- Hardwired cable and conduit design, installation, and commissioning
- Integration with current and future projects
- Updating/writing of operation procedures, alarm responses, job aids
- Schedule to be completed over a six-year time period coordinating with unit outages and other project scopes.

Future adaptability and control enhancements or changes are more readily implemented and in shorter time reducing additional future risk. Needs for control enhancements are expected based on lessons learned from events that occur and a needed change to the control logic (= standard work)

Project Justification (Section 4):

Priority Code Title: Critical Projects
Rank: 06
Definition: These projects, if deferred will have a high likelihood of significantly impacting asset reliability in the near term. This category also includes spending to address long-standing safety issues and regulatory commitments that have some flexibility with respect to implementation.

Basis Explanation:

This project removes substantial financial and reputational risks and will save the company money. It addresses the multiple issues presented in the problem description. The presented option provides the highest economical long-term benefit.

Economic Benefit Evaluation (Section 5):

X	**ROR Reduction:**	GADS historic data results can be very subjective on outage and derates with estimates of having a DCS and the amount of time to diagnose and repair the issues (along with the number of units the issue may affect). Estimate 0.3% ROR Reduction.
	O&M and/or PSCR Cost Changes:	
	Changes in Periodic Factor	
	Heat Rate Improvements	

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

	Economics - Parameters for IRR Calculation	
	Other:	Reduction in O&M cost due to troubleshooting issues caused by hardwired relay failures and quicker repair and recover with a DCS will decrease resources and duration cause by the existing system components. This will provide more energy value for our customers in added unit availability and power production from our asset(s). The DCS will reduce risks and provide additional protection for dam safety through improved overtopping protection. This DCS project will provide added equipment protection against severe equipment failures.

Funding and Timing (Section 6):

Identify funding that has already been spent or committed, if any: $82,620.
Timing Impact – Is an outage required? YES
Estimated Outage Duration in Days: 120
Desired implementation year: 2023
Outage Type: Unit

Specify the impact if the recommended implementation year is changed:
Outages would be over a rolling 3-year period during the execution phases with approx. 120-day outage/two units each year and complete site outage of 30 days each year. The project would begin in 2023 and 2024 with engineering and planning. Execution of outages to install equipment would begin in 2025 with units 1&2, 2026 for units 3&4, and 2027 for units 3&4. 2028 would include project closeout.
An engineering study was performed in 2021/2022 to develop a detailed scope, schedule, and budget costing $82,620 (51% dollars).

System Engineer: Kevin A. Ortner

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

Conceptual Estimate (Section 7):

Year	Loaded Cost (51% dollars)	Description	Total Project Cost (CE & DTE)
2023	$1,000,000	Engineering and Design for Units 1 and 2. Total project cost is $1,960,784.00, loaded cost is CE 51% share.	$1,960,784
2024	$2,106,300	Engineering and Design for Units 1 and 2. Total project cost is $4,130,000.00, loaded cost is CE 51% share.	$4,130,000
2025	$3,763,290	Engineering and Design for Units 3 and 4 and execution of project for units 1 and 2. Total project cost is $7,379,000.00, loaded cost is CE 51% share.	$7,379,000
2026	$3,855,090	Engineering and Design for Units 5 and 6 and execution of project for units 3 and 4. Total project cost is $7,559,000.00, loaded cost is CE 51% share.	$7,559,000
2027	$2,351,100	Execution of project for units 5 and 6 and project close out. Total project cost is$4,610,000.00, loaded cost is CE 51% share.	$4,610,000
2028	$250,000	Project closeout. Total project cost is $490,196.00, loaded cost is CE 51% share.	$490,196
	$13,408,400	Total project cost	$26,290,980

Total Cost: $ 13,408,400

Asset Strategy IRR & Justification

IRR:
Justification:
A/S recommends approval of this project based on obsolete equipment and no parts available for old control system. Due to the new license, we need a control system that will last the remainder of the life of the unit and this DCS system will meet those requirements.

DocuSign Envelope ID: 9050B136-95EE-470F-A834-1DE7B63C8BF6

Approvals:

Concept Approval List

Present Need: On approval, this document authorizes the Generation Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization. EPM will begin work on this project when a completed and approved charter is in place.

Title	Approver	Approval Limit	Signature	Date
Generation Planning Supervisor	George McKenzie	$100K	DocuSigned by: George L. Mckenzie II F35F930DD948493...	4/19/2023 | 1:15 PM ED
Director of Generation Planning	David Thornock	$250K	DocuSigned by: David E Thornock 31C4AFE905164D3...	4/19/2023 | 2:50 PM ED
Director of Generation Asset Strategy	Scott Hugo	$250K	DocuSigned by: Scott A Hugo 7743CD0EABA24C0...	4/26/2023 | 9:46 AM ED
Exec Director of Electric Supply Engineering	Richard Blumenstock	$2M	DocuSigned by: Richard Blumenstock C3E2F0B9920949B...	4/26/2023 | 5:26 PM ED
VP of Electric Supply	Timothy Sparks	$5M	DocuSigned by: Timothy J Sparks 8016E70683B04D6...	5/1/2023 | 7:45 AM EDT
SVP of Transformation and ENG	Tonya Berry	$20M	DocuSigned by: Tonya L Berry BEAA3C1321D54C4...	5/1/2023 | 8:28 AM EDT

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

Consumers Energy Count on Us®

Concept Approval

Ludington Pumped Storage Unit Governors

Date: 6/10/2024

Prepared by: Paul Ohep

Figure 1. Ludington pumped storage station.

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

Executive Summary

The Ludington Pumped Storage Plant Unit Governor systems are essential for hydraulic control and overall plant safety. Currently, the system is obsolete and lacks redundancy, posing significant risks to reliability and safety. A comprehensive upgrade is needed to address these issues.

Problem Description

The governor system controls water flow through wicket gate adjustments, managing various operational modes, including emergencies. It is identified as high-risk due to its lack of redundant controls and mechanical defenses.

Current Challenges

The Atlas electrical controller, installed in the early 2000s, lacks OEM (Original Equipment Manufacturer) support and essential parts. Only one spare controller exists for all six units, and its reliability is uncertain. Additionally, the controller's limited compatibility with the plant's Ovation system complicates troubleshooting. Mechanical failures frequently impact wicket gate operations, and historical oil pump failures risk operational mechanisms.

Alternative Solutions Considered

Do Nothing: Estimated at $19.8M per occurrence, this option poses high failure risks, potential capacity, and NEV losses, and increased dam failure risk.

Controls Replacement Only: Estimated at $4.0M, this option does not address critical mechanical components, leading to incomplete risk mitigation.

Partial Replacement (Selected Option): Estimated at $17,719,930, this approach includes a selective upgrade of control and mechanical systems, integrating with the Ovation system. It enhances reliability, ensures spare part availability, and improves safety.

Conclusion

The partial replacement option is chosen for its balanced approach, addressing critical risks without unnecessary expenditure. It ensures long-term stability and safety by upgrading both control and mechanical components, aligning with industry best practices and leveraging modern technological advancements.

Financial Summary

Funding Type: Capital

Cost: 51% dollars - $**9,037,164**. 100% dollars - $**17,719,930**

Proposed Start Implementation Year and span

2022, 8-year span.

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

Problem Description

The Ludington Pumped Storage Plant employs a sophisticated governor system responsible for hydraulic control over water flow through the plant's pump/turbine system. This system is critical for managing the unit's operations across various modes, including emergency scenarios, power generation, and mechanical safety.

System Description and Issues

1. **Governor System Functionality:**
    - **Primary Role:** Controls water flow through adjustments in wicket gate positions, influencing power output levels.
    - **System Components:** Utilizes high-pressure oil for operating servo motors linked to wicket gates.
    - **Operational Scope:** Ensures smooth transitions in operational modes such as generation control, pump operations, and emergency dewatering.
2. **Critical Risk Factors:**
    - **System Reliability:** Identified as a high-risk component in the "Issue-Specific Semi-Quantitative Risk Analysis for Emergency Overflow Spillway Operation" report due to its lack of redundant controls and mechanical defense in-depth components.
    - **Safety Implications:** Essential for preventing scenarios like reservoir overtopping and dam failure, which pose significant safety risks.

Current System Challenges

1. **Atlas Electrical Controller Issues:**
    - **Aging Technology:** Installed in the early 2000s; lacks current OEM support with essential parts no longer available from the original manufacturer, General Electric.
    - **Spare Unit Risks:** Currently, only one spare Atlas controller is available for all six units, which increases the risk of operational disruptions if the active unit is damaged by external factors like lightning strikes or overheating. Additionally, the spare controller is the same age as the original equipment and has not been used for several years, so its reliability cannot be fully guaranteed at this time.
    - **Integration and Maintenance Challenges:** The Atlas controller's limited capability with the plant's Ovation system complicates troubleshooting, leading to longer downtime during failures. This system's shortcomings are compounded by its inadequate production historian capabilities.
2. **Mechanical System Deterioration:**
    - **Operational Reliability:** Frequent mechanical failures have impacted the effectiveness of wicket gate operations, posing risks of "runaway" unit conditions under failure modes. The probability of a runaway unit condition under certain

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

modes of operation does exist but could be minimized by modern design features.

- **Component Wear:** Historical oil pump failures could cause binding of the distributing valve, making the operating mechanism stuck in its current position.

3. Outdated Component Concerns:

- **Reliability Threats from Aging Components:** The existing electrical system contains various original relays, timers, and instruments that are beyond their service life, posing risks to unit reliability.
- **System Obsolescence:** Continuous reliance on these outdated components without readily available replacements heightens the risk of unexpected failures.
- **OEM Support Discontinuation:** Original system components are obsolete, with sporadic support transitions impacting long-term maintenance and parts availability.

4. Conclusion

The Unit governor systems at the Ludington Pumped Storage Plant are crucial for ensuring safe and efficient plant operations. Currently, the system is compromised by outdated components and a lack of redundancy, highlighting a pressing need for a comprehensive upgrade. A critical spare component of this system (Atlas) has become completely obsolete, significantly increasing the risk to the station. Fortunately, the past 50 years have seen significant technological advancements that address many of the issues historically experienced with the LPS governors. These modern solutions not only enhance the system's reliability but also correct previous deficiencies, providing a valuable opportunity to significantly improve the system’s performance and safety. Upgrading these components is crucial to mitigate the high level of risk associated with the current governor system.

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

Alternative Solutions/Alternatives Considered

1. Do Nothing – Estimated cost of $19.8M per occurrence.

The "Do Nothing" alternative involves maintaining the current governor systems at the Ludington Pumped Storage Plant (LPS) without implementing the proposed upgrades. This option would forgo any modernization efforts and continue operations with the existing Atlas controllers and mechanical systems, which are significantly outdated and lack modern safety features.

Implications

1. **Reliability and Risk:**
    - **Failure Probability:** The current probability of a critical failure in this system is estimated at 20% within the next five years, with an annual increase of 5% thereafter. A critical failure is defined as an event that causes a forced outage lasting at least two weeks.
    - **Unit reliability:** A scenario in which our only spare Atlas controller failed if in use would result in one of the units being offline for 8 months.
2. **Increased Costs:**
    - **ROR and O&M Costs:** Continuing with the existing system will result in increased Repair, Operating, and Maintenance costs due to the aging components that are nearing or have reached the end of their service life.
    - **Component Replacement – cost of $4.4M (100% dollars):** As many parts are now obsolete, finding suitable replacements could be costly and potentially require custom solutions, further increasing expenses. If Atlas were to fail the plant only has 1 spare Atlas for all six units and no ability to obtain a new spare. The cost of replacement for one unit would be an estimated $4.4M. This considers all loadings and a 50% markup for emergency rush installation.
    - **Net Energy Value losses - $2.7:** An 8-month outage of a single unit at Ludington Pumped Storage Plant is estimated to result in a net energy value (NEV) loss of $2.7 million. This estimation is based on an annual NEV of $4 million per unit. The calculation assumes a worst-case scenario, as such an extended outage would result from an unplanned failure rather than scheduled maintenance.
    - **Potential Capacity losses - $12.7M:** If one unit is out of service for 8 months, the estimated potential capacity losses are $12.7 million. This is based on the following assumptions:
        1. Cost of New Entry (CONE): $127K/MW-year
        2. 75% of CONE: $95K/MW-year (used for calculation)
        3. With 178 average Zonal Resource Credits (ZRCs) for all Ludington units, the loss calculation is as follows:

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

4. Replacement for 3 out of 4 seasons (75% of the year): 178 ZRCs * 75% * $95K = $12.7M

   This estimation assumes the need to replace capacity during a forced outage to avoid future accreditation impacts (no three-year penalty), valuing capacity at 75% of CONE.

- **Safety Concerns:** This option neglects one of the highest contributing systems to reservoir overtopping risks as identified in the "Issue-Specific Semi-Quantitative Risk Analysis for Emergency Overflow Spillway Operation" report. Continuing with the current system could significantly increase the risk of dam failure due to inadequate response capabilities during critical conditions.

3. **Technological Obsolescence:**

- **Outdated Technology:** The current unit governor systems use technology surpassed in efficiency, reliability, and safety. Better technology exists today that can substantially decrease the risk of failure and improve operational control.

Conclusion

While initially cost saving, the "Do Nothing" option presents substantial long-term risks and costs, making it an unsustainable choice. The increasing likelihood of failures on obsolete critical components, combined with the outdated nature of the current systems and the availability of advanced technology, strongly argues against this alternative.

2. Controls replacement only– Internal loaded estimate of $4.0M (100% Dollars)

Option 2 focuses on the replacement of the electrical control systems for all six units at the Ludington Pumped Storage Plant. This option is limited to updating the control systems without addressing any of the mechanical components.

Implementation Details

- **Cost and Timing:** The project is estimated to cost $4.0M in capital expenditure. Implementations are planned during the plant's scheduled outages, which occur every three years and last for three weeks, thereby minimizing operational disruptions.
- **Equipment Lifespan:** The upgraded electrical control systems are expected to last 20-25 years, significantly improving the reliability of control operations.

Limitations

- **Exclusion of Essential Mechanical Components:** Option 2 focuses solely on updating the electrical controls and does not address the critical mechanical components necessary for the plant's operational integrity. The following key components identified by internal subject matter experts as crucial for reliable operation remain unchanged and are not included in this upgrade:

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

- **Distribution Valve (Secondary Mechanical Rate):** Essential for controlling the flow and pressure within the system.
- **EHI (Electro-Hydraulic Interface):** Crucial for interfacing between electrical signals and hydraulic operations.
- **Retarding Valves for Wicket Gate Servomotors**: Important for controlling the speed and positioning of the wicket gates.
- **Drain Oil Piping for Governor Pressure Tank:** Necessary for maintaining proper oil pressure and flow.
- **Governor Oil Sump Sight Glass and Sump Foaming**: Critical for monitoring and maintaining oil levels and quality (first unit only).
- **Emergency Distributing Valve Bypass:** Provides a critical safety mechanism during system failures.
- **Hydraulic Piping and Tubing:** Integral for the seamless transfer of hydraulic fluids throughout the system.
- **Air Brake System:** Essential for the safe operation and maintenance of mechanical movements within the governor system.
- **Incomplete Solution:** While the control upgrades may enhance certain operational aspects, critical mechanical issues remain unmitigated, which can lead to increased system vulnerability.

Risk Assessment

- **Initial Failure Probability Reduction:** The likelihood of critical failures is projected to decrease to 3% within the first five years post-implementation.
- **Long-term Risk Increase:** The probability of failures is expected to increase by 2.5% annually after the initial period, due to the aging and unreplaced mechanical components.

Conclusion

While Option 2 offers a less expensive alternative with minimal disruption to plant operations, it provides an incomplete solution by neglecting essential mechanical components of the system. This option's scope is limited to control replacement, which does not address the mechanical vulnerabilities crucial for reliable system operation. The failure to replace key components identified by our subject matter experts results in this option not being viable for ensuring the long-term operational stability and safety of the plant.

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

3. Select Replacement – Internal estimate $17,719,930 (100% dollars).

Option 3 entails a selective upgrade of the control and mechanical systems at the Ludington Pumped Storage Plant, targeting components most critical for improving reliability and operational efficiency. This option integrates a new control scheme compatible with the upcoming Ovation system and replaces essential mechanical components that are nearing the end of their service life and have a history of damage or failure.

Implementation Details

- **Control System Upgrade:**
  - **Integration with Ovation System:** The new control system will be designed to pair seamlessly with the advanced Ovation system, enhancing the plant's operational capabilities through improved control and diagnostics.
  - **Electrical Components Replacement:** Critical electrical components and instruments will be updated to ensure ongoing spare parts availability and to maintain system reliability.
- **Mechanical System Upgrades:**
  - **Component Replacement:** Major mechanical components such as the distributing valve, pilot valve, unloader, and brake valve will be replaced due to their critical role in system operation and current end-of-life status.
  - **Retention of Key Components:** Servo motors, accumulators, significant portions of the power piping, and the existing cabinet structure will be retained, minimizing the scope and cost of physical changes.
- **Safety Enhancements:**
  - **Defense in Depth Improvements:** New safety features, including a distributing valve bypass, will be incorporated to enhance the system's overall safety profile and operational resilience.
- **Cost and Schedule:**
  - **Estimated Cost:** The total capital expenditure for this option is estimated at $17,719,930 for all units.
  - **Implementation Schedule:** The replacement work will be strategically planned to coincide with scheduled outages to minimize disruption to plant operations.

Industry Benchmarking

- **Sector Best Practices:** Feedback from major hydroelectric OEMs (Original Equipment Manufacturer) and budgetary assessments indicate that this partial replacement strategy is commonly adopted by utilities with similar units. This approach aligns with industry best practices and meets reliability targets effectively.

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

Risk Assessment

- **Balanced Approach:** By selectively replacing and retaining components, this option strikes a balance between cost-efficiency and substantial system improvements. It addresses the most critical vulnerabilities without the need for a complete system overhaul.
- **Reliability and Spare Parts:** Updates to control and mechanical systems will significantly reduce the risk of failures and ensure easier maintenance through improved parts availability.
- **Reduced Initial Failure Probability:** Post-implementation, the probability of a critical failure is estimated to decrease to 1% within the first five years.

Conclusion

Option 3 presents a robust strategy for the governor system modernization at Ludington Pumped Storage Plant. It presents a comprehensive approach to upgrading critical components, ensuring compatibility with new technological standards, and adherence to industry best practices. This approach effectively addresses the plant's needs, proposing a solution that enhances long-term operational stability.

Recommended Alternative: Option 3 - $17,719,930 (100% dollars)

After thorough evaluation of all alternatives for modernizing the governor system at Ludington Pumped Storage Plant, Option 3 - Partial Replacement has been selected as the most viable and beneficial approach. This decision is grounded in a comprehensive analysis of the plant's needs, the potential risks associated with different strategies, and the overall goal of enhancing system reliability and safety while ensuring cost-effectiveness.

Rationale for Partial Replacement

1. **Balanced Approach to Modernization:**
    - **System Compatibility and Upgrades:** The partial replacement will integrate seamlessly with the new Ovation system, enhancing control and monitoring capabilities. This strategy allows for the retention of robust existing components such as servo motors and accumulators, while outdated and critical components like the distributing valve, pilot valve, unloader, and brake valve are replaced to address specific vulnerabilities.
    - **Reduction in Risks:** By replacing obsolete components and improving the system design, this option significantly decreases the likelihood of unit failure and the associated risk of dam failure. Additional safety measures and defense-in-depth features are incorporated to bolster system reliability during extreme conditions.

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

2. **Cost and Efficiency Considerations:**
    - **Cost-Effective Solution:** Compared to a complete replacement, this option is less costly and avoids unnecessary expenditure on replacing still-functional components. It provides a targeted, effective upgrade without the extensive capital outlays required for a full system overhaul.
    - **Minimized Operational Disruption:** The upgrades can be implemented during scheduled outages, thereby minimizing disruption to plant operations, and reducing the downtime typically associated with more extensive refurbishments.
3. **Addressing Obsolescence and Enhancing Reliability:**
    - **Spare Part Availability:** The upgrade ensures that all replaced components are supported with readily available spare parts, addressing one of the critical vulnerabilities of the current system.
    - **Addressing Legacy Issues:** The existing control system and mechanical components have demonstrated increasing failure rates. This trend is poised to worsen, as highlighted by the rise in failures over the past decade and the expected continuation of this trend. Modernizing these components directly addresses these reliability issues.
    - **Improved OEM Support**: Transitioning to newer systems with robust OEM support from GE/Nexus facilitates better maintenance and quicker responses to system issues, which enhances overall plant reliability.
4. **Enhancements in Monitoring and Troubleshooting:**
    - **Improved Diagnostic Capabilities:** The integration with advanced systems like Ovation enhances the plant's ability to perform condition monitoring and decreases troubleshooting time, directly reducing operational costs and system downtime.
    - **Updated Documentation:** Replacing old, often illegible electrical drawings with updated, accurate documentation will further enhance maintenance efficiency and system operability.

Option 3 - Partial Replacement stands out as the most strategic approach for updating the governor systems at Ludington Pumped Storage Plant. It balances the need for modernization with cost considerations, addresses the critical risks associated with the current system's obsolescence, and aligns with industry best practices for reliability and safety enhancements. By choosing this option, the plant will not only meet current operational demands but also establish a foundation for sustainable long-term performance and safety.

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

Budget Revision Justification

The initial estimate for the modernization of the governor systems at Ludington Pumped Storage Plant was set at $4.55 million (51% dollars). However, recent developments in the bidding process have necessitated a significant revision of the project budget. The current internal estimate has been adjusted to $9,890,751 (51% dollars), reflecting updated market conditions and actual bids received.

Reasons for Budget Increase

1. **Actual Bids Exceeding Initial Estimates:**

- The lowest cost bid received for the project was slightly under $13 million (100% dollars), significantly higher than the initially estimated $9.1 million. This discrepancy highlights a substantial underestimation in the original financial planning.
- The only other bid received was over $20 million, further indicating that the initial cost expectations were unrealistically low.

2. **Initial Budgeting Basis:**

- The original estimates were based on bids received four years ago. Since then, market conditions have changed, and costs for materials, labor, and technological components have increased, impacting the overall project cost.

Scope of work

The project aims to modernize the governor systems of all six units at Ludington Pumped Storage Plant (LPS). This comprehensive upgrade is designed to enhance operational reliability, safety, and compliance with current technological standards.

Components of Modernization

1. **Controller and Electrical System Upgrades:**
    - **Controller Replacement:** The current Atlas controllers will be replaced with state-of-the-art controllers featuring Human-Machine Interfaces (HMIs) for enhanced user interaction and monitoring.
    - **Auxiliary Electrical Equipment:** Introduction of new auxiliary electrical systems to support the upgraded controllers.
    - **PLC Enhancements:** Additional Programmable Logic Controller (PLC) functionalities will be incorporated to minimize failure modes and provide component redundancy.
2. **Mechanical System Redesign:**
    - **Hydraulic Control Devices:** Installation of new hydraulic controls tailored to address and rectify existing operational challenges.

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

- **Safety Features:** Implementation of advanced safety features like a distributing valve bypass to mitigate risks associated with unit control loss.

3. **System Compatibility and Integration:**
    - **Ovation System Compatibility:** Ensuring new systems are compatible with the future Ovation system to enhance trending and troubleshooting capabilities.
    - **Drawing Package:** A new, clear drawing package will be provided to replace outdated and illegible documentation, facilitating better maintenance and operational procedures.
4. **Implementation Schedule:**
    - **Staggered Installation:** The upgrade will be executed on two units per year, aligned with each unit's scheduled periodic outage to minimize operational disruption.

Compliance and Longevity

- **Codes and Standards:** All modernization efforts will adhere to applicable international and industry-specific standards.
- **Service Life Specifications:**
    - **Mechanical Components:** Specified for a minimum of 50 years of mechanical service life.
    - **Electrical Controls:** Specified for at least 20 years of service life, ensuring long-term reliability and efficiency.

Funding and Timing

- Funding that has been previously committed for this project: $440,225
- A Scheduled outage is required for this project.
- Desired implementation year: first year spend 2022 with installation planned for 2025-2028.
- System Engineer: Steven Morris

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

Conceptual Estimate

Year	Loaded Cost	Description
2022	**$ 96,011**	51% dollars. Engineering and planning
2023	**$ 128,504**	51% dollars. Engineering and planning
2024	**$777,250**	51% dollars. Engineering and planning. Procurement and preparation for installation
2025	**$1,431,751**	51% dollars. Final design and installation
2026	**$2,182,915**	51% dollars. Installation
2027	**$2,182,915**	51% dollars. Installation
2028	**$2,512,316**	51% dollars. Installation
2029	**$25,500**	51% dollars. Monitoring, Post Maintenance testing, Documentation and Closeout

Total Cost: 51% dollars - $9,037,164. 100% dollars – $17,719,930

Asset Strategy Approval Comments

The Asset Strategy team recommends approving Option 3 - Partial Replacement for the governor systems at Ludington Pumped Storage Plant due to critical concerns about part obsolescence and dam safety.

Key Points Supporting Approval

1. **Mitigation of Obsolescence and Reliability Issues:**
    - **End-of-Life Components:** Critical components have reached their service life and are obsolete, significantly impacting system reliability and necessitating their replacement to avoid Unit availability.
2. **Enhancement of System Redundancy and Reliability:**
    - **Redundancy Improvements:** The introduction of redundancies and defense in depth will provide a failsafe operational setup, crucial for maintaining operational integrity.

This investment **is** included in the current electric rate case.

Amount set for Bridge year: $345,000

Amount set for test period: $424,000

Docusign Envelope ID: 64F4632D-762E-4D5D-BC5C-F2ADD390D5F9

Approvals

Title	Approver Name	Date
Generation Planning Manager George L. Mckenzie II	DocuSigned by: George L. Mckenzie II E35E930DD948493...	6/14/2024 | 9:34 AM EDT
Director of Generation Asset Strategy Scott Hugo	DocuSigned by: Scott Hugo 31EC7A87F8F84C0...	6/14/2024 | 7:41 AM EDT
Exec Director of Electric Supply Engineering Richard T. Blumenstock	DocuSigned by: Richard T. Blumenstock C3E2F0B9920940B...	6/15/2024 | 9:07 AM EDT
VP of Electric supply Srikanth Maddipati	DocuSigned by: Srikanth Maddipati 67DA622787D2488...	7/31/2024 | 12:41 AM EDT

Consumers Energy
Generation Project Initiation Document & Concept Approval
Project Process for input to the Business Planning System (BPS)

SELECT Project Initiation or Concept Approval Stage

○ Project Initation ◉ Concept Approval

SELECT Capital or Major Maintenance Funding

☒ Capital ☐ Major Maintenance

General Information	
Proposed Project Title:	LPS Lower Penstock Expansion Joint Chamber Waterstop
Generating Site / Plant/ Unit	

Problem Statement / Opportunity:

The Lower Penstock Expansion Joint (LPEJ) Chambers enclose the penstock expansion joints in concrete chambers below grade. The penstock expansion joints allow penstock expansion with seasonal temperature changes. There are six LPEJ chambers and seals aligning with each of the six units at LPS. The waterstop is a membrane intended to prevent groundwater from leaking into the LPEJ chamber. Some joints have been leaking since shortly following plant construction. In February 2017, a depression was discovered upstream of the powerhouse near Unit 3, which was caused by transport of soil into the chamber by inflowing groundwater through the waterstop. Historically, Consumers Energy sealed the waterstop leaks into the LPEJ chambers through the use of hydrophobic polyurethane grout. The waterstops are at the end of their expected life and grouting is no longer an effective solution. This is a threat to generation. If the settlement of the LPEJ chamber(s) and penstock reaches a defined threshold the affected unit(s) will remain in a forced outage until the LPEJ chamber(s)/penstock can be stabilized and re-adjusted back into an acceptable elevation / orientation impacting PSCR. This is Potential Failure Mode (PMF) number LPS–19–N– IV– 01, “Failure of the penstock resulting from settlement of the Lower Penstock Expansion Joint (LPEJ) encasement chamber initiated by internal erosion through a defect in the LPEJ concrete waterstop. “

Project Description / Project Scope:

The intent of the waterstop replacement is to prevent further loss of material fines and stabilize the chamber and penstock expansion joint movement. Scope would include engineering the design for the proposed waterstop strategy and dewatering plan, a dewatering pump test, replacement of the physical waterstop and dewatering the surrounding groundwater. The evaluated options include: installing a new waterstop in place of the current one, an interior surface seal on top of the current waterstop and an exterior surface seal. Following the completion of the Schnabel Engineering options study installation of a new conventional waterstop was the chosen option.

In 2021, the Unit 3 chamber was stabilized to allow for the Unit 3 waterstop to be replaced without impacting the penstock or impacting the long term ability to generate from Unit 3. The Unit 3 chamber was stabilized due to the 1.3" of offset due to settlement of the upstream side of the chamber; this impacted the steel expansion joint portion of the penstock. To mitigate the risk of the

Consumers Energy

Generation Project Initiation Document & Concept Approval

Project Description / Project Scope:
penstock binding and ensure continued operability of Unit 3, the Unit 3 chamber was stabilized by installing a secant pile shaft and placing grout underneath the chamber to raise it back to it's pre-2017 state. In addition, FERC required 3 PFMA (Potential Failure Mode Analyses) for the project, which resulted in an increase in engineering costs for 2021.

Project Justification: (place an X to the left of each justification)

	Safety: If safety provides specific safety requirement (MIOSHA, etc.,).	

	Regulatory: If regulatory provides specific requirement (EPA, MDEQ, etc.,).	

X	Compliance: If compliance provides specific CEC compliance requirement.	FERC compliance within Dam Safety requirements for probable failure mode idenfied per independent Engineering Analysis probable failure mode number LPS–19–N– IV– 01

Economic: For economic projects provide inputs needed the economic evaluation including:		
	ROR Reduction	
	O&M and / or PSCR cost changes:	
	Changes in periodic factor:	
	Heat Rate Improvements:	
	Other: Describe (Strategic, broke/fix, infrastructure, facilities, etc.,)	Broke Fix, Infrastructure, threat to generation

Alternatives considered: (all $$ values are in 100% Dollars)
Alternative 1: Replace Waterstop The options study came up with 3 options to replace the waterstop: 1. Replace Waterstop with a Conventional Waterstop 2a. Replace Waterstop with Interior Surface Seal in the Dry 2b. Replace Waterstop with Interior Surface Seal in the Wet 3. Replace Waterstop with Exterior Surface Seal Alternative 2: Do nothing

Consumers Energy
Generation Project Initiation Document & Concept Approval

Alternatives considered: (all $$ values are in 100% Dollars)

Alternative 2a was eliminated because it is more expensive than doing option 2b in the wet, with a total of $5,100,000 for all 6 chambers in the dry.
Alternative 2b is estimated to be $3,000,000 for all six chambers. Alternative 2b was eliminated because it would be high maintenance given the expected life of the components and the difficulty of properly aligning both sides of the expansion joint chamber during installation. As a course of normal maintenance the bolting would need to be retorqued every 5-10 years. The Teflon facings would need to be replaced every 10 years. The neoprene pads would need to be replaced every 20 years.

This would result in estimated major maintenance costs of $278,520 every 5-10 years, $472,560 in Years 10 and 30 after construction, and $736,980 in Years 20 and 40 after construction. These added maintenance costs would make the total cost of this option more expensive than Alternative 1, with an added risk of potential misalignment and requirement for mitigation actions. There are 6 chambers.

Alternative 3 was not selected due of the risks associated with excavating the shafts to nearby critical infrastructure, adjacent penstocks and adjacent chambers, the high cost associated to this option, the risk of misalignment during installation and risk of backfill of the shafts and gallery interfering with the movement of the expansion joint.

If we do not replace the waterstops, groundwater will continue to leak into the Lower Penstock Expansion Joint (LPEJ) Chambers, transporting fines and potentially causing settlement of the chamber that will require mitigation to maintain compliance to FERC Dam Safety requirements for LPS. We have observed settlement of the Unit 3 LPEJ Chamber at present. If the leakage issue and joint degradation is not addressed, fines will continue to be transported into the LPEJ chamber leading to continued settlement up to and including the requirement to be make unit(s) unavailable to prevent penstock binding and potential failure.

Additionally, if the “Do Nothing” option is selected, there will be continued O&M costs associated with injecting grout in the LPEJ chamber(s) waterstops to temporarily reduce the amount of leakage into the expansion joints, which has been proven to be a short term fix (see grouting history attachment).

Alternative Selected:

Alternative 1 was selected as it prevents groundwater and fine soils from being transported into the LPEJ Chamber(s), addressing the cause of voids in Transformer Alley. It prevents further settlement of the LPEJ Chamber(s), which ensures the units can continue operating through the next license period.

Alternative 1 (conventional waterstop) is a proven technology that is able to accommodate seasonal movements, requires minimal maintenance and has an expected life of 50 years. The groundwater would need to be dewatered, which is included in the cost. The estimated cost of Alternative 1 is $950,000 per chamber. Alternative 1 in total costs $7,500,000 and has minimal ongoing maintenance over the lifetime of the waterstop.

Consumers Energy
Generation Project Initiation Document & Concept Approval

Project Benefits:
Replacing the waterstops stabilizes the LPEJ chambers and penstocks from additional settling movement as fine soils will no longer be transported through the waterstop by groundwater and leading to undermining the LPEJ chambers. This also eliminates the threat to generation due to the penstock binding potential caused by LPEJ chamber settlement and reduces the risk of a potential dam safety failure mode further allowing the units to maintain expected operational goals for the next license period. This also eliminates the cause of voids / depressions in transformer alley allowing that area to be resurfaced that to date has been avoided due to risk of damage by depressions. This further eliminates O&M costs associated with grout injection in the expansion joint chambers that have proven to be only a temporary solution.

Present Need:
The waterstops need to be replaced in order to prevent the lower penstock expansion joint chambers from settling and stop the formation of new voids in transformer alley. This also reduces costs associated with additional inspection and monitoring of the LPEJ chambers and costs associated with additional sand removal from the station sump and oil/water separator.

Timing Impact – Is an outage required?	
Estimated Outage Duration if needed	NA
Desired implementation year:	2020
Specify the impact if the recommended implementation year is changed:	If the project is delayed, more settlement of the LPEJs could continue to the threshold where the unit(s) may need to remain unavailable until the problem is addressed and more expensive repairs may be necessary.

Engineering and Conceptual Development
Provide the status of engineering and conceptual development below. Is additional engineering required to provide adequate cost/benefit information to fully evaluate the project? If yet, has conceptual funding been requested for funding been built into this request?
A detailed engineering options study was conducted by Schnabel Engineering to determine three options to address this, but additional engineering will need to done in early 2020. Additional engineering will be needed for dewatering.

Cost Estimation	
Total Estimated Project cost (51% dollars)	~~$3,675,049~~ 14,630,000
Identify funding that has already been spent or committed, if any. (Whole dollars)	$96,200
Contingency included in the estimated project cost in $	$551,257

Consumers Energy
Generation Project Initiation Document & Concept Approval

• Was the estimate developed based on a previous project of similar size and scope? • Was a formal estimate completed based on detailed engineering? • Was a formal estimate completed based on a conceptual engineering design? • Was an informal estimate done based on the recommended project concept? • If an informal estimate was done, please identify the basis for having confidence in this estimated cost. • The project planning workbook provides an excellent tool to support this process. If an estimate has been completed, provide the estimate with the submittal.
The construction budget estimate was based on a preliminary estimate from a contractor working with Schnabel Engineering on constructability. This value was added into the planning workbook. Project management and overheads were added to this estimate to get spending for 2020 and 2021. The budget assumes three LPEJs would be done in 2020 and the remaining three will be done in 2021. The final dollars will be added to the LTFP after detailed engineering with more detailed cost estimates. This estimate is assuming we would do option 1. Updated based on actual costs for the waterstop replacement construction, engineering, associated dewatering, asset monitoring and Unit 3 stabilization in 2021. Costs went up due to bids coming in higher than originally estimated and the costs of stabilizing Unit 3 chamber were added in. Closeout dollars were added to 2024.

Requested Cash Flow (whole dollar values): 51% Dollars	
Year	Dollar Value
2020	$403,826
2021	$5,620,000
2022	$3,878,000
2023	$2,703,000
2024	$25,500

Priority Code	
• Select a recommended project priority code and provide a basis.	
• Priority code table provided below	
Priority code	**Basis**
5	If the Lower Penstock Expansion Joint Chambers continue to allow the transport of water and sediments, the chambers could continue to settle, which could lead to a penstock to bind and a forced unit outage or penstock failure.

Consumers Energy
Generation Project Initiation Document & Concept Approval

Priority Basis Chart		
Rank	Title	Definitions
1	Legal, Regulatory	These are the items that CEC is required to do without flexibility
2	Safety	Safety items that must be addressed within one year due to hazard to employees.
3	Strategic	These are board approved projects, submitted outside the standard budget and LTFP processes. This work instruction does not apply for these items.
4	Critical Reliability	Deferral has a high likelihood of significantly impacting asset reliability in the near term. This category also includes spending to address long standing safety issues and regulatory commitments that have some flexibility with respect to implementation.
5	Important Reliability	Deferral has a high probability of impacting asset reliability. Projects that will significantly improve unit performance, key performance indicators will generally be in this category.
6	Desired Reliability	Repeated deferrals will impact long term reliability. One time short term deferral, while undesirable, is unlikely to impact reliability in a significant way. In general, items that are in this category in future years are good candidates for the up levers list.
7	Reliability and Performance Improvement	Spending that, while desirable, is lower priority. These items will be the primary candidates for the capital and major maintenance down levers lists.

Project Initiation Submittal Date:	5/28/19 (PID) 10/1/219 (CAD)

Upload to SharePoint Site per workflow:

Concept Approvals Only

On approval, this document authorizes the Generation Engineering group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization. EPM will begin work on this project when a completed and approved charter is in place

Approvals:
Approvals will be obtained via SharePoint Workflow according to the Total Project Value listed below

Consumers Energy
Generation Project Initiation Document & Concept Approval

Director Generation Planning (Approval limit $250k)
Director Asset Strategy Generation (Approval limit $250k)
Executive Director of Planning (Approval limit $500k)
VP of Electric Grid Integration (Approval limit $2,000k)
SVP of Transformation, Engineering & Ops (Approval limit $10,000k)

Additional Supporting information:
LPS Lower Penstock Expansion Joint Grouting History

Change the Project Stage on SharePoint to appropriate Project Stage of workflow.

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

Consumers Energy Count on Us®

Concept Approval

Covert Generating Station Generator Step-Up transformer replacement.

Date: 12/1/2023

Prepared by: John Slinkard and Paul Ohep

Figure 1. Covert Generating Station aerial view.

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

Executive Summary

Addressing the critical need for operational reliability at Consumers Energy's power generation facilities, this proposal explores the optimal strategy for ensuring a backup Generator Step-Up (GSU) transformer is readily available at Covert Generating Station. The urgency of this project stems from the increased risk of transformer failure due to the presence of corrosive sulfur, coupled with long procurement lead times of 2 to 4 years for GSU transformers.

Four options were meticulously evaluated: overhauling the existing GSU, procuring a new site-specific spare GSU, exploring leasing alternatives, and purchasing a single larger spare GSU that could serve both Covert Generating Station and Zeeland Generating Station.

Option 2, which proposes the procurement of a site-specific spare GSU, has emerged as the most viable solution. It ensures immediate availability of a replacement transformer, minimizing downtime and associated financial losses. This option mitigates potential complications arising from multiple installations associated with utilizing a leased GSU or usage of multi-site transformer. Moreover, it also offers the opportunity for CE to recover some costs through leasing agreements with other utilities.

This initiative, backed by the Asset Strategy Group, ensures that Covert Generating Station is equipped to address transformer failures swiftly and efficiently. Implementing this solution safeguards our ability to deliver reliable power to our consumers and demonstrates a strategic foresight in asset management.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	$16,355,000

Proposed Start Implementation Year

2024

Project Span Whole Years

4 Years

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

Problem Description

The Covert Generating Station features a combination of three gas turbine-powered plants and three steam turbine-powered plants, arranged in a one-on-one combined cycle configuration. This setup entails that each gas turbine unit powers the secondary winding of a three-winding transformer (GSU), while the corresponding steam-powered unit powers the tertiary winding.

GSU Explained: A Generator Step-Up (GSU) transformer is a critical component that steps up the voltage generated by a turbine before it is transmitted to the grid, ensuring efficient power transfer.

A GSU's failure can lead to significant power generation issues. Specifically, the GSUs at Covert are rated for 500 MVA and are equipped with forced oil and forced air cooling mechanisms. If a GSU were to fail, both the gas and steam turbine units connected to it would be unable to transmit power, leading to a potential loss of up to 400 MVA of generation capacity. This would prevent the generation of market value for Consumers Energy and its customers.

Further complicating the situation is the long lead time of 2 to 4 years for procuring a replacement GSU, and the lack of spare units at other facilities. The plant is projected to operating until at least 2040, thus making it crucial to have a reliable GSU ready for replacement.

Figure 2. Typical Step-Up transformer

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

Alternative Solutions/Alternatives Considered

1. **Do Nothing – Cost: $130.9 million ($16.4M for new GSU plus $114M in energy value and potential capacity lost)**

   This approach involves continuing the operation without procuring a spare GSU, essentially accepting the risks associated with a potential GSU failure. When under load, a failure of the GSU transformer is a serious concern, not only because of the high financial costs but also due to safety implications. Such a failure could lead to cascading consequences where other critical equipment, such as the generator or the 345kV breaker, could be damaged or fail.

   The GSU transformer is a critical component, and its failure would render the combined plant, consisting of one steam turbine and one gas turbine, inoperative. An overhaul or replacement of a GSU transformer, in the event of a failure, is expected to take a minimum of 12 months.

   There is an estimated 20% risk that the generator or the 345kV breaker might be damaged during an in-service failure of a GSU. The replacement cost for the generator is estimated at $20M and for a 345kV breaker, it is around $1M. These costs are not included in the alternative cost.

   The economic considerations for not having a spare GSU transformer on site, with an anticipated downtime of a full year, are significant. The breakdown for both potential capacity lost, and average energy value lost are as follows:

   Capacity value potential loss impacts - $66.6M:

   For this option, where the procurement and installation of the new GSU transformer are involved, a critical consideration is the multi-year financial impact, as determined by the Midcontinent Independent System Operator (MISO). MISO calculates and accredits capacity based on a rolling three-year average of historical capacity credits. Therefore, any outage that exceeds the 30-day threshold can significantly affect these calculations.

   Given the expected duration of the entire process is about one full year, this threshold will be exceeded. This prolonged downtime will, therefore, trigger the multi-year financial impact, altering the capacity accreditation and potentially affecting financial projections for several years.

   Average ZRC Reduction Post-Outage:

   - In the event of a 365-day outage, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for each season (based on 354 ZRCs per season).
   - This scenario leads to a potential annual daily loss of 118 ZRCs per season for each of these three years (354 ZRCs-236 ZRCs).

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

2. **Cumulative Potential Loss of Capacity Value Over Three Years:**
    - The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the 365-day outage and the additional 118 ZRCs/day applied over 90 days times four seasons over the subsequent three years.
3. **Calculation of Total Potential Loss:**
    - To estimate the potential capacity loss for this option:
        1. Calculate the Reduced Capacity Credits:
            - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
            - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).
        2. Add the Immediate Loss:
            - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (354 in this case). This gives us the immediate loss in capacity credits for that outage (31,860).
        3. Calculate the Total Revenue Loss:
            - Add the results from steps 1 and 2 to get a combined figure (63,720).
        4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)
    - This leads to a total estimated potential loss of capacity value of an estimated $16.6 million per season over the three-year period following the outage.
    - The total potential capacity value impact for a one-year outage, accounting for all four seasons, and including the impact on the subsequent three years is given by multiplying $16.6 million times four, resulting in an estimated $66.6 million potential impact.

<u>Average energy value estimated loss - $47.9M:</u>

For the scenario of a transformer failure with no spare on-site, there is a substantial potential loss in energy production due to an assumed 365-day outage. This loss can be quantified by considering the Net Energy Value (NEV) for that station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

This figure represents the potential average revenue loss for the Covert Generating Station during the outage period.

This analysis emphasizes the potential financial impact of not having a spare GSU on-site. Considering both the immediate potential loss of capacity value due to the outage, the reduced capacity credits in the subsequent three years as well as the energy value lost.

Overall advantages and disadvantages:

- **Advantages:** There is no immediate expenditure or need for storage.
- **Disadvantages:** This approach carries the highest long-term cost and risk, including the potential loss in revenue, safety hazards, and extended downtime for repairs or replacements.

2. Procure and Store a Spare GSU on-site Cost: $31.7M (including $15.3M in potential capacity value and energy value losses)

This alternative solution involves the strategic decision of procuring and maintaining a spare GSU transformer at the plant site.

- The procurement cost of the spare GSU is quoted at $12.5 million, based on an estimate from a well-known manufacturer of power transformers.
- The cost of constructing an appropriate foundation at the Covert site for the spare GSU is projected to be $200,000, as estimated by a specialized civil engineering company.
- Additional expenses related to engineering, Stand Up Transformer (SUT), and other logistical aspects are anticipated to be around $280,000.
- In the cost estimation process for large capital projects, it is a common industry practice to incorporate budget to account for unforeseen expenses that might occur during the project. The typical industry standard for such budgets can vary from 5% to 10% of the total project cost, depending on the project's complexity and risk level. For this specific project, we have included a conservative budget of 5% to the total estimated cost, considering our high predictability and control over project variables. Additionally, to cover regular operational and administrative expenses related to the project, a 20% overhead has been factored in. Consequently, the comprehensive cost estimate for this option now stands at $16.355 million (internal estimate).
- The economic considerations for procuring a spare GSU for the Covert Generating Station, with an assumed downtime of 31 days, are significant but more manageable when compared to leasing.

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

The breakdown for potential capacity lost, and average energy value lost are as follows:

Capacity value potential loss impacts - $11.2M:

For this option, the installation of the new GSU transformer stored on-site is anticipated to take approximately 30 days or slightly more. Specifically, if an outage exceeds 30 days, it triggers a potential multi-year financial impact due to the way MISO calculates and accredits capacity over time.

In this scenario, we will assume a worst-case scenario outage duration of 31 days within a single season. This results in the Station losing all 354 ZRCs (Zonal Resource Credits) for the season. This loss of ZRCs would result in a multiyear capacity impact, as capacity accreditation by MISO is based on a three-year average of historical capacity credits. It is important to note that if the outage had been limited to 30 days or less, or if the outage spans across parts of two separate seasons there would be no loss of ZRCs for either season, and consequently, no capacity impact.

Average ZRC Reduction Post-Outage:

- In the event of a 31-day unplanned outage during a single season, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for that season (based on 354 ZRCs per season).
- This scenario leads to a potential daily capacity loss of 118 ZRCs across an entire season (90 days) for each of these three years (354 ZRCs-236 ZRCs).

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the 31-day outage and the additional 118 ZRCs/day applied over 90 days (full season) over the subsequent three years.
- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:
        - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
        - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

2. Add the Immediate Loss:
    - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (31 x 354 in this case). This gives us the immediate loss in capacity credits for that outage (10,974).
3. Calculate the Total Revenue Loss:
    - Add the results from steps 1 and 2 to get a combined figure (42,834).
4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)

- This leads to a total estimated potential loss of capacity value of an estimated $11.2 million over the three-year period following the outage.

Average energy value estimated loss – $4.1M:

For the Covert Generating Station, under the scenario of leasing a spare GSU, there is a substantial potential loss in energy production due to an assumed 31-day outage. This loss can be quantified by considering the Net Energy Value (NEV) of the station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 31-day outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($47.9M/year)/(365days/year)) x 31 days = $4.1M

This figure represents the potential average revenue loss for the Covert Generating Station during the outage period.

On-site spare overall advantages and disadvantages:

Advantages:

- Having a spare GSU on-site ensures rapid restoration of operations in case of a failure, thereby minimizing revenue losses.

Disadvantages:

- The approach necessitates a sizable upfront investment and requires additional storage space on-site.

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

3. **Leasing a GSU Transformer - $36.8M in energy and potential capacity losses plus $720,000 over 20 years ($36,000/year):**

This alternative explores the feasibility of entering into a lease agreement for a GSU transformer. Leasing for units of this size is a standard approach, often entailing a reservation fee of an estimated $3,000 per month. Over a span of 20 years, which is the expected life expectancy of such units, the total cost amounts to $720,000. This translates to an annual expense of an estimated $36,000. However, leasing comes with certain conditions and restrictions:

- The owner of the leased equipment can request the unit back at any point, based on their requirements.
- Availability is not guaranteed as the unit may not be on hand when needed. An industry search and examination of the transformer strategic reserve indicated that there are currently no spare units available for lease.
- Potential capacity value and energy value impacts.

Capacity value potential loss impacts - $25.0M:

For the leasing option in the GSU project, we are assuming the occurrence of an unplanned outage at the most inopportune time, specifically a scenario where a 90-day outage spans across two MISO seasons. The outage is projected to last for 31 days in one season, with the remaining duration extending into the next season. This situation results in the loss of Zonal Resource Credits (ZRC) capacity value for two separate seasons, which, due to MISO's capacity accreditation method based on a three-year historical average, effectively doubles the amount of lost capacity value over the next three years.

Average ZRC Reduction Post-Outage:

- In the event the postulated scenario, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for that season (based on 354 ZRCs per season).
- This scenario leads to a potential daily capacity loss of 118 ZRCs across an entire season (90 days) for each of these three years (354 ZRCs-236 ZRCs).
- For the unplanned 90-day outage spanning across two seasons assumed in this case, the 354 ZRCs will be multiplied times two to yield 708 ZRCs.

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the first 31-day outage in one season and then for the 59-

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

day outage on the following season. It also adds 118 ZRCs/day applied over 90 days (full season) over the subsequent three years.

- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:
        - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
        - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).
        - This result is multiplied times two to account for the impacts to a second season. (63,720)
    2. Add the Immediate Loss:
        - Next, multiply the number of days the plant is offline by the total ZRCs lost (354 in this case). This gives us the immediate loss in capacity credits for the 90-day outage (31,860).
    3. Calculate the Total Revenue Loss:
        - Add the results from steps 1 and 2 to get a combined figure (95,580).
    4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)
- This leads to a total potential loss of capacity value of an estimated $25.0 million over the three-year period following the outage.

<u>Average energy value estimated loss - $11.8M:</u>

For the Covert Generating Station, under the scenario of leasing a spare GSU, there is a substantial potential loss in energy production due to an assumed 90-day outage. This loss can be quantified by considering the Net Energy Value (NEV) of the station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 90-day outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($47.9M/year)/(365days/year)) x 90 days = $11.8M

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

Leasing option overall advantages and disadvantages:

Advantages: Leasing could offer a lower upfront cost compared to purchasing a new or spare unit outright.

Disadvantages:

- Unpredictable Availability: The availability of a leased GSU is uncertain, which can pose a significant operational risk.
- Recall Risk: There's always a possibility that the unit's owner may recall the GSU at any time, potentially causing unplanned operational downtime.
- Financial Risk: In the event of a plant shutdown due to the unavailability of a GSU, there could be a substantial financial impact.

4. Purchasing a Larger, Multi-Site GSU Transformer – Cost: $58M - $27.4M plus $30.6M in potential capacity and energy value losses:

This alternative considers purchasing a single larger spare GSU transformer that is suitable for both Zeeland Generating Station (ZGS) and Covert Generating Station (CGS). Internal economic models project the final costs to be estimated at $58M when factoring in additional expenses such as reinstallation of original overhauled GSU, modifications needed to accommodate the larger GSU at ZGS, additional outage costs and potential capacity and energy value losses. The breakdown of the internal estimate includes:

- $14M for the larger GSU transformer.
- $3M for transportation from another site and modifications needed at ZGS to accommodate bigger transformer.
- $1.25M for design and installation needs.
- $4.1M overhaul and re-installation cost of original GSU.
- $3.75M overhead estimate.
- $1.3M contingent cost to ensure compatibility with the original infrastructure. (5%)

Financial impacts:

For this option, which involves utilizing a common spare GSU for both Covert and Zeeland Generating Stations, several scenarios need to be considered to understand the financial implications fully. These scenarios vary depending on where the spare transformer is stored, and which site experiences a transformer failure. For this analysis, the worst-case scenario is assumed: the spare transformer is staged at Covert Generating Station, and a failure occurs at Zeeland Generating Station's Phase 2 transformer.

Assumptions:

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

For the multi-site spare option of the GSU project, the approach assumes two distinct outages, each with different implications for potential capacity value losses:

1. **First Outage - Unplanned and Single Season:**
    - The first outage, lasting 31 days, is considered unplanned and is expected to occur entirely within a single MISO season.
    - As this outage exceeds the 30-day threshold, it results in the complete loss of Zonal Resource Credits (ZRC) capacity value for that season. This loss also impacts the subsequent three years due to MISO's method of calculating capacity credits based on a three-year historical average.
    - This initial outage accounts for the period required to replace a failed GSU with the spare transformer.
2. **Second Outage - Planned and Spanning Two Seasons:**
    - The second outage, also spanning 31 days, is planned strategically to occur across the transition between two MISO seasons.
    - By dividing the outage between two seasons, each portion remains under the 30-day threshold in any single season, thereby avoiding additional ZRC capacity value penalties.
    - This outage involves reinstating the original GSU after its refurbishment, replacing the temporarily installed spare transformer.

<u>Capacity Value Potential Losses – $17.4M</u>

Average ZRC Reduction Post-Outage:

- In the event of a 31-day unplanned outage, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 366.7 ZRCs per year for that season (based on 550 ZRCs per season at Zeeland).
- This scenario leads to a potential daily capacity loss of 183.3 ZRCs across an entire season (90 days) for each of these three years (550 ZRCs-366.7 ZRCs).

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 550 ZRCs during the first 31-day unplanned outage and the additional 183.3 ZRCs/day applied over 90 days (full season) over the subsequent three years.
- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

1. We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (366.7 in this case) and the maximum possible ZRCs of 550.
2. Multiply this difference (183.3) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (49,491).

2. Add the Immediate Loss:
   - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (550 in this case). This gives us the immediate loss in capacity credits for that outage (17,050).
3. Calculate the Total Revenue Loss:
   - Add the results from steps 1 and 2 to get a combined figure (66,541).
4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)

This leads to a total estimated potential loss of capacity value of an estimated $17.4 million over the three-year period following the first unplanned outage.

For the multi-site spare option in the GSU project, the second outage is assumed to be planned to occur between MISO seasons. This careful timing ensures that the 31-day planned outage does not fall entirely within a single MISO season, thereby avoiding any loss of Zonal Resource Credits (ZRC) and potential capacity value.

Average energy value estimated loss - $13.2M:

For the Zeeland Generating Station, under the scenario of a multi-site spare GSU, there is a substantial potential loss in energy production due to two projected 31-day outages (62 total days). This loss can be quantified by considering the Net Energy Value (NEV) and the plant's generation capacity.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $77.5M per year for the Zeeland Phase 2 Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 62-day total outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($77.5M/year)/(365days/year)) x 62 days = $13.2M

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

This figure represents a significant potential revenue loss for the Zeeland Generating Station during the outage period.

Overall advantages and disadvantages for the multi-site spare option:

Advantages:

- **Flexibility**: A single spare unit could cater to multiple sites, potentially offering more operational flexibility.

Disadvantages:

- **Higher Costs**: The overall cost is significantly more than the initial purchase price when factoring in the additional work required.
- **Complexity**: This option could entail more logistical and operational complexities due to the constant movement and installation work.

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

Recommended Alternative: #2 – Purchase a spare Covert specific GSU

Option 2 emerges as the best long-term solution for ensuring a reliable spare GSU transformer at the Covert site. It eliminates dependencies on external variables and logistics that could influence the availability of the spare GSU. Additionally, the purchased unit could seamlessly be integrated as the new GSU at the location, thereby mitigating the need for multiple installations of temporary spares.

Project Benefits and Objectives:

1. **Reduction in Downtime and Financial Losses:** Opting for a dedicated spare GSU for Covert significantly reduces unit downtime in case of GSU issues or failures. This preemptive measure results in lowered financial losses during such events.
2. **Facilitation of Proactive Engineering Design and Planning:** Having a spare GSU readily available allows for easier engineering design and forward planning. This ensures that the installation of a spare or replacement GSU can be executed efficiently ahead of any emergent needs.
3. **Mitigation of Compatibility Issues:** This option mitigates potential challenges associated with installing GSUs not specifically designed for the Covert site, system, or application. It also prevents the complexities and risks of multiple installations within a short time.
4. **Revenue Recovery through Lease Agreements:** Owning a spare GSU provides Covert with the opportunity to enter lease agreements with other utilities that may require a spare, thereby enabling cost recovery over time.
5. **Addressing Increased Risk of Failure:** The oil analysis of Covert's transformers indicated the presence of chemicals for corrosive sulfur, putting them at an increased risk of failure. Having a spare GSU acts as a failsafe, ensuring continuity in operations while mitigating actions are taken.

Conclusion: Given the considerations, Option 2 proves to be strategically sound, financially prudent, and operationally efficient. It ensures reliability, provides contingency against unforeseen GSU failures, and aligns well with long-term planning objectives, making it the most favorable choice.

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

Scope of Work

The aim of this project is to ensure continuous operation at the Covert site by procuring and installing a spare Generator Step-Up (GSU) transformer that can be readily deployed at any GSU location within the facility.

Scope Description:

- **Procurement of Spare GSU Transformer:**
  The project entails defining the technical specifications for a compatible GSU transformer, initiating a procurement process, and ensuring quality assurance and compliance testing for the selected unit.
- **Infrastructure Development:**
  A dedicated foundation will be designed and constructed to facilitate quick installation of the transformer at any GSU location in Covert. This includes establishing a power supply and installing necessary accessories to maintain the transformer in an operational, "ready to use" condition.

Funding and Timing

- No funding has been previously committed for this project.
- No outage is required for this project.
- Desired implementation year: 2024
- Impact if the recommended implementation year is changed: Changing the recommended implementation year could lead to potential delays in addressing and mitigating the risks associated with GSU failures at the Covert site. Consequently, this may result in extended downtimes and increased financial losses, while also potentially jeopardizing the reliability of power supply from the plant.

System Engineer

- System Engineer: Keith R. Grzegorczyk

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

Conceptual Estimate

Year	Loaded Cost	Description
2024	**$1,765,000**	Project engineering for Spec/RFQ/Procurement activities/Pos to secure support, Initial payment.
2025	**$25,000**	Engineering and resource needs (no payments required to SMIT)
2026	**$4,763,000**	Estimated progress payment, construction of spare GSU storage foundation, engineering, quality assurance travel.
2027	**$9,802,000**	Final payment, delivery, construction of storage foundation, closeout.

Total Cost: $16,355,000

Asset Strategy Approval Comments

The Asset Strategy Group strongly recommends approval, given the challenges currently faced at Zeeland Station and Covert Station and the extended lead times for transformers, now ranging from 2 to 4 years. Ensuring that our key capacity plants have a spare GSU on hand is of utmost importance.

DocuSign Envelope ID: 5F30BA2D-FCF5-4A3F-9D3A-A7E88DB3864D

Approvals

Title	Approver Name	Date
Generation Planning Manager John D Slinkard	DocuSigned by: John D Slinkard D640D95639854BE...	1/9/2024 | 7:55 AM EST
Director of Generation Asset Strategy Scott Hugo	DocuSigned by: Scott Hugo 31EC7A87E8E34C6...	1/8/2024 | 9:46 AM EST
Exec Director of Electric Planning Richard T. Blumenstock	DocuSigned by: Richard T. Blumenstock C3E2F0B9020949B...	1/10/2024 | 9:16 AM EST
VP of Electric Grid Integration Srikanth Maddipati	DocuSigned by: Srikanth Maddipati 67DA622787D2488...	1/10/2024 | 10:00 AM EST

Concept Approval

Zeeland Phase 2 Gas Turbine upgrades.

Date: 5/23/2025

Prepared by: Paul Ohep

Figure 1. Zeeland Generating station.

Executive Summary

The Zeeland Generating Station, a critical asset in Consumers Energy's portfolio, is set to undergo significant upgrades to enhance its performance and reliability. This project focuses on the Zeeland Phase 2 gas turbines, leveraging advanced technologies to support the transition to a more renewable energy portfolio.

Problem Description

The Zeeland Generating Station operates with a combination of four gas turbines and one steam turbine in a combined cycle configuration. These units are maintained under a Long-Term Service Agreement (LTSA) with GE, ensuring their periodic overhaul. In 2028, the Zeeland Phase 2 site is scheduled for Major Inspection outages, presenting an opportunity to implement substantial improvements. The primary goal is to replace the "hot" or combustion components of the turbines, which degrade over their 32,000-hour design lifespan.

Proposed Solution

The project proposes the implementation of two advanced technologies:

- **Advanced Gas Path (AGP)**: This technology aims to elevate the output and efficiency of the turbines by replacing existing parts with high-performance components, resulting in notable improvements in output and heat rate efficiency. Specifically, the AGP upgrade is expected to improve output by 51 MW at full/base load and enhance heat rate efficiency by 2.5%.
- **Axial Fuel Staging (AFS)**: This upgrade enhances the turbines' output turndown capability, allowing for lower load operations while maintaining emissions compliance. This flexibility is crucial as Consumers Energy moves towards a diverse energy portfolio reliant on renewable sources.

Alternative Solutions Considered

- **Do Nothing**: Maintaining the current setup without upgrades would result in unrealized savings of $40.7M and a decrease in market competitiveness and operational flexibility.
- **Install AGP Only**: This option involves an initial capital investment of $51.0M, with projected incremental revenue of $121.8M through 2040 and a favorable NPV gain of $45.5M.
- **Install AFS Only**: This option was not pursued further due to significant financial hurdles and the lack of additional capacity revenue.

Recommended Option

The recommended option is to install both AGP and AFS technologies, with an initial investment cost of $55.7M. This comprehensive upgrade is expected to provide superior flexibility, emissions compliance, future market competitiveness, and standardization benefits. The potential NPV savings are estimated at $40.8M from 2025 through 2040.

Funding and Timing

- **No prior funding committed**.
- **Scheduled outage required**.
- **Desired implementation year**: First year spend in 2025, installation in 2028.
- **Impact of delay**: Delaying implementation beyond 2028 poses significant risks and missed opportunities, potentially delaying benefits realization by 5-6 years.

Conclusion

The AGP-AFS upgrade is a forward-thinking approach that promises significant performance enhancements, substantial long-term financial benefits, and improved adaptability to support Consumers Energy's energy portfolio. This investment is justified by the considerable potential savings and the strategic alignment with the transition to renewable energy sources.

Financial Summary

Estimated investment: **$55.7M total NPV cost based on 13.59% charge rate ($44.9M budget for LTFP)**

Proposed Start Implementation Year and duration

First year spend 2025, installation year 2027.

Problem Description

The Zeeland Generating Station, a key asset in Consumers Energy's portfolio, operates using a combination of four gas turbines and one steam turbine, configured as a combined cycle plant. These critical units are maintained under a Long-Term Service Agreement (LTSA) with GE, which ensures their periodic overhaul and upkeep, restoring them to near-original condition. A crucial aspect of these overhauls, conducted during major outages managed by GE, involves replacing the "hot" or combustion components of the turbines. These components typically degrade over their 32,000-hour design lifespan.

In 2028, the Zeeland Phase 2 site is scheduled for Major Inspection outages, presenting an opportune moment to undertake substantial improvements in both Phase 2 gas turbines. This project is centered around the implementation of upgraded replacement parts that significantly enhance performance and reliability.

Advanced Gas Path (AGP): This technology aims to elevate the output and efficiency of the turbines. AGP involves replacing existing turbine and combustion parts with high-performance, technologically advanced parts. The enhancement is expected to deliver notable improvements in output and heat rate efficiency, while maintaining the same level of reliability.

Axial Fuel Staging (AFS): In conjunction with AGP, AFS is another important upgrade. It enhances the turbines' output turndown capability, crucial for flexible operation. This is achieved by replacing and adding advanced combustion hardware, allowing for lower load operations while still adhering to emissions compliance. Such advancements are increasingly vital as Consumers Energy moves towards a diverse energy portfolio heavily reliant on renewable sources. The AFS technology is instrumental in ensuring that the Zeeland Phase 2 combined cycle gas turbines maintain operational flexibility to support this transition, accommodating the variability inherent in renewable energy sources.

Alternative Solutions/Alternatives Considered

1. Do Nothing – Cost: $40.8M (unrealized savings)

This alternative involves maintaining the current status quo at Zeeland Generating Station, where there is no immediate requirement to replace the turbine and combustion parts with higher performing components.

Cost Implication

- **Cost:** $40.8M (Unrealized Savings) + Unrealized AFS benefits
- **Impact:** Choosing this option results in forgoing the potential savings that could be achieved through Alternatives #2 and #3.

Detailed Analysis

- **Unrealized Potential Savings:** If neither Alternative #2 (AGP installation) nor Alternative #4 (AGP & AFS installation) is selected, Zeeland Phase 2 stands to lose potential savings $40.8M with AGP & AFS over the period from 2025 to 2040. These savings are detailed in the AGP & AFS alternative description.
- **Market Competitiveness and Flexibility:** Without implementing either of these advanced technologies, there is a significant risk that Zeeland Phase 2 will become less competitive and flexible in the rapidly evolving electrical generation market. The introduction of renewable energy sources demands greater flexibility from conventional generation assets, which this option fails to address.
- **Opportunity Cost:** The cost of this "Do Nothing" option is effectively the lost opportunity to save and improve. While not investing in upgrades might seem to save money in the short term, it equates to a considerable loss in terms of unrealized savings and market adaptability.

Opting to maintain the current setup without upgrades translates into a significant loss of potential savings and a decrease in market competitiveness and operational flexibility. This option, while seemingly cost saving, could lead to substantial opportunity costs and a failure to adapt to the changing dynamics of the energy market.

2. Install AGP only- Cost: initial capital investment of $51,011,000

This alternative entails the installation of an Advanced Gas Path (AGP) in Zeeland Phase 2's gas turbines, a significant upgrade to enhance performance and efficiency.

Financial Overview:

- **Cost:** Total customer cost of $51M over the life of the upgrade in today's dollars based on a fixed charge rate of 13.59% (Based on internal estimates incorporating contractor quotes and overhead loadings).
- **Revenue:**
  - The projected incremental revenue for this project is estimated to be $121.8M through 2040.
  - The projected incremental capacity revenue is projected to be $34.8M through 2040.
- **Impact:** The AGP only option will provide a favorable NPV gain of $45,524,000 through 2040. This is based on an Aurora internal economic model performed in February of 2025.

Table 1 below summarizes the incremental revenues and costs for the AGP only option.

Net Present Value Results	AGP Only case with 588 MW Capacity Revenue Cap
Current Nameplate Capacity (MW)	553
Upgraded Capacity (MW)	604
NPV, Incremental Energy Revenue AGP only (K$)	($121,803)
NPV, Incremental Capacity AGP only (K$)	($34,846)
NPV, Incremental Operating Costs AGP only (K$)	$60,114
NPV, Investment AGP only (K$)	$51,011
NPV, Total Value of Phase 2 Upgrade (K$)	**($45,524)**

Table 1. Revenue and costs table for AGP only option

Economics modeling assumptions:

The economic model for this option is based on the following AGP assumed features:

- Capacity value is assumed at 75% of the cost of new entry.
- Capacity accreditation is estimated at 90% for all seasons.

Output Improvement

- **Improvement:** +51MW at Full/Base Load, based on GE's quotes.

Heat Rate Improvement

- **Improvement:** -2.5% Efficiency Improvement across Load Range.

Components and Work Scope:

- AGP Parts: Includes all necessary AGP components, new Gas Control Valves (GCVs), and Stop-Ratio Valve (SRV). The cost is escalated from the 2025 base by 3% per year.
- Comprehensive Upgrade: The upgrade involves replacing hot parts with AGP components, transitioning from DLN2.6 combustors to DLN2.6+ to enable AGP performance enhancements, increasing the shaft torque limit rating, revising control curves, and adjusting control constants.
- Turbine Model Change: These modifications will upgrade the turbine model from 7FA.03 to 7FA.04.
- GCVs/SRV Replacement: To realize the full potential of the AGP/DLN2.6+ work, replacing the GCVs/SRV is crucial. This will also address the gas supply pressure limitations in the upper output range by reducing approximately 25 psi of pressure drop across these components.

Financial Outlook:

The AGP-only upgrade, with a comprehensive scope of work to elevate turbine efficiency and performance, represents a strategic investment towards modernizing the Phase 2 turbine. The project is anticipated to result in significant Net Present Value (NPV) savings of $45.5 million over a fifteen-year period, to 2040. This includes considerations for incremental energy and capacity revenue, along with a detailed analysis of operating costs and investment requirements.

3. Install Advance Fuel Staging only

The AFS-only option explores the introduction of Axial Fuel Staging technology to the turbines at Zeeland Generating Station, focusing solely on this upgrade without the inclusion of Advanced Gas Path (AGP) components. The AFS technology is designed to enhance combustion efficiency and reduce emissions, aligning with operational improvements and environmental compliance objectives.

Although the AFS-only upgrade offers notable operational benefits, such as enhanced emissions control, it encounters significant financial hurdles. These challenges stem from a lack of additional capacity revenue and the inability of increased energy revenue alone to cover the substantial upfront investment and ongoing operational costs. Crucially, the AFS-only strategy misses out on the considerable operational improvements associated with AGP enhancements, including a capacity boost of 51MW and a heat rate improvement of 2.5%.

Based on prior experience with modeling AFS only upgrade with Phase 1 and vendor recommendations, it was decided not to look further into this option as it is not typically installed on its own and will most certainly result in losses over time (as modeled for phase 1 upgrade).

4. Install AGP and AFS – initial investment cost - $55.7M – Recommended option

This alternative proposes a comprehensive upgrade to the Zeeland Phase 2 gas turbines by installing both Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies.

Financial Overview:

- **Cost:** Long term financial budget of $44.9M. Total customer cost of $55,669,000 over the life of the upgrade in today's dollars based on a fixed charge rate of 13.59% (Based on internal estimates incorporating contractor quotes and overhead loadings).
- **Impact:** Potential Net Present Value savings of an estimated $40.793M from 2025 through 2040 from the upgrade. This is based on an Aurora internal economic model performed in February of 2025.

Components and Work Scope:

- **AGP Parts and Work:** AGP components include new Gas Control Valves (GCVs), Stop-Ratio Valve (SRV), and related replacement work.
- **Comprehensive Turbine Upgrade:** Incorporates the scope of Alternative #2 (AGP installation) while adding AFS components. This includes replacing hot parts with AGP components, upgrading combustors to DLN2.6+, and making necessary revisions to control curves and constants.
- **Turbine Model Change:** These upgrades will transform the turbine model from 7FA.03 to 7FA.04.
- **Enhanced Gas Supply Efficiency:** Replacement of GCVs/SRV will mitigate gas supply pressure limitations in high output ranges by reducing pressure drop.

AGP + AFS upgrade Economic benefits breakdown and assumptions:

Table 3 below shows a summary of the NPV incremental costs and revenues for this option.

Net Present Value Results	AGP+AFS full upgrade
Current Nameplate Capacity (MW)	553
Upgraded Capacity (MW)	604
NPV, Incremental Energy Revenue Full upgrade (K$)	($120,623)
NPV, Incremental Capacity Full upgrade (K$)	($34,846)
NPV, Incremental Operating Costs Full upgrade (K$)	$59,007
NPV, Investment Full upgrade (K$)	$55,669
NPV, Total Value of Phase 2 Full Upgrade (K$)	**($40,793)**

Table 3. Revenue and costs table for AGP and AFS option

Economics modeling assumptions:

The economic model for this option is based on the following AGP assumed features:

- Capacity value is assumed at 75% of the cost of new entry.
- Capacity accreditation is estimated at 90% for all seasons.

Differences between AGP only and AFG+AFS upgrades:

Tables 2 and 3 above show that, based solely on quantitative modeling, the AGP-only upgrade appears to be more valuable by $5M over the next 15 years compared to the full AGP+AFS upgrade. The reason for this is that our model doesn't assign an appreciable impact from lowering the minimum load (when adding AFS) as units are typically chosen based on mid- and max-load capabilities rather than minimum load. Dispatch decisions are made when there is an expected increase in demand.

However, when considering both quantitative and qualitative impacts, the full AGP+AFS upgrade offers significantly more value than the additional ~$4.7M provided by the AGP-only option.

Below is a breakdown of the full benefits of AGP+AFS upgrade over AGP-only option:

1. Flexibility
    - For a Renewable Grid – The flexibility that will be offered in the real world is difficult to model, and we believe it will be very valuable to support a grid that requires its baseload generation (like Ph2) to respond to the flexibility required by Renewable Generation. One main reason we believe this is masked by the modeling is because the model doesn't show the peak LMP highs and lows as much as what actually happens in the real world.
    - Leading to Equipment Reliability – The cost avoidance in equipment reliability due to cycling could be significant (Heat Recovery Steam Generator (HRSG) failures usually add up to many millions of dollars, and Ph2 has two HRSGs) in the future for an extra $4M now due to reducing the number of future shut-downs because Ph2's minimum load can go low enough for a few critical hours, namely for the "shoulder-month" days in Fall and Spring where LMP prices drop significantly for a few hours at night. That critical load reduction could also start to occur more in the afternoon as additional solar generation comes online, requiring two major load-following events where a lower min load capability could be the difference between shutting down for a few hours or staying at minimum load (spinning reserve).

2. Emissions Compliance – AFS will be valuable operationally and legally / for regulatory factors because during start-up, AFS will help Phase 2 get into emissions compliance mode much earlier into the start-up process. This is important, because Ph2's air permit will most likely change as it is changing for Ph1 (due to the AGP part of the upgrades) to include much more strict emissions compliance standards during start-ups (potentially lower emissions rates but also less exceptions for start-up emissions).

3. Future Market Competitiveness – AFS is a relatively new technology, and the growth rate in gas plants adding the technology (and newer plants being built with the technology) is trending toward exponential. By the early 2020s, GE had only 4-5

examples of the technology being used, but 2024 saw two more installations, with 2025/2026 seeing numerous more installations according to GE as stated at the May 2024 7F Users Conference. Utilities are starting to see the major value of the flexibility offered by AFS, and as more plants retrofit or are built new with the technology, ZGS Ph2's flexibility value will remain competitive with the market supporting a more Renewable grid.

4. Standardization and Capital Spares Reduction – The Full Upgrade case would standardize the parts between our Phase 1 and Phase 2 units as they would then be the exact same turbines. That benefit is somewhat difficult to quantify value-wise, but it goes a long way to benefiting reliability, troubleshooting when issues arise, and having spare parts.
5. Installation timing efficiency - Installing the AFS upgrades simultaneously with the AGP (and DLN2.6+) is recommended due to the significant amount of additional fuel routing required for the AFS upgrade.

Overall, the Full Upgrade (AGP & AFS) provides superior flexibility for supporting a grid that is going quickly to Renewables for ~$5M less value out of around $40M savings to our customers over the next 15 years.

Scope of Work

Scope of Work Activities for Erickson's and GE's Major Inspection at Zeeland Phase 2:

1. Erickson's Responsibilities:

- Provide cranes and lifting services as part of the already scheduled and budgeted GE Long-Term Service Agreement (LTSA) Major Inspection work.

2. GE Parts/Software Scope of Supply:

Advanced Gas Path (AGP) Components:

- AGP Stage 1 Nozzle Kit and Support Ring.
- AGP Stage 2 and 3 Nozzle Kits.
- AGP Stage 1, 2, and 3 Bucket Kits.
- AGP Stage 1, 2, and 3 Shroud Kits.
- Cooling and sealing air orifice modification.
- Provision of installation and modification documents.
- OpFlex Enhanced Transient Stability Model-Based Controls platform.
- Firing temperature increase and revised Model-Based Control (MBC) software changes.
- 7FA.04 length 1AO, 2FO, 2AO wheelspace thermocouples.

DLN 2.6+ Components:

- ML A033 Major Disassembly Tool Kit.
- ML 0513 Gas-Only Fuel Nozzle Assembly.
- ML 0572 Fuel Gas Emergency Stop Valve.
- ML 0701 Combustion Chamber Arrangement.
- ML 0702 Transition Piece Assembly.
- ML 0703 Combustion Liner Arrangement.
- ML 0717 Transition Piece Arrangement.
- ML 0719 Aft Combustion Case Arrangement.
- ML 0726 Combustion Tuning Piping.
- ML 1214 Spark Plug Assembly.

Gas Control Valves (GCVs) / Stop Ratio Valve (SRV):

- High Recovery Gas Control Valves (GCVs).
- Stop Ratio Valve (SRV).
- Supporting piping, conduit, and hydraulic components.
- Modifications to Gas Turbine Controls.

Axial Fuel Staging (AFS) Components:

- AFS injectors and sealing.
- Fuel delivery tubing and valving.
- Additional 5th fuel circuit and manifold for AFS.
- Manway covers.

3. GE Work Scope:

- Removal of old turbine parts.
- Installation of new AGP and AFS components.
- Modifications to existing parts as required.
- Revision of control curves and constants to integrate the new upgrades.

This comprehensive scope of work outlines the key activities and components involved in the upgrade project for Zeeland Phase 2, ensuring the successful integration of Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies.

Funding and Timing

- No funding has been previously committed for this project.
- A Scheduled outage is required for this project.
- Desired implementation year: First year spend 2025, installation year 2028
- Impact if the recommended implementation year is changed:
    - Delaying the implementation of Advanced Gas Path (AGP) and Axial Fuel Staging (AFS) technologies at Zeeland Phase 2 to a year beyond the recommended 2028 poses significant risks and missed opportunities. Postponing these upgrades until the next outage of opportunity, potentially 5-6 years later during the next Hot Gas Path Inspection, would result in a considerable delay in realizing the benefits for Consumers Energy's customers.
- System Engineer: Tim D. Boerema

Conceptual Estimate

Year	Loaded Cost	Description
2025	**$60,000**	Initial engineering work
2026	**$7,969,033**	25% Payment for Lump Sum
2027	**$24,834,311**	AGP/AFS Payment for Design and engineering
2028	**$12,036,656**	AGP/AFS 75% payment, installation, and closeout

Total Cost: $44,900,000

Asset Strategy Approval Comments

The Asset Strategy Group recommends approval. The AGP-AFS upgrade is a forward-thinking approach that not only promises significant performance enhancements but also substantial long-term financial benefits and improved adaptability of the turbines to support Consumers Energy's energy portfolio. This investment is justified by the considerable potential savings.

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric Supply		

Zeeland Generating Station, Unit 1A&B Advanced Gas Path Upgrade

AGP Upgrade Performance Report

July 18, 2025
Revision: Final

Test Engineer: Timothy J. Miller
Equipment Performance Testing Section
Asset Strategy Department

TABLE OF CONTENTS

1.0 Summary 1
1.1 Unit 1-A Performance 1
1.2 Unit 1-B Performance 2
2.0 Overview and Test Objectives 3
3.0 Introduction 3
3.1 Design Conditions 3
3.2 Expected Performance Improvement 4
4.0 Results 5
4.1 Unit 1-A Performance 6
4.2 Unit 1-B Performance 8
5.0 Conclusions and Recommendations 10
5.1 Unit 1-A Performance 10
5.2 Unit 1-B Performance 11
5.3 Recommendations 11

LIST OF FIGURES

Appendix A: Zeeland Unit 1-A EBSILON Outputs 1
Figure 1: Zeeland Unit 1-A (7FA) June 24, 2024 GVTC 2
Figure 2: Zeeland Unit 1-A (7FA) Corrected to June 27, 2025 Conditions 3
Figure 3: Zeeland Unit 1-A (7FA) Corrected to Design Conditions 4
Figure 4: Zeeland Unit 1-A (7F.04) June 27, 2025 5
Figure 5: Zeeland Unit 1-A (7F.04) Corrected to Design Conditions 6
Appendix B: Zeeland Unit 1-B EBSILON Outputs 1
Figure 6: Zeeland Unit 1-B (7FA) June 24, 2024 GVTC 2
Figure 7: Zeeland Unit 1-B (7FA) Corrected to June 29, 2025 Conditions 3
Figure 8: Zeeland Unit 1-B (7FA) Corrected to Design Conditions 4
Figure 9: Zeeland Unit 1-B (7F.04) June 29, 2025 5
Figure 10: Zeeland Unit 1-B (7F.04) Corrected to Design Conditions 6

LIST OF TABLES

Table 1: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions 1
Table 2: Zeeland Unit 1-A Corrected to Design Conditions 1
Table 3: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions 2
Table 4: Zeeland Unit 1-B Corrected to Design Conditions 2
Table 5: Zeeland Unit 1-A & 1-B Design Conditions 4
Table 6: Zeeland Unit 1-A & 1-B Expected Performance Improvement – Evaporative Cooler Off 5
Table 7: Zeeland Unit 1-A & 1-B Expected Performance Improvement – Evaporative Cooler On 5
Table 8: Zeeland Unit 1-A Pre-Outage and Post-Outage Observed Conditions 6
Table 9: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions 7
Table 10: Zeeland Unit 1-A Corrected to Design Conditions 7
Table 11: Zeeland Unit 1-B Pre-Outage and Post-Outage Observed Conditions 8
Table 12: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions 9
Table 13: Zeeland Unit 1-B Corrected to Design Conditions 9
Table 14: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions 10
Table 15: Zeeland Unit 1-A Corrected to Design Conditions 10
Table 16: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions 11
Table 17: Zeeland Unit 1-B Corrected to Design Conditions 11

APPENDECIES

Appendix A: Zeeland Unit 1-A EBSILON Outputs
Appendix B: Zeeland Unit 1-B EBSILON Outputs
Appendix C: Zeeland Unit 1-A & 1-B Advanced Gas Path Contract
Appendix D: GE 7FA Correction Curves
Appendix E: GE 7F.04 Correction Curves

CORRESPONDENCE LIST

Jason Rickets	Phillip Guerrero
Matt Bufka	Garrett Jackson
Tim Boerema	Richard Blumenstock
Nathan Hoffman	Scott Hugo
Mark Wittbrodt	Paul Ohep
Kavan Negaran	Evan Michner

1.0 SUMMARY

Zeeland Units 1-A and 1-B received the Advanced Gas Path (AGP) upgrade in the spring of 2025. Data from the June 24, 2024 GVTC was used to represent the pre-outage state of the Unit 1-A and 1-B 7FA gas turbines. Data from June 27, 2025, and June 29, 2025 was used for the post-outage comparison of Unit 1-A and 1-B 7F.04 respectively.

1.1 UNIT 1-A PERFORMANCE

For Unit 1-A, the AGP upgrade achieved a +25.1 MW improvement in power output and a -131.9 Btu/kWh Gross Heat Rate improvement in terms of Higher Heating Value (HHV). The full set of results are summarized below in Table 1.

Table 1: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions

Zeeland Unit 1-A Corrected to 6/27/25: 12:00 – 13:00 (89.6°F, 55% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	157.97	183.02	25.05	15.86
Gross Ht Rate (HHV) [Btu/kWh]	10,278.3	10,146.4	-131.9	-1.28

Both the pre-outage 7FA and post-outage 7F.04 gas turbine data were then corrected to the design conditions listed in Table 5 including fuel composition. Correcting to design conditions showed a power output improvement of +25.6 MW and a gross heat rate improvement of -147.0 Btu/kWh. The full set of results are summarized below in Table 2.

Table 2: Zeeland Unit 1-A Corrected to Design Conditions

Zeeland Unit 1-A Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.04	179.66	25.62	16.63
Gross Ht Rate (HHV) [Btu/kWh]	10,384.6	10,237.5	-147.0	-1.42

This is a power output improvement of +16.6%, which exceeds the GE estimate of +13.2%. Likewise, the gross heat rate improved by -1.42%, but fell short of the GE estimate of -2.5%. As discussed in Section 4.1, Unit 1-B power output and heat rate improvement much better aligns with the GE estimate which brings to question the accuracy of the station fuel flow orifice for Unit 1-A.

1.2 UNIT 1-B PERFORMANCE

For Unit 1-B, the AGP upgrade achieved a +25.6 MW improvement in power output and a -332.5 Btu/kWh Gross Heat Rate improvement in terms of HHV. The full set of results are summarized below in Table 3.

Table 3: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions

Zeeland Unit 1-B Corrected to 6/29/25: 15:45 – 16:45 (95.8°F, 45% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	155.85	181.43	25.58	16.41
Gross Ht Rate (HHV) [Btu/kWh]	10,302.1	9,969.7	-332.5	-3.23

Both the pre-outage 7FA and post-outage 7F.04 gas turbine data were then corrected to the design conditions listed in Table 5 including fuel composition. Correcting to design conditions showed a power output improvement of +24.3 MW and a gross heat rate improvement of -313.1 Btu/kWh. The full set of results are summarized below in Table 4.

Table 4: Zeeland Unit 1-B Corrected to Design Conditions

Zeeland Unit 1-B Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.71	178.99	24.28	15.70
Gross Ht Rate (HHV) [Btu/kWh]	10,359.8	10,046.7	-313.1	-3.02

Unit 1-B achieved a power output improvement of +15.7%, which exceeds the GE estimate of +13.2%. Likewise, the Unit 1-B gross heat rate improved by -3.02%, which also exceeds the GE estimate of -2.5%.

2.0 OVERVIEW AND TEST OBJECTIVES

Zeeland Units 1-A and 1-B were upgraded from their original 7FA combustion turbine design with the GE Advanced Gas Path (AGP) hardware during the spring of 2025. Per the contract, a power improvement of +13.2% and a heat rate improvement of -2.5% was expected when corrected to design conditions with the evaporative cooler in service. In addition to the power and heat rate improvements, the upgrade included the Axial Fuel Staging (AFS) system which will allow for a minimum load of 50 MW_n while maintaining emissions compliance. This is down from the 100 MW_n minimum load from the original design and offers greater dispatch flexibility. A copy of the contract is included in Appendix C.

For comparison purposes, data from the June 24, 2024 Generator Verification Test Capacity (GVTC) was used to compare with post-upgrade. The GVTC data was chosen since the run would have occurred only a few weeks following the spring compressor wash, thereby the original design would not be additionally penalized for operating in a "dirty" state. Post-outage data was chosen from full load operation with evaporative coolers on after a few weeks following the return to service.

Both data sets would be input into the Consumers Energy EBSILON model of the Zeeland gas turbines to correct to the same set of conditions. The EBSILON model utilizes the full set of correction curves for both the original 7FA design and the post-upgrade 7F.04. For this analysis, the 2024 GVTC data was corrected to the 2025 ambient conditions and both data sets were corrected to design conditions.

3.0 INTRODUCTION

The Zeeland Generating Station, located in Zeeland, MI, is a natural gas simple cycle and combined cycle power plant. The simple cycle units were commissioned in 2000, followed by the combined cycle in 2002. Consumers Energy purchased the entire facility in 2008. The original plant construction plan consisted of three "Phases". Phase 1 was the construction of two simple cycle GE 7FA gas turbines, Units 1-A and 1-B. Phase 2 was the construction of a 2x1 combined cycle unit which includes two identical GE 7FA gas turbines, Unit 2-A and 2-B, and one steam turbine, Unit 2-C. The 2x1 configuration refers to two gas turbines exhausting into two heat recovery steam generators and driving a single steam turbine. The power block for the combined cycle is comprised of three major components: two gas turbine-generators, two Heat Recovery Steam Generators (HRSGs), and one steam turbine generator. Phase 3 of construction was never completed and was to convert the two simple cycle units into an identical 2x1 combined cycle.

The gas turbine-generators for Units 1-A and 1-B were originally General Electric Model PG7241(FA) and rated for 174.0 MWg at ISO conditions. Both Units 1-A and 1-B received the Advanced Gas Path (AGP) upgrade in the spring of 2025 and are now considered General Electric Model 7F.04-0922T-L4.

3.1 DESIGN CONDITIONS

For the AGP upgrade, the plant design conditions were used in the contract as opposed to gas turbine ISO conditions. For the Zeeland Plant, the design conditions are 92°F ambient temperature and 60% relative

humidity. With evaporative coolers in service and performing at design efficiency, this provides compressor inlet conditions of 81.8°F and 92.2% relative humidity. Table 5 below is the complete set of design conditions specified in the contract and/or post-upgrade correction curves.

Table 5: Zeeland Unit 1-A & 1-B Design Conditions

Parameter	Units	Pre-Uprate Value	Post-Uprate Value
Ambient Air Inlet Temperature	°F	92.0	92.0
Ambient Air Relative Humidity	%	60.0	60.0
Compressor Inlet Temperature	°F	81.8	81.8
Compressor Inlet Relative Humidity	%	92.2	92.2
Barometric Pressure	psi_a	14.35	14.35
Shaft Speed	RPM	3,600	3,600
Generator Power Factor	—	0.85	0.85
Inlet Pressure Drop	inH_2O	4.0	4.1
Exhaust Pressure Drop	inH_2O	5.8	6.1
Fuel Temperature	°F	51	51
Fuel LHV	Btu/lb	20,159.0	20,159.0
Fuel Composition (Natural Gas)			
Methane (CH_4)	% mol	93.256	93.256
Ethane (C_2H_6)	% mol	2.953	2.953
Propane (C_3H_8)	% mol	0.442	0.442
N-Butane (C_4H_{10})	% mol	0.113	0.113
N-Pentane (C_5H_{12})	% mol	0.036	0.036
Hexanes, Avg. (C_6H_{14})	% mol	0.033	0.033
Nitrogen (N_2)	% mol	2.405	2.405
Carbon Dioxide (CO_2)	% mol	0.761	0.761

3.2 EXPECTED PERFORMANCE IMPROVEMENT

The expected performance improvement per the contract is for the case with 92°F ambient temperature, 60% relative humidity, and with the evaporative cooler in service targeting a 92.2% relative humidity at the gas turbine compressor inlet. The performance improvement was stated within the contract as what to expect from the pre-outage state of the 7FA, meaning the existing machine will have approximately 25 years of degradation included in the estimated performance improvement.

It should be noted that the contract does not state if the heat rate improvement is based upon the Lower Heating Value (LHV) or Higher Heating Value (HHV) of natural gas. Since gas turbine OEM's usually state heat rate in terms of LHV, it is assumed this is the basis for the percentage improvement listed. For the purposes of this performance evaluation, all heat rate improvements and values will be reported in terms

of HHV since this is how the plant is dispatched. Table 6 and Table 7 show the expected performance across the load range both without and with the evaporative cooler in service.

Table 6: Zeeland Unit 1-A & 1-B Expected Performance Improvement – Evaporative Cooler Off

Ambient Temperature	**°F**	**-20**	**0**	**30**	**59**	**75**	**92**	**105**
Gas Turbine Output	%	8.0	11.3	16.2	14.5	13.3	12.5	9.6
Gas Turbine Heat Rate	%	-1.4	-1.8	-2.2	-2.9	-2.5	-2.6	-2.7

Table 7: Zeeland Unit 1-A & 1-B Expected Performance Improvement – Evaporative Cooler On

Ambient Temperature	**°F**	**59**	**75**	**92**	**105**
Compressor Inlet Temp	°F	53	67	81.8	90
Gas Turbine Output	%	15.1	13.4	13.2	13.3
Gas Turbine Heat Rate	%	-2.6	-2.5	-2.5	-2.6

4.0 RESULTS

As stated previously, data from the June 24, 2024 GVTC was used to represent the pre-outage state of the Unit 1-A and 1-B 7FA gas turbines. Data from June 27, 2025, and June 29,2025 was used for the post-outage comparison of Unit 1-A and 1-B 7F.04 respectively.

All operating conditions were first input into the Consumers Energy EBSILON model of Units 1-A and 1-B. Heat rate and power output corrections were then applied to the gas turbine to align fuel flow and power output measured during the 2024 GVTC for each unit. The measured natural gas composition from the station gas chromatograph was used within the model to define the fuel stream and calculate heat content on a mass basis. EBSILON utilizes the GERG-2008 methodology to determine the physical properties of the natural gas composite mixture. The 7FA gas turbines were then corrected to the 2025 conditions being used for comparison following the original set of correction curves which are included for reference in Appendix D. Finally, the 2024 GVTC data was then corrected to the design conditions listed in the contract.

For the post-outage 7F.04, the EBSILON gas turbine component was updated to revise the correction curves with the new set provided by GE (24A-167 Rev A) which are included for reference in Appendix E. All operating conditions were first input into the Consumers Energy EBSILON model from their respective 2025 run. Heat rate and power output corrections were then applied to the gas turbine to align fuel flow and the measured power output. Likewise, the measured natural gas composition from the station gas chromatograph was used within the model to define the fuel stream and calculate heat content on a mass basis. The 2025 data set was then corrected to design conditions listed in the contract, including natural gas composition. Both data sets corrected to design conditions were then directly compared to determine the realized gains from the AGP upgrade.

It is worth noting that some of the "design" conditions listed in the contract do not align with the "design" conditions listed in the GE correction curves for the 7F.04. For example, the contract states an exhaust pressure drop of 6.1 inWC where the curve set states 4.91 inWC at rated compressor inlet temperature. For the purposes of this analysis, the conditions agreed upon and listed in the contract will be used.

4.1 UNIT 1-A PERFORMANCE

Pre-outage data from the June 24, 2024, from the 14:00 — 16:00 GVTC was used to directly compare with the Unit 1-A post-outage run on June 27, 2025, from 12:00 — 13:00. The pre-outage data set was chosen because the ambient conditions were relatively close to the design conditions it will be corrected to and thereby minimize correction curve error. In addition, the pre-outage data set would have been from a run a few weeks following the spring compressor water wash and summer readiness outage. Similarly, the post-outage data was chosen for the same reasons. The operating conditions for both data sets are summarized in Table 8 below.

Table 8: Zeeland Unit 1-A Pre-Outage and Post-Outage Observed Conditions

Observed Conditions	**6/24/2024**	**6/27/2025**	**Units**
	14:00 – 16:00	**12:00 – 13:00**	
Temperature	85.50	89.58	°F
Atmospheric Pressure	29.21	29.21	$inHg_a$
Relative Humidity	42.67	54.95	%
Evap Cooler Out Temperature	69.20	78.18	°F
Air Inlet Pressure Drop	2.95	2.79	inWC
Exhaust Pressure Drop	4.80	3.99	inWC
Fuel Gas Temp	78.26	77.22	°F
Fuel Gas Pressure	469.79	480.14	Psi_a
Fuel Flow	20.24	22.17	lb/sec
Fuel HHV [Btu/SCF]	1,085.21	1,070.52	Btu/SCF
Fuel HHV [Btu/lb]	22,677.57	23,276.33	Btu/lb
Generator Output	162.15	183.02	MW_g
Gross Heat Rate (HHV)	10,190.6	10,146.4	Btu/kWh
Fuel Composition			
Nitrogen (N_2)	1.4753	0.6064	% mol
Carbon Dioxide (CO_2)	0.6086	0.2649	% mol
Methane (CH_4)	86.4233	90.9505	% mol
Ethane (C_2H_6)	11.0484	7.9348	% mol
Propane (C_3H_8)	0.3962	0.2003	% mol
n-Butane (C_4H_{10})	0.0257	0.0189	% mol
n-Pentane (C_5H_{12})	0.0041	0.0036	% mol
Isobutane ($HC(CH_3)_3$)	0.0103	0.0161	% mol
Isopentane ($CH(CH_3)_2(C_2H_5)$)	0.0080	0.0046	% mol
Specific Gravity	0.6253	0.6012	

The Consumers Energy EBSILON model of the original GE 7FA gas turbine was set to "Design" mode with the June 24, 2024 data set. By having the model in "Design" mode, the evaporative cooler, inlet pressure drop, and exhaust pressure drop components would hold and replicate their 2024 performance when correcting to a new set of conditions. The natural gas composition was set within the EBSILON model on a percent mole basis to match the pre-outage conditions. Correction factors for the gas turbine power output and heat rate were then adjusted to align the model with the power output and fuel flow observed.

After the "Design" run, a separate "Off-Design" model profile was created which utilized the pre-outage power output correction, heat rate correction, evaporative cooler performance, inlet pressure drop, exhaust pressure drop, and natural gas composition with the June 27, 2025 observed conditions. This allowed for a direct comparison from pre-outage to post-outage in which the AGP upgrade achieved a +25.1 MW improvement in power output and a -131.9 Btu/kWh Gross Heat Rate improvement in terms of HHV. The full set of results are summarized below in Table 9.

Table 9: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions

Zeeland Unit 1-A Corrected to 6/27/25: 12:00 – 13:00 (89.6°F, 55% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	157.97	183.02	25.05	15.86
Gross Ht Rate (HHV) [Btu/kWh]	10,278.3	10,146.4	-131.9	-1.28

To determine if the contractual estimates were achieved, the EBSILON model was updated to utilize the new set of correction curves for the upgraded GE 7F.04 gas turbine. Similar to the pre-outage, a "Design" profile was used to determine the power output correction, heat rate correction, evaporative cooler performance, inlet pressure drop, and exhaust pressure drop from the June 27, 2025 post-outage data set. The natural gas composition was again set to what was measured by the station gas chromatograph during the post outage run.

Both the pre-outage 7FA and post-outage 7F.04 gas turbine models were then run to correct all variables to the design conditions listed in Table 5 including fuel composition. Correcting to design conditions showed a power output improvement of +25.6 MW and a gross heat rate improvement of -147.0 Btu/kWh. The full set of results are summarized below in Table 10.

Table 10: Zeeland Unit 1-A Corrected to Design Conditions

Zeeland Unit 1-A Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.04	179.66	25.62	16.63
Gross Ht Rate (HHV) [Btu/kWh]	10,384.6	10,237.5	-147.0	-1.42

This is a power output improvement of +16.6%, which exceeds the GE estimate of +13.2%. Likewise, the gross heat rate improved by -1.42%, but fell short of the GE estimate of -2.5%. All EBSILON model outputs For Unit 1-A are shown in Figure 1 through Figure 5 in Appendix A. As will be seen in the following section,

the Unit 1-B heat rate improvement better aligns with the GE estimate which raises the question as to the accuracy of the station fuel flow orifice for Unit 1-A.

4.2 UNIT 1-B PERFORMANCE

Pre-outage data from the June 24, 2024, from the 14:00 — 16:00 GVTC was used to directly compare with the Unit 1-B post-outage run on June 29, 2025, from 15:45 — 16:45. The pre-outage data set was chosen because the ambient conditions were relatively close to the design conditions that it will be corrected to and thereby minimize correction curve error. In addition, the pre-outage data set would have been from a run a few weeks following the spring compressor water wash and summer readiness outage. Similarly, the post-outage data was chosen for the same reasons. The operating conditions for both data sets are summarized in Table 11 below.

Table 11: Zeeland Unit 1-B Pre-Outage and Post-Outage Observed Conditions

Observed Conditions	**6/24/2024**	**6/29/2025**	**Units**
	14:00 – 16:00	**15:45 – 16:45**	
Temperature	85.50	95.84	°F
Atmospheric Pressure	29.21	29.21	$inHg_a$
Relative Humidity	42.67	44.93	%
Evap Cooler Out Temperature	67.79	77.48	°F
Air Inlet Pressure Drop	5.21	2.58	inWC
Exhaust Pressure Drop	4.64	4.27	inWC
Fuel Gas Temp	77.16	75.58	°F
Fuel Gas Pressure	469.79	479.97	Psi_a
Fuel Flow	20.11	21.95	lb/sec
Fuel HHV [Btu/SCF]	1,085.21	1,074.84	Btu/SCF
Fuel HHV [Btu/lb]	22,677.57	22,887.51	Btu/lb
Generator Output	161.00	181.43	MW_g
Gross Heat Rate (HHV)	10,198.2	9,969.7	Btu/kWh
Fuel Composition			
Nitrogen (N_2)	1.4753	1.1726	% mol
Carbon Dioxide (CO_2)	0.6086	0.4937	% mol
Methane (CH_4)	86.4233	88.6602	% mol
Ethane (C_2H_6)	11.0484	9.3213	% mol
Propane (C_3H_8)	0.3962	0.2989	% mol
n-Butane (C_4H_{10})	0.0257	0.0264	% mol
n-Pentane (C_5H_{12})	0.0041	0.0046	% mol
Isobutane ($HC(CH_3)_3$)	0.0103	0.0130	% mol
Isopentane ($CH(CH_3)_2(C_2H_5)$)	0.0080	0.0092	% mol
Specific Gravity	0.6253	0.6136	

The Consumers Energy EBSILON model of the original GE 7FA gas turbine was set to “Design” mode with the June 24, 2024 data set. By having the model in “Design” mode, the evaporative cooler, inlet pressure

drop, and exhaust pressure drop components would hold and replicate their performance when correcting to a new set of conditions. The natural gas composition was set within the EBSILON model on a percent mole basis to match the pre-outage conditions. Correction factors for the gas turbine power output and heat rate were then adjusted to align the model with the power output and fuel flow observed. For Unit 1-B, the measured evaporative cooler outlet temperature was lower than the wet bulb temperature, which is not possible, and that data is considered erroneous. With the bad temperature measurement, the evaporative cooler was set in the model to target 91.0% relative humidity at the outlet which is similar to what Unit 1-A achieved.

After the "Design" run, a separate "Off-Design" model profile was created that utilized the pre-outage power output correction, heat rate correction, evaporative cooler performance, inlet pressure drop, exhaust pressure drop, and natural gas composition with the June 29, 2025 observed conditions. This allowed for a direct comparison from pre-outage to post-outage in which the AGP upgrade achieved a +25.6 MW improvement in power output and a -332.5 Btu/kWh Gross Heat Rate improvement in terms of HHV. The full set of results are summarized below in Table 12.

Table 12: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions

Zeeland Unit 1-B Corrected to 6/29/25: 15:45 – 16:45 (95.8°F, 45% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	155.85	181.43	25.58	16.41
Gross Ht Rate (HHV) [Btu/kWh]	10,302.1	9,969.7	-332.5	-3.23

To determine if the contractual estimates were achieved, an EBSILON model was updated to utilize the new set of correction curves for the upgraded GE 7F.04 gas turbine. Similar to the pre-outage, a "Design" profile was used to capture the power output correction, heat rate correction, evaporative cooler performance, inlet pressure drop, and exhaust pressure drop from the June 29, 2025 post-outage data set. The natural gas composition was again set to what was measured by the station gas chromatograph during the post outage run.

Both the pre-outage 7FA and post-outage 7F.04 gas turbine models were then run to correct all variables to the design conditions listed in Table 5 including fuel composition. Correcting to design conditions showed a power output improvement of +24.3 MW and a gross heat rate improvement of -313.1 Btu/kWh. The full set of results are summarized below in Table 13.

Table 13: Zeeland Unit 1-B Corrected to Design Conditions

Zeeland Unit 1-B Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.71	178.99	24.28	15.70
Gross Ht Rate (HHV) [Btu/kWh]	10,359.8	10,046.7	-313.1	-3.02

Unit 1-B achieved a power output improvement of +15.7%, which exceeds the GE estimate of +13.2%. Likewise, the Unit 1-B gross heat rate improved by -3.02%, which also exceeds the GE estimate of -2.5%. All EBSILON model outputs for Unit 1-B are shown in Figure 6 through Figure 10 in Appendix B.

5.0 CONCLUSIONS AND RECOMMENDATIONS

Zeeland Units 1-A and 1-B received the Advanced Gas Path (AGP) upgrade in the spring of 2025. Data from the June 24, 2024 GVTC was used to represent the pre-outage state of the Unit 1-A and 1-B 7FA gas turbines. Data from June 27, 2025, and June 29, 2025 was used for the post-outage comparison of Unit 1-A and 1-B 7F.04 respectively.

5.1 UNIT 1-A PERFORMANCE

For Unit 1-A, the AGP upgrade achieved a +25.1 MW improvement in power output and a -131.9 Btu/kWh Gross Heat Rate improvement in terms of HHV. The full set of results are summarized below in Table 14.

Table 14: Zeeland Unit 1-A Corrected to June 27, 2025 Ambient Conditions

Zeeland Unit 1-A Corrected to 6/27/25: 12:00 – 13:00 (89.6°F, 55% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	157.97	183.02	25.05	15.86
Gross Ht Rate (HHV) [Btu/kWh]	10,278.3	10,146.4	-131.9	-1.28

Correcting to design conditions showed a power output improvement of +25.6 MW and a gross heat rate improvement of -147.0 Btu/kWh. The full set of results are summarized below in Table 15.

Table 15: Zeeland Unit 1-A Corrected to Design Conditions

Zeeland Unit 1-A Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-A - 7FA 6/24/24	**1-A - 7F.04 6/27/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.04	179.66	25.62	16.63
Gross Ht Rate (HHV) [Btu/kWh]	10,384.6	10,237.5	-147.0	-1.42

This is a power output improvement of +16.6%, which exceeds the GE estimate of +13.2%. Likewise, the gross heat rate improved by -1.42%, but fell short of the GE estimate of -2.5%. As discussed in Section 4.1, Unit 1-B power output and heat rate improvement much better aligns with the GE estimate which brings to question the accuracy of the station fuel flow orifice for Unit 1-A.

