Founded in 1852
by Sidney Davy Miller

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May 1, 2024

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing MI 48917

Re: Upper Michigan Energy Resources Corporation
Case No. U-21541

Dear Ms. Felice:

Enclosed for electronic filing on behalf of Upper Michigan Energy Resources Corporation in the above-captioned case are the following:

(1) Application;
(2) Proposed Notice of Hearing;
(3) Certification of Richard F. Stasik;
(4) Index of Exhibits;
(5) Direct Testimony and Exhibits of Richard F. Stasik, Anthony Reese, Jared J. Peccarelli, Ann E. Bulkley, Aaron L. Nelson, and James M. Beyer.
(6) Non-confidential documentation which complies with Part II of the Rate Case Filing Requirements established by the Commission's Order dated May 18, 2023, issued in Case No. U-18238;
(7) Proposed Protective Order;
(8) Appearances of Sherri A. Wellman, Paul M. Collins, and Benjamin J. Holwerda; and
(9) Proof of Service reflecting electronic service on the Staff case coordinator and intervenors in Case Nos. U-15351, U-15981, U-16830, U-17669, and U-18061.

Concurrently with this filing, the Staff case coordinator and the parties to Case Nos. U-U-15351, U-15981, U-16830, 17669, and U-18061 are being provided all exhibits and non-confidential workpapers in native format with all formulae intact, as well as non-confidential documentation addressing Part III of the Rate Case Filing Requirements approved in Case No. U-18238, via the following secure portal link:

https://filelocker.mcps.com/pickup?claimID=rU5JE7dB2CGKQNeK&claimPasscode=i4jwP8h85ACaHbjH&emailAddr=39259

Claim ID: rU5JE7dB2CGKQNeK
Claim Passcode: i4jwP8h85ACaHbjH

Finally, as requested by the Staff case coordinator, four hard copies of this filing and one hard copy of non-confidential workpapers will be directly served on the case coordinator.

Should you have any questions, please kindly advise.

Very truly yours,

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

By: Sherri A. Wellman Digitally signed by: Sherri A. Wellman DN: CN = Sherri A. Wellman email = wellmans@millercanfield.com C = AD O = Miller Canfield Date: 2024.05.01 15:21:45 -04'00'

Sherri A. Wellman

SAW/vs
Enclosures
cc w/enc: Richard Stasik (Richard.Stasik@wecenergygroup.com)
Koby Bailey (Koby.Bailey@wecenergygroup.com)
Theodore Eidukas (Theodore.Eidukas@wecenergygroup.com)

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
UPPER MICHIGAN ENERGY RESOURCES	)	Case No. U-21541
CORPORATION for authority to increase electric	)	
rates and for other relief.	)	

APPLICATION

Upper Michigan Energy Resources Corporation ("UMERC" or the "Company") hereby requests authority from the Michigan Public Service Commission ("MPSC" or the "Commission") to increase rates for retail electric service and for related relief, and in support thereof respectfully represents as follows:

I. INTRODUCTION

1. UMERC is a public service corporation organized under the laws of the State of Michigan, and, in addition to providing natural gas service in Menominee county, UMERC provides retail electric service in cities, villages, and townships in the counties of Alger, Baraga, Delta, Dickinson, Gogebic, Houghton, Iron, Marquette, Menominee, and Ontonagon. UMERC currently provides retail electric service to approximately 37,000 customers.

2. UMERC is a corporation organized under the laws of the state of Michigan, with its principal offices located in Milwaukee, Wisconsin, and with service centers located at 800 Industrial Park Drive, Iron Mountain, Michigan, and 1717 Tenth Avenue, Menominee, Michigan. UMERC is a subsidiary of WEC Energy Group, Inc ("WEC"[1]).

[1] Previously, WEC was known as Wisconsin Energy Corporation.

3. UMERC'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.; 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq; 1969 PA 419, as amended, MCL 24.201 et seq.; and the Michigan Administrative Hearing System's Administrative Hearing Rules, R 792.10401 et seq. Pursuant to these statutory provisions, the Commission has power and jurisdiction to regulate UMERC's retail electric rates for service rendered in the State of Michigan.

4. On August 6, 2014, in Case No. U-17682, Wisconsin Energy Corporation ("WE Corp") and Integrys Energy Group, Inc. sought approval pursuant to MCL 460.6q, for the transfer of control of Wisconsin Public Service Corporation ("WPS Corp") and Michigan Gas Utilities Corporation from Integrys to WE Corp. On April 23, 2015, the Commission issued its Order Approving Amended and Restated Settlement Agreement ("ARSA"), approving the requested transfer while acknowledging at paragraph 6g of the ARSA, WE Corp's intention to petition the Commission for the creation of a Michigan-only jurisdictional utility and a commitment to pursue a "long-term solution" and invest in new Upper Peninsula ("UP") electric generation.

5. Pursuant to the understandings reached in the ARSA, on June 14, 2016, Wisconsin Electric Power Company ("WEPCO")[2] and WPS Corp[3] on behalf of their parent corporation, WEC, filed their application in Case No. U-18061 seeking all necessary approvals to establish UMERC as a jurisdictional utility serving electric and natural gas customers only in Michigan, and as part of the establishment of UMERC, WEPCO and WPS Corp advised they would transfer

[2] WEPCO at this time provided retail electric service in both Wisconsin and Michigan.

[3] WPS Corp at this time provided retail electric and natural gas service in both Wisconsin and Michigan.

distribution assets located in Michigan to UMERC and cease to serve in Michigan. On December 9, 2016, the Commission issued its Order Approving Settlement Agreement in Case No. U-18061, which approved the formation of UMERC as a Michigan-only jurisdictional utility authorized to (i) provide electric service to all retail customers within the Michigan service territory of Wisconsin Electric Power Company ("WEPCO") and (ii) provide electric and natural gas service to all retail customers within the Michigan service territory of WPS Corp.[4]

6. The approved Settlement Agreement in Case No. U-18061, among other things, directed UMERC to adopt: (i) WEPCO's current Michigan tariff base electric rates for purposes of providing service to former WEPCO Michigan customers in UMERC's WEPCo Rate Zone and, (ii) WPS Corp's current Michigan tariff base electric and natural gas rates for service to customers in UMERC's WPSC Rate Zone. The WEPCO base electric rates adopted by UMERC for its WEPCo Rate Zone were last approved by the Commission in its Opinion and Order issued June 12, 2012, in Case No. U-16830, as based on a 2012 test year and an authorized rate of return on common equity of 10.10%. The WPSC Corp base electric rates adopted by UMERC for its WPSC Rate Zone were last approved by the Commission in its Order Approving Settlement Agreement issued on April 23, 2015, in Case No. U-17669, as based on a 2015 test year and an authorized rate of return on common equity of 10.20%.

7. On October 25, 2017, the Commission issued its Opinion and Order in Case No. U-18224, taking up the long-term generation solution for the UP, and granting certificates of public necessity to UMERC to design, construct, own, and operate Reciprocating Internal Combustion Engine ("RICE Units") electric generation units in Baraga Township, Baraga County, and

[4] Initially, Tilden Mining Company L.C. ("Tilden") and Empire Iron Mining Partnership ("Empire") (jointly the "Mines") continued to receive electric service from WEPCO. Empire ceased operations prior to 2019.

Negaunee Township, Marquette County, and finding that the RICE units represented "the most reasonable and prudent means of meeting the power need." Additionally, the Commission approved the Retail Large Curtailable Special Contract ("Tilden Special Contract") between UMERC and Tilden.

8. On March 31, 2019, UMERC began commercial operation of the RICE Units, and on that same day WEPCO's Presque Isle Power Plant was retired from service. Additionally, pursuant to Commission directives and contractual terms, effective April 1, 2019, WEPCO transferred service of Tilden to UMERC and UMERC began providing electric service under the Tilden Special Contract as approved in Case No. U-18224.[5]

9. On December 28, 2023, UMERC filed its rate Filing Announcement in this docket pursuant to the Rate Case Filing Requirements established by the Commission's May 18, 2023 Order in Case No. U-18238.

II. REQUESTED BASE RATE INCREASE

10. This is UMERC's first electric base rate case. UMERC's rates for retail electric service were last established by the Commission in 2012 for the WEPCo Rate Zone and in 2015 for the WPS Corp Rate Zone. UMERC's rates for retail electric service established in Case Nos. U-16830 and U-17669 do not reflect the current cost of providing retail electric service and UMERC requires rate relief.

11. Based on 2025 projected costs of providing service to the UMERC's customers, the Company's existing retail base rates for electric services will be unreasonably low, inadequate

[5] Pursuant to its February 20, 2020 Order in Case No. U-20643, the Commission approved the First Amendment to the Special Contract.

and preclude the Company from earning a reasonable return on its investments to provide service to customers. An increase in electric rates is critical to allow UMERC to continue to provide safe and reliable electric service to meet service quality and reliability expectations.

12. Additionally, this rate filing presents data for a historical year ended December 31, 2022, as required by the rate case filing requirements. UMERC proposes that electric rates be established based upon a projected test year ending December 31, 2025. The use of this projected test year data allows the revised electric base rates established in this case to more closely reflect the conditions that will likely exist at and after the time the revised base rates set by the final order in this case are placed in effect.

13. Several factors have, and are expected to continue to have, a significant impact on the Company's costs of providing service to its electric customers. The key drivers for this request include (i) needed infrastructure investments in new Upper Peninsula electric generation as envisioned by the Commission in Case No. U-17682, as well as to maintain reliability and safety; (ii) inflation inclusive of projected inflation for 2025 (4.56% for labor and 2.35% for non-labor); (iii) changes in capitalization and increased interest costs; (v) increased property tax expense; and (vi) a forecasted decrease in sales volumes due to customers choosing to take retail access services.

14. Based on a 2025 test year, the Company is requesting an annual base rate revenue increase of $11,162,357 for non-Tilden customers.[6] This revenue increase reflects the proposed depreciation rates for the RICE Units requested in Case No. U-21542. The Company's filing also includes alternative exhibits reflecting an annual base rate revenue increase without the requested depreciation rates. The 2025 test year annual base rate revenue increase of $11,162,357 for non-

[6] The total UMERC electric revenue requirement impact is $8.3 million before adjusting for the impact of the Tilden Special Contract approve by the Commission in Case No. U-18224.

Tilden customers represents the results of a complete examination of the relevant items of investment, expenses, and revenues for the determination of just and reasonable retail electric service rates for UMERC's customers.

15. UMERC proposes that retail electric service rates be established to a rate of return on common equity of 10.25% resulting in an overall rate of return of 6.56%.

16. UMERC represents that the proposed annual base rate revenue increase of $11,162,357 for non-Tilden customers is required for the Company to provide reliable electric service in Michigan and a reasonable opportunity to earn the return to which the Company is entitled by law.

III. RATE DESIGN, TARIFF AND OTHER RATE-RELATED PROPOSALS

17. UMERC proposes to (i) implement a rate realignment factor to make the rates in the WEPCo and WPSC Rate Zones equal over time, (ii) implement a low income assistance (LIA) and senior credit as part of this rate case, (iii) discontinue residential and commercial direct load control programs due to equipment surpassing its end of life, (iv) close all non-LED lighting rate schedules due to lack of non-LED lighting availability, (v) implement a single new PSCR Loss Factor and single new PSCR Base Rate for both rate zones, (vi) terminate the Tax Cuts and Jobs Act of 2017 credits, and (vii) implement an inflow / outflow parallel generation rate schedule to replace the net metering rate schedule.

18. UMERC's proposed rates for each customer class rate schedule are reflected in Exhibit A-16, Schedule F5. These rates are designed to recover the annual base rate revenue increase of $11,162,357 for non-Tilden customers.

19. UMERC proposes to change the PSCR Base Rate and Loss Factor to $57.10/MWh and $1.0391/MWh respectively.

20. In addition, UMERC is seeking miscellaneous revisions to the terms and conditions of its tariffs.

21. UMERC proposes to implement its revised rates no earlier than January 1, 2025, and no later than the day after the Commission issues an order approving UMERC's request, if an order is issued after January 1, 2025.

IV. TESTIMONY AND EXHIBITS

22. This Application is accompanied and supported by the written testimony, exhibits and workpapers of six Company witnesses. The Company's presentation in this case was prepared in accordance with the Rate Case Filing Requirements of Case No. U-18238 as approved in the Commission's May 18, 2023 Order and consistent with the temporary waiver relating to Part III.[7] UMERC is also filing a proposed Protective Order to govern the release, use and disclosure of certain testimony, exhibits, workpapers, and responses in Part III of the Rate Case Filing Requirements that contain confidential information, or in future responses to audit inquiries and discovery.

V. REQUEST OF RELIEF

23. UMERC's current electric service rates, based on the projected 2025 test year, will be unjust and unreasonable. Such rates are insufficient to permit the Company to recover the costs of providing service to its customers, including a reasonable return on investments to provide such service, to which UMERC is entitled by law. UMERC's retail electric service rates are expected to be so low as to deprive it of a reasonable return on investments to provide such service to which UMERC is entitled by law. UMERC's retail electric service rates are expected to be so low as to

[7] The Company will not submit as part of Part III, the information called for in new Attachments 14, 15, 16 and 17.

deprive it of a reasonable return on its property and will amount to confiscation of the Company's property contrary to UMERC's rights under the Constitution of the United States and the Constitution and laws of the State of Michigan. The inadequacy of these rates reduces the Company's revenues and overall rate of return below a proper and reasonable level, and it is unjust and unreasonable to require UMERC to render electric service to its customers at such rates.

WHEREFORE, Upper Michigan Energy Resources Corporation requests the Commission to:

A. Issue and publish its notice of hearing setting an early hearing date;

B. Find and determine as based on the Company's direct case that for service rendered beginning January 1, 2025, existing rates and charges are unreasonably low and inadequate and should be increased to protect the constitutional rights of the Company to earn a reasonable and non-confiscatory return;

C. Authorize the Company to adjust its existing rates and charges so as to produce an annual increase in base rate revenue of not less than $11,162,357 for non-Tilden customers;

D. Approve changes in charges and terms and conditions of service as addressed in the supporting testimony and exhibits;

E. Authorize all other changes and suggestions made and supported in the Company's testimony and exhibits and as address in this Application; and

G. Grant such other and further relief as may be lawful and proper.

Respectfully submitted,

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Dated: May 1, 2024

By: Sherri A. Wellman

Digitally signed by: Sherri A. Wellman
DN: CN = Sherri A. Wellman
email = wellmans@millercanfield.com C = AD O = Miller Canfield
Date: 2024.05.01 15:22:05 -04'00'

One of its Attorneys
Sherri A. Wellman (P38989)

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One Michigan Avenue, Suite 900
Lansing, MI 48933
(517) 487-2070

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

NOTICE OF HEARING
FOR THE ELECTRIC CUSTOMERS OF
UPPER MICHIGAN ENERGY RESOURCES CORPORATION
CASE NO. U-21541

- Upper Michigan Energy Resources Corporation requests Michigan Public Service Commission approval to increase its retail electric rates and for related relief.

- The information below describes how a person may participate in this case.

- You may call or write Upper Michigan Energy Resources Corporation, 800 Industrial Park Drive, Iron Mountain, Michigan, (800) 242-9137, or 1717 Tenth Avenue, Menominee, Michigan 49858, (800) 450-7260, for a free copy of its application. Any person may review the application at the offices of Upper Michigan Energy Resources Corporation or on the Commission's website at: michigan.gov/mpscedockets.

- The prehearing conference in this matter will be held:

DATE/TIME:	**__________, ________, 2024, 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 Michigan Energy Resources Corporation's (UMERC) May 1, 2024 application for approval to increase its existing rates and charges for retail electric service. UMERC requests Commission approval to: 1) annually increase retail electric base rate revenue by $11,162,357; 2) adjust its existing retail electric service so as to produce a return on common equity of not less than 10.25%; 3) make effective no later than January 1, 2025, its proposed increase to annual revenue, and approve other modifications to the rates, rules, and regulations; and 4) all other changes and suggestions made and supported in UMERC's testimony and exhibits.

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 **____________, 2024**. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon UMERC's attorney, Sherri A. Wellman, Miller, Canfield, Paddock & Stone, P.L.C., One Michigan Avenue, Suite 900, 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-21541**. 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 UMERC's request may be reviewed on the Commission's website at: michigan.gov/mpscedockets and at the office of Upper Michigan Energy Resources Corporation. 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.

__________, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
UPPER MICHGAN ENERGY RESOURCES	)	
CORPORATION for authority to increase electric	)	Case No. U-21541
rates and for related relief.	)	

CERTIFICATION OF RICHARD F. STASIK

Richard F. Stasik, Director-State Regulatory Affairs WEC Energy Group ("WEC"), states that, other than the new Part III requirements that are subject to the temporary waiver and specifically identified in the Application, he has provided the data required pursuant to the Rate Case Filing Requirements established by the Commission's order dated May 18, 2023, issued in Case No. U-18238, and pursuant to these requirements, certifies the data so provided on behalf of Upper Michigan Energy Resources Corporation, a subsidiary of WEC.

