

Founded in 1852
by Sidney Davy Miller

MILLER CANFIELD

Paul Michael Collins
TEL +1.517.483.4908
FAX +1.517.374.6304
E-MAIL Collinsp@MillerCanfield.com

Miller, Canfield, Paddock and Stone, P.L.C.
123 West Allegan Street
Suite 200
Lansing, Michigan 48933-1738
TEL (517) 487-2070
FAX (517) 374-6304
millercanfield.com

MICHIGAN
ILLINOIS
NEW YORK
OHIO
WASHINGTON, D.C.
CALIFORNIA
CANADA
MEXICO
POLAND
UKRAINE
QATAR

May 22, 2026

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway, 3rd Floor
Lansing, MI 48917

Re: Upper Peninsula Power Company
Case No. U-22032

Dear Ms. Felice:

Enclosed for electronic filing on behalf of Upper Peninsula Power Company in regard to the above-captioned matter are the following:

1. Application;
2. Proposed Notice of Hearing;
3. Proposed Protective Order;
4. Index of Exhibits
5. Non- Confidential Direct Testimony and Exhibits of:
 - (a) Eric W. Stocking
 - (b) Natasha L. Wonch
 - (c) Nicholas E. Kates
 - (d) John S. Thompson, Ph.D.
 - (e) Morgan B. Impola
 - (f) Daniel J. Gervae
 - (g) Virgil E. Schlorke
 - (h) Gregory S. Gagnon
 - (i) Beth A. Blewett
 - (j) Nicole E. Bell
6. Documentation that complies with Part II of the Rate Case Filing Requirements;
7. Appearances of Sherri A. Wellman and Paul M. Collins; and
8. Proof of Service reflecting electronic service on intervenors in Case Nos. U-21555 and U-21286.

May 22, 2026

Confidential information will be filed under seal with the Commission and served upon Staff and intervenors after the issuance of the Protective Order and completion of the Non-Disclosure Certificate, as applicable.

Pursuant to the Rate Case Filing Requirements approved by the Michigan Public Service Commission on dated April 25, 2024 in Case No. U-18238, the Staff case coordinator and the parties to U-21555 and U-21286 are being provided all exhibits and workpapers in native format with all formulae intact, as well as documentation addressing Part III of the Rate Case Filing Requirements via the following secure portal link:

<https://filelocker.mcps.com/pickup?claimID=Ws6yxDop3tHaDHsW&claimPasscode=Kj7sdwrvEpNegGD&emailAddr=123304>

Claim ID: Ws6yxDop3tHaDHsW

Claim Passcode: Kj7sdwrvEpNegGD

As requested by the Staff case coordinator, five hard copies containing this filing and workpapers will be directly served on the Commission Staff.

Sincerely,

Miller, Canfield, Paddock and Stone, P.L.C.

By: _____
Paul Michael Collins

PC/vs

Enclosures

cc w/enc: Michael E. Moody (Moodym2@michigan.gov) and ag-enra-spec-lit@michigan.gov)
Holly L. Hillyer (holly@tropospherelegal.com)
John R. Liskey (john@liskeypllc.com)
Christopher M. Bzdok (chris@tropospherelegal.com)
Michael Pattwell (mpattwell@clarkhill.com)
Stephen A. Campbell (scampbell@clarkhill.com)
Timothy J. Lundgren (tjlundgren@varnumlaw.com)
Justin K. Ooms (jkooms@varnumlaw.com)
Olivia R.C.A. Flower (oflower@dykema.com)
Kyle M. Asher (kasher@dykema.com)
Hannah E. Buzolits (hbuzolits@dykema.com)
Eric Stocking (estocking@uppc.com)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

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

Case No. U-22032

APPLICATION

UPPER PENINSULA POWER COMPANY (“UPPCO” or the "Company”) requests authority from the Michigan Public Service Commission (“Commission”) to increase its rates for retail electric service, and in support thereof respectfully represents as follows:

INTRODUCTION

1. UPPCO is a public utility engaged in the generation, purchase, distribution and sale of electric energy in its service territory in the Upper Peninsula of Michigan. UPPCO serves certain cities, villages and townships located in the counties of Alger, Baraga, Delta, Houghton, Iron, Keweenaw, Marquette, Menominee, Ontonagon and Schoolcraft.

2. UPPCO is a corporation organized under the laws of the state of Michigan, with its principal office located at 1002 Harbor Hills Drive, Marquette, Michigan 49855, and is authorized to transact business in the state of Michigan. UPPCO is a subsidiary of Axium UP Holdings LLC ("Axium UP"). Axium UP acquired UPPCO and its parent Upper Peninsula Power Holding Company pursuant to an Order Approving Settlement Agreement issued May 26, 2021, in Case No. U-20995, in which the Commission approved, pursuant to Section 6q of 2008 PA 286, MCL 460.6q, the sale of UPPCO by Lake AIV, L.P.

3. UPPCO's retail electric service business is subject to the jurisdiction of the Commission pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and the Michigan Office of Administrative Hearing and Rules's Administrative Hearing Rules, R 792.10401 et seq. Pursuant to said statutory provisions, the Commission has power and jurisdiction to regulate UPPCO's retail electric rates for service rendered in the State of Michigan.

4. This Application is being filed in accordance with filing requirements contained in the Commission's Order in Case No. U-18238, dated April 25, 2024 and updated by the Commission's Staff on Jul 9, 2024.

5. UPPCO's present electric rates are based on the schedule of rates authorized by the Commission in its Order Approving Settlement Agreement dated September 26, 2024, in Case No. U-21555. That Order Approving Settlement Agreement granted rate relief of \$9.0 million annually, based on a 9.86% return on common equity, effective January 1, 2025. The Commission-approved rates were based on a test year consisting of a 12-month period ending December 31, 2025.

6. UPPCO's rates for retail electric service established in Case No. U-21555 do not reflect the current costs of providing retail electric service, and UPPCO requires further rate relief. Additionally, UPPCO is proposing to change its PSCR base and loss factor. The proposed revenue increase described in this Application, as supported by the Company's testimony, exhibits, and workpapers, is necessary to allow UPPCO to continue to provide safe and reliable electric service, to meet service quality and reliability expectations, and to allow UPPCO a reasonable opportunity to recover its costs of operation, including a reasonable rate of return.

REQUESTED RELIEF

7. For purposes of this case, UPPCO has undertaken a complete examination of its investments, expenses and revenues based on a projected 12-month period ending December 31, 2027. Using a 2027 calendar test year and a return on common equity of 10.55%, UPPCO calculates a base rate revenue deficiency of approximately \$17.3 million. UPPCO represents that such an increase is just and reasonable under the circumstances and is necessary to provide a reasonable return on UPPCO's electric utility plant and resources required to provide service in Michigan.

8. The key drivers contributing to the Company's revenue deficiency are:
- (a) the necessity of continuing investment in reliability infrastructure,
 - (b) increasing costs of capital, including debt and equity, and
 - (c) rising operational expenses for equipment and personnel needed to provide electric service.

9. UPPCO represents that its present return on investment is and will be below that required by sound regulation; that UPPCO's present retail electric rates and charges are unjust and unreasonable because they will produce increasingly inadequate retail electric service revenues to UPPCO, unless rate relief is granted to permit UPPCO to continue to achieve its goal of rendering adequate retail electric service to the public. UPPCO further represents that rate relief, effective in the near future, is necessary to protect the rights of UPPCO and to prevent it from being deprived of its property contrary to the Fourteenth Amendment of the Constitution of the United States of America and contrary to the provisions of the Constitution of 1963 of the State of Michigan.

10. UPPCO represents that in order to establish rates for retail electric service that are just and reasonable, it is essential that the Commission order an increase in retail electric base rates that will produce additional revenues on an annual basis of approximately \$17.3 million.

RATE DESIGN, TARIFF AND OTHER PROPOSALS

11. UPPCO's proposed rates for each customer class rate schedule are shown on Schedule F2 of Exhibit A-16. These rates are designed to recover the revenue deficiency, and also reflect an update to the Company's class cost of service study evidenced in Schedule F1 of Exhibit A-16. UPPCO requests Commission approval of the proposed rates.

12. In addition, UPPCO proposes to continue the Company's Residential Low-Income tariff.

13. UPPCO proposes to establish a new PSCR basing point in its base rates.

14. In 2016, the Michigan legislature passed, and the Governor signed into law, PA 341 which, in the part pertinent to this proceeding, amended MCL 460.1 et seq. by adding Section 6w (MCL 460.6w). Act 341 became effective on April 20, 2017 and directed the creation of a state reliability mechanism (SRM) and capacity charge. UPPCO has calculated the capacity charge consistent with the methodology used in the Commission's Order Approving Settlement Agreement in Case No. U-21555 dated September 26, 2024.

IMPLEMENTATION OF RATES

15. UPPCO proposes to implement its revised rates no later than March 22, 2027, after the Commission issues an order approving UPPCO's request.

TESTIMONY AND EXHIBITS

16. UPPCO is filing herewith written testimony of various witnesses, exhibits and work papers in support of the requested rate increase and related approvals requested herein. The

positions and relief described in the direct testimony and exhibits should be considered as if specifically requested in this Application. UPPCO is also filing a proposed Protective Order to govern the release, use and disclosure of certain testimony, exhibits, and responses in Part III that contain confidential information, or in future response to discovery.

17. UPPCO represents that the proposals contained in this Application, and in the supporting testimonies, exhibits and work papers are just, reasonable and in the public interest.

WHEREFORE, UPPER PENINSULA POWER COMPANY requests that this Commission:

- A. Set an early hearing date on this Application for rate relief;
- B. Find and determine that UPPCO's existing rates and charges for retail electric service are unreasonably low, inadequate, and should be increased;
- C. Authorize UPPCO to adjust its existing retail electric service rates so as to produce a return on common equity of not less than 10.55%;
- D. Authorize UPPCO to amend, revise, adjust and increase its retail electric rates as early as possible in 2027, but no later than March 22, 2027, as set forth in Exhibit A-15, Schedule F5, as requested in this Application and supporting testimony and exhibits
- E. Approve the capacity charge calculated by the Company which is based on the methodology from the Settlement Agreement in Case No. U-21555 and approve the capacity-related costs supported by the Company in this proceeding; and
- F. Grant UPPCO such other and further relief and authorizations as may be lawful and proper.

Respectfully submitted,

UPPER PENINSULA POWER COMPANY

Dated: May 22, 2026

By: _____

One of Its Attorneys
Sherri A. Wellman (P38989)
Paul M. Collins (P69719)
MILLER, CANFIELD, PADDOCK and STONE, PLC
123 W Allegan Street, Suite 200
Lansing, MI 48933
(517) 487-2070

Attorneys for Upper Peninsula Power Company

**STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

**NOTICE OF HEARING
FOR THE ELECTRIC CUSTOMERS OF
UPPER PENINSULA POWER COMPANY
CASE NO. U-22032**

- Upper Peninsula Power Company requests Michigan Public Service Commission's approval for authority to increase its rates for the generation and distribution of electricity and other relief.
- The information below describes how a person may participate in this case.
- You may call or write Upper Peninsula Power Company, 1002 Harbor Hills Dr., Marquette, MI 49855, (800) 562-7680 for a free copy of its application. Any person may review the application at the offices of Upper Peninsula Power Company or on the Commission's website at: michigan.gov/mpscdockets.
- The prehearing conference in this matter will be held:

DATE/TIME: _____, _____, 2026, at _____ a.m.

BEFORE: Administrative Law Judge _____

LOCATION: **Video/Teleconferencing**

PARTICIPATION: Any interested person may participate. Persons needing any assistance to participate should contact the Commission's Executive Secretary at (517) 284-8090, or by email at mpscdockets@michigan.gov in advance of the hearing.

The Michigan Public Service Commission (Commission) will hold a hearing to consider Upper Peninsula Power Company's (UPPCO) May 22, 2026 application for approval to increase its existing rates and charges for retail electric service. UPPCO seeks Commission approval to: 1) determine that UPPCO's existing rates and charges for retail electric service are unreasonably low and should be increased, 2) authorize UPPCO to adjust its existing rates and charges for retail electric service so as to produce a return on common equity of not less than 10.55% and reset its PSCR base; (3) authorize UPPCO to file and make effective, at the earliest possible date, but no later than March 22, 2027, its proposed increases to annual revenue, and approve other modification to the rates, rules, and regulations as proposed by UPPCO; (4) implement the capacity charge calculated by the Company and the capacity-related costs supported by the Company in its application; and (5) grant UPPCO such other and further relief and authorizations as may be lawful and proper.

All documents filed in this case shall be submitted electronically through the Commission's E-Dockets website at: michigan.gov/mpscedockets. Requirements and instructions for filing can be found in the User Manual on the E-Dockets help page. Documents may also be submitted, in Word or PDF format, as an attachment to an email sent to: mpscedockets@michigan.gov. If you require assistance prior to e-filing, contact Commission staff at (517) 284-8090 or by email at: mpscedockets@michigan.gov.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by _____, 2026. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon UPPCO's attorney, Paul M. Collins, Miller, Canfield, Paddock & Stone, P.L.C., 123 W Allegan Street, Suite 200, Lansing, MI 48933.

Any person wishing to participate without intervention under Mich Admin Code, R 792.10413 (Rule 413), or file a public comment, may do so by filing a written statement in this docket. The written statement may be mailed or emailed and should reference Case No. **U-22032**. Statements may be emailed to: mpscedockets@michigan.gov. Statements may be mailed to: Executive Secretary, Michigan Public Service Commission, 7109 West Saginaw Hwy., Lansing, MI 48917. All information submitted to the Commission in this matter becomes public information, thus available on the Michigan Public Service Commission's website, and subject to disclosure. Please do not include information you wish to remain private. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

Requests for adjournment must be made pursuant to Michigan Office of Administrative Hearings and Rules R 792.10422 and R 792.10432. Requests for further information on adjournment should be directed to (517) 284-8130.

A copy of UPPCO's request may be reviewed on the Commission's website at: michigan.gov/mpscedockets and at the office of Upper Peninsula Power Company. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

The Utility Consumer Representation Fund has been created for the purpose of aiding in the representation of residential utility customers in various Commission proceedings. Contact the Chairperson, Utility Consumer Participation Board, Department of Licensing and Regulatory Affairs, P.O. Box 30004, Lansing, Michigan 48909, for more information.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; 1982 PA 304, as amended, MCL 460.6j et seq.; and the Michigan Administrative Hearing System's Administrative Hearing Rules, 2015 AC, R 792.10401 et seq.

_____, 2026

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

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

Case No. U-22032

PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material that any Party discloses to another Party during the course of this proceeding. This Protective Order protects non-public, confidential information and materials so designated by the Disclosing Party as Protected Material, as defined herein. Accordingly, it is ordered:

I. “Protected Material” and Other Definitions

A. “Protected Material” consists of trade secrets or confidential, proprietary, or commercially sensitive information provided in Disclosing Party’s application, exhibits, discovery or audit responses, any witness’ related exhibits and testimony, motions, objections, briefing, responses to an order issued by the presiding hearing officer or the Michigan Public Service Commission (“MPSC” or the “Commission), and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material shall also consist of non-public confidential information and materials including, but not limited to, the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. To the extent permitted, information obtained under license from a third-party licensor, to which the Disclosing Party or witnesses engaged by the Disclosing Party is a licensee, that is subject to any confidentiality or non-

transferability clause. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses receives as a licensee and is authorized by the third- party licensor to disclose consistent with the terms and conditions of this Protective Order.

2. Information that is protected as confidential in another jurisdiction that the Applicant provides utility service, and the source of the other jurisdiction's protective designation is made known to the Receiving Party.

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Party without any obligation to hold it in confidence;
2. Information received from a third party free to disclose the information without restriction;
3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;
4. Information that is required by law or regulation to be disclosed, but only to the extent of the required disclosure; or information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent the order requires.

C. "Applicant" refers to the filing party in this proceeding.

D. "Disclosing Party" means a Party producing Protected Material in this proceeding.

E. "Party" refers to the Applicant, MPSC Staff ("Staff"), Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in this case under the Commission's Rules of Practice and Procedure, Mich Admin Code, R 792.10401 et al.

F. “Receiving Party” means any Party to this proceeding who requests or receives access to Protected Material. A Receiving Party is responsible for assuring that persons, representatives, or agents under its control or supervision comply with this Protective Order.

G. “Reviewing Representative” means a representative of the Receiving Party who is:

1. An attorney who has entered an appearance in this proceeding for a Receiving Party;
2. An attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.G.1;
3. An expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or an employee or other representative of a Receiving Party with significant responsibility in this case.

H. “Nondisclosure Certificate” refers to Attachment 1 to this Protective Order. Except as otherwise provided herein, the Reviewing Party and Reviewing Representatives will be required to sign Nondisclosure Certificates. However, Nondisclosure Certificates will not be required from administrative law judges, members of the Commission and its support staff, Staff (excluding consultants, third-party experts, agents or other similar persons), and Staff counsel, for whom by virtue of their employment are presumed to be bound by the terms of this Protective Order.

II. Access to and Use of Protected Material

A. This Protective Order governs the use of all provided Protected Material. This Protective Order protects: (i) the Protected Material; (ii) any copy or reproduction of the Protected Material made by any person; and (iii) any memorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected

Material in the possession of a Receiving Party and a Reviewing Representative shall be maintained in a secure place. Access to Protected Material shall be limited to the Receiving Party and the Reviewing Representative, after each has executed the Nondisclosure Agreement and provided a copy of the Nondisclosure Agreement to the Disclosing Party, subject to the limited exception in Paragraph I.H.

B. Protected Material must be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party and Reviewing Representative may analyze the Protected Material; make or respond to discovery; present evidence; prepare testimony, argument, briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. A Reviewing Representative shall not release or disclose the content of Protected Material to any other person or use the information for any other purpose.

C. The Disclosing Party may request the Receiving Party withhold certain information from a Reviewing Representative and retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, then the Disclosing Party shall submit the dispute to the presiding hearing officer simultaneously upon objection. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding hearing officer.

D. If a Receiving Party seeks access to Critical Energy Infrastructure Information (“CEII”) as defined in 16 U.S.C § 824o-1(a)(3) and FERC rules, specifically 18 CFR §

388.113(c), the Receiving Party and Reviewing Representative shall also sign the CEII Nondisclosure Certificate (Attachment 2 to this Protective Order) and provide a copy of the executed CEII Nondisclosure Certificates to the Disclosing Party.

E. The obligations under this Protective Order do not expire by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding hearing officer shall have access to all Protected Material that is submitted to the Commission under seal.

F. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

G. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary record for this case.

III. Procedures

A. The Disclosing Party shall identify what portion(s) of any document designated confidential it considers confidential. This can be done through highlights or other clear identifier. The Disclosing Party must mark any information that it considers confidential as “CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-22032.” Software executable files containing Protected Material may not be capable of being marked with the foregoing required protective language. The inability to mark software executable files containing Protected Material with such protective language shall not diminish

the requirements of this Protective Order. It shall be sufficient if the medium used to deliver software executable files containing Protected Material is marked with the required protective language. However, any output from the software executable files containing Protected Material that is generated only as a reproducible document, whether electronic or non-electronic, that is capable of being marked with the required protective language, shall be marked by the party who generated the output with such protective language and subject to the requirements of this Protective Order. If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL – SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-22032." Simultaneously, identical documents and materials, with the Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed;
2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons otherwise subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an

opportunity to take measures to protect the confidentiality of the Protected Material; and

3. Copies of the documents filed with the MPSC which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, shall be marked or identified as, “CONFIDENTIAL - SUBJECT TO PROTECTIVE ORDER IN CASE NO. U-22032” and shall be maintained in a separate portion of the record under seal, segregated in the files of the Commission, and withheld from inspection by any person not bound by the terms of this Order.

C. The Protected Material subject to this Order shall be shielded from disclosure to the extent permitted by law. If any person files a request under the Freedom of Information Act (“FOIA”) with the MPSC or the Michigan Attorney General seeking access to documents subject to this Protective Order, the MPSC’s Executive Secretary, Staff, or the Attorney General shall promptly notify the Disclosing Party, and the Disclosing Party may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. In light of Section 5 of the Freedom of Information Act, MCL 15.235, the notice must be given at least five (5) business days before the MPSC, Staff, and/or the Michigan Attorney General grant the request in full or in part.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge by motion whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. The Receiving Party challenging the protected status of the document must explicitly state its reason for challenging the confidential designation. In response to a motion, the Commission or the presiding hearing officer in this case may revoke a document’s protected status after notice and hearing. If the presiding hearing officer revokes a document’s protected status, then the document loses its protected status after 14 days unless a Party files an application for leave to appeal the ruling and a request for a stay to the Commission pursuant to

R 792.10433. If the application for leave is timely, the document's protected status will continue during the Commission appeal process. Any Party opposing the application for leave to appeal and the stay shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. Continued protected status post order, will be determined by the Commission in its order addressing the application for leave and the request for stay. Nothing in this paragraph shall prohibit the Disclosing Party from seeking a stay on appeal of the Commission's decision regarding the revocation of any document's protected status.

B. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

V. Retention of Documents

Protected Material remains the property of the Disclosing Party and, except as required by applicable law and State retention schedules, only remains available to the Receiving Party until the time expires for petitions for rehearing of a final MPSC order, until the MPSC has ruled on all petitions for rehearing in this case (if any), or until judicial review is completed and the time to take further appeal has expired. If the Disclosing Party seeks to have the Receiving Party return all Protected Material in the Receiving Party's possession or in the possession of its Reviewing Representatives, or certify in writing that all Protected Material has been destroyed, it is the responsibility of the Disclosing Party to contact the Receiving Party and make its request no earlier than the expiration of time for filing petitions for rehearing of a final MPSC order, until the MPSC has ruled on all petitions for rehearing in this case (if any), or until judicial review is completed and the time to take further appeal has expired. Further, for a Receiving Party that is associated with the State, the request must be consistent with the expiration of the State retention requirement.

Notwithstanding the foregoing, counsel for the Receiving Party may maintain a single confidential file of Protected Material subject to all other provisions in this Order. Should counsel seek to refer to the Protected Material in another Commission proceeding, the Disclosing Party must be the Applicant in said proceeding and counsel must ensure there is a protective order in said proceeding which protects the Protected Material from public disclosure.

VI. Limitations and Disclosures

This Protective Order does not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.1 through I.B.4. A Receiving Party intending to disclose information taken directly from materials identified as Protected Material must-before actually disclosing the information-do one of the following: (i) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or (ii) challenge the confidential nature of the Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record.

VII. Remedies

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes promptly notifying all Parties and the presiding hearing officer in writing. The written notice must identify the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

VIII. Modification

Formal Addendums to this agreement may be established by an ALJ upon motion by any party and after notice and hearing.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Administrative Law Judge

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-22032

Attachment 1

NONDISCLOSURE CERTIFICATE

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issue in Case No. U-22032, that I have read the Protective Order, and that I agree to be bound by the terms of the Protective Order.

Reviewing Representative:

Date: _____

Receiving Party:

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-22032

Attachment 2

NONDISCLOSURE CERTIFICATE

FOR CRITICAL ELECTRIC INFRASTRUCTURE INFORMATION

I hereby agree and certify my understanding that access to Critical Electric Infrastructure Information (“CEII”) as defined at 16 USC Section 824o-1(a)(3) and 18 CFR Section 388.113(c) is provided to me pursuant to the terms and restriction of this CEII Nondisclosure Certificate and the Protective Order issued in Case No. U-22032, that I have been given a copy of and have read the Protective Order, and I agree to be bound by the terms of this CEII Nondisclosure Certificate and the Protective Order. I further agree that:

1. I will use CEII only for the purpose for which it was requested;
2. I will only discuss CEII with a Party and/or Reviewing Representative;
3. I will keep CEII in a secure place in a manner that prevents unauthorized access;
4. I will destroy CEII or return it to the disclosing party upon request;

5. I understand that CEII is not subject to release under the Freedom of Information Act;

6. I understand that I am obligated to protect CEII even after a designation as CEII has lapsed until a determination by the administrative law judge that the information should no longer be designated as CEII; and

7. I will report all unauthorized disclosures of CEII to the Disclosing Party.

Reviewing Representative:

Date: _____

Title: _____

Receiving Party: _____

Printed Name: _____

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-22032

DIRECT TESTIMONY AND EXHIBITS OF

ERIC W. STOCKING

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

May 22, 2026

1 **QUALIFICATIONS**

2 **Q. Please state your name and business address for the record.**

3 A. My name is Eric W. Stocking. My business address is 1002 Harbor Hills Drive, Marquette,
4 Michigan 49855.

5 **Q. By whom are you employed and in what capacity?**

6 A. I am employed by Upper Peninsula Power Company (“UPPCO” or the “Company”), as the
7 Director of Regulatory Affairs & Power Supply.

8 **Q. Briefly describe your educational background and applicable professional
9 experience.**

10 A. I graduated from Michigan State University in 2009 with a Bachelor of Science in
11 Economics. In February 2010, I entered into employment with the Michigan Public
12 Service Commission (“MPSC” or the “Commission”) Staff as an economic analyst in the
13 Generation and Certificate of Need section with responsibilities related to generation
14 resource adequacy, load forecasting, integrated resource planning, capacity expansion
15 modeling, and utility capital investment related to compliance with Federal and State air
16 quality regulations. In the fall of 2016, I accepted the role of Economic Specialist in the
17 Resource Adequacy and Retail Choice section of the MPSC Staff, where I played an active
18 role in the implementation of several aspects of PA 341 and 342 of 2016, including the
19 provisions related to the State Reliability Mechanism and Integrated Resource Planning.
20 In November of 2017, I left my employment with the MPSC Staff and began working at
21 UPPCO as a Rate Analyst within the Regulatory Affairs department, and provided
22 testimony in UPPCO’s 2018 rate case, 2019 Integrated Resource Plan (“IRP”) proceeding,
23 among others. In November 2019, I assumed the role of Manager of Rates and Power

1 Supply with the Company. In this role, my primary responsibilities included power supply
2 and resource planning, managing regulatory affairs efforts, and leading cost of service and
3 rate design issues. In April 2023, I assumed my current role with the Company, where I
4 am responsible for leading all regulatory affairs, power supply, energy waste reduction,
5 and beneficial electrification efforts for UPPCO.

6 **Q. Have you previously testified before the Commission?**

7 A. Yes. I have provided testimony in several cases before the Commission. Recent notable
8 examples include the following proceedings on behalf of UPPCO: Case No. U-21286
9 (General Rate Case), Case No. U-20350 (Integrated Resource Plan) (“IRP”), Case No. U-
10 21513 (Depreciation Rates), Case No. U-21555 (General Rate Case), Case No. U-21809
11 (Integrated Resource Plan), as well as PSCR plan and reconciliation cases, most recently,
12 Case Nos. U-20810 and U-20811.

13
14 **PURPOSE OF TESTIMONY**

15 **Q. What is the purpose of your testimony in this proceeding?**

16 A. Initially, I will provide a general case overview and introduce the Company witnesses
17 that will be providing direct testimony in this proceeding. Following this overview, I will
18 provide supporting testimony in the following areas:

- 19 1. General Case Overview
- 20 2. Forecast Methodology
- 21 3. Projected Test Year Revenue Deficiency
- 22 4. Projected Test Year Cost of Service Study (“COSS”)
- 23 5. Projected Test Year Operations & Maintenance Costs
- 24 6. Storm Restoration Expense Tracker

1 7. Integrated Resource Plan (“IRP”) Deferrals

2 **Q. Are you sponsoring any exhibits, which were prepared by you or under your**
3 **direction?**

4 A. Yes, I am sponsoring the following exhibits in conjunction with my direct testimony.

- 5 • Exhibit A-1, Schedule A1 (EWS-1): Projected Revenue Deficiency
- 6 • Exhibit A-16, Schedule F1 (EWS-2): Projected Cost of Service Allocation Study
- 7 • Exhibit A-51 (EWS-3): Construction Policy: Extension Allowance Calculation
- 8 • Exhibit A-54 (EWS-4): Customer Charges by Voltage Class
- 9 • Exhibit A-55 (EWS-5): System Peaks – FERC Tests

10 **Q. Please identify other witnesses presenting direct testimony in support of the**
11 **Company’s filing and the topic that each witness will be addressing.**

12 A. The following witnesses will be providing direct testimony on behalf of UPPCO in this
13 proceeding:

- 14 • **Natasha L. Wonch** presents testimony in support of the Company’s proposed
15 revenue requirement calculations, including revenue, operating expenses, taxes, the
16 calculation of rate base, and projected bad debt expense.
- 17 • **Nicholas E. Kates** presents testimony in support of the Company’s proposed capital
18 structure, forecast adjustments, and pension and OPEB related expenses.
- 19 • **John S. Thompson, Ph.D.** presents testimony in support of the Company’s requested
20 Return on Equity (“ROE”) and common equity ratio.
- 21 • **Morgan B. Impola** presents testimony in support of the Company’s proposed capital
22 expenditures (“CAPEX”) for Distribution, including strategic underground
23 conversion of overhead conductors, distribution reliability metrics, the Company’s
24 vegetation management program, and proposed edits to the Company’s distribution
25 construction policy.

- 1 • **Daniel J. Gervae** presents testimony in support of the Company’s proposed CAPEX
2 for substation projects.
- 3 • **Virgil E. Schlorke** presents testimony in support of the Company’s proposed CAPEX
4 for power generation projects.
- 5 • **Gregory S. Gagnon** presents testimony in support of the Company’s proposed
6 CAPEX for information technology projects.
- 7 • **Beth A. Blewett** presents testimony in support of the Company’s employee benefits
8 and other human resources related matters.
- 9 • **Nicole E. Bell** presents testimony in support of the projected test year sales forecast,
10 proposed rate design, residential income assistance (“RIA”) tariff offering, State
11 Reliability Mechanism (“SRM”) capacity charge, and proposed tariffs.

12

13 **GENERAL CASE OVERVIEW**

14 **Q. What is UPPCO’s historical test year in this proceeding?**

15 A. UPPCO has used a historical test year ending December 31, 2025.

16 **Q. What is UPPCO’s projected test year in this proceeding?**

17 A. UPPCO has used a projected test year ending December 31, 2027.

18 **Q. How does the Company present the historical and projected test year revenue
19 deficiencies?**

20 A. The Company presents the historical and projected revenue deficiency calculations in
21 compliance with the Commission’s Standard Filing Requirements that were approved on
22 April 25, 2025 in Case No. U-18238.

23 **Q. Please provide a brief description of UPPCO and its service territory.**

24 A. UPPCO is the largest utility in Michigan’s Upper Peninsula, serving approximately
25 53,000 customers across 10 of the 15 counties. UPPCO was founded in 1947 through a
26 merger of several smaller entities, serving a predominantly rural service territory that

1 spans over 4,460 square miles. The Company owns 7 hydroelectric facilities and one
2 gas-fired turbine generator, with a total nameplate capacity of approximately 57 MW.

3 **Q. Please briefly describe the most recent UPPCO Commission-approved general rate**
4 **relief.**

5 A. On September 26, 2024, the Commission issued an order approving a settlement
6 agreement in Case No. U-21555 that resulted in a \$9.0 million annual increase in electric
7 revenues, among other items. The net revenue increase from the settlement agreement
8 was 8.57% overall and 5.93% for the residential customer class, with rates taking effect
9 on January 1, 2025.

10 **Q. In general terms, why has the Company initiated this rate proceeding?**

11 A. The primary drivers of this rate proceeding are UPPCO's continued infrastructure
12 investments and associated operating expenses and operation and maintenance ("O&M")
13 expenses needed to maintain reliable service and improve the reliability and resiliency of
14 UPPCO's distribution system. Also, general inflation and supply chain pressures
15 continue to impact the United States economy, putting upward pressure on the
16 Company's operational expenses. The Company is seeking rate relief in this proceeding
17 such that it can continue to effectively manage deployment of both capital and operations
18 resources that are required to ensure the Company's ability to continue to provide
19 exceptionally safe, reliable, and efficient delivery of electric services to our customers.
20 As discussed above, as UPPCO continues to invest in infrastructure necessary to improve
21 the reliability and resilience of its systems, as well as adapt itself to the increased pricing
22 levels observed throughout the U.S. economy over the last several years. The testimony
23 and exhibits presented in this case demonstrate that UPPCO's existing rates will not be

1 sufficient to cover the Company's cost of providing service during the projected test year,
2 including a reasonable return. Approval of the rates proposed in this case is reasonable
3 and necessary to allow UPPCO to timely recover costs and earn a reasonable return,
4 while meeting the Company's customers' needs for reliable service.

5 **Q. Please summarize the impact of key drivers on the revenue requirement presented**
6 **in this case.**

7 A. The Company requests jurisdictional rate relief in the amount of \$17.3 million, which is
8 summarized as shown in Table 1, below:

Table 1 (in millions)

Key Drivers: Revenue Requirements		
	Drivers	Revenue Requirement Impact
a.	Investment	\$ 3.2
b.	Cost of Capital	\$ 0.1
c.	Operating Expenses (excl. O&M)	\$ 5.1
d.	O&M Expenses	\$ 9.0
e.	Sales / Revenue	\$ (0.1)
f.	Total Revenue Requirement Impact	\$ 17.3

9
10 **Q. Please provide a summary of the key drivers as depicted in Table 1.**

11 A. Table 1 provides a financial bridge from the actual result of UPPCO's most recent electric
12 rate increase outcome, Case No. U-21555, to the Company's requested jurisdictional rate
13 relief in the instant proceeding, based on a projected test year ending December 31, 2027.
14 reflecting the individual impacts of investment, cost of capital, operating and O&M
15 expenses, and sales and revenue.

16 Based upon the evidentiary support provided in this application, UPPCO requests that the
17 Commission authorize the Company to adjust its retail electric generation and
18 distribution rates to result in a total revenue increase of \$17.3 million annually.

19

1 **FORECAST METHODOLOGY**

2 **Q. Please describe the general approach utilized by the Company in supporting its**
3 **projected test year positions and recommendations in this case.**

4 A. UPPCO utilized actual historical data as the point of departure for most estimated costs
5 for the projected test period. These historical costs were then adjusted for the impact of
6 inflation. Certain other costs reflect specific estimates or projections where general
7 impacts of inflation alone would not be adequate to represent a true projection of cost.
8 Costs not adjusted solely by the assumed inflation factor are addressed specifically in the
9 testimony of Company witness Kates, and evidenced in Confidential **Exhibit A-48 (NEK-**
10 **12).**

11 **Q. Please describe the major components of UPPCO’s forecast that informed the**
12 **projected test year ending December 31, 2027.**

13 A. The major components are as follows:

14 1. Sales and demand forecast. Based on historical data, UPPCO utilized a combination
15 of econometric forecasting and historical trends to derive its sales and demand
16 forecasts by specific rate categories (i.e., residential, commercial, industrial, lighting,
17 etc.). Company witness Bell provides direct testimony supporting UPPCO’s sales
18 and demand forecasts for the projected test year. A summary of historical and
19 forecasted sales volumes is included in Exhibit A-5 (NEB-1) Schedule E1, and
20 Exhibit A-15 (NEB-2) Schedule E1.

21 2. Power supply cost. For purposes of establishing jurisdictional revenue requirements,
22 UPPCO is proposing to modify its existing power supply cost mechanism (“PSCR”)
23 base cost. Company witness Bell provides support for the calculation of PSCR base
24 in her direct testimony, as well as Exhibit A-42 (NEB-11). To ensure that PSCR costs

1 do not affect the jurisdictional revenue increase requested in this case, the Company
2 has made an adjustment to present revenue equal to the difference between the current
3 and proposed PSCR base factors. Fuel and purchased power costs are represented at
4 Schedule C4 of Exhibit A-13 (NLW-28).

5 3. Operating revenue forecast. Based upon the sales and demand forecasts previously
6 discussed, UPPCO applies its currently approved retail and wholesale rates to derive
7 its present revenue forecast. UPPCO's projected test year operating revenues are
8 evidenced at line 2 of Schedule C1 of Exhibit A-13 (NLW-25), derived by the
9 multiplication of present rates to the projected test year billing determinants.

10 4. Operating expenditures forecast. First, operating expenditure forecasts, excluding
11 power supply costs, are derived through a combination of cost center budgets as well
12 as historical expenditures and trends. The primary cost centers that comprise
13 UPPCO's O&M forecasts are production, distribution, customer accounts, customer
14 service, and administrative and general expenses. For these costs, UPPCO used the
15 2025 historical test year actual costs as the basis for the projected test year. Then,
16 UPPCO escalated these 2025 actual values by an inflation factor to derive the
17 projected test year values, and subsequently made certain forecast adjustments to the
18 projected test year based upon other budgetary and/or known and measurable
19 information. A summary of these forecast adjustments is identified as Confidential
20 **Exhibit A-48 (NEK-12), forecast adjustment summary.** A summary of projected
21 operating expenses is detailed by Schedule C1 of Exhibit A-13, (NLW-25).

22 5. Capital expenditures forecast. The capital expenditures forecast is developed by the
23 Company's finance department, along with UPPCO's engineering and planning

1 departments, and reflects expenditures and in-service dates of major projects during
2 the year, as well as the amounts approved to fund routine and recurring capital project
3 work. Supporting testimony for the projected test year CAPEX forecast for
4 distribution, substation, power generation, fleet, facilities, information technology,
5 and AMI is provided by Company witnesses Impola, Gervae, Schlorke, Gagnon, and
6 Kates. Specifically, a summary of total CAPEX for the projected test year are
7 evidenced by Schedule B5 of Exhibit A-12 (NLW-24).

8 6. Capital Structure. In determining the Company's capital structure, UPPCO
9 establishes how it plans to fund its overall operations and growth. Consideration is
10 given to interest coverage and other regulatory restrictions, timing of capital
11 requirements, availability of equity capital, and corporate objectives such as credit
12 metrics, planned large capital projects, and short-term debt limitations. Support for
13 the Company's proposed capital structure through the end of the projected test year is
14 provided in the testimony of Company witness Kates, and a summary of the proposed
15 capital structure is included as Schedule D1 of Exhibit A-14 (NEK-7).

16
17 **PROJECTED TEST YEAR REVENUE DEFICIENCY**

18 **Q. Please explain the revenue deficiency depicted on Schedule A1 of Exhibit A-11**
19 **(EWS-1).**

20 A. Schedule A1 of Exhibit A-11 (EWS-1) calculates UPPCO's projected test year revenue
21 deficiency for the projected test period ending December 31, 2027, based upon its
22 projected rate base, adjusted net operating income, and overall rate of return. Once the
23 net income deficiency has been established, a revenue conversion factor is applied to

1 gross up this value for taxes, ultimately presenting this value as a revenue deficiency.

2 The revenue deficiency is then added to forecasted present revenue to establish total
3 revenue requirement, allowing the Company to achieve its required rate of return.

4 Line 24 of Exhibit A-11, Schedule A1, reflects UPPCO's total revenue deficiency of
5 \$18.801 million annually, and UPPCO's retail revenue deficiency of \$17.257 million
6 annually for the projected test year. These revenue deficiencies represent a percentage
7 increase of 13.5% and 12.4% compared to present total revenue, respectively.

9 **PROJECTED TEST YEAR COST OF SERVICE STUDY**

10 **Q. What is the purpose of your direct testimony relating to the Cost of Service study?**

11 A. The purpose of my direct testimony on this topic is to discuss and support the class Cost
12 of Service Study ("COSS") that is being utilized to design rates for the projected test
13 year.

14 Company Witness Bell's direct testimony related to rate design relies on the results of the
15 COSS for the projected test year to develop UPPCO's proposed changes to rate design for
16 the purposes of this proceeding, as well as the calculation of the SRM capacity charge
17 and its associated impacts to the proposed rates.

18 **Q. What exhibit and schedules support UPPCO's COSS study?**

19 A. As demonstrated in Schedule F1 of Exhibit A-16 (EWS-2), UPPCO presents its projected
20 test year COSS with the following sub-schedules:

- 21 1. Sch SUM – Summary of Operating Income & Rate Base (present and proposed)
- 22 2. Sch PLT – Electric Plant in Service
- 23 3. Sch D&A – Reserve for Depreciation and Amortization
- 24 4. Sch RBO – Additions & Deduction to Rate Base

- 1 5. Sch REV – Operating Revenues
- 2 6. Sch O&M – Operation & Maintenance Expense
- 3 7. Sch DAX – Depreciation & Amortization Expense
- 4 8. Sch OTX – Taxes Other Than Income Taxes
- 5 9. Sch ITX – Development of Income Taxes
- 6 10. Sch S&W – Development of Salaries & Wages Allocation Factor
- 7 11. Sch AF – Allocation Factors
- 8 12. Sch AP – Allocation Proportions
- 9 13. Sch ADA – Allocated Direct Assignments
- 10 14. Sch RRW – Total Revenue Requirements (Workpaper)

11

12 These schedules constitute the fundamentals of the COSS that is prepared for the retail
13 electric jurisdiction, along with the associated allocation methodologies, supplemental
14 analyses, and data.

15 **Q. What is the purpose of a class cost of service study?**

16 A. A class cost of service study is conducted in order to determine the revenue requirement
17 for each class of customers, and consequently design rates to recover the amounts
18 prescribed by the COSS. This task is accomplished by assigning, or allocating, the
19 detailed components of UPPCO’s revenue requirement to individual classes using
20 allocation factors that reflect the nature of the particular cost component being allocated.
21 In allocating the detailed total company cost components to classes, UPPCO’s total cost
22 of service is distributed among the various customer classes in such a manner that the
23 sum of the class revenue requirements equals the company's total revenue requirement.

1 This type of COSS is generally referred to as a "fully distributed" cost of service study,
2 since all company costs that make up the revenue requirement are allocated to classes.

3 **Q. Please generally describe the guiding principles relied upon by UPPCO in**
4 **performing the projected test year COSS.**

5 A. In general, a sound COSS approach should provide an outcome whereby the rates that a
6 certain customer group pays should be designed to recover the costs that those same
7 certain customers caused the utility to incur. Cost causation is the central principle which
8 is pertinent to all cost of service studies for allocating costs across customer classes.

9 **Q. Why are costs allocated to customer classes?**

10 A. Costs are allocated to customer classes in order to provide customer class revenue
11 guidelines for rate design purposes. In addition, the cost study results provide
12 information regarding the level of classified component costs per unit (i.e., demand cost
13 per kW or kWh, energy costs per kWh, and customer costs per customer per month)
14 which may be useful in the design of rates. The use of cost of service studies as a guide
15 to rate design is a standard practice among utilities.

16 **Q. Please generally describe the steps involved in conducting a class cost of service**
17 **study.**

18 A. There are three primary steps involved in performing a class cost of service study: (1)
19 functionalization, (2) classification, and (3) allocation. Functionalization identifies the
20 operational source where the costs are incurred, either directly or indirectly, with respect
21 to the physical process of providing service. For example, the costs of generating units
22 and purchased power (production function) are identified separately from costs associated

1 with transmission lines (transmission function) which are, in turn, segregated from the
2 costs of the distribution system (distribution function).

3 The second step in conducting a cost of service study, classification, refers to the
4 separation of costs according to the usage characteristic that drives the cost – i.e.,
5 demand, energy, and customer-related costs. Demand costs are costs that arise as a result
6 of the rate of power consumption over a short period of time (usually 15 minutes to an
7 hour). Energy costs are those costs that result from the volume of energy supplied over
8 time. Customer costs are costs that vary as a function of the number of customers.

9 The third and final step in conducting a cost of service study is allocation. Allocation is
10 the process of using customer class metrics, along with the knowledge that certain costs
11 are incurred exclusively for the benefit of specific identifiable customers (direct
12 assignments), to allocate the specific cost components that have been functionalized and
13 classified to individual customer classes. Customer class information such as non-
14 coincident peak demands, coincident peak demands, annual energy use, and customer
15 counts are utilized to inform rate class allocation factors.

16 **Q. Please describe how the Company’s projected test year COSS performs the process**
17 **of cost functionalization.**

18 A. After all the individual cost components representing the total revenue requirement have
19 been identified, the components are then separated according to the function or physical
20 service they provide. The FERC Uniform System of Accounts (“USOA”) definitions are
21 used as a guide to assign these items to their various functions. These functions are:

- 22 1. Production – costs associated with the production of energy and capacity, including
23 purchased power;

- 1 2. Transmission – costs associated with the high voltage system that transports the
2 power to load sinks;
- 3 3. Distribution – costs associated with distributing the energy from the transmission
4 system to the retail customers;
- 5 4. Customer Service – costs associated with providing service to the customer –i.e.,
6 service drops, metering, billing, the customer-related portion of transformers and
7 conductors, and similar costs; and
- 8 5. Administrative and General – common costs, such as management, buildings,
9 software, support services, and similar indirect costs that are incurred to support the
10 other functions of electric service.

11 **Q. Please describe how the Company’s projected test year COSS performs the process**
12 **of cost classification.**

13 A. Cost classification is the process of further categorizing the functionalized costs,
14 established in step one, according to the cost driving characteristic of the type of utility
15 service that is provided. The three primary cost classifications are demand-related costs,
16 energy-related costs, and customer-related costs.

17 Demand-related costs are those fixed costs that are related to the kilowatt ("kW") demand
18 that the customers place on the system at any point in time. These costs vary with the
19 maximum demand imposed on the various facilities of the power system by customers.

20 Energy-related costs are costs that are related to the kilowatt-hours ("kWh") of energy
21 that the customer utilizes over time. These costs, such as fuel and purchased energy
22 expenses, vary with the overall quantity of energy provided to retail customers.

23 Customer-related costs are those costs incurred as a result of the number of customers on

1 the system. These costs, such as meters, billing, and distribution service laterals, are
2 incurred for the sole purpose of serving individual customers.

3 **Q. Following functionalization and classification of the various components that make
4 up total cost of service, what is the next step in the process of calculating class costs
5 of service?**

6 A. After functionalization and classification, class responsibility for each cost is determined
7 using the allocation factors referred to above. Each identifiable element of the total
8 UPPCO revenue requirement is allocated to each customer class on the basis of the
9 demands imposed by the class (using either coincident peak ("CP") demands or non-
10 coincident peak ("NCP") demands), energy use by class at the generation source (i.e.,
11 after accounting for line and transformation losses), or number of customers served
12 (weighted by the appropriate weighting factor to recognize differences in types of
13 customers and their impacts upon the system). These allocations are then summarized
14 within the cost of service model to derive costs of service for each customer class.

15 **Q. Please describe the layout and operation of the projected test year COSS model you
16 are sponsoring in this proceeding.**

17 A. The class cost of service model I am sponsoring as Schedule F1 of Exhibit A-16,
18 Projected Test Year COSS, is organized as a cost matrix. Each row of the model
19 identifies a particular detailed component of the total cost incurred by UPPCO, needed to
20 provide service to its customers during the projected test period. The columns of the
21 study consist of the allocations of cost to each customer class. The development of the
22 cost of serving each customer class begins with the allocation of rate base, revenues, and

1 continues with the allocation of operating expenses, taxes, and the calculation of labor
2 and other allocators.

3 **Q. Please describe the output and sub-schedules of Schedule F1 of Exhibit A-16 (EWS-**
4 **2).**

5 A. The sub-Schedules are identified on the left-most column of the COSS output. Line 43 at
6 Pages 1 through 4 of sub-Schedule SUM in the class cost of service study summarize the
7 allocated components of revenue requirement and present the rates of return by customer
8 class at present rates. As indicated by this summary, the present rates charged to certain
9 customer classes produce a rate of return for that class that is below the system average
10 rate of return, while the present rates charged to other customer classes produce a higher
11 than system average rate of return. The rates of return at present rates are also shown as
12 ratios of the class return to the system return, which are referred to in the COSS as the
13 "Index Rate of Return". An Index Rate of Return of 1.00 means that the class return is
14 the same as the system return. An Index Rate of Return of less than 1.00 means that the
15 class return is less than the system return. Conversely, an Index Rate of Return of greater
16 than 1.00 means that the class return is greater than the system return.

17 Pages 5 through 8 of sub-Schedule SUM of the class cost of service study summarize the
18 allocated components of revenue requirement and present the rates of return by customer
19 class at UPPCO's required rate of return of 6.71%. The results summarized on this page
20 set forth the revenue requirements by customer class that are required for each class to
21 pay its respective costs of service.

22 Pages 9 through 20 of the class cost of service study summarize the allocation of rate
23 base to classes. The allocations of gross plant in service are provided on pages 9 through

1 20 as represented in sub-Schedule PLT. The allocations of reserve for depreciation are
2 provided on pages 21 through 24 as represented in sub-Schedule D&A. Additions and
3 deductions to rate base are provided on pages 25 through 28 along with the summary of
4 rate base by class of service as represented in sub-Schedule RBO at line 32.

5 As represented in sub-Schedule REV, allocated class Operating Revenues are provided on
6 pages 29 through 32. The allocation of operation and maintenance expense by account is
7 set forth on pages 33 through 52 as represented in sub-Schedule O&M. Pages 53 through
8 56 provide the detailed allocation of depreciation expense by account to customer classes
9 as represented in sub-Schedule DAX. Taxes Other than Income Taxes are allocated to
10 classes on pages 57 through 60 as represented in sub-Schedule OTX. The components of
11 Income Taxes and the calculation of Income Taxes by customer class are provided on
12 pages 61 through 76 as represented in sub-Schedule ITX. Of note, Income Taxes are not
13 directly allocated to customer classes, but rather the components used to calculate income
14 taxes are allocated to classes instead. These allocated income tax components are then
15 used to calculate the Income Tax liability independently for each class based upon the
16 class's allocated tax components.

17 The remaining pages of the class cost of service study provide the information used to
18 develop the allocation factors employed in the cost study. Pages 77 through 88 detail the
19 development of the salaries and wages allocation factors used in the cost of service study
20 as represented in sub-Schedule S&W. Pages 89 through 148 provide the detailed
21 information used to develop the other allocation factors employed in the class cost of
22 service study. These allocation factors consist of both externally and internally developed
23 allocation factors. Externally developed allocation ratios reflect customer class metrics

1 such as coincident peak and non-coincident peak demands at various voltage levels,
2 energy sales and as measured at both the generation level and at the meter (i.e., with and
3 without line and transformation losses), and number of customers by voltage level.

4 Externally developed allocation factors are developed outside of the cost of service model
5 and then input into it. In contrast, internally developed allocation factors are calculated
6 within the cost of service model using previously allocated cost components to derive
7 factors that reflect the combined impacts of multiple cost drivers. Finally, pages 145
8 through 148 provide a summary of total revenue requirements at present and claimed rate
9 of return.

10 **Q. Is the COSS the Company has presented in this filing transparent and verifiable?**

11 A. Yes. The class cost of service study submitted as Schedule F1 of Exhibit A-16 (EWS-2)
12 provides complete detail as to each allocation made on an account-by-account basis. In
13 addition, cross-references to supporting schedules are provided on all summary pages.

14 Every calculation made in the model can be readily verified by the Staff and any
15 intervening parties. Further, the COSS presented in this case is of the same form as that
16 which has presented in the Company's previous three general rate case proceedings.

17 Although the cost of service model UPPCO has employed in this filing is subject to
18 protective restrictions because its internal computations are confidential trade secrets,
19 UPPCO will provide a working model of its licensed cost of service study to the Staff and
20 intervenors upon execution of the necessary confidentiality agreements.

21 **Q. Do all tabs within the Company's COS include traditional Microsoft Excel**
22 **formulas?**

1 A. No. The COS model “COST OF SERVICE” tab, is the only tab that utilizes traditional
2 Microsoft Excel formulas to functionalize, classify, and allocate costs. The
3 “FUNCTIONS” and “UNBUNDLED” tabs contain summaries from the 20 cost
4 component files generated from the COS model. To generate these files, the COS model
5 menu item options “Add-Ins COS, Functions/Components, Create
6 Functions/Components Schedules” need to be selected. This will create 20 cost
7 component files and also update the FUNCTIONS and the UNBUNDLED sheets in the
8 COS model with the numbers found in these cost component files. Once generated, the
9 numbers found in these 20 cost components can be compared to the numbers found in the
10 FUNCTIONS and UNBUNDLED sheets of the COS Model. The “FUNCTIONS” tab of
11 the COS model summarizes the numbers found in the INTEGRATED RETAIL SYSTEM
12 column (Excel column E) for each of the 20 cost component files. These numbers will
13 appear as values since they are copied in as values from these cost component files. The
14 “UNBUNDLED” tab of the COS model copies the " Sch RRW -Total Revenue
15 Requirements (Workpaper)" page for each of the 20 cost components. These numbers
16 will appear as values since they are copied in as values from the 20 component files.
17 These 20 cost components are then summarized by rate class and cost component at
18 Present and Equalized rates of returns at the bottom of this tab.

19 **Q. What are the major sources of the cost data analyzed in UPPCO’s COSS?**

20 A. All cost of service data has been extracted from UPPCO’s projected test year revenue
21 requirements exhibits along with any associated workpapers. Where more detailed
22 information was required to perform various supplementary analyses related to certain

1 plant and expense elements, the data was either taken directly from UPPCO's various
2 software systems or derived from the historical books and records of UPPCO.

3 **Q. Please describe how you defined the customer classes in UPPCO's projected test**
4 **year COSS.**

5 A. The customer classes that were allocated costs in the projected test year COSS follow the
6 rate schedules under which UPPCO currently provides retail service in Michigan.

7 The customer classes shown in the UPPCO COSS consist of the following:

- 8 1. A-1: Residential Service in the Integrated System;
- 9 2. A-2: Residential Service in the Iron River District (CLOSED);
- 10 3. AH-1: Residential Heating Service;
- 11 4. C-1: General Service in the Integrated System;
- 12 5. H-1: Commercial Heating Service;
- 13 6. P-1: Light and Power Service;
- 14 7. CP-U: Large Commercial and Industrial Service;
- 15 8. RTMP: Real-Time Market Pricing;
- 16 9. WP-3: Light and Power Service, (served at transmission or sub-transmission
17 voltages) with a billing demand greater than 5,000 kW and a minimum of 500 kW of
18 on-site generation;
- 19 10. SL-3: Street Lighting for customer owned street lighting and/or traffic signal
20 systems;
- 21 11. SL-5: Street Lighting for municipality-owned street lighting systems;
- 22 12. SL-6: Street Lighting for UPPCO-owned street lighting systems;
- 23 13. Z-3: Dusk to Dawn Outdoor Security Lighting in the Integrated System; and

1 14. Z-4: Dusk to Dawn Outdoor Security Lighting in the Iron River District (CLOSED).

2 **Q. Are the customer classes defined in the same manner in UPPCO's projected test**
3 **year COSS as they were in UPPCO's previous general rate case proceeding,**
4 **approved by the Commission in its September 26, 2024 order in Case No. U-21555?**

5 A. Yes. The Company is not proposing to consolidate or otherwise change the structure of
6 its rate schedules in this proceeding.

7 **Q. Does the COSS allocate costs to the rate classes as defined in present rates?**

8 A. The COSS submitted for the projected test year in this proceeding is based upon rates that
9 are currently in effect, or present rates. All values in the COSS are allocated to each rate
10 class utilizing the allocator's defined name found in the column titled "Allocation Basis".

11 **Q. Regarding the classification of FERC account 364 through 368, does the projected**
12 **test year COSS classify these accounts in the same manner compared to the COSS**
13 **approved in UPPCO's last rate case, Case No. U-21555?**

14 A. Yes, it does.

15 **Q. Please describe UPPCO's approach in the development of its COSS.**

16 A. As stated earlier when describing the general procedures for preparing a COSS, UPPCO's
17 COSS attempts to associate costs with customer classes based on cost causation
18 principles. In some instances, there can be a direct association of costs to customers
19 based on causation. For example, some plant costs such as investment in meters and
20 services can be directly associated with the number of customers. In other cases,
21 causation can be based on a direct relationship between costs and some parameter that
22 can be related to customers. An example of this is fuel cost, which has a direct
23 relationship to customers' energy usage; therefore, fuel costs are allocated to customers

1 based on energy usage. Other costs may have relationships to customer parameters that
2 are not direct but are significantly influenced by those parameters. Distribution system
3 costs fall into this category.

4 **Q. How does UPPCO allocate the costs of Power Supply Resources to the rate classes?**

5 A. In this filing, the allocation of power supply resources employs the use of a 12CP 75% &
6 Energy 25% method in accordance with the MPSC's order in Case No. U-4771. The
7 Demand classified production allocation factor is weighted on the basis of 75% of the 12
8 months of coincident peak ("12-CP") Demand of firm system load, and 25% Energy. The
9 use of a 75% demand, 25% energy ratio allocation of power supply costs is the same
10 method that was proposed by UPPCO and approved, by virtue of the development of
11 rates included in the settlement agreement approved by the Commission in Case U-
12 21555.

13 In determining the cost causal factors associated with generation resources, it is useful to
14 recognize that an electric utility's power supply resources are generally composed of a
15 mix of peaking and base load generation. In such a power supply mix, a portion of an
16 electric utility's power supply resources often reflect the use of high capital costs
17 generation investment coupled with low fuel costs (i.e., base load generation) to meet a
18 level of continuous base load throughout most hours of the year. In instances in which an
19 electric utility employs capital intensive generation with the expectation of operating at a
20 fairly high continuous rate of use through all hours of the year, a trade-off between high
21 capital costs and low fuel costs tends to be the most economically efficient manner to
22 meet annual system load requirements. In contrast, peaks of short duration may be met
23 most efficiently by the use of peaking units which typically have lower capital costs than

1 base load generation, but higher fuel costs. Thus, a mix of peaking and base load
2 generation is employed to meet the total load of a utility throughout the year.
3 There are a number of allocation methods that analyze the operating and dispatch
4 characteristics of individual supply resources, and that separately allocate these
5 individual supply resources on the basis of when the resources are utilized and what the
6 customer class loads are at specific times. These allocation methods require extensive
7 operating data as well as extensive class load data by hour. In addition, these allocation
8 methods are often the subject of intense debate since a number of underlying assumptions
9 may be disputed by various parties. The 12CP 75% & Energy 25% method considers
10 peak demand impacts (which affects the total capacity requirements of the power supply
11 system) as well as average demand (i.e., energy) impacts (which affects the extent to
12 which the utility is willing to invest in higher capital cost base load generation).
13 Therefore, the 12CP 75% & Energy 25% allocation method recognizes those factors that
14 give rise to the power supply demand costs being allocated.

15 **Q. Please describe paragraph 8(g) of the settlement agreement in Case No. U-21555,**
16 **approved by the Commission’s September 26, 2024 order in the same case.**

17 A. This paragraph requires that UPPCO, in its next rate case filing, will include Federal
18 Energy Regulatory Commission (“FERC”) tests using the most recent 12-months of
19 system peaks available at the time of the filing and the projected system peaks for the test
20 year examining whether a 12CP or 4CP demand component of the production capacity
21 cost allocator would more appropriately align UPPCO’s cost with their causation.

1 **Q. Has the Company provided such an analysis in this proceeding, thereby satisfying**
2 **the requirements imposed by paragraph 8(g) of the settlement agreement approved**
3 **in Case No. U-21555?**

4 A. Yes. Exhibit A-55 (EWS-5) includes the results of the three FERC tests, applied to actual
5 coincident peak for the period of January through December 2025. Exhibit A-55 (EWS-
6 5) does not include a similar analysis for the projected test period of January through
7 December 2027, because UPPCO does not forecast its system peak demands on an hourly
8 basis, which is required in order to perform a forward-looking view of this analysis, nor
9 does UPPCO know the specific date and time of the Midcontinent Independent System
10 Operator (“MISO”) coincident peaks, which are also required in order to present the
11 correct UPPCO system coincident peak information.

12 **Q. Please describe each of the three FERC tests presented in Exhibit A-55 (EWS-5).**

13 A. The FERC has adopted three different tests to assess whether a 12 CP demand allocation
14 is appropriate. The FERC tests were set forth in FERC Opinion No. 501 issued on April
15 21, 2008. The three tests all involve mathematical comparisons using monthly coincident
16 peak load data. Utilities have come to apply these tests before FERC and in other
17 jurisdictions to assess whether demand costs should be allocated using 12 CP or using
18 factors based on a more seasonal calculation.

19 **Q. Please describe the FERC tests.**

20 A. The first test is the On and Off Peak test. In this test, FERC compares the average of the
21 system peaks during the defined peak period, as a percentage of the annual peak, to the
22 average of the system peaks during the defined off-peak periods, as a percentage of the

1 annual peak. Generally, FERC has held that a nineteen percentage point or less
2 difference between these two figures supports using a 12 CP allocation factor.

3 The second test is the Low-to-Annual Peak test. This test computes the lowest
4 monthly peak as a percentage of the annual peak. FERC considers a range of sixty-six
5 percent or higher as indicative of a 12 CP system.

6 The third test is the Average to Annual Peak test, whereby the average of the
7 twelve monthly peaks is computed as a percentage of the annual peak. Generally, FERC
8 considers a range of eighty-one percent or higher to be indicative of a 12 CP system.

9 **Q. What do the results of the FERC tests included in Exhibit A-55 (EWS-5) indicate?**

10 A. The test results do not suggest, in any definitive sense, whether a 12 CP or a 4 CP is more
11 appropriate for the system coincident peaks observed by UPPCO during this timeframe.
12 The test results either fall-short or exceed the threshold values, as defined by FERC,
13 depending upon which subset of customers or which CP scenario is observed.

14 **Q. As a result of this analysis, is the Company proposing any change to the allocation
15 method of production demand costs for the purpose of this proceeding?**

16 A. No. Due to the inconclusive results of these tests, as well as the fact that FERC itself
17 recognizes that the full range of a company's operating realities should be considered
18 alongside its peak demands when determining the appropriate allocation method, the
19 Company proposes to maintain its existing allocation method, consistent with the
20 derivation of rates that were included all recently approved rate case settlement
21 agreements.

22 **Q. How does UPPCO allocate transmission costs to customers?**

1 A. In the case of transmission costs, UPPCO employs the use of a 12CP allocation method.
2 Transmission plant must be built to meet the maximum demands placed upon it. The
3 maximum loadings that occur on UPPCO's transmission system each month are the most
4 appropriate metric to employ in allocating transmission costs, as they are analogous to
5 how UPPCO is billed for network transmission service on a monthly basis by American
6 Transmission Company (“ATC”).

7 It is important to note that, unlike generation resources, decisions to build transmission
8 plant do not entail tradeoffs between capital costs and energy costs. The same type and
9 size transmission line would be built to meet a given maximum load regardless of
10 whether the line is expected to be lightly loaded or heavily loaded at other times. Thus,
11 an allocation method such as 12CP 75% & Energy 25% method, which has an average
12 demand (i.e., energy) component, is not appropriate for allocating transmission costs. To
13 reflect the costs incurred and to allocate accordingly, the 12CP allocator is used at the rate
14 class level.

15 **Q. How does UPPCO allocate distribution costs to customers?**

16 A. In the case of distribution costs, UPPCO relies upon two significant cost causation
17 principles. Some distribution costs are incurred in order for customers to simply be
18 connected to the distribution system. Other distribution costs are incurred due to the
19 level of demand of customers.

20 **Q. How does UPPCO allocate electric production costs and investment to each rate
21 schedule?**

22 A. UPPCO first classifies production costs and investment within the appropriate categories
23 of Energy or Demand. The Energy classified production costs are allocated based on the

1 kWh energy usage by rate schedule. In accordance with the MPSC's order in Case No.
2 U-4771, UPPCO has allocated the Demand classified production costs and investment
3 using the Demand – Production allocator, which is weighted on the basis of 75% of the
4 12-CP Demand of firm system load, and 25% Energy.

5 **Q. How does UPPCO allocate transmission costs to each rate schedule?**

6 A. UPPCO classifies transmission costs and investment to Demand, and then transmission
7 costs and investment are allocated to the rate schedules using the Transmission allocator,
8 which is based upon the 12-CP demands of total system load (i.e., both firm and
9 interruptible).

10 **Q. Are Transmission O&M expenses allocated in the same manner as other**
11 **Transmission costs and plant investment?**

12 A. Transmission O&M expense is allocated similarly in the sense that the Transmission
13 O&M allocator is based upon the 12-CP demands of total system load (i.e., both firm and
14 interruptible).

15 **Q. How does UPPCO allocate customer costs to each rate schedule?**

16 A. In general, customer costs are allocated based on total annual customer counts by rate
17 schedule.

18 **Q. Please describe Exhibit A-54 (EWS-4).**

19 A. Exhibit A-54 (EWS-4) is provided to satisfy the requirement included in paragraph 8(d)
20 of the settlement agreement approved by the Commission in its September 26, 2024 order
21 in Case No. U-21555. This exhibit replicates a calculation made by the MPSC Staff in
22 Case No. U-21286, which was represented as a calculation of what UPPCO's fixed
23 customer charges, for the residential and commercial-secondary customer classes, in

1 accordance with the Commission's guidance from its opinion and order in Case No. U-
2 4331, dated January 18, 1974. By provided Exhibit A-54 (EWS-4), the Company does
3 not agree that this calculation is an accurate representation of the nature of costs that
4 should be included in the derivation of fixed customer charges.

