

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
UPPER PENINSULA POWER COMPANY))
for authority to increase retail electric rates)
for the generation and distribution of)
electricity and other relief)

MPSC Case No. U-21555

Direct Testimony
And Exhibits
of
Sebastian Coppola

On behalf of
Attorney General Dana Nessel

July 19, 2024

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1 **I. INTRODUCTION**

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

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

5 **Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.**

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

18 **Q. WHAT EXPERIENCE DO YOU HAVE WITH ELECTRIC UTILITIES?**

1 A. I have performed rate case analyses and filed testimony in several electric general rate
2 cases addressing issues on revenue requirement, sales level determination, operation and
3 maintenance expenses, capital expenditures, cost allocations, cost of capital, cost of
4 service and rate design, and various cost tracking mechanisms. In addition, I have
5 performed analysis of power costs and filed testimony in power supply cost recovery cases,
6 including reconciliation of annual power supply costs.

7 In my position as Senior Vice President of Finance at MCN, I also had responsibility for
8 project financing of independent power generation plants in which MCN was an owner.
9 In this regard, I was intricately involved and became knowledgeable of PURPA qualified
10 cogeneration plants in Michigan and other states. In addition, I was involved in negotiating
11 the development and financing of power generation and electricity distribution plants in
12 other countries, such as India.

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

16 A. In addition to having filed testimony in the Company's prior general rate case (Case No.
17 U-21286) and in some of the Company's other proceedings before the Commission, below
18 is a partial list of the most recent regulatory cases in which I have participated:

19 ○ Filed testimony on behalf of the Michigan Attorney General in Michigan Gas
20 Utilities Corporation (MGUC) 2024 gas rate case U-21540 on several issues,
21 including operation and maintenance expenses, capital expenditures, cost of
22 capital, and other items.

- 1 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy
2 Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- 3 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas
4 Company (DTE Gas) 2024 gas rate case U-21291 on several issues, including
5 sales, operation and maintenance expenses, capital expenditures, cost of capital,
6 and other items.
- 7 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-
8 2023 GCR reconciliation in case No. U-21065.
- 9 ○ Filed testimony on behalf of the Michigan Attorney General in Consumers
10 Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales,
11 operation and maintenance expenses, capital expenditures, cost of capital, and
12 other items.
- 13 ○ Filed testimony on behalf of the Michigan Attorney General in DTM Michigan
14 Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in
15 case No. U-21525.
- 16 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
17 Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
- 18 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2022-
19 2023 GCR reconciliation case No. U-21067.
- 20 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2022
21 PSCR reconciliation in case No. U-21049.
- 22 ○ Filed testimony on behalf of the Michigan Attorney General in the Indian
23 Michigan Power Company's 2023 electric rate case U-21461 on several issues,
24 including sales, operation and maintenance expenses, capital expenditures, cost
25 of capital, and other items.
- 26 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2023-
27 2024 GCR plan in case No. U-21271.
- 28 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2023-
29 2024 GCR plan in case No. U-21269.
- 30 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2023
31 electric rate case U-21389 on several issues, including operation and
32 maintenance expenses, capital expenditures, cost of capital, and other items.
- 33 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO 2023-
34 2024 GCR plan in case No. U-21277.
- 35 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Electric
36 Company (DTEE) 2023 rate case U-21297 on several issues, including

- 1 operation and maintenance expenses, capital expenditures, cost of capital, and
2 other items.
- 3 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-
4 2024 GCR plan in case No. U-21273.
 - 5 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas
6 rate case U-21308 on several issues, including sales revenues, operation and
7 maintenance expenses, capital expenditures, cost of capital, and other items.
 - 8 ○ Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-
9 2022 GCR plan reconciliation case No. U-20817.
 - 10 ○ Filed testimony on behalf of the Michigan Attorney General in DTEE 2021
11 PSCR plan reconciliation case No. U-20827.
 - 12 ○ Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-
13 2022 GCR plan reconciliation case No. U-20819.
 - 14 ○ Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula
15 Power Company 2022 general rate case No. U-21286.
 - 16 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-
17 2022 GCR plan reconciliation case No. U-20823.
 - 18 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2022-
19 2023 GCR plan case No. U-21062.
 - 20 ○ Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-
21 2023 GCR plan case No. U-21070.
 - 22 ○ Filed testimony on behalf of the Michigan Attorney General in CECo 2022
23 electric rate case U-21224 on several issues, including operation and maintenance
24 expenses, capital expenditures, cost of capital, and other items.
 - 25 ○ Filed testimony on behalf of the Public Counsel Division of Washington Attorney
26 General in the Avista 2022 electric and gas rate cases on several issues, including
27 operation and maintenance expenses, capital expenditures, and other items.

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

29 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

30 A. I have been asked by the Michigan Department of Attorney General (AG) to perform an
31 independent analysis of Upper Peninsula Power Company's ("UPPCO" or the

1 “Company”) Rate Case filing in Case No. U-21555. This testimony presents a report of
2 that analysis with related recommendations.

3 **Q. WHAT TOPICS ARE YOU ADDRESSING IN YOUR TESTIMONY?**

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

- 5 1. The level of proposed rate base and capital expenditures
- 6 2. Adjustments to the Company’s proposed working capital
- 7 3. Adjustments to depreciation expense
- 8 4. The Company’s cost of capital
- 9 5. The level of operations and maintenance expenses

10 The absence of a discussion of other matters in my testimony should not be taken as an
11 indication that I agree with those aspects of UPPCO’s rate case filing. The narrow focus
12 of my testimony is, instead, a consequence of focusing on certain issues within the
13 available resources.

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

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

- 17 1. Exhibit AG-1 DR Response – Generation Projects Not Started/Premature
- 18 2. Exhibit AG-2 DR Response – Distribution Projects Adjustments
- 19 3. Exhibit AG-3 DR Response – SHARP Cap Ex Project Adjustments
- 20 4. Exhibit AG-4 DR Response – EV Charging Program Grants
- 21 5. Exhibit AG-5 DR Response – Strategic Undergrounding Program
- 22 6. Exhibit AG-6 DR Response – Substation Project Adjustments

- 1 7. Exhibit AG-7 DR Response – New Service Center Location
- 2 8. Exhibit AG-8 DR Response – New Service Center Alternative HVAC
- 3 9. Exhibit AG-9 DR Response – Facility Projects Cost Adjustments
- 4 10. Exhibit AG-10 AG Adjustments to Capex and Depreciation Expense
- 5 11. Exhibit AG-11 DR Response – AMI Meters Installation
- 6 12. Exhibit AG-12 DR Response – Working Capital Items
- 7 13. Exhibit AG-13 Overall Cost of Capital
- 8 14. Exhibit AG-14 Cost of Common Equity
- 9 15. Exhibit AG-15 Cost of Common Equity-DCF
- 10 16. Exhibit AG-16 Cost of Common Equity-CAPM
- 11 17. Exhibit AG-17 Cost of Common Equity-Risk Premium
- 12 18. Exhibit AG-18 ROE Decisions by Regulatory Commissions
- 13 19. Exhibit AG-19 Midwest Peer Group ROE Decisions
- 14 20. Exhibit AG-20 Peer Group Selection Screening
- 15 21. Exhibit AG-21 Market to Book Ratios
- 16 22. Exhibit AG-22 Pro-Forma Cash Flow Coverage Ratios
- 17 23. Exhibit AG-23 DR Response - DBRS Report October 20, 2023
- 18 24. Exhibit AG-24 DR Response - DBRS Report October 20, 2023
- 19 25. Exhibit AG-25 February and May 2024 Blue Chip Report
- 20 26. Exhibit AG-26 DR Response – Zepp Article
- 21 27. Exhibit AG-27 DR Response - Values Line Report on Market Volatility vs. Risk
- 22 28. Exhibit AG-28 DR Response – UPPCO Alleged Risks and Limited Mechanisms
- 23 29. Exhibit AG-29 O&M Adjustments Summary
- 24 30. Exhibit AG-30 O&M Inflation Wag Adjustment
- 25 31. Exhibit AG-31 O&M Adjustments - Distribution Line Maintenance Expenses
- 26 32. Exhibit AG-32 Injuries and Damages Expense Adjustment
- 27 33. Exhibit AG-33 Uncollectible Accounts Expense
- 28 34. Exhibit AG-34 DR Response – O&M Historical Expenses
- 29 35. Exhibit AG-35 DR Response – Variable Pay & Incentive Compensation
- 30 36. Exhibit AG-36 ATC Services Billings

1 37. Exhibit AG-37 DR Response – A&G Historical Expenses

2 38. Exhibit AG-38 AG Revenue Deficiency Calculation

3 **II. SUMMARY CONCLUSIONS & RECOMMENDATIONS**

4 **Q. PLEASE PROVIDE A SUMMARY OF YOUR CONCLUSIONS AND ANY**
5 **ADJUSTMENTS TO THE COMPANY’S REVENUE DEFICIENCY**
6 **CALCULATION BEFORE YOU ADDRESS EACH TOPIC IN DETAIL.**

7 A. The Company filed for a jurisdictional rate increase of \$16.9 million.¹ The rate increase
8 represents an overall increase in rates of 16%.

9 Based on my analysis, I have identified several cost disallowances to the Company’s
10 proposed cost levels and capital projects totaling to a lower revenue requirement of \$9.9
11 million, which I recommend that the Commission adopt. As a result of these adjustments,
12 I have determined that the Company has a revenue deficiency of \$7.0 million. This revenue
13 deficiency would be a 6.7% increase in customer rates. My conclusions and related
14 adjustments are summarized below:

15 1. I recommend a reduction in capital expenditures of \$23.1 million and a
16 reduction of \$24.5 million to rate base for the test year, including a reduction
17 in working capital of \$6.5 million. This reduces the Company’s revenue
18 deficiency by \$2.1 million.

19 2. I recommend that the Commission adopt a lower cost of capital rate of 6.57%,
20 a capital structure with 50% equity capital and a return on common equity of

¹ Exhibit A-6, Schedule A1, shows total revenue deficiency of \$25.6 million and jurisdictional revenue deficiency of \$25.3 million.

1 9.85%. These recommendations reduce the Company's revenue deficiency
2 by \$2.3 million.

3 3. I recommend a lower level of Operations and Maintenance expenses for the
4 test year. This reduces the Company's revenue deficiency by \$4.5 million.

5 4. I recommend a lower amount of depreciation expense of \$1.1 million
6 pertaining to the lower capital expenditures and additions to plant discussed
7 above. This adjustment reduces revenue deficiency by the same amount.

8 The remainder of my testimony provides further details and support to these summary
9 conclusions and recommendations.

10 **III. CAPITAL EXPENDITURES AND RATE BASE**

11 **Q. WHAT ARE YOUR FINDINGS IN ANALYZING THE COMPANY'S PROPOSED**
12 **LEVEL OF CAPITAL EXPENDITURES ADDED TO RATE BASE?**

13 A. As shown in Exhibit A-7, Schedule B5, UPPCO incurred approximately \$28.3 million of
14 capital expenditures in 2023. For 2024 and 2025, the Company has forecasted total capital
15 expenditures of \$41.8 million and \$33.1 million, respectively. The proposed capital
16 expenditures for 2024 and 2025 represent a significant ramp up from historical capital
17 expenditures.

18 **Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE**
19 **CAPITAL EXPENDITURES HAVE NOT BEEN ADEQUATELY SUPPORTED OR**
20 **JUSTIFIED AND SHOULD BE REMOVED?**

1 A. Yes. I have analyzed the Company's forecasted capital expenditures by major department
2 or area and I have identified expenditures that were not adequately supported or justified
3 and should be removed. In my analysis, I will often use recent historical actual costs,
4 where applicable, to determine the reasonableness of the Company's forecasted costs.
5 This approach normalizes variability in costs from year to year and reflects the most recent
6 costs actually experienced by the Company.

7 To provide some allowance for future increases in costs, I applied an annual inflation
8 escalator of 2.7% for 2024 and 2.4% for 2025 in forecasting future capital expenditures.
9 These are the same Consumer Price Index (CPI)-based inflation factors utilized by the
10 Company in forecasting various future expenditures without additional projected wage
11 increases. As discussed in more detail later in the O&M section of my testimony, I do not
12 agree with the methodology used by the Company to include projected wage increases as
13 an addition to forecasted CPI inflation rates.

14 **A. Power Generation Projects**

15 As shown on page 1 of Exhibit A-7 (VES-1), Schedule B5.1, The Company forecasted
16 capital expenditures for Generation projects of \$3.9 million for 2024 and \$4.7 million for
17 2025. In contrast, the Company incurred capital expenditures of \$2.1 million in 2023. In
18 Exhibit A-20 (VES-2), the Company forecasted 15 capital projects larger than \$100,000
19 for 2024 and 2025 for a total cost of \$3.5 million and \$4.4 million, respectively. The
20 following table from the exhibit provides further details.

UPPCO Generation CAPEX			
Generation Projects > \$100K for 2024-25			
Line		2024	2025
1	3000.03.02 Bond Falls Left Embankment Groin Filter	364,938	
2	3000.03.02 Victoria Access Road Resurfacing & Drainage	260,670	
3	3000.03.02 McClure Surge Tank Roof Replacement	208,536	
4	3000.05.05 Victoria - Controls upgrade	1,109,672	
5	3000.05.07 Prickett Unit 2 Overhaul/Rewind	990,546	
6	3000.05.07 Hoist Unit 3 - Penstock Valve Replacement		182,000
7	3000.05.07 McClure Unit 1 Overhaul/Rewind		832,000
8	3000.05.08 Annual New Equipment/Generation Tools	208,536	208,000
9	3000.07.01 Bond Falls Inundation Mapping		101,982
10	3000.07.02 Hoist, McClure, Silver Lake Dam Concrete Refurbishment (2021 Part 12)	103,955	
11	3000.07.02 Bond Falls Canal Rip Rap	104,268	
12	3000.07.02 Prickett Intake Refurbishment	104,268	
13	3000.07.02 Victoria Gate Hoist Replacement		624,000
14	3000.07.02 Hoist Penstock Interior Lining Replacement		572,000
15	3000.08.01 McClure Substation Refurbishment		1,842,204
16	Total Generation Capital	3,455,389	4,362,186

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Beginning on page 4 of his direct testimony, Mr. Virgil Schlorke provides some explanations for each of the projects. In discovery, the Attorney General asked the Company to provide additional information for each of the projects, including what work had already been done on the project as of mid-June 2024, what work remained to be done and when, project cost bid information from contractors, and comparative costs between bids and initially estimated project costs. For the following projects, the information provided by the Company shows that either no work has yet been done on the project or the project is progressing on a longer timeline than previously forecasted, which makes completion of the project by the end of the projected test year unlikely to be in-service, and used and useful. The affected projects with the line number reference from Exhibit A-20 are:

1 **Victoria Access Road Resurfacing and Drainage (line 2)** – Reason: No work has been
2 completed as of June 15, 2024. The project has been moved out to the 3rd quarter of 2025.²
3 Recommendation: Project is still in the early phase of development and premature to
4 include in rate base in this rate case. The Commission should remove \$260,670 of capex
5 forecasted for 2024.

6 **Annual New Equipment and Generation Tools (line 8)** – Reason: The Company’s
7 forecasted amounts for 2024 and 2025 at \$208,536 and \$208,000 significantly exceed the
8 three-year average amount of \$92,415.³ The removal of several projects for 2024 and
9 2025, as I propose in this section of my testimony, makes it even less likely that any
10 increases in new equipment and tools will be necessary. Recommendation: The inflation
11 adjusted 3-year average amount for 2024 is \$94,910 or \$113,626 less than Company
12 forecast. For 2025, the inflation adjusted amount is \$97,188, which is \$110,812 less than
13 the Company’s forecast. The Commission should remove \$113,626 and \$110,812 of
14 capital expenditures from 2024 and 2025, respectively.

15 **Bond Falls Inundation Mapping (line 9)** - Reason: No work has been completed as of
16 June 15, 2024. The project has been moved out to 2025.⁴ Recommendation: The project
17 is still in the early phase of development and premature to include in rate base in this rate
18 case. The Commission should remove \$101,982 of capex forecasted for 2025.

² Exhibit AG-1 includes DR 3-AG-UPPCO-3.58.

³ Id. includes DR 3-AG-UPPCO-3.62.

⁴ Id. includes DR 3-AG-UPPCO-3.61.

1 **Bond Falls Canal Rip Rap (line 11)** - Reason: No work has been completed as of June
2 15, 2024. The project has been moved out to the 3rd quarter of 2025.⁵ Recommendation:
3 The project still in the early phase of development and premature to include in rate base in
4 this rate case. The Commission should remove \$104,268 of capex forecasted for 2024.

5 **Victoria Gate Hoist Replacement** – Reason: Although design and engineering work has
6 been completed, 2025 forecasted expenditures of \$624,000 consist of potential equipment
7 purchases. No FERC approval for the project has yet been received and no work bids have
8 been awarded. Construction is now forecasted for 2026.⁶ In-service date is not until 2026.
9 It is premature to include capex in rate base in this rate case when the project will not be
10 used and useful until 2026, which is past the end of the 2025 projected test year.
11 Recommendation: The Commission should remove \$624,000 of capital expenditures for
12 2025.

13 **Hoist Penstock Interior Lining Replacement** – The Company is currently working
14 through the contractor bidding process with awards scheduled for 3rd quarter 2024.
15 Forecasted construction is expected to begin in the 3rd quarter of 2025.⁷ The project is on
16 a timeline that makes it uncertain and unlikely the facilities will be in service in the
17 projected test year. It is premature to include capex in rate base when the project will not

⁵ Id.

⁶ Id.

⁷ Id.

1 likely be used and useful in the 2025 projected test year. Recommendation: The
2 Commission should remove \$572,000 of capital expenditures for 2025.

3 **McClure Substation Refurbishment** – Reason: Only site planning and layout have been
4 completed. There is no indications of design and engineering have been completed as of
5 July 3, 2024. It appears that project design and engineering will occur in the 2nd quarter of
6 2025. Project contractor bidding and construction should be completed after design and
7 engineering in the 2nd half of 2025.⁸ Project is on a timeline that makes it uncertain and
8 unlikely the facilities will be in service in the projected test year. It is premature to include
9 capex in rate base when the project will likely not be used and useful in the 2025 projected
10 test year. Recommendation: The Commission should remove \$1,842,204 of capital
11 expenditures for 2025.

12 The total amount of capital expenditures for the seven projects is \$478,564 for 2024 and
13 \$3,250,998 for the 2025. I recommend that the Commission remove these amounts for the
14 Company's forecasted capital expenditures for those years.

15 **B. Electric Distribution Projects**

16 As shown in Exhibit A-7 (JRR/DJG-1), Schedule B5.4, the Company forecasted capital
17 expenditures for Distribution facilities of \$15.9 million for 2024 and \$16.1 million for
18 2025. In comparison, the Company incurred capital expenditures of \$15.2 million in 2023.

⁸ Id.

1 In Exhibit A-21 (JRR-3), the Company forecasted 40 capital projects larger than \$50,000
2 for 2024 and 2025 for a total cost of \$15.9 million and \$16.1 million, respectively. Most
3 of the projects are to convert overhead electrical lines to underground locations (OH-UG)
4 with other projects and routine capital programs making up the remainder. The OH-UG
5 conversions are being done under the System Hardening & Reliability Projects (SHARP)
6 capital spending category.

7 Beginning on page 44 of his direct testimony, Company witness Jay Ringler discusses the
8 SHARP projects and what they entail. For other projects in Exhibit A-21, Mr. Ringler
9 provides little to no specific supporting information to justify the forecasted capital
10 spending for 2024 and 2025. In discovery, the AG asked the Company to provide
11 historical spending levels with the number of work units completed and forecasted to be
12 completed in 2024 and 2025 to better assess the reasonableness of the forecasted spending
13 in certain capital program categories. For the SHARP projects, the Attorney General asked
14 the Company to provide information on the current phase of development of each project
15 and the timeline for the next phase in order to determine the status and maturity of
16 development of the project. Additionally, the Company was asked to identify the number
17 of power outages experienced for each powerline slated for replacement.

18 In response, the Company provided some of the information requested, but often could not
19 quantify the number of work units to be installed or completed in 2024 and 2025 that would

1 substantiate the forecasted capital expenditures.⁹ This is a major shortcoming because the
2 forecasted spending level lacks adequate support. From various discovery responses
3 associated with the projects discussed below, it appears that the Company often based
4 forecasted capital expenditures on recent historical spending levels. Given the lack of
5 specific forecasted work units, in my proposed adjustments discussed below, I will also
6 rely on average historical spending primarily over the most recent three years from 2021
7 to 2023. In response to discovery request 3-AG-UPPCO-3.87, the Company provided
8 capital expenditures for specific recurring programs for each year 2021 to 2023.¹⁰

9 **Q. WHAT SPECIFIC CAPITAL SPENDING ADJUSTMENTS IN THE**
10 **DISTRIBUTION AREA DO YOU PROPOSE?**

11 A. Using as a reference the projects listed in Exhibit A-21 with specific line number
12 identification, I propose adjustments to forecasted capital expenditures for the following
13 projects with the related reason and recommendation:

14 **UPPCO Engineering, Designers and Clerks (line 2)** – The Company forecasted costs
15 for engineering and design work for capital projects of \$1,400,000 for 2024 and
16 \$1,450,000 for 2025. These amounts are significantly higher than the amounts spent in
17 the three prior historical years, which average to \$1,241,110.¹¹ The Company did not

⁹ Exhibit AG-2 includes DR 3-AG-UPPCO-3.87 with related attachments.

¹⁰ Id.

¹¹ Id.

1 provide any explanation or support for the increase in spending in direct testimony or in
2 response to discovery. Therefore, the increase remains unsupported.

3 To forecast a reasonable amount of capital expenditures for 2024, I increased the historical
4 average amount by the 2.7% inflation factor to arrive at the forecasted amount of
5 \$1,275,000. Similarly, for 2025, I applied an additional inflation factor of 2.4% to
6 determine a forecasted amount of \$1,306,000. These amounts are \$125,000 and \$144,000
7 lower than the amounts forecasted by the Company for 2024 and 2025, respectively. I
8 recommend that the Commission remove those amounts from the Company's forecasted
9 capital expenditures for those years.

10 **Sys. Hardening, OH to URD conv, and Copper Peplc (line 4)** - For this program, the
11 Company forecasted capital expenditures of \$350,000 for 2024 and \$356,000 for 2025.
12 The historical information shows that there was almost no capital spending for this
13 program in 2021 and 2022, and \$203,516 for 2023.¹² No work units, explanation, or other
14 supporting data were provided by the Company to justify the forecasted spending for 2024
15 and 2025 for this capital program. Instead of using a three-year average, which would
16 yield a very low amount, in this situation I used the 2023 actual spending to forecast a
17 reasonable capital spending level of 2024 and 2025 after adjusting for inflation. The result
18 is forecasted capital expenditures of \$209,000 for 2024 and \$214,000 for 2025. These
19 amounts are \$141,000 and \$142,000 lower than the Company's forecasts for 2024 and

¹² Id.

1 2025, respectively. I recommend that the Commission remove those amounts from the
2 Company's forecasted capital expenditures.

3 **Distribution Line Transformers (line 31)** - The Company forecasted capital expenditures
4 of \$4,200,000 for 2024 and \$4,000,000 for 2025 for this program. The historical
5 information shows that that in the past three years capital expenditures have ranged from
6 \$1.3 million to \$3.5 million with an average amount of \$2,294,983.¹³ No work units,
7 explanation or other supporting data was provided by the Company for the forecasted
8 spending in 2024 and 2025 for this line item. Using the historical average spending
9 amount of \$2,294,983 and adjusting for inflation results in forecasted capital expenditures
10 of \$2,357,000 for 2024 and \$2,414,000 for 2025. These amounts are \$1,843,000 and
11 \$1,586,000 lower than the Company's forecasts for 2024 and 2025, respectively. I
12 recommend that the Commission remove those amounts from the Company's forecasted
13 capital expenditures.

14 **Distribution Reclosers (line 32)** - The Company forecasted capital expenditures of
15 \$200,000 for 2024 and \$200,000 for 2025 for this program. The historical information
16 shows that that in the past three years capital expenditures have ranged from \$17,032 to
17 \$140,970 with an average amount of \$83,975.¹⁴ No work units, explanation, or other
18 supporting data were provided by the Company for the forecasted spending in 2024 and
19 2025 for this line item. Using the historical average spending amount of \$83,975 and

¹³ Id.

¹⁴ Id.

1 adjusting for inflation results in forecasted capital expenditures of \$86,000 for 2024 and
2 \$88,000 for 2025. These amounts are \$114,000 and \$112,000 lower than the Company's
3 forecasts for 2024 and 2025, respectively. I recommend that the Commission remove
4 those amounts from the Company's forecasted capital expenditures.

5 **Distribution Regulators (line 33)** - For this program, the Company forecasted capital
6 expenditures of \$150,000 for 2024 and also for 2025. The historical information shows
7 that that in the past three years capital expenditures have ranged from zero to \$76,265.
8 Using only the two years in 2021 and 2022 when the Company incurred capital
9 expenditures in this program results in an average amount of \$48,963.¹⁵ No work units,
10 explanation, or other supporting data were provided by the Company for the forecasted
11 spending in 2024 and 2025 for this line item. Using the historical average spending
12 amount of \$48,963 and adjusting it for inflation results in forecasted capital expenditures
13 of \$50,000 for 2024 and \$51,000 for 2025. These amounts are \$100,000 and \$99,000
14 lower than the Company's forecasts for 2024 and 2025, respectively. I recommend that
15 the Commission remove those amounts from the Company's forecasted capital
16 expenditures.

17 **SHARP Projects (lines 5-29)** – In addition to Exhibit A-21, the Company provided
18 Exhibit A-31, which shows only the SHARP projects proposed for 2024 and 2025. In
19 discovery, the Attorney General asked the Company to provide the current phase of

¹⁵ Id.

1 development for each project and also identify the next phase of development with the
2 completion date. The Company was also asked to provide the actual amount spent on
3 SHARP projects for each year 2021 to 2023.

4 The information provided in response to the discovery request shows that two projects in
5 2024 are either in the conceptual phase of development or represent a placeholder amount
6 for potential failures not yet known.¹⁶ Therefore, the placeholder amount of \$200,000
7 does not pertain to any specific projects and it is unknown on which future projects the
8 amount will be spent. In other recent rate cases, the Commission has rejected the inclusion
9 of placeholder amounts in rate base and should do the same in this case.

10 With regard to the Sys. Hardening, OH to URD Conv, and Copper Replc project, which is
11 in the conceptual design phase, this project was addressed above under line 4 of Exhibit
12 A-21 where I recommended disallowance of the proposed capital expenditures for 2024.

13 For 2025, of the 13 projects listed in Exhibit A-31, eleven are in the conceptual design
14 phase and only two were in the engineering design phase as of mid-June 2024. The eleven
15 projects comprise \$4.7 million, or nearly 75%, of the total capital expenditures of \$6.3
16 million forecasted for 2025. Given the early phase of development, it is likely that some
17 of the eleven projects may not proceed to construction as forecasted. Normally, I would
18 propose all projects at the conceptual design phase be removed from inclusion in rate base.

¹⁶ Exhibit AG-3 includes DR 03-AG-UPPCO-3.95 with related attachments.

1 However, during the past three years, the Company has completed several SHARP projects
2 each year with capital expenditures ranging from \$3.1 million to \$4.6 million and
3 averaging at \$3,898,000.¹⁷ Using this average amount and adjusting it for inflation results
4 in a forecasted capital spending amount of \$4,099,000 for the total program for 2025.
5 Giving the Company the benefit of the doubt that it will spend at least this amount during
6 2025, the difference from the \$6,366,000 forecast in Exhibit A-31 is \$2,237,000.

7 Therefore, I recommend that the Commission remove \$200,000 from the Company’s
8 forecasted capital expenditures for 2024 and \$2,237,000 from 2025 for the SHARP
9 program.

10 **Charge UP Michigan Grant EVC Installations (line 38)** – For 2024, the Company
11 included capital expenditures of \$580,000 for a grant program to accelerate the installation
12 of charging stations for electric vehicles (EV) in the Upper Peninsula. In the Commission
13 order dated April 14, 2022 in Case No. U-21137, the Company received approval to
14 establish a new tariff (C-1) for EV charging, make grant contributions, and defer the grant
15 costs for later review and recovery in a rate case. In December 19, 2023, the Company
16 filed a report with the Commission identifying six EV charging stations. However, no
17 grants or contribution amounts were reported.¹⁸ In direct testimony and response to
18 discovery, the Company did not identify any amounts paid or that will be paid in 2024 in

¹⁷ Id.

¹⁸ Exhibit AG-4 includes DR 3-AG-UPPCO-3.88e and a copy of the December 2023 report filed in Case No. U-21137.

1 support of the \$580,000 that it seeks to recover in rate base in this rate case. Therefore,
2 the \$580,000 remains unsupported and should be removed from rate base in this rate case.

3 **Q. ARE THERE OTHER CONCERNS YOU HAVE WITH THE SHARP PROJECTS**
4 **AND THE UNDERGROUNDING OF OVERHEAD LINES PERFORMED BY THE**
5 **COMPANY?**

6 A. Yes. Beginning on page 30 of his direct testimony, Mr. Ringler discusses the Company's
7 program and practice of converting overhead electric lines to underground lines. In the
8 settlement agreement in Case U-21286, the Company agreed to provide a report of its
9 practices regarding undergrounding overhead lines and, among other items, to identify
10 how the projects' costs and benefits compare to tree trimming and grid hardening.
11 Although in his testimony, Mr. Ringer discusses certain aspects of the undergrounding
12 program and related costs, there is not a detailed and clear analysis that the undergrounding
13 projects completed in prior years and forecasted to be completed in 2024 and 2025 have
14 been or will be the best and most economical solution.

15 In discovery, the AG asked the Company to provide more information about the evaluation
16 process used to select overhead line candidates for undergrounding and to provide actual
17 examples along with the analytical and financial models used in order to assess and
18 validate the Company's decision-making criteria. The responses provided by the
19 Company to several questions and requests show that the Company uses generic, high-
20 level, cost criteria and other factors to make an initial determination of which projects are

1 candidates for undergrounding. The high-level average costs used do not take into
2 consideration specific terrain, challenges, and costs of the individual project. No examples
3 of specific project cost calculations using the Company's decision model were provided
4 in response to discovery requests.

5 Therefore, it appears that the Company will proceed with a project on the assumption that
6 the targeted project is a good candidate for undergrounding until it encounters difficulties
7 with an underground installation or discovers that the project will entail higher costs than
8 initially assumed. Even after several questions and requests for clarification, the actual
9 undergrounding decision process remains still very foggy. The Company has made it clear
10 that it does not use a financial model or a present value financial analysis to determine that
11 proceeding with an undergrounding project is the best or most economical alternative.
12 Exhibit AG-5 includes responses to several questions posed to the Company on this matter.

13 The concern that arises from the Company's approach is that the Company is not making
14 sound economic decisions versus other alternatives that could equally reduce power
15 outages and improve service reliability at a lower cost. For example, of the 29 System
16 Hardening and Reliability Projects (SHARP) discussed on pages 44 through 57 of Mr.
17 Ringler's testimony nearly all of them entail undergrounding overhead lines. This is a
18 clear indication that the Company project analysis and evaluation is biased toward
19 undergrounding overhead lines versus other solutions.

20 **Q. WHAT IS YOUR RECOMMENDATION?**

1 A. I recommend that the Commission direct the Company to quickly put in place a more
 2 robust analytical tool that takes into consideration the specific economic attributes of each
 3 of the targeted undergrounding projects versus other alternatives, using sound present
 4 value financial discipline over the life of the project. This tool should be developed in
 5 collaboration with Staff and other interested stakeholders and used to evaluate all
 6 undergrounding projects targeted for 2025 and future years.

7 **C. Substations**

8 As shown in Exhibit A-7 (JRR/DJG-1), Schedule B5.4, the Company forecasted capital
 9 expenditures for Substation projects of \$4.2 million for 2024 and \$4.5 million for 2025.
 10 In comparison, the Company incurred capital expenditures of \$4.5 million in 2023. In
 11 Exhibit A-19 (DJG-2), the Company forecasted 18 capital projects larger than \$100,000
 12 for 2024 and 2025 for a total cost of \$4.0 million and \$4.4 million, respectively. The
 13 following table from the exhibit provides further details.

UPPCO Substation CAPEX			
Substation Projects > \$100K for 2024-25			
Line		2024	2025
1	2000.05.03 Ishpeming Substation Tools	104,268	
2	2000.05.06 Atlantic RTU and R&C Upgrade	479,633	
3	2000.05.06 Project Engineering for subsequent years	104,268	171,600
4	2000.05.06 Chatham Control Building replace		384,800
5	2000.05.08 Nine 219A Voltage Regulator Upgrades	236,688	
6	2000.05.08 MTU Bank 1 Replace Aging Transformer (UHV-0695)	960,308	
7	2000.05.08 MTU Bank 1 Transformer High Side Protection Equipment	208,536	
8	2000.05.08 Delta Bank 1 Transformer High Side Protection Equipment	260,670	208,000
9	2000.05.08 Delta RTU and R&C upgrade (Replace 4 351R's)	417,072	312,000
10	2000.05.08 M38 - 138/12.5KV XFMR and High side protection		592,800
11	2000.05.08 2025 Transformer Progress Payments M38	422,285	421,200
12	2000.05.08 2025 Transformer Progress Payments Munising	422,285	421,200
13	2000.05.08 2025 Transformer Progress Payments Chatham Transformers	422,285	421,200
14	2000.05.08 Keweenaw Sub High Side Protection		260,000
15	2000.05.08 Ontonagon Bank 2 (UHV-1220) Replace Aging Transformer - MFG 1967 - New 5/7 MVA		312,000
16	2000.05.08 Replace vipers, MTU, Seney, Bayview with OCR's		312,000
17	2000.05.08 Chatham Replace Aging Transformer (UHV-1733) - Mfg 1964 - New 5/7 MVA		384,800
18	2000.05.08 328A Voltage Regulators 100wk lead time		208,000
19	Total Substation Capital	4,038,300	4,409,600

1 Beginning on page 3 of his direct testimony, Mr. Daniel Gervae provides some
2 explanations for each of the projects. In discovery, the Attorney General asked the
3 Company to provide additional information for each of the projects, including what work
4 had already been done on the project as of mid-June 2024, what work remained to be done
5 and when, project cost bid information from contractors, and comparative costs between
6 bids and initially estimated project costs. For the following projects, the information
7 provided by the Company shows that either no work has yet been done on the project or
8 the project is progressing on a longer timeline than previously forecasted, which makes
9 completion of the project unlikely by the end of the projected test year to be in-service,
10 and used and useful. The affected projects with the respective line number reference in
11 Exhibit A-19 are:

12 **Chatham Control Building replace (line 4)** – Reason: No work has been done on this
13 project as of June 15, 2024. Some work on the project may begin in the 4th quarter of
14 2024. No contractor work bids have yet been sent out.¹⁹ Recommendation: The project
15 is still in the early phase of development and premature to include in rate base in this rate
16 case. The Commission should remove \$384,800 of capex forecasted for 2025.

17 **Nine 219A Voltage Regulator Upgrades (line 5)** – Reason: The \$236,688 in capital
18 expenditures forecasted for 2024 is only for the purchase of the regulators needed for the
19 project, which are now scheduled to be received and paid for in January 2025.²⁰ No other

¹⁹ Exhibit AG-6 includes DR 3-AG-UPPCO-3.64.

²⁰ Id. includes DR 3-AG-UPPCO-3.65.

1 work has been done on this project and none is scheduled until the middle of 2025.

2 Recommendation: The Commission should move the \$236,688 from 2024 to 2025.

3 **2025 Transformer Progress Payments M38 (line 11);**

4 **2025 Transformer Progress Payments Munising (line 12);**

5 **2025 Transformer Progress Payments Chatham Transformers (line 13);**

6 Forecasted capital expenditures for each project are the same at \$422,285 for 2024 and
7 \$421,200 for 2025. In response to discovery, the Company confirmed that the
8 expenditures are to purchase transformers which are not expected to be received until
9 August 2025.²¹ The Company did not provide a payment date for the purchases and it is
10 assumed that payment would occur subsequent to delivery and inspection. Only
11 preliminary design work has been done for the projects utilizing those transformers. Given
12 the long lead time, it is uncertain when actual delivery of the transformers will occur. No
13 design and engineering work has yet been completed for the projects. The projects are
14 still in the early phase of development and not likely to be completed and be used and
15 useful by the end of the 2025 projected test year. It is premature to include the forecasted
16 costs in rate base in this rate case. Therefore, I recommend that the Commission remove
17 \$1,266,855 for 2024 and \$1,263,600 for 2025 for the three projects from the Company's
18 forecasted capital expenditures.

19 **Keweenaw Sub High Side Protection (line 14);**

20 **Ontonagon Bank 2 Replace Aging Transformer - New 5/7 MVA (line 15);**

21 **Replace Vipers, MTU, Seney, Bayview with OCR's (line 16);**

22 **Chatham Replace Aging Transformer (UHV-1733) - New 5/7 MVA (line 17);**

²¹ Id. includes DR 3-AG-UPPCO-3.39.

UPPCO Facility CAPEX
Facility Projects > \$100K for 2024-2025

Line		2024	2025
1	4000.03 Hancock / New Houghton Service Center	9,644,790	
2	4000.03 Truck Garage Improvements	563,047	
3	4000.03 Yard/Parking Lot/Material Storage Improvements	698,801	
4	4000.03 Service Center HVAC Improvements	218,963	
5	4000.03 IRV Service Center & Garage Upgrades		343,200
6	4000.03 ONT Service Center & Garage Upgrades		504,400
7	4000.03 ISH Service Center & Garage Upgrades		192,400
8	4000.03 MUN Service Center & Garage Upgrades		520,000
1	9	11,125,601	1,560,000

2 The first project in the table above is for the construction of the new Quincy Hill Service
3 Center. In his direct testimony, Jason Brynick states that the existing Houghton Service
4 Center has reached the end of its useful life and would requires considerable costly
5 upgrades while still only providing limited use and having potential environmental
6 hazards. The new Service Center will be located approximately 4 miles from the current
7 location near an abandoned copper mine. In response to discovery, the Company reported
8 that it performed a Phase 1 environmental assessment of the new location and did not
9 uncover any environmental issues that need to be addressed prior to start of construction.
10 The Company will begin construction soon and expects a mid-2025 completion date.²³

11 The Company included capital expenditures of \$9,644,790 in 2024 in anticipation of
12 completing construction in 2024. It now appears that construction has been delayed and
13 the new service center will not become operational until mid-2025. The Company also

²³ Exhibit AG-7 includes DR 03-AG-UPPCO-3.101, 3.102, and 3.109.

1 obtained an appraisal of the value of the property of the current service center. The
2 appraised value is \$1.16 million.²⁴

3 **Q. WHAT IS YOUR RECOMMENDATION ABOUT THE FORECASTED**
4 **EXPENDITURES FOR THE NEW SERVICE CENTER TO BE INCLUDED IN**
5 **RATE BASE IN THIS RATE CASE?**

6 A. As stated above, the Company included capital expenditures of \$9,644,790 for 2024 for
7 the new service center in its rate case filing. It is now apparent that completion of the
8 project will lapse into the middle of 2025. As a result, it is reasonable to expect that at
9 least half the forecasted capital expenditures or \$4,822,790 will be incurred in 2025 instead
10 of 2024. Furthermore, once vacated, the Company should realize the appraised value of
11 \$1.16 million from the sale of the existing service center property, which the Company
12 will credit to general plant and rate base. Therefore, for 2025, the incremental amount
13 included in rate base should be \$3,662,790 (\$4,822,790 - \$1,160,000). I recommend that
14 the Commission reduce the Company’s forecasted capital expenditures for 2024 by
15 \$4,822,790 and increase 2025 capital expenditures by \$3,662,790.

16 **Q. WHAT IS YOUR ASSESSMENT OF THE NEW SERVICE CENTER UPDATED**
17 **COSTS AND THE ALTERNATIVE HVAC SYSTEM INSTALLATION?**

²⁴ Jason Brynick direct testimony at page 11.

1 A. On page 10 of his direct testimony, Mr. Brynick states that the Company was looking at
2 an alternative Heating Ventilating and Air Conditioning (HVAC) system for the new
3 service center building and garage. Mr. Brynick proposed that the cost of the alternative
4 HVAC system should be charged to Account 183 with any cost overruns of 10% or greater
5 subject to a prudency review. In discovery, the Attorney General asked the Company to
6 provide more details and justification for the alternative HVAC system and to explain why
7 only certain cost overruns should be subject to prudency review instead of the entire new
8 service center project.

9 In response, the Company seemed to reverse its position about conducting only partial
10 prudency review on the project and also referenced the updated information on the overall
11 project and the alternative HVAC system provided in response to DR 4-Staff-UPPCO-
12 4.9.²⁵ The information provided in this updated Staff DR shows that the cost of the base
13 project has increased to \$10,144,330 from the \$9,644,790 included in the rate case filing
14 in Exhibit A-18. In addition, the Company now proposes that the project cost be further
15 increased by \$1,269,489 in order to install a hybrid HVAC system using natural gas
16 heating in the garage and electric heating in the rest of the new Quincy Service Center.²⁶

17 The Company did not provide a cost/benefit analysis to justify the incremental capital
18 expenditures for the hybrid HVAC system. Instead, it provides operating cost data that
19 show the hybrid system will cost 64% more to operate annually. Clearly, the proposed

²⁵ Exhibit AG-8 includes DR 3-AG-UPPCO-3.103.

²⁶ Id. includes DR 4-Staff-UPPCO-4.9 Updated with related attachments.

1 hybrid system is not economically justified both in terms of higher capital costs and annual
2 operating expenses. The Company seems to want to justify the hybrid HVAC system
3 simply to avoid burning fossil fuels on the assumption that the electricity used to power
4 the electric HVAC system is generated entirely by non-fossil fuels.

5 **Q. WHAT IS YOUR RECOMMENDATION?**

6 A. I recommend that the Commission reject the incremental capital expenditures of
7 \$1,269,484 for the hybrid HVAC system. I also recommend that the Commission exclude
8 from this rate case any incremental costs for the new service center above the \$9,644,790
9 included in Exhibit A-18. In the next rate case, after the new service center project is
10 completed, Staff and intervenors can perform a full prudence review of the project and
11 recommend any adjustments to rate base for the final cost of the project after excluding
12 the incremental cost of the hybrid HVAC system, which is clearly not economically
13 justified.

14 **Q. ARE YOU PROPOSING OTHER ADJUSTMENTS FOR FACILITY CAPITAL**
15 **EXPENDITURES IN THIS RATE CASE?**

16 A. Yes. Excluding the new service center capital expenditures, Exhibit A-18 shows
17 \$1,480,811 for 3 projects in 2024 and \$1,560,000 for 4 projects in 2025. These amounts
18 represent a major escalation in spending for general facilities in contrast with capital
19 spending in the most recent historical three years. After removing capital expenditures

1 related to the new service center, the Company incurred capital spending in 2021 through
2 2023 ranging from approximately \$118,000 to \$689,000 and averaging at \$402,272.²⁷

3 In response to discovery, the Company identified some of the improvements it wishes to
4 make to facilities at various locations. Several of the projects entail replacing and
5 upgrading existing lighting and making improvements to supposedly create operational
6 cost efficiencies.²⁸ However, the Company did not quantify any cost savings from the
7 aforementioned operating cost efficiencies. It is perplexing to understand why, suddenly,
8 capital expenditures in this area need to triple in 2024 and 2025 from recent historical
9 levels of approximately \$400,000. Furthermore, the general statements about energy
10 efficiency and potential cost savings sound hollow when not quantified.

11 The Company can still undertake some of the needed improvements on a more gradual
12 basis by working within the historical spending level adjusted for inflation. Therefore, I
13 recommend that the 2024 capital expenditures for these miscellaneous facilities
14 improvements be set at \$413,000 after escalating the 3-year average spending amount by
15 inflation. Similarly for 2025, the inflation adjusted amount is \$423,000. These amounts
16 are \$1,068,000 and \$1,137,000 lower than the amounts forecasted by the Company for
17 2024 and 2025, respectively. I recommend that the Commission remove those amounts
18 from the Company forecasted capital expenditures.

²⁷ Exhibit AG-9 includes DR 3-AG-UPPCO-3.106 and related attachment.

²⁸ Id.

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E. Information Technology Capital Projects

As shown in Exhibit A-7, Schedule B5.6, the Company forecasted capital expenditures for Information Technology (IT) projects of \$4.7 million for 2024 and \$4.2 million for 2025. In comparison, the Company had IT capital expenditures of \$3.1 million in 2023. Exhibit A-22 shows the 16 projects and programs that make up the forecasted IT capital expenditures for 2024 and 2025. For four of the largest listed projects and programs, the capital expenditures have not been adequately supported or justified and those amounts should be removed from rate base in this rate case. The four projects are:

ERP/SAP Data Warehousing – On page 28 of his direct testimony Mr. Nicholas Kates discusses the components of the 2025 capital expenditures of \$832,000 forecasted for the ERP/SAP system on line 8 of Exhibit A-22. One of the components is \$520,000 for the implementation of the SAP data warehouse. Mr. Kates states that UPPCO seeks to better leverage the significant data in SAP for the purpose of better predicting customer and operational needs to continually improve customer service and operational performance. No other information or supporting data and analysis were provided. It is not clear how warehousing data without related functionality will achieve the stated objectives, which means potentially additional capital expenditures to build those functions. Although improving customer service and operational performance are noble goals, the Company needs to make a more compelling case that the benefits, financial and otherwise, justify the proposed capital expenditures. The Company has not made a convincing case that the \$520,000 proposed for this project is justified. Therefore, I recommend that the

1 Commission remove this amount from the Company’s forecasted capital expenditures for
2 2025.

3 **Itron IEE Upgraded & QRS Reporting and 150 Replacement CGR for AMI (EOS**
4 **12/30/2027)** – On lines 9 and 10 of Exhibit A-22, the Company forecasted \$1,564,020 for
5 2024 and \$1,820,000 for 2025 pertaining to upgrade and features for Advanced Metering
6 Infrastructure (AMI). Beginning on page 29 of his direct testimony, Mr. Kates states that
7 this capital spending is for maintaining and upgrading the AMI network and includes cost
8 for both equipment and software upgrades. He further explains that the current version of
9 the AMI data collection and translation application has reached the end of its useful life
10 and requires upgrades, particularly for data security and the communication network.

11 The Company request for a total of \$3.4 million in system upgrades and new equipment,
12 along with the statement that the AMI software has reached the end of its useful life, is
13 perplexing. The Company recently completed the installation of AMI meters and related
14 software and communication equipment less than three years ago in 2021.²⁹ It is
15 inconceivable that after such a short period, the software and some of the equipment has
16 reached its useful life and needs to be upgraded in 2024 and 2025. The Company has not
17 provided sufficient evidence to justify its request for \$3.4 million. The lack of adequate
18 evidence as to why and when that the identified upgrades are necessary, particularly so
19 soon after completion of the installation of the AMI network, makes it impossible to accept

²⁹ Exhibit AG-11 includes DR 4-StaffHH-UPPCO-4.1.

1 the proposed capital expenditures. Therefore, I recommend that the Commission remove
2 the forecasted capital expenditures of \$1,564,020 and \$1,820,000 for 2024 and 2025,
3 respectively, from inclusion in rate base in this rate case.

4 **Customer Billing and Payment Improvements** – On line 11 of Exhibit A-22, the
5 Company included \$307,590 of capital expenditures for Customer Billing and Payment
6 Improvements. On pages 31 and 32 of his direct testimony, Mr. Kates states that the
7 forecasted expenditures are for system changes to implement proactive messaging to
8 customers outside of billing statements through consented push notifications using email,
9 text messages, and voice alerts. In his brief testimony on this matter, Mr. Kates does not
10 explain what deficiencies exist with current customer communication and notification
11 channels or what is the compelling need to implement new channels of communication.

12 No evidence has been presented that customers are largely dissatisfied with current
13 communications or that they desire to be notified through email, text messages, or frequent
14 telephone calls. In other words, the Company’s proposal lacks sufficient evidence of a
15 compelling need to justify the proposed capital spending. Therefore, I recommend that
16 the Commission remove the amount of \$307,590 from the Company forecasted capital
17 expenditures for 2024.

18 **F. Capital Expenditures - Summary**

19 **Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING THE LEVEL**
20 **OF CAPITAL EXPENDITURES?**

1 A. The chart below summarizes my proposed reductions in capital expenditures in those areas
2 where the level of capital expenditures presented by the Company is excessive or not
3 adequately justified.

Summary of AG Disallowed Capital Expenditures	
	Amount (000)
Power Generation	\$ 3,730
Distribution	\$ 7,419
Substations	\$ 4,392
Facilities	\$ 3,365
Information Technology	\$ 4,212
Total	\$ 23,118

4

5 Based on my analysis and the information presented in my testimony above, I recommend
6 that the Commission reduce the Company's proposed capital expenditures by \$23.1
7 million and reduce average rate base by \$24.5 million, including a working capital
8 adjustment of \$6.5 million, as shown in Exhibit AG-10. The resulting effect of the lower
9 rate base from the reduction in capital expenditures is a reduction in the revenue deficiency
10 of \$2.1 million.

11

IV. Working Capital

12 **Q. THE COMPANY HAS PROPOSED \$90.0 MILLION OF WORKING CAPITAL IN**
13 **THIS CASE.³⁰ DO YOU AGREE WITH THIS LEVEL OF WORKING CAPITAL?**

³⁰ See Exhibit A-7 (NLW-22), Schedule B4.

1 A. No. I recommend two changes in the working capital level, which total to \$6.5 million
2 and reduce the amount of working capital for the projected test year to \$83.5 million from
3 the Company’s forecasted amount of \$90.0 million.

4 The first change to working capital reduces the amount of Cash and Bank Balances by
5 \$5.7 million from the Company’s projected test year amount of \$9.5 million, as discussed
6 further below.

7 The second change increases Accounts Payable by \$0.8 million, which reduces working
8 capital by the same amount. In discovery, the Attorney General asked the Company to
9 explain the decrease in the Accounts Payable balance between 2023 and the projected test
10 year. In response, the Company stated that they had inadvertently omitted the “GR/IR
11 clearing account balance” and that Accounts Payable should be higher by \$0.8 million.³¹
12 Therefore, I included this correction to working capital.

13 **Q. PLEASE EXPLAIN FURTHER YOUR RECOMMENDED CHANGE TO**
14 **WORKING CAPITAL RELATED TO CASH AND BANK BALANCES.**

15 A. In discovery, the Attorney General asked the Company about the increase of \$5.7 million
16 in Cash and Bank Balances over the historical 2023 balance of \$3.8 million to \$9.5 million
17 for the projected test year.³² In part (a) of the response, the Company stated that the

³¹ Exhibit AG-12 includes DR 2-AG-UPPCO-2.28.

³² Exhibit A-2 (NLW-6), Schedule B4, shows the historical 2023 cash balance of \$3.8 million. Exhibit A-7, Schedule B4, line 18 shows the projected test year Cash Balance of \$9.5 million,

1 increase was driven by increases in accrued interest and owner's equity. In the final
2 sentence of part (b) of the response, the Company stated that there was a calculation error
3 on the original workbook, but supposedly, the error did not affect the revenue requirement
4 in this case.³³

5 The Company's response is perplexing on multiple levels. First, accrued interest is a
6 routine liability reflecting quarterly payments of interest. The Company has not provided
7 any evidence that it needs to set aside any additional cash to pay any higher interest costs
8 in the projected test year than it did in the historical period.

9 Second, with regard to owner's equity, the term does not explain any specific reasons. If
10 the Company was trying to convey that it expects to receive a large infusion of equity
11 capital from its parent company during the projected test year and would have excess cash
12 on hand, the excess cash should be used to pay down short-term debt, which at the end of
13 historical year was rather large at \$45 million.

14 Third, the Company stated in its discovery response that it had made a calculation error in
15 the workbook supporting its rate case filing. If there was an error in the calculation of the
16 cash balance, it would result in a higher working capital balance, which increases rate base
17 and ultimately the revenue requirement calculated in the filed rate case. However,
18 irrespective of whether an error had occurred, the amount of Cash and Bank Balances

³³ Exhibit AG-12 includes DR 2-AG-UPPCO-2.31. In this discovery response, the Company noted that the increase the Attorney General inquired about was not Prepayments but was Cash and Bank Balances.