Dated: May 1, 2024

____
Richard F. Stasik

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase retail electric rates and for other relief.	)))))	Case No. U-21541

DIRECT TESTIMONY AND EXHIBIT OF
RICHARD F. STASIK

FOR

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

May 1, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase retail electric rates and for other relief.	)	Case No. U-21541

QUALIFICATIONS
OF
RICHARD F. STASIK
PART I

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard F. Stasik. My business address is WEC Energy Group, 231 West Michigan Street, Milwaukee, Wisconsin 53203.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am Director – State Regulatory Affairs at WEC Energy Group ("WEC"). WEC is the parent company of Upper Michigan Energy Resources Corporation ("UMERC" or the "Company").

Q. PLEASE ADDRESS YOUR RESPONSIBILITIES AS DIRECTOR – STATE REGULATORY AFFAIRS AT WEC.

A. On behalf of WEC, I oversee state regulatory rate reviews, policy, and advocacy efforts, including proceedings before Michigan Public Service Commission ("MPSC" or the "Commission") and regulatory bodies in other states, including Wisconsin and Minnesota. I also act as one of the lead witnesses for WEC's operating utility subsidiaries in those proceedings.

Q. WHAT IS YOUR EDUCATIONAL AND BUSINESS EXPERIENCE?

A. I hold a bachelor's degree, summa cum laude, in accounting and management information systems from the University of Wisconsin – Milwaukee and am a licensed Certified Public Accountant in the State of Wisconsin. Before joining WEC's regulatory team, my current role, in 2016 I was the IT Audit Manager at WEC starting in 2013. Prior to that I held internal and external audit positions in public accounting and companies in the financial services, manufacturing and health care industries for more than ten years.

Q. ON WHOSE BEHALF ARE YOU OFFERING THIS DIRECT TESTIMONY?

A. I am offering this direct testimony on behalf of UMERC.

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY AGENCY?

A. Yes. I have sponsored direct testimony before the MPSC in the annual State Reliability Mechanism charge proceedings for UMERC in Case Nos. U-20751, U-21103, and U-21222. I have also sponsored (i) direct and rebuttal testimony on behalf of UMERC in its Integrated Resource Plan filing in Case No. U-21081, and (ii) direct testimony on behalf of UMERC addressing the Company's preferred criteria for Legally Enforceable Obligations in Case No. U-21130. Finally, I have provided direct testimony on behalf of Michigan Gas Utilities Corporation ("MGUC") in its last general rate case, U-21366.

Outside of Michigan, I have sponsored testimony to the Federal Energy Regulatory Commission on rate and accounting issues associated with WEC's retired power plant cases (Docket Nos. ER19-226-000, AC19-49-000, AC18-231-000, and ER19-103-000) and to the Public Service Commission of Wisconsin on rate-making issues in rate cases (Docket Nos. 5-UR-109, 5-UR-110, 6690-UR-126, and 6690-UR-127).

RICHARD F. STASIK
DIRECT TESTIMONY
PART II

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide (i) an overview of UMERC, (ii) background on UMERC's formation as a Michigan-only jurisdictional utility effective January 1, 2017, (iii) background on UMERC's construction of the Reciprocating Internal Combustion Engine ("RICE") units which were placed in service in March 2019, (iv) cost allocation implications of the RICE units and the current Tilden Mining Company L.C., ("Tilden") Special Contract on UMERC's non-Tilden retail electric customers, (v) background on WEC and WEC Business Services ("WBS") and how each of these entities support UMERC's operations, (vi) key corporate initiatives for 2025, and (vii) UMERC's 2025 projected test year, including a summary of new matters that begin with the projected test year and their impact on UMERC's test year forecast. Lastly, I will introduce the remaining Company witnesses that further support UMERC's electric rate increase request.

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

A. Yes. I am sponsoring one Exhibit. A-20, which is a copy of the WEC Affiliated Interest Agreement ("AIA") that was presented to the Commission in Case U-18061 and is the basis for cross charging between affiliated entities within the WEC corporate structure.

Q. Did you prepare, and/or supervise the preparation of, this exhibit?

A. Yes.

<u>UMERC Overview</u>

Q. Please describe UMERC.

A. As will be described in greater detail later in my direct testimony, pursuant to the Commission's December 9, 2016 Order Approving Settlement Agreement in Case No. U-18061, UMERC was formed as a Michigan only jurisdictional electric and gas utility effective January 1, 2017, by transferring the Michigan operations and select assets of Wisconsin Electric Power Company ("Wisconsin Electric") and Wisconsin Public Service Corporation ("WPS Corp.") to UMERC.

UMERC continues to operate as a separate utility under parent company WEC, serving approximately 37,500 electric and 5,000 natural gas customers in the Upper Peninsula of Michigan.

UMERC's electric service territory is currently segmented into two rate zones. One rate zone, known as the WEPCo Rate Zone, covers customers previously served by Wisconsin Electric and the other rate zone, known as the WPSC Rate Zone, covers customers previously served by WPS Corp. The WEPCo Rate Zone encompasses approximately 28,000 electric retail customers in approximately 60 municipalities in Alger, Baraga, Delta, Dickinson, Goegebic, Houghton, Iron, Marquette, Menominee, and Ontonagon Counties. The WEPCo Rate Zone service territory map is show in Figure 1 below. The WPSC Rate Zone encompasses approximately 9,500 electric retail customers in approximately 15 municipalities in Menominee County. The WPSC Rate Zone service territory map is show in Figure 2 below.

Figure 1 – UMERC WEPCo Rate Zone Service Territory Map

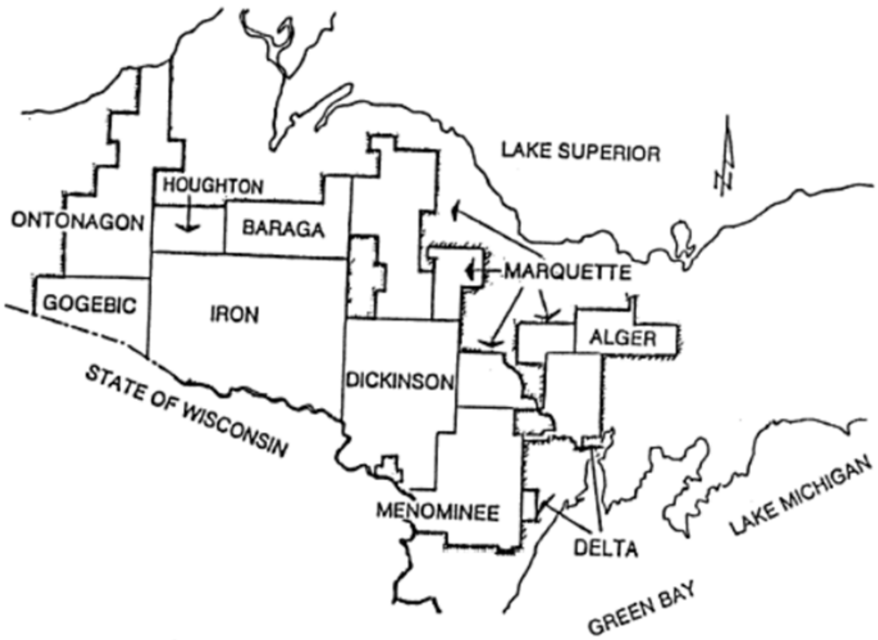


Figure 2 – UMERC WPSC Rate Zone Service Territory Map

UMERC Formation

Q. What was the basis for the creation of UMERC?

A. On August 6, 2014, in Case No. U-17682, MPSC approval was sought pursuant to MCL 460.6q., for the transfer of control of WPS Corp to WEC. On April 23, 2015, the Commission issued its Order Approving Amended and Restated Settlement Agreement ("ARSA") which among other things, approved the transfer and acknowledged WEC's intention to petition the Commission for the creation of a Michigan-only jurisdictional utility and the commitment to pursue a generation solution for the Upper Peninsula ("UP") of Michigan. Subsequently, consistent with the ARSA, UMERC's formation was authorized by the MPSC in Case No. U-18061.

Q. When UMERC was formed did UMERC hire employees to serve customers?

A. No. UMERC was formed by transferring the Michigan electric operations of Wisconsin Electric and WPS Corp, as well as the Michigan natural gas operations of WPS Corp to UMERC. Prior to UMERC's formation, Wisconsin Electric and WPS Corp operated as multi-jurisdictional utilities where the same individuals that provided utility service to customers in Wisconsin also performed services in Michigan, and the vast majority of those employees worked in Wisconsin. This method of operating resulted in a synergy of cost savings; in other words, there was an avoidance of duplication. Additionally, prior to UMERC's formation, Michigan customers were served by generation owned and operated by Wisconsin Electric and WPS Corp and paid for the "slice of system", including operating costs for those utilities' generation fleets.

At the time of UMERC's formation, new staff was not hired to serve UMERC's customers. To that end, WEC submitted for Commission review in Case U-18061 the AIA that covered services, including staff, that affiliate entities are authorized to provide services to UMERC. The primarily affiliated entities providing service to UMERC are Wisconsin Electric, WPS Corp and WBS.

Q. Have the methods used to cross charge costs between affiliated entities changed since the AIA was reviewed?

A. No. These methods remain the same as they were when the Commission reviewed the AIA in Case No. U-18061. When reasonable and practical, costs, including labor costs, are directly charged to the entity receiving the services from an employee of the affiliated entity. This is accomplished through a time tracking system where employees track the time they spent on activities performed and based on how employees charge their time, their labor costs are transferred through WEC's accounting system, SAP, to the utility for which the work was performed.

All benefits costs associated with the labor that is cross charged between utilities are captured in the benefits loader that is accumulated for all time charged in a given reporting period. These costs are then accumulated for the reporting period and charged to the utility for which work is performed as a non-labor cost.

Q. If UMERC doesn't have employees, how does it have labor costs?

A. TUMERC is cross charged for any labor performed on its behalf by employees of WEC affiliate entities per the terms of the AIA. Details on the mechanics of how these cross charges are reflected in UMERC's test year forecasted financial statements. which can be found in witness Reese's testimony.

Q. Please describe the assets and customers that were transferred to UMERC when it was formed on January 1, 2017?

A. All Michigan based electric distribution assets of Wisconsin Electric and WPS Corp, as well as the Michigan- based gas distribution assets and a former – and fully-remediated – manufactured gas plant owned by WPS Corp, were transferred to UMERC. Importantly, no electric generation assets were transferred to UMERC by either Wisconsin Electric or WPS Corp.

As of the date of UMERC's formation, 36,500 full service retail electric customers, 5,300 gas customers, 66 electric choice customers, and 17 gas transportation customers were transferred to UMERC from Wisconsin Electric and WPS Corp. No wholesale customers were transferred to UMERC.

Wisconsin Electric transferred to UMERC the substations, distribution lines, and other distribution assets used in providing retail electric service to Tilden and the Empire Mine ("the Mines") in Michigan. However, at the time of UMERC's formation, Wisconsin Electric continued to serve the Mines (retaining the right to use those distribution assets) until the termination of the 2015-2019 Large Curtailable Special Contracts between Wisconsin Electric and the Mines approved in the April 23, 2015 order in Case No. U-17682 ("Mines Special Contracts"), at which time Wisconsin Electric committed to transfer the Mines as customers to UMERC. This subsequently occurred in 2018 after UMERC completed the construction of the RICE generation units and placed them into service.

Q. What was the basis of the value of the assets transferred from Wisconsin Electric and WPS Corp to UMERC?

A. All of the Michigan electric distribution assets of Wisconsin Electric and WPS Corp, as well as the Michigan gas distribution assets of WPS Corp, were transferred to UMERC at net book value. At the time of the transfer, the actual original historical plant in-service cost and accumulated depreciation at the time of the transfer were transferred to UMERC.

Other transferred assets included existing construction work in progress ("CWIP"), accounts receivable net of an allowance for uncollectibles, and regulatory assets that are specific to the Michigan jurisdiction and various Michigan receivables were also transferred from Wisconsin Electric and WPS Corp at each asset's respective net book value with both the actual original historic beginning balance as well as any accumulated amortization being transferred to UMERC.

Q. If no generation assets were transferred to UMERC from Wisconsin Electric or WPS Corp, how did UMERC supply electric energy and the corresponding generation capacity to customers after UMERC was formed?

A. In Case U-18061, UMERC proposed and the Commission approved two Purchase Power Agreements ("PPAs"), one with Wisconsin Electric for the WEPCo Rate Zone (the "Wisconsin Electric PPA"), and one with WPS Corp WPSC Rate Zone (the "WPS Corp PPA").

These PPAs provided to UMERC customers a "slice of" Wisconsin Electric and WPS Corp generation system. The charges associated with these PPAs were structured to be similar to the costs UMERC customers would have been responsible for if the costs had been allocated as part of a retail rate case. The PPAs were formula-based, with two formulas– one for capacity costs and one for energy costs.

These PPAs were never intended to be a long-term generation solution for UMERC. Rather, they were intended to serve as "a bridge" until a long-term UP energy solution could be built and placed into operation. This long-term UP energy solution, as agreed to in the ARSA from Case U-17682 was realized through the development, construction and placing in service of the UP RICE Units and a new Special Contract with Tilden, which were reviewed and approved by the Commission in its Opinion and Order in Case U-18224 on October 25, 2017.

<u>**RICE Units Approval, Construction and In-Service**</u>

Q. If UMERC customers were being provided energy and capacity through the Wisconsin Electric PPA and WPS Corp PPA, why did UMERC seek approval to construct the RICE Units?

A. As referenced in the Order in Case U-18061, these PPAs were intended to serve as a "bridge" until a long-term UP generation solution could be achieved. As recognized by the Commission, the RICE Units were the cornerstone of the comprehensive UP generation solution to replace the Presque Isle Power Plant (PIPP) with a cleaner energy source and remain so to this day. Once the UP generation solution was determined after working with stakeholders, which included the Governor's office and the Commission, UMERC filed for approval of the UP energy solution in Case No. U-18224, specifically seeking approval of:

- A certificate of necessity ("CON") pursuant to MCL 460.6s for two RICE generation facilities located in the UP – (i) the 128.1 MW F. D. Kuester Generating Station located in Negaunee Township, and (ii) the 54.9 MW A.J. Mihm Generating Station located in Baraga Township.;
- A certificate of public convenience and necessity pursuant to MCL 460.502;
- A special contract with Tilden (hereafter the "Tilden Special Contract"); and,
- Related accounting and ratemaking authority—specifically, authorization for 100% deferred return on CWIP by accruing AFUDC on the entire CWIP balance during the construction period.

Q. What benefits of the UP RICE Units and the Tilden Special Contract were identified in Case U-18224?

A. The UP RICE Units would eliminate the need for $373 million in major transmission network upgrade expenditures, including the MISO Board-approved transmission project "Plains to National 138 kV transmission" project, and another proposed project in the MISO project database, the "Lakota to Winona line rebuild from 69 kV to 138 kV.

MPSC Staff supported Commission approval of the UP RICE Units and the Tilden Special Contract, agreeing with UMERC that the approvals would provide significant benefits to non-Tilden customers, as compared to the current power supply agreements and would reduce non-Tilden customers' risk exposure. Staff specifically stated that UMERC's non-Tilden customers will save $161 million in net present value ("NPV") over 30 years compared to the next best alternative.

Lastly, it was understood that the Tilden Special Contract would benefit UMERC and its customers by allowing for the construction of new, cleaner-energy UP electric generation (the RICE Units), consistent with the ARSA approved in Case U-17682, and aid in the eventual retirement of the older, less efficient, coal-fueled Presque Isle Power Plant ("PIPP").

Q. Which of UMERC's requested authorizations did the Commission provide in Case U-18224.

A. On October 25, 2017, after a contested case proceeding, the Commission issued its Opinion and Order granting the approvals described above. Specifically, the Tilden Special Contract was approved pursuant to Mich Admin Code, R 460.2031(1). Additionally, the Commission made the following findings pursuant to its MCL 460.6s authority:

- The power to be supplied as a result of the proposed construction of the two reciprocating internal combustion engine electric generation facilities in Baraga Township Baraga County, and Negaunee Township, Marquette County, is needed;
- The size, fuel type, and other design characteristics of the reciprocating internal combustion engine electric generation facilities represent the most reasonable and prudent means of meeting the power need; and
- The estimated purchase or capital costs of and the financing plan for the reciprocating internal combustion engine electric generation facilities, including, but not limited to, the costs of siting and licensing the reciprocating internal combustion engine electric generation units and the estimated cost of power from the reciprocating internal combustion

engine electric generation facilities will be recoverable in rates from the Company's customers, with a Commission-approved amount $277,200,000 for the construction of the reciprocating internal combustion engine electric generation facilities.

Further, the Commission granted UMERC certificates of public convenience and necessity pursuant to MCL 460.501 et seq., authorizing the company to construct, own, and operate RICE generation facilities in Baraga Township, Baraga County and Negaunee Township, Marquette County.

Q. Is there anything included in the Order issued by the Commission in Case U-18224 that was deferred by the Commission and needs to addressed in this general rate case?

A. Yes. As I noted above, while the Tilden Special Contract was approved by the Commission in the October 25, 2017 Order, the Commission's Order did not include approval of the ratemaking treatment in the Tilden Special Contract. Rather, the Commission's Order found that that matter shall be deferred until UMERC provides a cost of service study.