5.2 UNIT 1-B PERFORMANCE

For Unit 1-B, the AGP upgrade achieved a +25.6 MW improvement in power output and a -332.5 Btu/kWh Gross Heat Rate improvement in terms of HHV. The full set of results are summarized below in Table 16.

Table 16: Zeeland Unit 1-B Corrected to June 29, 2025 Ambient Conditions

Zeeland Unit 1-B Corrected to 6/29/25: 15:45 – 16:45 (95.8°F, 45% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	155.85	181.43	25.58	16.41
Gross Ht Rate (HHV) [Btu/kWh]	10,302.1	9,969.7	-332.5	-3.23

Correcting to design conditions showed a power output improvement of +24.3 MW and a gross heat rate improvement of -313.1 Btu/kWh. The full set of results are summarized below in Table 17.

Table 17: Zeeland Unit 1-B Corrected to Design Conditions

Zeeland Unit 1-B Corrected to Design Conditions (92°F, 60% RH, Evap On)				
	1-B - 7FA 6/24/24	**1-B - 7F.04 6/29/25**	**Difference**	**% Difference**
Generator Output [MWg]	154.71	178.99	24.28	15.70
Gross Ht Rate (HHV) [Btu/kWh]	10,359.8	10,046.7	-313.1	-3.02

Unit 1-B achieved a power output improvement of +15.7%, which exceeds the GE estimate of +13.2%. Likewise, the Unit 1-B gross heat rate improved by -3.02%, which also exceeds the GE estimate of -2.5%.

5.3 RECOMMENDATIONS

It was discovered for Unit 1-B that the measured evaporative cooler outlet temperature (compressor inlet) was lower than the wet bulb temperature which is not possible. This issue has been previously seen with Unit 1-B, and it is ***strongly recommended*** to replace the compressor inlet temperature thermocouples with new ones. The compressor inlet temperature is a critical measurement for any performance analysis and is also used for GVTC corrections.

Additionally, it is recommended the Unit 1-A fuel flow orifice and differential pressure measurement be checked for accuracy. The Unit 1-B performance results very closely align with the GE estimates for both heat rate and power output. It seems unlikely that both units are able to achieve essentially the same increase in power output but only one of the two can meet the heat rate estimates. The fuel flow orifice is the only measurement for gas flow and therefore a small amount of uncertainty will cascade through the analysis.

Appendix A: Zeeland Unit 1-A EBSILON Outputs

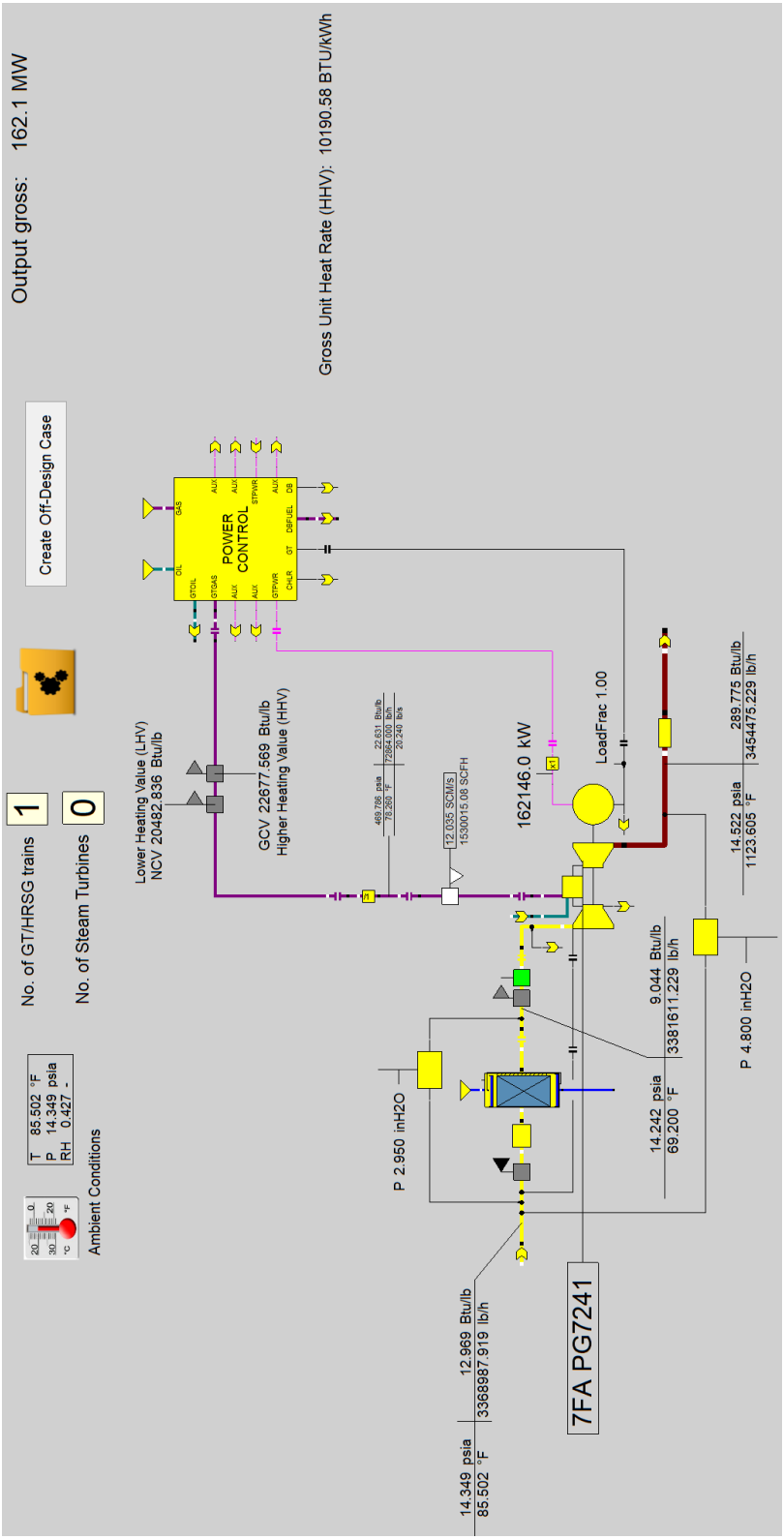


Figure 1: Zeeland Unit 1-A (7FA) June 24, 2024 GVTC

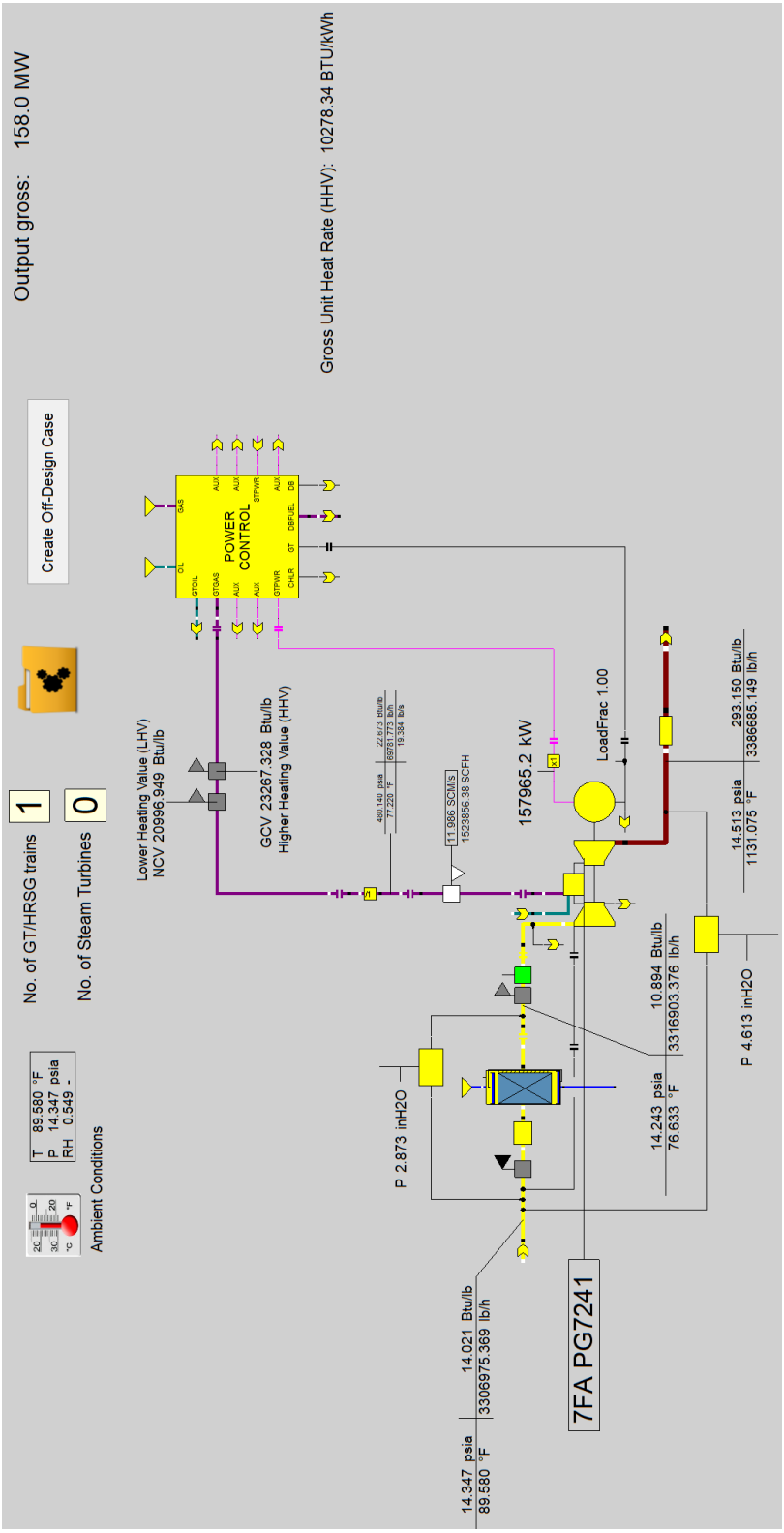


Figure 2: Zeeland Unit 1-A (7FA) Corrected to June 27, 2025 Conditions

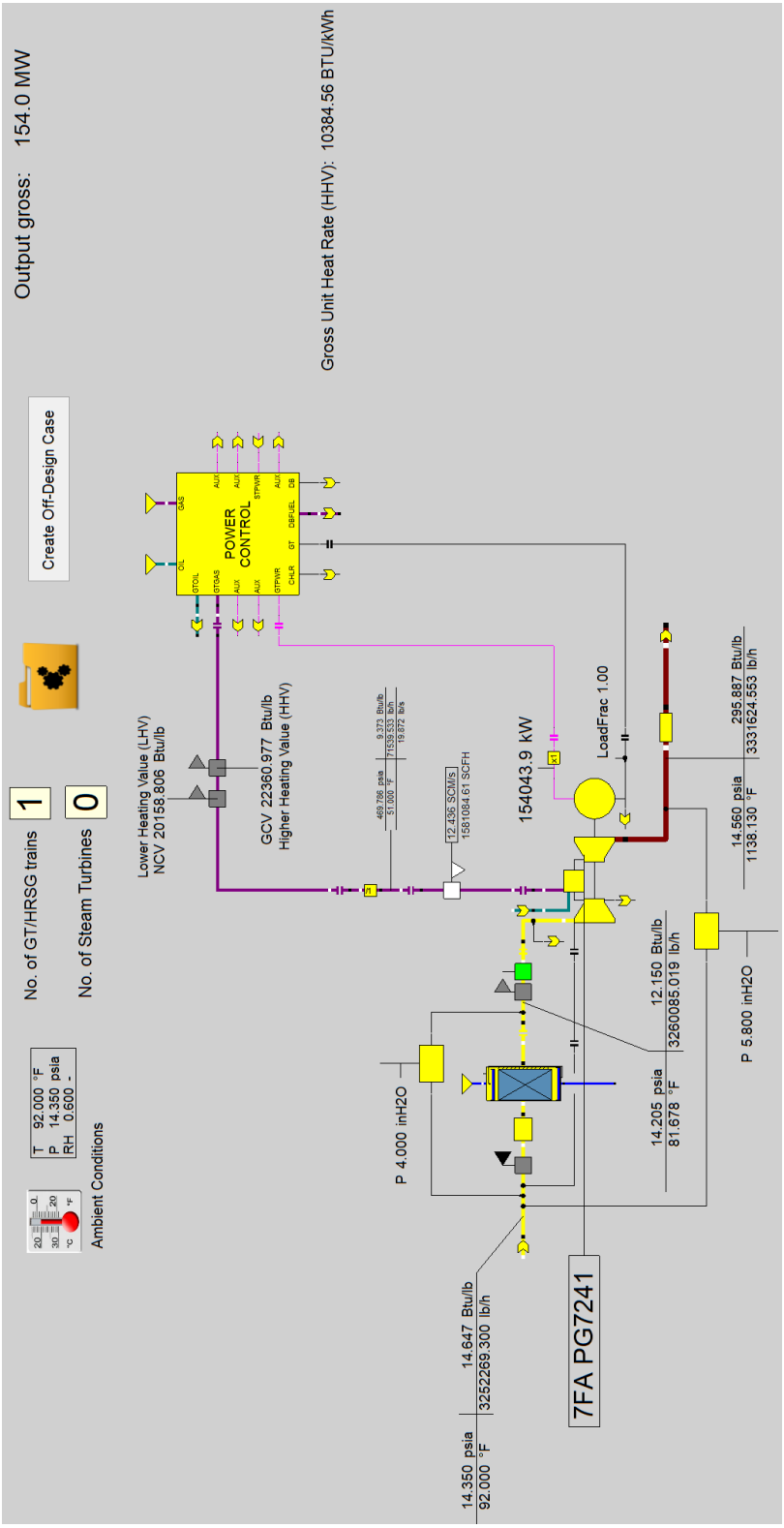


Figure 3: Zeeland Unit 1-A (7FA) Corrected to Design Conditions

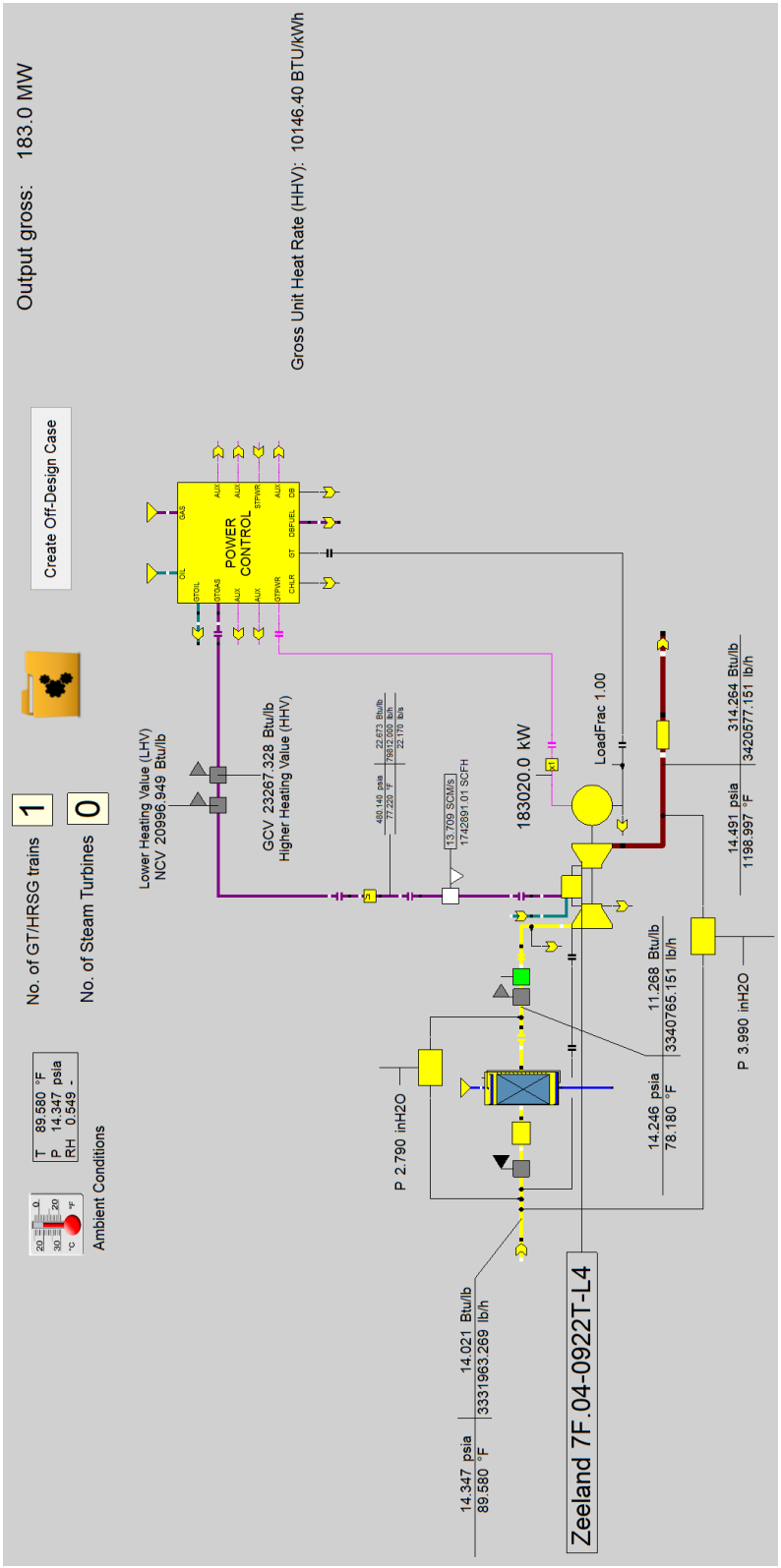


Figure 4: Zeeland Unit 1-A (7F.04) June 27, 2025

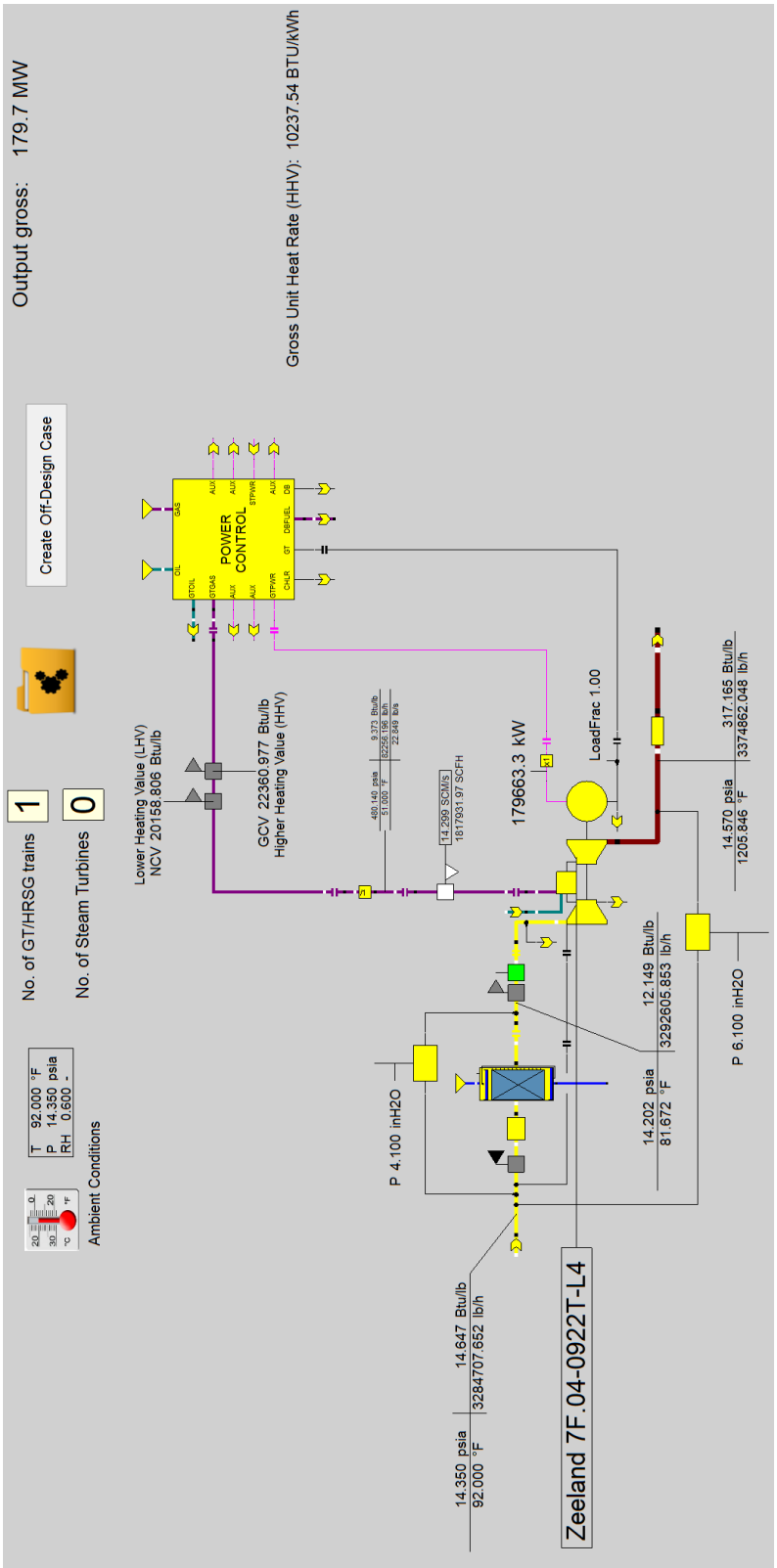


Figure 5: Zeeland Unit 1-A (7F.04) Corrected to Design Conditions

Appendix B: Zeeland Unit 1-B EBSILON Outputs

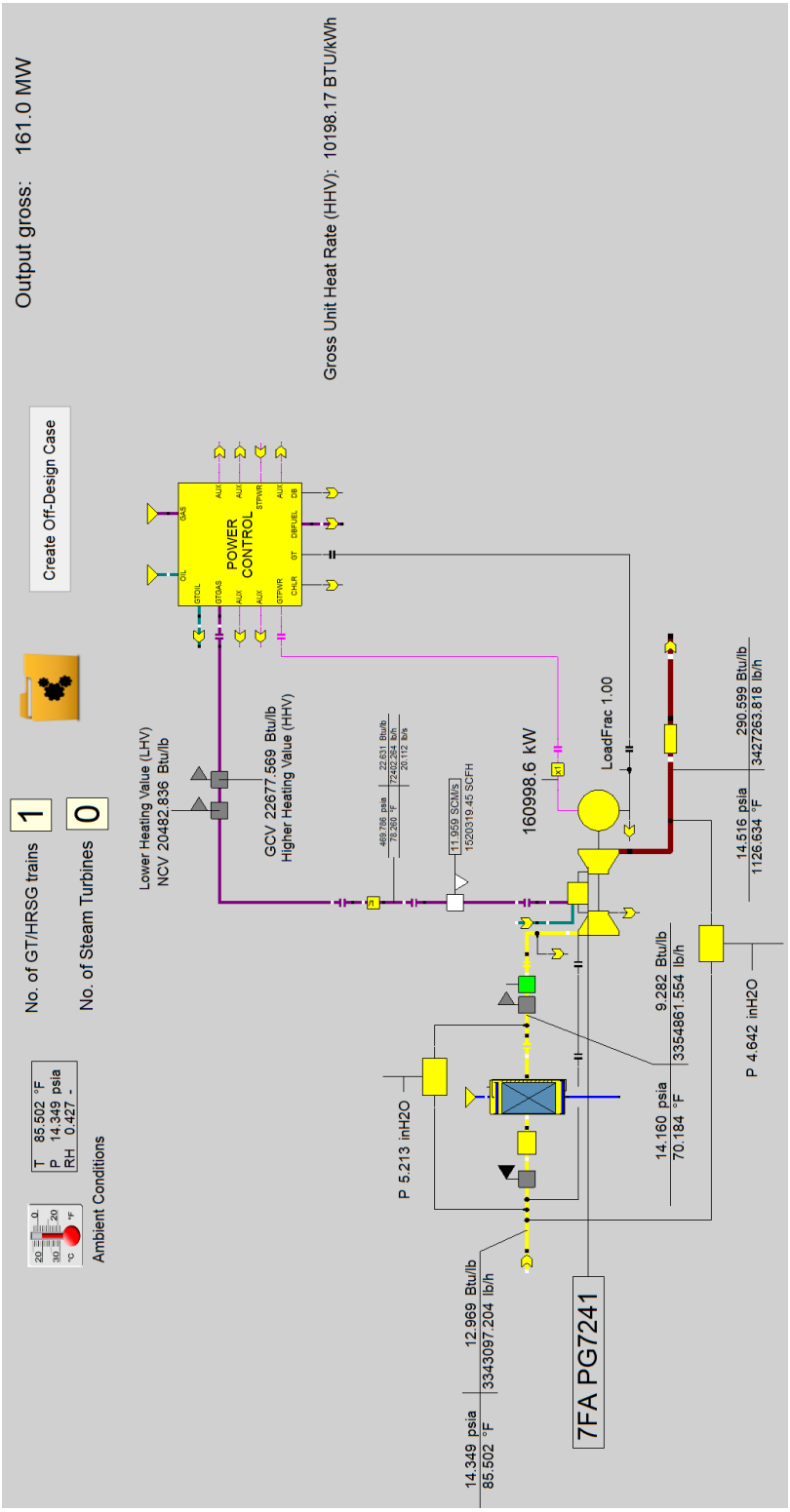


Figure 6: Zeeland Unit 1-B (7FA) June 24, 2024 GVTC

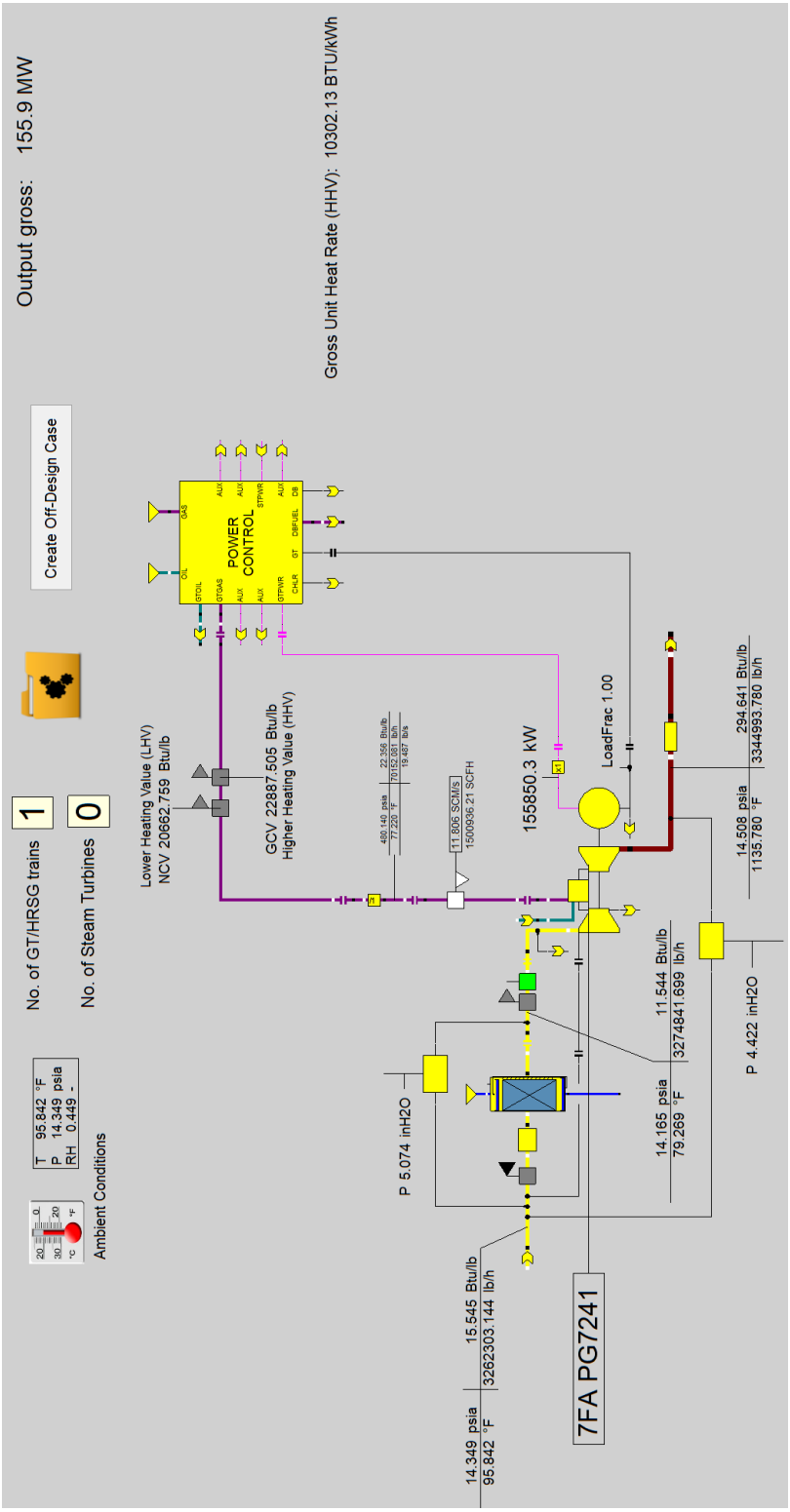


Figure 7: Zeeland Unit 1-B (7FA) Corrected to June 29, 2025 Conditions

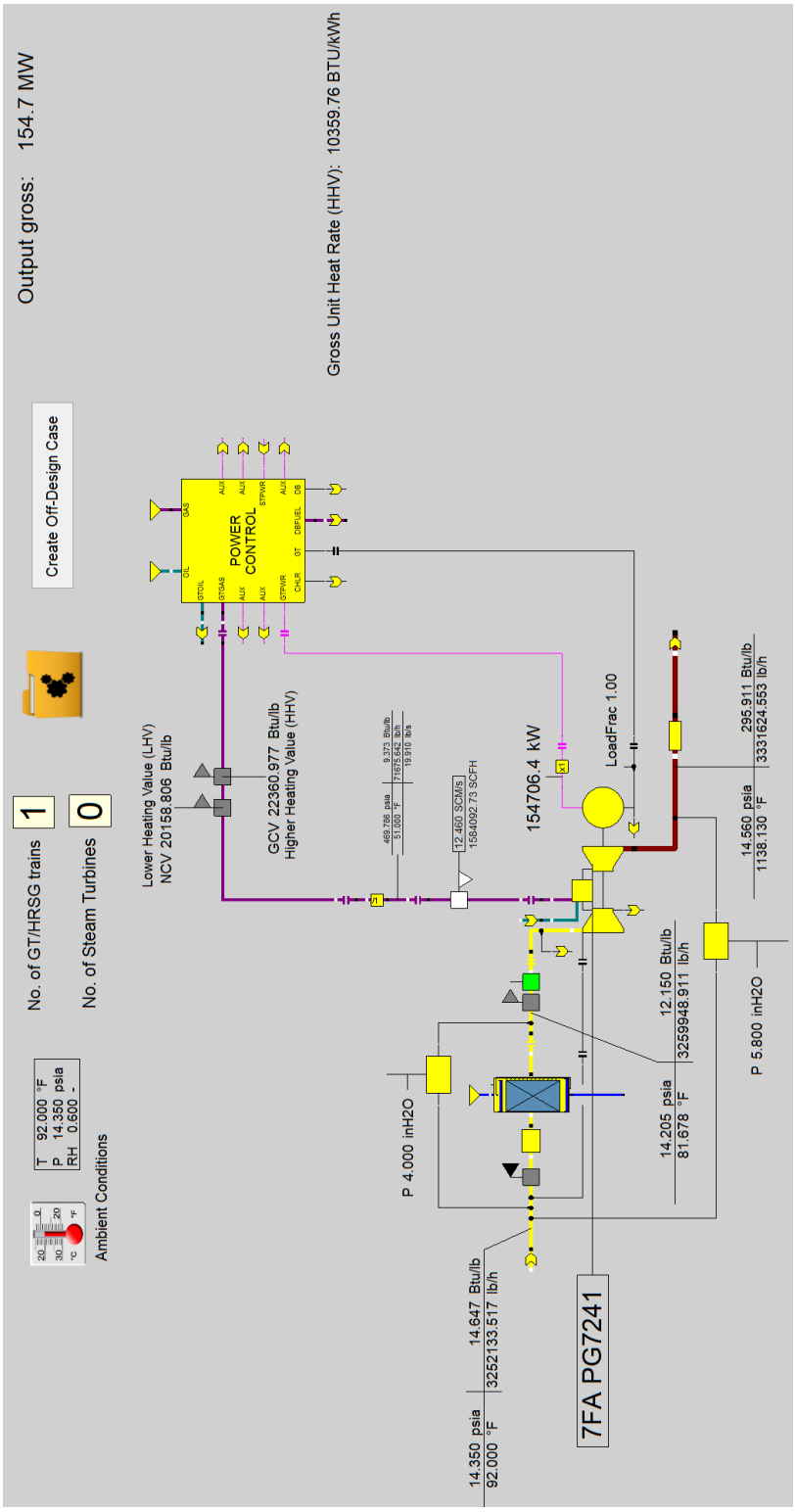


Figure 8: Zeeland Unit 1-B (7FA) Corrected to Design Conditions

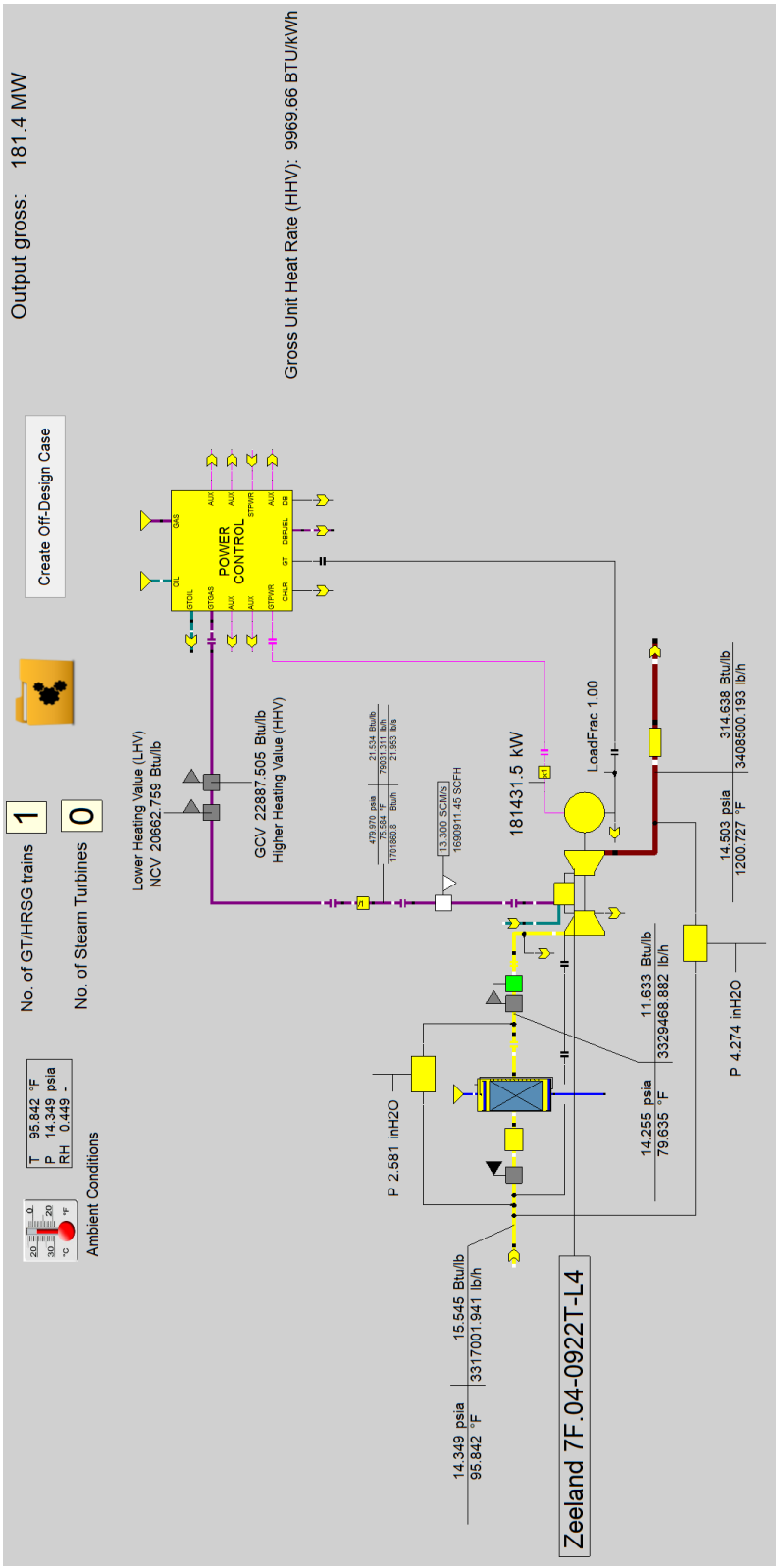


Figure 9: Zeeland Unit 1-B (7F.04) June 29, 2025

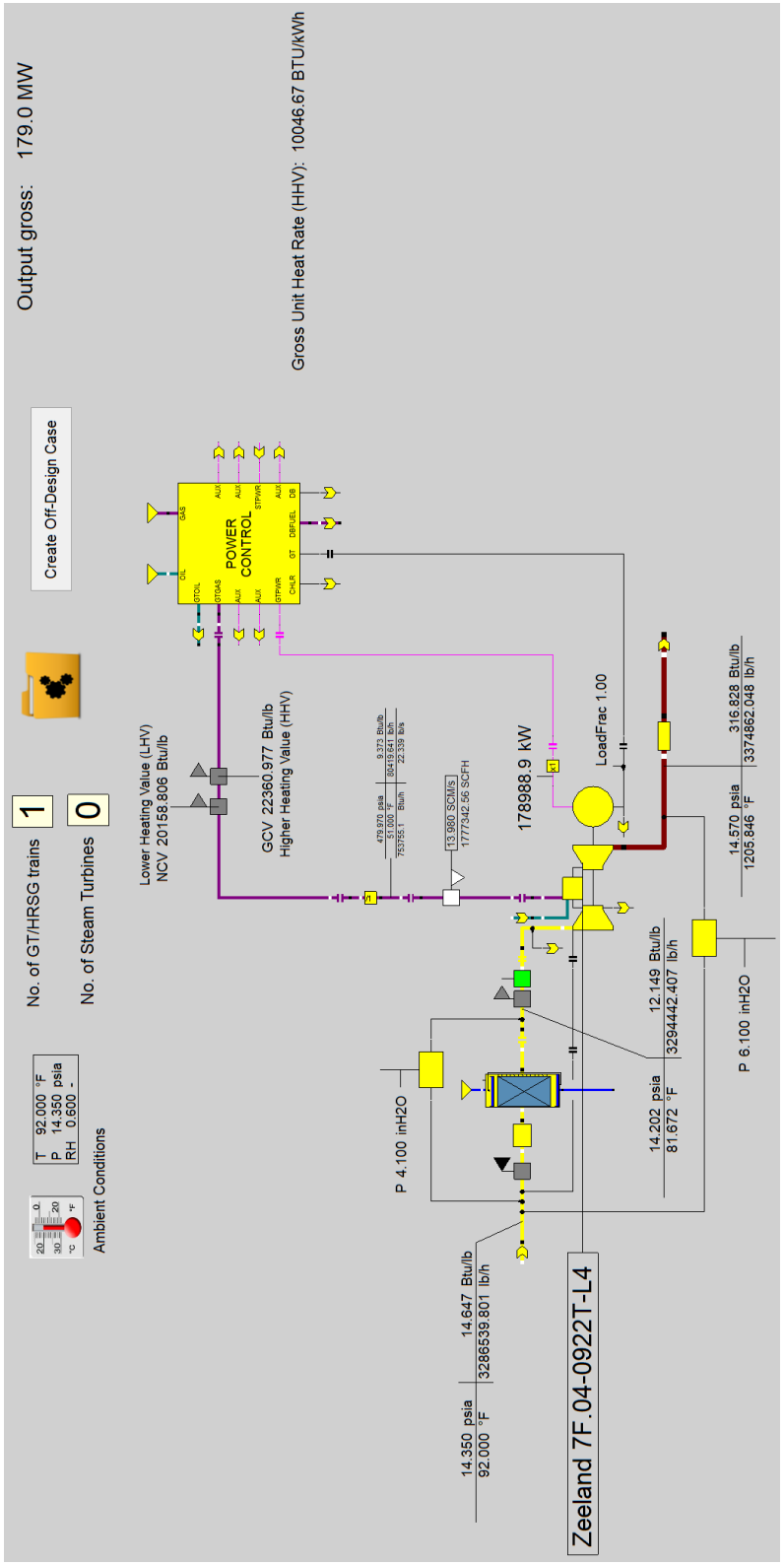


Figure 10: Zeeland Unit 1-B (7F.04) Corrected to Design Conditions

Appendix C: Zeeland Unit 1-A & 1-B Advanced Gas Path Contract

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

AMENDMENT NO. 4 TO THE LONG TERM SERVICE AGREEMENT FOR ZEELAND SIMPLE CYCLE FACILITY BETWEEN CONSUMERS ENERGY COMPANY AND GE VERNOVA INTERNATIONAL LLC.

THIS AMENDMENT NO. 4 ("Amendment 4") dated as of March 1, 2024 (the "Amendment 4 Effective Date", is made by and between GE Vernova International LLC, successor to General Electric International, Inc. ("Contractor") and Consumers Energy Company ("Owner") (each individually a "Party" and together the "Parties").

RECITALS

WHEREAS, Mirant Zeeland, L.L.C. (which later changed its name to Zeeland Power Company, LLC) and Contractor entered into that certain Long Term Service Agreement for the Zeeland Simple Cycle Facility dated June 16, 2004 (the "Agreement"); and

WHEREAS, Owner is the successor by merger to Zeeland Power Company, LLC; and

WHEREAS, the Parties have heretofore amended the Agreement by a letter agreement dated August 29, 2013 (which letter agreement can be considered to be "Amendment No. 1" to the Agreement); and

WHEREAS, the Parties have heretofore amended the Agreement by Amendment No. 2 dated January 2, 2014; and

WHEREAS, the Parties have heretofore amended the Agreement by Amendment No. 3 dated March 24, 2021; and

WHEREAS, the Parties have mutually agreed to further permanently modify certain provisions of the Agreement as set forth herein below; and

NOW, THEREFORE, in consideration of the mutual promises described herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

1. Defined Terms. Unless otherwise defined herein, all capitalized terms used in this Amendment 4 that are defined in the Agreement shall have the meanings given to them in the Agreement.

2. Owner shall have the option, in its sole discretion, to cancel this Amendment 4 upon written notice to Contractor at any time prior to March 15, 2024. Any such cancellation shall be effective upon Contractor's receipt of written notice.

   In the event that Owner cancels this Amendment 4 following the Amendment 4 Effective Date, Owner shall pay Contractor a cancellation amount equal to the following:

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

Cancellation Date			Cancellation Fee per Gas Turbine
Amendment 4 Effective Date	to	March 15, 2024	$2,907,000

Contractor shall invoice Owner immediately upon receipt of notice for cancellation of Amendment 4. The Parties agree that the damages likely to be incurred by Contractor in the event of a cancellation by Owner will be difficult to measure, that the cancellation amount is reasonable, and that the cancellation amount shall be paid as liquidated damages in lieu of all such actual damages and not as a penalty.

2. Amendments to the Agreement. As of the Amendment 4 Effective Date, the Agreement is hereby modified as follows:

A. Section I (Definitions) of the Agreement is hereby modified by changing or adding the following definitions:

"AGP Tech Upgrade Scope" shall mean Contractor's scope of supply to upgrade the Gas Turbines with upgrades including, but not limited to, AGP Capital Parts and DLN2.6+ Capital Parts, included in Attachment 1 to this Amendment 4.

"AGP Capital Parts" shall mean those upgraded buckets, nozzles, and shrouds Capital Parts, that shall replace such existing Capital Parts, as further set forth in Attachment 1 to this Amendment 4.

"DLN 2.6+ Capital Parts" shall mean those upgraded fuel nozzles, combustion caps, liners, and transition pieces Capital Parts, that shall replace such existing Capital Parts, as further set forth in Attachment 1 to this Amendment 4.

"AGP Tech Upgrade Installation Milestone Payment" shall mean, subject to Section VIII.P, eighteen million, four-hundred and twenty-five thousand dollars (US$18,425,000) for each Gas Turbine.

"AGP Tech Upgrade Maintenance Milestone Payment " shall mean, subject to Section VIII.J.6, the eleven million, two hundred thousand ($11,200,000).

B. Section II (Scope of Contractor's Obligations) of the Agreement is hereby amended by adding the following Section II. Q

Q. AGP Tech Conversion.

1. Contractor shall provide all Parts and Services as necessary to complete the AGP Tech Conversion (as outlined in the AGP Tech Upgrade Scope). The "AGP Tech Conversion" means (i) the

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

installation of a full set of new AGP Capital Parts and associated hardware to replace such then installed Capital Parts and (ii) the installation of a full set of new DLN2.6+ Capital Parts and associated hardware to replace such then installed Capital Parts, for each Gas Turbine, and (iii) all other items listed in Attachment 1 AGP Tech Upgrade Scope, in order to support the AGP Tech Conversion. Payment for the AGP Tech Conversion shall be in accordance with the provisions of Section VIII of the Agreement.

2. Such AGP Tech Conversion shall occur as the next scheduled Hot Gas Path or Major Inspection for each Gas Turbine.

C. Section VIII (Price And Payment Terms) of the Agreement is hereby amended by adding the following Section VIII. P:

P. AGP Tech Conversion Price and Payment.

1. In consideration of the AGP Tech Conversion, Owner shall pay Contractor the AGP Tech Upgrade Installation Milestone Payment for each Gas Turbine to have such AGP Tech Conversion.
2. Contractor shall invoice Owner for the AGP Tech Upgrade Installation Milestone Payment as follows:

   a. $4,606,250 on April 1, 2024 for each Gas Turbine
   b. $12,897,500 on January 15, 2025 for each Gas Turbine
   c. $921,250 upon mobilization to site for the AGP Tech Conversion for each Gas Turbine

3. Escalation for the AGP Tech Upgrade Installation Milestone Payment shall be calculated per Section VIII.C, except for the Base Index, which shall be the Composite Index for the year 2023.

D. Section VIII (Price And Payment Terms), sub-section J (Milestone Payments) of the Agreement is hereby amended by adding the following Section VIII.J.6:

6. In consideration of the AGP Tech Conversion, Owner shall pay Contractor the AGP Tech Upgrade Maintenance Milestone Payment. Contractor shall invoice Owner for such AGP Tech Upgrade Maintenance Milestone Payment approximately six (6) months prior to the first Hot Gas Path Inspection of the first Gas Turbine after the AGP Tech Conversion. For purpose of clarification, this one (1) payment and not intended to be per Gas Turbine. Escalation for the AGP Tech Upgrade Maintenance Milestone Payment shall be calculated per Section VIII.C, except for the Base Index, which shall be the Composite Index for the year 2023.

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

3. Entire Agreement. Except as expressly set forth in this Amendment 4, all other provisions of the Agreement (as previously amended by the letter agreement referenced hereinabove) remain unchanged and in full force and effect. In the event of a conflict between the terms of the Agreement and this Amendment 4, the terms hereof shall control. This Amendment 4 may be amended only by an instrument in writing executed by the Parties hereto.

4. Counterparts; Signatures. This Amendment 4 may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute one instrument. Any signature page of any such counterpart, or any electronic facsimile thereof, may be attached or appended to any other counterpart to complete a fully executed counterpart of this Amendment 4. Any electronic facsimile transmission of any signature of a Party shall be deemed an original and shall bind such Party.

5. Governing Law. This Amendment 4 shall be governed and construed in accordance with the laws of the Agreement, without regard to its conflicts of laws provisions.

6. No Third-Party Beneficiary. This Amendment 4 is intended solely for the benefit of the Parties and is not intended for the benefit of any third parties.

IN WITNESS WHEREOF, the Parties have caused this Amendment 4 to be executed as of the date first above written.

CONSUMERS ENERGY COMPANY	GE VERNOVA INTERNATIONAL LLC.
DocuSigned by:	DocuSigned by:
By: Jason L Ricketts	By:
4CDFDAB92EF14DF...	83A541BF22014C8...
Name: Jason L Ricketts	Name: Joshua Bird
Title: Sr Manager Plant Operations	Title: General Manager
Date: 2/26/2024 | 10:07 AM EST	Date: 2/23/2024 | 1:25 PM EST

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

Attachment 1

AGP Tech Upgrade Scope

CONSUMERS ENERGY

Site: ZEELAND GENERATING STATION

Unit Serial: 297502; 297503

Proposal Number: 1628149-440825

Revision: 1

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

Section 1: Scope of Supply

1.1 Scope of Supply

DLN 2.6+ GO Combustion System

Combustion System:

This upgrade includes an entirely new combustion system, except for the Transition Pieces (TPs) if the unit has a TIL 1774 compliant 24k EI combustion system. If the unit does not have DLN2.6e 24k EI combustion system, new TPs will be required. Here is the list of the combustion components within the Scope of Supply:

- ML A033 Major Disassembly Tool Kit
- ML 0513 Gas-Only Fuel Nozzle Assembly
- ML 0572 Fuel Gas Emergency Stop Valve
- ML 0701 Combustion Chamber Arrangement
- ML 0702 Transition Piece Assembly
- ML 0703 Combustion Liner Arrangement
- ML 0717 Transition Piece Arrangement Combustion
- ML 0719 Aft Combustion Case Arrangement
- ML 0726 Combustion Tuning Piping
- ML 1214 Spark Plug Assembly

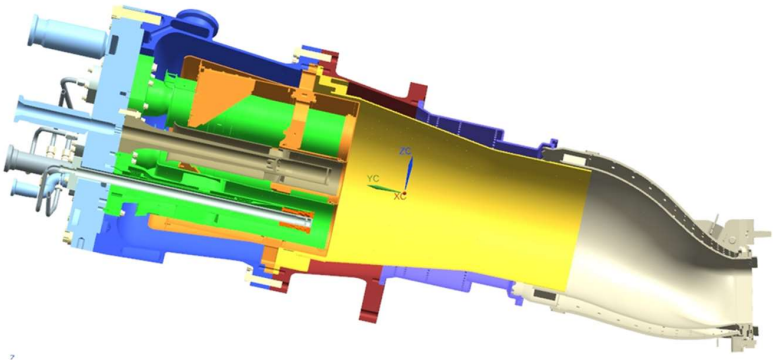


Figure 1: DLN2.6+ Combustion System

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

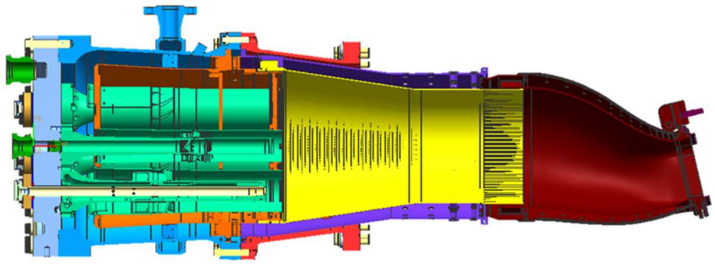


Figure 2: DLN2.6+ Combustion System, Gas Only Cross-section.

Accessories:

The following items will be provided as new or as an upgrade.

1. For 7FA cold fuel sites- Replace PM1 and Quat valves with no piping changes
2. New Gas piping arrangement, interconnect piping (MLI 0962/969G)
3. New air extraction piping (MLI0924)
4. New TMR ATID sensors
5. New spark plugs (MLI 1214)
6. Modifications to;
    - WW/FSD Drain
    - Cooling Water piping including aft leg cooling removal.
    - CDM Probe Holder
    - Strainer
    - COP Structure (removal)
    - Transducer Arrg
    - Manway Cover Arrangement (If required)
    - Cooling and Sealing Piping Arrangement
    - SPA Power Step Up Ignition Transformer
    - Static Starter Analysis
    - Control Oil Interconnect Piping
    - Field Temporary Sensor

Controls Systems:

Continuous Dynamics Monitoring (CDM) system, Enhanced Transient Stability (ETS), CLEC and AutoTune DX are required for this new combustion system. In case an existing MKVI is being migrated to a MKVIe system, an aux panel might be required to provide additional IO capability.

7F DLN 2.6+ AFS

AFS requires an additional GCV in the gas module as well as additional interconnect piping, manifold & pigtails. Because of variability in GT compartment layouts a laser scan will be performed to facilitate installation and limit field modifications if a recent laser scan has not already been completed.

Scope of supply includes:

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

1. AFS injectors
2. Modifications required to TP/impingement sleeve to accommodate AFS injector.
3. Routing of fuel circuit inside of unit to fuel AFS system
4. Modifications to manway covers to accommodate fuel circuit routing.
5. Flow sleeve assembly (for existing DLN2.6+ units only)
6. Controls integration
7. Accessories modifications required to fuel AFS.
    - Modification to fuel skid for AFS Valve
    - Downstream and Interconnecting Piping
    - Additional Fuel Gas Manifold Pressure Differential Transmitters
    - AFS Valve (VCG-5)

Impacted Components:

1. Gas supply skid
2. GT Instrumentation
3. Gas Control Valves
4. Gas fuel manifolds & pigtails
5. Combustor transition pieces
6. Combustion liner
7. Turbine shell arrangement
8. AFS fuel delivery and injectors
9. Combustor flow sleeve

7F AGP Tech Package

This modification will include the following:

- AGP Stage 1 Nozzle Kit and Support Ring
- AGP Stage 2 and 3 Nozzle Kits
- AGP Stage 1, 2, and 3 Bucket Kits
- AGP Stage 1, 2, and 3 Shroud Kits
- Cooling and sealing air orifice modification
- Installation and modification documents
- Firing temperature increase and revised Model Based Control (MBC) software changes (formerly known as control curve change)
- 7FA.04 or 7FA.05 length 1AO, 2FO, 2AO wheel space thermocouples (as appropriate)

High Output Stage 0

The implementation of high-output stage 0 upgrade on gas turbines with flared-enhanced compressor package 3 configuration (or higher) involves the following modifications:

- Redesigned stage R0 compressor rotor blades arrangement
- Redesigned stage S0 compressor stator vanes arrangement
- Replacement R0 staking inserts (if modification has been already implemented)
- Replacement S0 stator keys
- Control software updates

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

Enhanced Little Foot Aft Stator Vanes

The implementation of the enhanced little-foot aft stator modification includes the following compressor hardware:

- Stage S14 enhanced little-foot stator vanes arrangement.
- Stage S15 enhanced little-foot stator vanes arrangement.
- Stage S16 enhanced little-foot stator vanes arrangement.
- Retaining rings for all three stages
- Stator vanes' installation hardware (stator keys and shoulder pins)

Enhanced Compressor – Package 4

- Software modifications to upload the Optimum Start (also known as Strategic Anti-Rotating Stall Schedule, or STARSS) software.
- Modification of the IGV stop blocks *
- Enhanced IGVs (including assembly hardware)
- Enhanced R0 rotor blades with graphite coating on the dovetail
- Enhanced S0 thru S4 stator vanes (S0 and S1 retain the NUVS configuration)
- Enhanced-robust S5 stator vanes and S5 casing pins, also known as "load dams."
- MCC modification* for drilling provisions for the S5 pins
- S6 thru S8 stator vanes with full airfoil shot peening [optional]
- Enhanced S14 thru S16 stator vanes with shot peening. There are two options:
    - Vanes with larger bases and hook fits that require CDC machining (bit-foot design)
    - Vanes with original bases and retaining rings that do not require CDC machining (little-foot design)
- CDC S14 thru S16 stator grooves modification* [if implementing big-foot vanes only]
- CDC patch ring [if a previous patch ring in S14/S15/S16 requires replacement]

- **7FA Shaft HP Limit Increase (214MW)** Controls software modifications to increase GT shaft torque limit.
- New or modified load coupling (as required) depending on the existing configuration.
- 96GW 4-20 mAmp analog transducer mounted in the GPP(recalibration or replacement), if needed.
- Excitation software requires update due to the new shaft torque limit.

OpFlex Cold Day Performance

This modification includes the following:

- OpFlex Cold Day performance software

Variable IGV Angle Optimization

This modification will include the following:

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

- OpFlex™ Variable IGV Angle Optimization software
- OpFlex™ Variable IGV Angle Optimization HMI screens
- Controls Specifications update.

F-Class OpFlex Advantage Variable Peak Load

This modification includes the following:

- Modifications of Mark VIe Software.
- Advanced Fuel Scheduling
- OpFlex Peak Load
- Installation and modification documents.

Revised Control Curve

GE Performance Engineering will develop and document the revised exhaust temperature control curves that correspond to the new machine characteristics. This effort may include one or all of the curves as required: base load, peak load or part load. The exhaust temperature control curve information is then used by GE Controls Engineering to convert the curves into a control specification. The control specification is provided in documentation to the customer.

Performance Curves

GE will create gas turbine correction curves based on a thermal site-specific model.

TTKX Coefficient Modification

This modification includes the following:

- Installation and modification documents if any.
  - Requisition Management support.

Note: The TTKX Coefficient adjustment will be performed in collaboration with a scheduled DLN tuning.

Safety Shutoff Valve (SSOV) and Vent Valve (SSOVV)

The Safety Shut Off System (Valves + Engineering + Support + Accessories) includes the following:

- Safety Shut-off Isolation Valve (SSOV) [Qty.1]
- Safety Shut-off Vent Valve (SSOVV) [Qty.1]
- Vent Line Interconnect Piping
- Silencer
- Compressed Air Piping
- Supporting Structures
- Provision for Junction Box Interconnecting Cabling and Cable Trays
- Accessories Engineering for SSOV/SSOVV, supporting structures, and interconnect piping/cabling.
- Modifications to provide access (ladder, gratings, handrails, etc.) as required.
- Drawing Updates

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

- Controls Modifications
- Requisition Management
- Laser Scan

Triple Modular Redundant (TMR) Pressure Monitoring

The redundant sensor ventilation system upgrade includes:

- On base conduit and wiring for TMR pressure transmitters in the turbine compartment-(3) transmitters required per ventilation fan.
- Software modifications for the new transmitter configuration to incorporate lead/lag function as well as the trip functions for the ventilation fans.

Combustion Dynamics Monitoring (CDM) – Dual

CDM Equipment (typical)

- Dynamic Pressure Probes & Probe Holder
- Signal conditioner
- UCSx Cards as applicable
- Dual PAMC Acoustic Monitoring Card
- Cables and Tubing to make necessary connections.
- Conduit required for collection of probe cables to signal conditioner.
- Installation and Modification Documents including Controls Modifications

Field Laser Scan - 3D image.

DLN 2.6+ combustion system upgrade would require a scan of the areas outside (interconnecting piping) and inside of the gas turbine enclosure (fuel manifolds, interior geometry (turbine casing/combustion can interface) and the accessory compartments. This would include the top, bottom, both ends and left & right sides of the interiors and exteriors.

The key is to capture the as-built detail for each system or MLI (Model List Item) affected by the modification. Detailed scanning requirements will be defined by an ordering drawing created by GE Requisition Engineering.

Typical scope includes the following: Onsite survey, Scan, Registration, UG Model Generation, Estimated T&L, Equipment. All T&L, Equipment Rental, Targets, and extra baggage charges charged at actual cost.

1.2 Performance Effect

Expected Relative Performance Improvement- Evaps Off

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

	deg F	**-20**	**0**	**30**	**59**	**75**	**92**	**105**
GT Output	*%*	8.0%	11.3%	16.2%	14.5%	13.3%	12.5%	9.9%
GT Heat Rate	*%*	-1.4%	-1.8%	-2.2%	-2.6%	-2.5%	-2.6%	-2.7%

Expected Relative Performance Improvement- Evaps On

Ambient Temperature	*deg F*	**59**	**75**	**92**	**105**
Inlet Temperature	*deg F*	53	67	81.8	90
GT Output	*%*	15.1%	13.4%	13.2%	13.3%
GT Heat Rate	*%*	-2.6%	-2.5%	-2.5%	-2.6%

7F.04 Tech HOR0 AFS MECL Estimates -

Ambient Temperature	deg F	-20	0	30	59	75	92	105
Turndown Output	%	50.3%	38.0%	25.3%	24.9%	25.8%	28.3%	31.0%
Turndown Output	MW	103.8	79.2	52.6	48.1	47.1	47.8	47.7

Unit Operation & Site Conditions

	Pre-Uprate	**Post-Uprate**
Load Condition	Base	Base
Compressor Configuration	7F.03 UF EC2	7F.04 ECP4 HOR0
Combustor Configuration	DLN 2.6	DLN2.6+ (AFS Option)
Turbine Configuration	7FA.03	7F.04 Tech
Fuel Type	Natural Gas	Natural Gas
Exhaust Configuration	Simple Cycle	Simple Cycle
Diluent Injection Status	None	None
Inlet Air Treatment	Evaps (On or Off)	Evaps (On or Off)
Gas Turbine Condition	Clean, ≤25 FH since offline WW	Clean, ≤25 FH since offline WW

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

Rated Conditions

Parameter	Units	Pre-Uprate Value	Post-Uprate Value
Compressor Inlet Temperature	deg F	81.8	81.8
Compressor Inlet Relative Humidity	%	92.2%	92.2%
Barometric Pressure	psia	14.35	14.35
Shaft Speed	rpm	3600	3600
Generator Power Factor	ratio	0.85	0.85
Inlet Pressure Drop	inH2O	4.0	4.1
Exhaust Pressure Drop	inH2O	5.8	6.1
Fuel Temperature	deg F	51	51
Fuel Composition (Natural Gas)			
Methane (CH4)	% mol	93.256	93.256
Ethane (C2H6)	% mol	2.953	2.953
Propane (C3H8)	% mol	0.442	0.442
N-Butane (C4H10)	% mol	0.113	0.113
N-Pentane (C5H12)	% mol	0.036	0.036
Hexanes, Avg. (C6H14)	% mol	0.033	0.033
Nitrogen (N2)	% mol	2.405	2.405
Carbon Dioxide (CO2)	% mol	0.761	0.761

1.3 Emissions Effect

Estimated emission at base load:

- 9 ppmvd NOx @15% Oxygen.
- 9 ppmvd CO

1.4 Generator Evaluation

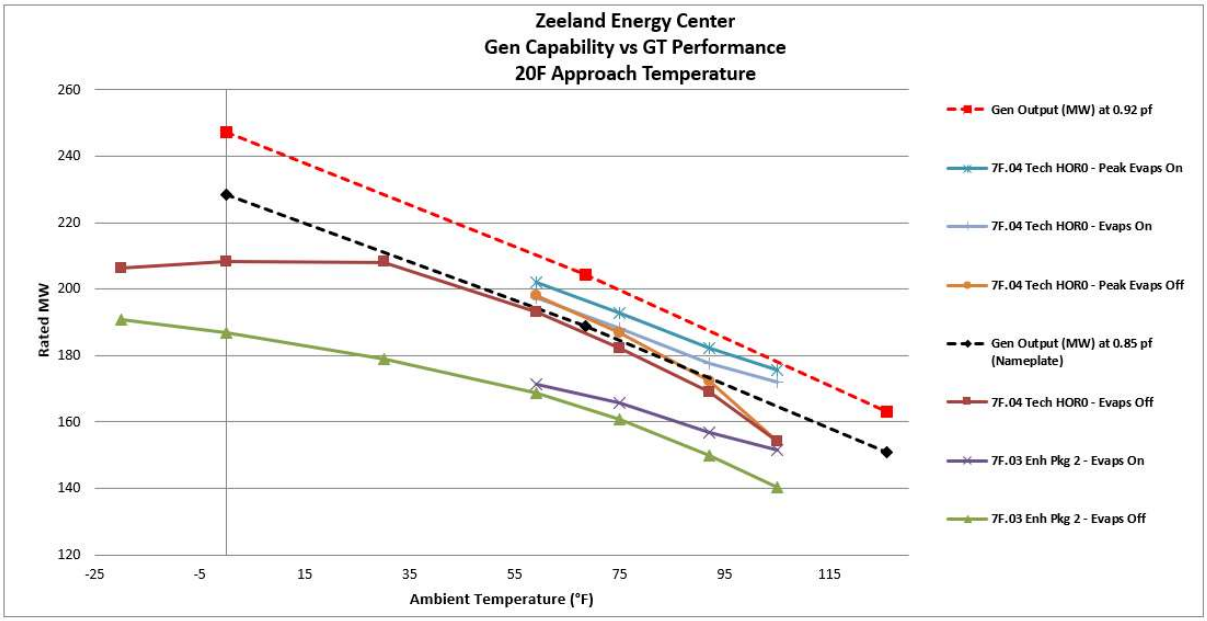
Conclusion, Generator Capability vs. Proposed GT Uprate:
A cursory review of Zeeland Generating Station Generator SNs 337X125 and 337X126 was performed to assess the ability of the generators to accommodate the following gas turbine configuration cases:

Pre-upgrade cases:
7F.03 Enh Pkg 2 - Evaps Off
7F.03 Enh Pkg 2 - Evaps On
Post-upgrade cases:
7F.04 Tech HOR0 - Evaps Off
7F.04 Tech HOR0 - Evaps On
7F.04 Tech HOR0 - Peak Evaps Off

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

7F.04 Tech HOR0 - Peak Evaps On
The review indicates that generator can meet gas turbine uprate cases with power factor as shown in the table and graph below.

Cases	Power Factor Required
7F.04 Tech HOR0 - Evaps Off	0.85 (nameplate)
7F.04 Tech HOR0 - Evaps On	0.90
7F.04 Tech HOR0 - Peak Evaps Off	0.88
7F.04 Tech HOR0 - Peak Evaps On	0.92



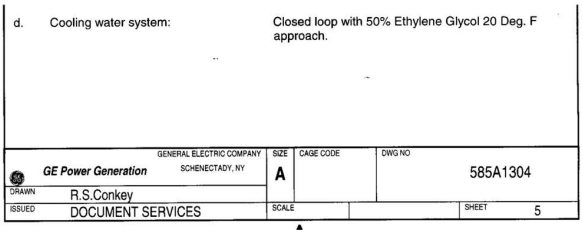
For the cases where Power Factor float is not required: This evaluation approach does not require uprated generator hardware changes (main generator, exciter, and other generator auxiliary equipment), as the generator will operate within its original design capabilities.
For the cases where Power Factor float is required: Operating at the higher power factor will reduce reactive power (VAR) output. This evaluation approach does not require uprated generator hardware changes (main generator, exciter, and other generator auxiliary equipment), as the generator will operate within its original design capabilities. If the reduced VAR output is unacceptable to the Customer (this could be due to a regulatory organization requirements and restrictions, as an example), and an uprate in MVA is desired, a Generator Detailed Study would have to be performed to thoroughly review this possibility.

Critical Assumptions:

1. Cooling Liquid Data – Needs Customer Confirmation
    a. Cooling Liquid Composition: 50% Ethylene Glycol / 50% Water with Fouling Factor of 0.001 - per C907 585A1304

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

b. Approach Temperature per C907 585A1304



2. Generator components are in their "New and Clean" conditions.
    a. The generator review does not take into consideration any generator component degradation due to age, environment or maintenance practices. The analysis assumes that the condition and performance of the generator is as it was when it was shipped.
3. The study is based on GE internal design records and deviations, which would not account for any hardware changes the unit experienced that were not performed by GE. The Customer shall advise if there was any 3rd party work performed (e.g., stator rewind, field rewind, exchange rotor, core repair, etc.)
4. Increased Power Factor is acceptable for the cases where Power Factor Float is required.
5. The graph shown above is for the reference only and does not provide any contractual guarantee with respect to overall GT-Generator performance.

Reliability Considerations:

This uprate assessment was based on GE internal design records and deviations, which does not account for any hardware changes outside of GE knowledge and experience.
It is strongly recommended that the generator undergo a thorough Test and Inspection per GEK 103566 to establish the current generator condition before increasing in MW operation, as the increase in MW will result in the generator experiencing higher than previous current loads and component temperatures. GE would be pleased to discuss this and other key reliability issues with the Customer.

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

Appendix 1 – Technical Assumptions

Original Manufacturing Information		
Serial Number(s)	297502	297503
Design Memo(s)	DM-GR0526	
MPL/ML#	ML-7A1WFA106-1	ML-7A1WFA106-2
Manufacturer	GE	
Equipment Code	7FA.03	
Product Line	F Fleet	
Nameplate	297502	297503
Site Location	ZEELAND GENERATING STATION	
Controls OEM	GE	
COD Date	21-05-2001	
Ship Date	19-09-2000	23-09-2000
Control System	Mark VIe TMR	
Starter OEM	GE	
Crossover	YES	
Service Relationship	CSA	

Site Information

Site Information	
Market Segment	Power Generation
Operation Cycle	GT
Country	UNITED STATES
Altitude	670 ft
Min Ambient Temp	-20 ºF
Design Ambient Temp	92 ºF
Max Ambient Temp	105 ºF
Relative Humidity	60 %

Current Configuration

Inlet/Exhaust	
Inlet Pressure Drop	4.04 in H_2O

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

Inlet/Exhaust	
IBH System	Yes
Exhaust Pressure Drop	5.75 in H_2O

Combustor	
Fuels	NATURAL GAS
Nox/Diluent	DLN
Augmentation	NONE
Combustion System	DRY LOW NOX 2.6

Operating Data

Region/PGS Service Region	NAM North America
PGS Service Sub Region	North America North
Sales Channel	Power Services Sales

Previous Requisitions:

Serial Number	FDM	ICN	SCOPE	Date
297502	F4694G3	CR135666	Comb Dynamics Monitoring w/RDLNT	07-12-2004
297502	F4694G4	CR135666	Comb Dynamics Monitoring w/ RDLNT	07-12-2004
297502	F4694G8	DR429878-1	Combustion Spread Monitor Upgrade (TIL 1524-3)	27-04-2009
297502	F6014G12	1555351-372427- 6 (ADDED SCOPE)	ADDED SCOPE: 7FA.03 OpFlex Sliding Fuel Pressure Control+(96FG-1 Sensor)	31-08-2021
297502	F6014G12	1555351-372427- 4	7FA.03 OpFlex Sliding Fuel Pressure Control	31-08-2021
297502	F6014G10	CR587328-1	7FA.03 TIL 1287 Excessive Gas Fuel Flow at Start-up	09-06-2014
297502	F6014G8	CR578567-1	7FA.03 2-Piece Uncambered IGVs (CID Minor)	12-03-2014

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

Serial Number	FDM	ICN	SCOPE	Date
297502	F6014G8	CR477059C-6	7FA.03 Enhanced Compressor Package 2/Bellows Crossfire Tubes (CID Minor)	12-03-2014
297502	F6014G7	CR477059C-3	7FA+e/s OP FLEX BALANCE AUTOTUNE, SS CBV (CID=minor)	30-05-2013 17:00:00
297502	F6014G9	CR551830-3	7FA.03 Exhaust Thermocouples Upgrade (CID Minor)	03-05-2013 17:00:00
297502	F6014G9	CR551830-1	7FA.03 Exhaust Thermocouples Upgrade (CID Minor)	03-05-2013 17:00:00
297502	F6014G2	CR437650-1	TIL 1345 - Over Speed Trip Test Procedure Automation	19-06-2009
297502	F4694G7	DR416814-1	HMI Upgrade	10-12-2008
297502	F4694G4	CR135666	Comb Dynamics Monitoring w/ RDLNT	07-12-2004
297502	F4694G3	CR135666	Comb Dynamics Monitoring w/RDLNT	07-12-2004
297503	F4694G4	CR135670	Comb Dynamics Monitoring w/ RDLNT	07-12-2004
297503	F4694G8	DR429878-2	Combustion Spread Monitor Upgrade (TIL 1524-3)	27-04-2009
297503	F6014G12	1555351-372427- 5	7FA.03 OpFlex Sliding Fuel Pressure Control	31-08-2021
297503	F6014G12	1555351-372427- 7 (ADDED SCOPE)	ADDED SCOPE: 7FA.03 OpFlex Sliding Fuel Pressure Control+(96FG-1 Sensor)	31-08-2021
297503	F6014G10	CR587328-2	7FA.03 TIL 1287 Excessive Gas Fuel Flow at Start-up	09-06-2014
297503	F6014G2	CR437622-1	TIL 1345 - Over Speed Trip Test Procedure Automation	19-06-2009
297503	F6014G4	DR494058-2	Mk V to Mk Ve upgrade w/Phase 2 Life Extension Package Beta Application	27-05-2011
297503	F6014G8	CR555489-1	7FA+e/s ENH CMPRS PKG-2 with UNCAMBERED 2PC IGV (CID=minor)	19-07-2013 17:00:00

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

Serial Number	FDM	ICN	SCOPE	Date
297503	F6014G8	CR477059C-5	7FA+e/s ENH CMPRS PKG-2 with UNCAMBERED 2PC IGV (CID=minor)	19-07-2013 17:00:00
297503	F6014G7	CR477059C-4	7FA+e/s OP FLEX BALANCE AUTOTUNE, SS CBV (CID=minor)	30-05-2013 17:00:00
297503	F6014G9	CR551830-2	7FA.03 Exhaust Thermocouples Upgrade (CID Minor)	03-05-2013 17:00:00
297503	F6014G9	CR551830-4	7FA.03 Exhaust Thermocouples Upgrade (CID Minor)	03-05-2013 17:00:00
297503	F4694G7	DR416814-2	HMI Upgrade	10-12-2008
297503	F4694G4	CR135670	Comb Dynamics Monitoring w/ RDLNT	07-12-2004

TIL Affected Units List:

Unit Serial Number	TIL No.	TIL Title	Status	CMU Required	Compliance Type	TAG
297502	1509-R4	F-CLASS FRONT END (R0, S0, AND R1) COMPRESSOR INSPECTIONS	INCOMPLETE	Yes	C - Compliance Required	FS5V
297503	1509-R4	F-CLASS FRONT END (R0, S0, AND R1) COMPRESSOR INSPECTIONS	INCOMPLETE	Yes	C - Compliance Required	FS5V
297502	1320-R2	INLET BLEED HEAT (IBH) PIPE SYSTEM INSPECTION AND CORRECTIVE ACTION	COMPLETE / RECURRING	Yes	M - Maintenance	FD4L
297502	1363-2R1	MODIFICATION TO MARK V TRIP COUNTER	COMPLETE / RECURRING	Yes	O - Optional	FW4Y
297502	1456-2R1	LUBRICATION PUMP MAINTENANCE PRACTICES	COMPLETE / RECURRING	Yes	M - Maintenance	FW4C
297502	1576-R1	GAS TURBINE ROTOR INSPECTIONS	COMPLETE / RECURRING	Yes	S - Safety	FS4PC - REV4, FS4PC

DocuSign Envelope ID: 7938E047-C52E-4176-96A8-DB84B4B4B2B8

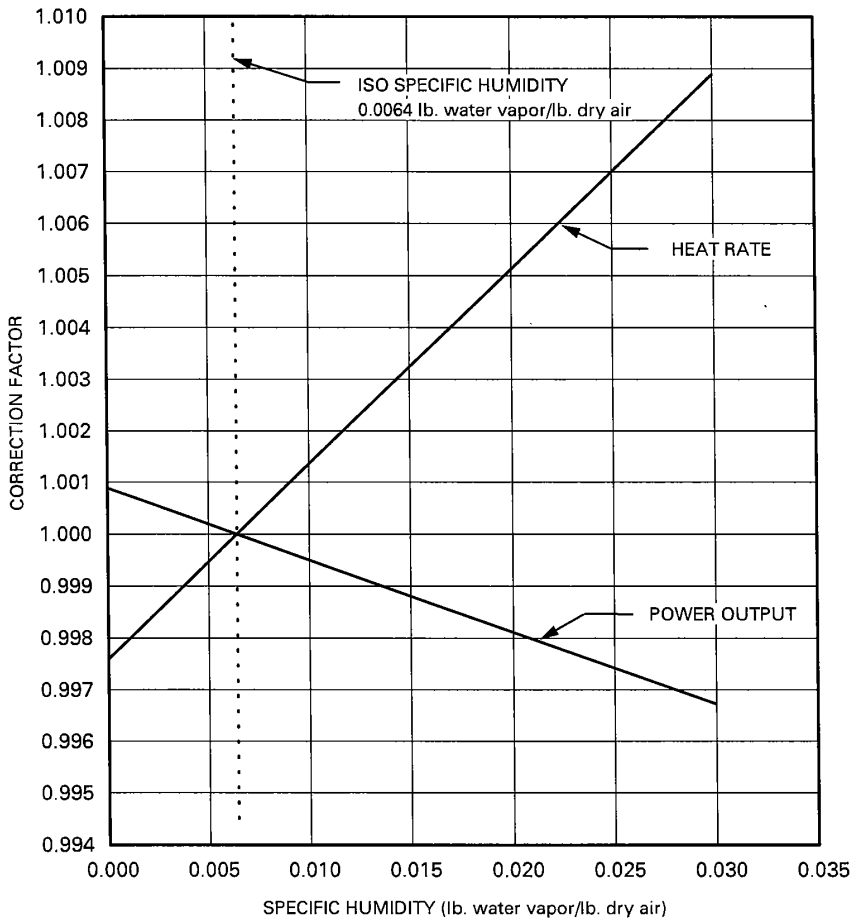
Unit Serial Number	TIL No.	TIL Title	Status	CMU Required	Compliance Type	TAG
297502	1582-R2	F AND H CLASS LIFT OIL HOSE INSPECTION AND REPLACEMENT	COMPLETE / RECURRING	Yes	C - Compliance Required	FW4O
297502	1619	TURBINE COMPARTMENT HIGH TEMPERATURE	COMPLETE / RECURRING	Yes	O - Optional	FW4Q
297502	1700	POTENTIAL GAS LEAK HAZARD DURING OFFLINE WATER WASHES	COMPLETE / RECURRING	Yes	S - Safety	FW4T
297502	2058	HAZGAS PROTECTION - GAS FUEL COMPARTMENT	COMPLETE / RECURRING	Yes	S - Safety	FW5P
297503	1320-R2	INLET BLEED HEAT (IBH) PIPE SYSTEM INSPECTION AND CORRECTIVE ACTION	COMPLETE / RECURRING	Yes	M - Maintenance	FD4L
297503	1363-2R1	MODIFICATION TO MARK V TRIP COUNTER	COMPLETE / RECURRING	Yes	O - Optional	FW4Y
297503	1456-2R1	LUBRICATION PUMP MAINTENANCE PRACTICES	COMPLETE / RECURRING	Yes	M - Maintenance	FW4C
297503	1576-R1	GAS TURBINE ROTOR INSPECTIONS	COMPLETE / RECURRING	Yes	S - Safety	FS4PC-REV4,FS4PC
297503	1582-R2	F AND H CLASS LIFT OIL HOSE INSPECTION AND REPLACEMENT	COMPLETE / RECURRING	Yes	C - Compliance Required	FW4O
297503	1619	TURBINE COMPARTMENT HIGH TEMPERATURE	COMPLETE / RECURRING	Yes	O - Optional	FW4Q
297503	1700	POTENTIAL GAS LEAK HAZARD DURING OFFLINE WATER WASHES	COMPLETE / RECURRING	Yes	S - Safety	FW4T
297503	2058	HAZGAS PROTECTION - GAS FUEL COMPARTMENT	COMPLETE / RECURRING	Yes	S - Safety	FW5P

Appendix D: GE 7FA Correction Curves

General Electric MS6001, MS7001 And MS9001 Gas Turbines

Corrections To Output And Heat Rate
For Non-Iso Specific Humidity Conditions

For Operation At Base Load On Exhaust
Temperature Control Curve



10/10/89
DA JAQUEWAY

498HA697
REV B

General Electric Model PG7241(FA) Gas Turbine

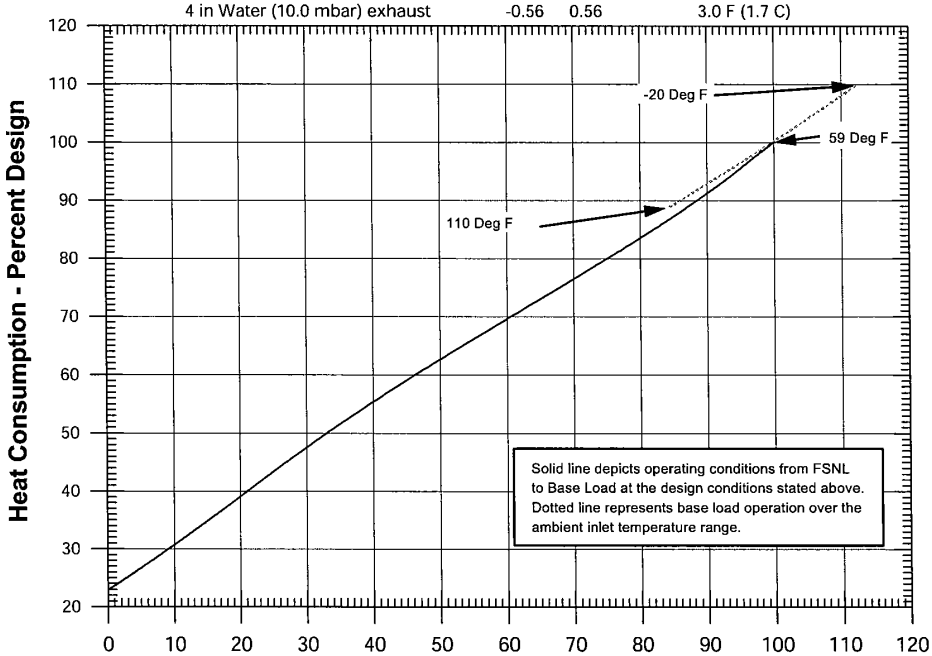
Estimated Performance - Configuration: DLN2.6 Combustor

Ambient Temperature 59 Deg F (15 Deg C), 60% Relative Humidity
Atmospheric Pressure 14.7 psia (1.013 Bar)

Fuel	Methane Gas @ 80 Deg.F , LHV = 21515 BTU/lb	
MODE:		Baseload
Evaporative Cooler Status:		ON
Design Output	kW	174000
Design Heat Rate (LHV)	Btu/kWh	9335
Design Heat Cons (LHV)x10^6	Btu/h	1624.3
Design Exhaust Flow x 10^3	lb/h	3629
Exhaust Temperature	deg. F	1112

Notes:
1. Altitude correction on curve 416HA662.
2. Ambient temperature and humidity correction on curve 544HA717 thru 544HA720.
3. Humidity effects on curve 498HA697 (use if evap. cooler is off).
4. Effect of modulating IGV's on Exhaust temperature and flow on curve 544HA721.
5. Plant Performance is measured at the generator terminals and includes allowances for the effects of excitation power, shaft driven auxiliaries, and 4.0 in H_2O (10.0 mbar) inlet and 5.5 in H_2O (13.75 mbar) exhaust pressure drops, evaporative cooler turned on @ baseload and a DLN combustor.
6. Additional inlet and exhaust pressure loss effects:

	% Effect on Output	% Effect on Heat Rate	Effect on Exhaust Temp.
4 in Water (10.0 mbar) inlet	-1.54	0.56	3.0 F (1.7 C)
4 in Water (10.0 mbar) exhaust	-0.56	0.56	3.0 F (1.7 C)

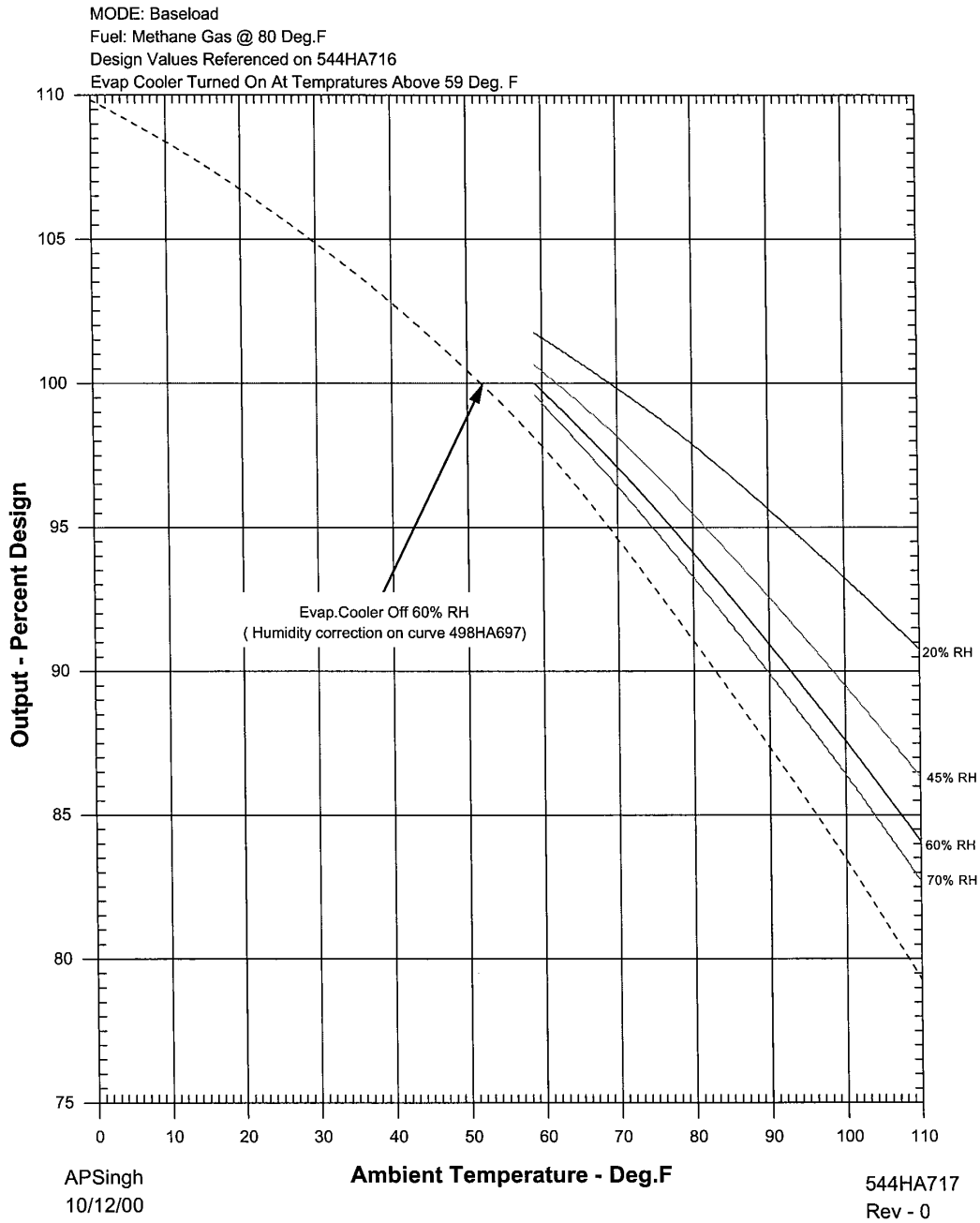


APSingh
10/12/00

544HA716
Rev - 0

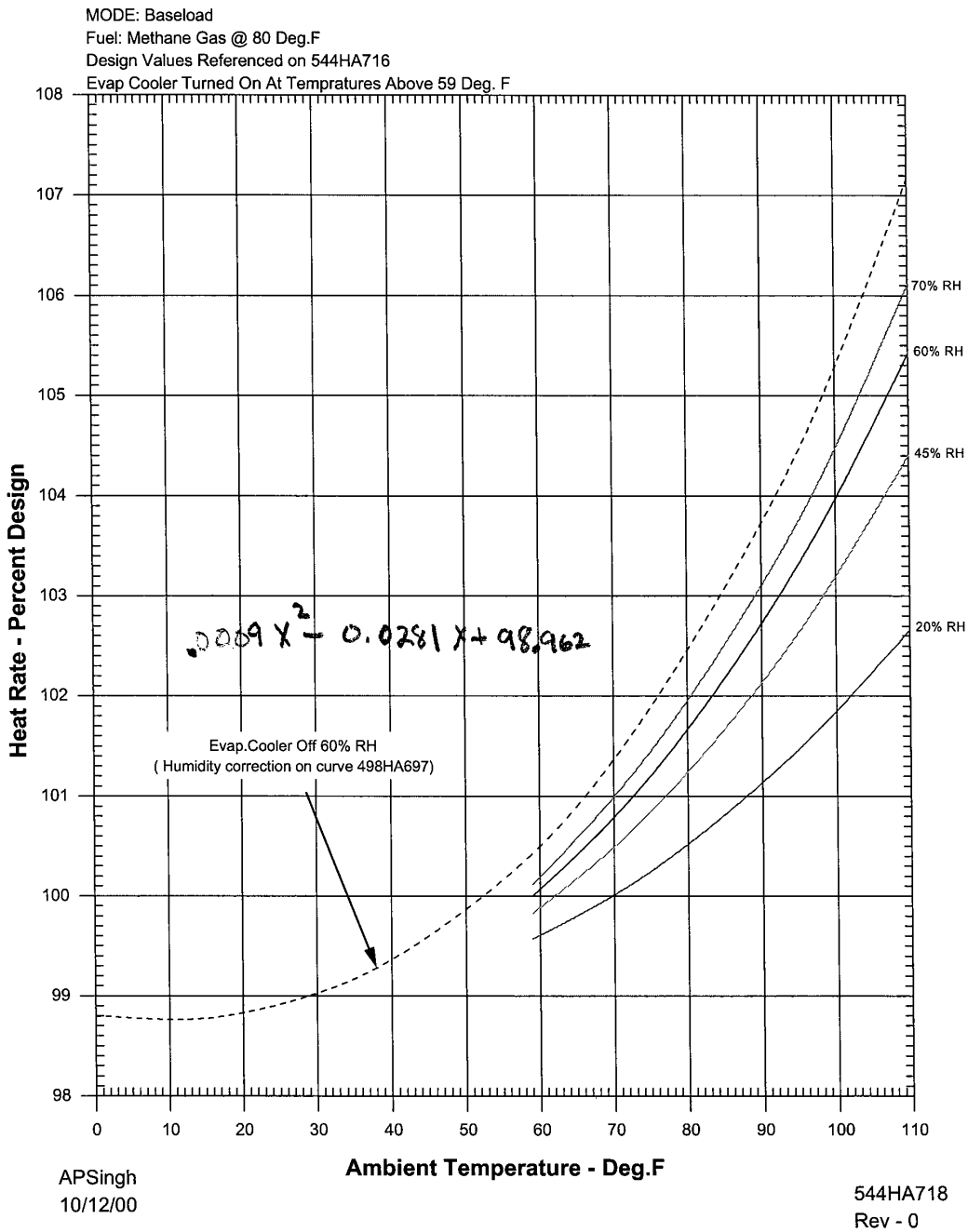
General Electric Model PG7241 (FA) Gas Turbine

Estimated Performance - Configuration: DLN 2.6 Combustor



General Electric Model PG7241 (FA) Gas Turbine

Estimated Performance - Configuration: DLN2.6 Combustor

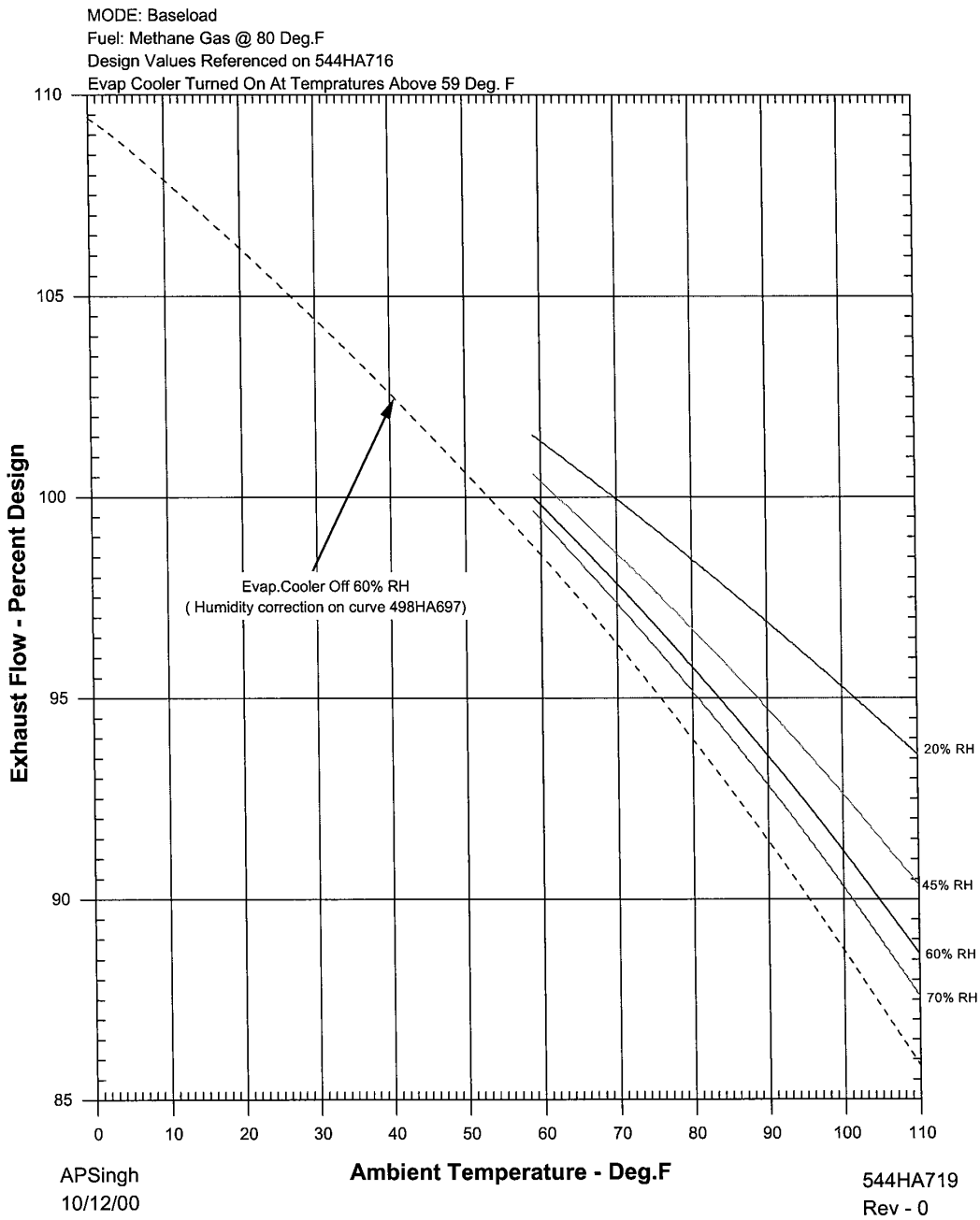


APSingh
10/12/00

544HA718
Rev - 0

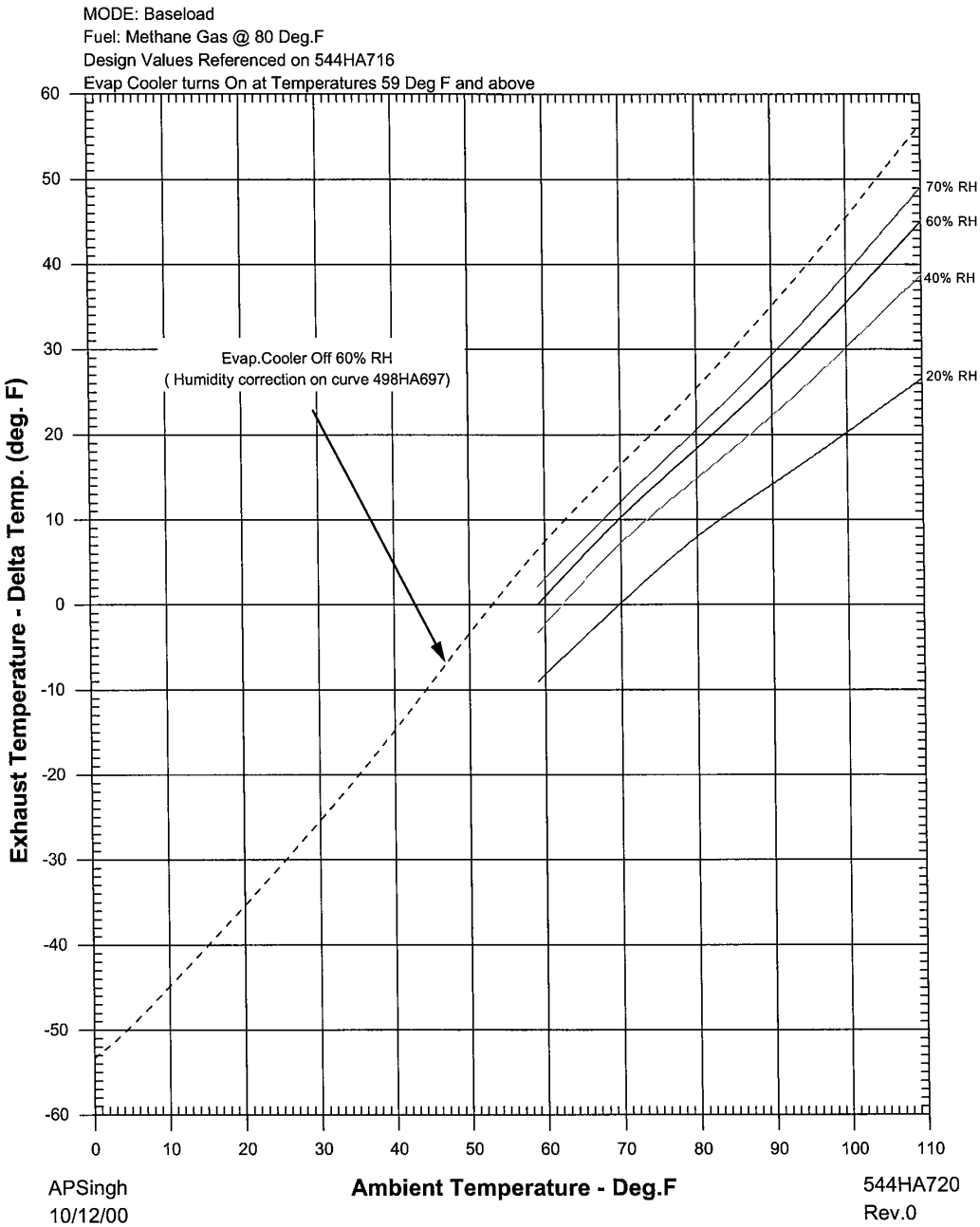
General Electric Model PG7241 (FA) Gas Turbine

Estimated Performance - Configuration: DLN 2.6 Combustor



General Electric Model PG7241(FA) Gas Turbine

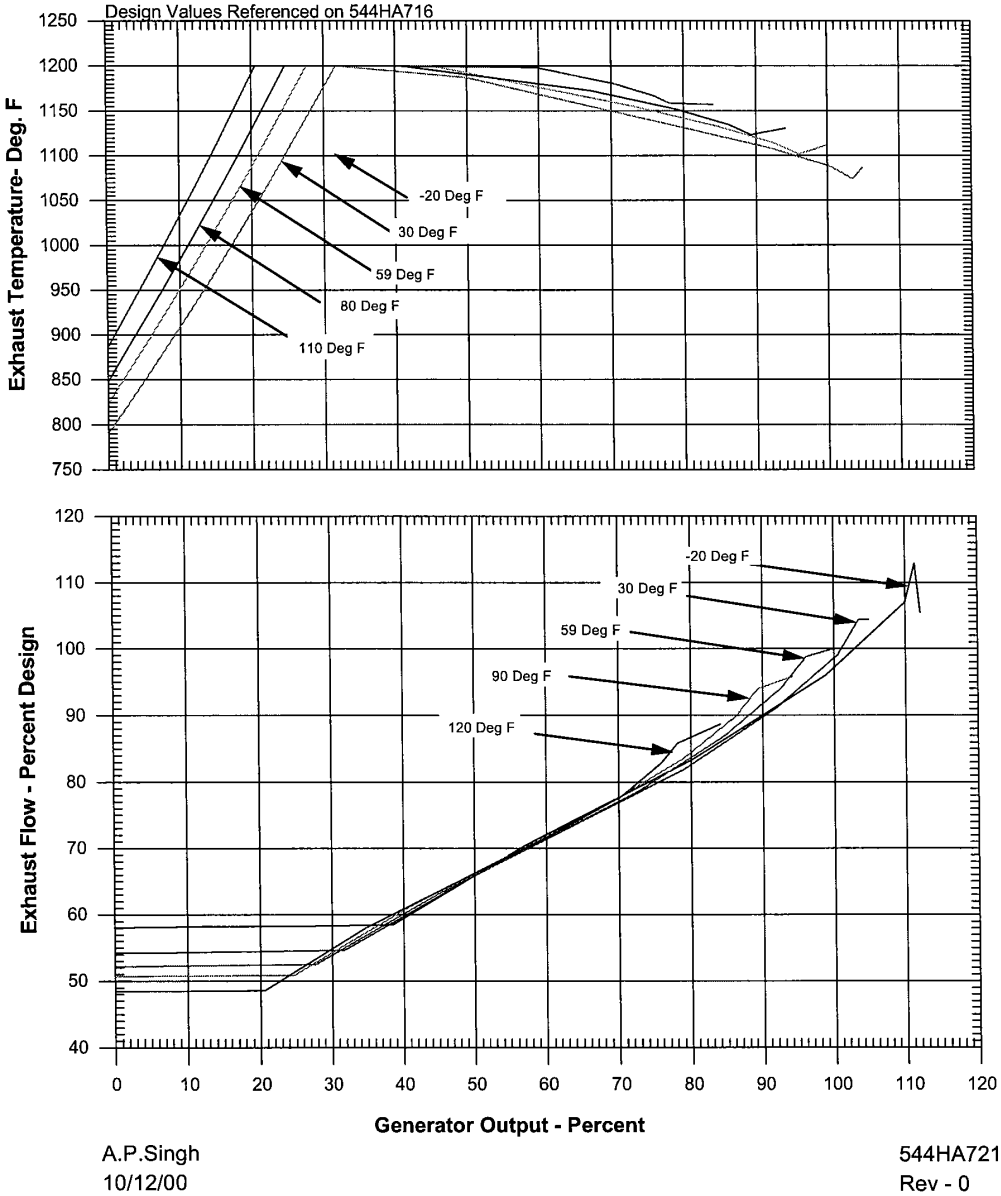
Estimated Performance - Configuration: DLN2.6 Combustor



GENERAL ELECTRIC MODEL PG7241(FA) GAS TURBINE

Estimated Performance - Configuration: DLN 2.6 Combustor

Mode: Baseload
Fuel: Methane Gas @ 80 Deg.F
Design Values Referenced on 544HA716



A.P.Singh
10/12/00

544HA721
Rev - 0

Appendix E: GE 7F.04 Correction Curves

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14
Estimated Performance
Gas Turbine Generator(s) 297502-3 ONLY

Reference Conditions and Corresponding Correction Curves

	Units	
Fuel		Gas
Fuel LHV	Btu/lb	See Gas Constituents
Load		Base
IGV Angle	degrees	On Schedule, See sheet 2
Diluent Injection Fluid		None
Generator Frequency	hertz	60
Generator Power Factor	ratio	0.85
Cycle Deck Version Used		7F.04-0922T-L4

	Applicable Correction Curve Sheet Numbers
Summary Page	Sheet 1
Control Curve Definition	Sheet 2
Reference SC Exhaust DP	Sheet 3

	Units	Value	Output	Heat Rate	Exhaust Flow	Exhaust Temp	Heat Consumption
Ambient Temperature & Humidity (Evap or SPRITS)		92 F 60 % RH	Sheet 4	Sheet 5	Sheet 6	Sheet 7	Sheet 8
Ambient Wetbulb Temperature	F	80.03	N/A	N/A	N/A	N/A	N/A
Compressor Inlet Temperature	F	81.84	Sheet 9	Sheet 10	Sheet 11	Sheet 12	Sheet 13
Compressor Inlet Relative Humidity	%	92.2%	Sheet 14	Sheet 15	Sheet 16	Sheet 17	Sheet 18
Shaft Speed	rpm	3600	N/A	N/A	N/A	N/A	N/A
Fuel Temperature	F	51	Sheet 19	Sheet 20	N/A	N/A	Sheet 21
Inlet Pressure Loss	in H2O	4.04	Sheet 22	Sheet 23	Sheet 24	Sheet 25	Sheet 26
Exhaust Pressure Loss (Rated)	in H2O	5.75	Sheet 27	Sheet 28	N/A	Sheet 29	Sheet 30
Exhaust Pressure Loss (Reference @ Rated CIT)	in H2O	4.91	Sheet 31	Sheet 32	N/A	Sheet 33	N/A
Barometric Pressure	psia	14.35	Sheet 34	Sheet 35	Sheet 36	Sheet 37	Sheet 38
Gas Fuel Composition		See Gas Constituents	Sheet 39	Sheet 40	Sheet 41	Sheet 42	Sheet 43
Wobbe Index	Btu/scf	See Gas Constituents	N/A	N/A	N/A	N/A	N/A
Inlet Bleed Heat Flow	lb/sec	0	N/A	N/A	N/A	N/A	N/A
Inlet Bleed Heat Tx Suppression	F	0	N/A	N/A	N/A	N/A	N/A
Partload Effects			N/A	N/A	N/A	N/A	N/A

Fuel Composition (Used for Gas Fuel)	Units	Value
METHANE (CH4)	mol frac	0.9326
ETHANE (C2H6)	mol frac	0.0295
PROPANE (C3H8)	mol frac	0.0044
iso-BUTANE (C4H10)	mol frac	0.0004
n-BUTANE (C4H10)	mol frac	0.0007
iso-PENTANE (C5H12)	mol frac	0.0002
n-PENTANE (C5H12)	mol frac	0.0002
HEXANE (C6H14)	mol frac	0.0003
HEPTANES (C7H16)	mol frac	0.0000
CARBON MONOXIDE (CO)	mol frac	0.0000
CARBON DIOXIDE (CO2)	mol frac	0.0076
HYDROGEN SULFIDE (H2S)	mol frac	0.0000
HYDROGEN (H2)	mol frac	0.0000
OXYGEN (O2)	mol frac	0.0000
NITROGEN (N2)	mol frac	0.0241
WATER (H2O)	mol frac	0.0000
NITRIC OXIDE (NO)	mol frac	0.0000
NITROGEN DIOXIDE (NO2)	mol frac	0.0000
METHANOL (CH3OH)	mol frac	0.0000
OCTANE (C8H18)	mol frac	0.0000
DISTILLATE (C12H26)	mol frac	0.0000
ETHYLENE (C2H4)	mol frac	0.0000
ACETYLENE (C2H2)	mol frac	0.0000
AMMONIA (NH3)	mol frac	0.0000
ARGON (AR)	mol frac	0.0000
CARBONYL SULFIDE (COS)	mol frac	0.0000
ETHYL ALCOHOL (C2H5OH)	mol frac	0.0000
DECAHYDRONAPTHALENE (C10H18)	mol frac	0.0000
Gas Fuel LHV - per ASTM D3588	Btu/lb	20159
Gas Fuel H/C Ratio	ratio	3.911
Wobbe Index	Btu/scf	1314.591

Additional Notes:

Inlet bleed heat may be active during very cold ambient conditions for compressor protection

Evaporative Cooler can be either ON or OFF

Post Uprate Correction Curves

Hot ambient conditions may reach the compressor discharge temperature limit

NOTE: These performance test correction curves and tables are provided for the sole purpose of correcting performance test data from the boundary conditions present at the time of test to the design, guarantee, or reference conditions listed on this sheet. The performance characteristics on these sheets do not constitute any new performance guarantee(s) or any change to existing performance guarantee(s).