5 **Q. Is the Company proposing to modify any of the fixed customer charges in this**
6 **proceeding?**

7 A. No. As described in the direct testimony of Company witness Bell, the Company's
8 proposal includes maintaining its existing fixed customer charges for each rate class.

9 **Q. Please describe Exhibit A-51 (EWS-3).**

10 A. This Exhibit accompanies the testimony of Company witness Impola, regarding line
11 extension construction policy, and the supports the calculation of the extension
12 allowances that UPPCO is proposing to include in the policy. These values calculate the
13 average net rate base amount for FERC accounts 364, 365, 366, and 367. The calculation
14 of extension allowances for residential, commercial and industrial (energy), and
15 commercial and industrial (demand) is consistent with prior calculations of these values,
16 approved for use in Case U-17895. UPPCO proposes to update the allowance values in
17 each subsequent rate case going forward, utilizing the method presented here.

18 **Q. Please summarize the results of UPPCO's projected test year COSS.**

19 A. The results of the COSS with respect to the revenue deficiency at present rates by rate
20 schedule and based upon the requested revenue requirement for UPPCO's retail
21 jurisdiction are summarized in sub-Schedule RRW of Schedule F1 of Exhibit A-11
22 (EWS-3).

1 **Q. In your opinion, does the COSS for the projected test year provide a reasonable**
2 **basis for establishing rates in this case?**

3 A. Yes, it does. The COSS for the projected test year is a reasonable estimate of revenue
4 requirements by rate schedule, given the total revenue requirement, and supports the rates
5 requested in this case, as explained further in the direct testimony of Company Witness
6 Bell.

7

8 **PROJECTED TEST YEAR OPERATIONS & MAINTENANCE COSTS**

9 **Q. Please describe the current level of O&M expenses experienced by the Company.**

10 A. As described by Exhibit A-3 (NLW-11), Schedule C5, during calendar year 2025 the
11 Company incurred O&M expenses totaling \$41.802 million, with \$40.915 million of the
12 total being attributable to providing service to the Company's jurisdictional retail
13 customers. Exhibit A-3 (NLW-11), Schedule C5 also provides a summary of total actual
14 O&M expenses by business line, including production, distribution, transmission,
15 customer accounts, customer service, sales, and administrative & general ("A&G").

16 **Q. Please describe the level of O&M expenses anticipated to be incurred by the**
17 **Company during the projected test period.**

18 A. As described by Exhibit A-13 (NLW-29), Schedule C5, during the projected test period
19 ending December 31, 2027, the Company expects to incur O&M expenses totaling
20 \$48.396 million, with \$47.668 million of the total being attributable to providing service
21 to the Company's jurisdictional retail customers. Similar to the prior discussion, Exhibit
22 A-13 (NLW-29), Schedule C5 provides a summary of total actual O&M expenses by
23 business line.

1 **Q. Explain how the projected O&M expenses included in Exhibit A-13 (NLW-29),**
2 **Schedule C5, were derived.**

3 A. Consistent with the discussion provided in the Forecast Methodology section of my direct
4 testimony, UPPCO utilized actual historical data (in this case, 2025) as the point of
5 departure for most estimated costs for the projected test period. These historical costs
6 were not adjusted for the impact of inflation during the bridge period, and the resulting
7 bridge period expenses were specifically escalated to projected test year expectations.
8 Certain other cost items reflect specific estimates or projections where general impacts of
9 inflation alone would not be adequate to represent a true projection of cost.

10 **Q. What is your opinion regarding the actual and projected O&M expenses shown in**
11 **Exhibit A-3 (NLW-11), Schedule C5, and Exhibit A-13 (NLW-29), Schedule C5,**
12 **respectively.**

13 A. The actual expenses for calendar year 2025 were incurred in a reasonable and prudent
14 manner, and the projected expenses for calendar year 2027 were derived based upon 2026
15 budget with zero inflation of O&M expense, but for known and measurable adjustments.
16 To derive the 2027 O&M projection for presentment in the instant case, a similar approach
17 was taken, whereby known and measurable changes to the 2026 budget were applied, as
18 well as expense category specific inflationary adjustments, as more fully described in the
19 direct testimony of Company witness Kates.

20

21 **STORM RESTORATION EXPENSE TRACKER**

22 **Q. Please describe the Company's proposal relating to a storm restoration expense**
23 **tracking mechanism.**

1 A. UPPCO is proposing a two-way deferral mechanism relating to actual storm restoration
2 expenses incurred within a given year. Under this proposal, any expense above or below
3 the amount included in the formation of rates would be recorded as a regulatory asset or
4 liability and collected or returned in a future rate case proceeding.

5 **Q. Does UPPCO propose any interest be applied to any deferred expenses that are**
6 **above or below the amount included in the formation of rates?**

7 A. No.

8 **Q. Please provide an overview of the actual level of storm restoration expenses incurred**
9 **by UPPCO over the last five years.**

10 A. Storm restoration expenses over the previous five years are as follows:

11 2021: \$444,607

12 2022: \$1,858,235

13 2023: \$1,395,803

14 2024: \$1,312,062

15 2025: \$2,252,073

16 **Q. What level of storm restoration expense is UPPCO proposing in the projected test**
17 **period in this proceeding?**

18 A. UPPCO is utilizing the five-year average, which equals \$1,452,556 per year.

19 **Q. Please describe the Company's perspective relating to the drivers of storm**
20 **restoration expense volatility.**

21 A. UPPCO believes that the observed weather events observed within the UPPCO service
22 territory, as well as across the state of Michigan, have become more frequent and severe in
23 recent years. Ice storms have crippled large portions of northern Michigan, as well as

1 increased incidence of elevated rates of precipitation and high winds. For a rural utility
2 such as UPPCO, whose system traverses a vast, largely wooded service territory, the level
3 of storm restoration expense experienced in a year is strongly correlated with the
4 frequency and severity of weather events experienced. Because weather is outside of the
5 utility’s control, UPPCO is simply seeking the opportunity to recover its expenses in a
6 timely manner, while simultaneously mitigating financial risk to the customer through an
7 average level of storm restoration expense included in rates with a tracker mechanism to
8 ensure that the Company collects only those storm tracker expenses that are actually
9 incurred.

11 **IRP DEFERRAL ACCOUNTS**

12 **Q. Please describe the various IRP related deferrals that the Commission has authorized**
13 **UPPCO to implement.**

14 A. The Commission has authorized UPPCO to defer IRP related costs in two separate
15 proceedings, namely UPPCO’s 2019 IRP in Case No. U-20350¹ (“U-20350 Deferral”),
16 and its 2024 IRP in Case No. U-21809² (“U-21809 Deferral”), stating most recently that:

17 *“UPPCO will be allowed to defer for consideration in a future rate case all*
18 *justifiable costs necessary for filing and processing of this IRP case, recorded*
19 *in UPPCO’s FERC Account 183, pursuant to Section 6t of 2016 PA 341, MCL*
20 *460.6t, and all other applicable laws.”*

¹ Settlement Agreement paragraph 19(i), as approved by Commission order on February 6, 2020 in Case No. U-20350.

² Settlement Agreement paragraph 14(f), as approved by Commission order on October 9, 2025 in Case No. U-21809.

1 **Q. Please describe the types of costs included in UPPCO's U-20350 Deferral.**

2 A. The costs included in UPPCO's U-20350 Deferral are primarily outside services.
3 Preparation of an IRP, inclusive of the requirements related to modeling scenarios,
4 stakeholder engagement, competitive solicitation, as well as the incremental legal fees
5 necessary to properly process an IRP case is a burdensome endeavor for a small utility
6 such as UPPCO. These IRP related requirements, as dictated by Michigan statute and
7 MPSC rulings, require the Company to engage additional outside services to perform
8 work that UPPCO does not possess the internal staff to produce. For instance, the U-
9 20350 Deferral includes the cost of outside services responsible for the following
10 components of the preparation of Case No. U-20350:

- 11 1. Legal (Michigan)
- 12 2. Legal (FERC)
- 13 3. Land Services (related to generation project siting)
- 14 4. IRP Modeling
- 15 5. Independent Bid Administrator (competitive solicitation)
- 16 6. Stakeholder Forum accommodations (Venue, materials).

17 **Q. Please describe the total deferred expense included in the U-20350 Deferral.**

18 A. The total amount of deferred expense included in the U-20350 deferral that UPPCO is
19 seeking approval to amortize and recover through rates totals \$1.225M.

20 **Q. Does the amount of U-20350 Deferral that UPPCO is seeking to amortize and recover**
21 **in this proceeding include costs attributable to the natural gas reciprocating internal**
22 **combustion engine ("RICE") generation asset that UPPCO had proposed in Case No.**
23 **U-20350, and subsequently withdrew?**

1 A. No. UPPCO is not seeking recovery of costs related to its RICE generation asset proposal
2 in U-20350. Costs relating to land acquisition and engineering design of the RICE
3 proposal are not included in UPPCO's presentation of the U-20350 Deferral in this case.

4 **Q. Over what time period does UPPCO propose to amortize the U-20350 Deferral, for**
5 **inclusion in rates.**

6 A. Ten years, beginning at the date that rates in the instant case take effect.

7 **Q. Please describe the costs included in UPPCO's U-21809 Deferral.**

8 A. The costs included in UPPCO's U-21809 Deferral fall generally into the same categories
9 as the U-20350 Deferral, specifically outside services (IRP modeling consultant,
10 competitive solicitation independent bid administration, legal), Venue and material costs
11 related to required stakeholder engagement forums, and regulatory (public notice).

12 **Q. Please describe the total deferred expense included in UPPCO's U-21809 Deferral.**

13 A. The total amount of deferred expense included in the U-21809 deferral that UPPCO is
14 seeking approval to amortize and recover through rates total \$0.828M.

15 **Q. Is UPPCO proposing to amortize the U-21809 Deferral over the same ten year period**
16 **that it is proposing to recover the U-20350 Deferral?**

17 A. Yes. UPPCO proposes to amortize both of its previously approved IRP deferrals over a
18 ten-year period, beginning on the date that rates in the instant case take effect.

19 **Q. What is the annual cost impact of UPPCO's proposal to recover both IRP deferrals**
20 **over a ten-year amortization period?**

21 A. Total IRP deferral totals \$2,053,418. Amortization of this amount over a ten-year period
22 equates to \$205,341 per year.

23 **Q. Why is UPPCO seeking recovery of its IRP deferrals at this time?**

1 A. Relating to the U-20350 Deferral, UPPCO had originally envisioned timing the recovery
2 of its deferred expenses with the construction and/or operation of the renewable projects
3 that were approved by the order approving the case. As evidenced in several areas within
4 the docket in Case No. U-20350³, and reiterated in Case No. U-21809, the projects
5 initially identified were subsequently unable to satisfy local permitting requirements, and
6 therefore the contracts for these facilities were terminated by their own terms. Paragraph
7 19(c) of the approved settlement agreement in UPPCO's IRP (Case No. U-20350) states
8 that in the event the 125 MW Solar is cancelled, modified, or reduced due to any reason,
9 the Company shall acquire the intended replacement capacity and associated energy
10 through a competitive bidding process¹ whereby 50% of the 125 MW capacity will be
11 from PPAs and 50% of the 125 MW capacity will be company-owned.

12 UPPCO filed an application for approval of various contracts relating to the
13 construction of its Republic Solar⁴ project, and for approval of a contract for the
14 Groveland Solar⁵ project in Case No. U-20350 in November and June of 2024,
15 respectively. The MPSC issued an order approving these applications in June 2025 and
16 August 2024, respectively.

³ For example, see UPPCO's June 20, 2024 Annual Report in Case No. U-20350. <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000E7wcvAAB>

⁴ <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000Nq4lgAAB>

⁵ <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000E9vOvAAJ>

1 At this time, UPPCO contends that significant progress toward construction of
2 these facilities has begun, and therefore it is appropriate to begin amortizing for recovery
3 the value of these IRP deferral assets.

4 Relating to the U-21809 Deferral, there were no significant incremental
5 generation resource additions prior to 2030 that were specifically named, and as such, no
6 coordination of construction progress and recovery is necessary. As a result of this, and
7 buttressed by the understanding that UPPCO will be filing its next IRP in 2029, UPPCO
8 proposes to begin amortization of these deferred assets, such that they will not accumulate
9 significantly over time.

10
11 **CONCLUSION**

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

13 A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-22032

DIRECT TESTIMONY AND EXHIBITS OF

NATASHA L. WONCH

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

May 22, 2026

1 **QUALIFICATIONS**

2 **Q. Please state your name, business address and position.**

3 A. My name is Natasha L Wonch. My business address is 1002 Harbor Hills Drive,
4 Marquette, MI 49855. I am the Director of Finance and Accounting for Upper Peninsula
5 Power Company (“UPPCO” or the “Company”).

6 **Q. For whom are you providing testimony?**

7 A. I am providing testimony on behalf of UPPCO in support of its request for an increase in
8 its retail electric rates.

9 **Q. Please describe briefly your educational, professional, and utility background.**

10 A. I have a Bachelor of Science in Accounting and Computer Information Systems from
11 Northern Michigan University. I am a Certified Public Accountant licensed in the state of
12 Michigan. I began my career in public accounting in 2008 and joined UPPCO in 2015 as
13 Payroll Administrator. I transitioned throughout the organization before being promoted
14 to Director of Finance and Accounting in 2022.

15 **Q. Have you previously testified in any regulatory proceedings?**

16 A. Yes. I have provided testimony in UPPCO’s State Reliability Mechanism (“SRM”)
17 capacity charge case, Energy Waste Reduction (“EWR”) reconciliation cases, and Cases
18 No. U-20276 and No. U-21555(General Rate Cases).

1

2 **PURPOSE OF TESTIMONY**

3 **Q. What is the purpose of your testimony in this proceeding?**

4 A. The purpose of my testimony is to present UPPCO’s 2025 historical test year revenue
5 requirement ending December 31, 2025 and the calculation of UPPCO’s revenue
6 requirement for the projected 12-month period ending December 31, 2027 (“projected
7 test year”).

8 **Q. How is your direct testimony organized?**

9 A. My direct testimony is organized in sections consistent with the topics I will be covering:

- 10 • Revenue Requirement Exhibits
- 11 • Projected Test Year Financial Metrics
- 12 • Projected Test Year Rate Base
- 13 • Projected Test Year Operating Income
- 14 • 2025 Historical Test Year Revenue Deficiency
- 15 • 2025 Historical Test Year Financial Metrics
- 16 • 2025 Historical Test Year Rate Base
- 17 • 2025 Historical Test Year Operating Income
- 18 • Projected Bad Debt Expense

19

20 **REVENUE REQUIREMENT EXHIBITS**

1 **Q. Are you sponsoring any exhibits in this proceeding?**

2 A. Yes. For the historical 2025 test year, I am sponsoring the following exhibits:

3 1. Exhibit A-1 (NLW-1 through NLW-2), Schedules A1 through A2,

4 2. Exhibit A-2 (NLW-3 through NLW-6), Schedules B1 through B4, and

5 3. Exhibit A-3 (NLW-7 through (NLW-18), Schedules C1 through C12.

6 For the projected test year, I am sponsoring the following exhibits:

7 4. Exhibit A-11 (NLW-19), Schedules A2,

8 5. Exhibit A-12 (NLW-20 through (NLW-24), Schedules B1 through B5, and

9 6. Exhibit A-13 (NLW-25 through (NLW-36), Schedules C1 through C12.

10 7. Exhibit A-44 (NLW-37), Projected Bad Debt Expense

11

12 **Q. Are you sponsoring any other exhibits?**

13 A. No.

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

15 A. Yes, they were.

16 **Q. Please describe Schedule A1 of Exhibit A-1 (NLW-1).**

1 A. Schedule A1 of Exhibit A-1 (NLW-1) calculates UPPCO's 2025 historical test year
2 revenue deficiency based on its 13-month average rate base, adjusted net operating
3 income, rate of return, and revenue conversion factor.

4 **Q. Please describe Schedule A2 of Exhibit A-1 (NLW-2).**

5 A. Schedule A2 of Exhibit A-1 (NLW-2) calculates UPPCO's historical financial metrics on
6 both a financial basis and ratemaking basis from 2021 through 2025.

7 **Q. Please describe Schedule B1 of Exhibit A-2 (NLW-3).**

8 A. Schedule B1 of Exhibit A-2 (NLW-3) calculates UPPCO's 2025 historical test year rate
9 base.

10 **Q. Please describe Schedule B2 of Exhibit A-2 (NLW-4).**

11 A. Schedule B2 of Exhibit A-2 (NLW-4) calculates UPPCO's 2025 historical test year utility
12 plant.

13 **Q. Please describe Schedule B3 of Exhibit A-2 (NLW-5).**

14 A. Schedule B3 of Exhibit A-2 (NLW-5) depicts UPPCO's 2025 historical test year
15 accumulated provision for depreciation.

16 **Q. Please describe Schedule B4 of Exhibit A-2 (NLW-6).**

17 A. Schedule B4 of Exhibit A-2 (NLW-6) calculates UPPCO's 2025 historical test year
18 working capital.

1 **Q. Please describe Schedule C1 of Exhibit A-3 (NLW-7).**

2 A. Page 1 of Schedule C1 of Exhibit A-3 (NLW-7) calculates UPPCO's 2025 historical test
3 year adjusted net operating income. Page 2 of Schedule C1 of Exhibit A-3 (NLW-7)
4 calculates UPPCO's 2025 historical test year interest synchronization.

5 **Q. Please describe Schedule C2 of Exhibit A-3 (NLW-8).**

6 A. Schedule C2 of Exhibit A-3 (NLW-8) calculates UPPCO's 2025 historical test year gross
7 revenue conversion factor.

8 **Q. Please describe Schedule C3 of Exhibit A-3 (NLW-9).**

9 A. Schedule C3 of Exhibit A-3 (NLW-9) calculates UPPCO's 2025 historical test year total
10 revenue.

11 **Q. Please describe Schedule C4 of Exhibit A-3 (NLW-10).**

12 A. Schedule C4 of Exhibit A-3 (NLW-10) calculates UPPCO's 2025 historical test year total
13 fuel and purchased power cost.

14 **Q. Please describe Schedule C5 of Exhibit A-3 (NLW-11).**

15 A. Schedule C5 of Exhibit A-3 (NLW-11) calculates UPPCO's 2025 historical test year total
16 operation and maintenance ("O&M") expense.

17 **Q. Please describe Schedule C6 of Exhibit A-3 (NLW-12).**

1 A. Schedule C6 of Exhibit A-3 (NLW-12) depicts UPPCO's 2025 historical test year total
2 depreciation and amortization expense.

3 **Q. Please describe Schedule C7 of Exhibit A-3 (NLW-13).**

4 A. Schedule C7 of Exhibit A-3 (NLW-13) calculates UPPCO's 2025 historical test year total
5 for taxes other than income taxes.

6 **Q. Please describe Schedule C8 of Exhibit A-3 (NLW-14).**

7 A. Schedule C8 of Exhibit A-3 (NLW-14) depicts UPPCO's 2025 historical test year federal
8 income taxes.

9 **Q. Please describe Schedule C9 of Exhibit A-3 (NLW-15).**

10 A. Schedule C9 of Exhibit A-3 (NLW-15) depicts UPPCO's 2025 historical test year state
11 income taxes.

12 **Q. Please describe Schedule C10 of Exhibit A-3 (NLW-16).**

13 A. Schedule C10 of Exhibit A-3 (NLW-16) depicts UPPCO's 2025 historical test year local
14 taxes.

15 **Q. Please describe Schedule C11 of Exhibit A-3 (NLW-17).**

16 A. Schedule C11 of Exhibit A-3 (NLW-17) depicts UPPCO's 2025 historical test year
17 Allowance for Funds Used During Construction ("AFUDC").

18 **Q. Please describe Schedule C12 of Exhibit A-3 (NLW-18).**

1 A. Schedule C12 of Exhibit A-3 (NLW-18) depicts UPPCO's 2025 historical test year
2 Income Tax Effect of Interest.

3 **Q. Please describe Schedule A2 of Exhibit A-11 (NLW-19).**

4 A. Schedule A2 of Exhibit A-11 (NLW-19) calculates UPPCO's projected test year financial
5 metrics absent rate relief and with full rate relief.

6 **Q. Please describe Schedule B1 of Exhibit A-12 (NLW-20).**

7 A. Schedule B1 of Exhibit A-12 (NLW-20) calculates UPPCO's projected 13-month average
8 test year rate base.

9 **Q. Please describe Schedule B2 of Exhibit A-12 (NLW-21).**

10 A. Schedule B2 of Exhibit A-12 (NLW-21) calculates UPPCO's projected 13-month average
11 test year utility plant.

12 **Q. Please describe Schedule B3 of Exhibit A-12 (NLW-22).**

13 A. Schedule B3 of Exhibit A-12 (NLW-22) depicts UPPCO's projected 13-month average
14 test year accumulated provision for depreciation.

15 **Q. Please describe Schedule B4 of Exhibit A-12 (NLW-23).**

16 A. Schedule B4 of Exhibit A-12 (NLW-23) calculates UPPCO's projected 13-month average
17 test year working capital.

18 **Q. Please describe Schedule B5 of Exhibit A-12 (NLW-24).**

1 A. Schedule B5 of Exhibit A-12 (NLW-24) calculates UPPCO's projected capital
2 expenditures with a projected test period 12 months ending 12/31/2027 with a projected
3 bridge period 12 months ending 12/31/2026.

4 **Q. Please describe Schedule C1 of Exhibit A-13 (NLW-25).**

5 A. Schedule C1 of Exhibit A-13 (NLW-25) calculates UPPCO's projected test year adjusted
6 net operating income and interest synchronization calculation.

7 **Q. Please describe Schedule C2 of Exhibit A-13 (NLW-26).**

8 A. Schedule C2 of Exhibit A-13 (NLW-26) calculates UPPCO's projected test year gross
9 revenue conversion factor.

10 **Q. Please describe Schedule C3 of Exhibit A-13 (NLW-27).**

11 A. Schedule C3 of Exhibit A-13 (NLW-27) calculates UPPCO's projected test year total
12 revenue.

13 **Q. Please describe Schedule C4 of Exhibit A-13 (NLW-28).**

14 A. Schedule C4 of Exhibit A-13 (NLW-28) calculates UPPCO's projected test year total fuel
15 and purchased power cost.

16 **Q. Please describe Schedule C5 of Exhibit A-13 (NLW-29).**

17 A. Schedule C5 of Exhibit A-13 (NLW-29) calculates UPPCO's projected test year total
18 O&M expense.

1 **Q. Please describe Schedule C6 of Exhibit A-13 (NLW-30).**

2 A. Schedule C6 of Exhibit A-13 (NLW-30) depicts UPPCO's projected test year total
3 depreciation and amortization expense.

4 **Q. Please describe Schedule C7 of Exhibit A-13 (NLW-31).**

5 A. Schedule C7 of Exhibit A-13 (NLW-31) calculates UPPCO's projected test year total for
6 taxes other than income taxes.

7 **Q. Please describe Schedule C8 of Exhibit A-13 (NLW-32).**

8 A. Schedule C8 of Exhibit A-13 (NLW-32) depicts UPPCO's projected test year federal
9 income taxes.

10 **Q. Please describe Schedule C9 of Exhibit A-13 (NLW-33).**

11 A. Schedule C9 of Exhibit A-13 (NLW-33) depicts UPPCO's projected test year state
12 income taxes.

13 **Q. Please describe Schedule C10 of Exhibit A-13 (NLW-34).**

14 A. Schedule C10 of Exhibit A-13 (NLW-34) depicts UPPCO's projected test year local
15 taxes.

16 **Q. Please describe Schedule C11 of Exhibit A-13 (NLW-35).**

17 A. Schedule C11 of Exhibit A-13 (NLW-35) depicts UPPCO's projected test year AFUDC.

1 **Q. Please describe Schedule C12 of Exhibit A-13 (NLW-36).**

2 A. Schedule C12 of Exhibit A-13 (NLW-36) depicts UPPCO's projected Income Tax Effect
3 of Interest.

4 **Q. Please describe Exhibit A-44 (NLW-37) Projected Bad Debt Expense**

5 A. Exhibit A-44 (NLW-37) depicts UPPCO's projected test year Bad Debt Expense.

6 **PROJECTED TEST YEAR FINANCIAL METRICS**

7 **Q. Please explain Schedule A2, pages 1 through 3, of Exhibit A-11 (NLW-19).**

8 A. Schedule A2, page 1 of Exhibit A-11 (NLW-19) develops financial metrics on a
9 ratemaking basis for UPPCO's projected test year. Absent rate relief, UPPCO's earned
10 rate of return on common equity would be 2.18% as evidenced on line 14.

11 Schedule A2, page 2 of Exhibit A-11 (NLW-19) develops additional financial metrics on
12 a ratemaking basis for UPPCO's projected test year. The following items metrics are
13 calculated (i) absent rate relief, and (ii) with full rate relief:

14 1. EBIT Interest Coverage Ratio, as evidenced on line 20.

15 a. Absent rate relief: 1.42

16 b. With full rate relief: 3.30

17 2. EBITDA Interest Coverage Ratio, as evidenced on line 25.

18 a. Absent rate relief: 3.29

1 b. With full rate relief: 5.17

2 3. Funds Flow from Operations (FFO) Interest Coverage Ratio, as evidenced on line 35.

3 a. Absent rate relief: 4.32

4 b. With full rate relief: 6.12

5 4. Overall Fixed Charge Coverage Ratio, as evidenced on line 42.

6 a. Absent rate relief: 1.37

7 b. With full rate relief: 2.79

8 Schedule A2, page 3 of Exhibit A-11 (NLW-19) develops additional financial metrics on
9 a ratemaking basis for UPPCO’s projected test year. The following metrics are calculated
10 (a) absent rate relief, and (b) with full rate relief:

11 1. Cash Flow Coverage of Dividend Ratio, as evidenced on line 48.

12 a. Absent rate relief: Not applicable, no common dividends.

13 b. With full rate relief: Not applicable, no common dividends.

14 2. Common Dividend Payout Ratio, as evidenced on line 51.

15 a. Absent rate relief: Not applicable, no common dividends.

16 b. With full rate relief: Not applicable, no common dividends.

17 3. Permanent Capitalization, as evidenced on line 55.

18 a. Absent rate relief: 338,128,889

19 b. With full rate relief: 338,128,889

20

1 **PROJECTED TEST YEAR RATE BASE**

2 **Q. Please explain Schedule B1 of Exhibit A-12 (NLW-20).**

3 A. Schedule B1 of Exhibit A-12 (NLW-20) calculates UPPCO’s projected test year rate base.
4 The projected test year total company rate base is 408,936,523, and the projected test
5 year Michigan retail rate base is 403,564,015, as shown on line 21. As shown on the
6 schedule, the component parts are taken from the various sources indexed to the left of
7 each value. All values shown are 13-month averages.

8 **Q. Please explain Schedule B2 of Exhibit A-12 (NLW-21).**

9 A. Schedule B2 of Exhibit A-12 (NLW-21) depicts UPPCO’s projected test year utility plant.
10 To arrive at the projected test year utility plant, the 2025 actual balance of utility plant
11 was projected forward using UPPCO’s projected 2026 through 2027 construction
12 budgets. The projected test year total company utility plant is 559,930,722, and the
13 projected test year Michigan retail utility plant is 552,481,363, as shown in line 13. All
14 values shown are 13-month averages.

15 **Q. Please explain Schedule B3 of Exhibit A-12 (NLW-22).**

16 A. Schedule B3 of Exhibit A-12 (NLW-22) depicts UPPCO’s projected test year
17 accumulated provision for depreciation. To arrive at the projected test year accumulated
18 provision for depreciation, the 2025 actual balance of accumulated provision for
19 depreciation was projected forward using UPPCO’s 2026 through 2027 construction

1 budgets. The projected test year total company accumulated provision for depreciation is
2 234,957,532, and the projected test year Michigan retail accumulated provision for
3 depreciation is 232,192,704 as shown on line 2. All values shown are 13-month
4 averages.

5 **Q. Please explain Schedule B4 of Exhibit A-12 (NLW-23).**

6 A. Schedule B4 of Exhibit A-12 (NLW-23) calculates UPPCO's projected test year working
7 capital. The projected test year total company working capital is 83,963,333, and the
8 projected test year Michigan retail working capital is 83,275,357 as shown on line 38.
9 All values shown are 13-month averages.

10 **Q. Please explain Schedule B5 of Exhibit A-12 (NLW-24).**

11 A. Schedule B5 of Exhibit A-12 (NLW-24) calculates UPPCO's projected capital
12 expenditures for 2027 with a bridge period of 2026. The supporting calculations are
13 included in Schedules B5.1 through B5.6 and Exhibits A-17 through A-20.

14
15 **PROJECTED TEST YEAR OPERATING INCOME**

16 **Q. Please explain Schedule C1 of Exhibit A-13 (NLW-25).**

17 A. Schedule C1 of Exhibit A-13 (NLW-25) calculates UPPCO's projected test year adjusted
18 net operating income. The projected test year total company adjusted net operating

1 income is 13,302,504 and the projected test year Michigan retail adjusted net operating
2 income is 14,103,969 as shown on Line 21. The interest synchronization calculation is
3 shown on page 2 of Schedule C1 of Exhibit A-13 (NLW-25).

4 **Q. Please explain Schedule C2 of Exhibit A-13 (NLW-26).**

5 A. Schedule C2 of Exhibit A-13 (NLW-26) calculates UPPCO's projected test year gross
6 revenue conversion factor. The projected test year gross revenue conversion factor is
7 1.3288 as shown on line 16.

8 **Q. Please explain Schedule C3 of Exhibit A-13 (NLW-27).**

9 A. Schedule C3 of Exhibit A-13 (NLW-27) calculates UPPCO's projected test year total
10 revenue. The projected test year total company revenues are 139,291,289, and the
11 projected test year Michigan retail total revenue is 139,286,255 as shown on line 6.

12 **Q. Please explain Schedule C4 of Exhibit A-13 (NLW-28).**

13 A. Schedule C4 of Exhibit A-13 (NLW-28) calculates UPPCO's projected test year total fuel
14 and purchased power cost of 48,112,158 as shown on line 6.

15 **Q. Please explain Schedule C5 of Exhibit A-13 (NLW-29).**

16 A. Schedule C5 of Exhibit A-13 (NLW-29) calculates UPPCO's projected test year total
17 O&M expense, exclusive of fuel and purchased power. The projected test year total

1 company O&M expense is 48,396,946 and the projected test year Michigan retail total
2 O&M expense is 47,668,291 as shown on line 11.

3 **Q. Please explain Schedule C6 of Exhibit A-13 (NLW-30).**

4 A. Schedule C6 of Exhibit A-13 (NLW-30) depicts UPPCO's projected test year total
5 depreciation and amortization expense. The projected test year total company total
6 depreciation and amortization expense is 18,637,347, and the projected test year
7 Michigan retail total depreciation and amortization expense is 18,379,877 as shown on
8 line 6. Depreciation on line 3 was calculated based upon projected plant balances and
9 closings for the projected test year, using the depreciation rates approved in Case No. U-
10 21513.

11 **Q. Please explain Schedule C7 of Exhibit A-13 (NLW-31).**

12 A. Schedule C7 of Exhibit A-13 (NLW-31) depicts UPPCO's projected test total for taxes
13 other than income taxes. The projected test year total company total taxes other than
14 income taxes is 10,445,238, and the projected test year Michigan retail total taxes other
15 than income taxes is 10,296,733 as shown on line 29.

16 **Q. Please explain Schedule C8 of Exhibit A-13 (NLW-32).**

17 A. Schedule C8 of Exhibit A-13 (NLW-32) depicts UPPCO's projected test year federal
18 income taxes. The projected test year total company federal income taxes are 868,478,

1 and the projected test year Michigan retail income taxes are 1,114,853 as shown on line
2 14.

3 **Q. Please explain Schedule C9 of Exhibit A-13 (NLW-33).**

4 A. Schedule C9 of Exhibit A-13 (NLW-33) depicts UPPCO's projected test year state
5 income taxes. The projected test year total company state income taxes are 87,236 and
6 the projected test year Michigan retail state income taxes are 165,391 as shown on line
7 14.

8 **Q. Please explain Schedule C10 of Exhibit A-13 (NLW-34).**

9 A. Schedule C10 of Exhibit A-13 (NLW-34) depicts UPPCO's projected test year local
10 taxes. The projected test year total company local taxes are \$0, as shown in the exhibit.

11 **Q. Please explain Schedule C11 of Exhibit A-13 (NLW-35).**

12 A. Schedule C11 of Exhibit A-13 (NLW-35) depicts UPPCO's projected test year AFUDC.
13 The projected test year total company AFUDC Debt is \$494,640 and the projected test
14 year Michigan retail AFUDC Debt is \$489,241 as shown on line 5.

15 **Q. Please explain Schedule C12 of Exhibit A-13 (NLW-36).**

16 A. Schedule C12 of Exhibit A-13 (NLW-36) depicts UPPCO's projected test year Income
17 Tax Effect of Interest. The projected test year total company impact on net operating

1 income is \$39,259 and the projected test year Michigan retail impact on net operating
2 income is \$41,407 as shown on line 11.

3 **2025 HISTORICAL TEST YEAR REVENUE DEFICIENCY (SUFFICIENCY)**

4 **Q. Please explain Schedule A1 of Exhibit A-1 (NLW-1).**

5 A. Schedule A1 of Exhibit A-1 (NLW-1) calculates UPPCO's historical 2025 test year
6 revenue deficiency (sufficiency) based on its rate base, adjusted net operating income,
7 rate of return and revenue conversion factor. This schedule indicates that the 2025 total
8 company revenue deficiency is \$4,544,375, and the 2025 Michigan retail revenue
9 deficiency is \$2,955,941. As shown on the schedule, the component parts are taken from
10 the various sources indexed to the left of each value.

11

12 **2025 HISTORICAL TEST YEAR FINANCIAL METRICS**

13 **Q. Please explain Schedule A2, pages 1 through 4, of Exhibit A-1 (NLW-2).**

14 A. Schedule A2, page 1 of Exhibit A-1 (NLW-2) depicts financial metrics on a financial
15 basis for 2021 through 2025. For this period, UPPCO's earned rate of return on common
16 equity was 9.36%, 3.51%, 5.03%, 4.28%, and 5.93% as seen on line 12.

17 Schedule A2, page 2 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a
18 financial basis for 2021 through 2025, calculating the EBIT Interest Coverage Ratio on

1 line 19, the EBITDA Interest Coverage Ratio on line 24, and the Funds Flow from
2 Operations (FFO) Interest Coverage Ratio on line 35.

3 Schedule A2, page 3 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a
4 financial basis for 2021 through 2025, calculating the Overall Fixed Charge Coverage
5 Ratio on line 42, the Cash Flow Coverage of Dividends Ratio on line 48, the Common
6 Dividend Payout Ratio on line 51, and Permanent Capitalization on line 59.

7 Schedule A2, page 4 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a
8 ratemaking basis for 2021 through 2025. For this period, UPPCO's earned rate of return
9 on common equity was 8.68%, 3.91%, 5.96%, 4.57%, and 8.16% as seen on line 73.

10 Schedule A2, page 5 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a
11 ratemaking basis for 2021 through 2025, calculating the EBIT Interest Coverage Ratio on
12 line 79, the EBITDA Interest Coverage Ratio on line 84, and the Funds Flow from
13 Operations (FFO) Interest Coverage Ratio on line 95.

14 Schedule A2, page 6 of Exhibit A-1 (NLW-2) depicts additional financial metrics on a
15 ratemaking basis for 2021 through 2025, calculating the Cash Flow Coverage of
16 Dividends Ratio on line 108, the Common Dividend Payout Ratio on line 111, and
17 Permanent Capitalization on line 119.

18 **2025 HISTORICAL TEST YEAR RATE BASE**

19 **Q. Please explain Schedule B1 of Exhibit A-2 (NLW-3).**

1 A. Schedule B1 of Exhibit A-2 (NLW-3) calculates UPPCO's 2025 historical test year rate
2 base. The 2025 total company rate base is 378,594,409, and the 2025 Michigan retail rate
3 base is 366,690,921, as shown on line 21. As seen on the schedule, the component parts
4 are taken from the various sources indexed to the left of each value. All values shown are
5 13-month averages.

6 **Q. Please explain Schedule B2 of Exhibit A-2 (NLW-4).**

7 A. Schedule B2 of Exhibit A-2 (NLW-4) depicts UPPCO's 2025 historical test year utility
8 plant. The 2025 total company utility plant is 501,542,009, and the 2025 Michigan retail
9 utility plant is 481,471,853, as shown on line 13. All values shown are 13-month
10 averages.

11 **Q. Please explain Schedule B3 of Exhibit A-2 (NLW-5).**

12 A. Schedule B3 of Exhibit A-2 (NLW-5) depicts UPPCO's 2025 historical test year
13 accumulated provision for depreciation. The 2025 total company accumulated provision
14 for depreciation is 211,457,405, and the 2025 Michigan retail accumulated provision for
15 depreciation is 202,257,221 as shown on line 2. All values shown are 13-month
16 averages.

17 **Q. Please explain Schedule B4 of Exhibit A-2 (NLW-6).**

18 A. Schedule B4 of Exhibit A-2 (NLW-6) calculates UPPCO's 2025 historical test year
19 working capital. The 2025 total company working capital is \$88,509,804, and the 2025

1 Michigan retail working capital is \$87,476,289 as shown on line 38. All values shown
2 are 13-month averages.

3

4 **2025 HISTORICAL TEST YEAR OPERATING INCOME**

5 **Q. Please explain Schedule C1 of Exhibit A-3 (NLW-7).**

6 A. Schedule C1 of Exhibit A-3 (NLW-7) calculates UPPCO's 2025 historical test year
7 adjusted net operating income. The 2025 total company adjusted net operating income is
8 \$21,546,878 and the 2025 Michigan retail adjusted net operating income is \$21,957,280
9 as shown on line 21. The interest synchronization calculation is shown on page 2 of
10 Schedule C1 of Exhibit A-3 (NLW-7).

11 **Q. Please explain Schedule C2 of Exhibit A-3 (NLW-8).**

12 A. Schedule C2 of Exhibit A-3 (NLW-8) calculates UPPCO's 2025 historical test year gross
13 revenue conversion factor. The 2025 gross revenue conversion factor is 1.3288.

14 **Q. Please explain Schedule C3 of Exhibit A-3 (NLW-9).**

15 A. Schedule C3 of Exhibit A-3 (NLW-9) calculates UPPCO's 2025 historical test year total
16 revenue. The 2025 total company revenues are \$136,747,740, and the 2025 Michigan
17 retail total revenue is \$135,888,339 as shown on line 6.

18 **Q. Please explain Schedule C4 of Exhibit A-3 (NLW-10).**

1 A. Schedule C4 of Exhibit A-3 (NLW-10) calculates UPPCO's 2025 historical test year total
2 fuel and purchased power cost of \$45,274,108 as shown on line 6.

3 **Q. Please explain Schedule C5 of Exhibit A-3 (NLW-11).**

4 A. Schedule C5 of Exhibit A-3 (NLW-11) calculates UPPCO's 2025 historical test year total
5 O&M expense, exclusive of fuel and purchased power. The 2025 total company O&M
6 expense is \$41,802,124 and the 2025 Michigan retail total O&M expense is \$40,915,498
7 as shown on line 11.

8 **Q. Please explain Schedule C6 of Exhibit A-3 (NLW-12).**

9 A. Schedule C6 of Exhibit A-3 (NLW-12) depicts UPPCO's 2025 historical test year total
10 depreciation and amortization expense. The 2025 total company total depreciation and
11 amortization expense is \$16,093,647, and the 2025 Michigan retail total depreciation and
12 amortization expense is \$15,768,521 as shown on line 6. Depreciation on line 3 was
13 calculated based upon the depreciation rates approved in Case No. U-21513.

14 **Q. Please explain Schedule C7 of Exhibit A-3 (NLW-13).**

15 A. Schedule C7 of Exhibit A-3 (NLW-13) depicts UPPCO's 2025 historical test year total
16 for taxes other than income taxes. The 2025 total company total taxes other than income
17 taxes is \$9,207,855, and the 2025 Michigan retail total for taxes other than income taxes
18 is \$8,848,851 as shown on line 29.

19 **Q. Please explain Schedule C8 of Exhibit A-3 (NLW-14).**

1 A. Schedule C8 of Exhibit A-3 (NLW-14) depicts UPPCO's 2025 historical test year federal
2 income taxes. The 2025 total company federal income taxes are \$3,451,272, and the
3 2025 Michigan retail income taxes are \$3,626,650 as shown on line 14.

4 **Q. Please explain Schedule C9 of Exhibit A-3 (NLW-15).**

5 A. Schedule C9 of Exhibit A-3 (NLW-15) depicts UPPCO's 2025 historic test year state
6 income taxes. The 2025 total company state income taxes are \$644,505 and the 2025
7 Michigan retail state income taxes are \$720,813 as shown on line 14.

8 **Q. Please explain Schedule C10 of Exhibit A-3 (NLW-16).**

9 A. Schedule C10 of Exhibit A-3 (NLW-16) depicts UPPCO's 2025 historical test year local
10 taxes. The 2025 total company local taxes are \$0, as shown in the exhibit.

11 **Q. Please explain Schedule C11 of Exhibit A-3 (NLW-17).**

12 A. Schedule C11 of Exhibit A-3 (NLW-17) depicts UPPCO's 2025 historic test year
13 AFUDC. The 2025 total company AFUDC is \$1,166,175 as shown on line 5.

14 **Q. Please explain Schedule C12 of Exhibit A-3 (NLW-18).**

15 A. Schedule C12 of Exhibit A-3 (NLW-18) depicts UPPCO's historical test year Income Tax
16 Effect of Interest. The historical test year total company impact on net operating income
17 is \$57,489 and the projected test year Michigan retail impact on net operating income is
18 \$33,061 as shown on line 11.

1

2 **PROJECTED BAD DEBT EXPENSE**

3 **Q. Please explain the Forecasted Bad Debt Expense as evidenced in Exhibit A-44**
4 **(NLW-37) Bad Debt Expense.**

5 A. Bad debt expense is accounted for in FERC 904. To calculate UPPCO's bad debt expense
6 for the projected test year ending December 31, 2027, UPPCO utilized a five-year trend
7 value of actual, historical and projected values. Actual data was utilized from 2021
8 through 2025 and budgeted data for 2026. All values were averaged resulting in an
9 inflation-adjusted value of \$327,726 for 2027.

10

11 **CONCLUSION**

12 **Q. Does this conclude your testimony?**

13 A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-22032

DIRECT TESTIMONY AND EXHIBITS OF

NICHOLAS E. KATES

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

May 22, 2026

1 **QUALIFICATIONS**

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

3 A. My name is Nicholas E. Kates. My business address is 1002 Harbor Hills Drive,
4 Marquette, MI 49855.

5 **Q. By whom are you employed and in what capacity?**

6 A. I am the Chief Financial Officer (“CFO”) for Upper Peninsula Power Company
7 (“UPPCO” or the “Company”).

8 **Q. Please summarize your background.**

9 A. I have a Bachelor of Science in Accounting and a Master of Business Administration
10 from Millikin University. I began my career in public accounting in 1991 and have
11 held various accounting, finance and information technology roles in manufacturing,
12 financial services, and electric utility organizations, culminating with my role as
13 Business Unit Chief Financial Officer of DSM Functional Materials prior to joining
14 UPPCO as Chief Financial Officer in 2015. In March 2020 I left UPPCO, taking the
15 role of CFO of a financial services organization. I subsequently returned to the role of
16 CFO at UPPCO in May of 2023. My primary accountabilities include leading the
17 accounting, finance, tax, corporate reporting, financial planning, information
18 technology, cyber security, and customer service functions for UPPCO.

19 **Q. Have you previously testified in any regulatory proceedings?**

20 A. Yes. I have testified before the Michigan Public Service Commission (“MPSC” or the
21 “Commission”) in Case No. U-20276 and Case No. U-21555.

1 **PURPOSE OF TESTIMONY**

2 **Q. What is the purpose of your direct testimony in this proceeding?**

3 A. I will provide testimony in the following areas: (1) explanation of UPPCO's
4 forecasted adjustments and inputs and (2) recommendations regarding the capital
5 structure and cost of capital utilized in the computation of UPPCO's overall rate of
6 return for the projected test year.

7 **Q. How is your direct testimony organized?**

8 A. My direct testimony is organized in sections consistent with the topics I will be
9 covering, as listed below:

10 Section I: Forecast Adjustments

11 Section II: Capital Structure

12 **Q. Are you sponsoring any exhibits related to your direct testimony?**

13 A. Yes.

14 **Q. Please identify the exhibits you are sponsoring**

15 A. I am sponsoring the following exhibits:

- 16 • Exhibit A-4 (NEK-1), Schedule D1, Historical Rate of Return Summary
- 17 • Exhibit A-4 (NEK-2), Schedule D2, Historical Cost of Long-Term Debt
- 18 • Exhibit A-4 (NEK-3), Schedule D3, Historical Cost of Short-Term Debt
- 19 • Exhibit A-4 (NEK-4), Schedule D4, Historical Cost of Preferred Stock

- 1 • Exhibit A-4 (NEK-5), Schedule D5, Historical Cost of Common Shareholders'
- 2 Equity
- 3 • Exhibit A-12 (NEK-6), Schedule B5.6, Projected Capital Expenditures –
- 4 Corporate Staff
- 5 • Exhibit A-14 (NEK-7), Schedule D1, Projected Rate of Return Summary
- 6 • Exhibit A-14 (NEK-8), Schedule D2, Projected Cost of Long-Term Debt
- 7 • Exhibit A-14 (NEK-9), Schedule D3, Projected Cost of Short-Term Debt
- 8 • Exhibit A-14 (NEK-10), Schedule D4, Projected Cost of Preferred Stock
- 9 • Exhibit A-14 (NEK-11), Schedule D5, Projected Cost of Common
- 10 Shareholders' Equity
- 11 • Confidential Exhibit A-48 (NEK-12), Forecast Adjustments/Inputs Summary
- 12 • Exhibit A-49 (NEK-13), Pension & OPEB Expense
- 13 • Exhibit A-50 (NEK-14), Willis Towers Watson OPEB Report
- 14 • Exhibit A-52 (NEK-15), Willis Towers Watson Pension Report
- 15 • Exhibit A-53 (NEK-16), Revolver Calculation

16 I am also referencing the following exhibits that are sponsored by Company witness
17 Morgan B. Impola and Natasha L. Wonch.

- 18 • Exhibit A-24 (MBI-7)
- 19 • Exhibit A-44 (NLW-37)

1 **SECTION I: PROJECTED TEST YEAR FORECAST ADJUSTMENTS/INPUTS**

2 **Q. Please describe how the Company’s projected test year revenue requirement**
3 **ending December 31, 2027 is developed?**

4 A. As discussed by Company witness Stocking, UPPCO’s methodology utilized a
5 historical 2025 test year. UPPCO then made forecast adjustments and applied specific
6 known and measurable differences to achieve the 2026 cost projections. To achieve
7 the cost projections for the 2027 test year, UPPCO applied specific known and
8 measurable differences where appropriate, cost specific forecast adjustments, and,
9 where other methodologies did not apply, escalated the projected 2026 costs by
10 expense specific inflationary rates or, where expense specific factors did not apply or
11 were not available, utilized a discounted core inflation index to derive the value
12 representing the January 1, 2027, through December 31, 2027 projected test year.
13 UPPCO utilized a discount from the Congressional Budget Office’s (“CBO”) 2027
14 core inflation projection of 0.6%.

15 **Q. How does UPPCO present its forecast adjustments/inputs for the projected test**
16 **year ending December 31, 2027?**

17 A. Please find Confidential Exhibit A-48 (NEK-12), Forecast Adjustments/Inputs
18 Summary.

19 **Q. Please explain Forecast Adjustments 1 and 2, Base Inflation (Core CPI) and**
20 **UPPCO Inflation Factor, in Confidential Exhibit A-48 (NEK-12), Forecast**
21 **Adjustment/Input Summary.**

1 A. Where specific known and measurable cost projections or expense specific inflation
2 projections were not available, UPPCO applied a discounted annual core inflation
3 factor of 0.0% and 2.0% for 2026 and 2027, respectively, to derive its projected test
4 year costs. The source for these projections was the core CPI rates for 2026 and 2027
5 as published in the Congressional Budget Office (“CBO”) report for February 2026¹,
6 titled, *The Budget and Economic Outlook: 2025 to 2035*. This source is reasonable
7 because the CBO provides nonpartisan analysis on budgetary and economic issues for
8 the United States Congress. UPPCO then applied a reasonable discount to these
9 projections to reflect expected lower inflation due to UPPCO specific productivity
10 and efficiency gains.

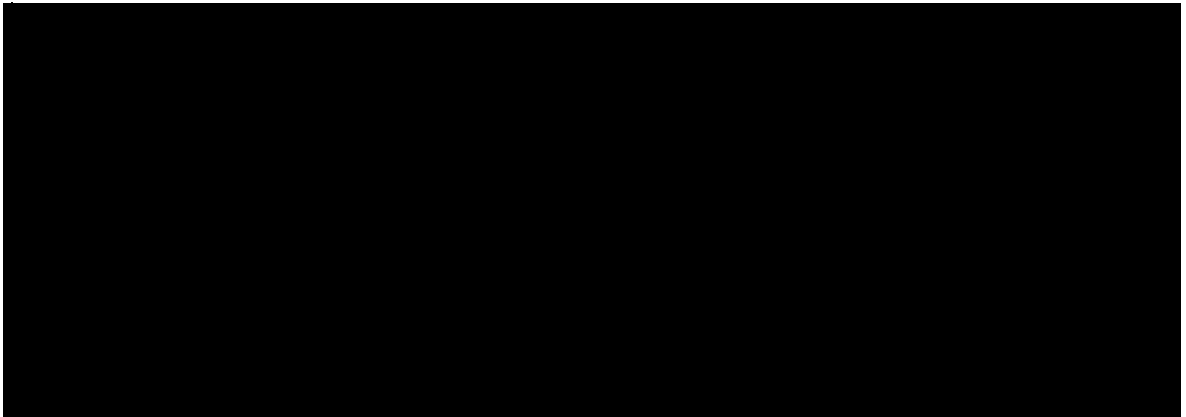
11 **Q. Please explain Forecast Adjustment 3, Salary & Wage (S&W) Adjustment –**
12 **Union, on Confidential Exhibit A-48 (NEK-12), Forecast Adjustment/Input**
13 **Summary.**

14 A. UPPCO applied a wage and salary adjustment of [REDACTED]
15 [REDACTED] for its union workforce. These rates are consistent with the
16 UPPCO Local Union No. 510 Collective Bargaining Agreement (“CBA”) effective
17 April 18, 2026 through April 18, 2031, and below the United States salary and wage

¹ [The Budget and Economic Outlook: 2025 to 2035 | Congressional Budget Office \(cbo.gov\)](https://www.cbo.gov/publications/2025/02/the-budget-and-economic-outlook-2025-to-2035)

1

increases as published by the CBO in their February 2026 report



2

3

Again, this source is reasonable because the CBO provides nonpartisan analysis on

4

budgetary and economic issues for the United States Congress.

5 **Q.**

Please explain Forecast Adjustment 4, Salary & Wage (S&W) Adjustment –

6

Non-Union, on Confidential Exhibit A-48 (NEK-12), Forecast Adjustment/Input

7

Summary.

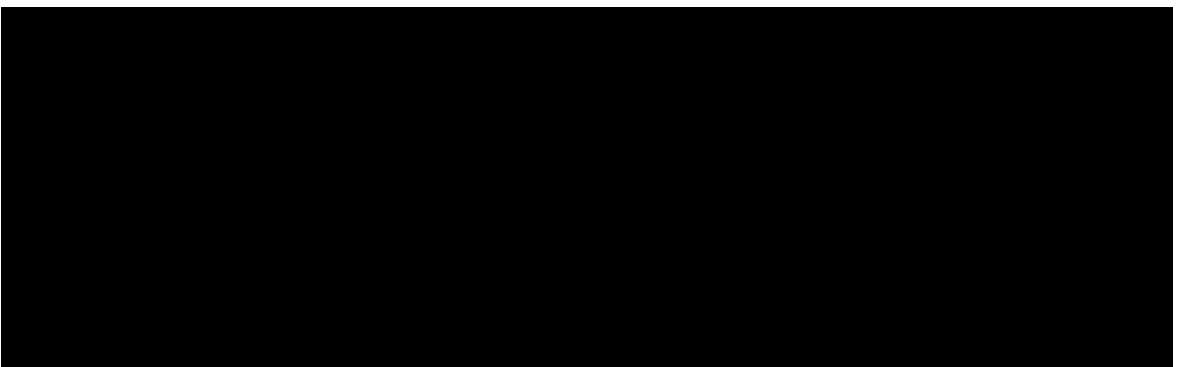
8 **A.**

UPPCO applied a [redacted] wage and salary adjustment for its non-

9

union, administrative employees for the projected test year.

10



11

1 **Q. Please explain Forecast Adjustment 5, Distribution Line Clearance, on**
2 **Confidential Exhibit A-48 (NEK-12), Forecast Adjustment/Input Summary.**

3 A. As supported in the direct testimony and exhibits of Company witness Impola,
4 UPPCO operates on a six-year distribution line clearance program and evidences
5 these expenditures in Exhibit A-24 (MBI-7), 6 Year Distribution Line Clearance
6 Program. Due to the quality control issue as described in witness Impola's testimony,
7 the 2025 line clearance mileage was below targeted levels, resulting in the need to
8 make up those miles in 2026 and 2027. Per witness Impola's testimony, UPPCO's
9 cost are driven by a dramatic increase in tree mortality as well as significant increases
10 in fuel prices. These factors have resulted in a line clearance specific inflation factor
11 utilization of 7.0%.

12 **Q. Please explain Forecast Adjustment 6, Bad Debt Expense, on Confidential**
13 **Exhibit A-48 (NEK-12), Forecast Adjustment/Input Summary.**

14 A. Bad debt expense is accounted for in FERC 904. To calculate UPPCO's bad debt
15 expense for the projected test year ending December 31, 2027, UPPCO utilized a
16 five-year trend value of actual, historical and projected values as evidenced on
17 Exhibit A-44 (NLW-37). Actual data was utilized from 2021 through 2025 and
18 budgeted data for 2026. All values were averaged and the CBO core inflation rate of
19 2.6% was utilized, resulting in an inflation-adjusted value of \$327,726 for 2027.

20 **Q. Please explain Forecast Adjustments 7 to 11 regarding Pension and OPEB**
21 **expenses on Confidential Exhibit A-48 (NEK-12), Forecast Adjustment/Input**
22 **Summary.**

1 A. Pensions are a type of employer-sponsored retirement plan. For the projected test year
2 ending December 31, 2027, pension expenses are evidenced at line 6, Total Pension
3 Expense of Exhibit A-49 (NEK-13), FERC 926 Summary. Other Post-Employment
4 Benefits (“OPEB”) expenses are typically the benefits (i.e., health, life insurance,
5 etc.), other than pension distributions, that employees may begin to receive from
6 their employer once they retire. For the projected test year ending December 31,
7 2027, OPEB expenses are evidenced at line 12, Total OPEB Expenses of Exhibit A-
8 49 (NEK-13), FERC 926 Summary. Both pension and OPEB expenses are recorded
9 in FERC 926. Willis Towers Watson US LLC (“WTW”) was engaged by UPPCO to
10 provide 2026 and 2027 forecasted benefit cost, based on the 2025 pension and
11 postretirement welfare valuations, for rate case purposes. These valuations were
12 performed in accordance with generally accepted actuarial principles and practices.
13 Exhibit A-50 (NEK-14), Willis Towers Watson OPEB Report and Exhibit A-52
14 (NEK-15), Willis Towers Watson Pension Report, provides the 2026 and 2027
15 budget estimates. This information was prepared in accordance with FASB ASC 715-
16 30 and 715-60.

17 **Q. Please describe the increase in Total Pension expense from 2025 to 2027 on line 6**
18 **of Exhibit A-49 (NEK-13), FERC 926 Summary.**

19 A. There are two main drivers for the increase in pension expense from 2025 to 2027.
20 1) Historical asset and other actuarial losses were recognized, which lowered
21 the asset value used in the calculation of pension expense and increased the
22 loss amortization. This increased expense by \$1.1M.

1 2) The change in the amortization period used to recognize deferred
2 (gain)/loss. This increased expense by \$0.9M.

3 **Q. Please describe the major drivers of the increase in UPPCO Retirement Benefits**
4 **as shown on line 3 of Exhibit A-49 (NEK-13), FERC 926 Summary.**

5 A. There are two main drivers for the increase in pension expense from 2025 to 2027.

6 1) Historical asset and other actuarial losses were recognized, which lowered
7 the asset value used in the calculation of pension expense and increased the
8 loss amortization. This increased expense by \$1.1M.

9 2) The amortization period used to recognize deferred (gain)/loss was changed
10 from 25 years to average future lifetime (15.2 year). This increased expense
11 by \$0.9M..

12 **Q. Is the current 25-year amortization period supported by accounting or actuarial**
13 **standards?**

14 A. No, the current amortization period of 25 years is not currently supported by
15 accounting standards. Under US GAAP standards (715-30-35-24) the required
16 maximum amortization period is the average remaining service period for the active
17 employees, but if the plan is all (or almost all) inactive the amortization period can be
18 extended to the average remaining life expectancy of the inactive participants. For the
19 UPPCO Retirement Plan, that average remaining service period is 8.5 and the average
20 life expectancy is 15.2. The plan is 92.5% inactive as of 1/1/2025.

1 The amortization period used in 2027 pension expense has been changed to align with
2 the longer period (average life expectancy) allowed under the US GAAP standards.

3 **Q. Please quantify the impact of the change in amortization period to the cost of the**
4 **UPPCO Retirement Plan.**

5 A. The change in the amortization period used to recognize deferred (gain)/loss increases
6 the 2027 pension expense by \$0.9M.

7 **Q. Please describe what the impact would be if UPPCO were not to change its**
8 **amortization period.**

9 A. Without the change in the amortization period, the unrecognized loss (regulatory
10 asset) remains on the balance sheet and will not be drawn down as the plan winds
11 down and terminates. This will result in a large one-time charge equal to the
12 remaining unrecognized loss (regulatory asset) at the time the plan terminates.

13 By following US GAAP standards, the unrecognized loss (regulatory asset) will be
14 fully recognized through benefit expense as the plan winds down and terminates
15 because the amortization period is aligned with the participants in the plan. This will
16 prevent the large one-time charge at time of plan termination.

17 **Q. Please quantify the impact of the change in discount rate to the UPPCO**
18 **Retirement Plan.**

19 A. For the UPPCO Retirement Plan a change in discount rate would change 2027
20 pension expenses as follows:

21 100 basis point decrease in discount rate increases 2027 benefit expense by \$225,000

1 100 basis point increase in discount rate decreases 2027 benefit expense by \$200,000

2 **Q. What led to the change in the discount rate?**

3 A. The discount rate is set in accordance with ASC 715-30-35-43 and is based on market
4 conditions (high quality corporate bonds) as of the measurement date and the duration
5 of the plan. The discount rate for the 2025 benefit expense is based on market
6 conditions as of December 31, 2024, and the discount rate for the 2027 estimated
7 benefit expense is based on market conditions as of September 30, 2025. During the
8 first 9 months of 2025, corporate bond rates decreased resulting in the discount rate
9 dropping 40 basis points for the UPPCO Retirement Plan.

10 **Q. Please describe the increase in Total OPEB expense from 2025 to 2027 on line 12**
11 **of Exhibit A-49 (NEK-13), FERC 926 Summary.**

12 A. There are two main drivers for the increase in OPEB expense from 2025 to 2027.

13 1) Normal operations which includes a smaller unrecognized gain recognition in 2027
14 due to the amount of unrecognized gains in 2027 AOCI being less than the amount in
15 2025. This increased expense by \$0.4M.

16 2) The expiration of the prior service credit base for the Administrative Medical and
17 Dental Plan and Non-Administrative Medical and Dental Plan. There was a plan
18 change that occurred prior to 2014 which lowered the plans' obligation. This plan
19 change credit was recognized through benefit expense over a fixed period of time.
20 The period ended in 2025. The expiration of the prior service credit increased expense
21 from 2025 to 2027 by \$0.3M.

1 **Q. Please describe the major drivers of the increase in Non-Administrative Medical**
2 **expense portion of the OPEB plan expenses shown in line 10 of Exhibit A-49**
3 **(NEK-13), FERC 926 Summary.**

4 A. There are two main drivers for the increase in OPEB expense from 2025 to 2027.

5 1) Normal operations which includes a smaller unrecognized gain recognition in 2027
6 due to the amount of unrecognized gains in 2027 AOCI being less than the amount in
7 2025. This increased expense by \$0.4M.

8 2) The expiration of the prior service credit base for the Non-Administrative Medical
9 and Dental Plan. There was a plan change that occurred prior to 2014 which lowered
10 the plan's obligation. This plan change credit was recognized through benefit expense
11 over a fixed period of time. The period ended in 2025. The expiration of the prior
12 service credit increased expense from 2025 to 2027 by \$0.2M.

13 **Q. What other factors contributed to the increase in the Non-Administrative**
14 **Medical expense portion of the OPEB plan expenses shown in line 10 (row 21)?**

15 A. There are no additional factors that contributed to the increase in the benefit expense
16 for the Non-Administrative Medical and Dental Plan.

17 **SECTION II: CAPITAL STRUCTURE**

18 **Q. Regarding the historical test year ending December 31, 2025, please explain**
19 **Schedule D1 of Exhibit A-4 (NEK-1).**

20 A. Schedule D1 develops UPPCO's historical test year overall rate of return of 6.59%, as
21 shown at line 22, based on UPPCO's 13-month average capital structure, and a 9.86%

1 ROE. As a percent of permanent capital, the 13-month historical debt and equity
2 balances are 50.08% and 49.92%, respectively, as evidenced at lines 2 and 6.

3 **Q. Regarding the historical test year ending December 31, 2025, please explain**
4 **Schedule D2 of Exhibit A-4 (NEK-2).**

5 A. Schedule D2 develops UPPCO's historical test year cost of long-term debt of
6 4.5598%, based on a 13-month average, as shown at line 24.

7 **Q. Regarding the historical test year ending December 31, 2025, please explain**
8 **Schedule D3 of Exhibit A-4 (NEK-3).**

9 A. Schedule D3 develops UPPCO's historical test year cost of short-term debt of
10 7.6329%, based on a 13-month average, as calculated at line 22.

11 **Q. Regarding the historical test year ending December 31, 2025, please explain**
12 **Schedule D4 of Exhibit A-4 (NEK-4).**

13 A. Schedule D4 indicates that UPPCO has no preferred equity outstanding.

14 **Q. Regarding the historical test year ending December 31, 2025, please explain**
15 **Schedule D5 of Exhibit A-4 (NEK-5).**

16 A. Schedule D5 develops UPPCO's 13-month average balance of Adjusted Common
17 Equity of \$168,534,222 for the historical test year, as shown on line 16 UPPCO
18 demonstrates a 9.86% ROE for the historical test year.

19 **Q. For the projected test year ending December 31, 2027, please explain Schedule**
20 **D1 of Exhibit A-14 (NEK-7).**

1 A. Schedule D1 develops UPPCO’s projected test year overall rate of return of 6.713%,
2 as shown at line 22, based on UPPCO’s 13-month average capital structure, and a
3 proposed 10.55% ROE. As a percent of permanent capital, the 13-month proposed
4 debt and equity balances are 50.01% and 49.99%, respectively, as evidenced at lines
5 2 and 6. These balances are in alignment with the balances ordered in U-21555.

6 **Q. For the projected test year ending December 31, 2027, please explain Schedule**
7 **D2 of Exhibit A-14 (NEK-8).**

8 A. Schedule D2 develops UPPCO’s projected test year cost of long-term debt of
9 4.5327%, based on a 13-month average, as shown at line 23. Long term debt cost is
10 derived from the existing long-term notes in the amount of \$127,100,000 issued June
11 3, 2021, at 3.59% and \$42,000,000 issued November 22, 2024, at 5.02%

12 **Q. For the projected test year ending December 31, 2027, please explain Schedule**
13 **D3 of Exhibit A-14 (NEK-9).**

14 A. Schedule D3 develops UPPCO’s projected test year cost of short-term debt of
15 5.9614%, based on a 13-month average, as calculated at line 22. Please find Exhibit
16 A-53 (NEK-16), Revolver Calculation, whereby UPPCO builds its projection of the
17 3-month Secured Overnight Financing Rate (“SOFR”). As evidenced in Exhibit A-53
18 (NEK-16), UPPCO utilized forecasted data from Canadian Imperial Bank of
19 Commerce (“CIBC”) and added the applicable margin rate of 1.625% to project
20 January 2026 through December 2027 revolver rates.