As will be discussed later in my testimony, UMERC will, as part of this general rate case proceeding, present a cost of service study that supports UMERC's proposed rate making treatment of the Tilden Special Contract, which will be sponsored by witness Aaron L. Nelson.

Q. After receiving the Commission's Order in Case No. U-18224, did UMERC construct the planned RICE Units?

A. Yes. Construction commenced on both approved RICE generation facilities on October 30, 2017, and was performed in parallel for each of the facilities. Both RICE generation facilities, with a combined total of 183 MW of generating capacity were placed in service on March 29, 2019.

Q. Did UMERC construct the RICE generation facilities within the Commission authorized $277.2 million for the construction of the RICE Units?

A. Yes. In fact UMERC was able to complete the construction of the RICE generation facilities at a total construction cost of $248.1 million. When the AFUDC on 100% of the CWIP balance is included in the capital costs, the total rate base addition pertaining to the RICE generation facilities is $260.9 million.

RICE Units & Tilden Special Contract Cost Allocation Implications

Q. After construction of the RICE generation facilities was completed, did the Tilden Mine become a UMERC customer?

A. Yes. Consistent with the ARSA approved in Case No. U-17682, and under the terms of the Tilden Special Contract that the Commission approved in Case No. U-18224, Tilden, as a customer of Wisconsin Electric, was transferred to UMERC on April 1, 2019, which is the first full day that the RICE Units were in service.

Q. After Tilden became a UMERC customer, was the then current Special Contract between UMERC and Tilden amended?

A. Yes. The Special Contract was modified by changing the Planning Load Charge Rate and the section regarding Generation Resources Capital Expense to address impacts arising from the Tax Cuts and Jobs Act of 2017. This amendment was approved by the Commission on February 20, 2020, in Case No. U-20643.

Q. Are there any unique cost allocation or ratemaking impacts that result from the structure of Tilden Special Contract?

A. Yes. The structure of the Commission-approved Tilden Special Contract identified the specific costs for which Tilden would be responsible, including Tilden's portion of the capital costs associated with the RICE Units being recovered over 20 years on a levelized basis. This structure resulted in a situation that, in the initial years of the contract's term, UMERC recovered fewer revenues from Tilden than it would have if traditional cost allocation and ratemaking were used to establish cost recovery from Tilden. This contract structure was a key element to reaching the ARSA that the Commission approved in Case No. U-17862 because it provided Tilden with predictable costs over the 20-year life of the contract.

The Tilden Special Contract structure's misalignment of UMERC's incurrence and recovery of capital costs results in a Company revenue deficiency specific to Tilden during the initial years of the Tilden Special Contract as compared to traditional cost allocation and ratemaking. Conversely, this same circumstance results in a revenue sufficiency in the later years specific to Tilden, as compared to traditional cost allocation and ratemaking. To be sure, under this structure, the total amount of revenue UMERC will recover from Tilden over the term of the Tilden Special Contract is the same as it would recover under traditional cost allocation and ratemaking – but the *timing* of when that recovery shifts from the early years of the contract to later years.

Further detail of the RICE Units' costs and the associated allocation between Tilden and non-Tilden retail electric customers proposed in this case is discussed in greater detail in the testimony of witness Nelson.

Q. What impact does the Special Contract's structure have on this rate case?

A. Because the contract has been in place for over five years, UMERC is projected to recover more revenues from Tilden than traditional cost recovery would suggest in Test Year 2025. Or said differently, UMERC's forecasted financial statements suggest that it has a revenue sufficiency from Tilden while showing a revenue deficiency for non-Tilden retail electric customers.

However, as proposed by UMERC, that revenue sufficiency for Tilden is correctly not used to reduce the non-Tilden retail electric customers' revenue deficiency because, in the years prior to the test year, UMERC recovered *fewer* revenues under the Tilden Special Contract than traditional cost allocation and ratemaking would support. During this time UMERC not only did not seek to recover this difference from its non-Tilden retail electric customers, UMERC also did not seek any increase in rates and instead held all customer base rates flat at the levels authorized by the Commission for UMERC's predecessor utilities in their most recent rate cases – filed in 2012 for WEPCO Rate Zone Customers and 2015 for WPS Rate Zone Customers.

<u>WEC and WBS Background</u>

Q. Please describe WEC.

A. WEC is a diversified energy production and delivery company with $26.6 billion in market cap as of year-end 2023, serving approximately 1.6 million electric and 3.0 million natural gas customers in Wisconsin, Michigan, Minnesota, and Illinois. WEC owns 52,000 miles of gas distribution in addition to 71,700 miles of electric distribution and holds a 60% ownership of American Transmission Company. Other energy infrastructure investments include 100% ownership of Bluewater Gas Storage LLC, and ownership interests in several wind energy farms in the Midwest and a large solar farm in Texas.

Q. Please describe WBS and describe its relationship to UMERC?

A. WBS is a non-regulated subsidiary of WEC. WBS provides a number of shared services to WEC and its operating subsidiary companies, including UMERC, under the AIA that applies to regulated and non-regulated companies. The AIA identifies the types of services that the affiliates may provide and receive, as well as certain requirements that are unique to WBS as a centralized service company.

Q. What services are provided to UMERC by WBS?

A. WBS provides the following services to UMERC and its other affiliates:

- Administrative (e.g., facility management, printing services);
- Communications (e.g., preparation and dissemination of information to employees, customers, governmental officials, the public and the media);
- Customer (e.g., meter reading and billing, credit, collections, call center operations, market research);
- Environmental (e.g., assessments, investigations, remediation);
- Executive Management (e.g., general business planning, allocation of financial resources);
- External Affairs (e.g., governmental relations, community support, regulatory policy, rate administration);
- Finance (e.g., accounting, finance, treasury, tax, internal audit, risk management, insurance and related financial services);
- Human Resources (e.g. employment, compensation, benefits, wellness);
- Information Technology (e.g., computing hardware, telecommunications, electronic data processing services, infrastructure and application architecture);
- Legal and Governance (e.g., legal advice, regulatory matter administration, real estate, shareholder services); and,
- Supply Chain (e.g., acquisition and provision of goods and services other than fuel, energy commodities or energy transmission).

WBS also provides the following specific services only to its regulated utility affiliates such as UMERC:

- Operational Support and Development (e.g., design, construction and maintenance of generation facilities and distribution infrastructure, technical training, project management, geospatial services, contract administration) and,
- Wholesale Energy and Fuels (e.g., interacting with the day ahead and real time energy market administrator Mid-Continent Independent System Operator ("MISO"), purchasing natural gas for the RICE Units, and operating natural gas fueled RICE generation facilities).

Q. How are costs allocated between the affiliated companies?

A. The basic pricing principles included in the AIA are unchanged from the arrangement that UMERC had with WEC and its non-regulated service company, WBS, that were reviewed in Case No. U-18061.

Services that WBS provides to a regulated utility affiliate are priced at cost. Services that a regulated party like UMERC receives from a non-regulated party (except WBS) are priced at the lower of market price or 10% over fully allocated embedded cost. Services that UMERC provides to another regulated affiliated party are priced at cost, services to a non-regulated affiliate are priced at the higher of market price or fully allocated embedded cost.

Q. Is the arrangement between WBS and UMERC a benefit to UMERC and its customers?

A. Yes, it is. The services provided by WBS represent activities that any utility would need to perform to effectively function as a separate company. WBS generates savings for UMERC and its customers because of the efficiencies and synergies it brings in providing these necessary services. Because WBS provides the same services to all operating utilities within WEC, the costs of these activities can be shared among all of the operating utility companies. Although some costs are variable to the size of the company, many of these costs are fixed; therefore, a smaller company would pay a higher amount in proportion to its relative size if the service was provided by an outside party exclusively to UMERC or fully staffed at the local level to perform the functions. UMERC could not self-provide the same overall services provided by WBS at a lower – or even the same – cost.

In addition to economies of scale, UMERC receives the benefit of access to in-house experts who can be retained only by larger companies. For example, many of the same requirements that one utility may face from an environmental or safety compliance perspective will impact other companies within WEC. Having one combined group providing support and research not only lowers the costs but helps to ensure strong compliance programs with broad internal institutional knowledge.

<u>Key Corporate Initiatives</u>

Q. What are UMERC's overall business objectives?

A. UMERC and its sister companies at WEC are focused on fundamentals such as safety, world-class reliability, customer care, financial discipline, and operating efficiency. By focusing on these fundamental objectives every day, WEC, and of course UMERC, provides safe, reliable energy to customers at a reasonable cost.

Q. What are some WEC corporate initiatives that impact UMERC and its customers?

A. Between 2024 and 2028, WEC expects to invest more than $23 billion across the company with a focus on modernizing infrastructure, reshaping its generation fleet for a clean, reliable future, continuing its rollout of advanced metering functionality, and upgrading systems and equipment. Included in these initiatives are programs that will benefit UMERC and its customers:

- Generation Fleet Reshaping: identification of a 100MW solar facility located in the UP of Michigan that, once operational at the end of 2026, will provide UMERC's non-Tilden retail electric customers with locally-sourced renewable electricity. On April 11, 2024, the Commission approved the project as part of UMERC's Integrated Resource Planning in Case U-21081.
- Enhancing field operations to maintain and improve customer care: replacing and standardizing the Work Management system, to Maximo, and upgrading the PCAD system. These projects will reduce system maintenance and operating costs and streamline dispatch and work order management processes.

Since UMERC's formation in 2017, the WEC companies, including UMERC, are able to leverage their expertise across the four state jurisdictions, by bringing to bear best practices in operations, customer service, and other areas that directly impact the service provided to customers as well as a superior ability to deliver that service safely and reliably. In its procurement practices, WEC is committed to developing a high-quality supply base to meet its current and future business requirements across the Midwest with particular emphasis on safety, supplier diversity, innovation, and cost reduction.

Q. How do UMERC and WEC together serve local communities in Michigan?

A. Local communities are served by UMERC and WEC in several ways. UMERC provided over $60,000 of support to community-based organizations in 2023 and sponsors community events such as Business After Hours hosted by United Way of Dickinson County, the annual Mountain Mud Sling hosted by Northern Lights YMCA, and the Humboldt Township children's fishing derby.

Two of WEC's foundations, the We Energies Foundation and the WPS Foundation, support UMERC directly, reviewing grant proposals and directing donations to nonprofit organizations in UMERC's service territories. For example, Feeding America's mobile food pantries, Imagination Factory Children's Museum, Marquette Maritime Museum, Casa of Menominee County's volunteer training and retention program, The Salvation Army, St. Vincent De Paul's Christmas food baskets, and equipment for several first responder organizations.

<u>UMERC's 2025 projected test year rate case</u>

Q. When were UMERC's base rates last approved?

A. This is UMERC's first rate case. The predecessor utilities – Wisconsin Electric and WPS Corp. – last requested and received base rate increases in 2012 (U-16830) and 2015 (U-17669), respectively. Essentially, UMERC customers' base rates have been steady for 13 years if they were previously served by Wisconsin Electric and for a decade if they were previously served by WPS Corp. These base rate "freezes" have been able to be achieved from the combination of the WEC's acquisition of Integrys Energy and the formation of UMERC as a stand-alone, Michigan-only utility.

Q. What is UMERC seeking as an authorized return ?

A. As covered in greater detail in the direct testimony of UMERC witnesses Ann Bulkley and Reese, the Company is seeking approval of a Return on Common Equity ("ROE") of 10.25%. The current returns used for determining interest calculations for PSCR purposes were authorized for UMERC's predecessor utilities (10.10% for Wisconsin Electric and 10.20% for WPS Corp) in their last electric rate cases and, as further explained and supported in the testimony of witness Reese, result in a weighted average ROE of 10.12%, which is used for historic rate purposes in this case.

Q. Is UMERC seeking any changes in its authorized capital structure?

A. No. In Case No. U-18061, WEC proposed that UMERC be capitalized with 50% permanent equity and 50% debt. Because this level is already consistent with the capitalization structure that the Commission has identified as being a target for Michigan utilities, UMERC is not proposing any changes.

Q. Are there any other elements that you would like to specifically point out that impact UMERC?

A. Yes. Because this rate case is the first one filed by UMERC since its formation and the several structural changes that have occurred as result of that formation and subsequent events, including the construction and in-service of the UP RICE generating facilities and the transfer of Tilden from Wisconsin Electric to UMERC, there are multiple issues that are included in the Company's direct case.

First, the last time rates were changed for UMERC customers, they were customers of multi-jurisdictional utilities with operations in not only the UP of Michigan, but also Wisconsin. As such, when rates were last authorized for UMERC customers, the costs for generation facilities were allocated between the two jurisdictions with customers of the UP paying the allocated costs for the "slice" of the integrated generation fleets of Wisconsin Electric and WPS Corp that served these customers in the UP. Fast-forwarding to the 2025 test year, these customers are served by a single, Michigan-only jurisdictional utility with dedicated, local RICE generation facilities, which provide the UP energy solution identified and approved in Case Nos. U-17682 and U-18224, and which provide reliable service at a lower cost than had the RICE Units not been constructed.

Second, UMERC has not had a rate case since the UP RICE generation facilities were placed in service on April 1, 2019. As such, the depreciation rates for those facilities have not been reflected in customer rates. Shortly prior to this rate case being filed, UMERC filed a limited scope application in Case U-21542 requesting approval of only depreciation rates specific to the UP RICE generation facilities. UMERC is requesting approval of these rates for ratemaking purposes in this case and is sponsoring *alternative* exhibits/schedules for purposes of determining UMERC's revenue requirements and associated revenue deficiency for non-Tilden retail electric customers.

Third, when rates were last established for customers in the WEPCo Rate Zone, Wisconsin Electric was not part of a holding company structure that included a service company. Once the WEC acquisition of Integrys Energy was completed in 2015, that changed and Wisconsin Electric began receiving services from WBS. Leveraging WBS to provide service to UMERC customers also causes certain costs to provide service to UMERC customers, particularly those in the WEPCo Rate Zone, to be lower than when rates were last established for those customers.

Fourth, the allocation of costs, including the costs of the dedicated and local (to the UP) RICE generation facilities, between Tilden and all other non-Tilden retail electric customers has not been authorized by the Commission yet.

Q. Why was the scope of the depreciation study filed in Case U-21542 limited to just the UP RICE Generation Facilities?

A. When UMERC was formed and the assets of Wisconsin Electric and WPS Corp that were used to provide service to Michigan customers were transferred to UMERC, those assets all had approved depreciation rates which were used to establish the rates that UMERC customers are currently paying. Furthermore, these assets are all distribution assets that have long lives and a change in depreciation rates for those assets was not deemed necessary to establish rates that are just and reasonable for UMERC customers. However, because the RICE generation facilities were new assets that have never been included in the rates of UMERC customers, establishing depreciation rates for those facilities is necessary to determine just and reasonable rates in this instant case.

Q. Has UMERC received Commission authorization for any new significant capital projects?

A. Yes. As I have previously addressed, on April 11, 2024, UMERC received Commission approval of UMERC's ex-Parte application for contracts acquire and construct the 100 MW Renegade Solar project ("Renegade Solar"). Renegade Solar is the project UMERC identified as the least-cost project that met the need identified in its Integrated Resource Plan filed and approved in Case No. U-21081. In addition to contracts necessary for UMERC's acquisition and construction of Renegade Solar, the Commission also approved UMERC's request to accrue Allowance for Funds Used During Construction ("AFUDC") on 100% of Renegade Solar construction work in progress.

Q. Is UMERC seeking any other Commission authorization related to Renegade Solar?

Yes. A small portion of Renegade Solar will be located in Ewing Township, Marquette County, which is not part of UMERC's service territory. Thus, UMERC filed for an Act 69 Certificate in Case U-21583. As of the prehearing conference on April 18, 2024, no parties made an appearance indicating opposition to the application. Based on these facts, UMERC anticipates that the Act 69 Certificate will be approved by Commission during the course of this rate case proceeding.

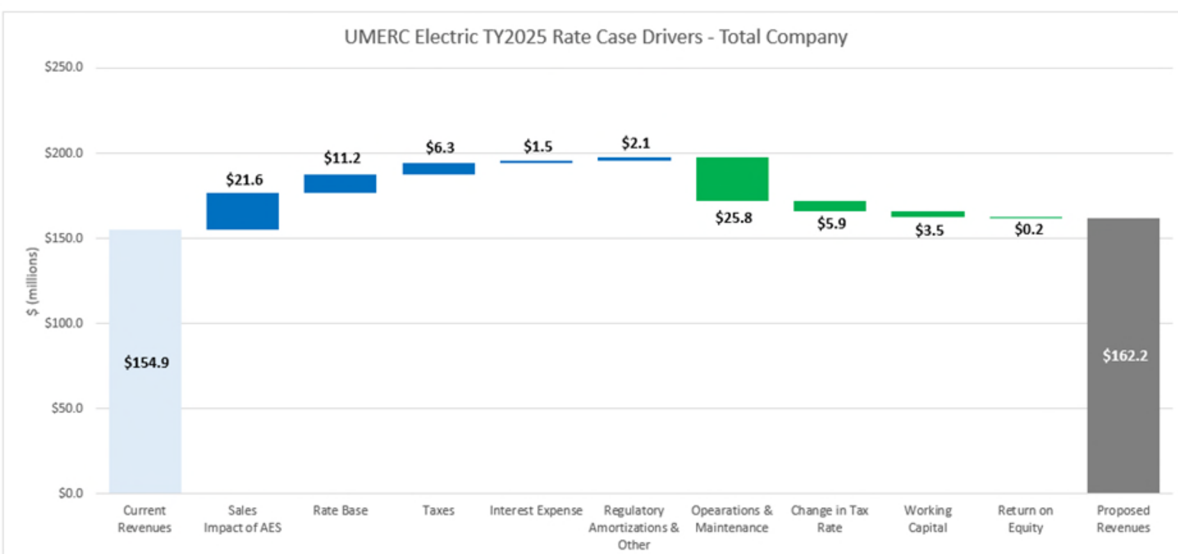
Additionally, UMERC will be accounting for the return on Renegade Solar's CWIP balance as authorized by the Commission – by accruing AFUDC on 100% of that CWIP balance.