1 included in the projected test year is excessive relative to the historical year and not
2 supported by any compelling evidence.

3 In summary, the Company has not made a convincing case that the amount of Cash and
4 Bank Balances for the projected test year should be set at \$9.5 million, or \$5.7 million
5 above historical amount of \$3.8 million. The historical amount is an adequate and
6 reasonable level of cash balance that the Company has actually experienced. Therefore, I
7 recommend the Commission adopt the historical cash balance of \$3.8 million for the
8 projected test year and remove the \$5.7 million unsupported excess from the working
9 capital balance included by the Company in this rate case.

10 In total, the Commission should reduce the Company's projected working capital balance
11 by \$6.5 million to take into account the two items discussed above.

12 **V. Cost of Capital and Capital Structure**

13 **A. Capital Structure**

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

16 A. I recommend that the capital structure shown on page 1 of Exhibit AG-13 be used in this
17 case. The first three lines show the projected long-term debt and common equity capital
18 of the Company, which represents the permanent capital structure for the test year ending
19 December 2025. The capital balances in this exhibit reflect the amounts shown in

1 Company Exhibit A-9 (NEK-6), Schedule D1, with an adjustment to rebalance the capital
2 structure. The long-term debt component in Exhibit AG-13 has been increased by \$5.1
3 million and the common equity component has been reduced by the same amount. The
4 result is a capital structure with 50% of common equity and 50% of long-term debt.

5 **Q. WHY DID YOU INCREASE LONG TERM DEBT BY \$5.1 MILLION AND**
6 **OFFSET THIS CHANGE WITH LOWER COMMON EQUITY?**

7 A. The Company proposed a permanent capital structure with a common equity component
8 of 51.5%. Although this level of common equity is below the Company self-imposed
9 historical test year equity level of 54.0%³⁴, it is higher than the Company's commitment
10 in a previous rate case (Case No. U-20995) to rebalance its capital structure.

11 Additionally, there are other factors that suggest a lower common equity level is
12 appropriate. These factors include: (1) the Commission's position in recent years that a
13 balanced capital structure of equal portions of debt and equity capital is appropriate in the
14 absence of evidence suggesting otherwise; (2) the Company's ability to shoulder a greater
15 debt load while maintaining its credit rating; (3) the use of significant debt leverage by
16 UPPCO's parent Company Upper Peninsula Power Holding Company (UPPHC) to fund
17 its equity investment in UPPCO; and (4) the fact that the common equity ratio of the peer

³⁴ Exhibit A-4 (NEK-1), Schedule D1, page 1.

1 group, used to assess the cost of common equity in this case, is approximately 47.7%.³⁵

2 Each of these factors is discussed below.

3 **Q. SUMMARIZE THE RATIONALE THAT THE COMPANY HAS PUT FORTH**
4 **FOR ITS PROPOSED 51.5% COMMON EQUITY RATIO IN THIS CASE.**

5 A. UPPCO has not provided any sound rationale for the proposed 51.50% equity ratio.
6 Starting on page 12 of his direct testimony, Company Chief Financial Officer Nicholas
7 Kates simply notes that the 51.5% / 48.5% mix of common equity and long-term debt is
8 “...directly aligned with the Commission order approving the settlement in case No. U-
9 21286...” and provides no further reasoning for the proposed capital structure. There is
10 no discussion about rating agency or debt covenant requirements that require a 51.50
11 equity ratio. Instead, he points to the testimony of Company witness Thompson, the cost
12 of equity witness, for an additional discussion on the proposed 51.5% common equity
13 ratio.

14 **Q. WHAT INFORMATION DOES MR. THOMPSON PRESENT IN HIS ATTEMPT**
15 **TO SUPPORT OF A 51.5% COMMON EQUITY RATIO?**

16 A. On pages 66 to 69 of his direct testimony and Exhibit A-52 (JST-10), Mr. Thompson
17 provides conflicting and unreliable information to support the proposed 51.50% equity
18 ratio. First, he argues that the capital structure of a company reflects the financial risk

³⁵ Exhibit AG-16 shows that the peer group equity ratio for each peer company and the average for the group, which is 47.7%.

1 level that debt and equity investors face when lending capital to the company and making
2 an equity investment. He correctly points to the average equity ratio of approximately
3 45% of his Utility peer group, which he uses to calculate the cost of equity capital. As
4 further discussed later in my testimony, this is the proper equity ratio to compare and to
5 use in setting the Company's equity ratio because it reflects the financial risk that equity
6 investors face for the return on equity capital in which they have invested. Any other
7 equity ratio is simply disconnected from the financial risk/reward that investors take into
8 consideration.

9 Second, Mr. Thompson veers off on a tangent contradicting his first argument by pointing
10 to the equity ratios of the operating companies within some of the peer group utilities to
11 argue that those equity ratios are more determinative of the equity ratio that the
12 Commission should set for the Company. This is a contradictory argument to the first
13 argument of the financial risk profile of the peer group used to calculate the cost of equity
14 for the Company. To calculate a proper cost of common equity the capital structure must
15 reflect the financial risk that equity investors take in investing in the utility. Thus, the
16 return on equity for the peer group reflects the 45% equity ratio of the publicly traded
17 companies that make up the peer group and not the capital structure of the underlying
18 operating companies that are not publicly traded companies and where management has
19 ample discretion to set an equity ratio it prefers.

20 Third, assuming for sake of argument that the operating companies' equity ratios were
21 superior, the ratios presented by Mr. Thompson in Exhibit A-52 do not reflect in all cases

1 the equity ratios approved by regulatory commissions. The source of the information
2 provided in the exhibit appears to be financial reports filed by the subsidiary companies
3 with the Security and Exchange Commission (SEC) instead of decisions by regulatory
4 commissions. For example, on page 2 of the exhibit, witness Thompson shows the Allete
5 operating company Minnesota Power with a 59.7% common equity ratio. However,
6 according to an SEC filing, the most recent common equity ratio approved by regulators
7 for Minnesota Power was 52.5%.³⁶ Similarly, witness Thompson's Exhibit A-52 shows
8 common equity ratios of 59% for United Illuminating, 50.0% for Rochester Gas & Electric
9 (RGE) and 50.8% for New York State Electric & Gas (NYSEG) but regulatory
10 commissions have assigned common equity ratios are 50% for United Illuminating and
11 48% for both RGE and NYSEG.³⁷

12 The 52.5% average developed by witness Thompson in his Exhibit A-52 is in part a
13 product of many high ratios which are not proven by the witness to be representative of
14 what regulators have utilized to set rates.

15 Therefore, the information provided by the Company in Exhibit A-52 is not only
16 contradictory but also unreliable and the Commission should disregard it.

17 **Q. HAS THE COMPANY PREVIOUSLY AGREED TO MOVE TO A BALANCED**
18 **CAPITAL STRUCTURE?**

³⁶ Allete's 2023 Form 10-K, page 17 at paragraph three.

³⁷ Avangrid's 2023 Form 10-K, pages 103 and 104

1 A. Yes. In Case No. U-20995, the Company agreed to the following commitment:

2 UPPCO under its new ownership shall actively manage its permanent capital
3 structure (debt and equity) consistent with the capital structure approved by the
4 Commission in the last rate case (U-20276) and address measures intended to
5 reduce the Company's equity percentage in UPPCO's next general rate case to
6 recognize the Staff's and the Attorney General's position for utilities to have a
7 balanced capital structure.³⁸

8 The proposed equity ratio of 51.50% in this rate case reflects zero progress toward
9 achieving a balanced capital structure. The Company provides no sound arguments
10 supporting the continuation of a 51.50% common equity ratio. The Company has proposed
11 a capital structure for the projected test year with an equity ratio unchanged from the last
12 rate case and still far away from the balanced capital structure of 50% debt and 50%
13 common equity capital that it agreed to work toward in Case No. U-20995.

14 In summary, the testimony of both witnesses Kates and Thompson do not provide
15 convincing arguments for the continuation of a 51.50% common equity ratio. The
16 Commission should reject the Company proposal and instead approve a capital structure
17 with a 50% equity ratio, as supported in my testimony.

18 **Q. PLEASE DISCUSS THE COMMISSION'S POSITION REGARDING THE NEED**
19 **FOR UTILITIES TO MAINTAIN A BALANCED CAPITAL STRUCTURE.**

³⁸ MPSC Case No. U-20995, Commission order of May 26, 2021, page 4, paragraph 9.

1 A. Starting with the Commission’s order of February 17, 2017 in Consumers Energy’s rate
2 case in Case No. U-17990, the Commission has encouraged a balanced capital structure
3 by stating:

4 The Commission expects that Consumers will have arrived at, or will present a
5 strategy to return to, a balanced structure within the five-year infrastructure plan time
6 period. If Consumers is unable to do so, a more complete analysis should be included
7 to explain why such a result is reasonable and prudent.

8 Although Consumers Energy gradually moved toward a balanced capital structure, in
9 Case No. U-21389, the Commission ultimately approved a balanced equity ratio of
10 50.02%. Similarly, for DTE Electric Company, the Commission has approved a 50%
11 common equity ratio in recent rate cases.³⁹

12 **Q. YOU STATED THAT THE COMMON EQUITY RATIO OF THE PEER GROUP**
13 **USED IN THE CALCULATION OF THE COST OF COMMON EQUITY IS**
14 **47.7%. PLEASE EXPLAIN WHY THIS IS RELEVANT IN DETERMINING THE**
15 **COMMON EQUITY RATIO FOR THE COMPANY.**

16 A. As shown in Exhibit AG-16, the average common equity of the peer group was 47.7%
17 during the four quarters ending in March 2024. The cost of equity for those companies in
18 the peer group is highly dependent on the financial risk reflected in their capital structure.
19 Thus, it is critical to synchronize the capital structure of the Company to the peer group
20 average, in order to have consistency with the cost of equity capital derived from those

³⁹ MPSC Case Nos. U-20836 and U-20561.

1 peer group companies. The Company's proposed common equity capital ratio of 51.5%
2 creates a disconnect that is not appropriate or acceptable.

3 **Q. YOU STATED EARLIER THAT THE COMMON EQUITY CAPITAL INVESTED**
4 **IN UPPCO BY THE PARENT COMPANY IS FUNDED TO SOME EXTENT BY**
5 **LONG TERM DEBT. PLEASE EXPLAIN.**

6 A. According to the October 20, 2023 credit report from DBRS Morningstar, the amount of
7 debt held by UPPCO's parent company, Upper Peninsula Power Holding Company or
8 UPPHC, is \$230 million over and above UPPCO's long-term debt of \$127 million. DBRS
9 Morningstar stated in its credit report that a condition of this debt is that UPPHC shall
10 maintain a total funded indebtedness to group capitalization of not more than 0.60 to 1.00,
11 which implies a 60% debt ratio.⁴⁰ DBRS Morningstar assigned a debt rating of BBB-low
12 or just barely investment grade to UPPHC due in part to its high debt leverage.

13 In response to a discovery request the Company provided its own and UPPHC's audited
14 financial statements.⁴¹ The financial statements show that at December 31, 2023, UPPHC
15 had total consolidated long-term debt on its balance sheet of \$354 million. This is a
16 significant amount of debt reflecting debt double leverage at the parent company at nearly
17 three times the \$125.4 million of long-term debt at UPPCO at December 31, 2023.

⁴⁰ Exhibit AG-23 includes a copy of the DBRS Morningstar report dated October 20, 2023 provided in Attachment FR187i from Part III Information.

⁴¹ DR 1-AG-UPPCO-1.8 attachments.

1 UPPHC's common equity ratio is 36% at the end of December 2021.⁴² This is in contrast
2 to the 51.5% equity ratio that UPPCO has requested in this rate.

3 The wide disparity in the equity ratio between UPPCO and its parent company
4 demonstrates that UPPCO's equity capital in effect has been partially funded by debt
5 capital in a classic case of debt double leverage. Therefore, the 51.5% requested common
6 equity ratio is excessive and inappropriate. The Commission should reject such a high
7 equity ratio and approve an equity ratio of no higher than 50%.

8 **Q. DOES THE COMPANY CASH FLOW SUPPORT AN EQUITY RATIO OF 50%**
9 **IN THIS RATE CASE?**

10 A. Yes. UPPCO's long-term debt is rated by DBRS Morningstar at BBB-high. According
11 to the rating agency in its October 2022 report, underlying this credit rating was a
12 forecasted Cash Flow to Debt ratio of 16% for the 2023-2024 period. While we do not
13 know what DBRS Morningstar assumed in this forecast, what is important here is that a
14 Cash Flow to Debt ratio of 16% is acceptable to the rating agency.

15 In Exhibit AG-22, I calculated the Company's Cash Flow to Debt ratio for the 2025 test
16 year adjusted for the 50% common equity ratio and 9.85% ROE that I advocate in this
17 case. In this exhibit, I start with UPPCO's actual results for the 12 months ending June
18 2023 in column (b) with cash flows of \$17.4 million and total debt of \$155.3 million,

⁴² UPPHC balance sheet at 12/31/2021 provided in response to 2-AG-UPPCO-27 Updated 12/2/2022.

1 which results in an initial Cash Flow to Debt ratio of 11.2% (\$17.4M ÷ \$155.3M). The
2 components of this ratio are shown on page 8 of the October 20, 2023 DBRS Morningstar
3 report.⁴³ Column (c) of Exhibit AG-22 continues the calculation of the ratio analysis for
4 the projected test year based on information contained in UPPCO's filing in this rate case
5 with the ratio result being 18.5%. Columns (d) and (e) reflect the impact on the ratio
6 results of reducing the authorized ROE of 10.7% (advocated by the Company) to 9.85%,
7 as well as the impact of using a 50% common equity ratio. The result of both changes is
8 shown in column (f) with a final adjusted Cash Flow to Debt ratio of 16.9%. This ratio is
9 comfortably above the 16% projection of DBRS Morningstar in its October 2022 report.
10 Morningstar did not make a projection of this ratio in its more recent October 2023 report.

11 Accordingly, my proposed equity ratio of 50% for UPPCO in this rate case provides an
12 adequate cushion for the Company to preserve its current credit rating. Therefore, I
13 recommend that the Commission approve a 50% equity ratio in this rate case.

14 **Q. WHAT IS THE REVENUE REQUIREMENT SAVINGS RELATED TO A**
15 **COMMON EQUITY RATIO OF 50% IN COMPARISON TO THE COMPANY'S**
16 **PROPOSED EQUITY RATIO OF 51.5%?**

17 A. The difference in revenue requirement between a 50% equity ratio and a 51.5% equity
18 ratio is approximately \$0.5 million annually. This reflects (a) the difference between the

⁴³ Exhibit AG-24 includes a copy of the DBRS Morningstar report dated October 20, 2023 provided in Attachment FR187i from Part III Information.

1 pre-tax cost of common equity of approximately 14.5% versus the cost of long-term debt
2 of 4.53%; (b) the Company's proposed rate base of approximately \$387.5 million; and (c)
3 the percentage of total capital being shifted from common equity to long term debt.

4 The \$0.5 million represents approximately 3% of the Company's identified revenue
5 deficiency. There is no valid reason for the Commission to accept the higher capital
6 structure and burdening customers with \$0.5 million of higher rates.

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

9 A. No. I used the capital balances sponsored by witness Kates in his Exhibit A-9 (NEK-6),
10 Schedule D1, page 1.

11 **B. Cost of Capital**

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

14 A. I recommend an overall return on capital of 6.57%, which includes a return on common
15 equity of 9.85% as shown in Exhibit AG-14.

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

17 A. For the long-term debt cost rate, I used the rate of 4.53% proposed by Company witness
18 Kates.

1 **Q. WHAT COST RATE DID YOU UTILIZE FOR PREFERRED STOCK?**

2 A. The Company has no Preferred Stock.

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

5 A. For Short-Term Debt and Deferred Taxes, I used the cost rates recommended by witness
6 Kates. Cost rates for JDITC reflect those rates I used for the permanent capital sources.

7 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OVERALL COST OF**
8 **CAPITAL IN EXHIBIT AG-13.**

9 A. To develop the overall cost of capital on line 11, column (f), I have first developed the
10 percentage weighting of each capital component in column (d) by dividing the individual
11 capital balances in column (b) by the total of all capital components in that column. Next,
12 I have multiplied the weightings in column (d) by the cost rates in column (e) to arrive at
13 the values in column (f). The total of the individual values in column (f) is the total cost
14 of capital of 6.57%.

15 Regarding the pretax weighted cost of capital on line 11, column (h), I have multiplied
16 each cost component in column (f) by the conversion factors in column (g). These
17 conversion factors are included to reflect the impact of income and other taxes paid by
18 UPPCO for calculation of the pretax weighted cost of 7.98% in column (h).

1 **Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN DETERMINING**
2 **THE COST OF COMMON EQUITY FOR THE COMPANY?**

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

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

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

18 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COST OF COMMON**
19 **EQUITY IN EXHIBIT AG-14.**

20 A. Determining the cost of common equity for an enterprise or an industry group is inexact
21 since investors can only estimate what the future cash flows from any enterprise may be
22 over time. Because of this uncertainty, most financial experts will not rely solely on any
23 one particular method. To determine the cost of common equity, I have utilized three

1 approaches to assessing this cost. These are the Discounted Cash Flow (DCF) Method,
2 the Capital Asset Pricing Model (CAPM), and the Utility Risk Premium approach.

3 The average of these three methods is 9.85% utilizing a 50% weighting for the DCF
4 approach and 25% for each of the CAPM and Utility Risk Premium approaches.

5 **Q. PLEASE EXPLAIN THE DEVELOPMENT OF YOUR PROXY GROUP OF PEER**
6 **COMPANIES.**

7 A. To develop an appropriate peer group, I started with the 38 electric utility companies
8 followed by the Value Line Investment Survey in its “Electric Utility Industry” sections.
9 Exhibit AG-20 shows the companies I considered and that 30 of these companies were
10 eliminated due primarily to (1) size considerations for the largest utilities with revenues
11 over \$3 billion; (2) no dividend growth; (3) reorganization or M&A activity; and (4) higher
12 risk considerations, such as off-shore wind generation construction and wildfire risk.

13 After eliminating companies in these categories, the result is the group of 8 companies
14 shown in Exhibit AG-20 (second from last column), all of which have growing earnings
15 and dividends, and are appropriately comparable to UPPCO.

16 **Q. HOW DOES YOUR PEER GROUP COMPARE TO THE COMPANY’S PEER**
17 **GROUP?**

18 A. The Company’s peer group is larger than my peer group and contains twenty-three
19 companies with a mix of both larger and smaller utilities. My peer group is comprised of

1 smaller utility companies with revenues under \$3 billion and contains six of the twenty-
2 three companies selected by UPPCO, as well as Portland General Electric and Unitil.

3 The Company's peer group contains several large utility companies that I removed from
4 consideration simply due to their large size. Some of the larger companies I removed,
5 which the Company included in its peer group, are Dominion Energy and CenterPoint
6 Energy (removed due to M&A activity), Edison International (removed due to wildfire
7 risk), and Entergy which was excluded due to a recent large earnings decline. Two smaller
8 companies that I removed were Allete due to M&A activity and Otter Tail due to its
9 significant earnings from the plastics and manufacturing businesses, which accounted for
10 70% of operating income in 2023. I also excluded Emera due to its larger size with more
11 than \$5 billion in revenues and with foreign operations.⁴⁴ The inclusion of the larger
12 companies in the UPPCO peer group is inappropriate given that these large utility holding
13 companies have little in common with UPPCO and in certain cases contain extraordinary
14 risks.

15 The Commission should recognize that several of the companies in the UPPCO peer group
16 reflect higher risk situations, as well as utility companies involved in corporate
17 reorganizations and the expected sale of one company (ALLETE). As such, the
18 Company's peer group is not truly reflective of the risk and business profile of UPPCO
19 and should be disregarded as deficient by the Commission.

⁴⁴ Value Line follows this Company but classifies it as a power provider and not a utility company.

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Discounted Cash Flow (DCF) Cost of Equity Method

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

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

$$R = D/P + g$$

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

Q. PLEASE EXPLAIN THE RESULTS OF YOUR DCF ANALYSIS.

A. The results of my DCF analysis are summarized in Exhibit AG-15. The stock price information in column (c) of this exhibit reflects the average of the high and low prices for each of these equity securities on each of the 30 trading days from May 1 to June 12, 2024. The annual dividend in column (d) is the projected average dividend level for 2024 and 2025 as projected by the Value Line Investment Survey. Column (h) shows the average long-term earnings growth rate based on (1) the estimate of earnings growth for the five years from 2023 to 2028 per Value Line; and (2) the earnings growth estimate by stock analysts over the next five years which is available from Yahoo.com.

1 The resulting calculation of the DCF Method is an average return on common equity for
2 the proxy group of 9.34%.

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

4 A. The DCF analysis relies upon financial market information for the dividend yield portion
5 of the equation. However, it also relies upon judgments of dividend and earnings growth
6 prospects of security analysts which may or may not be consistent with the beliefs of
7 investors. I place a fairly high degree of reliability in the DCF results when considered in
8 conjunction with the results of other methods in determining the cost of common equity.

9 **Q. HOW DOES YOUR DCF COST OF CAPITAL ESTIMATE COMPARE TO THE**
10 **COMPANY'S DCF ESTIMATE?**

11 A. Witness Thompson has developed four different DCF estimates based on Value Line,
12 IBES, and Zacks earnings growth rates as well as his "br + sv growth" approach. These
13 four estimates are shown on Exhibit A-46, page 3 and range from 9.3% to 10.4% with the
14 average for this range being 9.85%.

15 Witness Thompson's DCF dividend yield is 4.5% and reflects lower stock prices from
16 January and February 2024 which are now stale. In contrast, my DCF dividend yield is
17 4.1% which is 40 basis points lower. Also, his inclusion of various inappropriate
18 companies in his peer group (ALLETE, Dominion Energy and CenterPoint Energy) boosts
19 his results. Finally, his selective exclusion of certain ROE results below 8% is

1 yields from 1932 to 2022. Adding these two rates together results in the Utility Risk
2 Premium return of 10.20% on line 7 of Exhibit AG-17.

3 **Q. DOES THE COMPANY PROVIDE A UTILITY RISK PREMIUM ANALYSIS?**

4 A. No, not in the traditional sense of measuring achieved returns on utility stocks relative to
5 an interest rate benchmark such as utility bonds.

6 **Q. PLEASE SUMMARIZE WITNESS THOMPSON'S DISCUSSION ON UTILITY
7 RISK PREMIUM ON PAGES 55 THROUGH 58 OF HIS DIRECT TESTIMONY.**

8 A. Witness Thompson states in his testimony that he compared authorized ROEs from electric
9 utility rate case decisions from 1974 to 2023 and compared the authorized ROEs to utility
10 bond yields.⁴⁵ He ran a regression model with this data and claims that he found a strong
11 relationship between utility bond yields and ROEs. He also observed that authorized
12 ROEs have fallen less than utility bonds yields. Based on the results of his model, he
13 stated that the average risk premium over the 50-year study period is 3.89%. However,
14 after certain calculations, he concluded that the risk premium in January 2024 would be
15 4.71%. To this developed risk premium, he added a 6.08% Baa bond yield to arrive at his
16 10.79% ROE rate, which uses interest rates during the six months ended January 2024.
17 Witness Thompson's calculations are presented in Exhibit A-49 (JST-7).

⁴⁵ McKenzie testimony starting at page 61.

1 **Q. WHAT IS YOUR ASSESSMENT OF THE UTILITY RISK PREMIUM**
2 **CALCULATIONS PRESENTED BY WITNESS THOMPSON?**

3 A. There are three major flaws with witness Thompson’s Utility Risk Premium methodology.
4 First, it lacks any comparison of actual utility returns achieved from stock price
5 appreciation and dividends to bonds yields. It is the actual return on utility common
6 equities that is the key and necessary measurement in any risk premium analysis. Using
7 authorized ROEs as a substitute ignores investors’ return expectations. Second, the
8 analysis is upwardly biased in that 40 out of the 50 years in the study period reflect an
9 historic decline in interest rates from 15.62% in 1980 to 3.07% in 2020.⁴⁶
10 Third, Mr. Thompson assumes a direct relationship between declining interest rates and
11 ROE decisions as happening almost instantaneously on a monthly basis. Regulators
12 approach the serious business of establishing ROEs based on many factors including the
13 concept of “gradualism” in reducing or increasing ROEs that are not in lock step with
14 interest rate changes. This analysis has no validity as a tool to determine an appropriate
15 ROE in ratemaking proceedings.

16 **Capital Asset Pricing Model**

17 **Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL (CAPM)**
18 **APPROACH TO DETERMINING THE COST OF COMMON EQUITY CAPITAL.**

⁴⁶ From Exhibit A-49 (JST-7) page 2.

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

4
$$k_e = R_f + (B \times R_p)$$

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

6 R_f = the “risk free” rate of return

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

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

9 **Q. PLEASE EXPLAIN THE BETA OR “B” COMPONENT OF THE EQUATION.**

10 A. This measure of risk reflects the extent to which the price of a particular security varies in
11 relationship to the movement of the overall market. Securities that vary over time more
12 than the overall market will have a Beta that is greater than 1.00. Some securities vary
13 less in price over time than the overall market. In these cases, the Beta will be less than
14 1.00. Utility stocks tend to move less than the overall market. Reflective of this outcome,
15 the average Beta of my Peer Group is 0.89.

16 **Q. PLEASE EXPLAIN EXHIBIT AG-16 SHOWING THE RESULTS OF THE CAPM**
17 **APPROACH.**

18 A. Exhibit AG-16 shows the results of the CAPM method based upon (1) the forecasted
19 4.15% risk-free rate; (2) the Beta of each of the companies in the Peer Group taken from

1 Value Line; and (3) the 7.17% historical Market Risk Premium (R_p) return from the years
2 1926 to 2022.

3 Regarding the use of a risk-free rate for CAPM purposes, I used a 4.15% rate, which is the
4 forecasted average 30-year U.S. Treasury Bond. I arrived at the 4.15% rate by taking an
5 average of two recent forecasts withing the past five months. First, I used the February 1,
6 2024 Blue Chip average projected rate for 2025 of 4.00%. Second, I used the May 31,
7 2024 Blue Chip average projection for 2025 of 4.30%.⁴⁷ Recognizing the uncertainty in
8 the capital markets regarding when the Federal Reserve bank will reduce interest rates, I
9 believe that taking an average of the February and May 2024 Blue Chip projected rates for
10 2025 is appropriate.

11 The result of the CAPM approach using the forecasted 4.15% U.S. Treasury rate and the
12 group average 6.36% Beta-adjusted risk premium is a cost of equity capital of 10.51% for
13 the proxy group.

14 **Q. PLEASE ASSESS THE CAPM APPROACH.**

15 A. I believe that CAPM has value in assessing the relative risk of different stocks or portfolios
16 of stocks. As such, it can be useful. However, the key issue with CAPM is that it assumes
17 that the entire risk of a stock can be measured by the “Beta” component and as such the
18 only risk an investor faces is created by fluctuations in the overall market. In actuality,

⁴⁷ Exhibit AG-25 includes the February and May 2024 Blue Chip reports on the U.S. treasury bond forecasts.

1 investors take into consideration company-specific factors in assessing the risk of each
 2 particular security. Therefore, I give the CAPM approach less weight than the DCF
 3 approach in determining the cost of common equity.

4 **Q. HOW DOES YOUR CAPM ROE RESULTS COMPARE TO THE RESULTS**
 5 **PRESENTED BY COMPANY WITNESS THOMPSON?**

6 A. Witness Thompson presents the results of his CAPM analysis in Exhibit A-48 (JST-6). In
 7 the table below, I show witness Thompson’s ROE results reconciled to my CAPM
 8 estimate. In his analysis, he uses a Market Risk Premium (MRP) of 7.5% based on
 9 projected earnings growth of S&P 500 companies over the next three to five years and a
 10 company size adjustment, both of which are inappropriate.

Comparisson of CAPM Estimates of AG and Company Case		
<u>AG CAPM vs Company CAPM Estimates</u>	<u>AG Case</u>	<u>Company High Case</u>
1 Market Risk Premium (MRP)	7.17%	7.50%
2 Beta (based on proxy group companies)	<u>0.89</u>	<u>0.95</u>
3 MRP x Beta	6.36%	7.10%
4 Risk Free Rate	4.15%	4.50%
5 Small Size Adjustment	<u>0.00%</u>	<u>0.60%</u>
6 CAPM Return on Equity	<u>10.51%</u>	<u>12.20%</u>

11

1 **Q. WHAT IS THE BASIS FOR THE COMPANY’S USE OF A 4.5% RISK FREE**
2 **RATE IN ITS CAPM ANALYSIS?**

3 A. According to the footnotes on Exhibit A-48 (JST-6), the Company’s risk-free rate of 4.5%
4 rate is the historical six-month average of actual 30-year U.S. Treasury rates during the
5 period of August 2023 to January 2024. Although historical U.S. Treasury rates can be
6 used to forecast the cost of capital during periods of stable interest rates, this is not the case
7 at this point in time. With the Federal Reserve Bank having raised interest rates during
8 the past year to fight inflation, historical interest rates have been elevated and not
9 representative of where interest rates are likely to be in the 2025 projected test year. As
10 discussed above, the consensus from economists reflected in the February and May 2024
11 Blue Chip reports is that 30-year U.S. Treasury rates will be closer to 4.15% than the
12 Company’s historical rate of 4.50%.

13 What witness Thompson has done is to look back to historical periods of higher past rates
14 instead of recognizing that interest rates are expected to fall in the projected test year.

15 **Q. YOU STATED ABOVE THAT WITNESS THOMPSON DETERMINED HIS 7.5%**
16 **MRP BY USING PROJECTED RETURNS OF THE S&P 500 OVER A THREE TO**
17 **FIVE-YEAR PERIOD BASED ON DATA COMPILED FROM VALUE LINE AND**
18 **OTHER SOURCES. PLEASE COMMENT ON THIS APPROACH USED BY THE**
19 **COMPANY.**

1 A. Instead of using a proven historical market risk premium (MRP), the Company developed
2 its MRP based on future expected growth rates. The development of the Company's MRP
3 is dependent on the short-term projected returns of a select group of S&P 500 companies.
4 There are a number of problems with this approach to developing an MRP. First, short-
5 term fluctuations in expectations and projected stock market returns can cause the
6 developed MRP rates to vary significantly over short periods of time. Second, according
7 to witness Thompson's testimony on page 52, he has excluded from consideration all
8 companies not paying a dividend, as well as companies with growth rates that are negative
9 or above 20%. As such, his analysis is not balanced or fully representative of the S&P 500
10 index.

11 **Q. PLEASE EXPLAIN FURTHER THE SHORTCOMINGS WITH THE MARKET**
12 **RISK PREMIUM DEVELOPED BY WITNESS THOMPSON.**

13 A. Witness Thompson is using an extremely short projected period to measure results and
14 determine his projected risk premium. For the Company's CAPM estimate, the forecasted
15 market data used to calculate the projected MRP do not include a complete cycle of
16 economic expansion and contraction, which is what occurs over the long-term. To adopt
17 the Company's approach would be akin to only selecting the positive return years over the
18 97-year period compiled in the Ibbotson stock market return series and not the losses in
19 the downturn years. Expectedly and incorrectly, we would derive a far higher overall
20 return for the market and a far higher market risk premium, similar to what witness
21 Thompson has proposed.

1 For the above reasons, witness Thompson’s development of his MRP used in his Projected
2 CAPM approach to calculate the cost of equity rate is seriously flawed and should be
3 rejected.

4 **Q. IS THERE ACADEMIC RESEARCH THAT CONFIRMS THE USE OF A SHORT**
5 **PERIOD IS INAPPROPRIATE IN CALCULATING A RISK PREMIUM**
6 **FACTOR?**

7 A. Yes. The same concerns are echoed by Dr. Roger Morin on page 114 of his book “New
8 Regulatory Finance” where he states:

9 Therefore, an historical risk premium study should consider the longest possible
10 period for which data are available. Short-run periods during which investors earn a
11 lower risk premium than they expect are offset by short-run periods during which
12 investors earn a higher risk premium than they expect. Only over long time periods
13 will investor return expectations and realizations converge. Clearly, the accuracy of
14 the realized risk premium as an estimator of the prospective risk premium is
15 enhanced by increasing the number of years used to estimate it...

16 Clearly, the Company’s approach to calculating a market risk premium is not academically
17 or practically sound.

18 **Q. PLEASE COMMENT ON WITNESS THOMPSON’S SO-CALLED SIZE**
19 **ADJUSTMENT IN THIS CASE WHICH HE APPLIES IN HIS CAPM ANALYSIS.**

20 A. Witness Thompson discusses this topic on pages 53 to 55 of his testimony. His basic
21 proposition is that the CAPM does not fully account for observed differences in rates of

1 return attributable to firm size.⁴⁸ On page 54 of his testimony, he described the
2 calculations needed to develop this size adjustment which he stated are sourced from Kroll,
3 who now publish the well-known compilation of capital market series originally developed
4 by Professor Roger Ibbotson and previously published by Duff & Phelps.

5 Although the 2022 edition of Stocks, Bonds, Bills and Inflation published by Ibbotson
6 addresses the greater returns achieved by smaller firms, this information is pertinent to
7 companies in competitive industries and are not directly relevant to regulated utilities that
8 have a monopoly business. In my CAPM analysis, I used a peer group comprised of
9 utilities that are the smallest among the publicly-traded electric utilities. Therefore, my
10 analysis already captures the impact of financial factors, such as beta levels, stock
11 liquidity, and analyst coverage for the smaller utilities in arriving at a CAPM cost of equity
12 capital rate of 10.51%.

13 **Q. WHAT INFORMATION DID THE COMPANY RELY ON TO ARRIVE AT A**
14 **SMALL UTILITY SIZE ADJUSTMENT?**

15 A. In response to discovery, the Company provided an article authored by Mr. Thomas Zeep
16 published in 2002.⁴⁹ The thrust of the article was to rebut the work of Ms. Annie Wong
17 who concluded that firm size was a missing factor from CAPM for industrial stocks but
18 not for utility stocks.⁵⁰ Mr. Zeep in his article notes that new studies based on different

⁴⁸ Thompson testimony at page 53, line 22

⁴⁹ Exhibit AG-26 includes DR 1.AG-UPPCO-1.19.

⁵⁰ The conclusion was that no size premium should apply to utilities.

1 size water utilities support a small firm effect in the utility industry.⁵¹ First, Mr. Zeep
2 points to a study by the California PUC Advisory and Compliance staff in 1991 which
3 concluded that "...small water companies were more risky than larger water utilities..."

4 However, Mr. Zeep noted in his article that many of the companies studied were not
5 publicly traded and stated the following on page 3 of the article.

6 Part of the difficulty with examining the question of relative risk of utilities is that
7 the very small utilities are not publicly traded. The CPUC Staff study addressed
8 that concern by computing proxies for beta risk estimated with accounting data
9 for the period 1981-1991 for 58 water utilities.

10 Mr. Zeep also points to another study that compared the results of two small water
11 companies to two larger water companies using public data. The result of this limited DCF
12 study found that the cost of capital for the two smaller firms was higher than that of the
13 two larger firms.

14 The estimation of private company betas in the first study noted above and the limited size
15 of the second study (only four companies) are troubling factors. Also, these studies were
16 limited to water companies. Therefore, it is not possible to draw any conclusions from this
17 information. Even Mr. Zeep in his concluding remarks indicated that Wong's work
18 "...should be reexamined and placed in perspective..." As such, I interpret his position as
19 calling for more research on this matter.

⁵¹ This article is included in the Company's filed workpapers in this case.

1 **Q. PLEASE COMMENT ON THE COMPANY’S EXPECTED EARNINGS**
2 **ANALYSIS.**

3 A. In Exhibit A-50 (JST-8), witness Thompson derived a 10.80% projected average ROE rate
4 based on a calculation using the forecasted earnings of the companies in his peer group
5 and dividing those earnings by the forecasted book value of common equity for each
6 company. He also discusses his Expected Earnings Approach in his direct testimony on
7 pages 60 through 62.

8 However, the Expected Earnings Approach is not an academically sound methodology to
9 determine the cost of common equity for any company. What witness Thompson is doing
10 is simply dividing the projected earnings per share (“EPS”) approximately five years from
11 now for each peer group company, as estimated by Value Line, by the projected Book
12 Value of each peer group company. This exercise perhaps has some use in evaluating how
13 well each peer group company employs capital over the projected periods but is useless as
14 a tool to set the authorized ROE of a utility company. This method does not take into
15 account investors’ expectations or stock market parameters.

16 The Commission should also recognize the inherent circularity in relying upon this method
17 advocated by the Company. If utility commissions were to rely upon this methodology,
18 utilities in effect would indirectly be setting their own allowed ROE, or highly influencing
19 those ROEs, by estimating ever increasing EPS.

1 In summary, this approach appears to be another attempt to find a cost of capital
2 calculation method to fit a desired level of return on equity. My recommendation is that
3 the Commission should give no weight or reliance to this alternative method.

4 **Q. IN EXHIBIT A-51 (JST-9), WITNESS THOMPSON DEVELOPED A ROE**
5 **CALCULATION FOR A NON-UTILITY GROUP OF 49 COMPANIES FROM**
6 **DIVERSE ECONOMIC SECTORS BASED ON THE DCF PROCESS AND**
7 **ESTIMATED EARNINGS GROWTH FROM VALUE LINE, IBES, AND ZACKS.**
8 **WHAT IS YOUR VIEW OF THIS APPROACH?**

9 A. Witness Thompson presents an alternative calculation of the cost of equity capital for a
10 group of non-utility companies starting on page 63 of his direct testimony. This alternative
11 calculation has no merit within the utility industry. Two of the selection criteria for the
12 companies selected by this witness for his non-utility group are that they pay a dividend
13 and have a beta of less than 0.95. However, this is basically where the similarities to utility
14 companies end. The companies he selected include companies involved in computer
15 software and hardware, food processing, the beverage industry, drug manufacturing and
16 defense contractors. These companies have significantly higher business risk profiles with
17 price and market share competition not faced by utilities with monopoly power with
18 protected market areas and no price competition, and with other cost recovery mechanisms
19 and regulatory protections.

1 Witness Thompson also argues that this alternative cost of equity calculation is consistent
2 with language in the *Bluefield* and *Hope* cases pertaining to “business undertakings
3 attended with comparable risks and uncertainties”; and “the return to the equity owner
4 should be commensurate with returns on investments in other enterprises having
5 corresponding risks”.⁵² These arguments are far-fetched and inapplicable to companies in
6 very distinctive industries as electric utilities with monopoly businesses versus companies
7 in the computer, food processing, pharmaceutical, or defense industries. This proposed
8 alternative non-utility company group is a classic example of trying to fit a square peg in
9 a round hole.

10 The Commission has spoken clearly on the issue of alternative calculations for the cost of
11 equity using companies outside the utility’s industry sector. In Case U-20940, DTE Gas
12 argued for inclusion of regulated water utility companies in its proxy group. In its
13 December 9, 2021 order, the Commission stated the following:

14 Accordingly, the Commission agrees with the ALJ that water utilities are not
15 appropriately included in a proxy group for determining an appropriate ROE for
16 a gas utility.⁵³

17 Witness Thompson’s alternative non-utility group is even further afield than the water
18 utility companies proposed by DTE Gas in Case No. U-20940. Accordingly, the
19 Commission should reject this alternative analysis.

⁵² Thompson testimony beginning on page 63 at line 23.

⁵³ MPSC Case No. U-20940 at page 91.

1 **Q. PLEASE DISCUSS WHAT RETURN ON EQUITY RATES OTHER**
2 **REGULATORY COMMISSIONS HAVE GRANTED IN 2022 AND 2023?**

3 A. Since 1990, the return on equity rates approved by regulatory commissions in electric cases
4 has been on a steady decline from over 12.7% in 1990 to approximately 9.4% in 2020,
5 9.5% in 2022, and 9.6% in 2023. Unfortunately, the decline in ROE rates for Michigan
6 utilities has not been commensurate with the decline in ROE rates for most utilities in other
7 states.

8 Exhibit AG-18 shows the ROEs granted by state regulatory commissions for U.S. electric
9 utilities in 2022 and 2023. The average rate of the 32 ROE decisions in 2022 and the 48
10 decisions in 2023 averages to 9.6%. Approximately 75% of these ROE decisions are at a
11 rate no higher than 9.85%. Regarding 2023 ROEs above 9.85%, as can be seen on page 3
12 of this exhibit, half (or five) of the ten ROE decisions were from regulators in California.
13 Two of these decisions were from regulatory commissions in Alaska and North Carolina
14 with the other three being issued by the Michigan Commission.

15 This evidence supports my proposed ROE rate of 9.85% and makes the Company's current
16 ROE rate of 9.90% excessive. The Company's proposed ROE rate of 10.70% is even
17 further removed from reality and clearly unsupportable.

18 **Q. SHOULD THE COMMISSION BE CONCERNED THAT ESTABLISHING AN**
19 **AUTHORIZED ROE OF 9.85% IN THIS CASE WILL LEAD TO IMPAIRMENT**
20 **OF THE COMPANY'S ABILITY TO ACCESS THE CAPITAL MARKETS?**

1 A. No. In recent general rate case proceedings, certain rate case applicants have raised
2 arguments that they should receive a ROE of 10% or higher to ensure the financial
3 soundness of the business and to maintain its strong ability to attract capital in addition to
4 being compensated for risk. Exhibit AG-18 shows several electric utilities that have
5 accessed the capital markets at competitive interest rates since receiving a ROE near or
6 below my recommended rate of 9.85%.

7 Similarly, there is no evidence equity investors have abandoned utilities that have been
8 granted ROEs at 9.85% or below. On the contrary, stock investors continue to migrate to
9 utility stocks, recognizing that authorized ROEs are still above the true cost of equity.
10 Exhibit AG-21 shows the market to book ratios for each of the peer group companies, and
11 many of these companies have received rate orders during the past few years reflecting
12 ROEs as low as 9.2% for Unitil in May 2022 and 9.4% for Avista in August 2023.⁵⁴ Yet
13 this group of companies has an average Market to Book common equity value ratio of
14 approximately 1.3 times.

15 This information is provided to dispel the myth that the Company must receive a ROE at
16 or above 9.90%, or it will face dire consequences in the financial markets.

17 The fact that the Company needs to raise capital because of a large capital investment
18 program to upgrade its infrastructure and for other purposes is not unique to UPPCO.

⁵⁴ Based on data from Regulatory Research Associates shown on Exhibit AG-18.

1 Other electric utilities face the same issues and are able to raise capital with ROEs well
2 below 9.85%. Therefore, this issue is another “red herring”.

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

8 A. No. The stock market has historically been very volatile. Currently, this is measured by
9 the VIX which projects volatility over the next 30 days. In some periods, stock prices
10 move up and down more dramatically than at other times. The key factor is that the VIX
11 is telling us something about risk in the market over the next 30 days and not the risk
12 several months in the future. In setting ROE rates for utilities, the Commission’s focus is
13 the long-term financial health of the utility not the short-term gyrations of the stock market.

14 In Exhibit AG-27, I have included a Value Line Funds article written by Mitchell Appel,
15 President of Value Line Funds. Mr. Appel states that volatility is not risk. He goes on to
16 say later in this article that “...volatility is only risk if you act during down times, that is,
17 only if you sell a stock.”

18 Additionally, I will submit that those who invest money in equity portfolios over longer
19 periods of time and particularly in utility stocks have an aversion to market volatility and
20 the VIX. In fact, utility stocks are a safe haven for investors during times of uncertainty

1 and volatility because they are not as susceptible to as much volatility as the general stock
2 market. This is reflected in the average Beta value of 0.89 of the utility peer group used
3 in the CAPM discussed earlier, in contrast with the general stock market value of 1.

4 **Q. ON PAGE 26 AND 29 OF HIS DIRECT TESTIMONY, WITNESS THOMPSON**
5 **ALLEGES CERTAIN ISSUES AFFECTING UPPCO, SUCH AS LOW WATER**
6 **CONDITIONS AND FEWER COST RECOVERY MECHANISMS THAN**
7 **AVAILABLE TO OTHER UTILITIES. WHAT IS YOUR RESPONSE?**

8 A. In discovery, the Attorney General asked the Company to provide information about low
9 water conditions in its hydro power generation plants in the last ten years and the financial
10 impact of lost off-system sales and higher power purchase costs. In response, the
11 Company could not provide any information on low water conditions other than alluding
12 to vague investor concerns about periods of below-average water conditions.⁵⁵

13 On page 29 of his direct testimony, witness Thompson stated that UPPCO's cost recovery
14 mechanisms "...are more limited than those approved for other firms in the industry..."
15 In discovery, the Attorney General asked the Company if the Commission had denied any
16 cost recovery mechanism proposed by the Company and approved by the Commission for
17 other Michigan utilities during the last five years. In its response, the Company

⁵⁵ Exhibit AG-28 includes DR 1-AG-UPPCO-1.16.

1 acknowledged that no such requests for cost recovery mechanisms had been denied by the
2 Commission during the last five years.⁵⁶

3 Accordingly, the Commission should not be persuaded that UPPCO is at a disadvantage
4 relative to other utilities.

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

7 A. In Exhibit AG-14 I have summarized the cost of equity rates from the three methods I
8 discussed above. The range of returns for the industry peer group is from 9.34% at the
9 low end using the DCF approach, to 10.51%, at the high end using the CAPM approach.

10 As explained earlier in my testimony, I give 50% weight to the DCF method as a more
11 reliable approach to estimating the cost of equity, which from my analysis is a rate of
12 9.34%. In this regard, on line 4 of Exhibit AG-14, I have calculated a weighted return on
13 equity of the three methodologies using a 50% weight for DCF and 25% for each of the
14 other two methods. The result is a weighted average cost of common equity of 9.85%.

15 Therefore, I recommend that the Commission take note of the evidence and arguments I
16 have presented in my testimony and grant the Company a ROE of no more than 9.85%.

⁵⁶ Id. includes DR 1-AG-UPPCO-1.18.

1 **VI. Operations and Maintenance Expenses**

2 **Q. WHAT ARE YOUR FINDINGS IN ANALYZING THE COMPANY’S LEVEL OF**
3 **O&M EXPENSE INCLUDED IN THIS RATE CASE?**

4 A. A comparison of Schedule C5 from Exhibits A-3 (NLW-11) and from Exhibit A-8 (NLW-
5 27) shows that the Company forecasted an increase of \$4.1 million in O&M expenses for
6 the retail business between the 2023 historical year and the 2025 projected test year. In
7 Exhibit A-8, Schedule C5, the Company forecasted \$40.8 million of O&M Expense for
8 the projected test year. This expense level is an increase of 11%, from the \$36.8 million
9 incurred in 2023. Ms. Natasha Wonch, who sponsored the two exhibits, provided no
10 explanation in her direct testimony about the increase in expense between the historical
11 and the projected test year. Therefore, the information discussed below is based largely
12 on the Company’s responses to discovery requests.

13 **Q. IN YOUR ANALYSIS, HAVE YOU DETERMINED SPECIFIC AREAS WHERE**
14 **O&M EXPENSES SHOULD BE REDUCED?**

15 A. Yes. I have analyzed O&M expenses by major department, or area, and I have identified
16 more appropriate and reasonable expense levels that the Commission should consider. As
17 discussed in detail in my testimony below, I recommend that the Company’s forecasted
18 O&M expenses should be reduced by \$3.1 million. Exhibit AG-29 shows a summary of
19 my proposed O&M expense adjustments.

1 **A. Inflationary Adjustments to O&M Expenses**

2 **Q. HAVE YOU MADE ANY ADJUSTMENTS TO THE INFLATION INCREASE**
3 **ADJUSTMENTS TO O&M EXPENSES PROPOSED BY THE COMPANY IN**
4 **THIS RATE CASE?**

5 A. Yes. The Company used actual O&M expenses for 2023 and applied blended inflationary
6 cost rates for 2024 and 2025 consisting of both CPI inflation and estimated employee pay
7 increases. For its non-labor expenses, the Company used forecasted CPI rates of 2.7% for
8 2024 and 2.4% for 2025 sourced from the Congressional Budget Office, as of February
9 2024 and discussed in the direct of testimony Company witness Nicholas Kates.⁵⁷ To
10 adjust labor expenses, the Company used rates of increase of 4.53% for 2024 and 4.00%
11 for 2025.⁵⁸

12 In previous litigated rate cases, where other utilities have proposed inflation adjustments
13 consisting of both CPI and merit pay increases, the Commission has rejected such blended
14 rates and approved the use of only the CPI-Urban forecasted inflation rate.⁵⁹ The same
15 treatment should apply in this case. In Exhibit AG-30, I recalculated the inflation cost
16 difference applicable to the labor component of the Company's costs for the projected test
17 yea using the base inflation rates of 2.7% and 2.4% for 2024 and 2025, respectively.

⁵⁷ Nicholas Kates direct testimony at page 4. For simplicity, the Congressional Budget Office inflation rates are considered equivalent to the Consumer Price Index (CPI) and are referenced as CPI rates.

⁵⁸ Nicholas Kates direct testimony at page 5. The 4.53% increase reflects a weighted average rate of 5% for union employees and 4% for non-union employees.

⁵⁹ Case U-20561, Commission order dated May 8, 2020 at 186.

1 Line 1 of this exhibit shows the Company’s 2023 wages from its “Compensation
2 Summary” included in the filed workpapers in this case. Lines 5 shows the cumulative
3 pay adjustment factors for 2024 and 2025 based on the Company’s estimated pay
4 increases, while line 9 shows the cumulative estimated CPI inflation factors. The
5 difference between the two is shown on line 10, which is then multiplied by the wages on
6 line 1 to derive the excess wage inflation of \$268,000 and \$413,000 on line 11 in columns
7 (b) and (c). Adding the two amounts together produces a total excess wage inflation
8 adjustment of \$681,000.

9 I recommend that the Commission remove the excess inflation adjustment of \$681,000
10 from the Company’s projected test year O&M expense.

11 **B. Electric Distribution Expense**

12 **Q. WHAT ADJUSTMENTS DID THE COMPANY MAKE TO ITS ELECTRIC**
13 **DISTRIBUTION EXPENSE FOR THE PROJECTED TEST YEAR?**

14 A. As shown on line 4 of Schedule C5 in both Exhibits A-3 (NLW-11) and Exhibit A-8
15 (NLW-27), Distribution expense increased from \$16.9 million in 2023 to a forecasted
16 amount of \$17.2 million for the projected test year ending December 2025. Although the
17 Company did not provide any detailed forecasts for the various elements of Distribution
18 expense in filed testimony, in response to a discovery request the Company reported that
19 \$8.8 million or 52% of the Distribution expense in 2023 pertains to maintenance of its
20 major overhead (Acct 593) and underground (Acct. 594) distribution lines. This portion

1 of the expense fluctuates from year to year most likely due primarily to variability in storm
2 damage costs.⁶⁰

3 As shown in Exhibit AG-31, maintenance costs of major distribution lines reflect a great
4 deal of variability over the past five years with amounts as low as \$6.2 million in 2020 and
5 as high as \$9.0 million in 2022. The Company developed its projection for various
6 components of Distribution O&M expense based on the 2023 actual expense amount plus
7 inflation and other adjustments. For maintenance expense of major distribution lines, the
8 Company's approach of forecasting projected test year expense based on 2023 costs and
9 adding inflation is inappropriate because it uses a high expense level not representative of
10 amounts incurred in prior years. A proper approach is to use a five-year average of
11 expenses and to adjust the resulting average amount for inflation.

12 As shown in Exhibit AG-31, I developed a five-year average from the years 2019 to 2023
13 for both expense accounts, which is \$7,066,000. To this amount, I added \$396,000 of
14 inflation (reflecting the Company's CPI inflation estimate for 2 years), which results in a
15 forecasted expense amount of \$8,055,000 for the projected test year. This amount is
16 \$1,262,000 lower than the Company's forecast.

⁶⁰ Exhibit AG-34 includes DR 2-AG-UPPCO-2.34 with attachment.

1 I recommend that the Commission adopt the expense amount of \$8,055,000 for
2 Maintenance of major overhead and underground distribution lines for the projected test
3 year and reduce the Company's forecasted expense by \$1,262,000.