Please refer to the GE Vernova Thermal Performance Test Procedure for proper interpretation and use of these sheets.

David Walters
06/20/25

GE Vernova Test Correction Curve Tool: Version 11.1.0

24A-167 Rev A
Sheet 1

This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14
Estimated Performance
Gas Turbine Generator(s) 297502-3 ONLY

Cycle Deck Definition		
Fuel		Gas
Fuel LHV	Btu/lb	See Gas Constituents
Load		Base
IGV Angle	degrees	On Schedule, See below
Diluent Injection Fluid		None
Generator Frequency	hertz	60
Generator Power Factor	ratio	0.85
Cycle Deck Version Used		7F.04-0922T-L4

MBC Control Curve Definition			
Base Load Max Tfire Array (Encoded)			
CTIM, Tfire Array (X's) Control Tag °F		**Tfire Array (Y's) Control Tag °F**	
KCA_CTIM_TF[0]	-25.00	96.346	KCA_GFTF_MX[0]
KCA_CTIM_TF[1]	5.00	96.346	KCA_GFTF_MX[1]
KCA_CTIM_TF[2]	25.00	96.346	KCA_GFTF_MX[2]
KCA_CTIM_TF[3]	55.00	96.346	KCA_GFTF_MX[3]
KCA_CTIM_TF[4]	200.00	96.346	KCA_GFTF_MX[4]
KCA_CTIM_TF[5]	200.00	96.346	KCA_GFTF_MX[5]
KCA_CTIM_TF[6]	200.00	96.346	KCA_GFTF_MX[6]
Exhaust temperature Isotherm Limit			
Isotherm Control Tag		**Isotherm Limit (°F)**	
TTK_I[0]		1215.000	
Generator MW Max			
Gen Output Limit Control Tag		**Gen Output Limit (MW)**	
LK90MAX		214.000	
Base Load IGV Constant			
Base Load IGV Control Constant Tag		**Base Load Max IGV Limit**	
CSKGVMAX		86.000	
Base Load Max TCD Limit (Deg F)			
TCD Control Constant Tag		**Max TCD Limit °F**	
KCA_TCD_MX		805.000	

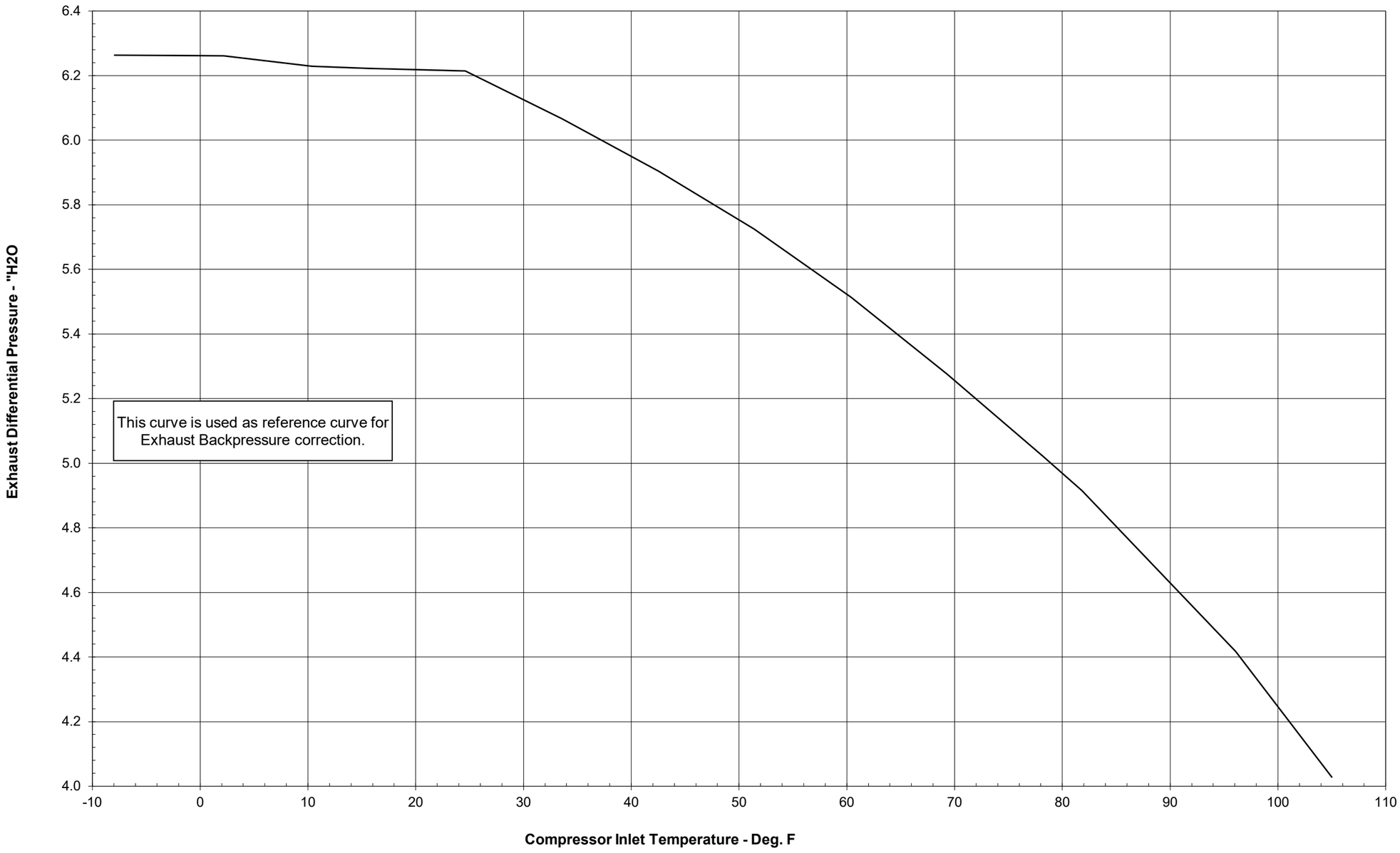
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Simple Cycle Exhaust Pressure

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Exhaust DP	inH2O	6.26	6.26	6.26	6.23	6.22	6.21	6.07	5.90	5.72	5.51	5.28	5.02	4.91	4.42	4.03

David Walters
06/20/25

24A-167 Rev A
Sheet 3

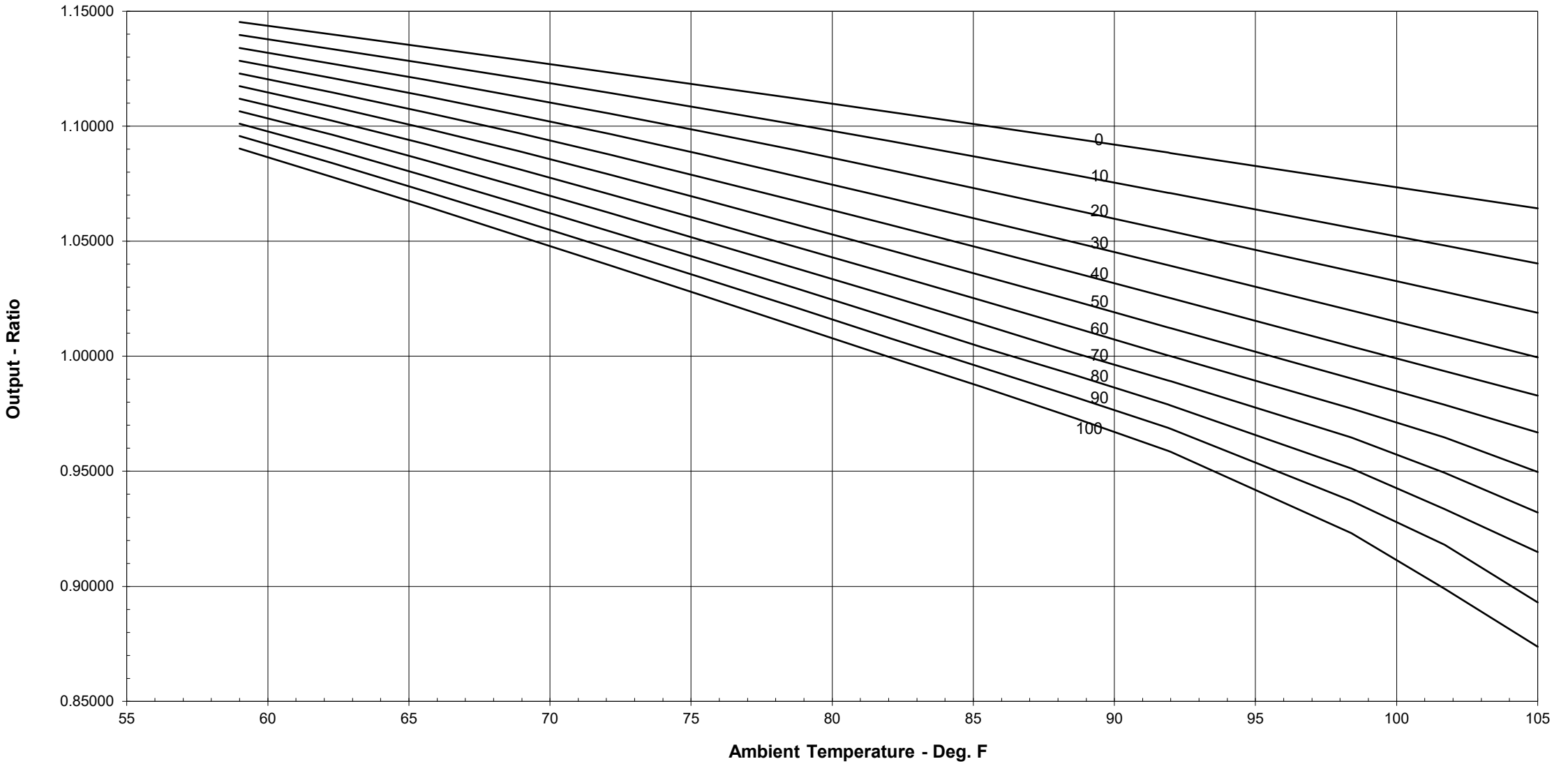
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Ambient Temperature and Humidity on Output

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Ambient Temperature - Deg. F

Relative Humidity - %	59.0	62.3	65.6	68.9	72.1	75.4	78.70	82.00	85.30	88.60	91.90	92.00	98.40	101.70	105.00
0	1.14534	1.13990	1.13440	1.12885	1.12343	1.11780	1.11212	1.10631	1.10046	1.09455	1.08858	1.08839	1.07647	1.07038	1.06432
10	1.13970	1.13353	1.12726	1.12087	1.11453	1.10776	1.10083	1.09374	1.08635	1.07876	1.07110	1.07087	1.05589	1.04813	1.04035
20	1.13404	1.12721	1.12016	1.11288	1.10553	1.09771	1.08959	1.08104	1.07236	1.06358	1.05470	1.05444	1.03706	1.02802	1.01891
30	1.12847	1.12093	1.11311	1.10491	1.09666	1.08771	1.07836	1.06884	1.05918	1.04942	1.03959	1.03929	1.01997	1.00983	0.99953
40	1.12293	1.11472	1.10607	1.09704	1.08779	1.07780	1.06761	1.05727	1.04681	1.03626	1.02561	1.02528	1.00420	0.99357	0.98290
50	1.11745	1.10850	1.09910	1.08917	1.07899	1.06827	1.05737	1.04635	1.03521	1.02396	1.01256	1.01221	0.99030	0.97893	0.96689
60	1.11198	1.10233	1.09219	1.08131	1.07050	1.05915	1.04765	1.03602	1.02429	1.01238	1.00034	1.00000	0.97727	0.96470	0.94971
70	1.10652	1.09623	1.08518	1.07369	1.06232	1.05042	1.03840	1.02625	1.01393	1.00143	0.98953	0.98916	0.96473	0.94939	0.93210
80	1.10111	1.09008	1.07834	1.06632	1.05446	1.04209	1.02959	1.01693	1.00404	0.99174	0.97906	0.97867	0.95120	0.93360	0.91491
90	1.09576	1.08393	1.07169	1.05919	1.04691	1.03411	1.02117	1.00800	0.99520	0.98230	0.96891	0.96849	0.93721	0.91808	0.89301
100	1.09031	1.07792	1.06522	1.05231	1.03964	1.02645	1.01305	0.99971	0.98667	0.97314	0.95889	0.95844	0.92309	0.89889	0.87374

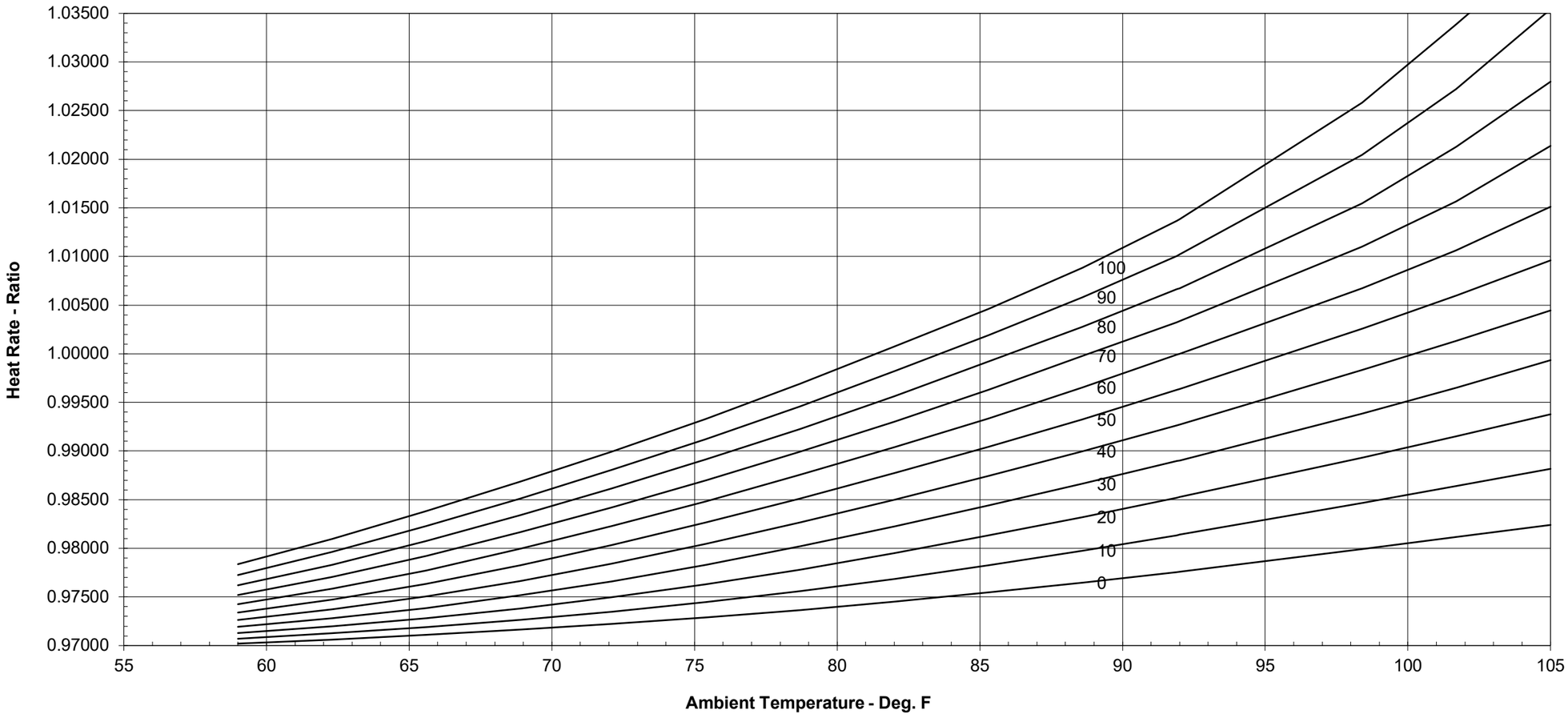
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Ambient Temperature and Humidity on Heat Rate

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Ambient Temperature - Deg. F

Relative Humidity - %	59.0	62.3	65.6	68.9	72.1	75.4	78.70	82.00	85.30	88.60	91.90	92.00	98.40	101.70	105.00
0	0.97020	0.97061	0.97110	0.97164	0.97223	0.97290	0.97366	0.97453	0.97547	0.97649	0.97757	0.97760	0.97992	0.98115	0.98240
10	0.97070	0.97127	0.97191	0.97265	0.97346	0.97447	0.97561	0.97686	0.97825	0.97976	0.98135	0.98140	0.98464	0.98638	0.98817
20	0.97129	0.97200	0.97283	0.97381	0.97496	0.97630	0.97780	0.97950	0.98131	0.98322	0.98520	0.98526	0.98931	0.99150	0.99378
30	0.97193	0.97281	0.97387	0.97517	0.97661	0.97831	0.98022	0.98226	0.98440	0.98664	0.98897	0.98904	0.99384	0.99651	0.99934
40	0.97263	0.97371	0.97507	0.97665	0.97842	0.98047	0.98268	0.98501	0.98745	0.98999	0.99265	0.99273	0.99834	1.00133	1.00446
50	0.97340	0.97474	0.97636	0.97824	0.98033	0.98266	0.98513	0.98772	0.99043	0.99327	0.99629	0.99638	1.00256	1.00597	1.00960
60	0.97425	0.97586	0.97774	0.97994	0.98228	0.98484	0.98755	0.99039	0.99336	0.99653	0.99990	1.00000	1.00674	1.01066	1.01512
70	0.97520	0.97704	0.97922	0.98167	0.98422	0.98700	0.98993	0.99301	0.99628	0.99979	1.00323	1.00334	1.01102	1.01566	1.02137
80	0.97620	0.97829	0.98074	0.98340	0.98615	0.98914	0.99228	0.99561	0.99921	1.00276	1.00663	1.00675	1.01548	1.02130	1.02798
90	0.97725	0.97962	0.98227	0.98513	0.98806	0.99124	0.99460	0.99823	1.00190	1.00580	1.01007	1.01020	1.02045	1.02724	1.03542
100	0.97837	0.98097	0.98381	0.98684	0.98995	0.99332	0.99693	1.00073	1.00461	1.00886	1.01366	1.01382	1.02579	1.03386	1.04223

David Walters
06/20/25

24A-167 Rev A
Sheet 5

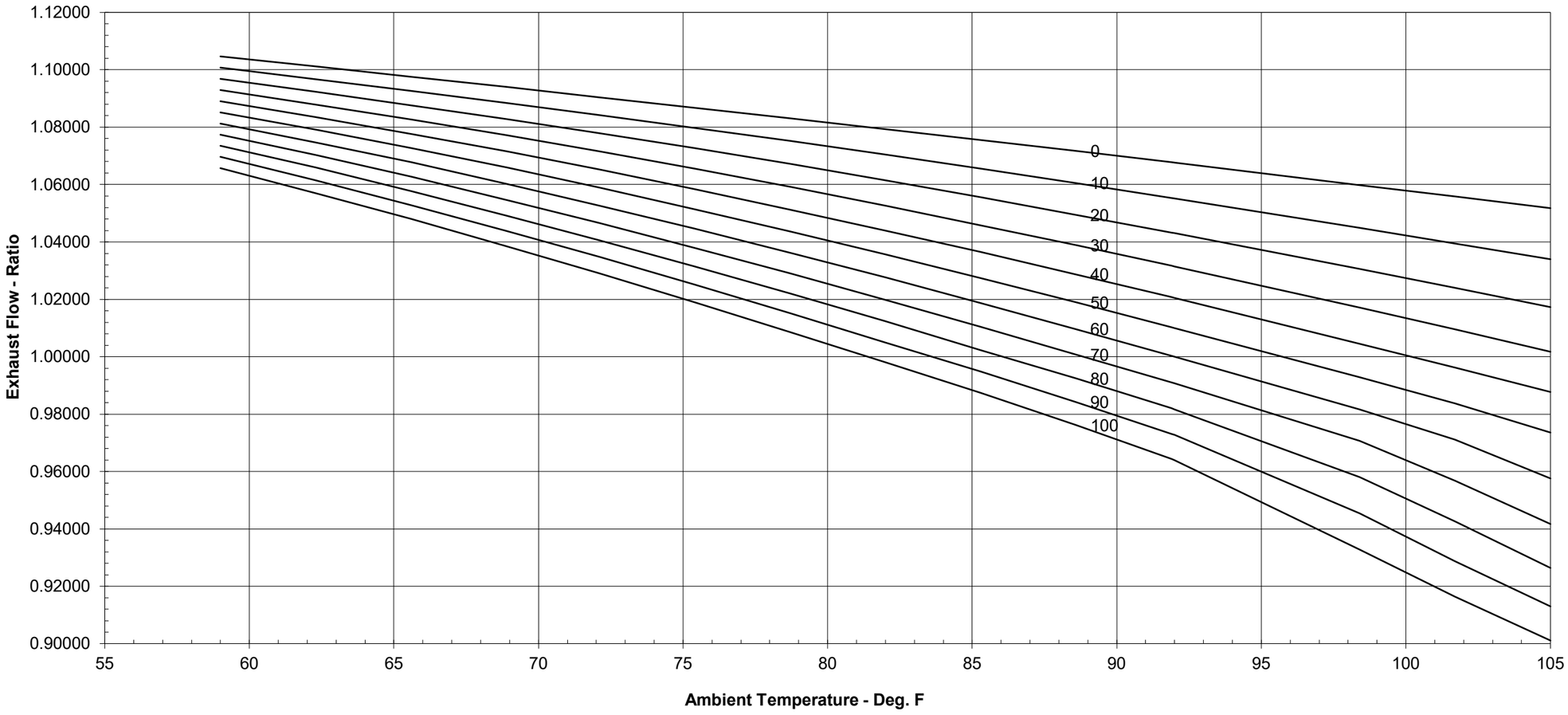
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Ambient Temperature and Humidity on Exhaust Flow

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Ambient Temperature - Deg. F

Relative Humidity - %	59.0	62.3	65.6	68.9	72.1	75.4	78.70	82.00	85.30	88.60	91.90	92.00	98.40	101.70	105.00
0	1.10466	1.10114	1.09757	1.09398	1.09045	1.08677	1.08307	1.07931	1.07552	1.07169	1.06780	1.06767	1.05984	1.05580	1.05177
10	1.10076	1.09674	1.09261	1.08840	1.08420	1.07976	1.07519	1.07052	1.06559	1.06049	1.05531	1.05516	1.04487	1.03946	1.03397
20	1.09684	1.09232	1.08763	1.08277	1.07790	1.07270	1.06725	1.06146	1.05553	1.04945	1.04323	1.04304	1.03061	1.02401	1.01728
30	1.09294	1.08790	1.08265	1.07717	1.07164	1.06557	1.05917	1.05258	1.04580	1.03884	1.03172	1.03150	1.01718	1.00955	1.00172
40	1.08904	1.08349	1.07768	1.07159	1.06528	1.05840	1.05129	1.04397	1.03643	1.02869	1.02074	1.02050	1.00449	0.99618	0.98770
50	1.08514	1.07909	1.07273	1.06594	1.05891	1.05140	1.04364	1.03564	1.02741	1.01896	1.01027	1.01000	0.99285	0.98369	0.97356
60	1.08125	1.07471	1.06778	1.06025	1.05267	1.04457	1.03621	1.02760	1.01873	1.00961	1.00027	1.00000	0.98165	0.97110	0.95757
70	1.07738	1.07035	1.06270	1.05466	1.04656	1.03792	1.02900	1.01982	1.01036	1.00064	0.99106	0.99076	0.97068	0.95684	0.94168
80	1.07352	1.06590	1.05770	1.04917	1.04059	1.03144	1.02201	1.01229	1.00226	0.99236	0.98200	0.98167	0.95808	0.94258	0.92637
90	1.06967	1.06143	1.05278	1.04379	1.03475	1.02513	1.01521	1.00498	0.99475	0.98421	0.97308	0.97273	0.94536	0.92874	0.91296
100	1.06572	1.05702	1.04794	1.03851	1.02905	1.01899	1.00860	0.99804	0.98741	0.97616	0.96428	0.96392	0.93276	0.91640	0.90107

David Walters
06/20/25

24A-167 Rev A
Sheet 6

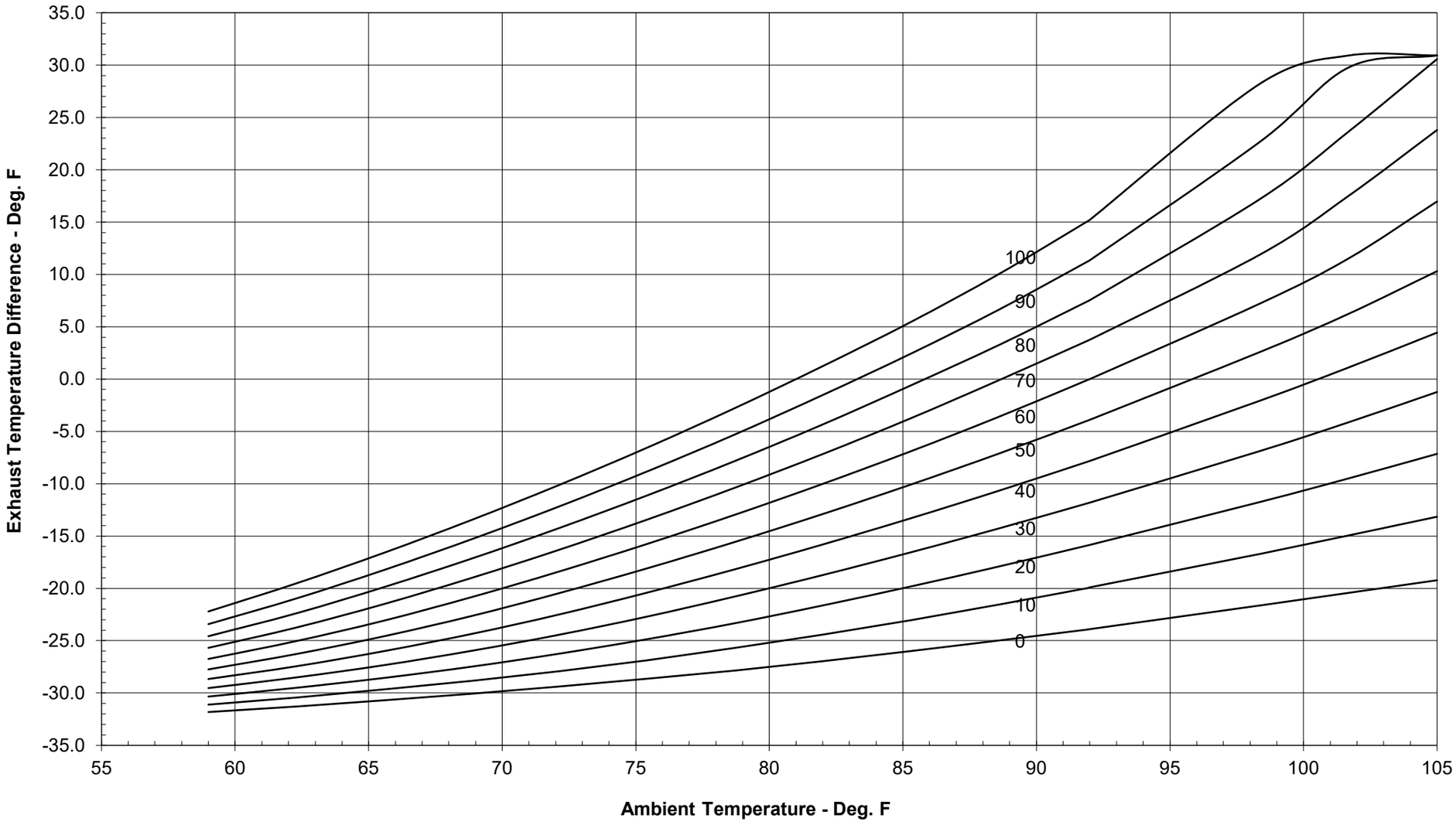
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Ambient Temperature and Humidity on Exhaust Temperature

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Ambient Temperature - Deg. F

Relative Humidity - %	59.0	62.3	65.6	68.9	72.1	75.4	78.70	82.00	85.30	88.60	91.90	92.00	98.40	101.70	105.00
0	-31.82	-31.28	-30.68	-30.05	-29.39	-28.65	-27.84	-26.95	-25.99	-24.98	-23.92	-23.88	-21.64	-20.44	-19.23
10	-31.11	-30.42	-29.66	-28.83	-27.93	-26.87	-25.70	-24.43	-23.04	-21.54	-19.97	-19.92	-16.69	-14.95	-13.16
20	-30.34	-29.50	-28.55	-27.47	-26.25	-24.87	-23.34	-21.63	-19.82	-17.91	-15.91	-15.85	-11.73	-9.48	-7.15
30	-29.53	-28.51	-27.33	-25.95	-24.45	-22.71	-20.79	-18.73	-16.55	-14.27	-11.88	-11.81	-6.85	-4.12	-1.24
40	-28.66	-27.44	-25.98	-24.33	-22.51	-20.43	-18.19	-15.81	-13.30	-10.67	-7.91	-7.82	-2.04	1.12	4.43
50	-27.74	-26.27	-24.56	-22.61	-20.48	-18.11	-15.58	-12.90	-10.08	-7.12	-3.99	-3.89	2.62	6.25	10.31
60	-26.75	-25.03	-23.07	-20.81	-18.42	-15.78	-12.98	-10.02	-6.90	-3.60	-0.11	0.00	7.25	11.54	16.97
70	-25.68	-23.74	-21.48	-18.97	-16.34	-13.46	-10.40	-7.17	-3.75	-0.11	3.64	3.76	11.93	17.53	23.80
80	-24.57	-22.38	-19.86	-17.12	-14.27	-11.15	-7.84	-4.34	-0.61	3.25	7.41	7.54	17.25	23.67	30.57
90	-23.42	-20.96	-18.22	-15.27	-12.21	-8.86	-5.31	-1.53	2.42	6.63	11.21	11.35	22.73	29.78	30.92
100	-22.21	-19.52	-16.58	-13.42	-10.15	-6.59	-2.79	1.23	5.45	10.04	15.05	15.21	28.27	30.92	30.92

David Walters
06/20/25

24A-167 Rev A
Sheet 7

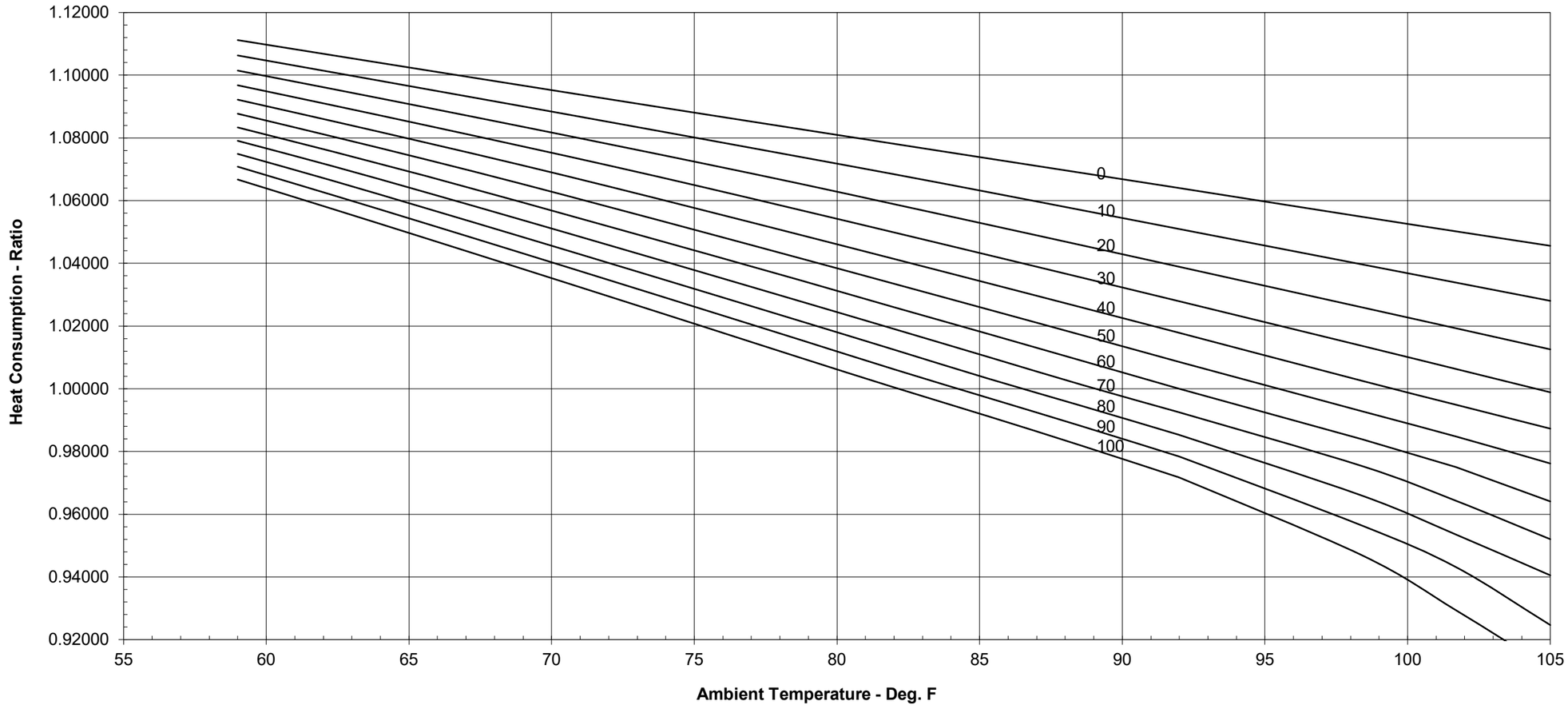
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Ambient Temperature and Humidity on Heat Consumption

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Ambient Temperature - Deg. F

Relative Humidity - Percent	59.0	62.3	65.6	68.9	72.1	75.4	78.70	82.00	85.30	88.60	91.90	92.00	98.40	101.70	105.00
0	1.11121	1.10640	1.10161	1.09684	1.09223	1.08751	1.08282	1.07813	1.07347	1.06882	1.06416	1.06401	1.05485	1.05020	1.04560
10	1.10631	1.10097	1.09559	1.09021	1.08495	1.07948	1.07398	1.06843	1.06272	1.05693	1.05112	1.05095	1.03967	1.03386	1.02805
20	1.10148	1.09565	1.08973	1.08374	1.07785	1.07170	1.06541	1.05889	1.05233	1.04573	1.03910	1.03889	1.02597	1.01928	1.01257
30	1.09679	1.09046	1.08402	1.07748	1.07102	1.06412	1.05703	1.04987	1.04266	1.03541	1.02812	1.02790	1.01369	1.00630	0.99887
40	1.09220	1.08541	1.07849	1.07142	1.06431	1.05675	1.04912	1.04142	1.03367	1.02589	1.01807	1.01783	1.00254	0.99489	0.98728
50	1.08772	1.08050	1.07312	1.06547	1.05777	1.04975	1.04165	1.03350	1.02530	1.01707	1.00880	1.00855	0.99283	0.98477	0.97617
60	1.08335	1.07572	1.06788	1.05962	1.05153	1.04309	1.03460	1.02606	1.01749	1.00887	1.00025	1.00000	0.98386	0.97498	0.96407
70	1.07908	1.07106	1.06263	1.05401	1.04556	1.03677	1.02794	1.01907	1.01015	1.00121	0.99273	0.99247	0.97536	0.96425	0.95202
80	1.07491	1.06642	1.05757	1.04862	1.03986	1.03077	1.02164	1.01247	1.00325	0.99448	0.98555	0.98527	0.96592	0.95348	0.94050
90	1.07083	1.06185	1.05269	1.04344	1.03441	1.02505	1.01566	1.00621	0.99709	0.98800	0.97866	0.97837	0.95637	0.94309	0.92464
100	1.06673	1.05741	1.04798	1.03846	1.02919	1.01959	1.00995	1.00044	0.99123	0.98176	0.97199	0.97168	0.94690	0.92933	0.91064

David Walters
06/20/25

24A-167 Rev A
Sheet 8

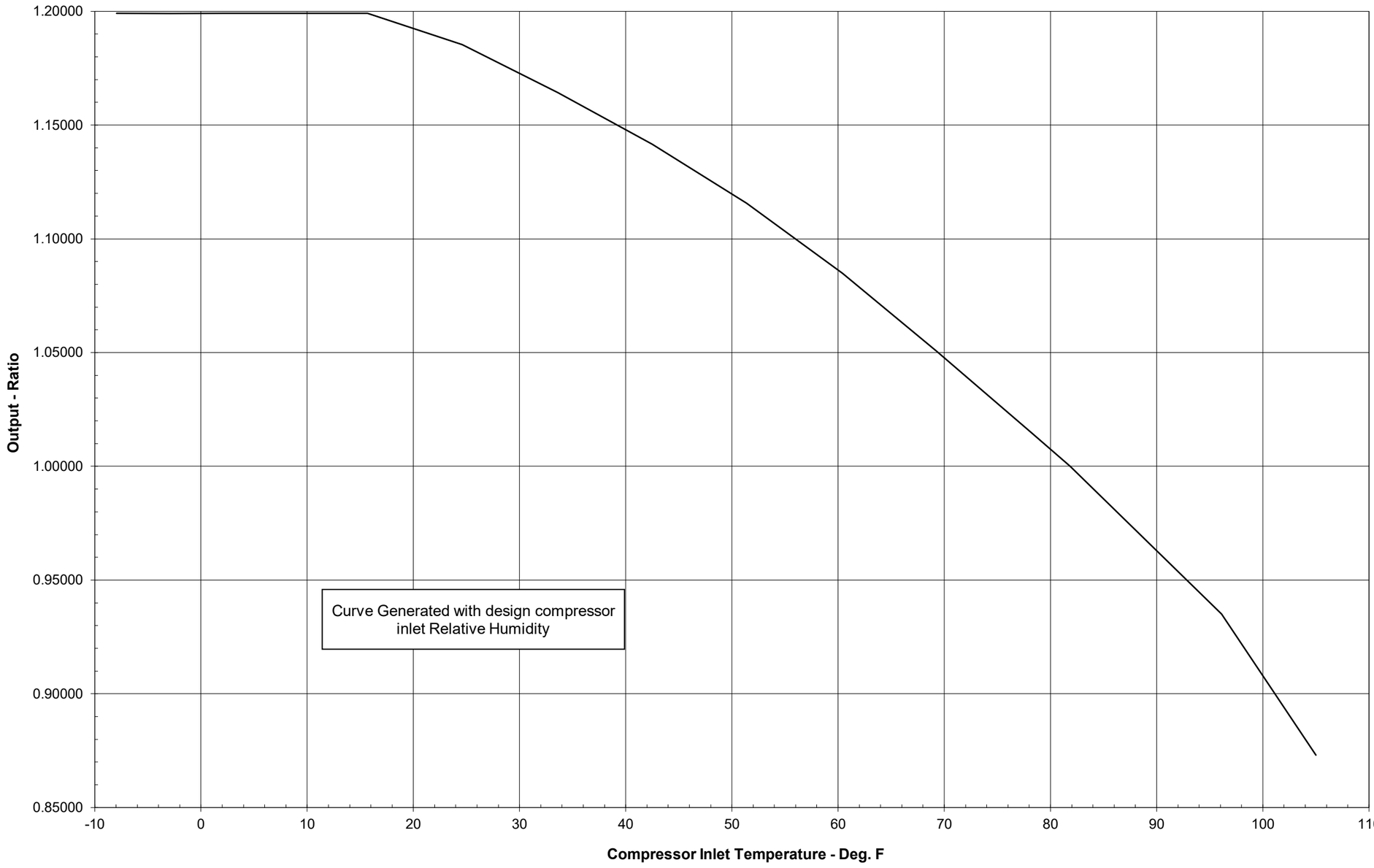
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Output

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Output Ratio		1.19906	1.19906	1.19905	1.19905	1.19905	1.18528	1.16429	1.14160	1.11567	1.08479	1.05044	1.01487	1.00000	0.93512	0.87305

David Walters
06/20/25

24A-167 Rev A
Sheet 9

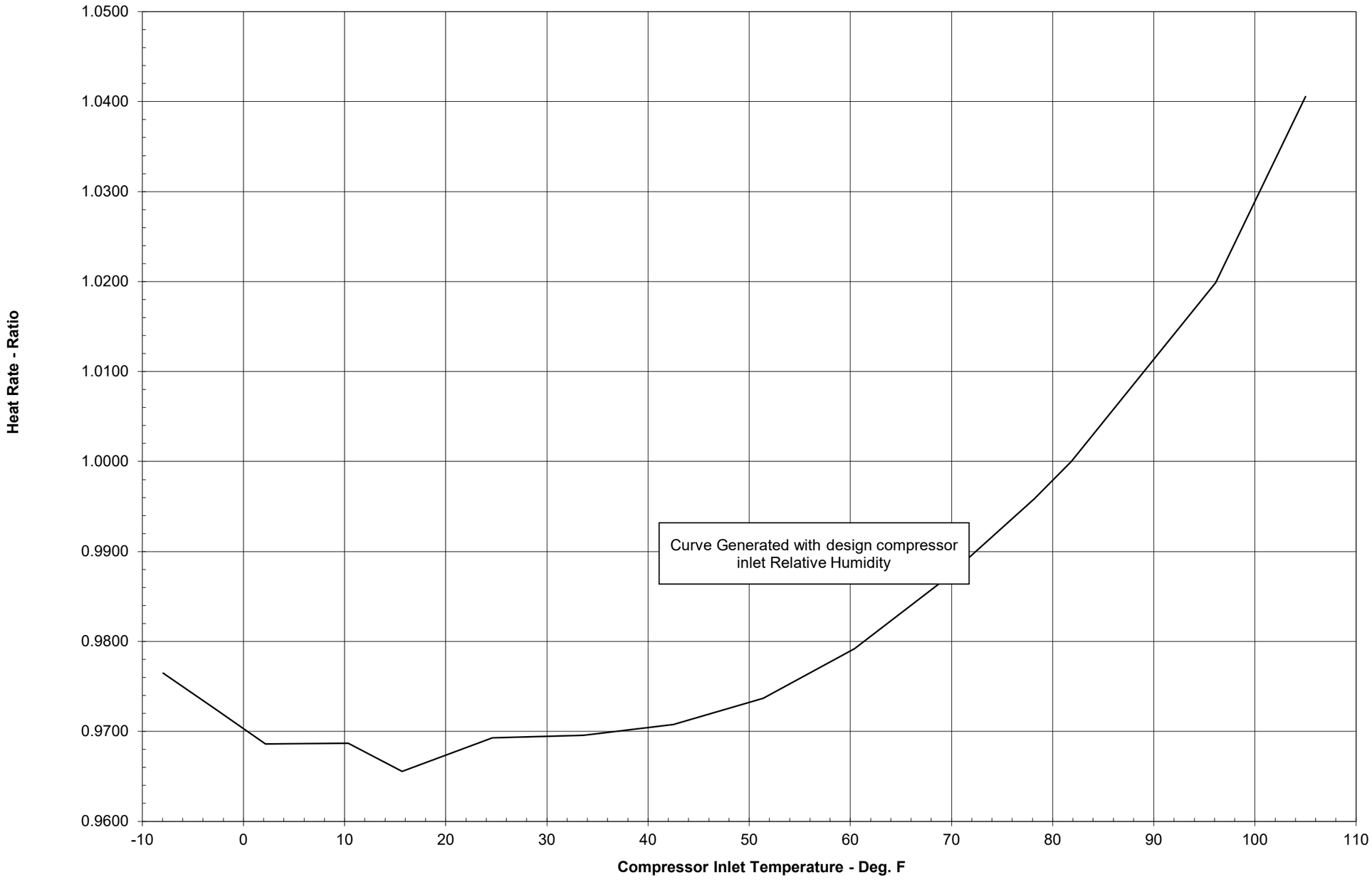
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Heat Rate

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Heat Rate Ratio		0.97648	0.97257	0.96860	0.96869	0.96556	0.96928	0.96956	0.97077	0.97369	0.97921	0.98688	0.99585	1.00000	1.01986	1.04056

David Walters
06/20/25

24A-167 Rev A
Sheet 10

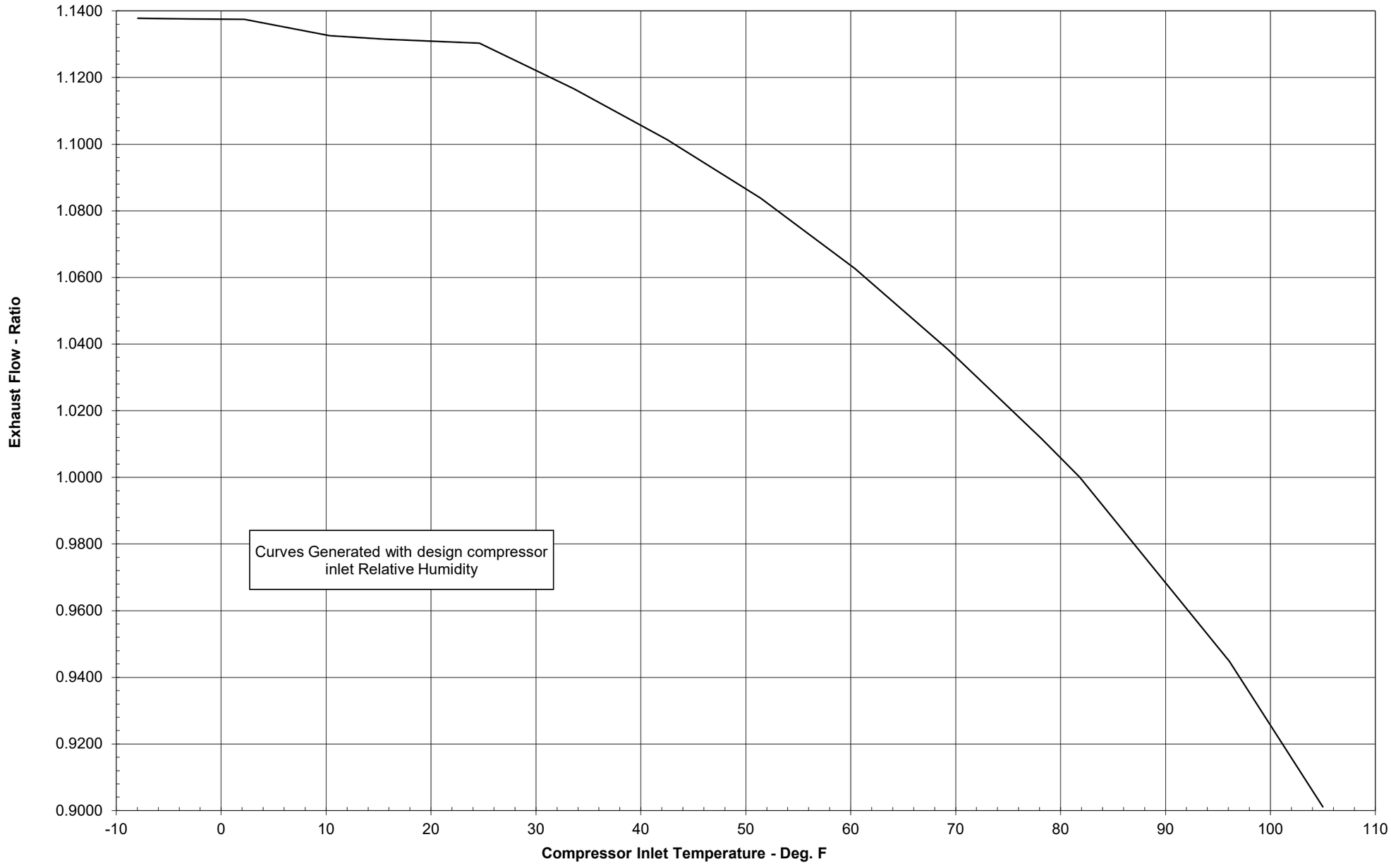
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Exhaust Flow

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Exhaust Flow Ratio		1.13778	1.13759	1.13741	1.13253	1.13143	1.13030	1.11665	1.10129	1.08379	1.06269	1.03827	1.01153	1.00000	0.94475	0.90111

David Walters
06/20/25

24A-167 Rev A
Sheet 11

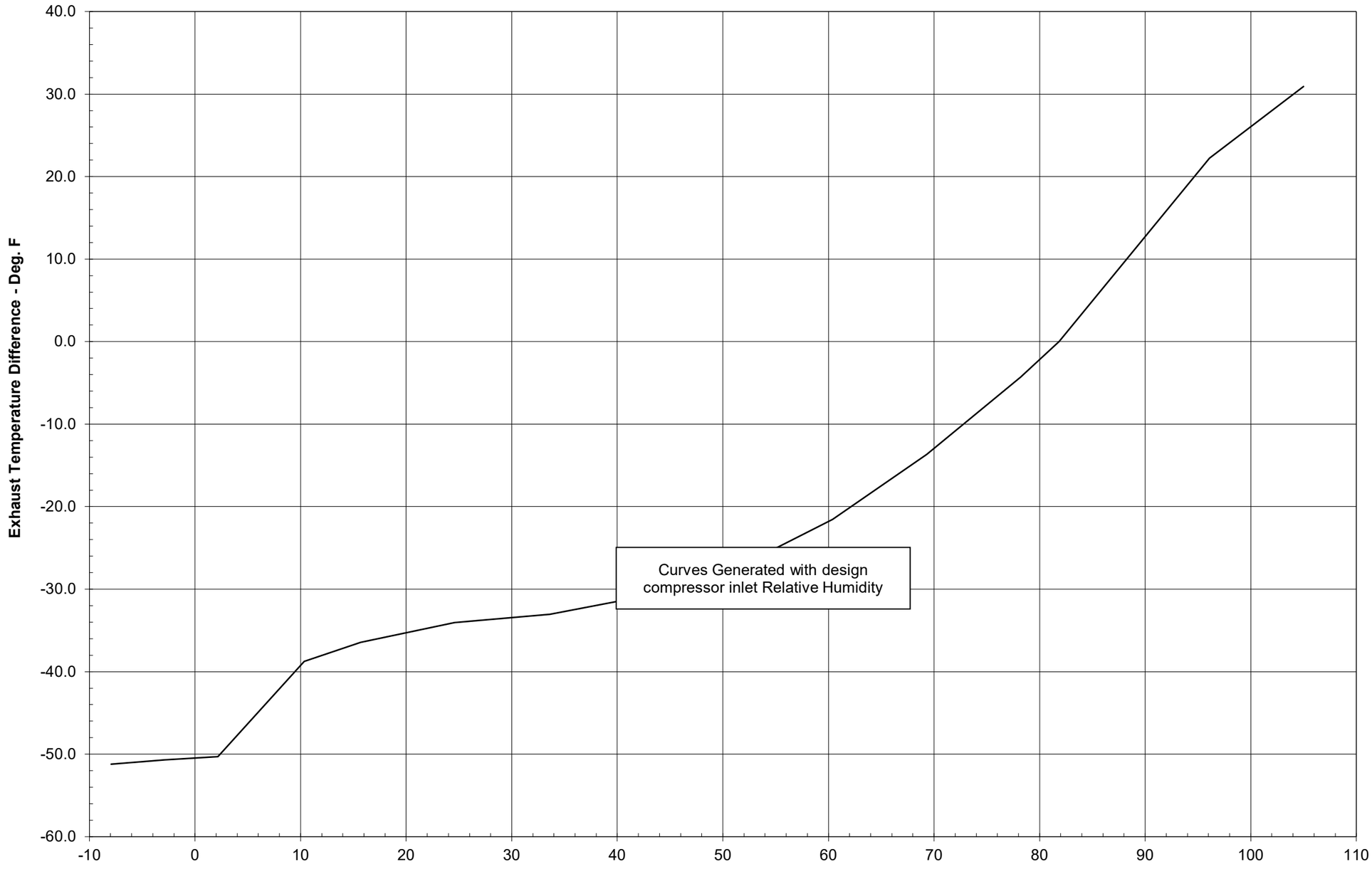
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Exhaust Temperature

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Tx Difference	F	-51.2	-50.7	-50.3	-38.8	-36.5	-34.0	-33.0	-30.9	-27.4	-21.6	-13.7	-4.3	0.0	22.2	30.9

David Walters
06/20/25

24A-167 Rev A
Sheet 12

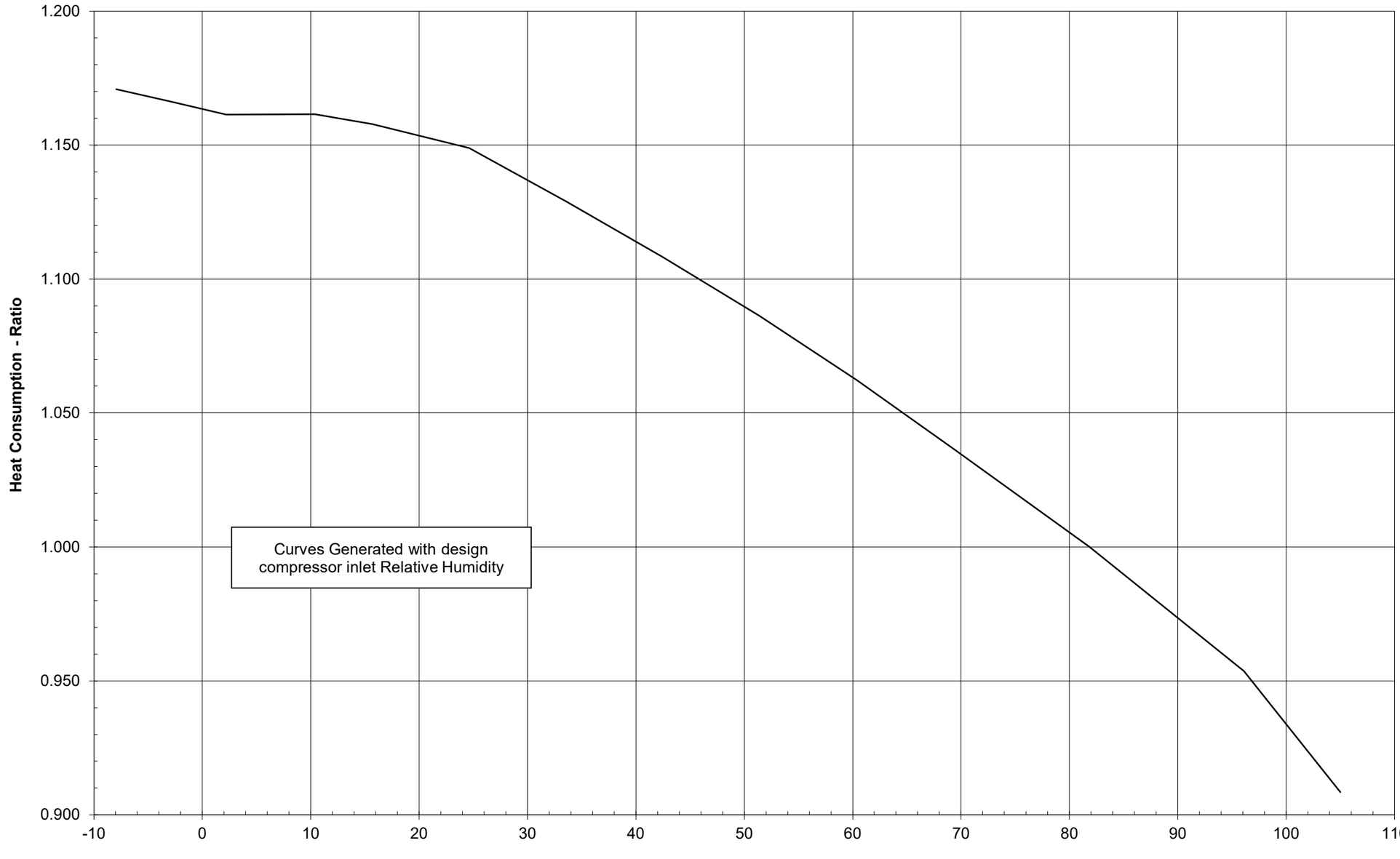
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Compressor Inlet Temperature on Heat Consumption

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units															
Compressor Inlet Temperature	F	-7.95	-2.87	2.18	10.36	15.70	24.60	33.60	42.50	51.40	60.40	69.30	78.20	81.84	96.10	105.00
Heat Consumption Ratio		1.17085	1.16617	1.16140	1.16152	1.15776	1.14888	1.12885	1.10823	1.08631	1.06224	1.03666	1.01066	1.00000	0.95370	0.90846

David Walters
06/20/25

24A-167 Rev A
Sheet 13

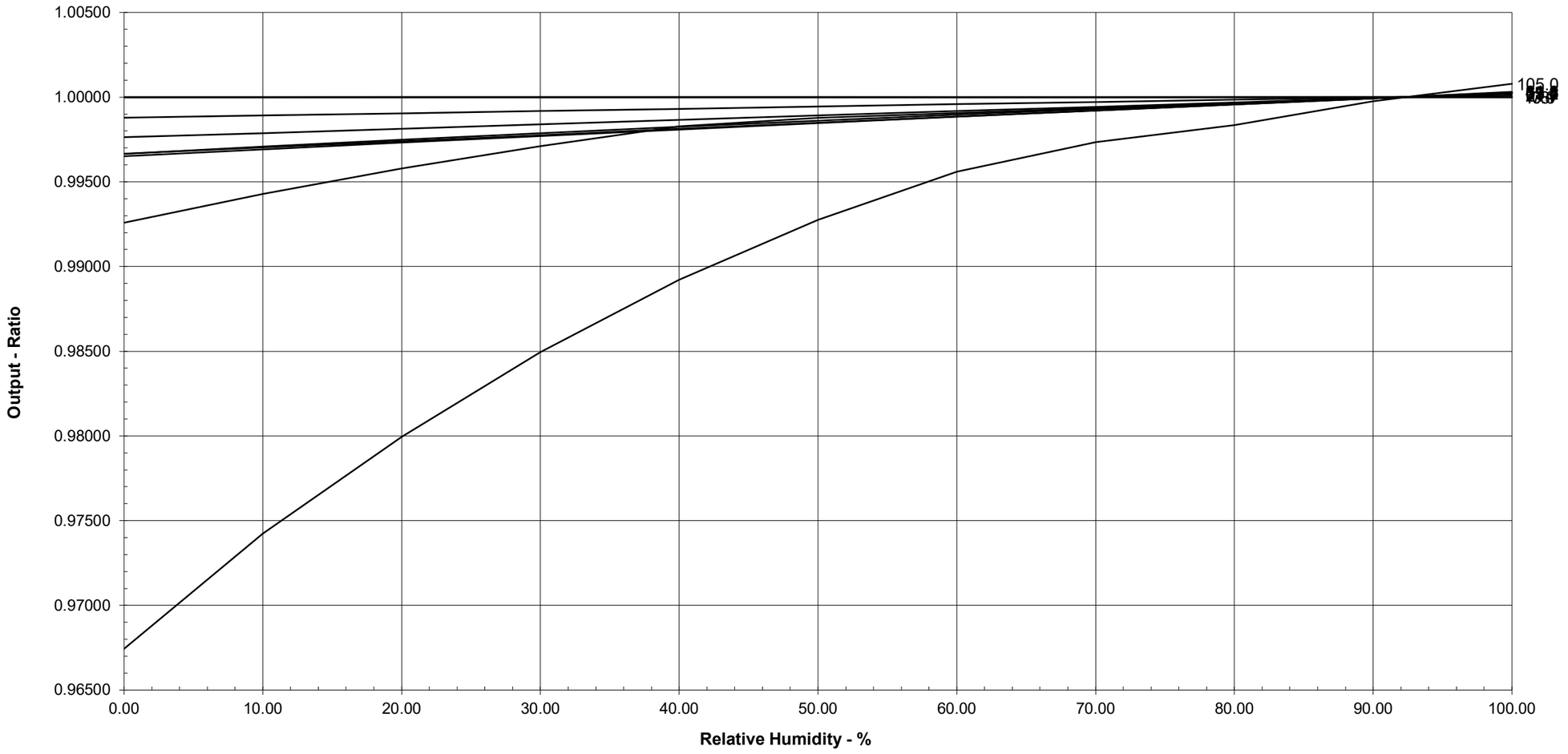
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Relative Humidity on Output at Different Compressor Inlet Temperatures

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Relative Humidity - %	-7.9	-0.1	7.8	21.7	35.6	49.4	63.3	77.2	81.8	105.0
92.2	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
0	1.00000	1.00000	1.00000	0.99879	0.99764	0.99666	0.99651	0.99665	0.99259	0.96743
10	1.00000	1.00000	1.00000	0.99892	0.99788	0.99703	0.99691	0.99707	0.99428	0.97425
20	1.00000	1.00000	1.00000	0.99905	0.99814	0.99739	0.99731	0.99748	0.99579	0.97995
30	1.00000	1.00000	1.00000	0.99918	0.99840	0.99776	0.99770	0.99787	0.99711	0.98494
40	1.00000	1.00000	1.00000	0.99931	0.99866	0.99812	0.99808	0.99825	0.99826	0.98921
50	1.00000	1.00000	1.00000	0.99945	0.99891	0.99848	0.99846	0.99862	0.99878	0.99275
60	1.00000	1.00000	1.00000	0.99958	0.99917	0.99885	0.99884	0.99897	0.99907	0.99559
70	1.00000	1.00000	1.00000	0.99971	0.99943	0.99921	0.99921	0.99931	0.99935	0.99735
80	1.00000	1.00000	1.00000	0.99984	0.99969	0.99957	0.99957	0.99963	0.99961	0.99836
90	1.00000	1.00000	1.00000	0.99997	0.99994	0.99992	0.99992	0.99994	0.99991	0.99975
100	1.00000	1.00000	1.00000	1.00010	1.00020	1.00028	1.00027	1.00022	1.00031	1.00079

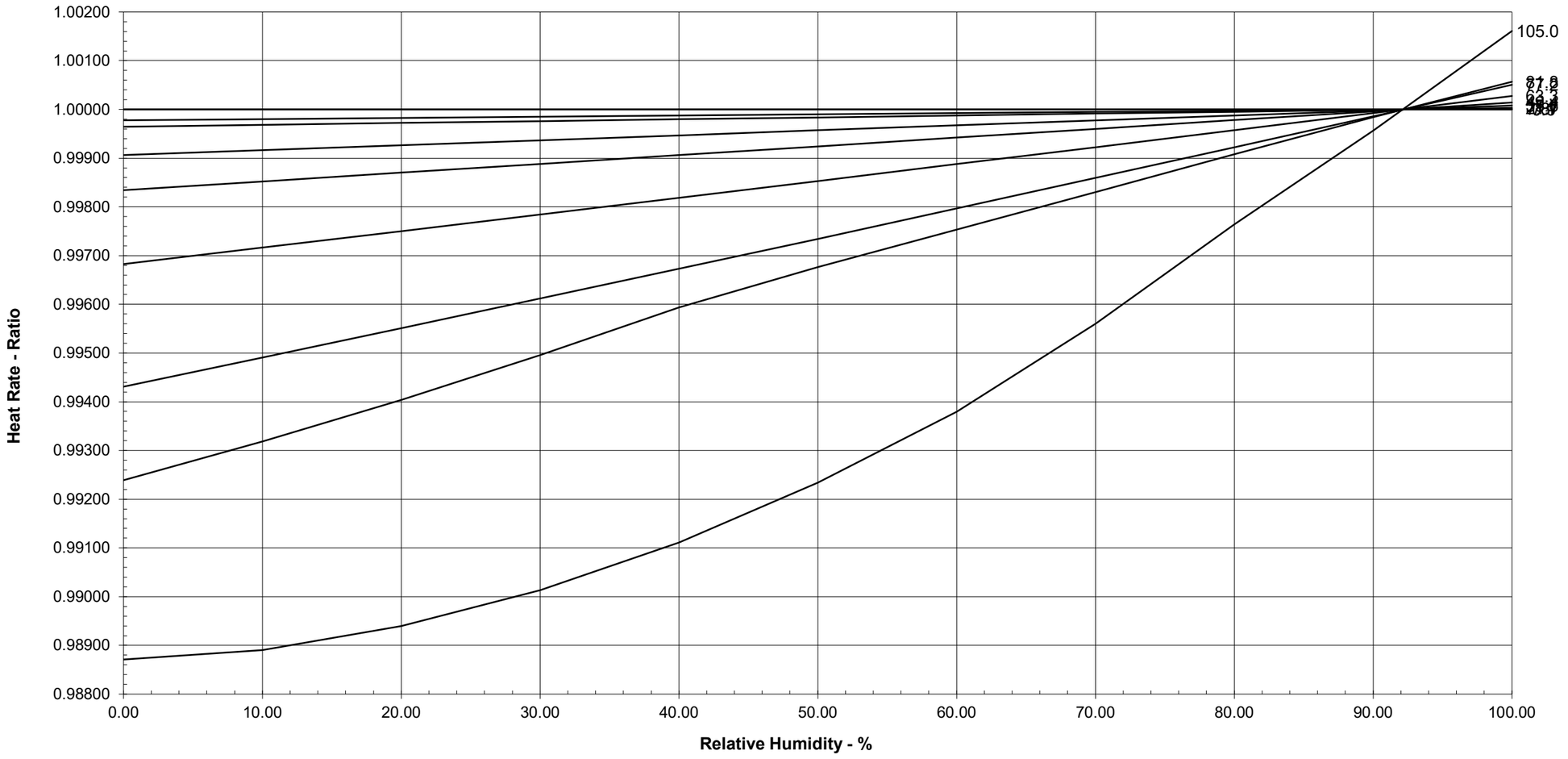
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Relative Humidity on Heat Rate at Different Compressor Inlet Temperatures

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Relative Humidity - %	-7.9	-0.1	7.8	21.7	35.6	49.4	63.3	77.2	81.8	105.0
92.2	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
0	1.00000	1.00000	0.99978	0.99964	0.99906	0.99834	0.99683	0.99431	0.99239	0.98871
10	1.00000	1.00000	0.99980	0.99968	0.99917	0.99852	0.99716	0.99491	0.99318	0.98891
20	1.00000	1.00000	0.99983	0.99972	0.99927	0.99870	0.99750	0.99551	0.99404	0.98939
30	1.00000	1.00000	0.99985	0.99976	0.99937	0.99888	0.99784	0.99612	0.99496	0.99013
40	1.00000	1.00000	0.99987	0.99980	0.99947	0.99906	0.99819	0.99673	0.99594	0.99111
50	1.00000	1.00000	0.99990	0.99984	0.99957	0.99924	0.99853	0.99735	0.99677	0.99234
60	1.00000	1.00000	0.99992	0.99988	0.99967	0.99942	0.99888	0.99797	0.99753	0.99380
70	1.00000	1.00000	0.99995	0.99991	0.99977	0.99960	0.99922	0.99859	0.99830	0.99560
80	1.00000	1.00000	0.99997	0.99995	0.99988	0.99978	0.99957	0.99922	0.99908	0.99764
90	1.00000	1.00000	0.99999	0.99999	0.99998	0.99996	0.99992	0.99986	0.99984	0.99957
100	1.00000	1.00000	1.00002	1.00003	1.00008	1.00014	1.00028	1.00051	1.00057	1.00161

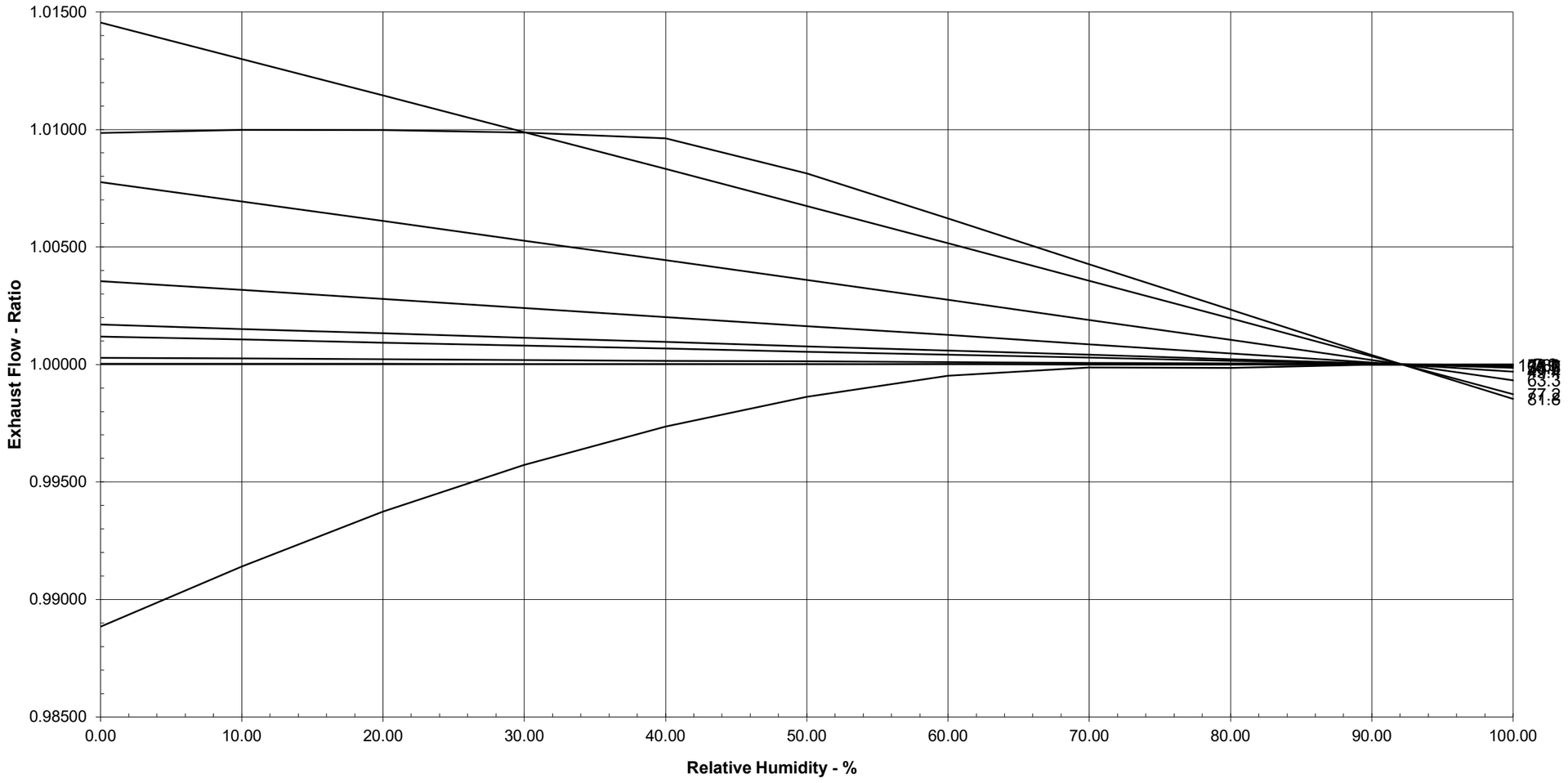
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Relative Humidity on Exhaust Flow at Different Compressor Inlet Temperatures

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Relative Humidity - %	-7.9	-0.1	7.8	21.7	35.6	49.4	63.3	77.2	81.8	105.0
92.2	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
0	1.00001	1.00003	1.00028	1.00119	1.00170	1.00354	1.00776	1.01455	1.00985	0.98884
10	1.00001	1.00003	1.00025	1.00106	1.00150	1.00317	1.00693	1.01300	1.00998	0.99141
20	1.00001	1.00002	1.00022	1.00093	1.00132	1.00279	1.00610	1.01145	1.00998	0.99375
30	1.00001	1.00002	1.00019	1.00080	1.00114	1.00240	1.00527	1.00989	1.00986	0.99573
40	1.00001	1.00002	1.00016	1.00067	1.00096	1.00202	1.00443	1.00832	1.00962	0.99735
50	1.00001	1.00001	1.00013	1.00054	1.00077	1.00164	1.00359	1.00674	1.00814	0.99862
60	1.00000	1.00001	1.00010	1.00041	1.00059	1.00125	1.00275	1.00515	1.00621	0.99952
70	1.00000	1.00001	1.00007	1.00029	1.00041	1.00086	1.00190	1.00356	1.00427	0.99988
80	1.00000	1.00000	1.00004	1.00016	1.00022	1.00047	1.00104	1.00196	1.00232	0.99985
90	1.00000	1.00000	1.00001	1.00003	1.00004	1.00008	1.00019	1.00035	1.00040	0.99999
100	1.00000	1.00000	0.99998	0.99990	0.99986	0.99969	0.99933	0.99873	0.99853	0.99996

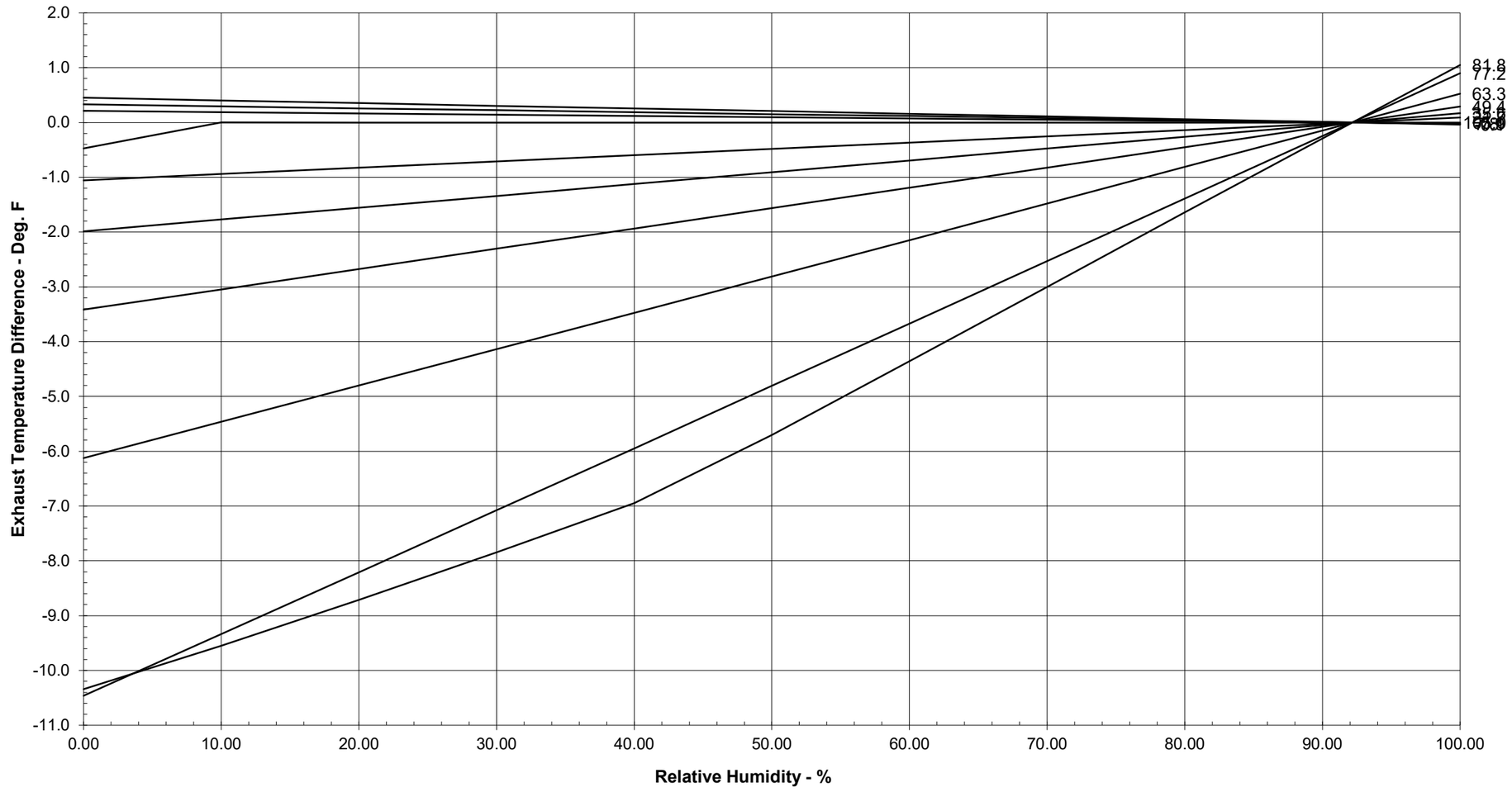
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Relative Humidity on Exhaust Temperature at Different Compressor Inlet Temperatures

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Relative Humidity - %	-7.9	-0.1	7.8	21.7	35.6	49.4	63.3	77.2	81.8	105.0
92.2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	0.21	0.45	0.33	-1.06	-1.99	-3.42	-6.12	-10.46	-10.34	-0.47
10	0.19	0.40	0.30	-0.94	-1.77	-3.05	-5.46	-9.34	-9.55	0.00
20	0.17	0.35	0.26	-0.83	-1.56	-2.68	-4.80	-8.21	-8.71	0.00
30	0.14	0.30	0.22	-0.71	-1.34	-2.30	-4.14	-7.08	-7.85	0.00
40	0.12	0.26	0.19	-0.60	-1.12	-1.93	-3.48	-5.95	-6.94	0.00
50	0.10	0.21	0.15	-0.48	-0.91	-1.56	-2.81	-4.81	-5.71	0.00
60	0.07	0.16	0.12	-0.37	-0.69	-1.19	-2.15	-3.67	-4.36	0.00
70	0.05	0.11	0.08	-0.25	-0.48	-0.82	-1.48	-2.53	-3.00	0.00
80	0.03	0.06	0.04	-0.14	-0.26	-0.45	-0.81	-1.39	-1.64	0.00
90	0.01	0.01	0.01	-0.02	-0.05	-0.08	-0.15	-0.25	-0.29	0.00
100	-0.02	-0.04	-0.03	0.09	0.17	0.29	0.52	0.90	1.05	0.00

David Walters
06/20/25

24A-167 Rev A
Sheet 17

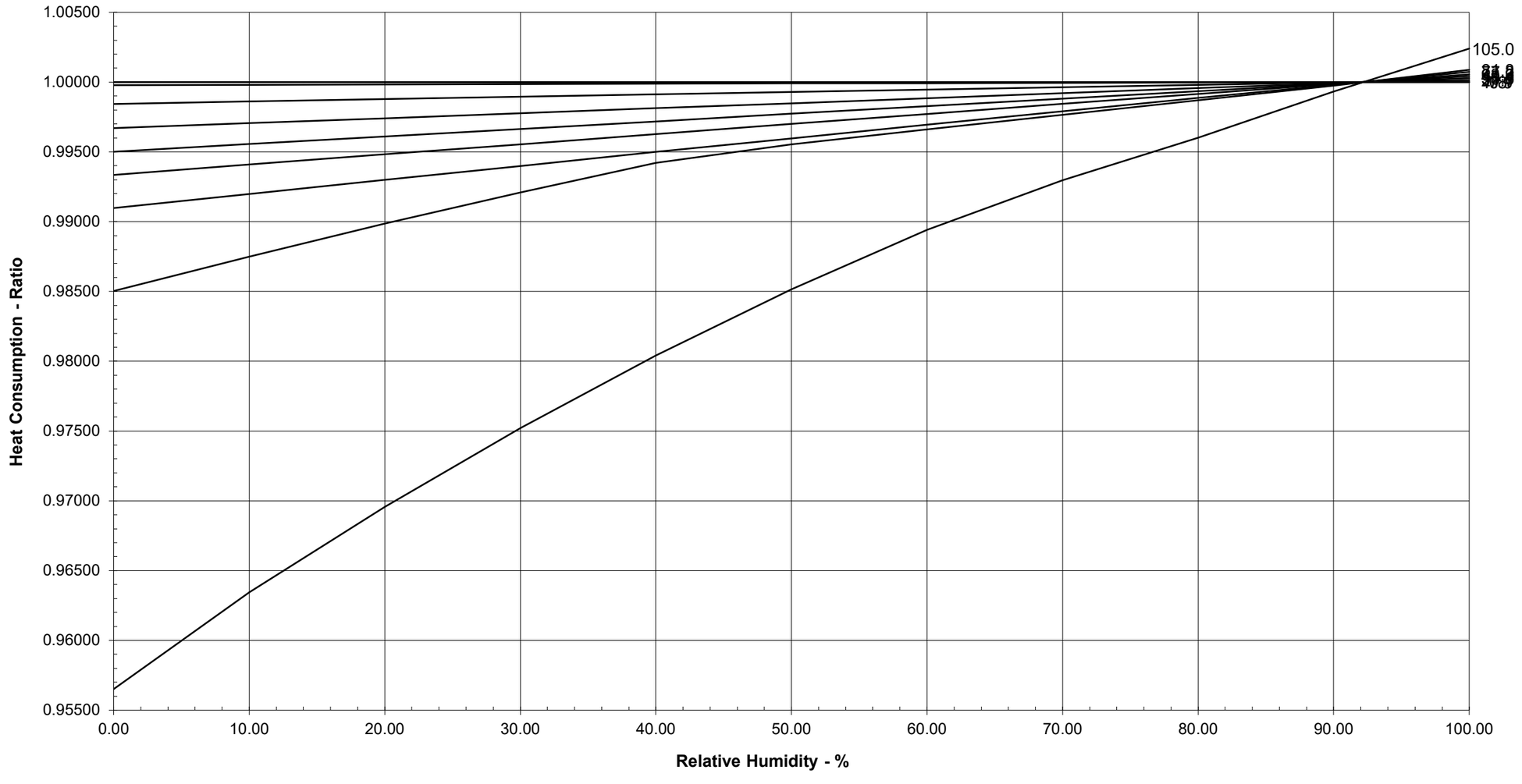
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Relative Humidity on Heat Consumption at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Relative Humidity - %	-7.9	-0.1	7.8	21.7	35.6	49.4	63.3	77.2	81.8	105.0
92.2	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
0	1.00000	1.00000	0.99978	0.99843	0.99670	0.99501	0.99335	0.99097	0.98503	0.95651
10	1.00000	1.00000	0.99980	0.99860	0.99705	0.99555	0.99409	0.99199	0.98750	0.96344
20	1.00000	1.00000	0.99983	0.99877	0.99741	0.99610	0.99482	0.99300	0.98985	0.96956
30	1.00000	1.00000	0.99985	0.99894	0.99777	0.99664	0.99555	0.99400	0.99209	0.97522
40	1.00000	1.00000	0.99987	0.99911	0.99813	0.99719	0.99628	0.99499	0.99421	0.98042
50	1.00000	1.00000	0.99990	0.99928	0.99849	0.99773	0.99700	0.99597	0.99555	0.98515
60	1.00000	1.00000	0.99992	0.99945	0.99885	0.99827	0.99772	0.99694	0.99661	0.98942
70	1.00000	1.00000	0.99995	0.99962	0.99920	0.99881	0.99843	0.99790	0.99765	0.99296
80	1.00000	1.00000	0.99997	0.99979	0.99956	0.99935	0.99914	0.99885	0.99869	0.99601
90	1.00000	1.00000	0.99999	0.99996	0.99992	0.99988	0.99985	0.99980	0.99976	0.99931
100	1.00000	1.00000	1.00002	1.00013	1.00028	1.00042	1.00055	1.00073	1.00088	1.00240

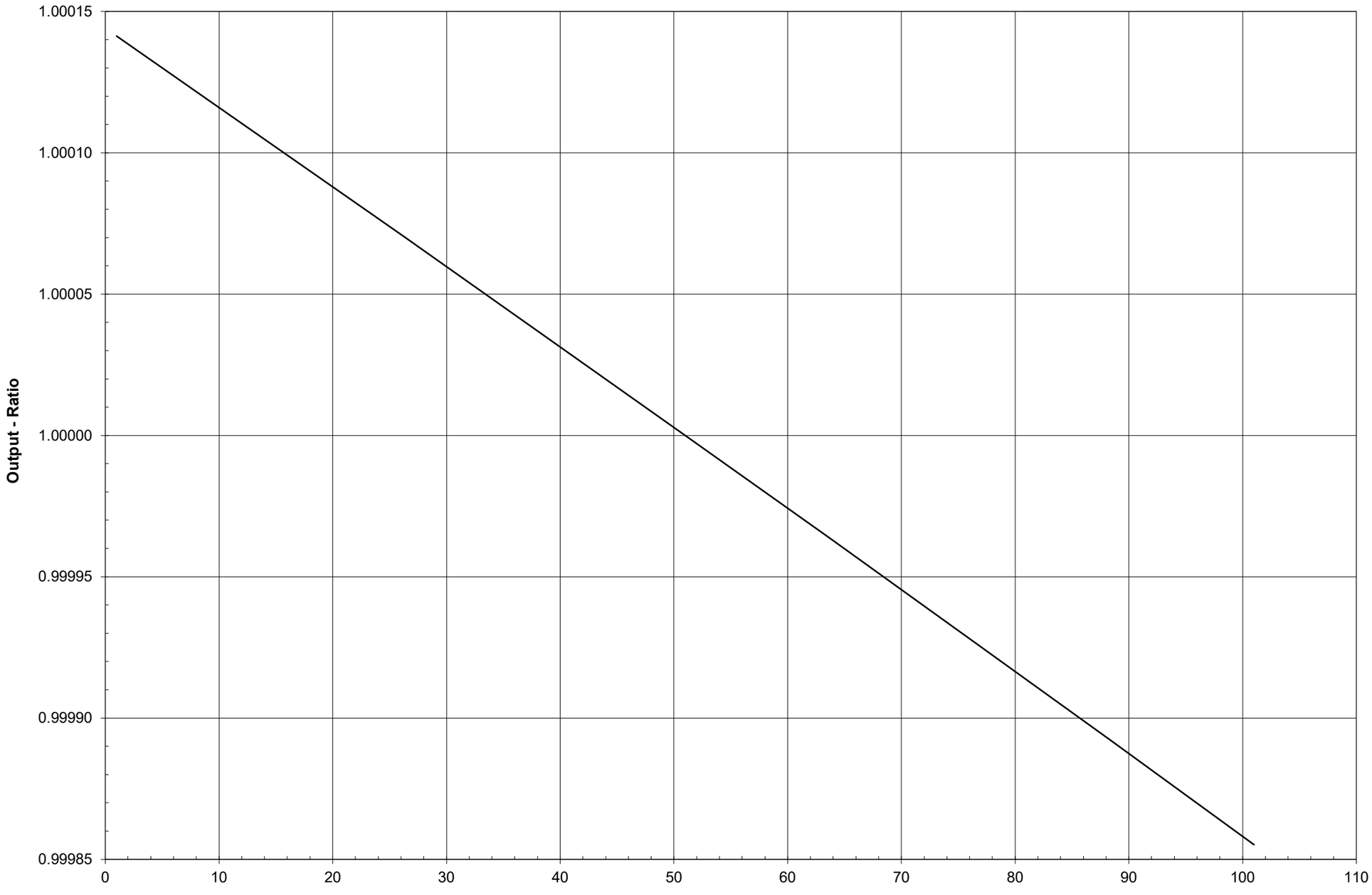
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Fuel Temperature on Output

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units									
Fuel Temperature	F	1.0	13.5	26.0	38.5	51.0	63.5	76.0	88.5	101.0
Output Ratio		1.00014	1.00011	1.00007	1.00004	1.00000	0.99996	0.99993	0.99989	0.99986

David Walters
06/20/25

24A-167 Rev A
Sheet 19

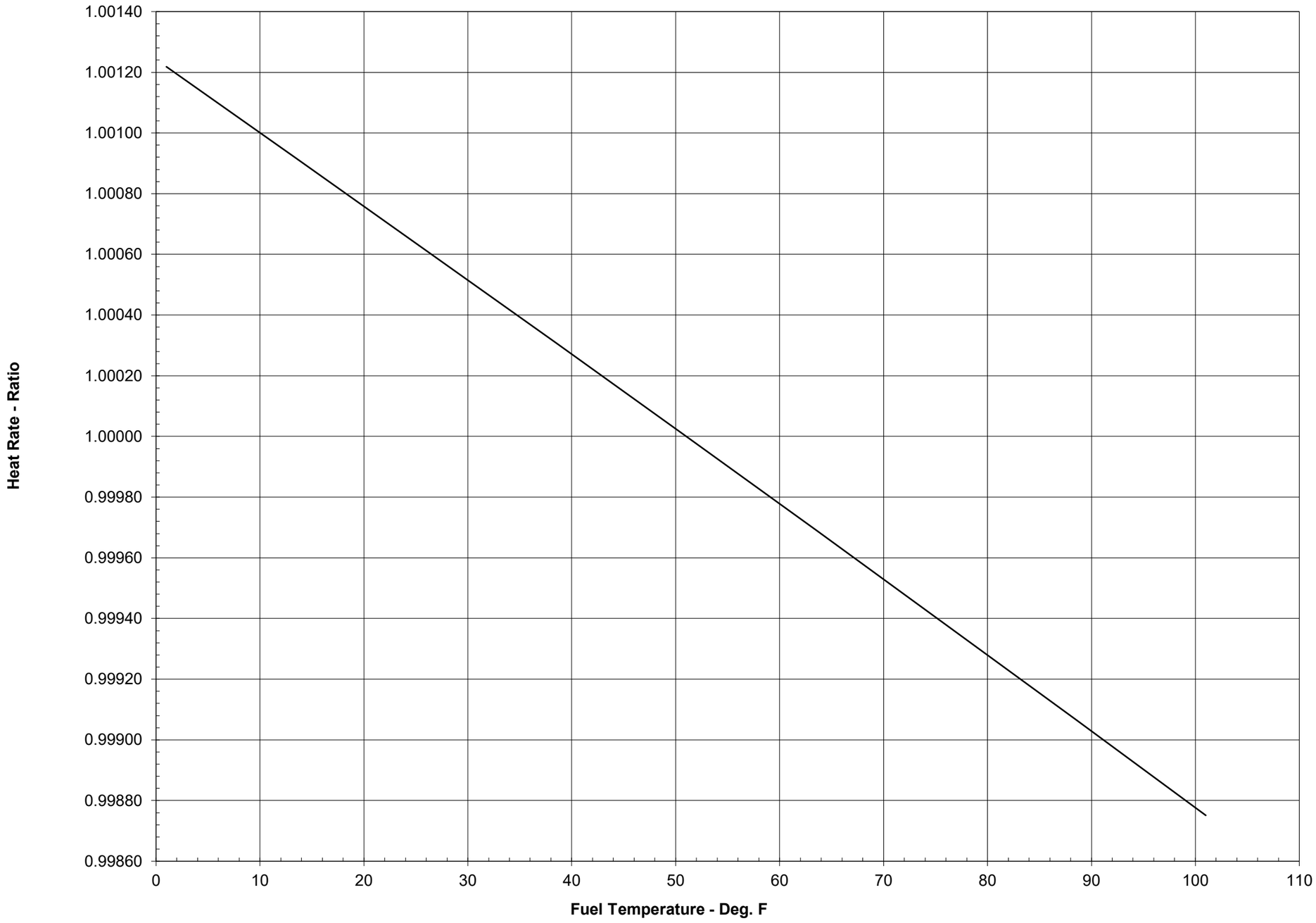
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Fuel Temperature on Heat Rate

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units									
Fuel Temperature	F	1.0	13.5	26.0	38.5	51.0	63.5	76.0	88.5	101.0
Heat Rate Ratio		1.00122	1.00092	1.00061	1.00031	1.00000	0.99969	0.99938	0.99907	0.99875

David Walters
06/20/25

24A-167 Rev A
Sheet 20

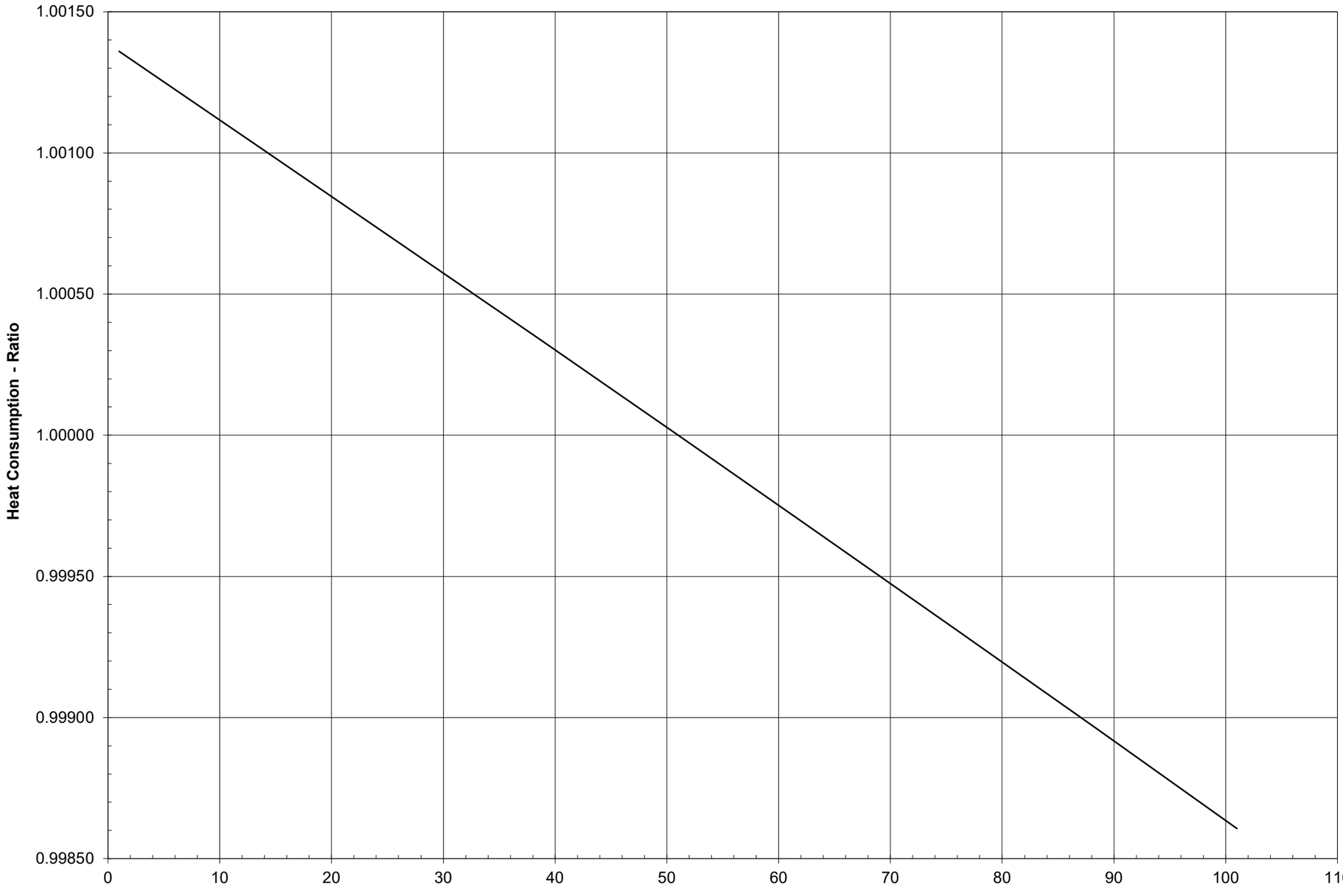
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Fuel Temperature on Heat Consumption

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units									
Fuel Temperature	F	1.0	13.5	26.0	38.5	51.0	63.5	76.0	88.5	101.0
Heat Consumption Ratio		1.00136	1.00102	1.00068	1.00034	1.00000	0.99966	0.99931	0.99896	0.99861

David Walters
06/20/25

24A-167 Rev A
Sheet 21

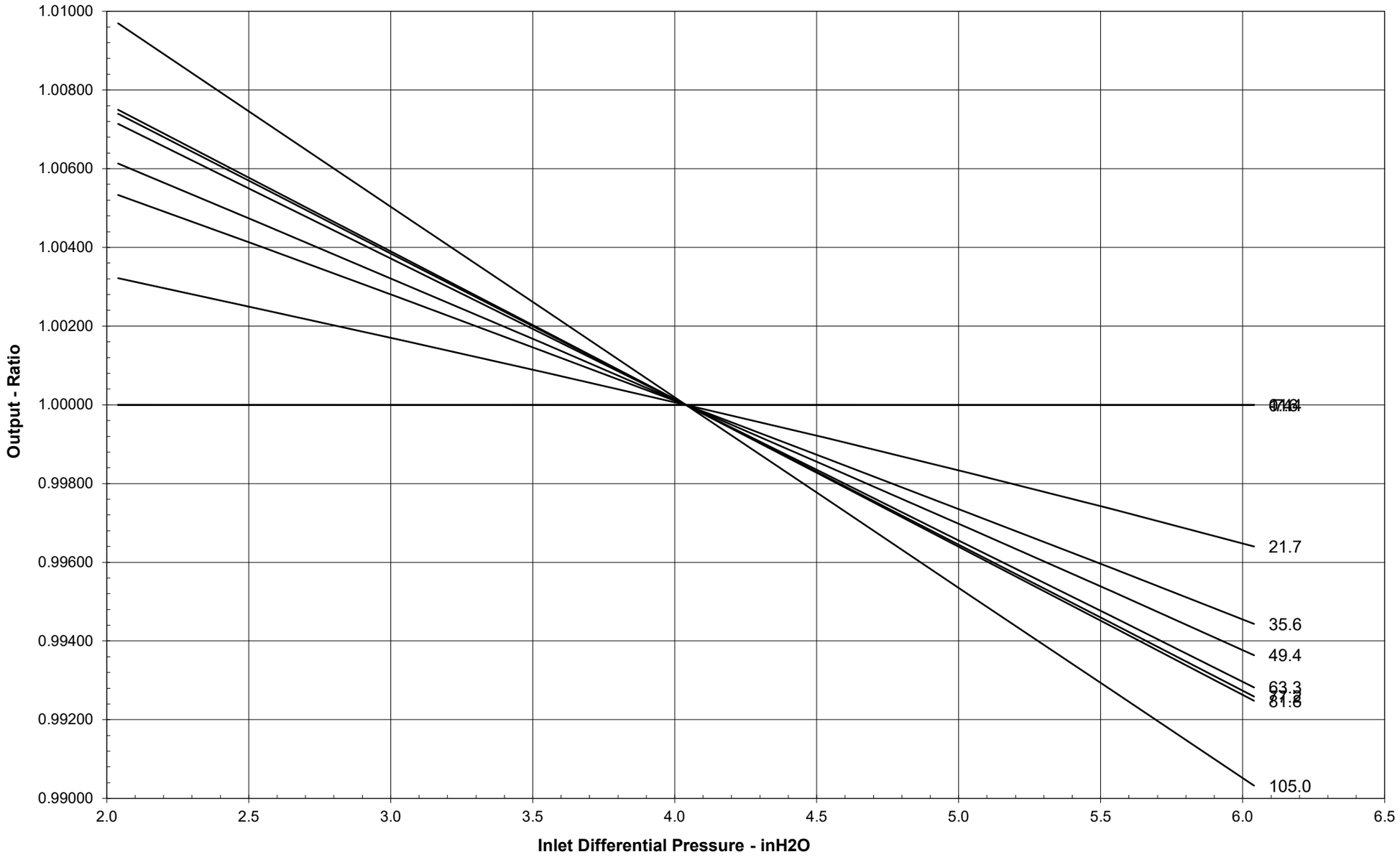
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Inlet Differential Pressure on Output at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Inlet dP (inH2O)	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
2.040	1.00000	1.00000	1.00000	1.00322	1.00533	1.00613	1.00714	1.00739	1.00750	1.00969
2.540	1.00000	1.00000	1.00000	1.00243	1.00402	1.00462	1.00536	1.00555	1.00562	1.00727
3.040	1.00000	1.00000	1.00000	1.00164	1.00270	1.00309	1.00358	1.00370	1.00375	1.00484
3.540	1.00000	1.00000	1.00000	1.00083	1.00136	1.00155	1.00179	1.00185	1.00188	1.00242
4.040	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
4.540	1.00000	1.00000	1.00000	0.99915	0.99863	0.99843	0.99821	0.99815	0.99812	0.99758
5.040	1.00000	1.00000	1.00000	0.99827	0.99724	0.99685	0.99641	0.99630	0.99624	0.99516
5.540	1.00000	1.00000	1.00000	0.99735	0.99584	0.99526	0.99462	0.99444	0.99436	0.99274
6.040	1.00000	1.00000	1.00000	0.99640	0.99443	0.99364	0.99282	0.99259	0.99248	0.99032

David Walters
06/20/25

24A-167 Rev A
Sheet 22

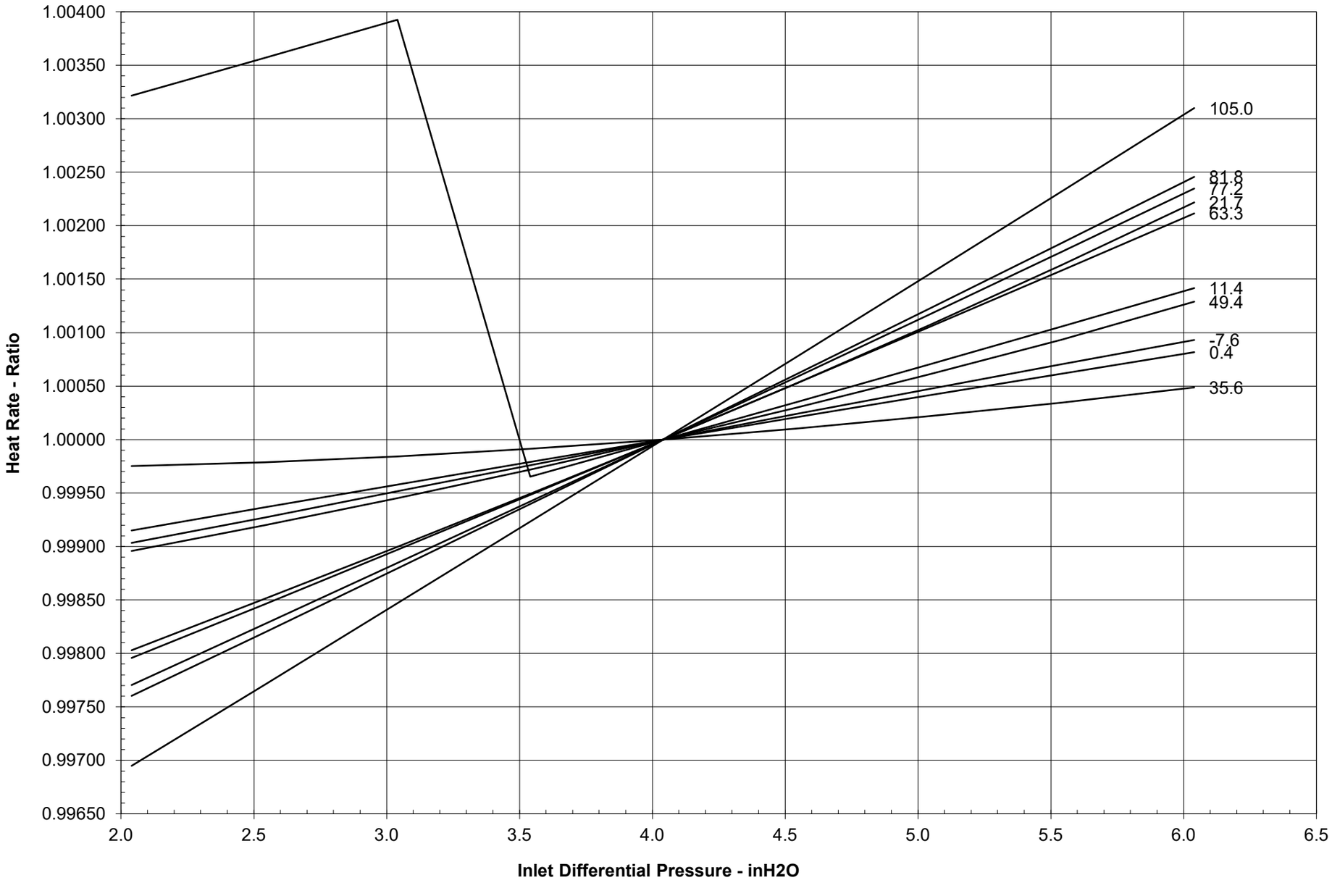
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Inlet Differential Pressure on Heat Rate at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Inlet dP (inH2O)