1 **Q. For the projected test year ending December 31, 2027, please explain Schedule**
2 **D4 of Exhibit A-14 (NEK-10).**

3 A. Schedule D4 indicates that UPPCO has no preferred equity outstanding.

4 **Q. For the projected test year ending December 31, 2027, please explain Schedule**
5 **D5 of Exhibit A-14 (NEK-11).**

6 A. Schedule D5 develops UPPCO's 13-month average balance of Adjusted Common
7 Equity of \$169,028,889 for the projected test year, as shown on line 16. UPPCO
8 requests a 10.55% ROE for the projected test year in this general rate case
9 proceeding, as further supported by Company witness Thompson's direct testimony
10 and exhibits.

11 **Q. What capital structure are you recommending be utilized in the overall rate of**
12 **return calculation?**

13 A. I am recommending that the capital structure shown on Schedule D-1 of Exhibit A-14
14 (NEK-7) be used. This capital structure represents the actual capital structure as of
15 December 31, 2025, adjusted for the projected changes in debt, equity, and deferred
16 income taxes through the end of the projected test year ending on December 31, 2027.
17 The development of the capital structure on a ratemaking basis is shown in columns
18 (b) through (d). The equity ratio as a percentage of permanent capital is 50.01%,
19 while the debt ratio as a percentage of permanent capital is 49.99%, both of which are
20 directly aligned with the Commission order approving settlement in Case No. U-

1 21555. This common equity ratio is further supported by the direct testimony and
2 exhibits of Company witness John Thompson

3 **Q. What Return on Equity (“ROE”) are you assuming to determine the overall cost**
4 **of capital for UPPCO?**

5 A. I am assuming an ROE for UPPCO of 10.55% as evidenced at line 6 of Schedule D1
6 of Exhibit A-14 (NEK-7). Again, this ROE is supported by Company witness
7 Thompson in his direct testimony and exhibits.

8 **Q. What is the overall rate of return for UPPCO that you recommend be used in**
9 **this case?**

10 A. I am recommending an overall rate of return of 6.713% on an after-tax basis. This
11 overall rate of return is the result of utilizing the capital structure and cost rates shown
12 on Schedule D1 of Exhibit A-14 (NEK-7) at line 22. The cost of the components and
13 the weighted cost are shown in columns (e) through (i). The overall rate of return that
14 I am recommending is the weighted cost of the various components of the capital
15 structure.

16 **Q. Please describe the development of UPPCO’s capital structure.**

17 A. Capital structure refers to the amounts and mix of a company’s financing components
18 which make up the funds used for its operations and capital investment. For the
19 Company, this includes long-term debt, common equity, short-term debt, and deferred
20 income taxes.

21 **Q. What is UPPCO’s long-term debt and short-term debt.**

1 A. Long-term debt consists of loans that have a due date or maturity that are more than
2 one year from the date of issuance. For UPPCO, long-term debt consists of
3 \$127,100,000 of senior secured fixed rate notes with a 3.59% cost rate and
4 \$42,000,000 of senior secured fixed rate notes with a 5.02% cost rate. Short-term debt
5 represents borrowings that are short-term in nature or less than one year and include
6 borrowings under the Company's credit facilities. For UPPCO, short-term debt
7 currently consists of a \$100,000,000 credit facility (capacity) at CIBC. UPPCO has
8 assumed a 13-month balance of \$38,949,506 for the projected test year as evidenced
9 in Schedule D1 of Exhibit A-14 (NEK-7) at line 10.

10 **Q. What is UPPCO's common equity?**

11 A. Equity is the net worth or represents the value of a company's assets less their
12 liabilities. Typically, common equity increases with net income and/or retained
13 earnings as well as with equity contributions from a parent company or return of
14 capital to a parent company. Also, common equity typically decreases when a
15 company makes dividend distributions. For UPPCO, the assumed 13-month balance
16 of common equity is \$169,028,889 for the projected test year as evidenced in
17 Schedule D1 of Exhibit A-14 (NEK-7) at line 6.

18 **Q. Please explain how the Company manages its current and future financing**
19 **requirements.**

20 A. The Company generally prioritizes financing its long-term capital, such as plant and
21 property, with long-term debt and equity. Also, UPPCO generally purposes to finance
22 its short-term capital requirements, such as seasonal working capital needs or certain

1 large capital projects expenditures, with short-term debt. As UPPCO approaches the
2 \$100,000,000 limit on its current revolver, the Company plans to roll the existing
3 revolver into a new tranche of long-term debt and subsequently take out a new short-
4 term credit facility.

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

6 A. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)	
UPPER PENINSULA POWER COMPANY)	Case No. U-22032
For authority to increase retail electric rates.)	
_____)	

DIRECT TESTIMONY AND EXHIBITS OF
JOHN S. THOMPSON, PHD
ON BEHALF OF
UPPER PENINSULA POWER COMPANY

May 22, 2026

TABLE OF CONTENTS

I.	INTRODUCTION	1
A.	Overview.....	1
B.	Summary of Conclusions.....	3
II.	ECONOMIC PRINCIPLES AND REGULATORY STANDARDS	7
A.	Economic Principles	7
B.	Regulatory Standards.....	10
C.	Practical Considerations.....	12
III.	COMPANY AND PROXY GROUP	14
A.	UPPCO.....	14
B.	Electric Utility Group	16
C.	UPPCO's Relative Risks	19
i.	Operating Risks.....	20
ii.	Regulatory Mechanisms.....	25
iii.	Implications of UPPCO's Size	27
IV.	CAPITAL MARKET AND ROE TRENDS.....	32
A.	Outlook for Capital Costs	32
B.	Affordability	47
V.	CAPITAL MARKET ESTIMATES.....	51
A.	Discounted Cash Flow Analyses	51
B.	Capital Asset Pricing Model	58
C.	Risk Premium Approach.....	62
D.	Expected Earnings Benchmark.....	65
E.	Non-Utility DCF Benchmark.....	67
F.	Return on Equity for UPPCO	71
VI.	CAPITAL STRUCTURE	72
	Exhibit A-32 (JST-1) – Qualifications of John S. Thompson	
	Exhibit A-33 (JST-2) – ROE Analysis – Summary of Results	
	Exhibit A-34 (JST-3) – Regulatory Mechanisms – Utility Group	
	Exhibit A-35 (JST-4) – Capital Structure	
	Exhibit A-36 (JST-5) – DCF Model – Utility Group	
	Exhibit A-37 (JST-6) – $br+sv$ Growth Rate – Utility Group	
	Exhibit A-38 (JST-7) – CAPM – Utility Group	
	Exhibit A-39 (JST-8) – Utility Risk Premium	
	Exhibit A-40 (JST-9) – Expected Earnings Benchmark – Utility Group	
	Exhibit A-41 (JST-10) – DCF Benchmark – Non-Utility Group	

1 **I. INTRODUCTION**

2 **Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A1. John S. Thompson, 2309 E. 5th Street, Austin, Texas, 78702.

4 **Q2. IN WHAT CAPACITY ARE YOU EMPLOYED?**

5 A2. I am an independent consultant in regulatory finance and economics. I am Principal
6 at Thompson Advisory, LLC, a firm providing financial and economic consulting
7 services.

8 **Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND**
9 **PROFESSIONAL EXPERIENCE.**

10 A3. A description of my background and qualifications, including a resume containing the
11 details of my experience, is attached as Exhibit A-32 (JST-1).

12 **A. Overview**

13 **Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?**

14 A4. The purpose of my testimony is to present to the Michigan Public Service Commission
15 (“Commission”) my independent evaluation of the just and reasonable rate of return
16 on equity (“ROE”) that Upper Peninsula Power Company (“UPPCO” or “the
17 Company”) should be authorized to earn on its investment in providing electric utility
18 service. In addition, I also examine the reasonableness of UPPCO’s requested capital
19 structure.

20 **Q5. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU**
21 **RELY ON TO SUPPORT THE OPINIONS AND CONCLUSIONS**
22 **CONTAINED IN YOUR TESTIMONY.**

23 A5. To prepare my testimony, I use information from a variety of sources that would
24 normally be relied upon by a person in my capacity. I am familiar with the
25 organization, finances, and operations of UPPCO from my participation in the
26 Company’s last rate proceeding before the Commission. In connection with the

1 present filing, I consider and rely upon discussions with corporate management,
2 publicly available financial reports, and prior regulatory filings relating to UPPCO. I
3 also review information relating generally to current capital market conditions and
4 specifically to investor perceptions, requirements, and expectations for UPPCO's
5 utility operations. These sources, coupled with my experience in the fields of
6 economics, finance and utility regulation, have given me a working knowledge of the
7 issues relevant to investors' required return for UPPCO, and they form the basis of my
8 analyses and conclusions.

9 **Q6. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?**

10 A6. Yes. I am sponsoring the following Exhibits, which were prepared by me:

Exhibit	Description
A-32 (JST-1)	Qualifications of John S. Thompson
A-33 (JST-2)	Summary of Results
A-34 (JST-3)	Regulatory Mechanisms – Utility Group
A-35 (JST-4)	Capital Structure
A-36 (JST-5)	DCF Model – Utility Group
A-37 (JST-6)	br+sv Growth Rate – Utility Group
A-38 (JST-7)	CAPM – Utility Group
A-39 (JST-8)	Utility Risk Premium
A-40 (JST-9)	Expected Earnings Benchmark – Utility Group
A-41 (JST-10)	DCF Benchmark – Non-Utility Group

11 **Q7. HOW IS YOUR TESTIMONY ORGANIZED?**

12 A7. After first summarizing my conclusions and recommendations, my testimony reviews
13 the economic principles and regulatory standards that guide my analysis. Next, I
14 review the Company and my selection of a comparable-risk proxy group of utilities
15 (“Utility Group”). This section includes a discussion of UPPCO's operating risks,
16 regulatory mechanisms, and implications of the Company's small size. I then analyze
17 current capital market and ROE trends, with a brief digression on affordability. With
18 this as a background, I present the application of generally accepted and widely

1 adopted quantitative analyses to estimate the current cost of equity for the Utility
2 Group. These include the discounted cash flow (“DCF”) model, the Capital Asset
3 Pricing Model (“CAPM”), and an equity risk premium approach based on allowed
4 ROEs for electric utilities, which are all methods that are commonly relied on in
5 regulatory proceedings. In order to evaluate the reasonableness of my ROE outcomes,
6 I further conduct two benchmark studies—one based on the expected rates of return
7 for electric utilities, while the other involves a DCF analysis on a group of low-risk
8 non-utility firms. Based on the cost of equity estimates indicated by my analyses, the
9 Company’s requested ROE is evaluated, taking into account the specific risks and
10 potential challenges for UPPCO’s utility operations in Michigan. My testimony
11 concludes with a discussion of the Company’s requested capital structure.

12 **B. Summary of Conclusions**

13 **Q8. WHAT ARE YOUR FINDINGS REGARDING THE FAIR ROE FOR UPPCO?**

14 A8. Based on the results of my analyses and the economic requirements necessary to
15 support continuous access to capital under reasonable terms, I recommend a
16 reasonable ROE range of 10.1% to 11.3% for UPPCO, and I conclude that UPPCO’s
17 requested ROE of 10.55% is conservative.

18 **Q9. HOW DID YOU REACH THAT CONCLUSION?**

19 A9. In estimating a fair ROE for UPPCO, my analyses focused on a proxy group of twenty-
20 one publicly traded electric utilities. As discussed in my testimony:

- 21 • In order to satisfy the requirements of *Bluefield* and *Hope*, my analysis
22 begins by selecting a group of proxy group of firms from the Value Line
23 Investment Survey’s (“Value Line”) “Electric Utility” industry with
24 triple-B credit ratings.
- 25 • Because investors’ required return on equity is unobservable and no
26 single method should be viewed in isolation, I applied the DCF, CAPM
27 and risk premium methods to estimate a just and reasonable ROE. My
28 objective analyses resulted in ROE estimates of 10.1% (DCF average),
29 11.4% (CAPM) and 10.7% (Utility Risk Premium).

- 1 • Based on the results of these analyses, I conclude that the cost of equity
2 for the large, publicly traded electric utilities in the proxy group fall in
3 the 10.1% to 11.3% range.¹
- 4 • I further conducted two benchmark studies based on the expected
5 returns for the firms in my proxy group, and a DCF study on low-risk
6 non-utility firms. These benchmark studies produced ROE estimates of
7 11.1% (Expected Earnings) and 9.9% to 11.5% (Non-Utility DCF),
8 which confirm the reasonableness of my objective ROE results.
- 9 • Were UPPCO generally comparable to my proxy group in terms of its
10 overall risk profile, I would be inclined to recommend the midpoint of
11 my reasonable ROE range for the Company, but it is not. Investors
12 would perceive UPPCO as distinct from my proxy group in terms of its
13 geographically isolated service territory, lower income households, high
14 proportion of industrial customers, relative lack of regulatory
15 mechanisms, and relatively small size. Collectively, these factors point
16 to greater risk for the Company and justify a higher ROE.
- 17 • Because an ROE at the high end of my recommended range would be
18 warranted for UPPCO to compensate for the additional uncertainties
19 associated with the Company's relative risks, I conclude that the 10.55%
20 ROE requested by the Company represents a conservative estimate of
21 investors' requirements for UPPCO.

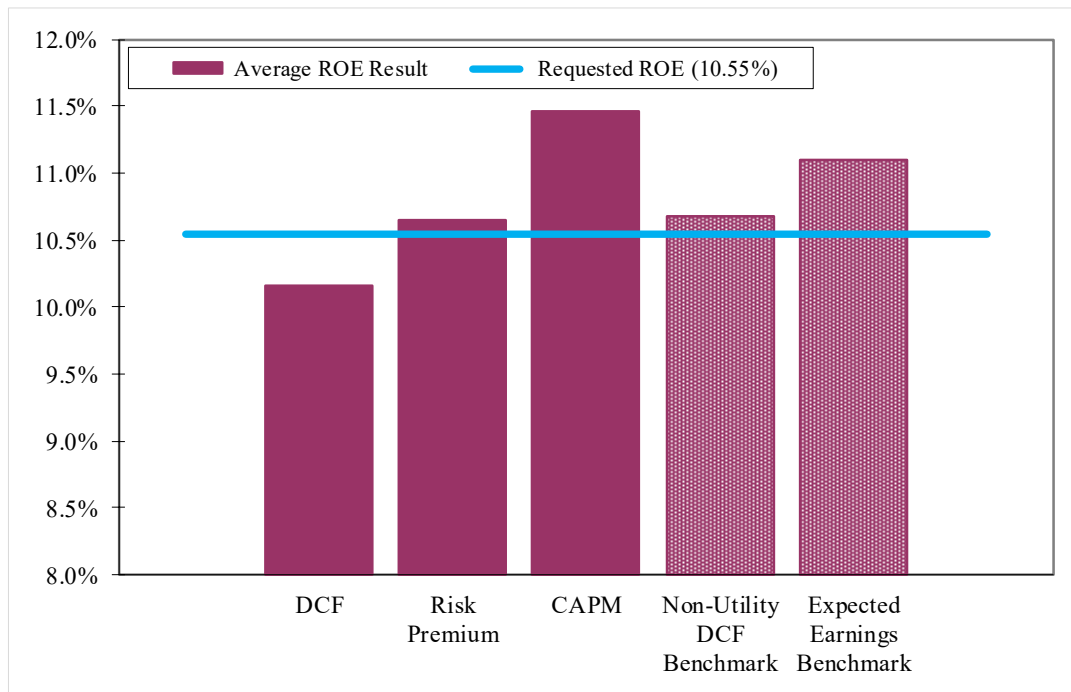
22 **Q10. HOW DOES UPPCO'S REQUESTED ROE COMPARE TO THE RESULTS OF**
23 **YOUR ANALYSES?**

24 A10. Figure 1 below summarizes the cost of equity estimates produced by my ROE analyses
25 and benchmarks and compares them with UPPCO's 10.55% ROE request:

¹ While I did not make an explicit adjustment to the results of my quantitative methods to include an adjustment for flotation costs associated with issuing common stock, this is another legitimate consideration that supports the reasonableness of my evaluation of a just and reasonable ROE for UPPCO in this case.

1
2

FIGURE 1
RESULTS OF ANALYSES VS. UPPCO REQUEST



3
4
5
6
7

As shown above, two of the three cost of equity methods I implement (as well as both of my benchmark studies) produce average ROE estimates that exceed UPPCO's 10.55% requested ROE. It is also worth noting that all three ROE methods produce average estimates of UPPCO's cost of equity that significantly exceed the Company's currently authorized ROE of 9.86%.

8
9

Q11. WHAT OTHER EVIDENCE DO YOU CONSIDER IN EVALUATING YOUR ROE RECOMMENDATION IN THIS CASE?

10
11

A11. The reasonableness of my recommended ROE range and UPPCO's request is reinforced by the following findings:

12
13
14
15

- Although trends in bond yields document a significant increase in the returns on long-term capital demanded by investors, awarded ROEs do not yet reflect the higher capital cost environment that has prevailed since 2021.

16
17

- UPPCO's awarded ROE has actually trended *downward* 14 basis points over a period in which utility bond yields have increased over 260 basis

1 points. This outcome violates the basic, common-sense direct
2 relationship between awarded ROEs and utility bond yields that has held
3 for over five decades.

- 4 • Consensus projections from top economists document that long-term
5 bond yields are expected to remain elevated at least through 2031.
- 6 • Concerns about customer affordability are mitigated when considered
7 in light of household income growth in UPPCO's service territory, the
8 relatively minimal fraction of household income spent on utility bills,
9 and general inflation.

10 These findings indicate that the 10.55% ROE requested by UPPCO is reasonable and
11 should be approved.

12 **Q12. IS A 10.55% ROE A REASONABLE COST FOR UPPCO'S CUSTOMERS TO**
13 **PAY?**

14 A12. Yes. Investors make investment capital available to UPPCO only if the expected
15 returns justify the risk. Customers will enjoy reliable and efficient service so long as
16 investors are willing to make the capital investments necessary to maintain and
17 improve UPPCO's utility system. Providing an adequate return to investors is a
18 necessary cost to ensure that capital is available to UPPCO now and in the future. If
19 regulatory decisions increase risk or limit returns to levels that are insufficient to
20 justify the risk, investors will look elsewhere to invest capital.

21 **Q13. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE**
22 **COMPANY'S CAPITAL STRUCTURE?**

23 A13. Based on my evaluation, I conclude that UPPCO's capital structure, consisting of
24 approximately 50.0% common equity financing, represents a reasonable basis on
25 which to establish the Company's return.

1 upstream suppliers to the utilities' customers. Gas utilities also experience very high
2 fixed costs from gas pipelines and distribution networks. Compared to these high fixed
3 costs, utilities' marginal costs of electricity or gas tend to be relatively low.³ In
4 standard economic theory, high fixed costs coupled with low marginal costs creates
5 "economies of scale" in which the average cost to a firm tends to fall over a large range
6 of output. If the average cost falls over the entire output that the market demands,
7 monopolies will naturally form because it will always be more efficient for a single
8 firm to serve the entire market as compared to two or more firms. If they are not
9 regulated, such "natural monopolies" would tend to price their output significantly
10 higher than what would occur in an otherwise competitive market, creating monopoly
11 profits for the natural monopoly and a "deadweight" efficiency loss for the market as
12 a whole.

13 **Q17. HOW ARE UTILITIES REGULATED?**

14 A17. Broadly speaking, utilities are regulated such that they ultimately are required to price
15 their utility service based on their cost of service, earning a return that is competitive
16 with other similar risk enterprises. Because direct price regulation is unfeasible, utility
17 regulation allows for a "just and reasonable" (i.e., competitive) ROE to attract capital
18 for utility investment. Under accepted regulatory standards, utilities are allowed to
19 price their utility service such that they recover the cost to serve their customers and
20 have the opportunity to earn competitive ROEs, allowing for differences in risk.

21 **Q18. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST**
22 **OF EQUITY CONCEPT?**

23 A18. The fundamental economic principle underlying the cost of equity concept is the
24 notion that investors are risk averse. In capital markets where relatively risk-free
25 assets are available (e.g., U.S. Treasury securities), investors can be induced to hold

³ The utilities' marginal costs are their per-unit cost of delivering electricity or natural gas to their customers.

1 riskier assets only if they are offered a premium, or additional return, above the rate of
2 return on a risk-free asset. Because all assets in capital markets compete with each
3 other for investor funds, riskier assets must yield a higher expected rate of return than
4 safer assets to induce investors to invest and hold them.

5 Given this risk-return tradeoff, the required rate of return (k) from asset (i) can
6 generally be expressed as:

$$7 \quad k_i = R_f + RP_i$$

8 where: R_f = Risk-free rate of return, and

9 RP_i = Risk premium required to hold riskier asset i .

10 Thus, the required rate of return for a particular asset at any time is a function
11 of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors
12 demanding correspondingly larger risk premiums for bearing greater risk.

13 **Q19. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE**
14 **IS PRESENT IN CAPITAL MARKETS?**

15 A19. Yes. The risk-return tradeoff can be readily observed in capital markets. Required
16 rates of return can often be directly inferred from market data and where generally
17 accepted measures of risk exist. Bond yields, for example, reflect investors' expected
18 rates of return, and bond ratings measure the risk of individual bond issues.
19 Comparing the observed yields on government securities, which are considered free
20 of default risk, to the yields on bonds of various rating categories is evidence of the
21 risk-return tradeoff, with riskier bonds demanding higher yields by investors.

22 **Q20. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED**
23 **INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER**
24 **ASSETS?**

25 A20. Yes. It is widely accepted, and consistent with economic theory, that the risk-return
26 tradeoff observed among various types of fixed income securities extends to all assets.
27 Documenting the risk-return tradeoff for assets other than fixed income securities,

1 adequate, under efficient and economical management, to maintain and
2 support its credit and enable it to raise money necessary for the proper
3 discharge of its public duties.⁴

4 The *Hope* case reemphasized the findings in *Bluefield* and established that the
5 rate-setting process must produce an end result that allows the utility a reasonable
6 opportunity to cover its capital costs. The Court stated:

7 From the investor or company point of view it is important that there
8 be enough revenue not only for operating expenses but also for the
9 capital costs of the business. These include service on the debt and
10 dividends on the stock.... By that standard, the return to the equity
11 owner should be commensurate with returns on investments in other
12 enterprises having corresponding risks. That return, moreover, should
13 be sufficient to assure confidence in the financial integrity of the
14 enterprise, so as to maintain credit and attract capital.⁵

15 In summary, the Supreme Court's findings in *Bluefield* and *Hope* established
16 that a just and reasonable ROE must be sufficient to 1) fairly compensate the utility's
17 investors, 2) enable the utility to offer a return adequate to attract new capital on
18 reasonable terms, and 3) maintain the utility's financial integrity. These standards
19 should allow the utility to fulfill its obligation to provide reliable service while meeting
20 the needs of customers through necessary system replacement and expansion, but the
21 Supreme Court's requirements can only be met if the utility has a reasonable
22 opportunity to actually earn its allowed ROE.

23 **Q23. HOW DOES A UTILITY'S AUTHORIZED ROE HELP TO MAINTAIN**
24 **REGULATORY STANDARDS?**

25 A23. The authorized ROE acts as a price signal in capital markets, and it informs investors
26 about the return they may receive if they allocate equity capital to a particular
27 investment, allowing them to make informed judgements about how best to allocate

⁴ *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) ("*Bluefield*"), <https://tile.loc.gov/storage-services/service/l1/usrep/usrep262/usrep262679/usrep262679.pdf> (last visited Feb. 3, 2026).

⁵ *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"), <https://tile.loc.gov/storage-services/service/l1/usrep/usrep320/usrep320591/usrep320591.pdf> (last visited Feb. 3, 2026).

1 their capital. Investors will commit money to a particular investment only if they
2 expect it to produce a return at least commensurate with those from other investments
3 with comparable risks. To maintain regulatory standards, the ROE must be sufficient
4 to compensate common equity investors for the use of their capital and support the
5 utility's financial integrity and ongoing ability to finance the plant and equipment
6 necessary to provide utility service.

7 **C. Practical Considerations**

8 **Q24. WHAT ARE THE CHALLENGES IN DETERMINING A JUST AND** 9 **REASONABLE ROE FOR A REGULATED COMPANY?**

10 A24. The actual return investors are requiring at a given time are unobservable. Different
11 methodologies have been developed to estimate investors' expected and required
12 return on capital, but all are merely theoretical tools and generally produce a range of
13 estimates, based on different assumptions and inputs. The DCF method, which is
14 frequently referenced and relied on by regulators, is only one theoretical approach to
15 gain insight into the return investors require; there are a number of other
16 methodologies for estimating the cost of capital and the ranges produced by the
17 different approaches can vary widely.

18 **Q25. DO BLUEFIELD AND HOPE PRESCRIBE A PARTICULAR METHOD IN** 19 **ORDER TO ESTABLISH A JUST AND REASONABLE ROE?**

20 A25. No. While the Bluefield and *Hope* decisions did not establish a particular method to
21 be followed in determining the allowed ROE (or in fixing rates),⁶ these and subsequent
22 cases enshrined the importance of an end result that meets the opportunity cost
23 standard of finance. Under this doctrine, the required return is established by investors
24 in the capital markets based on expected returns available from other comparable risk

⁶ *Id.* at 602 (finding, "the Commission was not bound to the use of any single formula or combination of formulae in determining rates." and, "[I]t is not theory but the impact of the rate order which counts.")

1 investments. Coupled with modern financial theory, which has led to the development
2 of formal risk-return models (e.g., DCF and CAPM), practical application of the
3 *Bluefield* and *Hope* standards involves the independent, case-by-case consideration of
4 a firm's risk along with current capital market data in order to evaluate a ROE that will
5 produce a balanced and fair end result for investors and customers.

6 **Q26. HOW DO YOU EVALUATE A JUST AND REASONABLE ROE FOR UPPCO**
7 **IN THE CONTEXT OF *BLUEFIELD* AND *HOPE*?**

8 A26. My goal is to generate the best estimate of the Company's ROE in today's capital
9 markets. My testimony presents an analysis of investors' expectations and
10 requirements using commonly referenced and theoretically sound financial models,
11 reasonable assumptions about rational investor behavior, and data inputs that are
12 consistent with the assumptions underlying the financial models that I utilize, all
13 within a consideration of broader capital market conditions and recent economic
14 trends. Each of the approaches I use to estimate the Companies' ROE has their own
15 strengths and weaknesses, and all involve some degree of judgment. None of the
16 models I use are inherently superior to any of the other models, and all of them are
17 accepted methodologies for estimating the cost of equity.

18 **Q27. HOW DO YOU APPROACH THE TASK OF MODEL AND DATA**
19 **SELECTION?**

20 A27. I use models that are generally accepted and widely adopted by investors and finance
21 professionals. In terms of data, the cost of equity is an inherently forward-looking
22 concept, and so it is imperative to use prospective or forward-looking data inputs
23 where feasible, as compared to historical measures.⁷ It is also important to use data
24 sources that are likely to be considered by investors, as this practice will more closely

⁷ In some cases, historical data inputs are unavoidable, such as the beta value used in CAPM analysis.

1 align my opinions and conclusions with the ROE requirements of investors in the
2 broader capital markets in which UPPCO participates.

3 **III. COMPANY AND PROXY GROUP**

4 **Q28. WHAT IS THE PURPOSE OF THIS SECTION?**

5 A28. My objective is to evaluate and recommend a fair and reasonable ROE for UPPCO.
6 Much of my work is predicated on a comparison of the Company with the utility
7 industry, and more specifically to a proxy group of publicly traded utilities included in
8 Value Line’s “Electric Utility” industry group. As a foundation for my opinions and
9 subsequent quantitative analyses, this section briefly reviews the operations and
10 finances of UPPCO. In addition, I explain the basis for the proxy group I use to
11 estimate the cost of equity and compare the investment risks of UPPCO with my
12 reference group. An understanding of the fundamental factors driving the risks and
13 prospects of electric utilities is essential in developing an informed opinion of
14 investors’ expectations and requirements that are the basis of the ROE.

15 **A. UPPCO**

16 **Q29. BRIEFLY DESCRIBE UPPCO AND ITS MICHIGAN UTILITY** 17 **OPERATIONS.**

18 A29. UPPCO’s regulated utility operations encompass the electric generation, transmission
19 and distribution functions. Originally formed in 1947, UPPCO provides service to
20 approximately 55,200 retail electric customers consisting of residential, commercial,
21 industrial, and government entities.⁸ While UPPCO only has approximately 62
22 industrial customers, this group represents a significant portion of the Company’s
23 electricity sales, as these large customers accounted for 20.3% of UPPCO’s operating
24 revenues from electricity sales in 2025.⁹ The Company’s service territory covers ten

⁸ FERC Financial Report, FERC Form No. 1, *Upper Peninsula Power Company* (Apr. 17, 2026).

⁹ *Id.*

1 counties constituting most of Michigan’s Upper Peninsula, where UPPCO is the
2 largest electricity provider. UPPCO’s generation and distribution assets include 3,300
3 miles of distribution line, 58 substations and 80 MW of generating capacity.¹⁰
4 UPPCO’s power requirements are met primarily through wholesale purchases, with
5 the remainder being supplied from seven company-owned hydroelectric generating
6 facilities and one 52-year-old combustion turbine.

7 During 2025, UPPCO’s total kilowatt hour sales distribution consisted of
8 33.9% residential, 18.6% commercial, 41.5% industrial, and 5.9% governmental and
9 sales for resale.¹¹ The large proportion of energy sales attributable to industrial
10 customers relates to the significant paper production and forest products industries
11 located in UPPCO’s service area. The Company’s 2025 peak load of 138 MW
12 occurred on August 7.¹² UPPCO’s energy supply mix in 2025 consisted almost
13 exclusively of hydro (13.0%) and purchased energy (87.0%) sources.¹³ UPPCO’s total
14 2025 electric operating revenues were approximately \$137.1 million and total assets
15 at year-end 2025 were \$505.5 million.¹⁴

16 **Q30. WHERE DOES UPPCO OBTAIN THE CAPITAL USED TO FINANCE ITS**
17 **INVESTMENT IN UTILITY PLANT?**

18 A30. As a wholly-owned subsidiary, UPPCO’s common equity capital is provided by
19 Axium UP Holdings, LLC. Axium is an affiliate of Axium Infrastructure, a portfolio
20 investment firm that invests in infrastructure assets. As of June 30, 2025, Axium

¹⁰ <https://business.keweenaw.org/list/member/upper-peninsula-power-company-houghton-396> (last visited Apr. 28, 2026).

¹¹ *FERC Financial Report, FERC Form No. 1, Upper Peninsula Power Company (Apr. 17, 2026)*.

In 2025, UPPCO’s total electric operating revenues consisted of 52.2% residential, 25.8% commercial, 20.3% industrial, 1.8% governmental and sales for resale.

¹² *Id.* at 401b.

¹³ *Id.* at 401a.

¹⁴ *Id.* at 300-301 and 110-111.

1 Infrastructure had approximately \$9.2 billion in assets under management and \$1.5
2 billion in co-investments.¹⁵

3 **Q31. DOES UPPCO ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL IN**
4 **THE FUTURE?**

5 A31. Yes. The Company must undertake investments to meet growing peak demand needs
6 and provide for necessary maintenance and replacements of its utility systems as it
7 continues to provide safe and reliable service to its customers. Continued support for
8 UPPCO's financial integrity and flexibility will be instrumental in attracting the capital
9 necessary to fund these projects in an effective manner.

10 **B. Electric Utility Group**

11 **Q32. HOW DO YOU IMPLEMENT QUANTITATIVE METHODS TO ESTIMATE**
12 **THE COST OF COMMON EQUITY FOR UPPCO?**

13 A32. Application of quantitative methods to estimate the cost of common equity requires
14 observable capital market data, such as stock prices and beta values. Moreover, even
15 for a firm with publicly traded stock, the cost of common equity can only be estimated.
16 As a result, applying quantitative models using observable market data only produces
17 an estimate of investors' expected return. Thus, the accepted approach to increase
18 confidence in the results is to apply quantitative methods to a proxy group of publicly
19 traded companies that investors regard as risk comparable. While the proxy group
20 provides a starting point in evaluating the cost of equity for UPPCO, as noted earlier,
21 economic and regulatory standards require that the Company's unique circumstances
22 and specific risks must be considered. Accordingly, differences in risk between
23 UPPCO and the proxy group must be considered in evaluating a fair ROE for the
24 Company.

¹⁵ PEI Events, Axiom Infrastructure, <https://live.peievents.com/infrastructure-investor-global-summit/sponsors-1/axium> (last visited Feb. 1, 2025).

1 **Q33. HOW DO YOU IDENTIFY THE PROXY GROUP OF UTILITIES RELIED ON**
2 **FOR YOUR ANALYSES?**

3 A33. I began with the following criteria:

- 4 1. Included in the Electric Utility industry groups compiled by Value
5 Line.
- 6 2. Paid common dividends over the last six months and have not
7 announced a dividend cut since that time.
- 8 3. No ongoing involvement in a major merger or acquisition that
9 would distort quantitative results.
- 10 4. Issuer rating of Baa1, Baa2, or Baa3 from Moody's Ratings
11 ("Moody's").
- 12 5. Issuer credit rating of BBB+, BBB, or BBB- from S&P Global
13 Ratings ("S&P").
- 14 6. Value Line Safety Rank of 1, 2 or 3.

15 These criteria result in the proxy group of twenty-one companies listed on page 1 of
16 Exhibit A-34 (JST-3), which I refer to as the "Utility Group."

17 **Q34. HOW DO YOU EVALUATE THE INVESTMENT RISKS OF THE UTILITY**
18 **GROUP?**

19 A34. My evaluation of relative risk considers five published benchmarks that are widely
20 relied on by investors; namely, credit ratings from Moody's and S&P, along with Value
21 Line's Safety Rank, Financial Strength Rating, and beta values. Credit ratings are
22 assigned by independent rating agencies for the purpose of providing investors with a
23 broad assessment of the creditworthiness of a firm. Ratings generally extend from
24 triple-A (the highest) to D (in default). Other symbols (*e.g.*, "+" or "-") are used to
25 show relative standing within a category. Because the rating agencies' evaluation
26 includes all of the factors considered important in assessing a firm's relative credit
27 standing, corporate credit ratings provide a broad, objective measure of overall
28 investment risk that is readily available to investors. Widely cited in the investment
29 community and referenced by investors, credit ratings are also frequently used as a

1 primary risk indicator in establishing proxy groups to estimate the cost of common
2 equity.

3 While credit ratings provide one of the most widely referenced benchmark for
4 investment risks, other quality rankings published by investment advisory services
5 also provide relative assessments of risks that are considered by investors in forming
6 their expectations for common stocks. Value Line's primary risk indicator is its Safety
7 Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is
8 intended to capture the total risk of a stock, and incorporates elements of stock price
9 stability and financial strength. Given that Value Line is perhaps the most widely
10 available source of investment advisory information, its Safety Rank provides useful
11 guidance regarding the risk perceptions of investors.

12 The Financial Strength Rating is designed as a guide to overall financial
13 strength and creditworthiness, with the key inputs including financial leverage,
14 business volatility measures, and company size. Value Line's Financial Strength
15 Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These
16 published indicators incorporate consideration of a broad spectrum of risks, including
17 financial and business position, relative size, and exposure to firm-specific factors.

18 Finally, beta measures a utility's stock price volatility relative to the market as
19 a whole and reflects the tendency of a stock's price to follow changes in the market.
20 A stock that tends to respond less to market movements has a beta less than 1.00, while
21 stocks that tend to move more than the market have betas greater than 1.00. Beta is
22 the only relevant measure of investment risk under modern capital market theory and
23 is widely cited in academics and in the investment industry as a guide to investors' risk
24 perceptions. Moreover, in my experience, Value Line is the most widely referenced
25 source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

26 Value Line is the largest and most widely circulated independent
27 investment advisory service, and influences the expectations of a large

1 number of institutional and individual investors. ... Value Line betas
2 are computed on a theoretically sound basis using a broadly based
3 market index, and they are adjusted for the regression tendency of betas
4 to converge to 1.00.¹⁶

5 **Q35. WHAT DO THESE MEASURES INDICATE WITH RESPECT TO THE**
6 **OVERALL RISKS OF THE UTILITY GROUP?**

7 A35. The average risk indicators for the Utility Group are shown in the table below:

8 **TABLE 1**
9 **UTILITY GROUP RISK INDICATORS**

Utility Group	<u>Credit Ratings</u>		<u>Value Line</u>		
	<u>Moody's</u>	<u>S&P</u>	<u>Safety</u>	<u>Financial</u>	<u>Beta</u>
			<u>Rank</u>	<u>Strength</u>	
Utility Group	Baa2	BBB+	2	B++	0.77

10 The Baa2 and BBB+ credit ratings corresponding to the Utility Group place their credit
11 risks solidly within the investment-grade range. Similarly, the average Value Line risk
12 indicators for the Utility Group, which incorporate a broad spectrum of risks, including
13 financial and business position and exposure to company specific factors, are generally
14 indicative of a company with a conservative risk profile.

15 **C. UPPCO's Relative Risks**

16 **Q36. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

17 A36. The cost of equity estimates developed later in my testimony are predicated on the
18 investment risk associated with the utilities in the proxy group. This section compares
19 the risks of the Utility Group with those that investors would associate with UPPCO
20 and evaluates the incremental return necessary to compensate for the Company's
21 greater relative risks.

¹⁶ Morin, Roger A., *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 71.

1 **i. Operating Risks**

2 **Q37. HOW DO THE CHARACTERISTICS OF UPPCO'S SERVICE TERRITORY**
3 **DIFFERENTIATE THE COMPANY FROM THE LARGER UTILITIES IN**
4 **THE PROXY GROUP?**

5 A37. There are a number of considerations that imply greater uncertainties for UPPCO when
6 compared to larger industry counterparts located elsewhere in the United States.
7 UPPCO's service territory is geographically isolated in a relatively vulnerable
8 economic region with exposure to cyclical commodity-based industries. As was
9 mentioned, the Company serves approximately 55,200 electric retail customers in ten
10 of the Upper Peninsula of Michigan's fifteen counties. UPPCO's service territory of
11 4,460 square miles covers primarily rural countryside, with a customer density of
12 about 12 customers per square mile, and industries served by the Company include
13 forest products, tourism, and manufacturing.¹⁷ The potential for uncertain and extreme
14 weather increases the complexities of operating in such an environment.

15 **Q38. HOW DO WEATHER-RELATED RISKS AFFECT UPPCO'S FINANCIAL**
16 **POSITION?**

17 A38. In addition to increasing UPPCO's overall risk profile (which in turn has a direct
18 impact on requirements for financial strength), the service territory's exposure to
19 adverse weather has a direct impact on the Company's need for financial strength.
20 UPPCO must maintain ready access to larger reserves of credit and liquidity than most
21 other utilities. Given the high value that UPPCO and its customers place on service
22 availability and reliability, rapid restoration of service after a weather-induced outage
23 is the Company's highest priority. UPPCO must be able to marshal significant internal
24 and external resources very quickly, and this leads to large needs for credit and
25 liquidity. Restoration efforts must be funded long before the recovery of prudently

¹⁷ <https://business.keweenaw.org/list/member/upper-peninsula-power-company-houghton-396> (last visited Apr. 28, 2026).

1 incurred costs can be expected. A financially strong utility will be better prepared to
2 deal with these situations when they inevitably arise, which ultimately benefits
3 impacted customers.

4 **Q39. DO EXTREME WEATHER EVENTS EXPERIENCED IN 2021 HIGHLIGHT**
5 **THE IMPORTANCE OF MAINTAINING UPPCO'S FINANCIAL**
6 **INTEGRITY?**

7 A39. Yes. A severe winter storm in February 2021 resulted in uncharacteristically frigid
8 temperatures that disrupted natural gas supplies and power plant operations at a time
9 of peak winter electricity demand, which produced dramatic spikes in the costs of
10 natural gas and wholesale power throughout the region. As a result, electric and
11 natural gas utilities incurred significant incremental procurement costs to maintain
12 service to customers. Utilities were required to secure liquidity quickly in order to
13 fund the extraordinary energy costs necessary to maintain service to customers. With
14 purchased energy accounting for around 87% of the Company's electricity supply,
15 UPPCO remains relatively vulnerable to future weather-related shocks of this type.
16 Continued support for the Company's financial strength is instrumental to ensure that
17 UPPCO can maintain access to the capital necessary to respond effectively under times
18 of turmoil in the energy and capital markets.

19 **Q40. HOW DO UPPCO'S RESIDENTIAL CUSTOMERS COMPARE TO OTHER**
20 **PARTS OF MICHIGAN AND THE UNITED STATES?**

21 A40. Generally speaking, the Company's customer base in the ten counties it services is
22 characterized by lower per capita income as compared to other parts of Michigan,
23 which itself falls below the United States more broadly on this metric. For example,
24 data from the U.S. Census Bureau show that median income for the ten counties in

1 UPPCO’s service territory averaged \$57,631 in 2024,¹⁸ as compared to \$79,460 for
2 Michigan¹⁹ and \$83,730 for the United States.²⁰ As MorningStar has noted:

3 GDP growth in the UP has been below the national average for the past
4 20 years. UPPCO operates in an economically stagnant service territory
5 with income levels somewhat below the national average.²¹

6 The relatively low-income profile of UPPCO’s service territory could exacerbate
7 demand risk for the Company.

8 **Q41. HOW DOES THIS EVIDENCE RELATE TO UPPCO’S RISK PROFILE?**

9 A41. Standard economic theory says that at lower levels of income, the demand for goods
10 and services becomes more “price elastic,” other things being equal. This means that
11 UPPCO’s lower income customers would be expected to be relatively more sensitive
12 to changes in price, and accordingly they would reduce their consumption more when
13 prices increase, as compared to higher income consumers elsewhere in Michigan or
14 the United States. As a practical matter, lower income service territories would lead
15 to elevated demand risk as compared to the proxy group companies.

16 Recent inflationary pressures have put upward pressure on utilities’ fuel and
17 infrastructure costs. For example, S&P listed “unprecedented inflation” as a notable
18 driver in utilities’ rate requests in 2022.²² More recently, inflation has moderated but
19 remains elevated. To the extent that UPPCO is able to pass inflation-induced operating
20 and infrastructure cost increases along to customers, it stands to reason that the

¹⁸ United States Census Bureau, *American Community Survey – Table S1901 | Income in the Past 12 Months (in 2024 Inflation-Adjusted Dollars)*, <https://data.census.gov/table/ACSST1Y2024.S1901?q=michigan+median+income> (last visited Feb. 6, 2026).

¹⁹ Federal Reserve Economic Data, *Median Household Income in Michigan*, <https://fred.stlouisfed.org/series/MEHOINUSMIA646N> (last visited Feb. 6, 2026).

²⁰ Federal Reserve Economic Data, *Median Household Income in the United States*, <https://fred.stlouisfed.org/series/MEHOINUSA646N> (last visited Feb. 6, 2026).

²¹ DBRS Morningstar, *Upper Peninsula Power Company*, Private Credit Rating Report (Dec. 19, 2025).

²² S&P Global Market Intelligence, *Inflation rearing its head in electric, gas general rate cases nationwide* (Oct. 4, 2022).

1 Company's relatively price sensitive customer base could create additional financial
2 risk for UPPCO.

3 **Q42. DOES THE COMPANY'S POWER SUPPLY MIX ADD TO THE COMPANY'S**
4 **RISK LEVEL?**

5 A42. Yes. As was mentioned, hydro sources supplied 13.0% of the Company's total energy
6 needs in 2025, while wholesale market purchases provided 87.0%.²³ Both of these
7 sources entail added risk. While hydropower confers advantages in terms of fuel cost
8 savings, lack of carbon emissions, and diversity, reduced hydroelectric generation due
9 to below-average water conditions may force the Company to rely more heavily on
10 more costly replacement power to meet its resource needs. As S&P has observed:

11 A reduction in hydro generation typically increases an electric utility's
12 costs by requiring it to buy replacement power or run more expensive
13 generation to serve customer loads. Low hydro generation can also
14 reduce utilities' opportunity to make off-system sales. At the same
15 time, low hydro years increase regional wholesale power prices,
16 creating potentially a double impact – companies have to buy more
17 power than under normal conditions, paying higher prices.²⁴

18 Investors recognize that the potential for volatility in energy markets,
19 unpredictable stream flows, and UPPCO's reliance on wholesale purchases to meet the
20 majority of its resource needs can expose the Company to the risk of reduced cash
21 flows and unrecovered power supply costs. UPPCO's reliance on purchased power to
22 meet shortfalls in hydroelectric generation magnifies the importance of strengthening
23 financial flexibility, especially in light of recent extreme weather and energy price
24 volatility.

²³ FERC Financial Report, FERC Form No. 1, *Upper Peninsula Power Company* (Apr. 11, 2025) at 401a.

²⁴ Standard & Poor's Corporation, *Pacific Northwest Hydrology And Its Impact On Investor-Owned Utilities' Credit Quality*, RatingsDirect (Jan. 28, 2008).

1 **Q43. HOW DOES CLIMATE CHANGE IMPACT INVESTORS' ASSESSMENT OF**
2 **UPPCO'S RISK EXPOSURE?**

3 A43. The risk posed by climate-related weather events magnifies concerns over the
4 Company's exposure to below-average water conditions. S&P concluded that "water-
5 intensive assets like power plants [are] especially vulnerable in the absence of
6 adaptation," and concluded that water stress is "a serious threat."²⁵ While noting that
7 the risks of such events are generally manageable under recovery mechanisms that
8 allow related costs to be recuperated, S&P also observed that:

9 In the most extreme events, including those of late, utility companies'
10 exposure to acute and chronic climate risks can damage assets or
11 disrupt supplies, which can weaken their financial position and
12 ultimately credit quality.²⁶

13 **Q44. WHAT OTHER FACTORS SPECIFIC TO UPPCO'S SERVICE AREA**
14 **WARRANT CONSIDERATION?**

15 A44. UPPCO's service area is characterized by a high concentration of sales to industrial
16 customers relative to the companies in the Utility Group. Approximately 20.3% of the
17 Company's total electricity sales are to industrial customers,²⁷ versus an average of
18 13.7% for the twenty-one firms in the Utility Group. Because these sales are more
19 sensitive to business cycle changes, the price of alternative energy sources, and
20 pressure from competitors, they are generally considered to be riskier than sales to
21 residential or commercial customers. For context, each of UPPCO's 62 industrial
22 customers account for approximately \$448,900 in operating revenues, on average, as
23 opposed to around \$1,460 for each of the Company's residential customers.²⁸ Indeed,
24 MorningStar recently highlighted UPPCO's "industrial customer concentration" as a

²⁵ S&P Global Ratings, *Keeping The Lights On: U.S. Utilities' Exposure To Physical Climate Risks*, RatingsDirect (Sep. 16, 2021).

²⁶ *Id.*

²⁷ FERC Financial Report, FERC Form No. 1, *Upper Peninsula Power Company* (Apr. 17, 2026) at 304.

²⁸ *Id.*

1 risk factor for the Company.²⁹ This exposure to a high concentration of industrial sales
2 implies a significant degree of risk to UPPCO's operations that must be offset by
3 sufficient financial fitness.

4 **Q45. CAN YOU GIVE SPECIFIC EXAMPLES OF THE RISKS ASSOCIATED**
5 **WITH UPPCO'S VOLATILE INDUSTRIAL CUSTOMER BASE?**

6 A45. Forest products and mining are two of the predominant industries served by the
7 Company. These are cyclical, commodity-based businesses that are susceptible to
8 heavy economic pressure. Indeed, UPPCO has experienced two customer
9 bankruptcies in the paper and mining sectors. NewPage Corporation, with a large
10 paper production center in Escanaba, Michigan, filed for bankruptcy in 2011,
11 temporarily closing its Michigan operations. Verso Corporation acquired NewPage in
12 2015 but filed for bankruptcy in early 2016, eventually emerging six months later.
13 New Page's and Verso's bankruptcies were some of the largest filings in paper industry
14 sector.

15 Further, in 2016 Cleveland-Cliffs, Inc. announced the closing of the Empire
16 Mine in Ishpeming, Michigan. Finally, another of UPPCO's largest customers,
17 Enbridge Inc., operates a petroleum pipeline under the Straits of Mackinac that has
18 faced long-running challenges due to pipeline integrity concerns.

19 **ii. Regulatory Mechanisms**

20 **Q46. WOULD INVESTORS ALSO CONSIDER THE IMPLICATIONS OF**
21 **REGULATORY MECHANISMS IN EVALUATING UPPCO'S RELATIVE**
22 **RISKS?**

23 A46. Yes. In response to the increasing sensitivity over fluctuations in costs and the
24 importance of advancing other public interest goals such as reliability, energy
25 conservation and safety, utilities and their regulators have sought to mitigate cost

²⁹ DBRS Morningstar, *Upper Peninsula Power Company*, Private Credit Rating Report (Dec. 19, 2025).

1 recovery uncertainty and align the interest of utilities and their customers. As a result,
2 adjustment mechanisms, cost trackers, and future test years have become increasingly
3 prevalent, along with alternatives to traditional ratemaking such as formula rates and
4 multi-year rate plans. As *RRA Regulatory Focus* explained in its most recent review
5 of adjustment clauses:

6 As utilities take on broader responsibilities, such as grid modernization
7 and decarbonization, adjustment clauses have become increasingly
8 specialized. Initially developed to manage commodity price volatility,
9 these mechanisms have expanded into a comprehensive suite of
10 mechanisms tailored to address specific cost categories and policy
11 mandates.

12 These mechanisms include provisions for recovering electric fuel and
13 gas commodity costs, purchased power expenses and conservation
14 program expenses. Additionally, some mechanisms are designed to
15 stabilize revenues, such as full or partial decoupling mechanisms that
16 protect utilities from fluctuations in energy sales.

17 On the capital side, separate mechanisms may support traditional
18 generation, renewable and nontraditional generation, environmental
19 compliance investments, delivery infrastructure upgrades and
20 transmission costs. In some instances, these mechanisms may even
21 provide utilities a cash return on construction work in progress
22 (CWIP).³⁰

23 This trend is shown on Exhibit A-34 (JST-3), which shows that the companies
24 in the Utility Group operate under a wide variety of cost adjustment mechanisms,
25 including revenue decoupling and adjustment clauses designed to address rising
26 capital investment outside of a traditional rate case and increasing costs of
27 environmental compliance measures, as well as riders to recover transmission-related
28 charges and other costs.

³⁰ S&P Global Market Intelligence, *Adjustment Clause: a state-by-state overview*, RRA Regulatory Focus (Sep. 2025).

1 **Q47. HOW DO THE REGULATORY MECHANISMS APPROVED FOR UPPCO**
2 **COMPARE TO THE PROXY GROUP?**

3 A47. UPPCO's regulatory adjustment mechanisms are relatively limited when compared to
4 the proxy group companies. The Company operates under a standard fuel and
5 purchased power cost recovery mechanism and determines its proposed cost of service
6 based on a future test year. UPPCO also has an energy efficiency adjustment
7 mechanism. As shown on page 1 of Exhibit A-34 (JST-3), these mechanisms are
8 widespread throughout the Utility Group companies, and they do not differentiate
9 UPPCO from the proxy group.

10 However, unlike many of the specific operating companies associated with the
11 Utility Group firms, the Company lacks broad cost tracking mechanisms that would
12 allow it to automatically recover ongoing capital investment outside of a traditional
13 rate case. UPPCO also does not benefit from a decoupling mechanism to insulate
14 utility margins from usage volatility. UPPCO's relative lack of regulatory mechanisms
15 distinguish the Company from the proxy group, giving investors a basis on which to
16 conclude that UPPCO has relatively higher risk, at least in the dimension of timely
17 cost recovery.

18 **iii. Implications of UPPCO's Size**

19 **Q48. HOW DOES A SMALL ELECTRIC UTILITY SUCH AS UPPCO COMPARE**
20 **TO THE LARGE, PUBLICLY TRADED FIRMS IN YOUR PROXY GROUP?**

21 A48. There is enormous disparity in size between UPPCO and the major participants in the
22 electric utility industry. Consider the twenty-one utilities making up the Utility Group,
23 for example, which dwarf UPPCO by any measure. For example, where the Utility
24 Group had average annual revenues in 2025 of approximately \$11.3 billion and total
25 capital of \$39.0 billion, UPPCO had revenues of \$137.1 million and total capital of

1 \$378.4 million.³¹ Similarly, compared with UPPCO’s 55,200 customers, the firms in
2 the Utility Group supply electric services to 3.0 million customers, on average.

3 **Q49. WHAT DIFFERENCE DOES THIS DISTINCTION IN SIZE MAKE?**

4 A49. The magnitude of the disparity between smaller utilities and the major electric utilities
5 included in the proxy group has important practical implications with respect to the
6 risks faced by UPPCO. All else being equal, it is well accepted that smaller firms are
7 more risky than their larger counterparts, due in part to their inherent lack of
8 diversification and absence of financial resiliency. The financial media has also noted
9 the challenge that UPPCO’s size presents, with DBRS Morningstar recently indicating
10 that its comprehensive business risk assessment for the Company “is constrained by
11 UPPCO's small scale which limits the Company's diversification and scale
12 advantages.”³²

13 In the case of a small electric utility, its earnings are principally dependent on
14 the economic, social, regulatory, and other factors affecting its limited service area.
15 This can result in significant exposure, especially where a key employer or industry
16 dominates the economy. Meanwhile, the large electric utilities generally serve
17 customers in numerous geographic locales, in many cases across multiple states. But
18 as Morningstar has noted, UPPCO’s small size in a rural and low-density area “limits
19 ... diversification that a larger utility would be able to achieve.”³³ Thus, where major
20 electric utilities are able to mitigate risks through geographical diversification, small
21 electric companies such as UPPCO are wholly exposed to the uncertainties associated
22 with economic conditions, natural disasters, demographics, and other factors that may
23 impact an extremely small, concentrated service area.

³¹ FERC Financial Report, FERC Form No. 1, *Upper Peninsula Power Company* (Apr. 17, 2026) at 112-113.

³² DBRS Morningstar, *Upper Peninsula Power Company*, Private Credit Rating Report (Dec. 19, 2025).

³³ *Id.*

1 **Q50. IS THERE EMPIRICAL EVIDENCE IN THE FINANCIAL LITERATURE**
2 **THAT A COMPANY’S SIZE AFFECTS ITS RELATIVE RISKS?**

3 A50. Yes. It is well established in the financial literature that smaller firms are more risky
4 than larger firms. For example, Eugene F. Fama and Kenneth R. French concluded in
5 their widely cited study that a firm’s relative size is a proxy for risk.³⁴ Similarly, a
6 classic University of Kansas study demonstrated that large firms are assigned higher
7 bond ratings than small firms with similar characteristics,³⁵ and there is ample
8 empirical evidence that investors in smaller firms realize higher rates of return than in
9 larger firms.³⁶ Common sense and accepted financial doctrine hold that these greater
10 risks mean that investors require higher returns from smaller companies, and unless
11 that compensation is provided in the rate of return allowed for a utility, the legal tests
12 embodied in the *Hope* and *Bluefield* cases cannot be met.³⁷

13 **Q51. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT REQUIRED TO**
14 **ACCOUNT FOR THIS SIZE PREMIUM?**

15 A51. One estimate of the size premium is available from Kroll,³⁸ which now reports the
16 widely-recognized Ibbotson Associates data based on historical returns for “Low-Cap”
17 and “Micro-Cap” stocks, in addition to its better-known data series for the S&P 500.
18 Low-Cap companies comprise the 6th through 8th size-deciles of those stocks listed on
19 the New York Stock Exchange, NYSE American, and NASDAQ, while Micro-Cap

³⁴ Eugene F. Fama and Kenneth R. French, *The Cross-Section of Expected Stock Returns*, The Journal of Finance (June 1992), p. 429.

³⁵ George E. Pinches, J. Clay Singleton, and Ali Jahankhani, *Fixed Coverage as a Determinant of Electric Utility Bond Ratings*, Financial Management (Summer 1978).

³⁶ See for example Rolf W. Banz, *The Relationship Between Return and Market Value of Common Stocks*, Journal of Financial Economics (September 1981) at 16.

³⁷ Similarly, a study reported in Public Utilities Fortnightly noted that the betas of small companies do not fully account for the higher realized rates of return associated with small company stocks. Michael Annin, *Equity and the Small-Stock Effect*, Pub. Util. Fortnightly (Oct. 15, 1995), at 43.

³⁸ Kroll compiles and publishes updated financial data originally presented in *Stocks, Bonds, Bills and Inflation* by Roger G. Ibbotson and Rex A. Sinquefeld.

1 stocks represent the 9th through 10th size-deciles. These size premiums are shown in
 2 the table below.

3 **TABLE 2**
 4 **KROLL SIZE PREMIUMS**

Companies Ranked by Market Value of Common Equity

Decile	Low End Breakpoint (\$M)	High End Breakpoint (\$M)	Size Premium
Mid Cap (3–5)	4,237.16	20,493.88	0.42%
Low Cap (6–8)	782.51	4,232.27	0.90%
Micro Cap (9–10)	3.75	782.17	2.59%

Breakdown of CRSP Deciles 1 - 10

1	53,677.50	4,542,663.30	0.01%
2	20,547.63	53,647.98	0.27%
3	10,784.34	20,493.88	0.40%
4	6,449.09	10,707.83	0.37%
5	4,237.16	6,442.61	0.65%
6	2,522.12	4,232.27	0.88%
7	1,472.35	2,518.43	1.05%
8	782.51	1,472.33	0.77%
9	351.13	782.17	1.68%
10	3.75	351.05	4.37%

Breakdown of CRSP 10th Decile

10A	183.29	351.05	3.01%
10w	272.05	351.05	2.15%
10x	183.29	270.97	4.07%
10B	3.75	183.11	7.24%
10y	81.80	183.11	5.79%
10z	3.75	81.56	10.38%

Source: Kroll, *2025 CRSP Deciles Size Premium*, Cost of Capital Navigator (2026).

5 As shown above, the individual firms in the Low-Cap group have market
 6 capitalizations at or below about \$4.23 billion but greater than \$783 million, with the
 7 market capitalization of Micro-Cap stocks falling between approximately \$3.8 million
 8 and \$782 million. These smaller companies have historically earned higher rates of
 9 return than the large companies comprising the S&P 500. For the 1926 to 2025 period,

1 Kroll reported a size premium in excess of the return implied by the CAPM of 90 basis
2 points for the Low-Cap sector, and 259 basis points for Micro-Cap companies.

3 **Q52. HOW ELSE MIGHT THE SIZE PREMIUM BE ESTIMATED FOR UPPCO?**

4 A52. The additional return attributable to the significant distinction in size between UPPCO
5 and the Utility Group can be estimated by reference to the relative size premiums
6 quantified by Kroll for their respective market capitalizations. Because UPPCO does
7 not have publicly traded common stock, its implied market capitalization is estimated
8 by multiplying the Company's total common equity of approximately \$209.3 million
9 by the average market-to-book ratio for the Utility Group of 2.17 times. This implies
10 a market capitalization for UPPCO of \$454.3 million. As shown above in Table 2, this
11 corresponds to the 9th decile of the publicly-traded firms, which had market
12 capitalizations ranging from \$351.1 to \$782.2 million and a size premium of 1.68%.

13 Meanwhile, the average market capitalization for the firms in the Utility Group
14 is \$32.6 billion, which corresponds to the 2nd decile. Subtracting the size premium
15 associated with the Utility Group of 27 basis points from the 168 basis point premium
16 for a firm in the 9th decile results in an implied size adjustment of 140 basis points to
17 reflect the additional risks of UPPCO relative to the much larger electric utilities in the
18 proxy group.

19 **Q53. PLEASE SUMMARIZE THE RISK EXPOSURES INHERENT TO UPPCO
20 AND THE NEED FOR ONGOING SUPPORT OF THE COMPANY'S
21 FINANCIAL STRENGTH AND ABILITY TO ATTRACT CAPITAL ON
22 REASONABLE TERMS.**

23 A53. UPPCO's investors face added risks related to the Company's small size, potentially
24 volatile power supply mix, economically vulnerable service area, and lack of
25 regulatory mechanisms. Nevertheless, UPPCO must simultaneously meet the long-
26 term energy needs of its service area. To continue to meet these challenges
27 successfully and economically, it is crucial that UPPCO receive adequate financial and

1 regulatory support. While providing an ROE that is sufficient to maintain UPPCO's
2 ability to attract capital, even under duress, is consistent with the economic
3 requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also
4 in customers' best interests. Ultimately, it is customers and the service area economy
5 that enjoy the benefits that come from ensuring that the utility has the financial
6 wherewithal to invest in infrastructure and take whatever actions are required to ensure
7 a reliable energy supply. By the same token, customers and the service area economy
8 suffer when the utility is unable to attract necessary capital.

9 **IV. CAPITAL MARKET AND ROE TRENDS**

10 **Q54. WHAT IS THE PURPOSE OF THIS SECTION?**

11 A54. This section presents capital market estimates of the ROE. First, I discuss the current
12 outlook for capital costs, including expectations for interest rates. I then discuss the
13 issue of affordability.

14 **A. Outlook for Capital Costs**

15 **Q55. PLEASE SUMMARIZE CURRENT ECONOMIC AND CAPITAL MARKET** 16 **CONDITIONS.**

17 A55. Following the economic contraction stemming from the COVID-19 pandemic in 2020,
18 U.S. real GDP improved significantly in 2021, with GDP growing at a pace of 5.7%.³⁹
19 Economic growth was more subdued in subsequent years, falling in a range of 2.5%
20 to 2.9% between 2022 and 2024.⁴⁰ More recently, real GDP growth slowed somewhat

³⁹ U.S. Dep't of Commerce, Bureau of Economic Analysis, <https://www.bea.gov/news/2022/gross-domestic-product-fourth-quarter-and-year-2021-second-estimate> (last visited Apr. 19, 2026).

⁴⁰ U.S. Dep't of Commerce, Bureau of Economic Analysis, <https://www.bea.gov/sites/default/files/2025-05/gdp1q25-2nd.pdf> (last visited Apr. 19, 2026).

1 to 2.2% in 2025.⁴¹ Meanwhile, the unemployment rate changed little in March 2026
2 at 4.3%.⁴²

3 A dramatic increase in global uncertainties following Russia’s invasion of
4 Ukraine in February 2022 overshadowed the underlying risk and price pressures
5 associated with the COVID-19 pandemic. Conflict in the Middle East surged in late
6 2023 and remained heightened into 2024 and 2025, compounding geopolitical risks.
7 More recently, war with Iran has added to global risk and uncertainty. Apart from
8 disrupting global trade, the Iran conflict has caused the price of crude oil to surge past
9 \$100 a barrel⁴³ as volatility in global stock markets has markedly increased. The
10 potential for long-term conflict has exacerbated concerns over crude oil supplies and
11 resulting supply-side price shocks that could reignite inflation and further dampen
12 economic growth.

13 Stimulative monetary and fiscal policies, coupled with supply-chain
14 disruptions and rapid price rises in the energy and commodities markets, led to
15 increasing concern that inflation would remain significantly above the Federal
16 Reserve’s longer-run benchmark of 2%. CPI inflation peaked in June 2022 at 9.1%,
17 its highest level since November 1981. Though inflation has moderated significantly
18 since its peak in June 2022, it continues to exceed the Federal Reserve’s 2.0% target.
19 In March 2026, CPI inflation stood at 3.3%,⁴⁴ and this represented a sharp increase
20 from 2.4% in the prior month.⁴⁵ The so-called “core” price index, which excludes

⁴¹ U.S. Dep’t of Commerce, Bureau of Economic Analysis, <https://www.bea.gov/news/2026/gdp-advance-estimate-4th-quarter-and-year-2025> (last visited Apr. 19, 2026).

⁴² News Release, U.S. Dep’t of Labor, Bureau of Labor Statistics, *The Employment Situation—March 2026* (Apr. 3, 2026), <https://www.bls.gov/news.release/pdf/empst.pdf> (last visited Apr. 19, 2026).

⁴³ BBC, *Oil above \$100 over conflicting claims on US-Iran talks* (Mar. 24, 2026), <https://www.bbc.com/news/articles/c625j162yy6o> (last visited Apr. 19, 2026).

⁴⁴ U.S. Dep’t of Labor, Bureau of Labor Statistics, *Consumer Price Index Summary* (Apr. 10, 2026), <https://www.bls.gov/news.release/cpi.nr0.htm> (last visited Apr. 19, 2026).