4 **C. Injuries and Damages**

5 **Q. THE COMPANY FORECASTED \$1.5 MILLION FOR INJURIES AND**
6 **DAMAGES FOR THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS**
7 **AMOUNT?**

8 A. No. The Company developed its forecasted expense for injuries and damages by using the
9 its 2023 expense amount of \$1.1 million and then escalating it for the projected test year
10 level by 34% to \$1.5 million. The established practice accepted by the Commission in
11 other utilities' rate cases is to use a five-year average of historical costs due to the fact that
12 the injuries and damages expense can vary significantly from year to year. In this rate
13 case, the Company shows that it experienced injuries and damages expense as low as
14 \$834,000 in 2020 and as high as \$1,106,000 in 2023, which is approximately 33% higher
15 than the 2020 cost level. The Company's approach is inappropriate and would result in a
16 highly inflated expense projection.

17 **Q. EXPLAIN HOW YOU DETERMINED A REASONABLE LEVEL OF INJURIES**
18 **AND DAMAGES EXPENSE FOR THIS RATE CASE.**

1 A. Exhibit AG-32 shows the calculation of a five-year average for injuries and damages
2 expense. As discussed earlier, this is a reasonable approach given the variability in annual
3 expense and the accepted methodology previously approved the Commission. Lines 1
4 through 5 of the exhibit show the expense amounts for each years 2019 to 2023. Line 6
5 shows the five-year average of \$948,000. Compared the Company's forecast on line 7,
6 my calculation shows that the forecasted expense should decrease by \$531,000.

7 Therefore, I recommend that the Commission adopt an Injuries and Damages expense
8 amount of \$948,000 for the projected test year and reduce the Company's forecasted O&M
9 expense by \$531,000.

10 **D. Uncollectible Accounts Expense**

11 **Q. THE COMPANY FORECASTED \$350,258 FOR UNCOLLECTIBLE ACCOUNTS**
12 **EXPENSE, EXCLUDING THE \$165,780 OF AMORTIZED PRIOR COSTS. DO**
13 **YOU AGREE WITH THIS EXPENSE AMOUNT?**

14 A No. The forecasted expense of \$350,258 is excessive and inappropriate. Exhibit A-14
15 (NEK-12) shows the Company's calculation of Bad Debt expense. The exhibit shows that
16 the Company calculated an initial expense amount of \$342,049 based on a five-year
17 average of booked uncollectible accounts expense for actual years 2020 to 2023 plus the
18 forecasted expense for 2024 and then escalated the amount by the 2025 CPI factor to arrive
19 at the 2025 amount of \$350,258.

1 There are several flaws with the calculation performed by the Company. First, the
2 Commission has long recognized the inferiority of the approach taken by the Company
3 using prior years booked expense to determine the projected test year expense. The booked
4 expense for uncollectible accounts can fluctuate from year to year due to a number of
5 reasons including subjective assumptions made by the Company, temporary events, and
6 the adequacy of the reserve account at the outset of any one particular year. Therefore,
7 using booked uncollectible expense, as the Company has done in this case, is not wise or
8 appropriate.

9 Second, the Company's use of the general inflation rate to increase the historical expenses
10 is inappropriate. Uncollectible costs are a function of electricity prices, not general
11 inflation, and should be forecasted based on future revenues for the projected test year that
12 may become uncollectible.

13 Third, using five years of uncollectible cost information is less desirable than a shorter
14 period, such as three years, which reflects more recent experience closer to the projected
15 test year.

16 **Q. WHAT APPROACH DO YOU RECOMMEND FOR ESTIMATING**
17 **UNCOLLECTIBLE ACCOUNTS EXPENSE IN THIS CASE?**

18 A. I calculated the Uncollectible Accounts Expense based on the actual net charge-offs
19 experienced by the Company relative to its sales revenue during the three most recent years
20 from 2021 to 2023. This is the methodology approved by the Commission in a number of

1 rate cases in recent years.⁶¹ This approach is shown in Exhibit AG-33, page 1. Lines 1, 2
2 and 3 show the Gross and Net Charge-offs of Uncollectible Accounts, as well as the
3 Company's Operating Revenues and the percentage of bad debts for each year in the final
4 column.

5 As shown in the exhibit, the net charge-offs to historical revenues average to 0.16% for
6 the three-year period, as shown on line 4. I applied the 0.16% average percentage to the
7 Company's projected Operating Revenues of \$127.5 million for the projected test year on
8 line 5 to develop the forecasted Uncollectible Accounts expense of \$203,000 on line 6.
9 This expense amount is lower than the Company's forecast by \$147,000.

10 Therefore, I recommend that the Commission adopt an uncollectible accounts expense
11 level of \$203,000 for the projected test year and reduce the Company's forecasted O&M
12 expense by \$147,000.

13 **E. 401k Plan Employee Savings Plan**

14 **Q. EXHIBIT A-16 (NEK-13) SHOWS THE EXPENSE FOR THE 401K EMPLOYEE**
15 **SAVINGS PLAN INCREASING 24% FROM \$679,000 IN 2023 TO \$843,000 FOR**
16 **THE PROJECTED TEST YEAR. DO YOU AGREE WITH THIS INCREASE?**

⁶¹ In Case No. U-20697, Consumers Energy filed its case using the ratio of net charge-offs to revenues for three years 2016 to 2018 and all parties to the case concurred with this approach. See page 204 of the Commission order. In DTE Gas and DTE Electric Case Nos. U-20940 and U-20162, the Commission approved the three-year net charge-offs approach. See U-20940, page 167 of the Commission order and U-20162 at page 87 of the Commission order.

1 A. No. Absent any change in the level of Company matching percentages, the Savings Plan
2 expense should primarily reflect changes in the number of employees and pay levels,
3 which I have adjusted downward to the CPI level as explained above in my testimony. On
4 page 10 of her direct testimony, Company witness Kay Ryan states that there have been
5 no substantive changes in UPPCO's benefits. I take this to mean that the plan provisions
6 related to matching benefits remain unchanged.

7 Accordingly, I calculated the savings plan expense for the projected test year at \$714,000
8 by using the most recent expense level in 2023 of \$679,000 and increasing it by the CPI
9 factors of 2.7% and 2.4% for 2024 and 2025. The resulting expense is \$129,000 lower
10 than the Company's projected test year level of \$843,367.

11 I recommend that the Commission set the level for the Company's 401k savings plan
12 expense at \$714,000 and reduce the Company's O&M expense by \$129,000.

13 **F. Variable Pay, Pay at Risk, and Incentive Compensation**

14 Beginning on page 5 of her direct testimony, Company witness Kay Ryan discusses the
15 Company's incentive compensation programs. Although she did not state the cost of these
16 benefit plans in her direct testimony, in response to discovery the Company disclosed that
17 it included \$1,104,869 of incentive compensation expense in this rate case filing related to

1 operational metrics and an additional \$276,217 related to achieving the Company's
2 EBITDA financial goal.⁶²

3 **Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S VARIABLE PAY**
4 **PLANS.**

5 A. The Company's Variable Pay Plans include two components: (a) the Incentive
6 Compensation plan oriented around financial performance, which at the target level
7 represents 20% of total payments; and (b) the Pay at Risk plan, which is oriented around
8 safety and certain operational metrics and at target represents 80% of total variable pay.

9 The Company's eight safety metrics monitor performance for the Dart OSHA Incident rate
10 and the related Dart Severity Rate, incident-free driven miles, Site-audit performance, and
11 Pre-Job assessment audit performance. The Company's operational metrics include (a)
12 SAIDI performance; (b) customer billing accuracy and timeliness; (c) eight MPSC
13 standard measures; (d) two metrics titled General Compliance and NERC Compliance; (e)
14 generation availability; and (f) environmental audits.

15 **Q. WHAT ARE THE REQUIREMENTS IDENTIFIED BY THE COMMISSION FOR**
16 **RECOVERY OF INCENTIVE COMPENSATION OR VARIABLE PAY PLANS?**

⁶² Exhibit AG-35 includes DR 5 Staff TMS-UPPCO-5.1 and 5.2. EBITDA = Earnings Before Interest Taxes Depreciation and Amortization expense.

1 A. In general, the Commission has ruled in several cases that in order for variable pay plan
2 costs to be recoverable in customer rates, the benefits must outweigh the costs. In this
3 case, the Company presented no testimony or exhibits showing how its plan metrics have
4 created any benefits for customers either historically or for the projected test year.

5 **Q. DO YOU BELIEVE THAT THE COMPANY’S INCENTIVE COMPENSATION**
6 **METRIC OF ACHIEVING A CERTAIN LEVEL OF EBITDA PROVIDES ANY**
7 **BENEFITS TO CUSTOMERS?**

8 A. No. Achieving the EBITDA performance metric benefits shareholders. This a cash flow-
9 based earnings measure comparable to net income or earnings per share utilized by other
10 utilities in Michigan. The Commission has consistently disallowed incentive
11 compensation expense related to financial measures.

12 **Q. DO YOU SEE ANY BENEFITS BEING ACHIEVED RELATED TO THE**
13 **COMPANY’S SAFETY METRICS.**

14 A. In the Company’s last general rate case, the AG asked the Company to provide additional
15 information in this area. Based on the information provided in response to discovery,
16 generally, the Company’s safety efforts seem to be effective and the Company has reduced
17 Worker’s Compensation costs and Property Damage claims. OSHA Recordable cases have
18 fallen from 11 in 2017 to 2 in 2021.⁶³ I will note that the Company’s Workers

⁶³ Case U-21286 UPPCO response to DR 3-AG-UPPCO-82.

1 Compensation expense has continued to decline and was \$85,646 in 2023, which is down
2 59% from 2022.⁶⁴ Although moving in the right direction, these costs savings do not
3 offset the cost of incentive compensation that the Company seeks to recover in this rate
4 case.

5 **Q. WHAT IS YOUR RECOMMENDATION FOR THE AMOUNT OF INCENTIVE**
6 **AND VARIABLE PAY TO BE INCLUDED IN PROJECTED TEST YEAR O&M**
7 **EXPENSE?**

8 A. I recommend that the Commission exclude the \$276,217 of incentive compensation related
9 to financial performance. With regard to the remainder of the incentive compensation
10 expense of \$1,104,869 pertaining to operational metrics, I would normally recommend
11 that the Commission also disallow recovery of this amount because the Company has not
12 made a convincing case that the benefits to customers exceed the costs. However, I am
13 cognizant of the fact that in other rate cases, the Commission has approved recovery of
14 certain portions of incentive compensation related to operational metrics. Therefore, I
15 recommend that the Commission approve only recovery of 50% of the \$1,104,869
16 incentive compensation expense pertaining to operational measures and disallow the
17 remaining amount of \$552,434.

⁶⁴ DR 2-AG-UPPCO-2.42.

1 As such, the Commission should remove \$828,651 of incentive compensation expense
2 (552,434 + \$276,217) from the Company's forecasted O&M expense.

3 **G. American Transmission Company (ATC) Services**

4 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO O&M EXPENSE FOR ATC**
5 **SERVICES.**

6 A. On page 2 of his direct testimony, Mr. Daniel Gervae discusses the services that UPPCO
7 provides to ATC. UPPCO has an agreement with ATC to provide services, such
8 maintenance and operation, switching, and constructions at 15 substations owned by ATC
9 or jointly owned by UPPCO and ATC.

10 In discovery, the Attorney General asked the Company to provide the amount of revenue
11 billed to ATC for services provided for each year 2021 to 2023 and forecasted for 2024
12 and 2025. In response, the Company reported that over the past three years it had billed
13 ATC on average approximately \$1,883,000 annually for those services and forecasted
14 revenues of \$1,097,000 for 2024 and \$1,124,000 for 2025. The Company also stated that
15 it did not record the amount billed to ATC as revenue and instead applied the billed
16 amounts as reductions or credits against O&M expense.⁶⁵

17 The \$1,124,000 that the Company forecasted as a reduction to O&M expense for the
18 projected test year is significantly lower than the \$1.8 million billed in 2023 and also lower

⁶⁵ Exhibit AG-36 included DR 3-AG-UPPCO-3.83.

1 than the average amount of \$1,883,000 billed during the past three years. Neither the
2 discovery response nor the direct testimony of Mr. Gervae report about any significant
3 change in the services to be provided by UPPCO to ATC. If anything, given the recent
4 increase in costs due to inflation the amount billed to ATC should be increasing not
5 decreasing.

6 The \$1,124,000 forecasted to be billed to ATC for the projected test year is clearly
7 understated. A more appropriate amount is the \$1,883,000 billed on average during the
8 past three years adjusted for inflation. That amount is \$1,935,000, or \$811,000 more than
9 forecasted by the Company.⁶⁶ Therefore, I recommend that the Commission reduce the
10 company's forecasted O&M expense forth projected test year by \$811,000.

11 **H. Employee Benefits Expense Discrepancy**

12 **Q. PLEASE EXPLAIN YOUR \$125,000 ADJUSTMENT TO O&M EXPENSE**
13 **RELATED TO A DISCREPANCY IN FORECASTED EMPLOYEE BENEFIT**
14 **COSTS.**

15 A. In Exhibit A-8, Schedule C5, the Company included Administrative and General (A&G)
16 Expenses of \$13.978 million for the projected test year. In discovery, the Attorney General
17 asked the Company to provide further details on the components of the forecasted A&G
18 expense. The component expenses provided in the discovery response show that the

⁶⁶ \$1,883,000 x 1.027 x 1.024 = \$1,935,000 - \$1,124,000 = \$811,000.

1 Company included \$3,088,236 of expense for Employee Pension and Benefits (Acct. 926)
2 in the \$13.978 million of total A&G expense.⁶⁷ However, in Exhibit A-16 (NEK-13), line
3 35, which is a further cost breakdown of Account 926 for the projected test year, the
4 Company can only support \$2,963,235 in expense for Employee Pension and Benefits.
5 The difference is \$125,000.

6 The evidence provided by the Company shows that the total A&G expense for the
7 projected test year is overstated by \$125,000. Therefore, I recommend that the
8 Commission remove this amount from the Company's forecasted O&M expense for the
9 projected test year.

10 **I. Supplemental Employee Retirement Plan (SERP)**

11 **Q. PLEASE DISCUSS THE AMOUNT OF SERP EXPENSE THAT THE COMPANY**
12 **INCLUDED IN O&M EXPENSE FOR THE PROJECTED TEST YEAR.**

13 A. As shown on Exhibit A-16 (NEK-13), the Company included \$10,620 of SERP expense
14 in the projected test year. This expense is for a small group of highly paid individuals who
15 exceed the IRS limits on allowed tax deductible expense. In recent years in other rate
16 cases, the Commission has consistently rejected the inclusion of SERP costs in customer
17 rates. Therefore, I recommend that the Commission remove the \$10,620 from the
18 projected test year O&M expense.

⁶⁷ Exhibit AG-37 includes DR 2-AG-UPPCO-2.35.

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J. Summary of O&M Adjustments

Q. PLEASE PROVIDE A SUMMARY OF THE O&M ADJUSTMENTS YOU PROPOSE IN THIS RATE CASE.

A. As shown in Exhibit AG-29, I recommend that the Commission remove \$4,525,000 from the Company’s forecasted O&M expense for the projected test year for total company and \$4,464,000 pertaining to the retail jurisdiction business.

VII. Depreciation Expense

Q. PLEASE DISCUSS THE DEPRECIATION EXPENSE ADJUSTMENT THAT YOU PROPOSE.

A. In Exhibit AG-10, I identified the adjustments to be made to the Company’s proposed capital expenditures. Those reductions lower the amount of depreciation expense that the Company will incur during the projected test year. On the same exhibit, I have calculated the reduction in depreciation expense of \$1,135,787. I recommend that the Commission reduce the Company’s depreciation expense by this amount for the projected test year.

VIII. Adjustments To Revenue Deficiency

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

1 A. Exhibit AG-38 summarizes the adjustments to rate base and operating income. The net
2 result is a jurisdictional revenue deficiency of \$7.0 million, which is a reduction of \$9.9
3 million from the Company's requested level of \$16.9 million.

4 I recommend the Commission adopt my proposed adjustments and issue an order granting
5 rate relief to the Company no greater than \$7.0 million. This revenue deficiency amount
6 represents an overall increase in customer rates of 6.7%.

7 **Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

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

Experience and Qualifications of Sebastian Coppola

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

EMPLOYMENT BACKGROUND

Mr. Coppola has been an independent consultant for 22 years. Before that, he spent three years as Senior Vice President and Chief Financial Officer of SEMCO Energy, Inc. with responsibility for all financial operations, corporate development and strategic planning for the company's Michigan and Alaska regulated and non-regulated operations. During the period at SEMCO Energy, he had also responsibility for certain storage and pipeline operations as President and COO of SEMCO Energy Ventures, Inc. Prior to SEMCO, Mr. Coppola was Senior Vice President of Finance for MCN Energy Group, Inc., the parent company of Michigan Consolidated Gas Company (now DTE Gas Company).

ENERGY INDUSTRY EXPERTISE

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

Experience and Qualifications of Sebastian Coppola

of these positions he interacted with various operating areas of the company and was intricately involved in construction and operating programs, defining gas purchasing strategies, rate case analysis, cost of capital studies and other regulatory proceedings.

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

ENERGY INDUSTRY AND REGULATORY EXPERIENCE

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

Mr. Coppola has extensive experience with gas and electric utilities in the areas of gas operations, gas supply and regulatory proceedings. He has led or participated in the financial operations, gas supply planning and/or gas cost recovery arrangements of two major gas utilities in Michigan and in Alaska. He has prepared

**Experience and Qualifications
of Sebastian Coppola**

testimony in multiple electric and gas general rate cases, Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) reconciliation proceedings, Cast Iron and Pipeline Replacement Programs and other regulatory cases on behalf of the Michigan Attorney General, Citizens Against Rate Excess (CARE), the Public Counsel Division of the Washington Attorney General, the Illinois Attorney General, the Maryland Office of Public Counsel, and the Ohio Office of Consumers Counsel in electric and gas utility rate cases, including AEP Ohio, Ameren-Illinois Utilities, Avista, Consumers Energy, DTE Electric Company, MichCon (DTE Gas Company), Michigan Gas Utilities Corp, Nicor Gas, PacifiCorp, Peoples Gas, Puget Sound Energy, SEMCO, Upper Peninsula Power Company, Washington Gas, and Wisconsin Public Service Company.

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

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

Experience and Qualifications of Sebastian Coppola

During his long career at DTE Gas, among other responsibilities, Mr. Coppola was responsible to oversee the operation of the MichCon Wet Header System, a pipeline that transported natural gas and gas liquids from Michigan gas producing fields in the Niagaran Reef in the northern area of the lower peninsula of Michigan to processing plants in Kalkaska, MI. His responsibility included ensuring the day-to-day flow of gas and liquids, and identifying operating issues requiring corrective action.

He was also responsible for the study to assess the feasibility of building the Saginaw Bay Pipeline, a transmission line to move Praire Du Chein natural gas reserves in the eastern area of Michigan to processing plants. Prior to the construction of the pipeline, Mr. Coppola worked with operating management to prepare requests for proposal for the construction project and the selection of qualified bids. During and subsequent to the construction of the pipeline, Mr. Coppola assisted in the management and oversight of the pipeline, including review of operating performance and profitability.

Additionally, as Manager of Materials Inventory, Warehousing and Procurement at DTE Gas, Mr. Coppola worked closely with suppliers of pipe, control valves, flanges, meters, fittings, equipment and thousands of other parts and materials used in the construction, repair and maintenance of DTE Gas's transmission, distribution and storage facilities, including repairs and upgrades to compressor stations, and replacement of cast iron mains, bare and wrapped steel pipelines and service lines. His responsibilities included the review of design and construction blueprints and plans with frequent visits to construction sites during excavation of new pipeline trenches, and during replacement of defective or leaky

Experience and Qualifications of Sebastian Coppola

pipes, and replacement of control valves. Mr. Coppola also made frequent visits and inspection to storage facilities owned by DTE Gas to understand materials requirements during planned construction projects. Mr. Coppola was also responsible to ensure that materials and equipment were ordered to meet material standards and safety codes.

Through these responsibilities, Mr. Coppola gained knowledge and expertise with field construction project procedures, pipeline trenching problems, installation inspections, operation and maintenance cycles, and the material procurement of pipe, valves, flanges, meters and thousands of other parts and equipment used in the construction of natural gas transmission, distribution and storage facilities.

During his career with MCN Energy Group, Mr. Coppola was responsible for the evaluation of investments in interstate pipelines, new gas storage facilities, gas cogeneration plants, and construction of new power plants in the U.S. and India. Mr. Coppola was a key member of the negotiating team with contractors and suppliers tasked to build the power facilities, including the evaluation of Engineering, Procurement and Construction (EPC) bids and contracts.

Subsequent to his move to SEMCO Energy Corporation in 1999, Mr. Coppola was responsible for the acquisition and integration of pipeline construction companies providing services to gas utilities and interstate pipelines. In addition to its gas utility business in Michigan and Alaska, serving approximately 350,000 customers, SEMCO Energy owned SEMCO Pipeline Construction, a non-regulated business providing gas pipeline and natural gas facilities construction services to gas utilities and interstate pipelines in the Midwest and Eastern regions of the U.S.

**Experience and Qualifications
of Sebastian Coppola**

SEMCO Pipeline Construction provided construction services similar to KS Energy, Northern Pipeline and other contractors used by the Company. During his tenure at SEMCO Energy, Mr. Coppola reviewed dozens of pipeline construction companies and acquired six companies. Mr. Coppola's responsibilities included management of the performance and profitability of the pipeline construction services business requiring field visits to construction projects and quality reviews. In this process, Mr. Coppola learned firsthand how pipeline construction companies operate, construction project challenges, their bidding practices and the bidding of construction projects, including pricing, bidding procedures and policies both from the contractor's side and the gas utility side.

Mr. Coppola has testified extensively on gas utility pipeline, service lines and inside meters replacement programs related to at-risk pipes that provide safety issues to customers and the general public.

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

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

Experience and Qualifications of Sebastian Coppola

Mr. Coppola performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operation and maintenance expenses, capital expenditures, cost allocations, cost of capital, cost of service and rate design, and various cost tracking mechanisms. In addition, he has performed analysis of power costs and filed testimony in power supply cost recovery cases, including reconciliation of annual power supply costs.

In his position as Senior Vice President of Finance at MCN, Mr. Coppola also had responsibility for project financing of independent power generation plants in which MCN was an owner. In this regard, he was intricately involved and became knowledgeable of PURPA qualified cogeneration plants in Michigan and other states. In addition, he was involved in negotiating the development and financing of power generation and electricity distribution plants in other countries, such as India.

➤ Specific Regulatory Proceedings and Related Experience:

- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2024 gas rate case U-21540 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company (DTE Gas) 2024 gas rate case U-21291 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2022-2023 GCR reconciliation in case No. U-21065.
- Filed testimony on behalf of the Michigan Attorney General in Consumers Energy (CECo) 2023 gas rate case U-21490 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in DTM Michigan Lateral Company (DMLC) 2023 Act 9 Transportation Service rate update in case No. U-21525.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2022 PSCR reconciliation in case No. U-21051.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2022-2023 GCR plan in case No. U-21067.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 PSCR reconciliation in case No. U-21049.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Power Company 2023 electric rate Case U-21461 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE 2023-2024 GCR plan in case No. U-21271.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023-2024 GCR plan in case No. U-21269.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2023 electric rate Case U-21389 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Energy Gas Company (SEMCO) 2023-2024 GCR plan in case No. U-21277.
- Filed testimony on behalf of the Michigan Attorney General in DTE Electric Company (DTEE) 2023 rate Case U-21297 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2023-2024 GCR plan in case No. U-21273.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 gas rate Case U-21308 on several issues, including sales revenues, operation and maintenance expenses, capital expenditures, cost of capital, and other items.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan reconciliation case No. U-20817.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 PSCR plan reconciliation case No. U-20827.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2021-2022 GCR plan reconciliation case No. U-20819.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2022 general rate case No. U-21286.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan reconciliation case No. U-20823.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022-2023 GCR plan case No. U-21062.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2022-2023 GCR plan case No. U-21070.
- Filed testimony on behalf of the Michigan Attorney General in CECo 2022 electric rate Case U-21224 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Public Counsel Division of Washington Attorney General in the Avista 2022 electric and gas rate cases on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in the Act 9 application in Case No. U-20993 by Saginaw Bay Pipeline Company to set transportation rates for services to DTE Gas Company.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2022 electric rate Case U-20836 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed rebuttal testimony on behalf the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gaslight & Coke Company (Peoples Gas) in Docket 17-0137.

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of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 gas rate Case U-21148 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan reconciliation case No. U-20554.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 20-0330.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2020-2021 GCR plan reconciliation case No. U-20552.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2020-2021 GCR plan reconciliation case No. U-20546.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2020 PSCR plan reconciliation case No. U-20526.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2020 PSCR plan reconciliation case No. U-20528.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR plan reconciliation case No. U-20236.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Ameren Illinois Company (Ameren) in Docket 20-0323.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021-2022 GCR plan case No. U-20816.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2021-2022 GCR plan case No. U-20822.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2021 electric rate Case U-20963 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2021 gas rate Case U-20940 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Michigan Lateral Company (DMCL) 2021 Act 9 filing to convert a pipeline and build two interconnections for transportation services to DTE Gas Company in case No. U-20894.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2021 power plant and tree trimming securitization costs in case No. U-21015
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2021 PSCR plan case No. U-20802.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2019-2020 GCR reconciliation case No. U-20234.
- Filed testimony on behalf of the Maryland Office of Public Counsel in Washington Gas Light Company's 2020 rate Case 9651 on several issues, including operation and maintenance expenses, capital expenditures, and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2020 Karn 1 & 2 Retirement Cost and Bond Securitization Case U-20889.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Reconciliation in case U-20222.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2020-2021 GCR plan case No. U-20543.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO Gas Company (SEMCO) 2020-2021 GCR plan case No. U-20551.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2020 electric rate Case U-20697 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, and other items.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in the complaint against Upper Peninsula Power Company's (UPPCO) Revenue Decoupling Mechanism (RDM) in Case No. U-20150.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2019 gas rate Case U-20650 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2019 gas rate Case U-20642 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR reconciliation Case U-20210.
- Prepared a report on the financial condition and risks of AltaGas and Washington Gas Light Company on behalf of the Maryland Office of People's Counsel filed with the Maryland Public Service Commission in July 2019 in Case No. 9449.
- Filed rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2018-2019 GCR reconciliation case U-20209.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR reconciliation case U-20215.
- Provided assistance and proposals to the Maryland Office of Peoples Counsel on Multi-Year Rate Plans and Performance-Based Ratemaking.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Reconciliation in case U-20203.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2018 PSCR Reconciliation in case U-20202.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure

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of Sebastian Coppola**

Program (Rider QIP) of the Northern Illinois Gas Company (Nicor Gas) in Docket 19-0294.

- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 electric rate Case U-20561 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, and other items.
- Filed testimony on behalf of the Michigan Attorney General in Indiana Michigan Power Company (I&M) 2019 electric rate Case U-20239 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019 gas rate Case U-20479 on several issues, including sales, operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2019-2020 GCR Plan case U-20245.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2019-2020 GCR Plan case U-20233.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2019 PSCR Plan case U-20221.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2019-2020 GCR Plan case U-20235.
- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2019-2020 GCR plan case U-20239.
- Filed rebuttal testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017-2018 GCR reconciliation case U-20076.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2017-2018 GCR reconciliation case U-20075.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 gas rate Case U-20322 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in I&M Tax Credit C Calculation in case U-20317.
- Filed direct testimony on behalf of the Illinois Attorney General in Nicor Gas 2018 rate case on capital expenditures and rate base additions in Docket 18-1775.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Tax Credit C Calculation in case U-20298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2017-2018 GCR Reconciliation case U-20078.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 Tax Credit C Calculation for the Gas and Electric Divisions in case U-20309.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company 2018 electric rate Case U-20276 on several issues, including excess deferred taxes, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2017 PSCR Reconciliation in case U-20068.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 rate Case U-20162 on several issues, including operation and maintenance expenses, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 Tax Credit B refund for the Electric Division in case U-20286.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 Integrated Resource Plan in case U-20165.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2018 Tax Credit B refund case U-20287 for the natural gas business.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit B refund case U-20189.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2018 electric rate Case U-20134 on several issues, including capital expenditures, cost of capital, rate design and other items.
- Filed direct testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 16-0197.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR reconciliation case U-17941-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2018-2019 GCR Plan case U-18417.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2018 Tax Credit A refund case U-20102.
- Filed testimony on behalf of the Michigan Attorney General in I&M 2018 PSCR Plan case U-18404.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018-2019 GCR Plan case U-18412.
- Filed testimony on behalf of the Michigan Attorney General in Upper Peninsula Power Company (UPPCO) 2018 Tax Credit A refund case U-20111.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2018 Tax Credit A refund case U-20106.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2018 PSCR Plan case U-18403.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2018 PSCR Plan case U-18402.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2017 gas rate Case U-18999 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in CEC0 2017 gas rate Case U-18424 on several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2016 PSCR reconciliation case U-17918-R.
- Assisted the Michigan Attorney General in the review of several GCR and PSCR cases during 2017 and 2018, and proposed terms for settlement of those cases.
- Assisted the Michigan Attorney General in the filing of comments with the Michigan Public Service Commission relating to rate case filing requirements in case U-18238, refunds of tax savings from the lower federal tax rate in case U-18494 and Performance Based Regulation.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the reconciliation of the rate surcharge for the Qualified Infrastructure Program (Rider QIP) of the Peoples Gas and Coke Company's (Peoples Gas) in Docket 15-0209.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 electric Rate Case U-18255 on a several issues, including revenue, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2017 electric rate Case U-18322 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital and other items.
- Filed direct and rebuttal testimony on behalf of the Illinois Attorney General for the re-opening of proceedings in the restructuring of the Peoples Gas's main replacement program and gas system modernization plan in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in the Upper Michigan Energy Resources Corporation (UMERC) application for a certificate of public necessity and convenience to build two power plants in the Upper Peninsula of Michigan in case U-18202.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in SEMCO application for a certificate of public necessity and convenience to build a pipeline in the Upper Peninsula of Michigan in case U-18202.
- Filed testimony on behalf of the Public Counsel Division of the Washington Attorney General in Puget Sound Energy's 2016 Complaint for Violation of Gas Safety Rules in Docket No. UE-160924.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2017 PSCR Plan case U-18143.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2015 Power Supply Cost Recovery (PSCR) reconciliation case U-17678-R.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2016 gas general rate case U-18124 on a several issues, including revenue, operations and maintenance costs, capital expenditures, working capital, cost of capital and other items.
- Filed testimony on behalf of the Illinois Attorney General for the restructuring of the Peoples Gas's main replacement program in Docket 16-0376.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2014-2015 GCR Plan reconciliation case U-17332-R.
- Filed testimony on behalf of the Michigan Attorney General in the formation of UMERC and the transfer of Michigan assets of Wisconsin Public Service Corporation and Wisconsin Electric Company to UMERC in Case U-18061.
- Filed testimony on behalf of the Michigan Attorney General in CECO Court of Appeals Remand Case U-17087 for review of the Automated Meter Infrastructure (AMI) opt-out fees.
- Filed testimony on behalf of the Michigan Attorney General in CECO 2016 electric Rate Case U-17990 on a several issues, including revenue, operations and maintenance costs, capital expenditure programs, cost of capital, rate design and other items.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in Michigan Gas Utilities Corporation (MGUC) 2016-2017 GCR Plan case U-17940.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 electric Rate Case U-18014 on a several issues, including revenue, revenue decoupling, operations and maintenance costs, capital expenditures, cost of capital, rate design and other items.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2016-2017 GCR Plan case U-17942.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2016-2017 GCR Plan case U-17941.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015 gas general rate case U-17999 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, Revenue Decoupling Mechanism (RDM) program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2016-2017 GCR Plan case U-17943.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2016 PSCR Plan case U-17918.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2014-2015 GCR Plan reconciliation case U-17334-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2016 PSCR Plan case U-17920.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan reconciliation case U-17333-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC Co 2015 gas general rate case U-17882 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, infrastructure cost recovery mechanism, cost of capital and other items..
- Filed testimony on behalf of the Michigan Attorney General in CEC Co Gas Choice and End-User Transportation tariff changes case U-17900.

**Experience and Qualifications
of Sebastian Coppola**

- Analyzed the gas rate case filings of MGUC in Case U-17880 and assisted the Michigan Attorney General in settlement of the case.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 PSCR reconciliation case U-17317-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2013-2014 GCR Plan reconciliation case U-17131-R.
- Filed testimony on behalf of the Michigan Attorney General in DTEE 2014 electric Rate Case U-17767 on a several issues, including operations and maintenance costs, capital expenditures, AMI program, cost of capital and other items.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas 2015-2016 GCR Plan case U-17691.
- Filed testimony on behalf of the Illinois Attorney General in Ameren Illinois Company's 2015 general rate case on operation and maintenance costs in Docket 15-0142.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 electric Rate Case U-17735 on a several issues, including sales, operations and maintenance costs, capital expenditures, cost of capital, AMI program, revenue decoupling and infrastructure cost recovery mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2015-2016 GCR Plan case U-17693.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2015-2016 GCR Plan case U-17690.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2015 PSCR Plan case U-17678.
- Analyzed the electric rate case filings of Northern States Power in Case U-17710 and Wisconsin Public Service Company U-17669, and assisted the Michigan Attorney General in settlement of these cases.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2013-2014 GCR Plan reconciliation case U-17133-R.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan reconciliation cases U-17130-R.

Experience and Qualifications of Sebastian Coppola

- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan reconciliation case U-17132-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 gas general rate case U-17643 on a several issues, including revenue, operations and maintenance costs, capital expenditures, main replacement program, cost of capital and other items..
- Filed testimony on behalf of the Illinois Attorney General in Wisconsin Energy merger with Integrys on the Peoples Gas and Coke Company's Accelerated Main Replacement Program Docket 14-0496.
- Filed testimony on behalf of Citizens Against Rate Excess in Wisconsin Public Service Company's 2013 PSCR plan reconciliation case U-17092-R.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 PSCR plan case U-17317.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014 OPEB Funding case U-17620.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2014-2015 GCR Plan case U-17333.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2014-2015 GCR Plan case U-17331.
- Filed testimony on behalf of the Michigan Attorney General in CEC0 2014-2015 GCR Plan case U-17334.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Company's 2014 PSCR plan case U-17299.
- Filed testimony in March 2013 on behalf of the Michigan Attorney General in CEC0's electric Rate Case U-15645 on remand from the Michigan Court of Appeals for review of the AMI program.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 PSCR plan case U-17298.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2012-2013 GCR Reconciliation case U-16920-R.
- Filed testimony on behalf of the Michigan Attorney General in DTE Gas Company 2012-2013 GCR Reconciliation case U-16921-R.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in CEC0 2012-2013 GCR Reconciliation case U-16924-R.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2012-2013 GCR Reconciliation case U-16922-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) reconciliation case U-16881-R.
- Filed testimony in Puget Sound Energy's 2013 Power Cost Only Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130167 on the power costs adjustment mechanism.
- Filed testimony in PacifiCorp's 2013 General Rate Case on behalf of the Public Counsel Division of the Washington Attorney General in Docket No. UE-130043 on power costs, cost allocation factors, O&M expenses and power cost adjustment mechanisms.
- Filed testimony on behalf of the Michigan Attorney General in SEMCO 2013-2014 GCR Plan case U-17132.
- Filed testimony on behalf of the Michigan Attorney General in MGUC 2013-2014 GCR Plan case U-17130.
- Filed testimony on behalf of the Michigan Attorney General in CEC0's 2012 electric Rate Case U-17087 on a several issues, including cost of service methodology, rate design, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism and other revenue/cost trackers.
- Filed reports on gas procurement and hedging strategies of four gas utilities before the Washington Utilities and Transportation Commission on behalf of the Washington Attorney General – Office of Public Counsel in April 2013.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2011-2012 GCR Plan reconciliation cases U-16481-R and U-16483-R.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company's 2012 Power Supply Cost Recovery (PSCR) plan case U-17091.

Experience and Qualifications of Sebastian Coppola

- Filed testimony in MichCon’s 2012 gas Rate Case U-16999 on a several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance costs, capital expenditures and infrastructure cost recovery mechanism.
- Filed testimony on behalf of the Washington Attorney General – Office of Public Counsel on executive and board of directors’ compensation in the 2012 Avista general rate case.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company’s 2011 Power Supply Cost Recovery (PSCR) reconciliation case U-16421-R.
- Filed testimony on behalf of the Ohio Office of Consumers Counsel in AEP Ohio’s power supply restructuring case in June 2012.
- Filed testimony on behalf of the Michigan Attorney General in MGUC and SEMCO 2012-2013 GCR Plan cases U-16920 and U-16922.
- Filed testimony for Citizens Against Rate Excess in Upper Peninsula Power Company’s 2012 PSCR plan case U-16881.
- Filed testimony for Citizens Against Rate Excess in Wisconsin Public Service Corporation’s 2012 PSCR plan case U-16882.
- Filed testimony for the Michigan Attorney General in CECo’s gas business Pilot Revenue Decoupling Mechanism in case U-16860.
- Filed testimony for the Michigan Attorney General in Consumers Energy Gas 2011 Rate Case U-16855 on several issues, including sales volumes, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO and MGUC 2010-2011 GCR Plan reconciliation cases U-16147-R and U-16145-R.
- Filed testimony for the Michigan Attorney General in Consumers Energy 2011 electric Rate Case U-16794 on several issues, including electric sales forecast, revenue decoupling mechanism, operations and maintenance cost, employee benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in CECo’s electric business Pilot Revenue Decoupling Mechanism in case U-16566.

**Experience and Qualifications
of Sebastian Coppola**

- Filed testimony on behalf of the Michigan Attorney General in SEMCO and MGUC 2011-2012 GCR Plan cases U-16483 and U-16481.
- Filed testimony for the Michigan Attorney General in Detroit Edison 2010 electric Rate Case U-16472 on several issues, including revenue decoupling mechanism, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony for the Michigan Attorney General in SEMCO 2009-2010 GCR reconciliation case U-15702-R.
- Filed testimony for Michigan Attorney General in MGUC 2009-2010 GCR reconciliation case U-15700-R.
- Filed testimony for Michigan Attorney General, in Consumers Energy Gas 2010 Rate Case U-16418 on several issues, including sales volumes, operations and maintenance costs, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General, in SEMCO 2010 Rate Case U-16169 on several issues, including sales volumes, rate design, operations and maintenance cost, executive compensation and benefits, capital expenditures and cost of capital.
- Filed testimony, for Michigan Attorney General in Consumers Energy 2009 electric Rate Case U-16191 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost and capital expenditures.
- Filed testimony for Michigan Attorney General, in MichCon 2009 gas Rate Case U-15985 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Filed testimony for Michigan Attorney General and was cross-examined in Consumers Energy 2009 gas Rate Case U-15986 on several issues, including sales volumes, revenue decoupling mechanism, operations and maintenance cost, capital expenditures and cost of capital.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO and MGUC 2010-2011 GCR Plan cases U-16147 and U-16145.

**Experience and Qualifications
of Sebastian Coppola**

- Prepared testimony and assisted Michigan Attorney General in settlement of SEMCO 2009-2010 GCR case U-15702.
- Prepared testimony and assisted Michigan Attorney General in settlement of MGUC 2009-2010 GCR case U-15700.
- Prepared testimony and assisted the Michigan Attorney General in discussions and settlement of SEMCO 2008-2009 GCR case U-15452 and reconciliation case U-15452-R.
- Prepared testimony and assisted Michigan Attorney General in discussions and settlement of MGUC 2008-2009 GCR reconciliation case U-15450-R.
- Prepared testimony for Michigan Attorney General in SEMCO GCR 2007-2008 Reconciliation Case U-15043-R.
- Prepared testimony for Michigan Attorney General filed in MGUC 2007-2008 GCR Reconciliation Case U-15040-R.
- Participated in drafting of testimony for all aspects of SEMCO rate case filing with the Regulatory Commission of Alaska (RCA) in 2001.
- Filed testimony in 2001 before the (RCA) and was cross-examined on the financing plans for the acquisition of Enstar Corporation and the capital structure of SEMCO.
- Developed a cost of capital study in support of testimony by company witness in the Saginaw Bay Pipeline Company rate request proceeding in 1989.
- Prepared testimony for company witness on cost of capital and capital structure in MichCon 1988 gas rate case.
- Filed testimony in MichCon gas conservation surcharge case in 1986-87.
- Testified before MPSC ALJ in MichCon customer bill collection complaints in 1983.
- Participated in analysis of uncollectible gas accounts expense for inclusion in rate filings between 1975 and 1988.
- Participated in analysis of allocation of corporate overhead to subsidiaries and use of the “Massachusetts Formula” at MichCon and at SEMCO in 1975 and 2000.

Experience and Qualifications of Sebastian Coppola

- Prepared support information on GCR and rate case-O&M testimony at MichCon from 1975 to 1988.
- Filed testimony in MichCon financing orders in 1987 and 1988.
- Participated in rate case filing strategy sessions at MichCon and SEMCO from 1975 to 2001.
- Provided Hearing Room assistance and guidance to counsel on financial and policy issues in various cases from 1975 to 2001.

EDUCATIONAL BACKGROUND

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



Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.58

Refer to lines 6-18 on page 5 of Mr. Schlorke's direct testimony on the Victoria Access Road. Please

- A. Explain what work has been done on this project as of June 15, 2024 and what work remains to be done and when.
- B. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
- C. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.

UPPCO Response:

- a. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
 - No work has been completed – the project has been moved out to 3rd quarter 2025.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
 - Due to the schedule change the project will not be bid out until 1st or 2nd quarter 2025. Therefore, there are no alternative bid costs or explanations to provide.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.
 - The forecasted cost is \$260,670 and without a selected bid there is no variance to explain.

Response by: Virgil Schlorke

Dated: July 3, 2024

Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.61

For each of the projects discussed beginning on line 13 on page 7 and through page 16 of Mr. Schlorke's direct testimony, except the item on row 8 of Exhibit A- 20, please:

- a. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.
- d. For the Hoist, McClure, silver Lake Dam Concrete Refurbishment, provide the amount to be spent each year and what the amount will be spent on. Provide any similar costs spent each year in 2021-2023.

UPPCO Response:

Prickett Unit 2 Overhaul/Rewind

- a. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
 - The unit has been disassembled and the generator rotor, stator, turbine runner and unit bearings sent off site for refurbishment. Refurbished parts are scheduled to be returned to the site during 3rd quarter 2024 with re-assembly and alignment completed end of 3rd quarter beginning of 4th quarter 2024.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
 - Bidder 1 = \$987,722, Bidder 2 = \$760,816. The selected bidder was Bidder 2 because they were the lowest evaluated bid.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.
 - The forecasted cost is \$990,546 versus the bid cost of \$760,816. The bid cost represents unit disassembly, refurbishment of generator stator & rotor, runner refurbishment and unit re-assembly only and does not cover the refurbishment of the wicket gates, unit bearings, bushings, and unit braking system. Additionally, the bid does not include third party technical project management support and internal project management.

Hoist Unit 3 – Penstock Valve Replacement

- a. Explain what work has been done on the project as of June 15, 2024 and what work

remains to be done and when.

- Design, engineering and valve procurement is complete with construction/installation scheduled for end of 3rd beginning of 4th quarter 2025.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
- The project is currently in the bidding process and has not been awarded. Therefore, there are no alternative bid cost or explanation to provide.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.
- The forecasted cost is \$359,052 and without a selected bid there is no variance to explain.

McClure Unit 1 Overhaul/Rewind

- a. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
- This project was originally scheduled for 2025 but during the winter of 2023 the unit started to experience increased vibration. Internal inspections identified a damaged and cracked runner. Based on this new information the unit is listed as unavailable and the overhaul project moved up to 2024. The scope of the project was adjusted to focus on the runner replacement with a generator rewind being planned and scheduled later as an individual project. The unit has been disassembled and the runner sent off site for removal from the shaft. A new replacement runner is currently being fabricated with delivery and installation scheduled for 4th quarter 2024.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
- For runner procurement we had 4 bidders: Bidder 1 = \$256,500, Bidder 2 = \$720,760, Bidder 3 = \$150,000, and Bidder 4 = \$492,000. The selected bidder for the runner was Bidder 3 based on lowest evaluated cost. For unit disassembly and reassembly, we had 2 bidders: Bidder 1 = \$229,427, and Bidder 2 = \$311,700. The selected bidder for the disassembly & reassembly was Bidder 1 based on lowest evaluated cost.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.
- The forecasted cost is \$469,215 versus a bid cost of \$379,427. The bid cost represents unit disassembly, reassembly, and new runner only and does not cover the refurbishment of the wicket gates, unit bearings, and bushings. Additionally, the bid does not include third party technical project management support and internal project management.

Bond Falls Inundation Mapping

- a. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
- No work has been completed – the project is not scheduled to start until 2025.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.

- This project was bid as part of a larger generation fleet wide process. There were 2 qualified line-item bids received. Bidder 1 = \$98,600, and Bidder 2 = \$121,297. The selected bidder was Bidder 1 because they were the lowest evaluated bid.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.
- The forecasted cost is \$101,982 versus a bid cost of \$98,600. The bid cost represents engineering/modeling only and does not include internal project management.

Hoist, McClure, Silver Lake Dam Concrete Refurbishment

- a. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
- Design & engineering started late 2023 and is currently ongoing and expected to be completed by the end of 2024. Construction schedule development and bidding will follow completion of the engineering phase.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
- There were 2 qualified bids received. Bidder 1 = \$141,800, and Bidder 2 = \$160,100. The selected bidder was Bidder 1 because they were the lowest evaluated bid.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.
- The forecasted cost for design & engineering is \$53,103 (actual) in 2023 & \$103,955 (forecasted) in 2024 for a total of \$157,058 versus a bid cost of \$141,800. The bid cost represents engineering & design only and does not include additional required concrete borings and internal project management.
- d. For the Hoist, McClure, silver Lake Dam Concrete Refurbishment, provide the amount to be spent each year and what the amount will be spent on. Provide any similar costs spent each year in 2021-2023.
- The project is currently in the design & engineering phase with construction schedule development following engineering and FERC review & approval. Engineering & design started in 2023 with \$53,103 being spent and \$103,955 forecasted for 2024.

Bond Falls Canal Rip Rap

- a. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
- No work has been completed – the project has been moved out to 3rd quarter 2025.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
- Due to the schedule change the project will not be bid out until 1st or 2nd quarter 2025. Therefore, there are no alternative bid costs or explanations to provide.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.

- The forecasted cost is \$104,268 and without a selected bid there is no variance to explain.

Prickett Intake Refurbishment

- a. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
 - Engineering & design development is currently ongoing. Engineering and design will continue into 2025 with Federal Energy Regulatory Commission (FERC) submittal for review and approval. Construction schedule development and bidding will follow completion of the engineering phase & FERC approval.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
 - Engineering and design development had 3 Bidders. Bidder 1 = \$199,500, Bidder 2 = \$112,500, and Bidder 3 = \$159,800. The selected bidder was Bidder 2 because they were the lowest evaluated bid.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.
 - The forecasted cost for engineering is \$104,268 in 2024 and \$75,732 in 2025 for a total of \$180,000 versus a bid cost of \$112,500. The bid cost represents engineering and design development only and does not include additional optional analysis, FERC review & approval, changes resulting from FERC review and internal project management.

Victoria Gate Hoist Replacement

- a. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
 - Engineering & design is complete and moving forward with FERC submittal and approval process. Equipment procurement, construction schedule development and bidding will follow the FERC approval process. Tentative schedule is as follows: FERC approval by end of 2024, Procurement, preconstruction work and bidding in 2025 with construction & installation in 2026.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
 - The Design development and engineering was bid out in 2021. Bidder 1 = \$125,000, Bidder 2 = \$79,000, Bidder 3 = \$199,150. The selected bidder was Bidder 2 because they were the lowest evaluated bid. The bidding process for construction is not scheduled to start until 2025.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.
 - The Design development and engineering is complete and cost \$161,955 (actual). Equipment procurement & preconstruction forecasted cost is \$624,000 in 2025 and construction installation forecasted cost is \$1,178,459 in 2026. The bidding process has not started, and no bids awarded therefore no variance to explain.

UPPCO Response to discovery request 3-AG-UPPCO-3.61

Hoist Penstock Interior Lining Replacement

- a. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
 - Currently working through the bidding process with award scheduled for end of 3rd quarter 2024 with actual construction scheduled for 3rd quarter 2025.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
 - No bids have been received yet.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.
 - The forecasted cost is \$572,000 and without a selected bid there is no variance to explain.

McClure Substation Refurbishment

- a. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
 - Site planning and layout have been completed. Design & engineering is scheduled to end of 2nd quarter. Following completion of engineering bidding will start with construction scheduled for 2nd half of 2025.
- b. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
 - The bidding process has not started yet.
- c. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.
 - The forecasted cost is \$1,842,204 and without a selected bid there is no variance to explain.

Response by: Virgil Schlorke

Dated: July 3, 2024

UPPCO Response to discovery request 3-AG-UPPCO-3.62

Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.62

Refer to lines 11-24 on page 10 and lines 1-3 on page 11 of Mr. Schlorke's direct testimony on the Annual New Equipment and Generation Tools. Please provide the comparable amounts spent each year 2021-2023, and explain how you arrived at the forecasted costs for 2024 and 2025.

UPPCO Response:

2021		2022		2023	
Gen Small Cap Materials	\$15,724	Victoria Gate Hoist Travel Motor	\$1,681	Prickett Stop Log Design	\$11,359
Bond Control Dam Hoist	\$15,696	Victoria Power Attic Vent Fan	\$19,677	Victoria Fuel Tank	\$14,518
Radio MindShare Multicast Bridge/Gateway	\$5,669	Prickett Stop Log Design	\$3,835	Prickett Fire Alarm System	\$14,633
		Victoria Fuel Tanks	\$11,327	E03 PH Fire Alarm System	\$17,412
		Western Hydro Buoys	\$13,879	E04 PH Fire Alarm System	\$15,340
				Hand Tools McClure	\$9,081
				Hand Tools Hoist	\$2,599
				Hoist Dam Buoys	\$71,860
				Victoria PH Roof Insulation	\$32,956
Total	\$37,089	Total	\$50,398	Total	\$189,757

Seeing an increase in smaller known and unidentified projects in 2023 combined with an increase in forecasted smaller projects for 2024 (\$104,488 initially identified) along with the increasing cost for equipment and materials resulted in setting a base estimated amount of \$200,000 annually plus A & G.

Response by: Virgil Schlorke

Dated: July 3, 2024

MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.87

Refer to Exhibit A-7 (JRR/DJG-1), Schedule B5-4, on distribution capital projects and programs. Please provide the supporting projects for each year 2023 to 2025 for lines 2 through 7 under each Distribution category. If 2024 and 2025 project are shown in Exhibit A-21, show those projects under each category corresponding to the summary lines 2-8 in Schedule B5.4 and provide the information in Excel.

UPPCO Response:

The project listings in Exhibit A-21 (JRR-3) correlate to the group numbers listed in Schedule B5.4 of Exhibit A-7 (JRR/DJG-1), shown in the first 2 decimal points after the 1000 designation for Distribution. For example, the lines having 1000.04.0X in A-21 correlate to the line item 04 in Schedule B5.4.

Please refer to the Excel attachment, 03-AG-UPPCO Ringler Attachments, tab "JRR-3," which is Exhibit A-21 (JRR-3) modified to indicate actual costs from 2021 to 2023 as well as the 2024 and 2025 projects.