	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
2.040	0.99903	0.99915	1.00322	0.99803	0.99975	0.99896	0.99796	0.99770	0.99760	0.99695
2.540	0.99927	0.99936	1.00357	0.99851	0.99979	0.99920	0.99846	0.99827	0.99820	0.99771
3.040	0.99952	0.99958	1.00393	0.99900	0.99984	0.99945	0.99897	0.99885	0.99879	0.99847
3.540	0.99976	0.99979	0.99965	0.99949	0.99991	0.99972	0.99948	0.99942	0.99940	0.99923
4.040	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
4.540	1.00024	1.00021	1.00035	1.00052	1.00010	1.00030	1.00052	1.00058	1.00061	1.00077
5.040	1.00047	1.00041	1.00070	1.00107	1.00022	1.00061	1.00105	1.00117	1.00122	1.00154
5.540	1.00070	1.00062	1.00106	1.00163	1.00035	1.00093	1.00158	1.00176	1.00184	1.00232
6.040	1.00093	1.00082	1.00141	1.00222	1.00049	1.00129	1.00211	1.00235	1.00246	1.00310

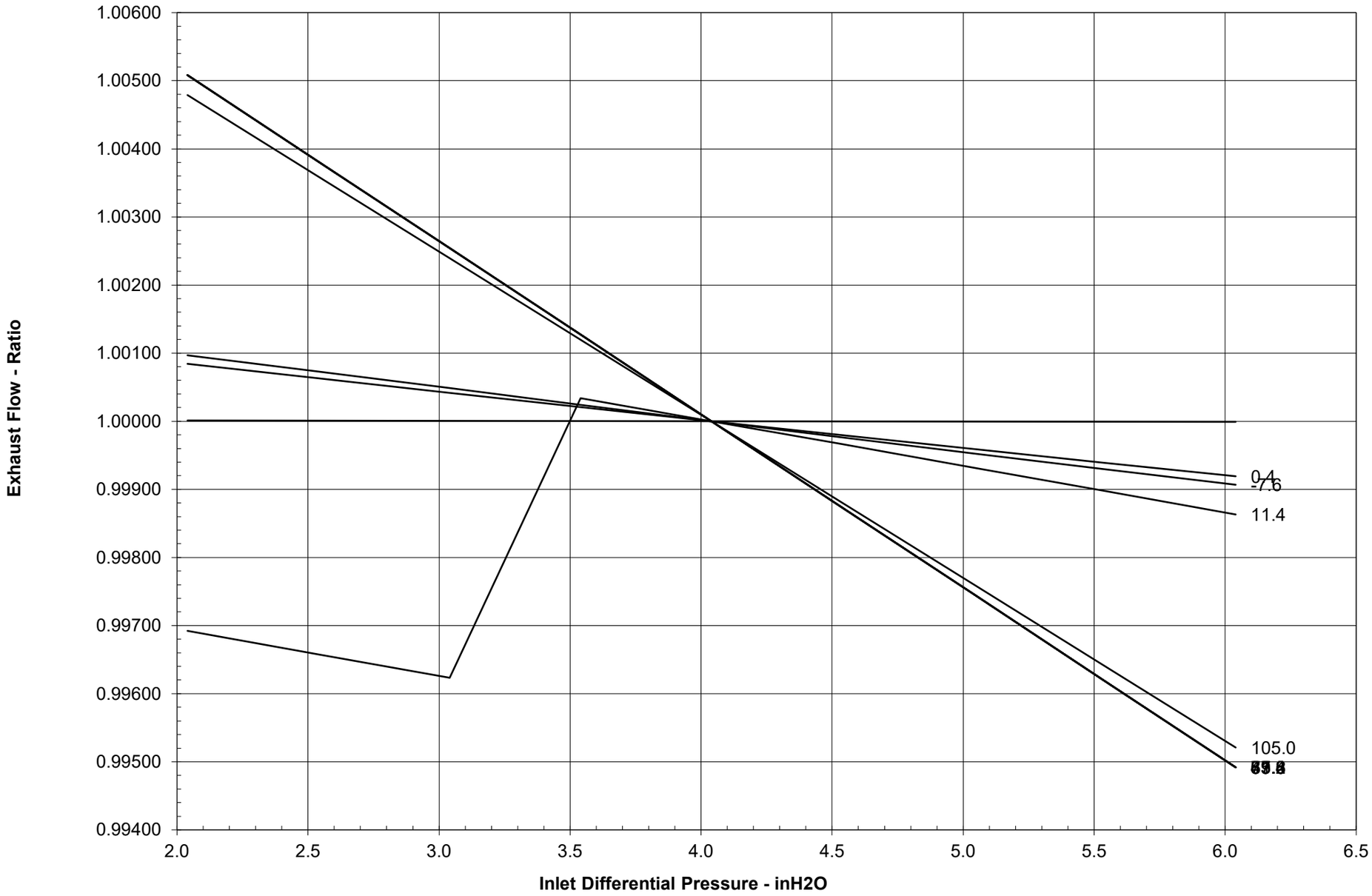
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Inlet Differential Pressure on Exhaust Flow at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Inlet dP (inH2O)	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
2.040	1.00097	1.00084	0.99692	1.00001	1.00508	1.00508	1.00508	1.00508	1.00508	1.00479
2.540	1.00073	1.00063	0.99658	1.00001	1.00381	1.00381	1.00381	1.00381	1.00381	1.00359
3.040	1.00048	1.00042	0.99623	1.00001	1.00254	1.00254	1.00254	1.00254	1.00254	1.00239
3.540	1.00024	1.00021	1.00034	1.00000	1.00127	1.00127	1.00127	1.00127	1.00127	1.00120
4.040	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
4.540	0.99976	0.99980	0.99966	1.00000	0.99873	0.99873	0.99873	0.99873	0.99873	0.99880
5.040	0.99953	0.99959	0.99932	0.99999	0.99746	0.99746	0.99746	0.99746	0.99746	0.99760
5.540	0.99930	0.99939	0.99897	0.99999	0.99619	0.99619	0.99619	0.99619	0.99619	0.99641
6.040	0.99907	0.99919	0.99863	0.99999	0.99492	0.99492	0.99492	0.99492	0.99492	0.99521

David Walters
06/20/25

24A-167 Rev A
Sheet 24

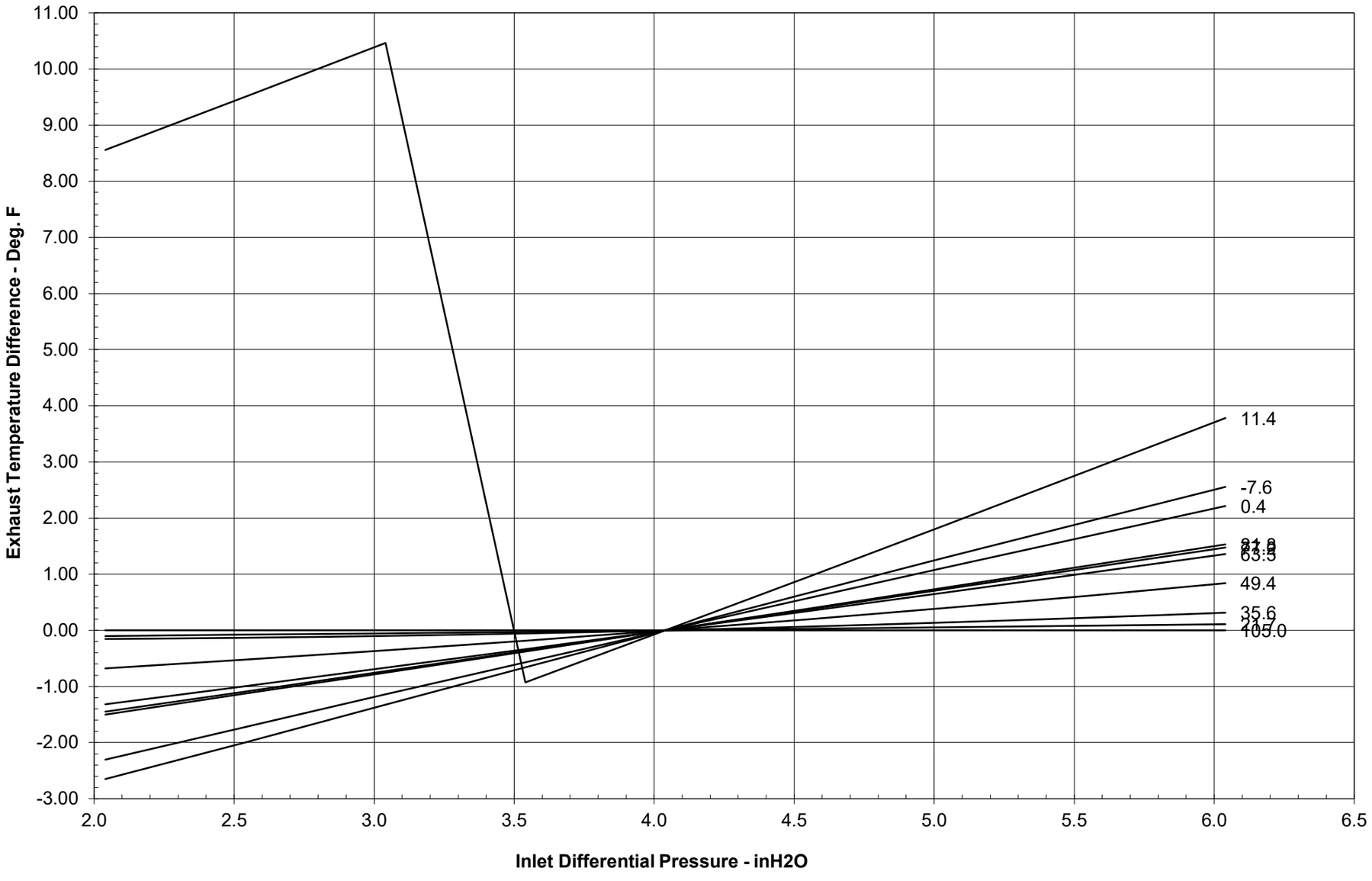
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Inlet Differential Pressure on Exhaust Temperature at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Inlet dP (inH2O)	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
2.040	-2.65	-2.30	8.56	-0.10	-0.15	-0.68	-1.32	-1.45	-1.50	0.00
2.540	-2.00	-1.72	9.51	-0.08	-0.13	-0.52	-0.99	-1.09	-1.13	0.00
3.040	-1.33	-1.14	10.46	-0.05	-0.10	-0.36	-0.66	-0.73	-0.75	0.00
3.540	-0.66	-0.57	-0.93	-0.03	-0.06	-0.18	-0.33	-0.36	-0.38	0.00
4.040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.540	0.65	0.56	0.93	0.03	0.07	0.19	0.34	0.37	0.38	0.00
5.040	1.30	1.12	1.88	0.05	0.14	0.40	0.67	0.73	0.76	0.00
5.540	1.93	1.67	2.82	0.08	0.22	0.61	1.02	1.10	1.15	0.00
6.040	2.55	2.21	3.78	0.11	0.31	0.84	1.36	1.47	1.53	0.00

David Walters
06/20/25

24A-167 Rev A
Sheet 25

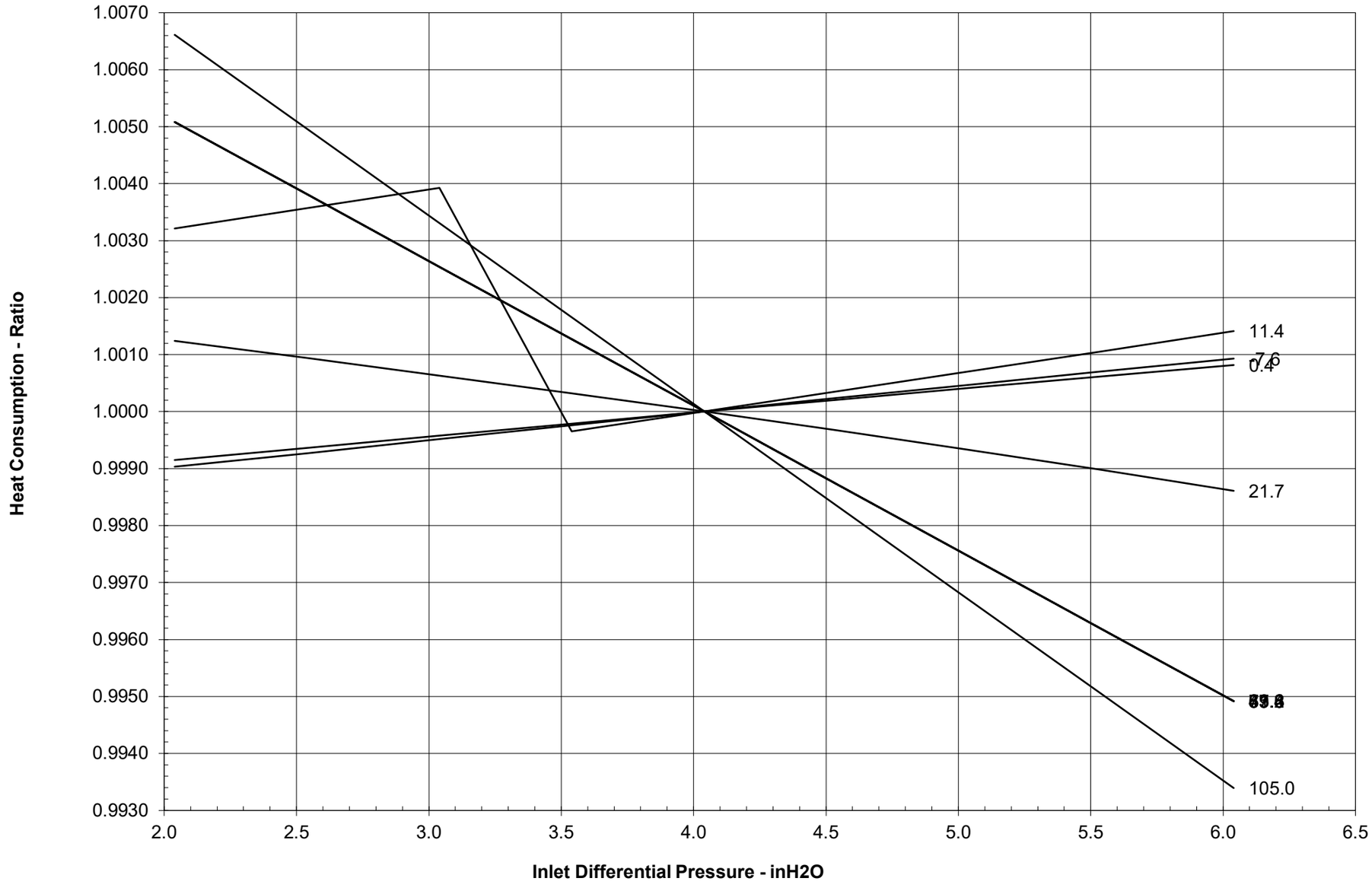
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Inlet Differential Pressure on Heat Consumption at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Inlet dP (inH2O)

	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
2.040	0.99903	0.99915	1.00322	1.00124	1.00508	1.00508	1.00508	1.00508	1.00508	1.00661
2.540	0.99927	0.99937	1.00357	1.00094	1.00381	1.00381	1.00381	1.00381	1.00381	1.00496
3.040	0.99952	0.99958	1.00393	1.00063	1.00254	1.00254	1.00254	1.00254	1.00254	1.00331
3.540	0.99976	0.99979	0.99965	1.00032	1.00127	1.00127	1.00127	1.00127	1.00127	1.00165
4.040	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
4.540	1.00024	1.00021	1.00035	0.99967	0.99873	0.99873	0.99873	0.99873	0.99873	0.99835
5.040	1.00047	1.00041	1.00070	0.99933	0.99746	0.99746	0.99746	0.99746	0.99746	0.99670
5.540	1.00070	1.00062	1.00106	0.99898	0.99619	0.99619	0.99619	0.99619	0.99619	0.99504
6.040	1.00093	1.00082	1.00142	0.99861	0.99492	0.99492	0.99492	0.99492	0.99492	0.99339

David Walters
06/20/25

24A-167 Rev A
Sheet 26

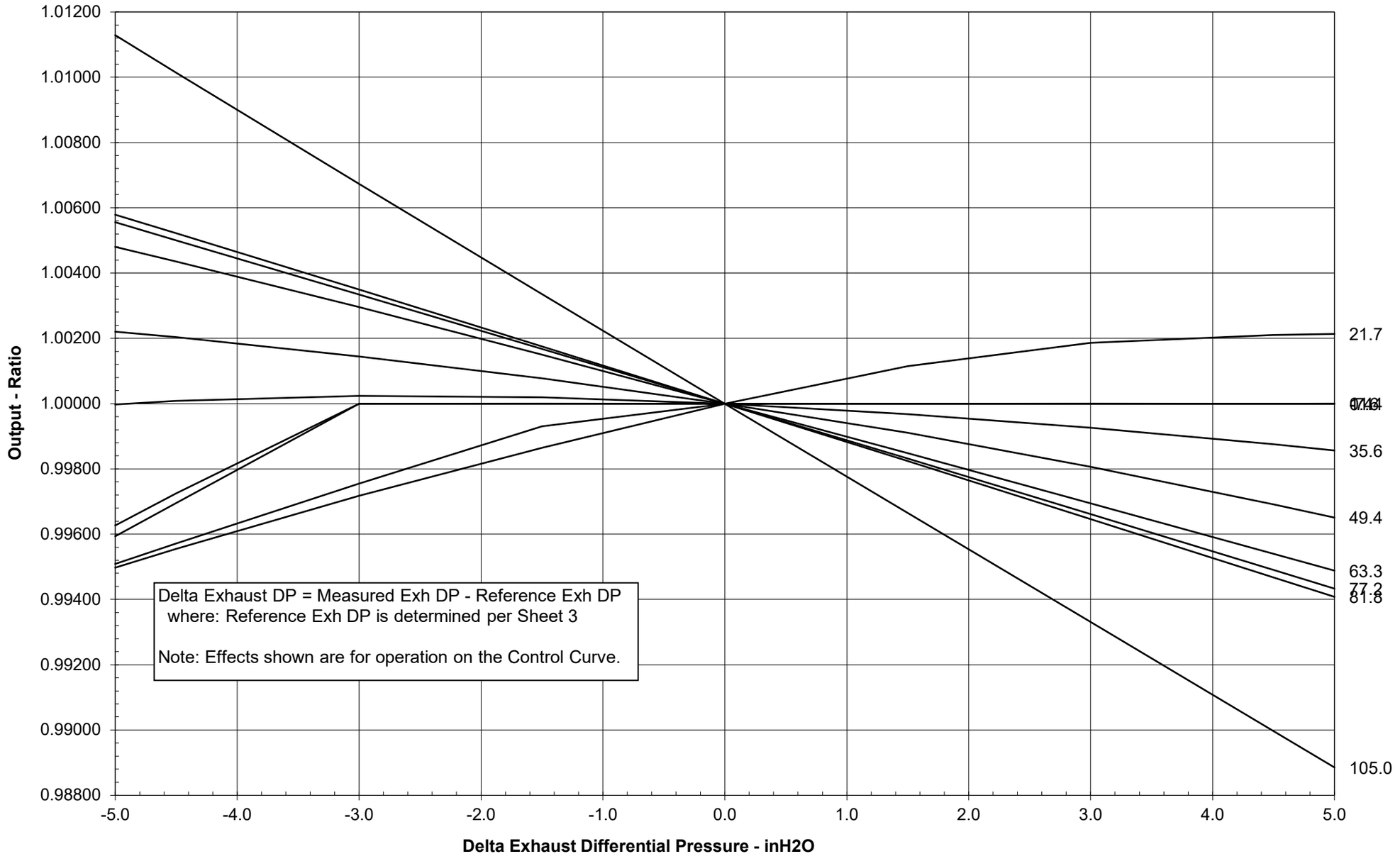
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Pressure on Output at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Delta Exhaust Differential Pressure - inH2O

	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
-5.00	0.99627	0.99594	0.99509	0.99497	0.99997	1.00220	1.00480	1.00556	1.00579	1.01129
-4.50	0.99725	0.99696	0.99572	0.99555	1.00008	1.00203	1.00435	1.00500	1.00522	1.01014
-3.00	1.00000	1.00000	0.99755	0.99717	1.00024	1.00145	1.00295	1.00335	1.00349	1.00673
-1.50	1.00000	1.00000	0.99931	0.99864	1.00020	1.00077	1.00149	1.00168	1.00175	1.00336
0.00	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
1.50	1.00000	1.00000	1.00000	1.00115	0.99968	0.99911	0.99848	0.99831	0.99824	0.99665
3.00	1.00000	1.00000	1.00000	1.00186	0.99926	0.99806	0.99695	0.99662	0.99646	0.99331
4.50	1.00000	1.00000	1.00000	1.00211	0.99876	0.99691	0.99540	0.99490	0.99468	0.98997
5.00	1.00000	1.00000	1.00000	1.00213	0.99856	0.99651	0.99488	0.99433	0.99408	0.98885

David Walters
06/20/25

24A-167 Rev A
Sheet 27

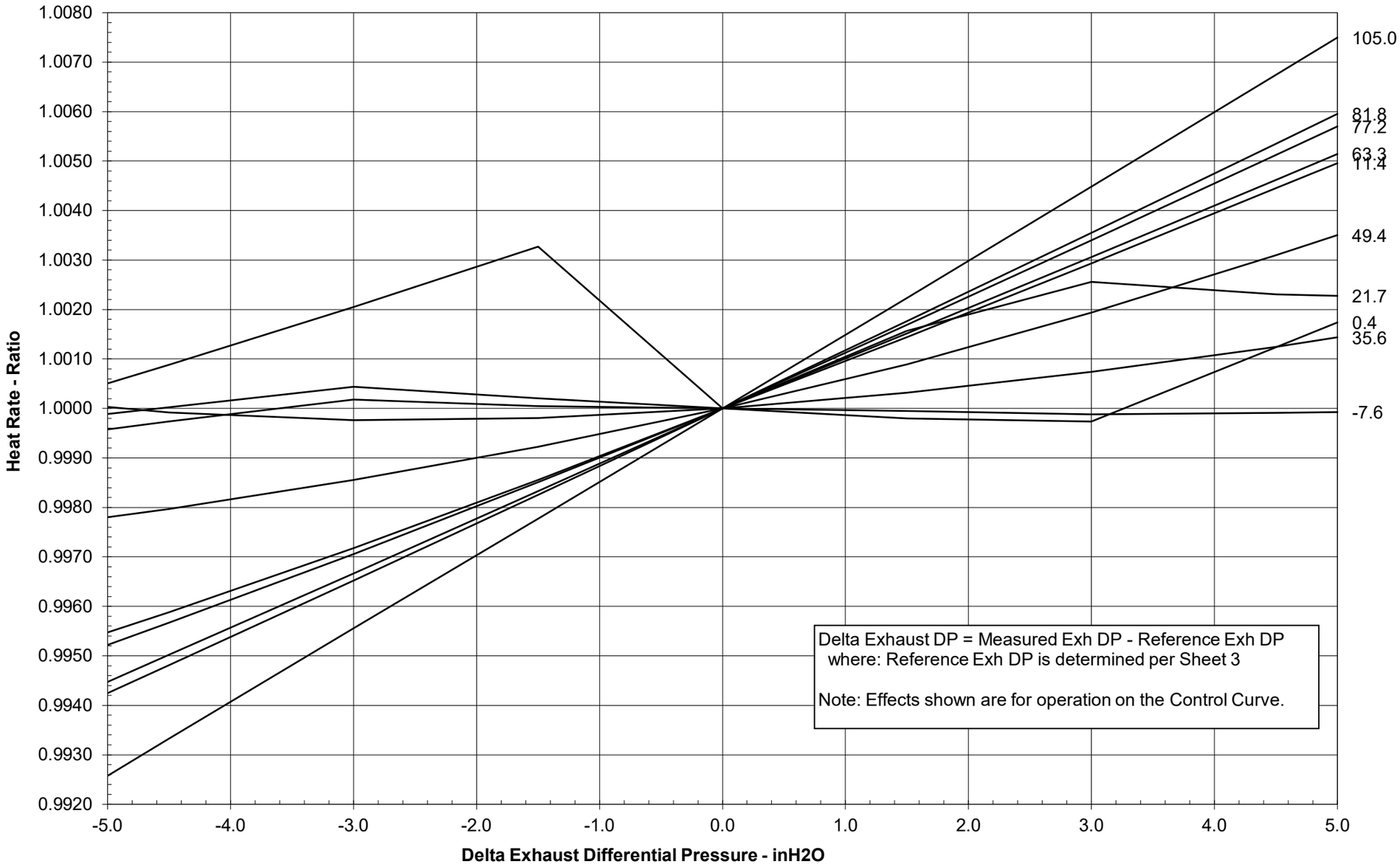
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Pressure on Heat Rate at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Delta Exhaust Differential Pressure - inH2O	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
-5.00	0.99958	0.99989	1.00050	0.99547	1.00003	0.99780	0.99522	0.99447	0.99425	0.99258
-4.50	0.99974	1.00003	1.00088	0.99588	0.99992	0.99797	0.99567	0.99502	0.99481	0.99332
-3.00	1.00018	1.00044	1.00205	0.99717	0.99976	0.99856	0.99705	0.99667	0.99652	0.99555
-1.50	1.00005	1.00021	1.00327	0.99855	0.99980	0.99923	0.99851	0.99833	0.99825	0.99777
0.00	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
1.50	0.99995	0.99980	1.00144	1.00157	1.00032	1.00089	1.00152	1.00169	1.00177	1.00223
3.00	0.99988	0.99974	1.00293	1.00256	1.00074	1.00194	1.00306	1.00340	1.00355	1.00448
4.50	0.99991	1.00124	1.00445	1.00231	1.00124	1.00310	1.00462	1.00512	1.00535	1.00674
5.00	0.99993	1.00174	1.00496	1.00228	1.00144	1.00350	1.00514	1.00570	1.00595	1.00750

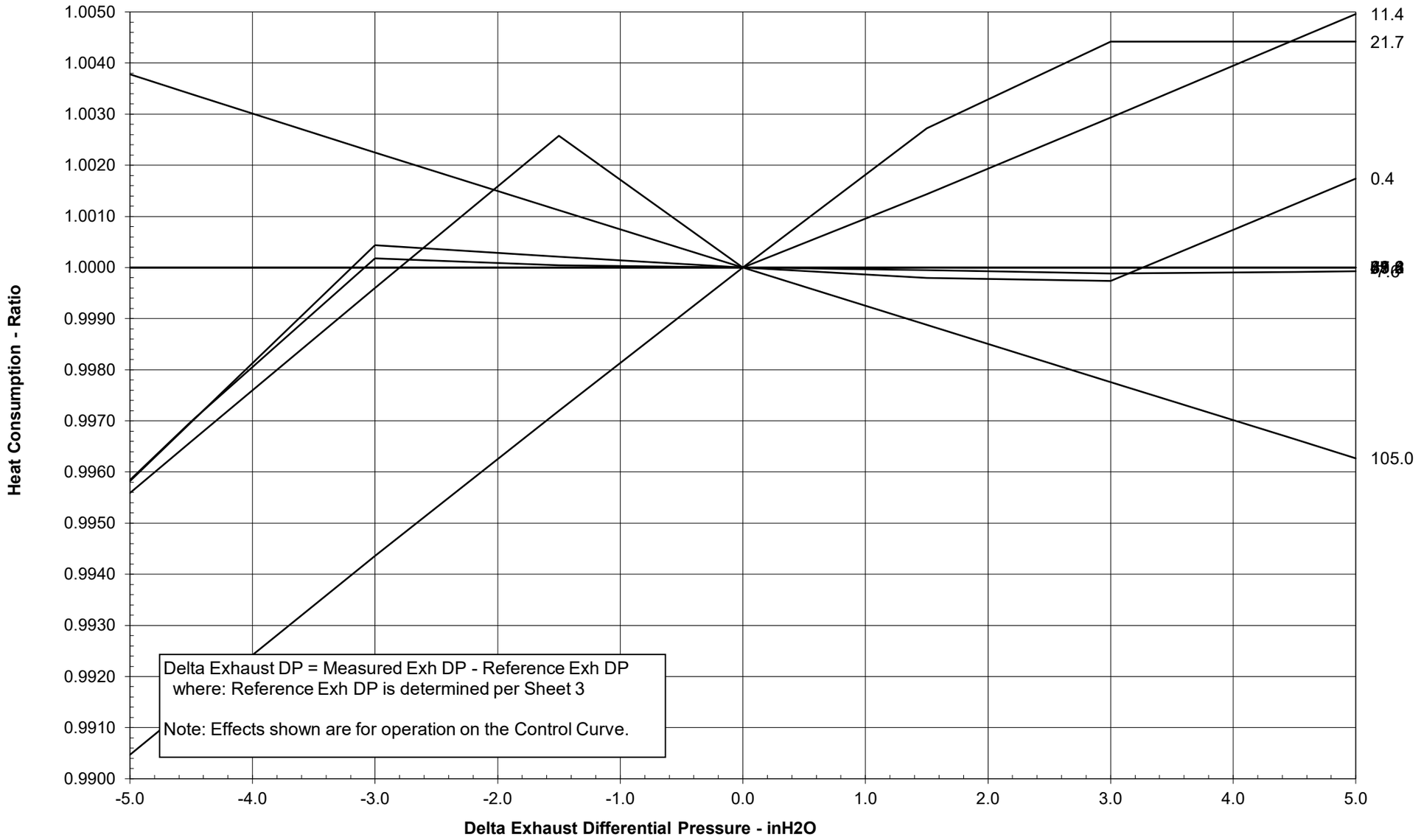
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Pressure on Heat Consumption at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Delta Exhaust Differential Pressure - inH2O	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
-5.00	0.99584	0.99582	0.99559	0.99047	1.00000	1.00000	1.00000	1.00000	1.00000	1.00378
-4.50	0.99699	0.99698	0.99660	0.99145	1.00000	1.00000	1.00000	1.00000	1.00000	1.00339
-3.00	1.00018	1.00044	0.99960	0.99436	1.00000	1.00000	1.00000	1.00000	1.00000	1.00225
-1.50	1.00005	1.00021	1.00257	0.99720	1.00000	1.00000	1.00000	1.00000	1.00000	1.00112
0.00	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
1.50	0.99995	0.99980	1.00144	1.00272	1.00000	1.00000	1.00000	1.00000	1.00000	0.99888
3.00	0.99988	0.99974	1.00293	1.00442	1.00000	1.00000	1.00000	1.00000	1.00000	0.99776
4.50	0.99991	1.00124	1.00445	1.00442	1.00000	1.00000	1.00000	1.00000	1.00000	0.99664
5.00	0.99993	1.00174	1.00496	1.00442	1.00000	1.00000	1.00000	1.00000	1.00000	0.99627

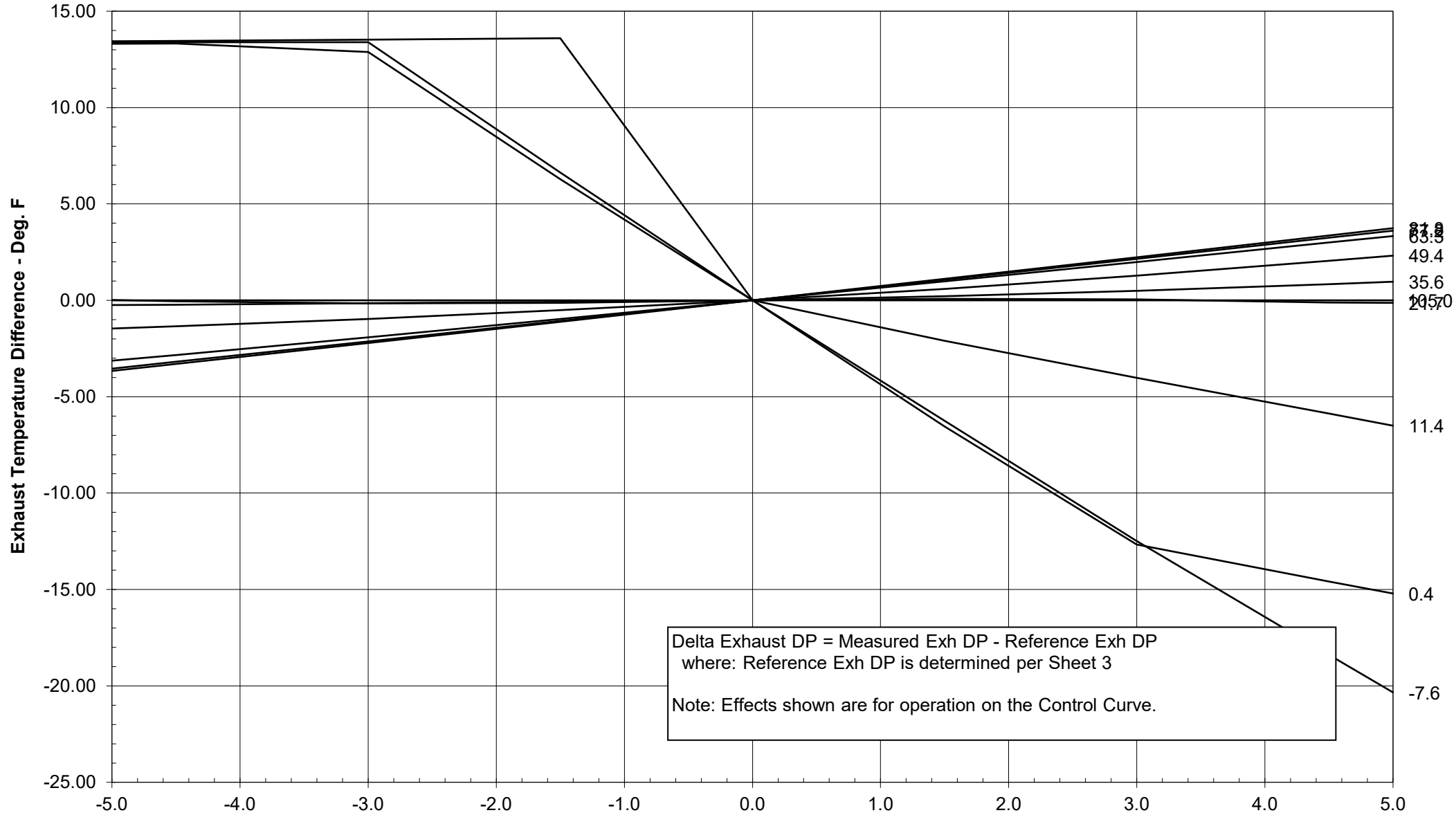
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Pressure on Exhaust Temperature at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Delta Exhaust Differential Pressure - inH2O

Compressor Inlet Temperature - Deg. F

Delta Exhaust Differential Pressure - inH2O	-7.6	0.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
-5.00	13.31	13.38	13.44	-0.24	0.02	-1.46	-3.13	-3.54	-3.66	0.00
-4.50	13.32	13.39	13.46	-0.22	-0.05	-1.35	-2.84	-3.19	-3.30	0.00
-3.00	12.89	13.39	13.53	-0.15	-0.16	-0.96	-1.92	-2.13	-2.21	0.00
-1.50	6.29	6.63	13.60	-0.08	-0.13	-0.51	-0.97	-1.07	-1.11	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.50	-6.24	-6.55	-2.10	0.08	0.22	0.59	0.99	1.07	1.12	0.00
3.00	-12.48	-12.66	-4.03	0.05	0.50	1.29	1.99	2.16	2.24	0.00
4.50	-18.40	-14.58	-5.88	-0.12	0.84	2.05	3.00	3.25	3.37	0.00
5.00	-20.34	-15.21	-6.50	-0.14	0.97	2.32	3.33	3.61	3.74	0.00

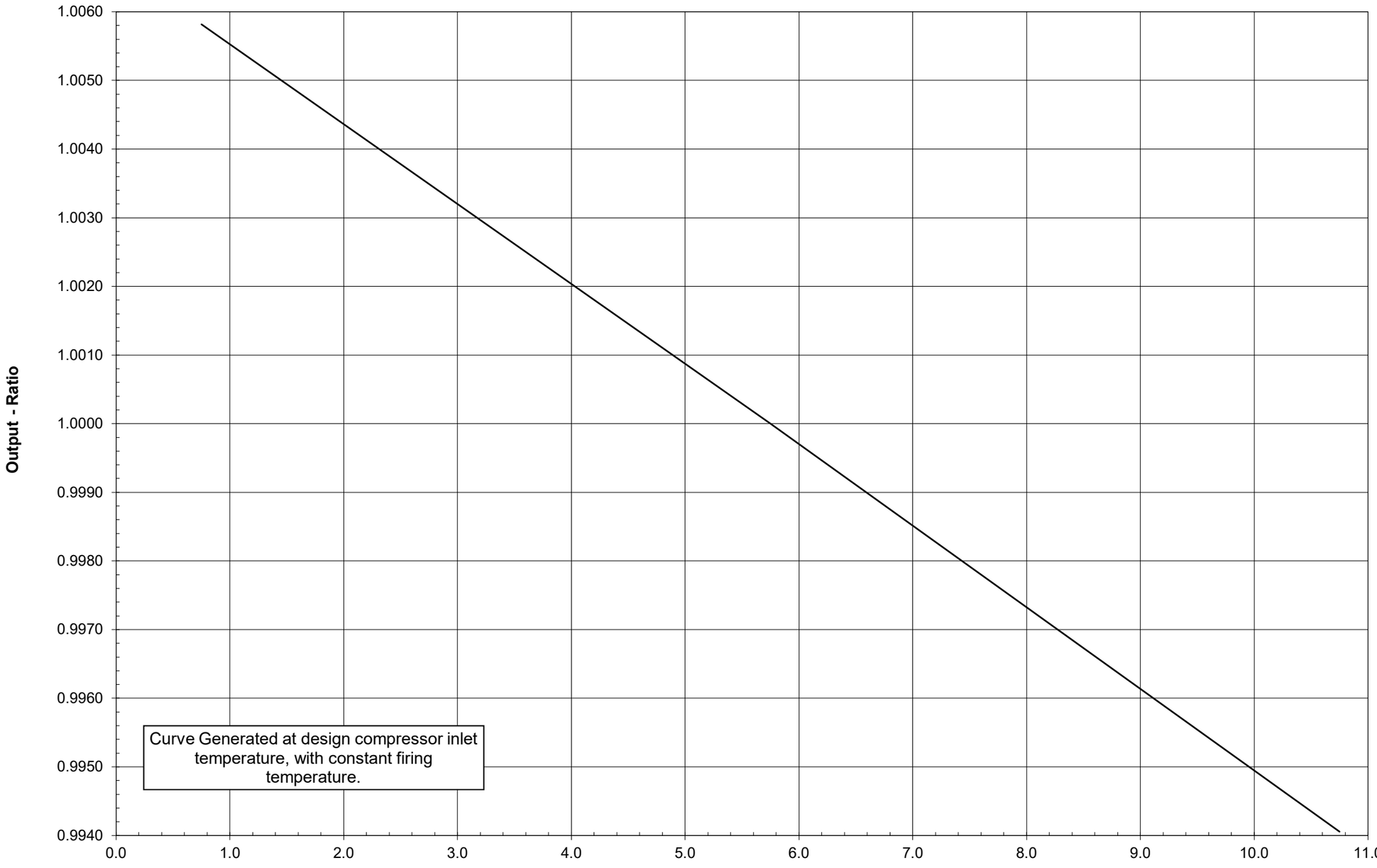
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Differential Pressure on Output

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units			
Exhaust DP	inH2O	0.75	5.75	10.75
Output Ratio		1.00582	1.00000	0.99406

David Walters
06/20/25

24A-167 Rev A
Sheet 31

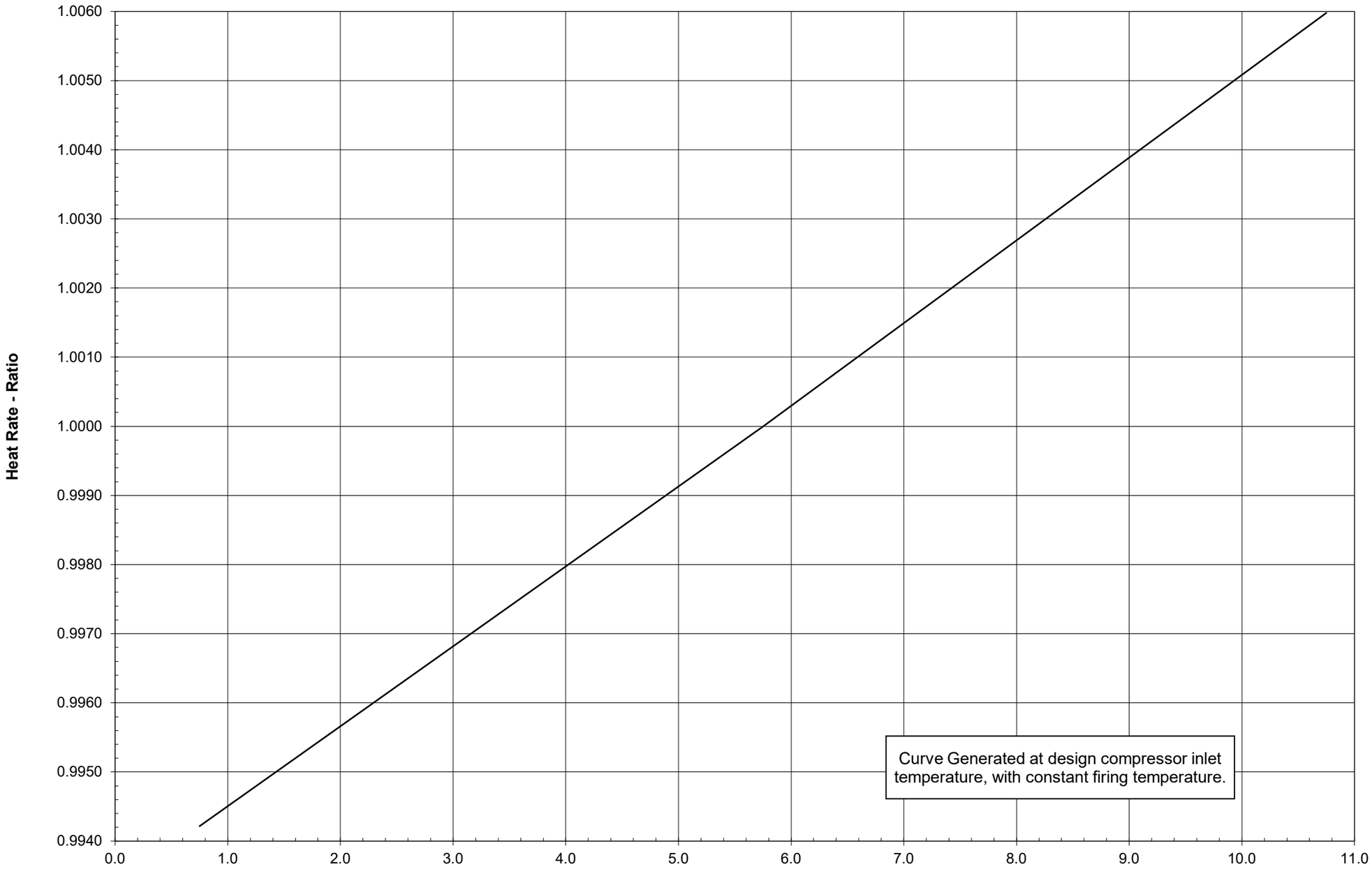
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Differential Pressure on Heat Rate

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units			
Exhaust DP	inH2O	0.75	5.75	10.75
Heat Rate Ratio		0.99422	1.00000	1.00598

David Walters
06/20/25

24A-167 Rev A
Sheet 32

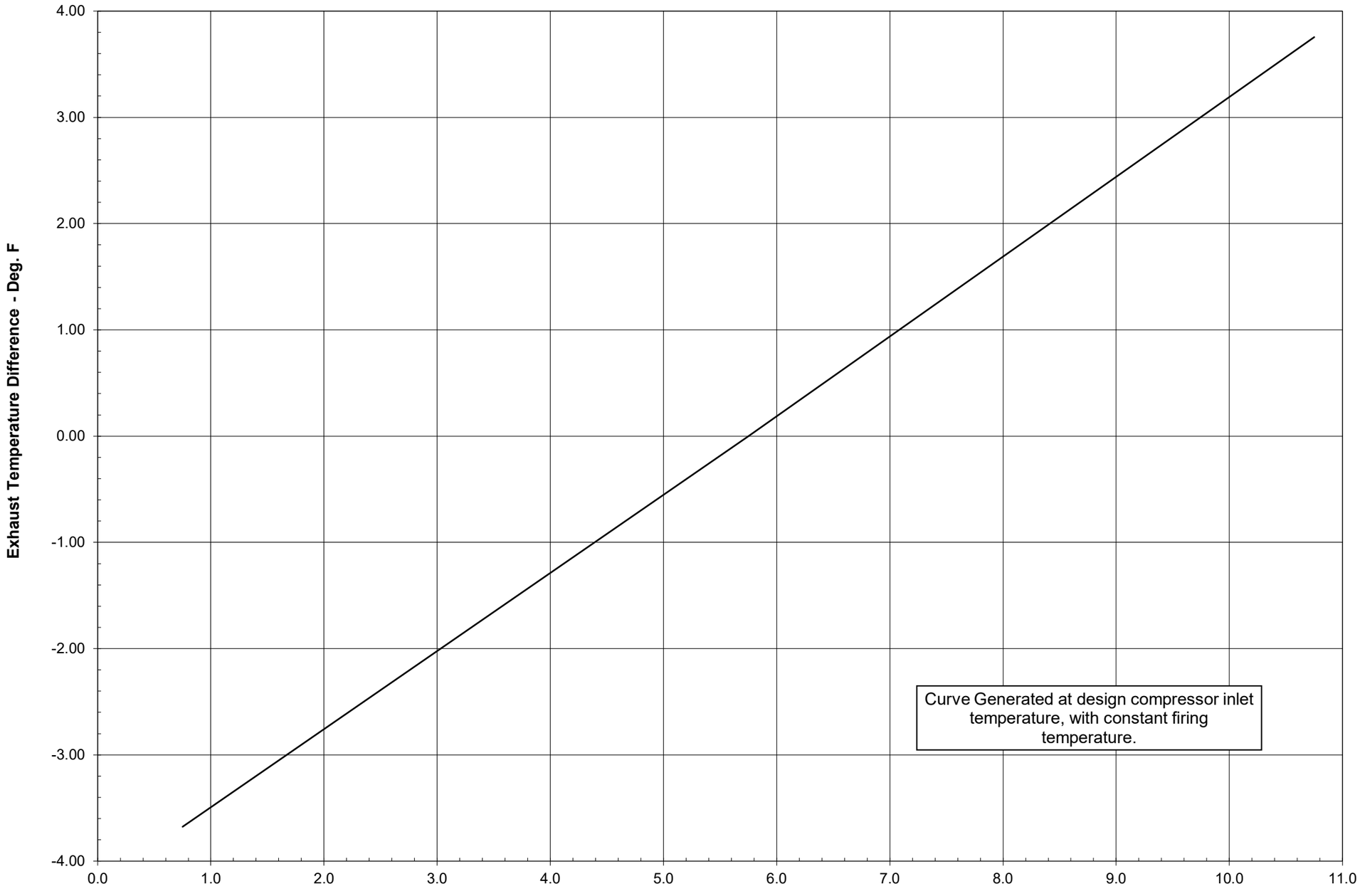
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Exhaust Differential Pressure on Exhaust Temperature

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



	Units			
Exhaust DP	inH2O	0.75	5.75	10.75
Tx Difference	F	-3.7	0.0	3.8

David Walters
06/20/25

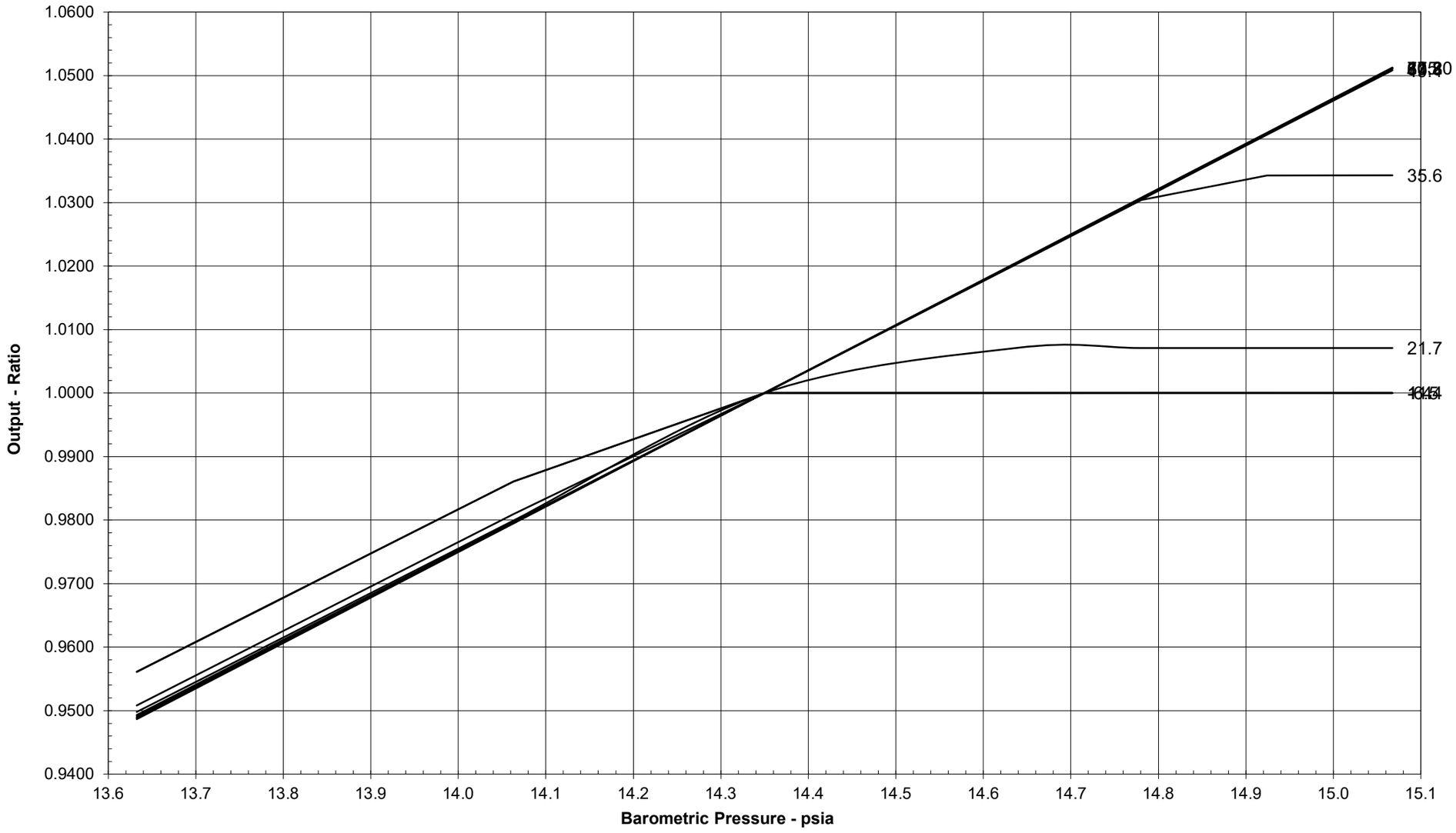
24A-167 Rev A
Sheet 33

This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Barometric Pressure on Output at Different Compressor Inlet Temps
Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Barometric Pressure - psia	-6.5	1.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
13.633	0.95609	0.95612	0.95081	0.94978	0.94930	0.94914	0.94891	0.94881	0.94883	0.94865
13.776	0.96609	0.96611	0.96084	0.95983	0.95945	0.95932	0.95913	0.95905	0.95907	0.95893
13.920	0.97608	0.97610	0.97088	0.96988	0.96959	0.96949	0.96935	0.96929	0.96930	0.96920
14.063	0.98608	0.98608	0.98091	0.97992	0.97973	0.97966	0.97957	0.97953	0.97954	0.97947
14.350	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
14.637	1.00000	1.00000	1.00000	1.00710	1.02027	1.02033	1.02043	1.02047	1.02046	1.02051
14.781	1.00000	1.00000	1.00000	1.00710	1.03040	1.03050	1.03064	1.03070	1.03068	1.03077
14.924	1.00000	1.00000	1.00000	1.00710	1.03429	1.04066	1.04085	1.04093	1.04091	1.04101
15.068	1.00000	1.00000	1.00000	1.00710	1.03429	1.05082	1.05106	1.05116	1.05113	1.05126

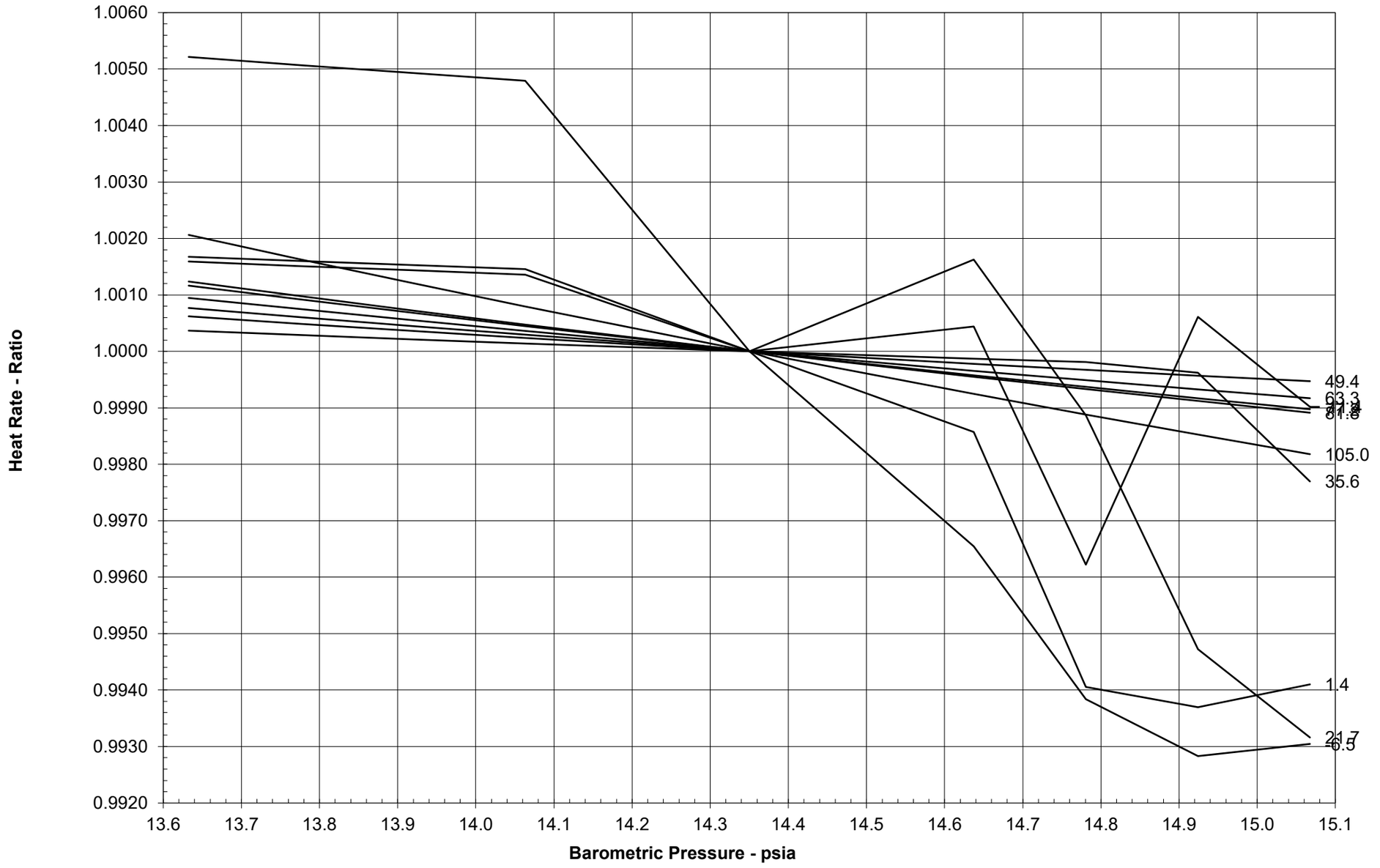
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Barometric Pressure on Heat Rate at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Barometric Pressure - psia	-6.5	1.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
13.633	1.00159	1.00168	1.00522	1.00077	1.00037	1.00062	1.00095	1.00116	1.00124	1.00206
13.776	1.00151	1.00160	1.00507	1.00061	1.00029	1.00049	1.00075	1.00092	1.00098	1.00163
13.920	1.00143	1.00153	1.00493	1.00045	1.00021	1.00036	1.00055	1.00068	1.00072	1.00121
14.063	1.00136	1.00146	1.00480	1.00029	1.00014	1.00024	1.00036	1.00045	1.00047	1.00079
14.350	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
14.637	0.99655	0.99857	1.00044	1.00163	0.99987	0.99978	0.99966	0.99957	0.99955	0.99924
14.781	0.99384	0.99405	0.99622	0.99887	0.99981	0.99967	0.99949	0.99937	0.99933	0.99888
14.924	0.99283	0.99370	1.00061	0.99472	0.99962	0.99957	0.99933	0.99917	0.99912	0.99853
15.068	0.99305	0.99410	0.99902	0.99316	0.99770	0.99947	0.99917	0.99897	0.99891	0.99818

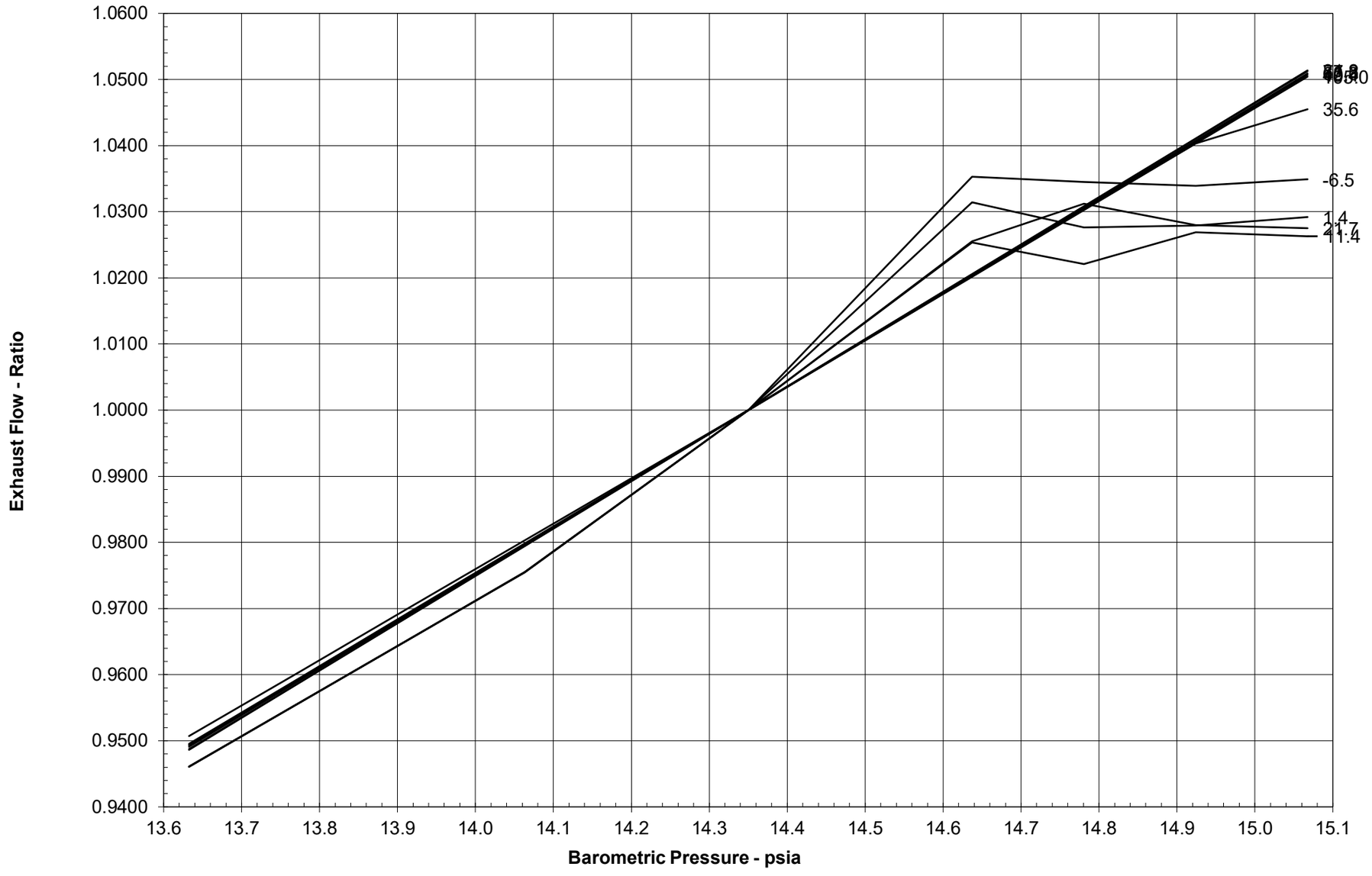
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Barometric Pressure on Exhaust Flow at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Barometric Pressure - psia	-6.5	1.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
13.633	0.94610	0.94608	0.94606	0.95071	0.94940	0.94931	0.94909	0.94874	0.94863	0.94953
13.776	0.95590	0.95588	0.95586	0.96057	0.95952	0.95945	0.95927	0.95899	0.95890	0.95963
13.920	0.96570	0.96568	0.96566	0.97042	0.96964	0.96958	0.96945	0.96925	0.96918	0.96972
14.063	0.97550	0.97548	0.97547	0.98028	0.97976	0.97972	0.97964	0.97950	0.97945	0.97982
14.350	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
14.637	1.03530	1.03143	1.02537	1.02550	1.02024	1.02028	1.02036	1.02050	1.02055	1.02018
14.781	1.03450	1.02760	1.02211	1.03122	1.03036	1.03042	1.03055	1.03075	1.03082	1.03026
14.924	1.03394	1.02794	1.02690	1.02795	1.04032	1.04055	1.04073	1.04101	1.04110	1.04035
15.068	1.03489	1.02919	1.02629	1.02751	1.04550	1.05069	1.05091	1.05126	1.05137	1.05043

David Walters
06/20/25

24A-167 Rev A
Sheet 36

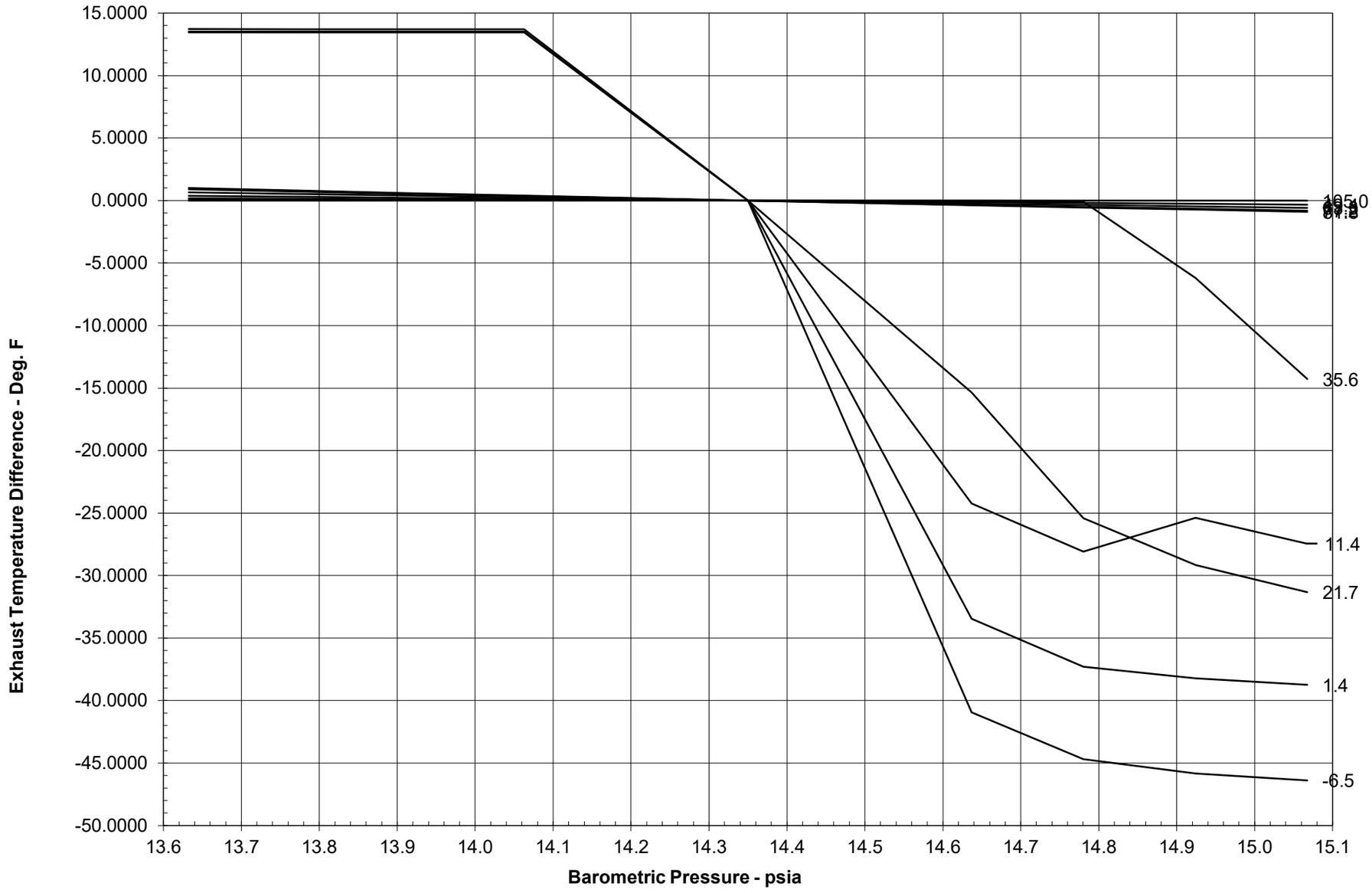
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Barometric Pressure on Exhaust Temperature at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Barometric Pressure - psia	-6.5	1.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
13.63	13.46	13.52	13.72	0.08	0.17	0.38	0.66	0.90	1.00	0.00
13.78	13.45	13.51	13.71	0.07	0.14	0.30	0.52	0.71	0.79	0.00
13.92	13.45	13.51	13.70	0.05	0.10	0.22	0.38	0.53	0.59	0.00
14.06	13.45	13.50	13.69	0.03	0.07	0.14	0.25	0.35	0.39	0.00
14.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14.64	-40.94	-33.46	-24.22	-15.35	-0.06	-0.14	-0.24	-0.34	-0.37	0.00
14.78	-44.69	-37.30	-28.09	-25.43	-0.09	-0.20	-0.36	-0.50	-0.55	0.00
14.92	-45.84	-38.22	-25.39	-29.17	-6.19	-0.27	-0.48	-0.66	-0.73	0.00
15.07	-46.39	-38.74	-27.44	-31.33	-14.27	-0.33	-0.59	-0.81	-0.90	0.00

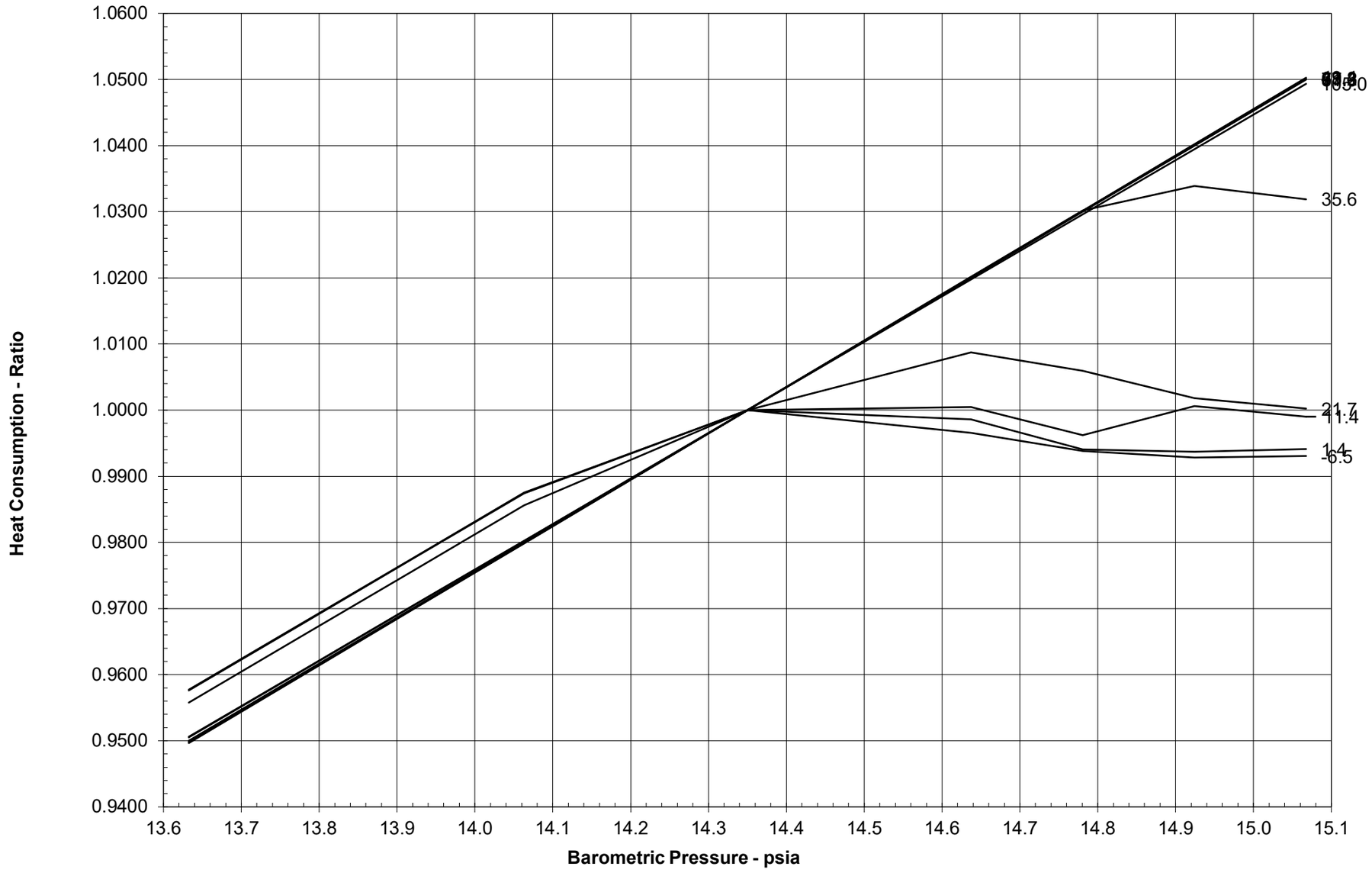
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Barometric Pressure on Heat Consumption at Different Compressor Inlet Temps

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Compressor Inlet Temperature - Deg. F

Barometric Pressure - psia	-6.5	1.4	11.4	21.7	35.6	49.4	63.3	77.2	81.8	105.0
13.633	0.95761	0.95772	0.95577	0.95052	0.94965	0.94973	0.94981	0.94992	0.95000	0.95061
13.776	0.96755	0.96765	0.96572	0.96041	0.95972	0.95979	0.95985	0.95993	0.96000	0.96049
13.920	0.97748	0.97759	0.97566	0.97031	0.96979	0.96984	0.96989	0.96995	0.97000	0.97037
14.063	0.98742	0.98752	0.98561	0.98021	0.97986	0.97989	0.97992	0.97997	0.98000	0.98025
14.350	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
14.637	0.99655	0.99857	1.00044	1.00873	1.02014	1.02011	1.02008	1.02003	1.02000	1.01974
14.781	0.99384	0.99405	0.99622	1.00595	1.03021	1.03016	1.03011	1.03005	1.03000	1.02961
14.924	0.99283	0.99370	1.00061	1.00178	1.03390	1.04021	1.04015	1.04007	1.03999	1.03948
15.068	0.99305	0.99410	0.99902	1.00021	1.03191	1.05027	1.05019	1.05008	1.04999	1.04934

David Walters
06/20/25

24A-167 Rev A
Sheet 38

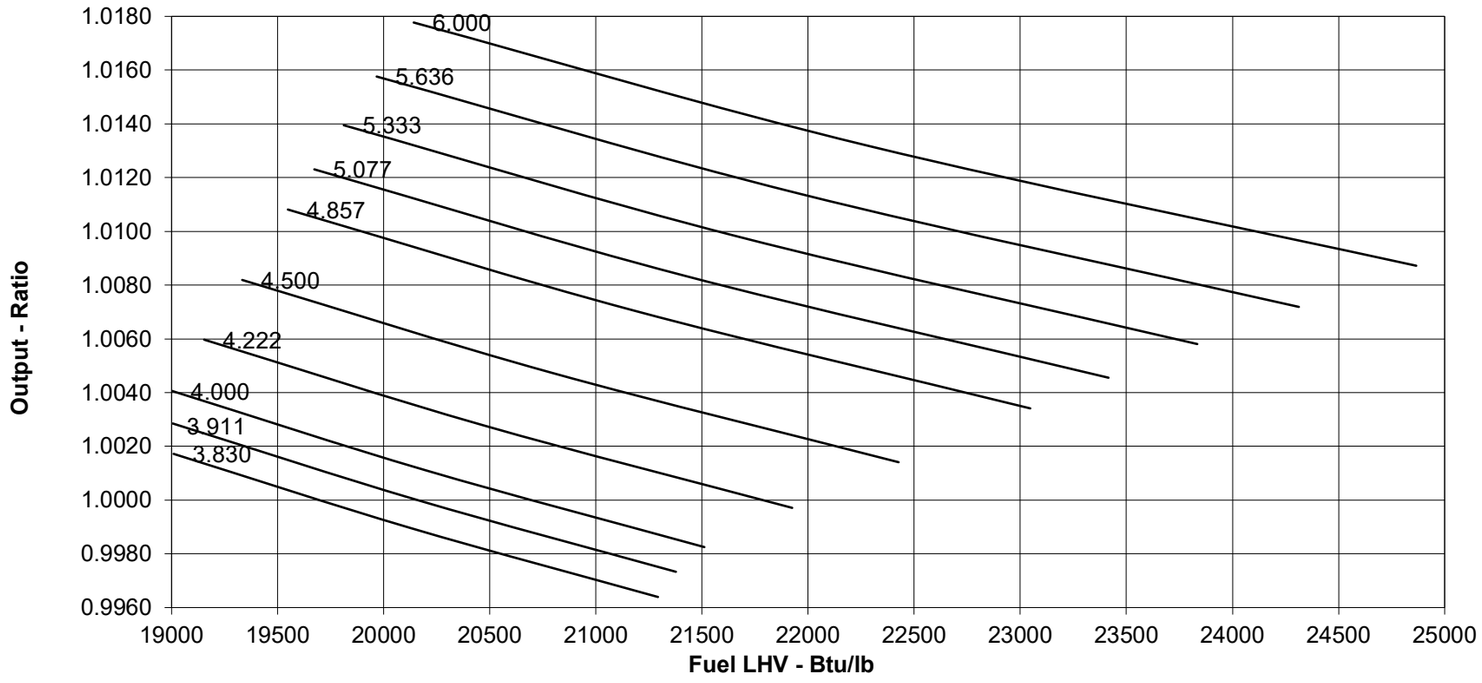
This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Gas Fuel Composition on Output

Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Fuel LHV - Btu/lb	Fuel H/C 3.830
19010	1.00172
20122	0.99897
21292	0.99639

Fuel LHV - Btu/lb	Fuel H/C 3.911
19006	1.00285
20159	1.00000
21377	0.99733

Fuel LHV - Btu/lb	Fuel H/C 4.000
19002	1.00406
20199	1.00111
21511	0.99825

Fuel LHV - Btu/lb	Fuel H/C 4.222
19154	1.00597
20468	1.00279
21925	0.99971

Fuel LHV - Btu/lb	Fuel H/C 4.500
19333	1.00819
20790	1.00474
22426	1.00141

Fuel LHV - Btu/lb	Fuel H/C 4.857
19548	1.01081
21182	1.00705
23047	1.00341

Fuel LHV - Btu/lb	Fuel H/C 5.077
19673	1.01231
21412	1.00836
23416	1.00455

Fuel LHV - Btu/lb	Fuel H/C 5.333
19811	1.01395
21670	1.00980
23834	1.00581

Fuel LHV - Btu/lb	Fuel H/C 5.636
19966	1.01576
21961	1.01140
24313	1.00719

Fuel LHV - Btu/lb	Fuel H/C 6.000
20141	1.01777
22293	1.01316
24866	1.00872

NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

David Walters
06/20/25

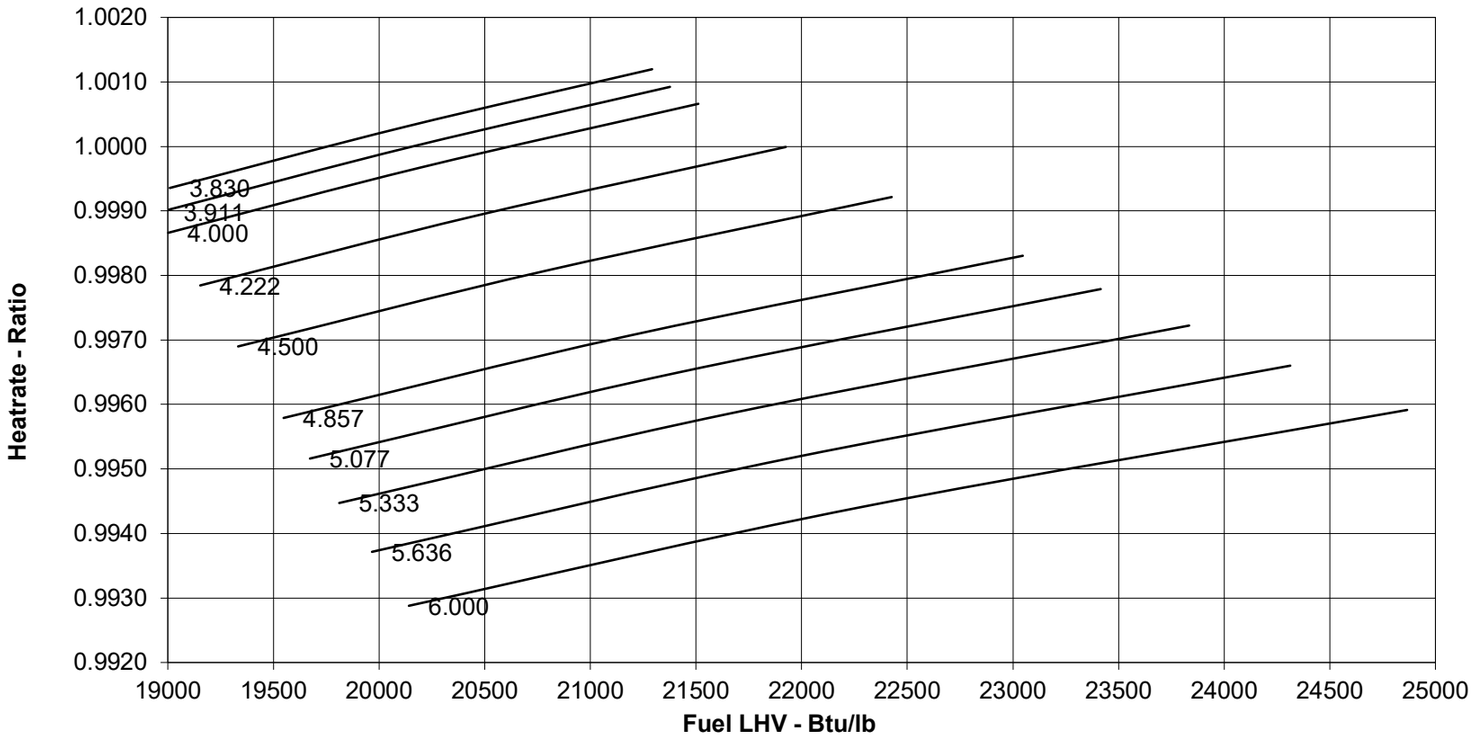
24A-167 Rev A
Sheet 39

This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Gas Fuel Composition on Heat Rate
Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Fuel LHV - Btu/lb	Fuel H/C 3.830
19010	0.99936
20122	1.00030
21292	1.00120

Fuel LHV - Btu/lb	Fuel H/C 3.911
19006	0.99902
20159	1.00000
21377	1.00092

Fuel LHV - Btu/lb	Fuel H/C 4.000
19002	0.99866
20199	0.99967
21511	1.00066

Fuel LHV - Btu/lb	Fuel H/C 4.222
19154	0.99785
20468	0.99893
21925	0.99999

Fuel LHV - Btu/lb	Fuel H/C 4.500
19333	0.99690
20790	0.99807
22426	0.99922

Fuel LHV - Btu/lb	Fuel H/C 4.857
19548	0.99579
21182	0.99706
23047	0.99831

Fuel LHV - Btu/lb	Fuel H/C 5.077
19673	0.99516
21412	0.99649
23416	0.99779

Fuel LHV - Btu/lb	Fuel H/C 5.333
19811	0.99447
21670	0.99587
23834	0.99722

Fuel LHV - Btu/lb	Fuel H/C 5.636
19966	0.99372
21961	0.99518
24313	0.99660

Fuel LHV - Btu/lb	Fuel H/C 6.000
20141	0.99288
22293	0.99442
24866	0.99591

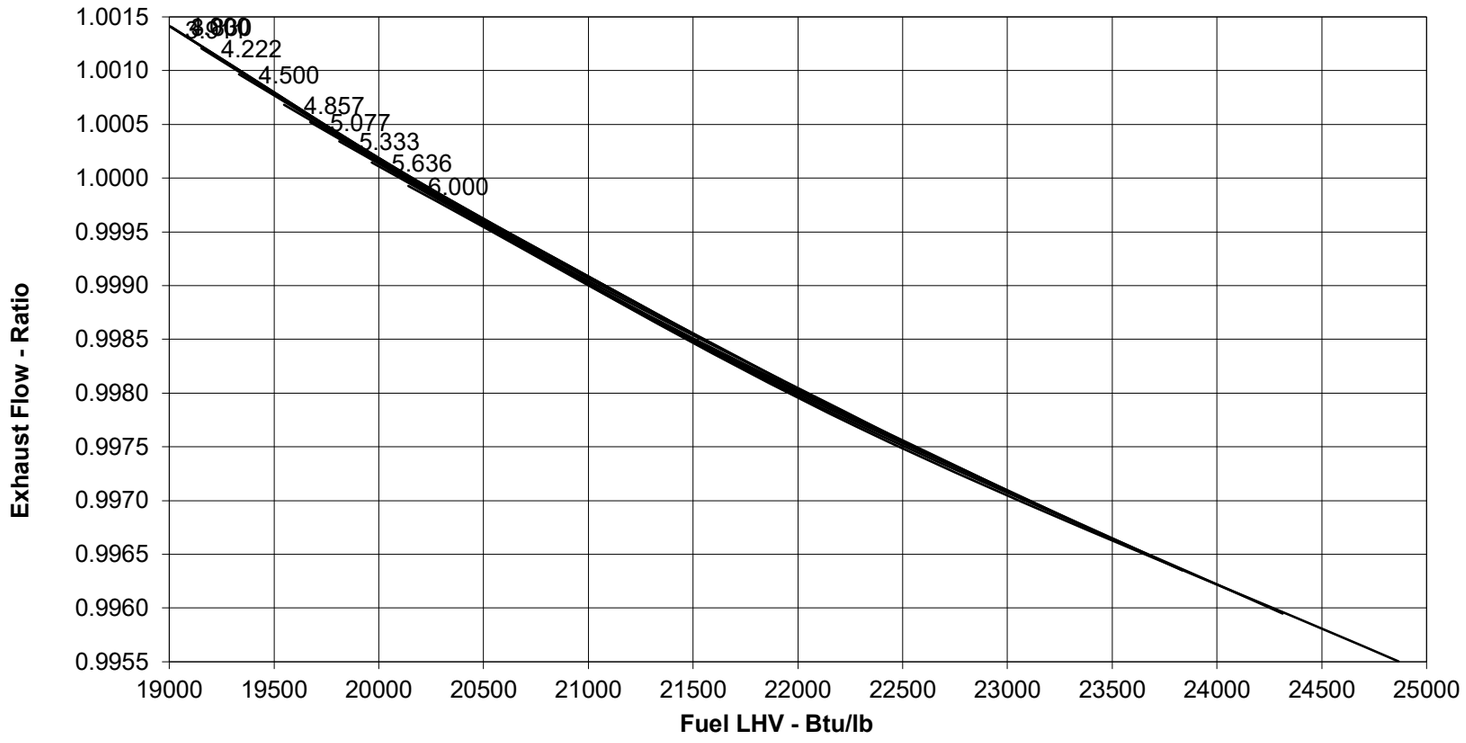
NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Gas Fuel Composition on Exhaust Flow
Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Fuel LHV - Btu/lb	Fuel H/C 3.830
19010	1.00141
20122	1.00004
21292	0.99877

Fuel LHV - Btu/lb	Fuel H/C 3.911
19006	1.00141
20159	1.00000
21377	0.99868

Fuel LHV - Btu/lb	Fuel H/C 4.000
19002	1.00141
20199	0.99995
21511	0.99854

Fuel LHV - Btu/lb	Fuel H/C 4.222
19154	1.00121
20468	0.99964
21925	0.99812

Fuel LHV - Btu/lb	Fuel H/C 4.500
19333	1.00097
20790	0.99927
22426	0.99763

Fuel LHV - Btu/lb	Fuel H/C 4.857
19548	1.00068
21182	0.99883
23047	0.99705

Fuel LHV - Btu/lb	Fuel H/C 5.077
19673	1.00052
21412	0.99858
23416	0.99671

Fuel LHV - Btu/lb	Fuel H/C 5.333
19811	1.00034
21670	0.99831
23834	0.99635

Fuel LHV - Btu/lb	Fuel H/C 5.636
19966	1.00015
21961	0.99801
24313	0.99595

Fuel LHV - Btu/lb	Fuel H/C 6.000
20141	0.99993
22293	0.99767
24866	0.99550

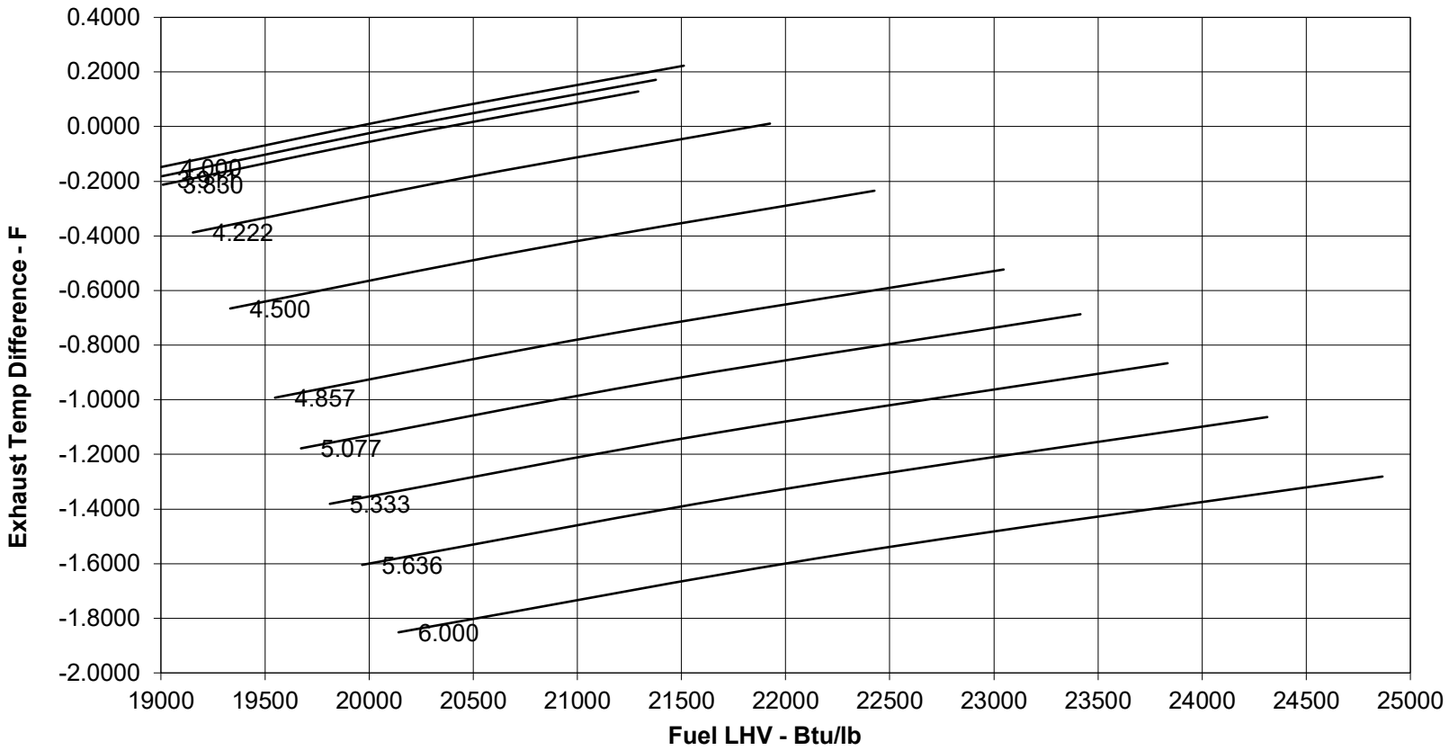
NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Gas Fuel Composition on Exhaust Temperature
Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Fuel LHV - Btu/lb	Fuel H/C 3.830
19010	-0.21257
20122	-0.03712
21292	0.12870

Fuel LHV - Btu/lb	Fuel H/C 3.911
19006	-0.18138
20159	0.00000
21377	0.17139

Fuel LHV - Btu/lb	Fuel H/C 4.000
19002	-0.14770
20199	0.03998
21511	0.22300

Fuel LHV - Btu/lb	Fuel H/C 4.222
19154	-0.38757
20468	-0.18583
21925	0.01102

Fuel LHV - Btu/lb	Fuel H/C 4.500
19333	-0.66578
20790	-0.44768
22426	-0.23478

Fuel LHV - Btu/lb	Fuel H/C 4.857
19548	-0.99235
21182	-0.75500
23047	-0.52313

Fuel LHV - Btu/lb	Fuel H/C 5.077
19673	-1.17787
21412	-0.92956
23416	-0.68689

Fuel LHV - Btu/lb	Fuel H/C 5.333
19811	-1.38103
21670	-1.12072
23834	-0.86619

Fuel LHV - Btu/lb	Fuel H/C 5.636
19966	-1.60445
21961	-1.33094
24313	-1.06333

Fuel LHV - Btu/lb	Fuel H/C 6.000
20141	-1.85141
22293	-1.56323
24866	-1.28112

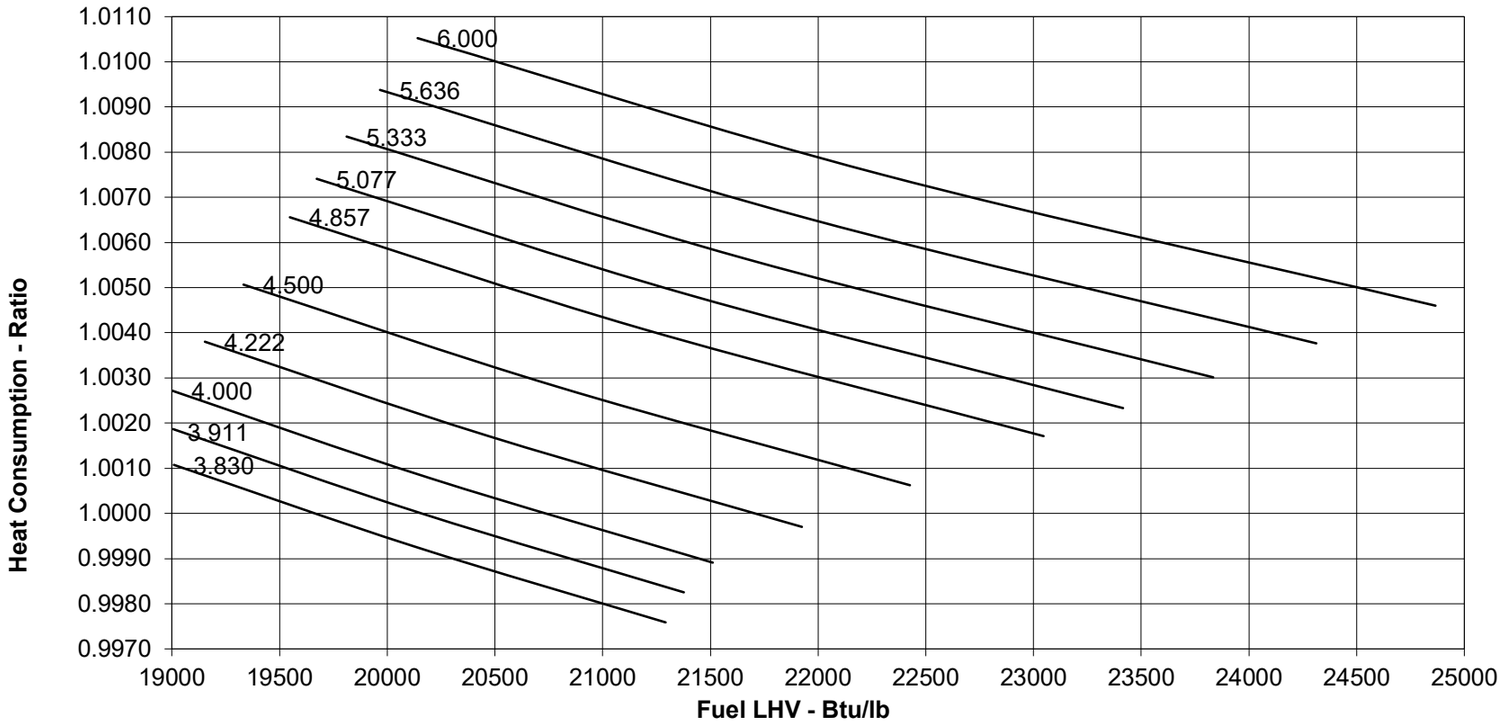
NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

GE Vernova Model 7F.04 Gas Turbine
Consumers Energy - Zeeland F6014G14

Estimated Performance

Effect of Gas Fuel Composition on Heat Consumption
Design Values Referenced on 24A-167 Rev A Sheet 1
Fuel: Gas
Mode: Base
Gas Turbine Generator(s) 297502-3 ONLY



Fuel LHV - Btu/lb	Fuel H/C 3.830
19010	1.00108
20122	0.99927
21292	0.99759

Fuel LHV - Btu/lb	Fuel H/C 3.911
19006	1.00187
20159	1.00000
21377	0.99825

Fuel LHV - Btu/lb	Fuel H/C 4.000
19002	1.00272
20199	1.00078
21511	0.99891

Fuel LHV - Btu/lb	Fuel H/C 4.222
19154	1.00380
20468	1.00172
21925	0.99970

Fuel LHV - Btu/lb	Fuel H/C 4.500
19333	1.00507
20790	1.00281
22426	1.00062

Fuel LHV - Btu/lb	Fuel H/C 4.857
19548	1.00656
21182	1.00409
23047	1.00171

Fuel LHV - Btu/lb	Fuel H/C 5.077
19673	1.00741
21412	1.00482
23416	1.00233

Fuel LHV - Btu/lb	Fuel H/C 5.333
19811	1.00834
21670	1.00563
23834	1.00301

Fuel LHV - Btu/lb	Fuel H/C 5.636
19966	1.00938
21961	1.00652
24313	1.00377

Fuel LHV - Btu/lb	Fuel H/C 6.000
20141	1.01052
22293	1.00751
24866	1.00460

NOTES: H/C ratio is the atom ratio of the combustible components of the gas fuel
Heating Value calculated per ASTM D3588 (14.696 psia, 60 deg F)

This document contains GE Vernova proprietary information and may not be used or disclosed to others except with written permission of the GE Vernova company.
All rights reserved. GE and the GE Monogram are trademarks of General Electric Company used under trademark license.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Generation O&M Expense
For the Years 2022 through September 2025
($000's)

Case No.: U-21870
Exhibit No.: A-20.1 (RTB-23)
Page: 1 of 4
Witness: RTBlumenstock
Date: October 2025