Q. What is the level of annual increase in base rates that UMERC is seeking in this case?

A. Including the effect of new RICE Unit depreciation rates as requested in pending Case No. U-21542, UMERC's direct case supports an annual revenue increase for non-Tilden retail electric customers of $11.1 million, which represents an increase of approximately 13.8% when compared to the Company's current base rate revenues for non-Tilden retail electric customers.

A summary of the drivers of UMERC's total retail electric system for the 2025 test year revenue requirement are shown in Figure 1 below. Items shown in blue are upward drivers and those shown in green are downward drivers. The total company drivers shown in Figure 1 are described in greater detail in the testimony of witness Reese. Company cost of service witness Nelson will provide the step through from the total retail electric system revenue deficiency to the proposed non-Tilden retail electric customer annual revenue increase of $11.1 million.

Figure 1: Rate Request Drivers Summary



Q. Please describe the key drivers of this rate case?

A. The underlying themes of the drivers related to this rate request can be categorized into three broad buckets. First, there is an increase in revenue requirements associated with a growth in rate base which is directly attributable to the construction and placing in-service of the RICE generation facilities. This generates an $11.2 million increase in revenue requirements.

Second, since rates were last established, UMERC has had many customer choose to take service from an AES which has reduced sales volumes resulting in an upward driver of $21.6 million to UMERC's revenue requirement.

The third driver, reduced operations and maintenance expenses ("O&M"), counter-acts the first two upward drivers. Reduced O&M, relative to when rates were last established for UMERC's predecessor utilities Wisconsin Electric and WPS Corp are derived from efficiencies gained by WEC's acquisition of Integrys Energy, the implementation of a service company for all of WEC's customers, including UMERC's customers, and the creation of UMERC in 2017 as a stand-alone Michigan-only jurisdictional utility. This overall O&M reduction of $25.8 million was achieved for UMERC customers despite historically high levels of inflation for materials and labor that UMERC has recently experienced as summarized in Table 1 below, and expects to persist through the 2025 test year.

Table 1: Annual Inflation for 2021, 2022 and 2023[1]

[1]https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm

Month	2021 Annual Inflation Rate	2022 Annual Inflation Rate	2023 Annual Inflation Rate
January	1.4%	7.5%	6.4%
February	1.7%	7.9%	6.0%
March	2.6%	8.5%	5.0%
April	4.2%	8.3%	4.9%
May	5.0%	8.6%	4.0%
June	5.4%	9.1%	3.0%
July	5.4%	8.5%	3.2%
August	5.3%	8.3%	3.7%
September	5.4%	8.2%	3.7%
October	6.2%	7.7%	3.2%
November	6.8%	7.1%	3.1%
December	7.0%	6.5%	3.4%

Additionally, UMERC has been and will continue to be impacted by the significant increases in interest rates that have taken place since early 2022, which are shown in Table 2 below.

Table 2: Federal Reserve Interest Rate Decisions since January 2022[2]

FOMC Meeting Date	Rate Change (bps)	Federal Funds Rate
July 26, 2023	+25	5.25% - 5.50%
May 3, 2023	+25	5.00% - 5.25%
March 22, 2023	+25	4.75% - 5.00%
February 1, 2023	+ 25	4.50% - 4.75%
December 14, 2022	+ 50	4.25% - 4.50%
November 2, 2022	+ 75	3.75% - 4.00%

[2] https://www.forbes.com/adivosor/investing/fed-funds-rate-history/

FOMC Meeting Date	Rate Change (bps)	Federal Funds Rate
September 21, 2022	+ 75	3.00% - 3.25%
July 27, 2022	+ 75	2.25% - 2.50%
June 16, 2022	+ 75	1.50% - 1.75%
May 5, 2022	+ 50	0.75% - 1.00%
March 17, 2022	+ 25	0.25% – 0.50%

Q. Explain briefly the other drivers in the case.

A. Beyond the key drivers previously explained, there are five other drivers of UMERC's requested revenue requirement increase. The first is taxes, which has both upward and downward components that, on a consolidated basis, results in a net upward driver of $0.4 million. This amount is comprised of a $6.3 million increase in taxes, primarily property taxes, that is offset by at $5.9 million decrease in income taxes due to the lower corporate tax rate signed into law since UMERC's predecessor utilities last filed a rate case. The additional upward drivers are Interest Expense, 1.2 million, and regulatory amortizations and other, $2.1 million. The final two downward drivers are working capital, $3.5 million, and return on equity of $0.2 million.

Further discussion of all drivers is included in the direct testimony of witness Reese.

Q. At part of its rate proposal has UMERC included all impacts from the Tax Cut and Job Act of 2017 ("TCJA")?

A. Yes. Although I have identified a $5.9 million decrease in income tax expense due to the lower corporate tax rate which is reflected in the revenue deficiency calculation, once the Company's new base rates go into effect, the current negative surcharges (or bill credits) resulting from the TCJA will expire.

Q. Will UMERC be proposing any changes to the demand response tariffs in this proceeding?

A. Yes. For both Rate Zones, UMERC is proposing to eliminate the direct load control programs for air conditioning and water heaters. The devices supporting this program have reached their end of life and no longer function. By not eliminating this program participating customers will continue to receive a credit without providing interruptible load that UMERC can rely upon if needed to reduce its load when called upon by MISO. Witness James Beyer provides additional details in his testimony.

Q. Will UMERC be introducing any changes to existing service conditions in this proceeding?

A. UMERC is only proposing to update the line extension allowances available to new customers as part of this rate case. This is being done to update extension allowances to reflect the updates in costs since rates for WPSC Rate Zone customers were last reset in Case No. U-17669.

Q. Is UMERC introducing any changes to tariffs in this proceeding?

A. Due to the implementation of parallel generation tariffs in 2018, UMERC, as part of this filing, is proposing to discontinue its net metering tariffs to new customers since those are no longer applicable.

Q. Will UMERC be introducing a Residential Income Allowance ("RIA") and Senior Bill Assistance program?

A. Yes, witness Beyer will describe in greater detail UMERC's proposal.

<u>Introduction of Company Witness</u>

Q. Please introduce the witnesses that UMERC is providing to support its request for rate relief.

A. UMERC's witnesses include:

1. Financial schedules, capital spending, cost of debt, and a summary of the capital investments made by UMERC since its formation – Anthony Reese
2. Return on equity and capital structure – Ann Bulkley of the Brattle Group
3. Rate design & tariff updates, including updates to UMERC's State Reliability Mechanism (SRM) charge – James Beyer
4. Cost of service – Aaron Nelson
5. Sales forecast – Jared Peccarelli

Q. Does this conclude your direct testimony at this time?

A. Yes it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase retail electric rates and for other relief.	))))))	Case No. U-21541

DIRECT TESTIMONY AND EXHIBITS OF

ANTHONY REESE

FOR

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

May 1, 2024

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Qualifications of Anthony Reese

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

A. My name is Anthony Reese. My business address is 231 West Michigan Street, Milwaukee, Wisconsin 53203. I am employed by WEC Business Services, LLC ("WBS"), a subsidiary of WEC Energy Group, Inc. ("WEC"), as Vice President and Treasurer. As part of that role, I am also the Vice President and Treasurer for Upper Michigan Energy Resources Corporation ("UMERC" or the "Company").

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of UMERC, which is a subsidiary of WEC.

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

A. I have a Bachelors of Arts degree in Accounting from Lakeland College and a Masters of Business Administration from the University of Wisconsin Milwaukee. I am also a Certified Public Accountant. Prior to joining WEC, I worked for three years in public accounting. Since 2006, I have held a number of positions of increasing responsibility within the finance organization, including Manager of Financial Planning and Analysis from 2011 to 2015, and I was appointed Controller of North Shore Gas Company and The Peoples Gas Light and Coke Company a few months after WEC was formed in 2015. In October 2019, I was named Vice President and Treasurer for WEC. I am responsible for long-range financial planning, forecasting and managing the utilities' revenue requirements, and oversight of WEC's treasury and cash management functions. I have also been involved in all aspects of financial rate case preparation, including evaluation of budgets, sales forecasting, and determination of revenue deficiencies.

Q. Have you previously testified before any regulatory agency?

A. Yes, I have. I have provided direct and rebuttal testimony to the Public Service Commission of Wisconsin in rate cases (Docket No. 5-UR-109 & 6690-UR-126), environmental trust financing (Docket No. 6630-ET-101) and renewable asset acquisition (Docket No. 6630-EB-103). I have also provided direct testimony to the Michigan Public Service Commission in Case Nos. U-21366 and U-21540 on behalf of WEC's subsidiary, Michigan Gas Utilities Corporation.

Summary and Purpose of Testimony

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide an explanation of the methodology used to develop UMERC's total retail electric revenue deficiency for the 2025 projected test year, summarize the drivers of UMERC's 2025 projected revenue deficiency, and provide an overview of the required financial filing schedules.

Q. Is this the first time UMERC has filed a base rate case?

A. Yes. As discussed in witness Stasik's direct testimony, the Commission approved the formation of UMERC in Docket U-18061 and UMERC began operations on January 1, 2017 by transferring Michigan jurisdictional electric and natural gas distribution assets into a stand-alone Michigan utility, whose assets were previously owned and operated by Wisconsin Electric Power Company ("WEPCO") and Wisconsin Public Service Corporation ("WPS Corp"). WEPCO and WPS Corp also transferred retail electric and natural gas customers to UMERC with the exception of the Empire Mine and Tilden Mining Company, L.C. ("Tilden"). The Michigan electric and natural gas base rates in effect for WEPCO and WPS Corp retail customers were adopted by UMERC and two rate zones were created: the WEPCO Rate Zone and the WPSC Rate Zone. Since January 1, 2017, rates have been adjusted for changes in natural gas, fuel, purchased power and transmission costs as allowed in the annual PSCR filings and GCR filings.

Q. Have there been any significant developments since January 1, 2017 that significantly impacted UMERC?

A. Yes. UMERC constructed two reciprocating internal combustion engine ("RICE") electric generation facilities ("RICE Units") for the benefit of UMERC's retail electric customers and the Tilden Mining Company L.C. ("Tilden"). UMERC also entered into a 20-year Special Contract with Tilden that provided for recovery of 50% of the RICE capital investment, including future capital additions, and also certain operating and maintenance ("O&M") costs related to the operation of the RICE Units. As part of this Special Contract, the Company agreed that it would not seek recovery of the 50% RICE capital costs allocated to Tilden from other UMERC retail customers regardless of UMERC's ability to collect those costs from Tilden under the Special Contract. The Company proposed in Case U-18824 that the remaining capital investment and O&M costs associated with the RICE and not addressed in the Special Contract would be allocated to the other retail electric customers of UMERC. The MPSC issued its Order and Opinion in Case No. U-18224 on October 25, 2017, which approved the construction of the RICE Units and the Tilden Special Contract. In that proceeding, the MPSC also deferred approval of the Company's proposed cost allocation until UMERC presented a cost of service study in its next rate filing. This is that filing. Company witness Aaron Nelson will present the cost of service study, which illustrates the proposed cost allocation.

Q. Did the MPSC approve the allocation of any costs in Case No. U-18224?

A. Yes. The MPSC has previously approved the allocation of fuel and natural gas transportation costs related to the operation of the RICE Units, purchased power costs and transmission costs between Tilden and UMERC's other electric retail customers that are recovered through the annual PSCR filings, such as Case No. U-21431.

Q. Are you requesting a base rate change for UMERC's natural gas operations?

A. No. The Company is not requesting a rate change for natural gas customers in this proceeding.

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-1, Schedules A1 through A3,
Exhibit A-2, Schedules B1 through B4,
Exhibit A-3, Schedules C1 through C11,
Exhibit A-4, Schedules D1 through D5,
Exhibit A-11, Schedules A1 and A2,
Exhibit A-12, Schedules B1 through B5.5,
Exhibit A-13, Schedules C1 through C11,
Exhibit A-14, Schedules D1 through D5,
Exhibit A-17 Known and Measurable ("K&M") O&M, Schedules G1 through G15
Exhibit A-18 RICE Units Depreciation Expense
Exhibit A-19 Schedule of Regulatory Assets and Liabilities

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

A. Yes, they were.

Q. Please provide a summary of the subjects you will address in your testimony.

A. I will address the following:

1. The total electric retail revenue deficiency relating to:
    a. Rate Base,

b. Operating Income,
c. Capital Structure,
d. Labor Charges,
e. Inflation Rates,
f. Operations and Maintenance ("O&M") Expenses,
g. Known and Measurable ("K&M") Items,
h. Depreciation Rates,
i. Taxes other than Income Taxes,
j. Amortization of Regulatory Assets and Liabilities,

2. Electric Costs and Revenues
3. Tilden Special Contract and related cost recovery

Q. Please explain, generally, why electric rate relief is sought at this time.

A. As detailed in my testimony or that of other Company witnesses, UMERC expects a total retail electric revenue deficiency of approximately $8.3 million or 5.3% in 2025, which includes $0.95 million of incremental electric revenue deficiency related to the RICE Unit depreciation expense, which is proposed in Case No. U-21542. Company cost of service witness Nelson will provide a step through from the total company electric revenue deficiency to the proposed non-Tilden customer annual revenue increase. The 2025 revenue deficiency drivers include:

- Investing in needed capital projects, notably the RICE Units, that improve reliability of the electric system in the UP, including the effects of the depreciation rates proposed in Case No. U-21542.
- Increased costs associated with maintenance at the RICE Units.
- Personal property tax increases associated with capital investments and tax rate increases;
- Changes in the recovery of regulatory assets and liabilities; and,
- Projecting a higher cost of capital in the 2025 test year.

My testimony supports the Company's capital investments and Witness Bulkley supports return on equity and capital structure.

These drivers are being impacted by two Macroeconomic factors (a) historic levels of inflation for materials and labor as well as (b) the significant and swift increases in interest rates that have been taking place since early 2022. Company Witness Stasik provides a table detailing out the Federal Reserve interest rate decisions since January of 2022 and annual inflation rates for both 2022, 2023 and 2024 by month.

The Total Electric Operations Revenue Deficiency

Q. What is the amount of rate relief UMERC is seeking in this proceeding?

A. UMERC's analysis of the test year ending December 31, 2025 indicates revenue deficiency of $7.3 million, for total retail electric operations.

The total electric operations revenue deficiency is based on the rates in effect for non-Tilden retail electric customers at the time of UMERC's formation as approved in the Commission's December 9, 2016 Order in Case U-18061, a proposed return on common equity of 10.25% which is supported by the testimony of witness Bulkley of the Brattle Group ("Brattle") and total depreciation and amortization expense based on rates and practices from cases No. U-17849, U-17446 and U-16269, and the revenues from the Tilden Special Contract. Incorporating the impacts of the proposed RICE Unit depreciation rates from Case No. U-21542, the total retail electric revenue deficiency is $8.3M which is reflected in Exhibit A-18.

Electric Jurisdictional	($ In Thousands)
Rate Base	$560,178
Adjusted NOI	31,331
Overall Rate of Return	5.59%
Required Rate of Return	6.56%
Income Required	$36,763

Electric Jurisdictional	($ In Thousands)
Income Deficiency (Sufficiency)	5,431
Revenue Multiplier	1.347
Revenue Deficiency (Sufficiency)	$7,314

My direct testimony and exhibits derive and support the total electric retail operations revenue deficiency. The total retail electric system revenue deficiency does not, however, paint the full picture. As described in the direct testimony of witness Stasik and later in my direct testimony, a significant amount (approximately 50%) of UMERC's sales volumes, revenues and costs are the result of the Tilden Special Contract. To prevent class cross-subsidization between Tilden and the Company's non-Tilden electric retail customers, these revenues and costs must first be allocated to classes, including Tilden. This circumstance is due to the significant portion of UMERC's customer base that Tilden represents and the specific cost recovery that is identified within the Tilden Special Contract approved by the Commission in Case No. U-18224. In his direct testimony and exhibits, Company cost of service witness Nelson derives the amount of rate relief that UMERC is seeking with respect to the Company's non-Tilden electric retail customers. The rates sponsored by Company witness Beyer are designed to produce the requested non-Tilden retail electric customer revenue requirement and are based on the cost of service study results sponsored by Company witness Nelson.

Q. What impact will the proposed depreciation rates in Case No. U-21542 have on the total retail electric operations revenue deficiency in 2025?

A. UMERC estimates in Exhibit A-18 that updating rates from Case No. U-21542 would increase the total retail electric operations revenue deficiency in 2025 by $0.95 million. This schedule shows the impacts to rate base as well as the deficiency.