Response by: Jay Ringler

Dated: July 3, 2024

UPPCO Response to discovery request 3-AG-UPPCO-3.87

Michigan Public Service Commission
Upper Peninsula Power Company
UPPCO Distribution Reliability CAPEX
Distribution Projects > \$50K for 2024-25

03-AG-UPPCO-3.87

Case No.: U-21555
Exhibit No.: A-21 (JRR-3)
Schedule:
Page: 1 of 1
Witness: Jay R. Ringler

UPPCO Distribution Reliability CAPEX Distribution Projects > \$50K for 2024-25						
Line	Improve Reliability Load Growth	2021	2022	2023	2024	2025
1	1000.04.01 Misc Capital Jobs less than \$50k but greater than \$10k	1,439,270	2,007,628	2,419,212	1,487,500	1,487,500
2	1000.04.01 UPPCO Engineering, Designers, Clerks	1,175,848	1,278,976	1,268,505	1,400,000	1,450,000
3	1000.04.02 UPPCO WIDE URD Replacment (tied to unforseen failures)	187,557	204,033	101,242	200,000	250,000
4	1000.04.02 SYS. HARDENING, OH TO URD CONV, AND COPPER REPLC	4	7,310	203,516	350,000	356,000
5	1000.04.02 HOT -OH-UG M38 747 Copper replacement on M38 Part 2				700,000	
6	1000.04.02 HOT -OH-UG KWN 927 Copper Harbor to Mtn. Lodge rebuild				850,000	
7	1000.04.02 IRV -OH-UG LIN 3063 Replace copper and establish tie around Sunset Lake				600,000	
8	1000.04.02 HOT- OH-OH OSC 717 Relocate Mohawk to Highway Part 3				150,000	
9	1000.04.02 ISH - OH-UG BARNUM 1231 N. Rose Street				118,000	
10	1000.04.02 ISH -OH-UG BARNUM 1231 Lake Breeze Lane				290,000	
11	1000.04.02 ISH -OH-UG BARNUM 1231 Bussone and Marra Drive				205,000	
12	1000.04.02 ISH -OH-UG PERCH LAKE 401 Squaw Lake OH to UG				225,000	
13	1000.04.02 DEL -OH-UG DELTA 589 M35 South OH/UG and Loop Tie				325,000	
14	1000.04.02 ISH -OH-UG PERCH LAKE Substation Feeder Exit Relocation				252,000	
15	1000.04.02 DEL -OH-UG MASONVILLE Substation Feeder Exit Rework				252,000	
16	1000.04.02 ISH -OH-UG BARNUM 1205 US41 Round-about Rework				189,000	
17	1000.04.02 ISH -OH-UG FORSYTH 2733 Escanaba River UG Cable Replacement				87,000	
18	1000.04.02 Cutout Replacement				750,000	900,000
19	1000.04.02 UPPCO - 2024 Carryover Costs				75,000	100,000
20	1000.04.02 ISH - OH-UG BARNUM 1231 Rundman Drive					110,000
21	1000.04.02 ISH - OH-UG BARNUM 1231 Part 1 South Camp RD UG					470,000
22	1000.04.02 ISH - OH-UG BARNUM 1231 Part 1 Sparks Drive					590,000
23	1000.04.02 ISH - OH-UG FORSYTH 2733 Serenity Drive					740,000
24	1000.04.02 ISH - OH-UG FORSYTH 2733 Little Shag Road-South Tap					290,000
25	1000.04.02 ISH - OH-UG PERCH LAKE 401 Part 1 Horseshoe Lake					230,000
26	1000.04.02 IRV - OH-UG LIN 3063 Lake Emily OH-UG conversion on US2					150,000
27	1000.04.02 HOT - OH-UG KWN 927 OH-UG conversion on US41					500,000
28	1000.04.02 HOT - UG Replacement of Portage Canal underwater crossings					1,500,000
29	1000.04.02 HOT - OH-UG M38 749 Mansfeldt Rd rebuild					250,000
30	1000.05.01 Distribution Stores, Shop, Lab & Work Tools	145,370	251,003	178,558	200,000	260,000
31	1000.05.02 Distribution Line Transformers	1,341,176	2,053,225	3,490,548	4,200,000	4,000,000
32	1000.05.03 Distribution Reclosers	140,970	93,923	17,032	200,000	200,000
33	1000.05.04 Distribution Regulators	21,660	76,265	0	150,000	150,000

UPPCO Response to discovery request 3-AG-UPPCO-3.87

Michigan Public Service Commission
Upper Peninsula Power Company
UPPCO Distribution Reliability CAPEX
Distribution Projects > \$50K for 2024-25

03-AG-UPPCO-3.87

Case No.: U-21555
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Witness: Jay R. Ringler

UPPCO Distribution Reliability CAPEX Distribution Projects > \$50K for 2024-25						
Line	Improve Reliability Load Growth	2021	2022	2023	2024	2025
34	1000.05.06 Meters & Installations (incl. PTs and CTs)	129,232	293,276	333,277	300,000	300,000
35	1000.06.01 Services	1,170,278	1,152,216	992,351	623,000	675,000
36	1000.06.02 Line Extensions**	1,684,518	1,358,760	1,697,429	807,500	935,000
37	1000.06.03 Lighting	30,736	80,394	79,368	59,000	50,000
38	1000.07.01 Charge UP Michigan Grant EVC Installations				580,000	
39	1000.07.01 Mandated Allowance and unforeseen (Road Moves etc.)	15,369	336,835	522,301	100,000	150,000
40	1000.08.01 GIS Conflation	-	-	311,146	150,000	
41	1000.04.01 MTF 69-to-12.47 conversion	-	386,929	25,854		
42	1000.04.02 Summer Homes Lake Crossing Autrain	191,163	52,326	-		
43	1000.04.02 Forsyth - Gwinn Fdr Tie	1,037,056	-	-		
44	1000.04.02 Little Lake Rd URD	1,040	77,100	287,801		
45	1000.04.02 Ahmeek relocation	117,942	7,694	-		
46	1000.04.02 Jurmu Road relocation to highway	141,760	-	-		
47	1000.04.02 KIS 1275 - GWN 657 UG Tie	437,507	-	-		
48	1000.04.02 OSC 717/KWN 927 Relocate double circuit	458,380	4,896	-		
49	1000.04.02 OSC 719 Jacobsville UG tie	-	166,536	16,294		
50	1000.04.02 WNA 907 Pike Lake Road UG replacement	202,674	77,544	(4,296)		
51	1000.04.02 CR480 Improvement Project	288,031	19,911	3,595		
52	1000.04.02 Britz Rd UG replacement	60,923	-	-		
53	1000.04.02 MTU 1403 Replace Franklin Square UG tie	-	52,005	93,876		
54	1000.04.02 FRY2733 - Shag Lakes UG Part1	-	360,126	76,081		
55	1000.04.02 BRM 1205/1237 Tie	-	310,849	326,298		
56	1000.04.02 KWN 927 System Hardening	-	931,533	110,465		
57	1000.04.02 Oneco Road UG replacement (OSC 707)	-	144,656	30,870		
58	1000.04.02 Copper replacement on M38 ph 1 (M38 747)	-	271,646	32,367		
59	1000.04.02 Relocate Mohawk to highway ph 1 (OSC717)	-	234,441	31,459		
60	1000.04.02 Sved Rd UG replacement	-	141,499	21,208		
61	1000.04.02 KIS 1275 / GWN657 Tie, Part2	-	57,726	716,498		
62	1000.04.02 Cutout replacement	-	842,605	1,176,137		
63	1000.04.02 HEN 1017 Chassell Painsedale rebuild	-	-	838,815		
64	1000.04.02 Copper Harbor to Mt Lodge rebuild0	-	-	66,682		
65	1000.04.02 ATL 891-Red Ridge to Freda UG rplc	-	-	392,966		
66	1000.04.02 Chatham Ski Hill UG replacement	-	-	66,103		

UPPCO Response to discovery request 3-AG-UPPCO-3.87

Michigan Public Service Commission
 Upper Peninsula Power Company
 UPPCO Distribution Reliability CAPEX
 Distribution Projects > \$50K for 2024-25

03-AG-UPPCO-3.87

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 Witness: Jay R. Ringler

UPPCO Distribution Reliability CAPEX

Distribution Projects > \$50K for 2024-25

Line	Improve Reliability Load Growth		2021	2022	2023	2024	2025
67	1000.04.02	OSC 717 Mohawk relocate to highway	-	-	18,329		
68	1000.05.06	Meter Testing Environment/Communications	299,843	338,175	90,128		
69	1000.06.03	LED Street Light Conversion	573,864	(3,726)	(4,102)		
70	Total Improve Reliability Load Growth Distribution Capital		11,292,172	13,668,316	16,027,914	15,875,000	16,093,500

UPPCO Response to discovery request 3-AG-UPPCO-3.87

Michigan Public Service Commission
Upper Peninsula Power Company
UPPCO Distribution Reliability CAPEX
Distribution Projects > \$50K for 2024-25

03-AG-UPPCO-3.87

Case No.: U-21555
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Witness: Jay R. Ringler

UPPCO Distribution Reliability CAPEX
Distribution Projects > \$50K for 2024-25

Line	Improve Reliability Load Growth	2021	2022	2023	2024	2025	UOM
30	1000.05.01 Distribution Stores, Shop, Lab & Work Tools	1,627	60	106			EA
31	1000.05.02 Distribution Line Transformers	419	463	809			EA
32	1000.05.03 Distribution Reclosers	40	20	17			EA
33	1000.05.04 Distribution Regulators	3	8				EA
34	1000.05.06 Meters & Installations (incl. PTs and CTs)	562	1,040	990			EA
35	1000.06.01 Services	920	492	475			WO
36	1000.06.02 Line Extensions**	281	185	220			WO
37	1000.06.03 Lighting	235	903	691			EA
38	1000.07.01 Charge UP Michigan Grant EVC Installations			-			WO
39	1000.07.01 Mandated Allowance and unforeseen (Road Moves etc.)	3	13	19			WO
40	1000.08.01 GIS Conflation			2			WO

MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.95

Refer to Exhibit A-31 on the SHARP projects. Please:

- a. Provide the phase of development that each project for 2024 and 2025 is currently in, i.e., initial concept approval, conceptual design, engineering, out for bid, construction, or completed. Identify the next phase and the completion date of that phase.
- b. Provide the number of power outages experienced for the line segment in each project during the three years 2021 to 2023.
- c. Provide the same information in the exhibit for projects completed each year 2021 to 2023.

UPPCO Response:

- a. Please refer to the Excel attachment, 03-AG-UPPCO Ringler Attachments, tab "JRR-12a," updated with the phase of development, next phase, and completion date of the next phase.
- b. Please refer to the Excel attachment, 03-AG-UPPCO Ringler Attachments, tab "JRR-12a," updated with the number of customer outages experienced caused by the nearest upstream overcurrent protection ("OCP") device serving the project area.
- c. Please refer to the Excel attachment, 03-AG-UPPCO Ringler Attachments, tab "JRR-12b," indicating the 2021-2023 SHARP projects, costs, and RASCL. Some projects had cost allocations in multiple years.

Response by: Jay Ringler

Dated: July 3, 2024

UPPCO Response to discovery request 3-AG-UPPCO-3.95

Michigan Public Service Commission Upper Peninsula Power Company System Hardening and Reliability Projects 2024 - 2025	Case No.: U-21555 Exhibit No.: A-31 (JRR-12) Schedule: Page: 1 of 1 Witness: Jay R. Ringler
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**System Hardening and Reliability Projects
2024 - 2025**

Line	2024 Distribution SHARP CapEx Projects				RASCL	Estimated Cost	Existing Phase	Next Phase	Expected Completion Date of Next Phase	# of customer outages experienced
1	1	West	1000.04.02	HOT - OH-UG M38 747 Copper replacement on M38 Part 2	RAL	\$700,000	In construction	As Built	12/1/2024	0
2	2	West	1000.04.02	HOT - OH-UG KWN 927 Copper Harbor to Mtn. Lodge rebuild	RA	\$850,000	In construction	As Built	11/1/2024	337
3	3	West	1000.04.02	IRV - OH-UG LIN 3063 Replace copper and establish tie around Sunset Lake	RA	\$600,000	Design in Progress	Engineer Approval	8/15/2024	26
4	4	West	1000.04.02	HOT - OH-OH OSC 717 Relocate Mohawk to Highway Part 3	RA	\$150,000	Design in Progress	Engineer Approval	7/31/2024	551
5	5	East	1000.04.02	ISH - OH-UG BARNUM 1231 N. Rose Street	RA	\$118,000	Design in Progress	Engineer Approval	8/1/2024	77
6	6	East	1000.04.02	ISH - OH-UG BARNUM 1231 Lake Breeze Lane	R	\$290,000	Design in Progress	Engineer Approval	8/15/2024	84
7	7	East	1000.04.02	ISH - OH-UG BARNUM 1231 Bussone and Marra Drive	R	\$205,000	Design in Progress	Engineer Approval	7/15/2024	206
8	8	East	1000.04.02	ISH - OH-UG PERCH LAKE 401 Squaw Lake OH to UG	R	\$225,000	In construction	As Built	11/1/2024	5
9	9	East	1000.04.02	DEL - OH-UG DELTA 589 M35 South OH to UG and Loop Tie	RA	\$325,000	Design in Progress	Engineer Approval	7/31/2024	7
10	10	East	1000.04.02	ISH - OH-UG PERCH LAKE Substation Feeder Exit Relocation	RA	\$252,000	In construction	As Built	11/1/2024	1,056
11	11	East	1000.04.02	DEL - OH-UG MASONVILLE Substation Feeder Exit Rework	R	\$252,000	In construction	As Built	11/1/2024	1,549
12	12	East	1000.04.02	ISH - OH-UG BARNUM 1205 US41 Round-about Rework	RC	\$189,000	Design in Progress	Engineer Approval	7/31/2024	0
13	13	East	1000.04.02	ISH - OH-UG FORSYTH 2733 Escanaba River UG Cable Replacement	RA	\$87,000	Design in Progress	Engineer Approval	7/31/2024	1,311
14	14	UPCO	1000.04.02	UPPCO Cutout Replacement	RAS	\$750,000	In construction	Complete	TBD	
15	15	UPCO	1000.04.02	UPPCO WIDE URD Replacment (tied to unforeseen failures)	RA	\$200,000	N/A	Design in Progress	TBD	
16	16	UPCO	1000.04.02	SYS. HARDENING, OH TO URD CONV, AND COPPER REPLC	RA	\$350,000	Conceptual design	Design in Progress	TBD	
17						Total	\$5,543,000			

Line	2025 Distribution SHARP CapEx Projects				RASCL	Estimated Cost	Existing Phase	Next Phase	Expected Completion Date of Next Phase	# of customer outages experienced
18	1	East	1000.04.02	ISH - OH-UG BARNUM 1231 Rundman Drive	RA	\$110,000	Conceptual design	Design In Progress	10/1/2024	15
19	2	East	1000.04.02	ISH - OH-UG BARNUM 1231 Part 1 South Camp RD UG	RA	\$470,000	Conceptual design	Design In Progress	10/1/2024	197
20	3	East	1000.04.02	ISH - OH-UG BARNUM 1231 Part 1 Sparks Drive	R	\$590,000	Conceptual design	Design In Progress	10/1/2024	221
21	4	East	1000.04.02	ISH - OH-UG FORSYTH 2733 Serenity Drive	R	\$740,000	Conceptual design	Design In Progress	10/1/2024	2,815
22	5	East	1000.04.02	ISH - OH-UG FORSYTH 2733 Little Shag Road-South Tap	RA	\$290,000	Conceptual design	Design In Progress	10/1/2024	100
23	6	East	1000.04.02	ISH - OH-UG PERCH LAKE 401 Part 1 Horseshoe Lake	R	\$230,000	Conceptual design	Design In Progress	10/1/2024	975
24	7	West	1000.04.02	IRV - OH-UG LIN 3063 Lake Emily-Iron River rebuild	RA	\$150,000	Design in Progress	Engineer Approval	10/1/2024	0
25	8	West	1000.04.02	HOT - OH-UG KWN 927 OH-UG conversion	RA	\$500,000	Conceptual design	Design In Progress	10/1/2024	2,456
26	9	West	1000.04.02	HOT - Replace Underwater Canal Crossing	RAS	\$1,500,000	Design in Progress	Engineer Approval	5/1/2025	0
27	10	West	1000.04.02	HOT - OH-UG M38 749 Mansfeldt Rd rebuild	RA	\$250,000	Conceptual design	Design In Progress	10/1/2024	57
28	11	UPCO	1000.04.02	UPPCO Cutout Replacement	RAS	\$900,000	Conceptual design	Complete	TBD	
29	12	UPCO	1000.04.02	UPPCO WIDE URD Replacment (tied to unforeseen failures)	RA	\$250,000	N/A	Design in Progress	TBD	
30	13	UPCO	1000.04.02	SYS. HARDENING, OH TO URD CONV, AND COPPER REPLC	RA	\$356,000	Conceptual design	Design in Progress	TBD	
31						Total	\$6,336,000			

32 RASCL: R – Reliability/Storm Hardening A – Age & Condition S – Safety C – Compliance/Voltage L – Load/Capacity

UPPCO Response to discovery request 3-AG-UPPCO-3.95

Michigan Public Service Commission
Upper Peninsula Power Company
System Hardening and Reliability Projects
2021 - 2023

Case No.: U-21555
Exhibit No.: A-31 (JRR-12)
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System Hardening and Reliability Projects
2021 - 2023

Line	2021 Distribution SHARP CapEx Projects			RASCL	Cost	
1	1	East	1000.04.02	Summer Homes Lake Crossing Autrain	RA	\$191,163
2	2	East	1000.04.02	Forsyth - Gwinn Fdr Tie	RL	\$1,037,056
3	3	East	1000.04.02	Little Lake Rd URD	RA	\$1,040
4	4	West	1000.04.02	Ahmeek relocation	RA	\$117,942
5	5	West	1000.04.02	Jurmu Road relocation to highway	RA	\$141,760
6	6	East	1000.04.02	KIS 1275 - GWN 657 UG Tie	RL	\$437,507
7	7	West	1000.04.02	OSC 717/KWN 927 Relocate double circuit	RA	\$458,380
8	8	West	1000.04.02	WNA 907 Pike Lake Road UG replacement	RA	\$202,674
9	9	East	1000.04.02	CR480 Improvement Project	RALC	\$288,031
10	10	West	1000.04.02	Britz Rd UG replacement	RA	\$60,923
11	11	UPCO	1000.04.02	UPPCO WIDE URD Replacment (tied to unforseen failures)		\$187,557
12	12	UPCO	1000.04.02	SYS. HARDENING, OH TO URD CONV, AND COPPER REPLC		\$4
13					Total	\$3,124,037
14						
Line	2022 Distribution SHARP CapEx Projects			RASCL	Cost	
15	1	East	1000.04.02	Summer Homes Lake Crossing Autrain	RA	\$52,326
16	2	East	1000.04.02	Little Lake Rd URD	RA	\$77,100
17	3	West	1000.04.02	Ahmeek relocation	RA	\$7,694
18	4	West	1000.04.02	OSC 717/KWN 927 Relocate double circuit	RA	\$4,896
19	5	West	1000.04.02	OSC 719 Jacobsville UG tie	R	\$166,536
20	6	West	1000.04.02	WNA 907 Pike Lake Road UG replacement	RA	\$77,544
21	7	East	1000.04.02	CR480 Improvement Project	RALC	\$19,911
22	9	West	1000.04.02	MTU 1403 Replace Franklin Square UG tie	RA	\$52,005
23	10	East	1000.04.02	FRY2733 - Shag Lakes UG Part1	RA	\$360,126
24	11	East	1000.04.02	BRM 1205/1237 Tie		\$310,849
25	12	West	1000.04.02	KWN 927 System Hardening	RA	\$931,533
26	13	West	1000.04.02	Oneco Road UG replacement (OSC 707)	RA	\$144,656
27	14	West	1000.04.02	Copper replacement on M38 ph 1 (M38 747)	RA	\$271,646
28	15	West	1000.04.02	Relocate Mohawk to highway ph 1 (OSC717)	RA	\$234,441
29	16	West	1000.04.02	Sved Rd UG replacement	RA	\$141,499
30	17	East	1000.04.02	KIS 1275 / GWN657 Tie, Part2	RA	\$57,726
31	18	UPCO	1000.04.02	Cutout replacement		\$842,605
32	19	UPCO	1000.04.02	UPPCO WIDE URD Replacment (tied to unforseen failures)		\$204,033
33	20	UPCO	1000.04.02	SYS. HARDENING, OH TO URD CONV, AND COPPER REPLC		\$7,310
34					Total	\$3,964,437
35						
36						
Line	2023 Distribution SHARP CapEx Projects			RASCL	Cost	
37	1	East	1000.04.02	Little Lake Rd URD	RA	\$287,801
38	2	West	1000.04.02	OSC 719 Jacobsville UG tie	R	\$16,294
39	3	West	1000.04.02	WNA 907 Pike Lake Road UG replacement	RA	(\$4,296)
40	4	East	1000.04.02	CR480 Improvement Project	RALC	\$3,595
41	5	West	1000.04.02	MTU 1403 Replace Franklin Square UG tie	RA	\$93,876
42	6	East	1000.04.02	FRY2733 - Shag Lakes UG Part1	RA	\$76,081
43	7	East	1000.04.02	BRM 1205/1237 Tie	RAC	\$326,298
44	8	West	1000.04.02	KWN 927 System Hardening	RA	\$110,465
45	9	West	1000.04.02	Oneco Road UG replacement (OSC 707)	RA	\$30,870
46	10	West	1000.04.02	Copper replacement on M38 ph 1 (M38 747)	RA	\$32,367
47	11	West	1000.04.02	Relocate Mohawk to highway ph 1 (OSC717)	RA	\$31,459
48	12	West	1000.04.02	Sved Rd UG replacement	RA	\$21,208
49	13	East	1000.04.02	KIS 1275 / GWN657 Tie, Part2	RA	\$716,498
50	14	UPCO	1000.04.02	Cutout replacement		\$1,176,137
51	15	West	1000.04.02	HEN 1017 Chassell Painsedale rebuild	LA	\$838,815
52	16	West	1000.04.02	Copper Harbor to Mt Lodge rebuild	RA	\$66,682
53	17	West	1000.04.02	ATL 891-Red Ridge to Freda UG rplc	RA	\$392,966
54	18	East	1000.04.02	Chatham Ski Hill UG replacement	RA	\$66,103
55	19	West	1000.04.02	OSC 717 Mohawk relocate to highway	RA	\$18,329
56	20	UPCO	1000.04.02	UPPCO WIDE URD Replacment (tied to unforseen failures)		\$101,242
57	21	UPCO	1000.04.02	SYS. HARDENING, OH TO URD CONV, AND COPPER REPLC		\$203,516
58					Total	\$4,606,307
59						
60						

RASCL: R - Reliability/Storm Hardening A - Age & Condition S - Safety C - Compliance/Voltage L - Load/Capacity

MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.88

Refer to Exhibit A-21 on Distribution capital projects and programs. Please:

- a. For line 1, provide that same information for each year 2021 to 2023.
- b. For line 2, explain what these costs are for and why they are not included with each forecasted project cost. Also, provide the same information for each year 2021 to 2023.
- c. For lines 3 and 4, provide the same information for each year 2021 to 2023. Confirm that these costs are for emergent projects not yet known. If not confirming, explain otherwise.
- d. For the SHARP projects on lines 5, 7, 8, 13, and 17, the amounts in this exhibit do not match the amounts in Exhibit A-31. Please explain why they differ and which amounts are correct.
- e. For lines 30 to 40:
 - i. Provide the amount spent each year 2021-2023 for each line item.

UPPCO Response to discovery request 3-AG-UPPCO-3.88

- ii. Provide the number of units purchased or work units completed and forecasted for each year 2021 to 2023 actual and forecasted for 2024 and 2025.
- iii. Explain what each of the line items 35 to 40 entail and where these activities or projects are explained and justified in filed testimony.

UPPCO Response:

- a. Please refer to the Excel attachment, 03-AG-UPPCO Ringler Attachments, tab "JRR-3," which is Exhibit A-21 (JRR-3) modified to indicate actual costs from 2021 to 2023.
- b. Please refer to the Excel attachment, 03-AG-UPPCO Ringler Attachments, tab "JRR-3," which is Exhibit A-21 (JRR-3) modified to indicate actual costs from 2021 to 2023. The UPPCO Engineering, Designers, Clerks budgetary line item brings visibility to the internal UPPCO labor effort for engineering, design, work order creation, and pre-closure review of these work orders in a single budget line item for the budgeting process rather than embedded in every individual project, which number in the hundreds.
- c. Please refer to the Excel attachment, 03-AG-UPPCO Ringler Attachments, tab "JRR-3," which is Exhibit A-21 (JRR-3) modified to indicate actual costs from 2021 to 2023. Yes, lines 3 and 4 are budgetary line items for emergent projects not yet known. These line items were described in my testimony on pages 56 and 57.
- d. The SHARP project amounts shown on lines 5, 7, 8, 13, and 17 of Exhibit A-21 do not match the amounts in Exhibit A-31. This appears to be due to timing of when the different Exhibits were developed and submitted for the rate case application.

Please refer to Excel attachment, 03-AG-UPPCO Ringler Attachments, tab "JRR-12," indicating the Exhibit A-21 costs for the lines in question directly to the projects listed in exhibit A-31. Then refer to Excel attachment, 03-AG-UPPCO Ringler Attachments, tab "JRR-3," which is Exhibit A-21 with the corrected values shown and explained below:

Line 5 – This budget item was changed to \$700,000.

Lines 7 and 8 – These two budget item amounts were inadvertently swapped in Exhibit A-31 and were correctly shown in A-21.

Lines 13 and 17 – \$40,000 was moved from one project to the other and have been corrected in the A-21 revision in the attachment.

- e. For lines 30 to 40:

- i. Please refer to the Excel attachment, 03-AG-UPPCO Ringler Attachments, tab "JRR-3," which is Exhibit A-21 (JRR-3) modified to indicate actual costs from 2021 to 2023.

- ii. Please refer to the Excel attachment, 03-AG-UPPCO Ringler Attachments, tab "JRR-3a," which indicates the number of units for lines 30-40 from Exhibit A-21 (JRR-3) from 2021 to 2023. The unit of measure ("UOM") indicated for each line is shown as either "EA" for each unit or "WO" for the number of work orders created under that line item. The forecasted budget for 2024 and 2025 are based on historical spend and the number of units are not specified at the time of the budgeting process.

- iii. Lines 35-40 are for routine, reoccurring budget lines from year to year or for special projects and are budgeted based on historical values. Each are described below:

Line 35 – Services – This budget line is for the installation and removal of electric services, if no system line extension is required, to provide service to new customers.

Line 36 – Line Extensions – This budget line is for new line extensions to provide service to new customers. When a line extension is required, the service line is also included in this budget item.

Line 37 – Lighting – This budget line is for installation and removal of street and yard lighting equipment.

Line 38 – Charge UP Michigan Grant EVC Installations – This line is for budgeting the added UPPCO capital investment included as part of Michigan Department of Environment, Great Lakes, and Energy ("EGLE") electric vehicle charging grant process under Case U-21137. Within the Case, UPPCO Rate C-1 was temporarily modified to encourage the development of electric vehicle fast chargers within UPPCO service territory. As part of the Order, a regulatory asset was created to track capital contributions by UPPCO in support of the grant process. Once fulfilled, this budget line item will no longer be needed.

Line 39 – Mandated Allowance and Unforeseen (Road Moves, etc) – This budget line item is to help account for capital expenditures associated with work which is not elective under UPPCO planning, such as governmental road moves.

Line 40 – GIS Conflation – This is a discreet, non-recurring, budget item to address the added costs associated with the effort to incorporate the new functionality into UPPCO’s Geographic Information System (“GIS”) to utilize a GPS coordinate based approach and to incorporate this new functionality into work planning and designs going forward. The scope and justification for this project is attached as “Conflation Scope Document.”

Response by: Jay Ringler

Dated: July 3, 2024



Upper Peninsula Power Company
1002 Harbor Hills Drive
Marquette, MI 49855
www.UPPCO.com

December 19, 2023

Lisa Felice
Executive Secretary
Michigan Public Service Commission
PO Box 30221
Lansing, MI 48909-7721

Re: Case No. U-21137

Dear Ms. Felice,

Enclosed for electronic filing is Upper Peninsula Power Company's 2023 Report detailing the electric vehicle chargers that have been installed pursuant to the Commission's approval of the demand waiver to its C-1 Tariff.

If you have any questions, please contact me.

Sincerely,

A handwritten signature in blue ink that reads "Eric Stocking". The signature is written in a cursive, flowing style.

Eric Stocking
Director of Regulatory & Power Supply
Upper Peninsula Power Company

Upper Peninsula Power Company Electric Vehicle Charger (“EVC”) Detail Report – 2023

Background

On April 14, 2022 the Michigan Public Service Commission (“MPSC” or the “Commission”) issued an Order in Case No. U-21137 approving, among other things, authority for Upper Peninsula Power Company (“UPPCO” or the “Company”) to implement a revised C-1 tariff which allows for new electric vehicle charger installations to exercise a demand waiver within the C-1 tariff structure. Order point D details the Company’s requirement to file, in the same docket, an annual report that provides details on the electric vehicle chargers that are installed, a map of their locations, and project utilization data by month and/or season. This report satisfies the Company’s reporting requirements for calendar year 2023.

C-1 EV Participating Electric Vehicle Chargers

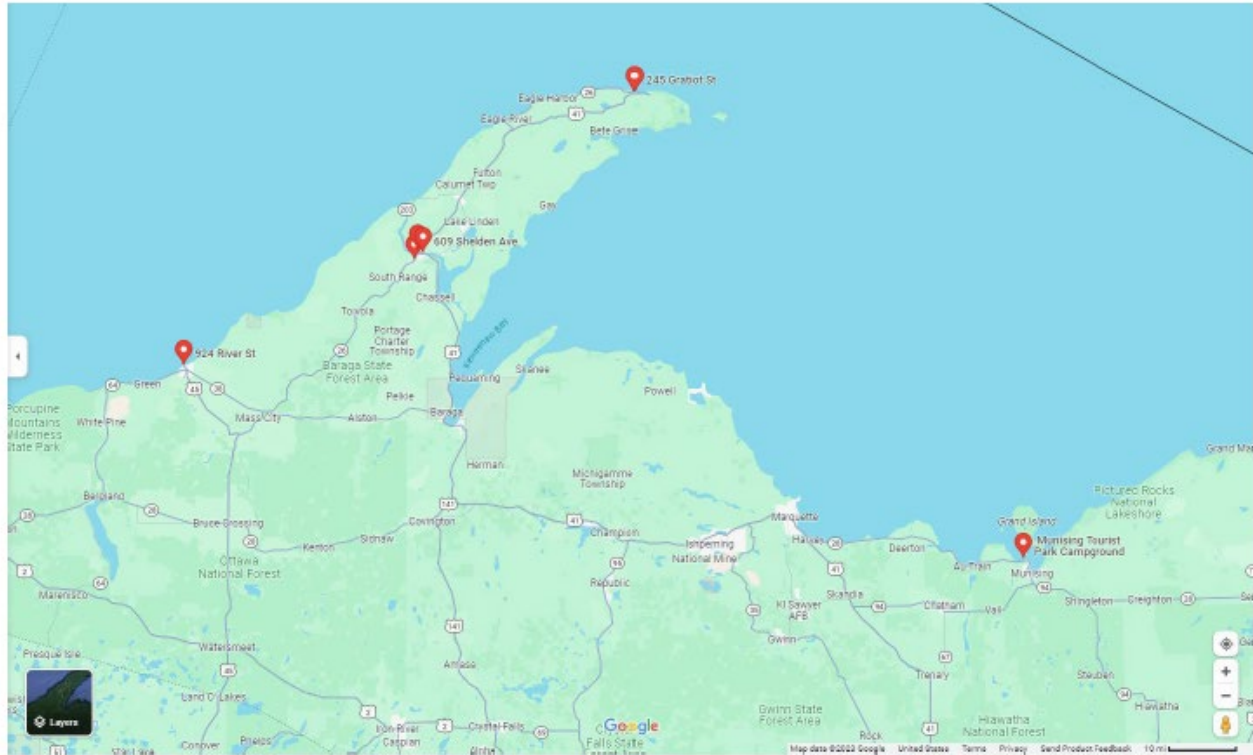
- South Shore Property Management
 - Munising, MI
- City of Houghton
 - Houghton, MI
- State Electric Company
 - Copper Harbor, MI
- City of Hancock
 - Hancock, MI
- Keweenaw Chevrolet
 - Houghton, MI
- Polaris Industries
 - Ontonagon, MI

Project Utilization by Month – 2023

	Maximum Demand (kW)												Total
	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	
South Shore Property Management	9.58	19.34	10.00	9.99	9.99	9.89	21.22	21.66	2.23	19.34	9.78	9.91	152.93
City of Houghton	78.00	91.77	86.28	124.29	122.69	122.83	123.17	127.38	126.35	116.32	115.93	98.66	1,333.67
State Electric Company	-	-	114.65	0.40	131.65	136.15	107.00	97.00	136.15	115.05	95.55	0.40	934.00
City of Hancock	-	-	-	-	-	57.49	64.87	62.44	65.22	63.52	-	-	313.54
Keweenaw Chevrolet	-	-	-	-	-	-	-	-	-	-	-	-	-
Polaris Industries	-	-	-	-	-	-	-	-	-	-	46.89	10.08	56.97

	Monthly Energy (kWh)												Total
	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	
South Shore Property Management	19	81	122	34	56	131	785	1,360	620	725	79	27	4,039
City of Houghton	204	2,125	1,731	1,845	1,721	1,781	2,701	2,456	1,922	2,356	855	913	20,610
State Electric Company	-	-	300	150	450	500	900	750	950	350	350	200	4,900
City of Hancock	-	-	-	-	-	34	623	887	1,860	1,391	-	-	4,795
Keweenaw Chevrolet	-	-	-	-	-	-	-	-	-	-	-	-	-
Polaris Industries	-	-	-	-	-	-	-	-	-	-	1,269	818	2,087

Map of C-1 EV Electric Vehicle Chargers



MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.81

Refer to lines 13-23 on page 33 of Mr. Ringler's direct testimony on Strategic Undergrounding versus overhead lines:

- a. Please explain what costs the design software includes to estimate distribution project costs and why permitting, easements, outside engineering, and special equipment costs are not included.
- b. Does the Company only use high-level estimated costs to determine and select projects for strategic undergrounding? If yes, why. If no, explain further and provide the other selection criteria.

UPPCO Response:

- a. As mentioned in my testimony, UPPCO's "by-foot" rates were created using the design software, AKA "Staking Tool," which was mentioned in response to question 80.a above.

UPPCO uses the Staking Tool to estimate distribution project costs. Using this tool, UPPCO created by-foot rates for performing rough, high-level estimates for future project budgeting purposes. The by-foot estimates are based on typical job parameters, material, labor, equipment, and contract costs. The estimated costs for overhead projects include initial line clearance and cycle clearance for the expected life of the project as well as the annual increased maintenance cost of overhead versus underground as discussed previously. Line clearance is typically required for overhead projects, but the cost can vary substantially due to many factors, such as the last cycle trim in the area, possible rerouting, additional pole height, etc. Therefore, for the purpose of these high-level estimates, UPPCO feels that the historical cycle clearance cost is a good average to use for the initial line clearance cost for overhead projects.

The design parameters and Staking Tool calculation results are shown in the "Staking By-Foot Cost" tab in the Excel attachment, "03-AG-UPPCO-3.81 & 3.82 Per Foot Costs." Permitting, easements, outside engineering, and special equipment costs are not included in these by-foot rates because they are not always required for UPPCO Strategic Undergrounding projects and can be quite variable when they are necessary depending on the specific conditions of the project site.

- b. No, UPPCO does not only use high level estimates to select strategic undergrounding projects. As mentioned in my testimony beginning on page 25, UPPCO bases project selection on reliability factors, such as worst feeder analysis, multiple device operations / repetitive outages, and inspection results / age of existing assets. UPPCO typically uses high level estimates for initial budgetary purposes, but will have a Designer complete a field review and detailed design/estimate prior to project construction.

Permitting, easements, outside engineering, and special equipment costs are project specific details that are unclear at the high-level, budgetary stage of a project and become clear with the completion of the detailed design. If UPPCO has recently completed a similar project, historical permitting, easements, outside engineering, and special equipment will be included at the high-level estimate stage of budgeting. For the detailed design, Designers take field measurements, and determine the construction standards, installation methods, and equipment needed to construct the proposed distribution project. At this time, the Designer identifies if any additional project-specific costs would be incurred, such as permitting, easements, outside engineering, or special equipment. The field information is then put into the design software which will calculate the material, labor, and equipment costs and apply the material and labor overhead percentages.

Response by: Jay Ringler

Dated: July 3, 2024

UPPCO Response to discovery request 3-AG-UPPCO-3.81

03-AG-UPPCO-3.81 & 3.82 Per Foot Costs

Inputs to Staking (2-8-24):

1-ph OH to OH rebuild

U:\Job Packs\Per foot estimates\1PH OH EST COST

Basic: **\$197,398.97/mi = \$37.49/ft**

- Install 1 mile of 1ph 1/0 ASCR, 240' spans, 22-40' class 3 poles, 8 tangent poles, 2 DE pole, 12 various sized angles, 14 anchors/guys, flagging for whole project, 1 person/truck, 2 hours extra labor each day. Removal of 22 poles and 1 mile of wire
- No permitting, tree clearance, outside engineering, easements, or special equipment (rock truck, vac truck, etc.) included

3-ph OH to OH rebuild

U:\Job Packs\Per foot estimates\3PH OH EST COSTS

Basic: **\$358,273.63/mi = \$67.85/ft**

- Install 1 mile of 3ph 336 ASCR with 1/0 neutral, 240' spans, 22-45' class 3 poles, 10 tangent poles, 2 DE pole, 10 various sized angles, 12 anchors/guys, flagging for whole project, 1 person/truck, 2 hours extra labor each day. Removal of 22 poles and 1 mile of wire
- No permitting, tree clearance, outside engineering, easements, or special equipment (rock truck, vac truck, etc.) included

1-ph OH to UG conversion

U:\Job Packs\Per foot estimates\1PH EST COST

Basic (design 1): **\$147,635.21/mi = \$27.96/ft**

Worst (design 2): **\$186,831.66/mi = \$35.38/ft**

- **Basic:** Install 1 mile of 1ph 25kV 1/0, 75% plow 25% bore (in 2" conduit), 5 jboxes, 2-40'3 risers. Removal of 22 poles. 10 tangent, 10 various angles, 2 DE, 1 person/truck
- **Worst:** Install 1 mile of 1ph 25kV 1/0, 50% plow 50% bore (in 2" conduit), 10 jboxes, 2-40'3 risers. Removal of 22 poles. 10 tangent, 10 various angles, 2 DE, 1 person/truck
- No permitting, tree clearance, outside engineering, easements, or special equipment (rock truck, vac truck, etc.) included

3-ph OH to UG conversion

U:\Job Packs\Per foot estimates\3PH EST COST

Basic (design 1): **\$448,872.48/mi = \$85.01/ft**

Worst (design 2): **\$580,761.22/mi = \$109.99/ft**

- **Basic:** Install 1 mile of 3ph 25kV 4/0, 75% plow 25% bore (in 6" stick conduit), 5 jboxes, 2-45'3 risers. Removal of 22 poles. 15 tangent, 5 various angles, 2 DE, 1 person/truck
- **Worst:** Install 1 mile of 3ph 25kV 4/0, 50% plow 50% bore (in 6" stick conduit), 10 jboxes, 2-45'3 risers. Removal of 22 poles. 15 tangent, 5 various angles, 2 DE, 1 person/truck
- No permitting, tree clearance, outside engineering, easements, or special equipment (rock truck, vac truck, etc.) included

UPPCO Response to discovery request 3-AG-UPPCO-3.81

03-AG-UPPCO-3.81 & 3.82 Per Foot Costs - Maintenance

By-foot Costs from Staking Feb. 2024		
System	OH-OH	OH-UG
1-Phase	\$37.49	\$28-\$35
3-Phase	\$67.85	\$85-\$109

		<u>% Pri Sys</u>	<u>Per Mi</u>	<u>Per Ft</u>	<u>Proj Life (Yrs)</u>
Line Clear:	\$3,206,845	100%	\$8,506	\$1.61	42 \$12.89
Annual	2023	% Pri Sys	Per Pri Mi	Per Pri Ft	Cost per Ft
OH Maint:	\$8,088,391	90%	\$3,354.63	\$0.64	\$26.68
UG Maint:	\$694,700	90%	\$771.89	\$0.15	\$6.14
Maint Diff:	\$7,393,691		\$2,582.74	\$0.49	\$20.54

OH-OH	Staking	Init. LC	OH Mt Add	OH-OH Tot	OH-UG
1-Phase	\$37.49	\$1.61	\$25.21	\$64.31	\$28-\$35
3-Phase	\$67.85	\$1.61	\$25.21	\$94.67	\$85-\$109

Infl. %: **0.50%**

<u>Year</u>	<u>Maint Diff</u>	<u>System</u>	<u>Miles</u>
1	\$20.54	OH Pri	2,170
2	\$20.65	OH Sec	596
3	\$20.75	OH Svc	520
4	\$20.85	UG Pri	810
5	\$20.96	UG Sec	45
6	\$21.06	UG Svc	378
7	\$21.17		
8	\$21.27		
9	\$21.38		
10	\$21.49		
11	\$21.60		
12	\$21.70		
13	\$21.81		
14	\$21.92		
15	\$22.03		

UPPCO Response to discovery request 3-AG-UPPCO-3.81

16	\$22.14
17	\$22.25
18	\$22.36
19	\$22.47
20	\$22.59
21	\$22.70
22	\$22.81
23	\$22.93
24	\$23.04
25	\$23.16
26	\$23.27
27	\$23.39
28	\$23.51
29	\$23.62
30	\$23.74
31	\$23.86
32	\$23.98
33	\$24.10
34	\$24.22
35	\$24.34
36	\$24.46
37	\$24.59
38	\$24.71
39	\$24.83
40	\$24.96
41	\$25.08
42	\$25.21
43	\$25.33
44	\$25.46
45	\$25.59
46	\$25.71
47	\$25.84
48	\$25.97
49	\$26.10
50	\$26.23
51	\$26.36
52	\$26.50
53	\$26.63
54	\$26.76
55	\$26.89
56	\$27.03
57	\$27.16
58	\$27.30
59	\$27.44
60	\$27.57
61	\$27.71

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Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.82

Refer to lines 1-8 on page 34 of Mr. Ringler's direct testimony on unit costs of overhead lines versus underground lines. Please provide the calculations in Excel with source data showing how you get the unit cost. Provide the year of the underlying data and explain what it represents.

UPPCO Response:

Note, in line 8 on page 34 of my testimony, the range for 1-phase underground should have been shown as \$28-35, not \$38-35 as indicated. This was a typo.

As mentioned in response to Question 81 above, UPPCO uses the Staking Tool to create "by-foot" rates for high level budgetary estimating purposes.

For underground, as shown in the "Staking By-Foot Cost" tab in the Excel attachment, "03-AG-UPPCO-3.81 & 3.82 Per Foot Costs," UPPCO inputs a range of parameters to account for the variability of ground conditions for proposed underground projects. These values are used to compare to overhead projects costs.

For overhead, the Staking Tool by-foot values are used, plus the initial line clearance costs along with the increased on-going maintenance costs of overhead compared to underground, which I will describe further below.

In the testimony, on lines 1-2 on page 34, I state the cost of line clearance was \$8,506 per mile in 2023, which is about \$1.61 per foot on the overhead primary system; this value is used for the initial line clearance cost for an overhead replacement project.

In Exhibit A-29 (JRR-10), the 2023 overhead maintenance costs were reported as \$8,088,391 compared to underground at \$694,700 on the entire overhead and underground systems. These values were used to calculate the increased on-going maintenance costs of overhead compared to underground over the life of the project.

Most costs of typical reliability improvement projects are to replace aged overhead primary facilities with new overhead or underground primary facilities. UPPCO does not track costs allocated to the primary system separately from secondary and services, but it is assumed that most of the maintenance costs are for the primary system. Therefore, UPPCO used 90% of the 2023 maintenance costs with a ½% inflationary adder on the difference between the overhead and underground cost to calculate the increased of maintaining overhead versus underground over the life of the project. For the purpose of this calculation, the life of the project was assumed to be 42 years.

Refer to the “By-Foot w Maint” tab in the Excel attachment, “03-AG-UPPCO-3.81 & 3.82 Per Foot Costs,” to view the calculation methodology and formulae to arrive at the per-foot values shown in lines 3, 4, and 8 on page 34 of my testimony.

Response by: Jay Ringler

Dated: July 3, 2024

MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.83

Refer to lines 1-14 on page 35 of Mr. Ringler's direct testimony on unit costs of overhead lines versus underground lines and digging incidents. Please explain if the Company includes the cost of locating and staking, and the cost of digging incidents damaging the underground lines in the cost of maintenance and repair of underground lines in the financial model when evaluating whether to undertake a strategic undergrounding project. If yes, explain how. If no, explain why not.

UPPCO Response:

As mentioned in my testimony in lines 15-17 on page 35, the costs of locating and maintenance and repair of underground lines are included in Exhibit A-29 (JRR-10) as are the costs for the overhead distribution system. Exhibit A-29 was introduced in my testimony in line 1 on page 18 and typical maintenance costs are listed in lines 9-11 on the same page.

This information, along with other information in my testimony, corroborate the fact that the costs for operating and maintaining ("O&M") UPPCO's underground distribution facilities is far less than the O&M cost of overhead facilities on an overall as well as on per mile basis. As such, the O&M costs for proposed underground projects is not a determining factor in the evaluation of discrete segments of line covered in each project. Rather, the strategic undergrounding projects put forth are based on the criteria already described and based on SHARP criteria and on the conditions present for the specific project under consideration, such as the soil type, vegetation, accessibility, number of customers, etc.).

Response by: Jay Ringler

Dated: July 3, 2024

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2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.84

Beginning on line 6 of page 44 and through page 57 of his direct testimony, Mr. Ringler discusses the SHARP projects planned for 2024-2025.

- a. It appears that nearly all of the 29 projects entail undergrounding overhead lines. Given this wholesale shift to undergrounding overhead lines, it does seem that the conversion of overhead line to undergrounding is no longer strategic but a common practice. Please explain why this result does not show a fundamental problem with the Company's evaluation methodology and why the Company has undertaken such a complete shift to undergrounding overhead lines.
- b. The testimony shows a worst performing ranking for each project. Please:
 - i. Provide what the range of the ranking is, such as 9 out of xx.
 - ii. Provide the supporting data and calculations in Excel that show how you arrived at the worst performing rank value.

UPPCO Response:

- a. Refer to Exhibit A-31 (JRR-12), "System Hardening and Reliability Projects 1024-2025," which summarizes each of the planned SHARP projects discussed in my testimony on pages 44-57. UPPCO has not completely shifted all SHARP projects to underground. UPPCO's design preference is to install underground cable to replace aged overhead facilities where it is reasonable and practical to do so. Some projects are planned as underground, but during the detailed design may be shifted to an overhead design. An example of this situation is with the HOT-OH-UG KWN 927 Copper Harbor to Mtn. Lodge Rebuild listed in the aforementioned Exhibit A-31 (JRR-12). Several surface and below ground issues were encountered during the design phase, such as significant rock and a private water line along the existing pole line. And, originally, UPPCO proposed moving the line to the road ROW, but it is part of the National Scenic Byway and the permit could not be obtained for overhead or underground construction along the road.

UPPCO endeavors to replace aged overhead infrastructure with underground as surface and conditions allow and at a reasonable cost to achieve an expected reliability improvement. However, each project is individually reviewed by Distribution Engineering with consideration of the merits of remaining overhead versus moving to underground, including initial construction cost as well as on-going maintenance costs.

The evaluation criteria used by UPPCO is well documented throughout my testimony and the fact that the analysis may indicate some consistent findings does not invalidate the evaluation nor the outcome. Projects are selected based on UPPCO's criteria which will, at times, point toward more underground projects than overhead, but as mentioned in lines 1-11 on page 21 of my testimony, overhead projects will still be undertaken when the circumstances make undergrounding impractical

UPPCO Response to discovery request 3-AG-UPPCO-3.84

or is not deemed a long-term cost-effective solution. Improved overhead construction practices are already in place to help achieve an overall distribution system that is more hardened to pole breakages and long-term maintenance savings in cases where underground is not a viable solution.

b. Worst Performing Feeder Ranking:

- i. UPPCO's worst feeder ranking is described in my testimony on page 26. As stated UPPCO's worst feeder ranking is based on the number of feeders that experienced outages over the time period being reviewed. If 100 feeders experienced outages over the selected period, then the ranking would be 1 to 100 with 1 being the worst. Likewise, if 50 feeders experienced outages over the selected period, then the ranking would be 1 to 50 with 1 being the worst.
- ii. Please reference the Excel attachment, 03-AG-UPPCO-3.84 Worst Feeders 2021-2023, which indicates the worst UPPCO feeders over the past three years in terms of the number of events, SAIDI, SAIFI, and CAIDI for each feeder that experienced an outage over the 3-year period.

Response by: Jay Ringler

Dated: July 3, 2024

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2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.64

Refer to line 21 on page 4 and lines 1-4 on page 5 of Mr. Gervae's direct testimony on the Chatham Controls Substation replacement. Please:

- a. Explain what poor condition means.
- b. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.
- c. Provide the alternative bid costs received with the selected bid amount, explaining why it was selected.
- d. Provide the forecasted cost of the project versus the selected bid cost and explain the reasons for any variance of 5% or greater.

UPPCO Response:

- a. The existing building at Chatham Substation was manufactured in 1966 and was previously located at our Barnum Substation in Ishpeming. In 1993 it was disassembled and moved to Chatham Substation and has been in service there ever since. The condition of the building has degraded to the point where we do not wish to risk the sensitive control and protection equipment to rodent infestation or other environmental factors that could cause equipment failure. The metal is in poor condition and we constantly face rodent intrusion issues.
- b. No work has been done as of 6/26/2024. UPPCO intends to begin work in Sept/October 2024.
- c. No bids have been sent or received yet.
- d. UPPCO has only made estimates based on similar prior projects, no bids have been received yet.

Response by: Dan Gervae

Dated: July 3, 2024

**MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request**

3-AG-UPPCO-3.65

Refer to lines 5-9 on page 5 of Mr. Gervae's direct testimony on the 9 Voltage Regulator Upgrade projects. Please-

- a. Confirm that the costs forecasted for 2024 are only to purchase the regulators. If not confirming, provide the costs for the regulators separately from the cost of installation.
- b. Provide the date that the regulators were ordered, the month and year when paid or will be paid and the amount, and the expected delivery date.
- c. Identify when the 9 regulators are needed and for which projects. Provide the date that each of these projects are planned to start and be completed.
- d. Explain what work has been done on each project as of June 15, 2024 and what work remains to be done and when.

UPPCO Response:

- a. Confirmed.
- b. Ordered 9/25/2023, expected delivery and pay date of 1/15/2025.
- c. The regulators will be used at the following projects: Seney & Munising Substations (replace regulators that are >150% of recommended # of operations) These projects will start and finish in summer of 2025. .
- d. Work for this project has not yet begun.

Response by: Dan Gervae

Dated: July 10, 2024

MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.69

Refer to lines 18-21 on page 7 and lines 1-17 on page 8 of Mr. Gervae's direct testimony on the Transformer Progress Payments. Please:

- a. Confirm that the costs forecasted for 2024 and 2025 are only to purchase the transformers. If not confirming, provide the costs for the transformers separately from the cost of installation.
- b. Provide the date that the transformer and related equipment were ordered, the month and year when paid or will be paid and the amount, and the expected delivery date.
- c. Explain what work has been done on each project as of June 15, 2024 and what work remains to be done and when.

UPPCO Response:

- a. Confirmed.
- b. Ordered 3/25/2024, expected to receive 8/12/2025.
- c. Preliminary design only.

Response by: Dan Gervae

Dated: July 3, 2024

MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.70

Refer to lines 18-22 on page 8 of Mr. Gervae's direct testimony on the 2025 Keweenaw Sub High Side Protection project. Please:

- a. Provide the distance from the service center in miles.
- b. How does the High-Side Protection resolve the distance and remoteness problem?
- c. Explain what work has been done on the project as of June 15, 2024 and what work remains to be done and when.

UPPCO Response:

- a. 42 miles.
- b. This device would better protect this expensive asset and it would allow remote operation from our system operations center to switch load to another substation quickly in the event of a problem, eliminating the need to travel to this location just to transfer the load and restore customers.
- c. No work has begun as of this date.

Response by: Dan Gervae

Dated: July 3, 2024

**MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request**

3-AG-UPPCO-3.71

Refer to lines 3-11 on page 9 of Mr. Gervae's direct testimony on the 2025 Ontonagon Bank 2 Transformer replacement project. Please:

- a. Confirm that the costs forecasted for 2024 and 2025 are only to purchase the regulators. If not confirming, provide the costs for the regulators separately from the cost of installation.
- b. Provide the date that the transformer and related equipment were ordered, the month and year when paid or will be paid and the amount, and the expected delivery date.
- c. Explain what work has been done on each project as of June 15, 2024 and what work remains to be done and when.

UPPCO Response:

- a. Confirmed. Except to clarify, the transformer (Not regulator) is being ordered in 2025
- b. The equipment for this project has not been ordered yet. We expect to order the unit in April 2025, at which time an initial 30% down payment will be due for the transformer plus design costs, and the Company will receive it a year later. We expect minimal design costs until early 2026.
- c. Project has not commenced. See response to part b.