2022 Emergenent Reliability Expense

Description	Cost ('000's)	Details	Site	Month
JHC1 Boiler safety Programs FAC inspection	$ 120	broke fix	BESS	Jan
Hydro - Croton Shoreline Structure Compliance	$ 40	Funding needed to get property owners to sign easement, open house at township, real estate agents and potential for legal fees if easement isnt signed	Hydro	April
Hydros Update innundation maps	$ 42	Increase in scope of the AuSable Dam Breach Study and innudation maps. If we wait until 2023 it will be more expensive, consultants are avalable this year to complete the work, it is related to public safety. This funding will lower 2023 budget needed	Hydro	aug
Hydro - Croton Shoreline Structure Compliance	$ 25	Additional funds to cover real estate costs for getting easements signed. (122 of 206 signed)	Hydro	aug
Hydros Relief Well Piezometer Cleaning - WE	$ 64	Asking for funds to use for Waste Elimination	Hydro	Feb
Hydro - Hardy Chimney Repair	$ 175	Emergent request approved via email on 6/7/2022	Hydro	June
Hydros Annual FERC Dam Safety Requirements including Part 12 Inspections	$ 13	Moving funds from Tippy Powerhouse apron monitoring	Hydro	June
Hardy - new HQ building - IT costs - request from checkbook	$ 11	IT Costs ($6500 for phones/equipment; $4,100 for labor to move people in/close project)	Hydro	March
Hydro - Hardy - Replace U3 Penstock Expansion Joints	$ 13	Expansion bolts are rusted and cannot be adjusted, and the joint is leaking large amounts of water into the sump area, which is an environmental concern. Solution is to cut out old bolts and replace with new	Hydro	Nov
Hardy Hydro Embankment Stabilization	$ 47	Emergent CL approved on 9/14/2022 - Significant erosion on the embankment, there are drainage issues that need to be corrected to protect the integrity of the dam. The project will include various tasks to successfully execute the repairs.	Hydro	sept
Jackson - extra work/broke fix spring outage - emergent request	$ 197	Approved emergent via email on 4/15/2022	JGS	April
JGS Base Outage-Boiler Plant Equipment	$ 105	Broke/fix items discovered during plant outage. 7EA Duct Liner Plate&Diffuser Crack Repairs/LM6 turbine Exhaust Damper Repair/East Sky Vent Control Vavle Repairs	JGS	April
ST8 EHC Restoration-Major Maint	$ 215	The unit will continue to carry a minimum 15 MW derate without the clean & rinse flush, actuator rebuilds, and accumulator rebuilds. If the system and fluid are left in their current state, the gelling condition will have an increasing effect on other parts of the system. The effect will be a larger derate and possibly removing the unit from service (105 MW derate) until the clean & rinse flush, accumulator rebuilds, and actuator rebuilds are performed. JGS Spring Outage	JGS	Feb
JGS Cooling Tower Expansion Joints	$ 35	broke fix	JGS	Jan
JGS Base Outage-Boiler Plant Equipment	$ 190	Request for increased scope in Spring outage and contractor additional charges on POs for Fall 2021 outage work.Net with return from PP-10065	JGS	March
JGS - ST8/9 EHC Restoration	$ 175	The EHC fluid is highly degraded and beyond it's useful life. This EHC fluid and the varnish in the system could take off until 9 causing up to a 105 MW derate. This issue needs to be addressed during the outage before it takes itself offline unexpectedly. This needs to be addressed in the spring 2022 outage.	JGS	March
JGS Non-LTSA Turbine and jet engine repairs	$ 150	Request of funding for write off to O&M. Fuel Nozzle work completed in 2018. GE provided parts. Install charges need to be moved to MM. Net request	jgs	Nov
JHC2 Turbine Valve Inspection	$ 62	Site approved CL to transfer funds between JHC U2 O&M projects.	JHC	April
JHC 3 Environmental SCR UBAS Nomnals, net of muni credit of $9k	$ 131	In need of 2 additional reactor cleanings at 70k each. Given the increase in dispatch on units 2 and 3, we are exhausting reactors faster than expected. The units remain at full load without dispatching down at night.	JHC	aug
JHC2 Turbine Valve Inspection	$ 68	True-up. Project received final acceptance. Net zero changelog for JHC Cap.	JHC	aug
JHC Site Plant Managed MM true ups, net of muni credit of $4k	$ 43	See note embedded in this cell/cleaning up ytd (over) under runs for site MM with internal cl and small request for balance.	JHC	aug
JHC 3 Forced Outage Funding	$ 93	Last request - needed 100k more than original request - pull from U3 Mill in November	jhc	Dec
JHC 3 Secondary Air Heater Cleaning, net of muni cr o $8k	$ 112	$150k approved in Jan BUG/New request Addl Env requirements	JHC	Feb
JHC2 Generator Overhaul and Rewedge	$ 310	Add'l GE and NB work associated with outage extension, SUT, and closeout.	JHC	Feb
JHC3 Outage Base-Boiler and Critical Maintenance, net of muni cr of $25k	$ 350	request as line item was pulled from ttfy 2022/2023 and this is a must have for break/fix/funded with JHC returns	JHC	Feb
JHC1 HEPS	$ 140	broke fix	JHC	jan
JHC1 NERC and Non-NERC PRC005 maintenance	$ 80	broke fix	JHC	Jan
JHC1 Transformer base maintenance	$ 100	broke fix	JHC	Jan
JHC2 Turbine Generator Inspection	$ 15	broke fix	JHC	Jan
JHC2 Turbine valve inspection	$ 15	broke fix	JHC	Jan
JHC3 BFP Turbine Inspection	$ 467	broke fix	JHC	Jan
JHC3 Secondary Air Heater Cleaning	$ 150	broke fix	JHC	Jan
JHC 3 - Fall Dive Inspection Intakes	$ 35	The 2022 dive inspection budget was wiped out due to the unexpected discharge nozzle replacements during the spring diving inspections. These inspections ensure the intake screens are clean for cooling water passage and intact, these reside in Lake Michigan.	JHC	July
JHC Deepwater Intake Screen Inspection	$ 75	During the spring dive inspections, numerous diffuser nozzles were found off of the dischaarge header and had to be replaced. This is public facing equipment that can affect Lake Michigan. Regulatory requirement per 316(a).	JHC	May
JHC3 Periodic Outage Major Maintenance	$ 109	Many issues identified during outage contributing to addl. spend. A few items include outage duration shortened and plant labor unable to complete priority 1 work requiring o/s. Multiple valves failed during shut down not previously part of outage scope. Scope growth of Eng inspections. Addl. work was identified to mitigate env. risk of bottom ash sediment entering water ways during online maint activities. All decisions based on reliability for summer months and Env issues.	JHC	May
JHC3 Forced Outage Funding	$ 154	Campbell unit 3 tripped offline 11/14. As a result of the trip, we lost steam supply to UBAS and as a result plugged up the crossover line requiring clearing. During the trip, steam from the turbine seals impacted the turbine turning gear motor and will require it to be sent off site to be inspected and baked out to dry. We need explosive deslagging at least around the burner opening to remove the eyebrows to support improved combustion once back online. There are a number of priority 1 balance of plant work orders that we need to utilize contracted support to complete. We learned we need to purchase additional turbine oil due to water intrusion and we had to pull parts out of stock for our opacity monitor.	jhc	Nov
JHC 2 Forced Outage - boiler leak	$ 100	Unit 2 has a suspected boiler leak in the south wall of the furnace. We need to access the ashpit, erect scaffolding and likely hang a sky climber to access the leak and contracted labor to deslag the boiler. $50k for tube leak repairs and $50k for boiler deslag.	jhc	Nov
JHC 3 Forced Outage - boiler leak	$ 280	Unit 3 There is a confirmed boiler leak. This will require contracted labor to erect scaffolding, hang a sky climber for access and make the repairs to the boiler leak(s). This will also require explosive deslagging to be performed to provide safe access into the furnace area. Additional costs include our own NDE resources for QA/QC and then balance of plant repairs while the unit is offline. This is unrelated to the most recent U3 forced outage. $200k for boiler repair, $55k for deslag, $10k for NDE, and $15k for BOP repairs & misc.	jhc	Nov
JHC FH Coal Pile Runoff Pond Cleaning, net of muni cr of $5k	$ 137	Coal Pile runoff minor issue turned into total pond cleaning using funds from chute liner repairs	jhc	Oct
JHC 3 2023 Periodic outage, net of muni c r of $1k	$ 19	Learned in 2022 Spring Per outage Linear amplifiers for communicatoin to sub station must be replaced in 2023 outage or sooner if forced outage. Had to order for lead time and to have at first available opportunity to install. Also needed ACI lances same scenario	JHC	sept
JHC 2 Periodic outage	$ 130	Due to downlever funds depleted and will not be able to do U2 priority 1 outage work in fall outage. Needs: furnace backpass cleaning 86k, priority 1 PA fan bearings, DA safety reliefs, APH bearings, 201A valve, scaffolding 34k/covered by forced outage return	JHC	sept
JHC1 Boiler Safety Programs FAC Inspection	$ 50	Changelog in August was entered in error as return of $25k. Should have been a request of $25k so September Changelog is request of $50k to true-up this project and adjust for error	jhc	sept
JHC 2 2021/20212 Periodic outage	$ 85	Invoice error for U2 2021 fall/2022 continued spring outage hit Aug, 2022 Project had been trued up in July and no way to cover. Mistake was thought this was covered in another project./using forced outage funds above	jhc	sept
JRW Ash Pond Post-Closure Care	$ 16	Net $0 transfer of $8K from PT-10990 Karn Lined Impoundment and $8K PT-10993 - JCW Landfill Inspections to cover Fees	jrw	Oct
Karn 1 Oil Spill	$ 200	New MM project PT-50108 for ICS Karn 1 Oil Spill. Funds transferred from BPS # 9585	Karn	April
Karn 2 Forced Outage	$ 230	New MM project PT-50107 for Karn 2 Forced Outage. Funds transferred from BPS # 9587	Karn	April
Emergent - Karn 2 Whip the Byproduct Silo MM for SDA functioning	$ 50	Approved via email on 8/12	Karn	aug
Karn 1 Screen Drive and Boiler Repairs.	$ 250	Superheat air distribution damper - screen drive and gunite in reheat boiler. Boiler repair, brick repair and screen drive repairs	Karn	aug
Karn 2 Wet Coal removal from Mill	$ 75	Wet coal was loaded into the mills and brought the unit offline. Estimated $75k required to remove.	Karn	aug
Karn 3 Periodic Outage	$ 298	Funding CL101 and CL104 from internal transfers 1. K 3&4 Periodic Outage BPS 6263 ($250k) 2. K3 Boiler Repairs BPS 6256 ($75k) 3. K4 Boiler Repairs BPS 6026 ($75k) 4.) Karn Site Tank Inspections BPS 6090 ($135k). Net Ask from checkbook $85k for both projects. Scope: Boiler Repair Dead Air Space; Combustion Air Heater Repairs; Reheat Pendant Cleaning; Condenser Cleaning; Traveling Scrn / Pit Cleaning; BOP Work	Karn	aug
Karn 4 Periodic Outage	$ 322	Funding CL101 and CL104 from internal transfers 1. K 3&4 Periodic Outage BPS 6263 ($250k) 2. K3 Boiler Repairs BPS 6256 ($75k) 3. K4 Boiler Repairs BPS 6026 ($75k) 4.) Karn Site Tank Inspections BPS 6090 ($135k). Net Ask from checkbook $85k for both projects. Scope: Combustion Air Heater Repairs; Reheater Pendant Cleaning; Cooling Tower Forebay Cleaning; Condenser Tube Cleaning; HP Turbine Brg #1 Inspection; BOP Work	Karn	aug
DEK 2 Mill Maintenance Materials	$ 152	Requesting funding for Karn 2F ($75k) and 2C ($77k) Mill repairs	Karn	Dec
DEK 2 Mill Maintenance Materials (3 mills)	$ 450	Repair of emergent grinding zone of Unit 2 Mills 07-09 through 07/16/2022.	Karn	July
Karn Conveyor Repairs (12A &18)	$ 67	To fund Karn Conveyor Repairs 12A and 18 using funds from JH Campbell U2 forced outage	Karn	June
Karn 1 Steam Leak Outage	$ 100	To fund Karn 1 Steam Leak Outage PT-60091 using funds from JH Campbell U2 forced outage	Karn	June
Karn 1 Online Steam Repair	$ 40	To fund Karn 1 Online Steam repair PT-60096 using funds from JH Campbell U2 forced outage	Karn	June
Karn 4 Cooling Tower Fore Bay Cleaning/CCWP Cavitation	$ 30	To fund Karn 4 Cooling Tower Fore Bay Cleaning/CCWP Cavitation using funds from JH Campbell U2 forced outage	Karn	June
Karn 3 Cooling Tower Fore Bay Cleaning/CCWP Cavitation	$ 30	To fund Karn 3 Cooling Tower Fore Bay Cleaning/CCWP Cavitation using funds from JH Campbell U2 forced outage	Karn	June
Karn 1 - Forced Outage - Boiler Repair	$ 130	To fund PT-60085, Karn 1 - Forced Outage - Boiler Repair using Forced outage funds BPS ID: 6071.	Karn	June
Karn 2 Hold (K2 Boiler Leak Repair Outage)	$ 199	Funding with cost underruns from PT-60084, PT-60083, PT-50108	Karn	May
Karn 3&4 Maintenance Outage	$ 30	Funding project with Karn forced outage funds 6071	Karn	May
K3&4 4B ID Fan Balance Repairs	$ 10	Funding project with Karn forced outage funds 6071	Karn	May
Karn 1 Forced Outage - Boiler Leak	$ 230	Funding project with Karn forced outage funds 6071	Karn	May
Karn 1 Maintenance Outage	$ 105	Net zero transfer of $52.5K from PT-60093 Karn 3 Periodic outage and $52.5K from PT-60094 Karn 4 Periodic outage	Karn	Nov
Karn 2 Boiler Tube Leak	$ 125	Funding request to repair boiler tube leak at Karn 2	Karn	Nov
Karn 1&2 Maintenance - Demand	$ 20	Net $0 transfer of $20K from PT-11134 to DEK1&2 Maintenance to help cover cost of Vacuum Exhauster.	Karn	Oct
Karn 2B Mill Classifier Shaft	$ 230	Contracted labor and B&W service representative and parts & materials to rebuild the 2-D mill grinding zone and 2-B mill classifier	Karn	Oct
Karn 2 Atomizer rebuild- bearings- key components	$ 35	Net zero budget transfer of $35,000 from BPS 6163 PT-10982 Karn 1 SDA Atomizer Rebuild to cover atomizer wheel rebuild costs per Tashia Walraven	Karn	sept
Karn 1 Maintenance Outage	$ 70	Net zero $ request to fund Karn 1 Maintenance Outage EHC System Flush (expanded scope); Funding coming from PT-60094 $14,493, PT-11059 $7,454, PT-10945 $10,000, PT-11112 $3,482, PT-60085 $31,721, PT-50108 $2,850	Karn	sept
Karn 2 Forced Outage August 2022 (Wet Coal in Mill) (CL103 $75,000 on August CL)	$ 37	Net zero $ request to fund Karn 2 Forced Outage (Expanded Scope) EHC System/Valve Replacement	Karn	sept
Karn 2 Maintenance Outage Oct 2022	$ 250	Net zero $ request to fund Karn 2 Maintenance Outage for Boiler Fouling / EHC Flush. Funding coming from Ops 1&2 Normals Labor/OT $75k, Ops 3&4 Normals Labor/OT $25k, PT-10984 $25k, PT-10945 $60k, PT-10944 $25k, PT-60095 $30k, PT-60091 $10k	Karn	sept
LPS U2 Penstock Study	$ 15	broke fix	LPS	Jan
LPS Operations, net of muni credit of $37	$ 38	Oil Water Separator cleaning and investigation of release to LPS tailrace Jan 14	LPS	March
LPS Unit 3 Lower and Upper Expansion Joint Repacking, net of muni cr of $6k	$ 6	Moving funds from LPSP FERC Dam Safety to extend monitoring	LPS	March
ZGS CO2 Isolation System Block/Bleed	$ 40	Install a better CO2 isolation system, double block and bleed for gas turbine CO2 systems making it safer and easier for Ops to tage out the gas turbines./fund internally with 4160 V Motor funds	ZGS	April
ZGS Deep well cleaning	$ 350	broke fix	ZGS	Jan
Emergent - Zeeland main steam bypass failure	$ 175	Emergent approved on 11/9/2022 - We discovered a steam leak on one of the large-bore piping systems. This is in the 20" main steam to cold reheat bypass line. We can see steam coming out from beneath the insulation and lagging. We had a similar failure in 2012.	ZGS	Nov
Zeeland 2C GSU	$ 120	Emergent CL approved on 9/14/2022 - GSU gassing trending towards failure - need to troubleshoot and inspect immediately	ZGS	sept
	$ 9,452			

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-201 (RTB-23)
Page: 2 of 4
Witness: RTBlumenstock
Date: October 2025

Consumers Energy Company
Generation O&M Expense
For the Years 2022 through September 2025
($000's)

2023 Emergenent Reliability Expense

Description	Cost (000's)	Details	Site	Month
Battery Projects - O&M Costs	$ 6	Moving funds from #12797 to put all Battery funds in one area.	BESS	Mar
Covert Gas - 2B Circ water pump motor and the HRSG	$ 168	Emergent approval via email on 8/8/2023; HRSG is $100k; motor is $68k	CGS	Aug
Emergent - CGS HP Steam leak repair	$ 30	Repair HP Steam leak on unit 1	CGS	Oct
Emergent247 Covert Normal O&M	$ 200	Due to unforseen expenditures like Asset Mgmt Agreement with USPG, Software agreements and acquisition costs (not capital) we are in need of funds to support on-going day-to-day operations. Eartier this year, funding was returned for PSCR dollars and the $125M challenge.	CGS	Oct
Emergent246 Covert Fall Outage	$ 300	Need funding to cover the fall outage. Dollars were returned earlier this year for the $125M initiative under the assumptions that there would be enough funding under Normals to cover MM fall outage. Due to unforseen expenditures, those funds are no longer available.	CGS	Oct
5971 Hydros License Initiatives	$ 50	Increase in cost related to fixed payments forcing us to go over budget. This $50,000 puts us back to our original amount before the cut.	Hydro	April
Hydro - Hardy Units 2&3 Expansion Joint Leak Repairs	$ 112	The Hardy Generation Station Units 2&3 have expansion joints that have significant water leakage, causing our sump pits to fill up very rapidly <8 hours requiring pumping. However, due to the Mio oil spill, we cannot run the sumps in automatic. If we get a high sump alarm, we need to call in operators to manually pump down the sump. We have tightened up on the packing as far as we can, and did not solve the issue. Therefore, we need to repack the joints, we have contracted cost of $90,000, our internal team is just not skilled enough to complete this evolution.	Hydro	Feb
Hydro Tippy Headquarters Maint	$ 64	Headcount misaligned during budgeting transfering from Croton.	Hydro	Feb
Hydro - Croton - Hazardous Waste Removal	$ 20	Hazardous waste removal from Croton basement.	Hydro	Feb
Hydro - Croton Station Unit 4 Collector Ring Repairs	$ 24	Appr BUG	Hydro	Jan
9924 Hydro Croton Headquarters Maint	$ 21	Funding needed to cover oil sheen clean up at Croton	Hydro	July
9761 Hydro Croton Headquarters OPS	$ 11	The renewables safety action team has a human struggle elimination campaign ongoing. As a part of the campaign an ergonomic evaluation was completed at Hardy. It was noted that the penstock access covers and oil tank covers were a major safety concern due to the weight of the covers. This funding will be used to replace the covers to a more ergonomic friendly material that will still maintain their integrity	Hydro	July
5973 Hydros Annual FERC Dam Safety Requirements including Part 12 Inspections	$ 39	This is to replace the downstream dive that was determined to not be safe based on Diver Dan's past experiences. Also something we want to start utilizing more (ROV), with potential for CEC purchasing a better unit for in-house. However, we have limited time this year to complete the inspection because it's tied with our 2023 Part 12; hence, will need contractor support this year.	Hydro	July
5960 Hydros Concrete Repairs	$ 35	Fisher is currently working on Croton Bear Trap repairs. After removing vegetation from the bear trap, water was observed leaking from some of the joints. In order to seal the joints, they need to stop the leaks first with chemical injections. They also observed a few other old patch areas that are failing and would be beneficial to repair at the same time.	Hydro	June
Hydro - Croton Shoreline Structure Compliance	$ 20	Funding needed to cover additional cost of getting landowners to sign easements so that we will be in compliance.	Hydro	Mar
9928 Hydro Five Channels Headquarters Maint	$ 16	Charges from the Foote Auto Voltage Regulator capital project were deemed to be O&M, project was commissioned twice caused by a premature failure. Funding needed to cover the transfer in costs.	Hydro	Nov
Emergent279 Hydro - Loud unit 1 cracked shifting ring	$ 25	The loud unit 1 shifting ring was found to be cracked during the periodic inspection . The crack will eed to be stitched together in the field before the unit can be rewatered and returned to service. Costs are for machine shop to come to site, perform the stitching, as well as confined space rescue. If the work is not compeilted, the unit can not be rewatered or retruned to service due to risk of a ring failure and uncontrolled release of water into the plant.	Hydro	Oct
5917 JGS Base Outage-Boiler Plant Equipment	$ 170	Request of funding for Fall outage work scope. Duct Burner Ignitor Sleeving - $60k. CCW Heat Exchanger Cleaning - $64k. Glycol Heat Exchanger Washer Installation - $6.2k. LM1-6 MTGB Panel Access Mods - $22k. Lube Oil Cleaning - $10.5k. STG Bearing Inspect/Repair (TIL) - $25k	JGS	Aug
6046 Jackson Capacity Factor Used For Water and Chemicals	$ 200	Request of funding to cover projected water spend for August 2023. Current forecasted dollars is $75k. Total projected spend $275k	JGS	July
JGS Base Outage-Boiler Plant Equipment	$ 100	Request of funding.	JGS	Mar
JGS Plant Chiller Fouling - MM	$ 40	Request of funding.	JGS	Mar
Jackson Long Term Service Agreement - Running Maintenance Contract -MM	$ 100	Request of funding.	JGS	Mar
JGS 8 Condenser Cleaning and Eddy Current Testing	$ 26	Set funding back to zero. Funding was taken twice in January reductions.	JGS	Mar
JGS 9 Condenser Cleaning and Eddy Current Testing	$ 26	Set funding back to zero. Funding was taken twice in January reductions.	JGS	Mar
5918 JGS Non-LTSA Turbine and jet engine repairs	$ 100	Request of funding. GT7 S17, EGV 1, EGV 2, Stator Segment Damage Repair - Hook Fit Damage	JGS	Sept
JHC 2 Forced Outage Funding	$ 67	Requesting site keep returned funds from the completed Recycle Slurry Storage Tank to help maintain small forecast for future forced outages	JHC	Feb
JHC1 Forced Outage Funding	$ 67	Requesting site keep returned funds from the completed Recycle Slurry Storage Tank to help maintain small forecast for future forced outages	JHC	Feb
JHC3 Forced Outage Funding	$ 67	Requesting site keep returned funds from the completed Recycle Slurry Storage Tank to help maintain small forecast for future forced outages	JHC	Feb
JHC 3 Environmental SCR UBAS	$ 124	Due to budget cuts only 1 reactor cleaning was left in plan however known that two more are required. JHC has mitigated approximately 40k however request is to fund the balance of two reactor cleanings.	JHC	Mar
JHC - fund program shortfalls	$ 335	Various program shortfalls - funded via waste elimination returns	JHC	Mar
Emergent - JHC 3 Boiler Leak	$ 350	Approved emergent via email on 5/16	JHC	May
9645 JHC3 Forced Outage Funding	$ 481	**This is an emergent request** JHC 3 will need to take a forced outage to complete backpass cleaning in the reheater section to eliminate a 40MW derate and eliminate the potential for a reheat tube leak due to accelerated flyash erosion. Aside from the back pass cleaning, the furnace will be deslagged, 3 boiler safety valves will be repaired, and work to repeair multiple non-return check valves will be completed. There is other high priority balance of plant work that will be completed.	JHC	Nov
5460 JHC FH Dumper Outage Repairs	$ 50	From Dan Balt: Using quote from the last time that this cable was replaced as a preventative measure in 2018. Emergent repair - this particular component was on a 5 year replacement cycle to prevent this exact event from happening. These are the main reasons why we need to pursue getting a replacement and why the Positioner is important to the operation of the Unit 3 Dumper: -It allows for automated car unloading, nearly eliminating operator error and judgement, which has in the past caused significant car damage. oCar repairs can be greater than $100k oCan also cause additional damage to the Unit 3 Dumper Table and drive. -When the Positioner has been out of service, many times, Operators use the Retarders (Dumper table component) to stop train movement when moving cars across the table. oPositioner eliminates the manual use of the Retarders. oDamage to any of the 4 Retarders can cost up to $30k each if the whole assembly were in need of replacement.	JHC	Nov
5535 JHC FH Normal Maintenance	$ 43	Funding depleted in FH normal maint for track repairs. Emergent need to replace track switch heaters after fall inspection.	JHC	Nov
Emergent210 Campbell Battery Energy Storage (BESS)	$ 150	Funding is needed to complete engineering ($85k) and submit a MISO deposit ($65k) to install a 750MW/3000MWh BESS at the Campbell site.	JHC	Sept
Emegent242 JHC Misc MM over runs	$ 93	Request to use Dumper Outage MM funds to cover site MM over runs. Give back of Dumper outage would net this request to zero.	JHC	Sept
9210 Karn Results	$ 150	With the closure of Karn 1&2, D.I. Water Trailer will be required for Karn 3&4. Estimating $25K per month July - December. $150,000 total.	Karn	July
Emergent - Karn 3 Boiler Leak Repair	$ 20	Repair K3 Boiler leak to make unit available	Karn	Oct
13294 LPS Commons Gen Circuit Breaker Pumping Pole Maint	$ 87	Project True up transferring funds from Fish Barrier Net Installation project.	LPS	April
9822 LPS Maintenance Demand Break/Fix (67.7%)	$ 72	Requesting funds from MM project returns to cover over runs in Maint spending. The over runs are related to funding being pulled earlier in the year.	LPS	Aug
LPS National Compressor Hanwha Service DAC 3/4	$ 15	New compressors were installed and went into service late 2021. There was not major maintenance project setu p to account for their required service intervals to maintain the equipment. The changelog is to support alignment of MM funding to maintain the under warranty compressors while we work to create a MM project to account for this maintenance going forward.	LPS	Feb
13294 LPS - Commons Generator Circuit Breaker Pumping Pole Maintenance	$ 9	Funding needed to complete install of pumping poles. This will offset some of the return from the downlever earlier in the year.	LPS	June
LPS U4 Governor oil pump replacement	$ 36	We are seeing indication that the governor oil pump installed November 2022 is failing in the same fashion it was replaced in November. Gen Planning is working with the pump vendor on a root cause. This will be an O&M replacement / repair as the installed unit has not been in service over 24 months.	LPS	Mar
LPS County Road Commission repair	$ 13	Drain repair and cleanout on the lakeshore drive bridge that we must have the county road commission repair.	LPS	Mar
9822 LPS Maintenance Demand Break/Fix (67.7%)	$ 38	Oil Sheen clean up came in higher than planned.	LPS	Nov
13294 LPS Commons Generator Circuit Breaker Pumping Pole Maintenance	$ 86	This project had a reduction earlier in the year, part of the company challenge reductions. The parts for this project had already been pulled out of stock, causing this project to be over budget. We were unsuccessful in checking the parts back in stock. Funding will get the project back on budget.	LPS	Nov
Emergent - LPS oil sheen recovery	$ 79	Emergent email on 10/2: Due to the recent ICS at Ludington related to the oil sheen recovery plan, we have an emergent O&M changelog request for $79k in CE Major Maintenance (MM) for the clean-up and the baffle wall (not determined to be capital).	LPS	Oct
10547 ZGS 345kV Bkr 177 277 Maintenance	$ 15	Project pushed to 2024 however our ask is to keep $15K total in the 2023 budget for our agility to address/mitigate potential risks as these moving schedules may allow. We would like to perform the latch checks on the 299 in spring (using this funding) to mitigate risk of pumping on and potential damage to the 18 GSU prior to the 299 breaker replacement fall of 2024 (we performed similar on 199 when mobiles were landed in spring 2022). Note from Saroni Brahma	ZGS	April
6601 ZGS Base Outage Funding-Boiler Plant Equipment	$ 230	No funding for fall outage we have returns to offset all but 55k of this request. Please see Jason's note below regarding needs. We have several valves that need repaired in the facility. Both HRSG main steam attemperators, HRSG 2A hp steam dump and 2A CRH main iso valve that has a bad packing leak. There is also a need for some contingency money for discoverable items, line supervisor OT for outage support and operator OT for FIN evolutions. All items are high risk rated.	ZGS	Aug
Zeeland Generating Station - Operator Bonus	$ 66	Request to use changelog giveback for the HP Economizer Feed Reg Valve overhaul for the Zeeland bonus. Bonus was not accrued due to misunderstanding on timing of cancellation of bonus program.	ZGS	Feb
ZGS - Bus Suppt & Services Non Labor	$ 13	Use Zeeland give back of Economizer Feed Reg Valve overhaul to cover a portion of training needed to prepare newer staff to take on responsibilities of those close to retirement. Total need 35k however site to attempt to mitigate balance.	ZGS	Feb
6601 ZGS Base Outage Funding-Boiler Plant Equipment	$ 87	May downlever higher than balance of plant funds in project. Need to replenish site with overage.	ZGS	June
6601 ZGS Base Outage Funding-Boiler Plant Equipment	$ 30	Jason Ricketts - We have discovered a few MM outage items that have caused our base outage funding needs to grow to approximately $300K. Those items are the RO carbon filters have extreme bio fouling and need to have all of the media replaced. We also had 10 HRSG drain valves fall out and need to be chopped and swapped. At this time, I estimate that we will need a $30K change log to cover	ZGS	Nov
6601 ZGS Base Outage Funding-Boiler Plant Equipment	$ 90	Scope covered internally with itsa give back. Latest outage numbers due to inline drain valve repairs. Planning and inspections still underway and potential risk still unkown and will be disclosed with inspection outcomes.	ZGS	Oct
Totals =	$ 4,866			

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-201 (RTB-23)
Page: 3 of 4
Witness: RTBlumenstock
Date: October 2025

Consumers Energy Company
Generation O&M Expense
For the Years 2022 through September 2025
($000's)

2024 Emergenent Reliability Expense

Description	Cost (000's)	Details	Month	Site
Gen Ops - Covert Steam Sampling System Repair	$ 25	True-up of project costs	nov	COS
PP-10218 Covert U 3 HP Steam Leak Repair	$ 45	True-up of project with funds from the NERC Relay/DC Testing Compliance & Capacity Factor Projects.	sep	COS
Gen Ops - Covert 2B Circulating Water Pump O&M	$ 55	Additional cost of installation of modified pump.	nov	COS
Emergent35 Covert 1A Circulatine Water Pump	$ 60	Need funding for repair of 1A Circulating Water Pump	Feb	COS
12825 Covert - HEPS/FAC/DAST Inspections	$ 65	Need for developing plan and drawings.	Jan	COS
Emergent138 Covert ABT Discharge Line Repair	$ 65	The leak is below ground, and we are expecting to do the excavation. We discovered the leak when water started bubbling up. The biggest concern is that the temporary discharge line goes across the road where there is a potential for it to be damaged. We have to dig down several feet to find and repair the leak. This needs to be done prior to the fall outage.	June	COS
Emergent328 Overhaul 2A circ water pump	$ 70	Brokerfix	Jan	COS
Emergent36 Covert 1B Circulating Water Pump	$ 75	Need funding for repair of 1B Circulating Water Pump	Feb	COS
6263 DEK3-4 Periodic Outage Major Maintenance	$ 100	Request of funding to replace $100k of $250k down lever pulled in May 2024.	June	COS
Gen Ops - Covert Unit 1 Steam Turbine Valve Repair	$ 121	True-up of project costs.	nov	COS
Covert 1B Circulating Water Pump	$ 127	True-up of 1B Circulating Water Pump project with funding from LTSA	Oct	COS
Gen Ops - Covert Unit 3 HRSG Harp Repair	$ 130	True-up of project costs due to discovery of broke fix	nov	COS
Covert 1A Circulating Water Pump	$ 137	True-up of 1A Circulating Water Pump project with funding from LTSA	Oct	COS
Gen Ops - Covert Unit 3 HRSG Harp Repair	$ 140	Additional need for funding due to discovery of brokefix and extended crane rental fees	nov	COS
Gen Ops - Covert Fall Outage	$ 165	True-up of project costs due to discovery broke fix and valve purchase $20k.	nov	COS
PP-10219 Covert Fall Outage	$ 170	Additional funding needed to address issues at the Covert Generating Station during the fall outage.	sep	COS
Covert 2B Circulatine Water Pump Modifications	$ 187	Need to removal, modify and install the 2B circulating water pump.	Oct	COS
Covert - 12823 Covert - Base Outage Funding MM -Boiler Plant Equipment	$ 200	Need to write PO's for CMI to do inspections on all 3 units. No funding left for fall outage due to circ water pump repairs.	Aug	COS
Emergent67 Covert SCR Cleanings	$ 250	Asking for funding to complete necessary SCR cleanings in 2024 for all 3 units.(note we cut this funding in 2023 and DP data shows it is required now in order to mitigate summer derate)	Mar	COS
EMERGENT - Covert Unit 1 Steam Turbine Valve Repair	$ 250	A recent inspection at Covert identified a crack on a high-pressure control valve bushing. These can become a very serious or dangerous issue and definitely take the unit offline when it fails. We need to address this issue immediately at our earliest outage of opportunity which is this fall to avoid safety and forced outage issues.	sep	COS
Emergent121 Covert 2B Circulating Water Pump O&M	$ 270	Need this pump replaced to return Unit 2 to full operation. $150k for the replacement pump itself from Kennedy since Dubric can't get us one in time (not covered under warranty). $120k for install, removal and modifications.	June	COS
12823 Covert - Base Outage Funding MM -Boiler Plant Equipment	$ 300	Request funding for Spring Outage for Oil flushes and SCR Cleanings pushed from 2023.	Feb	COS
Emergent123 Covert Unit 3 Reheat Crossover Pipe Project	$ 480	Covert Unit 3 experienced a leak in the HRSG reheat crossover pipe at the top of the unit. The location of the leak is 4 or 5 feet downstream of the reheat attemperator. Cut the old attemperator assembly out and rigg it down, fly the new assembly up into place, fit, weld, heat treat, NDE, and reinsulation on Unit 3 plus crane support.	June	COS
Covert - Emergent151 Covert Unit 3 Dropped Reheat Header Repair	$ 500	Work required to remove broken harp supports, provide temporary lifting gear for rigging and support steel to lift the harp to the original design location, lifting the harp, and repair and reinstallation of the harp supports.	Aug	COS
Emergent46 Croton 3 head plate crack repair	$ 10	Croton 3 Head plate cracked can leak contaminants back into river (Emergent/Regulatory)	Jan	Hydro
Emergent52 Alcona road and parking lot repair	$ 19	There is a 100 year centennial celebration this year at Alcona, and we will be hosting a public event at the site and we need to fix these areas for public safety.	Mar	Hydro
Emergent141 Hydro - Hodenpyl Rental Air Compressor	$ 27	Hodenpyl air compressor has failed. We need funds to cover a one month rental for air compressor. Transferring funds from Croton to cover.	July	Hydro
5971 Hydros License Initiatives	$36	Bruak Fix The inner upweller at Croton was found on the trash rack Mobiety to retrive, inspect repair and return upweller to proper location.	July	Hydro
Emergent51 Webber Debris clean-up	$ 40	Athor the recent runoff event, there is a large accumulation of woody debris we have to remove from the intake side of the Webber Hydro Station.	Mar	Hydro
Emergent352 Loud Left Spillway Wall Sinkhole Remediation	$ 50	Left Wall Sinkhole discovered during inspection in 2023. Repair needed to keep dam in safe operating condition. We will have to notify FERC of ground disturbance activities. Planning on using concrete/cement type materials to fix the issue. Scope is a little more than typical concrete project which is why we split it out but transferring funds from concrete repairs to cover.	Jan	Hydro
Gen Ops- License Int	$ 50	Review of water Temp Control Tech at Hardy and Croton (15K) & During the Archaeological shoreline inspection a new site was discovered. It required extensive work above the original estimate (35K)	nov	Hydro
Emergent114 Rogers Unit 1 Resurface Bearings	$ 63	Rogers Unit 1 needs some bearings replaced. It requires us to pull the turbine shaft to complete.	May	Hydro
5971 Hydros License Initiatives	$ 80	Funds needed for a cultural resource site inspection for the Manistee, Muskegon and Au Sable Rivers.	Feb	Hydro
5971 Hydros License Initiatives	$ 88	Shoreline study increased in cost more than we planned. Transferring funding from Alcona Unit 1 Concrete Repairs to cover.	May	Hydro
Emergent60 JGS Chiller Condenser Cleaning	$ 40	Tube cleaning is a necessary maintenance activity to maintain efficient heat transfer in the heat exchanger of the chiller. Tube cleaning needs to be performed annually to remove deposits and scale left behind by water. Inefficient heat exchange causes loss of efficiency and performance of chillers. The 4-chiller arrangement at the plant is marginal during the hottest periods of the year. Fouled heat exchangers make their heat transfer capability that more of a challenge. Chillers expend up to 30 percent in additional energy due to inefficiencies and poor maintenance. The more a chiller becomes fouled, the more energy it will consume and increase O&M costs.	Mar	JGS
Gen Ops - JGS Drift Eliminators	$ 54	Drift Eliminators material purchase. The drift eliminators are used to minimize water droplets and moisture going to the inlet plenum and on to the gas turbine as part of the inlet air to the turbine. The existing drift eliminators in the LM6000 filter houses are the original ones and are brittle and falling apart. Recent cooling coil performance testing by EPTS identified an average cooling coil efficiency loss of 15.9% from expected which is a reduction of total plant output of 2.85 MW under summer GVTC conditions. $100K expense in 2025 for the removal/replacement of the drift eliminators and cooling coil cleaning.	nov	JGS
12813 Jackson 9 Generator Stator Corona Repair	$ 70	GE provided us with a schedule that supports the fall's planned outage window to accomplish the ST9 generator corona repair. However, the window for AGTS would be need to be three days versus the six days AGTS outlined in their proposal and their PO was based on. To not affect the outage, we've gotten an updated proposal from AGTS which would complete their work in three days by doing two shifts. This would require a $51,284 MoC to their current PO.	July	JGS
5917 JGS Base Outage-Boiler Plant Equipment	$ 70	Request of funding. STG Bearing Work. Both bearing metal temperature thermocouples for the Unit 9 high pressure steam turbine have failed (i.e., reading faulty values). These thermocouples are critical indications that are part of the unit's turbine supervisory instrumentation that protect the unit from a bearing failure related to bearing wear by detecting temperature increase associated with bearing babbitt degradation. They need to be replaced at the next unit outage when faulty. A compensatory measure (i.e., monitoring bearing oil drain temperatures) is in place until the instrumentation can be restored and is not intended to be a long term action. Associated with WO 41891935.	May	JGS
Emergent - JGS Heat Exchange Pate Repair	$ 75	The closed cooling water heat exchangers are fouled & have one or more failed plates. Approved email 3/5.	Mar	JGS
Emergent32 JGS-Install Grounding Cables- North Switchyard fence	$ 83	During recent walkdown with CE Substation group, it was identified that the North section of the switchyard fence lacked grounding. Due to the potential safety risks this poses, the plant needs to install permanent grounding straps to each section of fence in order to protect people and equipment should an electrical failure occur that energizes the fence and to safely discharge static electricity build up. Current conditions do not provide a safe path to ground for this section of fence.	Jan	JGS
12813 Jackson 9 Generator Stator Corona Repair	$ 90	Request of funding to cover project gap for execution of work. Quotes for work higher than originally anticipated.	May	JGS
JGS Base Outage PP-10097	$ 150	Full outage discovery items.	Oct	JGS
6046 Jackson Capacity Factor Used For Water and Chemicals	$ 200	Request of funding to lower gap in full year expected spend.	July	JGS
JGS - 5917 JGS Base Outage-Boiler Plant Equipment	$ 225	Request of funding. HRSG 5 Tube Leak. Economizer leak identified on HRSG5 requiring repair to return the unit to service and restore station back to full capacity – associated derate of 70MW for the duration of the outage.	Aug	JGS
6263 DEK3-4 Periodic Outage Major Maintenance	$ 45	Request of funding for outage work scopes/Karn 3&4 Reliability.	Mar	Karn
6232 Karn 3&4 Maintenance - Maintain-Roof Repairs	$ 45	Request of funding. During Emergency Roof Leak Response visit on Febnuary 13, 2024, we identified several roof	May	Karn
6230 Karn 3&4 Maintenance - Demand	$ 70	Request of funding. Water well leak repairs/chemical spill.	June	Karn
6230 Karn 3&4 Maintenance - Demand	$ 100	Move of Major Maint. Outage funding to Normals for forced outage work scopes including residual oil heater repair.	Mar	Karn
Karn 3&4 Louver Repairs	$ 100	This request only covers the scaffold costs. Anticipate utilizing plant resources to complete the work. There are approximately 10 to 12 louvers per unit that are inoperable, some stuck open allowing cold air to get into the plant during the winter. This caused freezing issues last winter affecting unit availability and even forced a must run condition when not necessarily economic for our customers. These issues occurred despite plant heating in service. Significant scaffolding over open areas (not accessible with lifts or JLGs) is required.	sep	Karn
10770 DEK3 DA and DA Storage Tank Inspection 2024	$ 115	Request for additional funding needed for outage.	Mar	Karn
10786 DEK4 DA & DA Storage Tank Inspection 2024	$ 115	Request for additional funding needed for outage.	Mar	Karn
8663 Karn FH Oil	$ 120	Karn Fuel Handling - Request for Fleet charges	July	Karn
Karn 4D Vac Pump Control Wiring	$ 160	Control wiring for K4D Vac Pump	Oct	Karn
6265 K34 Opacity Critical Equipment repairs	$ 180	Karn 3 – $80k MM (Refurbish 2 DA valves)	May	Karn
6230 Karn 3&4 Maintenance - Demand	$ 230	Karn Maintenance - Request for Fleet/Maint expenses due to forced outages/OT	July	Karn
Covert - Emergent153 Covert Emissions Testing	$ 250	Emission testing at Covert	Aug	Karn
Gen Ops- Ludington Unit 6 Trash Rack Repairs	$ 13	Repairs for Unit 6 trash rack repairs cost more than estimate.	nov	LPS
Ludington Unit 6 Trash Rack Repairs	$ 13	Funding needed because repairs needed for the trash rack were more extensive than originally anticipated.	Oct	LPS
Emergent99 LPS - NERC relay testing	$ 15	Additional funding needed to finish NERC relay testing. Transferring funds from Wicket Gate repair to cover.	May	LPS
Gen Ops- LPS Unit 3 south trash rack Dive and Repair	$ 20	Repairs to Unit 3 south trash rack cost more than estimate.	nov	LPS
PH-80089 LPS - Unit 4 & 6 Trash Rack Uplift Study	$ 26	Funding needed to complete the study	sep	LPS
B-PH-00168 LPS Unit 3 South Trash Rack Dive and Repair	$ 36	Based on an inspection of the LPS Unit 3 south trash rack on 8/29, additional funding is needed to perform emergent repairs and a dive to remove debris from the sill slot during the Unit 3 pumping outage this fall.	sep	LPS
Emergent28 Unifier Maintenance Fee - Ludington Plan	$ 37	Funding needed to cover Unifier Maint. Plan	Feb	LPS
LPS - 13520 LPS - Main transformers 6 & 12 year maintenance	$ 41	Outage scope includes two transformers for this year but we only have the budget for one transformer. By doing the second one this year it gets us caught up(should have done one last year 2023), it will also save us money with the contractor. Using funding from other MM projects coming in under budget.	Aug	LPS
Emergent80 LPS Repair damage to U1 Gate	$ 50	Emergent repair on Unit 1 wicket gate cavitation	Mar	LPS
Emergent31 LPS Station Drainage Sump and Oil/water Separator Cleaning	$ 54	Requesting funds be transferred from WE. Funds needed to clean the oil/water separator and station drainage sump at LPS during the all-unit outage in May 2024.	Feb	LPS
LPS Unit 1 High Speed Event	$ 75	Funding needed for parts to fix Unit 1 after high speed event		LPS
Emergent60 LPS Warranty Unit 5 Runner Blade Crack Repair	$ 132	We have discovered a crack in the pump discharge / turbine inlet side of runner blade 9 where it meets the runner band. The crack exceeds allowable criteria set by Toshiba for this area (which is about 3/8" in length) and occurred in a designated "No Weld Zone" per Toshiba design drawings. Due to the size and location of the crack, repair is necessary immediately. This repair will require specialized welding practices and skilled resources to perform.	Mar	LPS
LPS Turbine Oil	$ 332	The current turbine oil condition across the units shows a degraded additive package with respect to anti foaming performance. This degraded condition can lead to additional equipment wear and potential damage if continued degradation is observed. Per analysis a 50% oil replacement and mixing can return the additive package to specification and restore operating life of the turbine oil across the units to approx 20 years or more as advised by the manufacturer. The money being requested will cover the purchase of 40,000 gallons, which is enough for all 6 turbines plus 1000 gallons to mix with the extra oil in the clean oil tanks.	nov	LPS
6639 ZGS NERC Relay and DC Testing Compliance - missing from AS view	$ 40	Pulling 40k from #0227 Excitation and Isolation to cover NERC testing that was intended to be completed in 2023 however couldn't due to outage changes.	Feb	ZGS
Emergent - Zeeland - GT1B compressor blade crack	$ 425	Approved emergent on 10/9/2024	Oct	ZGS
2024 Totals =	$ 8,346			

Site	Spend '$000
Covert	3,987
Hydro	463
Jackson	1,057
Karn	1,530
Ludington	844
Zeeland	465
Total	8,346

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-201 (RTB-23)
Page: 4 of 4
Witness: RTBlumenstock
Date: October 2025

Consumers Energy Company
Generation O&M Expense
For the Years 2022 through September 2025
($000's)

January -September 2025 Emergenent Reilability Expense

Description	Cost (000's)	Details	Site	Month
BESS - Airpark - commissioning expenses	$ 200	Team has approached asset strategy needing approx $200k to commission and finalize airpark	BESS	Jan
Gen Ops - CGS HEPS/FAC Emergent Request #2	$ 535	This is a true up to the original request for Covert HEPS discovery/repairs and since this is a significant increase we would like BUG and VP approval to proceed. We are building an offsetting strategy of downlevers that we will bring to the April change log to offset these requests. This request is for $535k of additional O&M to finish the repairs.	CGS	April
Covert - auxiliary boiler leak repair	$ 46	EMERGENT approved email 8/11/2025	CGS	Aug
Gen Ops - Covert Software Maintenance	$ 78	Moving funds from Gen Ops Common to fund Covert SureService software maintenance agreement	CGS	Feb
CGS - 1. Cable Vault Tray Supports – Failed	$ 68	This has been entered as a threat to generation (cable tray failure could compromise conductors and result in unit trip) – seeking planning and funding in 2025	CGS	Jan
Covert - Site Diesel Generators– air inlet louver drive motors failed for both engines	$ 20	Louvers are supposed to open automatically upon engine start to ensure sufficient air for the engine and turbo chargers	CGS	Jan
Covert - Ammonia Fan Rebuilds	$ 93	moving 2025 funds to O&M for fan rebuild of the old design.	CGS	Jan
Covert HEPS & FAC - Emergent Changelog	$ 1,182	The team has evaluated whether these are "must do" vs potential deferral repairs. The plan includes the must do repairs. This project needs immediate approval to mitigate outage extensions.	CGS	Mar
EMERGENT - Covert Unit 1 Steam Turbine Valve Repair	$ 250	A recent inspection at Covert identified a crack on a high-pressure control valve bushing. These can become a very serious or dangerous issue and definitely take the unit offline when it fails. We need to address this issue immediately at our earliest outage of opportunity which is this fall to avoid safety and forced outage issues.	CGS	Sept
PP-10219 Covert Fall Outage	$ 170	Additional funding needed to address issues at the Covert Generating Station during the fall outage.	CGS	Sept
NEW - Covert HRSG Cycling Assessment	$ 33	Funding needed to complete a cycling assessment of the HRGSs at Covert. The study will look at current startup and shutdown procedures and practices to determine if any of these factors may induce cycling-related damage.	CGS	Sept
NEW - Covert Circ Pump Vibration Analysis	$ 62	The analysis being performed is highly technical and required to determine the root cause of our historical vibration issues with the pumps at Covert.	CGS	Sept
PP-10218 Covert U 3 HP Steam Leak Repair	$ 45	True-up of project with funds from the NERC Relay/DC Testing Compliance & Capacity Factor Projects.	CGS	Sept
Gen Ops- Ausable River Queen Clean up	$ 100	Cleanup costs related to the Ausable River Queen incident. USEPA holding us accountable on some of the invoices. Plan is to recoup money from owners but unsure of timeline and plan.	Hydro	April
Hardy spill tube aeration flow meters and lighting	$ 55	•Modify the lighting circuit that lights the caverns by spill tubes 2 &3 to keep it out of the water running down the wall that has faulted that circuit. This is more a safety issue, there is no light down there but your flashlight when trying to complete maintenance or daily operation duties in those areas.	Hydro	Aug
Emergent - Foote Downstream Concrete Repair	$ 205	Emergent - The hydro team requires $205k of O&M to finish this work. In our reviews we found out this project has been progressing and these are actual costs. We explored multiple options including stoppage of work. The decision to proceed now will save the customer approx. $30k on demob/mob of the crane. The majority of the work is completed.	Hydro	Jan
Webber voids were discovered	$ 400	voids were discovered under the left side of the spillway tumble bay slab	Hydro	Jan
Mio Spillway hollow chamber leakage sealing	$ 110	Leakage has been known, 2024 dive inspection found source. Need to repair to prevent sand ballast washout from the hollow chamber - dam stability	Hydro	Jan
Mio Spillway Hollow Chamber repair	$ 50	The divers discovered additional work needed. If work is completed now it would save remobilizing the contractor. Risk of not doing the work is loss of fill(washout) and destabilizing the powerhouse/spillway.	Hydro	May
Croton Unit 1 Generator	$ 80	There is a broken bus bar between the collector ring and the rotor poles on the Croton Unit 1 Generator.	Hydro	May
JGS MM Base Outage	$ 325	Funding request to execute Fall outage needs-includes emergent repair to fire protection header- safety issue.	JGS	Aug
JGS- Duct Burner Iso Valves	$ 160	JGS Duct Iso Valves. Request for install monies.	JGS	Aug
JGS - Cooling Tower Repairs	$ 271	This is 1st & 2nd quarter immediate issues identified during the ICT level 2 inspections in the fall 2024 outage. Materials is being purchased 4th quarter 2024 and fall outage work scope will be done thru levers/flex or change log processes	JGS	Jan
JGS - LM Filter House Drift Eliminator Repl and Cooling Coil Cleaning	$ 50	The existing drift eliminators in the LM6000 filter houses are the original ones and are brittle and falling apart. Recent cooling coil performance testing by EPTS identified an average cooling coil efficiency loss of 15.9% from expected which is a reduction of total plant output of 2.85 MW under summer GVTC conditions.	JGS	Jan
JGS - 480V WavePro Breaker Replacements	$ 75	Work was delayed in 2024 and a portion of the initial funding was utilized to address cubicle modifications due to an identified arc flash risk. These requested funds are to complete the rebuild and installation of the remaining half (quantity: 17) of the 480V breakers.	JGS	Jan
JGS Duct Burner Isolation Valves	$ 140	Funding to replace the duct burner isolation valves on the HRSGs during the Fall outage – ahead of the originally planned Spring 2026 execution. We are continuing to experience valve failures in the field resulting in significant losses in power production. Our recent GVTC testing had poor results which will have significant impact to our 2026 capabilities.	JGS	July
		We are requesting $140k of O&M (cost plus expediting) to purchase replacements for all the failed isolation valves along with remaining carbon steel valves that are at risk of failing	JGS	July
JGS Plant Normals	$ 315	Request for funding. Outside Services in Maint area has been higher than what was provided in budget. (Cooling tower and Chiller work)	JGS	July
JGS MM Base Outage	$ 100	Request for fall outage work scopes. Net with return from water/chemicals.	JGS	July
JGS HRSG 7 Perforated Plate Distribution Wall	$ 150	Request for fall outage work scopes. Net with return from water/chemicals.	JGS	July
Gen Ops-Karn 4 Burner Oil Pump Leak PT-11178	$ 180	Funding request. Net zero request with funding returns from K4 Main Transformer Bladder Replacement & Karn 3 Boiler Waterwall Tube Samples	Karn	April
K3 Station Power Relay (Non-NERC) Maintenance	$ 41	AET for testing of non-NERC relays on Karn 3- Fall outage. Funding was pulled in Feb as part of $50M challenge.	Karn	Aug
Karn B Aux Boiler FD Fan Shaft/Bearing Repair	$ 60	Karn B Aux Boiler FD Fan Shaft/Bearing Repair. Emergent Broke/Fix work.	Karn	Aug
Karn 3-4 Periodic Outage- Fall 2025 Outage	$ 250	Request for Fall outage funding as site does not currently have funding.	Karn	Aug
Gen Ops- Karn GSU Fire	$ 300	Initial ask to fund ICS at Karn for O&M	Karn	Feb
Karn 3 & 4 - FW Heater safety relief testing & setting	$ 40	Components need testing; not suspected to have been inspected before	Karn	Jan
Karn Forced Outage	$ 110	Request of funding. Site does not currently have funding for forced outages	Karn	July
Karn Fire & Transformer Move - Emergent Changelog	$ 2,000	HLI to Transport (1) Transformer by rail from West Olive, MI to Essexville, MI. -$1.2M	Karn	Mar
Karn ICS Additional Costs	$ 3,200	Estimated additional spending needed for Karn, POs written	Karn	Mar
Karn 3&4 Louver Repairs	$ 100	This request only covers the scaffold costs. Anticipate utilizing plant resources to complete the work. There are approximately 10 to 12 louvers per unit that are inoperable, some stuck open allowing cold air to get into the plant during the winter. This caused freezing issues last winter affecting unit availability and even forced a must run condition when not necessarily economic for our customers. These issues occurred despite plant heating in service. Significant scaffolding over open areas (not accessible with lifts or JLGs) is required.	Karn	Sept
Gen Ops - LPS - Unit 2 Penstock Intake Repair	$ 10	Error in calculation going from 100% to 51% in previous changelog, did not request enough funding.	LPS	April
Gen Ops - LPS intake gate slot bubbler orifices	$ 13	The intake gate slot bubbler orifices need to be replaced.	LPS	April
Ludington Fish Barrier Net-Installation, Cleaning, Repairs & Removal	$ 128	Part of it is HDR, looks like their costs are about $10k more per month with their new contract. Part of it is UCC being more attentive about staffing this project. UCC's contract ends November 30, no new contract yet for December's rates	LPS	Aug
LPS Turbine Oil	$ 28	Funding needed for testing and delivery of the oil	LPS	Aug
LPS environmental	$ 43	Environmental allocation came in higher than planned in 2025	LPS	Aug
Emergent - LPS - Unit 1 outage	$ 561	Emergent - Est. repair costs for the LPS Unit#1 Forced Outage due to a Runaway event on 12/4/24.	LPS	Jan
LPS - Unit 4 & 6 Trash rack uplift study	$ 70	Delays in developing the Statement of Work will more likely than not push the field work into January 2025	LPS	Jan
LPS Unit 1 South Trash Rack Repairs	$ 60	Funding, time, and resources for this trash rack repair were used to offset the emergent repair of the Unit 3 south trash rack. Having repaired the Unit 1 south and Unit 3 south trash rack in 2024, we have a better idea of the level of effort needed to effect these repairs.	LPS	Jan
Ludington Fish Barrier Net-Installation, Cleaning, Repairs & Removal	$ 36	Run rate for Barrier net install was higher than planned	LPS	July
LPS IPB Inspection and Maintenance	$ 46	The IPB on MTB1 needs to be cleaned. This was discovered from the MTB1 inspection.	LPS	Mar
LPS Turbine Oil	$ 38	Monthly storage fee required for turbine Oil purchased at the end of 2024. Moving money from normals since the storage fee is hitting the project	LPS	Mar
			LPS	Sept
B-PH-00168 LPS Unit 3 South Trash Rack Dive and Repair	$ 36	Based on an inspection of the LPS Unit 3 south trash rack on 8/29, additional funding is needed to perform emergent repairs and a dive to remove debris from the sill slot during the Unit 3 pumping outage this fall.	LPS	Sept
PH-80089 LPS - Unit 4 & 6 Trash Rack Uplift Study	$ 26	Funding needed to complete the study	LPS	Sept
2025 TOTALS =	$ 12,744			

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-204 (RTB-26)
Witness: RTBlumenstock
Date: October 2025

Consumers Energy Company
Generation O&M Expense
Year over Year O&M Expense
($000's)

		($/1000) Actuals 12 Months Ending 12/31/2017	($/1000) Actuals 12 Months Ending 12/31/2018	($/1000) Actuals 12 Months Ending 12/31/2019	($/1000) Actuals 12 Months Ending 12/31/2020	($/1000) Actuals 12 Months Ending 12/31/2021	($/1000) Actuals 12 Months Ending 12/31/2022	($/1000) Actuals 12 Months Ending 12/31/2023	($/1000) Actuals 12 Months Ending 12/31/2024	($/1000) Projected Bridge Period 16 Months Ending 4/30/2026	($/1000) Projected Test Year 12 Months Ending 4/30/2027
1	**BASE O&M**	**$ 114,090**	**$ 77,719**	**$ 96,814**	**$ 106,821**	**$ 106,195**	**$ 106,818**	**$ 93,864**	**$ 91,052**	**$ 105,324**	**$ 68,705**
	Admin/Generation Commons	$ 1	$ 1,407	$ (3,013)	$ (1,584)	$ (1,173)	$ 4,302	$ 873	$ 3,974	$ 12,121	$ 9,102
	Adjustment					$ -	$ -	$ -	$ -	$ -	$ -
	Alcona (Hydros)	$ 232	$ 215	$ 217	$ 713	$ 728	$ 231	$ 639	$ 980	$ 1,188	$ 990
	Allegan (Hydros)	$ 141	$ 240	$ 212	$ 758	$ 766	$ 183	$ 752	$ 664	$ 1,043	$ 826
	Battery					$ -	$ -	$ 30	$ 405	$ 622	$ 1,317
	Cadillac (Solar)	$ 47	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ -
	Campbell	$ 27,873	$ 22,075	$ 39,179	$ 33,492	$ 37,751	$ 36,060	$ 34,858	$ 33,333	$ 16,896	$ -
	Circuit West (Solar)	$ 42	$ -	$ -	$ 18	$ -	$ -	$ -	$ -	$ -	$ -
	Cobb (Classic 7)	$ 61	$ 271	$ 58	$ 124	$ 49	$ 751	$ 34	$ 42	$ -	$ -
	Combustion Turbines	$ 775	$ 702	$ 298	$ 5	$ -	$ -	$ -	$ -	$ -	$ -
	Cooke (Hydros)	$ 191	$ 197	$ 211	$ 643	$ 754	$ 209	$ 683	$ 804	$ 731	$ 455
	Covert	$ 11,943	$ -	$ -	$ -	$ -	$ 4	$ 5,196	$ 6,813	$ 9,923	$ 6,934
	Croton (Hydros)	$ 1,743	$ 5,778	$ 2,026	$ 969	$ 1,055	$ 2,507	$ 1,431	$ 1,366	$ 1,368	$ 1,274
	Electric Grid Integration	$ 17,846	$ 9,725	$ 5,475	$ 13,873	$ 15,248	$ 16,780	$ 11,276	$ 10,118	$ 15,682	$ 12,111
	Five Channels (Hydros)	$ 1,314	$ 1,449	$ 1,354	$ 708	$ 790	$ 890	$ 717	$ 874	$ 920	$ 678
	Foote (Hydros)	$ 247	$ 285	$ 269	$ 644	$ 688	$ 246	$ 614	$ 702	$ 983	$ 29
	GVSU (Solar)	$ 118	$ 220	$ 141	$ 122	$ -	$ -	$ -	$ -	$ -	$ -
	Hardy (Hydros)	$ 283	$ 335	$ 375	$ 886	$ 910	$ 347	$ 836	$ 645	$ 2,268	$ 1,782
	Hodenpyl (Hydros)	$ 220	$ 223	$ 198	$ 647	$ 641	$ 266	$ 708	$ 822	$ 1,930	$ 1,698
	Hydro Commons	$ 1,505	$ 383	$ 199	$ (3,183)	$ (3,123)	$ 760	$ (2,698)	$ (3,494)	$ (6,040)	$ (4,498)
	Jackson	$ 4,725	$ 3,634	$ 5,890	$ 5,569	$ 6,219	$ 2,851	$ 5,860	$ 5,806	$ 7,746	$ 6,000
	Karn	$ 22,492	$ 19,183	$ 29,970	$ 36,913	$ 28,482	$ 27,039	$ 16,554	$ 11,139	$ 14,903	$ 11,589
	Loud (Hydros)	$ 205	$ 198	$ 190	$ 604	$ 690	$ 201	$ 509	$ 540	$ 826	$ 674
	Ludington	$ 4,909	$ 1,661	$ 4,929	$ 5,224	$ 4,827	$ 3,360	$ 5,433	$ 6,017	$ 8,382	$ 6,877
	Mio (Hydros)	$ 209	$ 247	$ 216	$ 559	$ 675	$ 197	$ 648	$ 736	$ 897	$ 780
	Muskegon (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ 68	$ -	$ -	$ -
	Mustang Mile (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ 68	$ -	$ -	$ -
	Renewables Development	$ 9,341	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Rogers (Hydros)	$ 190	$ 277	$ 265	$ 651	$ 854	$ 206	$ 734	$ 795	$ 1,303	$ 1,052
	Solar Commons	$ 159	$ -	$ -	$ -	$ -	$ 387	$ -	$ -	$ -	$ -
	Tippy (Hydros)	$ 750	$ 2,611	$ 640	$ 1,020	$ 1,100	$ 759	$ 1,003	$ 1,035	$ 1,645	$ 1,423
	Washtenaw (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Weadock (Classic 7)	$ (240)	$ (53)	$ 0	$ (0)	$ 6	$ 18	$ 3	$ 15	$ -	$ -
	Webber (Hydros)	$ 141	$ 237	$ 224	$ 759	$ 892	$ 195	$ 726	$ 810	$ 1,096	$ 735
	Whiting (Classic 7)	$ (131)	$ (144)	$ 2	$ (0)	$ 85	$ 95	$ 25	$ 45	$ -	$ -
	WMU (Solar)	$ 93	$ 43	$ 36	$ 41	$ -	$ -	$ -	$ -	$ -	$ -
	Zeeland	$ 6,668	$ 6,322	$ 7,253	$ 6,645	$ 7,282	$ 7,972	$ 6,284	$ 6,069	$ 8,889	$ 6,876
2	**Environmental Operations**	**$ 24,258**	**$ 26,133**	**$ 10,485**	**$ 8,595**	**$ 10,092**	**$ 10,802**	**$ 9,225**	**$ 8,539**	**$ 5,110**	**$ 2,045**
	Campbell	$ 12,322	$ 13,659	$ 5,361	$ 4,861	$ 6,364	$ 6,781	$ 6,421	$ 6,513	$ 2,398	$ -
	Covert	$ -	$ -	$ -	$ -	$ -	$ -	$ 72	$ 142	$ 197	$ 152
	Hydro					$ -	$ -	$ 13	$ 11	$ 29	$ 22
	Jackson	$ 371	$ 444	$ 68	$ -	$ 137	$ 146	$ 135	$ 141	$ 208	$ 156
	Karn	$ 10,780	$ 11,433	$ 4,811	$ 3,635	$ 3,389	$ 3,579	$ 2,254	$ 1,488	$ 1,883	$ 1,416
	Ludington					$ -	$ -	$ 116	$ 68	$ 100	$ 76
	Weadock (Classic 7)	$ 336	$ 81	$ 35	$ 44	$ 11	$ -	$ -	$ -	$ -	$ -
	Whiting (Classic 7)	$ 203	$ 196	$ 50	$ 56	$ -	$ -	$ -	$ -	$ -	$ -
	Zeeland	$ 245	$ 320	$ 161	$ -	$ 191	$ 296	$ 213	$ 176	$ 295	$ 223
3	**Major Maintenance**	**$ 17,750**	**$ 44,378**	**$ 19,804**	**$ 25,088**	**$ 31,958**	**$ 32,411**	**$ 15,759**	**$ 28,844**	**$ 40,012**	**$ 32,982**
	Admin/Generation Commons	$ -	$ -	$ -	$ 26	$ -	$ -	$ -	$ -	$ 150	$ 150
	Adjustment					$ -	$ -	$ -	$ -	$ -	$ -
	Alcona (Hydros)	$ 430	$ 916	$ 461	$ -	$ 108	$ 505	$ -	$ 132	$ 25	$ 82
	Allegan (Hydros)	$ 587	$ 669	$ 868	$ 131	$ -	$ 579	$ -	$ 53	$ 25	$ 50
	Battery					$ -	$ -	$ -	$ -	$ 412	$ 126
	Cadillac (Solar)					$ -	$ -	$ -	$ -	$ -	$ -
	Campbell	$ 1,285	$ 10,246	$ 4,558	$ 8,496	$ 14,893	$ 6,503	$ 2,049	$ 1,495	$ 1,192	$ 279
	Circuit West (Solar)					$ -	$ -	$ -	$ -	$ -	$ -
	Cobb (Classic 7)	$ 39	$ 130	$ 103	$ -	$ 38	$ (662)	$ -	$ -	$ 109	$ 82
	Combustion Turbines					$ -	$ -	$ -	$ -	$ -	$ -
	Cooke (Hydros)	$ 520	$ 655	$ 600	$ -	$ -	$ 535	$ -	$ -	$ 407	$ 578
	Covert	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,144	$ 6,553	$ 8,681	$ 7,771
	Croton (Hydros)	$ (777)	$ 697	$ (1,060)	$ 180	$ 122	$ (1,136)	$ 24	$ 69	$ 75	$ -
	Electric Grid Integration					$ -	$ -	$ -	$ -	$ -	$ -
	Five Channels (Hydros)	$ (668)	$ (517)	$ (625)	$ -	$ -	$ -	$ -	$ 52	$ 145	$ 240
	Foote (Hydros)	$ 397	$ 741	$ 386	$ 85	$ 1	$ 496	$ 18	$ 974	$ 165	$ 1,005
	GVSU (Solar)					$ -	$ -	$ -	$ -	$ -	$ -
	Hardy (Hydros)	$ 696	$ 830	$ 686	$ 460	$ 236	$ 873	$ -	$ -	$ 470	$ 873
	Hodenpyl (Hydros)	$ 504	$ 661	$ 421	$ 45	$ 5	$ 531	$ -	$ -	$ 51	$ 143
	Hydro Commons	$ (761)	$ (383)	$ (199)	$ 3,183	$ 3,123	$ (760)	$ 2,685	$ 3,483	$ 6,011	$ 4,476
	Jackson	$ 3,510	$ 6,219	$ 2,716	$ 4,284	$ 3,982	$ 7,546	$ 2,822	$ 5,669	$ 5,712	$ 4,112
	Karn	$ 3,032	$ 7,887	$ 2,953	$ 2,792	$ 3,271	$ 6,898	$ 283	$ 2,027	$ 2,732	$ 1,824
	Loud (Hydros)	$ 361	$ 492	$ 317	$ -	$ -	$ 478	$ -	$ 47	$ -	$ 33
	Ludington	$ 2,621	$ 5,255	$ 2,865	$ 2,962	$ 2,712	$ 4,921	$ 2,533	$ 3,314	$ 5,842	$ 4,708
	Mio (Hydros)	$ 468	$ 742	$ 405	$ 47	$ -	$ 623	$ -	$ -	$ -	$ -
	Muskegon (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Mustang Mile (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Renewables Development	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Rogers (Hydros)	$ 519	$ 890	$ 632	$ 16	$ -	$ 518	$ 29	$ 22	$ 44	$ 108
	Solar Commons	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Tippy (Hydros)	$ 312	$ 213	$ 332	$ -	$ 41	$ 233	$ -	$ -	$ 511	$ 605
	Washtenaw (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Weadock (Classic 7)	$ 72	$ 12	$ 12	$ 15	$ 7	$ 13	$ 30	$ -	$ 108	$ 81
	Webber (Hydros)	$ 644	$ 457	$ 475	$ 57	$ -	$ 942			$ 8	$ 180
	Whiting (Classic 7)	$ 29	$ 46	$ 66	$ 10	$ -	$ 13	$ 22	$ -	$ 73	$ 55
	WMU (Solar)					$ -	$ -	$ -	$ -	$ -	$ -
	Zeeland	$ 3,930	$ 7,522	$ 2,831	$ 2,300	$ 3,419	$ 2,761	$ 3,121	$ 4,954	$ 7,063	$ 5,419
4	**Retention & Separation**	**$ -**	**$ -**	**$ 5,921**	**$ 12,028**	**$ 6,958**	**$ 2,339**	**$ 17,348**	**$ 8,626**	**$ 5,182**	**$ -**
	Campbell	$ -	$ -	$ -	$ -	$ -		$ 15,847	$ 8,626	$ 5,182	$ -
	Karn	$ -	$ -	$ 5,921	$ 12,028	$ 6,958	$ 2,339	$ 1,501	$ -	$ -	$ -
5	**TOTAL O&M**	**$ 156,097**	**$ 148,231**	**$ 133,024**	**$ 152,533**	**$ 155,204**	**$ 150,031**	**$ 118,848**	**$ 128,434**	**$ 150,445**	**$ 103,732**
	Admin/Generation Commons	$ 1	$ 1,407	$ (3,013)	$ (1,558)	$ (1,173)	$ 4,302	$ 873	$ 3,974	$ 12,271	$ 9,252
	Adjustment					$ -	$ -	$ -	$ -	$ -	$ -
	Alcona (Hydros)	$ 662	$ 1,131	$ 678	$ 713	$ 836	$ 736	$ 639	$ 1,112	$ 1,213	$ 1,072
	Allegan (Hydros)	$ 727	$ 908	$ 1,080	$ 889	$ 766	$ 762	$ 752	$ 717	$ 1,068	$ 876
	Battery					$ -	$ -	$ 30	$ 405	$ 1,033	$ 1,443
	Cadillac (Solar)	$ 47	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ -
	Campbell	$ 41,480	$ 45,980	$ 49,098	$ 46,849	$ 59,008	$ 49,344	$ 43,327	$ 41,340	$ 20,487	$ 279
	Circuit West (Solar)	$ 42	$ -	$ -	$ 18	$ -	$ -	$ -	$ -	$ -	$ -
	Cobb (Classic 7)	$ 99	$ 402	$ 161	$ 124	$ 87	$ 89	$ 34	$ 42	$ 109	$ 82
	Combustion Turbines	$ 775	$ 702	$ 298	$ 5	$ -	$ -	$ -	$ -	$ -	$ -
	Cooke (Hydros)	$ 711	$ 853	$ 810	$ 643	$ 754	$ 744	$ 683	$ 804	$ 1,138	$ 1,034
	Covert	$ 11,943	$ -	$ -	$ -	$ -	$ 4	$ 7,413	$ 13,508	$ 18,800	$ 14,858
	Croton (Hydros)	$ 966	$ 6,475	$ 967	$ 1,149	$ 1,176	$ 1,371	$ 1,455	$ 1,434	$ 1,443	$ 1,274
	Electric Grid Integration(Energy Supply)	$ 17,846	$ 9,725	$ 5,475	$ 13,873	$ 15,248	$ 16,780	$ 11,276	$ 10,118	$ 15,682	$ 12,111
	Five Channels (Hydros)	$ 646	$ 932	$ 729	$ 708	$ 790	$ 890	$ 717	$ 926	$ 1,065	$ 918
	Foote (Hydros)	$ 643	$ 1,025	$ 655	$ 730	$ 688	$ 742	$ 632	$ 1,676	$ 1,148	$ 1,034
	GVSU (Solar)	$ 118	$ 220	$ 141	$ 122	$ -	$ -	$ -	$ -	$ -	$ -
	Hardy (Hydros)	$ 979	$ 1,165	$ 1,062	$ 1,346	$ 1,146	$ 1,220	$ 836	$ 645	$ 2,738	$ 2,656
	Hodenpyl (Hydros)	$ 724	$ 884	$ 619	$ 692	$ 646	$ 797	$ 708	$ 822	$ 1,981	$ 1,841
	Hydro Commons	$ 744	$ -	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ -
	Jackson	$ 8,606	$ 10,298	$ 8,674	$ 9,853	$ 10,338	$ 10,544	$ 8,817	$ 11,616	$ 13,666	$ 10,269
	Karn	$ 36,304	$ 38,503	$ 43,655	$ 55,367	$ 42,100	$ 37,516	$ 19,091	$ 14,653	$ 19,518	$ 14,829
	Loud (Hydros)	$ 565	$ 688	$ 507	$ 604	$ 690	$ 679	$ 509	$ 587	$ 826	$ 708
	Ludington	$ 7,530	$ 6,917	$ 7,794	$ 8,186	$ 7,539	$ 8,281	$ 8,083	$ 9,399	$ 14,324	$ 11,661
	Mio (Hydros)	$ 677	$ 988	$ 621	$ 606	$ 675	$ 820	$ 648	$ 736	$ 897	$ 780
	Muskegon (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ 68	$ -	$ -	$ -
	Mustang Mile (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ 68	$ -	$ -	$ -
	Renewables Development	$ 9,341	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Rogers (Hydros)	$ 708	$ 1,166	$ 897	$ 667	$ 854	$ 724	$ 763	$ 818	$ 1,347	$ 1,160
	Solar Commons	$ 159	$ -	$ -	$ -	$ -	$ 387	$ -	$ -	$ -	$ -
	Tippy (Hydros)	$ 1,062	$ 2,824	$ 972	$ 1,020	$ 1,141	$ 992	$ 1,003	$ 1,035	$ 2,156	$ 2,028
	Washtenaw (Solar)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Weadock (Classic 7)	$ 168	$ 41	$ 47	$ 59	$ 24	$ 31	$ 33	$ 15	$ 108	$ 81
	Webber (Hydros)	$ 785	$ 694	$ 699	$ 816	$ 892	$ 1,138	$ 726	$ 810	$ 1,104	$ 915
	Whiting (Classic 7)	$ 102	$ 98	$ 118	$ 66	$ 85	$ 108	$ 47	$ 45	$ 73	$ 55
	WMU (Solar)	$ 93	$ 43	$ 36	$ 41	$ -	$ -	$ -	$ -	$ -	$ -
	Zeeland	$ 10,843	$ 14,163	$ 10,244	$ 8,945	$ 10,893	$ 11,029	$ 9,618	$ 11,199	$ 16,248	$ 12,518

Methodology for Quantifying Capital Investment Risk with Copperleaf Value Models – Consumers Energy

Purpose and scope

This document explains how the Company converts engineering and operational risk into dollar-denominated values for investment evaluation. It is intended for the reader to understand the logic behind the results; it does not require access to internal tools or data libraries. The same expected-value reasoning is applied year by year and results are discounted to present value using the Company's approved discount rate.

Model overview

The Company employs multiple model families; this document illustrates three commonly used examples:

1. Financial Risk Matrix — converts the chance of an adverse event and its consequence into an expected annual cost; value equals the risk avoided by the investment.
2. Lost Generation Risk (Energy Only) — quantifies the dollar value of lost energy (MWh) from derates or outages; value equals the avoided energy loss.
3. Financial Benefits & Costs — prices direct financial effects (costs avoided, revenues, and ongoing costs).

Principal value drivers

In practice, the Financial Risk Matrix and Lost Generation Risk models are the most widely used and account for the majority of risk-mitigation value in the Company's Long-Term Financial Plan. Capacity value lost risk is handled within the Financial Risk Matrix to avoid overlap with energy-only valuation.

Common frame (applies to all models)

- Baseline vs With-Project ("Outcome"): Baseline represents conditions if we do nothing; Outcome represents conditions after the investment. Annual value is the difference: Annual Value ($) = Baseline Expected Impact ($) − Outcome Expected Impact ($).
- Expected value: Uncertain events are priced by multiplying their consequence (in $ if they occur) by how likely they are to occur that year. This yields a single expected $ figure for the year.
- Discounting: After computing annual values across the planning horizon, we calculate NPV using a constant discount rate specified by Company finance policy.
- Evidence base (examples): work orders and repair history; outage/derate logs and time-to-restore; unit operating profile and duty cycle; inspection findings and sensor trends; OEM notices; age/obsolescence; supply-chain lead times; peer and industry

experience (including EPRI guidance); and structured SME judgments recorded through Company procedures.

1) Financial Risk Matrix (general risk in dollars)

What it measures: the expected annual cost of a defined hazard (safety, environmental, compliance, or financial), and the amount of that cost the project removes.

How it works, step by step

- Define the hazard and pathway. We state what can go wrong, how it unfolds, and which impact categories it touches. This ensures the risk we price is specific and non-overlapping with other models.
- Monetize the consequence. For each year, we determine the dollar impact if the event occurs in that year. This can include response and repair cost, regulatory or contractual impacts, and business effects appropriate for that hazard. Values are drawn from Company-maintained sources that reflect current costs and obligations.
- Quantify how often it may occur. For each year, we express likelihood as either a frequency (events per year) or a probability for that year. Figures are derived from the evidence base above and recorded through our governance process.
- Convert uncertainty into dollars. Expected annual risk equals consequence × likelihood. This yields a single dollar amount for that year under Baseline.
- Reflect the project's effect. With the project in place, severity and/or frequency typically decline. We determine the with-project consequence and likelihood in the same manner and compute the Outcome expected risk.
- Value created. Annual value is the avoided risk (Baseline minus Outcome). We then discount and sum across years to get NPV.

Capacity value lost risk (handled here)

- Use Capacity Calculator outputs for each year to identify the magnitude and timing of potential capacity exposure relative to accreditation or obligations. These exposure drivers are not re-estimated here.
- Monetize the exposure by applying the Company's capacity valuation parameters for the relevant years (market/regulatory cost components for our jurisdiction and obligations). These parameters are maintained internally and updated on defined cycles as conditions change. The result is a dollar consequence if the exposure materializes in that year.
- Account for chance by assigning, for each year, the likelihood that the exposure will materialize as a dollar impact, consistent with the same evidence base and governance protocols used elsewhere.
- Compute expected annual capacity value loss under Baseline and re-compute under Outcome if the project reduces the exposure (magnitude, timing, or likelihood). The difference is the annual value attributable to mitigating capacity value risk.

2) Lost Generation Risk (energy only)

What it measures: the dollar value of lost energy production due to unit derates or full outages and the portion of that loss the project avoids. This model does not address capacity market value or capacity accreditation.

How it works, step by step

- Describe the operational shortfall for each year: either a derate (the unit can run but at reduced MW) or a complete outage (the unit cannot produce). Specify the MW affected and the expected duration to restore normal operation.
- Translate MW and time into energy. Lost MWh per event equals MW affected × 24 hours × number of days, adjusted for how the unit is expected to operate during that period (capacity factor for the affected window). Operating profiles come from Company-maintained sources that reflect expected duty cycles.
- Monetize the lost energy. Multiply lost MWh by the applicable energy value ($/MWh) for that year (net of costs as appropriate). Energy values are obtained from Company-maintained price/valuation sources refreshed on defined cycles.
- Account for chance. Express how often such a derate/outage is expected in that year (frequency or probability) based on history, condition, and SME protocols, and multiply by the dollar consequence to get the expected annual loss under Baseline.
- Project effect. The project may shorten the duration, reduce the MW affected, reduce the likelihood, or some combination. Recompute the Outcome expected loss with those changes.
- Value created. Annual value is the avoided energy loss; NPV aggregates those annual values.

3) Financial Benefits & Costs

Note: This model does not include capacity value lost risk; those impacts are valued within the Financial Risk Matrix using outputs from the Capacity Calculator.

What it measures: direct financial effects that show up as dollars—costs we avoid, revenues we gain, or ongoing costs attributable to the project.

How it works, step by step

- Identify the financial streams that the project influences (e.g., avoided corrective capex, avoided O&M, incremental revenue, or ongoing costs attributable to the project). Streams are kept distinct to prevent double-counting.
- Size the dollar amounts for each stream by year, using Company-maintained financial and operational sources (e.g., standard labor/material costs, contract terms, or tariff mechanisms).
- Represent uncertainty by assigning a likelihood (0–1) for each stream in each year, following the same governance used elsewhere.

- Compute expected value for each stream and year (amount × likelihood) and sum across streams to obtain the net annual financial effect.
- Value created is the net with-project improvement relative to Baseline, discounted to NPV.

Additional model families employed

- Safety Risk (personnel and public harm, medical/claim costs, and associated operational impacts)
- Regulatory Compliance Risk (violations, penalties, corrective actions, and programmatic impacts)
- Environmental Risk (releases, remediation/response, permitting, and stewardship commitments)
- Other specialized models are applied as warranted by the investment context. All follow the same expected-value logic and governance described in this document.

Relationship to prior business-case practice

- Alignment with prior business-case practice.
    - These value models formalize the same expected-value logic historically used in our narrative business cases (likelihood × impact by year, discounted to present value).
- Structured improvements introduced by Copperleaf.
    - The platform enforces a consistent, systematic structure across all investments: common Baseline vs Outcome framing; governed, Company-maintained input sources updated on defined cycles; a uniform year-by-year treatment of uncertainty; and a single NPV roll-up.
- Implications for portfolio decision-making.
    - This removes variability in author style and assumptions, places projects on a level playing field, enables like-for-like comparison across technologies and sites, and gives leadership a clear portfolio view of risk and value.
- Impact for customers and ratepayers.
    - A more objective, repeatable method for selecting the optimal risk-mitigation portfolio—supporting lower total cost and better reliability outcomes.

Governance, transparency, and QA

- Recorded reference values: For each plant, we keep the values that drive the calculations—Net Energy Value (NEV), Net Demonstrated Capacity (NDC), fuel cost, and capacity factor—and update them on defined cycles as those inputs change. Other supporting engineering context is maintained separately; we don't time-stamp every data point inside the value model.

- Consistency: The same rules are applied to Baseline and Outcome; differences in value come from the project's effect, not from changing the standard.
- Reasonableness checks: Unit consistency (e.g., MW→MWh, $/MWh→$), bounds on probabilities, and year-to-year continuity are verified.
- Change control: When inputs are updated, the prior set and the new set are retained; impacts of changes can be traced year by year.

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.26%	10.68%	11.77%
90-Day Avg. Stock Price	9.33%	10.76%	11.84%
180-Day Avg. Stock Price	9.40%	10.82%	11.91%
Average	9.33%	10.75%	11.84%
Median Results:			
30-Day Avg. Stock Price	9.65%	10.37%	11.19%
90-Day Avg. Stock Price	9.74%	10.42%	11.23%
180-Day Avg. Stock Price	9.85%	10.46%	11.20%
Average	9.75%	10.42%	11.21%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.28%	11.24%	11.19%
Current Bloomberg Beta	11.27%	11.23%	11.17%
Long-term Avg. *Value Line* Beta	11.51%	11.47%	11.42%
ECAPM:			
Current *Value Line* Beta	11.80%	11.77%	11.73%
Current Bloomberg Beta	11.79%	11.76%	11.72%
Long-term Avg. *Value Line* Beta	11.97%	11.94%	11.90%
Bond Yield Risk Premium	10.76%	10.66%	10.53%

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.03	$65.12	3.12%	3.22%	6.00%	6.80%	6.60%	6.47%	9.21%	9.68%	10.02%
Ameren Corporation	AEE	$2.84	$100.25	2.83%	2.94%	6.50%	7.90%	7.90%	7.43%	9.43%	10.37%	10.84%
American Electric Power Company, Inc.	AEP	$3.72	$109.81	3.39%	3.50%	6.50%	7.07%	6.40%	6.66%	9.90%	10.16%	10.58%
Avista Corporation	AVA	$1.96	$36.66	5.35%	5.50%	5.50%	5.98%	5.80%	5.76%	10.99%	11.26%	11.48%
Dominion Resources, Inc.	D	$2.67	$59.75	4.47%	4.72%	6.00%	13.98%	13.60%	11.19%	10.60%	15.91%	18.76%
DTE Energy Company	DTE	$4.36	$136.68	3.19%	3.29%	4.50%	7.41%	7.00%	6.30%	7.76%	9.59%	10.72%
Entergy Corporation	ETR	$2.40	$89.29	2.69%	2.80%	3.00%	13.00%	9.50%	8.50%	5.73%	11.30%	15.86%
Evergy, Inc.	EVRG	$2.67	$72.23	3.70%	3.81%	7.50%	5.87%	5.70%	6.36%	9.50%	10.17%	11.34%
IDACORP, Inc.	IDA	$3.44	$126.41	2.72%	2.82%	6.00%	8.60%	8.20%	7.60%	8.80%	10.43%	11.44%
NextEra Energy, Inc.	NEE	$2.27	$72.78	3.11%	3.24%	8.50%	7.58%	7.90%	7.99%	10.81%	11.23%	11.75%
OGE Energy Corporation	OGE	$1.69	$44.68	3.77%	3.89%	6.50%	6.64%	6.30%	6.48%	10.19%	10.37%	10.53%
Pinnacle West Capital Corporation	PNW	$3.58	$88.45	4.05%	4.14%	5.00%	6.90%	2.10%	4.67%	6.19%	8.81%	11.09%
Portland General Electric Company	POR	$2.10	$42.26	4.97%	5.10%	6.50%	5.30%	3.40%	5.07%	8.45%	10.16%	11.63%
PPL Corporation	PPL	$1.09	$36.14	3.02%	3.13%	7.50%	7.42%	7.70%	7.54%	10.55%	10.67%	10.83%
Southern Company	SO	$2.96	$92.78	3.19%	3.30%	6.50%	6.72%	6.80%	6.67%	9.79%	9.97%	10.10%
Xcel Energy Inc.	XEL	$2.28	$73.35	3.11%	3.23%	7.00%	8.06%	7.80%	7.62%	10.22%	10.85%	11.29%
Mean				3.54%	3.66%	6.19%	7.83%	7.04%	7.02%	9.26%	10.68%	11.77%
Median				3.19%	3.29%	6.50%	7.24%	6.90%	6.67%	9.65%	10.37%	11.19%

Notes:
[1] Bloomberg Professional as of September 30, 2025
[2] Bloomberg Professional 30-day average as of September 30, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] S&P Capital IQ
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.03	$63.26	3.21%	3.31%	6.00%	6.80%	6.60%	6.47%	9.31%	9.78%	10.11%
Ameren Corporation	AEE	$2.84	$98.00	2.90%	3.01%	6.50%	7.90%	7.90%	7.43%	9.49%	10.44%	10.91%
American Electric Power Company, Inc.	AEP	$3.72	$106.86	3.48%	3.60%	6.50%	7.07%	6.40%	6.66%	9.99%	10.25%	10.68%
Avista Corporation	AVA	$1.96	$37.03	5.29%	5.45%	5.50%	5.98%	5.80%	5.76%	10.94%	11.21%	11.43%
Dominion Resources, Inc.	D	$2.67	$57.81	4.62%	4.88%	6.00%	13.98%	13.60%	11.19%	10.76%	16.07%	18.92%
DTE Energy Company	DTE	$4.36	$135.01	3.23%	3.33%	4.50%	7.41%	7.00%	6.30%	7.80%	9.63%	10.76%
Entergy Corporation	ETR	$2.40	$85.96	2.79%	2.91%	3.00%	13.00%	9.50%	8.50%	5.83%	11.41%	15.97%
Evergy, Inc.	EVRG	$2.67	$69.59	3.84%	3.96%	7.50%	5.87%	5.70%	6.36%	9.65%	10.32%	11.48%
IDACORP, Inc.	IDA	$3.44	$120.93	2.84%	2.95%	6.00%	8.60%	8.20%	7.60%	8.93%	10.55%	11.57%
NextEra Energy, Inc.	NEE	$2.27	$71.99	3.15%	3.27%	8.50%	7.58%	7.90%	7.99%	10.85%	11.27%	11.78%
OGE Energy Corporation	OGE	$1.69	$44.45	3.79%	3.91%	6.50%	6.64%	6.30%	6.48%	10.21%	10.39%	10.55%
Pinnacle West Capital Corporation	PNW	$3.58	$89.46	4.00%	4.10%	5.00%	6.90%	2.10%	4.67%	6.14%	8.76%	11.04%
Portland General Electric Company	POR	$2.10	$41.15	5.10%	5.23%	6.50%	5.30%	3.40%	5.07%	8.59%	10.30%	11.77%
PPL Corporation	PPL	$1.09	$35.13	3.10%	3.22%	7.50%	7.42%	7.70%	7.54%	10.64%	10.76%	10.92%
Southern Company	SO	$2.96	$91.78	3.23%	3.33%	6.50%	6.72%	6.80%	6.67%	9.83%	10.01%	10.13%
Xcel Energy Inc.	XEL	$2.28	$70.61	3.23%	3.35%	7.00%	8.06%	7.80%	7.62%	10.34%	10.97%	11.41%
Mean				3.61%	3.74%	6.19%	7.83%	7.04%	7.02%	9.33%	10.76%	11.84%
Median				3.23%	3.34%	6.50%	7.24%	6.90%	6.67%	9.74%	10.42%	11.23%

Notes:
[1] Bloomberg Professional as of September 30, 2025
[2] Bloomberg Professional 90-day average as of September 30, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] S&P Capital IQ
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	S&P Capital IQ Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Alliant Energy Corporation	LNT	$2.03	$61.87	3.28%	3.39%	6.00%	6.80%	6.60%	6.47%	9.38%	9.85%	10.19%
Ameren Corporation	AEE	$2.84	$96.89	2.93%	3.04%	6.50%	7.90%	7.90%	7.43%	9.53%	10.47%	10.95%
American Electric Power Company, Inc.	AEP	$3.72	$104.26	3.57%	3.69%	6.50%	7.07%	6.40%	6.66%	10.08%	10.34%	10.77%
Avista Corporation	AVA	$1.96	$37.53	5.22%	5.37%	5.50%	5.98%	5.80%	5.76%	10.87%	11.13%	11.36%
Dominion Resources, Inc.	D	$2.67	$55.51	4.81%	5.08%	6.00%	13.98%	13.60%	11.19%	10.95%	16.27%	19.13%
DTE Energy Company	DTE	$4.36	$131.69	3.31%	3.42%	4.50%	7.41%	7.00%	6.30%	7.89%	9.72%	10.84%
Entergy Corporation	ETR	$2.40	$83.88	2.86%	2.98%	3.00%	13.00%	9.50%	8.50%	5.90%	11.48%	16.05%
Evergy, Inc.	EVRG	$2.67	$67.27	3.97%	4.10%	7.50%	5.87%	5.70%	6.36%	9.78%	10.45%	11.62%
IDACORP, Inc.	IDA	$3.44	$116.64	2.95%	3.06%	6.00%	8.60%	8.20%	7.60%	9.04%	10.66%	11.68%
NextEra Energy, Inc.	NEE	$2.27	$70.21	3.23%	3.36%	8.50%	7.58%	7.90%	7.99%	10.93%	11.35%	11.86%
OGE Energy Corporation	OGE	$1.69	$43.94	3.84%	3.96%	6.50%	6.64%	6.30%	6.48%	10.26%	10.44%	10.60%
Pinnacle West Capital Corporation	PNW	$3.58	$89.37	4.01%	4.10%	5.00%	6.90%	2.10%	4.67%	6.15%	8.77%	11.04%
Portland General Electric Company	POR	$2.10	$41.30	5.08%	5.21%	6.50%	5.30%	3.40%	5.07%	8.57%	10.28%	11.75%
PPL Corporation	PPL	$1.09	$34.54	3.16%	3.27%	7.50%	7.42%	7.70%	7.54%	10.69%	10.81%	10.98%
Southern Company	SO	$2.96	$89.23	3.32%	3.43%	6.50%	6.72%	6.80%	6.67%	9.93%	10.10%	10.23%
Xcel Energy Inc.	XEL	$2.28	$69.15	3.30%	3.42%	7.00%	8.06%	7.80%	7.62%	10.41%	11.04%	11.49%
Mean				3.68%	3.80%	6.19%	7.83%	7.04%	7.02%	9.40%	10.82%	11.91%
Median				3.31%	3.43%	6.50%	7.24%	6.90%	6.67%	9.85%	10.46%	11.20%

Notes:
[1] Bloomberg Professional as of September 30, 2025
[2] Bloomberg Professional 180-day average as of September 30, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] S&P Capital IQ
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
Ameren Corporation	AEE	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
American Electric Power Company, Inc.	AEP	4.79%	0.65	13.34%	8.55%	10.35%	11.10%
Avista Corporation	AVA	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
Dominion Resources, Inc.	D	4.79%	0.80	13.34%	8.55%	11.63%	12.06%
DTE Energy Company	DTE	4.79%	0.80	13.34%	8.55%	11.63%	12.06%
Entergy Corporation	ETR	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
Evergy, Inc.	EVRG	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
IDACORP, Inc.	IDA	4.79%	0.70	13.34%	8.55%	10.78%	11.42%
NextEra Energy, Inc.	NEE	4.79%	0.90	13.34%	8.55%	12.49%	12.70%
OGE Energy Corporation	OGE	4.79%	0.85	13.34%	8.55%	12.06%	12.38%
Pinnacle West Capital Corporation	PNW	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
Portland General Electric Company	POR	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
PPL Corporation	PPL	4.79%	0.80	13.34%	8.55%	11.63%	12.06%
Southern Company	SO	4.79%	0.70	13.34%	8.55%	10.78%	11.42%
Xcel Energy Inc.	XEL	4.79%	0.70	13.34%	8.55%	10.78%	11.42%
Mean						11.28%	11.80%
Median						11.20%	11.74%

Notes:
[1] Bloomberg Professional 30-day average as of September 30, 2025
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2026 - Q1 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
Ameren Corporation	AEE	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
American Electric Power Company, Inc.	AEP	4.62%	0.65	13.34%	8.72%	10.29%	11.05%
Avista Corporation	AVA	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
Dominion Resources, Inc.	D	4.62%	0.80	13.34%	8.72%	11.60%	12.03%
DTE Energy Company	DTE	4.62%	0.80	13.34%	8.72%	11.60%	12.03%
Entergy Corporation	ETR	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
Evergy, Inc.	EVRG	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
IDACORP, Inc.	IDA	4.62%	0.70	13.34%	8.72%	10.73%	11.38%
NextEra Energy, Inc.	NEE	4.62%	0.90	13.34%	8.72%	12.47%	12.69%
OGE Energy Corporation	OGE	4.62%	0.85	13.34%	8.72%	12.03%	12.36%
Pinnacle West Capital Corporation	PNW	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
Portland General Electric Company	POR	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
PPL Corporation	PPL	4.62%	0.80	13.34%	8.72%	11.60%	12.03%
Southern Company	SO	4.62%	0.70	13.34%	8.72%	10.73%	11.38%
Xcel Energy Inc.	XEL	4.62%	0.70	13.34%	8.72%	10.73%	11.38%
Mean						11.24%	11.77%
Median						11.16%	11.71%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
Ameren Corporation	AEE	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
American Electric Power Company, Inc.	AEP	4.40%	0.65	13.34%	8.94%	10.21%	10.99%
Avista Corporation	AVA	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
Dominion Resources, Inc.	D	4.40%	0.80	13.34%	8.94%	11.55%	12.00%
DTE Energy Company	DTE	4.40%	0.80	13.34%	8.94%	11.55%	12.00%
Entergy Corporation	ETR	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
Evergy, Inc.	EVRG	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
IDACORP, Inc.	IDA	4.40%	0.70	13.34%	8.94%	10.66%	11.33%
NextEra Energy, Inc.	NEE	4.40%	0.90	13.34%	8.94%	12.45%	12.67%
OGE Energy Corporation	OGE	4.40%	0.85	13.34%	8.94%	12.00%	12.34%
Pinnacle West Capital Corporation	PNW	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
Portland General Electric Company	POR	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
PPL Corporation	PPL	4.40%	0.80	13.34%	8.94%	11.55%	12.00%
Southern Company	SO	4.40%	0.70	13.34%	8.94%	10.66%	11.33%
Xcel Energy Inc.	XEL	4.40%	0.70	13.34%	8.94%	10.66%	11.33%
Mean						11.19%	11.73%
Median						11.11%	11.67%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.79%	0.74	13.34%	8.55%	11.16%	11.70%
Ameren Corporation	AEE	4.79%	0.71	13.34%	8.55%	10.90%	11.51%
American Electric Power Company, Inc.	AEP	4.79%	0.71	13.34%	8.55%	10.83%	11.46%
Avista Corporation	AVA	4.79%	0.71	13.34%	8.55%	10.85%	11.47%
Dominion Resources, Inc.	D	4.79%	0.68	13.34%	8.55%	10.57%	11.26%
DTE Energy Company	DTE	4.79%	0.77	13.34%	8.55%	11.39%	11.88%
Entergy Corporation	ETR	4.79%	0.82	13.34%	8.55%	11.84%	12.22%
Evergy, Inc.	EVRG	4.79%	0.74	13.34%	8.55%	11.15%	11.69%
IDACORP, Inc.	IDA	4.79%	0.74	13.34%	8.55%	11.13%	11.68%
NextEra Energy, Inc.	NEE	4.79%	0.79	13.34%	8.55%	11.54%	11.99%
OGE Energy Corporation	OGE	4.79%	0.87	13.34%	8.55%	12.26%	12.53%
Pinnacle West Capital Corporation	PNW	4.79%	0.78	13.34%	8.55%	11.44%	11.91%
Portland General Electric Company	POR	4.79%	0.74	13.34%	8.55%	11.12%	11.68%
PPL Corporation	PPL	4.79%	0.88	13.34%	8.55%	12.30%	12.56%
Southern Company	SO	4.79%	0.73	13.34%	8.55%	11.04%	11.62%
Xcel Energy Inc.	XEL	4.79%	0.70	13.34%	8.55%	10.78%	11.42%
Mean						11.27%	11.79%
Median						11.14%	11.69%

Notes:
[1] Bloomberg Professional 30-day average as of September 30, 2025
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2026 - Q1 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.62%	0.74	13.34%	8.72%	11.12%	11.67%
Ameren Corporation	AEE	4.62%	0.71	13.34%	8.72%	10.85%	11.47%
American Electric Power Company, Inc.	AEP	4.62%	0.71	13.34%	8.72%	10.79%	11.42%
Avista Corporation	AVA	4.62%	0.71	13.34%	8.72%	10.80%	11.44%
Dominion Resources, Inc.	D	4.62%	0.68	13.34%	8.72%	10.51%	11.22%
DTE Energy Company	DTE	4.62%	0.77	13.34%	8.72%	11.35%	11.85%
Entergy Corporation	ETR	4.62%	0.82	13.34%	8.72%	11.81%	12.20%
Evergy, Inc.	EVRG	4.62%	0.74	13.34%	8.72%	11.10%	11.66%
IDACORP, Inc.	IDA	4.62%	0.74	13.34%	8.72%	11.09%	11.65%
NextEra Energy, Inc.	NEE	4.62%	0.79	13.34%	8.72%	11.50%	11.96%
OGE Energy Corporation	OGE	4.62%	0.87	13.34%	8.72%	12.24%	12.51%
Pinnacle West Capital Corporation	PNW	4.62%	0.78	13.34%	8.72%	11.40%	11.88%
Portland General Electric Company	POR	4.62%	0.74	13.34%	8.72%	11.08%	11.65%
PPL Corporation	PPL	4.62%	0.88	13.34%	8.72%	12.28%	12.54%
Southern Company	SO	4.62%	0.73	13.34%	8.72%	10.99%	11.58%
Xcel Energy Inc.	XEL	4.62%	0.70	13.34%	8.72%	10.73%	11.39%
Mean						11.23%	11.76%
Median						11.09%	11.66%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.40%	0.74	13.34%	8.94%	11.06%	11.63%
Ameren Corporation	AEE	4.40%	0.71	13.34%	8.94%	10.79%	11.43%
American Electric Power Company, Inc.	AEP	4.40%	0.71	13.34%	8.94%	10.72%	11.38%
Avista Corporation	AVA	4.40%	0.71	13.34%	8.94%	10.74%	11.39%
Dominion Resources, Inc.	D	4.40%	0.68	13.34%	8.94%	10.44%	11.16%
DTE Energy Company	DTE	4.40%	0.77	13.34%	8.94%	11.30%	11.81%
Entergy Corporation	ETR	4.40%	0.82	13.34%	8.94%	11.78%	12.17%
Evergy, Inc.	EVRG	4.40%	0.74	13.34%	8.94%	11.05%	11.62%
IDACORP, Inc.	IDA	4.40%	0.74	13.34%	8.94%	11.03%	11.61%
NextEra Energy, Inc.	NEE	4.40%	0.79	13.34%	8.94%	11.46%	11.93%
OGE Energy Corporation	OGE	4.40%	0.87	13.34%	8.94%	12.21%	12.49%
Pinnacle West Capital Corporation	PNW	4.40%	0.78	13.34%	8.94%	11.35%	11.85%
Portland General Electric Company	POR	4.40%	0.74	13.34%	8.94%	11.02%	11.60%
PPL Corporation	PPL	4.40%	0.88	13.34%	8.94%	12.25%	12.52%
Southern Company	SO	4.40%	0.73	13.34%	8.94%	10.93%	11.54%
Xcel Energy Inc.	XEL	4.40%	0.70	13.34%	8.94%	10.67%	11.34%
Mean						11.17%	11.72%
Median						11.04%	11.61%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.79%	0.78	13.34%	8.55%	11.42%	11.90%
Ameren Corporation	AEE	4.79%	0.75	13.34%	8.55%	11.24%	11.77%
American Electric Power Company, Inc.	AEP	4.79%	0.70	13.34%	8.55%	10.74%	11.39%
Avista Corporation	AVA	4.79%	0.81	13.34%	8.55%	11.70%	12.11%
Dominion Resources, Inc.	D	4.79%	0.73	13.34%	8.55%	11.06%	11.63%
DTE Energy Company	DTE	4.79%	0.79	13.34%	8.55%	11.56%	12.01%
Entergy Corporation	ETR	4.79%	0.78	13.34%	8.55%	11.49%	11.95%
Evergy, Inc.	EVRG	4.79%	0.94	13.34%	8.55%	12.83%	12.96%
IDACORP, Inc.	IDA	4.79%	0.75	13.34%	8.55%	11.20%	11.74%
NextEra Energy, Inc.	NEE	4.79%	0.78	13.34%	8.55%	11.45%	11.93%
OGE Energy Corporation	OGE	4.79%	0.95	13.34%	8.55%	12.95%	13.05%
Pinnacle West Capital Corporation	PNW	4.79%	0.77	13.34%	8.55%	11.38%	11.87%
Portland General Electric Company	POR	4.79%	0.78	13.34%	8.55%	11.45%	11.93%
PPL Corporation	PPL	4.79%	0.86	13.34%	8.55%	12.13%	12.43%
Southern Company	SO	4.79%	0.70	13.34%	8.55%	10.81%	11.44%
Xcel Energy Inc.	XEL	4.79%	0.69	13.34%	8.55%	10.67%	11.34%
Mean						11.51%	11.97%
Median						11.44%	11.91%

Notes:
[1] Bloomberg Professional 30-day average as of September 30, 2025
[2] Long-Term Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2026 - Q1 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.62%	0.78	13.34%	8.72%	11.38%	11.87%
Ameren Corporation	AEE	4.62%	0.75	13.34%	8.72%	11.20%	11.73%
American Electric Power Company, Inc.	AEP	4.62%	0.70	13.34%	8.72%	10.69%	11.35%
Avista Corporation	AVA	4.62%	0.81	13.34%	8.72%	11.67%	12.09%
Dominion Resources, Inc.	D	4.62%	0.73	13.34%	8.72%	11.02%	11.60%
DTE Energy Company	DTE	4.62%	0.79	13.34%	8.72%	11.53%	11.98%
Entergy Corporation	ETR	4.62%	0.78	13.34%	8.72%	11.45%	11.92%
Evergy, Inc.	EVRG	4.62%	0.94	13.34%	8.72%	12.82%	12.95%
IDACORP, Inc.	IDA	4.62%	0.75	13.34%	8.72%	11.16%	11.71%
NextEra Energy, Inc.	NEE	4.62%	0.78	13.34%	8.72%	11.42%	11.90%
OGE Energy Corporation	OGE	4.62%	0.95	13.34%	8.72%	12.94%	13.04%
Pinnacle West Capital Corporation	PNW	4.62%	0.77	13.34%	8.72%	11.34%	11.84%
Portland General Electric Company	POR	4.62%	0.78	13.34%	8.72%	11.42%	11.90%
PPL Corporation	PPL	4.62%	0.86	13.34%	8.72%	12.11%	12.42%
Southern Company	SO	4.62%	0.70	13.34%	8.72%	10.76%	11.41%
Xcel Energy Inc.	XEL	4.62%	0.69	13.34%	8.72%	10.62%	11.30%
Mean						11.47%	11.94%
Median						11.40%	11.88%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2
[2] Long-Term Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM COE (K)	ECAPM COE (K)
Alliant Energy Corporation	LNT	4.40%	0.78	13.34%	8.94%	11.33%	11.83%
Ameren Corporation	AEE	4.40%	0.75	13.34%	8.94%	11.14%	11.69%
American Electric Power Company, Inc.	AEP	4.40%	0.70	13.34%	8.94%	10.62%	11.30%
Avista Corporation	AVA	4.40%	0.81	13.34%	8.94%	11.63%	12.06%
Dominion Resources, Inc.	D	4.40%	0.73	13.34%	8.94%	10.96%	11.55%
DTE Energy Company	DTE	4.40%	0.79	13.34%	8.94%	11.48%	11.95%
Entergy Corporation	ETR	4.40%	0.78	13.34%	8.94%	11.40%	11.89%
Evergy, Inc.	EVRG	4.40%	0.94	13.34%	8.94%	12.81%	12.94%
IDACORP, Inc.	IDA	4.40%	0.75	13.34%	8.94%	11.11%	11.67%
NextEra Energy, Inc.	NEE	4.40%	0.78	13.34%	8.94%	11.37%	11.86%
OGE Energy Corporation	OGE	4.40%	0.95	13.34%	8.94%	12.93%	13.03%
Pinnacle West Capital Corporation	PNW	4.40%	0.77	13.34%	8.94%	11.29%	11.81%
Portland General Electric Company	POR	4.40%	0.78	13.34%	8.94%	11.37%	11.86%
PPL Corporation	PPL	4.40%	0.86	13.34%	8.94%	12.08%	12.39%
Southern Company	SO	4.40%	0.70	13.34%	8.94%	10.70%	11.36%
Xcel Energy Inc.	XEL	4.40%	0.69	13.34%	8.94%	10.55%	11.25%
Mean						11.42%	11.90%
Median						11.35%	11.85%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14

[2] Long-Term Beta

[3] Market Return

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL VALUE LINE BETA

Company	Ticker	[1] 2013	[2] 2014	[3] 2015	[4] 2016	[5] 2017	[6] 2018	[7] 2019	[8] 2020	[9] 2021	[10] 2022	[11] 2023	[12] 2024	[13] Average
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.85	0.90	0.90	0.78
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.85	0.90	0.90	0.75
American Electric Power Company, Inc.	AEP	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.75	0.80	0.80	0.70
Avista Corporation	AVA	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0.95	0.90	0.90	0.95	0.81
Dominion Resources, Inc.	D	0.70	0.70	0.70	0.65	0.65	0.60	0.55	0.80	0.85	0.85	0.85	0.90	0.73
DTE Energy Company	DTE	0.80	0.75	0.75	0.65	0.65	0.55	0.55	0.95	0.95	0.95	0.95	1.00	0.79
Entergy Corporation	ETR	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.95	0.95	1.00	0.78
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.90	0.90	0.95	0.94
IDACORP, Inc.	IDA	0.75	0.80	0.80	0.75	0.70	0.55	0.55	0.80	0.80	0.80	0.85	0.85	0.75
NextEra Energy, Inc.	NEE	0.70	0.70	0.75	0.65	0.65	0.55	0.55	0.90	0.90	0.95	1.00	1.05	0.78
OGE Energy Corporation	OGE	0.85	0.90	0.95	0.90	0.95	0.85	0.75	1.10	1.05	1.00	1.05	1.10	0.95
Pinnacle West Capital Corporation	PNW	0.75	0.70	0.75	0.70	0.70	0.55	0.50	0.90	0.90	0.90	0.95	0.95	0.77
Portland General Electric Company	POR	0.75	0.80	0.80	0.70	0.70	0.60	0.55	0.85	0.90	0.85	0.90	0.95	0.78
PPL Corporation	PPL	0.65	0.60	0.70	0.70	0.75	0.70	0.70	1.15	1.10	1.05	1.10	1.10	0.86
Southern Company	SO	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.90	0.95	0.95	0.70
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0.60	0.50	0.50	0.80	0.80	0.80	0.85	0.85	0.69
Mean		0.72	0.73	0.75	0.68	0.69	0.59	0.57	0.91	0.90	0.89	0.93	0.95	0.79

Notes:
[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Value Line, dated December 30, 2022.
[11] Value Line, Dated December 29, 2023.
[12] Value Line, Dated December 27, 2024.