⁴⁵ U.S. Dep’t of Labor, Bureau of Labor Statistics, *TED: The Economic Daily, Consumer prices up 2.4 percent over year ended February 2026* (Oct. 24, 2025), <https://www.bls.gov/opub/ted/2026/consumer-prices-up-2-4-percent-over-year-ended-february-2026.htm> (last visited Apr. 19, 2026).

1 more volatile energy and food costs, rose at an annual rate of 2.6% in March 2026.⁴⁶
2 PCE inflation stood at 2.8% in February 2026, or 3.0% after excluding more volatile
3 food and energy costs.⁴⁷

4 The investment community continues to monitor the extent to which import
5 tariffs, elevated energy costs, and disruptions to global commerce and supply chains
6 may reignite inflation and lead to economic recession. Oscillating trade developments
7 and concerns over high prices have also contributed to an erosion of consumer
8 confidence. In April 2026, the University of Michigan consumer sentiment index,
9 which measures consumer expectations about current and future economic conditions,
10 sank roughly 11% from its level in the prior month.⁴⁸ This measure was 17% weaker
11 than its average in 2025 and well below its historical average,⁴⁹ demonstrating relative
12 consumer pessimism. Investors continue to face the prospect of heightened market
13 volatility and persistent inflation as capital markets respond to these uncertainties.

14 **Q56. HAVE CREDIT RATING AGENCIES COMMENTED ON THE RISKS**
15 **FACED BY UTILITIES AND THEIR INVESTORS?**

16 A56. Yes. Although S&P noted it expects a more stable environment for credit quality, it
17 observed that the electric utility industry “consistently operates with high cash flow
18 deficits at about \$100 billion annually,” and concluded that:

19 Because about 40% of the [investor-owned utility] industry is actively
20 operating with minimal credit cushion, an unexpected event outside of
21 the base case could result in a negative outlook or even a possible
22 downgrade for many IOU utilities if financial levers are not quickly
23 implemented to restore credit quality.⁵⁰

⁴⁶ U.S. Dep’t of Labor, Bureau of Labor Statistics, *Consumer Price Index Summary* (Apr. 10, 2026), <https://www.bls.gov/news.release/cpi.nr0.htm> (last visited Apr. 19, 2026).

⁴⁷ Bureau of Economic Analysis, *Personal Income and Outlays, February 2026*, BEA 26-20 (Apr. 9, 2026), <https://www.bea.gov/news/2026/personal-income-and-outlays-february-2026> (last visited Apr. 19, 2026).

⁴⁸ University of Michigan, *Surveys of Consumers, Preliminary Results for April 2026*, <https://www.sca.isr.umich.edu/> (last visited Apr. 19, 2026).

⁴⁹ University of Michigan, *Surveys of Consumers, Tables*, <https://www.sca.isr.umich.edu/tables.html> (last visited Apr. 19, 2026).

⁵⁰ S&P Global Ratings, *North America Regulated Utilities, Industry Credit Outlook 2026* (Jan. 14, 2026).

1 In addition to concerns over declining credit metrics, S&P cited financial pressures
2 from significant capital spending, regulatory risks associated with higher customer
3 bills and ongoing wildfire risks as key concerns for investors.⁵¹

4 In its most recent annual review of the utility industry, Moody’s noted,
5 “Macroeconomic factors are likely to be modestly credit negative over the next 12 to
6 18 months, driven by upward pressure on natural gas prices and a slight upward trend
7 in inflation.”⁵² Their annual review further noted, “Rising demand, higher power
8 prices, persistent inflation and elevated capital spending have the potential to increase
9 some utilities’ exposure to affordability concerns,” concluding that a continuation of
10 supportive regulation would be required to offset ongoing pressure from still-high
11 interest rates and other negative pressures on utilities’ credit standing.⁵³

12 More recently, Moody’s further emphasized utilities’ risk related to issues
13 surrounding affordability. In particular, Moody’s explained:

14 Over the longer term, increased electricity demand from data centers,
15 electrification and stronger industrial needs, along with potentially
16 constrained pipeline capacity that could drive natural gas prices higher,
17 would elevate electricity prices further and add to affordability
18 concerns.

19 * * * * *

20 When elected officials publicly prioritize bill affordability, especially
21 during periods of elevated electricity or gas prices, they often exert
22 pressure on regulators to limit rate increases or impose rate freezes,
23 reduce allowed revenues, or delay cost recovery. Such interventions
24 can weaken utilities’ cash flow predictability and financial performance
25 and lead to pressure on credit quality.⁵⁴

⁵¹ *Id.*

⁵² Moody’s Ratings, *Electric and Gas Utilities – US*, Outlook (Oct. 31, 2025).

⁵³ *Id.*

⁵⁴ Moody’s Ratings, Sector In-Depth, Electricity, gas prices continue to outpace inflation, sustaining affordability pressures (Mar. 19, 2026).

1 The political environment surrounding the issue of affordability presents real risks for
2 utilities and their investors.

3 Utilities are also exposed to supply chain risk and procurement cost pressures
4 associated with increasing tariff barriers to trade. In 2024, China accounted for over
5 50% of low-voltage transformer imports, while Mexico is the largest trading partner
6 for medium and high-voltage transformers.⁵⁵ Utilities in the U.S. also rely heavily on
7 imports from China, Canada, and Mexico for breakers and switchgear. Wood
8 Mackenzie, a global data and analytics provider for the energy industry, noted that
9 critical path aspects of transmission and distribution projects have:

10 [F]aced tremendous security of supply and cost pressure the past five
11 years with increased competition for the materials with the rise of
12 renewables and transmission & distribution construction, increased
13 storm response and volatile metals markets. . . . The additional cost
14 pressure from tariffs coupled with supply pressure via new electric
15 generation assets to support AI data centres, and a shift of federal
16 investments from renewables builds to T&D infrastructure may
17 exacerbate what the last five years have been.⁵⁶

18 Apart from contributing to higher prices for materials and equipment, supply
19 chain disruptions and shortages have the potential to delay necessary construction and
20 maintenance of utility infrastructure. Chris Seiple, Vice Chairman at Wood Mackenzie
21 concluded that, “In a business with 5-to-10-year planning cycles, not knowing what a
22 project will cost next year or the year after is disruptive and causes massive uncertainty
23 for US power industry participants.”⁵⁷ Similarly, S&P concluded that tariff policies
24 will contribute to financial volatility and weakened investor confidence in the utility
25 sector over the medium to long-term.⁵⁸ While the Supreme Court ruled in February

⁵⁵ Wood Mackenzie, *Navigating the impact of President Trump’s tariffs on utility supply chains* (Jan. 16, 2025), <https://www.woodmac.com/news/opinion/the-impact-of-proposed-tariffs-on-utility-supply-chains/> (last visited Apr. 19, 2026).

⁵⁶ *Id.*

⁵⁷ Wood Mackenzie, *Tariffs to increase costs and slow down development for US power industry* (Jun. 2, 2025), <https://www.cbo.gov/publication/61823> (last visited April 19, 2026).

⁵⁸ S&P Global Ratings, *Navigating Tariffs’ Credit Implications Across Asset Classes, Comments* (Jun. 17, 2025).

1 2026 that many of President Trump’s broad “emergency” tariffs were unlawful,⁵⁹ the
2 White House immediately signaled its intention to ratchet up a “global tariff” from
3 10% to 15% in response to the Court’s decision.⁶⁰ It is reasonable to expect that the
4 recently volatile supply chain and tariff environment would be a concern for UPPCO’s
5 investors.

6 **Q57. WHAT BENCHMARKS ARE AVAILABLE FOR GENERAL CHANGES IN**
7 **CAPITAL COSTS?**

8 A57. Although the cost of equity is not observable, a number of market benchmarks provide
9 a gauge for the direction of capital costs, including required returns on common stocks.
10 Yields on 30-year Treasury bonds are generally accepted as a guide to the risk-free
11 rate. While yields on long-term Treasury bonds can be impacted by monetary policy
12 (e.g., quantitative easing) or a flight to safety in times of turmoil, they provide an
13 observable benchmark for underlying trends in capital costs. Similarly, utility bonds
14 are actively traded in the debt markets and the resulting yields offer a touchstone for
15 the direction and magnitude of the return utilities must offer to attract capital.
16 Although not specific to long-term capital costs, the target range for the Federal Funds
17 rate established by the Federal Reserve is also widely followed by investors as a metric
18 for monetary policies and underlying capital market conditions.

19 **Q58. DO THESE BENCHMARKS INDICATE THAT THE COST OF EQUITY HAS**
20 **INCREASED IN RECENT YEARS?**

21 A58. Yes. Table 3 below compares capital market benchmarks in March 2026 with average
22 levels for 2021.

⁵⁹ SCOTUSblog, Supreme Court strikes down tariffs (Feb. 20, 2026), <https://www.scotusblog.com/2026/02/supreme-court-strikes-down-tariffs/> (last visited Apr. 19, 2026).

⁶⁰ PBS News, Trump increases global tariffs to 15% after Supreme Court decision, <https://www.pbs.org/newshour/economy/president-trump-increases-global-tariffs-to-15-after-supreme-court-decision> (Apr. 19, 2026).

1
2

TABLE 3
CAPITAL MARKET BENCHMARKS

Series	2021	March 2026	Change (bps)
10-Year Treasury Bonds	1.44%	4.25%	281
30-Year Treasury Bonds	2.05%	4.85%	280
Baa Utility Bonds	3.35%	5.99%	264
Prime Loan Rate	3.25%	6.75%	350
Federal Funds Rate	0.13%	3.63%	350

Source: <https://fred.stlouisfed.org>; Moody's Credit Trends.

3
4
5
6
7
8

As shown above, trends in bond yields since 2021 document a substantial increase in the returns on long-term capital demanded by investors. With respect to Baa utility bonds, the average yield in March 2026 was 264 basis points above the level prevailing during 2021, while Treasury bond yields have increased 280 basis points, on average. The Prime Rate and the midpoint of the Federal Reserve's target range for the Federal Funds rate have both increased 350 basis points.

9
10

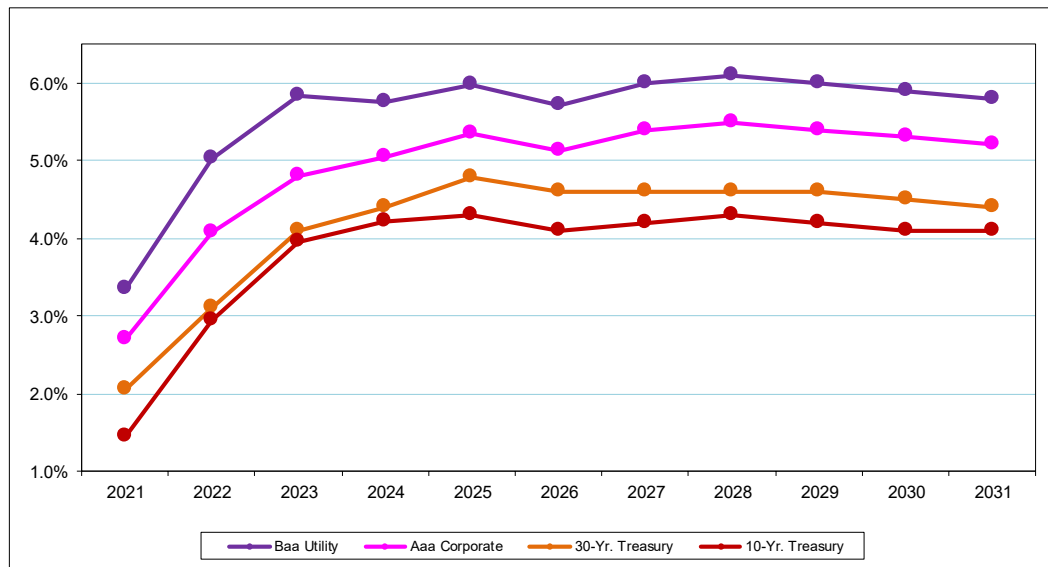
Q59. DO INVESTORS ANTICIPATE THAT THESE HIGHER BOND YIELDS WILL BE SUSTAINED?

11
12
13
14

A59. Yes. As illustrated in Figure 2 below, the most recent long-term consensus projections from top economists published by Blue Chip Financial Forecasts document that long-term bond yields are expected to remain elevated when compared to recent historical levels.

1
2

**FIGURE 2
PROJECTED INTEREST RATES**



Source: Moody's Investors Service; <https://fred.stlouisfed.org/>; Wolters Kluwer, Blue Chip Financial Forecasts (Dec. 1, 2025).

3 This evidence shows that long-term capital costs—including the ROE—have
4 increased substantially, and that investors expect these higher capital costs to be
5 sustained at least through 2031.

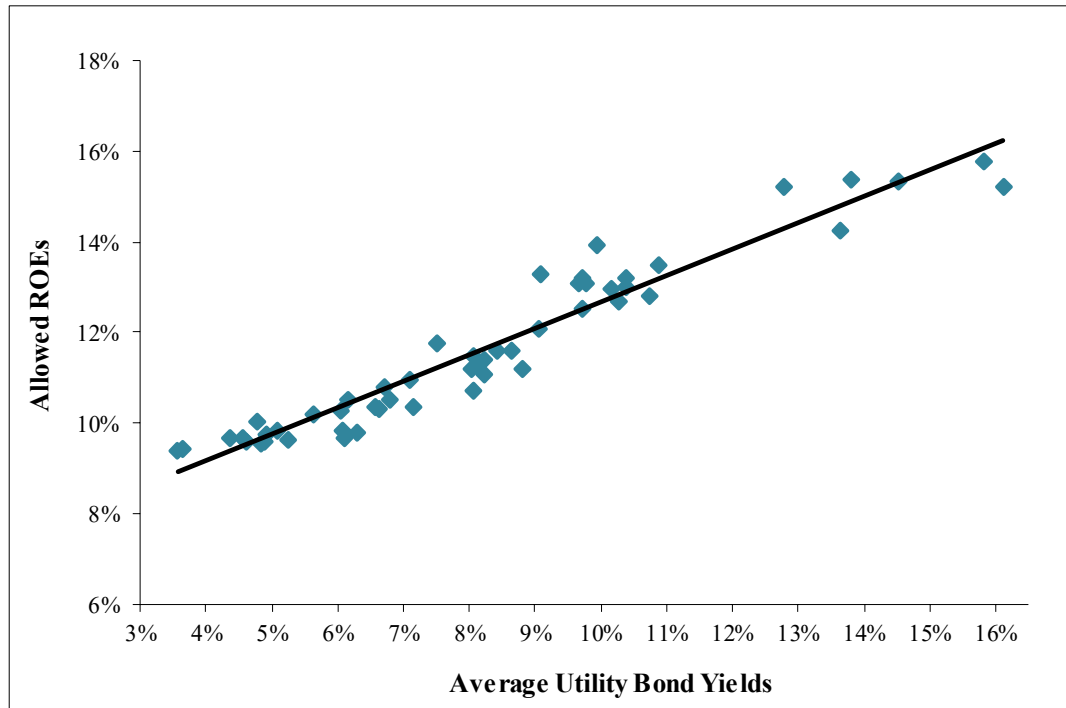
6 **Q60. DO AUTHORIZED ROES EXHIBIT A STRONG POSITIVE RELATIONSHIP**
7 **WITH BOND YIELDS?**

8 A60. Yes. The strong positive relationship between allowed ROEs and bond yields is
9 confirmed by the data underlying my own risk premium study, which shows a positive
10 relationship between allowed ROEs and average utility bond yields from 1974 to
11 2025.⁶¹ The allowed ROE and utility bond yield data from page 2 of Exhibit A-39
12 (JST-8) is displayed below.

⁶¹ Exhibit A-39 (JST-8) at 2.

1
2

FIGURE 3
ALLOWED ROES AND UTILITY BOND YIELDS (1974-2025)



Source: Exhibit JST-8, page 2; Moody's Creditrends.

3
4

The data displayed above show a clear, positive relationship between allowed ROEs and average utility bond yields from 1974 to 2025.

5
6

Q61. IS THE POSITIVE RELATIONSHIP BETWEEN ALLOWED ROES AND INTEREST RATES STATISTICALLY SIGNIFICANT?

7
8
9
10

A61. Yes. In order to measure this relationship, I performed a simple regression analysis on the data underlying Figure 3 with allowed ROE as the dependent variable and average utility bond yield as the independent variable. My regression analysis resulted in the following estimated relationship:

11

$$\text{Allowed ROE} = 0.0712 + 0.5826(\text{Average Utility Bond Yield})$$

12
13

The coefficient estimate of 0.5826 indicates that allowed ROEs increase approximately 58 basis points with each 100 basis point increase in average utility

1 bond yields, on average, over the 1974 to 2025 period.⁶² I also note that this
2 relationship is statistically significant at a level exceeding 99%, indicating very high
3 statistical reliability, and the regression R-Square value of 0.93 reveals that almost all
4 of the movement in allowed ROEs over the last five decades is explained by changing
5 bond yields. This evidence strongly supports—and indeed directly measures—the
6 statistically significant positive relationship between allowed ROEs and utility bond
7 yields.

8 **Q62. ARE NATIONAL AUTHORIZED ROES FROM 2022 TO 2025**
9 **SIGNIFICANTLY LOWER THAN IN PRIOR YEARS, AFTER**
10 **CONTROLLING FOR CAPITAL COSTS?**

11 A62. Yes. This finding is confirmed and measured by adding a dummy variable for years
12 2022 to 2025 to the equation I previously estimated with allowed ROE as the
13 dependent variable and average utility bond yield as the independent variable.⁶³ This
14 regression specification captures the effect on allowed ROEs of the period 2022 to
15 2025, and resulted in the following coefficient estimates:

$$\begin{aligned} \text{Allowed ROE} &= 0.0727 + 0.5703(\text{Average Utility Bond Yield}) \\ &\quad - 0.0065(2022 \text{ to } 2025) \end{aligned}$$

18 The coefficient estimate of -0.0065 demonstrates that national authorized
19 ROEs from the 2022 to 2025 time period are approximately 65 basis points lower than
20 in the previous period, after controlling for changes in utility bond yields. As before,
21 both coefficient estimates are statistically significant, and the higher regression R-
22 Square value of 0.94 shows that allowed ROEs from 1974 to 2025 are even better
23 explained when the post-2021 period is accounted for. These regression results

⁶² The same relationship holds when utility bond yields fall.

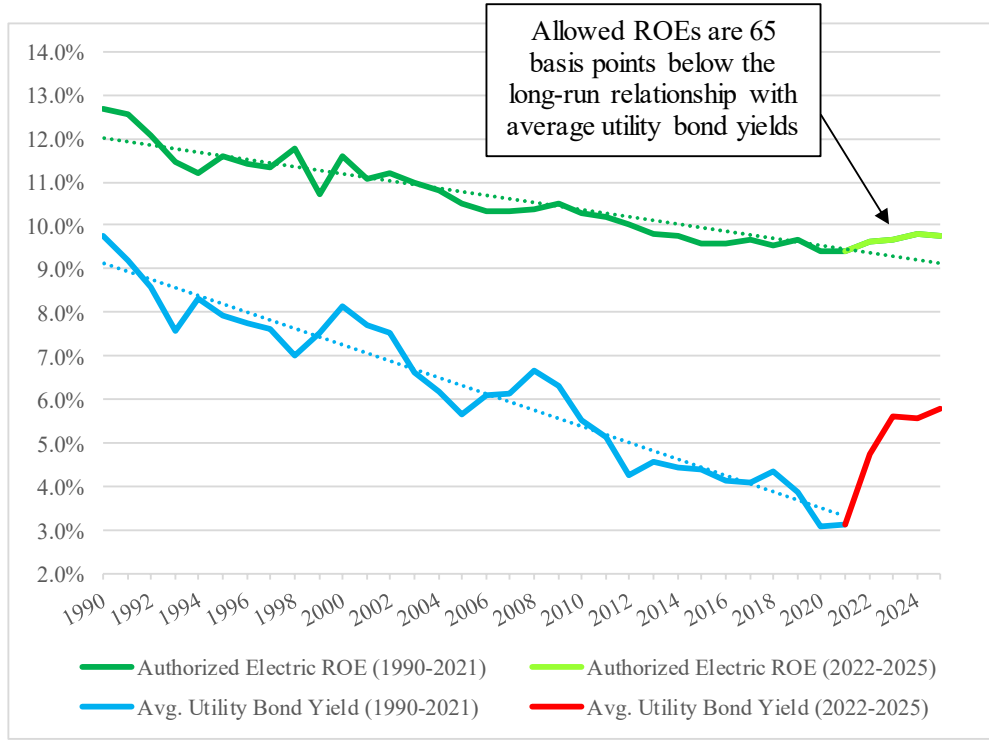
⁶³ In regression analysis, the use of a “dummy variable” is a widespread technique wherein a simple binary variable captures the effect of the presence or absence of a particular attribute. In the present case, the dummy variable captures the effect of being in the 2022 to 2025 time period, or not.

1 demonstrate that authorized ROEs have been lower since 2021 after controlling for
2 capital costs, and by a substantial margin.

3 **Q63. CAN YOU ILLUSTRATE THE DISCONNECT BETWEEN RECENTLY**
4 **ALLOWED ROES FOR ELECTRIC UTILITIES AND UNDERLYING**
5 **CAPITAL COSTS?**

6 A63. Yes. The disconnect between recently allowed ROEs and the recent increase in capital
7 costs documented in Table 3 is illustrated in the figure below.

8 **FIGURE 4**
9 **TRENDS IN AUTHORIZED ELECTRIC ROES AND BOND YIELDS**



Source: Allowed ROEs from Exhibit JST-8, page 2. Average utility bond yields from Moody's Investors Service.

10 As shown above, national authorized ROEs for electric utilities (green line)
11 declined steadily from 1990 until 2021, in line with falling interest rates (blue line),
12 but by a lesser degree. This is consistent with the regression evidence, which showed
13 that allowed ROEs mirror approximately 58% of the movement in utility bond yields.

1 As discussed below, financial research also supports the conclusion that equity risk
2 premiums and interest rates are inversely related, which is apparent in the figure above.

3 As the figure above demonstrates, the upward shift in capital costs that began
4 in 2022 has been swift and dramatic. While it took 22 years for interest rates to fall
5 by one-half,⁶⁴ the Baa utility bond yield almost doubled in just 22 months.⁶⁵ Figure 4
6 also clearly shows that allowed ROEs have only made a slight move upward since
7 2021, and do not currently reflect the sharp increase in utility bond yields that has
8 occurred since early 2022.

9 **Q64. IS THE INVESTMENT COMMUNITY AWARE OF THE DISPARITY**
10 **BETWEEN RECENTLY ALLOWED ROES AND UNDERLYING CAPITAL**
11 **COSTS?**

12 A64. Yes. For example, S&P Global Market Intelligence noted:

13 The first nine months of 2024 saw a slight uptick in the average
14 authorized ROEs for electric and gas utilities, influenced by the higher-
15 interest-rate environment. However, the effect of interest rate increases
16 on authorized returns has not been proportional, as regulators are
17 slower to adjust ROEs upward than downward. Additionally,
18 affordability concerns persist as regulators navigate customer rate hikes
19 due to significant but necessary capital investment in the energy
20 transition amid inflationary pressures.⁶⁶

21 Similarly, a Wall Street Journal article highlighted the cost pressures faced by utilities
22 and noted that, “Investors should exercise caution when picking up utility stocks.”⁶⁷

23 As the article observed, “Higher interest rates haven’t only increased debt-financing
24 costs for utility companies but also raised the cost of capital that they are expected to

⁶⁴ In 1990 the average yield on Baa utility bonds was 10.06%. It wasn’t until 2012 that the average yield fell below 5.03%.

⁶⁵ During December 2021, the yield on Baa utility bonds averaged 3.27%. Over the six months ending December 2023, monthly average bond yields ranged from 5.68% to 6.61%.

⁶⁶ S&P Global Market Intelligence, *Major energy rate case decisions in the US – January-September 2024*, Regulatory Focus (Oct. 30, 2024).

⁶⁷ Jinjoo Lee, *Utilities Get an Inflation Shock*, Wall Street Journal (Jan. 3, 2024). <https://www.wsj.com/finance/investing/utilities-get-an-inflation-shock-cb821c4e> (last visited Feb. 3, 2026).

1 deliver.” Meanwhile, Value Line noted that historical allowed ROEs are “based on a
2 historically low and now out-of-date cost of capital.”⁶⁸ Additionally, Utility Dive
3 reported, “Generally, utilities’ authorized return on equity has lagged recent increases
4 in interest rates and inflation,” attributing this observation to Morningstar analysts.⁶⁹
5 This evidence supports a conclusion that investors are aware of the inconsistency
6 between recently awarded ROEs and higher interest rates.

7 **Q65. HOW DOES UPPCO’S ROE HISTORY COMPARE WITH NATIONAL**
8 **TRENDS?**

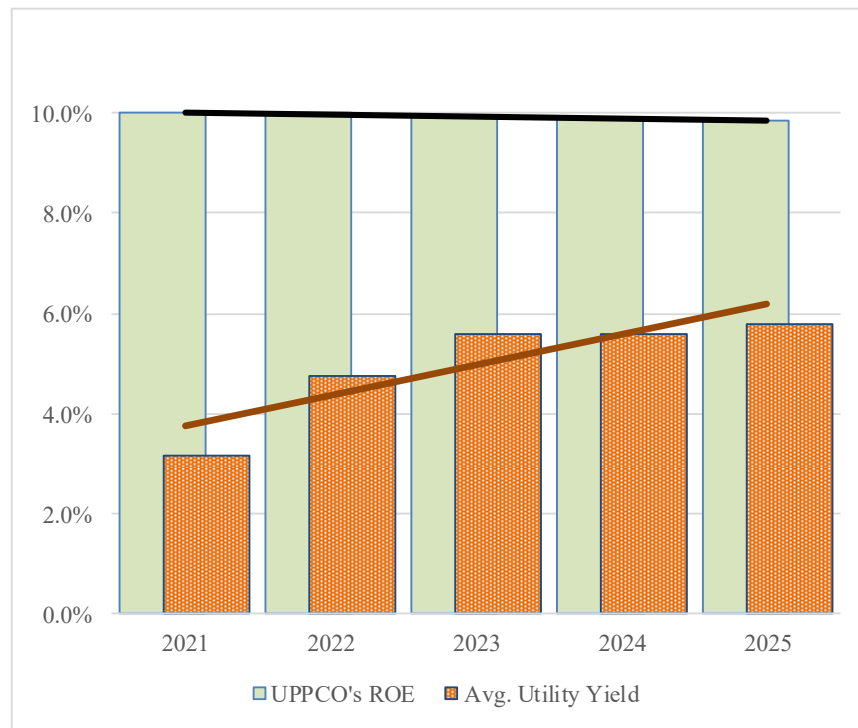
9 A65. While national authorized ROEs have made modest upward gains since 2021,
10 UPPCO’s allowed ROE has actually decreased. For example, the data underlying
11 Figure 4 above show that national authorized ROEs were approximately 35 basis
12 points higher in 2025 than they were in 2021. While this movement is nowhere near
13 the corresponding 266 basis point increase in average utility yields that occurred, at
14 least national authorized ROEs have generally been moving in the same direction as
15 utility bond yields. UPPCO, on the other hand, has actually experienced a decrease in
16 its authorized ROE over a period in which utility bond yields have increased
17 dramatically. Figure 5 below documents this finding.

⁶⁸ The Value Line Investment Survey, *Electric Utility (East) Industry* (May 10, 2024).

⁶⁹ Utility Dive, *North American utility credit metrics weaken on rising capex, regulatory lag: Morningstar* (May 17, 2024), <https://www.utilitydive.com/news/electric-utility-credit-metrics-capex-morningstar-eei/716425/> (last visited Feb. 3, 2026).

1
2

FIGURE 5
UTILITY BOND YIELDS AND UPPCO'S AWARDED ROE



Source: Moody's Investors Service; <https://fred.stlouisfed.org/>.

3
4
5
6
7
8
9
10
11
12
13
14

As shown above, UPPCO's average awarded ROE has trended 14 basis points lower over a period when average utility bond yields have climbed 266 basis points. UPPCO's authorized ROE since 2021 is even more out of step with utility bond yields than national ROEs are. If an ROE of 10.00% was just and reasonable for UPPCO in 2021, then it stands to reason that the Company's authorized ROE in today's capital markets should be substantially higher.

Q66. THE FEDERAL RESERVE LOWERED THE TARGET RANGE FOR THE FEDERAL FUNDS RATE SEVERAL TIMES IN 2025. DOES THIS CHANGE YOUR CONCLUSION THAT THE COST OF EQUITY IS NOW SIGNIFICANTLY HIGHER?

A66. No. Current bond yields embody the market's expectations of future events, including Federal Reserve monetary policy and inflation trends. The 25 basis point cuts to the

1 target range for the Federal Funds rate in September, October and December 2025
2 were anticipated by the market. For example, in response to the September 2025 rate
3 cut, Guy Lebas, Chief Fixed Income Strategist at Janney Capital Management,
4 observed, “This was about as close to expectations as humanly possible (and) basically
5 what was baked into markets ahead of time.”⁷⁰ Meanwhile, Uto Shinohara, Senior
6 Investment Strategist at Mesirow Currency Management, confirmed that “the Fed
7 delivered a widely expected rate cut” in October 2025.⁷¹ Similarly, CNN.com reported
8 “The Fed delivered its third-straight rate cut, which was widely anticipated by Wall
9 Street” in December 2025.⁷² It should be noted that the forecasts of leading economists
10 presented in Figure 2 also consider expectations for future changes in Federal Reserve
11 monetary policies.

12 Long-term interest rates and capital costs are also influenced by a host of
13 considerations beyond the Federal Funds rate, which is an overnight lending rate
14 between banks. For example, Moody’s noted the potential for higher broad-based
15 tariffs on imports and deficit-financed tax cuts to “result in some combination of higher
16 inflation and interest rates.”⁷³ There is no indication that the impact of any near-term
17 cuts in the Federal Funds rate would erase the significant increase in key interest rate
18 benchmarks documented in Table 3.

⁷⁰ Reuters.com, *Instant View: Analysts react after Fed cuts interest rates by quarter of a percentage point* (Sep. 17, 2025), <https://www.reuters.com/business/view-fed-lowers-rates-by-quarter-point-powell-says-was-risk-management-cut-2025-09-17/> (last visited Jan. 30, 2026).

⁷¹ Reuters.com, *Instant View: Fed delivers expected rate cut; Powell says December rate cut not assured* (Oct. 29, 2025), <https://www.reuters.com/business/view-fed-delivers-expected-rate-cut-nods-limits-data-during-shutdown-2025-10-29/> (last visited Jan. 30, 2026).

⁷² CNN.com, *Wall Street tries to rally as Fed cuts rates* (Dec. 10, 2025), <https://www.cnn.com/business/live-news/federal-reserve-interest-rate-12-10-2025> (last visited Jan. 30, 2026).

⁷³ Moody’s Investors Service, *Trump Take Two (Take Two)*, Economic View (Nov. 19, 2024).

1 **Q67. DOES THIS EVIDENCE SUPPORT A MATERIAL INCREASE TO UPPCO'S**
2 **ROE?**

3 A67. Yes. As indicated above, trends in bond yields provide direct evidence that the cost of
4 equity for electric utilities has increased dramatically. Considering these changes in
5 capital market conditions, a significant increase to UPPCO's ROE is warranted,
6 especially when long-run ROE and interest rate trends are accounted for.

7 **B. Affordability**

8 **Q68. HAS AFFORDABILITY BECOME AN ISSUE IN REGULATORY**
9 **PROCEEDINGS IN RECENT YEARS?**

10 A68. Yes. In my experience, affordability is being increasingly referenced in state
11 regulatory proceedings as a consideration for ROE determination. Consistent with this
12 observation, S&P Global recently reported:

13 As we enter 2026, affordability remains a key issue shaping the US
14 power and utility sector, moving from a background concern to a
15 binding constraint on what utilities can earn and build. This shift is
16 driven by mounting pressure at state and federal levels, with energy
17 prices having risen much faster than inflation and customer
18 dissatisfaction at historic highs.⁷⁴

19 Similarly, Moody's noted that, "Rising demand, higher power prices, persistent
20 inflation and elevated capital spending have the potential to increase some utilities'
21 exposure to affordability concerns."⁷⁵ There is little doubt that customer affordability
22 is a concern within today's utility regulatory landscape.

⁷⁴ S&P Global, *Record amount of utility rate requests in 2025 amid affordability concerns* (Jan. 23, 2026), <https://www.spglobal.com/market-intelligence/en/news-insights/research/2026/01/record-amount-of-utility-rate-requests-in-2025-amid-affordability-concerns> (last visited Jan. 30, 2026).

⁷⁵ Moody's Ratings, *Electric and Gas Utilities – US*, Outlook (Oct. 31, 2025).

1 **Q69. HAVE UPPCO'S RESIDENTIAL ELECTRICITY RATES BECOME LESS**
2 **AFFORDABLE FOR THE COMPANY'S CUSTOMERS IN RECENT YEARS?**

3 A69. No. For example, data compiled by the Commission show that UPPCO's average
4 retail electricity rates have increased 16.9% over the ten year period from January 2014
5 to January 2024,⁷⁶ which implies constant annual growth of around 1.47% per year.
6 Meanwhile, median household income in UPPCO's service territory increased
7 approximately 47.6% from 2014 to 2024, or around 3.97% per year.⁷⁷ These median
8 income figures show that UPPCO's residential electricity rates have actually become
9 *more affordable* to their Upper Peninsula residential customers over approximately the
10 last decade.

11 UPPCO's average retail electricity rates have also grown less than overall
12 inflation in the United States. For example, average CPI inflation in the United States
13 from 2014 to 2024 was approximately 2.86% per year,⁷⁸ as compared to 1.47% growth
14 in UPPCO's retail electricity rates. These data show that UPPCO's rates actually
15 *declined* in real (inflation adjusted) terms from 2014 to 2024.

16 **Q70. HOW HAS UPPCO'S RESIDENTIAL CUSTOMER ELECTRICITY**
17 **SPENDING CHANGED IN RECENT YEARS?**

18 A70. Like the Company's residential rates, UPPCO's average residential customer bill has
19 increased less than median incomes in UPPCO's service territory from 2014 to 2024.
20 For example, in 2014 UPPCO received around \$1,313 in revenue per residential
21 customer, while in 2024 the Company received approximately \$1,405.⁷⁹ These figures

⁷⁶ Michigan Public Service Commission Utility Rate Books, *Comparison of Average Rates (in Cents per kWh) for MPSC-Regulated Electric Utilities in Michigan*, <https://www.michigan.gov/-/media/Project/Websites/mpsc/consumer/electric/rates1.pdf> (last visited Jan. 30, 2026).

⁷⁷ U.S. Census Bureau, *American Community Survey*, <https://data.census.gov/all?q=s1901> (last visited Apr. 28, 2026).

⁷⁸ Federal Reserve Economic Data, *Consumer Price Index for All Urban Consumers: All Items in U.S. City Average*, <https://fred.stlouisfed.org/series/CPIAUCSL> (last visited Feb. 3, 2026).

⁷⁹ FERC Financial Report, FERC Form No. 1, *Upper Peninsula Power Company* (May 7, 2015); FERC Financial Report, FERC Form No. 1, *Upper Peninsula Power Company* (Apr. 11, 2025).

1 correspond to a 7.0% increase in average electricity spending per residential customer
2 over this ten year period, and they imply constant annual growth of around 0.68%.
3 This is considerably lower than median income growth, which was 3.97% per year in
4 UPPCO's service territory.

5 As a practical matter, these data indicate that the average UPPCO retail
6 customer was spending a significantly smaller portion of their household income on
7 electricity in 2024 than they were ten years prior. Residential electricity bills have
8 become *more affordable* for UPPCO's residential customers over the last decade when
9 viewed in the context of median household income.

10 **Q71. DO HOUSEHOLDS GENERALLY SPEND A LARGE PORTION OF THEIR**
11 **INCOME ON ELECTRICITY?**

12 A71. No. On average, electricity bills are a very small fraction of household incomes in
13 Michigan, and also in UPPCO's narrower service territory. This finding is supported
14 by recent reporting from S&P, which showed that electricity bills comprised around
15 1.8% of household income in Michigan, which was less than the national average of
16 2.0%.⁸⁰ The counties in UPPCO's service territory had average median household
17 income of \$57,631 in 2024, while UPPCO's average revenue per residential customer
18 in 2024 was approximately \$1,405.⁸¹ This would mean that, on average, UPPCO's
19 residential customers spent roughly 2.4% of their household incomes on electricity in
20 2024. In Michigan and in the Upper Peninsula, households spend a very small fraction
21 of their incomes on electricity.

22 **Q72. DO THE REGULATORY STANDARDS SET FORTH IN *BLUEFIELD* AND**
23 ***HOPE* REFERENCE CUSTOMER AFFORDABILITY?**

24 A72. No. As was discussed, the Supreme Court's guidance in *Bluefield* and *Hope*
25 establishes that a just and reasonable ROE for a regulated utility is one that fairly

⁸⁰ S&P Global Ratings, *North America Regulated Utilities* (Jan. 14, 2026).

⁸¹ FERC Financial Report, FERC Form No. 1, *Upper Peninsula Power Company* (Apr. 11, 2025).

1 compensates a utility's investors, allows the utility to attract capital on reasonable
2 terms, and preserves the utility's financial integrity. In other words, ROE
3 determination does not explicitly consider customer affordability.

4 **Q73. IS THE ISSUE OF AFFORDABILITY SEEN AS A POTENTIAL RISK**
5 **FACTOR IN THE EYES OF UTILITY INVESTORS?**

6 A73. Yes. For example, S&P recently noted that “rising concerns around affordability could
7 limit regulatory appetite for further [capex] spending growth”⁸² for electric utilities.
8 Similarly, Moody’s recently reported that “Rising demand, higher power prices,
9 persistent inflation and elevated capital spending have the potential to increase some
10 utilities’ exposure to affordability concerns.”⁸³ Citing Moody’s, Utility Dive explained
11 the link between affordability and utility risk:

12 Rising electricity prices increase the risk to regulated U.S. utilities of
13 “adverse regulatory or political intervention” that could hurt their credit
14 quality, according to Moody’s Investors Service.

15 “As power supply ramps up to meet rising load forecasts, the potential
16 for higher electricity prices may leave U.S. regulated utilities with
17 greater credit exposure to social risk,” Moody’s said in a report
18 Wednesday.

19 Moody’s said it considers affordability a key credit metric and social
20 risk for regulated utilities because their rates go through regulatory
21 review processes that can lead to “adverse outcomes” if regulators feel
22 that customers have become financially overburdened.⁸⁴

23 Utility Dive similarly referenced Morningstar’s observations as to the credit risks
24 associated with affordability:

25 “Furthermore, as regulators seek to balance utility investment needs
26 and consumer affordability because of the current economic condition,

⁸² S&P Global, *North American electric utilities review*, Commodity Insights (Jul. 23, 2025).

⁸³ Moody’s Ratings, *Regulated Electric and Gas Utilities – US, Outlook stable; supportive regulation to offset modestly negative macro factors* (Oct. 31, 2025).

⁸⁴ Utility Dive, *Rising power prices increase credit risk for utilities: Moody’s* (Sep. 13, 2024) (emphasis added), <https://www.utilitydive.com/news/electricity-prices-utility-regulatory-risk-moodys-inflation-eia/726936/> (last visited Feb. 3, 2026).

1 this often exerts downward pressure on the ROE,” the analysts said.
2 “Having a relatively low ROE compared with the actual cost of capital
3 can directly impact credit metrics.”⁸⁵

4 This evidence shows that ratings agencies are keenly aware of the credit risks utilities
5 are facing from affordability. There is no doubt that utility investors are also aware of
6 these risks.

7 V. CAPITAL MARKET ESTIMATES

8 **Q74. WHAT IS THE PURPOSE OF THIS SECTION?**

9 A74. This section presents capital market estimates of the cost of equity. I describe the DCF,
10 CAPM and risk premium analyses conducted to estimate the cost of common equity
11 for the Utility Group. Finally, I comment on expected earnings and non-utility DCF
12 benchmarks, and then discuss UPPCO’s requested ROE in light of my ROE findings.

13 **A. Discounted Cash Flow Analyses**

14 **Q75. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF EQUITY?**

15 A75. DCF models assume that the price of a share of common stock is equal to the present
16 value of the expected cash flows (i.e., future dividends and stock price) that will be
17 received while holding the stock, discounted at investors’ required rate of return.
18 Rather than developing annual estimates of cash flows into perpetuity, the DCF model
19 can be simplified to a “constant growth” form:⁸⁶

$$P_0 = \frac{D_1}{k_e - g}$$

⁸⁵ Utility Dive, *North American utility credit metrics weaken on rising capex, regulatory lag: Morningstar* (May 17, 2024), <https://www.utilitydive.com/news/electric-utility-credit-metrics-capex-morningstar-eei/716425/> (last visited Feb. 3, 2026).

⁸⁶ The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (i.e., no changes in risk or interest rate levels and a flat yield curve); and all the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors’ required return that is widely referenced in utility ratemaking.

1 where: P_0 = Current price per share;
2 D_1 = Expected dividend per share in the coming year;
3 k_e = Cost of equity;
4 g = Investors' long-term growth expectations.

5 The cost of equity (k_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

6 This constant growth form of the DCF model recognizes that the rate of return
7 to stockholders consists of two parts: 1) dividend yield (D_1/P_0), and 2) growth (g). In
8 other words, investors expect to receive a portion of their total return in the form of
9 current dividends and the remainder through price appreciation.

10 **Q76. WHAT STEPS ARE REQUIRED TO APPLY THE DCF MODEL?**

11 A76. The first step is to determine the expected dividend yield (D_1/P_0) for the firm in
12 question. This is usually calculated based on an estimate of dividends to be paid in
13 the coming year divided by the current price of the stock. The second step is to
14 estimate investors' long-term growth expectations (g) for the firm. The final step is to
15 sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its
16 cost of common equity.

17 **Q77. HOW DO YOU DETERMINE THE DIVIDEND YIELD FOR THE UTILITY
18 GROUP?**

19 A77. Estimates of dividends to be paid by each of these utilities over the next twelve months,
20 obtained from Value Line, serve as D_1 . This annual dividend is then divided by a 30-
21 day average stock price for each utility to arrive at the expected dividend yield. The
22 stock prices, expected dividends, and resulting dividend yields for the firms in the
23 Utility Group are presented on page 1 of Exhibit A-36 (JST-5).

1 **Q78. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF**
2 **MODEL?**

3 A78. The next step is to evaluate long-term growth expectations, or “g”, for the firm in
4 question. In constant growth DCF theory, earnings, dividends, book value, and market
5 price are all assumed to grow in lockstep, and the growth horizon of the DCF model
6 is infinite. But implementation of the DCF model is more than just a theoretical
7 exercise; it is an attempt to replicate the mechanism investors used to arrive at
8 observable stock prices. A wide variety of techniques can be used to derive growth
9 rates, but the only “g” that matters in applying the DCF model is the value that
10 investors expect.

11 **Q79. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING**
12 **THEIR LONG-TERM GROWTH EXPECTATIONS?**

13 A79. Implementing the DCF model seeks to replicate the forward-looking evaluation of
14 real-world investors. In the case of utilities, dividend growth rates are not likely to
15 provide a meaningful guide to investors’ current growth expectations. Utility dividend
16 policies reflect the need to accommodate business risks and investment requirements
17 in the industry, as well as potential uncertainties in the capital markets. As a result,
18 dividend growth in the utility industry generally lags growth in earnings as utilities
19 conserve financial resources to provide a hedge against heightened uncertainties.

20 A measure that plays a pivotal role in determining investors’ long-term growth
21 expectations are future trends in earnings per share (“EPS”), which provide the source
22 for future dividends and ultimately support share prices. The importance of earnings
23 in evaluating investors’ expectations and requirements is well accepted in the
24 investment community, and surveys of analytical techniques relied on by professional
25 analysts indicate that growth in earnings is far more influential than trends in dividends
26 per share (“DPS”).

1 The availability of projected EPS growth rates also is key to investors relying
2 on this measure as compared to future trends in DPS. Apart from Value Line,
3 investment advisory services do not generally publish comprehensive DPS growth
4 projections, and this scarcity of dividend growth rates relative to the abundance of
5 earnings forecasts attests to their relative influence. The fact that securities analysts
6 focus on EPS growth, and that DPS growth rates are not routinely published, indicates
7 that projected EPS growth rates are likely to provide a superior indicator of the future
8 long-term growth expected by investors.

9 **Q80. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE**
10 **WAY OF GROWTH FOR THE FIRMS IN THE UTILITY PROXY GROUP?**

11 A80. The projected EPS growth rates for each of the firms in the Utility Group reported by
12 IBES,⁸⁷ S&P Capital IQ, Value Line and Zacks Investment Research (“Zacks”) are
13 displayed on page 2 of Exhibit A-36 (JST-5).

14 **Q81. HOW ELSE ARE INVESTORS’ EXPECTATIONS OF FUTURE LONG-**
15 **TERM GROWTH PROSPECTS SOMETIMES ESTIMATED WHEN**
16 **APPLYING THE CONSTANT GROWTH DCF MODEL?**

17 A81. In constant growth theory, growth in book equity will be equal to the product of the
18 earnings retention ratio (one minus the dividend payout ratio) and the earned rate of
19 return on book equity. Furthermore, if the earned rate of return and the payout ratio
20 are constant over time, growth in earnings and dividends will be equal to growth in
21 book value. Even though these conditions are never met in practice, this “sustainable
22 growth” approach may provide a rough guide for evaluating a firm’s growth prospects
23 and is frequently proposed in regulatory proceedings.

24 The sustainable growth rate is calculated by the formula, $g = br + sv$, where “b”
25 is the expected retention ratio, “r” is the expected earned return on equity, “s” is the

⁸⁷ Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by London Stock Exchange Group (LSEG).

1 percent of common equity expected to be issued annually as new common stock, and
2 “v” is the equity accretion rate. Under DCF theory, the “sv” factor is a component of
3 the growth rate designed to capture the impact of issuing new common stock at a price
4 above, or below, book value. The sustainable, “br+sv” growth rates for each firm in
5 the Utility Group are summarized on page 2 of Exhibit A-36 (JST-5), with the
6 underlying details being presented on Exhibit A-37 (JST-6).

7 The sustainable growth rates developed in Exhibit A-37 (JST-6) incorporate an
8 “adjustment factor” because Value Line’s reported returns are based on year-end book
9 values. Since earnings is a flow over the year while book value is determined at a
10 given point in time, the measurement of earnings and book value are distinct concepts.
11 It is this fundamental difference between a flow (earnings) and point estimate (book
12 value) that makes it necessary to adjust to mid-year in calculating the ROE. Given
13 that book value will increase or decrease over the year, using year-end book value (as
14 Value Line does) understates or overstates the average investment that corresponds to
15 the flow of earnings. To address this concern, earnings must be matched with a
16 corresponding representative measure of book value, or the resulting ROE will be
17 distorted. The adjustment factor determined in Exhibit A-37 (JST-6) is solely a means
18 of converting Value Line’s end-of-period values to an average return over the year, and
19 the formula for this adjustment is supported in recognized textbooks and has been
20 adopted by other regulators.⁸⁸

21 **Q82. ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH THE**
22 **“BR+SV” GROWTH RATE?**

23 A82. Yes. First, in order to calculate the sustainable growth rate, it is necessary to develop
24 estimates of investors’ expectations for four separate variables; namely, “b”, “r”, “s”,
25 and “v.” Given the inherent difficulty in forecasting each parameter and the difficulty

⁸⁸ See, Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 305-306; *Bangor Hydro-Electric Co. et al.*, 122 FERC ¶ 61,265 at n.12 (2008).

1 of estimating the expectations of investors, the potential for measurement error is
2 significantly increased when using four variables, as opposed to referencing a direct
3 projection for EPS growth. Second, empirical research in the finance literature
4 indicates that sustainable growth rates are not as significantly correlated to measures
5 of value, such as share prices, as are analysts' EPS growth forecasts.⁸⁹ The
6 "sustainable growth" approach is included for completeness, but evidence indicates
7 that analysts' forecasts provide a superior and more direct guide to investors' growth
8 expectations. Accordingly, I give less weight to cost of equity estimates based on
9 br+sv growth rates in evaluating the results of the DCF model.

10 **Q83. WHAT COST OF EQUITY ESTIMATES ARE IMPLIED FOR THE UTILITY**
11 **GROUP USING THE DCF MODEL?**

12 A83. After combining the dividend yields and respective growth projections for each utility,
13 the resulting cost of equity estimates are shown on page 3 of Exhibit A-36 (JST-5).

14 **Q84. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF**
15 **MODEL, IS IT APPROPRIATE TO ELIMINATE ILLOGICAL ESTIMATES?**

16 A84. Yes. It is essential that the cost of equity estimates produced by quantitative methods
17 pass fundamental tests of reasonableness and economic logic. Accordingly, DCF
18 estimates that are implausibly low or high should be eliminated.

19 **Q85. HOW DO YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE**
20 **RANGE?**

21 A85. My evaluation of DCF estimates at the low end of the range is based on the
22 fundamental risk-return tradeoff, which holds that investors will only take on more
23 risk if they expect to earn a higher rate of return to compensate them for the greater
24 uncertainty. Because common stocks lack the protections associated with an
25 investment in long-term bonds, a utility's common stock imposes far greater risks on

⁸⁹ Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 307.

1 investors. As a result, the rate of return that investors require from a utility's common
2 stock is considerably higher than the yield offered by senior, long-term debt.
3 Consistent with this principle, DCF results that are not sufficiently higher than the
4 yield available on less risky utility bonds must be eliminated.

5 **Q86. HAVE SIMILAR TESTS BEEN APPLIED BY OTHER REGULATORS?**

6 A86. Yes. FERC has noted that adjustments are justified where applications of the DCF
7 approach and other methods produce illogical results. FERC evaluates low-end DCF
8 results against observable yields on long-term public utility debt and has recognized
9 that it is appropriate to eliminate estimates that do not sufficiently exceed this
10 threshold.⁹⁰ FERC's current practice is to exclude low-end estimates that fall below
11 the six-month average yield on Baa-rated utility bonds, plus 20% of the CAPM market
12 risk premium.⁹¹ In addition, FERC also excludes estimates that are "irrationally or
13 anomalously high."⁹²

14 **Q87. DO YOU EXCLUDE ANY ESTIMATES AT THE LOW OR HIGH END OF**
15 **THE RANGE OF DCF RESULTS?**

16 A87. Yes. As highlighted on page 3 of Exhibit A-36 (JST-5), I eliminate low-end DCF
17 estimates ranging from 1.6% to 7.5%. Based on my professional experience and the
18 risk-return tradeoff principle that is fundamental to finance, it is inconceivable that
19 investors are not requiring a substantially higher rate of return for holding common
20 stock. After removing these illogical values, the lower end of the DCF results is set
21 by a cost of equity estimate of 7.5%, while the upper end is established by a cost of
22 equity estimate of 14.5%. While a 14.5% cost of equity estimate may exceed the

⁹⁰ See, e.g., *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 at PP 19, 387-89.

⁹¹ Based on the average yield on Baa-rated utility bonds for the six month period ending March 2026 of 5.84%, and the current market risk premium from Exhibit A-38 (JST-7) of 8.20%, FERC's low-end threshold would equate to approximately 7.48%.

⁹² *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 171 FERC ¶ 61,154 at P 152 (2020).

1 majority of the remaining values, retained low-end DCF estimates in the 7.5% to 7.8%
2 range are assuredly far below investors' required rate of return. Taken together and
3 considered along with the balance of the results, the remaining values provide a
4 reasonable basis on which to frame the range of plausible DCF estimates and evaluate
5 investors' required rate of return.

6 **Q88. WHAT COST OF EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF**
7 **RESULTS FOR THE UTILITY GROUP?**

8 A88. As shown on page 3 of Exhibit A-36 (JST-5) and summarized in Table 4, below, after
9 eliminating illogical values, application of the constant growth DCF model results in
10 the following cost of equity estimates:

11 **TABLE 4**
12 **DCF RESULTS – UTILITY GROUP**

<u>Growth Rate</u>	<u>Average</u>
IBES	11.1%
S&P Capital IQ	9.9%
Value Line	9.9%
Zacks	10.6%
br + sv	9.2%

13 **B. Capital Asset Pricing Model**

14 **Q89. PLEASE DESCRIBE THE CAPM.**

15 A89. The CAPM is a theory of market equilibrium that measures risk using the beta
16 coefficient. Assuming investors are fully diversified, the relevant risk of an individual
17 asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta
18 reflecting the tendency of a firm's stock price to follow changes in the market. A stock
19 that tends to respond less to market movements has a beta less than 1.00, while stocks
20 that tend to move more than the market have betas greater than 1.00. The CAPM is
21 mathematically expressed as:

1
$$R_j = R_f + \beta_j(R_m - R_f)$$

2 where: R_j = required rate of return for stock j;
3 R_f = risk-free rate;
4 R_m = expected return on the market portfolio; and,
5 β_j = beta, or systematic risk, for stock j.

6 Under the CAPM formula above, a stock's required return is a function of the
7 risk-free rate (R_f), plus a risk premium that is scaled to reflect the relative volatility of
8 a firm's stock price, as measured by beta (β). Like the DCF model, the CAPM is an
9 *ex-ante*, or forward-looking model based on expectations of the future. As a result, in
10 order to produce a meaningful estimate of investors' required rate of return, the CAPM
11 must be applied using estimates that reflect the expectations of actual investors in the
12 market, not with backward-looking, historical data.

13 **Q90. HOW DO YOU APPLY THE CAPM TO ESTIMATE THE COST OF**
14 **COMMON EQUITY?**

15 A90. Application of the CAPM to the Utility Group based on a forward-looking estimate
16 for investors' required rate of return from common stocks is presented on Exhibit A-
17 38 (JST-7). In order to capture the expectations of today's investors in current capital
18 markets, the expected market rate of return is estimated by conducting a DCF analysis
19 on the dividend paying firms in the S&P 500.

20 The dividend yield for each firm is obtained from Value Line, and the growth
21 rate is equal to the average of the earnings growth projections for each firm published
22 by Value Line, IBES, and Zacks with each firm's dividend yield and growth rate being
23 weighted by its proportionate share of total market value. After removing growth rates
24 that were negative or greater than 20%, the weighted average of the projections for the
25 individual firms implies an average growth rate over the next five years of 11.5%.
26 combining this average growth rate with a year-ahead dividend yield of 1.5% results
27 in a current cost of common equity estimate for the market as a whole (R_m) of 13.0%.

1 Subtracting a 4.8% risk-free rate based on the average yield on 30-year Treasury bonds
2 for the six months ending March 2026 produces a market equity risk premium of 8.2%.

3 **Q91. WHAT BETA VALUES DO YOU USE?**

4 A91. As noted earlier in my discussion of risk measures for the proxy group, I rely on the
5 beta values reported by Value Line, which in my experience is the most widely
6 referenced source for beta in regulatory proceedings.

7 **Q92. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?**

8 A92. Financial research indicates that the CAPM does not fully account for observed
9 differences in rates of return attributable to firm size. Accordingly, a modification is
10 required to account for this size effect. As explained by Morningstar:

11 One of the most remarkable discoveries of modern finance is the
12 finding of a relationship between firm size and return. On average,
13 small companies have higher returns than larger ones. . . . The
14 relationship between firm size and return cuts across the entire size
15 spectrum; it is not restricted to the smallest stocks.⁹³

16 According to the CAPM, the expected return on a security should consist of
17 the riskless rate, plus a premium to compensate for the systematic risk of the particular
18 security. The degree of systematic risk is represented by the beta coefficient. The
19 need for the size adjustment arises because differences in investors' required rates of
20 return that are related to firm size are not fully captured by beta. To account for this,
21 researchers have developed size premiums that need to be added to CAPM cost of
22 equity estimates to account for the level of a firm's market capitalization in
23 determining the CAPM cost of equity.⁹⁴ Accordingly, my CAPM analyses
24 incorporated an adjustment to recognize the impact of size distinctions, as measured
25 by the market capitalization for the firms in the Utility Group.

⁹³ Morningstar, *2015 Ibbotson SBBI Classic Yearbook*, at p. 99 (footnote omitted).

⁹⁴ Originally compiled by Ibbotson Associates and published in their annual yearbook entitled, "Stocks, Bonds, Bills and Inflation," these size premia are now developed by Kroll.

1 **Q93. WHAT IS THE BASIS FOR THE SIZE ADJUSTMENT?**

2 A93. The size adjustment required in applying the CAPM is based on the finding that *after*
3 *controlling for risk differences reflected in beta*, the CAPM overstates returns to
4 companies with larger market capitalizations and understates returns for relatively
5 smaller firms. The size adjustments utilized in my analysis are sourced from Kroll,
6 who now publish the well-known compilation of capital market series originally
7 developed by Professor Roger G. Ibbotson of the Yale School of Management.
8 Calculation of the size adjustments involve the following steps:

- 9 1. Divide all stocks traded on the NYSE, NYSE American, and
10 NASDAQ indices into deciles based on their market capitalization.
- 11 2. Using the average beta value for each decile, calculate the implied
12 excess return over the risk-free rate using the CAPM.
- 13 3. Compare the calculated excess returns based on the CAPM to the
14 actual excess returns for each decile, with the difference being the
15 increment of return that is related to firm size, or “size
16 adjustment.”

17 *New Regulatory Finance* observed that “small market-cap stocks experience higher
18 returns than large market-cap stocks with equivalent betas,” and concluded that “the
19 CAPM understates the risk of smaller utilities, and a cost of equity based purely on a
20 CAPM beta will therefore produce too low an estimate.”⁹⁵ As FERC has recognized,
21 “[t]his type of size adjustment is a generally accepted approach to CAPM analyses.”⁹⁶

22 **Q94. IS THIS SIZE ADJUSTMENT RELATED TO THE RELATIVE SIZE OF**
23 **UPPCO AS COMPARED WITH THE PROXY GROUP?**

24 A94. No. This size adjustment is specific to the CAPM and merely corrects for an observed
25 inability of the beta measure to fully reflect the risks perceived by investors for the
26 firms in the proxy group. My evaluation of the implications of UPPCO’s relative size
27 were presented earlier in my testimony.

⁹⁵ Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 187.

⁹⁶ Opinion No. 531-B at P 117.

1 **Q95. WHAT COST OF EQUITY IS INDICATED FOR THE UTILITY GROUP**
2 **USING THE CAPM APPROACH?**

3 A95. As shown on Exhibit A-38 (JST-7), the CAPM approach implies an average ROE of
4 11.4% after adjusting for the impact of firm size.

5 **C. Risk Premium Approach**

6 **Q96. PLEASE BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.**

7 A96. The risk premium method of estimating investors' required rate of return extends to
8 common stocks the risk-return tradeoff observed with bonds. The cost of equity is
9 estimated by first determining the additional return investors require to forgo the
10 relative safety of bonds and to bear the greater risks associated with common stock,
11 and by then adding this equity risk premium to the current yield on bonds. Like the
12 DCF model, the risk premium method is capital market oriented. However, unlike
13 DCF models, which indirectly impute the cost of equity, risk premium methods
14 directly estimate investors' required rate of return by adding an equity risk premium
15 to observable bond yields.

16 **Q97. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD**
17 **FOR ESTIMATING THE COST OF EQUITY?**

18 A97. Yes. This method is routinely referenced by the investment community and in
19 academia and regulatory proceedings, and provides an important tool in estimating a
20 fair ROE for UPPCO.

21 **Q98. HOW DO YOU IMPLEMENT THE RISK PREMIUM METHOD?**

22 A98. Estimates of equity risk premiums for utilities are based on surveys of previously
23 authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best
24 estimates of the cost of equity, however determined, at the time they issued their final
25 order. Such ROEs should represent a balanced and impartial outcome that considers
26 the need to maintain a utility's financial integrity and ability to attract capital.

1 Moreover, allowed ROEs are an important consideration for investors and have the
2 potential to influence other observable investment parameters, including credit ratings
3 and borrowing costs. Thus, when considered in the context of a complete and rigorous
4 analysis, this data provides a logical and frequently referenced basis for estimating
5 equity risk premiums for regulated utilities.

6 **Q99. HOW DO YOU CALCULATE EQUITY RISK PREMIUMS BASED ON**
7 **ALLOWED RETURNS?**

8 A99. The ROEs authorized for electric utilities by regulatory commissions across the U.S.
9 are compiled by RRA. On page 2 of Exhibit A-39 (JST-8), the average yield on public
10 utility bonds is subtracted from the average allowed ROE for electric utilities to
11 calculate equity risk premiums for each year between 1974 and 2025.⁹⁷ As shown
12 there, over this period these equity risk premiums for electric utilities average 3.91%,
13 and the yields on public utility bonds average 7.70%.

14 **Q100. WHAT CAPITAL MARKET RELATIONSHIP MUST BE CONSIDERED**
15 **WHEN IMPLEMENTING THE RISK PREMIUM METHOD?**

16 A100. Equity risk premiums are not constant and tend to move inversely with interest rates.
17 In other words, when interest rate levels are relatively high, equity risk premiums
18 narrow, and when interest rates are relatively low, equity risk premiums widen. The
19 implication of this inverse relationship is that the cost of equity does not move as much
20 as, or in lockstep with, interest rates. Accordingly, for a 1 percent increase or decrease
21 in interest rates, the cost of equity may only rise or fall some fraction of 1 percent.
22 When implementing the risk premium method, adjustments may be required to
23 incorporate this inverse relationship if the current interest rate is different from the
24 average interest rate over the study period.

⁹⁷ My analysis encompasses the entire period for which published data is available.

1 Current bond yields are lower than those prevailing over the risk premium
2 study period. Given that equity risk premiums move inversely with interest rates, these
3 lower bond yields also imply an increase in the equity risk premium that investors
4 require to accept the higher uncertainties associated with an investment in utility
5 common stocks versus bonds. In other words, higher required equity risk premiums
6 offset the impact of declining interest rates on the ROE.

7 **Q101. HAS THIS INVERSE RELATIONSHIP BEEN DOCUMENTED IN THE**
8 **FINANCIAL RESEARCH?**

9 A101. Yes. The inverse relationship between equity risk premiums and interest rates has been
10 widely reported in the financial literature. As summarized by *New Regulatory*
11 *Finance*:

12 Published studies by Brigham, Shome, and Vinson (1985), Harris
13 (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and
14 Lakonishok (1983), Morin (2005), and McShane (2005), and others
15 demonstrate that, beginning in 1980, risk premiums varied inversely
16 with the level of interest rates – rising when rates fell and declining
17 when rates rose.⁹⁸

18 Other regulators have also recognized that, while the cost of equity trends in the same
19 direction as interest rates, these variables do not move in lockstep.⁹⁹ This relationship
20 is illustrated in the figure on page 3 of Exhibit A-39 (JST-8).

21 **Q102. WHAT ROE IS IMPLIED BY THE RISK PREMIUM METHOD USING**
22 **SURVEYS OF ALLOWED ROES?**

23 A102. Based on the regression output between the interest rates and equity risk premiums
24 displayed on page 3 of Exhibit A-39 (JST-8), the equity risk premium for electric
25 utilities increases by approximately 42 basis points for each percentage point drop in

⁹⁸ Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports (2006) at 128.

⁹⁹ See, e.g., California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-7, https://www.enterymississippi.com/wp-content/uploads/eml_frp.pdf (last visited Nov. 30, 2025); *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 147 (2014).

1 the yield on average public utility bonds.¹⁰⁰ As illustrated on page 1 of Exhibit A-39
2 (JST-8), with an average yield on public utility bonds for the six-month period ending
3 March 2026 of 5.68%, this implies a current equity risk premium of 4.81% for electric
4 utilities. Adding this equity risk premium to the average yield on Baa-rated utility
5 bonds for the six-month period ending March 2026 of 5.84% implies a current ROE
6 of 10.65%.

7 **D. Expected Earnings Benchmark**

8 **Q103. WHAT OTHER ANALYSIS DO YOU CONDUCT TO EVALUATE THE** 9 **REASONABLENESS OF YOUR DCF, CAPM AND RISK PREMIUM** 10 **RESULTS?**

11 A103. I also evaluate the reasonableness of my DCF, CAPM and risk premium ROE
12 outcomes using an expected earnings benchmark. Reference to rates of return
13 available from alternative investments of comparable risk can provide an important
14 benchmark in assessing the return necessary to assure confidence in the financial
15 integrity of a firm and its ability to attract capital. This expected earnings approach is
16 consistent with the economic underpinnings for a just and reasonable rate of return
17 established by the United States Supreme Court in *Bluefield* and *Hope*. Moreover, it
18 avoids the complexities and limitations of capital market methods and instead focuses
19 on the returns earned on book equity, which are readily available to investors.