Response by: Dan Gervae

Dated: July 10, 2024

**MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request**

3-AG-UPPCO-3.72

Refer to lines 12-17 on page 9 of Mr. Gervae's direct testimony on the Viper. MTU, Seney, Bayview projects. Please:

- a. Explain what work has been done on each project as of June 15, 2024 and what work remains to be done and when.
- b. Explain whether the unit still works and what problems have been experienced in the past three years, and whether the Company has sought assistance from the equipment and system vendor or manufacturer. If no, explain why not.
- c. Identify what the 2024 and 2025 capital expenditures will be spent on.

UPPCO Response:

- a. Project has not commenced yet.
- b. These units still work, but they have not always been as reliable as the OCR's that UPPCO uses as our standard equipment. We have had some vacuum bottles test poorly during routine testing, and there have been water ingress problems that required a lot of interface with the manufacturer to find a solution. These units are not compatible with our current standard relay protection package and as such, the Company needs to upgrade these items as time permits.
- c. Expenditures include the purchase of 6 Cooper OCR's @ \$28,000 Ea., new relay protection and controls total 3 relay/control panels @ \$50,000 ea., and design engineering, and construction labor @ \$78,000.

Response by: Dan Gervae

Dated: July 10, 2024

**MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request**

3-AG-UPPCO-3.73

Refer to lines 18-22 on page 9 and lines 1-5 on page 10 of Mr. Gervae's direct testimony on the 2025 Chatham Transformer replacement project. Please:

- a. Confirm that the costs forecasted for 2025 are only to purchase the transformer. If not confirming, provide the costs for the transformer separately from the cost of installation.
- b. Provide the date that the transformer and related equipment were ordered, the month and year when paid or will be paid and the amount, and the expected delivery date.
- c. Explain what work has been done on each project as of June 15, 2024 and what work remains to be done and when.

UPPCO Response:

UPPCO assumes that this question pertains to the Ontonagon transformer replacement project.

- a. Confirmed. The 2025 cost is for the transformer down payment only. There is a small cost in 2024 for spec work and planning.
- b. The equipment has not been ordered yet. It will be ordered in April 2025 and 30% down payment is required at that time.
- c. Project has not commenced. Transformer will not arrive until 2026, so further costs will be incurred then (after unit arrives and design is complete).

Response by: Dan Gervae

Dated: July 10, 2024

**MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request**

3-AG-UPPCO-3.74

Refer to lines 6-10 on page 10 of Mr. Gervae's direct testimony on the 2025 Chatham Transformer replacement project. Please:

- a. Confirm that the costs forecasted for 2025 are only to purchase the transformer. If not confirming, provide the costs for the transformer separately from the cost of installation.
- b. Provide the date that the transformer and related equipment were ordered, the month and year when paid or will paid and the amount, and the expected delivery date.
- c. Explain what work has been done on each project as of June 15, 2024 and what work remains to be done and when.

UPPCO Response:

- a. Assuming that based on the reference to Mr. Gervae's testimony, this request refers to 328A Voltage Regulators, Project, then confirmed that the costs forecasted for 2025 are only to purchase the Regulators.
- b. Regulators were ordered 9/25/2023
- c. Project has not commenced.

Response by: Dan Gervae

Dated: July 10, 2024

MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.101

Refer to lines 10-16 on page 9 of Mr. Brynick's direct testimony on the new Service Center. Please:

- a. Explain if the Quincy Mine is now abandoned and what natural resources were mined or are currently mined.
- b. Has the Company completed a full environmental review of the purchased land for contaminants and obtained a clean report? If no, explain and provide details.

UPPCO Response

- a. Copper was mined, but the mine is no longer active.
- b. Phase 1 environmental study was completed prior to land purchase and the report showed no issues. See Attachments CONFIDENTIAL 3-AG-UPPCO-3.101b1 and 3-AG-UPPCO-3.101b2 which reference the Quincy Hill location ESA, as well as the Quincy Hill Mine Report, respectively.

Response by: Jason Brynick

Dated: July 3, 2024

MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.102

Refer to lines 1-9 on page 10 of Mr. Brynick's direct testimony on the new Service Center. Please:

- a. Identify which bid the Company accepted and provide a copy of the analysis selecting that bid over the others.
- b. Explain what work has been done on the new service center as of the end of May 2024. Identify the remaining phases of the project, the timeline for each phase, and the related cost during each phase.

UPPCO Response

- a. See Exhibit A-56 (JJB-6) which was provided in my original testimony. Moyle Construction was the low bid and was the selected contractor.
- b.
 - i. Contract (phase) 1 – Site Clearing \$ 390K - Complete.
 - ii. Contract (phase) 2 – Site Preparation - \$1,329K – 80% Complete with estimated completion July 2024.
 - iii. Contract (phase) 3 – General Construction - \$9,695K – Underway with estimated completion July 2025.

Response by: Jason Brynick

Dated: July 3, 2024

**MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request**

3-AG-UPPCO-3.109

Refer to the regional map in Exhibit A-61. Please:

- a. Explain how far from the current service center the new service center would be located.
- b. Provide the location of any other service facilities in the north or east of the Portage Canal and the distance from the new proposed service center.

UPPCO Response

- a. Approximately 4 miles.
- b. None. There are no other locations.

Response by: Jason Brynick

Dated: July 3, 2024

MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.103

Refer to lines 16-20 on page 10 and page 11 of Mr. Brynick's direct testimony on the new Service Center alternative mechanical and HVAC system. Please:

- a. Explain fully what the base mechanical and HVAC system is that has been included in the \$11.6 million project cost and the cost of this base system.
- b. Explain fully the alternative mechanical and HVAC system that is being contemplated, what it entails, the related cost, and what cost savings it provides over the base system.
- c. Explain why a cost deferral in Account 183 is necessary if the alternative mechanical and HVAC system is more cost effective and the Company can fully justify this decision.
- d. Explain why only costs in excess of 10% of the base cost should be subject to review for prudence instead of the entire cost of the project.

UPPCO Response

- a. Natural gas radiant heat for the garage and natural gas boilers for the office building. Base HVAC cost \$1,211,950. Please reference UPPCO's response to Staff Discovery Request 4-Staff-UPPCO-4.9.
- b. As noted above, Base HVAC is a fully natural gas system with an estimated installation cost of \$1,211,950. UPPCO evaluated two other options: 1) Option 1 which is a full electric HVAC system with an estimated install cost of \$2,402,907, and 2) Option 2 which is a Hybrid HVAC system, whereby the office is electric and the garage is natural gas, with an estimated install cost of \$1,544,575.00. Operating expenses for each of the three alternatives are listed in a table at the top of page 4 of Attachment Proposed Quincy Hill Service Center comparative Analysis of Commercial Heating and Cooling systems (2024-06-June) in Response to UPPCO Response to 4-Staff-UPPCO-4.9. Please reference UPPCO's response to Staff Discovery Request 4-Staff-UPPCO-4.9
- c. I don't disagree with the assertion. At the time, UPEA had not yet completed its analysis, so the Account 183 was a regulatory construct that would contemplate cost recovery approved for the building and site construction but allow for the HVAC system work and analysis to be completed by UPEA.

UPPCO Response to discovery request 3-AG-UPPCO-3.103

- d. Please see response to 03-AG-UPPCO-3.103c. In this scenario, UPPCO was assuming approved cost recovery of building and site construction, the 10% was allowing for variance on estimated HVAC costs which, at the time, UPEA was still working through. Of course, UPPCO supports review for prudence of the entire cost of the project and did not intend to suggest or indicate otherwise.

Response by: Jason Brynick

Dated: July 3, 2024

**Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
MPSC Staff's
Fourth Discovery Request**

4-Staff-UPPCO-4.9

9. Referring to pages 6 and 7 of witness Brynick's testimony, please provide any updated project descriptions or costs applicable to the Houghton Service Center renovation project.

UPPCO Response

For clarification, UPPCO is not renovating the Houghton Service Center. As described beginning at line 3 on page 8 of my testimony, the Company is relocating its operations to a new facility, Quincy Hill, constructed in Hancock.

As indicated to UPPCO by UP Engineers and Architects (UPEA), the Company's project engineering consultant, UPPCO expects to receive updated project costs/schedule by June 12th, including any modifications due to incorporation of UPPCO's efficient heating and cooling solution(s) for the Quincy Hill facility.

On June 14, 2024, UPPCO intends to update this discovery response to include: 1) updated schedule, 2) updated project costs, and 3) UPEA's final report on the evaluation of efficient heating and cooling systems.

Updated Response June 14, 2024

UPPCO has the following updates:

- Beginning at line 10 on page 13 of my testimony, I state that the project is planned to be completed by end of the projected test year, December 31, 2025. This has not changed. Please find "Attachment UPPCO revised schedule 5-24-24" – which supports a July 2025 completion date.
- Also, please find "Attachment Contract 6.10.24" – which supports a fixed price bid of \$11.414 million (see Article 5, page 3 of 8) which will be completed per the schedule noted above.
- Explain derivation of the final costing of \$11.414 million.
 - Please find "Attachment Schedule of Value Table Details – 6.6.24".
 - In column D, UPEA's original cost estimate was \$9.420 million. As represented in Exhibit A-59 (JJB-9), UPPCO identified an original construction estimate of \$9.420 million, plus a 10% contingency.
 - Beginning at line 14 of page 10 of my testimony, I provide an estimate of "baseline" costs. These costs are identified as baseline because they

- were the basis of the fixed price bid that was selected, but also, they served as the foundation of bridging any cost updates that may occur due to completion of the noted ongoing mechanical/HVAC design work being performed by UPEA.
- Beginning at line 18 of page 10, UPPCO qualifies the bid as utilizing natural gas as its primary heat source. Second, UPPCO further qualifies that UPEA was still in process of completing an alternatives analysis that evaluated efficient sources of electric heating and cooling.
 - In column E, UPPCO approved a contract update of \$84.4K for related contract work, earth work and utilities. These changes are noted in column F.
 - In column G, UPPCO approved a contract update of \$639.9K for general mobilization of resources, as well as other aspects. These changes are noted in column H.
 - In column I, UPPCO approved a contract update of \$1.269 million that incorporated final HVAC design considerations. These changes are noted in column J.
 - Excluding the \$1.269 million of incremental efficient heating and cooling, please provide an apples-to-apples comparison of the cost changes between baseline costs identified in Exhibit A-59 (JJB-9) and final contract value of \$11.414 million.
 - Final contract value of \$11.414 million less \$1.269 million of HVAC design equals \$10.145 million. See Attachment “Schedule of Value Table Details – 6.6.24” at column I.
 - Original contract bid price of \$9.420 million plus a 10% contingency of \$0.942 million equals \$10.362 million. See Exhibit A-59 (JJB-9).
 - The decision analysis supporting the final mechanical/HVAC design is outlined in “Attachment Proposed Quincy Hill Service Center: Comparative Analysis of Commercial Heating and Cooling Systems” dated June 6, 2024. Specifically, beginning on page 4 under the section header of Recommendations, UPPCO is implementing UPEA’s recommendations for the Garage Buildings and Office Buildings.
 - In summary, on page 5, “By implementing a blended system into the proposed Quincy Service Center, UPPCO will be moving closer to the reduction, and forthcoming removal of fossil fuels from the HVAC systems. Cost, current technology, and intended use requirements were all taken into consideration for the development of this study.”

Response by: Jason Brynick

Dated: ~~May 31, 2024~~ June 14, 2024

THE REMAINDER OF THE EXHIBIT CONSISTS OF 4 PAGES
OF A COMPARISON OF PROJECT COSTS FOR THE NEW SERVICE CENTER
AND AN 8 PAGE REPORT ON THE ALTERNATIVE HVAC SYSTEM BY UPEA

Group	Description	\$ 9,420,000.01		\$ 9,504,439.64		\$ 10,144,330.45		\$ 11,413,818.69		Comments
		Original	Contract 2	Delta Contract 2 less Original.	Contract 3	Delta Contract 3 less Contract 2.	Addendum 5 "HVAC"	Addendum 5 less Contract 3		
General Conditions	Project Manager	\$ 69,044.45	\$ 69,044.45	\$ -	\$ 116,157.04	\$ 47,112.59	\$ 116,157.04	\$ -	Increase due to Contract 3 update	
General Conditions	Project Superintendent	\$ 100,357.40	\$ 100,357.40	\$ -	\$ 174,664.45	\$ 74,307.05	\$ 174,664.45	\$ -	Increase due to Contract 3 update	
General Conditions	Temporary facilities and support	\$ 16,979.60	\$ 16,979.60	\$ -	\$ 29,551.80	\$ 12,572.20	\$ 29,551.80	\$ -	Increase due to Contract 3 update	
General Conditions	Surveying	\$ 22,000.00	\$ 22,000.00	\$ -	\$ 22,000.00	\$ -	\$ 22,000.00	\$ -	n/c	
General Conditions	Mobilization	\$ 91,025.00	\$ 91,025.00	\$ -	\$ 91,025.00	\$ -	\$ 91,025.00	\$ -	n/c	
General Conditions	Jobsite lifts and hoists	\$ 34,320.00	\$ 34,320.00	\$ -	\$ 59,731.31	\$ 25,411.31	\$ 59,731.31	\$ -	Increase due to Contract 3 update	
General Conditions	Jobsite safety and security	\$ 3,520.00	\$ 3,520.00	\$ -	\$ 6,126.52	\$ 2,606.52	\$ 6,126.52	\$ -	Increase due to Contract 3 update	
General Conditions	Temporary heating fuel and heaters	\$ -	\$ -	\$ -	\$ 31,800.00	\$ 31,800.00	\$ 31,800.00	\$ -	Added due to Contract 3 update	
General Conditions	Temporary openings	\$ -	\$ -	\$ -	\$ 27,312.96	\$ 27,312.96	\$ 27,312.96	\$ -	Added due to Contract 3 update	
General Conditions	Snow removal - parking lot and grounds	\$ -	\$ -	\$ -	\$ 21,827.14	\$ 21,827.14	\$ 21,827.14	\$ -	Added due to Contract 3 update	
General Conditions	Snow removal - membrane roof install	\$ -	\$ -	\$ -	\$ 25,194.24	\$ 25,194.24	\$ 25,194.24	\$ -	Added due to Contract 3 update	
General Conditions	Labor cost adjustment	\$ -	\$ -	\$ -	\$ 68,985.00	\$ 68,985.00	\$ 68,985.00	\$ -	Added due to Contract 3 update	
General Conditions	Permits	\$ 11,000.00	\$ 11,000.00	\$ -	\$ 11,000.00	\$ -	\$ 11,000.00	\$ -	n/c	
General Conditions	Closeout and final cleaning	\$ 4,180.00	\$ 4,180.00	\$ -	\$ 4,180.00	\$ -	\$ 4,180.00	\$ -	n/c	
Concrete	Office Footings	\$ 48,670.92	\$ 50,616.13	\$ 1,945.21	\$ 50,616.13	\$ -	\$ 50,616.13	\$ -	Increase due to Contract 2 update	
Concrete	Office poured foundation walls	\$ 26,797.24	\$ 28,027.11	\$ 1,229.87	\$ 28,027.11	\$ -	\$ 28,027.11	\$ -	Increase due to Contract 2 update	
Concrete	Office Slab on Grade	\$ 62,461.63	\$ 62,461.63	\$ -	\$ 62,461.63	\$ -	\$ 62,461.63	\$ -	n/c	
Concrete	Project Rebar Package	\$ 200,079.77	\$ 218,632.26	\$ 18,552.49	\$ 218,632.26	\$ -	\$ 218,632.26	\$ -	Increase due to Contract 2 update	
Concrete	Garage Footings	\$ 107,727.17	\$ 112,759.11	\$ 5,031.94	\$ 112,759.11	\$ -	\$ 112,759.11	\$ -	Increase due to Contract 2 update	
Concrete	Garage poured foundation walls	\$ 112,394.37	\$ 115,571.81	\$ 3,177.44	\$ 115,571.81	\$ -	\$ 115,571.81	\$ -	Increase due to Contract 2 update	
Concrete	Garage Slab on Grade	\$ 261,690.06	\$ 261,690.06	\$ -	\$ 306,416.16	\$ 44,726.10	\$ 306,416.16	\$ -	Increase due to Contract 3 update	
Concrete	Garage Sealer	\$ 31,304.68	\$ 31,304.68	\$ -	\$ 31,304.68	\$ -	\$ 31,304.68	\$ -	n/c	
Concrete	Cold Storage Footings	\$ 47,004.31	\$ 49,022.85	\$ 2,018.54	\$ 49,022.85	\$ -	\$ 49,022.85	\$ -	Increase due to Contract 2 update	
Concrete	Cold Storage Slab on Grade	\$ 67,443.44	\$ 71,250.25	\$ 3,806.81	\$ 71,250.25	\$ -	\$ 71,250.25	\$ -	Increase due to Contract 2 update	
Concrete	Cold Storage Sealer	\$ 7,854.00	\$ 7,854.00	\$ -	\$ 7,854.00	\$ -	\$ 7,854.00	\$ -	n/c	
Concrete		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
Masonry	Office 12" CMU	\$ 130,760.72	\$ 130,760.72	\$ -	\$ 159,609.32	\$ 28,848.60	\$ 159,609.32	\$ -	Increase due to Contract 3 update	
Masonry	Office 4" CMU	\$ 114,123.15	\$ 114,123.15	\$ -	\$ 114,123.15	\$ -	\$ 114,123.15	\$ -	n/c	
Masonry	Cast Sills	\$ 17,948.89	\$ 17,948.89	\$ -	\$ 17,948.89	\$ -	\$ 17,948.89	\$ -	n/c	
Masonry	Garage 8" CMU	\$ 152,966.46	\$ 152,966.46	\$ -	\$ 224,143.41	\$ 71,176.95	\$ 229,805.20	\$ 5,661.79	Increase due to Contract 3 update and addendum 5	
Metals	Office steel stud bearing walls and floor system -	\$ 136,196.74	\$ 136,196.74	\$ -	\$ 136,196.74	\$ -	\$ 170,339.55	\$ 34,142.81	Increase due to addendum 5	
Metals	Office steel stud bearing walls and floor system - Labor	\$ 27,904.80	\$ 27,904.80	\$ -	\$ 27,904.80	\$ -	\$ 27,904.80	\$ -	n/c	
Metals	Office bar joists and metal deck roof system - Materials	\$ 131,586.62	\$ 131,586.62	\$ -	\$ 131,586.62	\$ -	\$ 131,586.62	\$ -	n/c	
Metals	Office bar joists and metal deck roof system - Labor	\$ 15,182.00	\$ 15,182.00	\$ -	\$ 15,182.00	\$ -	\$ 15,182.00	\$ -	n/c	
Metals	Office steel - Materials	\$ 32,896.65	\$ 32,896.65	\$ -	\$ 32,896.65	\$ -	\$ 32,896.65	\$ -	n/c	
Metals	Office steel - Labor	\$ 4,555.32	\$ 4,555.32	\$ -	\$ 4,555.32	\$ -	\$ 4,555.32	\$ -	n/c	
Metals	Garage misc. Metals - Materials	\$ 54,827.76	\$ 54,827.76	\$ -	\$ 54,827.76	\$ -	\$ 54,827.76	\$ -	n/c	
Metals	Garage misc. Metals - Labor	\$ 5,728.80	\$ 5,728.80	\$ -	\$ 5,728.80	\$ -	\$ 5,728.80	\$ -	n/c	
Metals	Garage steel stud parapet framing	\$ 9,732.80	\$ 9,732.80	\$ -	\$ 9,732.80	\$ -	\$ 9,732.80	\$ -	n/c	
Metals	Trench Drain Grating	\$ 13,828.87	\$ 13,828.87	\$ -	\$ 13,828.87	\$ -	\$ 13,828.87	\$ -	n/c	
Metals	Steel framing for mechanical equipment	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 111,294.84	\$ 111,294.84	Added due to addendum 5	
Wood,Plastics,Composites	Office Roof Edge & Window Blocking	\$ 9,114.20	\$ 9,114.20	\$ -	\$ 9,114.20	\$ -	\$ 9,114.20	\$ -	n/c	
Wood,Plastics,Composites	Office Mezzanine Plywood Floor	\$ 17,525.20	\$ 17,525.20	\$ -	\$ 17,525.20	\$ -	\$ 17,525.20	\$ -	n/c	
Wood,Plastics,Composites	Office Casework, Countertops, and Window Sills	\$ 24,794.00	\$ 24,794.00	\$ -	\$ 24,794.00	\$ -	\$ 24,794.00	\$ -	n/c	
Wood,Plastics,Composites	Casework, Countertops, Window Sill Labor	\$ 5,497.80	\$ 5,497.80	\$ -	\$ 5,497.80	\$ -	\$ 5,497.80	\$ -	n/c	
Wood,Plastics,Composites	Garage Roof Edge Blocking	\$ 4,463.72	\$ 4,463.72	\$ -	\$ 4,463.72	\$ -	\$ 4,463.72	\$ -	n/c	
Wood,Plastics,Composites	Meter Room Plywood Floor	\$ 2,503.94	\$ 2,503.94	\$ -	\$ 2,503.94	\$ -	\$ 2,503.94	\$ -	n/c	

Group	Description	Original	Contract 2	Delta Contract 2 less Original.	Contract 3	Delta Contract 3 less Contract 2.	Addendum 5 "HVAC"	Addendum 5 less Contract 3	Comments
Wood,Plastics,Composites				\$ -		\$ -		\$ -	
Thermal and Moisture	Office Below Grade Insulation	\$ 8,467.64	\$ 8,467.64	\$ -	\$ 8,467.64	\$ -	\$ 8,467.64	\$ -	n/c
Thermal and Moisture	Office Cavity Wall Insulation	\$ 33,357.97	\$ 33,357.97	\$ -	\$ 33,357.97	\$ -	\$ 33,357.97	\$ -	n/c
Thermal and Moisture	Office Interior Board Insulation and Z-furring	\$ 29,446.05	\$ 29,446.05	\$ -	\$ 29,446.05	\$ -	\$ 29,446.05	\$ -	n/c
Thermal and Moisture	Office Sound Wall Insulation	\$ 17,406.40	\$ 17,406.40	\$ -	\$ 17,406.40	\$ -	\$ 17,406.40	\$ -	n/c
Thermal and Moisture	Office Mezzanine Floor Insulation	\$ 11,721.60	\$ 11,721.60	\$ -	\$ 11,721.60	\$ -	\$ 11,721.60	\$ -	n/c
Thermal and Moisture	Membrane Roof System	\$ 413,600.00	\$ 413,600.00	\$ -	\$ 413,600.00	\$ -	\$ 413,600.00	\$ -	n/c
Thermal and Moisture	Roof Hatch, Decorative Fascia	\$ 33,000.00	\$ 33,000.00	\$ -	\$ 33,000.00	\$ -	\$ 33,000.00	\$ -	n/c
Thermal and Moisture	Garage Below Grade Insulation	\$ 19,244.63	\$ 19,244.63	\$ -	\$ 19,244.63	\$ -	\$ 19,244.63	\$ -	n/c
Thermal and Moisture	Garage Interior Board Insulation and Z-furring	\$ 34,291.40	\$ 34,291.40	\$ -	\$ 34,291.40	\$ -	\$ 34,291.40	\$ -	n/c
Thermal and Moisture	Garage Metal Building Insulation	\$ 38,156.80	\$ 38,156.80	\$ -	\$ 38,156.80	\$ -	\$ 38,156.80	\$ -	n/c
Thermal and Moisture	Parapet Wall Insulation	\$ 5,984.22	\$ 5,984.22	\$ -	\$ 5,984.22	\$ -	\$ 5,984.22	\$ -	n/c
Thermal and Moisture	Cold Storage Below Grade Insulation	\$ 9,198.94	\$ 9,198.94	\$ -	\$ 9,198.94	\$ -	\$ 9,198.94	\$ -	n/c
Thermal and Moisture				\$ -		\$ -		\$ -	
Openings	Doors, Frames, and Hardware	\$ 79,559.70	\$ 79,559.70	\$ -	\$ 80,344.50	\$ 784.80	\$ 80,344.50	\$ -	Increase due to Contract 3 update
Openings	Doors, Frames, and Hardware Labor	\$ 12,751.20	\$ 12,751.20	\$ -	\$ 12,751.20	\$ -	\$ 12,751.20	\$ -	n/c
Openings	Aluminum Entry Doors - Material	\$ 12,826.00	\$ 12,826.00	\$ -	\$ 12,826.00	\$ -	\$ 12,826.00	\$ -	n/c
Openings	Aluminum Entry Doors - Labor	\$ 4,400.00	\$ 4,400.00	\$ -	\$ 4,400.00	\$ -	\$ 4,400.00	\$ -	n/c
Openings	Aluminum Windows - Type A, B, C - Material	\$ 91,006.30	\$ 91,006.30	\$ -	\$ 91,006.30	\$ -	\$ 91,006.30	\$ -	n/c
Openings	Aluminum Windows - Type A, B, C - Labor	\$ 22,770.00	\$ 22,770.00	\$ -	\$ 26,422.40	\$ 3,652.40	\$ 26,422.40	\$ -	Increase due to Contract 3 update
Openings	Translucent Panels - Kalwall Panel System Materials	\$ 85,817.60	\$ 85,817.60	\$ -	\$ 85,817.60	\$ -	\$ 85,817.60	\$ -	n/c
Openings	Translucent Panels - Labor	\$ 16,500.00	\$ 16,500.00	\$ -	\$ 16,500.00	\$ -	\$ 16,500.00	\$ -	n/c
Openings	Interior Glazing - Glass	\$ 4,197.60	\$ 4,197.60	\$ -	\$ 4,197.60	\$ -	\$ 4,197.60	\$ -	n/c
Openings	Interior Glazing - Labor	\$ 2,420.00	\$ 2,420.00	\$ -	\$ 2,420.00	\$ -	\$ 2,420.00	\$ -	n/c
Openings	Overhead Doors material	\$ 43,453.58	\$ 43,453.58	\$ -	\$ 43,453.58	\$ -	\$ 43,453.58	\$ -	n/c
Openings	Overhead Doors labor	\$ 14,484.53	\$ 14,484.53	\$ -	\$ 14,484.53	\$ -	\$ 14,484.53	\$ -	n/c
Finishes	Office Light gauge steel stud framing	\$ 13,527.36	\$ 13,527.36	\$ -	\$ 13,527.36	\$ -	\$ 13,527.36	\$ -	n/c
Finishes	Office Drywall	\$ 170,016.00	\$ 170,016.00	\$ -	\$ 170,016.00	\$ -	\$ 170,016.00	\$ -	n/c
Finishes	Office Painting	\$ 61,242.50	\$ 61,242.50	\$ -	\$ 62,162.50	\$ 920.00	\$ 62,162.50	\$ -	Increase due to Contract 3 update
Finishes	Office Acoustical Ceilings	\$ 50,529.60	\$ 50,529.60	\$ -	\$ 50,529.60	\$ -	\$ 52,158.00	\$ 1,628.40	Increase due to addendum 5
Finishes	Office Flooring and Base	\$ 89,776.50	\$ 89,776.50	\$ -	\$ 89,776.50	\$ -	\$ 89,776.50	\$ -	n/c
Finishes	Garage Misc. Painting	\$ 10,807.50	\$ 10,807.50	\$ -	\$ 10,807.50	\$ -	\$ 10,807.50	\$ -	n/c
Finishes	Epoxy Flooring in Mechanical Room	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,559.90	\$ 2,559.90	Added due to addendum 5
Specialties	Mapes Canopies	\$ 10,955.74	\$ 10,955.74	\$ -	\$ 10,955.74	\$ -	\$ 10,955.74	\$ -	n/c
Specialties	Mapes Canopies - Labor	\$ 4,435.20	\$ 4,435.20	\$ -	\$ 4,435.20	\$ -	\$ 4,435.20	\$ -	n/c
Specialties	Toilet partitions, bathroom access., lockers	\$ 23,300.20	\$ 23,300.20	\$ -	\$ 24,049.00	\$ 748.80	\$ 24,049.00	\$ -	Increase due to Contract 3 update
Specialties	Specialties Labor	\$ 6,098.40	\$ 6,098.40	\$ -	\$ 6,098.40	\$ -	\$ 6,098.40	\$ -	n/c
Furnishings	Recessed entry mats	\$ 10,039.70	\$ 10,039.70	\$ -	\$ 10,039.70	\$ -	\$ 10,039.70	\$ -	n/c
Special Construction	Modular Office - Garage	\$ 23,202.16	\$ 23,202.16	\$ -	\$ 23,202.16	\$ -	\$ 23,202.16	\$ -	n/c
Special Construction	Garage - Pre-engineered metal building material pkg	\$ 1,098,628.87	\$ 1,098,628.87	\$ -	\$ 1,185,717.67	\$ 87,088.80	\$ 1,185,717.67	\$ -	Increase due to Contract 3 update
Special Construction	Garage Pre-engineered metal building system labor	\$ 180,268.00	\$ 180,268.00	\$ -	\$ 180,268.00	\$ -	\$ 180,268.00	\$ -	n/c
Special Construction	Garage Interior metal liner panel labor	\$ 12,658.80	\$ 12,658.80	\$ -	\$ 12,658.80	\$ -	\$ 12,658.80	\$ -	n/c
Special Construction	Garage exterior metal siding labor	\$ 25,872.00	\$ 25,872.00	\$ -	\$ 25,872.00	\$ -	\$ 25,872.00	\$ -	n/c
Special Construction	Cold storage pre-engineered metal building material	\$ 241,305.77	\$ 241,305.77	\$ -	\$ 241,305.77	\$ -	\$ 241,305.77	\$ -	n/c
Special Construction	Cold Storage Pre-engineered metal building labor	\$ 43,560.00	\$ 43,560.00	\$ -	\$ 71,766.60	\$ 28,206.60	\$ 71,766.60	\$ -	Increase due to Contract 3 update
Special Construction	Cold Storage exterior metal siding labor	\$ 15,079.68	\$ 15,079.68	\$ -	\$ 15,079.68	\$ -	\$ 15,079.68	\$ -	n/c
Special Construction	Cold Storage exterior metal roofing labor	\$ 19,712.00	\$ 19,712.00	\$ -	\$ 19,712.00	\$ -	\$ 19,712.00	\$ -	n/c
Mechanical/Plumbing	Mobilization	\$ 41,580.00	\$ 41,580.00	\$ -	\$ 41,580.00	\$ -	\$ 81,657.50	\$ 40,077.50	Increase due to addendum 5
Mechanical/Plumbing	Permits	\$ 3,300.00	\$ 3,300.00	\$ -	\$ 3,300.00	\$ -	\$ 3,300.00	\$ -	n/c

TAB: Schedule of Values Table

Group	Description	Original	Contract 2	Delta Contract 2 less Original.	Contract 3	Delta Contract 3 less Contract 2.	Addendum 5 "HVAC"	Addendum 5 less Contract 3	Comments
Mechanical/Plumbing	Garage Radiant Heaters Materials	\$ 38,777.20	\$ 38,777.20	\$ -	\$ 38,777.20	\$ -	\$ 38,777.20	\$ -	n/c
Mechanical/Plumbing	Garage Radiant Heaters Labor	\$ 21,780.00	\$ 21,780.00	\$ -	\$ 21,780.00	\$ -	\$ 21,780.00	\$ -	n/c
Mechanical/Plumbing	Gas piping materials	\$ 11,000.00	\$ 11,000.00	\$ -	\$ 11,000.00	\$ -	\$ 11,000.00	\$ -	n/c
Mechanical/Plumbing	Gas piping labor	\$ 15,400.00	\$ 15,400.00	\$ -	\$ 15,400.00	\$ -	\$ 15,400.00	\$ -	n/c
Mechanical/Plumbing	Garage fans, louver materials	\$ 58,010.70	\$ 58,010.70	\$ -	\$ 58,010.70	\$ -	\$ 64,753.15	\$ 6,742.45	Increase due to addendum 5
Mechanical/Plumbing	Garage fans, louver labor	\$ 12,502.60	\$ 12,502.60	\$ -	\$ 12,502.60	\$ -	\$ 12,502.60	\$ -	n/c
Mechanical/Plumbing	ERV system materials	\$ 3,960.00	\$ 3,960.00	\$ -	\$ 3,960.00	\$ -	\$ 3,960.00	\$ -	n/c
Mechanical/Plumbing	ERV system labor	\$ 3,124.00	\$ 3,124.00	\$ -	\$ 3,124.00	\$ -	\$ 3,124.00	\$ -	n/c
Mechanical/Plumbing	Plumbing materials, office	\$ 29,304.00	\$ 29,304.00	\$ -	\$ 29,304.00	\$ -	\$ 31,558.00	\$ 2,254.00	Increase due to addendum 5
Mechanical/Plumbing	Plumbing labor, office	\$ 28,912.40	\$ 28,912.40	\$ -	\$ 28,912.40	\$ -	\$ 28,912.40	\$ -	n/c
Mechanical/Plumbing	Plumbing materials, shops	\$ 58,615.70	\$ 58,615.70	\$ -	\$ 58,615.70	\$ -	\$ 79,782.60	\$ 21,166.90	Increase due to addendum 5
Mechanical/Plumbing	Plumbing labor, shops	\$ 28,912.40	\$ 28,912.40	\$ -	\$ 28,912.40	\$ -	\$ 41,005.80	\$ 12,093.40	Increase due to addendum 5
Mechanical/Plumbing	Plumbing fixtures	\$ 55,440.00	\$ 55,440.00	\$ -	\$ 55,440.00	\$ -	\$ 55,440.00	\$ -	n/c
Mechanical/Plumbing	Boiler room materials - including boilers	\$ 60,965.30	\$ 60,965.30	\$ -	\$ 60,965.30	\$ -	\$ 205,666.35	\$ 144,701.05	Increase due to addendum 5
Mechanical/Plumbing	Boiler room labor	\$ 18,753.90	\$ 18,753.90	\$ -	\$ 18,753.90	\$ -	\$ 30,556.35	\$ 11,802.45	Increase due to addendum 5
Mechanical/Plumbing	Hydronic baseboard, coils materials	\$ 27,225.00	\$ 27,225.00	\$ -	\$ 27,225.00	\$ -	\$ 27,225.00	\$ -	n/c
Mechanical/Plumbing	Hydronic baseboard, coils labor	\$ 13,750.00	\$ 13,750.00	\$ -	\$ 13,750.00	\$ -	\$ 13,750.00	\$ -	n/c
Mechanical/Plumbing	Mini Split materials	\$ 9,350.00	\$ 9,350.00	\$ -	\$ 9,350.00	\$ -	\$ 10,155.00	\$ 805.00	Increase due to addendum 5
Mechanical/Plumbing	Mini Split labor	\$ 4,688.20	\$ 4,688.20	\$ -	\$ 4,688.20	\$ -	\$ 4,688.20	\$ -	n/c
Mechanical/Plumbing	RTU and vav's materials	\$ 56,180.30	\$ 56,180.30	\$ -	\$ 56,180.30	\$ -	\$ 441,921.35	\$ 385,741.05	Increase due to addendum 5
Mechanical/Plumbing	RTU and vav's labor	\$ 10,450.00	\$ 10,450.00	\$ -	\$ 10,450.00	\$ -	\$ 24,365.00	\$ 13,915.00	Increase due to addendum 5
Mechanical/Plumbing	Ducting materials	\$ 25,080.00	\$ 25,080.00	\$ -	\$ 25,080.00	\$ -	\$ 31,750.00	\$ 6,670.00	Increase due to addendum 5
Mechanical/Plumbing	Ducting labor	\$ 26,620.00	\$ 26,620.00	\$ -	\$ 26,620.00	\$ -	\$ 26,620.00	\$ -	n/c
Mechanical/Plumbing	Hydronic piping materials	\$ 64,806.50	\$ 64,806.50	\$ -	\$ 64,806.50	\$ -	\$ 75,829.25	\$ 11,022.75	Increase due to addendum 5
Mechanical/Plumbing	Hydronic piping, labor	\$ 37,972.00	\$ 37,972.00	\$ -	\$ 37,972.00	\$ -	\$ 37,972.00	\$ -	n/c
Mechanical/Plumbing	Insulation Subcontractor	\$ 223,502.40	\$ 223,502.40	\$ -	\$ 223,502.40	\$ -	\$ 254,304.00	\$ 30,801.60	Increase due to addendum 5
Mechanical/Plumbing	Controls Subcontractor	\$ 143,873.40	\$ 143,873.40	\$ -	\$ 143,873.40	\$ -	\$ 147,330.30	\$ 3,456.90	Increase due to addendum 5
Mechanical/Plumbing	TAB Subcontractor	\$ 10,560.00	\$ 10,560.00	\$ -	\$ 10,560.00	\$ -	\$ 11,940.00	\$ 1,380.00	Increase due to addendum 5
Fire Suppression	Fire suppression Office	\$ 36,850.00	\$ 36,850.00	\$ -	\$ 36,850.00	\$ -	\$ 36,850.00	\$ -	n/c
Fire Suppression	Fire Suppression Garage	\$ 85,250.00	\$ 85,250.00	\$ -	\$ 85,250.00	\$ -	\$ 85,250.00	\$ -	n/c
Fire Suppression	Fire Suppression Cold Storage	\$ 48,400.00	\$ 48,400.00	\$ -	\$ 48,400.00	\$ -	\$ 48,400.00	\$ -	n/c
Electrical	Mobilization	\$ 2,750.00	\$ 2,750.00	\$ -	\$ 2,750.00	\$ -	\$ 2,750.00	\$ -	n/c
Electrical	Switch Gear Package	\$ 56,298.00	\$ 56,298.00	\$ -	\$ 56,298.00	\$ -	\$ 176,496.00	\$ 120,198.00	Increase due to addendum 5
Electrical	Lighting Package	\$ 97,361.00	\$ 97,361.00	\$ -	\$ 97,361.00	\$ -	\$ 97,361.00	\$ -	n/c
Electrical	Generator	\$ 110,521.40	\$ 110,521.40	\$ -	\$ 110,521.40	\$ -	\$ 301,738.80	\$ 191,217.40	Increase due to addendum 5
Electrical	Feeders	\$ 114,052.40	\$ 114,052.40	\$ -	\$ 114,052.40	\$ -	\$ 210,652.40	\$ 96,600.00	Increase due to addendum 5
Electrical	Rough-In	\$ 144,324.40	\$ 144,324.40	\$ -	\$ 144,324.40	\$ -	\$ 153,880.90	\$ 9,556.50	Increase due to addendum 5
Electrical	Trim Out	\$ 83,853.00	\$ 83,853.00	\$ -	\$ 83,853.00	\$ -	\$ 87,477.80	\$ 3,624.80	Increase due to addendum 5
Electrical	Camera Package	\$ 52,995.80	\$ 52,995.80	\$ -	\$ 52,995.80	\$ -	\$ 53,369.55	\$ 373.75	Increase due to addendum 5
Electrical	Card Reader Package	\$ 63,962.80	\$ 63,962.80	\$ -	\$ 63,962.80	\$ -	\$ 63,962.80	\$ -	n/c
Earthwork	Erosion controls	\$ 7,480.00	\$ 7,480.00	\$ -	\$ 7,480.00	\$ -	\$ 7,480.00	\$ -	n/c
Earthwork	Clearing, grubbing, and strip topsoil	\$ 132,462.00	\$ 132,462.00	\$ -	\$ 132,462.00	\$ -	\$ 132,462.00	\$ -	n/c
Earthwork	Site balance and general fill	\$ 153,846.00	\$ 153,846.00	\$ -	\$ 153,846.00	\$ -	\$ 153,846.00	\$ -	n/c
Earthwork	Pond excavation	\$ 28,523.00	\$ 28,523.00	\$ -	\$ 28,523.00	\$ -	\$ 28,523.00	\$ -	n/c
Earthwork	Class II fill - office/garage	\$ 38,269.11	\$ 38,269.11	\$ -	\$ 38,269.11	\$ -	\$ 38,269.11	\$ -	n/c
Earthwork	Class II fill - cold storage	\$ 12,756.37	\$ 12,756.37	\$ -	\$ 12,756.37	\$ -	\$ 12,756.37	\$ -	n/c
Earthwork	Class II fill - parking areas	\$ 46,060.96	\$ 46,060.96	\$ -	\$ 46,060.96	\$ -	\$ 46,060.96	\$ -	n/c
Earthwork	Building excavation and backfill - office/garage	\$ 36,003.00	\$ 36,003.00	\$ -	\$ 36,003.00	\$ -	\$ 36,003.00	\$ -	n/c
Earthwork	Building excavation and backfill - cold storage	\$ 12,001.00	\$ 12,001.00	\$ -	\$ 12,001.00	\$ -	\$ 12,001.00	\$ -	n/c

Attachment Schedule of Values Table Details-6.6.24

TAB: Schedule of Values Table

Group	Description	Original	Contract 2	Delta Contract 2 less Original.	Contract 3	Delta Contract 3 less Contract 2.	Addendum 5 "HVAC"	Addendum 5 less Contract 3	Comments
Earthwork	Topsoil, seed and mulch	\$ 51,128.00	\$ 51,128.00	\$ -	\$ 51,128.00	\$ -	\$ 51,128.00	\$ -	n/c
Earthwork	Remove spoils	\$ -	\$ 33,955.44	\$ 33,955.44	\$ 33,955.44	\$ -	\$ 33,955.44	\$ -	Contract change order - Contract 2
Earthwork	Well removal	\$ -	\$ 3,654.21	\$ 3,654.21	\$ 3,654.21	\$ -	\$ 3,654.21	\$ -	Contract change order - Contract 2
Exterior Improvements	Concrete Curbs	\$ 74,052.00	\$ 74,052.00	\$ -	\$ 80,557.20	\$ 6,505.20	\$ 80,557.20	\$ -	Increase due to Contract 3 update
Exterior Improvements	Concrete Sidewalks	\$ 59,279.00	\$ 59,279.00	\$ -	\$ 59,279.00	\$ -	\$ 59,279.00	\$ -	n/c
Exterior Improvements	Aggregate laydown area	\$ 308,809.60	\$ 308,809.60	\$ -	\$ 308,809.60	\$ -	\$ 308,809.60	\$ -	n/c
Exterior Improvements	Aggregate parking lot base	\$ 65,276.20	\$ 65,276.20	\$ -	\$ 65,276.20	\$ -	\$ 65,276.20	\$ -	n/c
Exterior Improvements	HMA Paving & Fine Grading	\$ 216,815.50	\$ 216,815.50	\$ -	\$ 232,523.35	\$ 15,707.85	\$ 232,523.35	\$ -	Increase due to Contract 3 update
Exterior Improvements	Bollards and pavement markings & ADA signage	\$ 20,531.94	\$ 20,531.94	\$ -	\$ 20,531.94	\$ -	\$ 20,531.94	\$ -	n/c
Exterior Improvements	Fencing and motorized gates	\$ 316,009.10	\$ 316,009.10	\$ -	\$ 330,404.80	\$ 14,395.70	\$ 330,404.80	\$ -	Increase due to Contract 3 update
Utilities	Storm pipe and catch basins	\$ 123,752.20	\$ 124,473.50	\$ 721.30	\$ 124,473.50	\$ -	\$ 124,473.50	\$ -	Increase due to Contract 2 update
Utilities	Water Main	\$ 137,302.00	\$ 147,648.38	\$ 10,346.38	\$ 147,648.38	\$ -	\$ 147,648.38	\$ -	Increase due to Contract 2 update
Utilities	Sanitary	\$ 145,557.61	\$ 145,557.61	\$ -	\$ 145,557.61	\$ -	\$ 145,557.61	\$ -	n/c



Upper Peninsula Power Company

Proposed Quincy Hill Service Center

Comparative Analysis of Commercial Heating and Cooling Systems

June 6, 2024

Introduction

Commercial heating and cooling systems play a vital role in maintaining indoor environmental quality and occupant comfort while significantly impacting energy consumption and environmental sustainability. UPEA has investigated a variety of systems to provide an in-depth comparative analysis of different types of commercial heating and cooling systems, evaluating their performance, energy efficiency, and environmental sustainability. By examining various technologies such as traditional HVAC systems, heat pumps, geothermal systems, and radiant heating/cooling systems, this analysis aims to identify the most environmentally sustainable while economically feasible solutions for the new UPPCO Quincy Hill Service Center buildings.

Commercial buildings account for a significant portion of energy consumption globally, with heating and cooling systems being primary contributors. The choice of heating and cooling systems in commercial buildings not only affects energy efficiency and operating costs but also has substantial implications for environmental sustainability. By evaluating each of the following systems, and the opportunity to combine them, UPEA has determined that combinations of systems can be implemented to provide the best possible solution.

Systems Considered:

Traditional HVAC Systems:

Traditional Heating, Ventilation, and Air Conditioning (HVAC) systems are widely used in commercial buildings. These systems typically comprise of a furnace or boiler for heating and a chiller for cooling, with air ducts distributing conditioned air throughout the building. While traditional HVAC systems provide effective climate control, they often exhibit higher greenhouse gas emissions due to reliance on fossil fuels.

Heat Pumps:

Heat pumps offer an energy-efficient alternative to traditional HVAC systems by utilizing renewable energy sources such as air, water, or geothermal heat. These systems can provide both heating and cooling by transferring heat from one medium to another. Air-source heat pumps extract heat from outdoor air during winter and expel heat outdoors during summer, while ground-source heat pumps harness stable underground temperatures for heating and cooling. Heat pumps offer significant energy efficiency and lower carbon emissions compared to conventional HVAC systems. Heat pumps have some limitations as discovered in this analysis. In areas with significant air exchange such as a garage, the “recovery” or time to reheat would likely be extensive and reduce economic and thermal efficiency. Additional considerations should be taken with the cost of heat pumps as they are significantly more expensive than traditional HVAC systems.

Geothermal Systems:

Geothermal heating and cooling systems leverage the consistent temperature of the earth's subsurface to regulate building temperatures. These systems use loops of underground pipes filled with a heat transfer fluid to exchange heat with the ground. Geothermal systems can achieve remarkable energy efficiency and significantly reduce carbon emissions compared to traditional HVAC systems. However, they require substantial upfront investment and may be constrained by geological factors. In the region of this project, geothermal is not a reasonable economic or technologically achievable methodology due to the required depths to reach heat sources, the limited heat potential at depth, and the associated cost per heating unit. Additionally, as described

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with utilizing heat pumps, the recovery time can be significantly problematic in certain areas such as garage areas. Overall, geothermal systems are better suited where subsurface thermal potential is greater.

Radiant Heating

Gas radiant heaters for garages are a type of heating system designed to provide warmth and comfort to garage spaces using natural gas or propane as a fuel source. These heaters work on the principle of radiant heating, which involves emitting infrared radiation to heat objects and surfaces within the garage, rather than heating the air directly. Overhead gas radiant heaters are specifically used in this application to accomplish multiple goals such as rapid snow melt, minimizing clearances from building components, and optimizing ceiling space. While electric radiant heaters technical potential could theoretically be met, commercially available options will not offer a comparable heat output, meet the required clearance distances within the proposed building, or meet the economic potential required with the current building design. Due to the reduced heat output per heating unit, an estimated four times the number of radiant heating units would be required to accomplish the same heat output as compared to the gas fired radiant heating units. This layout can be visualized in the attached Figure 1. The electric heating units proposed are 21” wide rather than 12” wide, greatly expanding the overall space required to meet the same heating demand as the gas fired radiant heaters. The additional space required is greater than the building currently proposed can support. This coupled with required clearances would require a redesign of the building’s height to maintain safe distances from the equipment within the building. Operationally speaking, by utilizing current rate schedules, the electric radiant system, if implemented, would cost significantly more per year to operate. These calculations can be seen in the tables below. An additional consideration outside of construction cost that should be considered is total headspace occupied. The continual maintenance of four times the total equipment within garage building could be a cumbersome and expensive endeavor. The associated cost of implementing electric radiant heaters along with the associated building modifications can be seen below.

Cost Comparison for Implementation of Electric Radiant Heaters – Garage Section

	Natural Gas System	Electric System	Note
Building Update	\$ 0.00	\$ 1,241,000.00	Increase building height
Radiant Heaters	\$ 346,290.00	\$ 623,322.00	Cost of equipment
Backup Generator	\$ 110,500.00	\$ 322,025.00	Increase in capacity
Electric System Update	\$ 0.00	\$ 84,400.00	Change in service & equipment
Total Cost Estimate	\$ 456,790.00	\$ 2,270,747.00	Cost Delta = \$ 1,813,957.00

Estimated Yearly Operating Expenses – Gas, Hybrid, & Electric Operation

System Design	Cost Associated	Total
All Gas Heat	Gas heating, electric building operations (light, etc.)	\$41,929.28
Hybrid HVAC System	Electrified Office building, Gas Radiant Heat	\$68,683.38
Full Electrification	Electric Radiant Heating	\$169,289.60

*** See appendix A for cost breakdown

Comparative Analysis

Commercial heating and cooling systems and their associated costs reveal varying levels of energy efficiency, environmental impact, and sustainability. Traditional HVAC systems, while ubiquitous, tend to have higher energy consumption and greenhouse gas emissions but come at a somewhat reduced cost. Heat pumps and geothermal systems offer superior energy efficiency and reduced environmental impact, particularly when electrified by ever increasing renewable sources. Heat pump systems come at a substantial cost; however, installation of these systems offers some tax-based incentives (not included in estimates). Radiant heating systems provide local heat for specific tasks such as rapid heating and snow melting. For this project, the current technologies and associated cost do not offer adequate economic potential as discussed.

Recommendations

Following the investigation of each of the system elements, UPEA offers the following recommendations for each building segment.

Garage Building - Based on the current technologies, replacing the gas fired radiant units with an electrified system does not meet reasonable economic potential and is not recommended for the required needs of the facility. The clearance required (building modifications required), the update to the electrical system, and the total number of required units would greatly increase costs as well as decrease the effective use of the system. The use of heat pumps also poses significant troubles including cost, effective use for drying/snow melting, and heat recharge time.

UPEA recommends retaining gas fired radiant heaters for the garage area. With the current proposed construction type, upgrading the system in the future as electric heating technologies advance would not require significant construction to implement new units.

Office Building – Total electrification of this building offers achievable potential and is recommended. Utilizing multiple systems while taking design and cost into consideration provided a blended approach to this HVAC design. UPEA recommends implementing a heat pump system for both the roof top unit as well as the hydronic system, backed up by electric boilers. By utilizing both these systems, we are ensuring constant efficiency while still maintaining the need to be able to expand the system in the future. Additionally, the system as designed would not require significant changes to the designed building and can readily be interchanged with the recommended systems. The following cost comparison projects show that by utilizing a hybrid system, the building can both be more efficient and be equally affordable.

Capital Construction Cost Comparison of Proposed Systems

Component	Existing Design - Gas System	Full Electrification	Hybrid System
Garage Building	\$ 346,290.00	\$ 2,270,747.00	\$ 346,290.00
Office Building	\$ 755,160.00	\$ 1,993,818.00	\$ 1,993,818.00
Backup Generator	\$ 110,500.00	\$ 322,025.00	\$ 191,217.00
HVAC Cost Estimate	\$ 1,211,950.00	\$ 4,586,590.00	\$ 2,531,325.00
Total Building Cost	\$10,144,330.41	\$15,668,920.41*	\$11,413,818.69.00

*Based on change order construction estimates.

By implementing a blended system into the proposed Quincy Service Center, UPPCO will be moving closer to the reduction, and forthcoming removal of fossil fuels from the HVAC systems. Cost, current technology, and intended use requirements were all taken into consideration for the development of this study.