Q. What test period is UMERC's proposed rate increase based on?

A. UMERC has used a projected 12-month test year ending December 31, 2025.

2022 Historic Test Year Exhibits

Q. Please explain the basis for the historic test year exhibits.

A. The historic test year exhibits are related to UMERC's electric operations. The majority of electric utility accounts are specific to the electric operations, however, common accounts are allocated between UMERC's electric and natural gas operations based on an historic allocation factor of 95.3% to electric and 4.7% to natural gas. The historic allocation factor is based on a blend of common allocation factors used by WEPCO and WPS Corp prior to the formation of UMERC.

Q. Please explain Schedule A1 of Exhibit A-1.

A. Schedule A1 of Exhibit A-1 calculates UMERC's 2022 historic test year electric revenue deficiency based on its rate base, adjusted net operating income, rate of return, and revenue conversion factor. This schedule develops the 2022 electric operations revenue deficiency of $3.3 million, as shown on Line 16, using a 10.12% return on common equity. The component parts of this schedule are taken from the various sources indexed to the left of these amounts.

Q. Please explain the basis for using 10.12% ROE in Exhibit A-1 Schedules A1 and A2.

A. The Company used the 10.12% ROE because although the Commission in Case No. U-18061 authorized UMERC to use the WEPCO approved ROE of 10.10% for PSCR purpose and the WPS Corp approved ROE of 10.20% for PSCR and GCR purposes, UMERC did not receive an approved total Company ROE. Exhibit A-1. Schedule A-3 shows the calculation of the 10.12% ROE using the weighted average authorized returns from the most recent rate cases of WEPCO and WPS Corp (Case Nos. U-16830 and U-17669, respectively). The weighted average of WPS Corp and WEPCO actual net utility plant assets transferred into UMERC at its formation were used.

Q. Please explain Schedule A2 of Exhibit A-1

A. Schedule A2 of Exhibit A-1 provides 2018 through 2022 historical year financial metrics. The ratios calculated include Return on Common Equity, EBIT Interest Coverage, EBITDA Interest Coverage, FFO Interest Coverage, Overall Fixed Charge Coverage, Cash Flow Coverage of the Dividend, Common Dividend Payout Ratio, Permanent Capitalization Balances and Percentages.

Q. Please explain Schedule B1 of Exhibit A-2.

A. Schedule B1 of Exhibit A-2 calculates UMERC's 2022 historic test year electric rate base. The component parts of this schedule are taken from the various sources indexed to the left of these amounts.

Q. Please explain Schedule B2 of Exhibit A-2.

A. Schedule B2 of Exhibit A-2 calculates UMERC's 2022 historic test year electric utility plant.

Q. Please explain Schedule B3 of Exhibit A-2.

A. Schedule B3 of Exhibit A-2 depicts UMERC's 2022 historic test year electric operations accumulated provision for depreciation.

Q. Please explain Schedule B4 of Exhibit A-2.

A. Schedule B4 of Exhibit A-2 calculates UMERC's 2022 historic test year electric operations working capital.

Q. Please explain Schedule C1 of Exhibit A-3.

A. Schedule C1 of Exhibit A-3 calculates UMERC's 2022 historic test year adjusted net operating income for the electric operations.

Q. Please explain Schedule C2 of Exhibit A-3.

A. Schedule C2 of Exhibit A-3 calculates UMERC's 2022 historic test year gross revenue conversion factor.

Q. Please explain Schedule C3 of Exhibit A-3.

A. Schedule C3 of Exhibit A-3 calculates UMERC's 2022 historic test year electric operations revenue.

Q. Please explain Schedule C4 of Exhibit A-3.

A. Schedule C4 of Exhibit A-3 calculates UMERC's 2022 historic test year fuel, purchased power, transmission and other expenses included in UMERC's PSCR.

Q. Please explain Schedule C5 of Exhibit A-3.

A. Schedule C5 of Exhibit A-3 calculates UMERC's 2022 historic test year electric operations O&M expense, exclusive of fuel, purchased power transmission and other expenses included in Schedule C4.

Q. Please explain Schedule C6 of Exhibit A-3.

A. Schedule C6 of Exhibit A-3 depicts UMERC's 2022 historic test year electric operations depreciation and amortization expense.

Q. Please explain Schedule C7 of Exhibit A-3.

A. Schedule C7 of Exhibit A-3 calculates UMERC's 2022 historic test year total electric operations taxes other than income taxes.

Q. Please explain Schedule C8 of Exhibit A-3.

A. Schedule C8 of Exhibit A-3 depicts UMERC's 2022 historic test year federal income taxes associated with the electric operations.

Q. Please explain Schedule C9 of Exhibit A-3.

A. Schedule C9 of Exhibit A-3 depicts UMERC's 2022 historic test year state income taxes associated with the electric operations.

Q. Please explain Schedule C10 of Exhibit A-3.

A. Schedule C10 of Exhibit A-3 depicts UMERC's 2022 historic test year local taxes.

Q. Please explain Schedule C11 of Exhibit A-3.

A. Schedule C11 of Exhibit A-3 depicts UMERC's 2022 historic test year electric operations AFUDC.

Q. Please explain Schedule D1 of Exhibit A-4.

A. Schedule D1 of Exhibit A-4 develops UMERC's 2022 historic test year overall rate of return of 5.86% (shown on Line 22) based on UMERC's 13-month average capital structure, and a 10.12% ROE.

Q. Please explain Schedule D2 of Exhibit A-4.

A. Schedule D2 of Exhibit A-4 develops UMERC's 2022 historic test year embedded cost of long-term debt of 3.36%, based on a 13-month average, as shown on Line 20.

Q. Please explain Schedule D3 of Exhibit A-4.

A. Schedule D3 of Exhibit A-4 develops UMERC's 2022 historic test year cost of short-term debt of 2.63%, based on a 13-month average, as shown on Line 26.

Q. Please explain Schedule D4 of Exhibit A-4.

A. Schedule D4 of Exhibit A-4 indicates that UMERC has no preferred equity outstanding, as shown on Line 2.

Q. Please explain Schedule D5 of Exhibit A-4.

A. Schedule D5 of Exhibit A-4 develops UMERC's 13-month average balance of Common Equity of $186.2 million for the 2022 historic test year, as shown on Line 16.

2025 Projected Test Year Exhibits

Q. Please explain the basis for the projected test year exhibits.

A. The projected test year exhibits[1] are related to UMERC's electric operations. The majority of electric utility accounts are specific to the electric operations, however, where item-specific allocation factors are not available, the allocation factor is used to allocate common amounts to both electric and gas operations. This factor is made available to financial analysts throughout the Company to assist them to charge costs depending on the specific circumstances and nature of the charges they are projecting for the forecasted test year. The factors are based on a weighted composite of operation-specific non-fuel O&M, margin, and net plant amounts. The amounts used in the calculations are per the most recent MPSC annual report at the time the projected test year is prepared, in this instance 2022. The common allocation factors are reviewed periodically but are typically only changed during a rate proceeding.

Q. Please explain Schedule A1 of Exhibit A-11.

A. Schedule A1 of Exhibit A-11 calculates UMERC's 2025 projected test year electric operations revenue deficiency based on its rate base, adjusted net operating income, rate of return on equity ("ROE") of 10.25%, and revenue conversion factor. This schedule indicates that the 2025 Total Company retail electric revenue deficiency is $7.3 million, or 4.7%. The impacts of the depreciation rate for the RICE Units, as proposed in pending Case No. U-21542, are reflected in Exhibit A-18, and are an additional $0.95M revenue deficiency for an adjusted total Company retail electric revenue deficiency of

[1] The projected test year exhibits calculate a deficiency before applying the impacts of the depreciation rate for the RICE Units, as proposed in pending Case No. U 21542.

approximately $8.3 million or 5.3%. The component parts of this schedule are taken from the various sources indexed to the left of each value.

Q. Please explain Schedule A2 of Exhibit A-11.

A. Schedule A2 of Exhibit A-11 provides 2025 projected test year financial metrics with and without rate relief on a ratemaking basis. The ratios calculated include Return on Common Equity, EBIT Interest Coverage, EBITDA Interest Coverage, FFO Interest Coverage, Overall Fixed Charge Coverage, Cash Flow Coverage of the Dividend, Common Dividend Payout Ratio, and Permanent Capitalization Balances and Percentages.

Rate Base

Q. Please explain Schedule B1 of Exhibit A-12.

A. Schedule B1 of Exhibit A-12 calculates UMERC's 2025 projected test year electric utility rate base. The component parts of this schedule are taken from the various sources indexed to the left of these amounts.

Q. Please explain Schedule B2 of Exhibit A-12.

A. Schedule B2 of Exhibit A-12 depicts UMERC's 2025 projected test year electric utility plant. To arrive at the 2025 projected test year utility plant, the September 30, 2023 actual balance of utility plant was projected forward using UMERC's 2023, 2024, and 2025 construction projections.

Q. Please explain Schedule B3 of Exhibit A-12.

A. Schedule B3 of Exhibit A-12 depicts UMERC's 2025 projected test year accumulated provision for depreciation for the electric utility plant. To arrive at the 2025 projected test year accumulated provision for depreciation, the September 30, 2023 actual balance of accumulated provision for depreciation was projected forward using UMERC's existing plant and 2023, 2024, and 2025 construction projections.

Q. Please explain Schedule B4 of Exhibit A-12.

A. Schedule B4 of Exhibit A-12 calculates UMERC's 2025 projected test year electric operations working capital.

Q. Please explain Schedule B5 of Exhibit A-12.

A. Schedule B5 and associated sub schedules B5.1 through B5.5 of Exhibit A-12 depict UMERC's electric utility capital expenditures by function and FERC plant account for the 2022 historical year, projected bridge period and 2025 test year.

Q. What significant rate base items have been added or are forecasted to be added to UMERC's rate base since UMERC's inception?

A. Approximately two-thirds of UMERC's 2025 forecasted Net Plant portion of projected test period rate base, shown on line 17 of Exhibit A-12, Schedule B-1 is electric generating facilities added or planned to be added since UMERC's inception in 2017. The two RICE facilities: Mihm and Kuester, placed in service in 2019, have a 2025 13-month average net plant balance of $215.8 million. The construction of these facilities was approved in Case No. U-18224.

The Renegade Solar Project has a 2025 13 month average construction work in progress (CWIP) balance of $138.6 million. The contracts for this project were approved in Case No. U-21081, which included authorization to utilize allowance for funds used during construction ("AFUDC") on 100% of the construction work in progress balance during construction. Consistent with the approval, UMERC is forecasting AFUDC revenue during the 2025 projected test year on the cash portion of this balance.

<u>Operating Income</u>

Q. Please explain Schedule C1 of Exhibit A-13.

A. Schedule C1 of Exhibit A-13 calculates UMERC's 2025 projected test year adjusted net operating income related to the electric operations.

Q. Please explain Schedule C2 of Exhibit A-13.

A. Schedule C2 of Exhibit A-13 calculates UMERC's 2025 projected test year gross revenue conversion factor.

Q. Please explain Schedule C3 of Exhibit A-13.

A. Schedule C3 of Exhibit A-13 calculates UMERC's 2025 projected test year total electric revenue.

Q. Please explain Schedule C4 of Exhibit A-13.

A. Schedule C4 of Exhibit A-13 calculates UMERC's 2025 projected test year fuel, purchased power, transmission and regional market expenses that are included in UMERC's PSCR filings. Expenses included in this schedule are addressed in the testimony of Company witness Beyer.

Q. Please explain Schedule C5 of Exhibit A-13.

A. Schedule C5 of Exhibit A-13 calculates UMERC’s 2025 projected test year total electric operations O&M expense, exclusive of fuel, purchased power, transmission and regional market expenses included in Schedule C4.

Q. Please explain Schedule C6 of Exhibit A-13.

A. Schedule C6 of Exhibit A-13 depicts UMERC’s 2025 projected test year total electric utility depreciation and amortization expense based on rates and practices approved in Case Nos. U-17849, U17446 and U16269. The impacts of the depreciation rate for the RICE Units, as proposed in pending Case No. U-21542, are reflected in Exhibit A-18.

Q. Please explain Schedule C7 of Exhibit A-13.

A. Schedule C7 of Exhibit A-13 calculates UMERC’s 2025 projected test year total for taxes other than income taxes related to the electric operations.

Q. Please explain Schedule C8 of Exhibit A-13.

A. Schedule C8 of Exhibit A-13 depicts UMERC’s 2025 projected test year federal income taxes allocated to the electric operations.

Q. Please explain Schedule C9 of Exhibit A-13.

A. Schedule C9 of Exhibit A-13 depicts UMERC’s 2025 projected test year state income taxes allocated to the electric operations.

Q. Please explain Schedule C10 of Exhibit A-13.

A. Schedule C10 of Exhibit A-13 depicts UMERC’s 2025 projected test year local taxes.

Q. Please explain Schedule C11 of Exhibit A-13.

A. Schedule C11 of Exhibit A-13 depicts UMERC's 2025 projected test year electric operations AFUDC.

<u>Capital Structure</u>

Q. Please explain Schedules D1 of Exhibit A-14.

A. Schedule D1 of Exhibit A-14 develops UMERC's 2025 projected test year overall rate of return of 6.56%, shown on Line 22, Column G based on UMERC's 13-month average permanent common equity ratio set at 50% with a 10.25% ROE, as shown on Line 6.

Q. Please explain Schedules D2 of Exhibit A-14.

A. Schedule D2 of Exhibit A-14 develops UMERC's 2025 projected test year embedded cost of long term debt of 4.67%, based on a 13-month average, as shown on Line 21. There are two new debt issues: one in the 2024 bridge year, a $60 million 30-year issue in July 2024, with an expected interest rate of 6.95% and one in the 2025 test year, a $50 million 30-year issue in July 2025, also with an expected interest rate of 6.95%.

Q. Please explain Schedules D3 of Exhibit A-14.

A. Schedule D3 of Exhibit A-14 develops UMERC's 2025 projected test year cost of short-term debt of 5.32%, based on a 13-month average, as shown on Line 26. The forecasted borrowing rate includes $210 thousand of fixed fees for credit facility fees and amortization and rating agency fees.

Q. How did you determine the cost rates of long and short term debt reflected in the weighted cost of capital?

A. The cost rate of long term debt reflects the embedded weighted cost of existing long term debt adjusted for two forecasted new issues. The rate for those new issues is forecasted at 6.95% in both July 2024 and July 2025. It includes the 30-year forecasted benchmark Treasury at 4.45% plus a 250 basis point spread. The 250 basis point spread can be split into multiple components – 120 basis points for the historical credit spread between Treasuries and A rated utilities when the markets are in good order, 20 basis points for issuing in the private placement market, 40 basis points for both infrequency of issuance and for small size and 70 basis point spread risk for market volatility. UMERC estimated a test year incremental short term debt rate of 4.63% This forecast average annual rate began with the Company's Q1 2024 overnight borrowing rate of 5.50% with reductions of 25 bps each in Q3 and Q4 of 2024 and 50 bps each in Q3 and Q4 of 2025 per the Federal Open Market Committee ("FOMC") March 2024 Dot Plot, which shows consensus expectations of interest rates for future decisions by the FOMC.

Q. Please explain Schedule D4 of Exhibit A-14.

A. Schedule D4 of Exhibit A-14 indicates that UMERC has no preferred equity outstanding, as shown on Line 2.

Q. Please explain Schedule D5 of Exhibit A-14.

A. Schedule D5 of Exhibit A-14 develops UMERC's 13-month average balance of Common Equity of $241.75 million for the 2025 projected test year, as shown on Line 16. UMERC requests a 10.25% ROE for the 2025 projected test year in this general rate case proceeding, as supported by witness Bulkley.

Q. Does UMERC present any other evidence on cost of capital?

A. Yes, it does. Witness Bulkley provides evidence on UMERC's cost of equity by presenting analytical studies employing various industry models.

<u>Labor Charges</u>

Q. Does UMERC have employees?

A. No, as addressed in witness Stasik's direct testimony, UMERC does not have employees. However, while UMERC doesn't have its own employees, it receives labor charges from affiliate utilities and WEC Business Services (WBS) via the Affiliated Interest Agreement. Employees of affiliated companies perform daily operational work as well as support services such as accounting, human resources, supply chain, etc. Pursuant to the AIA, Exhibit A-20, Article II, 1 (a): All Services that any Regulated Party provides to another Regulated Party will be priced at cost, with cost determined pursuant to Section III.2. (Article III.2.(a) also covers the labor overheads "iii. All appropriate overheads will follow labor costs."). Any labor charges included in this case are charges from affiliated companies. Benefit costs are presented as non-labor in FERC 926. Exhibit A-17, Schedule G1 shows a breakdown of Labor and Nonlabor O&M costs. In 2025 test year, we are projecting $4.42M of affiliate labor charges as well as $1.38M of employee benefit costs.

<u>Inflation Rates</u>

Q. Please explain Schedule G15 of Exhibit A-17.

A. Schedule G15 calculates the non-labor inflation rates for 2024 and 2025 using a simple average of forecasted CPI inflation rates published by the Philadelphia Federal Reserve Bank and the Blue Chip Economic Indicators published by Wolter Kluwer. This methodology is similar to that used in WEC's filings for its Michigan Gas Utilities Corporation, most recently in Case No. U-21540. The non-labor inflation rates calculated are 2.50% for 2024 and 2.35% for 2025.