20 **Q104. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS** 21 **APPROACH?**

22 A104. The expected earnings approach is based on the concept that investors compare each
23 investment alternative with the next best opportunity. If the utility is unable to offer a
24 return similar to that available from other opportunities of comparable risk, investors

¹⁰⁰ This is consistent with the relationship I previously discussed in which authorized ROEs move approximately 58 basis points with each 100 basis point change in utility bond yields.

1 will become unwilling to supply the capital on reasonable terms. For existing
2 investors, denying the utility an opportunity to earn what is available from other
3 similar risk alternatives prevents them from earning their opportunity cost of capital.
4 This outcome would violate the *Hope* and *Bluefield* standards and undermine the
5 utility's access to capital on reasonable terms.

6 **Q105. HOW IS THE EXPECTED EARNINGS APPROACH TYPICALLY**
7 **IMPLEMENTED?**

8 A105. The traditional comparable earnings test identifies a group of companies that are
9 believed to be comparable in risk to the utility. The actual earnings of those companies
10 on the book value of their investment are then compared to the allowed return of the
11 utility. While the traditional comparable earnings test is implemented using historical
12 data taken from the accounting records, it is also common to use projections of returns
13 on book investment, such as those published by recognized investment advisory
14 publications (*e.g.*, Value Line). Because these returns on book value equity are
15 analogous to the allowed return on a utility's rate base, this measure of opportunity
16 costs results in a direct, "apples to apples" comparison.

17 **Q106. WHAT OTHER CONSIDERATION SUPPORTS REFERENCE TO**
18 **EXPECTED RETURNS ON BOOK VALUE?**

19 A106. Regulators do not set the returns that investors earn in the capital markets, which are
20 a function of dividend payments and fluctuations in common stock prices, both of
21 which are outside their control. Regulators can only establish the allowed ROE, which
22 is applied to the book value of a utility's investment in rate base, as determined from
23 its accounting records. This is analogous to the expected earnings approach, which
24 measures the return that investors expect the utility to earn on book value. As a result,
25 the expected earnings approach provides a meaningful guide to ensure that the allowed
26 ROE is similar to what other utilities of comparable risk will earn on invested capital.
27 This expected earnings test does not require theoretical models to indirectly infer

1 investors' perceptions from stock prices or other market data. As long as the proxy
2 companies are similar in risk, their expected earned returns on invested capital provide
3 a direct benchmark for investors' opportunity costs that is independent of fluctuating
4 stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations
5 inherent in any theoretical model of investor behavior

6 **Q107. WHAT ROE BENCHMARK IS INDICATED FOR UPPCO BASED ON THE**
7 **EXPECTED EARNINGS APPROACH?**

8 A107. For the firms in the Utility Group, the year-end returns on common equity projected
9 by Value Line over its forecast horizon are shown on Exhibit A-40 (JST-9). As I
10 explained earlier in my discussion of the $br+sv$ growth rates used in applying the DCF
11 model, Value Line's returns on common equity are calculated using year-end equity
12 balances, which understates the average return earned over the year.¹⁰¹ Accordingly,
13 these year-end values were converted to average returns using the same adjustment
14 factor discussed earlier and developed on Exhibit A-37 (JST-6). As shown on Exhibit
15 A-40 (JST-9), Value Line's projections suggest an average ROE of 11.1% for the
16 Utility Group

17 **E. Non-Utility DCF Benchmark**

18 **Q108. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

19 A108. This section presents the results of my DCF analysis applied to a group of low-risk
20 firms in the competitive sector, which I refer to as the "Non-Utility Group." I do not
21 rely on this analysis to arrive at my recommended ROE range of reasonableness;
22 however, it is my opinion that this is a relevant consideration in evaluating a fair ROE
23 for the Company.

¹⁰¹ For example, to compute the annual return on a passbook savings account with a beginning balance of \$1,000 and an ending balance of \$5,000, the interest income would be divided by the average balance of \$3,000. Using the \$5,000 balance at the end of the year would understate the actual return.

1 **Q109. DO UTILITIES HAVE TO COMPETE WITH UNREGULATED FIRMS FOR**
2 **CAPITAL?**

3 A109. Yes. The cost of capital is an opportunity cost based on the returns that investors could
4 realize by putting their money in other alternatives. Clearly, the total capital invested
5 in utility stocks is only a small fraction of total common stock investment, and there
6 is an abundance of alternatives available to investors. Utilities must compete for
7 capital, not just against firms in their own industry, but with other investment
8 opportunities of comparable risk. This understanding is consistent with modern
9 portfolio theory, which assumes that rational investors will hold a diverse portfolio of
10 stocks, not just companies in a single industry.

11 **Q110. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO**
12 **CONSIDER INVESTORS' REQUIRED ROE FOR NON-UTILITY**
13 **COMPANIES?**

14 A110. Yes. The cost of equity capital in the competitive sector of the economy underpins
15 utility ROEs because regulation purports to serve as a substitute for the actions of
16 competitive markets. The United States Supreme Court has recognized that it is the
17 degree of risk, not the nature of the business, which is relevant in evaluating an allowed
18 ROE for a utility. The *Bluefield* case refers to “business undertakings attended with
19 comparable risks and uncertainties.” It does not restrict consideration to other utilities.
20 Similarly, the *Hope* case states:

21 By that standard the return to the equity owner should be commensurate
22 with returns on investments in other enterprises having corresponding
23 risks.¹⁰²

24 As in the *Bluefield* decision, there is nothing to restrict “other enterprises” solely to
25 the utility industry.

¹⁰² *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 391 (1944).

1 **Q111. WHAT CRITERIA DO YOU APPLY TO DEVELOP THE NON-UTILITY**
2 **GROUP?**

3 A111. My comparable risk proxy group was composed of thirty-six United States companies
4 followed by Value Line that:

- 5 1. pay common dividends;
- 6 2. have a Safety Rank of “1”;
- 7 3. have a Financial Strength Rating of “A” or greater;
- 8 4. have a beta of 0.95 or less; and,
- 9 5. have investment grade credit ratings from Moody’s and S&P.

10 **Q112. HOW DO THE OVERALL RISKS OF YOUR NON-UTILITY GROUP**
11 **COMPARE WITH THE UTILITY GROUP AND THE COMPANY?**

12 A112. Table 5 compares the Non-Utility Group with the Utility Group across the measures
13 of investment risk discussed earlier:

14 **TABLE 5**
15 **COMPARISON OF RISK INDICATORS**

	<u>Credit Ratings</u>		<u>Value Line</u>		
	<u>Moody's</u>	<u>S&P</u>	<u>Safety</u>	<u>Financial</u>	<u>Beta</u>
			<u>Rank</u>	<u>Strength</u>	
Non-Utility Group	A2	A	1	A+	0.77
Utility Group	Baa2	BBB+	2	B++	0.77

16 As shown above, all of the risk indicators for the Non-Utility Group suggest less risk
17 than for the Utility Group.

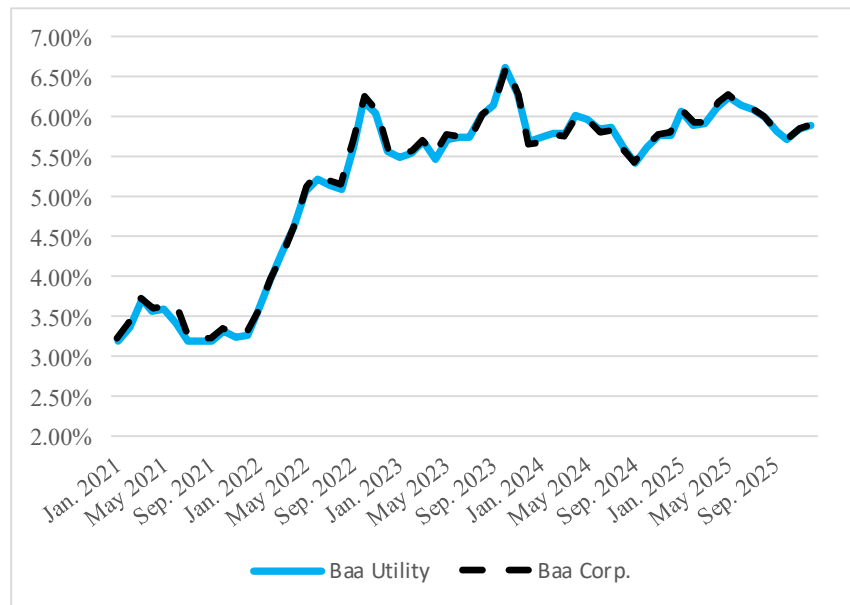
18 The companies that make up the Non-Utility Group are representative of the
19 pinnacle of corporate America. These firms, which include household names such as
20 Coca-Cola, Home Depot, Procter & Gamble, and Walmart, have long corporate
21 histories, well-established track records, and exceedingly conservative risk profiles.
22 Many of these companies pay dividends on a par with utilities, with the dividend yield
23 for the group averaging 2.5%. Moreover, because of their significance and name

1 recognition, these companies receive intense scrutiny by the investment community,
2 which increases confidence that published growth estimates are representative of the
3 consensus expectations reflected in common stock prices.

4 **Q113. DO SIMILAR BOND YIELDS FOR UTILITIES AND NON-UTILITIES**
5 **IMPLY SIMILAR RISK?**

6 A113. Yes. This can be seen by examining the average monthly yields on Baa utility bonds
7 and Baa corporate bonds, which are displayed in the figure below.

8 **FIGURE 6**
9 **BAA UTILITY YIELDS AND BAA CORPORATE YIELDS**



Source: Moody's Investors Service.

10 It is foundational in finance that similar risk investments ought to have similar
11 returns. As shown above, Baa utility bonds and Baa corporate bonds exhibited nearly
12 identical market yields over the five year period from January 2021 to December
13 2025. Moreover, the two series shown above have a 0.9995 correlation coefficient,
14 indicating near perfect correlation. This evidence confirms that credit ratings are a
15 reasonable basis on which to compare the overall investment risks of utilities and their
16 unregulated peers. When the information from Table 5 is considered in this light, the

1 Non-Utility Group is clearly lower risk than the Utility Group, implying a lower
2 expected return and making it a conservative DCF reference group.

3 **Q114. WHAT ARE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-**
4 **UTILITY GROUP?**

5 A114. I apply the DCF model to the Non-Utility Group using the same analysts' EPS growth
6 projections described earlier for the Utility Group. The results of my DCF analysis
7 for the Non-Utility Group are presented in Exhibit A-41 (JST-10). As summarized in
8 Table 6, after eliminating illogical values, application of the constant growth DCF
9 model results in the following cost of equity estimates:

10 **TABLE 6**
11 **DCF RESULTS – NON-UTILITY GROUP**

<u>Growth Rate</u>	<u>Average</u>
IBES	10.2%
S&P Capital IQ	10.3%
Value Line	11.5%
Zacks	9.9%

12 As discussed earlier, reference to the Non-Utility Group is consistent with
13 established regulatory principles. Required returns for utilities should be in line with
14 those of nonutility firms of comparable risk operating under the constraints of free
15 competition. Because the actual cost of equity is unobservable, and DCF results
16 inherently incorporate a degree of error, cost of equity estimates for the Non-Utility
17 Group provide an important benchmark in evaluating a just and reasonable ROE for
18 UPPCO.

19 **F. Return on Equity for UPPCO**

20 **Q115. PLEASE SUMMARIZE YOUR ROE FINDINGS FOR UPPCO.**

21 A115. I implemented DCF, CAPM and risk premium analyses on a proxy group of twenty-
22 one utilities, and generated average results of 10.1% (DCF), 11.4% (CAPM) and
23 10.7% (risk premium). Based on these figures, I conclude that 10.1% to 11.3% is a

1 reasonable ROE range for the proxy group. Given the Company's relatively small
2 size, limited service area, and relative lack of regulatory mechanisms, an ROE at the
3 upper end of my range would be warranted for UPPCO. With that in mind, I consider
4 the Company's requested ROE of 10.55% to be a reasonable though conservative
5 estimate of equity investors' required returns.

6 VI. CAPITAL STRUCTURE

7 **Q116. WHAT IS THE ROLE OF CAPITAL STRUCTURE IN SETTING A** 8 **UTILITY'S RATE OF RETURN?**

9 A116. Capital structure reflects the mix of capital—debt, preferred securities, and common
10 equity—used to finance a utility's assets. The proportions of the total capitalization
11 attributable to each source of capital are typically used to weight the costs of investor-
12 supplied capital in calculating an overall rate of return.

13 **Q117. HOW MIGHT UPPCO'S CAPITAL STRUCTURE REQUEST BE** 14 **EVALUATED?**

15 A117. As with ROE, it is generally accepted that the norms established by comparable firms
16 provide a valid benchmark to evaluate a reasonable capital structure for a utility. The
17 capital structure maintained by other utilities should reflect their collective efforts to
18 finance themselves so as to minimize capital costs while preserving their financial
19 integrity and ability to attract capital. Moreover, these industry capital structures
20 should also incorporate the requirements of investors (both debt and equity), as well
21 as the influence of regulators.

22 **Q118. WHAT COMMON EQUITY RATIO IS IMPLICIT IN UPPCO'S REQUESTED** 23 **CAPITAL STRUCTURE?**

24 A118. As summarized in the testimony of Nicholas E. Kates, the Company's proposed capital
25 structure consists of 50.0% equity and 50.0% long-term debt in this filing.

1 **Q119. IS THIS CONSISTENT WITH INDUSTRY BENCHMARKS FOR OTHER**
2 **UTILITY OPERATING COMPANIES?**

3 A119. Yes. Because this proceeding focuses on the ROE for the UPPCO's Michigan
4 regulated utility operations, the capital structures of other regulated utility operating
5 companies provide a consistent basis of comparison. The first three pages of Exhibit
6 A-35 (JST-4) display capital structure data for the group of utility operating companies
7 owned by the firms in the Utility Group. As shown there, common equity ratios for
8 these utilities ranged from 41.1% to 63.1% and averaged 52.5%. Forty-one of these
9 fifty-three operating companies maintained common equity ratios that exceed the
10 50.0% requested by UPPCO.

11 **Q120. WHAT ARE THE EQUITY RATIOS CORRESPONDING TO THE**
12 **COMPANIES IN THE UTILITY GROUP?**

13 A120. As shown on page 4 of Exhibit A-35 (JST-4), common equity ratios for the Utility
14 Group ranged from a low of 33.3% to a high of 64.1% at year-end 2025. Also shown
15 on page 4 of Exhibit A-35 (JST-4), Value Line expects common equity ratios for the
16 Utility Group to range between 32.5% and 68.8% over its three-to-five year forecast
17 horizon.

18 **Q121. WHAT OTHER EVIDENCE SUPPORTS THE REASONABLENESS OF THE**
19 **COMPANY'S REQUESTED CAPITAL STRUCTURE?**

20 A121. Reference to recent findings for electric utilities in other regulatory proceedings also
21 supports the reasonableness of UPPCO's requested 50.0% common equity ratio. The
22 table below presents the range of common equity ratios approved for electric utilities
23 over the past eight quarters, as reported by RRA:

1
2

TABLE 7
ELECTRIC UTILITY ALLOWED COMMON EQUITY RATIOS

	Low	--	High	Average
Q1-24	41.25%	--	53.72%	49.68%
Q2-24	44.36%	--	52.26%	49.77%
Q3-24	45.57%	--	52.83%	50.27%
Q4-24	41.00%	--	53.01%	47.39%
Q1-25	41.73%	--	57.00%	48.76%
Q2-25	41.00%	--	53.01%	47.39%
Q3-25	41.00%	--	52.66%	47.94%
Q4-25	37.94%	--	59.60%	50.69%
Average	41.73%	--	54.26%	48.98%

Source: S&P Global Market Intelligence, *Major Rate Case Decisions*, RRA Regulatory Focus (Feb. 4, 2025 and Apr. 2026). Excludes limited issue riders, and capital structures that include cost-free items.

3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18

As shown above, the Company’s requested 50.0% common equity ratio falls within the range of capital structures recently approved for other utilities, and slightly above the average common equity ratio of 48.98% approved over the last two years.

Q122. DO ONGOING ECONOMIC AND CAPITAL MARKET UNCERTAINTIES ALSO INFLUENCE THE APPROPRIATE CAPITAL STRUCTURE FOR UPPCO?

A122. Yes. Financial flexibility plays a crucial role in ensuring the wherewithal of a utility to meet funding needs, and utilities with higher financial leverage may be foreclosed or have limited access to additional borrowing, especially during times of financial market stress. As Moody’s observed:

Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to capital markets to assure adequate sources of funding and to maintain financial flexibility. During times of distress and when capital markets are exceedingly volatile and tight, liquidity becomes critically important because access to capital markets may be difficult.¹⁰³

¹⁰³ Moody’s Investors Service, *FAQ on credit implications of the coronavirus outbreak*, Sector Comment (Mar. 26, 2020).

1 More recently, Moody’s emphasized that the utility sector “is likely to continue to
2 generate negative free cash flow and credit quality is likely to suffer unless utilities
3 fund this negative free cash flow appropriately with a balance of debt and equity
4 financing.”¹⁰⁴

5 Similarly, while noting that cash flows in the utility industry are generally
6 predictable and stable, S&P highlighted that “unexpected events beyond the base case
7 still occur.”¹⁰⁵ S&P observed that, “Utilities with financial cushion from their
8 downgrade threshold are more able to absorb these unexpected events while
9 maintaining credit quality,” and concluded that “balanced equity and debt funding
10 [will be required] to maintain credit quality.”¹⁰⁶ The Company’s capital structure must
11 maintain adequate equity to preserve the flexibility necessary to maintain continuous
12 access to capital even during times of unfavorable energy or financial market
13 conditions.

14 **Q123. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR**
15 **ASSESSMENT OF A COMPANY’S CAPITAL STRUCTURE?**

16 A123. Utilities, including UPPCO, are facing significant capital investment plans in order to
17 continue to provide reliable service to their customers. Coupled with the potential for
18 turmoil in capital markets, this warrants a stronger balance sheet to deal with an
19 uncertain environment. As S&P noted:

20 [W]e expect IOU capital spending will grow at unprecedented levels
21 during the next decade. To maintain credit quality over this timeframe,
22 the industry must fund these projects in a credit-supportive manner.¹⁰⁷

23 Similarly, Moody’s noted that higher interest rates and the pressure of
24 maintaining credit metrics while funding capital investments were leading to greater

¹⁰⁴ Moody’s Investors Service, *Regulate Electric and Gas Utilities – US, Rising capital expenditures will require higher annual equity funding*, Sector In-Depth (Nov. 8, 2023).

¹⁰⁵ S&P Global Ratings, *North America Regulated Utilities*, Industry Credit Outlook 2026 (Jan. 14, 2026).

¹⁰⁶ *Id.*

¹⁰⁷ *Id.*

1 reliance on common equity.¹⁰⁸ Moody’s concluded that the utility sector “is likely to
2 continue to generate negative free cash flow and credit quality is likely to suffer unless
3 utilities fund this negative free cash flow appropriately with a balance of debt and
4 equity financing.”¹⁰⁹

5 In addition, the investment community also considers the impact of other
6 considerations, such as leases, purchased power agreements, and postretirement
7 benefit and asset retirement obligations in its evaluation of a utility’s financial
8 standing. Considering the magnitude of the Company’s ongoing infrastructure
9 investments, a conservative financial profile is warranted to maintain continuous
10 access to capital under reasonable terms, even during times of adverse capital market
11 conditions.

12 **Q124. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO UPPCO’S**
13 **CAPITAL STRUCTURE?**

14 A124. UPPCO’s capital structure is consistent with industry benchmarks, although the
15 Company’s requested common equity ratio of 50.0% falls below the average
16 maintained by other utility operating companies. While industry averages provide one
17 benchmark for comparison, each firm must select its capitalization based on the risks
18 and prospects it faces, as well as its specific needs to access the capital markets. The
19 Company’s capital structure reflects the need to address the funding of ongoing capital
20 expenditures and support UPPCO’s financial integrity and access to capital on
21 reasonable terms. Based on this evidence, and considering the importance of
22 maintaining the Company’s financial strength and credit standing, I conclude that
23 UPPCO’s capital structure represents a reasonable mix of capital sources from which
24 to calculate the overall rate of return

¹⁰⁸ Moody’s Investors Service, *Regulated Electric and Gas Utilities – US; Rising capital expenditures will require higher annual equity funding*, Sector In-Depth (Nov. 8, 2023).

¹⁰⁹ *Id.*

1 **Q125. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

2 A125. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-22032

DIRECT TESTIMONY AND EXHIBITS OF

MORGAN B. IMPOLA

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

May 22, 2026

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

2 A. My name is Morgan B. Impola. My business address is 19693 Campus Drive, Hancock,
3 MI. I am the Manager of Distribution Engineering for Upper Peninsula Power Company
4 (“UPPCO” or the “Company”).

5 **Q. For whom are you providing testimony?**

6 A. I am providing testimony on behalf of UPPCO in support of its request for an increase in
7 its retail electric rates.

8 **Q. Please describe briefly your educational, professional, and utility background.**

9 A. I have a Bachelor of Science Degree in Electrical Engineering from the University of
10 Saint Thomas in St. Paul, Minnesota and have 15 years of experience in the electric
11 utility industry. I began my career in Minnesota with Xcel Energy in June 2010 as a
12 Distribution Area Engineer at the Edina Service Center. Thereafter, I also worked for
13 Xcel Energy as the MetroWest Operating Engineer out of the Chestnut Service Center. In
14 January 2016, I began working for UPPCO as a Regional Engineer in Houghton,
15 Michigan. In May 2023, I was promoted to my current role as the Manager of
16 Distribution Engineering.

17 **PURPOSE OF TESTIMONY**

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

1 A. The purpose of my direct testimony is to describe and provide support for UPPCO's
2 distribution capital expenditures, including System Hardening and Reliability Projects
3 ("SHARP"), and provide support for changes to UPPCO's Line Extension Policy.

4 **EXHIBITS**

5 **Q. Are you sponsoring any Exhibits in this proceeding?**

6 A. Yes. I am sponsoring the following Exhibits, which were either prepared by me or under
7 my direct supervision:

- 8 1. Exhibit No. A-12 (MBI-1), Schedule B5.4
- 9 2. Exhibit No. A-19 (MBI-2), Routine Distribution CAPEX Detail
- 10 3. Exhibit No. A-20 (MBI-3), System Hardening & Reliability Projects
- 11 4. Exhibit No. A-21 (MBI-4), Historical Distribution Reliability Indices
- 12 5. Exhibit No. A-22 (MBI-5), Historical Major Event Days ("MEDs")
- 13 6. Exhibit No. A-23 (MBI-6), Historical Distribution Outages by Cause
- 14 7. Exhibit No. A-24 (MBI-7), Line Clearance History
- 15 8. Exhibit No. A-25 (MBI-8), Pole Inspection History
- 16 9. Exhibit No. A-26 (MBI-9), Underground Inspection History
- 17 10. Exhibit No. A-27 (MBI-10), Underground Outage History Comparison
- 18 11. Exhibit No. A-28 (MBI-11), Historical Maintenance Costs
- 19 12. Exhibit No. A-29 (MBI-12), Cancellation of Closed Line Extension Policy
- 20 13. Exhibit No. A-30 (MBI-13), Proposed Line Extension Construction Policy
- 21 14. Exhibit No. A-31 (MBI-14), Proposed Street Lighting Rules

1 Additionally, I will refer in my testimony to the SL-6 street lighting tariff proposal,
2 sponsored by Company witness Bell in Exhibit A-16, Schedule F5.

3 **Q. Please describe Exhibit A-12 (MBI-1), Schedule B5.4.**

4 A. Exhibit A-12 (MBI-1), Schedule B5.4 describes the total distribution related capital
5 expenditures that occurred during the historical test period (calendar year 2025), and
6 those planned to occur during the bridge period (calendar year 2026) and the projected
7 test period, ending December 31, 2027.

8 **Q. Please describe Exhibit A-19 (MBI-2), Routine Distribution CAPEX Detail.**

9 A. Exhibit A-19 (MBI-2), provides additional detail of the distribution capital projects in the
10 bridge and projected test year that are not classified as reliability driven projects, which I
11 describe in detail later in my testimony. This Exhibit is provided to allow parties to see
12 the detail behind the values included in Exhibit A-12, Schedule B5.4, which equate to the
13 sum of the values included in Exhibit A-19 (MBI-2), A-20 (MBI-3), and A-18 (DJG-1),
14 which is sponsored by Company witness Gervae.

15 **Q. How is your testimony organized regarding distribution system reliability?**

16 A. My testimony is organized as follows:

- 17 1. Distribution System Conditions
- 18 2. Local System Load Forecasts
- 19 3. Reliability Metrics and System Goals
- 20 4. Maintenance and Upgrade Plans

- 1 5. Capital Expenditure Decision Criterion
- 2 6. Customer Value Determination
- 3 7. System Hardening & Reliability Projects
- 4 8. Line Extension Construction Policy
- 5 9. Comparison to Distribution Plan (U-20147)

6 **DISTRIBUTION SYSTEM CONDITIONS**

7 **Q. Please provide an overview of UPPCO’s distribution system conditions.**

8 A. UPPCO serves approximately 59,000 meters in Michigan’s Upper Peninsula with a
9 service territory of approximately 4,500 square miles in 10 of the 15 counties in the
10 Upper Peninsula. UPPCO’s distribution system includes approximately 4,500 line-miles
11 of overhead and underground conductor routed primarily in non-urban areas. The
12 overhead lines consist of approximately 2,150 miles of primary, 580 miles of secondary,
13 and 510 miles of service line. The underground lines consist of approximately 830 miles
14 of primary, 45 miles of secondary, and 375 miles of service line. Therefore, UPPCO’s
15 distribution system is comprised of approximately 72% overhead conductor and 28%
16 underground conductor. Much of UPPCO’s rural distribution system is routed off the
17 road right-of-way, along lakes, and in cross-country areas that are difficult to access. The
18 result is approximately 13 meters per line mile of distribution system over a heavily
19 wooded service territory.

20 UPPCO’s overhead system consists of approximately 72,000 primarily wood poles with
21 an average age of 41 years. The expected useful life of a typical utility wood pole is 30-
22 50 years, which is the age range for 40% of UPPCO poles. Over 35% of UPPCO’s poles

1 were installed greater than 50 years ago placing them beyond the average useful lifespan
2 for a wood pole. Poles weaken with age and are more likely to fail during storm
3 conditions.

4 A significant amount of UPPCO’s underground cable was installed in the 1970’s with
5 175 mil insulation and a bare concentric neutral. This vintage of cable is more prone to
6 faults, and the neutral could corrode causing a safety hazard and overcurrent protection
7 issues as they get older.

8 **LOCAL SYSTEM LOAD FORECASTS**

9 **Q. Please provide an overview of local system load forecasts.**

10 A. UPPCO performs a detailed forecast on an annual basis. This data is used to feed the
11 ATC load forecast which is in turn used to feed into the MISO load forecast. The forecast
12 is based on UPPCO’s system coincident peak demand for the summer season loads.
13 UPPCO’s 10-year annual average system load growth from 2016 to 2025 was 3.85%.
14 This average includes customer load changes and distributed generation sources
15 connected to the distribution system.

16 **RELIABILITY METRICS & SYSTEM GOALS**

17 **Q. Please provide an overview of UPPCO’s reliability metrics and goals.**

18 A. For reliability metrics, UPPCO has used the Institute of Electrical and Electronic
19 Engineers (“IEEE”) Guide for Electric Distribution Reliability Indices, Standard 1366,
20 since 2012. SAIDI (“System Average Interruption Duration Index”), SAIFI (“System

1 Average Interruption Frequency Index”), and CAIDI (“Customer Average Interruption
2 Duration Index”) are often used to compare performance among utilities.

3 As evidenced in Exhibit A-21 (MBI-4), Historical Distribution Reliability Indices,
4 UPPCO’s 5-year reliability data is shown for All-Weather conditions and Excluding
5 Major Event Days (“MEDs”). This reliability data has been filed annually with the
6 Michigan Public Service Commission (“MPSC” or the “Commission”) in the docket for
7 Case No. U-12270 since 2013. Consistent with IEEE Standard 1366, MEDs are days on
8 which system interruption performance exceeds a statistically defined threshold and
9 reflects the impacts of infrequent, extreme events that are outside normal operating
10 conditions.

11 Please note, UPPCO removes transmission-caused outages from its filed reliability
12 indices calculations based on language in IEEE 1366-2022, Section 6.2, stating,
13 “Interruptions that occur as a result of outages on customer-owned facilities, or loss of
14 supply from another utility, should not be included in the index calculation.”

15 Transmission is defined as greater than 50,000 volts. UPPCO does not own any
16 transmission lines. Transmission service is provided through the American Transmission
17 Company (“ATC”), which is another utility, so outages caused by loss of transmission
18 should not be included in UPPCO-specific reliability indices.

19 The MPSC has created “MI Power Grid” to outline performance requirements and
20 improve service quality and electric reliability in Michigan. UPPCO is trying to improve
21 the resilience and reliability of the Company’s distribution system in order to meet the
22 Michigan reliability goals and improve the customer experience. UPPCO sets an

1 aggressive SAIDI goal each year based on 90% of the previous 5-year average SAIDI,
2 excluding MEDs. The goal for 2026 is 157 minutes.

3 In 2025, excluding transmission-caused events and major event days (“MEDs”),
4 UPPCO’s SAIDI was 190 minutes and SAIFI was 1.29 events per average UPPCO
5 customer. However, including MEDs, UPPCO’s 2021-2025 5-year average SAIDI was
6 403 minutes, and UPPCO’s SAIFI was 1.66 events per average UPPCO customer.
7 UPPCO’s past capital expenditures for system hardening and reliability improvements,
8 combined with more aggressive line clearance efforts to remove dead and dying trees
9 outside the utility right-of-way, have reduced the 5-year average SAIFI and will continue
10 to improve outage performance over time.

11 Exhibit A-22 (MBI-5), Historical Major Event Days (“MEDs”), shows the variability of
12 weather-related events that UPPCO customers experienced according to IEEE 1366
13 metrics for a MED. However, the IEEE metric cannot fully represent the customer
14 experience during a storm as the MED metric requires an outage to be measured by a full
15 calendar day from midnight to midnight. In UPPCO’s experience, even though a MED
16 ends at midnight, storm restoration efforts may continue into the following days
17 accumulating daily SAIDI minutes that do not reach the threshold of an MED. For this
18 reason, UPPCO continuously strives to improve its customer experience by increasing
19 system reliability and resilience and accounts for MEDs in its reliability improvement
20 project planning.

21 As evidenced in Exhibit A-23 (MBI-6), Historical Distribution Outages by Cause,
22 UPPCO depicts the 5-year average from 2021-2025 of all sustained outages by cause

1 sorted by SAIDI. Vegetation-related outages represent the highest percentage cause in
2 terms of SAIDI minutes at 51% and 45% for both all-weather conditions and excluding
3 MEDs, respectively. Weather-related outages are the second most common in all-weather
4 conditions and cause 25% of these outages by SAIDI. Equipment-related outage events
5 are the second most common when excluding MEDs at 18% of these outages measured
6 by SAIDI. In terms of the number of outage events and the number of customers affected,
7 vegetation-related outages top the list under both all-weather conditions and excluding
8 MEDs. The high number of vegetation-related outages underscores the need to maintain
9 UPPCO's on-cycle line clearance program. UPPCO places a high priority on line
10 clearance. This has significantly aided in the downward trend of the aforementioned
11 reliability metrics. Since the completion of UPPCO's accelerated line clearance program
12 from 2014 to 2017, UPPCO has maintained a 6-year line clearance cycle.

13 **MAINTENANCE & UPGRADE PLANS**

14 **Q. Please provide an overview of UPPCO's maintenance and upgrade plans.**

15 A. Strong winds are the main cause of tree-related outages. Most tree-related outages in the
16 last few years have been caused by off-road right-of-way ("ROW") trees falling onto the
17 line. Tree-related outages are not often caused by trees growing into the line or from dead
18 trees spontaneously falling. While the weather is unpredictable and uncontrollable, a
19 systematic line clearance program can greatly aid in both reducing the number of tree-
20 related outages and in improving UPPCO's ability to respond to and restore the system in
21 a timely manner. When UPPCO seeks competitive bids for tree-trimming, it
22 utilizes specifications developed from the American National Standards Institute

1 (“ANSI”) A300 and the International Society of Arboriculture (“ISA”) pruning standards
2 for line clearance that its contractors must follow. These include the identification
3 and removal of priority trees located off the normal utility clearance right-of-way that
4 may pose an imminent danger to the system. UPPCO’s line clearance has been improving
5 for many years, and the Company has maintained its enhanced tree trimming
6 specification on a 6 year cycle since 2017.

7 Trained and experienced contractors as well as the UPPCO Line Clearance Supervisor
8 have the ability to identify hazard trees each day in the field. Tree diseases, caused by the
9 Spruce Bud Worm, Emerald Ash Borer, Beech Tree Disease, Oak Wilt, and other
10 emerging forest health threats have become prominent in UPPCO’s service territory and
11 have significantly changed the line clearance program.

12 For line clearance, UPPCO’s current utility right-of-way (“ROW”) only extends 10-
13 feet beyond the edge of the conductor. This presents challenges for and can limit the
14 effectiveness of line clearance efforts. Even when line clearance is performed to
15 specifications, a 70-foot tree growing off the utility ROW can still easily fall into a pole
16 line located 35 feet above ground and cause an outage. In fact, any tree 40-foot tall or
17 larger could contact a line 35 feet above ground.

18 UPPCO is taking additional steps to mitigate vegetation threats on the system.

19 Utilization of new equipment on the system, such as side trimmers, is helping to drive
20 trimming efficiency and address off ROW priority trees. An increased utilization of
21 herbicides is controlling non-compatible species regrowing inside of the right of way.

22 Additionally, outages caused by large trees are being investigated to determine the cause
23 of failure and to assess if current UPPCO specifications are sufficient to address

1 vegetation issues. These inspections are being driven by cause locations reported by line
2 crews at the time of restoration. We continue to explore and adapt new technologies as is
3 prudent to improve the safety and reliability of our vegetation management program.

4 In addition to its line clearance program, UPPCO must also undertake many different
5 activities to make its system less susceptible to outages, reduce the number of customers
6 affected by any single outage, and make the system more flexible so outages can be
7 restored more quickly.

8 One effective way to become more resilient to outages is to “harden” the distribution
9 system from storm activity.

10 **Q. Please list the components of UPPCO’s system hardening practices.**

11 A. UPPCO’s system hardening practices include:

- 12 1. Line Clearance
- 13 2. Overhead Inspections
- 14 3. Underground Inspections
- 15 4. System Hardening and Reliability Projects
- 16 5. Effective Shared Facilities Program
- 17 6. Enhanced Restoration Process
- 18 7. Optimize Technology

19 I will describe each of these in more detail as follows.

20 **Q. Is line clearance an important part of the Company’s system hardening practices?**

1 A. Yes. As previously mentioned, UPPCO has detailed line clearance specifications, and the
2 management of the vegetation in proximity to the distribution system is now on
3 cycle. Maintaining an on-cycle line clearance program reduces potential outages due to
4 falling trees and also provides crews with good accessibility to locate and restore
5 service in a timely manner. Additionally, a line clearance process that is on-cycle avoids
6 future costs to clear an overgrown ROW. UPPCO contends that maintaining a line
7 clearance program on cycle is less costly in the long run than clearing a ROW when an
8 overhead distribution system becomes overgrown due to cycle slippage in the
9 maintenance cycle or neglect.

10 **Q. Please describe UPPCO's line clearance process.**

11 A. UPPCO has approximately 2,150 miles of overhead right of way which must be trimmed
12 on a regular basis in order to provide a safe and reliable electrical distribution system for
13 the Company's customers and the general public. UPPCO also clears right-of-way to
14 ensure enough access to restore service in the event of a weather or non-weather-related
15 outage, and to deter the growth of incompatible vegetation. UPPCO trims vegetation
16 around its overhead lines to a specification consistent with ANSI A300 and ISA
17 standards which includes identifying and removing priority trees that are imminent of
18 falling on power lines. The majority of UPPCO's distribution system lies within county
19 road right-of-way providing limited clearance thus requiring private easements or
20 permissions to be secured for line clearance activities beyond this boundary. While many
21 of the native tree species in the Upper Peninsula tower in excess of 70 feet and grow in
22 relatively close proximity to the line, UPPCO's 6-year cycle approach still proves

1 adequate for a typical healthy forest trimmed in good fashion taking into account tree
2 growth and canopy spread over the years. However, the last several years have seen a
3 drastic increase in the number of off-right-of-way, dead or dying trees caused by a
4 handful of harmful diseases or insect infestations. This has increased tree mortality in
5 our service area and, in turn, caused a drastic increase in both the quantity and associated
6 costs to address these potential threats to reliability.

7 **Q. Has UPPCO successfully maintained an on-cycle 6-year line clearance program?**

8 A. Yes. Please reference Exhibit A-24 (MBI-7), UPPCO Line Clearance History, which
9 indicates the miles of line cleared in each UPPCO district as well as the associated costs.

10 To summarize, UPPCO cleared the following line miles over the past 5 years:

11	2021	376 miles
12	2022	375 miles
13	2023	377 miles
14	2024	383 miles
15	2025	313 miles

16 **Q. In calendar years 2026 and 2027, how many line miles will UPPCO be targeting for**
17 **its distribution line clearance program?**

18 A. UPPCO intends to continue its 6-year vegetation management cycle and is targeting to
19 trim no less than 372 line-miles per year putting 2026 and 2027 in line with the miles
20 cleared in 2021-2024. In 2025, a quality control issue with one of UPPCO's trimming
21 vendors resulted in a need to revisit areas believed to be trimmed out, resulting in reduced

1 overall mileage. UPPCO has since instituted an audit program to inspect 100% of
2 completed spans, eliminating a reoccurrence of the issue.

3 **Q. Please describe any significant factors that affect the cost experienced by the**
4 **Company in administering its line clearance program.**

5 A. The costs experienced by UPPCO to clear its rights-of-way have increased due to several
6 factors. First, as described above, the cost increases are partially due to the higher cost
7 associated with the drastic increase in tree mortality of off right-of-way trees, which
8 UPPCO refers to as “priority” trees. Addressing “priority” trees requires that the
9 responding contractor incur increased travel expenses in order to investigate both
10 customer and company tree removal requests that occur both in and out of the planned
11 cycle trim areas in order to determine the severity of the situation, the impact to the
12 system, public safety, and the increased risk of fire danger. These processes often
13 require additional negotiation with customers and landowners to obtain permission to cut
14 these priority trees, and in some instances, to remove the associated debris caused by
15 their removal. As a result, the line clearance expenses are projected to increase annually
16 by 7 %.

17 Furthermore, fluctuating fuel prices over the last several years have contributed to
18 additional price increases in contractor expenses due to the vast amount of service
19 territory that needs to be traversed to accomplish the annual line clearance miles
20 necessary to remain on-cycle. To help manage this and provide appropriate transparency
21 in this specific cost area, UPPCO has initiated a Diesel Fuel Escalation Policy to help
22 provide a mechanism whereby a positive or negative adjustment to the contract base rate

1 will be implemented, which is tied to set values and benchmarked against published
2 values for the “Retail On-Highway Diesel Prices” in the Midwest region, as published on
3 the U.S. Energy Information Administration website. This is intended to keep any
4 contractor price increase tied to fuel prices from being lost in contractor base rates, or not
5 addressed at all, jeopardizing the contractor’s viability of operations, while also
6 automatically reducing UPPCO costs as fuel prices decrease.

7 **Q. Please describe the actions taken by UPPCO to maximize the cost effectiveness and**
8 **quality of its line clearance program.**

9 A. In addition to the information provided above, UPPCO utilizes ANSI A300 and ISA
10 approved utility line clearance practices in its line clearance specifications. In an effort
11 to maximize the cost effectiveness of the Company’s line clearance program, UPPCO
12 relies upon multiple qualified utility line clearance contractors. This allows UPPCO to
13 maintain competitive pricing when soliciting pricing quotes by comparing production and
14 pricing performance over a variety of service locations, right-of-way, geographic and
15 environmental conditions. UPPCO also leverages this information to achieve a
16 performance-based assignment of the various cycle project areas comprising the
17 Company’s 6-year line clearance cycle.

18 **Q. Describe UPPCO’s Overhead Inspection Program.**

19 A. UPPCO implements a comprehensive overhead facilities inspection and treatment
20 program. Replacement of poles in poor condition and the treating of ground lines on
21 otherwise sound poles eliminates potential issues before they occur. UPPCO’s overhead

1 inspection includes the identification of potential National Electric Safety Code
2 (“NESC”) clearance issues. Through the 12-year inspection cycle, UPPCO reviews all
3 poles to which UPPCO has facilities attached, including non-UPPCO-owned poles. Some
4 items are identified and repaired during the inspection process, such as pole treatment at
5 the ground line, repairing grounds, and installing guy markers. Other identified “danger
6 and reject” poles are scheduled for replacement within a year after the inspection results
7 are received. From 2021 to 2025, an average of 1.8% of the inspected poles were
8 classified as danger or reject poles. This percentage has been generally steady as a result
9 of UPPCO’s continued pole inspection practices over the years. A record of UPPCO’s
10 pole inspections is shown in Exhibit A-25 (MBI-8), Pole Inspection History. As seen in
11 this table, the 5-year average cost for the professional overhead system inspection and
12 pole treatment was approximately \$193,369 per year or roughly \$32 per pole. The
13 overhead inspection program is an on-going maintenance activity that needs to be
14 continued.

15 **Q. Describe UPPCO’s Underground Inspection Program.**

16 A. UPPCO implements an underground inspection program to identify equipment in poor
17 condition, undermined or tilting equipment, and safety issues – before these issues trigger
18 outages. This program entails performing visual inspections of the physical components
19 of the existing underground system on a 6-year cycle. Some items are identified and
20 repaired during the inspection process, such as treating for ants, clearing vegetation, re-
21 leveling, filling gaps in the ground surface, and painting. UPPCO also inspects all newly
22 installed underground facilities during the next construction season after the facilities
23 were put in the ground. A record of UPPCO’s underground inspection history

1 is evidenced in Exhibit A-26 (MBI-9), Underground Inspection History. As seen in this
2 table, the 5-year average cost for the professional underground system inspection was
3 approximately \$69,786 or roughly \$49 per cabinet. Additionally, an average of
4 114 cabinets were refinished over this period, extending the life of these assets, at an
5 average cost of \$40,635 per year, roughly \$356 per cabinet. The underground inspection
6 program is an on-going maintenance activity that needs to be continued.

7 **Q. Describe UPPCO's Existing Underground Cable Replacement Plan.**

8 A. As mentioned earlier in my testimony, much of UPPCO's underground cable was
9 installed in the 1970's with 175 mil insulation and a bare concentric neutral, which is
10 more prone to faults. UPPCO has test equipment to locate failed underground cable. For
11 radial lines, repairs are made to restore service. If the line is looped, then often times the
12 crew will switch the feed to restore power and leave the failed section of cable out of
13 service. This provides time for Engineering to review the system and determine if the
14 cable section or multiple sections should be replaced, rather than repaired, based on age
15 of the cable and the number of previous failures. UPPCO anticipates replacement of
16 underground cables due to failure and has a budget item to allow for these replacements
17 during the course of the year, thereby providing flexibility to perform opportune cable
18 replacements with a short turnaround time improving the reliability of the system serving
19 those customers.

20 **Q. Describe the Rerouting of Overground to Underground ("strategic
21 undergrounding") program.**

1 A. Selective rerouting of overhead lines to underground in areas that have a high tree
2 density, are prone to frequent tree/storm related outages, and/or have limited accessibility
3 is another way to improve system reliability. These projects are capital intensive; and
4 therefore only the worst areas are targeted for rerouting. This is a capital expenditure
5 requiring budget funding and prioritization.

6 **Q. Does undergrounding increase system reliability?**

7 A. Yes. UPPCO's Outage Management System ("OMS") tracks causes and devices in
8 outage data, including events involving underground distribution equipment failures.
9 Exhibit A-27 (MBI-10), Underground Outage History Comparison, captures the number
10 and impact of underground related events. UPPCO experiences very few underground
11 dig-ins and equipment failures, such as padmount transformer and underground cable
12 failures. The data in Exhibit A-27 (MBI-10) includes events that *involve*, or serve,
13 underground facilities. Some of these events involve overhead facilities that feed the
14 underground system, such as an animal causing the riser fuse to operate or an arrester
15 failure on the riser. The purpose of this Exhibit is to demonstrate that, even including
16 events that are not strictly caused by failure of UPPCO's underground system, the impact
17 to UPPCO's customers is much less than all other events in terms of SAIDI, SAIFI, and
18 the number of customers affected. For all outage events, excluding transmission-caused,
19 over the period of 2021-2025, UPPCO experienced 9,132 events affecting 486,436
20 customers over the 5-year period. This resulted in a SAIDI of 2,016 minutes and a SAIFI
21 of 8.29 events. Outages involving underground facilities accounted for only 559 of those
22 events, affected 2,233 customers, and resulted in a SAIDI of 6.93 minutes and a SAIFI of

1 0.04 events. Therefore, events that involved underground facilities comprised only 6.1%
2 of total outage events and affected less than 1% of all customers who experienced
3 outages over the 5-year period. Thus, the data indicates reliability is significantly
4 improved for customers served by underground systems compared to those served by
5 overhead.

6 **Q. Does undergrounding decrease maintenance costs?**

7 A. Yes. As mentioned previously, approximately 72% of UPPCO's 4,500 total electric line
8 miles are configured as overhead conductor and the remaining 28% of the total line miles
9 as underground. Exhibit A-28 (MBI-11), Historical Maintenance Costs, documents
10 UPPCO's overhead and underground maintenance costs from 2021-2025. The overhead
11 and underground miles are a snapshot in time from UPPCO's GIS system for each year.
12 The data indicates UPPCO's average underground maintenance cost for calendar years
13 2021 through 2025 was only 8% of UPPCO's total cost to maintain the distribution
14 systems, but more significantly on a per mile basis, underground maintenance averaged
15 only \$592 per mile compared to overhead at about \$2,504 per mile. The maintenance
16 costs described above are attributable to activities such as trouble calls/callouts,
17 outage/storm restoration, line clearance activity, inspection programs, locating, and asset
18 refurbishment, among others.

19 **Q. Does strategic undergrounding increase customer value?**

20 A. Replacement of overhead lines with underground provides value to UPPCO customers in
21 several ways. As mentioned in reference to Exhibit A-27 (MBI-10), outages involving

1 underground account for 6% of the total number of outages, so customers receive a huge
2 improvement in reliability with strategic undergrounding. Additionally, ongoing
3 maintenance costs of underground are significantly reduced as mentioned above.
4 Although, for most projects, it is a major capital investment to convert overhead to
5 underground the investment pays off over time. To illustrate the customer value of
6 converting from an overhead system to underground, I will use the LIN 3063 Emily Lake
7 1-phase OH to UG project from 2025 as an example. This project installed approximately
8 4,300 feet of new 1-phase underground facilities to replace existing overhead system at a
9 cost of \$164,046.01. This job cost approximately \$38 per foot. By way of comparison,
10 UPPCO estimates the average cost for a typical 1-phase overhead system hardening
11 project to be about \$45 per foot. So UPPCO experienced a savings of \$7 per foot by
12 converting to underground, which equates to an estimated savings of \$30,100 in
13 construction costs compared to rebuilding the line overhead. Additionally, based on the
14 5-year average annual maintenance costs in Exhibit A-28 (MBI-11), the average cost to
15 maintain overhead was \$2,504 per mile, or 47¢ per foot, versus underground, which was
16 \$592 per mile, or 11¢ per foot. This results in annual savings of \$1,912 per mile, or 36¢
17 per foot, with underground maintenance versus overhead maintenance. Over the 40-year
18 expected life of the aforementioned project, the operations and maintenance cost savings
19 is expected to be about \$61,000. This value does not account for inflationary increases
20 that may happen over that 40-year period. Therefore, looking at this project in terms of
21 either capital or maintenance expenditures, there are direct savings to UPPCO customers
22 from strategic undergrounding projects. Other strategic undergrounding projects have
23 different levels of return based on the length and complexity of the project.

1 **Q. How does strategic undergrounding decrease customer costs?**

2 A. The increased customer value discussed above does not account for other savings, such as
3 the expected reduction in repetitive outage credits to customers, nor does it account for
4 the intrinsic value of customer satisfaction in the decreased number of outages. Much
5 debate has ensued over the cost of outages to customers; however, a definitive and
6 industry-accepted method has yet to be created. Loss of food or medicine, home heating
7 and cooling, temporary lodging, lost revenue to businesses, etc., are all dependent on
8 various factors, such as demography, outage duration, ambient temperature, customer
9 actions, and even customer expectations. That being said, in Case No. U-20629, an
10 intervenor, Citizens' Utility Board of Michigan ("CUB"), suggested that outages may
11 cost the average customer \$3-4 per hour. UPPCO's all-weather 5-year average SAIDI,
12 reported in Exhibit A-27 (MBI-10) was 403 minutes, or 6.4 hours, per customer per year
13 for all outages, but averaged 1.4 min, or 0.022 hours, per customer per year for
14 underground-related events. UPPCO's all-weather 5-year average SAIDI, reported in
15 Exhibit A-27 (MBI-10) was 403.2 minutes per customer per year for all outages, but
16 averaged 1.39 min per customer per year for underground-related events. Assuming a
17 customer cost of \$3.50 per hour, each customer would save \$23.44 per year. So, in the
18 LIN 3063 Lake Emily 1-phase OH to UG example above, the 45 customers would see an
19 outage cost savings of \$1,054 per year for the life of the installed assets, or about \$42,000
20 over 40 years. Another tool to calculate the financial impact of an outage is the
21 Interruption Cost Estimate (ICE) calculator developed by Lawrence Berkeley National
22 Laboratory. Using UPPCO's all-weather 5-year average SAIDI and SAIFI, the ICE
23 calculator determines the residential cost impact to be \$27.15 and the non-residential cost

1 impact to be \$12,559.19 annually for customers in Michigan. These are unrealized
2 savings since they are avoided costs as a result of reduced outages, but they do represent
3 another value of strategic undergrounding to customers. Of course, undergrounding
4 projects can vary significantly in cost due to various factors, such as complexity, ground
5 conditions, ROW availability, access, easements, brushing/line clearance, municipal
6 and/or environmental permitting, customers density, and even customer acceptance.

7 For the reasons discussed above and to reduce overhead system maintenance costs,
8 UPPCO plans to replace more overhead system with underground cable and equipment
9 where it makes sense to do so.

10 **Q. Are overhead lines always replaced with underground lines when poles near the end**
11 **of their useful lives?**

12 A. No. Replacing poles with taller and stronger poles is also an effective system hardening
13 method. When system hardening an overhead line, UPPCO targets a 25% increase in pole
14 height. This target moves the conductor closer to the tree top, but not outside the reach of
15 line trucks. Additionally, UPPCO has standardized the use of Class 3 poles and fiberglass
16 crossarms for new overhead distribution line construction. Not only can the taller height
17 often help to avoid tree-related outages altogether, but the increased strength can also
18 help to prevent the pole from breaking if a tree does fall on the line. Broken poles or
19 crossarms, especially during storm conditions, take significantly more time to replace
20 than fixing a broken conductor or removing a tree from the line, so installing stronger and
21 taller poles will strengthen the distribution system and improve both the duration and

1 frequency of outages. This is a capital expenditure requiring budget funding and
2 prioritization.

3 **Q. Please describe UPPCO’s Shared Facilities program.**

4 A. The purpose of UPPCO’s shared facilities program is to ensure that foreign attachments
5 are accounted for, included in pole loading calculations, and that existing facilities are
6 brought up to current NESC standards when new attachments are requested. UPPCO
7 requires an attachment agreement with all potential pole attaching companies. In
8 addition, requests for new attachments must be accompanied by a certified engineering
9 analysis of the existing poles, conductors, and anchor points. These studies are then
10 reviewed by UPPCO, and all NESC clearance violations and pole strength issues must be
11 corrected prior to any new attachments being made. UPPCO did not previously track the
12 annual number of pole attachment requests due to the limited nature of requests; however
13 it is estimated that approximately 300 new pole attachments would be requested annually
14 prior to 2024. Midway through 2024, UPPCO began receiving a significant increase in
15 pole attachment requests as a result of the Rural Digital Opportunity Fund (“RDOF”)
16 program. Since July 2024, UPPCO has reviewed around 3,000 pole attachment requests.
17 Pole space sharing is a requirement of state and federal law, and UPPCO will continue to
18 improve the overall strength of the distribution system through review of shared facilities
19 attachment requests and the subsequent make-ready work.

20 **Q. Please describe how UPPCO enhances the restoration process.**

1 A. UPPCO’s restoration process is enhanced by increasing the ability for crews to identify,
2 locate, access the outage location, and by increasing the flexibility of the system for the
3 crews to restore service. While these practices do not necessarily eliminate outage events,
4 they make the system more resilient when outages do occur. Several of the practices
5 already mentioned help crews to better access outage locations, such as continuing the
6 line clearance program and rerouting overhead lines to underground.

7 This program also includes rerouting cross-country lines to road ROWs to make the
8 system more accessible to crews. Early design practice was to run distribution systems
9 via the most direct route to save on cost and effort to get service to outlying areas. Over
10 time, however, access points can be overrun with vegetation, which creates obstacles for
11 utility crews working to identify and access outage locations and to make necessary
12 repairs. UPPCO sees significant value and places a higher priority on projects that
13 include rerouting overhead off-ROW lines to an on-ROW underground system, which
14 improves reliability and reduces future maintenance costs. Additionally, these projects
15 increase accessibility, reduce line clearance requirements, and provide UPPCO’s line
16 crews with the ability to more quickly patrol the system and efficiently locate outage
17 causes. These projects are capital-intensive and require planning and budgeting. Because
18 of this, these projects are strategically targeted and weighed against other potential
19 reliability improvement projects and prioritized accordingly.

20 In some cases, the Company may also add switching capability to increase the flexibility
21 of the distribution system. Due to UPPCO’s rural service territory, creating networks or
22 loops within the distribution system can be impractical on a large scale due to the nature
23 of long circuits outside of urban areas. Closing a gap, however, in a rural distribution

1 system where pockets of higher customer densities do exist allows crews to open the
2 system as near as possible to the outage, then close a normally open point to restore
3 power to customers that otherwise would have been without power until the system can
4 be repaired. The practice of switching to partially restore service significantly reduces the
5 duration of the outage and improves SAIDI metrics. These design considerations are
6 taken into account as part of the capital expenditure budget and prioritization process.

7 **Q. Does UPPCO also use technology solutions to harden the distribution system?**

8 A. Yes. Technological solutions are also considered by UPPCO when it is planning for
9 upcoming reliability improvement projects. UPPCO optimizes distribution technology in
10 several forms:

11 a) The implementation of a robust OMS provides the ability to dispatch outages
12 more quickly to the correct outage location. Additionally, UPPCO implemented
13 Automated Meter Infrastructure (“AMI”), which automatically reports customer
14 outages and sends them to UPPCO’s OMS, indicating exactly which customers
15 are experiencing an outage. This allows more efficient use of dispatching
16 resources and aids in diagnosing system issues. UPPCO continues to work with
17 the OMS and AMI vendors to leverage the AMI system for validation of outage
18 data records and improving overall OMS operation.

19 b) Reverse-sensing voltage regulators have also been installed in specific locations
20 that can operate in reverse load flow so that they perform properly when
21 switching the distribution system for partial restoration. This eliminates the

1 requirement for field personnel to manually adjust regulators when switching
2 occurs and frees those personnel to address other outages.

3 c) UPPCO utilizes electronically controlled reclosers to handle temporary faults and
4 create precise coordination between protective line devices and the substation.
5 These reclosers are able to provide valuable insight into the performance of a
6 section of line and data that can be used to locate a difficult fault or record peak
7 information. Circuits that have a history of multiple device operations are
8 prioritized first.

9 d) When evaluating projects to improve reliability to an area, UPPCO considers
10 Distribution Automation (“DA”) projects. However, due to UPPCO’s mostly
11 rural service territory, there are not a lot of areas to effectively implement DA.
12 UPPCO installed a partial DA project at a very remote substation fed by a radial
13 transmission line. Prior to this project, the line crew needed to travel a long
14 distance to the substation to isolate and switch to a back-up feeder. UPPCO added
15 a SCADA-controlled switch which provides the system operators in the control
16 center the ability to remotely operate the field switch. Although it is not
17 automatic, it reduces outage response from a couple hours to only a few minutes
18 for transmission-related outage events.

19 e) Many areas of UPPCO’s service territory are impacted by seasonal loading. This
20 can be problematic for many fault locating devices that function off a fixed
21 amperage threshold as the summer amperage and winter amperage may differ
22 greatly. To better manage the fluctuating amperage across a year, UPPCO utilizes
23 amperage tracking fault indicators that adjust the trip threshold of the fault

1 indicator based on the nominal line amperage rather than a fixed amperage
2 threshold. This allows the fault indicator to be more precise and provide the line
3 crew with a valuable tool to better locate a fault across the course of the year.

4 **CAPITAL EXPENDITURE DECISION CRITERIA**

5 **Q. Please identify UPPCO's primary capital decision criterion as it relates to selecting**
6 **distribution system hardening projects.**

7 A. For those system hardening practices which I have described which require capital
8 investments to improve reliability, UPPCO uses the following decision criterion to
9 prioritize its capital projects:

- 10 1. IEEE Indices (SAIDI, SAIFI, and CAIDI) and the number of outages per feeder
- 11 2. Worst Feeder Ranking
- 12 3. Multiple Device Operations
- 13 4. Field Crew Experience
- 14 5. Inspection Results

15 **Q. Please describe these decision criteria in greater detail.**

16 A. The following provides additional background on each of the decision criterion:

- 17 1. IEEE Indices: As mentioned in the Reliability Metrics section above, the IEEE
18 reliability indices are typically used to compare performance among utilities. This
19 data, however, can also be used internally to compare performance among
20 different districts, feeders, devices, or even down to the fault location level.

1 UPPCO's methodology to analyze where to invest in reliability improvement or
2 system hardening is partly based on a ranking of UPPCO's feeders. For purposes
3 of ranking UPPCO's worst feeders, the IEEE indices are used as well as the
4 number of outages per feeder.

5 2. Worst Feeder Ranking: An analysis of the reliability indices by individual feeder,
6 or circuit, considers the effect of outages on a specific feeder not only as related to
7 the average UPPCO customer, but also as it relates to the geographic region of
8 where that feeder is routed. UPPCO typically reviews the 3-year outage history
9 for the whole company to help prioritize capital improvements by feeder,
10 although at times the 5-year and 2-year outage histories are also used to best
11 determine where the biggest reliability improvements are warranted. A point
12 system is used on each of the four measures (SAIDI, SAIFI, CAIDI, and # of
13 outage events) with the worst feeder in each category getting the top ranking of #1
14 worst feeder. UPPCO has about 100 feeders in the 5-year data set, so the worst
15 feeder in each category is assigned 1 point and the best feeder assigned 100
16 points. The points are added for each of the four measures, and the feeder with the
17 least number of points is considered the worst reliable overall.

18 3. Multiple Device Operations: Another factor that is used in determining where to
19 target distribution reliability and age/condition improvement projects is the
20 number of device operations. Since UPPCO's feeders are inherently large
21 electrical circuits covering an average of over 50 line-miles per feeder and 16% of
22 the most rural feeders being over 100 miles in total circuit length, no single
23 project can improve an entire feeder's reliability. This metric, in addition to fault

1 location data, can therefore further clarify where reliability improvement work is
2 needed on a specific feeder.

3 4. Field Crew Experience: Line personnel are quite familiar with outage-prone areas
4 and difficult-to-access areas that require complicated power restoration
5 operations. Crews are frequently canvassed, so that their operational experience
6 can be used to help pinpoint areas where targeted capital expenditures can best
7 improve system reliability.

8 5. Inspections: UPPCO also considers other ongoing maintenance activities, such as
9 annual overhead line inspections. For example, if several poles along a line
10 require replacement due to the inspection results, UPPCO may consider rerouting
11 the line underground, or replacing with larger poles instead of a like-for-like
12 replacement.

13 **CUSTOMER VALUE DETERMINATION**

14 **Q. Please describe UPPCO's customer value determination on its distribution system**
15 **capital spending projects.**

16 A. Providing a better customer experience and meeting the State's goals to reduce outages
17 and improve reliability will require additional capital investment by the Company for
18 system hardening. Due to UPPCO's low customer density and miles of line per customer,
19 it is difficult to significantly improve reliability and resiliency of UPPCO's system at
20 current investment levels.

1 UPPCO's distribution projects have historically had a focus on ensuring Michigan Public
2 Service Commission ("MPSC") compliance for distribution system adequacy, safety, and
3 proper voltage levels, with varying scope due to the dynamic nature of system integrity
4 and the distribution system load profile driven by customer demographics over time.
5 With increasing customer expectations along with the updated requirements of the
6 MPSC's revised Service Quality and Reliability Standards for Electric Distribution
7 Systems, more emphasis is being placed on reliability improvement and faster storm
8 restoration. UPPCO therefore finds it necessary to increase the levels of capital spending
9 on reliability projects to improve service to customers.

10 In addition to projects necessary for safety, compliance, voltage, or system loading
11 issues, the selection of specific reliability-based projects is determined using a
12 combination of (1) the severity of the outage data at a given location, (2) the age and
13 condition of the existing distribution facilities, (3) the availability of capital resources, (4)
14 the number of customers benefiting, and (5) logistical considerations such as design
15 complexity, constraints due to access, right of way, easements, permitting, and weather,
16 as well as with material, labor, and contractor resource availability.

17 Reliability and age/condition often overlap in outage statistics; therefore, UPPCO uses
18 this data to help indicate the best locations to direct capital improvements. Capital budget
19 dollars are then allocated to the specific locations that have the greatest need for
20 distribution reinforcement.

21 UPPCO's system hardening efforts are a systematic and efficient approach designed to
22 improve reliability over time. Targeted projects on UPPCO's worst feeders will improve

1 customer satisfaction, reduce the number and duration of outages, make UPPCO's
2 distribution more resilient during storms, and move UPPCO closer to the State's goals to
3 reduce the number and duration of outages and improve customer experience.

4 **Q. Please describe UPPCO's plan for managing its distribution assets, and identify key**
5 **projects that help provide a safe, reliable, efficient electric system for its customers.**

6 A. For typical distribution reinforcement projects, UPPCO has a 5-year planning horizon.
7 Each year upcoming project designs are reviewed, and potential issues, such as
8 easements, permits, resource availability, landscape, and customer demographic changes,
9 are reviewed prior to design finalization. If any issues arise during the review process,
10 options are considered which could still provide similar benefits. Project scopes may be
11 adjusted based on this review, or other higher priority projects may have been uncovered
12 since the last review, and these projects may be reprioritized within a budget year, or
13 even within the 5-year planning horizon as system conditions evolve from year to year.

14 **SYSTEM HARDENING**

15 **Q. Please describe Exhibit A-20 (MBI-3) and identify both the project driver**
16 **classification system and the distribution capital expenditure projects that UPPCO**
17 **has identified, as incremental to its sustaining and/or base capital level of spending.**

18 A. UPPCO is planning to implement the projects shown in Exhibit A-20 (MBI-3), 2026 –
19 2027 SHARP projects, which lists each SHARP project planned for 2026 and 2027. The
20 purpose and anticipated benefits for each project are summarized in a column listing the
21 Company's project classification. UPPCO's project classification system is as follows: R

1 – Reliability/System hardening; A – Age & Condition; S – Safety; C –
2 Compliance/Voltage; and L – Load/Capacity. The identification of these projects
3 ultimately informs UPPCO’s improved reliability and load growth component of the
4 Company’s distribution CAPEX plan. UPPCO creates and updates by-foot rates for
5 typical, standard, overhead and underground projects which can be used for high-level
6 estimating and for cost comparisons between projects. However, these by-foot rates can
7 be quite variable due to actual surface and underground conditions and SHARP are not
8 strictly chosen and prioritized based on cost; they are also designed with the intent to
9 improve crew accessibility, provide new switching corridors for the crew to perform
10 stepped restorations, replace infrastructure nearing its useful end of life, maintain the
11 system in a safe state, or increase capacity for load growth. Projects with these objectives
12 will inherently improve safety and reliability due to new construction spacing standards,
13 increasing switching corridors, and reducing crew patrol time, but are difficult to quantify
14 in terms of SAIDI and SAIFI metrics or cost benefits. As mentioned previously,
15 customers will benefit somewhat monetarily with reduced outages, but they will also
16 experience intrinsic value that cannot be measured.