FIGURE 1 - Garage Building Plan Section

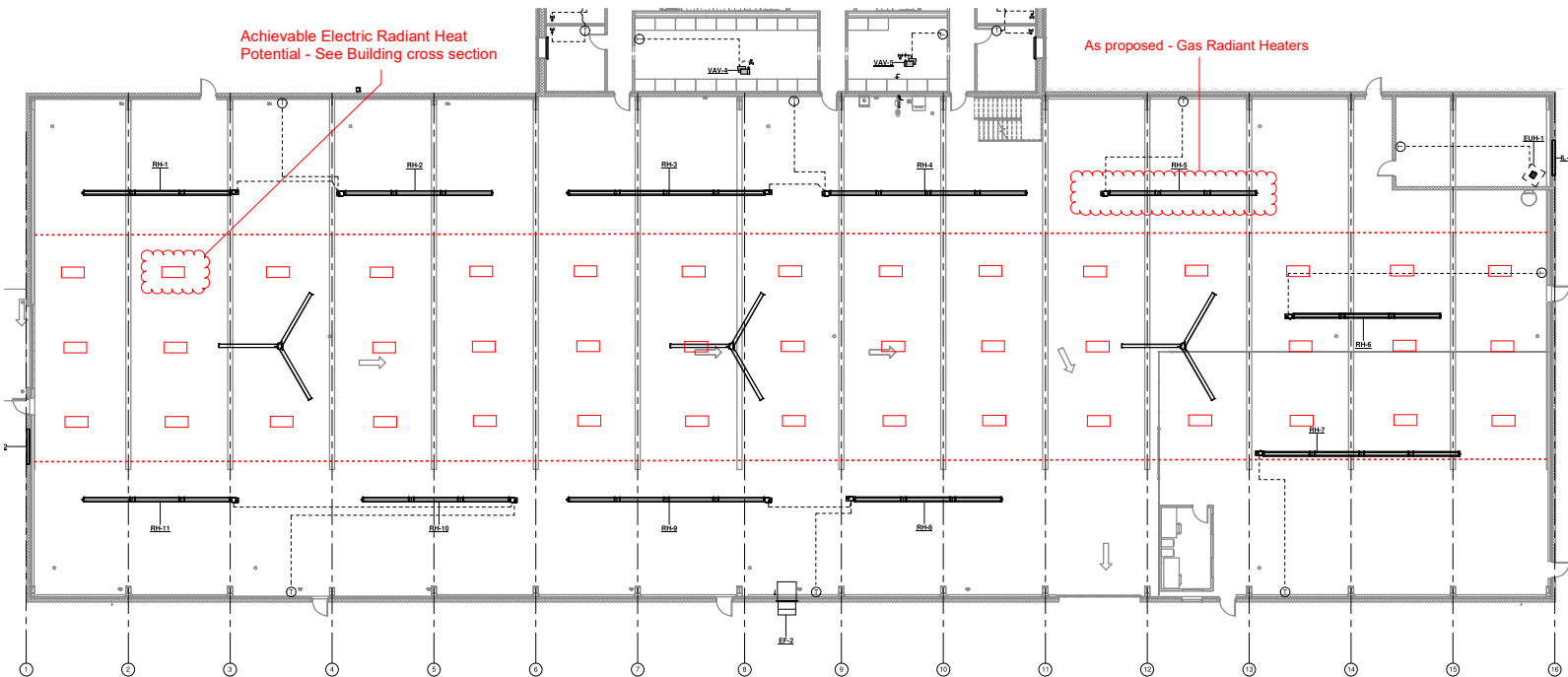
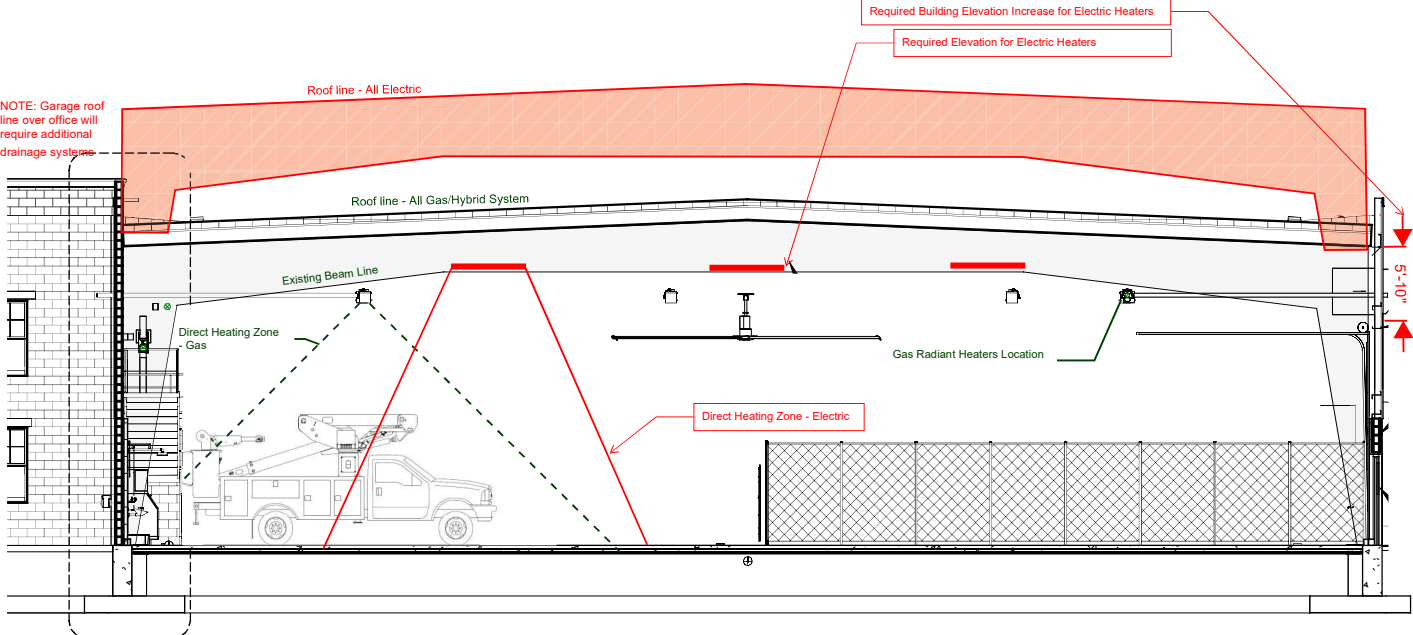


FIGURE 1 - Garage Building Cross Section



NOTE: Garage roof line over office will require additional drainage systems

Appendix A- Operating cost comparison for gas, hybrid & electric building designs

All Gas				Hybrid				All Electric	
Rate: P-1				Rate: P-1				Rate: CP-U	
Month	Monthly Elec.	Monthly Gas	Monthly Total	Month	Monthly Elec.	Monthly Gas	Monthly Total	Month	Monthly Elec.
Jan	\$ 3,646.93	\$ 3,246.00	\$ 6,892.94	Jan	\$ 5,534.96	\$ 2,767.57	\$ 8,302.53	Jan	\$ 21,335.02
Feb	\$ 2,211.98	\$ 2,839.26	\$ 5,051.24	Feb	\$ 5,024.43	\$ 2,437.29	\$ 7,461.72	Feb	\$ 20,021.89
March	\$ 2,013.59	\$ 2,417.11	\$ 4,430.70	March	\$ 4,832.69	\$ 2,109.66	\$ 6,942.36	March	\$ 18,269.86
April	\$ 1,666.15	\$ 1,451.22	\$ 3,117.37	April	\$ 4,079.83	\$ 1,305.73	\$ 5,385.56	April	\$ 13,667.72
May	\$ 1,634.93	\$ 637.20	\$ 2,272.13	May	\$ 4,015.31	\$ 599.50	\$ 4,614.81	May	\$ 11,095.71
June	\$ 1,831.89	\$ 626.58	\$ 2,458.47	June	\$ 4,188.45	\$ 95.58	\$ 4,284.03	June	\$ 9,230.98
July	\$ 1,965.88	\$ 33.45	\$ 1,999.33	July	\$ 4,418.95	\$ 33.45	\$ 4,452.40	July	\$ 9,166.88
Aug	\$ 1,904.48	\$ 27.61	\$ 1,932.09	Aug	\$ 4,308.23	\$ 27.61	\$ 4,335.84	Aug	\$ 9,121.88
Sep	\$ 1,681.76	\$ 343.03	\$ 2,024.79	Sep	\$ 4,037.03	\$ 329.22	\$ 4,366.25	Sep	\$ 10,006.60
Oct	\$ 1,649.84	\$ 1,146.43	\$ 2,796.27	Oct	\$ 4,062.67	\$ 1,021.11	\$ 5,083.79	Oct	\$ 12,683.13
Nov	\$ 1,817.77	\$ 1,833.54	\$ 3,651.31	Nov	\$ 4,209.38	\$ 1,589.28	\$ 5,798.67	Nov	\$ 14,826.90
Dec	\$ 2,313.12	\$ 2,989.53	\$ 5,302.65	Dec	\$ 5,102.37	\$ 2,553.05	\$ 7,655.42	Dec	\$ 19,863.04
Total	\$ 24,338.32	\$ 17,590.97	\$ 41,929.28	Total	\$ 53,814.32	\$ 14,869.06	\$ 68,683.38	Total	\$ 169,289.60

Offices also in:
Iron Mountain
Ishpeming
Marinette
Sault Ste Marie

U.P. Engineers & Architects, Inc.

www.UPEA.com

MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.106

Refer to Exhibit A-18 on Facilities Capex. Please:

- a. Expand the exhibit to include detailed projects and related cost for 2021 to 2023 and provide in Excel.
- b. Identify what makes up the amount of \$9,644,790 on line 1.
- c. For each item on lines 2-8, explain what each item entail and why it is necessary to be undertaken in 2024 or 2025.

UPPCO Response

- a. See Attachment 3-AG-UPPCO-106a.
- b. Costs related to design and construction of the new service center.
- c. See Attachment 3-AG-UPPCO-106c.

Response by: Jason Brynick

Dated: July 3, 2024

2021		2022		2023	
Description	Amount	Description	Amount	Description	Amount
Cold storage building	\$ 578,485	Cold storage building carry over from 2021	\$ 30,500	Phase 1 environmental study / Houghton service center	\$ 7,988
HVAC Repair	\$ 27,500	Pallet racking	\$ 15,500	UP Engineers architectural fees / new service center design work	\$ 291,033
Office roof replacement	\$ 18,483	Cardboard baler	\$ 13,468	Ishpeming north parking lot asphalt replacement	\$ 143,307
Bathroom fixture replacement	\$ 22,550	Cardboard baler electric	\$ 1,320	Replace concrete approaches to garage doors	\$ 12,715
Front entry way repair	\$ 9,850	Yard access gate concrete	\$ 30,000	New HVAC system for system operating center	\$ 107,000
Yard gate upgrade	\$ 14,250	Property purchase for new service center	\$ 335,000	Ishpeming yard expansion	\$ 76,960
Install rollup garage door	\$ 18,313	Phase 1 environmental study new property	\$ 4,900	Replace defective wiring and lighting Ontonagon garage	\$ 35,730
		Easement work	\$ 3,000	Ishpeming north office expansion	\$ 15,000
		Site survey	\$ 6,000		
		Site planning	\$ 14,000		
	\$ 689,431		\$ 453,688		\$ 689,733

Case No. – U-21555
Exhibit No. – A-18

Question 106 / Bullet C

Line 2 – Truck Garage Improvements

- **Ishpeming truck garage overhead door replacement-**
 - *Replacing the doors will improve energy efficiency with better insulation and correct ongoing mechanical issues. Will also improve visibility by adding doors that have windows.*
- **Ishpeming truck garage roof replacement-**
 - Replacing the roof will correct numerous leaks, some of which allow water into our meter test room and conference room. Will also be adding insulation to improve energy efficiency.
- **Ontonagon truck garage overhead door replacement-**
 - Replacing the doors will allow line trucks to access all sides of the building by increasing the height of one of the doors. Original door was too low to allow all line trucks safe access. Willm also improve energy efficiency with better insulated doors and increased visibility with doors with windows.
- **Escanaba Service Center LED lighting Upgrade-**
 - Replace aged florescent light fixtures in office building and truck garage with new LED fixtures. Many of the fixtures are in poor condition and not emitting the level of light needed. We will also be installing additional fixtures. Installing new LED lights along with adding fixtures will improve overall lighting in the shop and improve energy efficiency.

Line 3 – Yard/Parking Lot/Material Storage Improvements

- **Concrete and Pallet Racking Installation-**
 - Install concrete slab that pallet racking can be anchored to. This will allow us to store materials off the ground and out of the snow and ice. Previously these items were stored on wooden pallets on the ground that would be frozen down and buried in snow. This would create safety on productivity issues when needing to access materials in the winter months. This work is planned to take place at two of our locations this year, Iron River, and Escanaba. Having these items off the ground will also help with snow plowing.
- **New Asphalt Install / Ishpeming North Yard**
 - Install asphalt over current gravel parking lot to allow safe forklift access to pallet racking.

- **Replace Asphalt Ishpeming West Yard**
 - Replace current asphalt that is in poor condition and will also improve drainage during heavy rain events.
- **Line 4 - HVAC Improvements / Escanaba Service Center**
 - Install additional zoning on current system to distribute heating and cooling more evenly throughout office area. Adding additional controls to air louvers to improve system functionality.
- **Line 5 – Iron River Service Center & Garage Upgrades**
 - Fluorescent lighting with new LED throughout
 - Bathroom fixtures with new energy efficient
 - Building insulation & windows
- **Line 6 – Ontonagon Service Center & Garage Upgrades**
 - Fluorescent lighting with new LED in office building.
 - Bathroom fixtures with new energy efficient.
 - Building siding, insulation & windows throughout.
 - Replace outdated electric baseboard heat registers with new energy efficient.
- **Line 7 – Ishpeming Service Center & Garage Upgrades**
 - Windows and man doors with new energy efficient
- **Line 8 – Munising Service Center & Garage Upgrades**
 - Fluorescent lighting with new LED in office building.
 - Bathroom fixtures with new energy efficient.
 - Building siding, insulation & windows throughout.
 - Upgrade HVAC system throughout.

Adjustments to Capital Expenditures, Rate Base and Depreciation Expense
(\$000)

Line	Description (a)	Capital Expenditure Reductions ¹			Rate Base Reduction (e)	Depreciation Rate ² (f)	Reduction in Depreciation Expense (g)
		2024 (b)	2025 (c)	Total (d)			
Capital Expenditures:							
1	Generation						-
2	Victoria Access Road Resurfacing & Drainage	\$ 260,670		\$ 260,670	\$ 260,670	3.39%	\$ 8,837
3	Annual New Equipment/Generation Tools	113,626	110,812	224,438	169,032	3.39%	5,730
4	Bond Falls Inundation Mapping		101,982	101,982	50,991	3.39%	1,729
5	Bond Falls Canal Rip Rap	104,268		104,268	104,268	3.39%	3,535
6	Victoria Gate Hoist Replacement		624,000	624,000	312,000	3.39%	10,577
7	Hoist Penstock Interior Lining Replacement		572,000	572,000	286,000	3.39%	9,695
8	McClure Substation Refurbishment		1,842,204	1,842,204	921,102	3.39%	31,225
9	Distribution						
10	UPPCO Engineering, Designers and Clerks	125,000	144,000	269,000	197,000	4.23%	8,333
11	Sys. Hardening, OH to URD conv, and Copper Peplc	141,000	142,000	283,000	212,000	4.23%	8,968
12	Distribution Line Transformers	1,843,000	1,586,000	3,429,000	2,636,000	4.23%	111,503
13	Distribution Reclosers	114,000	112,000	226,000	170,000	4.23%	7,191
14	Distribution Regulators	100,000	99,000	199,000	149,500	4.23%	6,324
15	SHARP Projects/Program	200,000	2,233,000	2,433,000	1,316,500	4.23%	55,688
16	Charge UP Michigan Grant EVC Installations	580,000		580,000	580,000	4.23%	24,534
17	Substations						
18	Chatham Control Building replace		384,800	384,800	192,400	2.27%	4,367
19	Nine 219A Voltage Regulator Upgrades	236,688	(236,688)	-	118,344	2.27%	2,686
20	Transformer Progress Payments - 3 projects	1,266,855	1,263,600	2,530,455	1,898,655	2.27%	43,099
21	Five Substation Projects for 2025		1,476,800	1,476,800	738,400	2.27%	16,762
22	Service Center & Facilities						
23	New Service Center	4,822,790	(3,662,790)	1,160,000	2,991,395	3.60%	107,690
24	Other Facilities Projects	1,068,000	1,137,000	2,205,000	1,636,500	3.60%	58,914
25	Information Technology						
26	ERP/SAP Data Warehousing		520,000	520,000	260,000	20.00%	52,000
27	AMI/IEE Upgrade and QRS Reporting	1,564,000		1,564,000	1,564,000	20.00%	312,800
28	AMI Infrastructure Replacement		1,820,000	1,820,000	910,000	20.00%	182,000
29	Customer Billing and Payment Improvements	308,000		308,000	308,000	20.00%	61,600
30	Total	\$ 12,847,897	\$ 10,269,720	\$ 23,117,617	\$ 17,982,757		\$ 1,135,787
31							
32	Working Capital¹				6,500,000		
33							
34	Total Rate Base Deduction				\$ 24,482,757		

Source: (1) See AG witness Coppola Direct Testimony.

(2) Depreciation rates from 2025 High level Depreciation Forecast - 1-30-24_matches PTY, Tab: 2025 Forecasted Adds.

**Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Staff HH's
Fourth Audit Request**

4-Staff HH-UPPCO-4.1

1. When did the company finish the installation of AMI meters?

UPPCO Response

The mass installation of AMI meters by UPPCO's installation subcontractor during UPPCO's AMI Implementation was completed in October of 2020. UPPCO's portion of mass installation was completed in April of 2021.

Response by: Jason Brynick

Dated: May 2nd, 2024

**Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
Second Discovery Request**

2-AG-UPPCO-2.28

28. Regarding Accounts Payable in Working Capital in Exhibit A-2, Schedule B4, and Exhibit A-7, Schedule B4, please:
- a. Explain why Accounts Payable is decreasing from \$9.0 million in 2023 to \$8.2 million in the projected test year for a 9% decrease and identify what expenses items between the historic and projected test years are declining that would cause a lower Accounts Payable amount.
 - b. Provide the calculations showing how you arrived at the \$8.2 million for the projected test year in Excel with formulas intact.

UPPCO Response

- a. Accounts Payable decreased in the projected test year due to a \$166k reduction in retention amount included in the Accounts Payable calculation for 2023 but cleared out in August 2023 and therefore not included in the projected test year. In addition, the GR/IR clearing account had a 13-month balance of (\$835k) in the historical test year and this was inadvertently not included in the projected test year and therefore AP should have been reported \$835K higher.
- b. Please refer to Attachment 2-AG-UPPCO-2.27 (2025 Projected Balance Sheet Workbook_V2_JSG-1.xls) to see how the projected test year amount was determined. In column H, select Accounts Payable to see which accounts are included in this category on the Working Capital Calculation. Column J states what the method of projection was and the monthly columns include calculations where applicable with links.

Response by: Natasha Wonch

Dated: June 12, 2024

**Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
Second Discovery Request**

2-AG-UPPCO-2.31

31. Refer to Prepayments in Working Capital on Exhibit A-7, Schedule B4, please:
- a. Explain why this item increases to \$9.5 million, or \$5.7 million over the historical 2023 balance, as shown on Exhibit A-2, Schedule B4.
 - b. Provide a schedule in Excel showing how the \$9.5 million for the 2025 projected test year was determined.

UPPCO Response

- a. Cash and Bank Balances were increased to \$9.5 million as shown on Exhibit A-7, Schedule B4, not Prepayments. The increase in cash and bank balances were driven by increases in accrued interest and owner's equity.
- b. Please refer to Attachment 2-AG-UPPCO-2.27 (2025 Projected Balance Sheet Workbook_V2_JSG-1.xls) to see how the projected test year amount was determined. In column H, select Cash and Bank Balances to see which accounts are included in this category on the Working Capital Calculation. Column J states what the method of projection was and the monthly columns include calculations where applicable with links. There was a calculation error on the original workbook submitted, so

Response by: Natasha Wonch

Dated: June 12, 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company - Electric Rate Case

Case No. U-21555
Exhibit AG-13
July 19, 2024
Page 1 of 1

Recommended Capital Structure & Cost Rates for Test
Year Ending December 31, 2025

(Thousands of Dollars)

Line	Description (a)	Capital Structure			Cost Rate** (e)	Total Cost (d) x (e) (f)	Conversion Factors*** (g)	Pre-Tax Wtd. Cost (f) x (g) (h)
		Capital Balances* (b)	% Permanent Capital (c)	% Total Capital (d)				
1	Long Term Debt	\$ 168,914	50.0%	43.65%	4.53%	1.98%	1.0000	1.98%
2	Preferred Stock	-	0.0%	0.00%	0.00%	0.00%	1.3288	0.00%
3	Common Equity	<u>168,914</u>	<u>50.0%</u>	<u>43.65%</u>	9.85%	<u>4.30%</u>	1.3288	<u>5.71%</u>
4	Total Permanent Capital	337,828	<u>100.0%</u>	87.30%		6.28%		7.69%
5	Short Term Debt	18,952		4.90%	5.93%	0.29%	1.0000	0.29%
6	Deferred Income Taxes	30,196		7.80%	0.00%	0.00%	1.0000	0.00%
7	JDITC							
8	Long Term Debt	-		0.00%		0.00%	1.0000	0.00%
9	Preferred Stock	-		0.00%		0.00%	1.3288	0.00%
10	Common Equity	<u>-</u>		<u>0.00%</u>		<u>0.00%</u>	1.3288	<u>0.00%</u>
11	Total Capitalization & Cost Rates	<u>\$ 386,976</u>		<u>100.00%</u>		6.57%		7.98%

Notes

- * All capital balances per Company Exhibit A-9, Schedule D1 except for Common Equity and Long Term Debt which are set at 50% in each case.
- ** All cost rates per Company Exhibit A-9, Schedule D1 except for Common Equity which is set forth on Exhibit AG-14.
- *** Conversion factors per Company Exhibit A-9, Schedule D1.

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company - Electric Rate Case

Case No. U-21555
Exhibit AG-14
July 19, 2024
Page 1 of 1

Summary of Cost of Common Equity Capital Analysis

<u>Line</u>	<u>Description</u> (a)	<u>Relative Weighting</u> (b)	<u>Peer Group</u> (c)	<u>Note</u> (d)
1	Discounted Cash Flow (DCF) Approach	50.00%	9.34%	1
2	Capital Asset Pricing Model (CAPM) Approach	25.00%	10.51%	2
3	Equity Risk Premium Approach	25.00%	10.20%	3
Cost of Common Equity			9.85%	

Note 1 See Exhibit AG-15

Note 2 See Exhibit AG-16

Note 3 See Exhibit AG-17

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company - Electric Rate Case

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 Exhibit AG-16
 July 19, 2024
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Capital Asset Pricing Model Application
(See Equation Below)

<u>Line</u>	<u>Company</u> (a)	<u>Ticker</u> (b)	<u>Common Equity to Capital %</u> (c)	<u>Current Beta (B)</u> (d)	<u>Risk Premium (Rp)</u> (e)	<u>Beta x Risk Premium Col. (d) x (e)</u> (f)	<u>Projected 2025 Risk Free Rate (Rf)</u> (g)	<u>Ke or 2025 CAPM ROE for Proxy Co. Col. (g) + (f)</u> (h)
1	Avista	AVA	49.2%	0.80	7.17%	5.74%	4.15%	9.89%
2	Black Hills	BKH	41.5%	1.05	7.17%	7.53%	4.15%	11.68%
3	IDACORP	IDA	51.3%	0.85	7.17%	6.09%	4.15%	10.24%
4	MGE Energy	MGEE	61.6%	0.80	7.17%	5.74%	4.15%	9.89%
5	NorthWestern	NWE	50.4%	0.95	7.17%	6.81%	4.15%	10.96%
6	PNM Resources	PNM	33.6%	0.90	7.17%	6.45%	4.15%	10.60%
7	Portland General Electric	POR	45.9%	0.90	7.17%	6.45%	4.15%	10.60%
8	Unitil	UTL	48.4%	0.85	7.17%	6.09%	4.15%	10.24%
14	Average		<u>47.7%</u>	<u>0.89</u>	<u>7.17%</u>	<u>6.36%</u>	<u>4.15%</u>	<u>10.51%</u>
15	High							11.68%
16	Low							9.89%

<u>Sources</u>	
Column (c)	From Data included in SEC filings for the four quarters ended September 2023
Column (d)	From the Value Line Investment Survey Publications of Aug. 11, Sept. 8, Sept. 15 (Unitil) and Oct. 20, 2023
Column (e)	Historic average - 1926 to 2022 Ibbotson returns of Stock Market vs. Yield on Government Bonds
Column (g)	Range and Average of Recent Blue Chip Financial Forecasts
	February 1, 2024 Projection 4.00%
	May 31 2024 Projection 4.30%
	Average of two projectiosns <u>4.15%</u>

Equation for CAPM $Ke = Rf + (B \times Rp)$ Where Ke = the Cost of Common Equity; Rf = the Risk Free Rate of Return;
 B = the Beta or covariance of the stocks price to overall market ; and
 Rp = the Expected Risk Premium of the overall market

Electric Utility Equity Risk Premium Approach

<u>Line</u>	<u>Description</u> (a)	<u>Projected Test Period</u> (c)	<u>Note</u> (d)
1	Proxy Group Debt Ratings (S & P)	AA to BBB	1
2	Number of Proxy Companies	8	
<u>Build-up of Common Equity Rate of Return</u>			
3	Long Term US Treasury Rate Projection	4.15%	2
4	Corporate Spread Over Treasury Bond Rate	<u>1.67%</u>	3
5	Sub Total (Line 3 + Line 4)	5.82%	
6	Historical Spread - Utility Common Stocks over Bonds	<u>4.38%</u>	4
7	Cost of Common Equity (Line 5 + Line 6)	<u>10.20%</u>	

Notes

- 1 Avista, Portland General Electric and Northwestern Energy are "A" rated, MGE is "AA" rated and the others in the "BBB" category.
- 2 See risk free rate from AG CAPM analysis
- 3 Reflects the average spread in 2023 of "A" rated issues (155 BP) and "BBB" issues (179 BP) based on new 30 Yr. issues in 2023 per AG Workpaper
- 4 Historical average per AG workpapers

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company - Electric Rate Case

Case No. U-21555
Exhibit AG-18
July 19, 2024

Electric Rate Case Return on Equity (ROE) Rates (2022 and 2023)*

Page 1 of 3

Line	Electric Company	Jurisdiction & Order Date			ROE Awarded in		Parent Company	Pub. Finan'ls Avail.	Long Term Debt Issued Since Date of Rate Order
					2022	2023			
1	Niagara Mohawk Power	NY	Jan. 20	2022	9.00%		National Grid, PLC	Foreign	
2	Southwestern Public Service	NM	Feb. 16	2022	9.35%		Xcel Energy	Yes	May 3, 2022 \$700M, 30 Yr. at 4.6%
3	Indiana Michigan Power	IN	Mar. 2	2022	9.70%		American Electric Power	Yes	Feb 27, 2023 \$850M, 10 Yr. at 5.625%
4	Public Service of Colorado	CO	Mar. 16	2022	9.30%		Xcel Energy	Yes	May 3, 2022 \$700M, 30 Yr. at 4.6%
5	Orange & Rockland Utilities	NY	Apr. 14	2022	9.20%		Consolidated Edison	Yes	Nov. 9, 2022 \$700M, 30 Yr. at 6.15%
6	Portland General Electric	OR	Apr. 25	2022	9.50%		Portland General Electric	Yes	Jan 3, 2023 \$200M, 7 Yr. and 10 Yr at 5.47% & 5.56%
7	Unitil Energy Systems	NH	May 12	2022	9.20%		Unitil	Yes	
8	Southwestern Electric Power	AR	May 23	2022	9.50%		American Electric Power	Yes	Feb 27, 2023 \$850M, 10 Yr. at 5.625%
9	Green Mountain Power	VT	Aug. 31	2022	8.57%		Energir	Private	
10	Oklahoma Gas & Electric	OK	Sep. 8	2022	9.50%		OGE	Yes	Jan 3, 2023 \$450M, 10 Yr. at 5.4%
11	El Paso Electric	TX	Sep. 15	2022	9.35%		JP Mrgn Chase TII Fund	Private	
12	Kingsport Power	TN	Oct. 25	2022	9.50%		American Electric Power	Yes	Feb 27, 2023 \$850M, 10 Yr. at 5.625%
13	Commenwealth Edison	IL	Nov. 17	2022	7.85%		Exelon	Yes	Jan 3, 2023 \$975M, 10 Yr. and 30 Yr at 4.9% & 5.3%
14	NSTAR Electric	MA	Nov. 30	2022	9.80%		Eversource	Yes	May 8, 2023 \$1.8Bil. 3Yr, 5Yr., 10Yr at 4.75% to 5.45%
15	Ameren Illinois	IL	Dec. 1	2022	7.85%		Ameren	Yes	May 2023 \$500M 10 Yr. at 4.95%
16	Delmarva Power & Light	MD	Dec. 14	2022	9.60%		Exelon	Yes	Jan 3, 2023 \$975M, 10 Yr. and 30 Yr at 4.9% & 5.3%
17	Duke Energy Ohio	OH	Dec. 14	2022	9.50%		Duke	Yes	March 2023 \$750M 10 Yr & 30 Yr at 5.25% & 5.65%
18	Pacificorp	OR	Dec. 16	2022	9.50%		Berkshire Hathaway Energy	Yes	May 15, 2023 \$1.2Bil. 31 Yr at 5.5%
19	Pudget Sound Energy	WA	Dec. 22	2022	9.40%		Alberta Investment Mgt. Co.	Private	
20	Wisconsin Public Service	WI	Dec. 22	2022	9.80%		WEC Energy	Yes	Jan. 9, 2023 - \$1.1 B; 3 and 5 Yr. at 4.75
21	Sierra Pacific Power	NV	Dec. 27	2022	9.56%		Berkshire Hathaway Energy	Yes	
22	Empire District Electric	OK	Dec. 29	2022	9.30%		Algonquin Power & Utilities	Foreign	
23	Wisconsin Electric Power	WI	Dec. 29	2022	<u>9.80%</u>		WEC Energy	Yes	Jan. 9, 2023 - \$1.1 B; 3 and 5 Yr. at 4.75
24	Average 2022 ROE Awarded under 9.9%				<u>9.29%</u>				

Notes for pages 1 and 2

* All ROE data from Regulatory Research Associates & excludes Limited Issue Rider cases

** A summary of all ROEs including those at 9.9% and above is included on page 3 of this exhibit

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company - Electric Rate Case

Case No. U-21555
Exhibit AG-18
July 19, 2024
Page 2 of 3

Electric Rate Case Return on Equity (ROE) Rates (2022 and 2023)*

ROEs Under 9.9%**

<u>Line</u>	<u>Electric Company</u>	<u>Jurisdiction & Order Date</u>		<u>ROE Awarded in</u>		<u>Parent Company</u>	<u>Pub. Finan'ls Avail.</u>	<u>Long Term Debt Issued</u>	
				<u>2022</u>	<u>2023</u>			<u>Since Date of Rate Order</u>	
1	Minnesota Power Enterpr.	MN	Jan. 23	2023	9.65%	Allete	Yes	Apr. 27, 2023	\$125M 10 Yr. at 4.9%
2	Cheyenne Light Fuel & Pwr.	WY	Jan. 26	2023	9.75%	Black Hills	Yes	Sep. 15, 2023	\$\$450M 10.5 Yr. at 6.15%
3	Duke Energy Progress	SC	Feb. 9	2023	9.60%	Duke Energy	Yes	Mar. 2023	\$500M (10 Yr), \$500M (30 Yr.) at 5.25% & 5.35%
4	Southwestern Electric Power	LA	Feb. 17	2023	9.50%	Xcel Energy	Yes	Jul. 31, 2023,	\$800M 10 Yr at 5.45%
5	Oncor Elec. Delivery	TX	Mar. 9	2023	9.70%	Sempra Energy	Yes	Jun. 2023	\$550M (3 Yr), \$700M (10 Yr.) at 5.4% & 5.5%
6	Versant Power	ME	May. 31	2023	9.35%	Enmax (City of Alberta, Can.)	Private		
7	Northern States Power	MN	Jun 1	2023	9.25%	Xcel Energy	Yes	Jul. 31, 2023,	\$800M 10 Yr at 5.45%
8	Central Maine Power	ME	Jun 6	2023	9.35%	Avangrid	Yes		
9	MDU Resources	ND	Jun 6	2023	9.75%	MDU Resources	Yes		
10	Consolidated Edison of NY	NY	Jul. 20	2023	9.25%	Consolidated Edison	Yes	Nov 2023	\$600M (10 Yr.) at 5.5%
11	Northern Indiana P. S.	IN	Aug. 2	2023	9.80%	NIPSCO	Yes	Jun 2024	\$600M (5 Yr) at 5.2%
12	Entergy Texas	TX	Aug. 3	2023	9.57%	Entergy	Yes	May 2024	\$1.2B (30 Yr.) at 7.125%
13	Duke Energy Progress	NC	Aug. 18	2023	9.80%	Duke Energy	Yes	Sep. 2023	\$600M (10 Yr), \$750M (30 Yr.) at 5.75% & 6.10%
14	Green Mountain Power	VT	Aug. 23	2023	9.58%	Eniger	Private		
15	United Illuminating Group	CT	Aug. 25	2023	8.63%	Avangrid	Yes	Oct. 2023	\$65M 10 Yr. 4.5% (Remarketed)
16	Tuscon Electric Power	AZ	Aug. 25	2023	9.55%	Fortis	Canada		
17	Avista	ID	Aug. 31	2023	9.40%	Avista	Yes		
18	Public Service of Colorado	CO	Sep. 6	2023	9.30%	Xcel Energy	Yes	Feb 2024	\$800M (10 Yr.) at 5.5%
19	MDU Resources	MT	Sep. 21	2023	9.65%	MDU Resources	Yes		
20	Duke Energy KY	KY	Oct. 12	2023	9.75%	Duke Energy	Yes	Jun 2024	\$1.5B (10 Yr & 30 Yr) at 5.45 & 5.80
21	New York State Elec. & Gas	NY	Oct. 12	2023	9.20%	Avangrid	Yes		
22	Rochester Gas & Electric	NY	Oct. 12	2023	9.20%	Avangrid	Yes		
23	Potomac Edison	MD	Oct. 18	2023	9.50%	Exelon	Yes	Feb 2024	\$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
24	Southwestern Public Service	NM	Oct. 19	2023	9.50%	Xcel Energy	Yes	Feb 2024	\$800M (10 Yr.) at 5.5%
25	NorthWestern Energy Group	MT	Oct. 25	2023	9.65%	NorthWestern Energy Group	Yes		
26	Madison Gas & Electric	WI	Nov. 3	2023	9.70%	MGE Energy	Yes		
27	Public Service of Oklahoma	OK	Nov. 3	2023	9.30%	American Electric Power	Yes	Jun 2024	\$1.0B (30 Yr.) 7%
28	Northern States Power	WI	Nov. 9	2023	9.80%	Xcel Energy	Yes	Feb 2024	\$800M (10 Yr.) at 5.5%
29	Wisconsin Power & Light	WI	Nov. 9	2023	9.80%	Alliant Energy	Yes		
30	Atlantic City Electric	NJ	Nov. 17	2023	9.60%	Exelon	Yes	Feb 2024	\$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
31	Pacificorp	WY	Nov. 28	2023	9.35%	Berkshire Hathaway	Yes		
32	Empire District Electric	AR	Dec. 7	2023	9.70%	Algonquin Power & Utilities	Canada		
33	Ameren Illinois	IL	Dec. 14	2023	8.72%	Ameren	Yes		
34	Baltimore Gas & Electric	MD	Dec. 14	2023	9.50%	Exelon	Yes	Feb 2024	\$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
35	Commonwealth Edison	IL	Dec. 14	2023	8.91%	Exelon	Yes	Feb 2024	\$1.7B (5 Yr, 10 Yr, 30 Yr) 5.15%, 5.45%, 5.6%
36	Portland General Electric	OR	Dec. 18	2023	9.50%	Portland General Electric	Yes		
37	Nevada Power	NV	Dec. 26	2023	9.52%	Berkshire Hathaway	Yes		
38	Idaho Power	ID	Dec. 28	2023	<u>9.60%</u>	IDACORP	Yes		
39	Average 2023 ROE Awarded under 9.9%				<u>9.48%</u>				

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Electric Rate Case Return on Equity (ROE) Rates (2022 and 2023)

Summary of All Cases (incl. ROEs at 9.9% and Above)*

<u>Line</u>	<u>Caption/No. of Cases</u>		<u>ROE % *</u>		<u>2022</u>	<u>2023</u>	<u>Explanations & Commentary</u>
	<u>State</u>	<u>Company</u>	<u>2022</u>	<u>2023</u>			
1	Number of ROE Decisions Under 9.9%				23	38	From Pages 1 and 2
2	ROEs Awarded at 9.90% or Higher						
3	Michigan	DTE Electric	9.90%	9.90%	1	1	
4		Consumer Energy Co.		9.90%		1	
5		Upper Peninsula Power		9.90%		1	
6	Ohio	Dayton Power & Light	10.00%		1		Distribution ROE Only; Smaller Utility (536K customers)
7	N. Carolina	Duke Energy Carolinas		10.10%		1	
8	Georgia	Georgia Power	10.50%		1		Troubled Nuclear Plant Construction
9	Alaska	Alaska Elec. Light & Power		11.45%		1	Small Juneau Alaska utility (17,600 customers)**
10	California	Pacific Gas & Electric	10.70%	10.70%	1	1	Wild Fire Risk
11	California	Pacific Gas & Electric	10.00%		1		Wild Fire Risk
12	California	San Diego Gas & Electric	10.20%	10.65%	1	1	
13	California	San Diego Gas & Electric	9.95%		1		
14	California	So. California Edison	10.30%	10.75%	1	1	Wild Fire Risk
15	California	So. California Edison	10.05%		1		Wild Fire Risk
16	California	Pacificorp		10.00%		1	
17	California	Liberty Utilities (CalPeco Elec.)		10.00%	-	1	Small Utility - Lake Tahoe (Rate Base of Approx. \$350M)***
18	Total Cases with ROEs Stated (Excl. Lmtd. Issue Riders)				<u>32</u>	<u>48</u>	
19	Avg. ROE Rate Awarded	Excluding 9.9% Plus Cases			<u>9.29%</u>	<u>9.48%</u>	
20		All Cases*			<u>9.54%</u>	<u>9.66%</u>	<u>Simple 2 Yr. Average</u> 9.6%

* All ROE data from Regulatory Research Associates & excludes Limited Issue Rider cases

** Per page 24 of Avista Form 10-K filed in early 2023.

*** Per Algonquin Investor Presentation of Nov. 10, 2023, page 16

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2022-2023 Midwest ROE Decisions Outside Michigan*

<u>Line</u>	<u>Company</u>	<u>State</u> <u>Jurisdiction</u>	<u>Month</u>	<u>Year</u>	2022-23 Authorized ROE Decision
	(a)	(b)	(c)	(d)	(e)
1	Indiana Michigan	Indiana	March	2022	9.70%
2	Northern Indiana Pub. Service	Indiana	August	2023	9.80%
3	Kingsport Power	Tennessee	October	2022	9.50%
4	Commenwealth Edison	Illinois	November	2022	7.85%
5	Ameren Illinois	Illinois	December	2022	7.85% **
6	Duke Energy Ohio	Ohio	December	2022	9.50%
7	Northern States Power	Minnesota	June	2023	9.25%
8	Wisconsin Public Service	Wisconsin	December	2022	9.80%
9	Wisconsin Electric Power	Wisconsin	December	2022	9.80%
10	Dayton Power & Light (DPL)	Ohio	December	2022	<u>10.00%</u> ***
11	Average of Above Decisions				<u>9.31%</u>

* As published by Regulatory Research Associates

** Reflects Electric Delivery Service ROE based on the average monthly 30-year U.S. Treasury rate for 2021 plus 580 basis points (Amerin 2022 Form 10-K, page 8).

*** This smaller utility (DPL) is owned by power provider AES. This Delivery Service ROE covers 536,000 customers who are all able to select an alternative "Competitive Retail Electric Service" provider (AES 2022 Form 10-K pages 17 and 18).

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Comparisson of AG and UPPCO Peer Groups

Line	Value Line Electric Utilities	2023 Revs. (\$M)	Elimination Factors							Total Factors	Peer Group per		
			Revs. Over Under	Reorg.	EPS	OS Wind	Large	Foreign	M & A		EPS	OS Wind	Large
			3 B +	100M	No Div. Grth	Foreign	M & A	Fall-Off	& Wldfr.	NU Ops			
1	AVANGRID	\$ 8,309			Yes		Yes				2		
2	Consolidated Edison	14,663	Yes								1		
3	Dominion Energy	14,393	Yes		Yes		Yes				3		x
4	Duke Energy	29,060	Yes								1		x
5	Eversource Energy	11,911	Yes				Yes		Yes		3		
6	Exelon	21,727	Yes								1		x
7	FirstEnergy	12,870	Yes								1		
8	NextEra Energy	28,114	Yes							Yes	2		
9	PPL Corp.	8,312	Yes								1		
10	Public Service Enterp. Group	11,237	Yes								1		
11	Southern Co.	25,253	Yes						Yes		2		x
12	ALLETE	1,880					Yes			Yes	2		x
13	Alliant Energy	4,027	Yes								1		
14	Ameren	7,500	Yes								1		
15	American Electric Power	18,882	Yes				Yes				2		
16	CMS Energy	7,462	Yes								1		x
17	CenterPoint Energy	8,646	Yes				Yes				2		x
18	DTE Energy	12,745	Yes								1		x
19	Entergy	12,147	Yes				Yes	Yes			3		x
20	Fortis	11,517	Yes			Yes					2		
21	Energy	5,508	Yes								1		x
22	MGE Energy	670										x	
23	OGE Energy	2,674	Yes								1		x
24	Otter Tail	1,349								Yes	1		x
25	WEC Energy	8,893	Yes				Yes				2		
26	Avista	1,752										x	x
27	Black Hills	2,331										x	x
28	Edison International	16,338	Yes						Yes		2		x
29	Hawaiian Electric	3,682	Yes		Yes			Yes	Yes		4		
30	IDACORP	1,766										X	x
31	NorthWestern	1,422										x	x
32	PNM Resources	1,939										x	x
33	Pacific Gas & Electric	24,428	Yes						Yes		2		
34	Pinnacle West Capital	4,696	Yes								1		x
35	Portland General Electric	2,923										x	
36	Sempra Energy	16,720	Yes			Yes					2		x
37	Xcel Energy	14,206	Yes						Yes		2		
38	Unitil	557										x	
	Totals		27	-	3	2	8	2	6	3	51	8	21 *

* The Company's Peer Group includes these 21 companies plus two foreign utility companies (Emera and Algonquin Power & Utilities)

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Companies Eliminated from Peer Group Consideration
(due to M & A, Reorg. and EPS Growth Concerns)

<u>Line</u>	<u>Company involved in M & A, Reorg.</u>	<u>Anticipated Actions to be Taken per Value Line</u>
1	Avangrid	Iberdola of Spain looking to acquire Company
2	Dominion Energy*	Selling various assets to reduce debt
3	Eversource	Looking to sell Off-Shore Wind and Water Distribution assets
4	Allete*	Being acquired by Global Infrastructure Partners
5	American Electric Power	Selling AEP OnSite Partners for \$0.3 billion
6	CenterPoint Energy*	Sale of two gas units pending for \$1.2 B to Bernhard Capital Ptns.
7	Entergy*	Looking to sell shut-down nuclear assets
8	WEC Energy	Puchasing \$0.5 billion stake in Texas solar project
	<u>Company with Earnings Disruption</u>	<u>Comments based on Value Line</u>
9	Entergy*	EPS in 2022 at \$5.37 falls to \$5.30 in 2024 and then recovers
10	Hawaiian Electric	2028 EPS down by approximately 50% (Wildfire issues)

* These companies have been included in the UPPCO's peer group

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Peer Group Market to Book Equity Ratios-March 31, 2024

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Line	Company (a)	Ticker (b)	Mkt. Val. p/Sh. Of Com. Equity Mar. 31, 2024* (c)	Millions		Book Value per Share (d) / (e) / (f)	Market to Book Ratio (c) / (f) / (g)
				Book Value of Com. Equity** (d)	Common Shares** (e)		
1	Avista	AVA	35.02	2,521	78.2	32.24	1.09
2	Black Hills	BKH	54.60	3,334	68.9	48.39	1.13
3	IDACORP	IDA	92.89	2,415	50.7	47.63	1.95
4	MGE Energy	MGEE	78.72	1,159	36.2	32.02	2.46
5	NorthWestern	MGEE	50.93	2,813	64.8	43.41	1.17
6	PNM Resources	PNM	37.64	2,356	90.2	26.12	1.44
7	Portland General Electric	POR	42.00	3,459	103.0	33.58	1.25
8	Unitil	UTL	52.35	511	16.2	31.54	1.66
9	Average						1.31

* Per Yahoo

** Per SEC Filings on Form 10-Q for quarter ended March 2024

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Projected 2025 Rating Agency (DBRS Morningstar) Cash Flow Ratios
(With ROE at 9.85% and a 50.0% Common Equity Ratio)

Line	Caption	12 M.E June 2023	2025 Cash Flow to Debt (\$ Millions)			
		Cash Flow to Debt Ratio (\$Millions)	Projected Test Yr. Items Per Company	ROE Reduced to 9.85% vs 10.7% per Company	Equity Reduced to 50.0% vs 51.5% per Company	Pro Forma Ratio with 9.85% ROE & 50% Equity
	(a)	(b)	(c)	(d)	(e)	(f)
1	Cash Flows					
2	Net Income	\$ 4.8	\$ 18.6	\$ (1.5)	\$ (0.5)	\$ 16.6
3	Depreciation & Amortization	12.7	14.0			14.0
4	Deferred Taxes	(0.1)	1.2	-	-	1.2
5	Total Cash Flows	<u>\$ 17.4</u>	<u>\$ 33.8</u>	<u>\$ (1.5)</u>	<u>\$ (0.5)</u>	<u>\$ 31.8</u>
6	Total Debt	<u>\$ 155.3</u>	<u>\$ 182.8</u>	<u>\$ -</u>	<u>\$ 5.1</u>	<u>\$ 187.9</u>
7	Ratio % for Col. (b), (c) & (f) (Line 5 / Line 6)	<u>11.2%</u>	<u>18.5%</u>	<u>-0.8%</u>	<u>-0.7%</u>	<u>16.9%</u>
8	Morningstar DBRS Projection for 2023-24 (October 2022 Projection)					<u>16.0%</u>

Col. (b) Per October 20,2023 report of Morningstar DBRS (See page 8 of FR 187 included in part III information provided by Company)
Col. (c) Net Income and Depreciation & Amortization per Exhibit A-6, Schedule A2. Deferred Taxes equals twelve times the monthly change in Company's Bal. Sheet Workbook
Total Debt is from Exhibit A-9 (NEK-6), Schedule D1
Col. (d) Reflects \$174 M of common equity (Exh. A-9, Sch D1) x 0.85% ROE Reduction per AG Recommendation
Col. (e) Reflects \$5.1 M of common equity shifted to long-term debt. This amount times 9.85% equals approximately \$502 K or \$0.5 M
Col. (f) For lines 2 through 6, the result is the sum of columns c, d and e
Line 8 Per October 28, 2022 report of Morningstar DBRS, page 2 (provided as DR 1-AG-UPPCO-19 Attachment (c) in Case U-21286)

Private Rating Report

Upper Peninsula Power Company

DBRS Morningstar

October 20, 2023

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Private Ratings

Issuer	Debt	Rating	Rating Action	Trend
Upper Peninsula Power Company	Issuer Rating	BBB (high)	Confirmed	Stable
Upper Peninsula Power Company	Senior Notes	BBB (high)	Confirmed	Stable

Rating Update

DBRS Limited (DBRS Morningstar) confirmed Upper Peninsula Power Company's (UPPCO or the Company) Issuer Rating and Senior Notes at BBB (high) with Stable trends. UPPCO is a cost-of-service rate-regulated integrated electric utility located entirely in the Upper Peninsula (UP) of the state of Michigan. UPPCO is regulated by the Michigan Public Service Commission (MPSC) and owns electricity distribution and generation assets. DBRS Morningstar views UPPCO as benefitting from (1) a strong regulatory supportive environment, (2) a strong financial profile, and (3) low-risk renewable electricity generation included in the rate base. The primary challenges are (1) a weaker franchise area and a relatively small size of operations, (2) industrial customer concentration, and (3) a high level of debt at UPPCO's parent Upper Peninsula Power Holding Company (UPPHC; rated BBB (low) with a Stable trend by DBRS Morningstar).

In March 2023, MPSC approved UPPCO's rate settlement agreement, which has a 9.9% rate of return and a deemed equity thickness of 51.5%. The approved rates resulted in an increase to annual revenues of \$10.8 million, which was made effective July 1, 2023. The deemed equity thickness has decreased from the previous level of 54.0%. DBRS Morningstar continues to view the Michigan regulatory environment as strong.

DBRS Morningstar notes that UPPCO's key financial metrics in 2022 and for the last 12 months ended June 30, 2023, weakened compared with 2021 primarily because of increased debt and decreased earnings. DBRS Morningstar expects that financial metrics will improve for the full-year 2023 and 2024 based on the updated settlement agreement effective on July 1, 2023. DBRS Morningstar expects the Company will maintain its capital structure near the updated regulatory capital structure.

The Company's construction of a 62.5-megawatt (MW) utility-scale solar generation project is expected to be completed in 2025 rather than 2024 as the Company assesses how to best incorporate the solar tax credits included in the Inflation Reduction Act. UPPCO is currently in discussions with developers for the construction on the project. Competitive procurement for construction of the solar generation facility has been preapproved by the MPSC as part of the fully settled Integrated Resource Plan (IRP). Cost recovery through the rate base will be subject to a subsequent regulatory proceeding. The project is

expected to cost approximately \$130 million. DBRS Morningstar expects the solar project will be completed under a Build Transfer Agreement (BTA) with a fixed-price Engineering Procurement Construction (EPC) contract by an experienced solar developer.

DBRS Morningstar does not expect to take a positive credit rating action in the near term as UPPCO's ratings are primarily limited to the utility's size and franchise area. DBRS Morningstar notes a negative rating action could occur if financial metrics decrease significantly from the forecast on a sustained basis or if there are significant negative regulatory changes that result in a material decrease in the Company's credit risk profile.

Financial Information

	12 months Jun. 30	12 months Dec. 31	
	2023	2022	2021
Cash flow/debt (%)	11	13	21
Total debt/capital (%)	46	45	42
EBIT interest coverage (times (x))	1.18	1.93	3.75

Issuer Description

UPPCO is an integrated cost-of-service rate-regulated electricity utility (distribution and generation). UPPCO's operations are entirely in Michigan's UP. UPPCO has 53,000 customers. UPPCO is regulated by the MPSC under a cost-of-service framework. UPPHC is a holding company that owns 100% of the equity in UPPCO.

Rating Considerations

Strengths

1. Strong regulatory environment

UPPCO's service area is solely in the state of Michigan and is regulated by the MPSC. MPSC approves the rates through a General Rate Case (GRC). DBRS Morningstar views the regulatory environment in Michigan as strong compared with other North American regions. UPPCO is currently operating under an approved GRC, which has a strong deemed equity thickness of 51.5% and a return on equity (ROE) of 9.9%. Michigan law allows regulated electric utilities to complete a new GRC every 12 months following the approval of the previous GRC and requires that the GRC be ruled on by the MPSC within 10 months of being submitted. This effectively limits regulatory lag to one year. Regulatory lag is further reduced as the MPSC sets UPPCO's revenue requirement based on projected test years rather than on historical test years. Additionally, all energy costs are passed through to customers and reconciled annually, based on forecast energy costs through the Power Supply Cost Recovery (PSCR) rider. The MPSC also requires utilities to complete IRPs every five years where new generation and longer-term capital expenditures (capex) are submitted and approved.

2. Strong financial profile

DBRS Morningstar views UPPCO's financial metrics as being supportive of the ratings. UPPCO is forecast to keep its financial profile aligned with the regulatory deemed equity structure. Financial metrics are expected to improve in 2024 as revenues reflect the new rate settlement and further improve following the completion of the solar generation facility in 2025.

3. Low-risk renewable generation included in rate base

UPPCO is an integrated utility that owns both electricity distribution and generation assets. UPPCO owns 57 MW of generation across eight plants. UPPCO's generation capacity is 60% hydroelectric generation and 40% peaking thermal facilities. All the generation assets except for three of the hydroelectric power plants are included in the rate base. As an integrated utility, UPPCO is well positioned to grow its regulated rate base by building new renewable generation assets to meet Michigan's Renewable Portfolio Standards (RPS). UPPCO is currently in the process of selecting an experienced contractor to build 62.5 MW of solar generation facility in the UP. The project will be completed under a BTA with a fixed-price EPC contract by an experienced solar developer. This solar generation facility will be included in UPPCO's rate base, will earn a regulated return, and will assist UPPCO in meeting its RPS requirements.