Q. Please explain how increasing labor costs are incorporated into this rate case.

A. UMERC does not have direct labor, but labor is cross charged from affiliates including WEPCO and WPS union labor as well as WBS management employees to operate UMERC as allowed per WEC Energy Groups Affiliated Interest Agreement. The labor inflation factors were calculated by using the projected general wage increases for the companies supporting UMERC by pay group (contract rates for union employees) and weighting them by the 2022 actual labor dollars charged to UMERC for each pay group. The labor inflation rates calculated are 4.48% for 2024 and 4.56% for 2025.

<u>O&M Expenses</u>

Q. Please describe how UMERC developed 2025 O&M expenses included in Schedule C5 of Exhibit A-13.

A. UMERC started with 2023 actual O&M expenses and inflated them to 2025 using the rates developed on Schedule G15 in Exhibit A-17. UMERC then adjusted this 2025 O&M expense value for the known and measurable ("K&M") items and incremental O&M, as described later in my direct testimony.

Q. Please explain Schedule G1 of Exhibit A-17.

A. Schedule G1 develops the O&M costs for UMERC's 2025 projected test year. This exhibit begins with 2023 actual O&M amounts. The 2023 expenses were first inflated at the estimated inflation factors as calculated on Exhibit A-17 Schedule G15. The O&M accounts were further adjusted for K&M items.

<u>Known and Measurable Items</u>

Q. How do UMERC's O&M expenses in 2025 compare to the O&M expenses that were used to set the Company's current rates for non-Tilden retail electric customers?

A. While this portion of my direct testimony addresses known and measurable increases in various O&M expenses in relation to 2023, it is worth noting that the O&M expenses proposed in this case for the 2025 test year represent a significant reduction from those used to set UMERC's current rates, as explained by witness Stasik at pages 26-27 of his direct testimony.

Q. Please describe the K&M adjustments included in the 2025 projected test year O&M expenses, as detailed on Schedule G1 of Exhibit A-17 compared to actual O&M expenses from 2023.

A. There are 13 FERC accounts effected by K&M adjustments. UMERC has defined K&M items to be any O&M cost item that was increased (or decreased) at a rate other than the rates of inflation calculated on Exhibit A-17 Schedule G15.

Each of these K&M adjustments is discussed in further detail below.

Q. Please explain Schedule G2 of Exhibit A-17.

A. Schedule G2 of Exhibit A-17 calculates the K&M adjustment for Account 549 Miscellaneous Other Power Generation Expenses. This adjustment relates to air fees payable to the Michigan DNR that are required to operate the RICE Units. The total K&M

adjustment of $25,588 relates to an increase in estimated air fees due in 2025 as compared to 2023 after inflation.

Q. Please explain Schedule G3 of Exhibit A-17.

A. Schedule G3 of Exhibit A-17 calculates the K&M adjustment for Account 553 Maintenance of Generating and Electric Plant. The main driver of the increase is scheduled engine maintenance occurring in 2025 versus 2023 inflated. The manufacturer of the engines, Wartsila, defines maintenance requirements based on 2,000 hour intervals of engine operating hours (i.e., every 2,000 hours of operation maintenance is scheduled). There are two classifications for maintenance schedule, minor and major. Major maintenance intervals occur every 20,000 and 30,000 engine operating hours, all other intervals are considered minor. Major maintenance interval work scope includes more disassembly, inspection and replacement of engine components than minor maintenance, therefore the cost is substantially higher. For example, expenses for minor maintenance are in the $2,000 to $5,000 per occurrence, while expenses for major maintenance range from about $300,000 to $800,000 depending upon scope and per occurrence. Based on current estimate of hours of dispatch, the engines will reach 30,000 hours of operation starting in fourth quarter of 2024, and ending in second quarter of 2026. The Company projects a K&M increase of $3,592,083 related to the additional scheduled maintenance described above.

Q. Please explain Schedule G4 of Exhibit A-17.

A. Schedule G4 of Exhibit A-17 calculates the K&M adjustment for Account 588 Distribution Operation Miscellaneous Expenses. This increase relates to a higher cost of locating services. This higher projected cost is a result of (1) a higher cost per locate resulting from a new contract for locating services provided by an outside vendor, and (2) a projected increase in the volume of locates due to increased project work. The Company projects a K&M increase of $36,665 related to the increases described above.

Q. Please explain Schedule G5 of Exhibit A-17.

A. Schedule G5 of Exhibit A-17 calculates the K&M adjustment for Account 592 Maintenance of Station Equipment. This adjustment relates to additional corrective and preventative maintenance related to UMERC's substations. Preventative maintenance in 2025 includes an increase in the number of substation oil changes as compared to 2023. The Company projects a K&M increase related to the additional station maintenance activities of $80,000 for the 2025 test year.

Q. Please explain Schedule G6 of Exhibit A-17.

A. Schedule G6 of Exhibit A-17 calculates the K&M adjustment for Account 593 Maintenance of Overhead Lines. The adjustment is based on the following incremental maintenance activities. UMERC projects an increased number of pole inspection and treatments required in 2025 as compared to 2023, as well as incremental increases to vegetation management. Additional corrective maintenance is also projected for cutouts and arrestors. These additional maintenance activities reflect the maintenance required to maintain aging equipment. The Company projects a K&M increase of $870,000 for the 2025 test year related to the maintenance activities identified above.

Q. Please explain Schedule G7 of Exhibit A-17.

A. Schedule G7 of Exhibit A-17 calculates the K&M adjustment for Account 903 Customer Record and Collection of $71,520. This adjustment is primarily associated with one-time credits received in 2023 from an IT vendor utilized for contract services.

Q. Please explain Schedule G8 of Exhibit A-17.

A. Schedule G8 of Exhibit A-17, page 1 of 2 calculates the K&M adjustment associated with uncollectible expense. UMERC has forecasted its 2025 projected test year uncollectible expense based on its 2-year historic average of net write-offs. This results in a total K&M decrease of $429,277 in Account 904.

Schedule G8 of Exhibit A-17, page 2 of 2, calculates the 2025 projected test year uncollectible expense. As shown on this exhibit, for the 2-year period 2022-2023, UMERC's average net uncollectibles have equaled 1.245% of UMERC's tariff revenues, which excludes Special Contract revenue from Tilden. This percent was multiplied by UMERC's 2025 projected test year revenues of $78.3 million, also excluding the Tilden Special Contract revenue, to arrive at a 2025 projected test year uncollectible expense of $974,429.

Q. Please explain Schedule G9 of Exhibit A-17.

A. Schedule G9 of Exhibit A-17 calculates the K&M adjustment for Account 920 Administrative and General Salaries. There are multiple headcount backfills in the corporate services area of WBS driving the increase in this Account. The cost of these positions and additional support are allocated to WEC Energy Groups utilities. UMERC's allocation represents a K&M increase of $101,905.

Q. Please explain Schedule G10 of Exhibit A-17.

A. Schedule G10 of Exhibit A 17 calculates the K&M adjustment for Account 921 Office Supplies and Expense. This K&M adjustment totaling $151,478 relates to two primary drivers: (1) an increase in the cross charged labor drove an increase in the cross charged facility costs that follows labor and (2) UMERC's allocation for non-labor corporate service costs in excess of inflation.

Q. Please explain Schedule G11 of Exhibit A-17.

A. Schedule G11 of Exhibit A-17 calculates the K&M adjustment for Account 923 Outside Services Employed. This K&M adjustment totaling $405,941 relates to several drivers. First, is increases associated with legal support for this rate proceeding. Second, relates to a substantial increase in hourly rates for external legal costs which is estimated to be 10% annually which exceeds the non-labor inflation rate which average 2.4% over the two-year build-up. Third, an increase for additional climate change disclosures. And fourth, cost increases in excess of standard inflation related to IT software and hardware maintenance and external audit fees. The Company projects a K&M increase of $405,941 for the 2025 test year.

Q. Please explain Schedule G12 of Exhibit A-17.

A. Schedule G12 of Exhibit A-17 calculates the K&M adjustment for Account 925 Injuries and Damages Expense. There has been an unfavorable trend for liability insurance primarily due to the fact that we remain in the midst of a historically difficult property casualty insurance market cycle. Our liability insurers have cited an uptick in major plaintiff-friendly verdicts and third-party litigation financing as reasons liability claim outcomes have trended unfavorably in recent years. The Company estimates a K&M increase of $60,079 for the 2025 test year.

Q. Please explain Schedule G13 of Exhibit A-17

A. Schedule G13 of Exhibit A-17 calculates the K&M adjustment for Account 926 Employee Pensions and Benefits Expenses. This $886,940 adjustment is associated with expected increases in employee benefit costs at the affiliated companies charging UMERC via the affiliate labor charges described previously in my testimony.

Q. Please explain Schedule G14 of Exhibit A-17.

A. Schedule G14 of Exhibit A-17, page 1 of 2 calculates the K&M adjustment associated with Account 930.2. UMERC has forecasted the projected test year Account 930.2 to be $57,901. That is a K&M increase of $16,772 from the 2023 costs inflated to 2025. This K&M adjustment is associated with UMERC's portion of the return on and of ("Return On/Of") WBS assets and net working capital as allowed in the shared service agreement between UMERC and WBS. The forecasted 2025 Service Company (WBS) Return On/Of is ($97,133) as shown on line 14 of page 2. The 2023 actual amount was $(108,646). The K&M increase largely represents the difference between the 2023 amount inflated and the forecasted 2025 Service Company (WBS) Return On/Of amount. Schedule G14 of Exhibit A-17, page 2 calculates the 2025 Service Company (WBS) Return On/Of, which is a combination of Return on Assets and a Depreciation Charge to UMERC from WBS.

<u>**Depreciation Rates**</u>

Q. What depreciation rates were used in this rate case?

A. UMERC used depreciation rates and practices approved in Case Nos. U-17849, U-17446 and U-16269.

Q. Does UMERC have a pending depreciation case filed with the MPSC?

A. Yes, a depreciation case No. U-21542 was filed in January of 2024 to propose depreciation rates for the RICE Units.

Q. What impact would those proposed depreciation study rates have on the annual rate increase?

A. As described above, UMERC estimates in Exhibit A-18 that the impacts of the proposed depreciation rates for the RICE Units would increase the 2025 revenue deficiency by $0.95 million.

<u>Taxes other than Income Taxes</u>

Q. Please explain Schedule C7 of Exhibit A-13

A. Exhibit A-13 schedule C7 calculates expenses associated with Account 408, UMERC has forecasted the projected test year to be $7.9 million. UMERC's personal property taxes are the main driver of the increase.

Q. How are Michigan Personal Property Taxes Calculated?

A. Michigan personal property taxes are based on the amount of taxable personal property reported in Michigan multiplied by an inflated composite jurisdictional specific mill rate.

Q. How does UMERC estimate personal property tax expense in the current forecasted test year?

A. For the current test year, UMERC forecasted its personal property tax expense by first estimating the amount of taxable personal property reported in Michigan related to forecasted changes in gross book value. Additionally, for the RICE Units, UMERC then used the projected multipliers published by the state of Michigan to project the cost to an assessed value. UMERC also uses the non-labor inflation rates to estimate changes in the composite jurisdiction mill rate for all personal property. This resulted in $8.4 million of personal property tax expense estimated in the projected test year.

Q. Were there any unique adjustments made to the original $8.4 million estimate of personal property tax expense in the current forecasted test year?

A. Yes, for the current test year, UMERC forecasted an adjustment to capitalize the personal property tax expense estimated related to a substantial generation plant investment accounted for in construction work in progress. This resulted in a reduction in personal property tax expense of approximately $0.9 million. Additionally, for the current test year, UMERC forecasted an adjustment to reduce personal property tax expense estimated by approximately $0.5 million related to a proposed conversion of its accounting method for property tax expense to a deferral method of accounting. In combination these two adjustments lowered the total personal property tax expense estimated resulting in $7.0 million assumed in the projected test year.

Q. Please describe the accounting method change proposed by UMERC for property tax expense.

A. In the state of Michigan, property tax expense for a given year is based on the ending property value for the tax year immediately preceding it. Michigan mails two tax bills each year, a summer bill, usually received in August, and a winter bill, usually received in December. Both bills are based on the prior year, end of year property values. Historically, UMERC has accrued its estimated property tax liability to expense in the year preceding the receipt of the actual tax bills. In the projected test year UMERC proposes transitioning to a deferral method of accounting where the estimated property tax liability would be accrued to a miscellaneous accrued asset rather than expense in the year preceding the receipt of the actual tax bills. This accrued asset would then be amortized to expense during the following year of which the property tax relates and when the payments are typically made. Furthermore, this method more precisely aligns the property tax expense recovery from customers to the year in which the payments are made.

Regulatory Amortizations

Q. Please describe Exhibit A-19.

A. Exhibit A-19 shows the balances of regulatory assets and liabilities and the regulatory amortizations recorded in the 2022 historical financial statements for those where the test year amortization is varying from the historic test year amount. The schedule then shows the forecasted activity in the regulatory assets and liabilities and the resulting regulatory amortizations included in the 2025 forecasted test year.

Q. Please describe significant changes in the annual amortizations of regulatory assets and liabilities included in the 2025 forecasted test year compared to the amortizations in the 2022 actual historical financial statements and the justification for those changes.

A. The changes in amortizations and justification are as follows:

MI AES deferral. This deferral was requested by WEPCO in 2013 to recover electric production costs (demand and energy) that were intended to be recovered from Michigan customers who subsequently switched to retail access service ("RAS"). The MPSC approved this deferral request in its August 29, 2013 Order in Case No. U-17463. The deferral was calculated using a fixed power supply per kWh factor from the sales forecast in Case No. U-16830. That factor was applied to actual RAS sales beginning September 2013 through December 2014. The deferral was discontinued in 2015 as a result of changes in load sharing ratios used by MISO that reflected updated kWh sales adjusted for RAS (i.e., 2014 actual kWh sales). This deferral was transferred from

WEPCO to UMERC with its formation, to be resolved in this rate filing. The 2025 test year forecast reflects an amortization of $313,915, which assumes a two-year recovery of this regulatory asset.

W3 ReAct deferral. With the MPSC Order Approving Settlement Agreement in Case No. U-17669, issued April 23, 2015, on or after the in-service date, WPS Corp was authorized to defer the revenue requirement related to the Weston 3 Regenerative Activated Coke Technology (ReACT) environmental project for the Michigan jurisdiction. The deferred balance was transferred from WPS Corp to UMERC and the deferral continued until the UMERC RICE Units were placed in service in March 2019. The 2025 test year forecast reflects an amortization of $909,285 which assumes a two-year recovery of this regulatory asset.

Plant Retirements (PIPP). In April 2019, WEPCO retired the Presque Isle Power Plant ("PIPP") and subsequently received approval from the MPSC in Case No. U-18061, to allocate the remaining net book value at retirement, plus future costs related to removal for PIPP decommissioning and PIPP material and supply inventories deemed obsolete based on an allocation factor of 6.595%. Costs allocated to UMERC were then allocated to Tilden (74.72%) and non-Tilden customers (25.28%). Recovery of the costs allocated to Tilden occurs through the Tilden Special Contract. Since established, the regulatory asset related to non-Tilden costs has been amortized based on the PIPP depreciation assumed in WEPCO's last rate case (No. U-16830). The proposed amortization for non-Tilden customers included in the 2015 test year is $187,250 which will provide for full recovery in 2037. This proposed amortization is a $7,230 increase over the 2022 actual amortization.

MI MISO SSR deferral. In June 2014 the MPSC Order Approving Settlement Agreement in Case No. U-17312 authorized WEPCO to defer (1) any Michigan allocated portion of System Support Resource ("SSR") uplift charges incurred by WEPCO in 2014 related to operation of PIPP, and (2) any Michigan allocated portion of revenues or credits received by WEPCO as part of the fixed component of compensation under its SSR agreement with MISO regarding operation of the PIPP. The Michigan deferral of SSR fixed revenue during 2014 created a regulatory liability, and the deferral of the associated PIPP SSR fixed uplift charge was netted against the regulatory liability. The fixed SSR revenue and uplift amounts were deferred during 2014. Variable SSR amounts were not deferred. After 2014, this deferral ended because these costs were included in subsequent PSCR filings. The 2025 test year reflects an amortization of ($133,026) which returns the liability to customers over two years.

Tax savings/remeasure. UMERC has implemented a series of deferrals associated with its net income tax savings resulting from the Tax Cut and Jobs Act ("TCJA") which became effective on January 1, 2018. The regulatory impact applies to reductions in current income tax expense and savings generated by remeasurement of UMERC's deferred tax asset and liabilities. UMERC is currently issuing bill credits to pass through tax savings to customers until the next rate filing. The 2025 test year incorporates the impacts of the TCJA in projected income tax expense, therefore the bill credits being issued currently will end on December 31, 2024. UMERC projects that there will be a net regulatory liability of $965,000, representing the actual savings from the TCJA less the amount returned to customers through the bill credits. The 2025 test year reflects an amortization of ($482,500) which assumes a two-year amortization of the credit associated with this regulatory liability. Since the actual amount of the regulatory liability will not be finalized until the conclusion of the bill credits, UMERC proposes to defer any residual regulatory asset or liability remaining at the end of the two year amortization period until its next rate filing.