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.31%
[2] Estimate of the S&P 500 Growth Rate	11.95%
[3] S&P 500 Estimated Required Market Return	13.34%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	321.64843	49.04	15,773.64		11.17%		-9.85%	
American Express Co	AXP	695.88223	332.16	231,144.24	0.56%	0.99%	0.01%	15.03%	0.08%
Verizon Communications Inc	VZ	4216.32481	43.95	185,307.48	0.45%	6.28%	0.03%	2.27%	0.01%
Texas Pacific Land Corp	TPL	22.97941	933.64	21,454.50		0.69%			
Broadcom Inc	AVGO	4722.36502	329.91	1,557,955.44		0.72%		40.05%	
Boeing Co/The	BA	756.1577	215.83	163,201.52				31.71%	
Solventum Corp	SOLV	173.3878	73	12,657.31	0.03%			1.28%	0.00%
Caterpillar Inc	CAT	468.47892	477.15	223,534.72	0.54%	1.27%	0.01%	6.56%	0.04%
JPMorgan Chase & Co	JPM	2749.75385	315.43	867,354.86	2.11%	1.90%	0.04%	8.55%	0.18%
Chevron Corp	CVX	2047.39391	155.29	317,939.80	0.77%	4.40%	0.03%	15.39%	0.12%
Coca-Cola Co/The	KO	4303.66725	66.32	285,419.21	0.69%	3.08%	0.02%	5.90%	0.04%
AbbVie Inc	ABBV	1766.55825	231.54	409,028.90	0.99%	2.83%	0.03%	13.98%	0.14%
Walt Disney Co/The	DIS	1797.93383	114.5	205,863.42	0.50%	0.87%	0.00%	13.12%	0.07%
Corpay Inc	CPAY	70.61438	288.06	20,341.18	0.05%			12.12%	0.01%
Extra Space Storage Inc	EXR	212.25361	140.94	29,915.02	0.07%	4.60%	0.00%	3.14%	0.00%
Exxon Mobil Corp	XOM	4263.24702	112.75	480,681.10	1.17%	3.51%	0.04%	11.40%	0.13%
Phillips 66	PSX	404.12427	136.02	54,968.98		3.53%		22.37%	
General Electric Co	GE	1060.43939	300.82	319,001.38		0.48%		20.51%	
HP Inc	HPQ	934.70185	27.23	25,451.93		4.25%		-0.60%	
Home Depot Inc/The	HD	995.38665	405.19	403,320.72	0.98%	2.27%	0.02%	5.04%	0.05%
Monolithic Power Systems Inc	MPWR	47.892	920.64	44,091.29		0.68%			
International Business Machines Corp	IBM	931.51924	282.16	262,837.47	0.64%	2.38%	0.02%	6.68%	0.04%
Johnson & Johnson	JNJ	2408.33887	185.42	446,554.19	1.09%	2.80%	0.03%	7.35%	0.08%
Lululemon Athletica Inc	LULU	113.46808	177.93	20,189.38	0.05%			1.24%	0.00%
McDonald's Corp	MCD	713.60443	303.89	216,857.25	0.53%	2.33%	0.01%	8.63%	0.05%
Merck & Co Inc	MRK	2497.78321	83.93	209,638.94	0.51%	3.86%	0.02%	15.57%	0.08%
3M Co	MMM	532.6297	155.18	82,653.48	0.20%	1.88%	0.00%	6.99%	0.01%
American Water Works Co Inc	AWK	203.19716	139.19	28,283.01	0.07%	2.38%	0.00%	6.60%	0.00%
Bank of America Corp	BAC	7406.94731	51.59	382,124.41		2.17%			
Pfizer Inc	PFE	5685.5505	25.48	144,867.83	0.35%	6.75%	0.02%	0.11%	0.00%
Procter & Gamble Co/The	PG	2340.48526	153.65	359,615.56	0.87%	2.75%	0.02%	4.08%	0.04%
AT&T Inc	T	7150.38548	28.24	201,926.89	0.49%	3.93%	0.02%	4.63%	0.02%
Travelers Cos Inc/The	TRV	225.13384	279.22	62,861.87		1.58%		54.50%	
RTX Corp	RTX	1338.54183	167.33	223,978.20	0.54%	1.63%	0.01%	7.41%	0.04%
Analog Devices Inc	ADI	491.95544	245.7	120,873.45	0.29%	1.61%	0.00%	17.18%	0.05%
Walmart Inc	WMT	7972.85112	103.06	821,682.04	2.00%	0.91%	0.02%	8.46%	0.17%
Cisco Systems Inc	CSCO	3953.19695	68.42	270,477.74	0.66%	2.40%	0.02%	8.32%	0.05%
Intel Corp	INTC	4651.583	33.55	156,060.61	0.38%			9.28%	0.04%
General Motors Co	GM	952.0778	60.97	58,048.18	0.14%	0.98%	0.00%	6.04%	0.01%
Microsoft Corp	MSFT	7433.16638	517.95	3,850,008.53	9.36%	0.70%	0.07%	14.84%	1.39%
Dollar General Corp	DG	220.10603	103.35	22,747.96	0.06%	2.28%	0.00%	5.24%	0.00%
Cigna Group/The	CI	266.92807	288.25	76,942.02	0.19%	2.10%	0.00%	10.86%	0.02%
Kinder Morgan Inc	KMI	2222.07762	28.31	62,907.02	0.15%	4.13%	0.01%	8.46%	0.01%
Citigroup Inc	C	1840.8979	101.5	186,851.14		2.36%		25.65%	
American International Group Inc	AIG	554.00385	78.54	43,511.46	0.11%	2.29%	0.00%	19.99%	0.02%
Altria Group Inc	MO	1679.89095	66.06	110,973.60	0.27%	6.42%	0.02%	4.72%	0.01%
HCA Healthcare Inc	HCA	233.9935	426.2	99,728.03	0.24%	0.68%	0.00%	10.76%	0.03%
International Paper Co	IP	527.98209	46.4	24,498.37		3.99%		54.45%	
Hewlett Packard Enterprise Co	HPE	1319.45006	24.56	32,405.69	0.08%	2.12%	0.00%	7.61%	0.01%
Abbott Laboratories	ABT	1740.45901	133.94	233,117.08	0.57%	1.76%	0.01%	9.97%	0.06%
Aflac Inc	AFL	534.83149	111.7	59,740.68		2.08%		25.77%	
Air Products and Chemicals Inc	APD	222.55364	270.9299	60,296.44	0.15%	2.64%	0.00%	3.42%	0.01%
Super Micro Computer Inc	SMCI	594.27331	47.94	28,489.46	0.07%			19.06%	0.01%
Royal Caribbean Cruises Ltd	RCL	271.62766	323.58	87,893.28		1.24%		22.77%	
Hess Corp	HES	445.24698	68.81	30,637.44	0.07%	0.47%	0.00%	12.54%	0.01%
Lennox International Inc	LII	35.12428	529.36	18,593.39		0.98%			
Archer-Daniels-Midland Co	ADM	480.46448	59.74	28,702.95	0.07%	3.41%	0.00%	4.70%	0.00%
Automatic Data Processing Inc	ADP	44.76425	649.54	29,076.17		0.15%			
Verisk Analytics Inc	VRSK	405.08952	293.5	118,893.77		2.10%			
AutoZone Inc	AZO	139.71497	251.51	35,139.71		0.72%			
Linde PLC	LIN	16.72871	4290.24	71,770.18	0.17%			13.66%	0.02%
Avery Dennison Corp	AVY	468.90953	475	222,732.03	0.54%	1.26%	0.01%	8.66%	0.05%
Enphase Energy Inc	ENPH	77.98159	162.17	12,646.27	0.03%	2.32%	0.00%	6.84%	0.00%
MSCI Inc	MSCI	77.36524	567.41	43,897.81		1.27%			
Ball Corp	BALL	272.1489	50.42	13,721.75	0.03%	1.59%	0.00%	12.27%	0.00%
Axon Enterprise Inc	AXON	78.50444	717.64	56,337.93				28.56%	
Dayforce Inc	DAY	158.00648	68.89	10,885.07					
Carrier Global Corp	CARR	851.02284	59.7	50,806.06	0.12%	1.51%	0.00%	11.41%	0.01%
Bank of New York Mellon Corp/The	BK	705.24082	108.96	76,843.04	0.19%	1.95%	0.00%	14.85%	0.03%
Otis Worldwide Corp	OTIS	392.47523	91.43	35,884.01		1.84%			
Baxter International Inc	BAX	513.62106	22.77	11,695.15	0.03%	2.99%	0.00%	12.49%	0.00%
Becton Dickinson & Co	BDX	286.62747	187.17	53,648.06	0.13%	2.22%	0.00%	7.29%	0.01%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Berkshire Hathaway Inc	BRK/B	1378.54564	502.74	693,050.04					
Best Buy Co Inc	BBY	210.10127	75.62	15,887.86	0.04%	5.03%	0.00%	4.17%	0.00%
Boston Scientific Corp	BSX	1481.75163	97.63	144,663.41	0.35%			14.86%	0.05%
Bristol-Myers Squibb Co	BMY	2035.43584	45.1	91,798.16		5.50%		82.51%	
Brown-Forman Corp	BF/B	303.60888	27.08	8,221.73	0.02%	3.35%	0.00%	2.43%	0.00%
Coterra Energy Inc	CTRA	763.13997	23.65	18,048.26		3.72%		30.08%	
Hilton Worldwide Holdings Inc	HLT	235.19375	259.44	61,018.67	0.15%	0.23%	0.00%	12.75%	0.02%
Carnival Corp	CCL	1167.54105	28.91	33,753.61				21.87%	
Builders FirstSource Inc	BLDR	110.54693	121.25	13,403.82				-4.21%	
UDR Inc	UDR	331.34719	37.26	12,346.00	0.03%	4.62%	0.00%	1.33%	0.00%
Clorox Co/The	CLX	122.30941	123.3	15,080.75	0.04%	4.02%	0.00%	0.34%	0.00%
Paycom Software Inc	PAYC	57.8768	208.14	12,046.48	0.03%	0.72%	0.00%	9.16%	0.00%
CMS Energy Corp	CMS	299.33546	73.26	21,929.32	0.05%	2.96%	0.00%	7.51%	0.00%
Colgate-Palmolive Co	CL	808.22082	79.94	64,609.17	0.16%	2.60%	0.00%	4.85%	0.01%
EPAM Systems Inc	EPAM	55.69691	150.79	8,398.54					
Conagra Brands Inc	CAG	479.04969	18.31	8,771.40		7.65%		-7.51%	
Airbnb Inc	ABNB	429.07956	121.42	52,098.84	0.13%			10.47%	0.01%
Consolidated Edison Inc	ED	360.65167	100.52	36,252.71	0.09%	3.38%	0.00%	5.20%	0.00%
Corning Inc	GLW	856.61871	82.03	70,268.43	0.17%	1.37%	0.00%	18.16%	0.03%
GoDaddy Inc	GDDY	138.44902	136.83	18,943.98					
Cummins Inc	CMI	137.78604	422.37	58,196.69	0.14%	1.89%	0.00%	10.71%	0.02%
Caesars Entertainment Inc	CZR	716.05159	198.26	141,964.39	0.35%	0.65%	0.00%	8.10%	0.03%
Danaher Corp	DHR	454.39915	89.7	40,759.60		5.08%		-1.37%	
Target Corp	TGT	121.79033	195.45	23,803.92	0.06%	1.35%	0.00%	4.68%	0.00%
Williams-Sonoma Inc	WSM	270.32939	457.26	123,610.82		1.42%		-2.85%	
Deere & Co	DE	853.43363	61.17	52,204.54		4.36%		23.10%	
Dominion Energy Inc	D	445.66693	49.01	21,842.14	0.05%			15.53%	0.01%
Dover Corp	DOV	137.13445	166.83	22,878.14	0.06%	1.25%	0.00%	11.53%	0.01%
Alliant Energy Corp	LNT	256.96923	67.41	17,322.30	0.04%	3.01%	0.00%	6.09%	0.00%
Steel Dynamics Inc	STLD	147.20459	139.43	20,524.74	0.05%	1.43%	0.00%	13.77%	0.01%
Duke Energy Corp	DUK	777.02168	123.75	96,156.43	0.23%	3.44%	0.01%	7.44%	0.02%
Regency Centers Corp	REG	181.55331	72.9	13,235.24	0.03%	3.87%	0.00%	5.02%	0.00%
Eaton Corp PLC	ETN	389.3	374.25	145,695.53	0.35%	1.11%	0.00%	13.81%	0.05%
Ecolab Inc	ECL	283.62491	273.86	77,673.52	0.19%	0.95%	0.00%	13.00%	0.02%
Revvity Inc	RVTY	116.07258	87.65	10,173.76	0.02%	0.32%	0.00%	6.16%	0.00%
Dell Technologies Inc	DELL	336.90462	141.77	47,762.97	0.12%	1.48%	0.00%	16.92%	0.02%
Emerson Electric Co	EMR	562.8	131.18	73,828.10	0.18%	1.61%	0.00%	10.06%	0.02%
EOG Resources Inc	EOG	545.99342	112.12	61,216.78		3.64%			
Aon PLC	AON	215.6266	356.58	76,888.13	0.19%	0.84%	0.00%	10.12%	0.02%
Entergy Corp	ETR	446.40907	93.19	41,600.86	0.10%	2.58%	0.00%	5.80%	0.01%
Equifax Inc	EFX	123.79738	256.53	31,757.74	0.08%	0.78%	0.00%	10.18%	0.01%
EQT Corp	EQT	624.06446	54.43	33,967.83		1.16%		41.56%	
IQVIA Holdings Inc	IQV	170	189.94	32,289.80	0.08%			8.97%	0.01%
Gartner Inc	IT	75.7358	262.87	19,908.67					
FedEx Corp	FDX	235.95546	235.81	55,640.66	0.14%	2.46%	0.00%	9.05%	0.01%
Brown & Brown Inc	BRO	329.84281	93.79	30,935.96	0.08%	0.64%	0.00%	11.27%	0.01%
Ford Motor Co	F	3909.00822	11.96	46,751.74		5.02%		-1.10%	
NextEra Energy Inc	NEE	2059.29259	75.49	155,456.00	0.38%	3.00%	0.01%	7.39%	0.03%
Franklin Resources Inc	BEN	519.19548	23.13	12,008.99		5.53%		-0.14%	
Garmin Ltd	GRMN	192.49395	246.22	47,395.86	0.12%	1.46%	0.00%	11.16%	0.01%
Freeport-McMoRan Inc	FCX	1435.77413	39.22	56,311.06		1.53%		24.99%	
Expand Energy Corp	EXE	238.14568	106.24	25,300.60		5.52%			
Dexcom Inc	DXCM	392.15527	67.29	26,388.13				23.31%	
General Dynamics Corp	GD	268.99334	341	91,726.73	0.22%	1.76%	0.00%	14.95%	0.03%
General Mills Inc	GIS	533.41642	50.42	26,894.86		4.84%		-2.94%	
Genuine Parts Co	GPC	139.09229	138.6	19,278.19		2.97%			
Atmos Energy Corp	ATO	160.52357	170.75	27,409.40		2.04%			
WW Grainger Inc	GWW	47.83224	952.96	45,582.21	0.11%	0.95%	0.00%	4.41%	0.00%
Halliburton Co	HAL	852.6021	24.6	20,974.01		2.76%			
L3Harris Technologies Inc	LHX	187.0948	305.41	57,140.62	0.14%	1.57%	0.00%	12.88%	0.02%
Healthpeak Properties Inc	DOC	694.92345	19.15	13,307.78	0.03%	6.37%	0.00%	4.24%	0.00%
Insulet Corp	PODD	70.39253	308.73	21,732.29				25.99%	
Fortive Corp	FTV	338.33635	48.99	16,575.10		0.49%			
Hershey Co/The	HSY	148.11072	187.05	27,704.11		2.93%		-8.41%	
Synchrony Financial	SYF	372.05755	71.05	26,434.69	0.06%	1.69%	0.00%	16.89%	0.01%
Hormel Foods Corp	HRL	549.99843	24.74	13,606.96		4.69%			
Arthur J Gallagher & Co	AJG	256.4	309.74	79,417.34		0.84%			
Mondelez International Inc	MDLZ	1293.94541	62.47	80,832.77	0.20%	3.20%	0.01%	1.85%	0.00%
CenterPoint Energy Inc	CNP	652.7284	38.8	25,325.86	0.06%	2.27%	0.00%	8.98%	0.01%
Humana Inc	HUM	120.27182	260.17	31,291.12	0.08%	1.36%	0.00%	14.02%	0.01%
Willis Towers Watson PLC	WTW	97.54799	345.45	33,697.95	0.08%	1.07%	0.00%	7.47%	0.01%
Illinois Tool Works Inc	ITW	291.5	260.76	76,011.54	0.18%	2.47%	0.00%	1.93%	0.00%
CDW Corp/DE	CDW	131.06075	159.28	20,875.36	0.05%	1.57%	0.00%	6.38%	0.00%
Trane Technologies PLC	TT	222.51536	421.96	93,892.58	0.23%	0.89%	0.00%	11.32%	0.03%
Interpublic Group of Cos Inc/The	IPG	366.26639	27.91	10,222.49	0.02%	4.73%	0.00%	9.40%	0.00%
International Flavors & Fragrances Inc	IFF	256.28708	61.54	15,771.91	0.04%	2.60%	0.00%	2.12%	0.00%
Generac Holdings Inc	GNRC	58.67595	167.4	9,822.35				20.91%	
NXP Semiconductors NV	NXPI	252.1146	227.73	57,414.06	0.14%	1.78%	0.00%	5.71%	0.01%
Kellanova	K	347.6692	82.02	28,515.83	0.07%	2.83%	0.00%	1.79%	0.00%
Broadridge Financial Solutions Inc	BR	117.12932	238.17	27,896.69		1.64%			
Kimberly-Clark Corp	KMB	679.49863	21.85	14,847.05	0.04%	4.58%	0.00%	3.88%	0.00%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Kimco Realty Corp	KIM	2850.79261	281.24	801,756.91	1.95%	0.71%	0.01%	18.09%	0.35%
Oracle Corp	ORCL	662.67821	67.41	44,671.14	0.11%	2.08%	0.00%	6.37%	0.01%
Kroger Co/The	KR	227.60164	126.04	28,686.91		1.59%		-9.37%	
Lennar Corp	LEN	946.45676	763	722,146.51	1.76%	0.79%	0.01%	18.00%	0.32%
Eli Lilly & Co	LLY	136.59098	275.105	37,576.86	0.09%			10.93%	0.01%
Charter Communications Inc	CHTR	207.4264	100.39	20,823.54		0.25%			
Loews Corp	L	560.8249	251.31	140,940.91	0.34%	1.91%	0.01%	6.54%	0.02%
Lowe's Cos Inc	LOW	53.14001	430.31	22,866.68		1.23%			
Hubbell Inc	HUBB	75.28728	162.76	12,253.76		1.74%			
IDEX Corp	IEX	491.62404	201.53	99,076.99	0.24%	1.79%	0.00%	8.31%	0.02%
Marsh & McLennan Cos Inc	MMC	209.36364	70.39	14,737.11	0.04%	1.76%	0.00%	6.47%	0.00%
Masco Corp	MAS	312.5	486.71	152,096.88		0.79%			
S&P Global Inc	SPGI	1282.68588	95.24	122,163.00	0.30%	2.98%	0.01%	5.90%	0.02%
Medtronic PLC	MDT	1165.87213	9.9	11,542.13		4.85%		-2.32%	
Viatris Inc	VTRS	1268.32638	75.39	95,619.13	0.23%	3.53%	0.01%	6.43%	0.01%
CVS Health Corp	CVS	418.71669	77.9	32,618.03	0.08%	2.11%	0.00%	6.31%	0.01%
DuPont de Nemours Inc	DD	1119.1251	167.32	187,252.01		0.27%		28.55%	
Micron Technology Inc	MU	166.60389	457.29	76,186.29	0.19%	0.95%	0.00%	8.26%	0.02%
Motorola Solutions Inc	MSI	104.59013	245.25	25,650.73	0.06%	1.17%	0.00%	13.77%	0.01%
Cboe Global Markets Inc	CBOE	1098.44973	84.31	92,610.30	0.23%	1.19%	0.00%	16.41%	0.04%
Newmont Corp	NEM	1188.01574	69.73	82,840.34	0.20%	2.29%	0.00%	19.22%	0.04%
NIKE Inc	NKE	470.85501	43.3	20,388.02		2.59%			
NiSource Inc	NI	224.61489	300.41	67,476.56		1.80%			
Norfolk Southern Corp	NSC	222.76844	82.91	18,469.73	0.04%	3.76%	0.00%	12.73%	0.01%
Principal Financial Group Inc	PFG	371.11518	71.14	26,401.13	0.06%	4.23%	0.00%	4.40%	0.00%
Eversource Energy	ES	143.18298	609.32	87,244.25	0.21%	1.52%	0.00%	4.95%	0.01%
Northrop Grumman Corp	NOC	3203.44121	83.82	268,512.44	0.65%	2.15%	0.01%	14.00%	0.09%
Wells Fargo & Co	WFC	229.53545	135.43	31,085.99	0.08%	1.62%	0.00%	18.58%	0.01%
Nucor Corp	NUE	984.43974	47.25	46,514.78		2.03%			
Occidental Petroleum Corp	OXY	193.72289	81.53	15,794.23	0.04%	3.43%	0.00%	7.99%	0.00%
Omnicom Group Inc	OMC	629.75598	72.97	45,953.29	0.11%	5.65%	0.01%	8.97%	0.01%
ONEOK Inc	OKE	199.38398	172.1	34,313.98	0.08%	1.16%	0.00%	11.82%	0.01%
Raymond James Financial Inc	RJF	2197.8374	15.08	33,143.39	0.08%	0.66%	0.00%	8.91%	0.01%
PG&E Corp	PCG	126.54407	758.15	95,939.39	0.23%	0.95%	0.00%	7.61%	0.02%
Parker-Hannifin Corp	PH	484.64	58.74	28,467.75		1.12%			
Rollins Inc	ROL	739.51524	37.16	27,480.39	0.07%	2.93%	0.00%	7.34%	0.00%
PPL Corp	PPL	217.75981	86.22	18,775.25	0.05%			16.62%	0.01%
Aptiv PLC	APTV	1248.94231	94.59	118,137.45		3.30%			
ConocoPhillips	COP	197.29757	132.13	26,068.93		0.67%		-2.19%	
PulteGroup Inc	PHM	119.42724	89.66	10,707.85		3.99%			
Pinnacle West Capital Corp	PNW	393.80738	200.93	79,127.72	0.19%	3.38%	0.01%	10.42%	0.02%
PNC Financial Services Group Inc/The	PNC	225.7	105.11	23,723.33	0.06%	2.70%	0.00%	6.81%	0.00%
PPG Industries Inc	PPG	398.68051	271.99	108,437.11					
DoorDash Inc	DASH	586.20849	246.95	144,764.19		0.16%		50.71%	
Progressive Corp/The	PGR	248.16085	106.61	26,456.43		0.41%			
Veralto Corp	VLTO	499.07975	83.46	41,653.20	0.10%	3.02%	0.00%	8.76%	0.01%
Public Service Enterprise Group Inc	PEG	198.80892	68.56	13,630.34	0.03%			9.31%	0.00%
Cooper Cos Inc/The	COO	384.83401	55.28	21,273.62	0.05%	5.99%	0.00%	9.60%	0.00%
Edison International	EIX	1493.87884	34.37	51,344.62		3.32%		-4.18%	
Schlumberger NV	SLB	1815.2193	95.47	173,298.99	0.42%	1.13%	0.00%	19.98%	0.08%
Charles Schwab Corp/The	SCHW	249.33332	346.26	86,334.16	0.21%	0.91%	0.00%	6.92%	0.01%
Sherwin-Williams Co/The	SHW	71.90733	262.33	18,863.45	0.05%	0.34%	0.00%	8.04%	0.00%
West Pharmaceutical Services Inc	WST	106.68516	108.6	11,586.01	0.03%	4.05%	0.00%	1.56%	0.00%
J M Smucker Co/The	SJM	52.16337	346.53	18,076.17	0.04%	2.47%	0.00%	4.10%	0.00%
Snap-on Inc	SNA	230.95396	188	43,419.34	0.11%	0.66%	0.00%	9.13%	0.01%
AMETEK Inc	AME	2085.41868	97.97	204,308.47				-3.85%	
Uber Technologies Inc	UBER	1100.19364	94.77	104,265.35	0.25%	3.12%	0.01%	6.75%	0.02%
Southern Co/The	SO	1289.43517	45.72	58,952.98	0.14%	4.55%	0.01%	9.19%	0.01%
Truist Financial Corp	TFC	525.18771	31.91	16,758.74		2.26%		58.26%	
Southwest Airlines Co	LUV	379.29277	76.62	29,061.41	0.07%	0.47%	0.00%	6.85%	0.00%
W R Berkley Corp	WRB	154.79225	74.33	11,505.71		4.47%			
Stanley Black & Decker Inc	SWK	175.45285	288.85	50,679.56	0.12%	4.15%	0.01%	2.40%	0.00%
Public Storage	PSA	1256.86538	145.71	183,137.85	0.45%			18.74%	0.08%
Arista Networks Inc	ANET	478.21236	82.34	39,376.01		2.62%			
Sysco Corp	SYY	683.01458	67.63	46,192.28	0.11%	1.06%	0.00%	16.37%	0.02%
Corteva Inc	CTVA	909.13717	183.73	167,035.77	0.41%	3.09%	0.01%	11.04%	0.04%
Texas Instruments Inc	TXN	178.2053	84.49	15,056.57	0.04%	0.09%	0.00%	10.03%	0.00%
Textron Inc	TXT	377.61212	485.02	183,149.43	0.45%	0.35%	0.00%	7.56%	0.03%
Thermo Fisher Scientific Inc	TMO	1112.93875	144.54	160,864.17	0.39%	1.18%	0.00%	8.43%	0.03%
TJX Cos Inc/The	TJX	81.00354	142.97	11,581.08		0.76%			
Globe Life Inc	GL	654.38544	109.95	71,949.68	0.17%	1.46%	0.00%	15.92%	0.03%
Johnson Controls International plc	JCI	44.83836	546.75	24,515.37	0.06%			4.39%	0.00%
Ulta Beauty Inc	ULTA	593.04367	236.37	140,177.73	0.34%	2.34%	0.01%	7.79%	0.03%
Union Pacific Corp	UNP	171.85625	174.92	30,061.10	0.07%			12.93%	0.01%
Keysight Technologies Inc	KEYS	905.67363	345.3	312,729.10	0.76%	2.56%	0.02%	14.00%	0.11%
UnitedHealth Group Inc	UNH	737.09167	170.85	125,932.11		2.41%		24.34%	
Blackstone Inc	BX	454.47119	69.99	31,808.44	0.08%	2.74%	0.00%	9.69%	0.01%
Ventas Inc	VTR	83.1	287.06	23,854.69	0.06%	1.00%	0.00%	8.77%	0.01%
Labcorp Holdings Inc	LH	132.12416	307.62	40,644.03	0.10%	0.64%	0.00%	14.51%	0.01%
Vulcan Materials Co	VMC	721.511	24.79	17,886.26		3.39%		-8.95%	
Weyerhaeuser Co	WY	1221.17743	63.35	77,361.59		3.16%		22.27%	

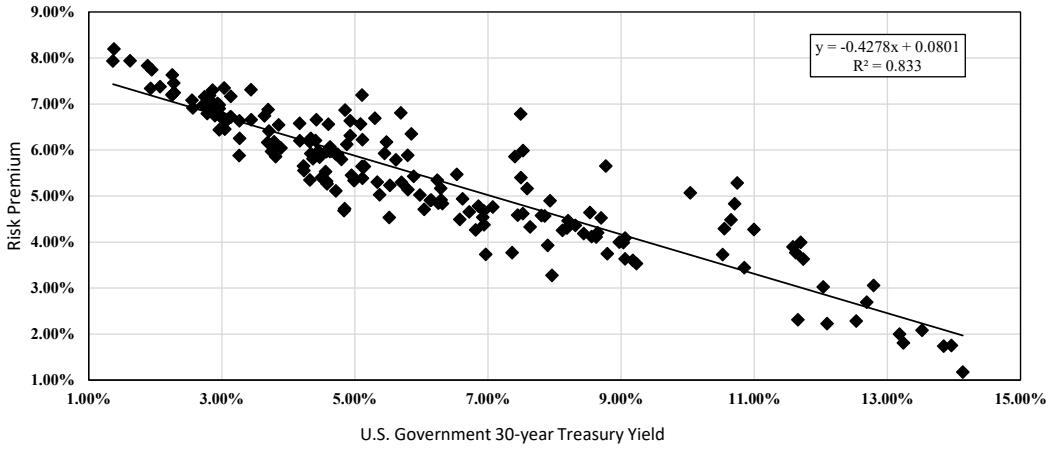
		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Williams Cos Inc/The	WMB	312.40558	329.07	102,803.30	0.25%	0.47%	0.00%	16.22%	0.04%
Constellation Energy Corp	CEG	307.63637	718.54	221,049.04				80.10%	
WEC Energy Group Inc	WEC	321.8664	114.59	36,882.67	0.09%	3.12%	0.00%	7.65%	0.01%
Adobe Inc	ADBE	418.6	352.75	147,661.15	0.36%			14.13%	0.05%
Vistra Corp	VST	338.82032	195.92	66,381.68	0.16%	0.46%	0.00%	10.35%	0.02%
AES Corp/The	AES	712.04956	13.16	9,370.57	0.02%	5.35%	0.00%	11.17%	0.00%
Expeditors International of Washington Inc	EXPD	135.71852	122.59	16,637.73	0.04%	1.26%	0.00%	4.89%	0.00%
Amgen Inc	AMGN	538.36185	282.2	151,925.71	0.37%	3.37%	0.01%	5.37%	0.02%
Apple Inc	AAPL	14840.39	254.63	3,778,808.51	9.19%	0.41%	0.04%	14.26%	1.31%
Autodesk Inc	ADSK	213	317.67	67,663.71	0.16%			15.08%	0.02%
Cintas Corp	CTAS	404.39145	205.26	83,005.39		0.88%			
Comcast Corp	CMCSA	3682.76213	31.09	114,497.07	0.28%	4.25%	0.01%	1.88%	0.01%
Molson Coors Beverage Co	TAP	185.38756	45.25	8,388.79	0.02%	4.15%	0.00%	0.78%	0.00%
KLA Corp	KLAC	131.68453	1078.6	142,034.93	0.35%	0.70%	0.00%	10.30%	0.04%
Marriott International Inc/MD	MAR	271.45784	260.44	70,698.48	0.17%	1.03%	0.00%	10.15%	0.02%
Fiserv Inc	FI	543.59318	128.93	70,085.47					
McCormick & Co Inc/MD	MKC	253.0412	66.91	16,930.99	0.04%	2.69%	0.00%	6.37%	0.00%
PACCAR Inc	PCAR	525.10339	98.32	51,628.17		1.34%		-3.95%	
Costco Wholesale Corp	COST	443.47709	925.63	410,495.70	1.00%	0.56%	0.01%	6.75%	0.07%
Stryker Corp	SYK	382.3073	369.67	141,327.54	0.34%	0.91%	0.00%	10.57%	0.04%
Tyson Foods Inc	TSN	285.76038	54.3	15,516.79	0.04%	3.68%	0.00%	18.82%	0.01%
Lamb Weston Holdings Inc	LW	139.35248	58.08	8,093.59		2.55%		-2.55%	
Applied Materials Inc	AMAT	796.64243	204.74	163,104.57	0.40%	0.90%	0.00%	7.67%	0.03%
Cardinal Health Inc	CAH	237.58268	156.4493	37,169.64	0.09%	1.31%	0.00%	13.03%	0.01%
Cincinnati Financial Corp	CINF	156.37642	158.1	24,723.11	0.06%	2.20%	0.00%	3.48%	0.00%
Paramount Global	PARA	298.12353	169.47	50,522.99	0.12%	0.94%	0.00%	0.38%	0.00%
DR Horton Inc	DHI	250.2073	201.7	50,466.81	0.12%	0.38%	0.00%	10.70%	0.01%
Electronic Arts Inc	EA	46.18907	318.16	14,695.51		1.72%			
Erie Indemnity Co	ERIE	24.00366	1496.53	35,922.20					
Fair Isaac Corp	FICO	1147.63662	49.04	56,280.10	0.14%	1.79%	0.00%	11.06%	0.02%
Fastenal Co	FAST	156.26929	197.62	30,881.94	0.08%	3.04%	0.00%	12.35%	0.01%
M&T Bank Corp	MTB	591.42618	80.65	47,698.52	0.12%	2.83%	0.00%	8.88%	0.01%
Xcel Energy Inc	XEL	661.88724	44.55	29,487.08		3.59%			
Fifth Third Bancorp	FITB	1240.80692	111	137,729.57		2.85%		29.15%	
Gilead Sciences Inc	GILD	140.23254	75.85	10,636.64	0.03%	3.69%	0.00%	15.87%	0.00%
Hasbro Inc	HAS	1458.80004	17.27	25,193.48	0.06%	3.59%	0.00%	14.17%	0.01%
Huntington Bancshares Inc/OH	HBAN	668.82594	178.14	119,144.65	0.29%	1.66%	0.00%	17.51%	0.05%
Welltower Inc	WELL	146.6146	140.08	20,537.77	0.05%			0.90%	0.00%
Biogen Inc	BIIB	191.2333	134.6	25,740.00	0.06%	2.38%	0.00%	9.85%	0.01%
Northern Trust Corp	NTRS	89.97878	217.93	19,609.08	0.05%	2.29%	0.00%	11.26%	0.01%
Packaging Corp of America	PKG	359.89414	126.76	45,620.18		3.41%			
Paychex Inc	PAYX	1079	166.36	179,502.44	0.44%	2.14%	0.01%	7.74%	0.03%
QUALCOMM Inc	QCOM	325.22627	152.39	49,561.23	0.12%	1.06%	0.00%	5.82%	0.01%
Ross Stores Inc	ROST	80.00469	638.89	51,114.20	0.12%			13.50%	0.02%
IDEXX Laboratories Inc	IDXX	1136.7	84.6	96,164.82		2.88%		-0.30%	
Starbucks Corp	SBUX	1096.51584	18.69	20,493.88	0.05%	4.39%	0.00%	19.79%	0.01%
KeyCorp	KEY	210.51946	63.06	13,275.36		0.89%		-1.49%	
Fox Corp	FOXA	235.58103	57.29	13,496.44		0.98%		-1.49%	
Fox Corp	FOX	283.69534	115.17	32,673.19	0.08%	2.92%	0.00%	12.69%	0.01%
State Street Corp	STT	455.25095	24.63	11,212.83	0.03%			16.72%	0.00%
Norwegian Cruise Line Holdings Ltd	NCLH	1556.18945	48.33	75,210.64	0.18%	4.30%	0.01%	9.63%	0.02%
US Bancorp	USB	114.25952	73.41	8,387.79		1.85%			
A O Smith Corp	AOS	615.86911	28.39	17,484.52	0.04%	1.76%	0.00%	13.08%	0.01%
Gen Digital Inc	GEN	219.71524	102.64	22,551.57		4.95%		-0.94%	
T Rowe Price Group Inc	TROW	402.83032	220.83	88,957.02	0.22%	1.49%	0.00%	11.23%	0.02%
Waste Management Inc	WM	176.26624	134.67	23,737.77		3.03%		-2.05%	
Constellation Brands Inc	STZ	445.96377	22.94	10,230.41	0.02%	3.66%	0.00%	14.17%	0.00%
Invesco Ltd	IVZ	278.805	682.91	190,398.72		0.70%			
Intuit Inc	INTU	1596.33576	158.96	253,753.53	0.62%	2.52%	0.02%	10.15%	0.06%
Morgan Stanley	MS	539.67967	64.22	34,658.23		2.83%		29.58%	
Microchip Technology Inc	MCHP	250.95514	490.38	123,063.38	0.30%			17.74%	0.05%
Crowdstrike Holdings Inc	CRWD	398.69029	282.25	112,530.33	0.27%	1.37%	0.00%	4.11%	0.01%
Chubb Ltd	CB	222.41928	67.49	15,011.08	0.04%			7.67%	0.00%
Hologic Inc	HOLX	431.34899	53.16	22,930.51		3.16%		24.02%	
Citizens Financial Group Inc	CFG	107.31884	217.17	23,306.43	0.06%	0.15%	0.00%	13.93%	0.01%
Jabil Inc	JBL	848.49668	107.81	91,476.43	0.22%			10.54%	0.02%
O'Reilly Automotive Inc	ORLY	263.50533	214.65	56,561.42		1.86%		20.50%	
Allstate Corp/The	ALL	381.89806	64.73	24,720.26	0.06%	4.28%	0.00%	3.64%	0.00%
Equity Residential	EQR	1358.43528	25.51	34,653.68	0.08%	3.61%	0.00%	6.51%	0.01%
Keurig Dr Pepper Inc	KDP	687.54288	17.02	11,701.98		4.70%		-0.96%	
Host Hotels & Resorts Inc	HST	195.27615	84.81	16,561.37				25.00%	
Incyte Corp	INCY	326.48476	187.67	61,271.39	0.15%	4.58%	0.01%	1.32%	0.00%
Simon Property Group Inc	SPG	114.83241	63.05	7,240.18		5.27%			
Eastman Chemical Co	EMN	142.38302	193.17	27,504.13	0.07%	3.62%	0.00%	5.18%	0.00%
AvalonBay Communities Inc	AVB	352	103.74	36,516.48	0.09%	5.21%	0.00%	8.23%	0.01%
Prudential Financial Inc	PRU	736.0429	83.53	61,481.66		7.85%		-0.74%	
United Parcel Service Inc	UPS	98.49061	247.44	24,370.52		1.02%			
Walgreens Boots Alliance Inc	WBA	124.38439	772.54	96,091.92	0.23%	0.42%	0.00%	13.50%	0.03%
STERIS PLC	STE	233.46506	499.21	116,548.09	0.28%	2.64%	0.01%	11.53%	0.03%
McKesson Corp	MCK	193.87788	312.53	60,592.65	0.15%	0.70%	0.00%	10.33%	0.02%
Lockheed Martin Corp	LMT	639.51731	212.58	135,948.59		1.13%		22.86%	

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Cencora Inc	COR	297.99253	31.58	9,410.60		4.94%		-2.52%	
Capital One Financial Corp	COF	59.52413	299.81	17,845.93	0.04%			9.42%	0.00%
The Campbell's Company	CPB	56.1863	226.95	12,751.48		1.45%			
Waters Corp	WAT	203.96784	94.37	19,248.45	0.05%			9.96%	0.00%
Nordson Corp	NDSN	116.31376	190.36	22,141.49	0.05%	3.15%	0.00%	10.59%	0.01%
Dollar Tree Inc	DLTR	229.74594	76.02	17,465.29	0.04%	3.51%	0.00%	5.78%	0.00%
Darden Restaurants Inc	DRI	240.62215	35.32	8,498.77	0.02%	2.15%	0.00%	16.37%	0.00%
Evergy Inc	EVRG	2.8698	8034.66	23,057.87	0.06%			1.72%	0.00%
Match Group Inc	MTCH	199.61839	118.46	23,646.79	0.06%	1.76%	0.00%	7.34%	0.00%
NVR Inc	NVR	210.16814	140.78	29,587.47	0.07%	0.80%	0.00%	5.03%	0.00%
NetApp Inc	NTAP	71.5	132.87	9,500.21	0.02%			10.59%	0.00%
Old Dominion Freight Line Inc	ODFL	281.17166	133.39	37,505.49	0.09%	1.56%	0.00%	8.89%	0.01%
DaVita Inc	DVA	295.34823	101.94	30,107.80		3.08%			
Hartford Insurance Group Inc/The	HIG	234.81506	88.12	20,691.90		1.59%			
Iron Mountain Inc	IRM	272.49	351.26	95,714.84	0.23%			14.66%	0.03%
Estee Lauder Cos Inc/The	EL	43.26181	523.16	22,632.85					
Cadence Design Systems Inc	CDNS	56.38801	204.44	11,527.96	0.03%	0.39%	0.00%	10.17%	0.00%
Tyler Technologies Inc	TYL	148.42757	76.98	11,425.95		3.69%		-9.02%	
Universal Health Services Inc	UHS	111.82344	190.58	21,311.31	0.05%	1.68%	0.00%	1.06%	0.00%
Skyworks Solutions Inc	SWKS	112.4344	349.53	39,299.20	0.10%	1.50%	0.00%	14.56%	0.01%
Quest Diagnostics Inc	DGX	1183.59922	26.04	30,820.92		6.14%		-4.68%	
Rockwell Automation Inc	ROK	468.25123	192.32	90,054.08		3.54%		23.73%	
Kraft Heinz Co/The	KHC	104.1703	562.27	58,571.83	0.14%	0.63%	0.00%	8.03%	0.01%
American Tower Corp	AMT	10664.9121	219.57	2,341,694.75	5.69%			16.62%	0.95%
Regeneron Pharmaceuticals Inc	REGN	72.6652	148.93	10,822.03		1.56%			
Amazon.com Inc	AMZN	38.69301	313.56	12,132.58	0.03%	1.16%	0.00%	13.40%	0.00%
Jack Henry & Associates Inc	JKHY	158.37552	74.34	11,773.64	0.03%	3.77%	0.00%	1.39%	0.00%
Ralph Lauren Corp	RL	1220.92111	123.75	151,088.99		0.53%		26.21%	
BXP Inc	BXP	403.12632	196.23	79,105.48	0.19%	0.24%	0.00%	17.38%	0.03%
Amphenol Corp	APH	310.65174	170.26	52,891.57	0.13%	2.65%	0.00%	17.29%	0.02%
Howmet Aerospace Inc	HWM	185.74867	493.39	91,646.54	0.22%			9.76%	0.02%
Valero Energy Corp	VLO	118.09116	132.4	15,635.27	0.04%	1.87%	0.00%	15.51%	0.01%
Synopsys Inc	SNPS	622.8527	246.6	153,595.48		2.64%			
CH Robinson Worldwide Inc	CHRW	56.35029	1318.02	74,270.81	0.18%			12.86%	0.02%
Accenture PLC	ACN	277.5357	152	42,185.43	0.10%	1.87%	0.00%	9.48%	0.01%
TransDigm Group Inc	TDG	926.175	114.52	106,065.56	0.26%	3.53%	0.01%	5.72%	0.01%
Yum! Brands Inc	YUM	577.12618	45.82	26,443.92		3.88%		-4.30%	
Prologis Inc	PLD	93.4	279.57	26,111.84		1.10%			
FirstEnergy Corp	FE	149.00594	414.3201	61,736.16	0.15%	0.10%	0.00%	14.67%	0.02%
VeriSign Inc	VRSN	121.2684	66.37	8,048.58	0.02%			4.67%	0.00%
Quanta Services Inc	PWR	270.40992	104.38	28,225.39	0.07%	2.72%	0.00%	8.89%	0.01%
Henry Schein Inc	HSIC	37.80677	286.49	10,831.26		1.54%			
Ameren Corp	AEE	24300	186.58	4,533,894.00		0.02%		39.00%	
ANSYS Inc	ANSS	488.39594	67.07	32,756.72		1.85%			
FactSet Research Systems Inc	FDS	358.47651	447.23	160,321.45	0.39%			15.50%	0.06%
NVIDIA Corp	NVDA	184.47021	258.36	47,659.72				58.37%	
Cognizant Technology Solutions Corp	CTSH	312.21582	229.48	71,647.29	0.17%	1.09%	0.00%	9.49%	0.02%
Intuitive Surgical Inc	ISRG	457	90.95	41,564.15	0.10%	1.28%	0.00%	10.81%	0.01%
Take-Two Interactive Software Inc	TTWO	302.72109	796.35	241,071.94	0.59%	2.01%	0.01%	13.64%	0.08%
Republic Services Inc	RSG	107.37901	193.35	20,761.73	0.05%	2.30%	0.00%	8.73%	0.00%
eBay Inc	EBAY	652.47246	89.335	58,288.63		2.89%			
Goldman Sachs Group Inc/The	GS	179	476.48	85,289.92		0.79%			
SBA Communications Corp	SBAC	408.97399	49.31	20,166.51				-3.65%	
Sempra	SRE	32.40989	5399.27	174,989.75	0.43%	0.71%	0.00%	16.74%	0.07%
Moody's Corp	MCO	57.44717	323.19	18,566.35	0.05%			7.13%	0.00%
ON Semiconductor Corp	ON	143.38553	75.76	10,862.89	0.03%			4.90%	0.00%
Booking Holdings Inc	BKNG	49.21418	156.46	7,700.05	0.02%			3.67%	0.00%
F5 Inc	FFIV	634.8	35.06	22,256.09	0.05%	2.74%	0.00%	4.26%	0.00%
Akamai Technologies Inc	AKAM	155.69102	55.63	8,661.09		0.58%			
Charles River Laboratories International Inc	CRL	5817	243.1	1,414,112.70	3.44%	0.35%	0.01%	12.93%	0.44%
MarketAxess Holdings Inc	MKTX	85.84652	177.35	15,224.88	0.04%	1.15%	0.00%	5.69%	0.00%
Devon Energy Corp	DVN	424.92635	1198.92	509,452.70				26.62%	
Bio-Techne Corp	TECH	2475.77228	19.53	48,351.83				40.59%	
Alphabet Inc	GOOGL	283.50043	128.35	36,387.28	0.09%	0.77%	0.00%	7.99%	0.01%
Allegion plc	ALLE	237.96909	81.65	19,430.18					
Netflix Inc	NFLX	225.1783	323.12	72,759.61		2.12%		-0.92%	
Agilent Technologies Inc	A	360.37704	270.19	97,370.27	0.24%	1.85%	0.00%	5.71%	0.01%
Warner Bros Discovery Inc	WBD	207.51775	141.43	29,349.24	0.07%	3.08%	0.00%	6.37%	0.00%
Trimble Inc	TRMB	573.79524	88.45	50,752.19	0.12%	1.22%	0.00%	15.63%	0.02%
Elevance Health Inc	ELV	1556.58934	162.2	252,478.79	0.61%	3.63%	0.02%	11.27%	0.07%
CME Group Inc	CME	952	237	225,624.00	0.55%	0.70%	0.00%	12.74%	0.07%
Juniper Networks Inc	JNPR	397.45252	82.62	32,837.53		0.10%			
DTE Energy Co	DTE	39.24063	287.91	11,297.77	0.03%	1.88%	0.00%	14.49%	0.00%
Nasdaq Inc	NDAQ	107.61382	498.69	53,665.94		0.66%			
Philip Morris International Inc	PM	665.02605	82.37	54,778.20	0.13%	2.76%	0.00%	12.81%	0.02%
Ingersoll Rand Inc	IR	209.06857	113.22	23,670.74	0.06%	1.41%	0.00%	7.22%	0.00%
Salesforce Inc	CRM	1864.27701	35.51	66,200.48	0.16%	1.46%	0.00%	6.33%	0.01%
Roper Technologies Inc	ROP	587.1	77.77	45,658.77	0.11%			8.64%	0.01%
Huntington Ingalls Industries Inc	HII	94.27157	491.25	46,310.91	0.11%	1.30%	0.00%	10.55%	0.01%
MetLife Inc	MET	50.84515	297.16	15,109.14					
Tapestry Inc	TPR	198.09598	98.5	19,512.45	0.05%	0.97%	0.00%	4.65%	0.00%

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
CSX Corp	CSX	297.55433	157.56	46,882.66					
Edwards Lifesciences Corp	EW	106.85273	106.78	11,409.73	0.03%	3.93%	0.00%	1.63%	0.00%
Ameriprise Financial Inc	AMP	897.27417	568.81	510,378.52	1.24%	0.53%	0.01%	15.34%	0.19%
Zebra Technologies Corp	ZBRA	323.2707	142.4	46,033.75	0.11%			8.38%	0.01%
Zimmer Biomet Holdings Inc	ZBH	146.84504	44.87	6,588.94	0.02%			15.69%	0.00%
Camden Property Trust	CPT	572.42309	168.48	96,441.84	0.23%	1.14%	0.00%	14.37%	0.03%
CBRE Group Inc	CBRE	522.14418	42.57	22,227.68		4.05%		72.38%	
Mastercard Inc	MA	522.37858	65.94	34,445.64		2.43%			
CarMax Inc	KMX	1340.885	39.19	52,549.28	0.13%			15.60%	0.02%
Intercontinental Exchange Inc	ICE	103.97653	128.27	13,337.07	0.03%	0.78%	0.00%	4.22%	0.00%
Fidelity National Information Services Inc	FIS	234.47273	163.4	38,312.84					
Smurfit WestRock PLC	SW	50.45921	216.6	10,929.46		1.48%			
Chipotle Mexican Grill Inc	CMG	193.4308	161.95	31,326.12		1.09%			
Wynn Resorts Ltd	WYNN	892.30835	26.37	23,530.17	0.06%	4.02%	0.00%	7.96%	0.00%
Live Nation Entertainment Inc	LYV	976.42819	67.31	65,723.38	0.16%			14.71%	0.02%
Assurant Inc	AIZ	317.37833	34.68	11,006.68	0.03%	2.54%	0.00%	3.57%	0.00%
NRG Energy Inc	NRG	985.87912	48.72	48,032.03	0.12%	1.89%	0.00%	9.16%	0.01%
Monster Beverage Corp	MNST	118.19213	213.75	25,263.57	0.06%	0.75%	0.00%	18.12%	0.01%
Regions Financial Corp	RF	331.77994	124.34	41,253.52	0.10%	4.05%	0.00%	1.97%	0.00%
Baker Hughes Co	BKR	161.97296	89.7	14,528.97		2.23%		-4.53%	
Mosaic Co/The	MOS	128.29733	188.96	24,243.06	0.06%	0.85%	0.00%	9.35%	0.01%
Expedia Group Inc	EXPE	357.78646	24.28	8,687.06		4.12%			
CF Industries Holdings Inc	CF	82.13689	201.96	16,588.37		1.51%		93.41%	
APA Corp	APA	5430	243.55	1,322,476.50	3.21%	0.34%	0.01%	12.93%	0.42%
Leidos Holdings Inc	LDOS	107.24765	220.53	23,651.32				37.61%	
Alphabet Inc	GOOG	1698.68253	341.38	579,896.24	1.41%	0.69%	0.01%	13.36%	0.19%
TKO Group Holdings Inc	TKO	117.07114	139.73	16,358.35	0.04%	4.34%	0.00%	1.55%	0.00%
First Solar Inc	FSLR	243.40969	147.5	35,902.93		1.08%			
Discover Financial Services	DFS	304.02031	192.74	58,596.87	0.14%	1.89%	0.00%	7.16%	0.01%
Visa Inc	V	1622.84369	161.79	262,559.88				31.34%	
Mid-America Apartment Communities Inc	MAA	529.95167	56.87	30,138.35	0.07%	1.62%	0.00%	9.79%	0.01%
Xylem Inc/NY	XYL	146.41484	273.73	40,078.13	0.10%	0.88%	0.00%	9.57%	0.01%
Marathon Petroleum Corp	MPC	20.59904	1227.61	25,287.59	0.06%			7.93%	0.00%
Tractor Supply Co	TSCO	119.53647	149.86	17,913.74	0.04%	0.85%	0.00%	13.35%	0.01%
Advanced Micro Devices Inc	AMD	967.73153	44.97	43,518.89					
ResMed Inc	RMD	1066.36978	32.61	34,774.32	0.08%	5.52%	0.00%	4.24%	0.00%
Mettler-Toledo International Inc	MTD	766.26603	84.08	64,427.65	0.16%			10.99%	0.02%
VICI Properties Inc	VICI	117.68293	81.08	9,541.73		2.00%		83.68%	
Copart Inc	CPRT	389.07976	25.83	10,049.93	0.02%			18.60%	0.00%
Jacobs Solutions Inc	J	64.40402	267.66	17,238.38	0.04%	3.84%	0.00%	2.46%	0.00%
Albemarle Corp	ALB	423.65036	84.37	35,743.38				40.81%	
Fortinet Inc	FTNT	914.30609	60.5205	55,334.26	0.13%	5.34%	0.01%	3.14%	0.00%
Moderna Inc	MRNA	2274.26158	182.42	414,870.80				40.62%	
Essex Property Trust Inc	ESS	170.95318	200.47	34,270.98	0.08%	0.50%	0.00%	14.51%	0.01%
CoStar Group Inc	CSGP	37.31801	310.07	11,571.20	0.03%	1.61%	0.00%	5.27%	0.00%
Realty Income Corp	O	346.92213	120.06	41,651.47	0.10%	0.33%	0.00%	19.43%	0.02%
Westinghouse Air Brake Technologies Corp	WAB	1369.0772	140.44	192,273.20	0.47%	4.05%	0.02%	3.51%	0.02%
Palantir Technologies Inc	PLTR	295.48149	219.53	64,867.05	0.16%	1.29%	0.00%	10.89%	0.02%
Pool Corp	POOL	289.48612	143.1	41,425.46		2.80%			
Western Digital Corp	WDC	668.9	203.62	136,201.42	0.33%			11.82%	0.04%
PepsiCo Inc	PEP	208	920.28	191,418.24					
TE Connectivity PLC	TEL	243.6087	87.63	21,347.43	0.05%	1.35%	0.00%	6.71%	0.00%
Diamondback Energy Inc	FANG	86.26612	100.18	8,642.14	0.02%	4.51%	0.00%	4.15%	0.00%
Palo Alto Networks Inc	PANW	272.19104	34.66	9,434.14	0.02%			9.69%	0.00%
ServiceNow Inc	NOW	534.79476	112.5	60,164.41	0.15%	3.31%	0.00%	5.30%	0.01%
Church & Dwight Co Inc	CHD	613.00822	29.33	17,979.53	0.04%	3.95%	0.00%	3.59%	0.00%
Federal Realty Investment Trust	FRT	119.7927	203.02	24,320.31				21.45%	
MGM Resorts International	MGM	96.79928	134.17	12,987.56	0.03%	1.31%	0.00%	13.09%	0.00%
American Electric Power Co Inc	AEP	1261.0323	133.9	168,852.22	0.41%	0.78%	0.00%	14.44%	0.06%
Invitation Homes Inc	INVH	62.13191	128.92	8,010.05	0.02%			4.49%	0.00%
PTC Inc	PTC	163.93126	110.76	18,157.03	0.04%	0.90%	0.00%	9.47%	0.00%
JB Hunt Transport Services Inc	JBHT	456.56204	75.1	34,287.81	0.08%	0.19%	0.00%	6.34%	0.01%
Lam Research Corp	LRCX	256.39065	391.64	100,412.83					
Mohawk Industries Inc	MHK	2308.35994	8.18	18,882.38	0.05%	6.23%	0.00%	8.74%	0.00%
GE HealthCare Technologies Inc	GEHC	2168.96248	734.38	1,592,842.67	3.87%	0.29%	0.01%	16.81%	0.65%
Pentair PLC	PNR	1125.41904	239.38	269,402.81		1.70%			
Vertex Pharmaceuticals Inc	VRTX	64.34122	954.66	61,423.99	0.15%	0.75%	0.00%	7.70%	0.01%
Amcor PLC	AMCR	634.89656	210.5	133,645.73	0.32%	2.26%	0.01%	8.09%	0.03%
Meta Platforms Inc	META	172.95895	83.34	14,414.40		6.34%		-1.68%	
T-Mobile US Inc	TMUS	773.96367	143.18	110,816.12	0.27%			14.47%	0.04%
United Rentals Inc	URI	652.9484	56.75	37,054.82	0.09%	1.32%	0.00%	4.60%	0.00%
Alexandria Real Estate Equities Inc	ARE	212.96828	236.06	50,273.29		1.22%		23.91%	
Honeywell International Inc	HON	327.70387	96.5	31,623.42	0.08%			7.43%	0.01%
Delta Air Lines Inc	DAL	188.0312	34.55	6,496.48		0.58%			
United Airlines Holdings Inc	UAL	491.133	35.68	17,523.63				-21.26%	
Seagate Technology Holdings PLC	STX	549.574	72.27	39,717.71				34.36%	
News Corp	NWS	60.306	630.28	38,009.67		0.53%		-9.33%	
Centene Corp	CNC	575.38125	133.27	76,681.06	0.19%	1.53%	0.00%	12.27%	0.02%
Apollo Global Management Inc	APO	159.07353	137.64	21,894.88	0.05%	0.35%	0.00%	15.18%	0.01%
Martin Marietta Materials Inc	MLM	955.37841	67.06	64,067.68	0.16%			12.38%	0.02%
Teradyne Inc	TER	3325.15089	444.72	1,478,761.10					

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
PayPal Holdings Inc	PYPL	154.85334	1165.87	180,538.86	0.44%	1.79%	0.01%	12.40%	0.05%
Tesla Inc	TSLA	373.2203	90.73	33,862.28	0.08%			2.01%	0.00%
Blackrock Inc	BLK	890.94873	129.95	115,778.79		0.57%			
KKR & Co Inc	KKR	705.76446	22.93	16,183.18	0.04%	6.11%	0.00%	3.37%	0.00%
Arch Capital Group Ltd	ACGL	41.94329	350.23	14,689.80		2.28%		29.71%	
Dow Inc	DOW	46.8885	586.04	27,478.54	0.07%			10.05%	0.01%
Everest Group Ltd	EG	272.22394	614.9	167,390.50		0.16%			
Teledyne Technologies Inc	TDY	33.94892	431.71	14,656.09	0.04%	1.61%	0.00%	9.94%	0.00%
Domino's Pizza Inc	DPZ	376.77633	30.71	11,570.80		0.65%			
GE Vernova Inc	GEV	1009.53563	45.01	45,439.20	0.11%	3.55%	0.00%	7.22%	0.01%
News Corp	NWSA	242.60711	83.08	20,155.80		1.20%			
Exelon Corp	EXC	435.47006	96.49	42,018.51		4.40%		32.78%	
Global Payments Inc	GPN	72.48637	125.22	9,076.74	0.02%			10.93%	0.00%
Crown Castle Inc	CCI	1919.06992	16.23	31,146.50		5.11%		32.40%	
Align Technology Inc	ALGN	215.19185	167.54	36,053.24		2.39%		21.00%	
Kenvue Inc	KVUE	200.06202	81.25	16,255.04	0.04%	3.45%	0.00%	2.09%	0.00%
Targa Resources Corp	TRGP	148.34336	101.37	15,037.57	0.04%			4.14%	0.00%
Bunge Global SA	BG	257.29319	30.54	7,857.73		3.93%			
LKQ Corp	LKQ	217	240.73	52,238.41					
Deckers Outdoor Corp	DECK	443.18347	146.32	64,846.61	0.16%	1.37%	0.00%	8.70%	0.01%
Workday Inc	WDAY	1064.65341	18.92	20,143.24		1.06%			
Zoetis Inc	ZTS	226.15913	337.49	76,326.44				-3.18%	
Equinix Inc	EQIX	341.05044	172.88	58,960.80	0.14%	2.82%	0.00%	6.48%	0.01%
Digital Realty Trust Inc	DLR	97.86399	783.24	76,650.99		2.40%		32.66%	
Molina Healthcare Inc	MOH	686.45361	53.79	36,924.34	0.09%	1.86%	0.00%	8.34%	0.01%
Las Vegas Sands Corp	LVS	54.2	191.36	10,371.71				-9.17%	

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Bloomberg Professional as of September 30, 2025
[5] Bloomberg Professional as of September 30, 2025
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of September 30, 2025
[9] Equals [7] x [8]
[10] Value Line, as of September 30, 2025
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9126763
R Square	0.8329780
Adjusted R Square	0.8320552
Standard Error	0.0058114
Observations	183

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03049	0.03049	902.68968	0.00000
Residual	181	0.00611	0.00003		
Total	182	0.03660			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0801	0.00	83.53	0.0000	0.0783	0.0820	0.0783	0.0820
U.S. Govt. 30-year Treasury	(0.4278)	0.01	(30.04)	0.0000	(0.4558)	(0.3997)	(0.4558)	(0.3997)

	[7] U.S. Govt. 30-year Treasury [7]	[8] Risk Premium [8]	[9] ROE [9]
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.79%	5.97%	10.76%
Blue Chip Near-Term Projected Forecast (Q1 2026 - Q1 2027) [5]	4.62%	6.04%	10.66%
Blue Chip Long-Term Projected Forecast (2027-2031) [6]	4.40%	6.13%	10.53%
AVERAGE			10.65%

Notes:
[1] Source: Regulatory Research Associates, rate cases through September 30, 2025
[2] Source: S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: S&P Capital IQ Pro, 30-day average as of September 30, 2025
[5] Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 44, No. 6, June 2, 2025, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.080145 + (-0.427757 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1980.1	13.97%	11.66%	2.31%
1980.2	14.25%	10.52%	3.73%
1980.3	14.30%	10.85%	3.45%
1980.4	14.32%	12.10%	2.23%
1981.1	14.82%	12.53%	2.28%
1981.2	15.05%	13.24%	1.81%
1981.3	15.31%	14.13%	1.17%
1981.4	15.59%	13.85%	1.74%
1982.1	15.71%	13.96%	1.75%
1982.2	15.60%	13.52%	2.08%
1982.3	15.85%	12.79%	3.06%
1982.4	16.03%	10.75%	5.28%
1983.1	15.54%	10.71%	4.83%
1983.2	15.13%	10.65%	4.48%
1983.3	15.39%	11.62%	3.77%
1983.4	15.37%	11.74%	3.63%
1984.1	15.06%	12.04%	3.02%
1984.2	15.18%	13.18%	2.00%
1984.3	15.38%	12.69%	2.69%
1984.4	15.69%	11.70%	3.99%
1985.1	15.48%	11.58%	3.90%
1985.2	15.27%	11.00%	4.27%
1985.3	14.84%	10.55%	4.29%
1985.4	15.11%	10.04%	5.07%
1986.1	14.42%	8.77%	5.65%
1986.2	14.27%	7.49%	6.78%
1986.3	13.26%	7.40%	5.86%
1986.4	13.52%	7.53%	5.99%
1987.1	12.90%	7.49%	5.40%
1987.2	13.17%	8.53%	4.64%
1987.3	13.14%	9.06%	4.08%
1987.4	12.76%	9.23%	3.53%
1988.1	12.74%	8.63%	4.11%
1988.2	12.70%	9.06%	3.63%
1988.3	12.78%	9.18%	3.60%
1988.4	12.97%	8.97%	4.00%
1989.1	13.02%	9.04%	3.99%
1989.2	13.22%	8.70%	4.52%
1989.3	12.38%	8.12%	4.26%
1989.4	12.83%	7.93%	4.90%
1990.1	12.62%	8.44%	4.19%
1990.2	12.85%	8.65%	4.20%
1990.3	12.54%	8.79%	3.75%
1990.4	12.68%	8.56%	4.12%
1991.1	12.66%	8.20%	4.46%
1991.2	12.67%	8.31%	4.36%
1991.3	12.49%	8.19%	4.30%
1991.4	12.42%	7.85%	4.57%
1992.1	12.38%	7.81%	4.58%
1992.2	11.83%	7.90%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.76%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.32%	4.84%
1993.4	11.04%	6.14%	4.91%
1994.1	11.07%	6.58%	4.49%
1994.2	11.13%	7.36%	3.77%
1994.3	12.75%	7.59%	5.16%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.33%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.72%	4.65%
1995.4	11.58%	6.24%	5.35%

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.97%	3.73%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.82%	4.26%
1997.2	11.62%	6.94%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.15%	4.91%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.48%	6.17%
1998.4	12.30%	5.11%	7.19%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.80%	5.14%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.26%	4.84%
2000.1	11.21%	6.30%	4.92%
2000.2	11.00%	5.98%	5.02%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.45%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.53%	5.23%
2001.4	11.99%	5.30%	6.69%
2002.1	10.05%	5.52%	4.53%
2002.2	11.41%	5.62%	5.79%
2002.3	11.65%	5.09%	6.56%
2002.4	11.57%	4.93%	6.63%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.34%	5.30%
2004.3	10.75%	5.11%	5.64%
2004.4	11.24%	4.93%	6.31%
2005.1	10.63%	4.71%	5.92%
2005.2	10.31%	4.47%	5.84%
2005.3	11.08%	4.42%	6.66%
2005.4	10.63%	4.65%	5.98%
2006.1	10.70%	4.63%	6.07%
2006.2	10.79%	5.14%	5.64%
2006.3	10.35%	5.00%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.79%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.96%
2008.3	10.43%	4.45%	5.98%
2008.4	10.39%	3.64%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.25%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.37%	5.81%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.20%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.70%	6.88%
2011.4	10.39%	3.04%	7.35%

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.94%	7.01%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.16%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.27%	6.63%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.05%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.70%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.25%
2019.4	9.89%	2.26%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.19%
2020.3	9.30%	1.37%	7.93%
2020.4	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.26%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.69%	1.95%	7.74%
2022.1	9.45%	2.25%	7.20%
2022.2	9.50%	3.05%	6.45%
2022.3	9.14%	3.26%	5.88%
2022.4	9.94%	3.89%	6.04%
2023.1	9.72%	3.75%	5.97%
2023.2	9.67%	3.81%	5.86%
2023.3	9.79%	4.23%	5.55%
2023.4	9.85%	4.58%	5.27%
2024.1	9.67%	4.32%	5.35%
2024.2	9.90%	4.58%	5.32%
2024.3	9.88%	4.23%	5.65%
2024.4	9.90%	4.50%	5.40%
2025.1	9.83%	4.72%	5.11%
2025.2	9.52%	4.84%	4.68%
2025.3	9.57%	4.85%	4.73%
AVERAGE	11.46%	6.03%	5.44%
MEDIAN	11.00%	5.11%	5.55%

Mr. Megginson Constant Growth DCF
As Filed

Company	Ticker	Annualized Dividend	Closing Monthly Stock Price				Dividend Yield	Expected Dividend Yield	Projected EPS Growth Rates			Cost of Equity
			Jun-25	Jul-25	Aug-25	Average			Value Line	Zacks	Average	
Alliant Energy	LNT	$2.03	$60.47	$65.01	$64.62	$63.37	3.20%	3.30%	6.00%	6.59%	6.30%	9.60%
Ameren	AEE	$2.84	$96.04	$101.13	$100.56	$99.24	2.86%	2.96%	6.50%	7.86%	7.18%	10.14%
DTE Energy	DTE	$4.36	$132.46	$138.41	$138.92	$136.60	3.19%	3.28%	4.50%	6.98%	5.74%	9.02%
Evergy	EVRG	$2.67	$68.93	$70.80	$71.95	$70.56	3.78%	3.91%	7.50%	5.73%	6.62%	10.52%
OGE Energy	OGE	$1.68	$44.38	$45.42	$45.09	$44.96	3.74%	3.86%	6.50%	6.32%	6.41%	10.27%
Pinnacle West	PNW	$3.58	$89.47	$90.62	$91.34	$90.48	3.96%	4.03%	5.00%	2.12%	3.56%	7.59%
Portland General Electric	POR	$2.10	$40.63	$41.12	$42.46	$41.40	5.07%	5.20%	6.50%	3.39%	4.95%	10.14%
PPLCorporation	PPL	$1.09	$33.89	$35.69	$36.47	$35.35	3.08%	3.20%	7.50%	7.67%	7.59%	10.79%
											Average:	**9.76%**
											Median:	**10.14%**

Mr. Megginson Constant Growth DCF
As Adjusted to Update Calculation of Stock Prices

Company	Ticker	Annualized Dividend	Average Monthly Stock Price				Dividend Yield	Expected Dividend Yield	Projected EPS Growth Rates			Cost of Equity
			Jun-25	Jul-25	Aug-25	Average			Value Line	Zacks	Average	
Alliant Energy	LNT	$2.03	$60.30	$62.78	$65.61	$62.90	3.23%	3.33%	6.00%	6.59%	6.30%	9.62%
Ameren	AEE	$2.84	$94.90	$97.08	$100.65	$97.54	2.91%	3.02%	6.50%	7.86%	7.18%	10.20%
DTE Energy	DTE	$4.36	$131.87	$133.99	$138.15	$134.67	3.24%	3.33%	4.50%	6.98%	5.74%	9.07%
Evergy	EVRG	$2.67	$66.66	$68.54	$71.84	$69.01	3.87%	4.00%	7.50%	5.73%	6.62%	10.61%
OGE Energy	OGE	$1.68	$43.69	$44.49	$45.26	$44.48	3.78%	3.90%	6.50%	6.32%	6.41%	10.31%
Pinnacle West	PNW	$3.58	$88.55	$90.10	$91.51	$90.05	3.98%	4.05%	5.00%	2.12%	3.56%	7.61%
Portland General Electric	POR	$2.10	$39.99	$40.33	$41.93	$40.75	5.15%	5.28%	6.50%	3.39%	4.95%	10.23%
PPLCorporation	PPL	$1.09	$33.60	$34.92	$36.24	$34.92	3.12%	3.24%	7.50%	7.67%	7.59%	10.82%
											Median:	**10.21%**

Mr. Coppola Constant Growth DCF
As Filed

Company	Ticker	Projected Avg. Annual Dividend (2025/2026)	Average 30-Day High/Low Stock Price	Expected Dividend Yield	Projected EPS Growth Rates			Cost of Equity
					Value Line	Yahoo! Finance	Average	
Alliant Energy	LNT	$2.10	$62.43	3.36%	6.00%	6.19%	6.09%	9.46%
Ameren	AEE	$2.94	$96.99	3.03%	6.50%	7.20%	6.85%	9.88%
American Electric Power	AEP	$3.89	$105.57	3.68%	6.50%	5.82%	6.16%	9.84%
CenterPoint Energy	CNP	$0.92	$36.69	2.51%	6.50%	N/A	6.50%	9.01%
Consolidated Edison	ED	$3.50	$100.77	3.47%	6.00%	5.48%	5.74%	9.21%
DTE Energy	DTE	$4.56	$134.15	3.40%	4.50%	5.68%	5.09%	8.49%
Evergy	EVRG	$2.78	$68.78	4.04%	N/A	6.04%	6.04%	10.08%
IDACORP	IDA	$3.59	$118.00	3.04%	6.00%	N/A	6.00%	9.04%
OGE Energy	OGE	$1.72	$44.25	3.89%	6.50%	5.34%	5.92%	9.80%
Portland General Electric	POR	$2.14	$40.71	5.26%	6.50%	4.00%	5.25%	10.51%
WEC Energy	WEC	$3.69	$105.81	3.49%	6.00%	7.01%	6.51%	9.99%
							Average:	**9.57%**

Mr. Coppola Constant Growth DCF
As Filed with All Growth Rates

Company	Ticker	Projected Avg. Annual Dividend (2025/2026)	Average 30-Day High/Low Stock Price	Expected Dividend Yield	Projected EPS Growth Rates			Cost of Equity
					Value Line	Yahoo! Finance	Average	
Alliant Energy	LNT	$2.10	$62.43	3.36%	6.00%	6.19%	6.09%	9.46%
Ameren	AEE	$2.94	$96.99	3.03%	6.50%	7.20%	6.85%	9.88%
American Electric Power	AEP	$3.89	$105.57	3.68%	6.50%	5.82%	6.16%	9.84%
CenterPoint Energy	CNP	$0.92	$36.69	2.51%	6.50%	8.17%	7.34%	9.84%
Consolidated Edison	ED	$3.50	$100.77	3.47%	6.00%	5.48%	5.74%	9.21%
DTE Energy	DTE	$4.56	$134.15	3.40%	4.50%	5.68%	5.09%	8.49%
Evergy	EVRG	$2.78	$68.78	4.04%	7.50%	6.04%	6.77%	10.81%
IDACORP	IDA	$3.59	$118.00	3.04%	6.00%	7.64%	6.82%	9.86%
OGE Energy	OGE	$1.72	$44.25	3.89%	6.50%	5.34%	5.92%	9.80%
Portland General Electric	POR	$2.14	$40.71	5.26%	6.50%	4.00%	5.25%	10.51%
WEC Energy	WEC	$3.69	$105.81	3.49%	6.00%	7.01%	6.51%	9.99%
							Average:	**9.79%**

Mr. Coppola Constant Growth DCF
As Filed with All Growth Rates and Updated through August 31, 2025

Company	Ticker	Projected Avg. Annual Dividend (2024/2025)	Average 30-Day Stock Price	Expected Dividend Yield	Projected EPS Growth Rates			Cost of Equity
					Value Line	Zacks	Average	
Alliant Energy	LNT	$2.10	$65.25	3.22%	6.00%	6.60%	6.30%	9.52%
Ameren	AEE	$2.94	$100.94	2.91%	6.50%	7.90%	7.20%	10.11%
American Electric Power	AEP	$3.89	$111.53	3.49%	6.50%	6.40%	6.45%	9.94%
CenterPoint Energy	CNP	$0.92	$38.02	2.42%	6.50%	7.80%	7.15%	9.57%
Consolidated Edison	ED	$3.50	$101.73	3.44%	6.00%	6.40%	6.20%	9.64%
DTE Energy	DTE	$4.56	$138.89	3.28%	4.50%	7.00%	5.75%	9.03%
Evergy	EVRG	$2.78	$70.99	3.91%	7.50%	5.70%	6.60%	10.51%
IDACORP	IDA	$3.59	$124.57	2.88%	6.00%	8.20%	7.10%	9.98%
OGE Energy	OGE	$1.72	$45.19	3.81%	6.50%	6.30%	6.40%	10.21%
Portland General Electric	POR	$2.14	$41.96	5.10%	6.50%	3.40%	4.95%	10.05%
WEC Energy	WEC	$3.69	$108.21	3.41%	6.00%	7.00%	6.50%	9.91%
							Average:	**9.86%**

Mr. Walters's Constant Growth DCF Using Projected EPS Growth Rates
As Filed

Company	Ticker	Annualized Dividend	13-Week Avg. Stock Price	Expected Dividend Yield	Projected EPS Growth Rates				Cost of Equity
					Zacks	S&P	I/B/E/S	Average	
Alliant Energy Corporation	LNT	$2.03	$63.75	3.39%	6.59%	6.80%	6.40%	6.60%	9.99%
Ameren Corporation	AEE	$2.84	$98.85	3.11%	7.86%	7.72%	8.90%	8.16%	11.27%
American Electric Power Company, Inc.	AEP	$3.72	$108.24	3.67%	6.43%	7.07%	6.65%	6.72%	10.38%
Avista Corporation	AVA	$1.96	$37.33	5.58%	5.82%	5.98%	6.90%	6.23%	11.81%
Dominion Resources, Inc.	D	$2.67	$58.53	5.19%	13.59%	13.98%	n/a	13.79%	18.98%
DTE Energy Company	DTE	$4.36	$136.09	3.43%	6.98%	7.33%	6.90%	7.07%	10.50%
Duke Energy Corporation	DUK	$4.26	$120.29	3.78%	6.56%	6.69%	6.77%	6.67%	10.45%
Entergy Corporation	ETR	$2.40	$86.44	3.05%	9.46%	10.15%	9.65%	9.75%	12.80%
Evergy, Inc.	EVRG	$2.67	$70.27	4.02%	5.73%	5.87%	6.00%	5.87%	9.89%
IDACORP, Inc.	IDA	$3.44	$121.31	3.07%	8.20%	8.60%	8.00%	8.27%	11.34%
NextEra Energy, Inc.	NEE	$2.27	$72.88	3.35%	7.89%	7.63%	8.05%	7.86%	11.21%
OGE Energy Corporation	OGE	$1.69	$44.65	4.01%	6.32%	6.64%	5.60%	6.19%	10.19%
Pinnacle West Capital Corporation	PNW	$3.58	$90.38	4.08%	2.12%	4.51%	2.20%	2.94%	7.02%
Portland General Electric Company	POR	$2.10	$41.57	5.25%	3.39%	4.66%	3.49%	3.85%	9.09%
PPL Corporation	PPL	$1.09	$35.46	3.31%	7.67%	7.42%	7.80%	7.63%	10.94%
Southern Company	SO	$2.96	$92.82	3.41%	6.77%	6.58%	7.25%	6.87%	10.27%
Xcel Energy Inc.	XEL	$2.28	$70.80	3.48%	7.79%	8.06%	8.80%	8.22%	11.70%
								Average	**11.05%**
								Median	**10.50%**

Mr. Walters's Constant Growth DCF Using Projected EPS Growth Rates
Updated Proxy Group to Remove DUK (Recent M&A Activity)

Company	Ticker	Annualized Dividend	13-Week Avg. Stock Price	Expected Dividend Yield	Projected EPS Growth Rates				Cost of Equity
					Zacks	S&P	I/B/E/S	Average	
Alliant Energy Corporation	LNT	$2.03	$63.75	3.39%	6.59%	6.80%	6.40%	6.60%	9.99%
Ameren Corporation	AEE	$2.84	$98.85	3.11%	7.86%	7.72%	8.90%	8.16%	11.27%
American Electric Power Company, Inc.	AEP	$3.72	$108.24	3.67%	6.43%	7.07%	6.65%	6.72%	10.38%
Avista Corporation	AVA	$1.96	$37.33	5.58%	5.82%	5.98%	6.90%	6.23%	11.81%
Dominion Resources, Inc.	D	$2.67	$58.53	5.19%	13.59%	13.98%	n/a	13.79%	18.98%
DTE Energy Company	DTE	$4.36	$136.09	3.43%	6.98%	7.33%	6.90%	7.07%	10.50%
Entergy Corporation	ETR	$2.40	$86.44	3.05%	9.46%	10.15%	9.65%	9.75%	12.80%
Evergy, Inc.	EVRG	$2.67	$70.27	4.02%	5.73%	5.87%	6.00%	5.87%	9.89%
IDACORP, Inc.	IDA	$3.44	$121.31	3.07%	8.20%	8.60%	8.00%	8.27%	11.34%
NextEra Energy, Inc.	NEE	$2.27	$72.88	3.35%	7.89%	7.63%	8.05%	7.86%	11.21%
OGE Energy Corporation	OGE	$1.69	$44.65	4.01%	6.32%	6.64%	5.60%	6.19%	10.19%
Pinnacle West Capital Corporation	PNW	$3.58	$90.38	4.08%	2.12%	4.51%	2.20%	2.94%	7.02%
Portland General Electric Company	POR	$2.10	$41.57	5.25%	3.39%	4.66%	3.49%	3.85%	9.09%
PPL Corporation	PPL	$1.09	$35.46	3.31%	7.67%	7.42%	7.80%	7.63%	10.94%
Southern Company	SO	$2.96	$92.82	3.41%	6.77%	6.58%	7.25%	6.87%	10.27%
Xcel Energy Inc.	XEL	$2.28	$70.80	3.48%	7.79%	8.06%	8.80%	8.22%	11.70%
								Average	**11.09%**
								Median	**10.72%**

Mr. Bandyk DCF
As Filed
(Two Step with EPS Growth Rates and GDP Growth Rate)

Company	Ticker	Annualized Dividend	Stock Price	Expected Dividend Yield	Projected EPS Growth Rates				Weight on EPS	Long-Term Gwth Rate	Weight LT Gwth	Cost of Equity
					Zacks	S&P	Value Line	Average				
Alliant Energy Corporation	LNT	$2.03	$65.70	3.19%	6.70%	6.81%	6.00%	6.50%	80.00%	3.80%	20.00%	9.15%
Ameren Corporation	AEE	$2.84	$101.61	2.89%	6.70%	6.88%	6.50%	6.69%	80.00%	3.80%	20.00%	9.00%
American Electric Power Company, Inc.	AEP	$3.72	$111.68	3.44%	6.30%	6.69%	6.50%	6.50%	80.00%	3.80%	20.00%	9.40%
Avista Corporation	AVA	$1.96	$37.24	5.42%	6.10%	5.88%	5.50%	5.83%	80.00%	3.80%	20.00%	10.84%
Dominion Resources, Inc.	D	$2.67	$60.44	4.66%	13.60%	13.49%	6.00%	11.03%	80.00%	3.80%	20.00%	14.25%
DTE Energy Company	DTE	$4.36	$138.49	3.25%	7.60%	7.87%	4.50%	6.66%	80.00%	3.80%	20.00%	9.34%
Duke Energy Corporation	DUK	$4.18	$123.29	3.50%	6.30%	6.32%	6.00%	6.21%	80.00%	3.80%	20.00%	9.22%
Entergy Corporation	ETR	$2.40	$89.41	2.78%	9.50%	8.88%	3.00%	7.13%	80.00%	3.80%	20.00%	9.24%
Evergy, Inc.	EVRG	$2.67	$72.20	3.81%	5.70%	5.72%	7.50%	6.31%	80.00%	3.80%	20.00%	9.62%
IDACORP, Inc.	IDA	$3.44	$126.05	2.83%	8.50%	8.23%	6.00%	7.58%	80.00%	3.80%	20.00%	9.65%
NextEra Energy, Inc.	NEE	$2.27	$73.52	3.20%	7.80%	7.11%	8.50%	7.80%	80.00%	3.80%	20.00%	10.21%
NorthWestern Corporation	NWE	$2.64	$56.51	4.80%	6.10%	5.94%	4.50%	5.51%	80.00%	3.80%	20.00%	9.97%
OGE Energy Corporation	OGE	$1.69	$44.90	3.87%	6.10%	5.92%	6.50%	6.17%	80.00%	3.80%	20.00%	9.57%
Pinnacle West Capital Corporation	PNW	$3.58	$91.26	4.01%	2.10%	5.55%	5.00%	4.22%	80.00%	3.80%	20.00%	8.14%
TXNM Energy	TXNM	$1.63	$56.82	2.94%	3.00%	6.55%	4.50%	4.68%	80.00%	3.80%	20.00%	7.44%
Portland General Electric Company	POR	$2.00	$42.51	4.83%	3.40%	6.54%	6.50%	5.48%	80.00%	3.80%	20.00%	9.98%
PPL Corporation	PPL	$1.09	$36.51	3.09%	6.80%	7.27%	7.50%	7.19%	80.00%	3.80%	20.00%	9.60%
Southern Company	SO	$2.88	$93.76	3.17%	6.50%	6.33%	6.50%	6.44%	80.00%	3.80%	20.00%	9.09%
Xcel Energy Inc.	XEL	$2.28	$72.98	3.23%	6.90%	7.26%	7.00%	7.05%	80.00%	3.80%	20.00%	9.64%
											Average:	**9.65%**

Mr. Bandyk DCF

Adjusted to Reflect Constant Growth DCF and Updated to Remove DUK, NWE, and TXNM (Recent M&A Activity)

Company	Ticker	Annualized Dividend	Stock Price	Expected Dividend Yield	Projected EPS Growth Rates				Cost of Equity
					Zacks	S&P	Value Line	Average	
Alliant Energy Corporation	LNT	$2.03	$65.70	3.19%	6.70%	6.81%	6.00%	6.50%	9.69%
Ameren Corporation	AEE	$2.84	$101.61	2.89%	6.70%	6.88%	6.50%	6.69%	9.58%
American Electric Power Company, Inc.	AEP	$3.72	$111.68	3.44%	6.30%	6.69%	6.50%	6.50%	9.94%
Avista Corporation	AVA	$1.96	$37.24	5.42%	6.10%	5.88%	5.50%	5.83%	11.24%
Dominion Resources, Inc.	D	$2.67	$60.44	4.66%	13.60%	13.49%	6.00%	11.03%	15.69%
DTE Energy Company	DTE	$4.36	$138.49	3.25%	7.60%	7.87%	4.50%	6.66%	9.91%
Entergy Corporation	ETR	$2.40	$89.41	2.78%	9.50%	8.88%	3.00%	7.13%	9.91%
Evergy, Inc.	EVRG	$2.67	$72.20	3.81%	5.70%	5.72%	7.50%	6.31%	10.12%
IDACORP, Inc.	IDA	$3.44	$126.05	2.83%	8.50%	8.23%	6.00%	7.58%	10.41%
NextEra Energy, Inc.	NEE	$2.27	$73.52	3.20%	7.80%	7.11%	8.50%	7.80%	11.01%
OGE Energy Corporation	OGE	$1.69	$44.90	3.87%	6.10%	5.92%	6.50%	6.17%	10.04%
Pinnacle West Capital Corporation	PNW	$3.58	$91.26	4.01%	2.10%	5.55%	5.00%	4.22%	8.22%
Portland General Electric Company	POR	$2.00	$42.51	4.83%	3.40%	6.54%	6.50%	5.48%	10.31%
PPL Corporation	PPL	$1.09	$36.51	3.09%	6.80%	7.27%	7.50%	7.19%	10.28%
Southern Company	SO	$2.88	$93.76	3.17%	6.50%	6.33%	6.50%	6.44%	9.61%
Xcel Energy Inc.	XEL	$2.28	$72.98	3.23%	6.90%	7.26%	7.00%	7.05%	10.29%
								Average:	**10.39%**

Mr. Megginson CAPM Analysis with Historical Market Risk Premium

As Filed

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1928-2024)**	**Historical Long-Term Government Bond Return (1928-2024)**	**Market Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.58%	0.80	11.79%	4.85%	6.94%	10.13%
Ameren Corporation	AEE	4.58%	0.80	11.79%	4.85%	6.94%	10.13%
DTE Energy Company	DTE	4.58%	0.80	11.79%	4.85%	6.94%	10.13%
Evergy, Inc.	EVRG	4.58%	0.75	11.79%	4.85%	6.94%	9.79%
OGE Energy Corporation	OGE	4.58%	0.85	11.79%	4.85%	6.94%	10.48%
Pinnacle West Capital Corporation	PNW	4.58%	0.75	11.79%	4.85%	6.94%	9.79%
Portland General Electric Company	POR	4.58%	0.75	11.79%	4.85%	6.94%	9.79%
PPL Corporation	PPL	4.58%	0.80	11.79%	4.85%	6.94%	10.13%
						Average:	**10.05%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: Exhibit S-4, Schedule D-5, page 6 of 14
[4] Source: Exhibit S-4, Schedule D-5, page 6 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Megginson CAPM Analysis
with Historical Market Risk Premium

As Adjusted to Account for Inverse Relationship in Interest Rates and the Market Risk Premium

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1926-2024)**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.58%	0.80	12.17%	4.58%	7.59%	10.65%
Ameren Corporation	AEE	4.58%	0.80	12.17%	4.58%	7.59%	10.65%
DTE Energy Company	DTE	4.58%	0.80	12.17%	4.58%	7.59%	10.65%
Evergy, Inc.	EVRG	4.58%	0.75	12.17%	4.58%	7.59%	10.27%
OGE Energy Corporation	OGE	4.58%	0.85	12.17%	4.58%	7.59%	11.03%
Pinnacle West Capital Corporation	PNW	4.58%	0.75	12.17%	4.58%	7.59%	10.27%
Portland General Electric Company	POR	4.58%	0.75	12.17%	4.58%	7.59%	10.27%
PPL Corporation	PPL	4.58%	0.80	12.17%	4.58%	7.59%	10.65%
						Average:	**10.56%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: *Kroll* Cost of Capital Navigator.
[4] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Megginson CAPM Analysis
with Projected Market Risk Premium

As Adjusted to Utilize Mr. Megginson's Approach in Case No. U-21540

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Company's Projected Mkt Return in Direct Testimony**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.58%	0.80	12.58%	4.58%	8.00%	10.98%
Ameren Corporation	AEE	4.58%	0.80	12.58%	4.58%	8.00%	10.98%
DTE Energy Company	DTE	4.58%	0.80	12.58%	4.58%	8.00%	10.98%
Evergy, Inc.	EVRG	4.58%	0.75	12.58%	4.58%	8.00%	10.58%
OGE Energy Corporation	OGE	4.58%	0.85	12.58%	4.58%	8.00%	11.38%
Pinnacle West Capital Corporation	PNW	4.58%	0.75	12.58%	4.58%	8.00%	10.58%
Portland General Electric Company	POR	4.58%	0.75	12.58%	4.58%	8.00%	10.58%
PPL Corporation	PPL	4.58%	0.80	12.58%	4.58%	8.00%	10.98%
						Average:	**10.88%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[4] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Coppola CAPM Analysis

As Filed

		[1]	[2]	[3]	[4]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Market Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.40%	0.80	7.35%	10.28%
Ameren Corporation	AEE	4.40%	0.80	7.35%	10.28%
American Electric Power Company, Inc.	AEP	4.40%	0.70	7.35%	9.55%
CenterPoint Energy, Inc.	CNP	4.40%	0.85	7.35%	10.65%
Consolidated Edison, Inc.	ED	4.40%	0.65	7.35%	9.18%
DTE Energy Company	DTE	4.40%	0.80	7.35%	10.28%
Evergy, Inc.	EVRG	4.40%	0.75	7.35%	9.91%
IDACORP, Inc.	IDA	4.40%	0.70	7.35%	9.55%
OGE Energy Corporation	OGE	4.40%	0.85	7.35%	10.65%
Portland General Electric Company	POR	4.40%	0.75	7.35%	9.91%
Wisconsin Energy Corporation	WEC	4.40%	0.70	7.35%	9.55%
				Average:	**9.98%**

Notes:
[1] Source: Exhibit AG-38
[2] Source: Exhibit AG-38
[3] Source: Exhibit AG-38
[4] Equals [1] + [2] x [3]

Mr. Coppola CAPM Analysis

As Adjusted to Account for Inverse Relationship in Interest Rates and the Market Risk Premium and Update Risk-Free Rate

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1926-2024)**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.60%	0.80	12.17%	4.60%	7.57%	10.66%
Ameren Corporation	AEE	4.60%	0.80	12.17%	4.60%	7.57%	10.66%
American Electric Power Company, Inc.	AEP	4.60%	0.70	12.17%	4.60%	7.57%	9.90%
CenterPoint Energy, Inc.	CNP	4.60%	0.85	12.17%	4.60%	7.57%	11.03%
Consolidated Edison, Inc.	ED	4.60%	0.65	12.17%	4.60%	7.57%	9.52%
DTE Energy Company	DTE	4.60%	0.80	12.17%	4.60%	7.57%	10.66%
Evergy, Inc.	EVRG	4.60%	0.75	12.17%	4.60%	7.57%	10.28%
IDACORP, Inc.	IDA	4.60%	0.70	12.17%	4.60%	7.57%	9.90%
OGE Energy Corporation	OGE	4.60%	0.85	12.17%	4.60%	7.57%	11.03%
Portland General Electric Company	POR	4.60%	0.75	12.17%	4.60%	7.57%	10.28%
Wisconsin Energy Corporation	WEC	4.60%	0.70	12.17%	4.60%	7.57%	9.90%
						Average:	**10.35%**

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2.
[2] Source: Exhibit AG-38
[3] Source: *Kroll* Cost of Capital Navigator.
[4] Source: Blue Chip Financial Forecasts, Vol. 44, No. 10, October 1, 2025, at 2.
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Bandyk CAPM Analysis

As Filed

Projected Market Risk Premium & Risk-Free Rate - Dr. Damodaran

Company	Ticker	[1] Risk-Free Rate	[2] *Value Line* Raw Beta	[3] Market Risk Premium	[4] Cost of Equity	[5] *Bloomberg* Raw Beta	[6] Market Risk Premium	[7] Cost of Equity
Alliant Energy Corporation	LNT	4.23%	0.92	4.05%	7.96%	0.66	4.05%	6.90%
Ameren Corporation	AEE	4.23%	0.85	4.05%	7.67%	0.60	4.05%	6.66%
American Electric Power Company, In	AEP	4.23%	0.77	4.05%	7.35%	0.61	4.05%	6.70%
Avista Corporation	AVA	4.23%	0.92	4.05%	7.96%	0.61	4.05%	6.70%
Dominion Resources, Inc.	D	4.23%	0.85	4.05%	7.67%	0.54	4.05%	6.42%
DTE Energy Company	DTE	4.23%	1.00	4.05%	8.28%	0.70	4.05%	7.07%
Duke Energy Corporation	DUK	4.23%	0.85	4.05%	7.67%	0.55	4.05%	6.46%
Entergy Corporation	ETR	4.23%	1.00	4.05%	8.28%	0.76	4.05%	7.31%
Evergy, Inc.	EVRG	4.23%	0.92	4.05%	7.96%	0.66	4.05%	6.90%
IDACORP, Inc.	IDA	4.23%	0.77	4.05%	7.35%	0.66	4.05%	6.90%
NextEra Energy, Inc.	NEE	4.23%	1.08	4.05%	8.60%	0.70	4.05%	7.07%
NorthWestern Corporation	NWE	4.23%	1.00	4.05%	8.28%	0.78	4.05%	7.39%
OGE Energy Corporation	OGE	4.23%	1.08	4.05%	8.60%	0.85	4.05%	7.67%
Pinnacle West Capital Corporation	PNW	4.23%	0.92	4.05%	7.96%	0.70	4.05%	7.07%
TXNM Energy	TXNM	4.23%	0.85	4.05%	7.67%	0.72	4.05%	7.15%
Portland General Electric Company	POR	4.23%	0.92	4.05%	7.96%	0.66	4.05%	6.90%
PPL Corporation	PPL	4.23%	1.15	4.05%	8.89%	0.87	4.05%	7.75%
Southern Company	SO	4.23%	0.92	4.05%	7.96%	0.64	4.05%	6.82%
Xcel Energy Inc.	XEL	4.23%	0.77	4.05%	7.35%	0.58	4.05%	6.58%
Average					**7.97%**			**6.97%**

Notes:
[1] Source: Exhibit CUB-5
[2] Source: Exhibit CUB-4
[3] Source: Exhibit CUB-5
[4] Equals [1] + [2] x [3]
[5] Source: Exhibit CUB-4
[6] Source: Exhibit CUB-5
[7] Equals [1] + [5] x [6]

Projected Market Risk Premium & Risk-Free Rate - *Kroll*

Company	Ticker	[1] Risk-Free Rate	[2] *Value Line* Raw Beta	[3] Market Risk Premium	[4] Cost of Equity	[5] *Bloomberg* Raw Beta	[6] Market Risk Premium	[7] Cost of Equity
Alliant Energy Corporation	LNT	4.76%	0.92	5.00%	9.36%	0.66	5.00%	8.06%
Ameren Corporation	AEE	4.76%	0.85	5.00%	9.01%	0.60	5.00%	7.76%
American Electric Power Company, In	AEP	4.76%	0.77	5.00%	8.61%	0.61	5.00%	7.81%
Avista Corporation	AVA	4.76%	0.92	5.00%	9.36%	0.61	5.00%	7.81%
Dominion Resources, Inc.	D	4.76%	0.85	5.00%	9.01%	0.54	5.00%	7.46%
DTE Energy Company	DTE	4.76%	1.00	5.00%	9.76%	0.70	5.00%	8.26%
Duke Energy Corporation	DUK	4.76%	0.85	5.00%	9.01%	0.55	5.00%	7.51%
Entergy Corporation	ETR	4.76%	1.00	5.00%	9.76%	0.76	5.00%	8.56%
Evergy, Inc.	EVRG	4.76%	0.92	5.00%	9.36%	0.66	5.00%	8.06%
IDACORP, Inc.	IDA	4.76%	0.77	5.00%	8.61%	0.66	5.00%	8.06%
NextEra Energy, Inc.	NEE	4.76%	1.08	5.00%	10.16%	0.70	5.00%	8.26%
NorthWestern Corporation	NWE	4.76%	1.00	5.00%	9.76%	0.78	5.00%	8.66%
OGE Energy Corporation	OGE	4.76%	1.08	5.00%	10.16%	0.85	5.00%	9.01%
Pinnacle West Capital Corporation	PNW	4.76%	0.92	5.00%	9.36%	0.70	5.00%	8.26%
TXNM Energy	TXNM	4.76%	0.85	5.00%	9.01%	0.72	5.00%	8.36%
Portland General Electric Company	POR	4.76%	0.92	5.00%	9.36%	0.66	5.00%	8.06%
PPL Corporation	PPL	4.76%	1.15	5.00%	10.51%	0.87	5.00%	9.11%
Southern Company	SO	4.76%	0.92	5.00%	9.36%	0.64	5.00%	7.96%
Xcel Energy Inc.	XEL	4.76%	0.77	5.00%	8.61%	0.58	5.00%	7.66%
Average					**9.38%**			**8.14%**

Notes:
[1] Source: Exhibit CUB-5
[2] Source: Exhibit CUB-4
[3] Source: Exhibit CUB-5
[4] Equals [1] + [2] x [3]
[5] Source: Exhibit CUB-4
[6] Source: Exhibit CUB-5
[7] Equals [1] + [5] x [6]

Mr. Bandyk CAPM Analysis

As Adjusted

Exclude 10-Year Treasury Bond Yield as Risk-Free Rate and Rely On Market Return Using CGDCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
			Value Line			Market		*Bloomberg*			Market	
Company	**Ticker**	**Risk-Free Rate**	**Raw Beta**	**Market Return**	**Risk-Free Rate**	**Risk Premium**	**Cost of Equity**	**Raw Beta**	**Market Return**	**Risk-Free Rate**	**Risk Premium**	**Cost of Equity**
Alliant Energy Corporation	LNT	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.66	12.58%	4.76%	7.82%	9.92%
Ameren Corporation	AEE	4.76%	0.85	12.58%	4.76%	7.82%	11.41%	0.60	12.58%	4.76%	7.82%	9.45%
American Electric Power Company, In	AEP	4.76%	0.77	12.58%	4.76%	7.82%	10.78%	0.61	12.58%	4.76%	7.82%	9.53%
Avista Corporation	AVA	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.61	12.58%	4.76%	7.82%	9.53%
Dominion Resources, Inc.	D	4.76%	0.85	12.58%	4.76%	7.82%	11.41%	0.54	12.58%	4.76%	7.82%	8.98%
DTE Energy Company	DTE	4.76%	1.00	12.58%	4.76%	7.82%	12.58%	0.70	12.58%	4.76%	7.82%	10.24%
Duke Energy Corporation	DUK	4.76%	0.85	12.58%	4.76%	7.82%	11.41%	0.55	12.58%	4.76%	7.82%	9.06%
Entergy Corporation	ETR	4.76%	1.00	12.58%	4.76%	7.82%	12.58%	0.76	12.58%	4.76%	7.82%	10.70%
Evergy, Inc.	EVRG	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.66	12.58%	4.76%	7.82%	9.92%
IDACORP, Inc.	IDA	4.76%	0.77	12.58%	4.76%	7.82%	10.78%	0.66	12.58%	4.76%	7.82%	9.92%
NextEra Energy, Inc.	NEE	4.76%	1.08	12.58%	4.76%	7.82%	13.21%	0.70	12.58%	4.76%	7.82%	10.24%
NorthWestern Corporation	NWE	4.76%	1.00	12.58%	4.76%	7.82%	12.58%	0.78	12.58%	4.76%	7.82%	10.86%
OGE Energy Corporation	OGE	4.76%	1.08	12.58%	4.76%	7.82%	13.21%	0.85	12.58%	4.76%	7.82%	11.41%
Pinnacle West Capital Corporation	PNW	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.70	12.58%	4.76%	7.82%	10.24%
TXNM Energy	TXNM	4.76%	0.85	12.58%	4.76%	7.82%	11.41%	0.72	12.58%	4.76%	7.82%	10.39%
Portland General Electric Company	POR	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.66	12.58%	4.76%	7.82%	9.92%
PPL Corporation	PPL	4.76%	1.15	12.58%	4.76%	7.82%	13.76%	0.87	12.58%	4.76%	7.82%	11.57%
Southern Company	SO	4.76%	0.92	12.58%	4.76%	7.82%	11.96%	0.64	12.58%	4.76%	7.82%	9.77%
Xcel Energy Inc.	XEL	4.76%	0.77	12.58%	4.76%	7.82%	10.78%	0.58	12.58%	4.76%	7.82%	9.30%
Average							**11.98%**					**10.05%**

Notes:
[1] Source: Exhibit CUB-5
[2] Source: Exhibit CUB-4
[3] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[4] Source: Exhibit CUB-5
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]
[7] Source: Exhibit CUB-4
[8] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[9] Source: Exhibit CUB-5
[10] Equals [8] - [9]
[11] Equals [1] + [7] x [10]
[12] Equals average of [6] and [11]

Mr. Megginson
Risk Premium Analysis

Evidence That Risk Premium Is Understated

Year	[1] Electric Utility Returns	[2] A-Rated Utility Bond Yield	[3] Utility Bond Risk Prem.	[4] 30 yr. Treasury Bond Yield	[5] Treasury Bond Risk Prem.
1932	-3.18%	5.85%	-9.03%	3.69%	-6.87%
1933	-21.03%	7.22%	-28.25%	3.12%	-24.15%
1934	-19.96%	5.36%	-25.32%	3.18%	-23.14%
1935	74.92%	4.29%	70.63%	2.81%	72.11%
1936	19.64%	3.83%	15.81%	2.77%	16.87%
1937	-34.80%	4.03%	-38.83%	2.66%	-37.46%
1938	18.92%	3.74%	15.18%	2.64%	16.28%
1939	9.95%	3.38%	6.57%	2.40%	7.55%
1940	-15.91%	3.10%	-19.01%	2.23%	-18.14%
1941	-30.03%	3.06%	-33.09%	1.94%	-31.97%
1942	15.21%	3.06%	12.15%	2.46%	12.75%
1943	53.69%	2.99%	50.70%	2.44%	51.25%
1944	6.78%	2.97%	3.81%	2.46%	4.32%
1945	52.05%	2.75%	49.30%	2.34%	49.71%
1946	9.56%	2.76%	6.80%	2.04%	7.52%
1947	-15.57%	3.05%	-18.62%	2.13%	-17.70%
1948	8.56%	3.06%	5.50%	2.40%	6.16%
1949	22.18%	2.78%	19.40%	2.25%	19.93%
1950	6.79%	2.86%	3.93%	2.12%	4.67%
1951	15.48%	3.29%	12.19%	2.38%	13.10%
1952	16.89%	3.22%	13.67%	2.66%	14.23%
1953	9.93%	3.38%	6.55%	2.84%	7.09%
1954	24.57%	3.11%	21.46%	2.79%	21.78%
1955	8.36%	3.35%	5.01%	2.75%	5.61%
1956	4.05%	3.91%	0.14%	2.99%	1.06%
1957	7.63%	4.36%	3.27%	3.44%	4.19%
1958	35.82%	4.49%	31.33%	3.27%	32.55%
1959	3.11%	4.96%	-1.85%	4.01%	-0.90%
1960	20.37%	4.65%	15.72%	4.26%	16.11%
1961	32.17%	4.65%	27.52%	3.83%	28.34%
1962	0.33%	4.44%	-4.11%	4.00%	-3.67%
1963	9.28%	4.46%	4.82%	3.89%	5.39%
1964	16.12%	4.54%	11.58%	4.15%	11.97%
1965	2.91%	4.83%	-1.92%	4.19%	-1.28%
1966	-3.78%	5.67%	-9.45%	4.49%	-8.27%
1967	-2.84%	6.67%	-9.51%	4.59%	-7.43%
1968	10.36%	6.87%	3.49%	5.50%	4.86%
1969	-13.20%	8.59%	-21.79%	5.95%	-19.15%
1970	10.03%	8.48%	1.55%	6.74%	3.29%
1971	2.20%	7.90%	-5.70%	6.32%	-4.12%
1972	3.60%	7.48%	-3.88%	5.87%	-2.27%
1973	-18.92%	8.24%	-27.16%	6.51%	-25.43%
1974	-20.63%	10.27%	-30.90%	7.27%	-27.90%
1975	44.17%	10.11%	34.06%	7.99%	36.18%
1976	27.02%	8.62%	18.40%	7.89%	19.13%
1977	11.20%	8.64%	2.56%	7.14%	4.06%
1978	-2.37%	9.70%	-12.07%	7.90%	-10.27%
1979	5.65%	11.79%	-6.14%	8.86%	-3.21%
1980	8.73%	14.63%	-5.90%	9.97%	-1.24%
1981	17.63%	16.29%	1.34%	11.55%	6.08%
1982	33.70%	14.43%	19.27%	13.50%	20.20%
1983	13.63%	13.52%	0.11%	10.38%	3.25%
1984	21.73%	13.11%	8.62%	11.74%	9.99%
1985	27.66%	10.97%	16.69%	11.25%	16.41%
1986	27.56%	9.12%	18.44%	8.98%	18.58%
1987	-7.41%	10.98%	-18.39%	7.92%	-15.33%
1988	15.74%	10.06%	5.68%	8.97%	6.77%

Mr. Megginson
Risk Premium Analysis

Evidence That Risk Premium Is Understated

Year	[1] Electric Utility Returns	[2] A-Rated Utility Bond Yield	[3] Utility Bond Risk Prem.	[4] 30 yr. Treasury Bond Yield	[5] Treasury Bond Risk Prem.
1989	28.60%	9.44%	19.16%	8.81%	19.79%
1990	3.56%	9.73%	-6.17%	8.19%	-4.63%
1991	28.55%	8.88%	19.67%	8.22%	20.33%
1992	4.19%	8.43%	-4.24%	7.26%	-3.07%
1993	10.16%	7.34%	2.82%	7.17%	2.99%
1994	-13.47%	8.76%	-22.23%	6.59%	-20.06%
1995	30.06%	7.23%	22.83%	7.60%	22.46%
1996	1.84%	7.59%	-5.75%	6.18%	-4.34%
1997	20.33%	7.16%	13.17%	6.64%	13.69%
1998	21.17%	6.91%	14.26%	5.83%	15.34%
1999	-18.62%	8.14%	-26.76%	5.57%	-24.19%
2000	69.24%	7.84%	61.40%	6.50%	62.74%
2001	-7.24%	7.83%	-15.07%	5.53%	-12.77%
2002	-10.25%	6.93%	-17.18%	5.59%	-15.84%
2003	29.39%	6.27%	23.12%	4.80%	24.59%
2004	30.24%	5.92%	24.32%	5.02%	25.22%
2005	25.14%	5.80%	19.34%	4.69%	20.45%
2006	16.63%	5.81%	10.82%	4.68%	11.95%
2007	20.11%	6.16%	13.95%	4.86%	15.25%
2008	-27.84%	6.54%	-34.38%	4.45%	-32.29%
2009	12.47%	5.79%	6.68%	3.47%	9.00%
2010	6.46%	5.56%	0.90%	4.25%	2.21%
2011	19.71%	4.33%	15.38%	3.82%	15.89%
2012	1.64%	4.00%	-2.36%	2.46%	-0.82%
2013	12.69%	4.81%	7.88%	2.88%	9.81%
2014	30.65%	3.94%	26.71%	3.41%	27.24%
2015	-4.60%	4.39%	-8.99%	2.47%	-7.07%
2016	18.18%	4.22%	13.96%	2.30%	15.88%
2017	13.35%	3.75%	9.60%	2.67%	10.68%
2018	1.99%	4.26%	-2.27%	2.97%	-0.98%
2019	27.30%	3.48%	23.82%	2.58%	24.72%
2020	1.55%	2.71%	-1.16%	1.67%	-0.12%
2021	17.01%	3.04%	13.97%	1.91%	15.10%
2022	1.67%	5.44%	-3.77%	3.97%	-2.30%
2023	-5.69%	5.16%	-10.85%	4.03%	-9.72%
2024	15.17%	5.60%	9.57%	4.40%	10.77%
Average	10.83%	6.27%	4.56%	4.96%	5.89%
		Avg. Risk Premium If Interest Rate < 6.27%	**7.76%**	**Avg. Risk Premium If Interest Rate < 4.96%**	**7.19%**

Source:
[1] Exhibit S-4, Schedule D5, at 11
[2] Exhibit S-4, Schedule D5, at 11
[3] Equals [1] - [2]
[4] Exhibit S-4, Schedule D5, at 11
[5] Equals [1] - [4]