17 I will now describe each of the SHARP projects listed in Exhibit A-20 (MBI-3).

18 **Q. Please describe SHARP project, ISH - UG CR 480 Install Feeder.**

19 A. The existing Freeman 203 circuit serving 20, mostly industrial customers, is a 35kV
20 overhead line that extends three miles from the substation before reaching the first
21 customer. Over two miles of this overhead line are only accessible by track equipment
22 and also contain 6 steel lattice structures that are in very poor shape. This rugged, 3 mile
23 section of line experienced 7 outages between 2023 to 2025, with an average outage

1 duration of 14 hours and 27 minutes. To help reduce the number of outages on this
2 troublesome section of line, a new substation will be constructed along the County Road
3 480 corridor, as discussed in the direct testimony of Company witness Gervae. The new
4 substation will result in distribution facilities with much better accessibility and less
5 exposure. Underground cable along the road right of way was determined to be the best
6 solution from the new substation to tie into the existing overhead facilities 3,500' away.
7 Later in my testimony I will describe a second project that will then be completed in 2027
8 to rebuild the existing overhead circuit from single- phase to three-phase. An added
9 benefit of this project is that it will serve all customers from the standard distribution
10 voltage of 12.47kV which reduces the inventory requirements of UPPCO non-standard
11 35kV components.

12 **Q. Please describe SHARP project, ISH - UG Asset Renewal BARNUM 1203 Part 2**
13 **North Wood Replacement**

14 A. This two-part project began in 2025 to address underground cable failures on BRM 1203
15 which is the #2 worst performing feeder. The underground cable has been in service for
16 over 40 years and is showing signs of reaching the end of its useful service life having
17 experienced 4 underground equipment failures in the last 3 years. The average outage
18 length to restore these issues is 5 hours and 43 minutes. Part 2 will replace the remaining
19 10,000 feet of cable around Chabeneau Lake and improve reliability to 19 customers.

20 **Q. Please describe SHARP project, DLT - OH 18th St Substation Install Feeders**

21 A. The existing Bayview substation is restricted by access constraints and lack of easements
22 that limit opportunities to improve the distribution system in the Escanaba area. As a

1 result, a new substation on 18th Road about 1 mile west of Bayview substation will be
2 constructed and Bayview will be retired from service. The new substation is centrally
3 located where new tie points can be established and existing tie points can be
4 strengthened to increase distribution system redundancy for all four feeders out of Delta
5 substation and the two existing Bayview feeders. Of these six feeders, four are ranked in
6 the top 11 worst performing feeders from 2023 to 2025. The new substation will supply a
7 feeder to the Cornell and north Gladstone area that will reduce line miles and present
8 exposure by about 40%. A second feeder to the South Gladstone area will reduce the
9 number of customers affected by a substation feeder trip by 50%. This project is for the
10 installation of two substation feeder exits that will tie into the existing distribution system
11 from the new substation location.

12 **Q. Please describe SHARP project, DLT - OH 18th St Substation 21st Road**
13 **Reconductor.**

14 A. Approximately 8,000 ft of existing overhead conductor between Delta 583 and Bayview
15 515 needs to be reconducted to sufficiently serve the Bayview 515 load once the
16 Bayview substation is retired. This project is being done in conjunction with the new 18th
17 St substation and is necessary for the retirement of Bayview substation.

18 **Q. Please describe SHARP project, ISH - Barnum substation feeder exit rebuild.**

19 A. Barnum 1231 and Barnum 1203 were the 1st and 2nd worst performing feeders over the
20 course of 2023 to 2025 based on UPPCO's feeder ranking system. This project is being
21 done in conjunction with a substation construction project that will allow the 4,500
22 customers on 1203 and 1231 to be split across four feeders instead of two. This change

1 will reduce customer exposure and allow for protective device coordination changes that
2 better isolate outages to a smaller area. In addition to reducing the customer count related
3 to outages on these feeders, this project will also reduce patrol time.

4 **Q. Please describe SHARP project, DLT - Fuller Park.**

5 A. This project is on DLT 589 which was the 4th worst performing feeder between 2023 to
6 2025. This project eliminates 6,000 feet of a heavily wooded overhead line and replaces it
7 with 5,600 feet of underground cable along the road right of way providing much better
8 access and reliability to 33 customers including the Delta County Fuller Park
9 campground.

10 **Q. Please describe SHARP project, KWN 927 Popeye Rock underground**

11 A. KWN 927 was the 7th worst performing feeder under all weather conditions, and was the
12 worst performing feeder after MED events between 2023 to 2025. The location of this
13 overhead to underground conversion project is difficult to access, patrol, or properly
14 maintain due to rocky terrain. Additionally this section of the distribution system is relied
15 on often as a tie point for all 1,200 customers served out of Keweenaw substation.

16 **Q. Please describe SHARP project, LIN 3063 Sunset Lake Part 2.**

17 A. This is part two of a two-part project that began in 2025 to address reliability issues
18 around Sunset Lake. LIN 3063 was the 20th worst performing feeder from 2022 to 2024
19 and four locations around Sunset Lake were ranked within the top 10 outage locations in
20 terms of SAIDI in the Iron River district of UPPCO's service territory. These four
21 locations experienced a combined total of 10 outages that resulted in a total SAIDI of
22 4.32. Currently the east and west sides of Sunset Lake are fed radially with each side of

1 the lake being a mix of underground and old overhead conductor. This project will
2 establish a two-phase loop around the lake to create redundancy and improve the
3 restoration time of future outages. Additionally, this project will increase the pole height
4 and replace aged overhead conductor sizes that no longer meet UPPCO standards, with a
5 standard conductor size that UPPCO utilizes today.

6 **Q. Please describe SHARP project, M38 747 Motley Rd Copper Replacement**

7 A. M38 747 experienced the 13th most outages between 2023 to 2025. This section of
8 overhead line is remote, old copper conductor that is difficult to access with standard
9 equipment. These factors make this area a prime area to complete an overhead to
10 underground conversion to improve reliability to the customers at the end of the line.
11 This project will convert 10,750 feet of overhead to underground.

12 **Q. Please describe SHARP project, KWN 927 Rebuild to Fort Wilkins**

13 A. KWN 927 was the 7th worst performing feeder under all weather conditions, and the
14 worst performing feeder after MED events between 2023 to 2025. The customers that
15 experienced the most outages over the past 3 years were in Eagle Harbor and Copper
16 Harbor area. Load growth in the Fort Wilkins State Historic State Park area, at the end of
17 the line, makes coordination of protective equipment challenging. Extension of the 3-
18 phase line 4,000 feet will allow even load distribution and improve reliability.

19 **Q. Please describe SHARP project, HEN 1009 Replace Portage Canal UG crossings**

20 A. The Portage Canal underwater cable crossings have been utilized for over 80 years and
21 have reached the point where they need to either be replaced or removed. Replacement
22 parts are not readily available for cable of this vintage and the termination structures on

1 each side of the Portage Canal need to be replaced with equipment that meets current
2 safety and construction standards. These two 3-phase underwater power cables are the
3 only distribution voltage crossings of the Portage Canal and are important tie points for
4 the cities of Houghton and Hancock, as well as the surrounding areas that are served by
5 the Elevation St substation on the north side of the Portage Canal and Henry St
6 substation, MTU substation, and Atlantic substation on the south side of the Portage
7 Canal. These four substations serve more than 12,000 customers in the most urban
8 environment in UPPCO service territory. These underwater distribution crossings have
9 been utilized to support load during emergencies and to accommodate planned
10 maintenance events for both UPPCO and ATC, which serves Henry St substation and
11 MTU substation on a radial ATC transmission line. Without these distribution ties,
12 around 20% of UPPCO customers would lose redundancy that Houghton, Hancock and
13 the surrounding areas have relied on over the last 80+ years. Additionally, it would
14 jeopardize UPPCO's ability to serve these customers during major substation or
15 transmission outage events which could result in thousands of customers out of power for
16 an extended period of time.

17 Over the past 7 years, UPPCO has considered cable injection and replacing the crossings
18 in their existing locations. However, cable injection had uncertainty related to the
19 condition of the crossing, lifespan increase, and the unavailability of parts to extend and
20 rebuild existing terminations further from the Portage Canal water edge. It also was
21 determined that the crossings could not be replaced in their current location due to boring
22 constraints related to the proximity of the existing crossing to the Portage Canal lift
23 bridge. As a result, it was determined that the best long-term solution was to complete the

1 bore 1.5 miles west from the current location. The 2026 portion of the construction
2 project will bore two new 3-phase 1,800 ft underwater crossings. Later in the testimony I
3 will describe additional construction planned for 2027 that will route existing overhead
4 facilities to the new underwater crossing location that will both restore the redundancy
5 currently in place and increase the load carrying capacity of these tie points. This project
6 will also set up the ability for potential additional ties to Osceola substation in Calumet to
7 improve reliability to an even greater number of UPPCO customers.

8 **Q. Please describe SHARP project, ISH - OH-OH CR 480 Add 2 Phases.**

9 A. This project will begin where the 2026 underground feeder extension from the new
10 County Road 480 substation ended. This overhead project will rebuild approximately 1
11 mile of existing single-phase construction as a three-phase overhead line and tie in the
12 new County Road 480 substation that is discussed earlier in the testimony.

13 **Q. Please describe SHARP project, ISH - OH Asset Renewal FORSYTH Serenity Drive**
14 **Part 2**

15 A. FRY 2733 was the 4th worst performing feeder in terms of SAIDI and outage events and
16 has the 10th worst SAIDI over the past 3 years. This project is the continuation of a two-
17 part project that began in 2025 that is downstream of one of the most active protective
18 devices on the feeder. Part two of this overhead replacement project rebuilds 7,500 feet of
19 overhead line as three-phase to provide redundancy to 1.5 miles of radial underground
20 serving over 600 customers on M-35.

21 **Q. Please describe SHARP project, ISH - Reliability Improvement GWINN 657 Seass**
22 **Drive-Rice Lake Tie**

1 A. GWN 657 was the 9th worst performing feeder between 2023 to 2025. Since 2022, the
2 customers in this project area have experienced 8 outages, with an average outage
3 duration of 8 hours and 13 minutes. Over 5,000 feet of the existing distribution system is
4 built overhead through a heavily wooded area where easement trimming is limited
5 because of the large size of the trees and proximity to lake front homes. This project
6 creates redundancy for 197 customers and will reduce exposure and outage duration.

7 **Q. Please describe SHARP project, DLT - OH-UG MASONVILLE Reliability**
8 **Improvement 33rd Road**

9 A. The existing overhead line is not accessible by truck and requires track equipment to
10 access, making restoration work difficult and time consuming. These 10 customers have
11 experienced nine outages over the past 3 years related to this section of line with an
12 average outage duration of 6 hours and 19 minutes. This project removes 5,000 feet of
13 heavily wooded overhead conductor and replaces it with 4,900 feet of underground
14 conductor along the road right of way. In addition to the improved access and reduced
15 tree clearance, this project will also allow for the removal of a Whitefish River crossing.

16 **Q. Please describe SHARP project, M38 747 Prickett Dam to Clayco Road OH-UG**
17 **conversion.**

18 A. M38 747 experienced the 13th most outages between 2023 to 2025. This section of
19 overhead line is remote, old copper conductor that is difficult to access with standard
20 equipment. These factors make this area a prime area to complete an overhead to
21 underground conversion to improve reliability to 475 customers. This project will also

1 convert this section of line from two phase to three phase which will allow the load to be
2 balanced more appropriately and better isolate outages to a smaller area.

3 **Q. Please describe SHARP project, OSC 719 Jacobsville OH to UG conversion**

4 A. OSC 719 was the 6th worst performing feeder between 2023 to 2025. The Jacobsville
5 area is struck often by inclement weather resulting in extended outages. This section of
6 overhead line is remote, old copper conductor and is a prime area to complete an
7 overhead to underground conversion to improve reliability to the customers in this area.

8 **Q. Please describe SHARP project, KWN 927 Silver River Rebuild**

9 A. KWN 927 is the 2nd worst performing feeder in terms of SAIDI and SAIFI and has
10 experienced the seventh most outage events over the past 3 years. This section of line
11 experienced nine outages between 2023 to 2025, with an average outage duration of 8
12 hours and 6 minutes. This project will strengthen this section of line against wind and
13 vegetation issues and improve reliability for 570 customers.

14 **Q. Please describe SHARP project, ELE 1125 Extension to Birch St**

15 A. This project is in conjunction with the replacement of the two Portage Canal underwater
16 cable crossings taking place in 2026. The new location for the underwater crossings will
17 be 1.5 miles west of the existing location where there is currently a single Elevation
18 feeder on the north side of the Portage Canal. Subsequently this requires a feeder to be
19 extended from Elevation St substation to tie into the underwater crossing at the new
20 location so that both underwater crossings can be tied into the distribution system on the
21 north side of the Portage Canal. An existing overhead route will need to be rebuilt as a
22 double circuit for approximately 1 mile from Elevation St substation to the new location.

1 This project will finalize the work on the north side of the Portage Canal related to the
2 relocated Portage Canal underwater crossings.

3 **Q. Please describe SHARP project, HEN 1009 Remove old Canal Crossing**

4 A. This project will remove the existing Portage Canal underwater crossing infrastructure on
5 each side of the Portage Canal, along with the existing underwater crossings, following
6 the replacement of the crossing to a new location 1.5 miles west of the current location.
7 The existing infrastructure is built in close proximity to the water edge and the Portage
8 Canal Lift bridge on both the Houghton and Hancock side of the Portage Canal. This
9 project will require reconfiguration work in addition to removal.

10 **Q. Please describe SHARP project, HEN 1017 Rebuild from WHSC to Jacker Ave**

11 A. This project is also in conjunction with the replacement of the two Portage Canal
12 underwater cable crossings taking place in 2026. The new location for the underwater
13 crossings will be 1.5 miles west of the existing location. The distribution system on the
14 south side of the Portage Canal already has two existing feeders to tie in the underwater
15 crossings, however one of the existing feeders is not sufficiently sized to carry the
16 amount of load that the new underwater crossings are capable of serving. As a result, the
17 existing overhead facilities on Canal Road will be rebuilt for 1.15 miles to increase the
18 load carrying capacity of the Portage Canal underwater crossings and strengthen the tie
19 between Houghton and Hancock.

20 **Q. Please describe SHARP project, UPPCO Cutout Replacement.**

21 A. UPPCO began a cutout replacement program in 2023 to make a concerted effort to
22 replace porcelain cutouts due to the increased breakage experienced by porcelain cutouts

1 over the past 20 years. This program has been incredibly effective. Over the 3-year period
2 of 2020 to 2022, cutout failures accounted for 44% of customer outage coded as
3 distribution equipment failures in UPPCO's OMS resulting in 43% of the total customer
4 minutes interrupted for equipment failures. Between 2023 to 2025, these percentages
5 decreased to 33% and 26% respectively. Additionally, the average number of outage
6 events between 2020 and 2022 caused by a failed cutout was 153. Whereas the average
7 number of outage events caused by a failed cutout between 2023 and 2025 was 95, with
8 only 64 cutout-caused events in 2024 and 73 in 2025. This resulted in a decrease of the
9 customer minutes interrupted due to failed cutouts by 48% when comparing 2020-2022 to
10 2023-2025. These numbers show that the cutout replacement program is improving
11 reliability.

12 **Q. Please describe SHARP project, Failed Underground Replacement**

13 A. This project was created and budgeted to address unforeseen cable replacement projects
14 that arise during the course of the budget year. These projects typically develop due to
15 cable failures. However, this funding could also be used if a customer-requested line
16 relocation or line extension provides an opportunity for UPPCO to perform some
17 additional work to take advantage of the customer project to improve reliability in the
18 area. As mentioned earlier in my testimony, UPPCO anticipates replacement of
19 underground cables due to failure and this budget item allows for these replacements
20 during the course of the year, thereby providing flexibility to perform opportune cable
21 replacements with a short turnaround time to further improve the reliability of the system
22 serving those customers.

23 **Q. Please describe SHARP project-System Hardening**

1 A. This project was created and budgeted to address unforeseen reliability improvement
2 projects that arise during the course of the budget year. This budget item allows for
3 UPPCO Engineering to use discretion and judgement to design and complete small
4 SHARP projects that may be completed in conjunction with other unplanned work. For
5 example, customer requests, such as line relocations or line extensions, or shared
6 facilities make-ready projects cannot be predicted, but when they occur, UPPCO can
7 capitalize on the opportunity to complete piggy-back projects to improve reliability to all
8 customers in the area. Other circumstances, such as storm restoration or overhead line
9 inspection results, may warrant a more urgent system hardening project. This budget item
10 allows Engineering to perform a quick analysis of these situations and facilitate a project
11 to make a direct and immediate impact in reliability for UPPCO's customers.

12 **LINE EXTENSION CONSTRUCTION POLICY**

13 Q. Please describe why UPPCO is submitting revisions for the Line Extension Policy.

14 A. The Line Extension Policy has not been revised since January 1, 2014, which was prior to
15 UPPCO being a stand-alone company. The specific changes will be described in the
16 following testimony and are documented in Exhibits A-29 (MBI-12), A-30 (MBI-13),
17 and A-31 (MBI-14). These exhibits are provided in redline form to show the changes
18 being made and may affect formatting of the final, clean copy when the redlines are
19 removed.

20 **Exhibit A-29 (MBI-12)**

21 Q. **Please explain why Sheets No. C-20.90 through C-20.96 are proposed for removal.**

1 A. Sheets C-20.90 through C-20.96 comprised UPPCO’s former line extension policy prior
2 to the creation and approval of UPPCO’s current line extension policy via Case No. U-
3 16166, which became effective January 1, 2011. The only reason to maintain these sheets
4 was for potential refunding during the 5-year developmental period for customer line
5 extensions installed under the former policy. The former Line Extension Construction
6 Policy was closed as of January 1, 2011, which is over 15 years ago, and therefore, the
7 policy has been closed significantly longer than the 5-year developmental period and is
8 no longer relevant to line extensions while the policy was in force. The removal of the
9 closed line extension policy will also reduce confusion for those reviewing the Policy.
10 Exhibit No. A-29 (MBI-12), documents the closed Line Extension Policy that is proposed
11 for removal.

12 **Exhibit A-30 (MBI-13)**

13 **Q. Please describe the change on Sheet No. C-19.00 under the Section III. – Line**
14 **Extension Construction Policy – header.**

15 A. The Company removed the reference at the top of the page stating, “For extensions prior
16 to January 1, 2011 see Sheet No. C-20.90 – C-20.96.” As described in my response to the
17 previous question, this reference is no longer necessary since the 5-year developmental
18 period for customer line extensions under the prior policy expired in 2016, and therefore,
19 is no longer applicable.

20 **Definitions**

21 **Q. Please describe the change on Sheet No. C-19.00, Section 1.b, Distribution System.**

1 A. The second paragraph was re-worded regarding extensions requiring the enlargement of
2 transmission facilities to more clearly describe UPPCO’s current process. UPPCO does
3 not presently own any transmission facilities. This section was modified to describe the
4 process UPPCO has been following for load additions that may require transmission
5 facility upgrades as well as UPPCO substation upgrades to serve the new customer load.

6 **Q. Please describe the change on Sheet No. C-19.10, Section 1.f, Investment.**

7 A. The last part of the last sentence in parenthesis is proposed for removal, which currently
8 states, “see Section 2 for definition of standard facilities.” The definition of “standard
9 facilities” is currently in Section 2 and UPPCO proposes moving the definition to the
10 Definition Section as new Section 1.h, Standard Facilities, in the proposed revision of the
11 Policy. This is also discussed in the response to the next question.

12 **Q. Please describe the additional paragraph on Sheet No. C-19.10, Section 1.h,**
13 **Standard Facilities.**

14 A. UPPCO believes that all relevant definitions should be placed in the “Definitions”
15 Section of the Policy. In the proposed revision, the first paragraph has been removed
16 from Section 2, General Policy, on Sheet C-19.20 and included as the new line on Sheet
17 C-19.10, Section 1.h Standard Facilities. This is appropriate because it will maintain all
18 the definitions in the Definitions Section of the Policy.

19 **Q. Please describe the new section on Sheet No. C-19.10, Section 1.i, Standard Service**
20 **Lengths.**

1 A. Standard service lengths vary by the expected maximum load to be served, which is
2 directly related to the customer service size. In the proposed draft revision, this section
3 was added to more clearly indicate the length of a standard service drop or lateral which
4 is provided at no cost to serve the new customer based on the customer’s main disconnect
5 switch size.

6 **Q. Please describe the new section on Sheet No. C-19.20, Section 1.j, Site Ready.**

7 A. The definition of “site ready” had been partially provided in the current Policy in Section
8 2.i.4 describing winter construction charges. This was the only area where site readiness
9 was defined in the current Policy. Since site readiness applies to all new customer
10 services, this language has been moved to the Definitions Section.

11 The current language only stipulates that “the dwelling foundation wall is installed and
12 backfilled and the trench route cleared and graded to within 6” of the final grade.”
13 However, there are several additional requirements that must be met prior to the customer
14 site being considered ready for construction, including (i) the customer payment, if
15 required, (ii) the Company’s receipt of signed contracts, (iii) permits and easements must
16 be fully executed, and (iv) the installation of an approved electric meter socket. All of
17 these items are also defined by MPSC Service Quality and Reliability (SQR) rule,
18 R460.702(v), which defines the “start date for new installations” and corresponds to a
19 customer’s site as being ready for service. Additionally, the language regarding the
20 dwelling foundation wall is proposed for removal, since some new services are extended
21 to free standing meter locations, such as for billboards, mobile homes or trailer, or central
22 farm services, which do not have a foundation wall. This language was replaced with

1 language stating “there is evidence for the continuing need for electric service.” This
2 terminology correlates with the language in Section 3.b describing extension allowance
3 qualifications.

4 **General Policy**

5 **Q. Please describe the change on Sheet No. C-19.20, General Policy, in the first**
6 **paragraph.**

7 A. The first paragraph from Section 2, General Policy, on Sheet C-19.20 was moved into the
8 Definitions Section as a definition on Sheet C-19.10, Section 1.h Standard Facilities. This
9 change is appropriate to consolidate all the definitions in the Definitions Section of the
10 tariff.

11 **Q. Please describe the change on Sheet No. C-19.20, Section 2.b., General Policy.**

12 A. This section describes the company’s available service voltages. The reference at the end
13 of the section in parenthesis in the current version of the Policy simply states, “See
14 Available Service Voltages” with no further reference. UPPCO’s standard service
15 voltages are included in its Electric Service Manual, which is available on UPPCO’s
16 website at www.uppco.com/residential/electric-service-manual/#electric-service-manual,
17 Section 3-1.2, Available Voltages. Therefore, this section of the Extension Policy was
18 updated to reflect the standard service voltages available to new customers, specifically
19 single-phase 120/240V and three-phase 120/208V and 277/480V.

20 **Q. Please describe the change on Sheet No. C-19.20, General Policy, Section 2.d.**

1 A. This section discusses line extensions where the Company is not assured as to the
2 stability and economic feasibility of a project, which may require an additional payment
3 and/or contract. Since the last two sentences are already included in Section 5,
4 Uneconomic Extensions, they were removed and replaced with a reference to Section 5.

5 **Q. Please describe the change on Sheet No. C-19.20, General Policy, Section 2.e.**

6 A. This section refers to UPPCO’s estimating process to determine the amount of company
7 investment needed to serve the customer load. The current wording is vague and did not
8 adequately indicate the actual costs that are necessary to extend facilities to the customer-
9 requested service location and that are included in the estimate of company investment.
10 UPPCO uses a design and estimate tool to create detailed estimates for construction
11 based on actual conditions observed by UPPCO designers in the field, such as rock,
12 pavement, driveways, road crossings, brushing, and other surface and underground
13 obstacles. The tool uses current material, labor, equipment, and underground contractor
14 rates to calculate a detailed estimate, including contractor costs, a materials list, and a
15 comprehensive sketch for construction. The tool is based on UPPCO’s current
16 distribution construction standards, best practices, and engineering guidance. The
17 proposed revision to this section of the Policy better summarizes UPPCO’s actual design
18 and estimating process.

19 **Q. Please describe the change on Sheet No. C-19.40, General Policy, Section 2.h.7).**

20 A. This section refers to the customer providing space for padmounted equipment when the
21 company installs underground facilities. The term “when requested” was removed in the

1 proposed draft since UPPCO installs underground as standard facilities and the customer
2 providing space for padmounted equipment is necessary for the installation and an
3 expectation of the customer to serve the new load.

4 **Q. Please describe the change on Sheet No. C-19.40, General Policy, Section 2.h.8).**

5 A. This section refers to applicants requesting the company to install underground
6 distribution systems. The term “at its discretion” was added in the draft revision of the
7 Policy since terrain and ground conditions may sometimes prohibit the practicality of
8 underground construction. UPPCO’s preference and first approach when designing any
9 new line extension is to install the new facilities underground to improve reliability and
10 reduce future maintenance, however, at times it is not feasible to install the facilities
11 underground, may be restricted by governmental authorities, or is cost prohibitive due to
12 surface or ground conditions, such as the presence of rock, significant tree cover, steep
13 inclines, wetlands, pavement/concrete, or other utilities’ facilities already installed
14 underground.

15 **Q. Please describe the change on Sheet No. C-19.50, General Policy, Section 2.h.9).**

16 A. This section refers to applicants requesting the Company to install underground electric
17 service laterals. The term “at its discretion” was added in the draft revision of the Policy
18 since terrain and ground conditions may prohibit the feasibility of underground
19 construction. The same reasoning applies to this change as Section 2.h.8 discussed above.

20 **Q. Please describe the change on Sheet No. C-19.50, Section 2.i.1.a) and b), Winter**
21 **Construction Charge.**

1 A. This section describes UPPCO’s winter construction charge timelines. In the current
2 tariff, two separate sections currently exist in the Policy to distinguish the timelines when
3 winter construction charges would be waived for (i) Subdivision customers and (ii) Non-
4 Subdivision customers. The current timeline to charge for winter construction is the same
5 for both types of customers (i.e. November 1 to April 15), but the timeline when winter
6 construction will not be charged only differs by two weeks between subdivision and non-
7 subdivision customers. UPPCO experiences very few true new subdivision projects and
8 these are typically in development for a year or more with the property owner. In the
9 draft revision of the Policy UPPCO proposes striking the Non-Subdivision customer
10 language in Section 2.i.1.b), maintaining the language for Subdivision customers with
11 some slight revision, and striking the terms “subdivision” and “non-subdivision” from the
12 section.

13 The proposed revision will eliminate confusion between what is considered a subdivision
14 project and what is considered a non-subdivision project and places all new installations
15 on the same timeline for winter construction charges. The timeline when winter
16 construction charges are not charged only provides the company one (1) month to
17 schedule the work and install the new line extension before winter construction
18 conditions may be present. This proposed change eliminates the need to distinguish
19 subdivision and non-subdivision customers and will reduce confusion regarding which
20 timeline applies to which type of customers.

21 Additionally, the term “underground” was replaced by “distribution” in the first sentence
22 of this section in the proposed revision of the Policy since winter construction may apply

1 to overhead installations as well as to underground installations. Winter construction is
2 inherently more difficult and complex due to frozen ground and snow cover, and may
3 require additional equipment, such as plow trucks, ground thawing equipment, rock
4 augers, etc. Accordingly, winter construction typically requires additional labor resources
5 to complete the work.

6 Also, in the sentence regarding the customer's application, the term "subdivision" was
7 replaced by "service" to clarify that this section does not apply to only subdivision
8 customers but to all customers, which was described above. And the term "underground
9 facilities" was removed in the second sentence of this section regarding site readiness
10 since the site must be ready for construction regardless of whether the new facilities are
11 overhead or underground.

12 The term "as defined in Section 1.j" was added to the second sentence regarding site
13 readiness for construction when winter construction charges will not be charged to
14 provide a reference to the new definition of Site Ready in the Definitions Section.

15 **Q. Please describe the change on Sheet No. C-19.50, Section 2.i.2, Winter Construction**
16 **Charge.**

17 A. This section describes UPPCO's winter construction charges waiver. The current
18 language reads, "The Winter Construction Charge will be waived by Company if the
19 Company's underground contractors do not actually charge the Company for winter
20 construction conditions." This is a misrepresentation on two levels. First, winter
21 construction charges are added to a customer estimate and are paid by the customer in

1 advance of construction prior to any actual construction work in the field by the
2 contractor. So it is not possible to “waive” the charges prior to the contractor actually
3 performing the installation work. Instead UPPCO would reimburse the contractor’s
4 winter construction charges after completion of the project, typically within 6 months,
5 after all actual charges are tallied and the work order is closed out. Second, contractor
6 charges are not the only cost that may be associated with winter construction. Winter
7 construction inherently brings more complications to underground cable and padmount
8 equipment installation, especially in UPPCO’s mostly rural service territory. Access to
9 the customer location is frequently along gravel or dirt roads that may be snow covered
10 and/or muddy and difficult to traverse with heavy line trucks. UPPCO crews may need to
11 plow snow to access padmounted equipment or pedestals installed by the contractor to
12 terminate and energize system and service cables, or use tracked equipment to terminate
13 risers. The cables become stiffer in cold temperatures so the ability to train (i.e. bend) and
14 terminate cables within the equipment, becomes more difficult and takes more time to
15 complete. Even if UPPCO’s underground installation contractor does not charge for
16 winter construction, UPPCO crews may still encounter winter conditions when they
17 arrive to complete the work and energize the new system and service.

18 Winter construction costs are difficult to estimate as the weather conditions during
19 construction are unknown at the time that the construction design was created and winter
20 construction conditions can vary significantly from snow cover to frost more than 2 feet
21 deep. For these reasons, UPPCO proposes to modify the language to reimburse all, or a
22 portion of, the winter construction charges based on the actual charges to the project after
23 the project is completed.

1 **Q. Please describe the change on Sheet No. C-19.50, Section 2.i.3, Winter Construction**
2 **Charge.**

3 A. This section describes UPPCO’s winter construction charges as non-refundable, but
4 states “except as voted.” This should have read, “except as noted,” which is a typo, and
5 will be corrected with the proposed change.

6 Further, language was added to allow the company to delay underground construction
7 due to winter conditions. Besides county and state weight restrictions that limit travel on
8 certain roads and highways during the winter months, there are numerous reasons that
9 make construction impractical or nearly impossible in the winter. Winter construction,
10 especially when frost is present, requires significant added labor and sometimes requires
11 specialized equipment, such as jack hammers or ground thawing equipment, to break up
12 the frozen ground to enable underground facilities installation. Additionally, winter
13 construction almost always requires a return trip in the springtime to adequately clean up
14 the area along the underground installation route, resulting in added cost. Further,
15 padmounted equipment installed during winter conditions may settle and tip as the
16 ground warms in the spring, which could present a safety hazard, and may require
17 additional labor to level in the spring. Underground installation by directional boring is
18 not always possible during the cold winter months. Boring requires a solution under high
19 pressure to loosen soil as the bit tunnels under ground. In extreme low temperatures, this
20 solution can freeze, thereby making this installation method impractical in the winter.
21 The additional labor, equipment, and materials can be estimated and billed to the
22 customer in advance of winter construction, however, at times, the amount of frost would

1 not allow for an underground installation that meets the company's expected quality for
2 an underground installation thereby jeopardizing the life span of the underground cable.
3 Frozen pieces of earth do not provide satisfactory backfill for the underground facilities.
4 Suitable fill, such as sand, is not available during the winter months since it is stored
5 outside and freezes when exposed to temperatures below 32°F for prolonged periods of
6 time. And pavement, if required, is not available since blacktop plants shut down for the
7 winter months. For the reasons described above, the Company should have the ability to
8 delay construction until road restrictions are lifted and practical installation methods may
9 be employed to assure underground facilities can be installed in a quality manner meeting
10 company standards and the expected life span of the facilities.

11 **Q. Please describe the change on Sheet No. C-19.60, Section 2.i.4, Winter Construction**
12 **Charge.**

13 A. This section describes when a customer's premises and/or construction site is deemed
14 ready for underground facilities installation. As described previously in my testimony,
15 the language in the proposed revision of this section was reworded and moved to Section
16 1.j, Definitions. Hence, this section number was deleted.

17 **Standard Underground or Overhead Extension Rules**

18 **Q. Please describe the change on Sheet No. C-19.70, Section 3.b.2)a), Extension**
19 **Allowances.**

20 A. This section states that extension allowances reflect the company's projected embedded
21 average cost of distribution facilities and further describes the process to revise

1 allowances. However, the current language describing the revision process is slightly
2 contradictory. UPPCO calculates the extension allowance based on the projected
3 embedded average cost of distribution facilities by customer class. However, UPPCO
4 only calculates the embedded average cost of distribution facilities by customer class
5 when it submits an application to adjust its rates, which is not performed on an annual
6 basis. Further, the language is unclear about how revised allowances would be submitted
7 to the MPSC, since typically, an approved tariff can only be changed through an order
8 issued by the MPSC. For these reasons, UPPCO's line extension allowances have not
9 been updated for some time. The change proposed in the revised draft of this section ties
10 the revision of allowances directly to a rate case proceeding and clearly defines when the
11 allowances would be recalculated and how they would be submitted to the Commission
12 for approval.

13 **Q. Please describe the changes on Sheet No. C-19.70, in Section 3.b.2)d), Extension**
14 **Allowances.**

15 A. This section indicates the projected embedded average cost of distribution facilities by
16 customer class. The values are calculated based on the summed total FERC 364, 365, and
17 367 account costs less depreciation as allocated by customer class in the company's cost
18 of service study sponsored as Exhibit A-16, Schedule F1 by Witness Stocking. The
19 revised extension allowances in this section of the proposed draft reflect the embedded
20 average cost of service by customer class based on the values provided in the Exhibit.

21 **Q. Please describe the changes on Sheet No. C-19.70, Section 3.b.2)e), Extension**
22 **Allowances.**

1 A. This section describes how the estimated demand is determined for energy and demand
2 commercial and industrial customers. UPPCO requires commercial and industrial
3 customers to submit a load study listing the planned connected loads and the expected
4 maximum coincidental loading that would be served by the company in any 15-minute
5 period. The customer load study along with UPPCO experience with similar existing
6 customers is used to determine the maximum expected coincidental loading, which is
7 then used to calculate the allowance. However, UPPCO's past experience indicates that
8 the customer-provided coincident loading value is typically overestimated resulting in a
9 larger allowance to the customer than should be applied. New customers who receive an
10 overestimated allowance subjects all other ratepayers to the difference, that is, current
11 ratepayers would subsidize new customers' line extension.

12 UPPCO proposes to recalculate the allowance based on the actual 15-minute peak
13 loading after 12 months in service. This method would be more timely than waiting until
14 after the 5-year developmental period and the proposed revision to the tariff language in
15 this section will result in a refund or true-up bill to the customer who requested the new
16 service and will not negatively affect current ratepayers. The proposed change to this
17 section and the true-up of the allowance for new demand customers places the line
18 extension cost beyond the allowance on the new customer rather than on current rate
19 payers.

20 The actual 15-minute demand over the 12-month service period would then be used to re-
21 calculate the allowance, which would also be used to re-calculate the amount available
22 for refunds over the 5-year developmental period as described in Section 3.b.5).

1 In the proposed revision to this section, a reference to the definition of the Development
2 Period in Section 1.g. was added, which describes the date when a new line extension is
3 considered energized, and will also serve as the in-service date for new demand
4 customers' 12-month in-service period.

5 **Q. Please describe the changes to Sheets No. C-19.80 and 19.90.**

6 A. These two sheets were combined in a 2011 update of the Policy to combine cancelled
7 tariff sheets. UPPCO proposes to remove these sheets, which are blank and are not
8 needed for the proposed revisions to the tariff.

9 **Q. Please describe the changes to the first line on Sheet No. C-20.00.**

10 A. The current page C-20.00 of the Policy omitted the section number and subsection letter
11 at the top of the page. Section "3" and subsection "b." were added to the top of the page,
12 which conforms to the format of the other pages in the Policy.

13 **Q. Please describe the change on Sheet No. C-20.00, Section 3.b.4), Adjustment to**
14 **Actual.**

15 A. The current language describes when adjustments to the estimated costs for actual
16 conditions encountered may be billed or refunded to the customer. The term "customer-
17 requested design changes" was added to the list of changes that may constitute an
18 adjustment to reflect actual costs, since any additional cost as a result of a customer's
19 request should be allocated to the customer.

1 Additionally, in UPPCO's experience, the \$100 limit is too narrow for current new
2 customer installations, therefore, UPPCO proposes a $\pm 10\%$ variance would be more
3 appropriate. The proposed language in this section replaces the \$100 limit with $\pm 10\%$.

4 **Q. Please describe the change on Sheet No. C-20.00 and C-20.10 affecting Section**
5 **3.b.5)c)(1), Refunds.**

6 A. In the draft revision of the Policy, this section was pushed from the bottom of Sheet C-
7 20.00 to the top of Sheet C-20.10, without any language changes, for page formatting
8 purposes only.

9 **Q. Please describe the change on Sheet No. C-20.10, Section 3.b.5)g).**

10 A. The current section of the Policy discusses refund amounts to customers connected prior
11 to March 1, 1983 based on the prior extension rules. Extensions prior to 1983 are no
12 longer eligible for refunds, and therefore, this section is not relevant. UPPCO proposes to
13 remove this section in its entirety.

14 **Q. Please describe the change on Sheet No. C-20.10, Section 3.c, Standard**
15 **Underground or Overhead Extension Rules.**

16 A. This section discusses the customer responsibility to have the site ready for installation of
17 facilities. This section only stated that if the "contractor arrives to find it not ready" then
18 "the customer shall be responsible for all costs associated with the return to the site." A
19 contractor is not always the first party to arrive on site to install facilities. At times
20 company personnel arrive first to perform work in advance of the company's contractor's

1 arrival and some installations do not require a contractor at all. So “the company or” was
2 added to the section in the draft revision of the Policy. Additionally, “and billed
3 accordingly” was added to make it clear that the company will bill for return trips when
4 the customer has notified the company that the site was ready when it was not.

5 **Miscellaneous Extensions**

6 **Q. Please describe the change on Sheet No. C-20.20, Section 4.b, Miscellaneous**
7 **Extensions.**

8 A. This section describes UPPCO’s practice to only install facilities deemed necessary to
9 render service. In the draft revision of the Policy, the term “standard” was added before
10 the word “facilities” to make it clear that only standard facilities are deemed necessary to
11 render service. Special Facilities are any and all facilities that are not standard. Therefore,
12 a reference to the definition of standard facilities in Section 1.h was added to clearly point
13 out the difference between special and standard facilities.

14 **Q. Please describe the changes on Sheet No. C-20.30, Section 4.c.1)a) (1) and (2),**
15 **Enlargement of Capacity, Commercial and Industrial.**

16 A. These sections describe how UPPCO provides an extension allowance for enlargement of
17 capacity for commercial and industrial customers. The proposed changes in these sections
18 are only formatting changes. The existing tariff language made reference to the allowance
19 values outlined in Section 3.b.2)d); however, the reference included subsections (2) and
20 (3) that do not exist in the current tariff. Therefore, these subsection numbers (2) and (3)
21 were deleted from the references in these sections in the proposed revision of the Policy.

1 Q. Please describe the changes on Sheet No. C-20.30, Section 4.c.1)b), Enlargement of
2 Capacity, Residential.

3 A. This section describes how UPPCO provides an extension allowance for enlargement of
4 capacity for residential customers. UPPCO proposes to replace the word “he” with “the
5 customer” to make the language gender neutral.

6 Further, UPPCO proposes to add the sentence, “This includes customers moving from a
7 Residential rate to a Commercial or Industrial rate” to clarify that this section does not
8 only apply to residential customers enlarging their load under a residential rate.

9 Q. Please describe the changes on Sheet No. C-20.40, Section 4.d.1), Distribution
10 System Facilities.

11 A. This current section of the Policy describes payments required by the customer. The last
12 sentence of this section describes the process to convert mercury vapor lights to high
13 pressure sodium. However, UPPCO no longer has any mercury vapor street or private
14 lighting in the system; furthermore, with the exception of some decorative and other
15 special lighting, nearly all high pressure sodium lights have been converted to LEDs.
16 Therefore, UPPCO proposes to remove the reference to mercury vapor and high pressure
17 sodium lights and add language that more clearly describes when private or street lighting
18 becomes a line extension falling under this line extension policy.

19 UPPCO lighting tariffs for municipalities, SL-6, and for other customers, Z-3, clearly
20 state the rate “charges are for lighting on existing company-owned distribution facilities.”
21 Although the tariffs allow for an additional charge for a span of wire and/or an additional

1 wood pole, the monthly charges are for secondary voltage facilities to serve the lighting
2 load at the desired location, not for the extension of UPPCO's distribution system.
3 Extension of additional distribution system facilities required to serve the load beyond
4 existing facilities would fall under the Line Extension Construction Policy. Therefore,
5 UPPCO proposes language clearly stating that installations requiring more than one pole
6 and/or span of overhead secondary wire shall be treated as line extensions under the
7 Policy.

8 **Q. Please describe the changes on Sheet No. C-20.40, Section 4.d.2)a), Overhead to**
9 **Underground Service Replacements.**

10 A. This section describes a customer-requested replacement of an existing overhead service
11 drop with an underground service lateral. UPPCO typically utilizes underground
12 contractors for underground construction. A payline for service replacements exists
13 within the underground contractor's contract specifically for this type of work due to the
14 necessity to work in the vicinity of existing gas, cable, telephone, or fiber lines,
15 established lawns and gardens, or other surface encumbrances, such as driveways and
16 sidewalks. The payline includes any means of conductor installation, including plowing,
17 trenching, directionally boring, and/or hand-digging as well as surface restoration on the
18 customer property with black dirt and seed. UPPCO's proposed language revision in this
19 section better reflects the customer-obligated costs of the contractor service replacement
20 payline as well as the cost for the company to remove the overhead service drop.

21 Additionally, proposed language was added to point out that the customer may qualify for
22 a service allowance if they are increasing their load per Section 4.c.2.

1 **Q. Please describe the changes on Sheet No. C-20.50, Section 4.d.4), Refunds.**

2 A. Section 4.d.4) describes the conditions where a contributor (i.e., new customer) may
3 receive a refund for distribution facilities payments. Subsection 4.d.4)b) stated, “The
4 existing facilities are on or within six feet of the contributor’s property.” This verbiage is
5 deemed unnecessary for refund eligibility, therefore, in the revised draft Policy UPPCO
6 proposes it be removed, which necessitated the following subsection to be renumbered
7 from 4.d4)c) to 4.d.4)b).

8 **Q. Please describe the changes on Sheet No. C-20.50, Section 4.f, Electric Services.**

9 A. This section describes the service allowance provided to a new customer. The current
10 language in the Policy states, “The Company will provide an allowance to cover the cost
11 of a standard electric service up to a maximum length of 125 feet.” Since service length is
12 limited by voltage drop, which varies based on service conductor size and customer load,
13 UPPCO developed standard service lengths based on the customer main disconnect size
14 and UPPCO’s standard service conductor sizes. Therefore, UPPCO proposes additional
15 language to the end of the sentence stating, “based on the customer’s main disconnect
16 size” to clarify the maximum “free” service length to new customers based on their
17 expected load. UPPCO also proposes a reference be added to this section stating,
18 “Standard service lengths are defined in 1.i”, which was discussed earlier in my
19 testimony.

1 Furthermore, UPPCO proposes that the verbiage in subsection 4.f.1) be modified to
2 replace “125’ in” length to “the standard service” length, which better reflects that not all
3 service sizes allow the same maximum lengths.

4 Additionally, UPPCO proposed to delete the formula for calculating the customer
5 payment for the service as it was deemed unnecessary since the customer responsibility is
6 clearly stated in Subsections 4.d.4)f. 1) through 4), therefore, the verbiage and formula
7 after Section 4.d.4)f.4) was removed in the draft version of the Policy.

8 **Q. Please describe the changes on Sheet No. C-20.60.**

9 A. This was a blank page and UPPCO proposes it be removed from the Policy.

10 **Q. Please describe the changes on Sheet No. C-20.70, Section 5, Uneconomic**
11 **Extensions.**

12 A. This section describes UPPCO’s policy on extensions that may be considered
13 uneconomic in nature. Language in this section protects UPPCO and its ratepayers from
14 ongoing maintenance costs from new customer services that may not be self-sustaining
15 based on the expected customer load, and hence, revenue from the customer. Proposed
16 language was added to this section to better portray the circumstances when a special
17 contract may be warranted when a new customer load may be uneconomic. The proposed
18 language added and revised in this section is deemed necessary to prevent an undue
19 burden on current rate payers due to new customer uneconomic line extensions.

20

1 **Q. Please describe the changes on Sheet No. C-20.70, Section 6, Exception to Extension**
2 **Rule Payments.**

3 A. This section describes that the customer payment required by the Policy may be waived if
4 it is less than \$20. This is deemed too low for current construction costs and UPPCO
5 proposes this be raised to \$100.

6 **Q. Please describe the changes on Sheet No. C-20.70, Section 7, Collection of Customer**
7 **Contributions for Construction.**

8 A. This section describes the collection of the advance customer payment. In the current
9 Policy this section is currently broken down between electric services in Subsection a.
10 and all other costs except services in Subsection b. Each subsection states that if the
11 customer payment required is less than \$20, the payment would be waived, in effect,
12 repeating the language in Section 6. Each subsection also stated that if the payment
13 required was greater than \$20, the company would bill the customer and require payment
14 in advance of construction. The two subsections were deemed overly complex and
15 confusing, therefore, UPPCO proposes to match the proposed value in Section 6 and
16 replace the \$20 limit with \$100. The Section would be consolidated and simplified to
17 read, "If the total advance customer payment required from the application of all sections
18 of these extension rules is greater than \$100, the Company will bill the customer and
19 require payment in advance of construction of the electric facilities." This revision makes
20 it clear that if the required customer payment is greater than \$100 then it will be collected
21 by the company in advance of construction and is consistent with Section 6, which states
22 the payment shall be waived if the required customer payment is less than \$100.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21

Proposed Changes to Street Lighting (SL-6) rules:

Q. Please describe the changes proposed to page D-54.00 of the SL-6 tariff, as represented in Exhibit No. A-16, Schedule F5, sponsored by Company witness Bell.

A. During review and revision of the line extension tariff as discussed in detail above, minor differences were noted in the additional pole and span of conductor verbiage between the dusk-to-dawn tariff, Z-3, and the municipal lighting tariffs, SL-6 and SL-X. Therefore, language in the municipal tariffs, SL-6 and SL-X, is proposed for revision to match the language in Z-3, specifically stating that mast arms longer than 6 feet in length and additional poles and spans of wire beyond one additional pole or 200 feet of conductor are considered special facilities for which the customer must make a non-refundable payment.

Language in the Special Terms and Conditions section of both lighting tariffs states that the monthly “charges are for lighting on existing company-owned distribution facilities.” This implies that no extension of facilities would be required to serve the lighting request. The language in this section continues to state that specific monthly charges would apply if the customer requests an additional wood pole or span of conductor up to 200 feet. The intent of this language is to allow the customer some leeway on the location of the new light to best serve their lighting needs, and not for development of a street lighting system beyond one pole or span of conductor either on the customer premises or along a road-right-of-way.

1 The proposed revision to the SL-6 tariff is consistent with the objective of the extension
2 rules where new customer service is not subsidized by existing rate payers and a new
3 lighting customer is not billed a contribution in aid of construction for costs that are
4 recovered in the monthly rates in the lighting tariffs.

5
6 **Exhibit A-31 (MBI-14)**

7 **Q. Please describe the changes proposed to pages D-60.10, D-60.20, and D-60.30 of the**
8 **SL-X tariff.**

9 A. As discussed in the previous response, during review and revision of the line extension
10 tariff, minor differences were noted in the additional pole and span of conductor verbiage
11 between the dusk-to-dawn tariff, Z-3, and the municipal lighting tariffs, SL-6 and SL-X.
12 The Z-3 tariff encompasses the dusk-to-dawn monthly service rate, special terms, and
13 conditions as well as the rules for applying the tariff. However, the municipal lighting
14 tariff, SL-6, only includes the monthly service rate and special terms and conditions; the
15 rules for applying the tariff are described in the SL-X tariff. Therefore, the SL-X tariff is
16 proposed for revision to match the rules outlined in the Z-3 tariff with respect to
17 installation of new lights on existing utility poles and for the extension of facilities
18 beyond one additional pole or 200-ft span of conductor.

19 Specifically, the language from Z-3 “Rules Applying” items (4) and (5) were copied and
20 pasted into SL-6, Section 3, Service Rules, as new Sections 3)b)1)e) and 3)b)1)f). Note,

1 the Section number “3)” was missing in the current SL-X Service Rules section header
2 and added in the proposed revision.

3 The only changes to pages D-60.20 and D-60.30 were for formatting due to page spacing
4 limitations. The addition of items 3)b)1)e) and f) into Section 3 as noted above pushed
5 items 3)b)2)c) and d) from page D-60.10 to D-60.20. The paragraph line spacing of Item
6 3)b)2)e) was changed to match that of d) and e). Furthermore, spaces between 3)e)1), 2),
7 and 3) were removed and item 3)f) was pushed to page D-60.30 due to page spacing
8 limitations.

9 The proposed revisions to SL-6 and SL-X tariffs provide direct and clear alignment
10 between the dusk-to-dawn lighting tariff, Z-3, and the municipal lighting tariffs, SL-6 and
11 SL-X, and consistency when applying the tariff language to both customer classes.

12 **COMPARISON TO DISTRIBUTION PLAN (U-20147)**

13 **Q. How does the proposed distribution spending for 2026 and 2027 align with the**
14 **proposed distribution spending in the Distribution Plan filed on January 31, 2025?**

15 A. The 2026 and 2027 distribution subtotals in Appendix 6 of the Distribution Plan filed
16 under Case No. 20147 are \$14,956,307 and \$15,263,070 respectively. In comparison, the
17 2026 and 2027 distribution budget is estimated to be \$18,257,000 per year. This equates
18 to a difference of \$3,300,693 in 2026 and \$ 2,993,930 in 2027.

19 The primary difference between the proposed spending in the 2026 and 2027 distribution
20 budget in this case and the Distribution Plan is related to the inclusion in this case of the

1 Portage Canal underwater crossing replacement work. At the time of the Distribution
2 Plan filing in early 2025, the estimated project cost and timeframe to secure labor
3 resources was unknown, and therefore, was not included in Appendix 6, Table 1 of the
4 Distribution Plan budget projections. Following preliminary engineering work that was
5 completed throughout 2025, the Company determined that \$2,500,000 was needed in
6 2026 to complete the underwater crossing replacement and \$2,500,000 was needed in
7 2027 to rebuild infrastructure to the new underwater crossing location that will be 1.5
8 miles west of the existing location. These project costs are included in Exhibit A-20
9 (MBI-3) and explained in more detail in the System Hardening and Reliability Projects
10 section of this testimony. When \$2,500,000 is added to the 2026 and 2027 Distribution
11 Subtotal in Appendix 6 of the Distribution Plan, the sum is within 5% of the 2026 and
12 2027 distribution budget set forth in this case.

13 **Q. On October 30, 2025, Staff filed comments in Case No. 20147 stating that UPPCO**
14 **should forecast specific reliability metrics in its next rate case, or Distribution Plan.**
15 **How does the Company respond to this comment?**

16 A. As described in the Reliability Metrics and System Goals section of this testimony,
17 UPPCO sets an aggressive SAIDI goal each year based on 90% of the previous 5-year
18 average SAIDI, excluding MEDs. The SAIDI goal for 2026 is 157 minutes. UPPCO does
19 not establish specific values for other reliability metrics. Due to the significant impact
20 that weather events can have on reliability metrics, UPPCO considers SAIDI to be the
21 most defensible metric to forecast reliability goals. SAIDI goals support long term
22 planning of achievable and cost-effective reliability projects and most directly reflect the

1 overall customer experience in a measurable way. By excluding MEDs, the SAIDI
2 reliability goal is less sensitive to the variable and non-recurring nature of weather events
3 or other sporadic conditions that are unlikely to recur in a consistent nature over time.
4 While other reliability metrics such as SAIFI, CAIDI, and total number of events are not
5 assigned individual forecasted goals, they are incorporated into UPPCO's feeder
6 ranking methodology used for project development and prioritization.

7 **Q. Does this complete your direct testimony in this proceeding?**

8 A. Yes.

9

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-22032

DIRECT TESTIMONY AND EXHIBIT OF

DANIEL J. GERVAE

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

May 22, 2026

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

2 A. My name is Daniel J. Gervae. My business address is 500 N. Washington St. Ishpeming,
3 MI 49849. I am the Director of Distribution & Substation Operations for Upper
4 Peninsula Power Company (“UPPCO” or the “Company”).

5 **Q. For whom are you providing testimony?**

6 A. I am providing testimony on behalf of UPPCO in support of its request for an increase in
7 its retail electric rates.

8 **Q. Please briefly describe your educational, professional, and utility background.**

9 A. I have a Bachelor of Science degree in Electrical Engineering Technology from Northern
10 Michigan University. I began my professional career in 1991 in the mining industry at
11 Copper Range Company in White Pine, MI as a Supervisor of Mine Services where I
12 oversaw installation of electric utilities and other infrastructure in the underground mine.
13 I was later hired by MJ Electric in Iron Mountain, MI as a Project Engineer, and was
14 eventually promoted to Project Superintendent overseeing large electric utility
15 construction projects from power plants to substations. I joined UPPCO in 2006 as a
16 Substation Project Coordinator and in 2010 was Promoted to Supervisor of Substation
17 Operations. In 2021, I became the Manager of Substation Engineering & Operations
18 followed by a promotion to Director of Substation & System Operations. In 2024, I
19 became Director of Distribution & Substation Operations which is my current role.

20 **Q. Have you testified previously before the Michigan Public Service Commission**
21 **(“MPSC”)?**

1 A. Yes. I have sponsored direct testimony in MPSC Case No. U-21555.

2 **Q. What is the purpose of your testimony?**

3 A. The purpose of my testimony is to describe and provide support for UPPCO's projected
4 capital projects relating to Substations.

5 **Q. Are you sponsoring any exhibits in this proceeding?**

6 A. Yes. I am sponsoring the following exhibit, which was either prepared by me or under
7 my direct supervision:

8 1. Exhibit No A-18 (DJG-1)

9 **Q. Please describe Exhibit No. A-18 (DJG-1).**

10 A. Exhibit A-18 provides an overview of the substation capital projects included in the
11 bridge period (calendar year 2026) and the projected test period (calendar year 2027).

12 **Q. How is your testimony organized?**

13 A. My testimony is organized as follows:

- 14 • Substation System Conditions
- 15 • 2026-2027 Substation Capital Projects
- 16 • 2025 Substation Capital Project Update

17

18 **SUBSTATION SYSTEM CONDITIONS**

19 **Q. Please provide an overview of UPPCO's Substation system.**

20 A. UPPCO serves approximately 53,471 customers in Michigan's Upper Peninsula with a
21 service territory of approximately 4,500 square miles in 10 of the 15 counties in the

1 Upper Peninsula. UPPCO owns, operates, and maintains 42 Substations and has a
2 maintenance/operations agreement with American Transmission Co. (“ATC”) to provide
3 services at 15 additional substations that are either jointly owned by UPPCO and ATC or
4 solely owned by ATC. UPPCO provides maintenance, switching, and construction
5 services to ATC on an annual basis. UPPCO has 101 distribution feeders serving
6 residential, commercial, and industrial customers across our service territory.

7
8 **2026-2027 SUBSTATION CAPITAL PROJECTS**

9 **Q. Please describe the Substation Tools Project.**

10 A. The Substation department maintains high voltage equipment, complex relay protection,
11 and SCADA systems. All of these require specialized tools to perform the required work.
12 These tools include Doble Engineering transformer and breaker testing equipment,
13 Omicron relay test sets, and many other very special, expensive tools. We have a service
14 agreement with Doble Engineering for leased equipment and consulting services in
15 support of the Doble transformer and breaker testing equipment that costs \$58,960
16 annually. Additionally, circuit breaker test sets cost \$32,970 each. We sometimes retire
17 outdated test equipment and replace it with necessary, modern test equipment on a
18 rotating basis to keep up with changing testing requirements. This budget also allows for
19 other specialized tooling purchases including presses, hot-line equipment, protective
20 grounds, etc.

21 **Q. Please describe Project Engineering Subsequent Years.**

1 A. Substation engineering must adapt to changing material lead times and anticipate future
2 project needs. We must have funds available to charge hours to in order to accommodate
3 our future and unforeseen needs. These needs include providing specifications and design
4 considerations for long lead time items such as transformers and SF6 gas breakers to
5 allow for projects development sometimes 3 years down the road.

6 **Q. Please describe the 2026 18th Road Substation Project**

7 A. UPPCO plans to build a new 69KV/12.47KV Substation at a new location along 18th Rd.
8 in Escanaba. Delta Feeder 583 and Bayview Feeders 515/517 will be re-fed from the new
9 substation. The new substation will completely replace the Bayview substation. This
10 project will be beneficial because UPPCO has been unable to obtain a distribution
11 easement between the Bayview Substation and US-2. In addition, access into Bayview
12 has always been difficult. This new substation will be installed along 18th Road and will
13 supply a 12.47kV feed to Cornell and north Gladstone area and a second 12.47kV feed to
14 the South Gladstone area. This project is for the installation of the substation feeder
15 exits. A central area was selected for the substation to help reduce the number of overall
16 outages seen by UPPCO customers in the Cornell and Gladstone areas. The selected
17 location allows the Cornell feeder to be split from the existing Delta feed, which will
18 reduce upstream line miles and potential outages, by approximately 40%. The Gladstone
19 area will be split between two different feeders to help reduce the number of customers
20 affected by a substation feeder trip by 50%. The proposed substation location also adds
21 new tie points and strengthens existing tie points to significantly increase distribution
22 system redundancy for all Delta circuits (Escanaba and Bark River Customers).

23 **Q. Please describe the 2026 Barnum Add 2 Feeders Project.**

1 A. The Barnum 1203 feeder and the Barnum 1231 feeder will be replaced by four new
2 feeders. The Barnum 1203 feeder is the worst performing UPPCO feeder in terms of
3 SAIDI and SAIFI and has experienced the third most outage events over the past 3
4 years. The Barnum 1231 feeder is the third worst performing feeder in terms of SAIDI
5 and SAIFI and has experienced the most outage events over the past 3 years. By
6 UPPCO's internal feeder ranking system, these two feeders rank as the #1 and #2 worst
7 performing feeders from 2023-2025. This project will allow the 4,500 customers on the
8 1203 and 1231 feeders to be split across four feeders instead of two. This change will
9 reduce customer exposure and allow for protective device coordination changes that
10 better isolate outages to a smaller area. In addition to reducing the customer count related
11 to outages on these feeders, this project will also reduce patrol time. The feeders will be
12 added to the Barnum Substation and the distribution portion of the project will involve a
13 new section of underground 3 phase along with separation of the previously
14 (permanently) tied circuits outside of the sub creating 4 feeders out the 2 existing today.

15 **Q. Please describe the 2026 Replace VCR Recloser with Vacuum Reclosers at MTU**
16 **Project.**

17 A. Over the course of upgrading our system protections over the last few years, it became
18 clear that OCR's were more reliable and accommodated our SEL 351S relay protection
19 design better. However, the vendor, Eaton Cooper, has discontinued the production of
20 OCR's. This has forced us to move to a new Vacuum Circuit Recloser ("VCR") option,
21 which we feel is an adequate alternative solution based on technical inquiries with
22 vendors and other utilities. The Eaton Cooper OCRs are the last of their kind on our
23 system and are more than 20 years old. As we take steps to replace these units, we are

1 looking to adhere to UPPCO's revised, more reliable standard as mentioned above using
2 SEL 351S relays which are housed inside our control building instead of outside attached
3 to the recloser stand.

4 **Q. Please describe the 2027 County Rd. 480 Substation Project**

5 A. The existing Freeman 203 circuit, which serves mostly industrial customers, is a 35kV
6 overhead line that extends three miles from the Freeman substation before reaching the
7 first customer. Over two miles of this overhead line are only accessible by track
8 equipment and also contain 6 steel lattice structures that are in very poor shape. This
9 rugged, 3-mile section of line experienced 7 outages in the last 3 years that have an
10 average outage duration of 14 hours and 27 minutes. To help reduce the number of
11 outages on this troublesome section of line, a new substation will be constructed along
12 the County Road 480 corridor. The new substation will result in distribution facilities
13 with much better accessibility and less exposure. Underground cable along the road right
14 of way was determined to be the best solution from the new substation to tie into the
15 existing overhead facilities that 3,500' feet away. An added benefit of this project is that
16 it will serve all customers from the standard distribution voltage of 12.47kV which
17 reduces the inventory requirements of UPPCO non-standard 35kV components. Because
18 of right of way congestion by a neighboring utility who constructed an overhead line
19 along the same route, underground was chosen and is the only viable option in this
20 instance.

21
22 **2025 SUBSTATION CAPITAL PROJECT UPDATE**

23 **Q. Please describe the 2025 MTU Bank 1 Replace Aging Transformer Project**

1 A. The age and condition of the existing transformer as well as the size of the unit, forced its
2 replacement. The former transformer is a 8.4MVA 69/12.470KVA unit that was installed
3 in 1967 and it was no longer large enough to serve nearby load. We replaced it with a
4 12/14/16MVA 69/12.47KV unit because of a load interconnect request from Michigan
5 Tech and UPPCO's need/ability to use this unit to back up other customer load in this
6 same substation As this unit acts as a second bank to serve the city of Houghton load and
7 provides operational flexibility to allow planned maintenance without customer
8 interruption.

9 **Q. Please describe the 2025 MTU Bank 1 Transformer High Side Protection Project**

10 A. This project is directly related to the above MTU Bank 1 Transformer Replacement
11 Project described above. The Institute of Electrical and Electronics Engineers ("IEEE")
12 IEEE C37.91-2021 (Guide for Protecting Power Transformers) is the primary standard
13 for high-side transformer protection, covering 3-phase transformers above 5 MVA and 10
14 kV. for better system protection and reliability. The newly installed transformer is above
15 10MVA. This new equipment was installed to protect the expensive and difficult-to-
16 replace transformer. Additionally, lead time for procurement of a new transformer was
17 approaching 2 years so maintaining the transformers that are currently installed or
18 installing soon was crucial.

19 **Q. Please describe the 2025 Delta RTU and R&C (Relay & Controls) Upgrade Project**

20 A. The Delta substation has an SEL Real-Time Automation Controller ("RTAC") Remote
21 Terminal Unit ("RTU"). The controls (43, 101, GTB, 79CO, etc.) at the substation are
22 virtual points on the HMI screen and are mapped to soft points in the RTAC RTU. We

1 had trouble with the operating system as it relates to the HMI Function of this unit. The
2 RTAC RTU was reprogrammed using HMI view only Function and traditional 101, 43,
3 and 79CO switches were installed. Relay settings were reviewed and coordinated with
4 distribution engineering for new 387E and 351S relays. 351Ss replaced the 351Rs in the
5 yard and were located in the control house. Old Oil Circuit Reclosers (“OCRs”) were be
6 replaced with New Cooper OCRs. RTU points list was brought to our current standard.
7 All local controls became hardwired physical panel switches. UPPCO performed the
8 design, construction, and checkout for all phases of this project.

9 **Q. Please describe the 2025 Delta Bank 1 Transformer High Side Protection Project**

10 A. This project is directly related to the Delta Bank 1 Transformer Replacement Project
11 from 2023, the IEEE recommends a high side breaker and relay protection for units
12 above 10MVA for better system protection and reliability. This new equipment was
13 installed to protect the expensive and difficult-to-replace transformer. As noted above,
14 lead time for procurement of a new transformer was approaching 2 years. We purchased
15 the transformer in 2023 and completed the project in 2024-25 with the addition of a new
16 protection and controls package.

17 **Q. Does this complete your direct testimony?**

18 A. Yes.

19

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-22032

DIRECT TESTIMONY AND EXHIBIT OF

VIRGIL E. SCHLORKE

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

May 22, 2026

1 **QUALIFICATIONS**

2 **Q. Please state your name, business address, and position.**

3 A. My name is Virgil E. Schlorke, and my business address is 800 Greenwood St.
4 Ishpeming, MI 49849.

5 **Q. For whom are you providing testimony?**

6 A. I am providing testimony on behalf of Upper Peninsula Power Company (“UPPCO”) in
7 support of its request for an increase in its retail electric rates.

8 **Q. Please describe briefly your educational, professional, and utility background.**

9 A. I graduated from Michigan Technological University with a Bachelors and Master of
10 Science in Civil Engineering. I am also a licensed Professional Engineer in the states of
11 Michigan and Wisconsin. I have over twenty-eight years of engineering and
12 management experience, seventeen of which are in managing electric generation assets,
13 and over eleven years in structural engineering and design, project construction
14 management for industrial buildings and building restoration. I started in the utility
15 industry in June of 2006 as a Regional Generation Supervisor at Wisconsin River Power
16 Company. In July of 2010, I transferred to UPPCO as the Manager of Generation and
17 was promoted to my current position of Director of Generation and Environmental
18 Services in February 2015.