De Pere Energy Center. The amortization of the De Pere Energy Center regulatory asset was complete in 2023, therefore no amortization is included in the 2025 test year, a reduction of $43,452 from the 2022 actual amortization.

Q. Are there any regulatory assets of liabilities that are not included in Exhibit A-19?

A. Yes, regulatory assets and liabilities that are recorded to comply with financial reporting requirements, but do not impact UMERC's revenue requirement are excluded from Exhibit A-19. These regulatory assets and liabilities are primarily related to income taxes. In addition, regulatory assets and liabilities associated with the Energy Waste Reduction and Renewable Energy programs are excluded. Costs and revenues associated with these two programs are excluded from the 2025 forecast test year and, therefore, have no impact on the projected revenue deficiency. Lastly, those regulatory assets and liabilities that are not projected to change in the test year from the 2022 historic test period are not shown, this includes any and all gas-operations-specific amortizations.

Matching of revenues and costs recovered through PSCR filings

Q. Has UMERC matched fuel, purchased power and transmission costs included in annual PSCR filing in the calculation of the revenue deficiency in this general rate case proceeding?

A. Yes. The PSCR cost recovery factors used to calculate Revenues on Present Rates in the financial filing schedules supporting this application were calculated, such that fuel, purchased power, transmission and regional market costs included in UMERC's annual PSCR filing equal PSCR cost revenues, resulting in one-for-one recovery of PSCR costs.

<u>Tilden Special Contract and related recovery of utility costs</u>

Q. Please explain how the Tilden Special Contract originated.

A. As described in witness Stasik's direct testimony, the Tilden Special Contract originated as part of an overall proposal to address the MPSC's directive to facilitate a long-term solution for new, cleaner generation in the Michigan upper peninsula ('UP") which would then allow for retirement of PIPP as captured in the Amended and Restated Settlement Agreement approved in Case No. U-17862. A significant driver of the need for a new generation resource in the UP (as opposed to a transmission alternative) was the electric load and energy requirements of Tilden. The Tilden Special Contract was an integral component to UMERC's commitment to construct the RICE Units. In its October 25, 2017 Opinion and Order in Case No. U-18224, the MPSC granted approval of a certificate of need to construct the RICE Units and approved the Tilden Special Contract. UMERC represented that the construction of the RICE Units, in conjunction with the Tilden Special Contract was the best solution to address generation needs of both Tilden, and the other non-Tilden retail electric customers of UMERC. With reference to the Tilden Special Contract, the MPSC agreed with UMERC's assertion that the non-Tilden retail electric customers benefit through risk reduction and reduced cost as compared with alternatives.

Q. What are the primary components of the energy charges under the Tilden Special Contract.

A. The amounts billed under the Tilden Special Contract contain three primary components. (1) Fuel, purchased power and transmission costs traditionally recovered in UMERC's annual PSCR filings, (2) other operating expenses including substantially all of the costs required to operate the RICE Units and (3) recovery of 50% of return on/of UMERC's capital investment in the RICE Units.

Q. Please describe the components of the fuel, purchased power and transmission billed under the Tilden Special Contract.

A. Under the Special Contract, Tilden pays UMERC for fuel costs to operate the RICE Units for its electric load, purchases and sales of power from MISO for its load, and transmission costs for transmission services for its load pursuant to the terms of the Special Contract. UMERC estimates that $45.1million of expenses related to fuel, purchased power and transmission will be billed under the Tilden Special Contract in the 2025 test year.

Q. Please describe the other operating costs billed under the Tilden Special Contract.

A. Under the Tilden Special Contract, Tilden pays for virtually all of the costs to operate and maintain the RICE Units. Those costs include the maintenance expenses recorded in FERC Account 588 related to major maintenance overhauls of the RICE Units. The 2025 test year forecast assumes that $12.6 million of operating and maintenance expenses to operate the RICE Units will be billed under the Tilden Special Contract. In addition to those costs, the Tilden Special Contract provides for recovery of administrative and general expenses and distribution expenses based on an amount specified in the Tilden Special Contract, adjusted annually for inflation. UMERC estimates that $1.0 million related to these additional expenses will be billed under the Tilden Special Contract .

Q. Please describe the recovery of the capital investment in the RICE Units under the Tilden Special Contract.

A. Under the Special Contract, Tilden is billed a firm planning load cost equating to 180 megawatts of energy demand, roughly equal to the total megawatt capacity of the RICE Units. Next, Tilden receives a 50% credit for non-firm (interruptible) load. The 2025 test year forecast assumes Tilden will make 100% its planning load interruptible, resulting in UMERC recovering 50% of its return on/of capital investment in the RICE Units, including capital improvements, through the Tilden Special Contract.

Q. Is there anything unique about the recovery of the RICE generation capital investment in the Tilden Special Contract?

A. Yes, there are three unique items. First, as part of its application for approval of the RICE Units, UMERC agreed that it would keep non-Tilden customers financially harmless for Tilden's portion (50%) of the return on/of capital investment associated with the RICE Units should UMERC be unable to recover the investment from Tilden. In doing so, UMERC accepted additional risk for its capital investment. Second, the Tilden Special Contract is designed to recover the 50% capital investment allocated to Tilden over a 20-year period, which is less than the estimated useful life of the RICE Units. Third, UMERC is recovering Tilden's 50% share of the return on/of capital investment under the Special Contract using a levelized recovery method. This levelized recovery method projected to generate less revenue than normal utility ratemaking in the initial years of the 20-year recovery period, but higher revenues in the later years.

Q. Are there any other billing components associated with the Tilden Special Contract?

A. Yes. The Tilden Special Contract also specifies the approach for recovering Tilden's (74.72%) allocation of UMERC's PIPP unrecovered plant and cost of removal. Similar to the recovery of the RICE capital investment, the recovery uses a levelized approach that incorporates a return on the unamortized balance over the 20-year contract period.

Q. Has the Company proposed an approach to allocate costs between Tilden and UMERC's non-Tilden retail electric customers?

A. Yes. In its filing for approval of the Tilden Special Contract (U-18224), UMERC proposed allocating costs to Tilden and non-Tilden customers in a manner consistent with the Tilden Special Contract. As I described earlier, this approach would result in the non-Tilden customers absorbing virtually no operating and maintenance expenses associated with the operation of the RICE Units. However, non-Tilden customers would be allocated all of the personal property tax expenses, most of the generation production related administrative and general expenses and other generation production expenses not directly related to the operating of the RICE Units.

For power supply expenses recovered thought UMERC's PSCR filings, UMERC proposed that the amounts billed to Tilden for fuel, purchased power and transmission would be credited to the total UMERC power supply expenses. This would result in UMERC's non-Tilden customers absorbing the remaining power supply expenses (including electric transmission and natural gas pipeline costs).

Finally, non-Tilden customers would be responsible for 50% of the RICE Units capital costs, recovered using traditional ratemaking. This would include recovery of depreciation expense and return on the net capital investment.

Q. Did the MPSC approve the Company's proposed regulatory treatment described above?

A. The MPSC deferred approval of the cost allocations for ratemaking purposes because it determined that the Company first needed to provide a full cost of service analysis before determining whether to use UMERC's proposed allocation method. Because the RICE generation facilities did not exist at the time of approval, UMERC was not able to provide the requested analysis. However, the MPSC did approve UMERC's proposed allocation for power supply costs recovered through UMERC's annual PSCR filings.

Q. Will UMERC provide the cost of service analysis as part of this filing?

A. Yes, Company witness Nelson has performed this analysis and has incorporated it in his testimony.

Q. Does this conclude your pre-filed direct testimony at this time?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase retail natural gas rates and for other relief.	)	Case No. U-21541

DIRECT TESTIMONY AND EXHIBITS OF

JARED J. PECCARELLI

FOR

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

May 1, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase retail natural gas rates and for other relief.	)	Case No. U-2xxxx

QUALIFICATIONS
OF
JARED J. PECCARELLI
PART I

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

A. My name is Jared Peccarelli. My business address is 231 West Michigan St., Milwaukee, WI 53203. I am employed by WEC Business Services, LLC ("WBS"), a subsidiary of WEC Energy Group, Inc. ("WEC"), as Manager - Sales Forecasting

Q. For whom are you providing testimony?

A. I am providing testimony on behalf of Upper Michigan Energy Resources Corporation ("UMERC" or the "Company"), a subsidiary of WEC.

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

A. I received both a Bachelor of Science degree in Computer Science and a Master of Business Administration degree with a finance concentration from the University of Wisconsin – Milwaukee. In addition, I have completed all coursework required for a Master of Science degree in Applied Economics from Marquette University in Milwaukee, Wisconsin. I was hired by We Energies (a subsidiary of WEC Energy Group) in November 2002 and worked in various roles in several departments prior to my current position. I joined the Sales Forecasting team in Finance as a Principal Analyst in 2014 and have developed or assisted in the development of long-term electric and natural gas sales forecasts for multiple WEC operating utility subsidiaries since then. I am currently responsible for overseeing the development of the long-term sales forecasts for all of the electric, natural gas and steam utility operating subsidiaries of WEC, including UMERC.

Q. Have you previously testified before any regulatory agency?

A. Yes. I have submitted direct testimony concerning sales forecasting on behalf of MGUC's general rate case proceedings before the Michigan Public Service Commission ("MPSC" or the "Commission") in Case Nos. U-21366 and U-21540. I have also submitted direct, rebuttal and surrebuttal testimony related to sales forecasts for multiple operating utility subsidiaries of WEC and before the Public Service Commission of Wisconsin, the Minnesota Public Utilities Commission and the Illinois Commerce Commission in general rate case proceedings.

JARED J. PECCARELLI
DIRECT TESTIMONY
PART II

Q. What is the purpose of your pre-filed direct testimony?

A. The purpose of my direct testimony is to provide an explanation of the methodology used to develop UMERC's weather normalization procedure and resulting sales forecast for the 2025 projected Test Year.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-5	E1	Annual Service Sales by Major Customer Classes and System Output 5-Year Historical;
A-15	E1	Market Outlook: 5-Year Annual Calendar Year Electric Forecast by Class

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. Please explain Exhibit A-5, Schedule E1.

A. Exhibit A-5, Schedule E1, is a summary of the five-year Historical Annual Service Area Sales by Major Customer Classes and System Output. This exhibit is filed in accordance with the Commission's rate case filing guidelines in Case No. U-18238.

Q. Please explain how UMERC's 2025 projected Test Year sales forecast was developed.

A. The Residential customer class sales forecast was developed using two statistical models for each Rate Zone: 1) an average use-per customer (UPC) model; and 2) a customer count model. The average UPC forecast was developed by creating regression models in the Itron MetrixND forecasting application using normal weather, household income, and cooling efficiency variables for the regions associated with each Rate Zone. The customer count forecast was developed by creating regression models in MetrixND using population and household count variables for the regions associated with each Rate Zone. The historical model data was based on monthly customer counts and monthly sales in kWh from the period January 2013 through March 2023. The monthly forecasted results from the average use-per customer and customer count were multiplied to calculate the monthly sales forecasts for both Rate Zones.

The Commercial customer class sales forecast was developed using two statistical models for each Rate Zone: 1) an average use-per customer (UPC) model; and 2) a customer count model. The average UPC forecast was developed by creating regression models in MetrixND using weather and labor variables for the regions associated with each Rate Zone. The customer count forecast was developed by creating regression models in MetrixND using Gross Domestic Product (GDP) and Household Income variables for the regions associated with each Rate Zone. The historical model data was based on monthly customer counts and monthly sales in kWh from the period January 2013 through March 2023. The monthly forecasted results from the average use-per customer and customer count were multiplied to calculate the monthly sales forecasts for both Rate Zones. Customers served by an Alternative Energy Supplier ("AES") including their deliveries were excluded from the customer count and average use-per-customer models.

The AES Commercial forecast was developed using class level historical monthly sales and customer counts. The average UPC forecast was developed by taking the growth rate of weather-normalized historical UPC and applying it to the forecast period. The customer count forecast was developed by applying the historical customer growth rate to the forecast period. The monthly forecasted results from the average UPC and customer count were multiplied to calculate the monthly sales forecast.

The Industrial customer class sales forecast was developed using historical monthly billed sales by customer from January 2021 through March 2023. The individual customer forecasts were aggregated by rate schedule for each Rate Zone.

The Company Use sales forecast was based on averaging monthly volumes from January 2021 through July 2023.

The Lighting sales forecast for the WPSC Rate Zone was developed by using a 6-year average of calendar month historical sales from January 2018 through March 2023. The Lighting sales forecast for the WEPCo Rate Zone was developed by using a 6-year average of calendar month historical sales from January 2018 through March 2023.

Distribution losses were calculated by month for each customer class within each Rate Zone by multiplying the customer class sales forecasts, described above, by the customer class distribution loss factors.

Q. Please explain how normal weather was defined when developing the sales forecast.

A. Normal weather was defined as the average of the most recent 20 years using heating degree days with a set point of 65 degrees Fahrenheit and cooling degree days with a set point of 65 degrees Fahrenheit. For the 2025 projected Test Year, the annual total of 8,393 heating degree days was based on the 20-year period of 2003 through 2022; the total of 342 cooling degree days was based on the 20-year period of 2003 through 2022.

Q. Please explain the development of the weather data.

A. Actual heating degree days were calculated on a daily basis by subtracting the average daily temperature from the set point of 65 degrees Fahrenheit. The calculation used a floor value of zero which meant that an average daily temperature equal to or greater than 65 degrees resulted in zero heating degree days for the day. Actual cooling degree days were calculated on a daily basis by subtracting 65 from the average daily temperature in degrees Fahrenheit. The calculation used a floor value of zero which meant that an average daily temperature equal to or less than 65 degrees resulted in zero cooling degree days for the day. Each day's average temperature was calculated by averaging all of the hourly temperature values for the day at the weather station located in Iron Mountain, Michigan. The hourly temperatures were provided by DTN, a third-party data, analytics and technology service provider.

Q. What is the 2025 Test Year forecast of system sales and retail choice deliveries?

A. The 2025 Test Year forecast of system sales and retail choice deliveries, excluding company use and losses, is 1,955,689 MWh as presented in Exhibit A-15, Schedule E1. System Output in the Test Year is projected to be 1,989,338 MWh.

Q. How does the 2025 Test Year forecast compare to 2023 weather-normalized deliveries?

A. The 2025 Test Year forecast of total deliveries is 1.3% lower than 2023 weather-normalized deliveries on a compound annual growth rate (CAGR) basis. The 2025 Test Year forecast of Residential deliveries is 0.1% lower than 2023 weather-normalized deliveries on a CAGR basis. The 2025 Test Year forecast of Commercial deliveries is 1.5% lower than 2023 weather-normalized deliveries on a CAGR basis. Commercial deliveries include SC&I system sales and retail choice customers. The

2025 Test Year forecast of Industrial deliveries is 1.4% lower than 2023 weather-normalized deliveries on a CAGR basis. Industrial deliveries include LC&I system sales, retail choice customers and the large iron ore mine. The 2025 Test Year forecast of Other deliveries is 3.6% higher than 2023 weather-normalized deliveries on a CAGR basis. Other deliveries include Street Lighting system sales.

Q. How does the 2025 Test Year forecast compare to the sales forecasts on which current rates were set?

A. Case U-16830 includes the sales forecast for the 2012 Test Year from which current rates were set for the WEPCo Rate Zone and Case U-17669 includes the sales forecast for the 2015 Test Year for which current rates were set for the WPSC Rate Zone.

The 2025 Test Year forecasted *deliveries* for the WEPCo Rate Zone, excluding the large iron ore mines[1], are 14.6% higher than the prior test year. However, the 2025 Test Year forecasted *sales* for the WEPCo Rate Zone, excluding the large iron ore mines, are 29.9% lower than the prior test year due to SC&I and LC&I customers switching to retail choice. The 2025 Test Year forecast of retail choice deliveries for the WEPCo Rate Zone is 236,534 MWh compared to zero deliveries in the prior test year.

The 2025 Test Year forecasted deliveries for the WPSC Rate Zone are 14.3% lower than the prior test year. The 2025 Test Year forecasted sales for the WPSC Rate Zone are 24.3% lower than the prior test year due to LC&I customers switching to retail choice. The 2025 Test Year forecast of retail choice deliveries for the WPSC Rate Zone is 30,524 MWh compared to zero deliveries in the prior test year.

In total, the 2025 Test Year forecasted deliveries for the combined WEPCo and WPSC rate zones, excluding the large iron ore mines, are 4.1% higher than the prior

1 One of the two large iron ore mines was shut down in 2015.

test years. However, the 2025 Test Year forecasted sales for the combined WEPCo and WPSC Rate Zones, excluding the large iron ore mines, are 27.9% lower than the prior test year due to SC&I and LC&I customers switching to retail choice. The 2025 Test Year forecast of retail choice deliveries for the combined WEPCo and WPSC Rate Zones is 267,058 MWh compared to zero deliveries in the prior test year.