Mr. Coppola
Risk Premium Analysis

Evidence That Risk Premium Is Understated

Year	[1] Electric Utility Returns	[2] A-Rated Utility Bond Yield	[3] Utility Bond Risk Prem.
1932	-2.73%	5.85%	-8.58%
1933	-22.17%	7.22%	-29.39%
1934	-21.13%	5.36%	-26.49%
1935	77.49%	4.29%	73.20%
1936	19.47%	3.83%	15.64%
1937	-37.55%	4.03%	-41.58%
1938	19.84%	3.74%	16.10%
1939	10.09%	3.38%	6.71%
1940	-17.64%	3.10%	-20.74%
1941	-32.99%	3.06%	-36.05%
1942	15.61%	3.06%	12.55%
1943	55.98%	2.99%	52.99%
1944	6.62%	2.97%	3.65%
1945	53.82%	2.75%	51.07%
1946	9.63%	2.76%	6.87%
1947	-16.97%	3.05%	-20.02%
1948	8.59%	3.06%	5.53%
1949	23.02%	2.78%	20.24%
1950	6.54%	2.86%	3.68%
1951	15.97%	3.29%	12.68%
1952	17.46%	3.22%	14.24%
1953	9.96%	3.38%	6.58%
1954	25.45%	3.11%	22.34%
1955	8.41%	3.35%	5.06%
1956	3.91%	3.91%	0.00%
1957	7.70%	4.36%	3.34%
1958	36.92%	4.49%	32.43%
1959	3.03%	4.96%	-1.93%
1960	20.88%	4.65%	16.23%
1961	32.95%	4.65%	28.30%
1962	0.14%	4.44%	-4.30%
1963	9.36%	4.46%	4.90%
1964	16.28%	4.54%	11.74%
1965	2.75%	4.83%	-2.08%
1966	-4.14%	5.67%	-9.81%
1967	-3.26%	6.67%	-9.93%
1968	10.54%	6.87%	3.67%
1969	-14.23%	8.59%	-22.82%
1970	10.25%	8.48%	1.77%
1971	1.96%	7.90%	-5.94%
1972	3.41%	7.48%	-4.07%
1973	-21.21%	8.24%	-29.45%
1974	-24.43%	10.27%	-34.70%
1975	47.27%	10.11%	37.16%
1976	28.40%	8.62%	19.78%
1977	11.22%	8.64%	2.58%
1978	-3.86%	9.70%	-13.56%
1979	4.82%	11.79%	-6.97%
1980	8.14%	14.63%	-6.49%
1981	17.95%	16.29%	1.66%
1982	35.82%	14.43%	21.39%
1983	13.72%	13.52%	0.20%
1984	22.75%	13.11%	9.64%
1985	29.23%	10.97%	18.26%
1986	29.03%	9.12%	19.91%
1987	-9.06%	10.98%	-20.04%
1988	16.52%	10.06%	6.46%
1989	30.12%	9.44%	20.68%
1990	3.30%	9.73%	-6.43%
1991	29.89%	8.88%	21.01%

Mr. Coppola
Risk Premium Analysis

Evidence That Risk Premium Is Understated

Year	[1] Electric Utility Returns	[2] A-Rated Utility Bond Yield	[3] Utility Bond Risk Prem.
1992	4.23%	8.43%	-4.20%
1993	10.37%	7.34%	3.03%
1994	-15.16%	8.76%	-23.92%
1995	31.53%	7.23%	24.30%
1996	1.51%	7.59%	-6.08%
1997	21.17%	7.16%	14.01%
1998	21.79%	6.91%	14.88%
1999	-20.04%	8.14%	-28.18%
2000	71.42%	7.84%	63.58%
2001	-25.34%	7.83%	-33.17%
2002	-23.18%	6.93%	-30.11%
2003	28.01%	5.78%	22.23%
2004	29.37%	5.46%	23.91%
2005	24.70%	5.56%	19.14%
2006	16.38%	5.83%	10.55%
2007	21.08%	6.06%	15.02%
2008	-27.73%	5.99%	-33.72%
2009	12.01%	5.88%	6.13%
2010	6.13%	5.64%	0.49%
2011	19.11%	4.09%	15.02%
2012	1.46%	3.95%	-2.49%
2013	12.27%	4.75%	7.52%
2014	29.90%	3.94%	25.96%
2015	-3.07%	4.39%	-7.46%
2016	18.24%	4.22%	14.02%
2017	13.26%	3.60%	9.66%
2018	2.13%	4.65%	-2.52%
2019	26.91%	3.48%	23.43%
2020	1.52%	2.71%	-1.19%
2021	16.81%	2.95%	13.86%
2022	1.61%	5.25%	-3.64%
2023	-5.70%	6.01%	-11.71%
2024	15.13%	5.54%	9.59%
Average	10.52%	6.26%	4.27%
		Avg. Risk Premium If Interest Rate < 6.26%	**7.29%**

Source:
[1] Workpaper AG-3B
[2] Workpaper AG-3B
[3] Equals [1] - [2]

Mr. Coppola Risk Premium Analysis
As Filed v. As Updated

	As Filed		As Updated	
Bond Yield				
Projected Near Term 30 Year Treasury Yield	4.40%	[1]	4.60%	[6]
Spread - Utility Bond Yield ("A" Rated) v. 30 Year Treasury Bond Yield	1.16%	[2]	1.19%	[7]
Projected Near Term Utility Bond Yield	5.56%	[3]	5.79%	[8]
Risk Premium				
Historical Utility Bond Risk Premium	4.25%	[4]	4.27%	[9]
Cost of Equity	**9.81%**	[5]	**10.06%**	[10]

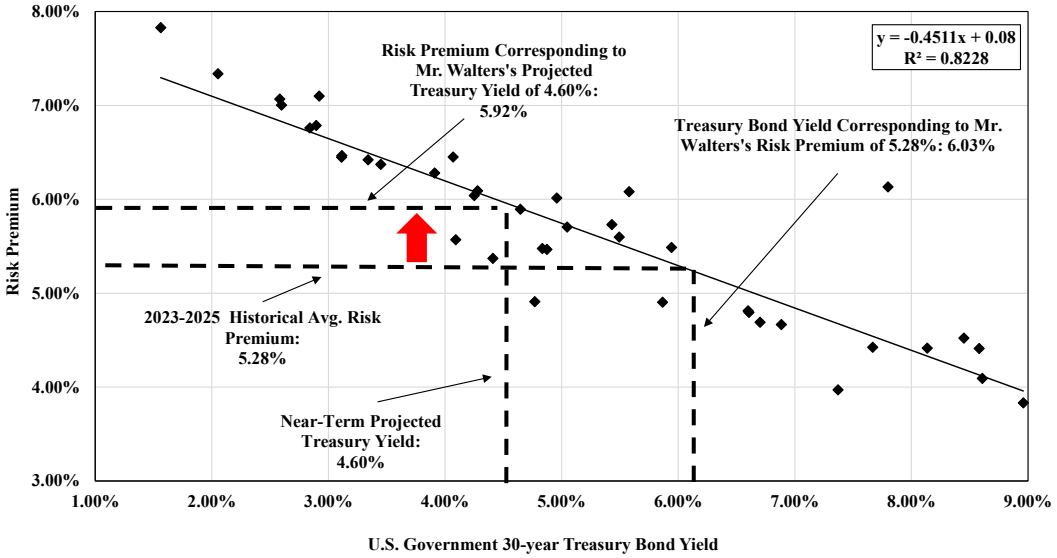
[1] Exhibit AG-39 (as relied on in Exhibit AG-38)
[2] Exhibit AG-39 and Workpaper AG-39A
[3] Equals [1] + [2]
[4] Exhibit AG-39 and Workpaper AG-39B
[5] Equals [3] + [4]
[6] *Blue Chip Financial Forecast* , Vol. 44, No. 10, October 1, 2025, at 2.
[7] Correction to average shown on Workpaper AG-39A
[8] Equals [6] + [7]
[9] Actual average shown on Workpaper AG-39B
[10] Equals [8] + [9]

Mr. Walters's Risk Premium Analysis
As Adjusted Treasury Bond Approach

Year	[1] Authorized Electric Returns	[2] 30 yr. Treasury Bond Yld	[3] Indicated Risk Premium
1986	13.93%	7.80%	6.13%
1987	12.99%	8.58%	4.41%
1988	12.79%	8.96%	3.83%
1989	12.97%	8.45%	4.52%
1990	12.70%	8.61%	4.09%
1991	12.55%	8.14%	4.41%
1992	12.09%	7.67%	4.42%
1993	11.41%	6.60%	4.81%
1994	11.34%	7.37%	3.97%
1995	11.55%	6.88%	4.67%
1996	11.39%	6.70%	4.69%
1997	11.40%	6.61%	4.79%
1998	11.66%	5.58%	6.08%
1999	10.77%	5.87%	4.90%
2000	11.43%	5.94%	5.49%
2001	11.09%	5.49%	5.60%
2002	11.16%	5.43%	5.73%
2003	10.97%	4.96%	6.01%
2004	10.75%	5.05%	5.70%
2005	10.54%	4.65%	5.89%
2006	10.34%	4.87%	5.47%
2007	10.31%	4.83%	5.48%
2008	10.37%	4.28%	6.09%
2009	10.52%	4.07%	6.45%
2010	10.29%	4.25%	6.04%
2011	10.19%	3.91%	6.28%
2012	10.02%	2.92%	7.10%
2013	9.82%	3.45%	6.37%
2014	9.76%	3.34%	6.42%
2015	9.60%	2.84%	6.76%
2016	9.60%	2.60%	7.00%
2017	9.68%	2.90%	6.79%
2018	9.56%	3.11%	6.45%
2019	9.65%	2.58%	7.07%
2020	9.39%	1.56%	7.83%
2021	9.39%	2.05%	7.34%
2022	9.58%	3.12%	6.47%
2023	9.66%	4.09%	5.57%
2024	9.78%	4.41%	5.37%
2025	9.68%	4.77%	4.91%
Average (All Years)	10.82%	5.13%	5.68%
Average (2023 - 2025)	9.71%	4.42%	5.28%

Source:
[1] Exhibit AB-14
[2] Exhibit AB-14
[3] Equals [1] - [2]

Mr. Walters's Risk Premium Analysis
As Adjusted Treasury Bond Approach



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9070927
R Square	0.8228171
Adjusted R Square	0.8181544
Standard Error	0.0042878
Observations	40

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00324	0.00324	176.46770	0.00000
Residual	38	0.00070	0.00002		
Total	39	0.00394			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0800	0.00	42.78	0.0000	0.0762	0.0838	0.0762	0.0838
30-year Treasury bond yield	(0.4511)	0.03	(13.28)	0.0000	(0.5198)	(0.3824)	(0.5198)	(0.3824)

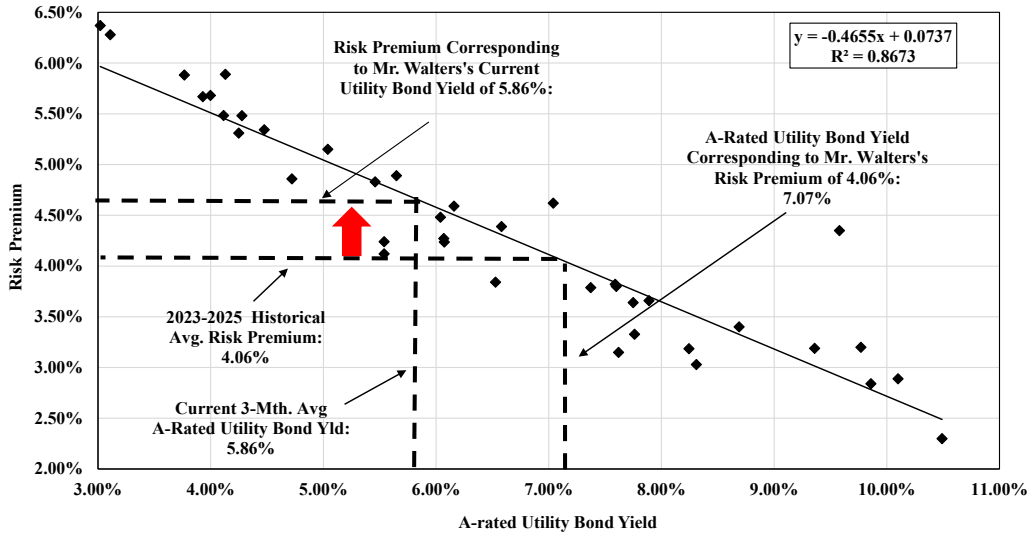
	30-year Treasury Bond Yield	Risk Premium	ROE
Mr. Walters's Adjusted Treasury Bond Approach Using Regression	4.60%	5.92%	10.52%

Mr. Walters's Risk Premium Analysis
As Adjusted Utility Bond Approach

Year	[1] Authorized Electric Returns	[2] A-Rated Utility Bond Yld	[3] Indicated Risk Premium
1986	13.93%	9.58%	4.35%
1987	12.99%	10.10%	2.89%
1988	12.79%	10.49%	2.30%
1989	12.97%	9.77%	3.20%
1990	12.70%	9.86%	2.84%
1991	12.55%	9.36%	3.19%
1992	12.09%	8.69%	3.40%
1993	11.41%	7.59%	3.82%
1994	11.34%	8.31%	3.03%
1995	11.55%	7.89%	3.66%
1996	11.39%	7.75%	3.64%
1997	11.40%	7.60%	3.80%
1998	11.66%	7.04%	4.62%
1999	10.77%	7.62%	3.15%
2000	11.43%	8.24%	3.19%
2001	11.09%	7.76%	3.33%
2002	11.16%	7.37%	3.79%
2003	10.97%	6.58%	4.39%
2004	10.75%	6.16%	4.59%
2005	10.54%	5.65%	4.89%
2006	10.34%	6.07%	4.27%
2007	10.31%	6.07%	4.24%
2008	10.37%	6.53%	3.84%
2009	10.52%	6.04%	4.48%
2010	10.29%	5.46%	4.83%
2011	10.19%	5.04%	5.15%
2012	10.02%	4.13%	5.89%
2013	9.82%	4.48%	5.34%
2014	9.76%	4.28%	5.48%
2015	9.60%	4.12%	5.48%
2016	9.60%	3.93%	5.67%
2017	9.68%	4.00%	5.68%
2018	9.56%	4.25%	5.31%
2019	9.65%	3.77%	5.88%
2020	9.39%	3.02%	6.37%
2021	9.39%	3.11%	6.28%
2022	9.58%	4.72%	4.86%
2023	9.66%	5.54%	4.12%
2024	9.78%	5.54%	4.24%
2025	9.68%	5.87%	3.81%
Average (All Years)	10.82%	6.48%	4.33%
Average (2023 - 2025)	9.71%	5.65%	4.06%

Source:
[1] Exhibit AB-15
[2] Exhibit AB-15
[3] Equals [1] - [2]

Mr. Walters's Risk Premium Analysis
As Adjusted Utility Bond Approach



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9232458
R Square	0.8523829
Adjusted R Square	0.8484982
Standard Error	0.0040565
Observations	40

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00361	0.00361	219.42275	0.00000
Residual	38	0.00063	0.00002		
Total	39	0.00424			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0733	0.00	34.52	0.0000	0.0690	0.0776	0.0690	0.0776
A-rated Utility Bond Yield	(0.4625)	0.03	(14.81)	0.0000	(0.5257)	(0.3993)	(0.5257)	(0.3993)

	Bond Yield	Risk Premium	ROE
3-Month Avg. A-rated Utility Bond Yield as of Aug 2025	5.86%	4.62%	10.48%
6-Month Avg. A-rated Utility Bond Yield as of of Aug 2025	5.88%	4.61%	10.49%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Electric Rate Case

Case No. U-21870
Work Paper AG-37B
September 30, 2025
Page 1 of 1

Growth Rates - Per Value Line and as published by Yahoo'

Line	Company	Ticker	Average	See Footnotes below
	(a)	(b)	(c)	
Value Line Growth				
1	Alliant Energy	LNT	6.00%	
2	Ameren	AEE	6.50%	
3	American Electric Power	AEP	6.50%	
4	CenterPoint Energy	CNP	6.50%	
5	Consolidated Edison	ED	6.00%	
6	DTE Energy	DTE	4.50%	
7	Evergy	EVRG	7.50%	**Do Not Include***
8	IDACORP	IDA	6.00%	
9	OGE Energy	OGE	6.50%	
10	Portland General Electric	POR	6.50%	
11	WEC Energy	WEC	6.00%	
12	Average		6.23%	

		Ticker	2025	2026	Average	
Yahoo Growth - 2025 &2026						
13	Alliant Energy	LNT	5.45%	6.92%	6.19%	
14	Ameren	AEE	7.16%	7.23%	7.20%	
15	American Electric Power	AEP	4.93%	6.70%	5.82%	
16	CenterPoint Energy	CNP	8.19%	8.14%	8.17%	**Do Not Include****
17	Consolidated Edison	ED	4.15%	6.80%	5.48%	
18	DTE Energy	DTE	5.62%	5.74%	5.68%	
19	Evergy	EVRG	5.87%	6.20%	6.04%	
20	IDACORP	IDA	6.17%	9.11%	7.64%	**Do Not Include****
21	OGE Energy	OGE	3.87%	6.80%	5.34%	
22	Portland General Electric	POR	2.96%	5.04%	4.00%	
23	WEC Energy	WEC	7.29%	6.73%	7.01%	
24	Average				6.23%	

* Evergy's EPS Growth reflects 6% growth vs. Value Line's stated earnings growth of 7.5%

** These short-term growth rates are inconsistent with longer term estimates

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Electric Rate Case

Case No. U-21870
Workpaper AG-39A
September 30, 2025
Page 1 of 2

30 Year Utility Debt Issues Rated "A" by Moody's and S & P in 2023 and 2024*

Line	Issuer	Date in 2024		Ratings		Issue Rate	Spread vs. 30 Yr. US Treas.
	(a)	(b)		(c)		(d)	(e)
	30 Year Utility "A" Rated **						
1	Union Electric	Jan	3	A2	A	5.25%	123
2	Northern Natural Gas	Jan	29	A2	A-	5.63%	127
3	Patomac Electric	Feb	26	A2	A	5.50%	110
4	Public Service Electric & Gas	Feb	28	A1	A	5.46%	108
5	Entergy Louisiana	Mar	4	A2	A	5.70%	135
6	Indianappolis Power & Light	Mar	7	A2	A-	5.75%	147
7	Duke Energy Ohio	Mar	11	A2	A	5.55%	130
8	San Diego Gas & Electric	Mar	18	A1	A	5.55%	115
9	Public Service of Colorado	Apr	1	A1	A	5.75%	130
10	Consolidated Edison of New York	May	6	A3	A-	5.75%	110
11	Commenwealth Edison	May	6	A1	A	5.65%	105
12	Entergy Arkansas	May	7	A2	A	5.75%	118
13	Entergy Mississippi	May	13	A2	A	5.85%	123
14	Baltimore Gas & Electric	June	3	A3	A	5.65%	110
15	Southwestern Public Service	June	3	A3	A-	6.00%	150
16	Pudget Sound Energy	June	4	A2	A-	5.69%	120
17	Oncor Delivery	June	17	A1	A+	5.55%	115
18	Ameren Illinois	June	17	A1	A	5.55%	115
19	Public Service Electric & Gas	Aug	1	A1	A	5.30%	105
20	Entergy Texas	Aug	12	A3	A	5.55%	140
21	Oklahoma Electric & Gas	Aug	12	A3	A-	5.60%	130
22	Wisconsin Electric Power	Sep	9	A2	A-	5.05%	108
23	Atmos Energy	Sep	17	A1	A-	5.00%	108
24	Consolidated Edison of New York	Nov	14	A3	A-	5.25%	70
25	***Average Spread "A" Rated or Better***					5.56%	**116**

* From Company Exhibi A-28 (MRB-9), and SEC filings

** Excludes long-term debt issued by California utility companies

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Electric Rate Case

Case No. U-21870
Workpaper AG-39A
September 30, 2025
Page 2 of 2

30 Year Utility Debt Issues Rated "A" by Moody's and S & P in 2023 and 2024*

Line	Issuer	Date in 2023		Ratings		Issue Rate	Spread vs. 30 Yr. US Treas.
	(a)	(b)		(c)		(d)	(e)
	30 Year Utility "A" Rated ***						
1	Connecticut Light & Power	Jan	3	A1	A+	5.25%	135
2	Commenwealth Edison	Jan	3	A1	A	5.30%	140
3	Public Service of New Hampshire	Jan	4	A1	A+	3.70%	133
4	Tuscon Electric & Power	Feb	15	A3	A-	5.50%	175
5	Union Electric	Feb	27	A2	A	5.45%	155
6	PPL Electric	Feb	27	A1	A+	5.25%	145
7	San Diego Gas & Electric	Mar	6	A2	A	5.35%	150
8	Evergy Kansas Central	Mar	7	A2	A	5.70%	185
9	Idaho Power	Mar	9	A2	A-	5.50%	170
10	AEP Transmission	Mar	9	A2	A-	5.40%	157
11	Duke Energy Ohio	Mar	20	A2	A	5.65%	200
12	Centerpoint-Houston Electric	Mar	20	A2	A	5.30%	165
13	Oklahoma Gas & Electric	Mar	21	A3	A-	5.60%	190
14	Indiana Michigan Power	Mar	21	A3	A-	5.63%	190
15	Public Service Electric & Gas	Mar	23	A1	A	5.75%	142
16	Public Service of Colorado	Mar	27	A1	A	5.25%	155
17	Baltimore Gas & Electric	May	8	A3	A	5.40%	158
18	Pudget Sound Energy	May	15	A2	A-	5.45%	160
19	Public Energy Elec. & Gas	Aug	3	A1	A	5.45%	115
20	Entergy Texas	Aug	8	A3	A	5.80%	160
21	Nevada :pwer	Sep	11	A2	A+	6.00%	163
22	Sierra Pacific Power	Sep	13	A2	A+	5.90%	160
23	Dominion Energy S. C.	Oct	4	A2	A	6.25%	140
24	Atmos Energy	Oct	5	A1	A-	6.20%	133
25	Duke Energy Florida	Nov	6	A1	A	6.20%	142
26	Consolidated Edison of NY	Nov	20	A3	A-	5.90%	137
27	Average Rate and Spread					6.01%	**156**

* From Company Exhibi A-28 (MRB-9), and SEC filings

** Excludes long-term debt issued by California utility companies

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
AG Workpapers

Case No.: U-21870
Exhibit No.: A-207 (AEB-3)
Page: 4 of 6
Witness: AEBulkley
Date: October 2025

MICHIGAN PUBLIC SERVICE COMMISSION **Case U-21870**
Consumers Energy - Electric Rate Case Work Paper AG-39B Pg 1 of 2
Electric Risk Premium Analysis (Pg 1 data per Mergent PU Manual)

		Moody's Electric Utility Common Stocks					Ylds. on	Electric
Line	Year	Yr End Avg. Mkt. Price	Avg. Divi-dent p/sh	% Market Gain/Loss	Dividend Yield	Total Return	"A" Rated Util. Bonds	Stocks vs. Bonds
1	1931	$ 43.23						
2	1932	39.42	$ 2.63	-8.81%	6.08%	-2.73%	5.85%	-8.58%
3	1933	28.73	1.95	-27.12%	4.95%	-22.17%	7.22%	-29.39%
4	1934	21.06	1.60	-26.70%	5.57%	-21.13%	5.36%	-26.49%
5	1935	36.06	1.32	71.23%	6.27%	77.49%	4.29%	73.20%
6	1936	41.60	1.48	15.36%	4.10%	19.47%	3.83%	15.64%
7	1937	24.24	1.74	-41.73%	4.18%	-37.55%	4.03%	-41.58%
8	1938	27.55	1.50	13.66%	6.19%	19.84%	3.74%	16.10%
9	1939	28.85	1.48	4.72%	5.37%	10.09%	3.38%	6.71%
10	1940	22.22	1.54	-22.98%	5.34%	-17.64%	3.10%	-20.74%
11	1941	13.45	1.44	-39.47%	6.48%	-32.99%	3.06%	-36.05%
12	1942	14.29	1.26	6.25%	9.37%	15.61%	3.06%	12.55%
13	1943	21.01	1.28	47.03%	8.96%	55.98%	2.99%	52.99%
14	1944	21.09	1.31	0.38%	6.24%	6.62%	2.97%	3.65%
15	1945	31.14	1.30	47.65%	6.16%	53.82%	2.75%	51.07%
16	1946	32.71	1.43	5.04%	4.59%	9.63%	2.76%	6.87%
17	1947	25.60	1.56	-21.74%	4.77%	-16.97%	3.05%	-20.02%
18	1948	26.20	1.60	2.34%	6.25%	8.59%	3.06%	5.53%
19	1949	30.57	1.66	16.68%	6.34%	23.02%	2.78%	20.24%
20	1950	30.81	1.76	0.79%	5.76%	6.54%	2.86%	3.68%
21	1951	33.85	1.88	9.87%	6.10%	15.97%	3.29%	12.68%
22	1952	37.85	1.91	11.82%	5.64%	17.46%	3.22%	14.24%
23	1953	39.61	2.01	4.65%	5.31%	9.96%	3.38%	6.58%
24	1954	47.56	2.13	20.07%	5.38%	25.45%	3.11%	22.34%
25	1955	49.35	2.21	3.76%	4.65%	8.41%	3.35%	5.06%
26	1956	48.96	2.32	-0.79%	4.70%	3.91%	3.91%	0.00%
27	1957	50.30	2.43	2.74%	4.96%	7.70%	4.36%	3.34%
28	1958	66.37	2.50	31.95%	4.97%	36.92%	4.49%	32.43%
29	1959	65.77	2.61	-0.90%	3.93%	3.03%	4.96%	-1.93%
30	1960	76.82	2.68	16.80%	4.07%	20.88%	4.65%	16.23%
31	1961	99.32	2.81	29.29%	3.66%	32.95%	4.65%	28.30%
32	1962	96.49	2.97	-2.85%	2.99%	0.14%	4.44%	-4.30%
33	1963	102.31	3.21	6.03%	3.33%	9.36%	4.46%	4.90%
34	1964	115.54	3.43	12.93%	3.35%	16.28%	4.54%	11.74%
35	1965	114.86	3.86	-0.59%	3.34%	2.75%	4.83%	-2.08%
36	1966	105.99	4.11	-7.72%	3.58%	-4.14%	5.67%	-9.81%
37	1967	98.19	4.34	-7.36%	4.09%	-3.26%	6.67%	-9.93%
38	1968	104.04	4.50	5.96%	4.58%	10.54%	6.87%	3.67%

	Moody's Electric Utility Common Stocks					Ylds. on	Electric
Year	Yr End Avg. Mkt. Price	Avg. Divi-dent p/sh	% Market Gain/Loss	Dividend Yield	Total Return	"A" Rated Util. Bonds	Stocks vs. Bonds
1969	$ 84.62	$ 4.61	-18.67%	4.43%	-14.23%	8.59%	-22.82%
1970	88.59	4.70	4.69%	5.55%	10.25%	8.48%	1.77%
1971	85.56	4.77	-3.42%	5.38%	1.96%	7.90%	-5.94%
1972	83.61	4.87	-2.28%	5.69%	3.41%	7.48%	-4.07%
1973	60.87	5.01	-27.20%	5.99%	-21.21%	8.24%	-29.45%
1974	41.17	4.83	-32.36%	7.93%	-24.43%	10.27%	-34.70%
1975	55.66	4.97	35.20%	12.07%	47.27%	10.11%	37.16%
1976	66.29	5.18	19.10%	9.31%	28.40%	8.62%	19.78%
1977	68.19	5.54	2.87%	8.36%	11.22%	8.64%	2.58%
1978	59.75	5.81	-12.38%	8.52%	-3.86%	9.70%	-13.56%
1979	56.41	6.22	-5.59%	10.41%	4.82%	11.79%	-6.97%
1980	54.42	6.58	-3.53%	11.66%	8.14%	14.63%	-6.49%
1981	57.20	6.99	5.11%	12.84%	17.95%	16.29%	1.66%
1982	70.26	7.43	22.83%	12.99%	35.82%	14.43%	21.39%
1983	72.03	7.87	2.52%	11.20%	13.72%	13.52%	0.20%
1984	80.16	8.26	11.29%	11.47%	22.75%	13.11%	9.64%
1985	94.98	8.61	18.49%	10.74%	29.23%	10.97%	18.26%
1986	113.66	8.89	19.67%	9.36%	29.03%	9.12%	19.91%
1987	94.24	9.12	-17.09%	8.02%	-9.06%	10.98%	-20.04%
1988	100.94	8.87	7.11%	9.41%	16.52%	10.06%	6.46%
1989	122.52	8.82	21.38%	8.74%	30.12%	9.44%	20.68%
1990	117.77	8.79	-3.88%	7.17%	3.30%	9.73%	-6.43%
1991	144.02	8.95	22.29%	7.60%	29.89%	8.88%	21.01%
1992	141.06	9.05	-2.06%	6.28%	4.23%	8.43%	-4.20%
1993	146.70	8.99	4.00%	6.37%	10.37%	7.34%	3.03%
1994	115.50	8.96	-21.27%	6.11%	-15.16%	8.76%	-23.92%
1995	142.90	9.02	23.72%	7.81%	31.53%	7.23%	24.30%
1996	136.00	9.06	-4.83%	6.34%	1.51%	7.59%	-6.08%
1997	155.73	9.06	14.51%	6.66%	21.17%	7.16%	14.01%
1998	181.84	7.83	16.77%	5.03%	21.79%	6.91%	14.88%
1999	137.30	8.10	-24.49%	4.45%	-20.04%	8.14%	-28.18%
2000	227.09	8.27	65.40%	6.02%	71.42%	7.84%	63.58%
Avg. for 69 Years Ended 2000					11.13%	6.69%	4.44%
Avg. for 24 Years Ended 2024 (Page 2)					8.79%	5.02%	3.77%
Wtd. Avg. for 93 Years					10.52%	6.26%	**4.27%**
Equity Risk Premium						***USE***	***4.25%***

Electric Risk Premium Analysis
(Dow Jones Utility Returns by Year 2001-2024)

		Return of the Dow Jones Utilities*				A Rated
		Dec. 31	%	Div.	Total	Utility
Line	Year	Close	Change	Yield	Return	Bonds**
1	2000	412.16				
2	2001	293.94	-28.68%	3.34%	-25.34%	7.83%
3	2002	215.18	-26.79%	3.61%	-23.18%	6.93%
4	2003	266.90	24.04%	3.97%	28.01%	5.78%
5	2004	334.95	25.50%	3.87%	29.37%	5.46%
6	2005	405.11	20.95%	3.75%	24.70%	5.56%
7	2006	456.77	12.75%	3.63%	16.38%	5.83%
8	2007	537.53	17.68%	3.40%	21.08%	6.06%
9	2008	370.76	-31.03%	3.30%	-27.73%	5.99%
10	2009	398.01	7.35%	4.66%	12.01%	5.88%
11	2010	404.99	1.75%	4.38%	6.13%	5.64%
12	2011	464.68	14.74%	4.37%	19.11%	4.09%
13	2012	453.09	-2.49%	3.95%	1.46%	3.95%
14	2013	490.57	8.27%	4.00%	12.27%	4.75%
15	2014	618.08	25.99%	3.91%	29.90%	3.94%
16	2015	577.82	-6.51%	3.44%	-3.07%	4.39%
17	2016	659.61	14.15%	4.09%	18.24%	4.22%
18	2017	723.37	9.67%	3.59%	13.26%	3.60%
19	2018	712.93	-1.44%	3.57%	2.13%	4.65%
20	2019	879.17	23.32%	3.59%	26.91%	3.48%
21	2020	864.64	-1.65%	3.18%	1.52%	2.71%
22	2021	980.78	13.43%	3.38%	16.81%	2.95%
23	2022	967.40	-1.36%	2.97%	1.61%	5.25%
24	2023	881.67	-8.86%	3.16%	-5.70%	6.01%
25	2024	982.24	11.41%	3.72%	15.13%	5.54%
24	24 Year Average (Data to page 1)				**8.79%**	**5.02%**

* Per Information available from Yahoo and Value Line
** Mergent Public Utility Manual for 2001 and Bloomberg for all other data

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
AG Workpapers

Case No.: U-21870
Exhibit No.: A-207 (AEB-3)
Page: 6 of 6
Witness: AEBulkley
Date: October 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy - Electric Rate Case

Case No. U-21870
Work paper AG-38A
September 30, 2025
Page 1 of 1

CAPM Market Risk Premium (MRP) Analysis*

Line	Year	Large Co. Total Returns	Long-Term Gov. Bonds Income	Difference	Year	Large Co. Total Returns	Long-Term Gov. Bonds Income	Difference	Year	Large Co. Total Returns	Long-Term Gov. Bonds Income	Difference
1	1926	11.62%	3.73%	7.89%	1958	43.36%	3.27%	40.09%	1991	30.47%	8.22%	22.25%
2	1927	37.49%	3.41%	34.08%	1959	11.96%	4.01%	7.95%	1992	7.62%	7.26%	0.36%
3	1928	43.61%	3.22%	40.39%	1960	0.47%	4.26%	-3.79%	1993	10.08%	7.17%	2.91%
4	1929	-8.42%	3.47%	-11.89%	1961	26.89%	3.83%	23.06%	1994	1.32%	6.59%	-5.27%
5	1930	-24.90%	3.32%	-28.22%	1962	-8.73%	4.00%	-12.73%	1995	37.58%	7.60%	29.98%
6	1931	-43.34%	3.33%	-46.67%	1963	22.80%	3.89%	18.91%	1996	22.96%	6.18%	16.78%
7	1932	-8.19%	3.69%	-11.88%	1964	16.48%	4.15%	12.33%	1997	33.36%	6.64%	26.72%
8	1933	53.99%	3.12%	50.87%	1965	12.45%	4.19%	8.26%	1998	28.58%	5.83%	22.75%
9	1934	-1.44%	3.18%	-4.62%	1966	-10.06%	4.49%	-14.55%	1999	21.04%	5.57%	15.47%
10	1935	47.67%	2.81%	44.86%	1967	23.98%	4.59%	19.39%	2000	-9.10%	6.50%	-15.60%
11	1936	33.92%	2.77%	31.15%	1968	11.06%	5.50%	5.56%	2001	-11.89%	5.53%	-17.42%
12	1937	-35.03%	2.66%	-37.69%	1969	-8.50%	5.95%	-14.45%	2002	-22.10%	5.59%	-27.69%
13	1938	31.12%	2.64%	28.48%	1970	3.86%	6.74%	-2.88%	2003	28.68%	4.80%	23.88%
14	1939	-0.41%	2.40%	-2.81%	1971	14.30%	6.32%	7.98%	2004	10.88%	5.02%	5.86%
15	1940	-9.78%	2.23%	-12.01%	1972	18.99%	5.87%	13.12%	2005	4.91%	4.69%	0.22%
16	1941	-11.59%	1.94%	-13.53%	1973	-14.69%	6.51%	-21.20%	2006	15.79%	4.68%	11.11%
17	1942	20.34%	2.46%	17.88%	1974	-26.47%	7.27%	-33.74%	2007	5.49%	4.86%	0.63%
18	1943	25.90%	2.44%	23.46%	1975	37.23%	7.99%	29.24%	2008	-37.00%	4.45%	-41.45%
19	1944	19.75%	2.46%	17.29%	1976	23.93%	7.89%	16.04%	2009	26.46%	3.47%	22.99%
20	1945	36.44%	2.34%	34.10%	1977	-7.16%	7.14%	-14.30%	2010	15.06%	4.25%	10.81%
21	1946	-8.07%	2.04%	-10.11%	1978	6.57%	7.90%	-1.33%	2011	2.11%	3.81%	-1.70%
22	1947	5.71%	2.13%	3.58%	1979	18.61%	8.86%	9.75%	2012	16.00%	2.46%	13.54%
23	1948	5.50%	2.40%	3.10%	1980	32.50%	9.97%	22.53%	2013	32.39%	2.88%	29.51%
24	1949	18.79%	2.25%	16.54%	1981	-4.92%	11.55%	-16.47%	2014	13.69%	3.41%	10.28%
25	1950	31.71%	2.12%	29.59%	1982	21.55%	13.50%	8.05%	2015	1.38%	2.47%	-1.09%
26	1951	24.02%	2.38%	21.64%	1983	22.56%	10.38%	12.18%	2016	11.96%	2.30%	9.66%
27	1952	18.37%	2.66%	15.71%	1984	6.27%	11.74%	-5.47%	2017	21.83%	2.67%	19.16%
28	1953	-0.99%	2.84%	-3.83%	1985	31.73%	11.25%	20.48%	2018	-4.38%	2.82%	-7.20%
29	1954	52.62%	2.79%	49.83%	1986	18.67%	8.98%	9.69%	2019	31.49%	2.55%	28.94%
30	1955	31.56%	2.75%	28.81%	1987	5.25%	7.92%	-2.67%	2020	18.40%	1.53%	16.87%
31	1956	6.56%	2.99%	3.57%	1988	16.61%	8.97%	7.64%	2021	28.71%	1.73%	26.98%
32	1957	-10.78%	3.44%	-14.22%	1989	31.69%	8.81%	22.88%	2022	-18.11%	2.61%	-20.72%
33					1990	-3.10%	8.19%	-11.29%	2023	26.29%	4.03%	22.26%
34									2024	25.02%	4.78%	20.24%
35									**99 Yr. Avg.**	12.29%	4.84%	7.32%
36												
37									**MRP Based on 99 Year History**			**7.32%**

*Data from 2023 SBBI Yearbook, by Ibbotson and Duff & Phelps and for 2023 and 2024 as follows
Lg. Co. Returns www.slickcharts.com/sp500/returns by Polygon
LT Gov. Bonds Year End Yield of 30 Year US Treasury Bond per US Treasury

USE ***7.35%***

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Revenue Deficiency
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Revised Exhibit No.: A-208 (PDD-63)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source - Adjustments	(c) Initial Filing {1}	(d) Adjustments	(e) Rebuttal Position
1	Rate Base	Exhibit No.: A-209 (PDD-64)	15,367,518	(37,159)	15,330,358
2	Adjusted Net Operating Income	Revised Exhibit No.: A-213 (PDD-68)	707,746	(100)	707,646
3	Overall Rate of Return	Line 2 / line 1	4.61%	0.01%	4.62%
4	Required Rate of Return	Exhibit No.: A-187 (MRB-22)	6.35%	-0.05%	6.30%
5	Income Required	Line 1 * line 4	975,589	(9,433)	966,156
6	Income Deficiency (Sufficiency)	Line 5 - line 2	267,843	(9,332)	258,510
7	Revenue Conversion Factor		1.3381	1.3381	1.3381
8	Revenue Deficiency (Sufficiency)	Line 6 * line 7	358,395	(12,488)	345,907
9	Return On - Campbell Regulatory Asset	Ex. A-81 (PDD-57), Line 5	77,486	(502)	76,984
10	Adjusted revenue deficiency (sufficiency)	Line 8 + Line 9	435,881	(12,989)	422,891

Notes

{1} Source: Exhibit No.: A-11 (PDD-28)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Rate Base
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-209 (PDD-64)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source - Adjustments	(c) Initial Filing {1}	(d) Adjustments	(e) Rebuttal Position
1	Total Utility Plant	Exhibit No.: A-211 (PDD-66)	19,958,747	(38,248)	19,920,498
2	Depreciation Reserve	Exhibit No.: A-211 (PDD-66)	(6,650,643)	1,089	(6,649,554)
3	Customer Advances for Construction	-	(66,473)	-	(66,473)
4	Net Utility Plant	Sum of lines 1 through 3	13,241,630	(37,159)	13,204,471
5	Working Capital	Exhibit No.: A-212 (PDD-67)	2,125,887	-	2,125,887
6	Total Rate Base	Line 4 + line 5	15,367,518	(37,159)	15,330,358

Notes

{1} Source: Exhibit No.: A-12 (PDD-31)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Utility Plant
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-210 (PDD-65)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source	(c) Utility Plant	(d) Depreciation Reserve	(e) Net Utility Plant
1	Utility Plant - Initial Filing	Exhibit No.: A-12 (PDD-31)	19,958,747	(6,650,643)	13,308,103
	Adjustments				
2	Update to 2025 HVD Substatio	Exhibit No.: A-211 (PDD-66), line 1	(10,992)	437	(10,555)
3	EGLE-MIEJ Grant Work	Exhibit No.: A-211 (PDD-66), line 2	(3,479)	93	(3,386)
4	Facilities - Other Equipment	Exhibit No.: A-211 (PDD-66), line 3	(49)	1	(48)
5	Facilities - Emergent Repairs	Exhibit No.: A-211 (PDD-66), line 4	(474)	4	(471)
6	LVD Lines Capacity	Exhibit No.: A-211 (PDD-66), line 5	(9,360)	140	(9,220)
7	ARP Collaboration Project	Exhibit No.: A-211 (PDD-66), line 6	(116)	13	(103)
8	Service Restoration Artificial Int	Exhibit No.: A-211 (PDD-66), line 7	(59)	7	(52)
9	HVD New Business - Cancellec	Exhibit No.: A-211 (PDD-66), line 8	(10,310)	154	(10,156)
10	Peer-Peer Automation	Exhibit No.: A-211 (PDD-66), line 9	(1,030)	20	(1,010)
11	CVR Underspending	Exhibit No.: A-211 (PDD-66), line 10	(1,617)	53	(1,564)
12	ARP-Field Device Asset Manag	Exhibit No.: A-211 (PDD-66), line 11	(62)	7	(55)
13	Product Family Enhancements	Exhibit No.: A-211 (PDD-66), line 12	(525)	140	(385)
14	Product Family Enhancements	Exhibit No.: A-211 (PDD-66), line 13	(175)	20	(155)
15	Total Adjustments	Sum of lines 2 through 11	(38,248)	1,089	(37,159)
16	Utility Plant - Rebuttal Position	Line 1 + line 15	19,920,498	(6,649,554)	13,270,944

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Spending Reconciliation
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-211 (PDD-66)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
				Cap Ex Adj. Increase / (Decrease)						Projected Test Year Impacts					
Line No.	Description	Schedule B-5 Category	Source	12-Mo Ended 12/31/24 Increase / (Decrease)	12-Mo Ending 12/31/25 Increase / (Decrease)	4-Mo Ending 04/30/26 Increase / (Decrease)	12-Mo Ending 04/30/27 Increase / (Decrease)	Composite Deprec. Rate	Property Tax Rate	Total CapEx Adjustment Increase / (Decrease)	Avg. Plant Adjustment Increase / (Decrease)	Avg. Accum. Deprec. Increase / (Decrease)	Avg. Net RB Increase / (Decrease)	Deprec. Increase / (Decrease)	Prop. Tax Increase / (Decrease)
1	Update to 2025 HVD Substations Reliability Spending	Electric Distribution - Distribution	Staff witness Durfee	-	(10,992)	-	-	2.98%	1.33%	(10,992)	(10,992)	(437)	(10,555)	(328)	(147)
2	EGLE-MIEJ Grant Work	Electric Distribution - Distribution	AG - Coppola	-	(1,385)	(1,385)	(1,420)	2.98%	1.33%	(4,189)	(3,479)	(93)	(3,386)	(104)	(46)
3	Facilities - Other Equipment	Operations Support -Common Other	Staff witness Hunter	-	-	-	(98)	5.15%	1.33%	(98)	(49)	(1)	(48)	(3)	(1)
4	Facilities - Emergent Repairs	Operations Support -Common Stuctures	Staff witness Hunter	-	-	-	(949)	1.56%	1.33%	(949)	(474)	(4)	(471)	(7)	(6)
5	LVD Lines Capacity	Electric Distribution - Distribution	Staff witness Boutet	-	-	-	(18,720)	2.98%	1.33%	(18,720)	(9,360)	(140)	(9,220)	(279)	(125)
6	ARP Collaboration Project	Information Technology - Intangibles/Compu	Staff witness Zichi	-	-	(46)	(139)	20.00%	1.33%	(185)	(116)	(13)	(103)	(23)	(2)
7	Service Restoration Artificial Intelligence Project	Information Technology - Intangibles/Compu	Staff witness Duell	-	-	(31)	(57)	20.00%	1.33%	(88)	(59)	(7)	(52)	(12)	(1)
8	HVD New Business - Cancelled Project	Electric Distribution - Distribution	ABATE - Fitzhenry	-	-	-	(20,619)	2.98%	1.33%	(20,619)	(10,310)	(154)	(10,156)	(307)	(138)
9	Peer-Peer Automation	Electric Distribution - Distribution	AG - Coppola	-	-	(895)	(270)	2.98%	1.33%	(1,165)	(1,030)	(20)	(1,010)	(31)	(14)
10	CVR Underspending	Electric Distribution - Distribution	Staff - Boutet	-	(1,159)	(92)	(733)	2.98%	1.33%	(1,984)	(1,617)	(53)	(1,564)	(48)	(22)
11	ARP-Field Device Asset Management	Information Technology - Intangibles/Compu	Staff witness Zichi	-	-	(25)	(74)	20.00%	1.33%	(99)	(62)	(7)	(55)	(12)	(1)
12	Product Family Enhancements - Customer - Capital (We	Information Technology - Intangibles/Compu	Staff witness Zichi	-	(525)	-	-	20.00%	1.33%	(525)	(525)	(140)	(385)	(105)	(7)
13	Product Family Enhancements - Customer - Capital (We	Information Technology - Intangibles/Compu	Staff witness Zichi	-	-	(88)	(175)	20.00%	1.33%	(263)	(175)	(20)	(155)	(35)	(2)
14	Total		Sum of lines 1 through 10	-	(14,060)	(2,561)	(43,254)			(59,875)	(38,248)	(1,089)	(37,159)	(1,294)	(511)

Notes

Source: Col. (h): WP-PDD-24
Source: Col. (i): Exhibit No.: A-161 (BJV-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Working Capital
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-212 (PDD-67)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Initial Filing {1}	(c) Adjustments	(d) Rebuttal Position
1	Cash, cash equivalents, and restricted cash	$ 50,385	$ -	$ 50,385
2	Accounts and notes receivable	280,141	-	280,141
3	Fuel Stock	64,489	-	64,489
4	Materials and supplies	216,848	-	216,848
5	Allowances	14	-	14
6	Prepayments	933,846	-	933,846
7	Accrued revenue	329,191	-	329,191
8	Deferred taxes	272,280	-	272,280
9	Deferred debits	998,077	-	998,077
10	Total assets	3,145,271	-	3,145,271
11	Accounts payable	474,206	-	474,206
12	Customer deposits	22,955	-	22,955
13	Accrued interest	66,062	-	66,062
14	Dividends payable	24,539	-	24,539
15	Accrued taxes	256,080	-	256,080
16	Other liabilities	72,728	-	72,728
17	Deferred credits	102,814	-	102,814
18	Total liabilities	1,019,384	-	1,019,384
19	Working capital	$ 2,125,887	$ -	$ 2,125,887

Notes

{1} Source: Exhibit No.: A-12 (PDD-34)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Net Operating Income
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Revised Exhibit No.: A-213 (PDD-68)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Initial Filing {1}	(c) Adjustments {2}	(d) Rebuttal Position
1	Sales Revenues	4,758,415	-	4,758,415
2	Other Revenues	262,208	-	262,208
3	Total Operating Revenue	5,020,623	-	5,020,623
4	Power supply costs	2,313,242	-	2,313,242
5	Other O&M Expense	804,952	(694)	804,259
6	Depreciation and Amortization	813,088	(1,294)	811,793
7	Property Taxes	280,500	(511)	279,989
8	General Taxes	36,638	-	36,638
9	Other (Local) Taxes	1,150	16	1,167
10	State Income Tax	33,324	539	33,863
11	Federal Income Tax	46,009	2,043	48,052
12	Total Operating Expenses	4,328,903	100	4,329,004
13	Net Operating Income	691,720	(100)	691,619
14	AFUDC	16,026	-	16,026
15	Net Operating Income, Including AFUDC	707,746	(100)	707,646
	Net Operating Income Adjustments			
16	Income Tax Effect of Interest {3}	---- Included in Lines 12, 13, and 14 ----		
17	Interest Synchronization Adjustment {3}	---- Included in Lines 12, 13, and 14 ----		
18	Total Adjusted Net Operating Income	707,746	(100)	707,646

Notes

{1} Source: Col.(b): Exhibit No.: A-13 (PDD-36)
{2} Source: Col.(c): Revised Exhibit No.: A-214 (PDD-69)
{3} Income tax effects of interest and interest synchronization adjustments are included in the calculation of local, state, and federal income tax. The separate calculations can be found on Revised Exhibit Nos.: A-216 (PDD-71) and A-217 (PDD-72)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Reconciliation of Adjusted Net Operating Income
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Revised Exhibit No.: A-214 (PDD-69)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source	(c) Sales Revenues	(d) Other Revenues	(e) Pwr Supply Costs	(f) Other O&M	(g) Deprec. & Amort.	(h) Property Taxes	(i) General Taxes	(j) CIT	(k) SIT	(l) FIT	(m) NOI	(n) AFUDC	(o) Adjusted NOI
1	Adjusted Net Operating Income - Initial Filing	Exhibit No.: A-13 (PDD-36)	4,758,415	262,208	2,313,242	804,952	813,088	280,500	36,638	1,150	33,324	46,009	691,720	16,026	707,746
	Adjustments														
2	HVD Lines Reliability	AG - Coppola	-	-	-	(677)	-	-	-	1	35	134	506	-	506
3	Product Family Enhancements - Customer - Capital (Web Rebate for Personalization)	Staff witness Zichi	-	-	-	(17)	-	-	-	0	1	3	12	-	12
4	Depreciation	Exhibit No.: A-211 (PDD-66) col.(n)	-	-	-	-	(1,294)	-	-	2	68	257	967	-	967
5	Property Tax Expense	Exhibit No.: A-211 (PDD-66) col.(o)	-	-	-	-	-	(511)	-	1	27	101	382	-	382
6	General Taxes		-	-	-	-	-	-	-	-	-	-	-	-	-
7	Income Tax Effect of Interest	Revised Exhibit No.: A-216 (PDD-71)	-	-	-	-	-	-	-	12	406	1,538	(1,957)	-	(1,957)
8	Interest Synchronization Adjustment	Revised Exhibit No.: A-217 (PDD-72)	-	-	-	-	-	-	-	0	2	8	(11)	-	(11)
9	Total Adjustments	Sum of lines 2 through 8	-	-	-	(694)	(1,294)	(511)	-	16	539	2,043	(100)	-	(100)
10	Adjusted Net Operating Income - Rebuttal Position	Line 1 + line 9	4,758,415	262,208	2,313,242	804,259	811,793	279,989	36,638	1,167	33,863	48,052	691,619	16,026	707,646

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Operations & Maintenance Expenses
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Exhibit No.: A-215 (PDD-70)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Initial Filing {1}	(c) Adjustments {2}	(d) Rebuttal Position
1	Electric Distribution & Restoration	300,994	(677)	300,317
2	Forestry	186,684	-	186,684
3	Generation	103,732	-	103,732
4	Operations Support	13,600	-	13,600
5	Information Technology Operations	55,297	-	55,297
6	Information Technology Investments	24,789	(17)	24,773
7	Information Technology - Security Operations	11,362	-	11,362
8	Information Technology - Security Investments	1,513	-	1,513
9	Customer Interactions	23,532	-	23,532
10	Billing & Payment	11,427	-	11,427
11	Demand Response	34,630	-	34,630
12	Pension Plans A/B	(45,156)	-	(45,156)
13	Defined Company Contribution Plan	16,507	-	16,507
14	401(k) Employees' Savings Plan	12,731	-	12,731
15	Active Health Care/Life Insurance/LTD	33,385	-	33,385
16	Retiree Health Care and Life Insurance	(48,867)	-	(48,867)
17	Other Benefits	2,780	-	2,780
18	Pension/OPEB Volatility Mechanism Amortization	(99)	-	(99)
19	Corporate Services	36,968	-	36,968
20	Uncollectible Expense	20,274	-	20,274
21	Injuries & Damages	5,083	-	5,083
22	Incentive Compensation	2,211	-	2,211
23	Job Work Expense	1,278	-	1,278
24	Interest expense on security deposits	298	-	298
25	Total Other O&M Expense	$ 804,952	$ (694)	$ 804,258

Notes

{1} Source: Col. (e), Exhibit No.: A-13 (PDD-41)
{2} Source: Col. (g), Exhibit No.: A-214 (PDD-69)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Income Tax Effect of Interest
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Revised Exhibit No.: A-216 (PDD-71)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exhibit No.: A-209 (PDD-64)	15,330,358
2	Weighted Cost of Debt, Excluding JDITC	Exhibit No.: A-187 (MRB-22)	0.0186
3	Allowable Interest Expense	Line 1 * Line 2	285,481
4	Projected Pro-Forma Interest Expense - Initial Filing	Exhibit No.: A-13 (PDD-49)	293,225
5	Increase/ (Decrease) In Allowable Interest Deduction	Line 3 - Line 4	(7,744)
6	Impact on Taxable Income	Line 5 * -1	7,744
7	Impact on Local Income Taxes	Line 6 * Local Income Tax Rate	12
8	Impact on State Income Taxes	Line 6 * State Income Tax Rate	406
9	Impact on Federal Taxable Income	Line 6 - Line 7 - line 8	7,326
10	Impact on Federal Income Tax	Line 9 * Federal Income Tax Rate	1,538
11	Impact on Net Operating Income	(Line 7 + Line 8 + Line 10) *-1	(1,957)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Interest Synchronization Adjustment
For the Projected 12-Month Period Ending April 30, 2027
$(000)

Case No.: U-21870
Revised Exhibit No.: A-217 (PDD-72)
Page: 1 of 1
Witness: PDDaly
Date: October 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exhibit No.: A-209 (PDD-64)	15,330,358
2	JDITC Debt-Related Portion of the Capital Structure	Exhibit No.: A-187 (MRB-22)	0.0023
3	Portion of Rate Base Funded by JDITC	Line 1 * Line 2	34,903
4	Cost of JDITC - Debt Portion	Exhibit No.: A-187 (MRB-22)	0.0443
5	Allowable JDITC Interest Expense	Line 3 * Line 4	1,545
6	Projected Pro-Forma Interest Expense - Initial Filing	Exhibit No.: A-13 (PDD-50)	1,588
7	Increase/ (Decrease) in Allowable JDITC Interest Expense	Line 5 - Line 6	(43)
8	Impact on Taxable Income	Line 7 * -1	43
9	Impact on Local Income Tax	Line 8 * Local Income Tax Rate	0
10	Impact on State Income Tax	Line 8 * State Income Tax Rate	2
11	Impact on Federal Taxable Income	Line 8 - Line 9 - line 10	40
12	Impact on Federal Income Tax	Line 11 * Federal Income Tax Rate	8
13	Impact on Net Operating Income	(Line 9 + Line 10 + Line 12) *-1	(11)

Question:

147. Refer to lines 5-10 on page 48 of Ms. Hayward's direct testimony on ROW acquisitions. Please:

a. Provide a list of the projects and location where the bridge period and test year ROW purchases will be required with the ROW cost for each project.

b. Provide the amount of ROW costs incurred for each year 2020 to 2024.

Response:

a. See Attachment 1 for a list of the projects and locations with bridge and test year ROW spends by project.

b. All ROW purchases for the HVD Lines Reliability program prior to 2024 were included in the Lines & Subs Capacity – HVD program under the ROW Procurement Investment Category. Those expenditures can be viewed in Exhibit A-130 (MPK-20), page 2 line 9. In 2024, ROW procurement costs for HVD Lines Reliability were moved from Lines & Subs Capacity – HVD into the HVD Lines Reliability Program under the ROW Acquisition Investment Category. The HVD Lines Reliability portion of those expenditures in 2020-2023 along with the 2024 total can be viewed in the table below.

2020	2021	2022	2023	2024
$2,105,913	$1,846,719	$1,715,688	$1,300,330	$895,861

Witness: Megan L. Hayward
Date: September 12, 2025

21870-AG-CE-0466
Hayward Attachment 1
Page 1 of 1

Project Name	Location	Bridge Year Expenditures	Test Year Expenditures
Alden	Kewadin	$250,000	$1,206,000
Allendale	Allendale	$27,000	
Broadway	Muskegon	$100,000	
Casino	Weidman	$1,200,000	$500,000
Cement City South	Clarklake	$617,000	$500,000
Cement City Center	Clarklake	$617,000	$300,000
Cooper	Cooper Twp	$400,000	$350,000
Dietz - Gaylord East	Boyne City		$1,540,000
Dietz - Gaylord West	Boyne City	$101,000	$504,000
Dontz	Manistee		$300,000
Erie	Temperance	$225,000	
Getty	Muskegon	$1,259,000	
Golden	Midland	$15,000	
Goodale	Battle Creek	$347,000	
Grand Valley	Standale	$1,500,000	
Greenville North	Greenville	$155,000	
Greenville South	Greenville		$900,000
Hanover	Mosherville	$250,000	$750,000
Leslie	Rives Junction	$25,000	$320,000
Maple City	Glen Arbor	$25,000	
Merrill	Merrill	$120,000	
Morrice South	Perry	$109,000	$175,000
Morrice North	Owosso	$250,000	
Mt. Pleasant	Mt. Pleasant	$798,000	
Nashville	Barry County	$1,055,000	
Newaygo	Newaygo	$20,000	
Niagara South	Saginaw	$50,000	
Niagara North	Saginaw	$262,000	
Orleans	Orleans		$400,000
Plainwell	Plainwell	$10,000	
Quincy East	Quincy		$840,000
Quincy West	Coldwater	$200,000	$900,000
Remus	Remus	$200,000	
Rogers	White Cloud		$450,000
Salem	Salem Township	$210,000	
Saranac	Clarksville	$100,000	
Shelby	Rothbury	$1,239,000	$265,000
Stover	Mancelona Township	$10,000	
Union City	Union City	$556,000	
Virginia Park	Laketown Township	$350,000	$800,000
Wirtz	Gladwin	$15,000	
	Total	**$12,667,000**	**$11,000,000**

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Actual and Forcasted 2025 Capital and O&M Spending

Case No.: U-21870
Exhibit No.: A-219 (MPK-29)
Page: 1 of 1
Witness: MPKelly
Date: October 2025

		2025 O&M Spending												
Line No.		Jan Actuals	Feb Actuals	Mar Actuals	Apr Actuals	May Actuals	Jun Actuals	Jul Actuals	Aug Actuals	Sep Actuals	Oct Fcst	Nov Fcst	Dec Fcst	**Total Current Fcst**
1	2.01 Lines Reliability - LVD	$16,739	$97,824	$40,047	$64,028	$49,558	$108,368	$127,375	$103,422	$137,118	$246,102	$700,119	$1,600,376	**$3,291,075**
2	2.04 Substations Reliability - LVD	$274,437	$235,570	$309,814	$217,835	$462,311	$406,201	$482,175	$538,353	$501,050	$500,244	$385,122	$332,232	**$4,645,345**

		2025 Capital Spending												
		Jan Actuals	Feb Actuals	Mar Actuals	Apr Actuals	May Actuals	Jun Actuals	Jul Actuals	Aug Actuals	Sep Actuals	Oct Fcst	Nov Fcst	Dec Fcst	**Total Current Fcst**
3	1.06 Distribution Transformer Purchases	$10,145,259	$16,921,075	$16,303,963	$21,384,981	$19,319,972	$18,155,495	$10,634,605	$12,137,417	$9,284,545	$12,585,616	$6,426,698	$3,848,475	**$157,148,102**
4	2.05 Substations Reliability - HVD	$1,683,961	$226,375	$1,732,374	$1,498,488	$967,652	$1,212,536	$622,492	$1,893,513	$1,322,687	$2,100,343	$3,908,535	$5,061,344	**$22,230,300**
5	2.12 Repetitive Outages - LVD	$320,943	$1,027,430	$1,173,196	$605,105	$645,065	$241,883	$253,984	$999,459	$1,100,815	$1,361,553	$1,795,002	$1,686,565	**$11,211,000**
6	2.14 Transformer Bank Replacements & Sub Rebuilds	$1,915,279	$2,914,937	$179,885	$1,236,824	$831,706	$389,688	$170,906	$1,822,818	$2,307,120	$3,377,107	$3,338,927	$8,820,881	**$27,306,079**
7	2.17 Metro Rehabilitation	$131,430	$286,330	$550,101	$318,413	$3,491	$140,193	$178,957	$1,485	$435,344	$1,141,722	$1,120,924	$880,409	**$5,188,800**
8	3.06 Lines New Business Capacity - LVD	$27	$2,332,105	$3,017,885	$1,756,211	$2,196,600	$1,573,146	$2,729,867	$2,662,565	$2,612,811	$2,929,454	$1,934,218	$884,756	**$26,962,200**

U21870-SA-CE-248
Requested By: Hunter Hansen (HH-6 - 1)
Respondent: Michael P. Kelly
Date of Response: 9/3/2025
Page **1** of **1**

Question:

1. In Case No. U-17990, on Exhibit A-65 (LDW-4), the Company proposed a cost-based update to its ongoing monthly cost to support AMI opt-out. The proposed cost for "Meter Reading @ 12 Reads Per Year" was proposed to be $19.26. In U21870-SA-CE-201_KELLY_ATT_1, it is proposed to be $0.29. Explain why the current cost has decreased so much since the proposal in U-17990.

Response:

The proposed cost for "Meter Reading @ 12 Reads Per Year" was based on non-AMI meters because non-transmitting electric meters cannot be separately tracked – see U21870-SA-CE-202. In U-17990, the cost was based on an allocation of labor and associated overhead for supervision, support, and vehicle costs for non-transmitting meters. A similar estimate has been provided in the attached spreadsheet as U21870-SA-CE-248_KELLY_ATT_1 whereby the "Meter Reading @ 12 Reads Per Year" would equal $12.61/meter/month.

(a)	(b)	(c)
Costs to Support Manual Reads	**Costs**	**Note**
Meter Counts		
Electric Manual Reads on Electric Meters	132,839	
Gas Manual Reads on Gas Meters	139,808	
Total Meter Count	**272,647**	
Yearly Salary Costs		
Supervision Salary and Benefit Cost	$ 439,548.00	4 Supervisors overseeing the Manual Reads
Schedulers Salary and Benefit Cost	$ 448,000.00	4 Schedulers overseeing the Manual Reads
Meter Reader Salary and Benefit Cost	$ 1,992,691.72	22 Meter Readers
Total Salary Cost	$ 2,880,239.72	
Yearly Vehicle Costs		
Meter Reading Vehicle Cost	$ 477,569.77	26 Vehicles - Fleet Overhead and Mileage
Yearly Technology/Equipment Costs		
Meter Reading Equipment Cost	$ 80,543.33	technology cost for maintenance and upkeep of 22 devices
Summary of Yearly Meter Reading Costs		
Yearly Salary Costs	$ 2,880,239.72	
Yearly Vehicle Costs	$ 477,569.77	
Yearly Technology/Equipment Costs	$ 80,543.33	
Total Yearly Manual Meter Reading Cost	**$ 3,438,352.82**	
Divide by the Number of Manual Reads	272,647	
Total Meter Reading Cost per Meter	**$12.61**	

Question:

191. Refer to Exhibit A-124 (MPK-14) and Mr. Kelly's testimony on pages 159 to 160 related to Service Calls and the O&M expense of $4.2 million in 2024 increasing to $5.7 million in the projected test year for a 36% increase.

Please:

a. Provide the expense increase related to the 17% increase in work hours and provide a schedule showing how the 17% increase in work was determined.

b. Mr. Kelly notes a 16% change in labor rates over the past five years for the union personnel involved. Provide the scheduled future increase in union labor rates and how they compare to forecasted CPI inflation rates.

Response:

a. The amount of test year expense related to the increase in work hours is $797,181. The Company's methodology for calculating work hours is described on page 159, line 17, through page 160, line 4, of my direct testimony. To further elaborate, the Company uses recent historical actual work volumes to project the number of monthly service call work orders at each Company service center. The Company then multiplies those service center work order totals by an hourly factor that indicates how long each type of service call job should take. The product of this multiplication gives a projected number of hours. These projections are as follows:

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Units	2,471	2,752	3,143	2,778	3,084	3,085	3,024	3,123	3,104	3,069	2,598	2,623	34,855
Hours	2,062	2,298	2,596	2,443	2,564	2,573	2,516	2,610	2,607	2,577	2,200	2,226	29,271

While the projected work hours were calculated in this way, the 17% increase cited in testimony simply reflects how much larger that is than the historical five-year average number of work hours, as shown below:

Type	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	5 Year Avg	Test Year	Variance
Hours	23,427	24,688	27,185	24,934	24,569	24,960	29,271	17%

b. Please refer to Exhibit A-128 (MPK-18), page 6, line 45, for the Company's projected inflation rates. The Company's current union contract, effective in June 2025, has the following union labor rate increases:

	2025	2026	2027	2028	2029
% Increase	3%	3.5%	3.5%	3.5%	3%

Witness: Michael P. Kelly
Date: September 16, 2025

U21870-AG-CE-0453
Page **1** of **1**

Question:

134. Refer to Exhibits A-125. Please:

a. Provide the quantities or work units supporting each of the expense items in each line for each year 2020 to 2027 and the projected test year in Excel.

b. For lines 4, 6, 9-11, 12, 17, 25, 29, and 33, provide the basis for the increase in expense from 2024 to 2025 and to the projected test year.

Response:

a. See Attachment 1 to this response.
b. The basis for the increase can be found in my testimony as follows:
    a. Line 4: page 131, lines 1 through 7
    b. Line 6: page 135 line 18 through page 136 line 2
    c. Line 9: page 140, lines 10 through 15
    d. Line 10: page 141 line 20 through page 142 line 8
    e. Line 11: page 143, lines 1 through 9
    f. Line 12: page 145, lines 8 through 13
    g. Line 17: page 160, lines 5 through 12
    h. Line 25: page 169, lines 1 through 5
    i. Line 29: page 172, lines 11 through 14
    j. Line 33: page 174, lines 15 through 19

Witness: Michael P. Kelly
Date: September 11, 2025

21870-AG-CE-0453
Attachment 1

Line No.	(a) Description (Boldface items indicate $000 and correspond to Exhibit A-125	(b) 2020 Actual	(c) 2021 Actual	(d) 2022 Actual	(e) 2023 Actual	(f) 2024 Actual	(g) 12 Mos Ended 12/31/2025	(h) Bridge Period 4 Mos Ending 4/30/2026	(i) 16 Mos Ending 4/30/2026	(j) Projected 12 Months Ending 4/30/2027
	Lines Reliability - LVD	**13**	**527**	**1,097**	**651**	**580**	**8,000**	**2,667**	**10,667**	**8,000**
	"Work Unit" Definition - Orders	Orders	Orders	Orders	Orders	Orders	Orders	Orders	Orders	Orders
1	*Work Units*	23	314	668	857	933	2,454	412	2,866	2,454
2	**Lines Reliability - HVD**	**226**	**188**	**287**	**261**	**109**	**784**	**284**	**1,068**	**891**
	HVD Lines Pole Inspections (O&M Portion of inspection)	340	963	709	1,082	1,117	805	268	1,073	805
	Test Operate Motor Operated Air Break Switches	270	319	332	342	384	386	39	425	386
	Motor Operated Air Break Switch Battery Replacements	21	95	45	12	82	52	13	65	52
	Substations Reliability - LVD	**2,393**	**2,771**	**2,992**	**3,100**	**3,525**	**5,458**	**1,672**	**7,130**	**5,475**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
3	*Work Units*	93	272	138	242	272	344	86	430	344
	Substations Reliability - HVD	**1,566**	**1,925**	**2,017**	**2,181**	**2,350**	**2,445**	**701**	**3,146**	**2,349**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
4	*Work Units*	125	145	155	148	156	209	52	261	209
	Lines Demand - HVD	**527**	**784**	**1,086**	**654**	**898**	**2,237**	**875**	**3,113**	**2,979**
	SAP Orders - Projects at specific structures / locations.	Projects	Projects	Projects	Projects	Projects	Projects	Projects	Projects	Projects
5	*Work Units*	119	146	196	174	149	160	50	210	170
	Substations Demand - LVD	**2,503**	**2,995**	**4,707**	**4,092**	**4,302**	**6,440**	**2,008**	**8,448**	**6,398**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
6	*Work Units*	237	384	268	226	337	313	78	391	313
	Substations Demand - HVD	**2,308**	**2,986**	**3,159**	**3,383**	**4,050**	**5,309**	**1,703**	**7,012**	**5,311**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
7	*Work Units*	348	392	278	382	578	295	73	368	295
	Corrective Maintenance	**4,064**	**4,535**	**4,131**	**4,130**	**4,615**	**4,970**	**1,631**	**6,601**	**5,236**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
8	*Work Units*	20,631	20,444	21,430	20,473	20,250	19,944	6,023	25,967	19,943
	Staking	**3,035**	**3,251**	**3,587**	**3,975**	**6,148**	**12,260**	**3,870**	**16,131**	**13,948**
9	*Please refer to discovery responses U21870-AG-CE-0441 through 0448 for supporting details regarding Staking O&M spending levels.*									
	Meter Services (and Credits)	**(1,120)**	**2,090**	**862**	**(3,934)**	**1,774**	**3,180**	**1,440**	**4,619**	**6,831**
	"Work Unit" Definition - Work Premise Hours (Expense)	Hours	Hours	Hours	Hours	Hours	Hours	Hours	Hours	Hours
		40,353	41,502	45,354	49,034	45,580	49,898	16,989	66,887	60,843
	Work Units									
	"Work Unit" Definition - Meter/Transformer Units (Credits)	Units	Units	Units	Units	Units	Units	Units	Units	Units
10	*Work Units*	97,961	129,972	211,163	440,405	90,586	77,789	19,207	96,996	57,623
	Streetlighting	**1,680**	**2,109**	**1,801**	**1,571**	**1,612**	**2,009**	**733**	**2,742**	**2,089**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
11	*Work Units*	8,422	9,203	10,732	10,616	7,884	10,748	3,551	14,300	10,750
	Service Calls	**3,871**	**4,518**	**4,110**	**4,434**	**4,194**	**4,632**	**1,805**	**6,438**	**5,699**
	"Work Unit" Definition - Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders	Work Orders
12	*Work Units*	18,813	19,876	20,258	23,325	24,210	25,316	8,128	33,445	25,316
	Alma Equipment Repair	**699**	**787**	**430**	**379**	**357**	**563**	**188**	**752**	**571**
	Work Units defined as follows, with data provided by year:									
	Salvage Services/Oil Recycling (gals of junk transformer oil sold)	20,009	20,554	39,926	60,477	32,748	26,800	9,000	35,800	35,000
	Training (units = headcount (OM&C (variable), 1 NEX, 1 EX))	12	11	11	12	12	12	12	12	12
	Storeroom Tasks/Material Handling (pieces of equip handled)	12,231	11,996	8,609	8,515	7,553	7,800	2,400	10,200	8,000
	Mobile Substation Inspections/Repairs (unit = inspection or repair session)	39	82	64	77	51	58	21	79	65
13	*Supervisor Salary/Expenses (unit = HC of 1 EX & 1 NEX)*	2	2	2	2	2	2	2	2	2
	Meter Reading	**1,439**	**1,740**	**1,712**	**6,016**	**1,645**	**1,876**	**627**	**2,503**	**1,971**
	"Work Unit" Definition - Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount
14	*Work Units*	11	17	14	14	14	14	14	14	14
	Meter Tech & Mgmt Sys Support	**934**	**1,019**	**1,085**	**1,199**	**1,063**	**1,310**	**448**	**1,758**	**1,393**
	"Work Unit" Definition - Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount
15	*Work Units*	25	27	23	24	24	24	25	25	25
	Smart Energy MTC - Elec	**8,846**	**8,986**	**9,020**	**8,756**	**9,611**	**9,226**	**3,096**	**12,322**	**9,226**
	"Work Unit" Definition - Meters	Meters	Meters	Meters	Meters	Meters	Meters	Meters	Meters	Meters
16	*Work Units*	1,888,948	1,852,736	1,847,762	1,857,803	1,894,313	1,914,448	1,920,000	1,920,000	1,930,000
	Service Restoration - LVD	**71,262**	**159,659**	**113,271**	**188,041**	**156,098**	**159,737**	**54,606**	**214,344**	**165,215**
17	*Service Restoration O&M is discussed in significant detail by Company witness Snider.*									
	Training	**5,366**	**10,807**	**10,993**	**12,076**	**11,107**	**10,846**	**5,492**	**20,564**	**15,833**
	"Work Unit" Definition - Headcount (per training hr)	*Hours*	*Hours*	*Hours*	*Hours*	*Hours*	*Hours*	*Hours*	*Hours*	*Hours*
18	*Work Units*	*65,120*	*153,566*	*168,071*	*158,990*	*161,116*	*143,964*	*64,216*	*208,379*	*220,930*
	Tools	**1,422**	**2,358**	**1,753**	**1,384**	**1,256**	**1,497**	**997**	**2,494**	**1,982**
	"Work Unit" Definition - # of Tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools
	Work Units	9,571	26,956	17,534	11,351	17,307	17,530	5,785	23,368	17,850
	"Work Unit" Definition - # of FR Items	FR Items	FR Items	FR Items	FR Items	FR Items	FR Items	FR Items	FR Items	FR Items
	Work Units	9,450	5,575	12,362	11,965	11,714	13,450	6,031	24,125	18,500
	"Work Unit" Definition - # of tested/repaired tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools	Tools
19	*Work Units*	10,802	11,940	12,375	12,800	13,220	13,235	4,367	17,205	13,300
	Field Operations Expenses	**1,665**	**2,372**	**2,194**	**2,369**	**2,154**	**2,509**	**869**	**3,378**	**2,608**
20	*Field Operations Expenses represent costs outside of salaries incurred by field operations workforce, i.e. travel expenses, meals, telecommunications. Units are not applicable*									
21	**Supervision / Admin-Staff**	**5,047**	**4,994**	**6,366**	**3,710**	**3,672**	**4,820**	**1,734**	**6,555**	**5,312**
	"Work Unit" Definition = Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount
	Work Units	153	176	172	157	156	171	171	171	171
	Grid Management - Distr	**3,768**	**6,363**	**6,134**	**5,514**	**4,646**	**4,741**	**1,439**	**6,180**	**4,271**
	"Work Unit" Definition - Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount
22	*Work Units*	99	161	181	167	148	146	155	155	155
	Underground Workforce		**128**	**172**	**327**	**713**	**1,113**	**694**	**1,807**	**2,236**
23	*This reflects 100% of the training costs and 5% of the salaries, expenses, and tools for underground workforce employees. The other 95% of salaries, expenses, and tools are capitalized. Units are not applicable.*									
	Work Management & Customer Delivery	**1,315**	**4,027**	**6,799**	**3,910**	**2,518**	**1,883**	**635**	**2,518**	**1,917**
	"Work Unit" Definition - Headcount	*Headcount*	*Headcount*	*Headcount*	*Headcount*	*Headcount*	*Headcount*	*Headcount*	*Headcount*	*Headcount*
24	*Work Units*	72	270	235	382	247	*310*	*103*	*413*	*310*
	Operations Management	**2,381**	**2,911**	**2,891**	**2,360**	**2,591**	**2,022**	**569**	**2,591**	**1,955**
	"Work Unit" Definition - Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount	Headcount
25	*Work Units*	8	8	6	6	5	4	4	4	4

Question:

9. Refer to the Direct Testimony of witness Jeffrey A. Myrom at p. 13. Witness Myrom states that "DCFC rebates will only be available for communities that do not have at least four 150 kW DCFC ports across two or more different host sites."

a. Please define "community."

b. Is "community" limited in physical space or defined by other traditional governmental boundaries?

Response:

a. A community is a governmental boundary.

b. Per "a" above, it is a traditional governmental boundary.

Witness: Jeffrey A. Myrom
Date: July 18, 2025

Question:

10. Refer to the Direct Testimony of Witness Jeffrey A. Myrom at pp. 14–15. The Company proposes to have the right to reject applications on a rolling basis that do not offer "quality customer experience" and cites several criteria to be used in evaluating future public DCFC site proposals.

a. Please detail the evaluation process that the company will use to assess each criterion and to compare applications to each other.

b. Please detail the methodology or rubric by which the Company will collectively assess the proposed criteria, including how the company will weight each metric for public DCFC projects to determine prioritization.

c. For each proposed criterion, will the Company use a sliding scale or a simple yes/no determinant?

d. Please indicate the minimum criteria that an application would need to meet to warrant the Company to reject an applicant's proposal.

e. Specifically, does a host site have to have security lighting?

f. Specifically, does a host site have to have a canopy?

g. Regarding the application closing dates:

   i. Will the Company have established application closing dates?

   ii. If there will not be an established application closing date, will applications simply have to meet the minimum criteria to be funded on a first-come, first-served basis?

   iii. If there will not be an established application closing date, how will applications be compared on a rolling basis?

Response:

a. The evaluation process will utilize the criteria detailed in my Direct Testimony on pages 14-15, paragraph "d", subparagraphs 1-6.

b. The evaluation criteria referenced in "a" above will be utilized on a "yes/no" basis per "c" below.

c. A yes/no determination will be made.

d. The minimum criteria are found on pages 14-15 of my Direct Testimony as follows:

   i. Per paragraph "d" subparagraph 1, lines 21-23: "In no case shall sites be allowed that do not offer 24-7 charging or that have no public amenities.".

   ii. Per paragraph "d", subparagraph 4, line 39: "The host site must have adequate security lighting".

iii. Per paragraph “d”, subparagraph 6, line 12: “all host sites must offer at least two 150 kW DCFC ports”.

e. Yes. Lighting is required.

f. No. A canopy is not required but could be a differentiating criterion regarding rebate selection.

g. The Company plans to review applications and designate rebates monthly. If an application does not meet the minimum criteria as noted in “d” above, then the applicant may re-apply with a revised site design. The goal of the temporary DCFC rebate program is to spur the growth of quality fast charging infrastructure and to do so as quickly as possible.

Witness: Jeffrey A. Myrom
Date: July 18, 2025

Question:

5. Referring to Figure 15 of Company witness Partlan's testimony, please provide all calculations and data used to support the anticipated nearly 400% increase in Make-ready field work orders between 2024 and 2026.

Response:

The projected make-ready field work orders in Figures 15 and 16 of my direct testimony included an Excel formula error which inflated the work order numbers. This error did not affect the dollar amounts associated with make-ready work in the bridge period or test year. Corrected Figures 15 and 16 are as follows:

FIGURE 15
MAKE-READY FIELD COMPLETE WORK ORDERS BY YEAR

Year	Make-Ready Field Complete Orders
2019 actual	1,007
2020 actual	752
2021 actual	829
2022 actual	1,236
2023 actual	1,655
2024 actual	1,640
2025 Projected	2,689
2026 Projected	3,119
2027 Projected	3,307

FIGURE 16
LVD ASSET RELOCATIONS INVESTMENT CATEGORY EXPENDITURES

Investment Categories	Bridge Period Capital	Bridge Period # of Units	Test Year Capital	Test year # of Units
Customer requested and other internal relocations	$45,018,000	4,163	$32,341,000	3,379
LVD underbuild relocations	$7,056,000	N/A	$7,484,000	N/A
Make-ready work	$45,837,000	3,728	$39,265,000	3,181
Total	**$97,911,000**		**$79,090,000**	

This still reflects an increase in make-ready work orders, albeit not an increase of 400%. As stated on page 33, line 9, through page 34, line 4, of my direct testimony, this increase is driven by an increase in broadband infrastructure work tied to certain federal programs, particularly the Broadband Equity Access

and Deployment ("BEAD") program. The BEAD program has earmarked approximately $1.6 billion in broadband funding for Michigan, and the Company expects that slightly more than 50% of this will be directed to the Company's service territory, leading to increased make-ready work.

The Company is projecting that federal broadband funding from all sources will impact its service territory as shown in column (a) below, with the associated annual percentage increase shown in column (b). Due to known timing modifications with the program, the Company adjusted 2025 and 2026 projections by 20 percentage points, as shown in columns (c) and (d). The adjusted percentage increase for each year was used to increase the number of projected work orders, as shown in column (e).

	(a) Federal broadband funding	(b) Increase in federal funding	(c) Adjustment	(d) Revised increase	(e) Work orders
2024 actual	$56M	-	-	-	1,640
2025 proj.	$103M	84%	-20%	64%	2,689
2026 proj.	$140M	36%	-20%	16%	3,119
2027 proj.	$148M	6%	-	6%	3,307

As noted above, the projected spending for make ready work, as shown in Figure 16, does not need to be revised. When accounting for the corrected number of work orders, the Company's unit cost for make-ready work in the bridge period and test year is commensurate with the actual unit costs in 2024, which are shown in Exhibit A-130 (MPK-20), page 2, line 40.

Witness: Jennifer M Partlan
Date: July 24, 2025

Consumers Energy
LVD Planning
CONCEPT APPROVAL

Notification Concept Number: 1034571392

Project Title: MARKEY/FOREST ESTATES LCP 452 **Work HQ:**

Date: 8/15/2024 **Proposed Year of System Changes:** 2026

Problem Description:

Zone analysis metrics identified this zone in the Bottom 3% with a 390 Index and Score of 17.

Additional project: A pending ATR proposal including this circuit would benefit from recommended solutions.

Alternative Solutions:

1. 1) Move 0.5 mile UG to OH and install 1 mile of HVD underbuilt to change the circuit source route.
   Estimated customer minutes saved = 174,000

   Estimated Design Hours = 590
   Estimated Loaded Cost = $227,266

2. Move 3680' 3 phase tangent from deep ROW to 1' east of Road ROW.
   Estimated customer minutes saved = 87,000

   Estimated Design Hours = 218
   Estimated Loaded Cost = $107,952

3. Reconductor 1.37 mile 3 phase tangent to Tree Wire construction
   Estimated customer minutes saved = 130,000

   Estimated Design Hours = 716
   Estimated Loaded Cost = $358,242

Recommended Alternative:

Alternative # 1 is recommended Relocate 0.5 miles of line and re-feed the source. This route is also HVD underbuilt ensuring greater protection from trees in the future due to larger easement for tree trimming along HVD corridors. The estimated customer minutes saved for alternative 1 is greater due to expanded tree trimming footprint around the lines and rerouting the source for these customers to avoid the trees that alternative 3 would mitigate.

Conceptual Estimate:

Program	Notification #	Loaded Cost	Plan Year	Description
LVD Reliability	1034571392	$227,266	2026	Relocate HVD underbuilt
Project Total		$227,266		

Consumers Energy
LVD Planning
CONCEPT APPROVAL

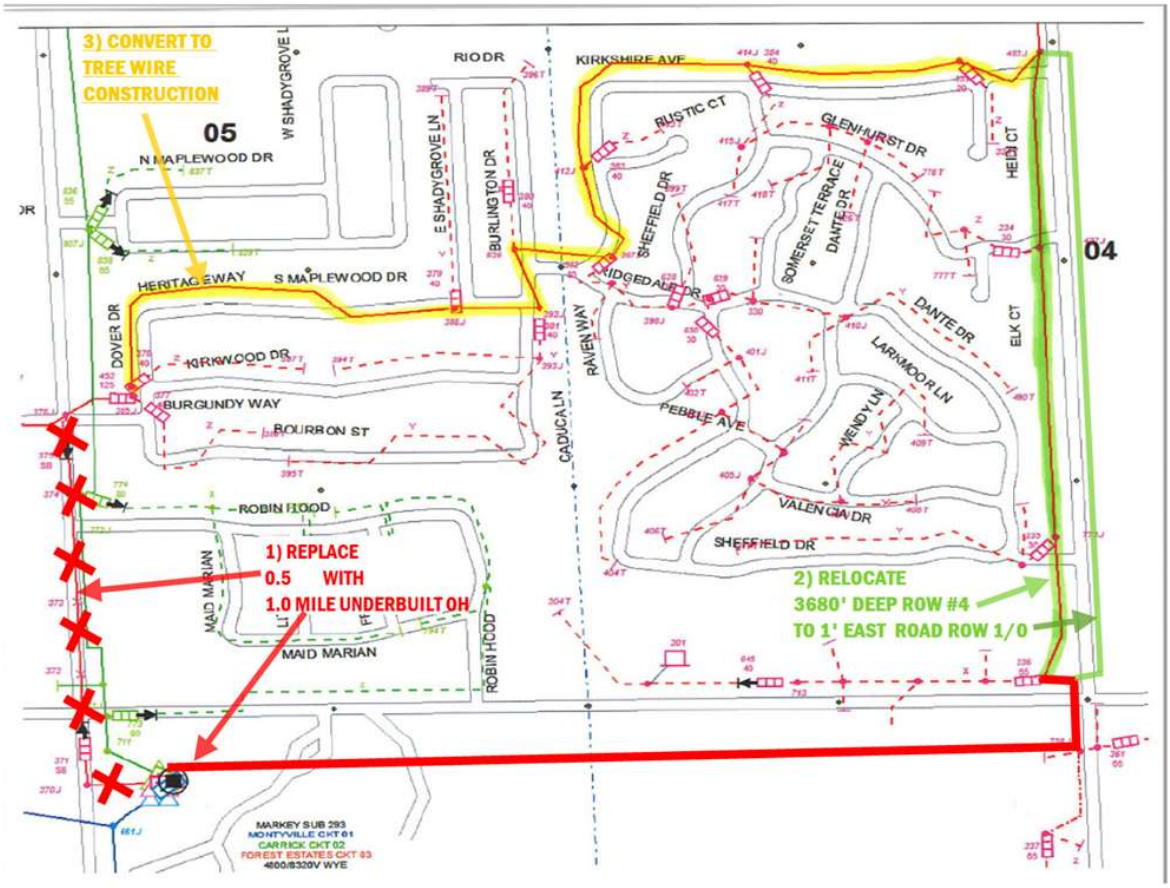
Present Need: On approval, this document authorizes the Low Voltage Distribution Design group to proceed with the work order design and material acquisition pending receipt of appropriate budget authorization.

Circuit Owner: Richard Klender **System Engineer:** JLBirchmeier

Approvals:

Director, LVD Circuit Planning	Jennifer Partlan	Approved
Executive Director, Electric Planning	Gregory R. Griffin	Approved

Scope Map:



U21870-AB-CE-0712
Page **1** of **1**

Question:

Request 44:

Please refer to the Direct Testimony of Jennifer Partlan, pages 60-61, where Ms. Partlan discusses the replacement of rejected poles, and provide the following information with respect to this discussion:

a. Provide the total number of LVD poles identified as "rejected" from groundline and visual inspections in 2022, 2023, and 2024, and the number of those poles that have been replaced to date.

b. Provide the system data that supports the conclusion that approximately "10% of the poles on the LVD system will be classified as rejected." Please provide the data in its original format with all formulae and links intact.

Response:

a. The Company did not begin conducting groundline inspections until August 2025, so there were no rejected poles identified through this practice from 2022 through 2024.
b. The Company's expectation that 10% of LVD poles will be classified as rejected is based on a combination of a) the average LVD pole age on the Company's system, which is correlated with expected deterioration (refer to page 69 of Exhibit A-129 (MPK-19) for further details); and b) a 2019 Electric Power Research Institute study on wood pole asset health, the results of which are provided as Attachment 1 to this response.

Witness: Jennifer M Partlan
Date: September 22, 2025

Distribution Asset Analytics (P180.005)

Technical Presentation

Bhavin Desai
Senior Program Manager

Task Force Meeting
March, 2019

www.epri.com

© 2019 Electric Power Research Institute, Inc. All rights reserved.

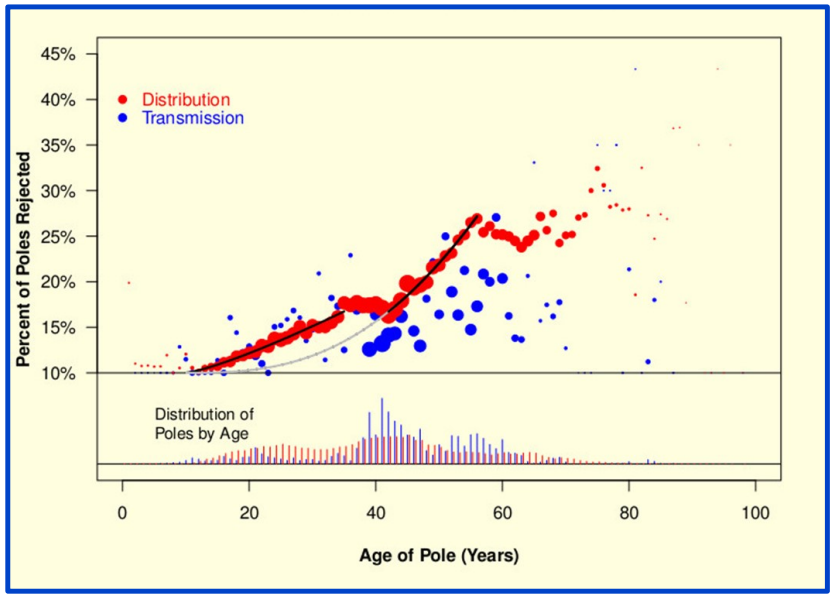
Wood Pole Inspection Data Analytics

Investigate Performance of Different Wood Species:

- Reject rate modeling as function of age at Inspection
  - Different climates/environments
  - Different treatment types
  - Impact of changes in inspection criteria –
    - Contractor to contractor variation
    - Contractor variations over time

Desired Data:

- Pole demographic data
  - E.g. age, wood species, in-service date
- Inspection results
  - E.g. date of inspection, reject status, other observations
- Replacement history
  - E.g. which, when and why



Modeling Reject Rate As Function of Wood Pole Age At Inspection

© 2019 Electric Power Research Institute, Inc. All rights reserved.

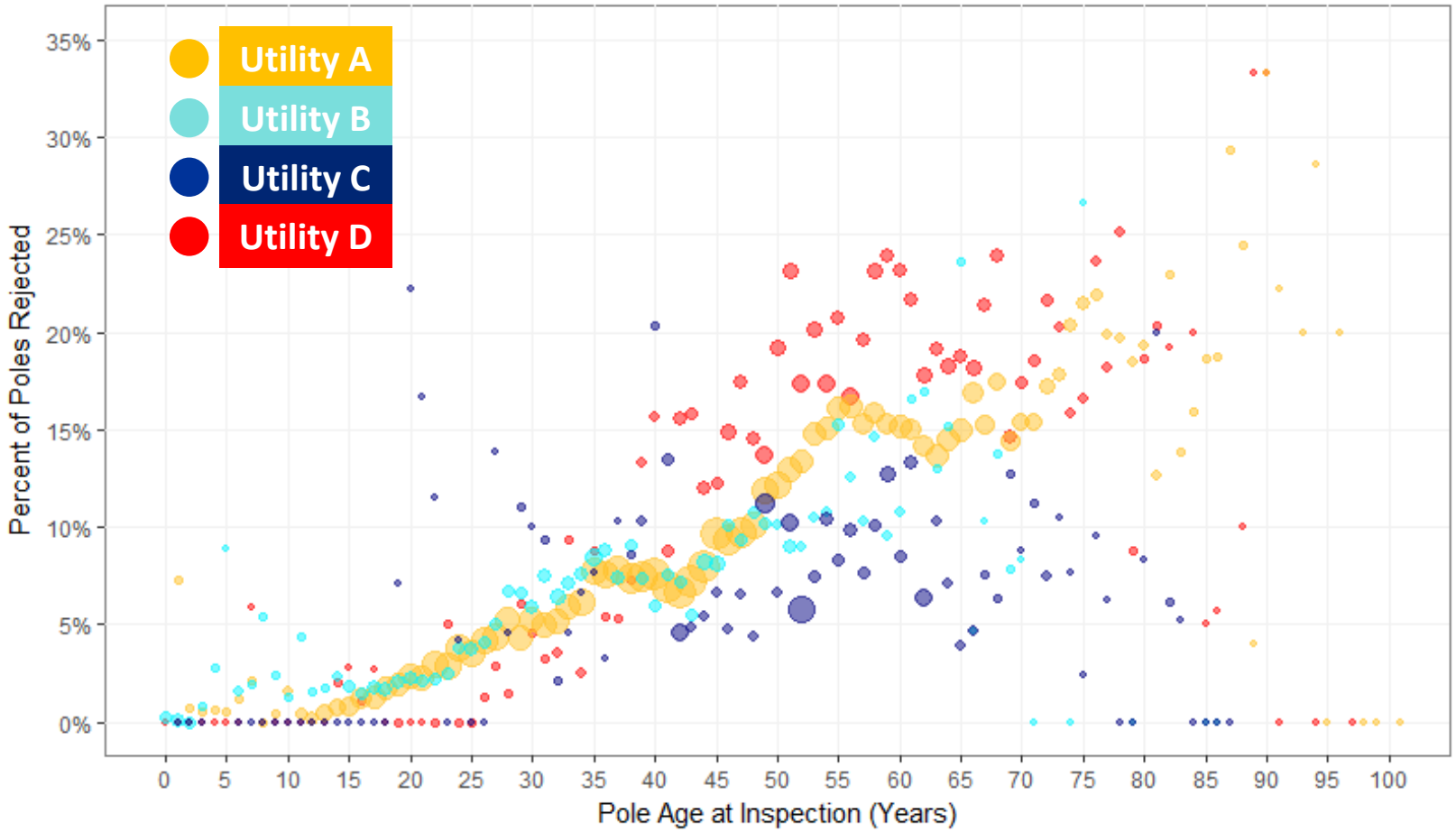
Wood Pole Inspection Data Analytics

Data Model and Summary – approx. 3 million poles from 7 utilities

	Received During	# of poles	T/D	Species	Original Treatment Type	Original Ground Line Cir.	Effective Ground Line Cir.	Visual inspection – heart rot, shell rot	GIS	Reject Status	Status
A	November '16	33,382 (T) 709,833 (D)	T&D	Y	Y	Y	Y	Y	Y	Y	Analysis completed
B-1	April '18	111,723	D	N	N	Y	Y	N	N	Y	Analysis in-progress
B-2	October '18	54,949	D	Y	Y	Y	Y	Y	Y	Y	Received new dataset
C	April '18	18,853	T	Y	Y	Y	Y	N	Y	Y	Received data – queued for further processing.
D	June '18	1,908,057	D	Y	Y	Y	Y	Y	Y	Y	Data curated; analysis in progress
E	May '18	274,368	D	Y	Y	Y	Y	N	N	Y	Data curation and analysis in progress
F	March '18	19,986	T	Y	Y	Y	Y	N	Y	Y	Received data – queued for further processing.
G	July '18	36,401	T	Y	Y	Y	Y	Y	Y	Y	Initial review
H	February '19	52,331	T	Y	Y	Y	Y	N	Y	Y	Initial review

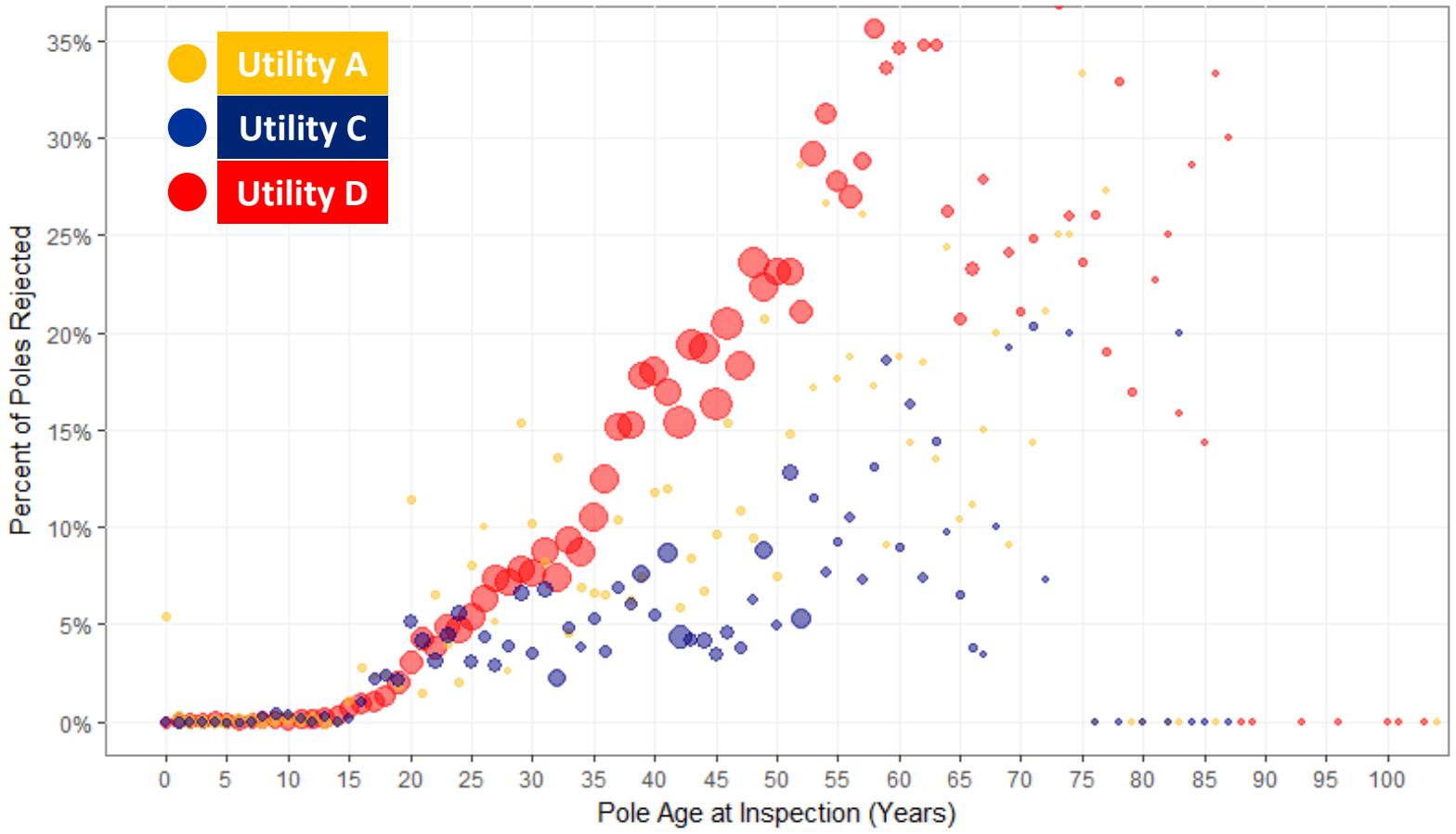
© 2019 Electric Power Research Institute, Inc. All rights reserved.

Reject Rates for Southern Pine Wood Poles Originally Treated with Creosote



© 2019 Electric Power Research Institute, Inc. All rights reserved.

Reject Rates for Southern Pine Wood Poles Originally Treated with Penta



Note: Utility B does not have sufficient data on SPP poles and utility A has a much smaller data set on SPP than their SPC data

© 2019 Electric Power Research Institute, Inc. All rights reserved.

Actionable Insights From Research To Date
Wood Pole Analysis

- Reject rate as function of age at time of inspection provides:
  - Projections of how many poles anticipated to be rejected in future years
  - Insights for resource planning and prioritizing inspections
  - Wood pole survivability (by wood species and original treatment type) in different regions
  - Impact of changes in inspection criteria –
    - Contractor to contractor variation
    - Contractor variations over time

© 2019 Electric Power Research Institute, Inc. All rights reserved.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No: A-228 (BJV-3)
Page: 1 of 1
Witness: BJVanBlarcum
Date: October 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjustment to Accrued Taxes
For the Projected 12-Month Period Ending April 30, 2027

Case No.: U-21870
WP-PDD-29

Line No	(a) Description	(b) Source	(c) Amount
1	Accrued Taxes - December 2024 13-Month Average Balance	WP-PDD-10, Line 27, Col. (f.1)	$ 286,119,648
	Exclude Historical Accrued Income Taxes:		
2	Accrued Federal Income Tax Payable	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2300000	17,256,743
3	Accrued Income Tax Payable - APB 28	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2300500	8,772,541
4	Accrued State Income Tax	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2301000	3,706,496
5	Accrued SBT Tax	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2301200	-
6	Accrued State Income Tax Payable - APB 28	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2301500	3,106,617
7	Accrued Local Income Tax Payable	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2301600	78,985
8	Accrued Local Income Tax Payable - APB 28	WP-PDD-10 - Accrued Taxes Tab - SAP Acct 2301700	97,882
9	Total Historical Accrued Income Taxes Removed	Sum of Lines 2 - 8	33,019,264
10	Historical Accrued Taxes, Net of Income Taxes	Line 1 - Line 9	253,100,384
	Include Projected Accrued Income Taxes:		
11	Accrued Federal Income Tax - April 2027	WP-PDD-36	2,330,667
12	Accrued State Income Tax - April 2027	WP-PDD-36	618,539
13	Accrued Local Income Tax - April 2027	WP-PDD-36	29,998
14	Projected Accrued Income Taxes - April 2027 13-Month Average Balance	Sum of Lines 11 - 13	2,979,204
15	Projected Accrued Taxes - April 2027 13-Month Average Balance	Line 10 + Line 14	256,079,588
16	Accrued Tax Adjustment	Line 15 - Line 1	(30,040,060)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
Exhibit No: A-229 (BJV-4)
Page: 1 of 1
Witness: BJVanBlarcum
Date: October 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21870
WP-PDD-36

Adjustment to Accured Income Taxes
For the Projected 12-Month Period Ending April 30, 2027
(DR) CR

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
Line		2026			2027										13 Mo Avg
No.	Description	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	4/30/2027
	Federal Income Taxes														
1	Accrual	-	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,058	2,058	2,058	2,058	
2	Accrual - Transfer to NOL C/F	-	-	(7,355)	-	-	(7,355)	-	-	(7,355)	-	-	(6,174)	-	
3	Payments	-	-	-	-	-	-	-	-	-	-	-	-	-	
4	Net Activity	-	2,452	(4,904)	2,452	2,452	(4,904)	2,452	2,452	(4,904)	2,058	2,058	(4,116)	2,058	
5	YTD Balance	2,452	4,904	-	2,452	4,904	-	2,452	4,904	-	2,058	4,116	-	2,058	2,331
	State Income Taxes														
6	Accrual	-	345	345	345	345	345	345	345	345	261	261	261	261	
7	Payments	-	-	-	(1,036)	-	-	(1,036)	-	-	(1,036)	-	-	(782)	
8	Net Activity	-	345	345	(691)	345	345	(691)	345	345	(775)	261	261	(521)	
9	YTD Balance	345	691	1,036	345	691	1,036	345	691	1,036	261	521	782	261	619
	Local Income Taxes														
10	Accrual		19	19	19	19	19	19	19	19	16	16	16	16	
11	Payments		-	-	(56)	-	-	(56)	-	(56)	-	-	-	(47)	
12	Net Activity		19	19	(37)	19	19	(37)	19	(37)	16	16	16	(31)	
13	YTD Balance	19	37	56	19	37	56	19	37	-	16	31	47	16	30
14	Total Federal & State Income Taxes	2,816	5,632	1,092	2,816	5,632	1,092	2,816	5,632	1,036	2,334	4,669	829	2,334	2,979

June 27, 2025

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917

RE: Case No. U-21538 – In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file transportation electrification plans and for other related matters.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find **Consumers Energy Company's Transportation Electrification Plan Annual Progress Report 2025**.

This is a paperless filing and is therefore being filed only in PDF. I have included a Proof of Service showing electronic service upon all intervenors from Case No. U-21585 (Consumers Energy Company's 2024 Electric Rate Case) and all parties who filed Initial Comments or Reply Comments in Case Nos. U-21492 and U-21538.

Sincerely,

Digitally signed by Spencer A. Sattler
Date: 2025.06.27 14:39:15 -04'00'

Spencer A. Sattler
Phone: 517-474-6638
Email: spencer.sattler@cmsenergy.com

cc: Parties per Attachment 1 to Proof of Service

Power MI Drive | Power MI Fleet | Consumers Energy Count on Us®

CONSUMERS ENERGY

Transportation Electrification Plan

Annual Progress Report 2025

Case No. U-21538
June 2025

Table of Contents

BACKGROUND 4
TEP EXECUTIVE SUMMARY & STRATEGY 7
TEP IMPLEMENTATION 12
TEP CUSTOMER PARTICIPATION & COSTS 28
TEP MANAGED CHARGING RESULTS 43
TEP LOOKING FORWARD & STAKEHOLDER FEEDBACK 46

Digital residential customer campaign sample

Table of Figures

Figure 1: Residential Customer Costs of Home Charger & Installation 28
Figure 2: Level 2 Site Host Category Participation (Pilot + Permanent Program) 30
Figure 3: Public L2 Site Project Costs Per Dual-Cord L2 31
Figure 4: Public Level 2 Sites by Location & Type 32
Figure 5: DCFC Site Project Costs 33
Figure 6: DCFC Site Make Ready Costs 34
Figure 7: Fast Charging Locations 35
Figure 8: PowerMIFleet Assessments by Customer Sector 36
Figure 9: In-Person Customer Education & Outreach Locations Overlaid on MIEJ Screen Map 40
Figure 10: EV Charging per Category & Time Block 43

Kids Food Basket and the Consumers Energy EV team celebrate the delivery of their new electric van to deliver nourishing meals to kids in need.