19 **Q. Have you testified previously before the Michigan Public Service Commission**
20 **(“MPSC”)?**

21 A. Yes. I have sponsored direct testimony in the following MPSC cases:

- 1 U-17796 – Renewable Energy Plan
- 2 U-17807 – Renewable Energy Reconciliation
- 3 U-17895 – General Rate Case
- 4 U-20276 – General Rate Case
- 5 U-18467 – Depreciation
- 6 U-21513 – Depreciation
- 7 U-21555 – General Rate Case

8 I have also sponsored rebuttal testimony in the following MPSC cases:

- 9 U-18467 - Depreciation

10

11 **PURPOSE OF TESTIMONY**

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

13 A. The purpose of my direct testimony is to describe and provide support for UPPCO’s
14 projected capital projects relating to Generation.

15

16 **EXHIBITS**

17 **Q. Are you sponsoring any exhibits in this proceeding?**

18 A. Yes. I am sponsoring the following exhibit, which was either prepared by me or under
19 my direct supervision:

1 1. Exhibit No A-12 (VES-1), Schedule B5.1.

2 **Q. Please describe Exhibit A-12 (VES-1), Schedule B5.1.**

3 A. Exhibit A-12 (VES-1), Schedule B5.1, consists of two pages summarizing capital
4 expenditures relating to steam, hydraulic, and other power generation resources during
5 the historic, bridge, and projected test periods.

6

7 **GENERATION SYSTEM CONDITIONS**

8 **Q. Please provide an overview of UPPCO's Generation facilities.**

9 A. UPPCO owns, operates, and maintains five hydroelectric generation facilities and three
10 storage reservoirs, which produce an average of 120,953 megawatts of clean renewable
11 energy annually, and one emergency-only combustion turbine. The hydroelectric
12 facilities are operated under Federal Energy Regulatory Commission (FERC) granted
13 licenses. The license is a contract with the federal government, which requires the
14 licensee to produce and deliver electricity while also ensuring public safety and meeting
15 numerous other environmental and recreational requirements. The primary driver behind
16 the Company's investment in its hydroelectric facilities is to ensure and maintain
17 compliance with the FERC licenses while continuing to provide safe and reliable
18 renewable energy to the benefit of its customers. Projects within the generation fleet are
19 generally identified and prioritized by working with the relevant regulators, resource
20 agencies, and consultants while considering material availability, equipment
21 obsolescence, and resource constraints.

1 **Q. What types of capital projects does UPPCO plan for its hydroelectric generation**
2 **fleet?**

3 A. Projects within the UPPCO hydroelectric generation fleet generally fit into 3 different
4 categories as follows.

5 1. Facility Refurbishment/Improvements: These projects ensure license compliance
6 by maintaining the integrity of the facilities and extending the life of the facilities
7 and building structures. These facilities and building structures protect the
8 generating equipment and ancillary components, while also directly and indirectly
9 supporting the operation and maintenance of the equipment, allowing the
10 Company to maintain compliance with its FERC licenses.

11 2. Power Generation & Delivery: These projects ensure license compliance by
12 maintaining the integrity of the generating and electric delivery equipment and
13 systems and also extending the life of these systems and equipment. Safe and
14 operational generating equipment and electric delivery systems are a requirement
15 of UPPCO's FERC licenses.

16 3. Dam Safety: These projects ensure license compliance by maintaining the
17 integrity of the water conveyance and retaining structure and also extending the
18 life of these structures. Structurally sound and safe water conveyance systems
19 and retaining structures (such as penstocks, surge tanks, dams, embankments,
20 spillways, etc.) are required by UPPCO's FERC licenses in order to ensure public
21 safety.

22

1 **PLANNED CAPITAL PROJECTS RELATING TO GENERATION**

2 **Q. Please describe Victoria Gate Hoist Replacement, as shown in line 6 of Exhibit A-12**
3 **(Schedule B5.1 p.2).**

4 A. This project is a multi-year project. Design and engineering are ongoing with
5 procurement scheduled for 2027 (\$524,736). The project is categorized as Dam Safety
6 because it addresses the potential inability to operate a traveling gate hoist which controls
7 75% of the gated spillway capacity. The current traveling gate hoist serves 3 gates and is
8 original equipment that was installed in the 1930s. Maintenance of the hoist has become
9 increasingly challenging due to equipment and component obsolescence. Additionally,
10 the current hoist poses a host of operational difficulties: (i) it is time consuming to
11 operate; (ii) labor intensive; (iii) poses significant employee safety risks; and (iv) has no
12 remote operation capability. A significant amount of the site’s spillway capacity (75%) is
13 dependent on this locally operated hoist and access to the site is difficult during major
14 storms because it requires use of bridges susceptible to flooding during PMF level storm
15 events. The inability to access and operate the traveling hoist could potentially lead to
16 overtopping and failure of the facility. This would result in significant license
17 deviations/violations, public safety issues, and environmental impacts. This project
18 replaces the single traveling gate hoist with a new traveling remote operated hoist. This
19 addresses equipment obsolescence and provides safer and more timely gate operation
20 while ensuring license compliance, public safety, and protection of the environment.

21 **Q. Please describe Victoria Behind Penstock Access, as shown in line 9 of Exhibit A-12**
22 **(Schedule B5.1 p.2).**

1 A. This project is a multi-year project. Design and engineering were completed in 2023 and
2 2024 with construction scheduled for 2026. Project engineering and construction costs
3 are estimated at \$442,623. The project is categorized as Dam Safety because it addresses
4 issues with access behind the penstock and a partially failed drainage culvert beneath the
5 penstock that were identified during the 9th Victoria Part 12D inspection completed in
6 2022. Lack of adequate access behind the penstock inhibits monitoring, inspection and
7 maintenance of the penstock and drainage culverts. Plugged or failed (partially or fully)
8 culverts alter the upstream drainage paths along the penstock, increasing the potential for
9 erosion of the ballast foundation and unintended loading of the penstock which could
10 lead to penstock rupture. A ruptured penstock would result in significant environmental
11 impacts, public and employee safety issues along with license deviations/violations. This
12 project involves slip lining the partially failed culvert and constructing a trail to provide
13 access behind the penstock to allow for penstock and culvert monitoring and
14 maintenance. This work will address dam safety issues, ensure license compliance, and
15 improve public and employee safety. The repair plan minimizes environmental impacts
16 by refurbishing the partially failed culvert. Installation of the access path provides for
17 improved monitoring and simplifies future maintenance of the penstock and drainage
18 culverts.

19 **Q. Please describe Dead River Concrete Refurbishment (2021 Part 12 FERC inspection**
20 **requirement), as shown in line 10 of Exhibit A-12 (Schedule B5.1 p.2).**

21 A. This project is a multiyear project with engineering being completed in 2023 and 2024
22 for \$53,044 and \$144,523 respectively with construction scheduled for 2027. Project
23 engineering costs were originally forecasted as \$103,955 in 2024 as part of rate case U-

1 21555. Total project engineering and construction costs are estimated at \$1,728,308.
2 The project is categorized as Dam Safety because it addresses FERC commitments for
3 concrete refurbishment resulting from the FERC required Part 12 Consultant Dam Safety
4 Inspections of the Silver Lake, Hoist, and McClure Dams in 2021. These concrete
5 refurbishment items have been bundled into a single engineering/design and construction
6 effort to maximize efficiencies and minimize duplication of work associated with
7 multiple sites and the resulting overall number of regulatory filings. Key items included
8 as part of the concrete refurbishment for each facility are as follows.

9 Silver Lake:

- 10 (i) Addressing current areas of eroded rock and preventing further undermining of
11 the spillway due to rock erosion during spill events.

12 Hoist:

- 13 (i) Refurbishment of the upstream face of the concrete dam & spillway mostly along
14 the water line area, which has experienced freeze thaw deterioration.
15 (ii) Refurbishment of the crest and downstream face of the concrete dam (including
16 the thrust block) in areas that have experienced freeze thaw deterioration.
17 (iii) Filling of the glacial pothole which is undercutting the toe of the concrete dam.
18 Refurbishment of the powerhouse access walkway.

19 McClure:

- 20 (i) Refurbishment of the concrete dam's left intake buttress and non-overflow
21 structure (including crack injection & grouting in the upstream intake stoplog
22 slots).

1 Not addressing these commitments would result in license compliance issues and
2 potential dam safety problems leading to public safety concerns. The project will address
3 all the FERC required Part 12 inspection commitments ensuring license compliance and
4 public safety.

5 **Q. Please describe Hoist Penstock Interior Lining Replacement, as shown in line 11 of**
6 **Exhibit A-12. (Schedule B5.1 p.2).**

7 A. This project is a multiple year project with a total expenditure of \$313,090 in 2025 and an
8 estimated expenditure of \$227,590 for 2026 resulting in a total project cost estimate of
9 \$540,680. The project is categorized as Dam Safety because it addresses the failing
10 interior lining of the Hoist Penstock. This lining is meant to protect the interior of the
11 penstock from corrosion and was identified as peeling away and missing in some places
12 during an internal inspection in 2021. Excessive corrosion would lead to thinning and
13 potential failure of the penstock. Penstock failure is considered a dam safety issue and
14 would cause significant environmental impacts, potential public and employee safety
15 issues, and result in license deviations/violations. This project repairs and overcoats the
16 interior lining, which will protect the penstock from internal corrosion and address the
17 dam safety issue. The project will also ensure license compliance and public safety while
18 avoiding environmental impacts.

19 **Q. Please describe Prickett Intake Refurbishment, as shown in line 14 of Exhibit A-12.**
20 **(Schedule B5.1 p.2).**

21 A. This project is a multi-year project. Design development and engineering were
22 completed in 2024 and 2025 with construction scheduled for 2026. Project engineering

1 and construction are estimated at \$4,208,252. This project is categorized as Dam Safety
2 because it addresses a potential intake structure stability issue. Structure performance
3 monitoring identified sediment movement from under the Intake structure and increased
4 uplift pressure under the intake structure, resulting in stability safety factors lower than
5 FERC required guidelines. Increased uplift pressure during a flood event could result in
6 a failure of the intake structure resulting in a complete release of the reservoir. This
7 would be considered a dam safety event and result in significant environmental impacts,
8 public and employee safety issues, and license deviations/violations. Dive inspections
9 identified a crack in the intake floor/foundation which when plugged (temporarily)
10 provided significant reductions in uplift pressures. Addressing this finding along with the
11 identified sediment movement, remediation/refurbishment will consist of installation of
12 bedrock-founded micro piles, foundation void grouting, and repairing/sealing the floor
13 crack, which will stabilize the foundation and improve the seepage cutoff, resulting in
14 lower uplift pressures. These improvements will address the dam safety issues, ensure
15 license compliance, and public and employee safety while avoiding environmental
16 impacts that could result from a failure.

17 **Q. Please describe Bergland Dam refurbishment (column repairs and sill replacement),**
18 **as shown in line 19 of Exhibit A-12 (Schedule B5.1 p.2).**

19 A. This is a multi-year project with bidding engineering and site exploration in 2026 and
20 actual engineering and site exploration starting in 2027 with final construction scheduled
21 for 2031. This is categorized as a Dam Safety project because it will address potential
22 structural steel pile strength reductions due to identified section loss and issues with
23 controlling leakage due to partial sill failure. This project is at Bergland dam which

1 consists of flash boards spanning between structural steel piles driven into the river
2 bottom with a wooden sill plate. Inspections have identified a partially deteriorated sill
3 plate and significant section loss of the structural steel piles due to long term corrosion.
4 Failure of the structural steel piles and/or loss of the sill plate could result in an
5 uncontrolled release of the reservoir. This would be considered a dam safety event and
6 result in environmental impacts, public and employee safety issues and license
7 deviations/violations. The project will address the dam safety issues through a
8 combination of refurbishing and/or replacing structural steel piles and the wooden sill
9 plates.

10 **Q. Please describe Generator Fan, as shown in row 20 of Exhibit A-12 (Schedule B5.1**
11 **p.2).**

12 A. This project is considered a Power Generation & Delivery project even though this
13 facility is not under a FERC license, because it falls under an EGLE emergency run
14 permit. The facility is our oil-fired combustion turbine and is intended to provide
15 emergency power during grid stability issues at an established capacity. If the unit is
16 unable to operate at its established capacity, it is considered a derate and it is not in an
17 acceptable condition. The unit currently has a failed cooling fan and during operation
18 may become temperature controlled, not allowing the unit to achieve its established
19 capacity and causing it to operate at a derate. The project is estimated at \$125,174 and
20 will refurbish/replace the cooling fan allowing normal operation avoiding a derate
21 through temperature control.

22 **Q. Please describe Victoria Road Resurfacing (phase 1 - 2027, phase 2 - 2028, as shown**
23 **in row 21 of Exhibit A-12 (Schedule B5.1 p.2).**

1 A. This is a multi-year project with construction scheduled for 2027 & 2028. Estimated
2 costs are \$341,384 in 2027 and \$341,384 in 2028 for a total project cost estimate of
3 \$682,768. The project is categorized as Facility Refurbishment/Improvements because it
4 maintains/improves access to the facility. Access to the Victoria site is via approximately
5 2 ½ miles of gravel surfaced roads with significant grade changes. Over the years
6 continued maintenance/grading and snow removal have thinned/removed the gravel ware
7 surface and road crown resulting in increased susceptibility to rain runoff induced
8 erosion. Runoff induced erosion could lead to access issues by making the road
9 impassable. Being unable to respond to developing conditions/issues in a timely fashion
10 due to access restrictions may lead to extended outages and/or dam failure resulting in
11 noncompliance with our FERC license. The access road surface will be replaced and
12 shaped to direct runoff avoiding erosion and therefore ensuring continued safe access.
13 There are no other alternatives to ensuring continued safe access.

14

15 **HISTORIC TEST YEAR CAPITAL PROJECTS RELATING TO GENERATION**

16 **Q. Please describe the purpose of this section of your direct testimony**

17 A. The purpose of this section is to describe and provide an update on the generation capital
18 projects that were included in the projected test year in the Company's prior general rate
19 case, Case No. U-21555. These projects were included in the projected test period in
20 Case No. U-21555 and similarly included in the historic test period in this proceeding.

21 **Q. Please describe Victoria – Controls upgrade, as shown in line 7 of Exhibit A-12.**

22 **(Schedule B5.1 p.2).**

1 A. This project was a multi-year project. Project scoping and bidding were completed in
2 2021; Equipment Design & Plant Engineering were completed in 2022 & 2023 with
3 installation completed in 2024 & 2025. The project was originally forecasted for
4 \$1,109,672 in 2024 as part of rate case U-21555 but actual costs came in at \$1,386,459 in
5 2024 and \$405,014 in 2025 with a total project cost of \$2,440,034. The project is
6 categorized as Power Generation & Delivery because it addresses a potential energy
7 generation equipment control failure. The existing programmable logic control (“PLC”)
8 system and generator unit governors are being replaced with modern PLC controls and a
9 low volume high pressure hydraulic governor system controlled by the new PLC system.
10 The current PLC control system uses an obsolete platform that is difficult to maintain due
11 to component obsolescence. The governors are original mechanical systems from the
12 1930s that, although functional, use a large quantity of oil and pose significant
13 environmental risk related to oil releases. Maintenance and repair of these governors is
14 challenging due to age, parts obsolescence, and lack of maintenance personal with
15 technical understanding of these systems. A failed controls system would result in license
16 deviations/violations. The project addresses equipment obsolescence and reliability
17 ensuring license compliance. There were no feasible alternatives to address obsolete
18 equipment and ensure continued license compliance.

19 **Q. Please describe Hoist Unit 3 – Penstock Valve Replacement, as shown in line 8 of**
20 **Exhibit A-12. (Schedule B5.1 p.2).**

21 A. This project was a multi-year project. Design, engineering, and procurement were
22 completed in 2022-2023 with installation in 2025. Project cost in 2025 was \$339,476
23 compared to \$182,000 which was forecasted in rate case U-21555 with a total project

1 cost of \$541,004. The project is categorized as Facility Refurbishment/Improvements
2 because it replaces the existing poorly functioning and unsafe valve with a new valve that
3 allows single unit isolation and provides for safe entry into the unit for inspections and
4 maintenance. The old Unit 3 Isolation valve was original to the powerhouse expansion
5 and unit installation in the 1940's. The old valve leaked severely due to worn and
6 antiquated valve sealing surfaces and design. Due to the inability of the old valve to
7 provide the unit isolation needed from the penstock, routine maintenance work was hard
8 to schedule and at times postponed because it required the entire powerhouse to be taken
9 offline. The inability to complete routine maintenance and conduct inspections could
10 lead to unit failure, which would result in license compliance issues and potential
11 deviations/violations along with environmental impacts. The project addressed these
12 issues, ensured license compliance and prevented potential environmental impacts.

13 **Q. Please describe Prickett Unit 2 Overhaul/Rewind, as shown in line 12 of Exhibit A-**
14 **12. (Schedule B5.1 p.2).**

15 A. This project was a multi-year project completed in 2024 & 2025 with project costs of
16 \$673,868 and \$690,723 respectively for a total cost of \$1,364,591. The work was
17 originally forecasted and planned as a single year project in 2024 for \$990,546 in rate
18 case U-21555. The project is categorized as Power Generation & Delivery because the
19 project addressed generating equipment potential failure issues. Generating Unit #2 at the
20 Prickett powerhouse was installed in 1931 and has had partial rebuilding and repairs done
21 over the last 90 years. The Unit was due for a major overhaul, including complete
22 disassembly to allow for a full inspection of all major components. Recent inspections
23 identified issues related to scroll case corrosion/cavitation, wicket gate

1 corrosion/cavitation/seals, turbine runner cavitation, and cleanliness of the generator.
2 Electrical testing of the unit's generator and exciter components has indicated a partial
3 short in the rotor. The electrical components were not functioning at optimal levels,
4 likely due to the extensive amounts of oil and debris baked onto the windings and coils
5 from multiple years of small oil weeps. With limited to no history on the generator's
6 past, it is assumed that all rotor poles are original to the 1931 installation and the most
7 recent stator rewind was 1980. Recent failure trends have provided additional scrutiny
8 from the risk insurance companies for generators assembled before 1950 due to the use of
9 asbestos and asphalt winding insulations. In the event of a phase-to-phase fault inside the
10 generator, the asphalt windings could combust resulting in a unit fire. Due to the age and
11 extensive oil-soaked condition of the unit, a complete rewind of the generator rotor and
12 stator had been a high priority recommendation from the risk insurance group. Testing
13 before the project confirmed that the rotor was not asphalt. Failure of the generating unit
14 due to any one of the above-mentioned items would have been catastrophic and resulted
15 in license deviations/violations, potential employee safety issues, and environmental
16 impacts. The project addressed all these issues by disassembling the unit and sending the
17 generator stator and rotor out for rewinding and sealing. Upon removal, the runner was
18 found cracked/damaged beyond repair and therefore a new runner was installed. There
19 were no feasible alternatives to address the potential equipment failure issues and ensure
20 continued license compliance.

21 **Q. Please describe Inundation Mapping, as shown in line 13 of Exhibit A-12. (Schedule**
22 **B5.1 p.2).**

1 A. This was a multi-year, multi-facility project, completed in 2025 for a total cost of
2 \$346,948. The work completed in 2025 primarily focused on two facilities at a cost of
3 \$217,085 which was originally forecasted as \$101,982 in rate case U-21555. The project
4 is categorized as Dam Safety because it addresses a deficiency in the dam safety program
5 Emergency Action Plan (EAP) requirements set out by the Federal Energy Regulatory
6 Commission (FERC). FERC requires hydro project licensees to develop and maintain an
7 EAP that covers the owner's response to a dam failure and provides information on
8 inundation during a failure. Recent Functional exercises of UPPCO's EAPs have
9 resulted in recommendations from FERC and other attendees to improve the inundation
10 mapping. The original inundation mapping, which is a key component to the EAP, was
11 developed using modeling methods which no longer meet industry standards combined
12 with overly course contours leading to potentially inaccurate inundation zones.
13 Additionally, the new FERC Comprehensive Assessment ("CA") process requires
14 additional inundation information (depth & velocity of inundation waters) to complete a
15 risk analysis which incorporates the consequences of a dam failure. The issues associated
16 with the inundation mapping combined with the need for additional inundation
17 information to support the CA process resulted in an unacceptable deficiency in our
18 emergency planning and license compliance. Not addressing these issues could have
19 potentially lead to license violations and public safety concerns. This project updated the
20 inundation mapping for all UPPCO owned high hazard dams. The work in 2025 was
21 predominantly related to the Bond Falls and Prickett dams but also finished some carry
22 over work on the Dead River dams (Silver Lake, Hoist, McClure) that began in 2024.
23 The project used current industry standard modeling, which provided the required

1 additional information and resulted in more accurate maps, therefore addressing the
2 issues identified and ensuring license compliance and public safety.

3 **Q. Please describe McClure Unit 1 Runner Replacement, as shown in line 15 of Exhibit**
4 **A-12. (Schedule B5.1 p.2).**

5 A. This project was a multi-year project with a spend of \$254,314 in 2025 and a total project
6 cost of \$749,624. The project is categorized as Power Generation & Delivery because it
7 addresses generating equipment operation and potential failure issues. Routine electrical
8 testing indicated that McClure Unit #1's generator and exciter components were not
9 functioning at optimal levels. Polarization index (PI) tests were low, likely due to the
10 extensive amounts of oil and debris baked onto the windings and coils from multiple
11 years of small oil weeps. Recent failure trends associated with electrical equipment have
12 provided additional scrutiny from the risk insurance companies for generators assembled
13 before 1950 due to the use of asbestos and asphalt winding insulations. In the event of a
14 phase-to-phase fault inside the generator, the asphalt windings could combust resulting in
15 a unit fire. Additionally, the unit was developing significant vibration and therefore
16 under limited operation. Failure of the generating unit due to either one of the issues
17 would be catastrophic and result in license deviations/violations, potential employee
18 safety issues, and environmental impacts. As part of investigating the vibration issues, an
19 internal inspection was conducted during the first quarter of 2024, and a
20 damaged/cracked runner was identified. Based on this information, the unit was listed as
21 unavailable. A new replacement runner was fabricated, installed, and the unit was put
22 back into service by March 2025. Additionally, during the outage, the generator stator
23 and rotor were cleaned and recoated. There were no feasible alternatives to address the

1 potential equipment failure issues, address generator derates and ensure continued license
2 compliance.

3 **Q. Please describe Generation Land only (Utility), as shown in row 16 of Exhibit A-12**
4 **(Schedule B5.1 p.2).**

5 A. In 2025 land was acquired under and adjacent to the McClure penstock for \$269,833 but
6 not originally included in rate case U-21555. This project is categorized as Dam Safety
7 because it addresses both protection of dam related assets and issues related to having
8 adequate rights to maintain and operate facilities under the jurisdiction of a FERC
9 license. The land under and adjacent to the McClure penstock (water conveyance
10 structure under FERC jurisdiction) was acquired to ensure that land development could
11 not negatively impact the operation of the penstock or monitoring instruments adjacent to
12 the penstock. The acquisition of this land solidifies UPPCO's rights to operate and
13 maintain the structures as required by the FERC license and removes any questions
14 related to those rights. Owning the land under and adjacent to the McClure penstock
15 ensures UPPCO has the adequate rights to complete operations and maintenance work
16 that are necessary to ensure dam safety, license compliance, and public safety while
17 avoiding environmental impacts.

18 **Q. Please describe McClure Substation Refurbishment, as shown in line 17 of Exhibit**
19 **A-12. (Schedule B5.1 p.2).**

20 A. This project was a complete substation rebuild/refurbishment which was put into service
21 in 2025 with a cost of \$2,287,112 in 2025 which was originally estimated at \$1,842,204
22 in rate case U-21555. The project is categorized as Power Generation & Delivery

1 because it addresses a potential energy delivery equipment failure issue. The McClure
2 Substation consists of two GSU transformers, associated breakers, switches, steel support
3 structures and metering components. The existing GSU transformers are 75 years old
4 and at the end of their life. The potential risk of catastrophic failure was a large concern.
5 Additionally, asset insurance providers have identified the current substation layout as
6 not meeting minimum National Fire Protection Association (“NFPA”) recommendations
7 for spacing between transformers and buildings. The failure of the transformers would
8 result in significant equipment and building damage, which, based on the most recent
9 insurance provider recommendation, may not be fully covered. This failure would have
10 resulted in environmental impacts, potential employee and public safety issues, and an
11 extended outage leading to license deviations/violations. This project replaced the 75-
12 year-old GSU transformers, adjusted the equipment layout to meet NFPA standards, and
13 incorporated spill containment to mitigate environmental impacts, ensure license
14 compliance, and ensure employee and public safety.

15 **Q. Please describe Hoist Powerhouse Walkway Replacement, as shown in line 18 of**
16 **Exhibit A-12 (Schedule B5.1 p.2).**

17 A. This project was completed in 2025 with a total cost of \$256,023 but was not originally
18 included in U-21555 rate case. The project is considered a Facility
19 Refurbishment/Improvement project because it focused on maintaining the integrity and
20 extending the life of the Hoist powerhouse while also ensuring employee safety by
21 replacing the access walkway. During FERC required Part 12 inspections the
22 cantilevered walkway on the downstream side of the powerhouse was identified as being
23 in poor condition and was, as a consequence, removed from service. Two of the

1 supporting S-beams were observed to have 100% web section loss and the remaining
2 beams were observed to be in similar condition with heavy corrosion and section loss.
3 Replacement of the walkway allowed for safe access to the left side of the tailrace,
4 ensuring employee safety and allowing for continued operation and maintenance of the
5 generation equipment. This will ensure license compliance. Replacement of the
6 powerhouse walkway included demolition and disposal of the existing walkway and
7 installation of a new walkway consisting of structural steel brackets and frame, new
8 walkway grating, new reinforced concrete approach slabs, and new handrail.

9 **Q. Does this complete your direct testimony?**

10 A. Yes.

11

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

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

Case No. U-22032

**DIRECT TESTIMONY AND EXHIBIT
OF GREGORY S. GAGNON ON BEHALF OF
UPPER PENINSULA POWER COMPANY**

May 22, 2026

1 **QUALIFICATIONS**

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

3 A. My name is Gregory S. Gagnon. My business address is 1002 Harbor Hills Drive,
4 Marquette, MI 49855.

5 **Q. By whom are you employed and in what capacity?**

6 A. I am the Director of Information Technology for Upper Peninsula Power Company
7 (“UPPCO” or the “Company”).

8 **Q. Please summarize your background.**

9 A. I graduated Magna Cum Laude from Northern Michigan University, with a Bachelor of
10 Science in Electronic Engineering Technology and a Minor in Computer Science. I have
11 over 43 years of experience in the Information Technology and communications field. I
12 served for four years in the US Air Force as a Telecommunication Control Specialist,
13 after which I joined a long-distance carrier, Superior Telecomm. In 1990, I joined
14 Marquette General Hospital (“MGH”) / UP Health Care Marquette. I held multiple
15 positions of increasing responsibility during my career at MGH, including
16 Telecommunication Technician, Data Communication Technician,
17 Telecommunications\Network Engineer, Supervisor of Enterprise Systems & Services,
18 and IT Manager for Enterprise Systems. I left MGH/UP Health Care Marquette after 24
19 years of service when I joined UPPCO in January 2015 as Director of Information
20 Technology. In my current role, I am responsible for maintaining reliable and secure IT
21 solutions that serve and support UPPCO’s business functions, including all corporate and
22 operational technology (“OT”) functions.

23 **Q. Have you previously testified in any regulatory proceedings?**

1 A. Yes, I have previously testified in UPPCO’s general rate case U-17895.

2

3 **PURPOSE OF TESTIMONY**

4 **Q. What is the purpose of your direct testimony in this proceeding?**

5 A. I will provide testimony regarding UPPCO’s Information Technology (“IT”) capital
6 projects.

7 **Q. How is your direct testimony organized?**

8 A. My direct testimony is organized in sections consistent with the topics I will be covering,
9 as listed below:

10 Section I: Information Technology Capital Projects

11 **Q. Are you sponsoring any exhibits related to your direct testimony?**

12 A. Yes.

13 **Q. Please identify the exhibits you are sponsoring**

14 A. I am sponsoring the following exhibit:

- 15 • Exhibit A-17 (GSG-1), Information Technology CAPEX Detail

16

17 **SECTION I: INFORMATION TECHNOLOGY CAPITAL PROJECTS**

18 **Q. Is the Company planning information technology projects that support business
19 operations for UPPCO?**

20 A. Yes. These projects are evidenced in Exhibit A-17 (GSG-1), Information Technology
21 CAPEX.

1 **Q. Why is UPPCO’s proposed information technology spend critical to the Company’s**
2 **success?**

3 A. Many of the challenges that utilities face today, including UPPCO, center on keeping
4 existing technologies safe, effective, and relevant for utility and business operations,
5 while developing and building new digital capabilities to support the continued
6 modernization of the electric grid and increased data utilization for improved decision-
7 making, both by the Company and its customers.

8 **Q. How is UPPCO’s IT department structured?**

9 A. UPPCO’s IT department is tasked with maintaining reliable and secure IT solutions that
10 serve and support UPPCO’s many business functions. These functions include, but are
11 not limited to, supporting the following platforms and/or services: (i) cyber security for
12 the entire business, (ii) continued improvement and maintenance of our Advanced
13 Metering Infrastructure (“AMI”), and the operationalization of AMI data, (iii)
14 Supervisory Control and Data Acquisition (“SCADA”), (iv) Enterprise Resource
15 Planning (“ERP”) for customer service and financial systems of record, (v) Geographic
16 Information System (“GIS”), and (vi) various operational technologies utilized in the
17 field. In addition, further support functions include day-to-day operational support of
18 end-user technologies such as desktops, laptops, and various mobile devices.

19 **Q. How does UPPCO endeavor to obtain the most cost-effective IT projects?**

20 A. In order to ensure the cost effectiveness of IT spending, the Company uses a competitive
21 bid process whenever possible, with final selection of application providers based on
22 cost, functional requirements, and assessment of implementation capability. For all new
23 applications, i.e. no incumbent application exists, competitive bidding is utilized. For

1 upgrades to existing systems and applications, UPPCO assesses the overall cost of the
2 upgrade and effectiveness of the existing application or system to determine whether we
3 need to investigate alternative applications or systems or seek competitive bids from
4 independent system integrators for upgrades.

5 **Q. Many IT projects involve services from third-party vendors, as well as internal**
6 **labor, please explain the difference between these services and the reasons why each**
7 **are needed.**

8 **A.** Greenfield system and application implementations, as well as upgrades to existing
9 infrastructure, involve the expertise of both internal and external resources. The choice of
10 which resources to utilize is based upon the specifics of the application and the
11 availability of appropriate skills and resources. Wherever possible, the Company utilizes
12 internal resources in order to minimize overall cost. Third-party vendors with application
13 specific software expertise typically implement and configure applications and/or SAAS
14 services, including interfaces to other UPPCO systems and applications. Internal labor is
15 more commonly utilized to set up the necessary hardware and infrastructure to support
16 software applications and conduct UAT ('User Acceptance Testing') and interface
17 Testing. In addition, UPPCO utilizes internal labor for project management oversight.

18 **Q. Please explain what the term "outdated" means when discussing IT assets and how**
19 **you will use this term in your testimony.**

20 **A.** We use the term "outdated" to describe systems or applications that are no longer
21 supported by the hardware or software provider. Unsupported systems and applications
22 no longer receive software or firmware updates to address evolving security threats and,
23 therefore, pose a significant cyber security risk to the organization. In addition, we use

1 this term to describe applications that do not or can no longer support functionality
2 required by the Company or its customers.

3 **Q. Please explain the IT capital project on line 1 of Exhibit A-17 (GSG-1)?**

4 A. As with any utility or business, UPPCO's IT department maintains a large and complex
5 infrastructure that provides the backbone for essentially all activities that take place
6 within the organization, from dispatching linemen to address emergency outages,
7 designing distributions networks for line extensions for new customers, or billing and
8 customer service operations. The makeup for this backbone is physical hardware and
9 appliances, including servers, routers, switches, desktop computers, mobile laptop
10 computers, security camera equipment, and other network infrastructure appliances that
11 enable a utility's required applications. These line items represents the costs for this new
12 and replacement infrastructure hardware.

13 **Q. Please explain why the capital spending on line 1 of Exhibit A-17 (GSG-1) is
14 needed?**

15 A. UPPCO maintains a record of installed inventory of hardware infrastructure currently in
16 place throughout its network and tracks the vintage of the physical equipment for
17 purposes of adhering to a scheduled replacement cycle. The Company has established
18 specific replacement cycles for equipment depending upon the equipment' purpose and
19 expected useful life. This best practice is employed in order to avoid emergency
20 downtime of essential elements of UPPCO's IT operations that would have a deleterious
21 impact on operations and our customers. The Company believes it is essential to maintain
22 the operational availability of its critical and non-critical network infrastructure for the

1 benefit of its customers through the regular maintenance and replacement of its hardware
2 in alignment with widely accepted technology best practices.

3 Further, this capital category represents the costs for new equipment for extensions of the
4 IT infrastructure to meet the needs of our customers and an ever-changing and dangerous
5 cyber landscape.

6 **Q. Please explain how the Company differentiates between Critical and Non-critical
7 infrastructure.**

8 A. UPPCO considers critical infrastructure to be any system or application that, if not
9 functioning properly, would impede UPPCO's ability to serve customers. Non-critical
10 infrastructure are systems or applications that enable UPPCO to be more efficient and
11 reduce costs, but do not directly impact service to customers.

12 **Q. Please provide details regarding the annual capital spend represented on line 1 of
13 Exhibit A-17 (GSG-1)?**

14 A. As evidenced on line 1 of Exhibit A-17 (GSG-1), UPPCO's planned capital spending in
15 this category in 2026 and 2027 is \$526K and \$391K respectively. The 2026 capital
16 spending includes \$316K for planned replacement of desktop and laptop computers,
17 \$90K for replacement printers and copiers, and \$120K for unplanned or emergency
18 replacement or additions for network hardware, including security camera equipment,
19 routers, switches, servers and other network infrastructure appliances. The 2027 capital
20 spend amount of \$381K includes \$261K for laptop and PC replacements at end-of-life
21 and \$120K for unplanned or emergency hardware replacement or additions for network
22 hardware, including security camera equipment, routers, switches, servers and other
23 network infrastructure appliances. This category of capital spend is on a five-year

1 planned replacement schedule. This schedule was established to ensure hardware remains
2 under factory warranty to minimize costs associated with hardware downtime and
3 uncovered maintenance and ensure hardware is functionally compatible with current
4 technology.

5 **Q. How will the capital spending represented on line 1 of Exhibit A-17 (GSG-1) benefit**
6 **the customers of UPPCO?**

7 A. Every utility relies upon its physical IT infrastructure (e.g., servers, routers, switches,
8 firewall appliances, laptops, desktops, wiring) to provide the backbone on which the key
9 applications required to serve their customers run. In the case of UPPCO, these essential
10 applications include SCADA, SAP UPPCO's ERP ("Enterprise Resource Planning")
11 system, Staking/Design, the customer portal, and many others, without which, UPPCO
12 would be unable to perform or deliver services and energy to customers. To maintain the
13 reliability of that infrastructure, and therefore service to customers, all prudent companies
14 employ a practice of scheduled replacement to maintain and replace equipment on a
15 planned schedule to avoid emergency downtime and manage costs over time. The
16 Company believes it is essential to maintain the operational availability of its critical
17 network infrastructure for the benefit of its customers through the regular maintenance
18 and replacement of its hardware in alignment with widely accepted technology best
19 practices.

20 **Q. How were the cost estimates presented on line 1 of Exhibit A-17 (GSG-1) derived?**

21 A. Replacement of hardware infrastructure, when done properly, is a matter of routine
22 purchasing of key equipment on a regular basis. As this is an activity of a frequent nature,
23 current year pricing is informed through soliciting quotes for proposed purchases from

1 previously qualified vendors. The 2027 cost estimates are informed by 2026 quoted
2 pricing.

3 **Q. Please explain the IT capital project(s) on line 4 of Exhibit A-17 (GSG-1)?**

4 A. Line No. 4 of Exhibit A-17 (GSG-1) represents a full redesign and modernization of
5 UPPCO's website to improve performance, usability, and functionality. The project will
6 focus on making the website fully responsive for mobile and tablet users, improving
7 accessibility to meet WCAG 2.1 compliance standards for people with disabilities (e.g.,
8 low vision users and users with learning or cognitive disabilities), simplifying and
9 condensing the site navigation to create a more streamlined customer experience, and
10 enhancing the internal search tool so that users can more easily find relevant information
11 using keyword searches.

12 **Q. Please explain why the capital spending on line 4 of Exhibit A-17 (GSG-1) is
13 needed?**

14 A. The current website structure and functionality do not adequately meet modern customer
15 expectations, industry standards, or WCAG 2.1 compliance. Each of the planned website
16 improvements require significant redesign and development work that goes beyond
17 routine maintenance. For example, many customers now access utility information
18 through mobile devices, and the website must display properly across all screen sizes.
19 Additionally, accessibility compliance is necessary to ensure the website can be used by
20 individuals with disabilities. Simplifying navigation and improving search capabilities to
21 meet these standards helps provide a better, more positive customer-centric experience
22 for all UPPCO customers.

1 **Q. How will the capital spending represented on line 4 of Exhibit A-17 (GSG-1) benefit**
2 **the customers of UPPCO?**

3 A. This investment will directly improve the customer experience by making the website
4 easier to use, faster to navigate, and more accessible to all users. Customers will benefit
5 from a mobile-friendly interface, improved usability for individuals with visual
6 impairments, fewer steps to locate important services and information, and more accurate
7 search results when looking for billing, outage, safety, and educational content. Overall,
8 the redesigned website will make it easier for customers to quickly find what they need
9 and interact with UPPCO online.

10 **Q. How were the cost estimates presented on line 4 of Exhibit A-17 (GSG-1) derived?**

11 A. Cost estimates for the website redesign are derived from a combination of direct quotes
12 from an independent website developer and estimates of labor costs, both internal and
13 external, for implementation.

14 **Q. Please explain the IT capital project on line 6 of Exhibit A-17 (GSG-1)?**

15 A. UPPCO's current customer portal solution, Mobius, is an end-of-life platform that no
16 longer meets customer expectations, operational functionality, or security standards. This
17 project will implement a state-of-the-art utility-specific customer portal developed by
18 Vertex. The new solution will offer customers an integrated platform to conduct end-to-
19 end business with UPPCO, improve operational efficiency and enhance digital
20 engagement and self-service. With the Vertex portal, UPPCO will implement proactive
21 messaging to customers outside of billing statements through consented push
22 notifications to notify them about outages, planned outages, service appointments, and
23 billing and payment information.

1 **Q. Please explain why the capital spending on line 6 of Exhibit A-17 (GSG-1) is**
2 **needed?**

3 A. UPPCO's current outdated customer portal solution, implemented in July of 2017, has
4 reached end-of-life and is no longer maintained for functionality or security by its
5 development company. As a result, UPPCO is experiencing increased call volumes for
6 routine tasks, higher manual workload, low adoption of e-bill and electronic payments,
7 and elevated cyber security risks.

8 **Q. Please provide details regarding the annual capital spend represented on line 6 of**
9 **Exhibit A-17 (GSG-1)?**

10 A. The total capital cost of the Vertex customer portal implementation is forecast to be
11 \$550,000. This amount is comprised of \$181,203 to Vertex for initial setup and licensing,
12 \$208,797 for internal labor, and \$160,000 for integration costs to third party systems,
13 including UPPCO's payment facilitator, Kubra, and its AMI provider, Itron.

14 **Q. How will the capital spending represented on line 6 of Exhibit A-17 (GSG-1) benefit**
15 **the customers of UPPCO?**

16 A. In addition to helping to ensure the safety and security of customer information through
17 advanced security measures and providing a state of the art utility customer portal for
18 communication and service requests, the new Vertex portal upgrade will provide
19 significant additional customer functionalities, including (i) the ability to view and
20 compare usage to other households; (ii) the ability to view appliance usage based on
21 customer profile; (iii) the ability to view DG/net consumption, time of use views, and
22 enhanced payment functionalities (digital wallet payments and direct credit card
23 payments); (iv) the ability to make and adjust payment arrangements electronically; (v)

1 the ability to set up voice, email, and text notifications for payments, usage alerts, and
2 outages; and (vi) the ability to request utility services directly through portal. In addition,
3 the new portal will have enabling technology allowing for future improved demand
4 response offerings such as time of use billing.

5 **Q. How were the cost estimates presented on line 6 of Exhibit A-17 (GSG-1) derived?**

6 A. Cost estimates for the 2026 capital expenditures are a result of direct quotes from all
7 relevant vendors/integration consultants and an estimate of internal labor hours based
8 upon the specific functional needs of the project. This selection of the portal vendor
9 (Vertex) was awarded through a competitive bid.

10 **Q. Please explain the IT capital project on line 8 of Exhibit A-17 (GSG-1)?**

11 A. UPPCO's Geographic Information System ("GIS") vendor is Environmental Systems
12 Research Institute, Inc ('ESRI') replacement represents the updating and replacement for
13 the host of applications generally designated as GIS. This includes ESRI for Utilities,
14 Offline mapping capability, CYME, the Hexagon Intergraph ("Hexagon") Outage
15 Management System ("OMS"), and GeoDigital.

16 **Q. Please explain why the capital spending on line 8 of Exhibit A-17 (GSG-1) is
17 needed?**

18 A. The current version reached end-of-life and end of support on March 1, 2026. Our current
19 version was put in service in July of 2015.

20 **Q. Please provide details regarding the annual capital spend represented on line 8 of
21 Exhibit A-17 (GSG-1)?**

22 A. As evidenced on line 8 of Exhibit A-17 (GSG-1), UPPCO's planned capital spending in
23 this category in 2026 is \$483,763. The 2026 capital spending includes \$101,920 for the

1 core ESRI for Utilities GIS application, \$150,000 for rebuilding offline map capabilities
2 for the GIS application, \$143,015 for the CYME (distribution capacity planner, power
3 flow analysis and load balancing) upgrade required for integration into the updated
4 version of ESRI, and \$88,828 for Hexagon and GeoDigital required updates.

5 **Q. How will the capital spending represented on line 8 of Exhibit A-17 (GSG-1) benefit**
6 **the customers of UPPCO?**

7 A. The proposed investments in the GIS application will maintain and improve the accuracy
8 of the documentation of the Company's electrical grid. This requires that a prudent
9 organization maintains up-to-date and vendor supported releases of software applications,
10 especially in critical functions such as engineering and design. Doing so ensures the
11 accuracy of data to support reliability, efficiency, and customer service. These systems
12 interface directly with the Company's OMS, CYME and Stakeout applications to ensure
13 efficient emergency response and accurate up to date data to better serve our customers.

14 **Q. How were the cost estimates presented on line 8 of Exhibit A-17 (GSG-1) derived?**

15 A. Cost estimates for the GIS applications upgrades are derived from individual scopes of
16 work ("SOWs") received from each of the vendors involved, broken down as follows:
17 ESRI - \$30,000, GIS Consultant - \$57,000, Geo Decisions for Off-Line maps - \$133,200,
18 CYME - \$128,085, Hexagon - \$62,600, Geo Digital - \$11,294, and \$61,584 for internal
19 labor.

20 **Q. Please explain the IT capital project on line 11 of Exhibit A-17 (GSG-1)?**

21 A. The IT capital spending outlined in line 11 of Exhibit A-17 (GSG-1) represent the costs
22 for maintaining and upgrading UPPCO's Advanced Metering Infrastructure ("AMI")

1 network. The costs in this category include replacing the connected grid routers
2 (“CGS”s), equipment, and hardware essential to the AMI communications network.

3 **Q. Please explain why the capital spending on line 11 of Exhibit A-17 (GSG-1) is**
4 **needed?**

5 A. The CGR hardware utilized in the communications network of UPPCO’s AMI will reach
6 end-of-life on December 31, 2027. This current version was released in November of
7 2011 and deployed in our network in 2019. After December 31 of 2027 the maker of this
8 product will no longer provide support for hardware or software failures or make updates
9 to protect against future cyber security threats. The replacement version of CGR, released
10 in June 2021, has an estimated 16-year life, with an estimated end-of-life of December
11 2037. CGRs form the backbone of the AMI relay network that communicates each
12 customer’s meter usage data to UPPCO for accurate billing purposes. This data is also
13 essential for SCADA operational needs. While this equipment is unlikely to fail all at
14 once, individual nodes will begin to fail over time and, due to the mesh nature of the AMI
15 communications network, individual failures will begin to cascade into a decrease ability
16 of the AMI system to reliably read and communicate customer usage data. This would
17 cause significant delays in billing to customers and delay the availability of information
18 for operational use by the Company.

19 **Q. Please provide details regarding the annual capital spend represented on line 11 of**
20 **Exhibit A-17 (GSG-1)?**

21 A. As evidenced on line 11 of Exhibit A-17 (GSG-1), UPPCO’s planned capital spending in
22 this category in 2027 is \$2,944,848. The capital spending includes \$2,556,848 for the
23 replacement equipment CGR nodes; this cost was derived from a quote from the captive

1 vendor, Itron. The \$388,000 in labor for replacement is based on the estimated time to
2 install, power up, and test each CGR and transformer in the field.

3 **Q. What benefits will the capital spending represented on line 11 of Exhibit A-17**
4 **(GSG-1) provide?**

5 A. The UPPCO AMI system ensures timely reporting and billing of customer usage data.
6 The CGR network is the physical backbone of that network, without which, the system
7 will not perform. Without a reliable AMI network and application layer, UPPCO would
8 instead need to revert to manual reading of customer meter data, which would result in a
9 significant increase in operational costs and a likely return to usage estimation for
10 periodic customer billing.

11 **Q. Please explain the IT capital project on line 12 of Exhibit A-17 (GSG-1)?**

12 A. The IT capital spending outlined in line 12 of Exhibit A-17 (GSG-1) represents the cost
13 of upgrading UPPCO's existing AspenTech / OSI Monarch SCADA system to the 2027
14 active supported version.

15 **Q. Please explain why the capital spending on line 12 of Exhibit A-17 (GSG-1) is**
16 **needed?**

17 A. Active support of UPPCO's SCADA system was ended by the product vendor,
18 Aspentech in December 2024. The current version remains in extended support through
19 2026 and will move to sustaining support in 2027. Active support allows for fixing all
20 functional and operational defects and bugs. At the end of 2026, absent an upgrade to the
21 new SCADA system, the application vendor will force UPPCO to move to a sustaining
22 support program. Sustaining support only addresses critical repairs. An upgrade is

1 necessary to avoid security vulnerabilities, loss of vendor support, and increased
2 operational risk.

3 **Q. Please provide details regarding the annual capital spend represented on line 12 of**
4 **Exhibit A-17 (GSG-1)?**

5 A. As evidenced on line 12 Exhibit A-17 (GSG-1), The total spend of \$726,025 is comprised
6 of: \$515,442 for vendor software licensing, upgrade costs, implementation fees, and
7 testing services.; \$71,295 for Microsoft Datacenter Licenses; \$14,933 for Microsoft SQL
8 Licenses; \$40,341 for HP Servers CPU Upgrades; and \$84,014 for Internal IT and cyber
9 security labor. Cost estimates are based upon vendor indexed quotes received in October
10 of 2025.

11 **Q. What benefits will the capital spending represented on line 12 of Exhibit A-17**
12 **(GSG-1) provide?**

13 A. This capital expenditure ensures that UPPCO can maintain a reliable and secure SCADA
14 operation, reduces risk of customer outages and customer outage restoration times, and
15 supports consistent electric service delivery.

16 **Q. Please explain the IT capital project on line 13 of Exhibit A-17 (GSG-1)?**

17 A. The IT capital spending outlined in line 13 of Exhibit A-17 (GSG-1) represents the cost
18 of upgrading UPPCO's existing Hexagon OMS to the 2027 active supported version.

19 **Q. Please explain why the capital spending on line 13 of Exhibit A-17 (GSG-1) is**
20 **needed?**

21 A. UPPCO is currently operating on a 2020 OMS release. The upgrade to the latest version
22 in 2027 is required to remain supported by the application vendor, and to avoid security
23 and increased operational risk.

1 **Q. Please provide detail regarding the annual capital spend represented on line 13 of**
2 **Exhibit A-17 (GSG-1)?**

3 A. As evidenced on line 13 Exhibit A-17 (GSG-1), cost is based on OMS software upgrade
4 and services from Hexagon that will cost \$300,000 and Internal Labor costs of \$45,288.

5 **Q. What benefits will the capital spending represented on line 13 of Exhibit A-17**
6 **(GSG-1) provide?**

7 A. A modernized OMS enables more efficient outage management, improves response
8 times, and reduces operational risk associated with outdated software and maintains
9 vendor support. Continuing with our current application without vendor support risks
10 future security breaches and reliable performance. In addition, the upgraded OMS
11 application will help UPPCO to better comply with outage reporting and the related
12 customer credits.

13 **Q. How were the cost estimates presented on line 13 of Exhibit A-17 (GSG-1) derived?**

14 A. Cost estimates were derived from direct quotes from the OMS vendor (Hexagon) and
15 estimates of internal labor time based upon our last OMS implementation in 2020.

16 **Q. Please explain the IT capital project on line 14 of Exhibit A-17 (GSG-1)?**

17 A. The IT capital spending outlined in line 14 of Exhibit A-17 (GSG-1) represents the cost
18 to install cyber security applications from Dragos within our SCADA environment in
19 order to monitor all north/south SCADA traffic at both of our data centers.

20 **Q. Please explain why the capital spending on line 14 of Exhibit A-17 (GSG-1) is**
21 **needed?**

22 A. The SCADA network is highly sensitive and restricted, and traditional Network
23 Detection and Response tools can be overly disruptive. Dragos provides for deep

1 visibility into OT (Operational Technology) or SCADA traffic without impacting
2 operations. This ensures grid security while providing advanced threat intelligence,
3 including insights derived from Dragos' collaboration with the National Security Agency.

4 **Q. Please provide details regarding the annual capital spend represented on line 14 of**
5 **Exhibit A-17 (GSG-1)?**

6 A. As evidenced on line 16 Exhibit A-17 (GSG-1), Total cost is estimated at \$111,730 and is
7 broken down as follows: (i) Dragos Deployment - \$4,920; (ii) Dragos Site Storage STS-
8 500 - \$43,749; (iii) Two Dragos Sensors NS-520 - \$41,996; and (iv) \$21,065 for
9 deployment and internal labor.

10 **Q. What benefits will the capital spending represented on line 14 of Exhibit A-17**
11 **(GSG-1) provide?**

12 A. The project enhances SCADA security, helping protect customers from service
13 disruptions caused by cyber threats or attacks on the electric grid.

14 **Q. How were the cost estimates presented on line 16 of Exhibit A-17 (GSG-1) derived?**

15 A. Cost estimates for hardware and Dragos deployment were derived from a direct quote
16 from the application vendor (Dragos) plus an estimate of internal labor hours required to
17 complete the implementation.

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

19 A. Yes

20
21
22
23
24
25
26
27

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-22032

DIRECT TESTIMONY AND EXHIBIT OF

BETH A. BLEWETT

ON BEHALF OF

UPPER PENINSULA POWER COMPANY

May 22, 2026

1 **QUALIFICATIONS**

2 **Q. Please state your name, business address and position.**

3 A. My name is Beth A. Blewett. My business address is 1002 Harbor Hills Drive,
4 Marquette MI 49855. I am the Director of Human Resources & Administration for
5 Upper Peninsula Power Company (“UPPCO” or “the Company”).

6 **Q. For whom are you providing testimony?**

7 A. I am providing testimony on behalf of UPPCO in support of its request for an increase in
8 its retail electric rates.

9 **Q. Please describe briefly your educational, professional, and utility background.**

10 A. I graduated from Ferris State University in 2002 with a Bachelor of Science in Human
11 Resource Management and from Michigan State University in 2020 with a Master of
12 Human Resources & Labor Relations. I have over 20 years of professional Human
13 Resources (“HR”) experience, with responsibility for all major HR functions, including
14 compensation and benefits design and administration, retirement plan oversight, talent
15 management, and labor relations. I began my HR career in June 2003 as a Human
16 Resources Assistant with March Coatings. In 2007, I joined Form Tech Concrete Forms
17 as a Human Resources Manager. In 2012, I transitioned to Clark Engineering, also
18 serving as Human Resources Manager. In 2015, I joined Michigan State University as a
19 Human Resources Generalist. I was promoted to Human Resources Manager in 2016 and
20 to Human Resources Director in 2020. In 2025, I left Michigan State University to
21 assume my current role as Director of Human Resources and Administration at UPPCO.

1 **Q. Have you previously testified in any regulatory proceedings before the Michigan**
2 **Public Service Commission (“MPSC” or “the Commission”)?**

3 A. No.

4 **PURPOSE OF TESTIMONY**

5 **Q. What is the purpose of your testimony?**

6 A. The purpose of my testimony is to present UPPCO’s compensation structure and benefit
7 plans for the 2025 historical period and 2027 projected test year. In summary, my
8 testimony will provide a reasonable and valid projection of compensation and benefits
9 expense incurred by the Company. I will discuss UPPCO’s market-based approach to
10 our overall compensation structure and philosophy, including the variable pay program
11 and the customer-related benefits that result from UPPCO’s ability to attract and retain a
12 talented, high-performing workforce.

13 **EXHIBITS**

14 **Q. Are you sponsoring any exhibits in this proceeding?**

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

17 1. Confidential Exhibit No. A-43 (BAB-1), Compensation Plan Administration Only
18

19 **PROJECTED TEST YEAR COMPENSATION & BENEFITS**

20 **Q. Please describe UPPCO’s compensation structure.**

1 A. UPPCO’s compensation programs are designed to attract and retain talented, high-quality
2 employees in a tight labor market with the necessary skills to safely and reliably serve
3 our customers. UPPCO does this by maintaining a total compensation structure that is
4 competitive with the compensation paid by other employers in our industry as well as
5 other non-energy organizations in the applicable labor markets in which we operate. A
6 substantial number of UPPCO employees are union members and represented by the
7 International Brotherhood of Electrical Workers, Local 510. The most recent collective
8 bargaining agreement (“CBA”) took effect on April 19, 2026. This CBA negotiated
9 competitive wages for the high-skilled, union-represented employees through April 19,
10 2031. For the administrative, non-represented employees including officers, the
11 compensation structure was established to compete for and retain high-quality, talented
12 employees in a market that includes regulated and non-regulated energy companies as
13 well as non-energy organizations. UPPCO’s compensation programs include fixed (base)
14 pay and variable pay, both of which are reviewed at least annually to ensure our
15 compensation programs will attract and retain a quality workforce, while remaining in
16 line with appropriate market factors, providing substantial value to UPPCO customers.

17 **Q. Does UPPCO offer any compensation programs for officers only?**

18 A. Yes, UPPCO offers a deferred compensation program for certain officers that is intended
19 to attract and retain qualified executives by maintaining a total compensation structure
20 that is competitive with the compensation paid by other employers in our industry and in
21 applicable labor markets in which we operate. UPPCO is not seeking recovery of the
22 costs of the executive deferred compensation program in this proceeding.

1 **Q. Has the Company's compensation structure materially changed since the approval**
2 **of UPPCO's last general rate case, Case No. U-21555?**

3 A. No.

4 **Q. How are increases in base pay determined?**

5 A. For represented employees, base pay increases annually by the amount negotiated in the
6 Collective Bargaining Agreement. Administrative, non-represented employees, including
7 officers, are offered the opportunity for an annual merit increase. Merit increases are
8 based on performance measures set by and evaluated by the employees and their
9 supervisor/manager. Performance measures are based on business objectives that are
10 determined each year. Administrative, non-represented positions may also be evaluated
11 annually for reclassifications and equity adjustments to account for changes in job duties,
12 internal equity, and market conditions.

13 **Q. When was UPPCO's compensation plan last updated?**

14 A. June 8, 2017. Please see Confidential Exhibit A-43 (BAB-1) for a copy of UPPCO's
15 Compensation Plan Admin Only.

16 **Q. Does UPPCO's compensation plan include a variable pay program?**

17 A. Yes, UPPCO's compensation plan also includes a variable pay program with two
18 components: i) pay-at-risk pay is based upon meeting certain key safety and operational
19 performance metrics, and ii) incentive pay is based upon the financial performance of the
20 Company. UPPCO is not seeking recovery of any costs relating to incentive pay.

1 **Q. Which variable pay plans are included in the Projected Test Year for the purposes**
2 **of this proceeding?**

3 A. Consistent with the treatment of a substantively identical compensation program in Case
4 No. U-21555, pay-at-risk pay, which does not have a financial performance qualifier, is
5 included in the projected test year costs for the calendar year ending December 31, 2027.
6 UPPCO is not seeking recovery of any costs relating to incentive pay.

7 **Q. Please describe UPPCO's pay-at-risk pay.**

8 A. UPPCO offers administrative, non-represented employees' additional performance-based
9 compensation on an annual basis, for meeting specific non-financial, safety, reliability,
10 operational, and customer-related operations metrics. This is called pay-at-risk. This pay
11 is based upon achieving results that will have a direct impact on increased customer
12 satisfaction, including increased distribution reliability metrics. UPPCO's pay-at-risk
13 pay is predicated on meeting these safety and operational goals. Placing a portion of
14 employee compensation at risk based on achievement of certain metrics encourages
15 employees to achieve high levels of performance, customer satisfaction, and productivity,
16 all to the benefit of UPPCO customers.

17 **Q. How do safety metrics benefit customers?**

18 A. Customers directly benefit from a safety-focused, highly qualified, and motivated utility
19 workforce. Strong safety performance reduces workplace injuries, which in turn lowers
20 operating costs and reduces inefficiencies associated with incidents and downtime.
21 Because these costs can ultimately impact customer rates, improving safety helps keep
22 service more reliable and affordable.

1 At UPPCO, safety metrics reinforce a proactive safety culture that prioritizes not only
2 employee well-being, but also the safety of customers and the public. Pay-at-risk safety
3 metrics drive early hazard identification and control during the planning phase, which
4 improves operational efficiency and reduces risk before work begins.

5 This proactive approach is delivering measurable results. Since 2022, proactive safety
6 reporting has increased by over 147%, contributing to an Experience Modification Rate
7 (EMR) of 0.93 which is below the national average. As a result, workers' compensation
8 payments have decreased by more than 90% since 2017, including a reduction from
9 \$68,860 in 2023 to \$20,191 in 2025.

10 Ultimately, these improvements translate into safer operations, greater reliability, and
11 lower long-term costs, direct benefits to our customers.

12 **Q. How do operational performance metrics benefit customers?**

13 A. Operational metrics benefit UPPCO's customers by encouraging an increased emphasis
14 on improving services delivered to our customers. The metrics are designed to motivate
15 employees to improve the Company's performance with respect to customer
16 communication, customer service, and field services, as well as to maintain safe and
17 reliable customer support, reduce the frequency and duration of planned and unplanned
18 service interruptions, and provide continuous improvement in the quality of service
19 provided to customers. For example, UPPCO strives to meet aggressive reliability
20 targets, providing significant benefit to its customers. This is illustrated by UPPCO's
21 five-year SAIDI results (excluding MED's). UPPCO's five-year average through 2024
22 was, on average, 47% better than other comparable utilities in Michigan and the Midwest.

1 Other operational metrics are structured to focus employee attention on activities that will
2 provide additional value to customers.

3 **Q. Has there been any substantive changes to the pay-at-risk performance metrics**
4 **since the approval of UPPCO’s last rate proceeding in Case No. U-21555?**

5 A. No.

6 **Q. Please explain UPPCO’s incentive pay program.**

7 A. UPPCO provides incentive pay to all administrative, non-represented employees, on an
8 annual basis for meeting a financial goal of Earnings Before Interest, Taxes,
9 Depreciation, and Amortization (“EBITDA”). This incentive pay is based upon
10 achieving results that have a direct impact on managing the cost of service to customers
11 and increasing operational efficiency. Consistent with the treatment of similar expenses
12 in Case No. U-21555, UPPCO is not seeking recovery of the costs of incentive pay in this
13 proceeding.

14 **Q. Does UPPCO offer any other incentive compensation programs not covered by the**
15 **UPPCO Compensation Plan?**

16 A. Yes. UPPCO offers a deferred compensation plan for certain officers. UPPCO is not
17 seeking recovery of the costs relating to executive deferred compensation in this
18 proceeding.

19 **Q. Is the Company’s overall compensation program, including base pay and variable**
20 **pay-at-risk components, reasonable?**

1 A. Yes. The approach used by the Company is reasonable and market-based, is consistent
2 with industry standards, and represents well-established best practices for creating an
3 emphasis on safety and customer focus through compensation design. The overall
4 compensation levels are a reasonable cost of doing business and are designed to promote
5 clear customer benefits. Performance-based pay encourages productivity and fiscal
6 responsibility, creating a structured alignment between employee incentives and customer
7 outcomes. UPPCO's organizational performance is improved by retaining highly skilled,
8 high-performing employees and by recognizing and awarding the knowledge, skills, and
9 experience that make them successful. Investors share in the expense of the program and
10 bear the costs of the incentive pay and deferred compensation plans. UPPCO's
11 competitive compensation program for its employees is reasonable.

12 **Q. Does the Company's variable pay-at-risk components include any incentives for**
13 **financial metrics?**

14 A. No.

15 **EMPLOYEE BENEFIT PLANS**

16 **Q. Who is eligible for UPPCO's benefit plans?**

17 A. (i) Full-time, regular, active administrative, non-represented employees and eligible
18 dependents; (ii) full-time, regular, active represented employees and eligible dependents;
19 (iii) retirees who have met eligibility criteria and eligible dependents.

20 **Q. What benefits does UPPCO offer to its active employees?**

1 A. UPPCO offers medical, health savings account (“HSA”), prescription, medical
2 emergency transport, cash in lieu of benefits (for employees waiving medical due to
3 alternate group medical coverage), dental, vision, flexible spending account (“FSA”), life
4 insurance, accidental death and dismemberment, short-term disability, long-term
5 disability, employee assistance program, identity theft protection, COBRA, 401(k) match,
6 401(k) non-elective age & service contribution (only applicable to non-pension eligible
7 employees hired on or after April 19, 2009), pension (only applicable to employees hired
8 prior to April 19, 2009), wellness program, holidays, vacation, vacation purchase, sick
9 pay, tuition reimbursement, and adoption assistance. On a voluntary basis, employees
10 may purchase additional employee life insurance, spouse life insurance, and child life
11 insurance.

12 **Q. Why does UPPCO offer these benefits?**

13 A. Offering these benefits allows UPPCO to attract and retain a qualified and motivated
14 workforce in a tight labor market that includes regulated and non-regulated energy
15 companies as well as non-energy organizations. UPPCO evaluates benefits annually and
16 compares cost and benefit design with the market. UPPCO’s ability to attract and retain
17 talented employees provides benefits to our customers in the form of increased quality of
18 service.

19 **Q. Have the benefits and/or benefits programs substantively changed since the**
20 **approval of UPPCO’s last general rate case, in Case No. U-21555?**

21 A. No.

22 **Q. Describe the medical benefits.**

1 A. UPPCO offers two fully insured medical plan options underwritten by Blue Cross Blue
2 Shield of Michigan (“BCBSM”). Prescription coverage is included with both options.
3 The first option is a High Deductible Health Plan (“HDHP”). By offering a HDHP,
4 UPPCO is also able to distribute tax-sheltered dollars into a Health Savings Account
5 (“HSA”) for employees. By depositing into employee HSAs, the UPPCO plan remains
6 competitive within the market and encourages employees to make good medical
7 consumer decisions. The second option is a traditional Preferred Provider Organization
8 (“PPO”) plan. The PPO plan offers employees the option for the first dollar coverage
9 through traditional copays at time of service, such as office visit & prescription drug
10 copays and lower deductible requirements. The PPO Plan is not eligible for HSA
11 contributions; however, it allows employees to elect a plan that distributes copays
12 throughout the year. Employees enrolled in the UPPCO medical benefits are also
13 enrolled in medical emergency transport coverage underwritten by MASA Medical
14 Transport Solutions. Adding this coverage to the medical benefits protects employees
15 from surprise emergency medical bills and ensures compliance with emergency medical
16 billing regulations.

17 **Q. Describe the Prescription Benefits.**

18 A. Prescriptions are integrated with the medical plans underwritten by BCBSM.

19 **Q. Does UPPCO pay the entire cost of the premium for medical and prescription**
20 **coverage for eligible employees and their dependents?**

1 A. No, UPPCO and eligible employees share the cost of the premiums for medical and
2 prescription coverage. All employees pay 20% of the premiums, including employees
3 represented by the Union as negotiated in the CBA that took effect April 16, 2026.