Weaknesses

1. Small size and rural service area

UPPCO is a relatively small utility that services approximately 53,000 customers. This small size limits UPPCO's ability to achieve the same economies of scale and diversification that a larger utility would be able to achieve. Additionally, UPPCO is in the UP of Michigan, which is a primarily rural and low-density area. The UP covers 16,452 square miles and has a population of approximately 310,000 residents. UPPCO's service area is forecast to grow at 1% per year going forward, which is below the U.S. national average.

2. Industrial customers represent a high portion of the operating margin

The primary industries in the UP are the mining and forestry industries and industrial customers. DBRS Morningstar notes its top customers are well diversified, with the top 10 customers representing only approximately 8% of 2022's revenue forecast. UPPCO's industrial customer base is diversified across different sectors, which partially offsets the industrial customer concentration.

3. High level of holding company debt

UPPCO's parent is UPPHC, which has a significant amount of debt. DBRS Morningstar notes this high level of holding company debt could put additional pressure on UPPCO to defer capex or increase leverage to service the UPPHC debt. DBRS Morningstar notes it currently does not view the high level of holding company debt as affecting UPPCO's ratings. However, if UPPHC's financial metrics deteriorate significantly on a sustained basis, it could begin to affect UPPCO's ratings.

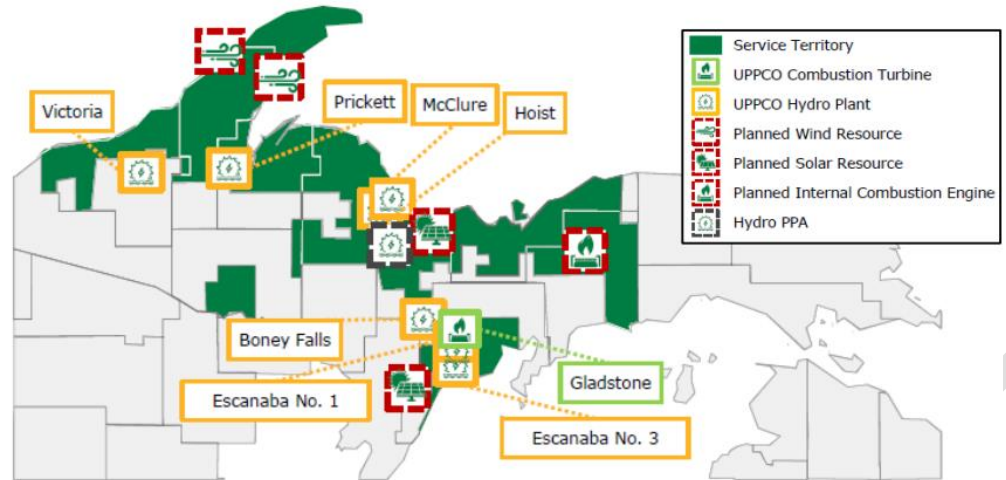
Corporate Structure



Source: DBRS Morningstar.

- UPPCO is the operating company and is the cost-of-service rate-regulated utility servicing 53,000 customers with operations entirely in Michigan's UP.
- UPPCO is regulated by the MPSC under a cost-of-service framework.
- UPPHC is the holding company that owns 100% of the equity interest in UPPCO.
- UPPHC will be 100% owned by Axium UP Holdings LLC, a subsidiary indirectly owned by Axium Infrastructure (Axium).
- UPPHC's debt is structurally subordinated to UPPCO.

UPPCO Franchise Area Summary



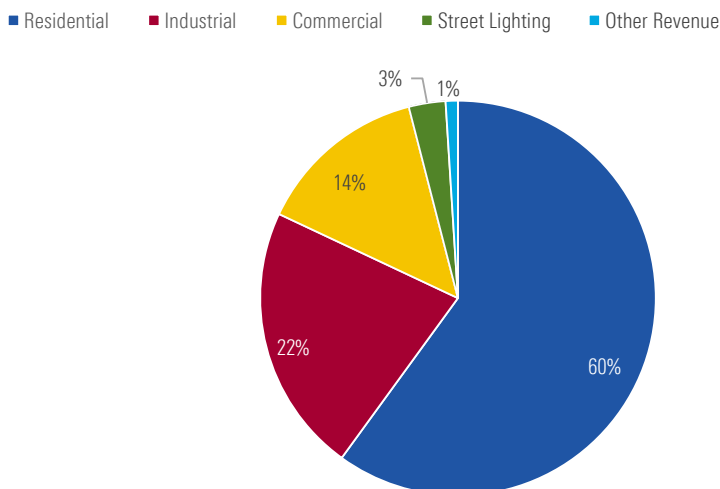
Source: DBRS Morningstar.

- The UP is primarily a rural and low-density area that covers 16,452 square miles and has a population of approximately 310,000.
- A significant portion of the UP's economic industry is in mining and forest products (including paper), which are cyclical industries.
- The forest products industry is important for the UP's economy and is responsible for approximately 30% of employment.
- GDP growth in the UP has been below the national average for the past 20 years with a compounded annual growth rate (CAGR) of 0.80%, a 10-year CAGR of 0.90%, and a five-year CAGR of 1.1%. These are all below the U.S. national average GDP CAGR of approximately 2%.

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Utility Operations

Exhibit 1 Gross Margin by Customer Class



Source: DBRS Morningstar.

- UPPCO's operations are entirely within Michigan's UP and service 53,000 customers across 10 of the UP's 15 counties.
- UPPCO was founded in 1947 and is headquartered in Marquette, Michigan. UPPCO's service area covers approximately 4,460 square miles; UPPCO owns 4,500 distribution line miles and 50 substations.
- Most of UPPCO's gross margin comes from residential customers at 60%, industrial customers at 22%, and commercial customers at 14%. About 3% is for street lighting and 1% is for sales under the three contracted hydro facilities with a local paper products company.
- Revenue is well diversified with the top 10 customers representing approximately 8% of total revenue.

Generation Assets

- UPPCO owns 57 MW of generation assets across eight plants composed of one peaking thermal plant and seven hydroelectric generation facilities.
- Three hydroelectric plants are not included in UPPCO's rate base because the power generated by these facilities is sold under contract with a local paper products company. These plants account for 1.3% of 2021 revenue.
- Approximately 80% of UPPCO's annual generation is from regulated assets with 20% from unregulated hydro assets.
- UPPCO is in the process of adding 62.5 MW of utility-scale solar generation to its rate base. The solar facility was approved by the MPSC and is expected to cost approximately \$110 million and reach completion in Q4 2025. The solar project will be completed under a BTA with a fixed-price EPC contract by an experienced solar developer. Construction of the project is expected to be straightforward and will be similar to other solar projects recently completed in Michigan.

Earnings and Outlook

(USD millions)	12 months Jun. 30		12 months Dec. 31	
	2023	2022	2021	2020
Net revenue	75.0	76.4	79.8	78.3
EBITDA	20.6	24.1	34.6	33.4
EBIT	7.9	11.5	22.4	21.5
Interest expense	6.7	6.0	6.0	6.4
Net income before nonrecurring items	4.8	6.8	13.1	13.1
Reported net income	4.8	6.8	17.3	13.1
ROE (%) ¹	3.37	4.84	9.55	9.78
Approved ROE (%)	9.90	9.90	9.90	9.90

¹ ROE is presented based on DBRS Morningstar-adjusted net income in the numerator and equity rate base provided by UPPCO.

Summary

- UPPCO benefits from predictable revenue through its regulated operations.
- Operating earnings decreased in 2023 partially because of inflation-related wage increases and increased cleanup costs from more storms than previous years.

Earnings Outlook

- Earnings are expected to improve in 2024, reflecting a full-year contribution to the increase in the settlement agreement, which was effective as of July 1, 2023.
- Revenues are expected to further improve after 2025 following the completion of the \$130 million solar project, which will be added to the rate base.

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Financial Profile

(USD millions)	12 months Jun. 30		12 months Dec. 31	
	2023	2022	2021	2020
Net income before nonrecurring items	4.8	6.8	13.1	13.1
Depreciation and amortization	12.7	12.6	12.2	12.0
Deferred income taxes and other	-0.1	0.6	4.1	3.6
Cash flow from operations	17.3	20.0	29.5	28.7
Dividends paid	0.0	0.0	0.0	0.0
Capex	-26.7	-24.2	-19.0	-18.4
Free cash flow (bef. working cap. changes)	-9.3	-4.2	10.5	10.3
Changes in noncash work. cap. items	6.7	2.9	-2.9	-3.5
Change in regulatory assets/liabilities	0.0	0.0	0.0	0.0
Net free cash flow	-2.6	-1.4	7.6	6.8
Net equity change	-13.8	-13.9	5.2	-12.9
Net debt change	18.0	12.0	17.1	8.0
Other investing and financing	-2.5	-0.7	-27.5	-0.2
Change in cash	-0.9	-4.0	2.4	1.8
Total debt	155.3	149.3	137.2	126.1
Cash and equivalents	1.1	3.5	7.5	4.3
Total debt in capital structure (%)	46	45	42	42
Cash flow/total debt (%)	11	13	21	23
EBIT gross interest coverage (x)	1.18	1.93	3.75	3.37

Summary

- UPPCO has historically generated strong cash flow from operations.
- Historically, UPPCO has been able to generate positive cash flow after funding historical capex.
- Other investing and financing in 2021 included a make-whole payment on redemption of long-term debt.

Financial Profile Outlook

- UPPCO is expected to have significantly above-average capex in 2024 and 2025 to fund the construction of the solar project that, upon completion, will be added to the rate base.
- DBRS Morningstar expects that the UPPCO's owners will contribute sufficient equity to fund the solar project to keep UPPCO's capital structure aligned with the regulatory structure.
- UPPCO's debt is expected to increase in 2024–25 because of draws to partially fund the solar project.

Regulation

GRC

- UPPCO is regulated by the MPSC under a cost-of-service framework.
- UPPCO is currently operating under its GRC that was approved on March 24, 2023.
- UPPCO has a deemed debt/equity structure of 48.5% debt and 51.5% equity and an after-tax ROE of 9.9%, which DBRS Morningstar views as being good to excellent.
- Electric utilities in Michigan can file GRCs 12 months following the approval of the previous GRC. Michigan law requires that the GRC must be decided on within 10 months of the filing or the GRC is automatically approved. This effectively limits the regulatory lag period to one year.
- The test year process also includes property and equipment under construction to be included in the rate base, which further adds to the certainty of revenue through periods of capex.
- As part of the rate settlement agreement allowing Axiom the purchase of UPPCO and UPPHC, UPPCO cannot request an adjustment to its base rates to take effect until after January 1, 2025.

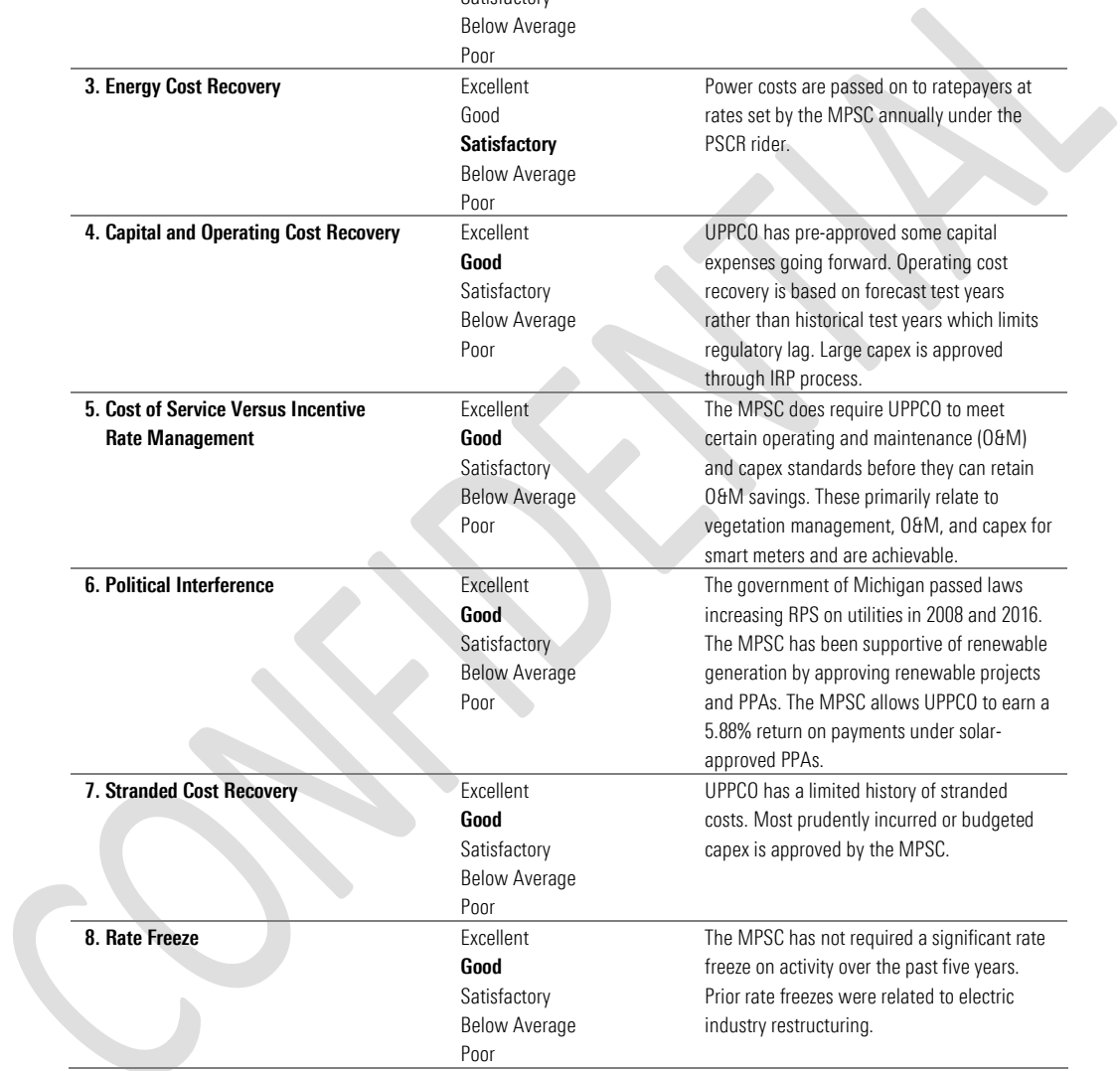
PSCR

- Power prices are 100% passed through a PSCR rider, which is updated annually based on forecast costs and demand.
- The PSCR being completed annually limits the effect of the changes of load and power prices on UPPCO's earnings.

IRP

- Michigan law requires utilities to complete an IRP every five years. The IRP serves as a guide for how the utility will meet the future needs of its customers in a cost-effective and reliable manner. The IRP is inclusive of the utility's load; the retirement of the existing generation; and timing of new electricity sources, such as natural gas and renewables.
- UPPCO most recently filed an IRP on February 12, 2019, which was approved on February 6, 2020. UPPCO will be required to file its next IRP by December 6, 2024.
- The IRP approved UPPCO to acquire 125 MW of solar capacity with up to 50% through the acquisition of its own capacity and 50% under power purchase agreements (PPAs).
- The MPSC also allows UPPCO to earn a 5.88% return on all payments under solar PPAs.

Assessment of Regulatory Framework of UPPCO		
Criteria	Score	Analysis
1. Deemed Equity	Excellent Good Satisfactory Below Average Poor	The MPSC allows UPPCO to have a deemed equity of 51.5%, which is higher than most other North American regulatory jurisdictions.
2. Allowed ROE	Excellent Good Satisfactory Below Average Poor	UPPCO has an authorized return on common equity of 9.9%, which is good.
3. Energy Cost Recovery	Excellent Good Satisfactory Below Average Poor	Power costs are passed on to ratepayers at rates set by the MPSC annually under the PSCR rider.
4. Capital and Operating Cost Recovery	Excellent Good Satisfactory Below Average Poor	UPPCO has pre-approved some capital expenses going forward. Operating cost recovery is based on forecast test years rather than historical test years which limits regulatory lag. Large capex is approved through IRP process.
5. Cost of Service Versus Incentive Rate Management	Excellent Good Satisfactory Below Average Poor	The MPSC does require UPPCO to meet certain operating and maintenance (O&M) and capex standards before they can retain O&M savings. These primarily relate to vegetation management, O&M, and capex for smart meters and are achievable.
6. Political Interference	Excellent Good Satisfactory Below Average Poor	The government of Michigan passed laws increasing RPS on utilities in 2008 and 2016. The MPSC has been supportive of renewable generation by approving renewable projects and PPAs. The MPSC allows UPPCO to earn a 5.88% return on payments under solar-approved PPAs.
7. Stranded Cost Recovery	Excellent Good Satisfactory Below Average Poor	UPPCO has a limited history of stranded costs. Most prudently incurred or budgeted capex is approved by the MPSC.
8. Rate Freeze	Excellent Good Satisfactory Below Average Poor	The MPSC has not required a significant rate freeze on activity over the past five years. Prior rate freezes were related to electric industry restructuring.



Financing Documents Summary

UPPCO Note Purchase Agreement Summary

- The \$127.1 million Senior Notes are secured with no principal and a bullet maturity in 2051.
- The Senior Notes will at all times rank at least pari passu with all other senior secured indebtedness of UPPCO.
- UPPCO will act solely in its name and will maintain its books, records, and account separately from any other persons.
- UPPCO shall maintain a total funded indebtedness to group capitalization of not more than 0.60 to 1.00. UPPCO was in compliance with this ratio as of June 30, 2023.

UPPCO Senior Secured Facility

- UPPCO has a \$75 million senior secured first-lien revolving credit facility not rated by DBRS Morningstar.
- The revolver is expected to be periodically termed out with long-term debt financing once it reaches a balance of approximately \$65 million.
- Obligations under the facility will rank at least pari passu with all other senior indebtedness of UPPCO.
- UPPCO shall not permit the debt-to-capitalization ratio of more than 0.60 to 1.00. UPPCO was in compliance with this ratio as of June 30, 2023.

UPPHC Note Purchase Agreement

- The \$230 million Senior Notes are secured with no principal and a bullet maturity in 2031.
- The Senior Notes will at all times rank at least pari passu with all other senior secured indebtedness of UPPHC.
- UPPHC will act solely in its name and will maintain its books, records, and account separately from any other persons.
- UPPHC shall maintain a total funded indebtedness to group capitalization of not more than 0.80 to 1.00. UPPHC was in compliance with this ratio as of June 30, 2023.
- UPPHC has a Debt Service Reserve Account (DSRA) and a Capex Reserve Account (CRA).
- UPPHC's DSRA is funded in the amount equal to the total of the next 12 months of debt payments, and the CRA in the amount of \$13.4 million.
- The DSRA is funded by a letter of credit (LOC) facility at UPPHC and the CRA by an LOC facility at Axium.

ESG Credit Risk Considerations

ESG Factor	ESG Credit Consideration Applicable to the Credit Analysis: Y/N	Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*		
Environmental		Overall:	N	N
Emissions, Effluents, and Waste	Do we consider that the costs or risks for the issuer or its clients result, or could result, in changes to an issuer's financial, operational, and/or reputational standing?	N	N	N
Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs and/or will such costs increase over time affecting the long term credit profile?	N	N	N
Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	N	N	N
Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?	N	N	N
Climate and Weather Risks	In the near term, will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact? In the long term, will the issuer's or client's business activities and infrastructure be materially affected financially by a 2C rise in temperature?	N	N	N
Social		Overall:	N	N
Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services could pose a financial or regulatory risk to the issuer?	N	N	N
Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts that could result in a material financial or operational impact?	N	N	N
	Do violations of rights create a potential liability that can negatively affect the issuer's financial wellbeing or reputation?	N	N	N
	Human Capital and Human Rights	N	N	N
Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	N	N	N
Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could it result, in financial penalties or client attrition to the issuer?	N	N	N
Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	N	N	N
Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	N	N	N
Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	N	N	N
Governance		Overall:	N	N
Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	N	N	N
	Are there any political risks that could impact the issuer's financial position or its reputation?	N	N	N
	Bribery, Corruption, and Political Risks	N	N	N
Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	N	N	N
Corporate / Transaction Governance	Does the issuer's corporate structure allow for appropriate board and audit independence?	N	N	N
	Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	N	N	N
	Does the Board and/or management have a formal framework to assess climate-related financial risks to the issuer?	N	N	N
	Corporate / Transaction Governance	N	N	N
Institutional Strength, Governance, and Transparency (Governments Only)	Compared with other governments, do institutional arrangements provide a similar degree of accountability, transparency, and effectiveness?	N	N	N
	Are regulatory and oversight bodies protected from inappropriate political influence?	N	N	N
	Are government officials exposed to public scrutiny and held to high ethical standards of conduct?	N	N	N
	Institutional Strength, Governance, and Transparency (Governments Only)	N	N	N
Consolidated ESG Criteria Output:		N	N	N

Environmental

There were no environmental factors that had a relevant or significant effect on the credit analysis. For more details about which environmental factors could have an effect on the credit analysis, please refer to the checklist above.

Regulated electricity utility companies like UPPCO can be exposed to environmental events, which can cause extensive damage to their equipment. If these environmental events were to occur, costs would be expected to be covered by the rate base.

Social

There were no social factors that had a relevant or significant effect on the credit analysis. For more details about which social factors could have an effect on the credit, please refer to the checklist above.

Governance

There were no governance factors that had a relevant or significant effect on the credit analysis. For more details about which governance factors could have an effect on the credit analysis, please refer to the checklist above.

A description of how DBRS Morningstar considers environmental, social, and governance factors within the DBRS Morningstar analytical framework can be found in the *DBRS Morningstar Criteria: Approach to Environmental, Social, and Governance Risk Factors in Credit Ratings* at <https://www.dbrsmorningstar.com/research/416784>.

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UPPCO Balance Sheet

(USD millions)	12 months Jun. 30		12 months Dec. 31		12 months Jun. 30		12 months Dec. 31	
	2023	2022	2021	2020	2023	2022	2021	2020
Assets					Liabilities & Equity			
Cash & equivalents	1.1	3.5	7.5	4.3	ST borrowings	0.0	0.0	0.0
Accounts receivable	8.2	9.2	7.8	8.7	Current portion LT debt	30.0	24.0	12.0
Inventories	6.1	3.9	3.5	3.2	Accounts payable & deferred tax	11.2	11.6	9.5
Prepaid expenses & others	10.2	11.9	13.4	10.3	Other current liabilities	5.6	6.0	4.9
Total Current Assets	25.6	28.6	32.2	26.6	Total Current Liabilities	46.7	41.6	26.5
Net fixed assets	275.6	272.9	260.4	253.7	Long-term debt	125.3	125.3	125.2
Future income tax assets	0.0	0.0	0.0	0.0	Regulatory liabilities	22.9	22.8	22.9
Goodwill & intangibles	0.0	0.0	0.0	0.0	Deferred income taxes	1.6	0.3	0.0
Regulatory assets	0.0	0.0	2.1	6.7	Other LT liabilities	10.6	10.6	9.7
Investments & others	88.7	85.2	82.9	59.8	Shareholders' equity	182.8	186.1	193.2
Total Assets	389.9	386.7	377.6	346.7	Total Liabilities & SE	389.9	386.7	377.6

UPPCO Balance Sheet, Liquidity, and Capital Ratios

	12 months Jun. 30		12 months Dec. 31	
	2023	2022	2021	2020
Current ratio	0.55	0.69	1.22	0.94
Total debt in capital structure (%)	45.9	44.5	41.5	42.5
Cash flow/total debt (%)	11.2	13.4	21.5	22.7
(Cash flow — dividends)/capex (x)	0.65	0.83	1.55	1.56
Dividend payout ratio (%)	0.0	0.0	0.0	0.0
Coverage Ratios (x)				
EBIT gross interest coverage	1.18	1.93	3.75	3.37
EBITDA gross interest coverage	3.08	4.03	5.80	5.25
Fixed-charges coverage	1.18	1.93	3.75	3.37
Profitability Ratios (%)				
EBITDA margin	27.5	31.5	43.4	42.7
EBIT margin	10.5	15.1	28.0	27.4
Profit margin	6.4	8.8	16.4	16.8
ROE	2.6	3.6	6.8	7.7
Return on capital	3.0	3.4	5.4	6.1

Rating History

	Current	2022	2021
Issuer Rating	BBB (high)	BBB (high)	BBB (high)
Senior Notes	BBB (high)	BBB (high)	BBB (high)

Notes:

All figures are in U.S. dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrsmorningstar.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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Private Rating Report

Upper Peninsula Power Company

DBRS Morningstar

October 20, 2023

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Private Ratings

Issuer	Debt	Rating	Rating Action	Trend
Upper Peninsula Power Company	Issuer Rating	BBB (high)	Confirmed	Stable
Upper Peninsula Power Company	Senior Notes	BBB (high)	Confirmed	Stable

Rating Update

DBRS Limited (DBRS Morningstar) confirmed Upper Peninsula Power Company's (UPPCO or the Company) Issuer Rating and Senior Notes at BBB (high) with Stable trends. UPPCO is a cost-of-service rate-regulated integrated electric utility located entirely in the Upper Peninsula (UP) of the state of Michigan. UPPCO is regulated by the Michigan Public Service Commission (MPSC) and owns electricity distribution and generation assets. DBRS Morningstar views UPPCO as benefitting from (1) a strong regulatory supportive environment, (2) a strong financial profile, and (3) low-risk renewable electricity generation included in the rate base. The primary challenges are (1) a weaker franchise area and a relatively small size of operations, (2) industrial customer concentration, and (3) a high level of debt at UPPCO's parent Upper Peninsula Power Holding Company (UPPHC; rated BBB (low) with a Stable trend by DBRS Morningstar).

In March 2023, MPSC approved UPPCO's rate settlement agreement, which has a 9.9% rate of return and a deemed equity thickness of 51.5%. The approved rates resulted in an increase to annual revenues of \$10.8 million, which was made effective July 1, 2023. The deemed equity thickness has decreased from the previous level of 54.0%. DBRS Morningstar continues to view the Michigan regulatory environment as strong.

DBRS Morningstar notes that UPPCO's key financial metrics in 2022 and for the last 12 months ended June 30, 2023, weakened compared with 2021 primarily because of increased debt and decreased earnings. DBRS Morningstar expects that financial metrics will improve for the full-year 2023 and 2024 based on the updated settlement agreement effective on July 1, 2023. DBRS Morningstar expects the Company will maintain its capital structure near the updated regulatory capital structure.

The Company's construction of a 62.5-megawatt (MW) utility-scale solar generation project is expected to be completed in 2025 rather than 2024 as the Company assesses how to best incorporate the solar tax credits included in the Inflation Reduction Act. UPPCO is currently in discussions with developers for the construction on the project. Competitive procurement for construction of the solar generation facility has been preapproved by the MPSC as part of the fully settled Integrated Resource Plan (IRP). Cost recovery through the rate base will be subject to a subsequent regulatory proceeding. The project is

expected to cost approximately \$130 million. DBRS Morningstar expects the solar project will be completed under a Build Transfer Agreement (BTA) with a fixed-price Engineering Procurement Construction (EPC) contract by an experienced solar developer.

DBRS Morningstar does not expect to take a positive credit rating action in the near term as UPPCO's ratings are primarily limited to the utility's size and franchise area. DBRS Morningstar notes a negative rating action could occur if financial metrics decrease significantly from the forecast on a sustained basis or if there are significant negative regulatory changes that result in a material decrease in the Company's credit risk profile.

Financial Information

	12 months Jun. 30	12 months Dec. 31	
	2023	2022	2021
Cash flow/debt (%)	11	13	21
Total debt/capital (%)	46	45	42
EBIT interest coverage (times (x))	1.18	1.93	3.75

Issuer Description

UPPCO is an integrated cost-of-service rate-regulated electricity utility (distribution and generation). UPPCO's operations are entirely in Michigan's UP. UPPCO has 53,000 customers. UPPCO is regulated by the MPSC under a cost-of-service framework. UPPHC is a holding company that owns 100% of the equity in UPPCO.

Rating Considerations

Strengths

1. Strong regulatory environment

UPPCO's service area is solely in the state of Michigan and is regulated by the MPSC. MPSC approves the rates through a General Rate Case (GRC). DBRS Morningstar views the regulatory environment in Michigan as strong compared with other North American regions. UPPCO is currently operating under an approved GRC, which has a strong deemed equity thickness of 51.5% and a return on equity (ROE) of 9.9%. Michigan law allows regulated electric utilities to complete a new GRC every 12 months following the approval of the previous GRC and requires that the GRC be ruled on by the MPSC within 10 months of being submitted. This effectively limits regulatory lag to one year. Regulatory lag is further reduced as the MPSC sets UPPCO's revenue requirement based on projected test years rather than on historical test years. Additionally, all energy costs are passed through to customers and reconciled annually, based on forecast energy costs through the Power Supply Cost Recovery (PSCR) rider. The MPSC also requires utilities to complete IRPs every five years where new generation and longer-term capital expenditures (capex) are submitted and approved.

2. Strong financial profile

DBRS Morningstar views UPPCO's financial metrics as being supportive of the ratings. UPPCO is forecast to keep its financial profile aligned with the regulatory deemed equity structure. Financial metrics are expected to improve in 2024 as revenues reflect the new rate settlement and further improve following the completion of the solar generation facility in 2025.

3. Low-risk renewable generation included in rate base

UPPCO is an integrated utility that owns both electricity distribution and generation assets. UPPCO owns 57 MW of generation across eight plants. UPPCO's generation capacity is 60% hydroelectric generation and 40% peaking thermal facilities. All the generation assets except for three of the hydroelectric power plants are included in the rate base. As an integrated utility, UPPCO is well positioned to grow its regulated rate base by building new renewable generation assets to meet Michigan's Renewable Portfolio Standards (RPS). UPPCO is currently in the process of selecting an experienced contractor to build 62.5 MW of solar generation facility in the UP. The project will be completed under a BTA with a fixed-price EPC contract by an experienced solar developer. This solar generation facility will be included in UPPCO's rate base, will earn a regulated return, and will assist UPPCO in meeting its RPS requirements.

Weaknesses

1. Small size and rural service area

UPPCO is a relatively small utility that services approximately 53,000 customers. This small size limits UPPCO's ability to achieve the same economies of scale and diversification that a larger utility would be able to achieve. Additionally, UPPCO is in the UP of Michigan, which is a primarily rural and low-density area. The UP covers 16,452 square miles and has a population of approximately 310,000 residents. UPPCO's service area is forecast to grow at 1% per year going forward, which is below the U.S. national average.

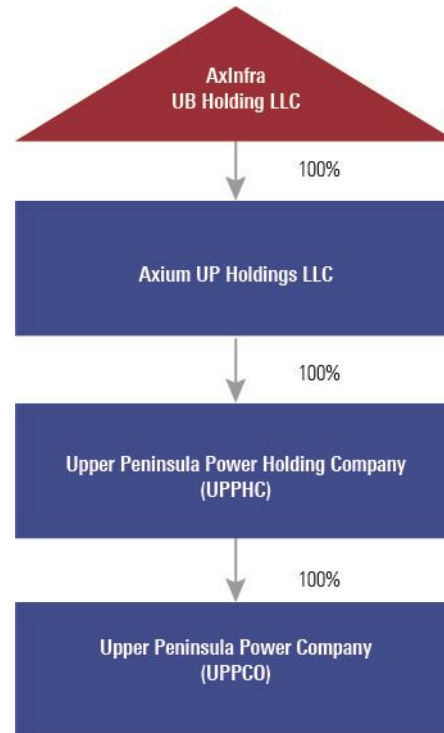
2. Industrial customers represent a high portion of the operating margin

The primary industries in the UP are the mining and forestry industries and industrial customers. DBRS Morningstar notes its top customers are well diversified, with the top 10 customers representing only approximately 8% of 2022's revenue forecast. UPPCO's industrial customer base is diversified across different sectors, which partially offsets the industrial customer concentration.

3. High level of holding company debt

UPPCO's parent is UPPHC, which has a significant amount of debt. DBRS Morningstar notes this high level of holding company debt could put additional pressure on UPPCO to defer capex or increase leverage to service the UPPHC debt. DBRS Morningstar notes it currently does not view the high level of holding company debt as affecting UPPCO's ratings. However, if UPPHC's financial metrics deteriorate significantly on a sustained basis, it could begin to affect UPPCO's ratings.

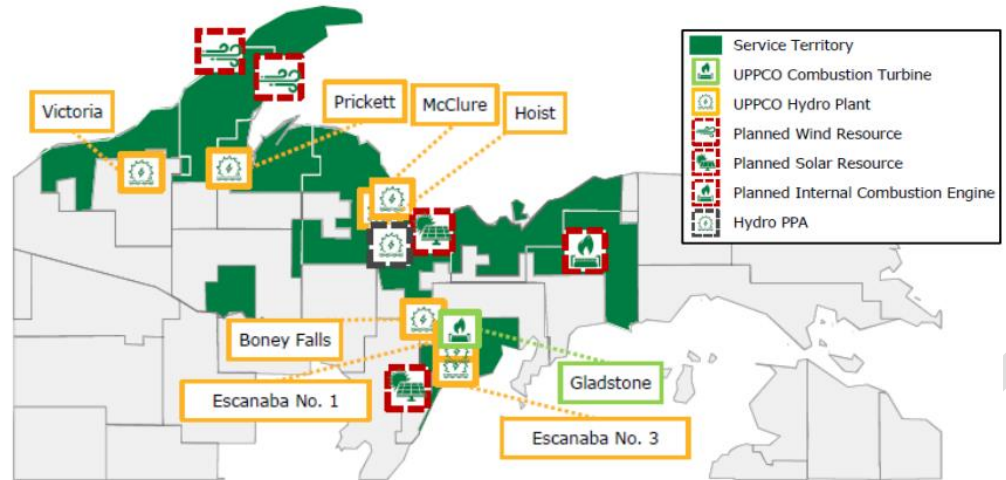
Corporate Structure



Source: DBRS Morningstar.

- UPPCO is the operating company and is the cost-of-service rate-regulated utility servicing 53,000 customers with operations entirely in Michigan's UP.
- UPPCO is regulated by the MPSC under a cost-of-service framework.
- UPPHC is the holding company that owns 100% of the equity interest in UPPCO.
- UPPHC will be 100% owned by Axiom UP Holdings LLC, a subsidiary indirectly owned by Axiom Infrastructure (Axiom).
- UPPHC's debt is structurally subordinated to UPPCO.

UPPCO Franchise Area Summary



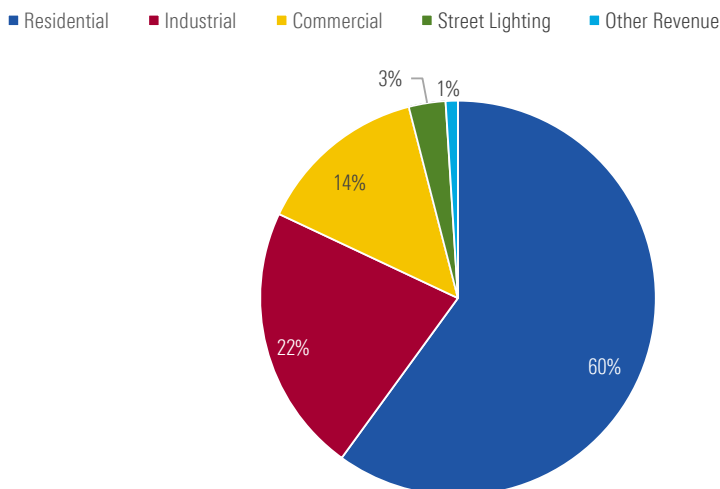
Source: DBRS Morningstar.

- The UP is primarily a rural and low-density area that covers 16,452 square miles and has a population of approximately 310,000.
- A significant portion of the UP's economic industry is in mining and forest products (including paper), which are cyclical industries.
- The forest products industry is important for the UP's economy and is responsible for approximately 30% of employment.
- GDP growth in the UP has been below the national average for the past 20 years with a compounded annual growth rate (CAGR) of 0.80%, a 10-year CAGR of 0.90%, and a five-year CAGR of 1.1%. These are all below the U.S. national average GDP CAGR of approximately 2%.

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Utility Operations

Exhibit 1 Gross Margin by Customer Class



Source: DBRS Morningstar.

- UPPCO's operations are entirely within Michigan's UP and service 53,000 customers across 10 of the UP's 15 counties.
- UPPCO was founded in 1947 and is headquartered in Marquette, Michigan. UPPCO's service area covers approximately 4,460 square miles; UPPCO owns 4,500 distribution line miles and 50 substations.
- Most of UPPCO's gross margin comes from residential customers at 60%, industrial customers at 22%, and commercial customers at 14%. About 3% is for street lighting and 1% is for sales under the three contracted hydro facilities with a local paper products company.
- Revenue is well diversified with the top 10 customers representing approximately 8% of total revenue.

Generation Assets

- UPPCO owns 57 MW of generation assets across eight plants composed of one peaking thermal plant and seven hydroelectric generation facilities.
- Three hydroelectric plants are not included in UPPCO's rate base because the power generated by these facilities is sold under contract with a local paper products company. These plants account for 1.3% of 2021 revenue.
- Approximately 80% of UPPCO's annual generation is from regulated assets with 20% from unregulated hydro assets.
- UPPCO is in the process of adding 62.5 MW of utility-scale solar generation to its rate base. The solar facility was approved by the MPSC and is expected to cost approximately \$110 million and reach completion in Q4 2025. The solar project will be completed under a BTA with a fixed-price EPC contract by an experienced solar developer. Construction of the project is expected to be straightforward and will be similar to other solar projects recently completed in Michigan.

Earnings and Outlook

(USD millions)	12 months Jun. 30		12 months Dec. 31	
	2023	2022	2021	2020
Net revenue	75.0	76.4	79.8	78.3
EBITDA	20.6	24.1	34.6	33.4
EBIT	7.9	11.5	22.4	21.5
Interest expense	6.7	6.0	6.0	6.4
Net income before nonrecurring items	4.8	6.8	13.1	13.1
Reported net income	4.8	6.8	17.3	13.1
ROE (%) ¹	3.37	4.84	9.55	9.78
Approved ROE (%)	9.90	9.90	9.90	9.90

¹ ROE is presented based on DBRS Morningstar-adjusted net income in the numerator and equity rate base provided by UPPCO.

Summary

- UPPCO benefits from predictable revenue through its regulated operations.
- Operating earnings decreased in 2023 partially because of inflation-related wage increases and increased cleanup costs from more storms than previous years.

Earnings Outlook

- Earnings are expected to improve in 2024, reflecting a full-year contribution to the increase in the settlement agreement, which was effective as of July 1, 2023.
- Revenues are expected to further improve after 2025 following the completion of the \$130 million solar project, which will be added to the rate base.

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Financial Profile

(USD millions)	12 months Jun. 30		12 months Dec. 31	
	2023	2022	2021	2020
Net income before nonrecurring items	4.8	6.8	13.1	13.1
Depreciation and amortization	12.7	12.6	12.2	12.0
Deferred income taxes and other	-0.1	0.6	4.1	3.6
Cash flow from operations	17.3	20.0	29.5	28.7
Dividends paid	0.0	0.0	0.0	0.0
Capex	-26.7	-24.2	-19.0	-18.4
Free cash flow (bef. working cap. changes)	-9.3	-4.2	10.5	10.3
Changes in noncash work. cap. items	6.7	2.9	-2.9	-3.5
Change in regulatory assets/liabilities	0.0	0.0	0.0	0.0
Net free cash flow	-2.6	-1.4	7.6	6.8
Net equity change	-13.8	-13.9	5.2	-12.9
Net debt change	18.0	12.0	17.1	8.0
Other investing and financing	-2.5	-0.7	-27.5	-0.2
Change in cash	-0.9	-4.0	2.4	1.8
Total debt	155.3	149.3	137.2	126.1
Cash and equivalents	1.1	3.5	7.5	4.3
Total debt in capital structure (%)	46	45	42	42
Cash flow/total debt (%)	11	13	21	23
EBIT gross interest coverage (x)	1.18	1.93	3.75	3.37

Summary

- UPPCO has historically generated strong cash flow from operations.
- Historically, UPPCO has been able to generate positive cash flow after funding historical capex.
- Other investing and financing in 2021 included a make-whole payment on redemption of long-term debt.

Financial Profile Outlook

- UPPCO is expected to have significantly above-average capex in 2024 and 2025 to fund the construction of the solar project that, upon completion, will be added to the rate base.
- DBRS Morningstar expects that the UPPCO's owners will contribute sufficient equity to fund the solar project to keep UPPCO's capital structure aligned with the regulatory structure.
- UPPCO's debt is expected to increase in 2024–25 because of draws to partially fund the solar project.

Regulation

GRC

- UPPCO is regulated by the MPSC under a cost-of-service framework.
- UPPCO is currently operating under its GRC that was approved on March 24, 2023.
- UPPCO has a deemed debt/equity structure of 48.5% debt and 51.5% equity and an after-tax ROE of 9.9%, which DBRS Morningstar views as being good to excellent.
- Electric utilities in Michigan can file GRCs 12 months following the approval of the previous GRC. Michigan law requires that the GRC must be decided on within 10 months of the filing or the GRC is automatically approved. This effectively limits the regulatory lag period to one year.
- The test year process also includes property and equipment under construction to be included in the rate base, which further adds to the certainty of revenue through periods of capex.
- As part of the rate settlement agreement allowing Axiom the purchase of UPPCO and UPPHC, UPPCO cannot request an adjustment to its base rates to take effect until after January 1, 2025.

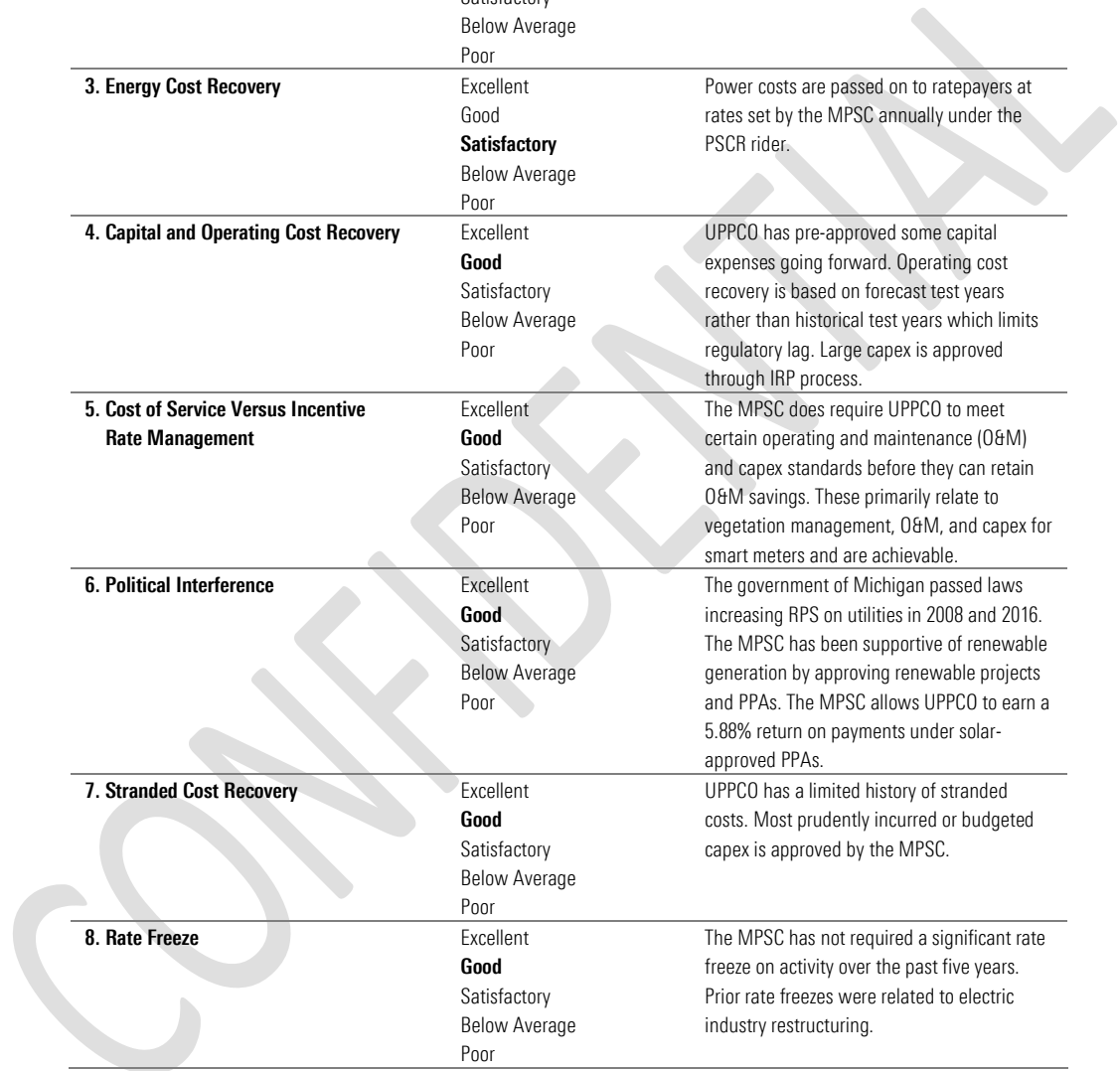
PSCR

- Power prices are 100% passed through a PSCR rider, which is updated annually based on forecast costs and demand.
- The PSCR being completed annually limits the effect of the changes of load and power prices on UPPCO's earnings.

IRP

- Michigan law requires utilities to complete an IRP every five years. The IRP serves as a guide for how the utility will meet the future needs of its customers in a cost-effective and reliable manner. The IRP is inclusive of the utility's load; the retirement of the existing generation; and timing of new electricity sources, such as natural gas and renewables.
- UPPCO most recently filed an IRP on February 12, 2019, which was approved on February 6, 2020. UPPCO will be required to file its next IRP by December 6, 2024.
- The IRP approved UPPCO to acquire 125 MW of solar capacity with up to 50% through the acquisition of its own capacity and 50% under power purchase agreements (PPAs).
- The MPSC also allows UPPCO to earn a 5.88% return on all payments under solar PPAs.

Assessment of Regulatory Framework of UPPCO		
Criteria	Score	Analysis
1. Deemed Equity	Excellent Good Satisfactory Below Average Poor	The MPSC allows UPPCO to have a deemed equity of 51.5%, which is higher than most other North American regulatory jurisdictions.
2. Allowed ROE	Excellent Good Satisfactory Below Average Poor	UPPCO has an authorized return on common equity of 9.9%, which is good.
3. Energy Cost Recovery	Excellent Good Satisfactory Below Average Poor	Power costs are passed on to ratepayers at rates set by the MPSC annually under the PSCR rider.
4. Capital and Operating Cost Recovery	Excellent Good Satisfactory Below Average Poor	UPPCO has pre-approved some capital expenses going forward. Operating cost recovery is based on forecast test years rather than historical test years which limits regulatory lag. Large capex is approved through IRP process.
5. Cost of Service Versus Incentive Rate Management	Excellent Good Satisfactory Below Average Poor	The MPSC does require UPPCO to meet certain operating and maintenance (O&M) and capex standards before they can retain O&M savings. These primarily relate to vegetation management, O&M, and capex for smart meters and are achievable.
6. Political Interference	Excellent Good Satisfactory Below Average Poor	The government of Michigan passed laws increasing RPS on utilities in 2008 and 2016. The MPSC has been supportive of renewable generation by approving renewable projects and PPAs. The MPSC allows UPPCO to earn a 5.88% return on payments under solar-approved PPAs.
7. Stranded Cost Recovery	Excellent Good Satisfactory Below Average Poor	UPPCO has a limited history of stranded costs. Most prudently incurred or budgeted capex is approved by the MPSC.
8. Rate Freeze	Excellent Good Satisfactory Below Average Poor	The MPSC has not required a significant rate freeze on activity over the past five years. Prior rate freezes were related to electric industry restructuring.



Financing Documents Summary

UPPCO Note Purchase Agreement Summary

- The \$127.1 million Senior Notes are secured with no principal and a bullet maturity in 2051.
- The Senior Notes will at all times rank at least pari passu with all other senior secured indebtedness of UPPCO.
- UPPCO will act solely in its name and will maintain its books, records, and account separately from any other persons.
- UPPCO shall maintain a total funded indebtedness to group capitalization of not more than 0.60 to 1.00. UPPCO was in compliance with this ratio as of June 30, 2023.

UPPCO Senior Secured Facility

- UPPCO has a \$75 million senior secured first-lien revolving credit facility not rated by DBRS Morningstar.
- The revolver is expected to be periodically termed out with long-term debt financing once it reaches a balance of approximately \$65 million.
- Obligations under the facility will rank at least pari passu with all other senior indebtedness of UPPCO.
- UPPCO shall not permit the debt-to-capitalization ratio of more than 0.60 to 1.00. UPPCO was in compliance with this ratio as of June 30, 2023.

UPPHC Note Purchase Agreement

- The \$230 million Senior Notes are secured with no principal and a bullet maturity in 2031.
- The Senior Notes will at all times rank at least pari passu with all other senior secured indebtedness of UPPHC.
- UPPHC will act solely in its name and will maintain its books, records, and account separately from any other persons.
- UPPHC shall maintain a total funded indebtedness to group capitalization of not more than 0.80 to 1.00. UPPHC was in compliance with this ratio as of June 30, 2023.
- UPPHC has a Debt Service Reserve Account (DSRA) and a Capex Reserve Account (CRA).
- UPPHC's DSRA is funded in the amount equal to the total of the next 12 months of debt payments, and the CRA in the amount of \$13.4 million.
- The DSRA is funded by a letter of credit (LOC) facility at UPPHC and the CRA by an LOC facility at Axium.

ESG Credit Risk Considerations

ESG Factor	ESG Credit Consideration Applicable to the Credit Analysis: Y/N	Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*		
Environmental		Overall:	N	N
Emissions, Effluents, and Waste	Do we consider that the costs or risks for the issuer or its clients result, or could result, in changes to an issuer's financial, operational, and/or reputational standing?	N	N	N
Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs and/or will such costs increase over time affecting the long term credit profile?	N	N	N
Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	N	N	N
Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?	N	N	N
Climate and Weather Risks	In the near term, will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact? In the long term, will the issuer's or client's business activities and infrastructure be materially affected financially by a 2C rise in temperature?	N	N	N
Social		Overall:	N	N
Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services could pose a financial or regulatory risk to the issuer?	N	N	N
Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts that could result in a material financial or operational impact?	N	N	N
	Do violations of rights create a potential liability that can negatively affect the issuer's financial wellbeing or reputation?	N	N	N
	Human Capital and Human Rights	N	N	N
Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	N	N	N
Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could it result, in financial penalties or client attrition to the issuer?	N	N	N
Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	N	N	N
Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	N	N	N
Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	N	N	N
Governance		Overall:	N	N
Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	N	N	N
	Are there any political risks that could impact the issuer's financial position or its reputation?	N	N	N
	Bribery, Corruption, and Political Risks	N	N	N
Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	N	N	N
Corporate / Transaction Governance	Does the issuer's corporate structure allow for appropriate board and audit independence?	N	N	N
	Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	N	N	N
	Does the Board and/or management have a formal framework to assess climate-related financial risks to the issuer?	N	N	N
	Corporate / Transaction Governance	N	N	N
Institutional Strength, Governance, and Transparency (Governments Only)	Compared with other governments, do institutional arrangements provide a similar degree of accountability, transparency, and effectiveness?	N	N	N
	Are regulatory and oversight bodies protected from inappropriate political influence?	N	N	N
	Are government officials exposed to public scrutiny and held to high ethical standards of conduct?	N	N	N
	Institutional Strength, Governance, and Transparency (Governments Only)	N	N	N
Consolidated ESG Criteria Output:		N	N	N

Environmental

There were no environmental factors that had a relevant or significant effect on the credit analysis. For more details about which environmental factors could have an effect on the credit analysis, please refer to the checklist above.

Regulated electricity utility companies like UPPCO can be exposed to environmental events, which can cause extensive damage to their equipment. If these environmental events were to occur, costs would be expected to be covered by the rate base.

Social

There were no social factors that had a relevant or significant effect on the credit analysis. For more details about which social factors could have an effect on the credit, please refer to the checklist above.

Governance

There were no governance factors that had a relevant or significant effect on the credit analysis. For more details about which governance factors could have an effect on the credit analysis, please refer to the checklist above.

A description of how DBRS Morningstar considers environmental, social, and governance factors within the DBRS Morningstar analytical framework can be found in the *DBRS Morningstar Criteria: Approach to Environmental, Social, and Governance Risk Factors in Credit Ratings* at <https://www.dbrsmorningstar.com/research/416784>.