BACKGROUND[1]

Consumers Energy (Consumers Energy, CE, or the Company) began the first phase of creating the Company's Transportation Electrification Plan (TEP) via the PowerMIDrive pilot, which was approved by the Michigan Public Service Commission (MPSC) in Case No U-20134. PowerMIDrive subsequently launched in June of 2019, with a goal of at least 70% off-peak load management for residential customers, and to provide early learnings regarding public charging infrastructure. The Company's TEP formation was further enhanced via the addition of the PowerMIFleet pilot approved in Case No U-20697, and efforts to optimize electric loads from fleets to at least 80% off-peak began in June 2021. The Company believed that the higher level of off-peak charging was possible for PowerMIFleet based on the learnings and promising early results of PowerMIDrive.

The PowerMIDrive and PowerMIFleet pilots were further refined in Case No U-20963, with the goal of moving closer to permanent programs. PowerMIDrive added the use of advanced metering infrastructure (AMI) for targeted outreach and load management verification. Furthermore, PowerMIDrive shifted the focus of public Level 2 (L2) charging infrastructure to destination charging to increase off-peak loads, and multi-dwelling units (MDUs) to enhance customer access and equity. PowerMIFleet added capital funds for fleets serving income qualified customers and disadvantaged communities, again to improve customer equity regarding transportation electrification. These enhancements were approved by the Commission in December 2021.

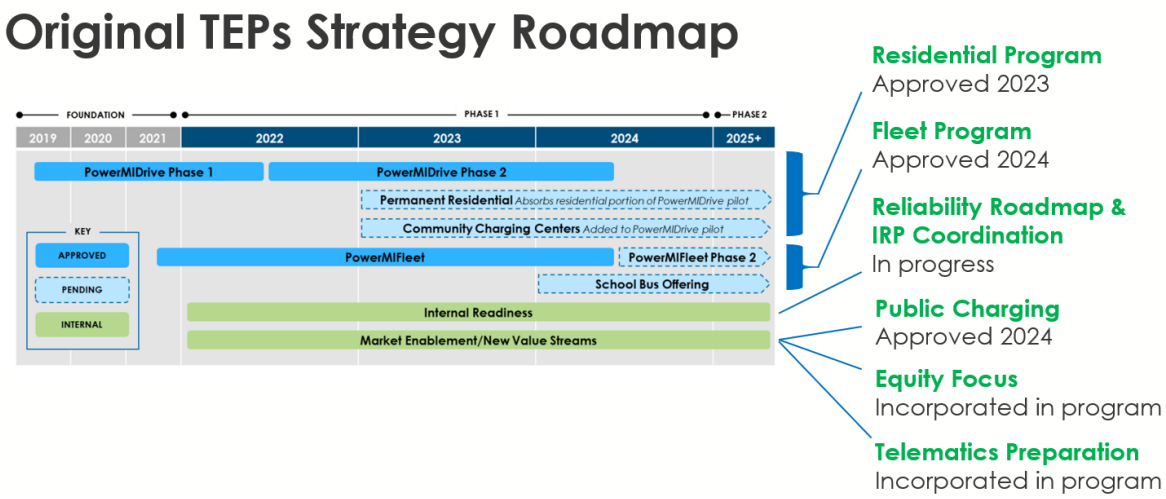
The first official TEP filing (under the heading of "Consumers Energy 2022-2030 Transportation Electrification Strategic Plan") was included in Case No U-21224. In January 2023, the Commission approved the Company's proposal to make the PowerMIDrive Residential program permanent, including the MDU component, and to add community charging rebates to the PowerMIDrive public infrastructure pilot. The community charging pilot was proposed by the Company to further increase equitable access to off-peak charging by customers.

Finally, in Case No U-21389, the Company proposed making both PowerMIFleet and the PowerMIDrive Public programs permanent based on the continued pilot refinements and learnings of the past four years. In March of 2024, the PowerMIDrive Residential, PowerMIDrive

[1] See 0688y00000EFQgtAAH for the Company's 2024 TEP report. See 0688y000008L9UaAAK and 0688y000008KyQSAA0 for the 2023 PowerMIDrive and PowerMIFleet annual reports. The original TEP strategy from 2022 was provided in 0688y000002lGMlAAM. Finally, additional reports from the pilot phases (2022-2020) leading to the TEP are also available at 0688y000003NM62AAG, 068t000000NieAVAAZ, and 068t000000D3t95AAB. All of these regulatory filings show the Company's consistent focus on optimizing the grid and increasing charging infrastructure via strategic locations to benefit customers.

Public, and PowerMIFleet programs were authorized by the Commission, creating the first comprehensive utility EV load management program approved without legislative mandates.

The goals laid out in the original TEP filing were achieved, as summarized in the graphic below excerpted from the original TEP filing.[2]



The strategic roadmap objectives in the Company's first TEP have all been approved and focus on equitable charging access such as the up to $1,000 income-qualified residential rebate, multifamily rebates, community charging rebates, and workplace charging rebates, in addition to PowerMIFleet's strategic focus on fleets serving income qualified and disadvantaged communities, non-profits, educational institutions, government agencies, and small and medium businesses.

Telematic preparation is also being achieved given the Company's focus on Level 2 charging, in addition to some long-duration direct current (DC) and Level 1 rebates, by focusing on key market segments that are likely to be off-peak. All of these use cases focus on situations providing 3 hours or more of plug-in time where telematics can be meaningfully engaged in the future.

In 2026 the Company will file an updated TEP, and annual reports thereafter will utilize the TEP reporting requirements published by the MPSC. This is the last annual update utilizing the format developed during the pilot phase of our TEP programs.

[2]See page 19 of Exhibit A-152 (JAM) in Case No. U-21224, which is page 2937 of 2942 in the PDF: 0688y000002IGMIAAM (site.com)

Consumers Energy's TEP programming was featured at the anchoring panel of the 2024 Peak Load Management Alliance EV Summit

Consumers Energy's TEP programming was recognized by EPRI for contributions in planning for millions of EVs on the road

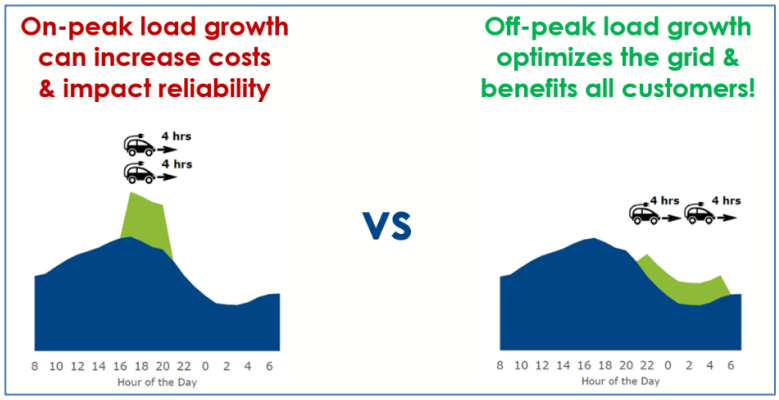
TEP EXECUTIVE SUMMARY & STRATEGY

Governor Whitmer and the State of Michigan have set a goal of two million EVs in Michigan by 2030, and in support of Michigan's goal and the size of the electric territory the Company serves, Consumers Energy set an ambition to be ready to serve one million of those EVs. The Company' s TEP is the strategic document that roadmaps how serving one million EVs (and more beyond 2030) will be achieved. Supporting the TEP are three essential customer load management programs (PowerMIDrive Residential, PowerMIDrive Public Charging, and PowerMIFleet), in collaboration with coordinated planning via the Company's reliability road map and integrated resource plan (IRP). All these TEPs elements are critical to meeting the goals while optimizing EV charging to the benefit of all customers.

Within this context, the Company's' TEP is focused on three primary strategies:

1) Load growth at the right time to benefit reliability and cost for all customers

Not all customers are EV drivers, but the goal of the Company's TEP continues to be that all customers should benefit from the EV programs by maximizing off-peak charging.



On-peak charging can dramatically increase distribution system needs at the service and distribution circuit transformer level. For example, most residential loads peak at near 10 kW, and even L2 charging can double that on a 50-amp circuit (an additional 9.6 kW), or potentially even triple such peak loads if multiple EVs in a household are charging or a more powerful 100-amp circuit L2 is utilized (an additional 19.2 kW). Given the growth trends of EVs, it is easy to imagine how reliability concerns and infrastructure replacement could occur near the grid edge with distribution infrastructure that was constructed to serve customers in a pre-EV era.

Without EV load management programs, most customers will pay no attention to on-peak time periods (presently 2 PM to 7 PM weekdays and likely shifting later over time as more solar generation is added to the grid) when charging. The Company knows this because in the spring of 2025 our AMI data analysis showed just 497 of the 39,950 EVs in the Company's electric territory enrolled in Rate 1050 (Nighttime Savers) without rebate and incentive engagement. That equates to a mere 1.2% of EV customers, consistent with data trends from the last several years, and thus relying on time of use (TOU) rates alone is not sufficient to incentivize residential EV load management.

Furthermore, in public settings time-of-use (TOU) rates alone for L2 infrastructure made less impact than when combined with specific use cases (e.g. destination locations like hotels) as noted in the annual reports throughout the pilot phase of PowerMIDrive, because the cost differential for charging is relatively low. This is why the PowerMIDrive Public program now exclusively focuses on TOU rates plus strategic off-peak use-case locations like workplaces for the morning hours, and community charging, multifamily, and destination charging for the overnight and weekend hours.

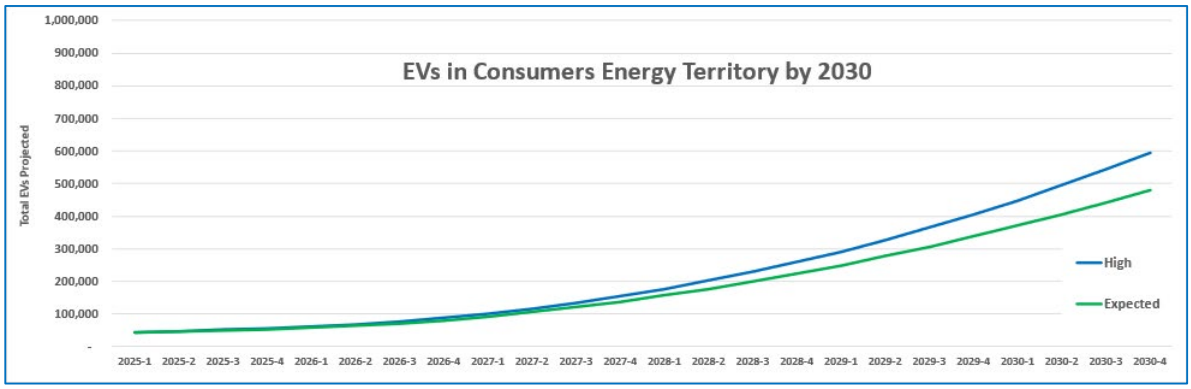
With EV load management programs more kilowatt-hours (kWh) can flow through the same infrastructure, which not only reduces reliability risks at the grid edge but also lowers costs for all customers by optimizing energy usage and infrastructure, while helping to avoid or delay local system upgrades. The off-peak charging results for all charging categories are summarized in the table below. Permanent TEP programs achieved nearly 96% off-peak charging and still maintained an impressive off-peak percentage close to 90% when direct current fast charging (DCFC) loads were included.

EV Customer Program Category	On-Peak 2PM-7PM	Off-Peak 7AM-2PM 7PM-11PM	Super Off-Peak 11PM-7AM & Weekends	Total Off-Peak by Category
Residential Single Family	*2.1%*	*6.6%*	*91.3%*	*97.9%*
Community Charging	*21.6%*	*33.8%*	*44.6%*	*78.4%*
Multifamily	*18.3%*	*35.2%*	*46.5%*	*81.7%*
Total Residential	***2.6%***	***7.4%***	***90.0%***	***97.4%***
Destination L2+L1	*20.6%*	*36.3%*	*43.1%*	*79.4%*
Fleet & Workplace	*8.9%*	*40.8%*	*50.3%*	*91.1%*
Original Pilot: DCFC	*24.5%*	*35.2%*	*40.3%*	*75.5%*
Total Commercial	***20.1%***	***36.8%***	***43.1%***	***79.9%***
Permanent Programs	***4.1%***	***13.9%***	***82.0%***	***95.9%***
Permanent & DCFC Pilot	**10.4%**	**20.5%**	**69.0%**	**89.6%**

2) Encourage and prepare for EV adoption at scale

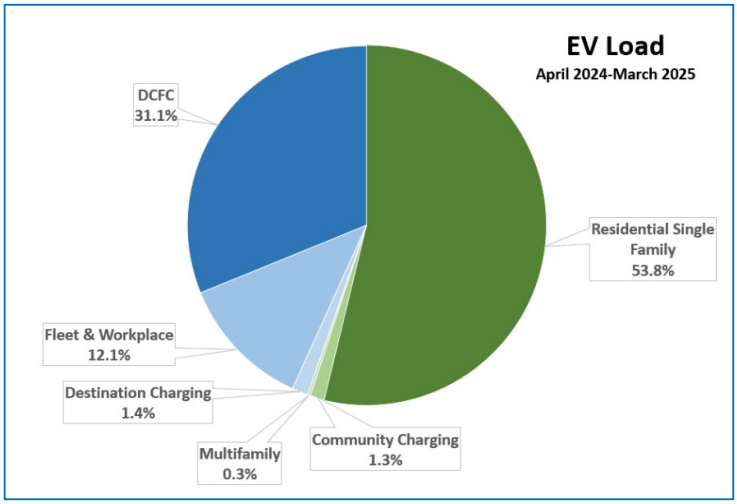
EV adoption is viral, with the most likely customers to buy or lease an EV being customers who live near someone with an EV. For example, residential distribution circuits that served three EVs near the start of the pilot may now be serving 17 or more EVs. Thus, while seasonal EV sales will vary, it is prudent to remain focused on the long term given how quickly EV adoption has been occurring and the potential for concentrated distribution level circuit impacts.

EV load growth has been at or above the "500K EV" by 2030 EV scenario utilized in the 2021 Integrated Resource Plan (IRP), annual TEP related reports, and prior electric rate cases. While the Company continues to prepare the TEPs to optimize load for one-million EVs by 2030 in support of the State's goal, and strongly supports EV adoption and Michigan's automotive manufacturing economic strength, EVs on the road are trending slightly lower than the prior approximate range of 630K EVs (i.e. the McKinsey projection from 2023) and the Company's prior 500K EV (2021 IRP projection) by 2030.



The latest data from the Secretary of State indicates that a range closer to 600K to 470K EVs by 2030 is more likely in the Company's territory. Nonetheless, those EVs are driving more miles per year due to improving public infrastructure, more EV models are entering the market (e.g. SUVs, crossovers, and trucks) that are using more kWh per mile, and the Company's electric territory continues to be a destination for many EVs that reside outside of our electric territory (e.g. travelers from the greater Chicago, Detroit, and Toledo metros) and to enable EV travel into the upper peninsula. Thus, total EV load growth, which is what truly matters for margin analysis and TEP program funding, remains solidly on track (see the financial graphic in following subsection).

Beyond EV adoption levels, residential and commercial charging continues to proportionately evolve. The Company's latest data shows a near 55/45 split between residential charging in green, and commercial charging in blue (up from approximately 70/30 in 2024, and 80/20 in 2023). The larger proportion of commercial charging is driven by the rapidly growing use of public fast charging (DCFC) as customers drive their EVs longer distances to enjoy the abundance of tourist destinations in our electric territory.



Near term, the Company believes that additional incentives are still needed to bring fast-charging infrastructure to more rural and underserved communities and has proposed a limited window of funding for a $50,000 rebate per 150 kW port, in communities where four such ports do not exist across at least two different host sites. Knowing that a fast-charging site exists within your community is important to spur continued EV adoption via charging confidence, while also enabling travel to and

through those communities by visitors. The rapid growth in fast charging clearly indicates that the infrastructure is valued and utilized by customers in the areas served.

As a planning estimate, utilizing the ratio of one 250 kW fast charger per every 85 EVs, and adoption trending between 470K and 600K EVs by 2030, the Company projects that approximately 1,400 to 1,700 EV service requests of 1 MW or greater could occur by 2030. With the near two-year timeframe to design a new service, procure and install make-ready equipment, and energize a site, we are taking prudent action now in preparation for forthcoming EV service requests by collaborating with our supply chain and low voltage distribution planning teams. We also encourage fast-charging developers and large fleet planners to proactively reach out to us to begin project specific planning, including through initiatives such as ERPI's GridFAST[3].

Circling back to the residential sector and the Company's focus on equitable access, at least one out of three residential customers may not live in a single-family home or be able to install L2 charging at their residence. The need for alternative charging locations in the future is very real, and access needs for workplace charging, community charging, and multifamily charging are expected to increase dramatically.

For example, the Company's viewpoint is that there will be a near 1-to-1 ratio of L2 chargers and light duty EVs, with approximately 2/3 of those being private at residences and fleet locations, and 1/3 of EV drivers seeking or relying on public L2. Utilizing the current EV growth rate projections, this means approximately 155,000 to 198,000 L2 plugs in equitable access and public locations may be needed in the Company's territory by 2030. Again, we believe that long-duration and equitable access locations like workplace, multifamily, community charging, and destination charging are where these L2 should be prioritized by TEP programming to optimize charging load. DCFCs support EV adoption and the continued societal benefits that come with it.

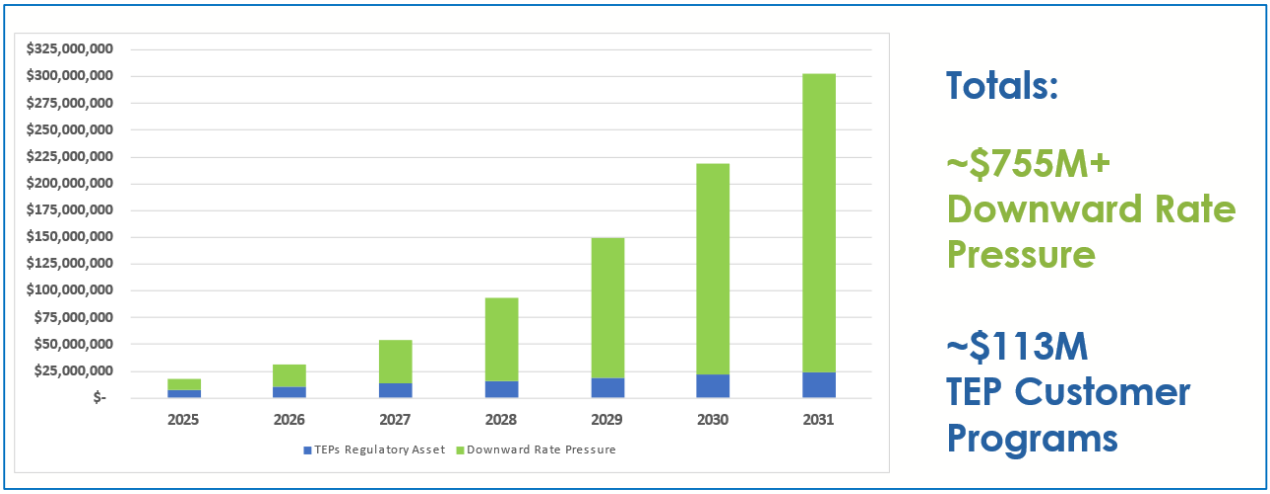
Projected Number of Plugs Needed

EVs	1,000,000	600,000	470,000
Residential Single Family L2	520,000	312,000	244,000
Equitable Access & Public L2 Multifamily, Community Charging, Workplace, Overnight Destination	330,000	198,000	155,000
Fleet L2	150,000	90,000	71,000
DCFC (1 MW sites)	11,800 (2,900)	7,100 (1,800)	5,500 (1,400)

[3]EPRI's collaborative interface can be found at: GridFAST.

3) The additional margin from EV load growth will continue to pay for EV load management programs while also creating downward rate pressure for all customers

Consumers Energy is fully convinced that EV load growth at the right time presents a unique opportunity where a portion of the additional margin from EV load growth is easily able to fund EV load management programs and accelerate charging infrastructure developments, while preserving margin for downward rate pressure benefiting all customers. In fact, utilizing the expected scenario for EV adoption, the projected investment in EV customer load management programming recovered via the regulatory asset is approximately $113 million, which is greatly outweighed by the downward rate benefit projected to be more than $755 million of remaining EV load margin between now and 2031. Thus, EV programs clearly pay for themselves and are not paid by non-EV driving customers. Moreover, all customers continue to benefit from EV load growth and continued electrification should be encouraged.



Using the three strategic principles above, Consumers Energy's TEP is focused on scaling programming and planning for key market segments in support of Michigan's EV goals. To date, even with efforts that do not include direct control, off-peak load management has achieved breakthrough results benefitting all customers. The Company's EV load management programs have achieved greater than 95% off-peak charging between April 2024 and March 2025, which is best in class for utilities and well beyond the original pilot goal of 70% off-peak charging.

The Company is also preparing for future technology developments, such as active charging management via telematics. All market segments in which active managed charging is likely to be acceptable to the customer are covered by our approved programs in the TEP. Furthermore, future technologies such as active managed charging and bidirectional power flows are not possible if a vehicle is not plugged in due to a lack of infrastructure, and our customer programs are working to optimize the likelihood of such opportunities.

TEP IMPLEMENTATION

The section below summarizes the implementation strategies taken by the Company to continue to optimize EV load growth, across all key market segments for charging, for the benefit of all customers.

Residential Single-Family Rebate & Incentives

The majority of EV charging occurs at home, and most residential EV drivers utilize L2 chargers, which can significantly impact residential peaks. Moreover, residential EV loads continue to be the largest kWh segment in the TEP. Thus, it is critical that we engage a significant proportion of residential EV drivers to maintain loads within residential design standards and optimize charging behaviors. To create an attractive load management program, Consumers Energy offers a combined offering of:

- **$500 (up to $1000 for income qualified customers) home installation rebate** for any UL, EnergyStar certified level 2 charger on a 240-volt circuit of 50 amps or less. This rebate typically covers up to half of the installation cost, thereby drawing customers in to discuss optimal rates and charging times to save money and optimize the grid.
- **$10 monthly incentive** for enrollment into the Smart Charging Incentive Program avoiding on-peak charging (over 12 months and thus $120 potential total incentive). This behavioral reinforcement over all four seasons of weather creates a gamification challenge to save and earn additional money, while also giving the customer confidence that off-peak charging is possible year-round. We continue to see customers maintain their off-peak charging after graduating from the program, which also avoids ongoing operational costs for incentives.

To be eligible for one, or both, of the rebate and incentive offers above, a customer must:

- Be a current full-service Consumers Energy electric customer
- Own, lease or have an EV on order
- Agree to enroll in a year-round TOU rate at home, with Nighttime Savers being the recommended option (Rate Code 1050)
    - Program weekday charging to occur during super off-peak timeframe (11PM-6AM) and avoid charging during on-peak times (2PM-7PM)

As Consumers Energy seeks to ensure that grid benefits are optimized while the EV market is rapidly expanding, the Company's residential program continued to analyze home EV charging patterns of participating customers. The team focused education efforts and customer awareness of the benefits a year-round TOU rate and off-peak charging can offer an EV driver (namely, approximately $1.30 per e-gallon equivalent), with an emphasis on 11 PM or later start time for charging to further assist all customers via super off-peak charging.

In 2025 we also began working with customers to voluntarily change their start time based on their daily driving habits. For example, a lower mileage driver or a plug-in hybrid owner may be willing to program their charging to start at 1AM or 2AM instead of 11PM. This helps create load diversity and decreases ramp rates at no additional cost to the program. Only a few months into this voluntary initiative, over 300 EV drivers have already modified their charging start time.

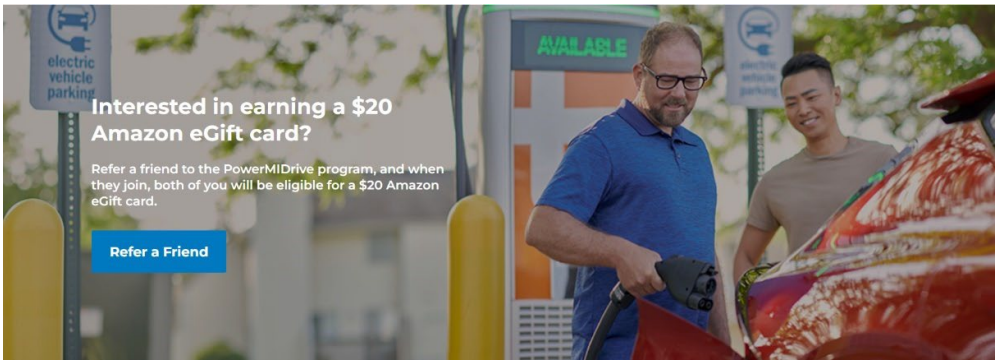
The Company continues internal collaboration with the Low Voltage Distribution Planning (LVDP) team to track residential transformers, looking for potential impacts where the electric grid supports multiple residences with home chargers. Analysis of residential participants continues to show no transformer reliability challenges from participating customer EV charging.

The fact that no residential customers that are utilizing a single 50-amp outlet have, to date, required make ready work on the Company's side of the meter is evidence supporting our 9.6 kW residential design standard for EV charging. These experiences were the basis for the decision to utilize a single National Electric Manufacturers Association (NEMA) 14-50 outlet as the residential standard in the permanent residential program.

However, we also know that the vast majority of EV drivers will continue driving EV and add more EVs to their household as their internal combustion engine (ICE) cars age out. Without further proactive strategy, such homes are likely to install additional charging circuits that could exceed residential neighborhood design standards as adoption continues to scale. To address this challenge, the team has begun work to implement the recently approved rebate of up to $500 for a UL listed dual cord L2 or splitter technology in which two or more EVs can charge from a single NEMA 14-50 outlet. This benefit also addresses ramp rates by spreading the load from multiple EVs across a greater time rather than having two L2 begin charging simultaneously (e.g. 9.6 kW charging over 4-6 hours is much better than 19.2 kW from two L2 charging over 2-3 hours).

PowerMIDrive team members test a power-sharing residential L2 that utilizes a single NEMA 14-50 outlet – a solution that reduces customer costs and gid impacts of homes with multiple EVs

Banner ad on the EV webpage for the new Referral Rewards program



Furthermore, we know that EV adoption is viral and the customers most likely to drive an EV are those who know someone with an EV. Customers in our programs also consistently report a 70 or greater net promoter score (NPS), which is incredibly high for utilities. Thus, in 2025 we also began implementation of a referral program, in which the referring customer and the referee upon enrolling in PowerMIDrive each receive a $20 gift card. This viral marketing approach helps to grow program participation and avoids email marketing clutter. In less than a month the referral program has already brought 28 potential new customers into the application process.

Regarding the popularity and efficacy of residential program participation, the key is the combination of rebates that get customers to participate in off-peak charging and an AMI-based incentive that positively reinforces off-peak charging behavior through all four seasons. The PowerMIDrive Residential strategies continue to show world class results, with single-family homes charging at 95% or greater off-peak and no system issues with over 8,200 EVs in the program. Rebates and behavioral incentives are providing the results needed to optimize residential EV charging as the sector continues to grow rapidly.

Sample of email communication sent to customers with AMI data indicating a high likelihood of EV ownership

Multifamily Property L2 Rebates

Approximately one of three Consumers Energy customers call a multifamily property home, and our TEP includes customer programming to ensure equitable access to off-peak charging for these residents. Multifamily properties with five or more residences typically do not have access to or the ability to install a private-use L2 for their EVs like single-family residents can. Without onsite or nearby L2 charging options, multifamily customers are more likely to rely on fast charging, which is usually similar in cost to gasoline and thus less likely to result in cost savings from driving EV. Thus, PowerMIDrive's multifamily charging rebate component is designed to incentivize multifamily property owners to invest in EV charging as an amenity for residential tenants.

PowerMIDrive Multifamily Property Charging in Wyoming, MI

In 2023, Consumers Energy launched multifamily property charger rebates as a permanent program offering. To ensure optimal grid benefits are achieved, the program provides a $7,500 rebate for at least two L2 charge ports on a maximum 100-amp circuit, thereby keeping EV charging loads similar to our single-family program. The chargers are required to be separately metered and enrolled on CE's commercial TOU rate, which offers a lower cost of electricity during the off-peak hours. To further encourage off-peak charging at multifamily properties, PowerMIDrive provides signage and educational materials to the property, and site hosts receive a $20/monthly bill credit for the first 12 months the chargers are installed if 80% or greater of charging avoids the peak window of 2pm-7pm Monday through Friday.

As of April 2025, a total of 48 L2 rebates have been paid to multifamily properties across Michigan. Of this total, 23 rebates were paid during the original and extended pilot offering, 23 rebates were paid under the under the permanent program offering, and 2 rebates were paid as part of our Enel X swap-out efforts.[4] An additional 54 rebates are committed to 26 MDU locations around the state for in-progress projects, illustrating rapid growth and interest in the program.

We are happy to report that nearly all multifamily property participants under the permanent program have achieved at least 80% off-peak charging each month since installation was completed. Only one site host exceeded the on-peak charging limit in a single month, and with coaching from the EV team there have been no recurrences.

[4] In the Fall of 2024, Enel X abruptly announced their exit from the U.S. market, which would have rendered commercial L2 unfunctional. Thus, PowerMIDrive assisted pilot program participants who were required to use this vendor to update the L2 and maintain equitable customer access.

Community Charging L2 Rebates

Sometimes it is not economically feasible to install L2 overnight charging within multifamily residences, or for low-income communities to install at-home charging within a single-family residence. In such cases, community charging can offer a viable alternative if located near such properties where overnight and weekend parking is permitted. Thus, PowerMIDrive's community charging rebate is designed to encourage municipalities and business customers to invest in L2 charging for their communities in public parking or curbside locations that are within 1-3 walkable blocks of a multifamily property or underserved residential neighborhood. The goal of this program offering is to further support equitable access to charging for multifamily residents and members of the community without access to home charging for their electric vehicles.

To ensure optimal grid benefits are achieved, the $7,500 rebate provides several eligible installation options, including at least two L2 charge ports on a 100-amp circuit or less. Alternatively, as a bring your own charger option, two NEMA 14-50 outlets designed for outdoor continuous use, or at least five L1 charge ports, are allowed if installed on a maximum 100-amp circuit. Thus, our community charging program allows for a bring-your-own-cord (BYOC) approach that other program categories have also expressed interest in for cost-savings. The chargers must be separately metered and enrolled on CE's commercial TOU rate to encourage off-peak charging when the cost of electricity is lower.

As of April 2025, a total of 76 community charging rebates have been paid to community charging locations around the state. This total includes 43 rebates classified as community charging from the original public L2 pilot, 12 rebates paid for the community charging pilot, and 21 rebates paid as part of the Enel X swap initiative. Currently, an additional 40 rebates are committed to 16 community site hosts for projects in progress, illustrating strong growth potential as many more communities need charging access.

Community Charging in Mt. Pleasant serves nearby apartments and student campus housing

Destination L2 & L1 Rebates

Consumers Energy's electric territory covers the majority of Michigan's lower peninsula, and many popular tourist destinations for Michiganders and tourists coming from out-of-state. Thus, PowerMIDrive's destination L2 and L1 charging rebate program is designed to improve charging infrastructure accessibility in locations where EV drivers are most likely to charge for longer off-peak time periods when traveling. Lower power destination charging also helps supplement fast charger locations that can see significant increases during specific seasons and holidays.

To ensure that optimal grid benefits are achieved, the permanent program provides a $7,500 rebate for at least two L2 charge ports on a circuit of 100-amps or less. At destinations where travelers are likely to park their EV for 48 hours or longer, host sites can also receive a $7,500 rebate per five level one (L1) charge ports on a 100-amp circuit.

The value of L1 charging is often overlooked, but at long term parking locations like airports and harbors, it can serve a multitude of EVs while avoiding idling challenges from L2s that usually finish charging in less than 8 hours and tie up that plug for the next 40 hours or more. Our first long-duration L1 locations are anticipated to be installed later this year.

PowerMIDrive Destination Charging at a hotel in Spring Lake

A separate meter for the chargers will be required and enrolled on CE's commercial TOU rate, which offers a lower cost of electricity during the off-peak hours. Similar to our efforts during the pilot phase, participants will be educated on the benefits of encouraging destination guests to charge during the off-peak and weekend hours. Participants will maintain their ability to set pricing and accessibility to reflect their individual business needs.

To date, including the pilot phase and Enel X swaps, 117 destination L2 rebates have been awarded to host sites statewide. This rebate category is increasing in popularity, with multiple locations in the rebate queue for completion in the next 12 months.

Workplace L2 Rebates

Similar to home, many people spend a large portion of their week at work. Moreover, for those without access to L2 charging at home, workplaces offer a great opportunity for charging access. We anticipate that residential and workplace charging will be the two largest targets for optimized charging going forward, as they are prime locations to spread and manage load over a longer time period that will not impact the customer.

For example, the typical commute is often 40 miles or less, meaning that L2 charging can be complete well before the current afternoon on-peak time period, and as more solar comes online we can consider spreading that load further into the prime solar generation hours. Equity benefits also exist with workplace charging, because it can supplement, or in some cases substitute for, charging at home (be it single or multifamily) if such an installation is not possible or economically feasible for the customer. For all these reasons, workplace charging is an important market segment for Consumers Energy's TEP as we look to future load management opportunities.

Similar to the other commercial charging programs, to ensure that optimal grid benefits are achieved, the permanent program will provide a $7,500 rebate for at least two L2 charge ports on a maximum 100-amp circuit. A separate meter for the chargers will be required and enrolled on CE's commercial TOU rate, which offers a lower cost of electricity during the off-peak hours.

However, given that some workplaces are adjacent to neighborhoods or multifamily housing, we recognized that a unique opportunity may exist that can aid equitable charging access. Thus, if the participating workplace agrees to allow access, and meets qualifications to serve as a community charging location (i.e., located within 1-3 walkable blocks of a multifamily property or underserved residential neighborhood), the rebate amount per two L2 chargers will increase from $7,500 to up to $10,000. In such cases, the workplace may choose to mandate specific overnight and weekend charging hours for the public, so as not to interfere with employee access to the charging stations during their work shifts.

PowerMIFleet combined Workplace & Community Charging in Flint

To date, 174 workplace rebates for L2 charging have been granted, which includes sites classified as workplace from the original PowerMIDrive pilot, Enel X

swaps, and PowerMIFleet pilot phase leading up to the permanent program. One site host in Flint has received the enhanced workplace plus community charging rebate to date, and additional sites are considering this arrangement in their plans. Currently, an additional 60 rebates are committed to 27 workplace locations for projects in progress around the state.

The load from workplace charging is included in the results for fleets via the PowerMIFleet program and continues to trend upwards with encouraging results. Presently we are achieving over 91% off-peak charging across workplace and fleet.

Workplace charging at Jackson College serves employees & commuting students

PowerMIFleet Rebates and Assessments

In the transportation sector, fleets tend to drive the most miles and thereby produce proportionately more emissions compared to other ICE vehicles. Thus, when fleets switch to electric, they can achieve outsized emissions reductions by proportionately more kWh per EV than a typical residential driver. Nonetheless, this transition is not easy given the technical challenges of switching to a new fuel type, especially for fleets with fewer resources such as those serving in public transport, education, government, non-profit, and small to medium sized businesses. Given this challenge, and the large number of people served by these fleets, the PowerMIFleet program was created to focus on helping those sectors reduce operating costs, eliminate emissions, and optimize the grid, to produce benefits for everyone.

Under the permanent program offering, with rebates as follows:

- $7,500 per two L2 charge ports
- $15,000 per long-duration DC charger of 50kW or less (mirroring L2 load shapes, but at a higher power to account for larger batteries within some fleets)

Like other customer programs within the TEP, chargers installed and rebated through PowerMIFleet must be separately metered and enrolled on the commercial TOU rate to encourage off-peak charging. A total of 137 L2 rebates and 11 long-duration DC rebates have been awarded to date, supporting 240 electric vehicles deployed to fleet organizations serving people across our electric territory.

Furthermore, when needed to help overcome technical challenges and ensure that the right EVs are utilized in the optimal use cases, PowerMIFleet has continued to partner with two fleet electrification assessment consultants to provide a customized, full-service assessment report to selected participants. As of March 31, 2025, a total of 61 fleet assessments have been completed with an additional four customer fleet assessments in progress. Anonymized assessments are then published on the PowerMIFleet website.

Going forward, PowerMIFleet will seek to partner with the customer sectors that will benefit most from a fleet electrification assessment, transitioning over time from light-duty to newer and more novel use cases for medium and heavy-duty EVs, as well as off-road, marine, and potentially aviation use cases. Thus, the frequency of fleet assessments is likely to decrease, but they remain a useful tool especially for organizations seeking supplemental grant funding.

To date, PowerMIFleet continues to trend upward achieving off-peak results of greater than 91%.

The Rapid Transit has begun the electric fleet transition by deploying 12 Ford E-Transit Vans

PowerMIFleet Electric School Bus Ribbon Cutting Ceremony with Jackson Public Schools and Highland Fleets

Jackson Public Schools deployed 21 electric school buses, the largest school bus project to date with PowerMIFleet

PowerMIFleet Enhanced Rebates for Income Qualified Fleets

As part of the pilot phase of PowerMIFleet, Consumers Energy received a one-time fund of $1.6M to support fleet electrification for organizations whose vehicle fleet serves an income-qualified community. As of April 2025, the EV team identified a total of 12 service organizations to support via enhanced rebates, with planning for additional outreach underway. Organizations include Dial-A-Ride organizations with Rides to Wellness programs for senior citizens and veterans, rural and urban school districts, and non-profit organizations who deliver meals to children in impoverished communities around the state. To date, ten organizations have deployed their new electric fleet vehicles, and the remaining two organizations are in the process of coordination vehicle delivery and driver training with our partner organization, Hoekstra Transportation.

We would like to thank the MPSC for their support in allowing us to provide this funding to worthwhile organizations around the state, connecting members of the community with emissions-free transportation, reducing operational costs via electrification, and providing the experience of riding and driving an electric vehicle from Michigan OEMs. The enhanced rebate funding via the $1.6M has been transformational for these agencies and non-profits in addition to the income-qualified communities they serve.

For example, Otsego County Food Pantry received a Ford E-Transit Cargo Van and L2 charger to support their food delivery and community services around the region. A ribbon cutting and food drive event to "jam the van" was celebrated in April 2025. Otsego County Food Pantry staff stated, "We are so excited, grateful, overwhelmed and amazed! Thank you, Consumers Energy!"

PowerMIFleet Income Qualified Community Fleet Vehicle in Gaylord made possible by the enhanced rebate program

Given the success of PowerMIFleet at optimizing the grid, less make-ready has been needed to date for the pilot phase projects still in the works. Thus, in the 2024 electric rate case the Company proposed utilizing any remaining make ready funds for additional income qualified fleet projects. The MPSC approved that request in early 2025 and the team is now working to deploy approximately $3M in additional enhanced rebates for fleets serving income-qualified customers. We are excited to see the collaborative projects that are in the works for deployment later this year and into 2026!

PowerMIFleet partnered with Grand Rapids to deploy a car share program helping income-qualified customers

L2 charging infrastructure being installed for Kids Food Basket and made possible via the enhanced rebates for income-qualified fleets

DCFC Rebate Pilot

PowerMIDrive's DCFC rebate component is presently a continuation of customer projects underway from the pilot phase of the Company's EV initiatives as we work to wrap up the 137 fast charging projects awarded. The DCFC rebates were designed to help create the start of a network of fast charging infrastructure, primarily along four-lane highways throughout the Company's electric service territory. However, much work remains to bring fast charging access to more of our rural and seasonal travel communities in support of customer travel and tourism impacts.

By incentivizing initial investment in DCFC infrastructure along such major expressways and travel corridors, benefits are already being realized by the broader community of EV drivers traveling within the state of Michigan. Convenient fast charging is a significant factor in ensuring EVs meet the needs of customers on longer-distance travel, and thus for EV adoption as well since consumers expect to be able to road-trip with their vehicle.

DCFC site hosts participating in the PowerMIDrive pilot are educated on the benefits of providing fast chargers to attract more traffic to their respective locations and supporting Michigan's economic development as our OEMs continue to electrify their vehicle offerings. Like public L2 sites, DCFC site hosts also maintain the ability to set pricing to reflect individual on-site needs. However, unlike public L2 locations, all DCFC rebate recipients implement a fee for charging and fast charging is usually more expensive per kWh than L2s that implement a fee.

The Company is pleased to report that a total of 88 of the 137 PowerMIDrive DCFC pilot sites are now operational across CE's territory to date. Of the remaining sites in progress, 24 are National Electric Vehicle Infrastructure (NEVI) sites focused on expanding fast charging to every 50 miles along major four-lane highways, and 25 sites have been selected by our team to help increase fast charging infrastructure in remaining areas. When the pilot is complete, the 137 fast charging rebates represent an important initial step toward the more than 1,400 fast charging locations projected to be needed by 2030. In particular, we believe that rural and seasonal travel communities still need incentive support to ensure the skeleton network of fast chargers is sufficient to support rapidly growing EV adoption.

PowerMIDrive partnered with GM Energy and Pilot Flying J to provide fast charging in Saginaw

Future Proofing at DCFC Pilot Sites

To help ensure the DCFC infrastructure installed allows for scalability with future EV growth and avoid rework such as replacing relatively new transformers during future upgrades, the PowerMIDrive Program was approved with approximately $40,000 in make ready budget per DCFC rebate in the pilot. These funds are designated to utility side upgrades such as transformers and line upgrades serving the host site.

PowerMIDrive Fast Charging Rebate Site in Glennie

The cost and scope of electrical upgrades at DCFC sites are evaluated with the specification to double the minimum required initial output capacity of 150 kW in aggregate per site. Thus, a 300 kVA transformer will continue to be installed at each non-NEVI DCFC site participating in the PowerMIDrive pilot as part of the electrical upgrade work performed by the Company.

As with the Company's previous TEP partnership with the Michigan Department of Environment, Great Lakes, and Energy (EGLE) on Charge Up Michigan program funding for DCFC sites, Consumers Energy has developed a close collaborative partnership with Michigan Department of Transportation (MDOT), as Federal NEVI funding awards were announced earlier this year. Of the total 41 NEVI site awards announced across Michigan, 24 of those awards fall in the Company's electric service territory and we have worked hard to ensure that all NEVI sites can be quickly completed after NEVI contracts are finalized.

PowerMIDrive Fast Charging Rebate Site at Birch Run

We are pleased to report that all 24 NEVI sites have completed the design phase in strong support of the State goals. These sites are ready to kick off construction as soon as contracts have been executed between MDOT and the site hosts.

As each NEVI site will require four 150kW DCFC stations, make-ready infrastructure is being designed accordingly, with a 750 kVA transformer planned at each location. We are prepared to complete these projects by end of 2025 but realistically anticipate that some will be completed in 2026 due to customer schedules.

Customer Education & Outreach

With EVs rapidly growing in the early adopter phase, customer outreach and education remain a key component of the Company TEP. We know that education alone is not enough, and pairing outreach with customer programs is necessary to create opportunities for engagement about EV load and cost optimization. Thus, a multi-faceted strategy continues to be implemented to raise awareness about how off-peak charging benefits both EV and non-EV customers, the cost savings achievable utilizing TOU rates, and the public EV charging infrastructure made possible in part by PowerMIDrive.

The program team utilizes both in-person and digital channels to reach customers, raise awareness of the rebate programs, and achieve program enrollment targets, including:

- Participation in National Drive Electric Week events (September-October)
- Participation in Drive Electric Earth Month events (April)
- Trade and auto shows
- EV101 presentations at community and business organizations
- Email and direct mail outreach campaigns and newsletters
- Press releases and earned media
- Social media posts and digital media advertisements including search terms
- Radio and TV interviews
- EV-focused virtual events, conferences and panels
- Government and trade association engagement

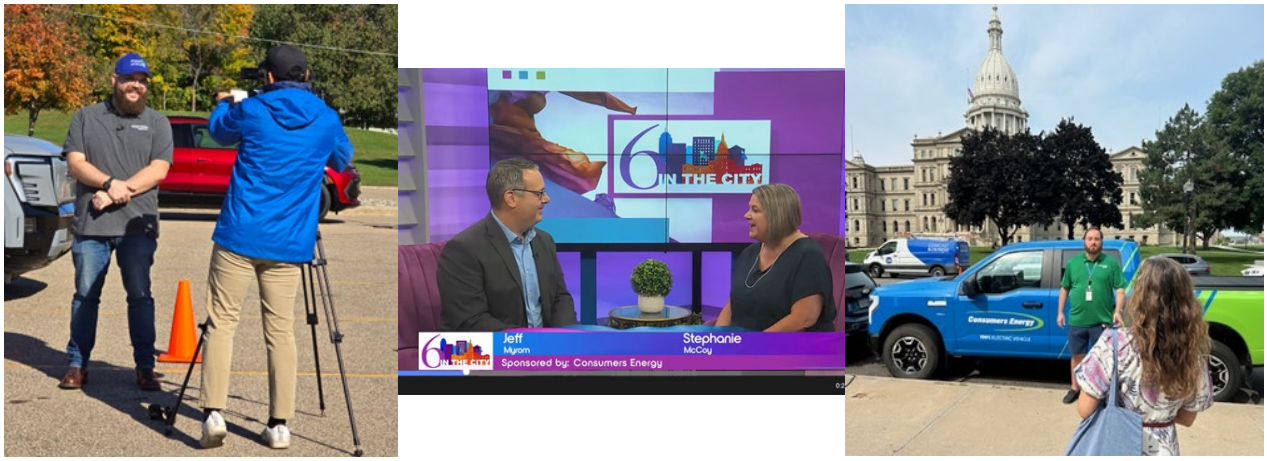
The combination of marketing and outreach lead to over 79,662 unique visitors to the PowerMIDrive residential website where customers can learn more information online, contact an EV specialist or complete their application.

The Company's EV team, which is dedicated to leading PowerMIDrive and PowerMIFleet, reaches tens of thousands of customers each year via these efforts. Team members include the following:

- Director of Customer Transportation Electrification Planning – Jeff Myrom
- PowerMIDrive Public and PowerMIFleet Program Manager – Bethany Tabor
- PowerMIDrive Public Team Members – Doug Reid, Paul Nicklowitz, and Scott Zenner
- PowerMIFleet Team Members – Steven Harris, Jenna Brown, and Kristi Baker
- PowerMIDrive Residential Program Manager – Brittany Fischer
- PowerMIDrive Residential Team Members – Stacey Walkowe, Maria Mejias, Justin Stowe, Nicolas Hutchens, and Jarrod Skogen
- Community Outreach Coordinator – Justin Stowe
- Education & Outreach Support – Therese Vainner and Brett Porterfield
- Media & Press Coordination – Brian Wheeler

PowerMIDrive & PowerMIFleet team members spoke with hundreds of customers at the 2025 auto show in Grand Rapids

PowerMIDrive team answering questions at an EV Summer Meetup in Muskegon



Media interviews get the word out to customers regarding our EV programs

TEP CUSTOMER PARTICIPATION & COSTS

Residential Single Family

As of March 31, 2025, PowerMIDrive Residential had over 7,933 EV customers, including 13 income qualified rebates in the program. These customers are participating through the up to $500 rebate (up to $1,000 for income qualified customers), the Smart Charging Incentive (i.e. $10 per month of charging super off-peak for 12 months), or both.

As part of the rebate process, the program collects residential applicant documentation to validate proof of purchase and installation of an eligible Level 2 home charger. While not all participants share their cost information or may have only part of the costs documented, these findings provide valuable insight into residential L2 retrofit costs. It also highlights the need for EV ready building codes since significant cost savings are possible during the construction process, and much of the housing stock does not have a NEMA 14-50 outlet in the parking area. Based on the program participant documentation received as of March 31, 2025, the average, high and low residential customer costs are outlined in Figure 1 below.

	Median Cost	Average Cost
Charger Only	$477	$502
Installation Included	$1,125	$1,363

Figure 1: Residential Customer Costs of Home Charger & Installation

Some residential participants did not require an electrical contractor for installation at their home because they were existing EV owners (i.e., a benefit of having a 240V outlet already in their garage), and therefore only provided cost documentation to verify proof of charger purchase. Project costs for these customers are captured in the "*Charger Only*" cost line item in Figure 1.

In cases where installation was required and an electrical contractor invoice was provided, the total out-of-pocket costs were significantly higher, as outlined in the "Installation Included" cost line item in Figure 1. Furthermore, the Company has received numerous inquiries from customers seeking general guidance on the scope of work required to install a Level 2 charger at home or looking for a referral to local electricians experienced with home charging station installations in their area. Based on this feedback, CE enhanced the Company's electric vehicle webpages to provide the resources such as a NEMA 14-50 outlet specifications so that customers feel more confident about charging their EV overnight at home.

Consumers Energy's insights from this data are that the standardization of a NEMA 14-50 outlet, assistance locating an electrician, and the rebate to assist with the costs of installation by a

qualified electrician is a clear benefit to customers and will help draw them into participating with the Company's permanent residential proposal. Moreover, the Company is now working to include power-sharing splitters and L2 chargers in the program to further improve grid impacts and customer installation costs as EV adoption continues to increase.

Allowing a rebate of up to $500 for the inclusion of home power-sharing technology incentivizes residential customers who are adding a 2nd or 3rd EV to stay within residential distribution design standards. Thus, this program strategy improves reliability for all by spreading the load over longer off-peak timeframes and reducing load ramps (e.g. two EVs charging at 9.6 kW spread over 4-6 hours on a single home circuit, instead of 19.2 kW spread over 2-3 hours). The undesirable alternative is that some customers would add a second EV charging circuit in their garage (which would not receive a rebate) not realizing the grid impact that this could have.

A power sharing splitter allows two L2 to safely utilize a single NEMA 14-50 outlet

A home charging setup for two EVs from a single NEMA 14-50 outlet offers power sharing for optimal load management as more homes adopt a second and third EV

PowerMIDrive Multifamily & Public Level 2

The program team has shifted emphasis to L2 host sites with off-peak use cases. In alignment with the Company TEP goals, this is intended to increase the proportion of off-peak charging that occurs at rebated locations, improve equity via access to charging (i.e. multifamily, community charging, workplace charging), prepare for potential active managed charging in the future via telematics, and help supplement the still limited DCFC infrastructure supporting long distance travel to destinations.

Since the launch of PowerMIDrive in 2019, a total of 415 L2 rebates have been paid to site host locations across the state of Michigan. Figure 2 below outlines the breakdown of public Level 2 site accessibility for paid rebates as of March 31, 2025.

Public Level 2 Site Host Type	Rebates Paid	% of Program Rebates (415 Total)
Multifamily	**48**	**12%**
Community Charging	**76**	**18%**
Destination	**117**	**28%**
Workplace	**174**	**42%**

Figure 2: Level 2 Site Host Category Participation (Pilot + Permanent Program)

Workplace Charging in Jackson

Based on the rebate verification documentation received for completed public Level 2 sites as of March 31, 2025, a breakdown of project costs is outlined in Figure 3 below.

Per Dual Cord L2	Median Cost	Average Cost
Total Project Cost (Installation, Network & Maintenance Plan Fees, + Charging Station Equipment)	$9,423	$12,264

Figure 3: Public L2 Site Project Costs Per Dual-Cord L2

Installation and electrical upgrades at each site continue to be the greatest variable in total project costs. Sites requiring longer extensions of electrical service or underground wiring had higher project costs. Sites that installed pedestal mounted chargers had higher equipment costs than sites that opted for wall mounted chargers, and networked chargers are more expensive than unnetworked L2.

In some circumstances, sites completed installation of chargers and experienced challenges with maintaining a WIFI signal, resulting in the need for technical troubleshooting or additional equipment to extend or strengthen network range. In addition to the networking costs, these reliability challenges are why more sites are interested in un-networked L2s, utilizing a permit fee, or offering L2 charging at no additional cost as an amenity to attract customers.

Community Charging in Rockford

Fleet charging setup at a rental car agency

Figure 4 below identifies locations of sites which have completed installation and received Level 2 charging station rebates as of March 31, 2025.

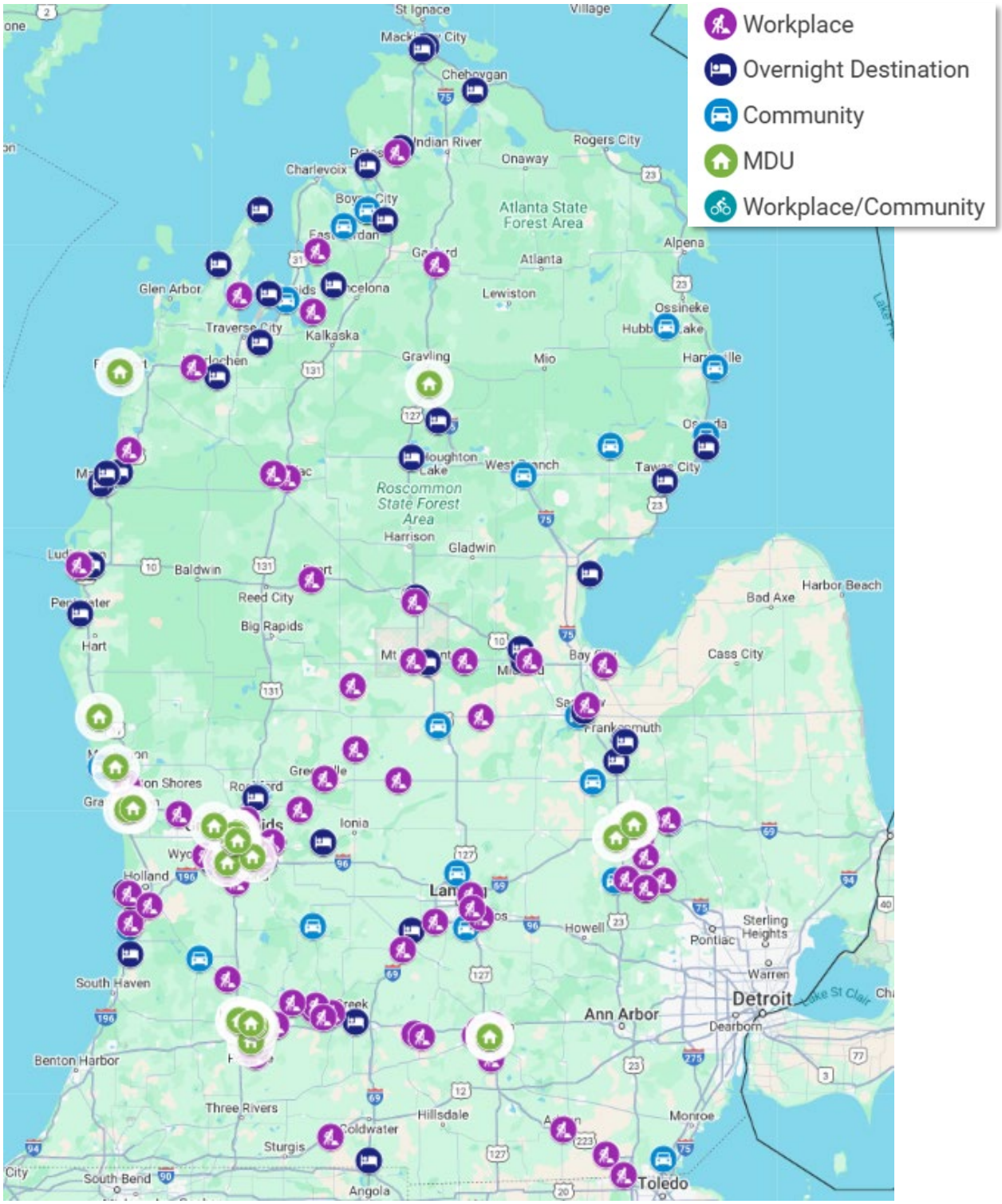


Figure 4: Public Level 2 Sites by Location & Type

DCFC Pilot

As of March 31, 2025, the continued implementation of the PowerMIDrive fast charging pilot had awarded a total of 88 of the 137 committed DCFC rebates for operational sites across the Company's service territory. The 49 DCFC projects still underway include 24 sites selected by MDOT to receive NEVI funding.

As part of our partnership with MDOT on DCFC sites awarded NEVI funding, we have begun make ready upgrade evaluations including a project scope and cost estimate for each site. This information will be included in each contractual agreement between NEVI site hosts and MDOT. The team is fully prepared with make ready plans and equipment to complete these projects once contracting is complete.

Because NEVI sites require four 150kW charge ports to qualify for federal funding, Consumers Energy is designing each NEVI site with a 750KVA transformer to ensure the infrastructure is adequate for the higher load of the chargers. Non-NEVI sites are more likely to utilize a transformer between 300 kVA and 500 kVA. In general, all these transformers are in short supply and can have lead times of 18-24 months, which is why the PowerMIDrive team is so focused on preparations for installation.

The PowerMIDrive team works in close collaboration with our Distribution Planning and Supply Chain partners to ensure we are forecasting new demand accurately and placing long lead time orders for higher power transformers, which have been challenged by supply chain limitations in the last several years. We encourage customers considering DCFC and large fleet projects to reach to us so that timelines can be optimized, and are actively working with EPRI and the EVs2Scale program to proactively forecast infrastructure needs to ensure timely installations in support of electrification.

Based on rebate verification documentation received for completed DCFC customer projects, a breakdown of project costs, excluding make ready upgrades, is outlined in Figure 5. Projects to date have primarily ranged between 125 kW and 200 kW.

	Median Cost	Average Cost	Standard Deviation
Total Project Cost **Scope includes installation, Network & Maintenance Plan Fees, and Charging Station Equipment**	$163,690	$192,163	$63,844
Project Cost in $/kW	$972	$1,010	$355

Figure 5: DCFC Site Project Costs

Figure 6 below outlines the breakdown of make-ready expenses for the 88 completed DCFC rebates in PowerMIDrive through March 31, 2025.

	Median Cost	Average Cost	Standard Deviation
DCFC Make Ready Scope includes 300-750 kVA transformer and service meter, underground or overhead multiphase extension, boring costs, and local system upgrades	$31,612	$40,014	$19,544
Make Ready Cost in $/kW	$189	$253	$128

Figure 6: DCFC Site Make Ready Costs

A DCFC in Wellston helps power travel between Manistee and Cadillac along the M-55 Corridor

A DCFC in Big Rapids aids EV travel along US-131

Figure 7 shows the geographic distribution of the 88 operational PowerMIDrive DCFC Rebate Sites and the 49 remaining fast charging rebates committed to projects in progress at customer locations. Consumers Energy does not own or operate any of these sites. All rebates are awarded to customers. Work remains to be done to support travel in much of our rural territory and tourist destinations.

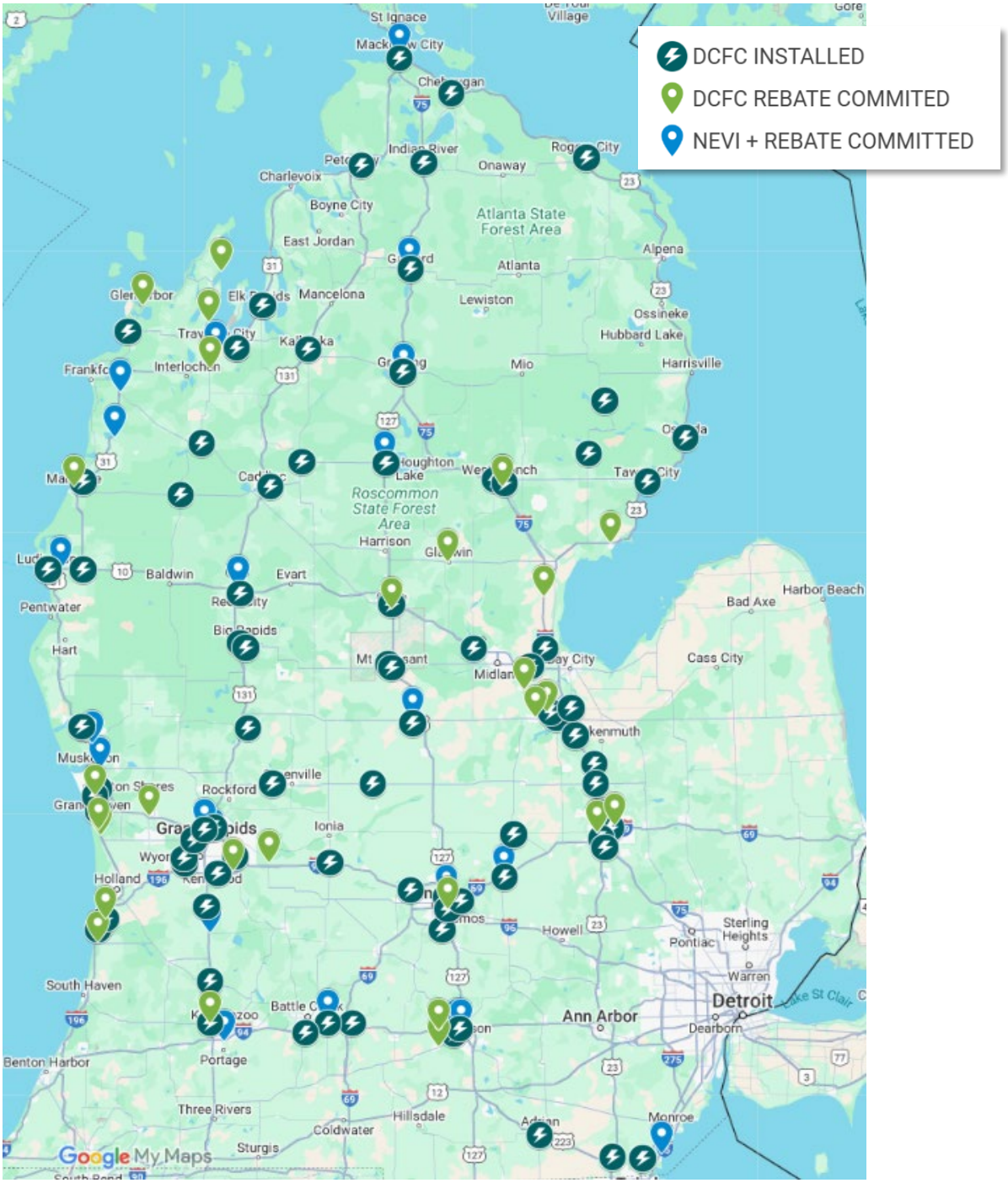


Figure 7: Fast Charging Locations

PowerMIFleet

As of March 31, 2025, a total of 61 customer fleet electrification assessments have been completed (most during the pilot phase), with four additional assessments still in progress. The strongest interest in assessment participation has been in the education and municipal sectors in aid of grant applications and funding requests, followed by small- to medium-sized retail businesses and transportation. This is why the permanent program chose to focus on these sectors, as they need the most assistance to transition to electric. As an additional benefit, fleet assessments within these sectors also benefit a large number and wide variety of Michiganders given their service territories. Figure 8 illustrates the breakdown of assessment participation for all 65 fleet assessments by customer sector.

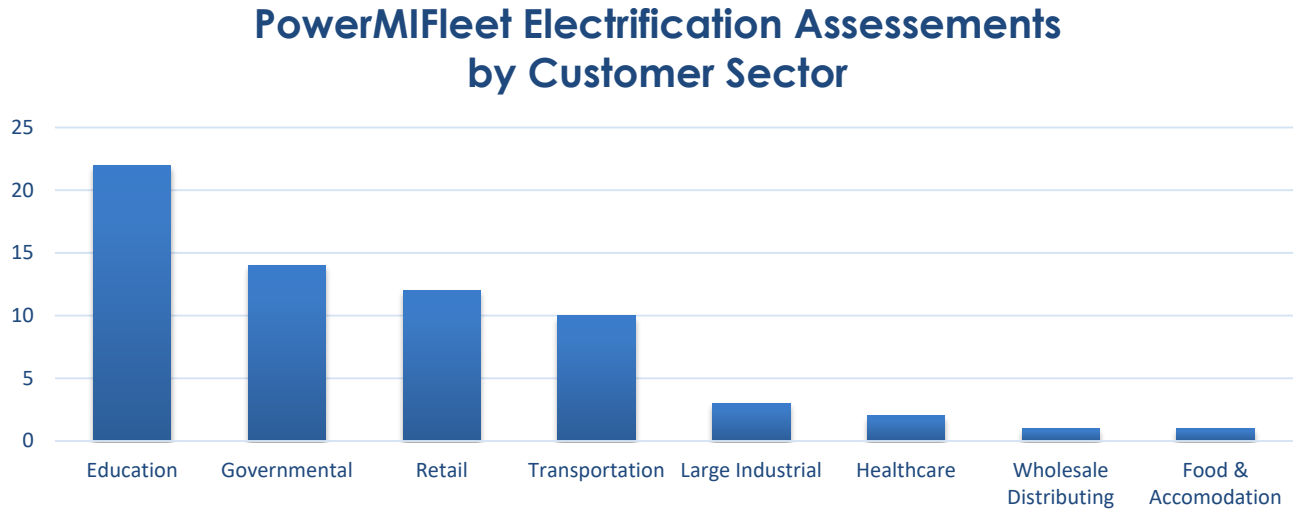


Figure 8: PowerMIFleet Assessments by Customer Sector

For the 61 completed customer fleet assessments to date, a total of 8,398 total vehicles were evaluated, with 2,987 of those vehicles, or 35%, recommended for electrification. In other words, more than 1 out of 3 vehicles are projected to save these agencies money compared to their ICE equivalent.

The PowerMIFleet team has established a quarterly follow-up cadence with assessment participants to provide technical support and guidance as organizational decisions are made to electrify fleet vehicles. In several cases, we have proactively provided workplace charging rebates to customers who wish to establish a network of chargers for employee use in preparation for future fleet EV deployment.

Furthermore, fleet charging rebates have also been provided to customers who did not require a fleet assessment prior to deploying fleet EVs. Going forward, fleet assessments will be reserved for novel fleet use cases where new learnings are available, or where a customer

fleet demonstrates that this service will bring their organization value, supporting an imminent fleet deployment.

As of March 31, 2025, a total of 137 L2 charger rebates and 11 DC charger rebates have been paid to PowerMIFleet program participants. An additional 79 L2 charger rebates and 88 DC long duration charger rebates are committed to customers with in-progress projects. Note that the majority of school districts awarded Michigan and/or EPA Clean School Bus funding make up nearly 100% of the long-duration DC charger rebates committed to in-progress projects at this time.

To date, PowerMIFleet rebates have supported a total of 240 vehicle deployments, with an additional 323 deployments anticipated in the next year. Figure 9 illustrates the breakdown of PowerMIFleet program participants' fleet electrification status by vehicle type to date, with more EVs yet to come given purchasing schedules, and state or federal funding award timelines.

A school district installs 30kW Long-Duration DC chargers to power new electric school buses

Some vehicles on order, or projects anticipated this year may ultimately become delayed or canceled due to the revocation of previously announced and/or awarded federal funding or contracts (e.g., Oshkosh mail delivery trucks, EPA Clean School Bus Grants).

However, until we have received confirmation of a project's cancelation, the totals will be included in "vehicles on order" category of Figure 9 below, and we will continue to partner with these customers to ensure their projects are successful if able to progress to deployment.

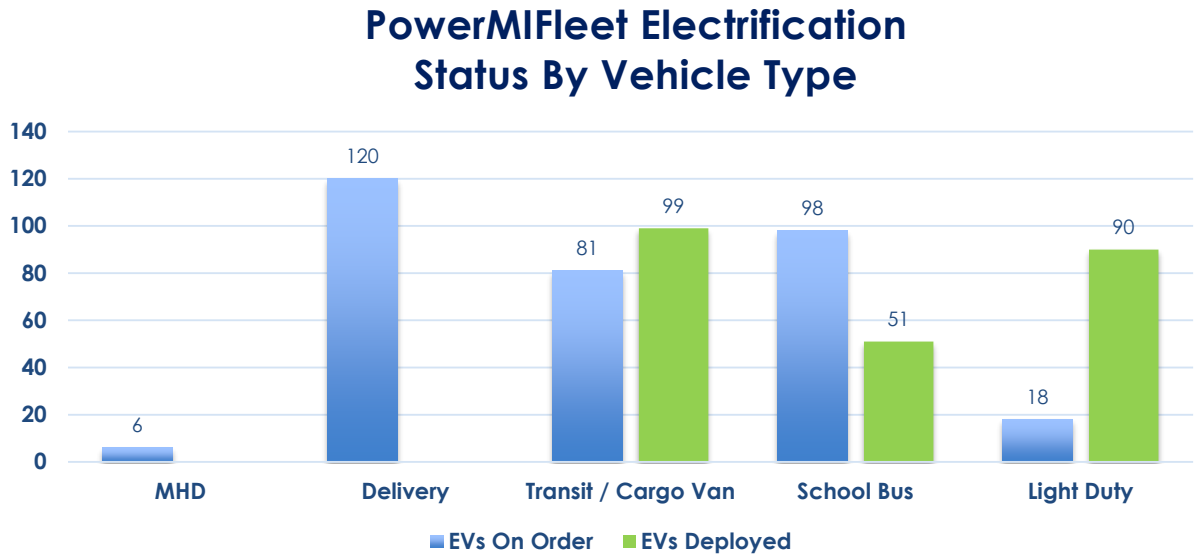


Figure 9: PowerMIFleet Customer Electrification Status by Vehicle Type

Fleet EVs can be operated and charged while loading indoors because there are no emissions, thereby creating new opportunities for building redevelopment

Consumers Energy helped the DNR electrify portions of their fleet and supported park visitors via L2s in State Parks for the Lake Michigan Circuit at Ludington and Pentwater

Finally, Figure 10 shows the geographic distribution of PowerMIFleet customer electrification projects as of March 31, 2025. The program team has intentionally sought projects from across our entire service territory to ensure fleet electrification benefits a wide variety of customers and use cases.

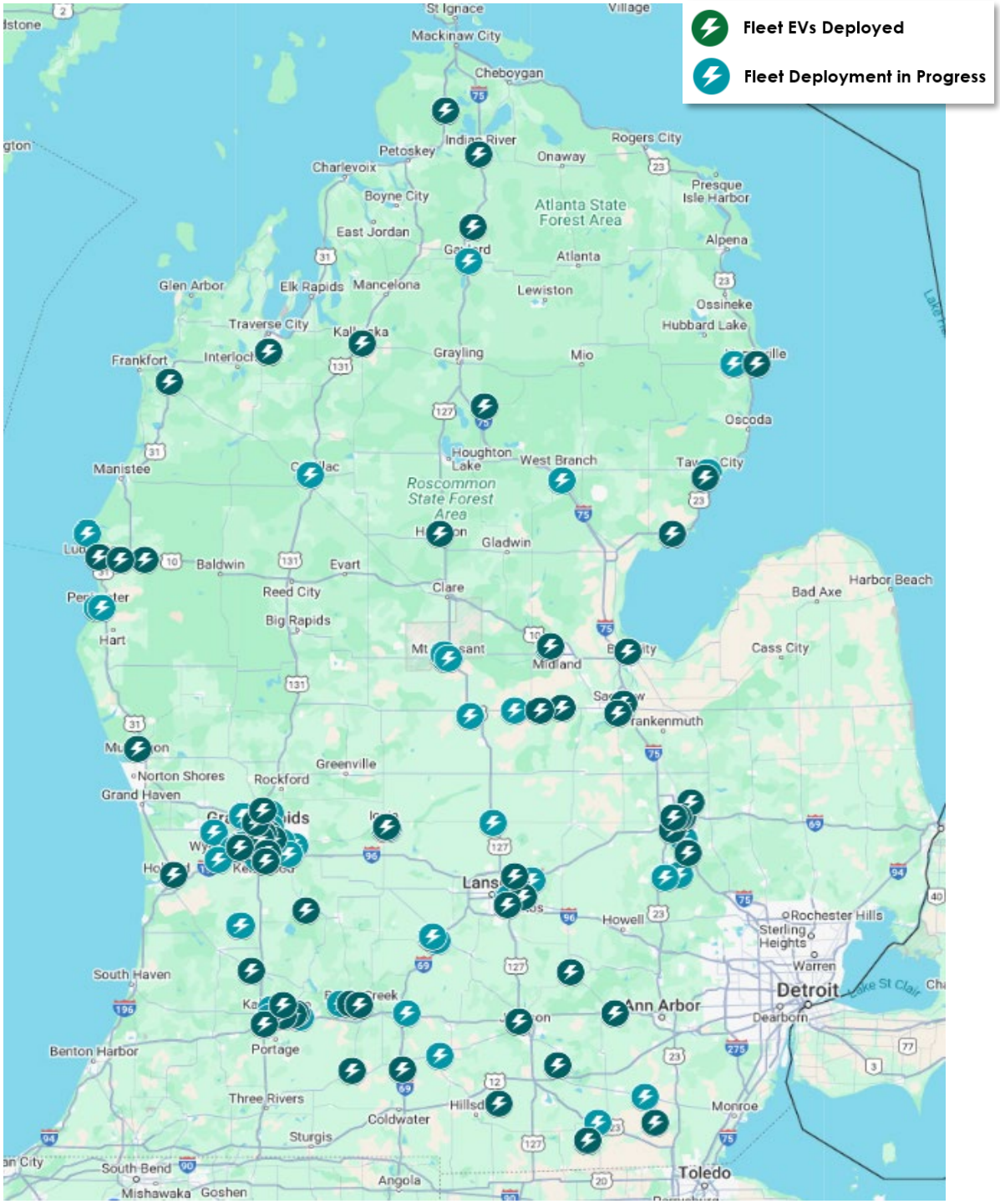


Figure 10 PowerMIFleet Customer Electrification Locations

Customer Education & Outreach

Through education and outreach efforts, the PowerMIDrive team was able to reach over 10,100 people. This includes 570 customers participating in our ride and drives, allowing them to experience driving electric and engage in program conversations regarding off-peak charging and TOU rates. Notably, 80% of the drivers experienced driving electric for the first time at our event.

PowerMIDrive team at 28th St. Metro Cruise

Between 2020 and 2024, the number of EVs in the Company's electric territory has grown dramatically, from approximately 8,800 EVs to nearly 40,000, which is a factor of 4.5 times. Given the rapidly growing state of EV market adoption, it is extremely important to identify segments of customers who are likely to already own an EV or purchase an EV as their next vehicle, and to get in front of the even larger number of customers intending to drive an EV in the future.

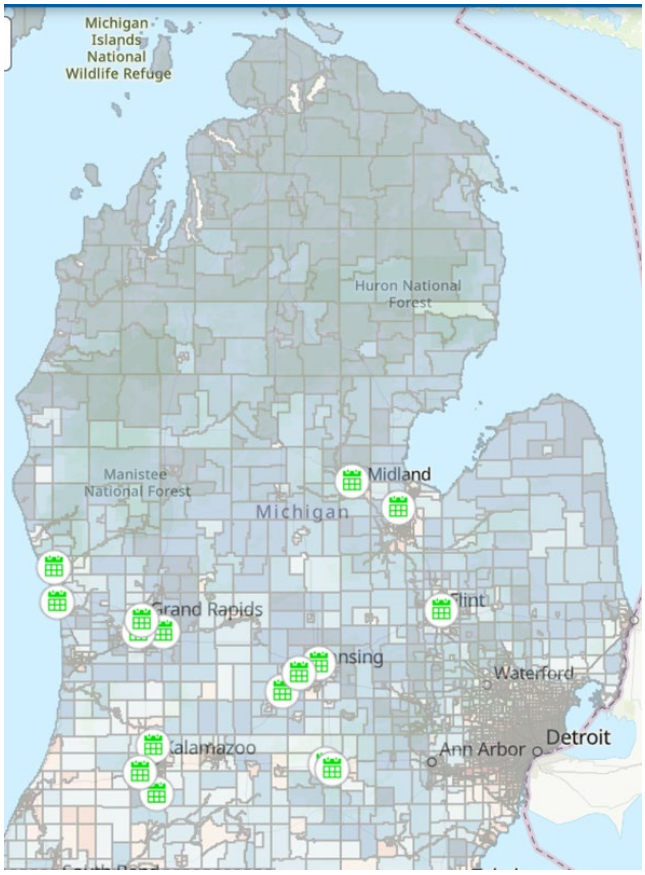


Figure 9: In-Person Customer Education & Outreach Locations Overlaid on MIEJ Screen Map

The number of direct customer contacts via phone calls and email communications has been high. A significant level of effort can be needed to assist customers with understanding their charging options, rate options, vehicle charging questions, and concerns about successful business models for public charging. This is why we have worked to continually enhance our website and outreach materials. In the last year, the program team made over 33,000 direct communications with EV customer contacts. This averages about 127 customer contacts per working day!

The level of specialized customer support has demonstrated that permanent staffing for EV customer specialists is a clear requirement for continued success. Our customer interactions also provide the team with direct insight into the challenges EV customers face regarding charging infrastructure, both at home and in public.

There is no substitute for getting in front of an engaged and interested audience, and Consumers Energy has actively sought such opportunities to educate customers about the benefits of pairing EVs with TOU rates, the expansion of public charging infrastructure, and EV charging etiquette. Over the last year,

The PowerMIDrive team hosted or attended 67 EV engagement events as presenter, panelist, or exhibitor, which is more than one per week. These events reached close to 4,000 participants, including many potential future EV drivers. Of these events, 8 were conducted within MIEJ (70+) and 3 in Justice 40 areas.

PowerMIDrive sponsored Clean Fuels Michigan's Disrupt event supporting EV charging start-ups

As shown in Figure 15, the program team organized and executed public L2 and DCFC charging station ribbon cutting ceremonies, car shows and ride and drives (e.g., Drive Electric Earth Day and National Drive Electric Week), EV101 presentations to both online and in-person, and EV driver social events.

The PowerMIDrive team at the Jackson Ride and Drive

We have found in-person events to be quite valuable in creating word of mouth campaigns for the program, earned media that helps reiterate program messaging, getting PowerMIDrive information into the hands of EV drivers and the EV curious, and often leading to additional speaking engagements for educational opportunities.

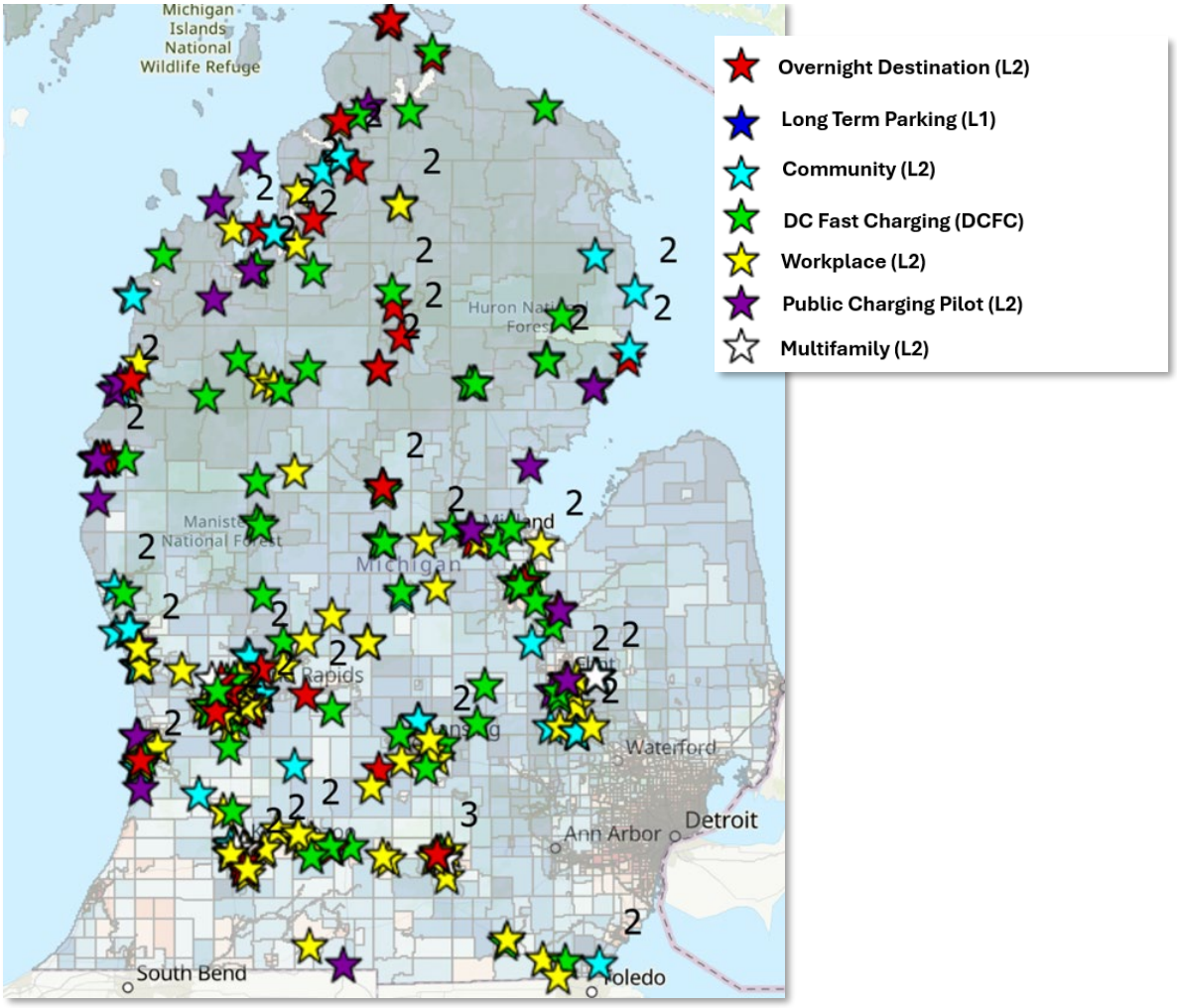
Customers get an overview of EVs before their ride and drive in Flint

Charging Up Underserved Communities

The PowerMIDrive and PowerMIFleet teams have also started tracking charging infrastructure rebates awarded within Justice 40 and MIEJ Screen areas of 70 and greater. The table and map below illustrate the results to date. We continue to actively engage with potential site hosts in these areas for rebate applications.

Site Host Category	Rebates in EJ40	Rebates in MIEJ 70+
Multifamily	**12**	**24**
Community Charging	**11**	**13**
Destination	**10**	**11**
Workplace	**15**	**41**
Public DCFC	**4**	**6**

Figure 12: EJ Rebates



TEP MANAGED CHARGING RESULTS

Charging Time Summary

A key strategy of our TEP customer programs is to maximize off-peak charging (residential and commercial) to benefit all customers via downward rate pressure and improved reliability. Optimized EV charging also directly supports our one-million EV by 2030 readiness in collaboration with Michigan's two million EV goal.

When the customer EV load management pilots initially began, it was projected that approximately 80% of charging would occur at home and 20% via public charging. The very first pilot also aimed to steer EV load to at least 70% off-peak charging. Initial pilot data tracked toward the 80/20 residential vs commercial projection but is now nearing 55/45 given the dramatic growth in demand for public charging. Furthermore, the TEP pilots not only achieved over 80% off-peak charging, but continued to optimize such that the total portfolio is now 89.6% off-peak!

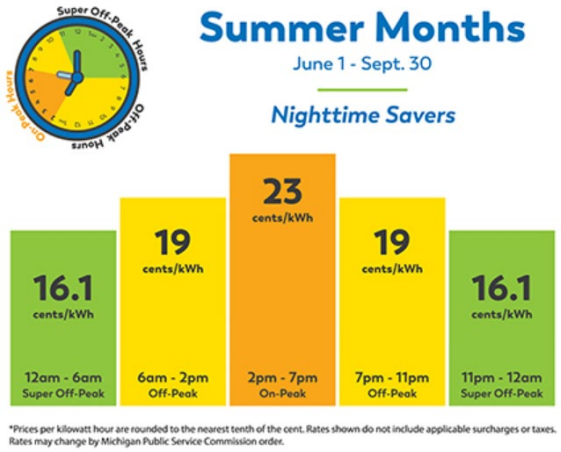
Per Figure 13, Consumers Energy is pleased to report that off-peak charging has continued despite the dramatic 42.8% year over year (YOY) load growth across all categories and is still achieving world-class results with 95.9% off-peak charging across all the permanent customer programs! However, the EV charging market continues to evolve and significant growth in commercial charging is occurring. YOY load growth in community, multifamily, destination, workplace and DCFC indicate that these remain important areas for the TEP going forward. The continued changes in the market are reflective of both increased miles driven by EV, and PowerMIFleet data which shows that many light duty EVs provide cost savings for fleets.

EV Customer Program Category	On-Peak 2PM-7PM	Off-Peak 7AM-2PM 7PM-11PM	Super Off-Peak 11PM-7AM & Weekends	Total Off-Peak by Category	Total kWh by Category	YOY Load Growth
Residential Single Family	*2.1%*	*6.6%*	*91.3%*	*97.9%*	*53.8%*	*8.7%*
Community Charging	*21.6%*	*33.8%*	*44.6%*	*78.4%*	*1.3%*	*26258.6%*
Multifamily	*18.3%*	*35.2%*	*46.5%*	*81.7%*	*0.3%*	*162.9%*
Total Residential	***2.6%***	***7.4%***	***90.0%***	***97.4%***	***55.3%***	***11.6%***
Destination L2+L1	*20.6%*	*36.3%*	*43.1%*	*79.4%*	*1.4%*	*69.8%*
Fleet & Workplace	*8.9%*	*40.8%*	*50.3%*	*91.1%*	*12.1%*	*64.5%*
DCFC Pilot	*24.5%*	*35.2%*	*40.3%*	*75.5%*	*31.1%*	*154.7%*
Total Commercial	***20.1%***	***36.8%***	***43.1%***	***79.9%***	***44.7%***	***118.7%***
TEP Programs	**4.1%**	**13.9%**	**82.0%**	**95.9%**	**68.9%**	**19.1%**
TEP Programs & DCFC Pilot	***10.4%***	***20.5%***	***69.0%***	***89.6%***	***100.0%***	***42.8%***

Figure 10: EV Charging per Category & Time Block
April 2024 to March 2025

Figure 13 above shows the percentage of charging that happens in different on-peak and off-peak time blocks, in addition to the percentage of charging per category. In the residential sector, single family charging continues to lead all categories, with 97.9% off-peak charging and 53.8% of the measurable EV load. Community charging, which launched in 2023 and remains a very small 1.3% of the total kWh, is growing more rapidly than any other category (26,258.6%!) indicating high demand for equitable charging access. Multifamily properties are also still a small percentage of the total at 0.3%, but experiencing strong YOY load growth of 162.9%. The program team is leaning in with continued outreach efforts for multifamily and community charging.

A multifamily charging installation with off-peak signage



Example of TOU rate informational materials

In the commercial space, the fleet and workplace programs are also performing well, with 91.1% off-peak charging, 12.1% of the total kWh, and 64.5% YOY load growth due to rapidly increasing EV adoption and the need for equitable charging access that workplaces can provide. Public L2 destination charging is still a small component of the total kWh at 1.4%, but growth of 69.8% YOY is indicating strong demand for this off-peak charging opportunity as more overnight and weekend EV travel locations are being enabled. Moreover, destination L2 infrastructure helps infill the still emerging but fast growing DCFC infrastructure to aid long distance travel and replicates the residential overnight charging experience that many customers are used to.

Our position remains that DCFC infrastructure is highly unlikely to benefit from managed charging other than through technological means (e.g., pairing with battery storage for energy arbitrage in the future as battery prices continue to fall and where make ready costs are higher than average) that do not impact the customer experience.

Customers needing to charge immediately to get to their location are unlikely to accept active charge management that increases their charging duration or be deterred by marginally higher costs when charging is a necessity to reach their destination.

However, fast charging is a key enabler of EV adoption in areas lacking infrastructure and off-peak utilization is still a respectable 75.5% given weekend travel to the many tourist destinations in Consumers Energy's electric territory. Given these factors, and the strong

utilization illustrated by 154.7% YOY load growth at host sites that have installed DCFCs, we believe it is prudent to incentivize one more round of fast charging rebates for communities lacking in infrastructure, which at this point are largely more rural areas with seasonal traffic. These communities will also benefit from attracting EV travelers coming from longer distances, such as Detroit, Toledo, and Chicago to Michigan's great destinations.

Fast charging sites in larger urban areas like Grand Rapids are likely to have a multitude of chargers

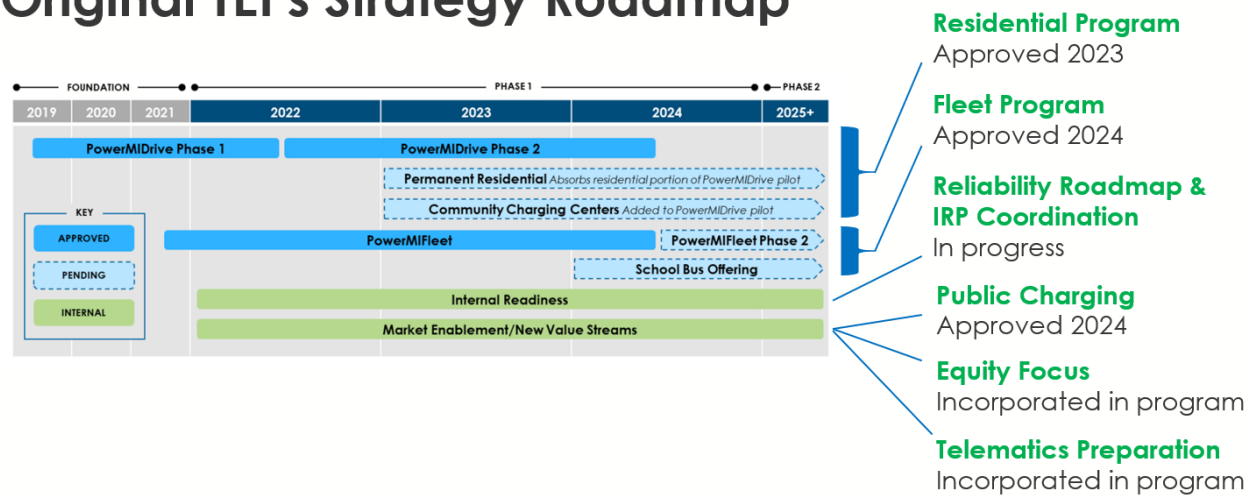
Fast charging sites up north and in more rural areas are more likely to only have two plugs, thereby challenging seasonal traffic and economic benefits to the community

TEP LOOKING FORWARD & STAKEHOLDER FEEDBACK

As an annual update, no changes to the Company TEP strategies are proposed in this report. With the goals from the first phase of the original TEP filing[5] complete, the Company continues to implement the present TEP to ensure:

1. Load growth at the right time to benefit reliability and cost for all customers.
2. Encourage EV adoption and prepare for the millions of EVs that will be on the road.
3. Utilize margin from EV load growth to pay for EV load management programs while also creating downward rate pressure for all customers.

Original TEPs Strategy Roadmap



The currently planned phases of the Company TEP logically expand upon existing programs and tactics. In early 2026 the Company will again engage stakeholders regarding potential changes to future phases of our TEP and file an updated TEP by July 2026.

Future TEP Roadmap

[5] See page 19 of Exhibit A-152 (JAM) in Case No. U-21224, which is page 2937 of 2942 in the PDF: 0688y000002IGMlAAM (site.com)

A fast-charging site in Saginaw supported by PowerMIDrive offers excellent lighting and a canopy

Explore our TEP programs at: ConsumersEnergy.com/EV

Power MI Drive | Power MI Fleet | Consumers Energy Count on Us®

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file transportation electrification plans and for other related matters.	)))))	Case No. U-21538

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Crystal L. Chacon, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on June 27, 2025, she served an electronic copy of **Consumers Energy Company's Transportation Electrification Plan Annual Progress Report 2025** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 27th day of June 2025.

Melissa K. Harris

Melissa K. Harris, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 06/11/2027
Acting in the County of Hillsdale

ATTACHMENT 1 TO CASE NO. U-21538

Party	Mailing Address	Email Address
Administrative Law Judge		
Hon. Sally L. Wallace	7109 W. Saginaw Hwy., 3rd Floor Lansing, MI 48917	wallaces2@michigan.gov
Consumers Energy Company		
Gary A. Gensch, Jr., Esq. Bret A. Totoraitis, Esq. Anne M. Uitvlugt, Esq. Spencer A. Sattler, Esq. Evan B. Keimach, Esq.	One Energy Plaza Jackson, MI 49201	gary.genschjr@cmsenergy.com bret.totoraitis@cmsenergy.com anne.uitvlugt@cmsenergy.com spencer.sattler@cmsenergy.com evan.keimach@cmsenergy.com mpsc.filings@cmsenergy.com
Michigan Public Service Commission Staff		
Nicholas Q. Taylor, Esq. Anna B. Stirling, Esq. Alena Clark, Esq. Daniel Sonneveldt, Esq. Lori Mayabb	Assistant Attorneys General Public Service Division 7109 W. Saginaw Hwy., 3rd Floor Lansing, MI 48917	taylorn10@michigan.gov stirlinga1@michigan.gov clarkA55@michigan.gov sonneveldtd@michigan.gov mayabbl@michigan.gov
Attorney General Dana Nessel		
Celeste R. Gill, Esq. Amanda Churchill	ENRA Division 525 West Ottawa Street 6th Floor Williams Building Post Office Box 30755 Lansing, MI 48909	gillc1@michigan.gov AG-ENRA-Spec-Lit@michigan.gov
Michigan Cable Telecommunications Association ("MCTA")		
Sean P. Gallagher, Esq.	Fraser Trebilcock Davis & Dunlap, P.C. 124 West Allegan Street Suite 1000 Lansing, MI 48933	sgallagher@fraserlawfirm.com
Michigan Environmental Council, Natural Resources Defense Council, Citizens Utility Board of Michigan, and Sierra Club		
Holly L. Hillyer, Esq. Christopher M. Bzdok, Esq. Tracy Jane Andrews, Esq. Natasha Fowles	Troposphere Legal 420 East Front Street Traverse City, MI 49686	holly@tropospherelegal.com chris@tropospherelegal.com tjandrews@tropospherelegal.com natasha@tropospherelegal.com
The Kroger Co.		
Kurt J. Boehm, Esq. Jody Kyler Cohn, Esq. Michael L. Kurtz, Esq.	Boehm, Kurtz & Lowry 36 East Seventh Street, Ste. 1510 Cincinnati, OH 45202	kboehm@bkllawfirm.com jkylercohn@bkllawfirm.com mkurtz@bkllawfirm.com
Michigan Municipal Association for Utility Issues		
Valerie J.M. Brader, Esq.	Rivenoak Law Group, P.C. 3331 W. Big Beaver Rd, Ste. 109 Troy, MI 48084	valerie@rivenoaklaw.com ecf@rivenoaklaw.com
Rick Bunch	Executive Director and Chairman Michigan Municipal Association for Utility Businesses 4989 Earhart Road Ann Arbor, MI 48105	rick@mi-maui.org
Ford Motor Company		
Valerie J.M. Brader, Esq.	Rivenoak Law Group, P.C. 3331 W. Big Beaver Rd, Ste. 109 Troy, MI 48084	valerie@rivenoaklaw.com ecf@rivenoaklaw.com

* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-21538

Energy Michigan, Foundry Association of Michigan, Michigan Energy Innovation Business Council, Institute for Energy Innovation, Advanced Energy United, Energy Michigan, Inc., and The Foundry Association of Michigan.		
Timothy J. Lundgren, Esq. Laura A. Chappelle, Esq. Justin K. Ooms, Esq.	Varnum LLP PO Box 352 Grand Rapids, MI 49501	tjlundgren@varnumlaw.com lachappelle@varnumlaw.com jkooms@varnumlaw.com
Michigan Energy Innovation Business Council and Advanced Energy United		
Dr. Laura S. Sherman	Michigan EIBC 115 W. Allegan, Ste. 710 Lansing, MI 48933	laura@mieibc.org
The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar		
Nicholas Wallace, Esq. Daniel Abrams, Esq. Alondra Estrada Carolyn Boyce	Environmental Law & Policy Center 35 East Wacker Drive, Suite 1600 Chicago, IL 60601	nwallace@elpc.org dabrams@elpc.org aestrada@elpc.org cboyce@elpc.org mpscdockets@elpc.org
Michigan Electric Transmission Company, LLC		
Richard J. Aaron, Esq. Olivia R.C.A. Flower, Esq. Hannah Buzolits, Esq. Courtney F. Kissel, Esq.	Dykema Gossett PLLC 201 Townsend Street, Suite 900 Lansing, MI 48933	raaron@dykema.com oflower@dykema.com HBuzolits@dykema.com ckissel@dykema.com mpscfilings@dykema.com
Urban Core Collective		
Amanda Urban, Esq. Mark Templeton, Esq. Jacob R. Schuhardt, Esq. Sam Heppell, Esq. Madison Wilson	Univ of Chicago Law School – Abrams Env Law Clinic 6020 South University Avenue Chicago, IL 60637	t-9aurba@lawclinic.uchicago.edu templeton@uchicago.edu jschuhardt@uchicago.edu heppell@uchicago.edu madisonswilson@uchicago.edu aelc_mpsc@lawclinic.uchicago.edu
Association of Businesses Advocating Tariff Equity		
Stephen A. Campbell, Esq. Michael J. Pattwell, Esq.	Clark Hill PLC 500 Woodward Avenue, Suite 3500 Detroit, MI 48226	scampbell@clarkhill.com mpattwell@clarkhill.com
Hemlock Semiconductor Operations LLC		
Jennifer Utter Heston, Esq.	Fraser Trebilcock Davis & Dunlap, P.C. 124 West Allegan Street Suite 1000 Lansing, MI 48933	jheston@fraserlawfirm.com
Great Lakes Renewable Energy Association		
Don L. Keskey, Esq. Brian W. Coyer, Esq.	University Office Place 333 Albert Avenue, Suite 425 East Lansing, MI 48823	donkeskey@publiclawresourcecenter.com bwcoyer@publiclawresourcecenter.com
Walmart, Inc.		
Melissa M. Horne, Esq.	Higgins, Cavanagh & Cooney, LLP 10 Dorrance Street, Suite 400 Providence, RI 02903	mhorne@hcc-law.com

* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-21538

American Federation of Labor and Congress of Industrial Organizations, Michigan State Utility Workers Council, Utility Workers Union of American, Local 223		
Benjamin L. King, Esq.	McKnight, Canzano, Smith, Radtke & Brault, P.C. 3950 W. 11 Mile Road Berkley, MI 48072	bking@michworkerlaw.com
DTE Electric Company		
Jon P. Christinidis, Esq.	One Energy Plaza, 1635 WCB Detroit, MI 48226	jon.christinidis@dteenergy.com
Michigan Electric and Gas Association		
Daniel Dundas, Esq.	7201 W. Saginaw Hwy., Ste. 305 Lansing, MI 48917	dan@megautilities.org

* Receives Confidential Materials

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21870

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Crystal L. Chacon, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on November 12, 2025, she served an electronic copy of **Consumers Energy Company's Official Exhibits** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 12th day of November, 2025.

Melissa K. Harris

Melissa K. Harris, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 06/11/2027
Acting in the County of Hillsdale

ATTACHMENT 1 TO CASE NO. U-21870

Party	Email Address
Administrative Law Judge	
Jonathan F. Thoits	thoitsj@michigan.gov
Counsel for Consumers Energy Company	
Gary A. Gensch, Jr., Esq. Bret A. Totoraitis, Esq. Anne M. Uitvlugt, Esq. Spencer A. Sattler, Esq. Evan B. Keimach, Esq. Mark R. Ruszkiewicz, Esq.	gary.genschjr@cmsenergy.com bret.totoraitis@cmsenergy.com anne.uitvlugt@cmsenergy.com spencer.sattler@cmsenergy.com evan.keimach@cmsenergy.com mark.ruszkiewicz@cmsenergy.com mpsc.filings@cmsenergy.com
Counsel for the Michigan Public Service Commission Staff	
*Amit B. Singh, Esq. *Michael J. Orris, Esq. *Adam M. Cozort, Esq. *Nicholas Q. Taylor, Esq. *Alena M. Clark, Esq. *Daniel E. Sonneveldt, Esq.	singha9@michigan.gov orrism@michigan.gov cozorta1@michigan.gov taylorn10@michigan.gov clarkA55@michigan.gov sonneveldtd@michigan.gov
Michigan Public Service Commission Staff	
*Mike Byrne *Bill Stosik *David Chislea *Bob Nichols *Nick Revere *Lori Mayabb	byrneM@michigan.gov stosikb@michigan.gov chislead@michigan.gov nicholsb1@michigan.gov reveren@michigan.gov mayabbl@michigan.gov
Counsel for Attorney General Dana Nessel	
*Lucas Wollenzien, Esq. *Celeste R. Gill, Esq. *Amanda Churchill	wollenzienl@michigan.gov gillc1@michigan.gov AG-ENRA-Spec-Lit@michigan.gov
Consultant for the Attorney General	
*Sebastian Coppola	sebcoppola@corplytics.com
Counsel for the Michigan Cable Telecommunications Association ("MCTA")	
Sean P. Gallagher, Esq. Jon Austin	sgallagher@fraserlawfirm.com jaustin@fraserlawfirm.com
Counsel for the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (collectively "MNSC")	
*Holly L. Hillyer, Esq. *Christopher M. Bzdok, Esq. *Tracy Jane Andrews, Esq. *Natasha Fowles *Tanya Stasio *Jordan Burt *Tyler Comings *Caroline Palmer *Rick Bunch *Julielyn Gibbons *Matt Bandyk *Sean Clark	holly@troposphere legal.com chris@troposphere legal.com tjandrews@troposphere legal.com natasha@troposphere legal.com tanya.stasio@aeclinic.org jordan.burt@aeclinic.org Tyler.comings@aeclinic.org cpalmer@synapse-energy.com rbunch@5lakesenergy.com jgibbons@5lakesenergy.com mbandyk@synapse-energy.com sean@troposphere legal.com

* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-21870

Counsel for the Citizens Utility Board of Michigan ("CUB")	
John Liskey, Esq.	john@liskeypllc.com
Counsel for The Kroger Co. ("Kroger")	
Kurt J. Boehm, Esq. Jody Kyler Cohn, Esq. Michael L. Kurtz, Esq.	kboehm@bkllawfirm.com jkylercohn@bkllawfirm.com mkurtz@bkllawfirm.com
Consultant for Kroger	
Justin Bieber	jbieber@energystrat.com
Counsel for Michigan Energy Innovation Business Council ("Michigan EIBC"), Institute for Energy Innovation ("IEI"), Advanced Energy United ("United"), Energy Michigan, Inc., and The Foundry Association of Michigan.	
*Timothy J. Lundgren, Esq. Laura A. Chappelle, Esq. *Justin K. Ooms, Esq.	tjlundgren@varnumlaw.com lachappelle@varnumlaw.com jkooms@varnumlaw.com
Counsel for The Ecology Center, The Environmental Law & Policy Center ("ELPC"), Union of Concerned Scientists ("USC"), and Vote Solar (Collectively referred to as "CEO")	
*Daniel Abrams, Esq. *Katie Duckworth, Esq. *Alondra Estrada *Katie Toolan	dabrams@elpc.org kduckworth@elpc.org aestrada@elpc.org ktoolan@elpc.org mpscdockets@elpc.org
Counsel for Michigan Electric Transmission Company, LLC ("METC")	
*Richard J. Aaron, Esq. *Olivia R.C.A. Flower, Esq. *Hannah Buzolits, Esq. *Courtney F. Kissel, Esq.	raaron@dykema.com oflower@dykema.com HBuzolits@dykema.com ckissel@dykema.com mpscfilings@dykema.com
Counsel for Urban Core Collective ("UCC")	
*Mark Templeton, Esq. *Jacob R. Schuhardt, Esq. *Emma Young *Alexandria Miskho *Heidi Peng *Willow Perlick *Aashney Shah	templeton@uchicago.edu jschuhardt@uchicago.edu eyoung28@uchicago.edu amiskho@uchicago.edu hhpeng@lawclinic.uchicago.edu willowperlick@lawclinic.uchicago.edu aashney@lawclinic.uchicago.edu aelc_mpsc@lawclinic.uchicago.ed
Counsel for the Association of Businesses Advocating Tariff Equity ("ABATE")	
*Stephen A. Campbell, Esq. *Michael J. Pattwell, Esq. *Benjamin J. Holwerda, Esq. Lauren Degnan	scampbell@clarkhill.com mpattwell@clarkhill.com bholwerda@clarkhill.com ldegnan@clarkhill.com
Consultants for ABATE	
*James Dauphinais *Jessica York *Christina Hildebrandt	jdauphinais@consultbai.com jyork@consultbai.com childrebrandt@consultbai.com
Counsel for Hemlock Semiconductor Operations LLC ("HSC") and Solar Technology LLC	
*Jennifer Utter Heston, Esq.	jheston@potomaclaw.com
Counsel for Great Lakes Renewable Energy Association ("GLREA")	
Don L. Keskey, Esq.	donkeskey@publiclawresourcecenter.com
Counsel for Walmart, Inc. ("Walmart")	
Melissa M. Horne, Esq.	mhorne@hcc-law.com

* Receives Confidential Materials