4 **Q. Describe the Dental Benefits.**

5 A. UPPCO offers dental coverage that is separate from the medical plan and it is
6 underwritten by MetLife. The plan is a traditional PPO design.

7 **Q. Does UPPCO pay the entire cost of the premium for dental coverage for eligible
8 employees and their dependents?**

9 A. No, UPPCO and eligible employees share the cost of the premiums for dental coverage.
10 All employees pay 40% of the premiums, including represented employees as negotiated
11 in the CBA that took effect April 16, 2026.

12 **Q. Describe the vision benefits.**

13 A. UPPCO offers vision coverage that is separate from the medical plan and it is
14 underwritten by VSP and purchased through BCBSM. UPPCO offers two levels of
15 coverage, basic and premier. By offering two levels of coverage, employees have the
16 option to choose less costly coverage, which is less costly for the employee and UPPCO.

17 **Q. Does UPPCO pay the entire cost of the premium for vision coverage for eligible
18 employees and their dependents?**

19 A. No, UPPCO and eligible employees share the cost of the premiums for vision coverage.
20 All employees pay 50% of the premiums for both the basic and premier plans, including

1 employees represented by the Union as negotiated in the CBA that took effect April 16,
2 2026.

3 **Q. Describe the Flexible Spending Account Benefit.**

4 A. UPPCO offers a flexible spending account (“FSA”) benefit that allows eligible
5 employees to redirect a certain amount of money per year from their pay into a limited
6 use health care FSA (if enrolled in the HDHP medical with HSA plan), a health care FSA
7 (if not enrolled in the HDHP medical with HSA plan), or a dependent care FSA that are
8 exempt from Federal, State, and Social Security (“FICA”) taxes. The most that can be
9 allocated into these accounts is tied to the limits set annually by the IRS.

10 **Q. Is there a cost to UPPCO for providing this benefit?**

11 A. Yes. While UPPCO does not contribute to these plans on behalf of participating eligible
12 employees, the administrative cost of the plan, including an annual fee of \$250 and a
13 monthly fee of \$4.90 per active employee, are paid by UPPCO.

14 **Q. Describe the identity theft protection Benefit.**

15 A. UPPCO offers identity theft protection to eligible employees. There are two levels of
16 benefits to choose from, premier and premier plus. Benefits are underwritten through
17 Norton Lifelock Benefit Solutions.

18 **Q. Is there a cost to UPPCO for providing this benefit?**

19 A. Yes. UPPCO pays the cost for the employee only premier plan coverage level for
20 eligible employees. Employees pay 100% of the dependent cost and the difference to
21 buy-up to the premier plus coverage level.

1 **Q. Describe the life insurance benefit.**

2 A. UPPCO offers basic life, supplemental life and dependent life insurance underwritten by
3 Prudential Life Insurance Company.

4 **Q. Is there a cost to UPPCO for providing basic life insurance?**

5 A. Yes. UPPCO pays 100% of the monthly cost of basic life insurance for eligible
6 employees.

7 **Q. Is there a cost to UPPCO for providing employee-only supplemental life insurance?**

8 A. No, there is no cost to UPPCO for providing this benefit. The rate eligible employees
9 pay for employee only supplemental life coverage is based on the amount of coverage
10 they select and their age.

11 **Q. Is there a cost to UPPCO for providing spouse supplemental life insurance?**

12 A. No, there is no cost to UPPCO for providing this benefit. The rate eligible employees
13 pay for spouse supplemental life coverage is based upon the amount of coverage selected.

14 **Q. Is there a cost to UPPCO for providing child(ren) supplemental life insurance?**

15 A. No, there is no cost to UPPCO for providing this benefit.

16 **Q. Describe the accidental death and dismemberment benefit.**

17 A. UPPCO offers an accidental death and dismemberment (“AD&D”) benefit that is
18 underwritten by Prudential Life Insurance Company. Eligible employees receive
19 Company-sponsored AD&D insurance benefits and have the option to purchase
20 additional AD&D insurance to cover themselves and their qualified dependents. AD&D

1 provides benefits in the event of an accidental injury that results in the death or
2 dismemberment of a covered person.

3 **Q. Is there a cost to UPPCO for providing basic AD&D coverage?**

4 A. Yes, UPPCO pays 100% of the cost for eligible employees.

5 **Q. Is there a cost to UPPCO for providing supplemental AD&D?**

6 A. No, there is no cost to UPPCO for providing this benefit. The rates eligible employees
7 pay are based on the amount of coverage selected.

8 **Q. Describe the short-term disability benefit.**

9 A. UPPCO offers short-term disability underwritten by Prudential Life Insurance Company.
10 In the event illness or injury prevents employees from being able to work, UPPCO
11 provides disability benefits to ensure the continuation of their income. Eligible
12 employees are automatically enrolled and covered by both short-term and long-term
13 disability benefits. This benefit is for employees only. This benefit is for employees
14 only. It does not pay for a spouse or child disability. The benefit for administrative, non-
15 represented employees is 60% of weekly earnings, up to \$2,000 weekly. Represented
16 employees receive a \$500 weekly benefit in accordance with the CBA.

17 **Q. Is there a cost to UPPCO for providing this benefit?**

18 A. Yes, UPPCO pays 100% of the premium cost for eligible employees.

19 **Q. Describe the long-term disability benefit.**

1 A. UPPCO offers long-term disability to employees that is underwritten by Prudential Life
2 Insurance Company. If an employee is unable to return to work for an extended period,
3 typically defined as beyond short-term disability benefits and in some cases longer,
4 UPPCO provides long-term disability benefits. This benefit is for employees only. It
5 does not pay for a spouse or child disability. The benefit for administrative, non-
6 represented employees is 60% of monthly earnings, up to \$15,000 monthly. Represented
7 employees receive a 66.66% of monthly earnings, up to \$5,000 monthly in accordance
8 with the CBA.

9 **Q. Is there a cost to UPPCO for providing this benefit?**

10 A. Yes, UPPCO pays 100% of the premium cost for eligible employees.

11 **Q. Describe the employee assistance program Benefit**

12 A. The employee assistance program (“EAP”) offers professional support and direction to
13 resolving employees’ problems or concerns. The program also provides both self-help
14 resources online, as well as confidential counseling for issues for employees and their
15 eligible dependents.

16 **Q. Is there a cost to UPPCO for providing this benefit?**

17 A. Yes, UPPCO pays 100% of the cost for eligible employees.

18 **Q. Describe the COBRA benefit.**

19 A. COBRA is the Consolidated Omnibus Budget Reconciliation Act benefit and allows
20 eligible employees and/or their covered dependents to extend medical, dental, and/or
21 vision coverage beyond the date on which eligibility would normally end. As a large

1 employer with more than 20 full-time employees, UPPCO is legally required to offer
2 COBRA if a qualifying event occurs that causes a loss of coverage under the group health
3 plans. To ensure the COBRA benefits are managed according to the law and follow any
4 changes that may happen under the law, UPPCO contracts with a third-party to distribute
5 notices and manage billing.

6 **Q. Is there a cost to UPPCO for providing this benefit?**

7 A. Yes, the cost to UPPCO for providing third-party COBRA coverage is an administrative
8 fee of approximately \$175 per month.

9 **Q. Describe the 401(k) matching plan benefit.**

10 A. Key features of the 401(k) matching plan include:

11 Company Matching Contribution – as required by the CBA, represented employees hired
12 prior to April 19, 2009, UPPCO matches of 50% on the first 6.5% of eligible
13 compensation that employees contribute to the 401(k) plan. The match occurs
14 automatically, and employees are always 100% vested in the Company match.

15 Company Matching Contribution – For administrative, non-represented employees and
16 represented employees, as required by the CBA, hired on or after April 19, 2009, UPPCO
17 matches dollar for dollar the first 5% of eligible compensation that employees contribute
18 to the 401(k) plan. The match occurs automatically, and employees are always 100%
19 vested in the Company match.

20 Age and Service Contribution – For administrative, non-represented employees and
21 represented employees, as required by the CBA, hired on or after April 19, 2009, UPPCO

1 makes a non-elective contribution to the employees 401(k) plan. The amount employees
2 receive depends on how much compensation they were paid during the year as well as the
3 group to which they are assigned. Groups consist of the sum of participants age and full
4 years of vesting service as of the end of each payroll period which end in the plan year
5 for which the contribution is made. Percentages listed are expressed as a percentage of
6 total eligible compensation for all participants eligible for the allocation:

7 0-34 = 3%

8 35-49 = 4%

9 50-64 = 5%

10 65-79 = 6%

11 80 and above = 7%

12 **Q. Describe the pension benefit.**

13 A. UPPCO offers a two-part traditional pension benefit to eligible employees. Part A
14 consists of administrative, non-represented employees hired prior to January 1, 2008 or
15 represented employees who transferred to an eligible administrative position between
16 January 1, 2009 and December 31, 2012. The plan was closed January 1, 2008, and
17 benefits were frozen as of December 31, 2017, however interest credits continue to apply.
18 Part A beneficiaries may elect a lump-sum benefit or monthly annuity payment.

19 Part B is closed to new entry and consists of represented employees hired prior to April
20 19, 2009. Employees enrolled in Part B Pension Benefits continue to accrue benefit as

1 long as they remain employed in an eligible position. Part B beneficiaries receive
2 benefits in the form of a monthly annuity payment.

3 **Q. Describe the wellness program benefit.**

4 A. UPPCO offers a formal wellness program to all regular full-time employees of UPPCO
5 and their spouses. The wellness program is designed to encourage preventive care
6 through completing an annual health exam to catch potential health concerns early,
7 before becoming a major concern. Employees and their spouses are also eligible for
8 reimbursements for wellness related activities and equipment.

9 **Q. Is there a cost to UPPCO for providing this benefit?**

10 A. The cost for providing this benefit is in the form of an HSA contributions or payroll
11 contributions received by the employee based on the employee's medical plan
12 enrollment. Employees and spouses are eligible to receive \$250 each for the completion
13 of an annual physical. Employees and spouses are eligible to receive up to \$250 each for
14 reimbursement of wellness related activities and/or equipment. UPPCO only experiences
15 costs for the health coaching or tobacco cessation as employees engage in the programs.
16 For lifestyle coaching, the pricing is \$300 per employee or eligible family member who
17 uses the program.

18 **Q. Describe the tuition reimbursement benefit.**

19 A. This benefit is available to any active, regular full-time employee. UPPCO recognizes
20 the value of continuing education and career development. Tuition reimbursement is
21 designed to help the Company improve and develop the knowledge and skills of its

1 employees and to help employees pursue UPPCO career related learning opportunities.
2 To engage in this program, employees must apply for consideration through their leader
3 and HR, to ensure the education program meets the outline of the program as well as
4 benefits their career within UPPCO. Employees will be reimbursed for tuition expenses,
5 textbooks and lab fees for any approved course. Reimbursements will be made, minus
6 any ineligible expenses, consistent with the Internal Revenue Service (“IRS”) regulations
7 pertaining to tax excludability for Educational Assistance Programs. Coursework must
8 be related to the employee’s current position or a reasonable promotional opportunity
9 within the Company or included as part of a degree program meeting this requirement.
10 Employees are eligible to be reimbursed per calendar year maximum of \$5,250 for
11 undergraduate or non-degree courses and \$8,000 for graduate courses with amounts
12 exceeding the annual IRS tax-excludable limits taxed as wages.

13 **Q. Describe the adoption assistance benefit.**

14 A. This benefit applies to any active regular full-time employees of UPPCO. UPPCO
15 recognizes that the adoption process can place a burden on an employee, both with time
16 constraints and finances. To show its commitment to employee families, UPPCO will
17 share some of this burden with employees who adopt. The maximum payment per
18 adoption is \$3,000, with an annual limit of \$3,000 per employee.

19 **Q. Please describe the cash-in-lieu of benefits program.**

20 A. This benefit applies to employees waiving UPPCO medical coverage due to enrollment in
21 an alternate group health insurance program, such as military coverage or coverage
22 through a spouse or parent. UPPCO recognizes the need to provide a form of benefit to

1 all eligible employees. By offering a cash-in-lieu program, all employees realize a form a
2 medical benefit. The monthly benefit is \$400 or \$184.62 bi-weekly per participating
3 employee, which is significantly less than the cost of medical premiums.

4 **Q. Please describe the paid time away programs.**

5 A. UPPCO offers paid holidays, vacation time, sick time, Family Medical Leave (“FMLA”),
6 and personal time. Paid holidays for represented employees are negotiated in the CBA.
7 Paid holidays for Administrative, non-represented employees are New Year’s Day, Good
8 Friday, Memorial Day, July 4th, Labor Day, Thanksgiving and the Friday after, Christmas
9 Eve, and Christmas Day. Vacation time is offered to employees on a sliding scale based
10 on years of service and is negotiated in the CBA for Represented employees. All
11 employees may purchase up to two weeks of additional vacation through payroll
12 deductions.

13 **Q. What benefits does UPPCO offer to its retirees?**

14 A. Medical (outlined by the CBA or Retiree Medical Care Credit Program), dental (closed to
15 new entrants and only applicable to a small group of retirees), vision, life insurance
16 (closed to new entrants), and pension payments (closed to new entrants).

17 **Q. Describe the medical benefits available to retirees.**

18 A. There are three separate medical plans available to retirees depending on their age and
19 plan availability at the time of retirement. Retirees up to age 65 are offered a traditional
20 PPO plan with prescription drugs, underwritten by BCBSM. Retirees over the age of 65
21 or enrolled in Medicare Disability are offered Medicare Advantage and Medicare

1 Prescription Drug Plan Coverage (“MA”, “PDP”) plan. There is one small segment of
2 retirees, enrolled in a closed Medicare Advantage and Medicare Prescription Drug Plan
3 mirroring a Medigap plan. The Medicare Advantage plans are underwritten by BCBSM
4 and the prescription drug plans are underwritten by Humana.

5 **Q. Does UPPCO pay the entire cost of medical benefit coverage for retirees?**

6 A. Generally, no. A limited number of formerly represented retirees have the option of
7 electing three years of free coverage as part of their retirement package. There are a very
8 limited number of formerly represented retirees that retired from UPPCO when the
9 Company sold the Presque Isle Power Plant. Part of the sale agreement allowed those
10 individuals to defer three years of free coverage until they needed it. Current represented
11 employees may also elect up to three years of free coverage upon retirement. Once the
12 three-year free coverage period has ended, the formerly represented retiree is responsible
13 for 50% of their medical premiums.

14 Administrative, non-represented employees who have attained age 45 accrue Retiree
15 Medical Care Credits (“RMCC”). Vesting occurs in their RMCC account once they have
16 completed three years of service after attaining age 45. Credits can be used to pay for
17 retiree medical. Former administrative, non-represented retirees may elect to use
18 RMCCs to share in the monthly premium cost of retiree medical in 25% increments.
19 Once the credits have been exhausted, UPPCO no longer pays for any portion of the
20 premiums.

21 **Q. Describe the dental benefits available to retirees.**

1 A. The dental benefit available to retirees in the same as that available to active represented
2 and non-represented administrative employees, with the exception that the retirees do not
3 have an orthodontia benefit.

4 **Q. Does UPPCO pay the cost of dental coverage for retirees?**

5 A. UPPCO pays 50% of the cost for dental coverage for pre-2001 retirees. UPPCO does not
6 pay for any dental benefit for post-2001 retirees and dependents.

7 **Q. Describe the vision benefits available to retirees.**

8 A. The vision benefit available to retirees is the same as that available to active represented
9 and administrative, non-represented employees.

10 **Q. Does UPPCO pay the cost of vision coverage for retirees?**

11 A. No. Retirees are responsible for 100% of the cost of vision coverage.

12 **Q. Describe the life insurance benefit available to retirees.**

13 A. This benefit is a closed benefit. A closed segment of administrative, non-represented
14 employees and represented employees retiring prior to May 1, 2018 are eligible for
15 retiree life insurance. The maximum life insurance benefit payable under the plan is
16 \$15,000.

17 **Q. Does UPPCO pay the cost of life insurance for retirees?**

18 A. Yes. UPPCO is responsible for 100% of the cost of the plan. The cost equates to \$6.48
19 per \$1,000 of coverage.

20 **Q. Is there anything else you would like to share regarding compensation and benefits?**

1 A. Yes. A physically and mentally healthy workforce is essential to sustained productivity.
2 Employees in good health are less likely to be absent and better positioned to perform at a
3 high level, which contributes to improved operational outcomes and customer
4 satisfaction. To support these objectives, UPPCO continues to refine its compensation
5 and benefits programs with a focus on promoting overall employee well-being while
6 maintaining competitiveness in attracting and retaining talent. At the same time, UPPCO
7 remains committed to disciplined cost management.

8 Where feasible, UPPCO prioritizes partnerships with Michigan-based benefit providers
9 that understand the unique challenges of delivering coverage across its service territory
10 and supporting retirees located throughout the United States. Collectively, these
11 partnerships enable UPPCO to offer benefit options that align with both its financial
12 objectives and coverage requirements.

13 **Q. Are UPPCO's compensation and benefits plans reasonable and prudent, and should**
14 **the Company be allowed to recover the costs of same programs in their entirety?**

15 A. Yes, the purpose of UPPCO's compensation and benefits is to attract and retain talented,
16 high-quality employees in a tight labor market with the necessary skills to serve our
17 customers safely and reliably. The labor market is tight for everyone; however, it is even
18 more challenging for UPPCO due to the remote nature of the areas we serve. In some
19 cases, the labor market for the skills we need requires us to compete for talent with much
20 larger utilities who are in much more desirable areas. UPPCO is also negatively
21 impacted by the housing market and lack of daycare options for employees with children.
22 The relatively few homes on the market for sale and the increased cost to buy homes are

1 very real barriers for UPPCO in attracting talent. Finding reliable and affordable daycare
2 in the areas we serve is also a significant challenge. Because of these challenges,
3 UPPCO must offer competitive pay and benefits to ensure we attract and retain the talent
4 necessary to serve our customers.

5 **Q. Does this complete your direct testimony?**

6 A. Yes.

7

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-22032

DIRECT TESTIMONY AND EXHIBITS OF
NICOLE E. BELL
ON BEHALF OF
UPPER PENINSULA POWER COMPANY

May 22, 2026

1 **QUALIFICATIONS**

2 **Q. Please state your name, business address, and the name of your employer for the**
3 **record.**

4 A. My name is Nicole E. Bell. My business address is 19693 Campus Drive, Hancock,
5 MI. I am employed by Upper Peninsula Power Company (“UPPCO” or the
6 “Company”).

7 **Q. Please describe your job responsibilities.**

8 A. My title is Manager of Rates and Power Supply within the Regulatory Affairs
9 department. My responsibilities in this role include a wide variety of issues touching
10 several aspects of UPPCO’s business, including tariff administration, Renewable
11 Portfolio Standard (“RPS”) compliance analysis, sales and peak demand forecasting,
12 rate design and revenue analysis, among other related duties.

13 **Q. Briefly describe your educational background and applicable professional**
14 **experience.**

15 A. I graduated from the Community College of the Air Force in 2013 with an Associate
16 of Applied Science in Weather Technology. I graduated from American Military
17 University in 2016 with a Bachelor of Science in Environmental Science. I graduated
18 from Grand Canyon University in 2021 with a Master’s in Business Administration.
19 In January 2011, I entered employment with the United States Air Force (“USAF”) as
20 a Weather Specialist, tasked with the observing, recording, forecasting, and
21 dissemination of weather data and information to military installations throughout the

1 United States. In January 2015, I completed my enlistment in the USAF and began
2 employment with the Tucson Electric Power Company (“TEPC”) as a Renewable
3 Energy Forecaster and Trading Analyst in the Wholesale Marketing and Renewables
4 departments of TEPC. My responsibilities in this position included the forecasting
5 and analysis of renewable resource output and availability, the updating and
6 maintaining of TEPC’s renewable resource forecasting models, and other analysis of
7 the department’s generation resources, including analysis of transactions between
8 TEPC and its counterparties. I cross-trained in several different positions throughout
9 the Wholesale Marketing department, where I completed tasks related to the
10 scheduling of power purchases and sales, creation and monitoring of transaction tags,
11 creation and monitoring of transmission reservations, and the conducting of daily
12 communication between counterparties. In January 2020, I left my employment with
13 TEPC. I began employment with UPPCO in March 2020 as a Regulatory Analyst
14 within the Regulatory Affairs department.

15 **Q. Have you previously testified before the Michigan Public Service Commission**
16 **(“MPSC”)?**

17 A. Yes. I have provided testimony in several cases before the Commission. Recent
18 notable examples include the following proceedings on behalf of UPPCO: Case No.
19 U-21555 (General Rate Case), Case No. U-21603 (2025 PSCR reconciliation), Case
20 No. U-22030 (2025 Renewable Energy reconciliation), and Case No. U-21883 (2026
21 PSCR Plan).

22 **PURPOSE OF TESTIMONY**

1 **Q. What is the purpose of your testimony in this proceeding?**

2 A. The purpose of my testimony is to present analysis and discussion of the following
3 topics in support of the Company's request for rate relief in this proceeding:

- 4 1. The development of the Company's current electric sales and peak demand
5 forecast for the period 2027 – 2031.
- 6 2. The Company's proposed rate design, pursuant to the results of the Company's
7 Cost of Service Study ("COSS") sponsored by Company Witness Stocking.
- 8 3. Propose the establishment of a new Power Supply Cost Recovery ("PSCR") Base
9 Rate for the purpose of determining the PSCR factors for future recovery of
10 power supply costs through the PSCR process.
- 11 4. State Reliability Mechanism ("SRM"): Capacity Charge
- 12 5. Projected participation in the Company's existing Residential Income Assistance
13 Program ("RIA").

14 **Q. Are you sponsoring any exhibits in this proceeding?**

15 A. Yes, I am sponsoring the following Exhibits:

- 16 I. Exhibit A-5, Schedule E1 (NEB-1):
- 17 II. Exhibit A-15, Schedule E1 (NEB-2):
- 18 III. Exhibit A-16, Schedule F2 (NEB-3):
- 19 IV. Exhibit A-16, Schedule F3 (NEB-4):
- 20 V. Exhibit A-16, Schedule F4 (NEB-5):
- 21 VI. Exhibit A-16, Schedule F5 (NEB-6):

1 VII. Exhibit A-42, (NEB-7):

2 VIII. Exhibit A-45, (NEB-8):

3 IX. Exhibit A-46, (NEB-9):

4 X. Exhibit A-47, (NEB-10):

5 **Q. Were these Exhibits prepared by you or under your direction?**

6 A. Yes, they were.

7

8 **1. Sales and Peak Demand Forecast**

9 **Q. Please describe Exhibit A-5 (NEB-1), Schedule E1.**

10 A. Exhibit A-5 (NEB-1), Schedule E1 contains three pages. Exhibit A-5 (NEB-1),
11 Schedule E1, page 1 provides an annual summary of historical service area sales by
12 major customer class for the years 2021 – 2025. This exhibit also summarizes
13 company use and distribution loss kilowatt-hours (“kWh”), and sums to total system
14 output.

15 Exhibit A-5 (NEB-1), Schedule E1, page 2 provides an annual summary of historical
16 bundled service sales by major customer class for the years 2021 – 2025. This exhibit
17 also summarizes company use and distribution loss kWh, and sums to total system
18 output.

19 Exhibit A-5 (NEB-1), Schedule E1, page 3 provides an annual summary of historical
20 Alternative Electric Supplier (“AES”) sales by major customer class for the years
21 2021 – 2025.

1 **Q. Please describe Exhibit A-15 (NEB-2), Schedules E1.**

2 A. Exhibit A-15 (NEB-2), Schedule E1 contains five pages. Exhibit A-15 (NEB-2),
3 Schedule E1, page 1 provides an annual summary of projected service area sales by
4 major customer class for the years 2027 – 2031. This exhibit also summarizes
5 company use and distribution loss kWh, and sums to total system output.

6 Exhibit A-15 (NEB-2), Schedule E1, page 2 provides an annual summary of projected
7 bundled service sales by major customer class for the years 2027 – 2031. This exhibit
8 also summarizes company use and distribution loss kWh, and sums to total system
9 output.

10 Exhibit A-15 (NEB-2), Schedule E1, page 3 provides an annual summary of projected
11 AES sales by major customer class for the years 2027 – 2031.

12 Exhibit A-15 (NEB-2), Schedule E1, page 4 provides an annual summary of total
13 service area system output, maximum demand, and average system load factor for
14 years 2021 – 2031.

15 Exhibit A-15 (NEB-2), Schedule E1, page 5 provides an annual summary of bundled
16 system output, maximum demand, and average system load factor for years 2021 –
17 2031.

18 **Q. Please explain how the Company developed its sales forecast for the 12-month**
19 **projected test period ending December 31, 2027 (“Projected Test Year”).**

20 A. The Company’s Residential sales forecast was developed utilizing a regression
21 model. The historical period used as the basis for the projection spans September 1,

1 2013 through August 31, 2025. Forecasted values for the period September 1, 2025
2 through December 31, 2025 were based on the Company's 2025 budget forecast. The
3 regression model incorporates seasonal, weather-related, and autoregressive variables
4 to project average residential usage and sales and was reviewed for overall
5 reasonableness based on historical trends and expected conditions during the
6 Projected Test Year. The resulting forecast is reflected in Exhibit A-15 (NEB-2),
7 Schedule E1.

8

9 The Company's Commercial sales forecast was developed utilizing a regression
10 model based on historical commercial sales within the Company's service territory.
11 The historical period used as the basis for the projection spans January 1, 2014
12 through December 31, 2024. The regression model incorporates seasonal, weather-
13 related, and autoregressive variables to project commercial sales and usage patterns.
14 The resulting forecast is reflected in Exhibit A-15 (NEB-2), Schedule E1.

15

16 The Company's Industrial sales forecast was developed utilizing a simple moving
17 average forecasting methodology based on historical Industrial sales within the
18 Company's service territory. The historical period used as the basis for the projection
19 spans January 1, 2023 through December 31, 2025. The model averages historical
20 Industrial customer usage over the three-year period to determine projected test year
21 sales. In addition, the forecast reflects a projected reduction in usage associated with
22 an energy efficiency project completed by a large Industrial customer. The Company

1 incorporated an approximate 10 percent reduction in that customer’s projected usage
2 based on the expected impact of the completed project. The resulting forecast is
3 reflected in Exhibit A-15 (NEB-2), Schedule E1.

4
5 The Company Use forecast was developed utilizing a simple moving average
6 forecasting methodology based on historical Company Use data from September 1,
7 2022 through August 31, 2025. The model averages the Company’s historical usage
8 over the three-year period to determine projected test year usage. The forecast also
9 reflects the expected impact of the Company’s new service center on Company Use
10 consumption during the portion of the projected test year not fully reflected in the
11 historical data. Because the building was completed and occupied during September
12 2025, usage associated with the facility is already incorporated into the historical
13 period for the remainder of the forecast. The resulting forecast is reflected in Exhibit
14 A-15 (NEB-2), Schedule E1.

15
16 The Street Lighting forecast was developed utilizing a simple moving average
17 forecasting methodology based on historical Street Lighting usage data from
18 September 1, 2022 through August 31, 2025. The model averages historical Street
19 Lighting usage over the three-year period to determine projected test year usage. The
20 resulting forecast is reflected in Exhibit A-15 (NEB-2), Schedule E1.

1 **Q. How did the Company project total AES customer sales throughout the forecast**
2 **period?**

3 A. For purposes of this proceeding, the Company projected AES customer sales and
4 demand based on current AES participation levels. After customer migrations in
5 calendar year 2021 caused participation in the Company’s AES program to exceed
6 the ten percent retail choice cap established by statute, those migrations became
7 reflected in the Company’s historical AES sales and demand for subsequent periods.
8 Because the composition of the AES customer group has not changed materially since
9 then, the Company assumed AES sales and demand would remain generally
10 consistent with current levels throughout the forecast period.

11 **Q. Are the effects of Energy Waste Reduction (“EWR”) included in the sales**
12 **forecast presented here?**

13 A. Yes, the effects of EWR on total sales in each applicable rate category are included in
14 the forecast presented in this proceeding and are implicitly assumed to continue at
15 average historical trend levels throughout the forecast period.

16 **Q. Please explain how the total company demand forecast was developed for the**
17 **projected test year.**

18 A. The total Company peak demand forecast was developed using a regression analysis
19 based on the historical relationship between monthly kWh sales and peak kilowatt
20 (“kW”) demand, along with weather and seasonal explanatory variables.

1 **Q. Please explain the procedures used to develop fixed charge counts for the**
2 **projected test year.**

3 A. The fixed charge forecasts for the Residential, Commercial, and Industrial sectors
4 were developed using a 12-month analysis of actual billed historical data at the rate
5 schedule level, including both monthly fixed charges and lamp counts. The 12-month
6 historical period used in the analysis was January 2025 – December 2025. This
7 analysis produced a known and measurable outlook of fixed charge billing
8 determinants for rate schedules A-1, AH-1, C-1, H-1, P-1, CP-U (Secondary,
9 Primary, and Transmission), WP-3, Z-3, SL-3, SL-5, and SL-6. The fixed charge
10 billing determinants are assumed to be static between the 2025 historical period and
11 the projected test year.

12 **Q. What weather and temperature assumptions were made in the development of**
13 **the Company’s sales and peak demand projection?**

14 A. UPPCO used a 10-year average of actual monthly weather observations at KI Sawyer
15 International Airport, as reported by the National Oceanic and Atmospheric
16 Administration (“NOAA”) between the years of 2016 – 2025 as the basis for assumed
17 future weather characteristics utilized in the forecast.

18 **Q. Please describe the Company’s kWh sales projection for the projected test year.**

19 A. As evidenced by Schedule E1 of Exhibit A-15 (NEB-2), the Company projects a total
20 bundled sales requirement of 614,344,209 kWh. This projection does not include

1 projected sales to AES customers, nor does it include total projected sales to the
2 RTMP rate schedule.

3 **Q. What is the total projected test year sales utilized as the basis for rate design in**
4 **this proceeding?**

5 A. The sales projection used as a basis for rate design in this proceeding totals 576,012
6 MWh. This value does not include sales made pursuant to the RTMP tariff and is
7 only partially inclusive of sales made to customers participating in the Company's
8 AES program, due to the nature of distribution rate billing to AES customers taking
9 service under the Company's CP-U and WP-3 tariffs.

10 **2. Proposed Rate Design**

11 **Q. Please describe Exhibit A-16 (NEB-3), Schedule F2.**

12 A. Exhibit A-16 (NEB-3), Schedule F2 provides a summary of revenues at current and
13 proposed rates for each rate schedule and calculates the net percentage increase
14 (decrease) for the 12-month period ending on December 31, 2027.

15 **Q. Please describe Exhibit A-16 (NEB-4), Schedule F3.**

16 A. Exhibit A-16 (NEB-4), Schedule F3 provides a detailed summary of proposed rates
17 by rate schedule for the 12-month period ending on December 31, 2027.

18 **Q. Please describe Exhibit A-16 (NEB-5), Schedule F4.**

19 A. Exhibit A-16 (NEB-5), Schedule F4 calculates average bills at current and proposed
20 rates by rate schedule for a range of usage levels, calculates the percentage increase

1 (decrease) comparison between average bills at each rate and usage level, and
2 calculates the average rate at each usage level for the 12-month period ending on
3 December 31, 2027.

4 **Q. Please describe Exhibit A-16 (NEB-6), Schedule F5.**

5 A. Exhibit A-16, Schedule F5 contains redline versions of the tariff sheets consistent
6 with the Company's proposed rate design for the 12-month period ending on
7 December 31, 2027.

8 **Q. What will you be addressing in connection with UPPCO's proposed rate design?**

9 A. I will address the following items related to rate design.

- 10 1. Rate Design for the A-1 Residential Rate Schedule.
- 11 2. Rate Design for the AH-1 Residential Heating Rate Schedule.
- 12 3. Rate Design for the C-1 General Service Rate Schedule.
- 13 4. Rate Design for the H-1 Commercial Heating Rate Schedule.
- 14 5. Rate Design for the P-1 Light and Power Rate Schedule.
- 15 6. Rate Design for the CP-U Rate Schedule.
- 16 7. Rate Design for the WP-3 Rate Schedule.
- 17 8. Rate Design for the RTMP Rate Schedule.
- 18 9. Rate Design for the SL-3, SL-5, & SL-6 Rate Schedule.
- 19 10. Rate Design for the Z-3 Rate Schedule.

20 **Q. What principles did the Company rely on when developing its rate design**
21 **proposal?**

1 A. The Company relies on a fully allocated, embedded COSS as the guiding principle for
2 determination of revenue requirements of each individual rate schedule. The
3 UPPCO's COSS is sponsored by Company witness Stocking. Both embedded and
4 marginal costs should be used as guidance in rate design.

5

6 In any place that the COSS recommends a substantial change in rates, the change may
7 be moderated to incorporate a reasonable amount of rate stability. The Company
8 recognizes that should any rate schedule experience a significant shift in electric rate
9 revenue requirement, the overall rate proposals may need to be revised.

10

11 Lastly, rate design should reflect cost of service to the extent practical.

12 **Q. Do UPPCO's proposed rates generally comport with the customer class level**
13 **results of the projected test year COSS?**

14 A. Yes, they do. The Company has identified the relationship between similar customer
15 classes within the total customer classification and solved the entire group to the total
16 required revenue. As a consequence of this method, some cross-subsidization
17 amongst rate schedules will persist; however, this method attempts to mitigate any
18 significant rate impact to any one rate schedule and ensures that the rates designed for
19 each customer grouping will recoup the required revenues.

20 **Q. Please describe UPPCO's proposed rate design for the A-1 rate schedule for the**
21 **12-month period ending on December 31, 2027.**

1 A. As evidenced by line 79, page 6 of Exhibit A-16 (EWS-2), Schedule F1 presented by
2 Company witness Stocking, the current rate levels within the A-1 schedule are
3 forecasted to under-recover the revenues required for this rate schedule by 12.91%.
4 UPPCO's proposed rate design for A-1 maintains the existing Service Charge of
5 \$15.00 per month, and derives a total volumetric energy rate of \$0.18255 / kWh. The
6 details related to the proposed rate design calculation for the A-1 schedule are shown
7 in Exhibit A-16 (NEB-4), Schedule F3.

8 **Q. Please describe UPPCO's proposed rate design for the AH-1 rate schedule for**
9 **the 12-month period ending on December 31, 2027.**

10 A. As evidenced by line 79, page 6 of Exhibit A-16 (EWS-2), Schedule F1, the current
11 rate levels within the AH-1 schedule are forecasted to under-recover the revenue
12 requirement for this rate schedule by 51.59%. UPPCO's proposed rate design for
13 AH-1 maintains a Service Charge of \$15.00 per month, and derives a total energy rate
14 of \$0.18255 for June – September, a total energy rate of \$0.18255 for all kWh less
15 than 500 kWh during the heating season, and a total energy rate of \$0.09128 for all
16 kWh greater than 500 kWh during the heating season. The details related to the
17 proposed rate design calculation for the AH-1 schedule are shown in Exhibit A-16
18 (NEB-4), Schedule F3.

19 **Q. Were rate schedules A-1 and AH-1 solved concurrently, as described above?**

20 A. Yes, they were.

1 **Q. Please describe the relationship assumed between A-1 and AH-1 used to design**
2 **rates for these two categories concurrently.**

3 A. A-1 and AH-1 customers are largely identical, except for AH-1 customers who heat
4 their homes by electric sources. As such, there is little difference between customers
5 within these rate schedules during the summer months. In light of this commonality,
6 for purposes of the proposed rate design in this proceeding, the following
7 relationships were established.

- 8 • Service Charge is equal between rate schedules,
- 9 • Distribution Energy Charge is equal, with the exception of AH-1 usage greater than
10 500 kWh during the heating season, which equals 50% of the standard distribution
11 energy charge.
- 12 • Power Supply energy charge is equal throughout all rate schedules and usage
13 tranches. Since UPPCO procures approximately 80% of its total retail energy
14 obligations through wholesale purchase transactions, it is equitable to charge AH-1
15 customers a uniform power supply rate. An exception to this are AH-1 customers
16 with usage greater than 500 kWh during the heating season, where rates are applied
17 equal to 50% of the standard power supply energy charge.

18 **Q. Please describe UPPCO's proposed rate design for the C-1 rate schedule for the**
19 **12-month period ending on December 31, 2027.**

20 A. As evidenced by line 79, page 6 of Exhibit A-16 (EWS-2), Schedule F1, the current
21 rate levels within the C-1 schedule are forecasted to under-recover the revenue
22 requirement for this rate schedule by 13.27%. UPPCO's proposed rate design for C-1

1 maintains a Service Charge of \$19.00, and derives a total energy rate of \$0.21185 per
2 kWh. The details related to the proposed rate design calculation for the C-1 schedule
3 are shown in Exhibit Exhibit A-16 (NEB-4), Schedule F3.

4 **Q. Please describe UPPCO’s proposed rate design for the H-1 rate schedule for the**
5 **12-month period ending on December 31, 2027.**

6 A. As evidenced by line 79, page 6 of Exhibit A-16 (EWS-2), Schedule F1, the current
7 rate levels within the H-1 schedule are forecasted to under-recover the revenue
8 requirement for this rate schedule by 44.21%. UPPCO’s proposed rate design for H-1
9 maintains a Service Charge of \$19.00 per month, and derives a total energy rate of
10 \$0.21185 per kWh for June – September, a total energy rate of \$0.21185 for all kWh
11 less than 1,000 kWh during the heating season, and a total energy rate of \$0.10592 for
12 all kWh greater than 1,000 kWh during the heating season. The details related to the
13 proposed rate design calculation for the H-1 schedule are shown in Exhibit A-16
14 (NEB-4), Schedule F3.

15 **Q. Please describe UPPCO’s proposed rate design for the P-1 rate schedule for the**
16 **12-month period ending on December 31, 2027.**

17 A. As evidenced by line 79, page 6 of Exhibit A-16 (EWS-2), Schedule F1, the current
18 rate levels within the P-1 schedule are forecasted to over-recover the revenue
19 requirement for this rate schedule by 17.63%. UPPCO’s proposed rate design for P-1
20 maintains a Service Charge of \$37.00 per month, and derives total demand charges of
21 \$11.16 per Kw, and a total Energy Charge of \$0.05298 per kWh. The details related

1 to the proposed rate design calculation for the P-1 schedule are shown in Exhibit A-
2 16 (NEB-4), Schedule F3.

3 **Q. Please describe UPPCO's proposed rate design for the CP-U rate schedule for**
4 **the 12-month period ending on December 31, 2027.**

5 A. As evidenced by line 79, page 7 of Exhibit A-16 (EWS-2), Schedule F1, the current
6 rate levels within the CP-U schedule are forecasted to under-recover the revenue
7 requirement for this rate schedule by 56.54% in CP-U Secondary, under-recover the
8 revenue requirement for this rate schedule by 138.24% in CP-U Primary, and under-
9 recover the revenue requirement for this rate schedule by 11.17% in CP-U
10 Transmission.

11

12 UPPCO's proposed rate design for CP-U Secondary maintains a Service Charge of
13 \$500.00 per month, and derives total firm demand charges of \$10.09 per kW, total
14 interruptible demand charges of \$10.09 per kW, total customer demand charge of
15 \$9.59 per kW, an on-peak energy charge of \$0.11591 per kWh, and an off-peak
16 energy charge of \$0.07536 per kWh.

17

18 UPPCO's proposed rate design for CP-U Primary maintains a Service Charge of
19 \$650.00 per month, and derives total firm demand charges of \$9.66 per kW, total
20 interruptible demand charges of \$9.66 per kW, total customer demand charge of

1 \$9.17 per kW, an on-peak energy charge of \$0.11173 per kWh, and an off-peak
2 energy charge of \$0.07263 per kWh.

3

4 UPPCO's proposed rate design for CP-U Transmission maintains a Service Charge of
5 \$1,500.00 per month, and derives total firm demand charges of \$3.63 per kW, total
6 interruptible demand charges of \$3.63 per kW, total substation transformer capacity
7 charge of \$1.04 per kVA, an on-peak energy charge of \$0.10764 per kWh, and an off-
8 peak energy charge of \$0.06998 per kWh. The details related to the proposed rate
9 design calculation for the CP-U schedule are shown in Exhibit A-16 (NEB-4),
10 Schedule F3.

11 **Q. Please describe UPPCO's proposed rate design for the WP-3 rate schedule for**
12 **the 12-month period ending on December 31, 2027.**

13 A. As evidenced by line 79, page 7 of Exhibit A-16 (EWS-2), Schedule F1, the current
14 rate levels within the WP-3 rate schedule are forecasted to over-recover the revenue
15 requirement for this schedule by 0.80%. UPPCO's proposed rate design for the WP-3
16 schedule maintains a Service Charge of \$1,500.00 per month, and derives total firm
17 demand charges of \$3.90 per kW, total interruptible demand charges of \$3.90 per
18 kW, substation transformer capacity of \$1.04 per KVA, total on-peak energy charges
19 of \$0.10764 per kWh, and total off-peak energy charges of \$0.06998 per kWh. The
20 details related to the proposed rate design calculation for the WP-3 schedule are
21 shown in Exhibit A-16 (NEB-4), Schedule F3.

1 **Q. Were rate schedules P-1, CP-U and WP-3 solved concurrently to mitigate any**
2 **significant rate increases to recover required revenues experienced by an**
3 **individual rate class?**

4 A. Yes, they were.

5 **Q. Please describe UPPCO's proposed rate design for the RTMP rate schedule for**
6 **the 12-month period ending on December 31, 2027.**

7 A. As evidenced by Exhibit A-16 (NEB-4), Schedule F3, UPPCO proposes to leave rates
8 for the RTMP class unchanged from the prior case. It is important to note that the
9 vast majority of costs (and revenue) attributable to providing service to the RTMP
10 class are outside the scope of this proceeding. These costs that are borne by UPPCO
11 as a product of providing RTMP service are passed along directly to the customer and
12 are applied as a direct offset to the PSCR related costs experienced by the Company's
13 non-RTMP customers.

14 UPPCO's proposed rate design for the RTMP schedule maintains a monthly customer
15 charge of \$1,000.00 per month, a demand charge of \$0.41 per kW, and a scheduling
16 charge of \$1,000 per month. The details related to the proposed rate design
17 calculation for the RTMP schedule are shown in Exhibit A-16 (NEB-4), Schedule F3.

18 **Q. Please describe UPPCO's proposed rate design for the Street Lighting (SL-3,**
19 **SL-5, and SL-6) and Outdoor Lighting rate schedules.**

20 A. The resulting rates are outlined in Exhibit A-16 (NEB-4), Schedule F3.

1 **Q. What is the bill impact to an average Residential customer as a result of the**
2 **Company’s proposed rate design in this proceeding for the 12-month period**
3 **ending on December 31, 2027?**

4 A. As evidenced by Schedule F4 of Exhibit A-16 (NEB-5), a residential customer,
5 previously taking service under the A-1 tariff, consuming 500 kWh per month will
6 receive a monthly bill of \$162.92. This constitutes an increase of \$22.44, or 15.97%
7 when compared to present revenues.

8 **Q. What is the bill impact to an average small Commercial customer as a result of**
9 **the Company’s proposed rate design in this proceeding for the 12-month period**
10 **ending on December 31, 2027?**

11 A. As evidenced by Schedule F4 of Exhibit A-16 (NEB-5), a C-1 customer consuming
12 2,500 kWh per month will receive a monthly bill of \$829.06. This constitutes an
13 increase of \$116.19, or 16.30% compared to a similarly calculated bill at current
14 rates.

15 **Q. What is the bill impact to an average large Commercial customer as a result of**
16 **the Company’s proposed rate design in this proceeding for the 12-month period**
17 **ending on December 31, 2027?**

18 A. As evidenced by Schedule F4 of Exhibit A-16 (NEB-5), a P-1 customer consuming
19 20,000 kWh, and 55 Kw per month will receive a monthly bill of \$3,831.04. This
20 constitutes an increase of \$193.69, or 5.33% compared to a similarly calculated bill at
21 current rates.

1 **Q. What is the bill impact to an average Industrial customer as a result of the**
2 **Company’s proposed rate design in this proceeding for the 12-month period**
3 **ending on December 31, 2027?**

4 A. As evidenced by Schedule F4 of Exhibit A-16 (NEB-5), a CP-U customer consuming
5 480,000 kWh, and 1,260 kW per month will receive a monthly bill of \$78,925.77.
6 This constitutes an increase of \$10,131.98, or 14.73% compared to a similarly
7 calculated bill at current rates.

8 **Q. What is the bill impact to an average Street Lighting customer as a result of the**
9 **Company’s proposed rate design in this proceeding for the 12-month period**
10 **ending on December 31, 2027?**

11 A. As evidenced by Schedule F4 of Exhibit A-16 (NEB-5), an SL-6 customer with one
12 100-Watt LED fixture, one pole, and one span of conductor will receive a monthly
13 bill of \$8.17. This constitutes an increase of \$0.87, or 11.95%.

14 **Q. Are the proposed rates for the 12-month period ending on December 31, 2027, in**
15 **this proceeding designed to collect the required revenues indicated by the**
16 **Company’s COSS presented in Exhibit A-16, Schedule F1?**

17 A. Yes.

18

19 **3. Establishment of PSCR Base**

20 **Q. Please describe Exhibit A-42 (NEB-7).**

- 1 A. Lines 1 through 30 of Exhibit A-42 (NEB-7) outline the following as forecasted for
2 the UPPCO system for the 2027 test year:
- 3 1. The forecasted Net PSCR Costs, which are equal to the PSCR costs of
4 generation, purchases, and transmission less
- 5 a. Opportunity sales revenues,
6 b. Real Time Market Price Tariff (“RTMP”) sales revenues,
7 c. RTMP transmission revenues,
8 d. Capacity sales revenue,
9 e. Renewable Energy Certificate (“REC”) sales revenue, and
10 f. Ancillary services revenues.
- 11 2. Megawatt hours of Generation plus purchased power less,
12 a. Opportunity sales and
13 b. RTMP sales,
- 14 3. The MWhs of System Requirement Sales subject to a PSCR Factor,
15 4. The average PSCR cost per MWh,
16 5. The current PSCR Base Rate,
17 6. The current PSCR Loss Factor, and
18 7. The resulting PSCR Factor;

1 And the current PSCR Base Rate and Loss Factors that was established in Case No.
2 U-20276.

3 Lines 31 through 60 of Exhibit A-42 (NEB-7) show:

- 4 1. The forecasted Net PSCR Costs, which are equal to the PSCR costs of
5 generation, purchases, and transmission less
 - 6 a. Opportunity sales revenues,
 - 7 b. RTMP sales revenues,
 - 8 c. RTMP transmission revenues,
 - 9 d. Capacity sales revenues,
 - 10 e. REC sales revenues, and
 - 11 f. Ancillary services revenues.
- 12 2. Megawatt hours of Generation plus purchased power less,
 - 13 a. Opportunity sales, and
 - 14 b. RTMP sales,
- 15 3. The MWhs of System Requirement Sales subject to a PSCR Factor,
- 16 4. The average PSCR cost per MWh,
- 17 5. The new proposed PSCR Base Rate, and
- 18 6. The proposed PSCR Loss Factor

1 as forecasted for the UPPCO system for the 2027 test year.

2 **Q. What is UPPCO's current estimate of the PSCR Factor for 2027?**

3 A. As shown on line 28 of Exhibit A-42, UPPCO has forecasted a PSCR Factor of
4 positive \$24.46/MWh for 2027 based on the current PSCR Base Rate, the current
5 PSCR Loss Factor, and the forecast of fuel and purchased power costs in this
6 proceeding.

7 **Q. How does UPPCO propose to determine the new PSCR Base Rate for the**
8 **UPPCO system?**

9 A. UPPCO proposes to establish a new PSCR Base Rate to be equal to the Net PSCR
10 Costs divided by the MWhs of generation plus purchased power less opportunity
11 sales and RTMP sales, as forecasted for the UPPCO system for the 2027 test year.
12 Based on the net PSCR costs forecasted for 2027, the proposed PSCR Base Rate will
13 yield an expected PSCR Factor of zero.

14 **Q. What is the current PSCR Base Rate for the UPPCO system?**

15 A. The current PSCR Base Rate for the UPPCO system is \$42.90/MWh as shown on line
16 24 of Exhibit A-42.

17 **Q. What is the proposed new PSCR Base Rate for the UPPCO system?**

18 A. The proposed new PSCR Base Rate for the UPPCO system is \$65.93/MWh as shown
19 on line 54 of Exhibit A-42. This change is reflected on pages 4 and 5 in Schedule F5,
20 Exhibit A-16 (NEB-6).

1 UPPCO proposes to implement the new PSCR Base Rate beginning with the
2 first business month after the effective date of new base rates established in this
3 proceeding.

4 UPPCO also proposes to implement a revised PSCR factor beginning with the
5 first business month after the effective date of new base rates established in this
6 proceeding. The revised PSCR factor will be consistent with the approved PSCR
7 Base Rate and Loss Factor and based on the PSCR plan sales and power supply costs
8 used to establish the PSCR factor at that time.

9 **Q. What is UPPCO’s proposed new PSCR Factor for 2027?**

10 A. Based on UPPCO’s proposal to establish a new PSCR Base Rate based on the net
11 PSCR costs forecasted for 2027, the proposed PSCR Factor is \$0.00/MWh, as shown
12 on line 58 of Exhibit A-42.

13

14 **4. STATE RELIABILITY MECHANISM CAPACITY CHARGE**

15 **Q. Please explain UPPCO’s considerations related to establishing a State**
16 **Reliability Mechanism (“SRM”) capacity charge in this proceeding.**

17 A. Pursuant to Section 6w of Public Act 341 of 2016 (“PA 341”), an electric utility
18 must establish a SRM capacity charge that meets the following criteria:

19 Section 6w (3)(a) states that:

1 *“For the applicable term of the capacity charge, include the capacity related*
2 *generation costs included in the utility’s base rates, surcharges, and power*
3 *supply cost recovery factors, regardless of whether those costs result from*
4 *utility ownership of the capacity resources or the purchase or lease of the*
5 *capacity resource from a third party.”*

6 Section 6w (3)(b) states that:

7 *“For the applicable term of the capacity charge, subtract all non-capacity-*
8 *related electric generation costs, including, but not limited to, costs previously*
9 *set for recovery through net stranded cost recovery and securitization and the*
10 *projected revenues, net of projected fuel costs, from all of the following:*

11 *(i) All energy market sales.*

12 *(ii) Off-system energy sales*

13 *(iii) Ancillary services sales.*

14 *(iv) Energy sales under unit-specific bilateral contracts.”*

15 Furthermore, the Commission’s September 26, 2024, Order in Case No. U-21555
16 clarified that the next review of UPPCO’s SRM capacity charge will occur in the
17 Company’s next general rate case (i.e., the instant case), in a manner consistent with
18 the direct testimony and exhibits of Company witness Stocking in that case. The
19 method utilized to calculate the SRM capacity charge presented in this testimony is
20 consistent with the method specified in Case U-21555.

1 **Q. Please describe the resources relied upon by UPPCO to derive the “total**
2 **capacity related generation costs included in the utility’s base rates” as required**
3 **by the statute.**

4 A. UPPCO relied upon the Production Demand Component file of its projected test year
5 COSS study, sponsored here as Exhibit A-45 (NEB-8) – Production Demand
6 Component.

7 **Q. Please provide additional details related to Exhibit A-45 (NEB-8) – Production**
8 **Demand Component.**

9 A. Exhibit A-45 is a subset of the total projected test year COSS presented in the instant
10 case as Exhibit A-16 (EWS-2), Schedule F-1. Exhibit A-45 applies the same form
11 and calculation as the COSS but only incorporates cost items that are functionalized
12 as production demand related cost components, or said simply, costs that are
13 associated with the production of capacity, namely UPPCO’s owned generation
14 assets.

15 **Q. Please describe how UPPCO derived the “total capacity related generation costs**
16 **included in the utility’s base rates” as required by the statute.**

17 A. UPPCO relied upon the information contained in Exhibit A-45 to derive the various
18 components of “Capacity Related Revenue Requirement” that has been previously
19 included in the prior calculation of UPPCO’s capacity charge, specifically the MPSC
20 Staff’s calculation in Case No. U-18254. The components that comprise the

1 calculation of Capacity Related Revenue Requirement are as follows, and separately
2 listed on Exhibit A-46 (NEB-9) – State Reliability Mechanism Capacity Charge:

- 3 • Plant In Service (Production Demand Component)
- 4 • Depreciation Reserve (Production Demand Component)
- 5 • Construction Work in Progress (Production Demand Component)
- 6 • Materials & Supplies (Production Demand Component)
- 7 • Property, Payroll, & Income Tax (Production Demand Component)
- 8 • O&M Non Fuel (Production Demand Component)
- 9 • Depreciation Expense (Production Demand Component)
- 10 • Amortizations (Production Demand Component)
- 11 • Real Estate and Property Tax (Production Demand Component)
- 12 • Total Rate Base (Total Company, all cost components).

13 To derive the total generation cost as required by Section 6w(3)(a), UPPCO
14 mimicked the formula used to derive the same figure in Case No. U-18254, and Case
15 No. U-21555. Step one includes identifying the applicable net rate base amount,
16 calculated as the sum of Plant in Service, Depreciation Reserve, Construction Work
17 in Progress, Materials and Supplies, and Property, Payroll, and Income tax production
18 demand components defined above multiplied by the instant case required rate of
19 return.

1 Step two takes the result of step one, and adds O&M non-fuel, Depreciation Expense,
2 and Amortization production demand components as defined above.

3 Step three is to apportion the amount of Real Estate and Property Tax production
4 demand components as defined above by the ratio of production demand related net
5 rate base to the total rate base (including all cost components) and add the resulting
6 value to the results of step 2.

7 The resulting Capacity Related Revenue Requirement is described at line 23 of
8 Exhibit A-46 (NEB-9), totaling \$9.61 million for UPPCO's Total Integrated Retail
9 System.

10 **Q. Please describe how UPPCO calculated the required offsets to the Capacity**
11 **Related Revenue Requirement, as required by Section 6w(3)(b).**

12 A. The required 3(b) offsets require the Company to consider four factors: energy market
13 sales, off-system energy sales, ancillary services revenue, and energy sales under
14 unit-specific bilateral sales. I will address each of these items separately.

15 **Q. Please describe the Company's calculation of energy market sales that**
16 **are appropriate to be netted from the total Capacity Related Revenue**
17 **Requirement discussed above.**

18 A. Exhibit A-47 (NEB-10) – SRM 3(b) Offset Calculation provides a summary of the
19 market value associated with each of UPPCO's generation units, defined as hourly
20 production multiplied by the hourly LMP at the UPPC.Integrated pricing node. In
21 total, the market value of UPPCO's generation anticipated for the projected test year

1 totals \$6.01 million. The Company allocated the market value of UPPCO's
2 generation to customer classes by utilizing the firm 12CP allocator, as replicated at
3 line 40 of Exhibit A-46 (NEB-9).

4 **Q. Does UPPCO include the cost of its Purchased Power Agreements (“PPAs”) in**
5 **the formation of total Capacity Related Revenue Requirement?**

6 A. No. UPPCO's current PPAs are firm, energy only contracts. UPPCO does not pay
7 for capacity attributes through the terms or conditions of these PPA's, nor does
8 it acquire any capacity attributes as a result. Therefore, it is inappropriate to include
9 the cost of these PPAs in the formation of capacity related revenue requirement, and
10 it is consequently inappropriate to subtract any value associated with them pursuant
11 to the 3(b) offset requirements. At the time at which the Company receives energy
12 and capacity through a PPA that is tied to a specific generation resource, UPPCO
13 would capture the capacity-related portion of the payments under that PPA within this
14 calculation.

15 **Q. Please describe the Company's calculation of off-System energy sales that**
16 **are appropriate to be netted from the total Capacity Related Revenue**
17 **Requirement discussed above.**

18 A. UPPCO does not have any off-system energy sales.

19 **Q. Please describe the Company's calculation of ancillary service revenues that**
20 **are appropriate to be netted from the total Capacity Related Revenue**
21 **Requirement discussed above.**

1 A. Ancillary service revenue is depicted at page 29 of Exhibit A-16 (EWS-2), Schedule
2 F1, the projected test year COSS at line 18, Schedule REV. UPPCO applied the same
3 allocation of ancillary services revenue to customer classes that exists within the
4 COSS to the formation of the SRM Capacity Charge in Exhibit A-46 (NEB-9), as
5 shown by line 27.

6 **Q. Please describe the total SRM capacity charge as calculated by Exhibit A-46**
7 **(NEB-9).**

8 A. Exhibit A-46 (i) calculates the total Capacity Related Revenue Requirement at line
9 23, (ii) reflects the necessary 3(b) offsets at lines 25 through 29, and (iii) calculates
10 the net Capacity Related Revenue Requirement at line 31. At line 34 of Exhibit A-
11 46, the Net Capacity Related Revenue Requirement is divided by UPPCO's 2026/27
12 Summer Planning Reserve Margin Requirement ("PRMR") as submitted to the
13 Midcontinent Independent System Operators ("MISO") Module E process. This
14 calculation results in a SRM Capacity Charge of \$27,823 / MW-Year, or \$76.23 /
15 MW-Day.

16 **Q. Should the costs and revenue associated with providing service to UPPCO's Real**
17 **Time Market Pricing ("RTMP") customer be included in the derivation of the**
18 **SRM Capacity Charge?**

19 A. No. The RTMP customer takes service from UPPCO as a customer directly
20 interconnected with ATC, with energy rates equal to the applicable real time LMP,
21 and transmission rates equal to the transmission costs that the Company is billed from
22 the ATC and MISO. As such, and understanding that Commission precedent has

1 long held that RTMP power supply costs are segregated from full requirements
2 customer costs that are included in PSCR calculations, there is no basis to assign a
3 SRM capacity charge, based upon the embedded cost of UPPCO generation, to the
4 RTMP class rates.

5 Furthermore, the generation service to the RTMP customer is non-firm, and subject to
6 interruptions by UPPCO, the MISO, the ATC, or other regulating
7 authorities. Therefore, the RTMP customer load can be characterized as fully
8 interruptible. As a result, UPPCO does not incur any incremental purchased capacity
9 related costs through the process of serving the RTMP customer.

10 **Q. Please explain how the SRM Capacity Charges for each rate class calculated at**
11 **line 31 of Exhibit A-46 (NEB-9) are incorporated into the rate design schedules**
12 **sponsored by Company Witness Bell.**

13 A. As described in further detail in my testimony, the total power supply revenue
14 requirement reflected in Exhibit A-16, Schedule F3 (NEB-4) is apportioned to two
15 categories, Capacity Related and non-Capacity related. The Capacity related revenue
16 requirement is defined by the values included in Exhibit A-46, and the non-Capacity
17 related value is defined as the difference between the total power supply revenue
18 requirement established by the projected test year COSS and the rate class capacity
19 related revenue requirement.

20 **Q. Does the Company's proposal regarding the SRM capacity charge comport with**
21 **Section 6w of PA 341 of 2016, and with prior Commission directive and**
22 **precedent related to the calculation of this value.**

1 A. Yes, the Company’s proposal is consistent with guidance provided by both the statute
2 and the Commission. Further, paragraph 8(c) of the settlement agreement resolving
3 all issues in Case No. U-21555, which was approved by Commission order on
4 September 26, 2024, stated that “UPPCO will adopt the State Reliability Mechanism
5 (“SRM”) capacity charge calculation method supported in the Direct Testimony and
6 Exhibits of Eric Stocking.”⁸

7 **Q. Is your proposed method for calculating the SRM capacity charge in this**
8 **proceeding consistent with the method that you proposed in your direct**
9 **testimony and exhibits in Case No. U-21555?**

10 A. Yes, it is.

11

12

13 **5. Residential Income Assistance Program**

14 **Q. Please describe the authorized participation in the Company’s Residential**
15 **Income Assistance (“RIA”) program.**

16 A. Please refer to the Commission’s March 24, 2023 order approving settlement in Case
17 No. U-21286. Specifically, paragraph 9 (j)(3) describes that the costs for the
18 program, to be included in the calculation of rates, based upon an assumed RIA
19 participation of 1,500 per month.

20 **Q. Please describe the actual participation in the RIA program in 2025.**

1 A. Table 1 below outlines the actual monthly participation in the Company's RIA
2 program.

	RIA Participation	
	Credits	Amount
Jan-25	1235	\$ 18,390
Feb-25	1235	\$ 18,360
Mar-25	1260	\$ 18,675
Apr-25	1223	\$ 18,143
May-25	1185	\$ 17,610
Jun-25	1346	\$ 20,055
Jul-25	1224	\$ 18,240
Aug-25	1154	\$ 17,160
Sep-25	1304	\$ 19,350
Oct-25	1253	\$ 18,570
Nov-25	1191	\$ 17,760
Dec-25	1373	\$ 20,445
Average	1249	\$ 18,563

3

4 The Company notes that an assumed participation level of 1,500 has been consistent
5 with the actual participation experienced since implementing this tariff provision.

6 **Q. Is the Company proposing an adjustment to the assumed RIA participation rate**
7 **for the purpose of ratemaking in this proceeding?**

8 A. No.

9 **Q. Does this complete your direct testimony in this proceeding?**

10 A. Yes, it does.

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

This form is issued as provided for by 1939 PA 3, as amended, and by 1933 PA 254, as amended. The filing of this form, or an acceptable alternative, is necessary to ensure subsequent service of any hearing notices, Commission orders, and related hearing documents.

General Instructions:

Type or print legibly in ink. For assistance or clarification, please contact the Public Service Commission at 517-284-8090.

*Please Note: The Commission will provide **electronic** service of documents to all parties in this proceeding.*

THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Upper Peninsula Power Company Docket No. U- 22032

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Peninsula Power Company
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Sherri A. Wellman
Address Miller Canfield
123 West Allegan Street, Suite 200
City Lansing State MI
Zip 48933 Phone 517-483-4954
Email wellmans@millercanfield.com
Date 05/22/2026

<input type="radio"/> I am not an attorney
<input checked="" type="radio"/> I am an attorney whose:
Michigan Bar # is P- <u>38989</u>
_____ Bar # is: _____
(state)

Signature: _____

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

This form is issued as provided for by 1939 PA 3, as amended, and by 1933 PA 254, as amended. The filing of this form, or an acceptable alternative, is necessary to ensure subsequent service of any hearing notices, Commission orders, and related hearing documents.

General Instructions:

Type or print legibly in ink. For assistance or clarification, please contact the Public Service Commission at 517-284-8090.

*Please Note: The Commission will provide **electronic** service of documents to all parties in this proceeding.*

THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Upper Peninsula Power Company Docket No. U- 22032

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Peninsula Power Company
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Paul M. Collins
Address Miller Canfield
123 West Allegan Street, Suite 200
City Lansing State MI
Zip 48933 Phone 517-483-4908
Email collinsp@millercanfield.com
Date 05/22/2026

<input type="radio"/> I am not an attorney
<input checked="" type="radio"/> I am an attorney whose: Michigan Bar # is P- <u>69719</u> _____ Bar # is: _____ (state)

Signature: _____

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)	
UPPER PENINSULA POWER COMPANY)	Case No. U-22032
for authority to increase its rates for)	
the generation and distribution of)	
<u>electricity and other relief.</u>)	

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
 COUNTY OF INGHAM)

Victoria Seyfried, being first duly sworn, deposes and states that on May 22, 2026, she served Upper Peninsula Power Company’s direct case, as electronically filed on this date, upon the parties listed on the attached Service List via electronic mail.

Victoria Seyfried

Subscribed and sworn to before me
on this 22nd day of May, 2026.

 Kacey O’Neill, Notary Public
 State of Michigan, County of Livingston
 My Commission Expires: 12/26/2026
 Acting in the County of Ingham

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of)
UPPER PENINSULA POWER COMPANY) Case No. U-22032
for authority to increase its rates for)
the generation and distribution of)
electricity and other relief.)

SERVICE LIST

Attorney General Dana Nessel

Michael E. Moody
Holly L. Hillyer
Moodym2@michigan.gov
ag-enra-spec-lit@michigan.gov
holly@tropospherelegal.com

CUB/CARE

John R. Liskey
Christopher M. Bzdok
john@liskeypllc.com
chris@tropospherelegal.com

**Association of Businesses Advocating
Tariff Equity (ABATE)**

Michael Pattwell
Stephen A. Campbell
mpattwell@clarkhill.com
scampbell@clarkhill.com

Billerud Americas Corporation

Timothy J. Lundgren
Justin K. Ooms
tjlundgren@varnumlaw.com
jkooms@varnumlaw.com

**Calumet Electronics Corporation and
Michigan Technological University**

Olivia R.C.A. Flower
Kyle M. Asher
Hannah E. Buzolits
oflower@dykema.com
kasher@dykema.com
hbuzolits@dykema.com