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UPPCO Balance Sheet

(USD millions)	12 months Jun. 30		12 months Dec. 31		12 months Jun. 30		12 months Dec. 31		
	2023	2022	2021	2020	2023	2022	2021	2020	
Assets					Liabilities & Equity				
Cash & equivalents	1.1	3.5	7.5	4.3	ST borrowings	0.0	0.0	0.0	0.0
Accounts receivable	8.2	9.2	7.8	8.7	Current portion LT debt	30.0	24.0	12.0	13.8
Inventories	6.1	3.9	3.5	3.2	Accounts payable & deferred tax	11.2	11.6	9.5	9.0
Prepaid expenses & others	10.2	11.9	13.4	10.3	Other current liabilities	5.6	6.0	4.9	5.6
Total Current Assets	25.6	28.6	32.2	26.6	Total Current Liabilities	46.7	41.6	26.5	28.4
Net fixed assets	275.6	272.9	260.4	253.7	Long-term debt	125.3	125.3	125.2	112.3
Future income tax assets	0.0	0.0	0.0	0.0	Regulatory liabilities	22.9	22.8	22.9	25.2
Goodwill & intangibles	0.0	0.0	0.0	0.0	Deferred income taxes	1.6	0.3	0.0	0.0
Regulatory assets	0.0	0.0	2.1	6.7	Other LT liabilities	10.6	10.6	9.7	10.0
Investments & others	88.7	85.2	82.9	59.8	Shareholders' equity	182.8	186.1	193.2	170.7
Total Assets	389.9	386.7	377.6	346.7	Total Liabilities & SE	389.9	386.7	377.6	346.7

UPPCO Balance Sheet, Liquidity, and Capital Ratios

	12 months Jun. 30		12 months Dec. 31	
	2023	2022	2021	2020
Current ratio	0.55	0.69	1.22	0.94
Total debt in capital structure (%)	45.9	44.5	41.5	42.5
Cash flow/total debt (%)	11.2	13.4	21.5	22.7
(Cash flow — dividends)/capex (x)	0.65	0.83	1.55	1.56
Dividend payout ratio (%)	0.0	0.0	0.0	0.0
Coverage Ratios (x)				
EBIT gross interest coverage	1.18	1.93	3.75	3.37
EBITDA gross interest coverage	3.08	4.03	5.80	5.25
Fixed-charges coverage	1.18	1.93	3.75	3.37
Profitability Ratios (%)				
EBITDA margin	27.5	31.5	43.4	42.7
EBIT margin	10.5	15.1	28.0	27.4
Profit margin	6.4	8.8	16.4	16.8
ROE	2.6	3.6	6.8	7.7
Return on capital	3.0	3.4	5.4	6.1

Rating History

	Current	2022	2021
Issuer Rating	BBB (high)	BBB (high)	BBB (high)
Senior Notes	BBB (high)	BBB (high)	BBB (high)

Notes:

All figures are in U.S. dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrsmorningstar.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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We rate more than 4,000 issuers and nearly 60,000 securities worldwide, providing independent credit ratings for financial institutions, corporate and sovereign entities, and structured finance products and instruments. Market innovators choose to work with us because of our agility, transparency, and tech-forward approach.

DBRS Morningstar is empowering investor success as the go-to source for independent credit ratings. And we are bringing transparency, responsiveness, and leading-edge technology to the industry.

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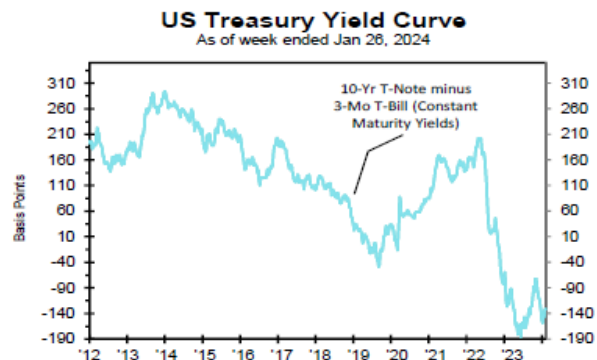
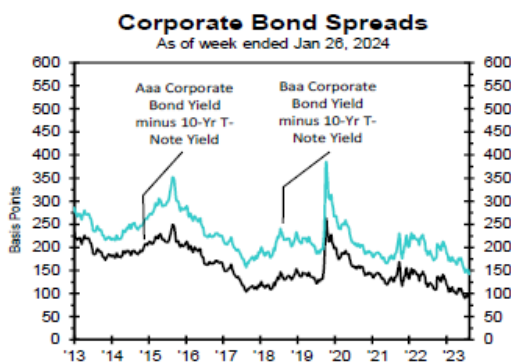
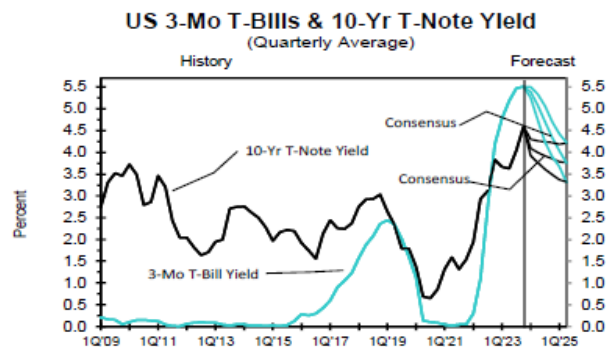
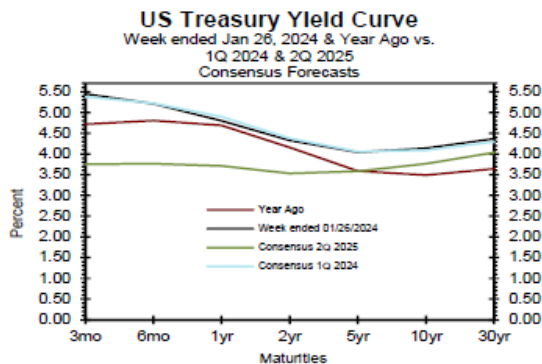
2 ■ BLUE CHIP FINANCIAL FORECASTS ■ FEBRUARY 1, 2024

Consensus Forecasts of U.S. Interest Rates and Key Assumptions

Interest Rates	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month				Latest Qtr	1Q 2024	2Q 2024	3Q 2024	4Q 2024	1Q 2025
	Jan 26	Jan 19	Jan 12	Jan 6	Dec	Nov	Oct	4Q 2023	2024	2024	2024	2024	2025	2025
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.3	5.1	4.7	4.4	4.1	3.8
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.5	8.2	7.9	7.6	7.3	7.0
SOFR	5.31	5.31	5.31	5.36	5.33	5.32	5.31	5.32	5.3	5.2	4.8	4.5	4.2	3.9
Commercial Paper, 1-mo.	5.32	5.33	5.32	5.32	5.32	5.33	5.33	5.33	5.3	5.1	4.7	4.4	4.1	3.9
Treasury bill, 3-mo.	5.45	5.46	5.47	5.47	5.44	5.52	5.60	5.52	5.4	5.1	4.7	4.3	4.0	3.8
Treasury bill, 6-mo.	5.21	5.20	5.22	5.25	5.34	5.44	5.57	5.45	5.2	5.0	4.6	4.3	4.0	3.8
Treasury bill, 1 yr.	4.80	4.79	4.77	4.83	4.96	5.28	5.42	5.22	4.9	4.7	4.4	4.1	3.9	3.7
Treasury note, 2 yr.	4.33	4.32	4.30	4.36	4.46	4.88	5.07	4.80	4.4	4.2	4.0	3.8	3.7	3.5
Treasury note, 5 yr.	4.04	4.02	3.93	3.96	4.00	4.49	4.77	4.42	4.1	3.9	3.8	3.7	3.6	3.6
Treasury note, 10 yr.	4.14	4.12	4.00	3.98	4.02	4.50	4.80	4.44	4.1	4.0	3.9	3.9	3.8	3.8
Treasury note, 30 yr.	4.37	4.34	4.19	4.12	4.14	4.66	4.95	4.58	4.3	4.2	4.2	4.1	4.0	4.0
Corporate Aaa bond	5.07	5.04	4.98	4.97	4.95	5.52	5.87	5.45	5.0	5.0	4.9	4.9	4.8	4.8
Corporate Baa bond	5.57	5.55	5.50	5.51	5.51	6.15	6.53	6.07	6.0	6.0	5.9	5.9	5.8	5.8
State & Local bonds	4.17	4.10	4.05	4.03	4.13	4.56	4.88	4.52	4.3	4.3	4.2	4.2	4.1	4.1
Home mortgage rate	6.69	6.60	6.66	6.62	6.82	7.44	7.62	7.29	6.7	6.6	6.5	6.3	6.2	6.1

Key Assumptions	History								Consensus Forecasts-Quarterly					
	1Q 2022	2Q 2022	3Q 2022	4Q 2022	1Q 2023	2Q 2023	3Q 2023	4Q 2023	1Q 2024	2Q 2024	3Q 2024	4Q 2024	1Q 2025	2Q 2025
Fed's AFE \$ Index	108.3	113.5	118.8	119.8	115.5	114.6	115.0	116.6	115.2	114.9	114.7	114.5	114.7	114.6
Real GDP	-2.0	-0.6	2.7	2.6	2.2	2.1	4.9	3.3	1.4	0.9	0.9	1.4	1.8	2.0
GDP Price Index	8.5	9.1	4.4	3.9	3.9	1.7	3.3	1.5	2.2	2.2	2.3	2.2	2.2	2.1
Consumer Price Index	9.2	9.7	5.5	4.2	3.8	2.7	3.6	2.8	2.5	2.4	2.4	2.3	2.2	2.2
PCE Price Index	7.7	7.2	4.7	4.1	4.2	2.5	2.6	1.7	2.2	2.3	2.2	2.2	2.1	2.1

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).



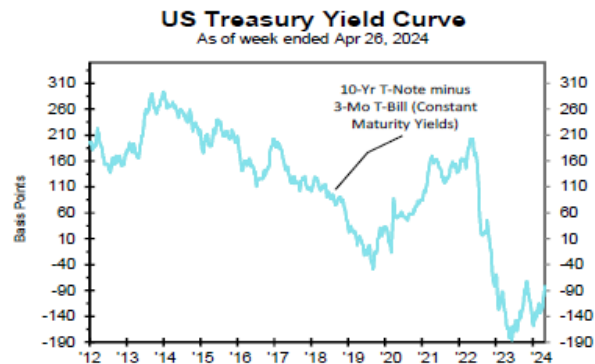
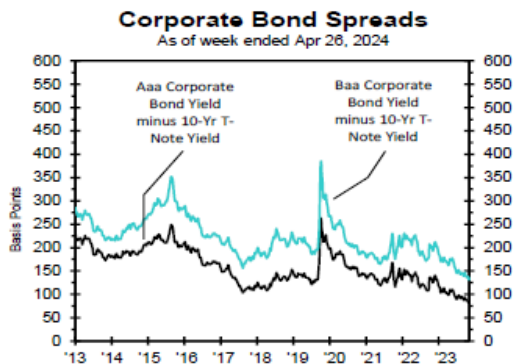
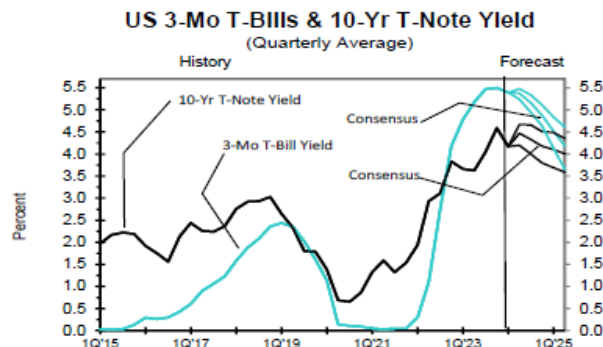
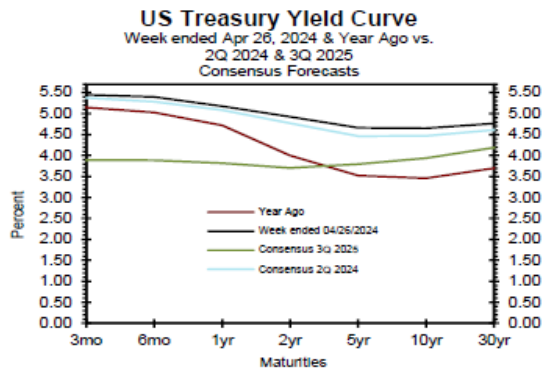
2 ■ BLUE CHIP FINANCIAL FORECASTS ■ MAY 1, 2024

Consensus Forecasts of U.S. Interest Rates and Key Assumptions

Interest Rates	History								Consensus Forecasts-Quarterly Avg.						
	Average For Week Ending				Average For Month				Latest Qtr	2Q	3Q	4Q	1Q	2Q	3Q
	Apr 26	Apr 19	Apr 12	Apr 5	Mar	Feb	Jan	1Q 2024	2024	2024	2024	2025	2025	2025	2025
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.4	5.2	4.9	4.6	4.3	4.0	
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.5	8.4	8.1	7.8	7.4	7.1	
SOFR	5.31	5.31	5.31	5.33	5.31	5.31	5.32	5.31	5.3	5.2	4.9	4.6	4.3	4.0	
Commercial Paper, 1-mo.	5.30	5.33	5.31	5.31	5.32	5.31	5.32	5.32	5.3	5.2	4.9	4.6	4.2	3.9	
Treasury bill, 3-mo.	5.45	5.45	5.44	5.42	5.47	5.44	5.45	5.45	5.4	5.2	4.9	4.5	4.2	3.9	
Treasury bill, 6-mo.	5.40	5.39	5.37	5.34	5.36	5.28	5.21	5.28	5.3	5.1	4.8	4.5	4.2	3.9	
Treasury bill, 1 yr.	5.18	5.17	5.12	5.04	4.99	4.92	4.79	4.90	5.1	4.9	4.6	4.4	4.1	3.8	
Treasury note, 2 yr.	4.93	4.96	4.86	4.70	4.59	4.54	4.32	4.48	4.8	4.6	4.3	4.1	3.9	3.7	
Treasury note, 5 yr.	4.66	4.66	4.51	4.34	4.20	4.19	3.98	4.12	4.5	4.3	4.1	4.0	3.9	3.8	
Treasury note, 10 yr.	4.65	4.63	4.48	4.35	4.21	4.21	4.06	4.16	4.5	4.3	4.2	4.1	4.0	3.9	
Treasury note, 30 yr.	4.77	4.74	4.59	4.50	4.36	4.38	4.26	4.33	4.6	4.5	4.4	4.3	4.2	4.2	
Corporate Aaa bond	5.48	5.46	5.30	5.21	5.11	5.13	5.01	5.08	5.3	5.2	5.1	5.0	5.0	4.9	
Corporate Baa bond	5.98	5.97	5.80	5.73	5.62	5.65	5.53	5.60	6.1	6.1	6.0	5.9	5.9	5.8	
State & Local bonds	4.31	4.29	4.27	4.23	4.12	4.12	4.09	4.11	4.4	4.4	4.2	4.2	4.2	4.1	
Home mortgage rate	7.17	7.10	6.88	6.82	6.82	6.78	6.64	6.75	7.0	6.8	6.6	6.5	6.3	6.2	

Key Assumptions	History								Consensus Forecasts-Quarterly					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q
	2022	2022	2022	2023	2023	2023	2023	2024	2024	2024	2024	2025	2025	2025
Fed's AFE \$ Index	113.5	118.8	119.8	115.5	114.6	115.0	116.6	115.5	117.2	117.5	116.6	115.8	115.0	114.8
Real GDP	-0.6	2.7	2.6	2.2	2.1	4.9	3.4	1.6	2.0	1.7	1.6	1.8	1.9	2.0
GDP Price Index	9.1	4.4	3.9	3.9	1.7	3.3	1.6	3.1	2.7	2.4	2.3	2.3	2.2	2.2
Consumer Price Index	10.0	5.3	4.0	3.8	3.0	3.4	2.7	3.8	3.4	2.6	2.4	2.4	2.4	2.4
PCE Price Index	7.2	4.7	4.1	4.2	2.5	2.6	1.8	3.4	2.9	2.3	2.2	2.3	2.2	2.1

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR.H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).



**Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
First Discovery Request**

1-AG-UPPCO-1.19

19. On page 30 to 32 of witness Thompson's testimony, he discusses the additional risk and return attendant to smaller firms generally. Please provide a copy of the G. Pincher article referenced on page 31 related to the additional risk and return specific to smaller utility companies and any other literature specifically focused on utility companies and their cost of equity capital.

UPPCO Response

Please refer to WP-21.pdf, which was provided with the Company's workpapers, which were provided to the Attorney General at the same time that UPPCO filed its direct case. Please also refer to Attachment U-21555 AG-UPPCo DR1-19, Thomas M. Zepp, *Utility stocks and the size effect—revisited*, *The Quarterly Review of Economics and Finance*, 43 (2003) 578-582, who concluded that "there is a small firm effect in the utility sector." A copy of this article is attached.

Response by: Dr. John Thompson

Dated: June 10, 2024



NORTH-HOLLAND

The Quarterly Review of Economics and Finance
43 (2003) 578–582

The *QUARTERLY REVIEW*
of *ECONOMICS*
And *FINANCE*

Short communication

Utility stocks and the size effect—revisited

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Received 7 January 2002; received in revised form 27 August 2002; accepted 29 August 2002

Abstract

Wong concluded there is weak empirical support that firm size is a missing factor from the capital asset pricing model for industrial stocks but not for utility stocks. Her weak results, however, do not rule out the possibility of a small firm effect for utilities. The issue she addressed has important financial implications in regulated proceedings that set rates of return for utilities. New studies based on different size water utilities are presented that do support a small firm effect in the utility industry.

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Keywords: Utility stocks; Beta risk; Firm size

Annie Wong concludes there is some weak evidence that firm size is a missing factor from the capital asset pricing model (“CAPM”) for industrial stocks but not for utility stocks (Wong, 1993, p. 98). This “firm size effect” is an observation that small firms tend to earn higher returns than larger firms after controlling for differences in estimates of beta risk in the CAPM. Wong notes that if the size effect exists, it has important implications and should be considered by regulators when they determine fair rates of return for public utilities. This paper re-examines the basis for her conclusions and presents new information that indicates there is a small firm effect in the utility sector.

1. Reconsideration of the evidence provided by Wong

Wong relies on Barry and Brown (1984) and Brauer (1986) to suggest the small firm effect may be explained by differences in information available to investors of small and large firms.

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She states that requirements to file reports and information generated during regulatory proceedings indicate the same amount of information is available for large and small utilities and thus, if the differential information hypothesis explains the small firm effect, then the uniformity of information available among utility firms would suggest the size effect should not be observed in the utility industry. But contrary to the facts she assumes, there are differences in information available for large and small utilities. More parties participate in proceedings for large utilities and thus generate more information. Also, in some jurisdictions smaller utilities are not required to file all of the information that is required of larger firms. Thus, if the small firm effect is explained by differential information, contrary to Wong’s hypothesis, differences in available information suggests there is a small firm effect in the utility industry. Wong did not discuss other potential explanations of the small firm effect for utilities.²

Wong’s empirical results are not strong enough to conclude that beta risks of utilities are unrelated to size. In the period 1963–1967, when monthly data were used to estimate betas, her estimates of utility betas as well as industrial betas increased as the size of the firms decreased, but she did not find the same inverse relationship between size and beta risk for utilities in other periods. Being unable to demonstrate a relationship between size and beta in other periods may be the result of Wong using monthly, weekly and daily data to make those beta estimates. Roll (1980) concluded trading infrequency seems to be a powerful cause of bias in beta risk estimates when time intervals of a month or less are used to estimate betas for small stocks. When a small stock is thinly traded, its stock price does not reflect the movement of the market, which drives down the apparent covariance with the market and creates an artificially low beta estimate.

Ibbotson Associates (2002) found that when annual data are used to estimate betas, beta estimates for the smaller firms increase more than beta estimates for larger firms. Table 1 compares Value Line (2000) beta estimates for three relatively small water utilities that are made with weekly data and an adjusted beta estimated with pooled annual data for the utilities for the 5-year period ending in December 2000. In making the latter estimate, it is assumed that the underlying beta for each of water utilities is the same. The *t*-statistics for the unadjusted beta

Table 1
Beta estimates reported by Value Line and estimated with pooled annual returns for relatively small water utilities

	Value Line ^a	Estimated with annual data ^b
Connecticut Water Service	0.45	
Middlesex Water	0.45	
SJW Corporation	0.50	
Average	0.47	0.78
<i>t</i> -statistic		2.72 ^{c,d}

^a As reported in Value Line (2000). Betas estimated with 5 years of weekly data.

^b Estimated with pooled annual return premiums for the 5-year period ending December 2000. Proxy market returns are total returns for the S&P 500 index. Dummy variable in 1999 to reflect the proposed acquisition of SJW Corporation included in analysis.

^c Significant at the 95% level.

^d The *t*-statistic for the null hypothesis that the true beta is 0.18 (the derived unadjusted Value Line beta) when the estimated betas is 0.65 (the unadjusted estimated beta) is 1.97. It is significant at the 95% level.

estimate is reported in parentheses. As was found by Ibbotson Associates (2002) for stocks in general, when annual data are used to estimate betas for small utility stocks, the beta estimate increases.

Wong used the Fama and MacBeth (1973) approach to estimate how well firm size and beta explain future returns in four periods. She reports weak empirical results for both the industrial and utility sectors. In every one of the statistical results reported for utilities, the coefficient for the size effect has a negative sign as would be expected if there is a size effect in the utility industry but only one of the results was found to be statistically significant at the 5% level. With the industrial sector, though she found two cases to have a significant size effect, a negative sign for the size coefficient occurred only 75% of the time. What is puzzling is that with these weak results, Wong concludes the analysis provides support for the small firm effect for the industrial industry but no support for a small firm effect for the utility industry.

2. New evidence on risk premiums required by small utilities

Two other studies support a conclusion that small utilities are more risky than larger ones. A study made by Staff of the Water Utilities Branch of the California Public Utilities Commission Advisory and Compliance Division (CPUC Staff, 1991) used proxies for beta risk and determined small water utilities were more risky than larger water utilities. Part of the difficulty with examining the question of relative risk of utilities is that the very small utilities are not publicly-traded. This CPUC Staff study addressed that concern by computing proxies for beta risk estimated with accounting data for the period 1981–1991 for 58 water utilities. Based on that analysis, CPUC Staff concluded that smaller water utilities were more risky and required higher equity returns than larger water utilities. Following 8 days of hearings and testimony by 21 witnesses regarding this study, it was adopted by the California Public Utilities Commission in CPUC Decision 92-03-093, dated March 31, 1992.

Table 2 provides the results of another study of differences in required returns estimated from discounted cash flow (“DCF”) model estimates of the costs of equity for water utilities of different sizes. The study compares average estimates of equity costs for two smaller water utilities, Dominguez Water Company and SJW Corporation, with equity cost estimates for two larger companies, California Water Service and American States Water, for the period 1987–1997. All four utilities operated primarily in the same regulatory jurisdiction during that period. Estimates of future growth are required to make DCF estimates. Gordon, Gordon, and Gould (1989) found that a consensus of analysts’ forecasts of earnings per share for the next 5 years provides a more accurate estimate of growth required in the DCF model than three different historical measures of growth. Unfortunately, such analysts’ forecasts are not generally available for small utilities and thus this study assumes, as was assumed by staff at the regulatory commission, that investors relied upon past measures of growth to forecast the future. The results in Table 2 show that the smaller water utilities had a cost of equity that, on average, was 99 basis points higher than the average cost of equity for the larger water utilities. This result is statistically significant at the 90% level. In terms of the issues being addressed by Wong, the 99 basis points could be the result of differences in beta risk, the small firm effect or some combination of the two.

Table 2
Small firm equity cost differential: case study based on a comparison of DCF equity cost estimates for larger and smaller California water utilities (1987–1997)

	Larger water utilities ^a			Smaller water utilities ^b			Smaller utilities minus larger utilities
	D ₀ /P ₀ (%)	Estimated growth (%) ^c	Equity cost estimate (%) ^d	D ₀ /P ₀ (%)	Estimated growth (%) ^c	Equity cost estimate (%) ^d	
1987	6.60	7.17	14.24	5.38	10.06	15.98	1.74
1988	6.75	6.30	13.48	5.81	9.08	15.42	1.94
1989	7.10	6.30	13.84	6.47	7.00	13.93	0.09
1990	7.24	6.19	13.87	6.96	7.51	14.99	1.11
1991	6.94	6.29	13.67	6.64	6.24	13.30	-0.36
1992	6.18	5.96	12.50	6.50	6.71	13.65	1.14
1993	5.32	5.68	11.30	5.49	6.31	12.15	0.85
1994	6.03	4.40	10.70	5.80	4.86	10.94	0.25
1995	6.44	3.86	10.55	6.44	4.88	11.64	1.09
1996	5.60	4.06	9.88	5.77	5.58	11.67	1.79
1997	4.93	3.31	8.40	4.52	4.89	9.64	1.23
Average difference							0.99
t-statistic							1.405 ^e

Limited to period for which Dominguez Water Company data were available. 1998 excluded due to pending buyout.

^a American States Water and California Water Service.

^b Dominguez Water Company and SJW Corporation.

^c Average of 5- and 10-year dividends per share growth, 10-year earnings per share growth and estimates of sustainable growth from internal and external sources for the most recent 10-year period when data are available (1991–1997), otherwise most recent 5-year period (1987–1990).

^d DCF equity cost as computed by California PUC staff: $k = (D_0/P_0) \times (1 + g) + g$.

^e Significant at the 90% level.

3. Concluding remarks

Wong's concluding remarks should be re-examined and placed in perspective. She noted that industrial betas tend to decrease with increases in firm size but the same relationship is not found in every period for utilities. Had longer time intervals been used to estimate betas, as was done in Table 1, she may have found the same inverse relationship between size and beta risk for utilities in other periods. She also concludes "there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not the utility stocks" (Wong, 1993, p. 98), but the weak evidence provides little support for a small firm effect existing or not existing in either the industrial or utility sector. Two other studies discussed here support a conclusion that smaller water utility stocks are more risky than larger ones. To the extent that water utilities are representative of all utilities, there is support for smaller utilities being more risky than larger ones.

Notes

1. Vice President.
2. The small firm effect could also be a proxy for numerous other omitted risk differences between large and small utilities. An obvious candidate is differentials in access to financial markets created by size. Some very small utilities are unable to borrow money without backing of the owner. Other small utilities are limited to private placements of debt and have no access to the more liquid financial markets available to larger utilities.

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VLFAAlert



ValueLinefunds

4th Quarter 2018

Volume VII, Issue IV

00207257



Mitchell Appel
President
Value Line Funds

Dear Fellow Shareholder,

Thank you for choosing Value Line Funds as a part of your diversified investment portfolio. For over half a century, Value Line Funds has championed sound investment principles and helped thousands of investors accomplish their financial goals with our actively managed family of mutual funds.

We hope you enjoy this edition of the VLFAAlert and thank you for your continued support.

Volatility is Not Risk:

Why the Difference is Critical to Long-Term Results

2017 lulled many equity investors into a comfort zone based on historically low volatility. 2018 has been more volatile—with tighter monetary policy and geopolitical and trade policy uncertainty among the drivers of the increase. But volatility levels in 2018 are actually historically normal—even with the bouts of volatility anticipated ahead of the November mid-term elections. But volatility is not risk. And recognizing the difference can be critical to your long-term investment returns.

Defining Our Terms

Volatility is simply the measure of the up and down movements of the market. For example, since 1950, when the Value Line Funds were first established, the average maximum drawdown in the broad U.S. equity market during midterm election years has been -17%, with weakness tending to be concentrated in the pre-election days. However, the good news is that there has been a consistent tendency historically for post-drawdown rallies, averaging +32% in the subsequent year.¹ Volatility? Yes! Uncertainty? Yes! But volatility is only risk if you act during down times—that is, only if you sell. To which the often-invoked quip may well be the most prudent answer: "Don't just do something, sit there."

Risk, on the other hand, is the probability of a permanent loss. You might think of risk as the possibility of having to lower your quality of life in the future.

"Volatility is not synonymous of risk but—for those who truly understand it—of wealth."

- Francois Rochon*

Recognizing the Difference

Volatility is independent of risk. Too many investors let an investment's short-term price movements, or perceptions of short-term price movements, drive their buying and selling decisions. Too often volatility is regarded as something to be

avoided. But since short-term price moves are unknowable and independent of underlying fundamentals and value, such volatility should not be a determinant.

And ALL investments have risk of some kind, including cash and CDs. One just needs to pick the risks that are best to take based on your individual tolerance level, time horizon and financial needs and goals.

As famed investor and Berkshire Hathaway CEO Warren Buffet wrote:

"Stock prices will always be far more *volatile* than cash-equivalent holdings. *Over the long term*, however, currency-denominated instruments are *riskier* investments — far riskier investments — than widely diversified stock portfolios that are bought over time and that are owned in a manner invoking only token fees and commissions. **That lesson has not customarily been taught in business schools, where volatility is almost universally used as a proxy for risk. Though this pedagogic assumption makes for easy teaching, it is dead wrong: Volatility is far from synonymous with risk.** Popular formulas that equate the two terms lead students, investors and CEOs astray."²

"Volatility is our friend.

Volatility has nothing to do with risk."

- Mohnish Pabrai*

(continued on back)

Value Line Article on Volatility vs. Risk

It's a Matter of Time, Not Timing

Most experienced investors do not fear volatility, only unrecoverable loss. But most losses, as measured by a day, a week, a quarter or a year, are recoverable over time. Declines in principal value have historically been temporary. Of course, there are true risks. A company could go totally out of business. An innovation could transform an industry so profoundly to make a once "blue chip" company a relic. A geopolitical event could happen to negate all assumptions. But these occurrences are rare. For the vast majority of investors, maintaining a long-term perspective is the real key to attaining gains over their investing lifetime. Historically, since World War II, the longer you hold stocks, the narrower the range of returns.³ In other words, even if volatility is a concern, it decreases the longer you hold stocks. It's the old adage: what matters is time in the market, not market timing.

"You can't overlook the volatility, but you don't let it push you around in the market."

*- Boone Pickens**

solutions designed to meet a broad array of investment goals. Whether you are looking for income or long-term capital appreciation, whether you choose to invest in equities, taxable or tax-exempt fixed income or a hybrid fund of multiple asset classes, you can rely on the solid fundamentals of Value Line Funds.

Value Line Funds Include:
Equity Funds
Premier Growth Fund
Larger Companies Focused Fund
Mid Cap Focused Fund
Small Cap Opportunities Fund
Hybrid Funds
Asset Allocation Fund
Capital Appreciation Fund
Fixed Income Funds
Tax Exempt Fund
Core Bond Fund

**Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
First Discovery Request**

1-AG-UPPCO-1.16

16. Witness Thompson on page 26 of his testimony discusses problems with low hydro generation. Provide a list of instances in the last ten years with specific dates with a description of the problem and identify the impact on system sales or off-system sales and revenues, and also the impact on increased power purchases in each case. Provide this information in Excel.

UPPCO Response

Dr. Thompson's discussion of the potential exposures that the investment community associates with hydroelectric generation was not based on an historical analysis or study; nor was such a study necessary to support his testimony. Rather, Dr. Thompson's discussion serves to demonstrate that investors recognize the ongoing potential for periods of below-average water conditions to impact a utility's exposure to volatility in wholesale power markets.

Response by: Dr. John Thompson

Dated: June 10, 2024

**Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
First Discovery Request**

1-AG-UPPCO-1.18

18. Refer to witness Thompson's testimony on page 29 where he states that the utilization of special regulatory mechanism's for UPPCO "...are more limited than those approved for other firms in the industry..." Identify any mechanisms UPPCO sought approval for and the Commission denied approval. Identify also if the Commission approved the use of those mechanisms for other Michigan utilities.

UPPCO Response

Dr. Thompson's opinion that "the mechanisms currently in place for UPPCO are more limited than those approved for other firms in the industry" is based on a comparison between UPPCO, the publicly traded utilities in his proxy group, and their respective operating companies. These comparison groups' regulatory mechanisms can be referenced in Exhibit A-45 (JST-3).

Response by: Dr. John Thompson

Dated: June 10, 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company - Electric Rate Case

Case No. U-21555
 Exhibit AG-29
 July 19, 2024
 Page 1 of 1

Operations & Maintenance - Summary

<u>Line</u>	<u>Description</u> (a)	<u>Thousands of Dollars</u>		<u>Note or Ref.</u> (d)
		<u>Retail</u> (b)	<u>Total</u> (c)	
1	O & M Per Company	\$ <u>40,823</u>	\$ <u>41,361</u>	1
	<u>Attorney General Changes</u>			
2	Excess Wage Inflation		(681)	Exhibit AG-30
3	Distribution - Lines Maintenance		(1,262)	Exhibit AG-31
4	Injuries & Damages		(531)	Exhibit AG-32
5	Uncollectible Accounts Receivable		(147)	Exhibit AG-33
6	Company 401k Employee Savings Plan		(129)	Coppola Testimony
7	Incentive Compensation Expense		(829)	Coppola Testimony
8	American Transmission Company Services		(811)	Coppola Testimony
9	Pension & Benefits Error		(125)	Coppola Testimony
10	SERP Expense		(11)	Coppola Testimony
11	Total Change (Sum of L2 to L10)	\$ <u>(4,464)</u> *	\$ <u>(4,525)</u>	
12	AG Revised O & M Level (L1 + L11)	\$ <u>36,359</u>	\$ <u>36,836</u>	
13	Change in O & M (L12 less L1)	\$ (4,464)	\$ (4,525)	

* Reflects 98.67% allocation to Retail Jurisdictional business of the total amount per DR 3AG-UPPCO-1.111.

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company - Electric Rate Case

Case No. U-21555
Exhibit AG-30
July 19, 2024
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Adjustment of Excess Wage Inflation

<u>Line</u>	<u>Caption or Item Description</u> (a)	<u>Non-Union</u> (b)	<u>Union</u> (c)	<u>Total</u> (d)	<u>Notes</u> (e)
1	2023 Base Wages, Salaries, Overtime and Double Time	\$ 8,937	\$ 10,235	\$ 19,172	1
2	Company Wage Inflation Rates ⁴				
3	2024	1.040	1.050		2
4	2025	<u>1.040</u>	<u>1.040</u>		2
5	Two-year compounding factor	<u>1.082</u>	<u>1.092</u>		L 3 x L 4
6	Consumer Price Index ⁴				
7	2024	1.027	1.027		3
8	2025	<u>1.024</u>	<u>1.024</u>		3
9	Two-year compounding factor	<u>1.052</u>	<u>1.052</u>		L 7 x L 8
10	Inflation Result Difference	0.030	0.040		Line 5 less Line 9
11	Inflation Excess Over CPI	\$ <u>268</u>	\$ <u>413</u>	\$ 681	L 1 x L 10

Notes

- 1 Per 2023 Compensation Summary provided by Company in Case Filing
- 2 Witness Kates testimony page 5, lines 5 and 15
- 3 Witness Kates testimony page 4, line 15
- 4 Annual inflation factors plus 1 to calculate compounding factor

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company - Electric Rate Case

Case No. U-21555
Exhibit AG-31
July 19, 2024
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Distribution Line Maintenance - Dollars in Thousands

<u>Line</u>	<u>Caption</u> (a)	<u>Line Maintenance Costs</u>		<u>Total for</u>	<u>Note or Reference</u> (e)
		<u>Acct 593</u> (b)	<u>Acct 594</u> (c)	<u>Both Accounts</u> <u>Col. (b) + (c)</u> (d)	
1	2019	\$ 6,631	\$ 489	\$ 7,120	1
2	2020	5,772	426	6,198	1
3	2021	6,516	672	7,188	1
4	2022	8,339	671	9,010	1
5	2023	<u>8,088</u>	<u>695</u>	<u>8,783</u>	1
6	Five Year Average	\$ 7,069	\$ 591	\$ 7,660	Sum (L1 to L5) / 5
7	Inflation Factor	<u>5.16%</u>	<u>5.16%</u>	<u>5.16%</u>	Co. Rates of 2.7% and 2.4%.*
8	Inflation Increase for 2024 and 2025	<u>\$ 365</u>	<u>\$ 31</u>	<u>\$ 396</u>	L6 x L7
9	AG Estimate of Line Clearing Costs	\$ 7,434	\$ 621	\$ 8,055	L6 + L8
10	Company Estimate of Line Maint. Costs	<u>8,409</u>	<u>908</u>	<u>9,317</u>	1
11	AG's Expense Reduction & Lower O & M	\$ (975)	\$ (287)	\$ (1,262)	L9 less L10

1 From Discovery Response 2-AG-UPPCO-2.34 Attachment: Data for Account 593000 & 594000

* Rates for 2024 and 2025 fom page 4 of witness Kates Testimony

**MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company - Electric Rate Case**

**Case No. U-21555
Exhibit AG-32
July 19, 2024
Page 1 of 1**

Injuries & Damages - Dollars in Thousands

<u>Line</u>	<u>Caption</u> (a)	<u>Amount</u> (b)	<u>Note</u> (c)
	Historical Injuries & Damages		
1	2019	\$ 852	1
2	2020	834	1
3	2021	921	1
4	2022	1,029	1
5	2023	<u>1,106</u>	1
6	Five Yr. Average <i>(average of lines 1 through 5)</i>	\$ 948	
7	Injuries & Damages Estimate Per Company	<u>\$ 1,479</u>	1
8	Reduction in Injuries & Damages and in O & M (L6 less L7)	<u>\$ (531)</u>	

1 From Discovery Response 2-AG-UPPCO-2.42 Attachment: Data for Account 925000 (data for 2019 to 2023)

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company - Electric Rate Case

Case No. U-21555
Exhibit AG-33
July 19, 2024
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Uncollectibles - Dollars in Thousands

Line	Year or Caption (a)	Historic Bad Debts Per Company*			Operating Revenues* (e)	Percent Bad Debts & Bad Debt Calc. Col. (d) / (e) (f)
		Gross Write-offs (b)	Less Recoveries (c)	Net Write-offs (d)		
1	2021	\$ 365	\$ 240	\$ 125	\$ 109,283	0.11%
2	2022	441	175	266	109,450	0.24%
3	2023	324	185	139	114,953	<u>0.12%</u>
4	Average Percent (Avg. L1, L2, L3)					0.16%
5	Projected Revenues*					<u>127,474</u>
6	AG Projected Uncollectibles (L4 x L5)					\$ 203
7	Uncollectibles per Company**					<u>350</u>
8	Reduction in Uncollectibles and O & M (L6 less L7)					\$ (147)

* Information is from Discovery Response 2-AG-UPPCO-2.37 Attachment

** Per Exhibit A-14 (NEK-12)

**Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Staff TMS's
Fifth Audit Request**

5-Staff TMS-UPPCO-5.1

1. Has the Company included any costs of the Incentive Pay in the current case revenue requirement?
 - a. If so, what is the amount that has been included for the projected test year?

UPPCO Response

Yes, our operating expenses include \$276,217.36 of incentive pay in the current case revenue requirement. Witness Ryan's testimony on page 6, lines 10 and 11 are misstated.

Response by: Natasha Wonch

Dated: 4/24/2024

**Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Staff TMS's
Fifth Audit Request**

5-Staff TMS-UPPCO-5.2

2. For the Pay-at-Risk compensation:
- a. What is the amount of Pay-at-Risk compensation that has been included in the current case revenue requirement for the projected test year?

UPPCO Response

The amount of Pay-at-Risk compensation included in the current rate case revenue requirement operating expenses is \$1,104,869.45.

Response by: Natasha Wonch

Dated: 4/24/2024

**Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case**

**Upper Peninsula Power Company's Responses to
Attorney General's
Second Discovery Request**

2-AG-UPPCO-2.34

34. Refer to Distribution O&M Expenses in Exhibit A-3, Schedule C5, which shows a 2023 expense level of \$16.679 million. These expenses increase to \$17.243 million in the 2025 projected test year, as shown on Exhibit A-8, Schedule C5. Please:
- a. Provide a schedule in Excel showing a comparison of the component expenses by FERC account or similar breakdown for each year 2019 to 2023 actual and forecasted for 2024 and 2025 on the same schedule.
 - b. For any variances in each account of 7.5% or greater between 2023 and 2025, identify the reasons for the increase or decrease with related dollar amount in the same worksheet provided in subpart (a).
 - c. Provide a schedule in Excel showing 2023 and 2025 labor expenses by FERC account and provide explanations for all increases exceeding the projected rate of inflation used by the Company for 2024 and 2025.

UPPCO Response

- a. See Attachment 2-AG-UPPCO-2.33 (2.33-36,38,42,43 AG Response Attachment), tab 2.33-36 esc>7.5%.
- b. See Attachment 2-AG-UPPCO-2.33 (2.33-36,38,42,43 AG Response Attachment), tab 2.33-36 esc>7.5%.
- c. See part a, labor is included in those FERC accounts and labor is not one for one match to FERC.

Response by: Natasha Wonch

Dated: June 12, 2024

UPPCO Response to discovery request 2-AG-UPPCO-2-34

		2025	2024	2023	2022	2021	2020	2019	2023 - 2025 Change	
FERC	FERC Description	(A-8 C5)	Bridge Year	(A-3 C5)	Actual	Actual	Actual	Actual		
	<u>2-AG-UPPCO-2.34</u>									
	<u>Refer to Distribution O&M Expenses</u>									
580	Operation supervision and engineering.	1,850,843	1,798,478	1,649,744	1,758,379	1,907,712	2,148,389	1,993,391	12%	Used 3 year average to project where labor and vehicles will be charged for FERC accounting, which shifted costs between FERC accounts, up 1%
582	Station expenses (Major only).	1,543,956	1,491,385	1,440,987	1,268,746	1,116,598	1,248,345	1,123,429	7%	
583	Overhead line expenses (Major only).	66,984	64,326	53,661	38,725	26,932	148,709	42,161	25%	Used 3 year average to project where labor and vehicles will be charged for FERC accounting, which shifted costs between FERC accounts, up 1%
584	Underground line expenses (Major only).	3,055	2,934	3,644	4,238	2,402	(1,114)	8,853	-16%	Used 3 year average to project where labor and vehicles will be charged for FERC accounting, which shifted costs between FERC accounts, up 1%
585	Street lighting and signal system expenses.	24,907	24,121	15,806	21,450	24,465	29,498	42,121	58%	budgeted increase in material costs from 23-24, escalated by 2.4% from 2024 to 2025
586	Meter expenses.	760,002	731,993	747,815	686,992	717,345	494,273	638,371	-2%	
588	Miscellaneous distribution expenses.	1,999,817	1,936,420	2,015,640	1,971,358	1,554,591	1,864,071	1,582,579	-1%	
589	Rents.	118,786	115,999	140,516	114,371	137,268	126,638	48,591	-15%	Used 3 year average to project where labor and vehicles will be charged for FERC accounting, which shifted costs between FERC accounts, up 1%
590	Maintenance supervision and engineering (Major only).	70,379	67,849	192,550	207,159	206,384	166,945	143,688	-63%	Used 3 year average to project where labor and vehicles will be charged for FERC accounting, which shifted costs between FERC accounts, up 1%
592	Maintenance of station equipment (Major only).	954,711	1,105,370	859,450	933,298	936,026	1,054,161	811,947	11%	Used 3 year average to project where labor and vehicles will be charged for FERC accounting, which shifted costs between FERC accounts, up 1%
593	Maintenance of overhead lines (Major only).	8,409,127	8,016,168	8,088,391	8,338,676	6,516,136	5,772,104	6,631,532	4%	
594	Maintenance of underground lines (Major only).	908,479	882,992	694,700	670,732	671,781	426,063	489,806	31%	Budgeted increase in material costs from 23-24, escalated by 2.4% from 2024 to 2025
595	Maintenance of line transformers.	567,026	553,636	985,605	570,619	174,764	183,920	901,703	-42%	Used 3 year average to project where labor and vehicles will be charged for FERC accounting, which shifted costs between FERC accounts, up 1%
596	Maintenance of street lighting and signal systems.	1,463	1,429	2,567	1,755	2,903	1,086	20,849	-43%	Used 3 year average to project where labor and vehicles will be charged for FERC accounting, which shifted costs between FERC accounts, up 1%
597	Maintenance of meters.	(77,601)	(75,768)	(48,316)	(49,159)	(24,019)	(7,388)	32,396	61%	Predicting larger number of meters on hand - pre-cap on meters to be installed.
598	Maintenance of miscellaneous distribution plant.	41,139	40,172	36,488	106,962	67,702	16,836	20,624	13%	budgeted increase in material costs from 23-24, escalated by 2.4% from 2024 to 2025
	Total Distribution	17,243,071	16,757,503	16,879,248	16,644,300	14,038,991	13,672,537	14,532,042		

The 2024 budget was estimated based on LTM 8/2023 activity, planned known and measurables, headcount, and costs that would be charged to other activities or capital work. Then the 2024 budget was escalated using 4% for Union Employees (per CBA) and 4% for Admin Employees, 4.5% for Vehicle Expense and 2.4% for other expenses per the Projected CBO core inflation for 2025 at 1/16/2024 to arrive at the Project Test Year 2025. Please reference the 2021-2025 FERC Mapping-New to 3 digit FERC document to see the walk from 2024 to 2025.

MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Third Discovery Request

3-AG-UPPCO-3.63

Refer to lines 12-20 on page 2 of Mr. Gervae's direct testimony on the services provided to ATC. Please provide the amount of revenue billed each year to ATC for services provided in 2021-2023, and forecasted for 2024 and 2025. Provide a reference where this revenue is shown and included in an exhibit, schedule, and line number. If not clearly shown, provide evidence that the revenue has been included in the reported amount in the exhibit, schedule, and line number.

UPPCO Response:

Total billed to ATC in each year as follows:

2021 \$2,093,341.64
2022 \$1,756,665.31
2023 \$1,797,871.73

Total Forecasted Amounts per year.

2024 \$1,096,854
2025 \$1,124,251

The services provided to ATC are not recorded as revenue. ATC billed charges are a debit to receivable and a credit to operating expenses. This is included on the U-21555 2023 Historic Revenue Requirement Model_V2 as a reduction in operating expenses on Exhibit A-3 (NLW-11), Schedule C5, Lines 3, 4, and 9 and the receivable is included in Capital Structure Adj on Exhibit A-4 (NEK-1), Schedule D1, Line 20. For the U-21555 2025 Projected Test Year Revenue Requirement Model, the 2025 receivable balance is included on Exhibit A-9 (NEK-6), Schedule D1, Line 20. The credits to operating expenses are included on Exhibit A-8 (NLW-23), Schedule C5, Lines 3, 4, and 9.

Response by: Dan Gervae

Dated: July 3, 2024

Upper Peninsula Power Company
MPSC Case No. U-21555
2024 Rate Case

Upper Peninsula Power Company's Responses to
Attorney General's
Second Discovery Request

2-AG-UPPCO-2.35

35. Refer to Administrative and General Expenses in Exhibit A-3, Schedule C5, which shows a 2023 expense level of \$11.062 million. These expenses increase to \$13.978 million in the 2025 projected test year, as shown on Exhibit A-8, Schedule C5. Please:
- a. Provide a schedule in Excel showing a comparison of the component expenses by FERC account or similar breakdown for each year 2019 to 2023 actual and forecasted for 2024 and 2025 on the same schedule.
 - b. For any variances in each account of 7.5% or greater between 2023 and 2025, identify the reasons for the increase or decrease with related dollar amount in the same worksheet provided in subpart (a).
 - c. Provide a schedule in Excel showing 2023 and 2025 labor expenses by FERC account and provide explanations for all increases exceeding the projected rate of inflation used by the Company for 2024 and 2025.

UPPCO Response

- a. See Attachment 2-AG-UPPCO-2.33 (2.33-36,38,42,43 AG Response Attachment), tab 2.33-36 esc>7.5%.
- b. See Attachment 2-AG-UPPCO-2.33 (2.33-36,38,42,43 AG Response Attachment), tab 2.33-36 esc>7.5%.
- c. See part a, labor is included in those FERC accounts and labor is not one for one match to FERC.

Response by: Natasha Wonch

Dated: June 12, 2024

UPPCO Response to discovery request 2-AG-UPPCO-2-35

		2025	2024	2023	2022	2021	2020	2019	2023 - 2025 Change	
FERC	FERC Description	(A-8 C5)	Bridge Year	(A-3 C5)	Actual	Actual	Actual	Actual		
	2-AG-UPPCO-2.35									
	Refer to Administrative and General Expenses									
920	Administrative and general salaries.	4,581,896	4,477,502	3,967,202	4,634,607	3,313,389	3,162,046	2,467,355	15%	2024-5 926 includes PAR that should be in 920.
921	Office supplies and expenses.	2,183,565	2,097,705	2,147,712	2,089,506	1,468,860	1,498,570	1,862,539	2%	
923	Outside services employed.	997,016	924,819	911,666	713,334	386,154	853,665	1,060,892	9%	Increased Consulting and Legal Expense for 2024 was escalated for 2025
924	Property insurance.	850,900	783,100	884,231	740,360	740,033	617,256	523,063	-4%	
925	Injuries and damages.	1,479,468	1,034,718	1,106,084	1,029,110	920,888	834,459	852,481	34%	See 2.42 Injuries and Damages
926	Employee pensions and benefits.	3,088,236	1,987,613	1,320,209	2,055,627	3,414,489	3,816,069	3,896,404	134%	2024-5 926 includes PAR that should be in 920.
928	Regulatory commission expenses.	774,711	756,553	696,051	691,651	631,057	673,380	720,923	11%	Increased Legal Expense for the Rate Case in 2024 was escalated for 2025
930	General Advertising & Misc General Exp	10,624	10,375	15,534	9,210	13,280	12,500	30,000	-32%	2023 has 2023 and 2024 MICHIGAN CHAMBER OF COMMERCE membership, did not forecast in 2025
931	Rents.	11,720	11,446	14,237	12,883	6,417	6,009	7,320	-18%	The 2024 budget was estimated based on LTM8/2023 activity. 2023 ended higher than anticipated, so 2024 budget escalation for 2025 (at 2.4% the projected CBO core inflation 2025 at 1/16/2024) was insufficient.
	Total Admin & General	13,978,135	12,083,832	11,062,924	11,976,289	10,894,568	11,473,955	11,420,976		

MICHIGAN PUBLIC SERVICE COMMISSION
Upper Peninsula Power Company

Computation of Revenue Deficiency for Projected Test Year 2025

Line	Description (a)	Retail Company Filed Amount (b)	AG Recommended Adjustments (c)	Revised Amount (d)
1	Rate Base ⁽¹⁾	\$ 382,710,728	\$ (24,482,757)	\$ 358,227,971
2	Rate of Return	7.02%	-0.45%	6.57%
3	Income Required	\$ 26,873,947	\$ (3,338,369)	\$ 23,535,578
4	Adjusted Net Operating Income ⁽²⁾	14,886,919	4,103,431	18,990,350
5	Income Deficiency (Sufficiency)	\$ 11,987,028	\$ (7,441,800)	\$ 4,545,228
6	Revenue Multiplier	1.3288	1.3288	1.3288
7	Revenue Deficiency (Sufficiency)	15,928,364	\$ (9,888,665)	6,039,699
	Other Adjustments:			
8	Revenue Offset U-20995	1,241,192		1,241,192
9	Revenue Adjustment U-20757	165,779		165,779
10	Revenue Adjustment U-20276 - Pension Expense	(421,484)		(412,379)
15	Revenue Deficiency (Sufficiency) - Total	\$ 16,913,851	\$ (9,888,665)	\$ 7,034,291

⁽¹⁾ Rate Base Adjustments Exhibit AG-10

⁽²⁾ AG adjustments to Operating Income - Increase (Decrease):

		Source
O&M Expenses	4,464,000	Exhibit AG-29
Depreciation Expense	1,135,787	Exhibit AG-10
Total	\$ 5,599,787	
Effective Tax Rate (1-1/1.3288)	24.74%	
Taxes	(1,385,619)	
Interest Synchronization on Capital Adjustments	(110,738)	RevDef-WP1
Adjusted Net Operating Income	\$ 4,103,431	

PROOF OF SERVICE - U-21555

The undersigned certifies that a copy of the *Attorney General's Testimony and Exhibits of Sebastian Coppola* was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 19th day of July 2024.

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