Q. What is the impact on the 2025 Test Year revenue deficiency associated with the change in sales between the 2025 Test Year and the 2012 Test Year from the Final Order of Case. U-16830 for the WEPCo Rate Zone and the 2015 Test Year 2015 from the Final Order of Case U-17669 for the WPSC Rate Zone?

A. The reduction in total system sales, excluding the large iron ore mines, which is due to C&I customers switching to retail choice (as explained above), results in an increase to the Test Year 2025 revenue deficiency.

Q. Does this complete your direct testimony at this time?

A. Yes, it does.

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

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase retail electric rates and for other relief	)	Case No. U-21541

DIRECT TESTIMONY AND EXHIBITS OF

ANN E. BULKLEY

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

May 1, 2024

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase retail electric rates and for other relief	)))))	Case No. U-21541

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. I am a Principal at The Brattle Group ("Brattle"). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this direct testimony before the Michigan Public Service Commission ("Commission") on behalf of Upper Michigan Energy Resources Corporation ("UMERC" or the "Company").

Q. Please describe your education and experience.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with over 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. My resume and a summary of testimony that I have filed in other proceedings is attached as Attachment A to this testimony.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the appropriate return on equity ("ROE") for UMERC, and to assess the reasonableness of its proposed capital structure for ratemaking purposes.

Q. Are you sponsoring any exhibits in support of your direct testimony?

A. Yes. I am sponsoring Exhibit **A-14**, Schedules D6 through D16, which were prepared by me or under my direction.

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. In developing my recommendation regarding the Company's proposed ROE in this proceeding, I have estimated the cost of equity by applying several traditional estimation methodologies to the proxy group, specifically the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also takes into consideration the Company's relative business and regulatory risk as compared with the proxy group, and the Company's proposed capital structure as compared with the capital structures of the operating utilities of the proxy group companies. While I do not make specific adjustments to my ROE recommendation for these factors, I did consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

Q. How is the remainder of your testimony organized?

A. The remainder of my direct testimony is organized as follows:

- Section II provides a summary of my analyses and conclusions.
- Section III reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section IV discusses current and projected capital market conditions and the effect of those conditions on UMERC's cost of equity.
- Section V explains my selection of the proxy group.
- Section VI describes my analyses and the analytical basis for my recommendation of the appropriate ROE for UMERC.
- Section VII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for UMERC in this case.
- Section VII provides an assessment of the reasonableness of UMERC's proposed capital structure.
- Section IX presents my conclusions and recommendations.

II. SUMMARY OF ANALYSIS AND CONCLUSION

Q. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. The key factors that I considered in my cost of equity analyses and recommended ROE for the Company in this proceeding are:

- The United States Supreme Court's *Hope* and *Bluefield* decisions[1] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.

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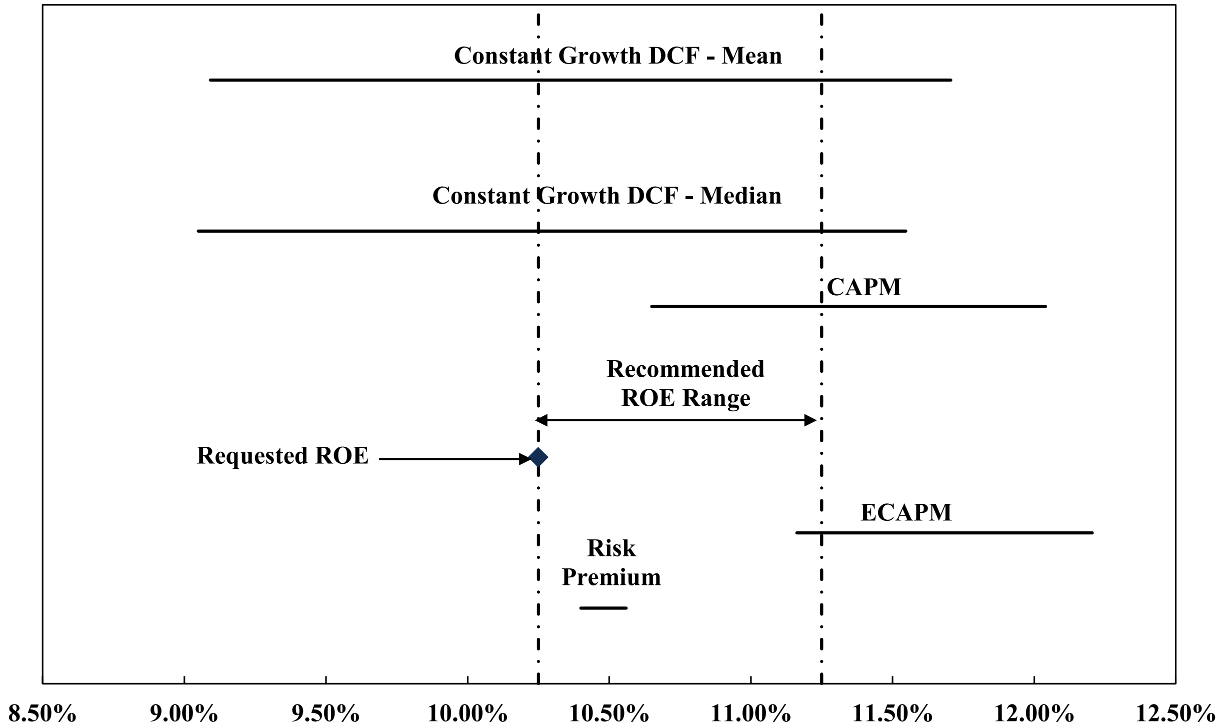
[1] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope"); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield").

- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis).
- Although the companies in my proxy group are generally comparable to UMERC, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I considered the Company's regulatory, business, and financial risks relative to the proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q. What are the results of the models that you have used to estimate the cost of equity for the Company in this proceeding?

A. Figure 1 summarizes the range of results of my cost of equity analyses.

Figure 1: Summary of Cost of Equity Analytical Results



As shown, the range of results across all methodologies is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies.

Q. Are prospective capital market conditions expected to affect the results of the cost of equity for the Company during the period in which the rates established in this proceeding will be in effect?

A. Yes. Capital market conditions are expected to affect the results of the cost of equity estimation models. Specifically:

- Long-term interest rates have increased substantially in the past two years and are expected to remain relatively high at least over the next year in response to inflation.

- Since (i) utility dividend yields are less attractive than the risk-free rates of government bonds; (ii) interest rates are expected to remain near current levels over the next year, and (iii) utility stock prices are inversely related to changes in interest rates; utility share prices may remain depressed.
- Rating agencies have responded to the risks of the utility sector, citing factors including elevated capital expenditures, interest rates, and inflation that create pressures for customer affordability and prompt rate recovery, and have noted the importance of regulatory support in their current outlooks.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of rising interest rates and have expected the sector to underperform in 2024.
- Consequently, it is important to consider that if utility share prices decline, the results of the DCF model, which relies on current utility share prices, would understate the cost of equity during the period that the Company's rates will be in effect.

It is appropriate to consider all of these factors when estimating a reasonable range of the investor-required cost of equity and the recommended ROE for the Company.

Q. What is your recommended ROE for the Company in this proceeding?

A. Considering the analytical results of the cost of equity models, current and prospective capital market conditions, and the Company's regulatory, business, and financial risk relative to the proxy group, I conclude that an ROE in the range of 10.25 percent to 11.25 percent is reasonable. The Company is requesting a more moderate return of 10.25 percent.

Q. Is UMERC's requested capital structure reasonable and appropriate?

A. Yes. The Company's proposed permanent capital structure of 50.0 percent equity and 50.0 percent long-term debt is within the range of the actual capital structures of the utility operating subsidiaries of the proxy group companies, and the Company's proposed equity ratio is below the average of the proxy group. Further, the Company's proposed equity ratio is reasonable considering credit rating agencies' continued concern with the negative effect on the cash flows and credit metrics associated relatively high interest rates and inflation, record levels of capital spending, and the need to fund capital spending in a credit supportive manner.

III. REGULATORY GUIDELINES

Q. Please describe the guiding principles to be used in establishing the cost of capital for a regulated utility.

A. The U.S. Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's authorized ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the specific means of arriving at a fair return are not important, only that the end result (*i.e.*, an ROE that reflects investors' requirements for investments of comparable risks and supports a utility's credit quality and access to capital) leads to just and reasonable rates.[2]

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes. For example, in its decision in Case No. U-20963, the Commission stated that:

> The criteria for establishing a fair ROR for public utilities is rooted in the language of the landmark United States (U.S.) Supreme Court cases *Bluefield Waterworks & Improvement Co v Public Serv Comm of West Virginia*, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923), and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944). The Supreme Court has made clear that, in establishing a fair

[2] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

> ROR, consideration should be given to both investors and customers. As stated on page 12 of the December 23, 2008 order in U-15244 (December 23 order), "the rate of return should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise." Nevertheless, the Commission observes that the determination of what is fair or reasonable, "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use." Meridian Twp v City of East Lansing, 342 Mich 734, 749; 71 NW2d 234 (1955).[3]

Further, in Case No. U-21389 the Commission also noted that the return to shareholders should be commensurate with the returns on investments in other enterprises with corresponding risks.[4] This guidance is in accordance with my view that an authorized rate of return on equity must be sufficient to enable regulated companies, like UMERC, the ability to attract equity capital on reasonable terms.

Q. Is fixing a fair rate of return just about protecting the utility's interests?

A. No. As the court noted in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties."[5] As the Court went on to explain in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests."[6]

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[3] MPSC Case No. U-20963, 12/22/2021 Order, at 221-222.

4 MPSC Case No. U-21389, March 1, 2024, at 64.

5 Bluefield, 262 U.S. at 679, 693.

[6] *Hope*, 320 U.S. at 591, 603.

Q. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable electric service while maintaining its financial integrity. That return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost.

Q. Is a utility's ability to attract capital also affected by the ROEs authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other utilities. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, over the same time period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.

Q. What is the standard for setting the ROE in a jurisdiction?

A. The stand-alone ratemaking principle is the foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. In order to maintain this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for the Company's utility operations.

Q. Does the fact that the Company is wholly-owned by WEC Energy Group, a publicly-traded company, affect your analysis?

A. No. In this proceeding, consistent with stand-alone ratemaking principles, it is appropriate to establish the cost of equity for UMERC, not its publicly-traded parent, WEC Energy Group, Inc. ("WEC Energy"). More importantly, however, it is appropriate to establish a cost of equity and capital structure that provide UMERC the ability to attract capital on reasonable terms, both on a stand-alone basis and within WEC Energy. While UMERC is committed to investing the required capital to provide safe and reliable service, because it is a subsidiary of WEC Energy, the Company competes with the other WEC Energy subsidiaries for discretionary investment capital. In determining how to allocate its finite discretionary capital resources, it would be reasonable for WEC Energy to consider the authorized ROE of each of its subsidiaries.

Q. Is the regulatory framework, including the authorized ROE and equity ratio, important to the financial community?

A. Yes. The regulatory framework is one of the most important factors in investors' assessments of the risk of utilities. Specifically, the authorized ROE and equity ratio for regulated utilities is very important for determining the degree of regulatory support for supporting a utility's creditworthiness and financial stability in the jurisdiction. To the extent that authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, such actions are considered by both debt and equity investors in the overall risk assessment of the regulatory jurisdiction in which the company operates.

Q. Are you aware of any utilities that have experienced a credit rating downgrade and/or market response related to the financial effects of a rate case decision?

A. Yes. There are numerous examples in which utilities have experienced a negative market response related to the financial effects of a rate decision, including credit rating downgrades and material stock price declines. For example, ALLETE, Inc.,[7] CenterPoint Energy Houston Electric,[8] and Pinnacle West Capital Corporation ("PNW")[9] each received credit rating downgrades following rate case decisions in the past few years for reasons that included below average authorized ROEs. The most recent example is the decision by the Illinois Commerce Commission ("ICC") in mid-December 2023 that rejected the multiyear grid plan proposals of Ameren Illinois Co. ("Ameren IL") and Commonwealth Edison Co. ("ComEd") and authorized lower-than-expected ROEs for both utilities. Specifically, the ICC authorized an ROE for Ameren IL of 8.72 percent and 8.905 percent

7 Moody's Investors Service, "Credit Opinion: ALLETE, Inc. Update following downgrade," April 3, 2019, at 3.

8 Fitch Ratings, "Fitch Downgrades CenterPoint Energy Houston Electric to BBB+; Affirms CNP; Outlooks Negative," February 19, 2020.

9 S&P Capital IQ Pro; Fitch Ratings, "Fitch Downgrades Pinnacle West Capital & Arizona Public Service to 'BBB+'; Outlooks Remain Negative," October 12, 2021; and Moody's Investors Service, "Rating Actions: Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3; outlook negative," November 17, 2021.

for ComEd, which was a significant reduction from the Administrative Law Judge's recommendations of 9.24 percent and 9.28 percent, respectively.[10]

Q. How did the market respond to the ICC's Decisions for these utilities?

A. While the Standard & Poor's ("S&P") 500 Index was increasing, the share prices of the parent companies of both Ameren IL and ComEd (*i.e.*, Ameren Corp. and Exelon Corp., respectively) each dropped more than 7 percent on December 14, 2023 after the ICC's decision, and declined again by more than 4.4 percent and 6.4 percent the following day, respectively.[11] As of the close on January 5, 2023, Ameren and Exelon's stock prices were, respectively, 8.9 percent and 11.4 percent below where their stock prices closed on December 13, 2023, or the day immediately prior to the ICC's decisions.[12]

In addition, the reactions of equity analysts were universally negative, and questioned whether the parents of both Ameren IL and ComEd (*i.e.*, Ameren Corp. and Exelon Corp., respectively) will shift their capital spending out of the jurisdiction as a result of the uncertainty associated with the multiyear rate plan and low authorized ROEs. For example:

- Barclays characterized the ICC's ROE authorizations as "draconian" and "one of the lowest awarded in recent memory, especially in an elevated interest rate and cost of capital environment."[13] Barclays also stated it found it hard to believe

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[10] Allison Good, "Ameren, Exelon shares fall after Illinois regulators reject grid plans," *Platts*, December 15, 2023.

[11] Yahoo! Finance.

[12] Ameren Corp.'s stock price closed at $81.32 on December 13, 2023 and $74.05 on January 5, 2023. Exelon Corp.'s stock price closed at $41.00 on December 13, 2023 and $36.31 on January 5, 2023.

[13] Barclays, "AEE/EXC: Coal Stocking-Stuffer in Illinois," December 14, 2023.

utilities "can deploy capital under the same magnitude on the updated grid plans to be filed, especially under the current proposed ROE framework."

- In its assessment of the impact on Exelon, the parent of ComEd, UBS stated that, "[t]he actions taken by the ICC today call into question, in our view, the regulatory backdrop in which EXC operates."[14]

- Wells Fargo stated that it was not mincing words, and that the ICC's orders were "onerous" and that:

  > We now view IL as one of the worst regulatory jurisdictions in the U.S. (nipping at CT's heels). We think the totality of the recent orders suggest that the regulatory balancing act between customers and investors is currently heavily skewed toward customers. As a result, we wonder if AEE & EXC will allocate capital away from IL. Keep in mind, IL represents ~25% of both AEE's & EXC's total rate base."[15]

- In its evaluation of Ameren IL, BofA Securities characterized the ICC's decision as "punitive" and stated that it was a surprise based on numerous conversations with investors that believed the ICC may authorize an ROE above the ALJ's recommendation, not substantially lower, and that the downside surprise was one of the biggest in recent memory for their regulated utility coverage.[16] While BofA Securities acknowledged that Ameren IL represents less than 20 percent of Ameren Corp.'s consolidated rate base, it will nonetheless need offsets or capital expenditures elsewhere in order to hit its earnings growth rate targets.[17]

- After the decisions, Guggenheim questioned, "Is Illinois Becoming the Next Connecticut?" Guggenheim noted that investors questioned whether Illinois was "slowly becoming a CT-esque jurisdiction," and that equity and debt holders are going to be wary of Illinois as a jurisdiction going forward and that the ICC is "simply sending a negative message to investors."[18]

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[14] UBS, First Read Exelon Corp., "Negative Rate Case Outcome – Rating and PT Under Review," December 14, 2023.

[15] Wells Fargo, "The ICC Delivers a Lump of Coal for AEE & EXC," December 14, 2023.

[16] BofA Securities, Ameren Corporation, "Illinois delivers downside surprise," December 15, 2023.

[17] *Id*.

[18] Guggenheim, "IL: Is Illinois Becoming the Next Connecticut? To Be Determined, but Taking a Neutral Stance on the State," December 15, 2023.

Also, after the ICC's decisions, Regulatory Research Associates ("RRA") lowered its rating of the Illinois regulatory jurisdiction from Average/2 to Average/3 due to the "concerning pattern of restrictive" rate actions in the state.

Q. What are your conclusions regarding the regulatory principles to be used in establishing the cost of capital in this proceeding?

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn a ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

IV. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. The models used to estimate the cost of equity rely on market data and thus the results of those models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analysis uses current and projected market data, including stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE, and the reasonableness of an ROE to be used for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: (1) relatively high inflation; (2) changes in monetary policy; and (3) elevated interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the cost of equity estimation models.

A. Inflation Expected to Remain Above Federal Reserve's Target Level for Near-Term

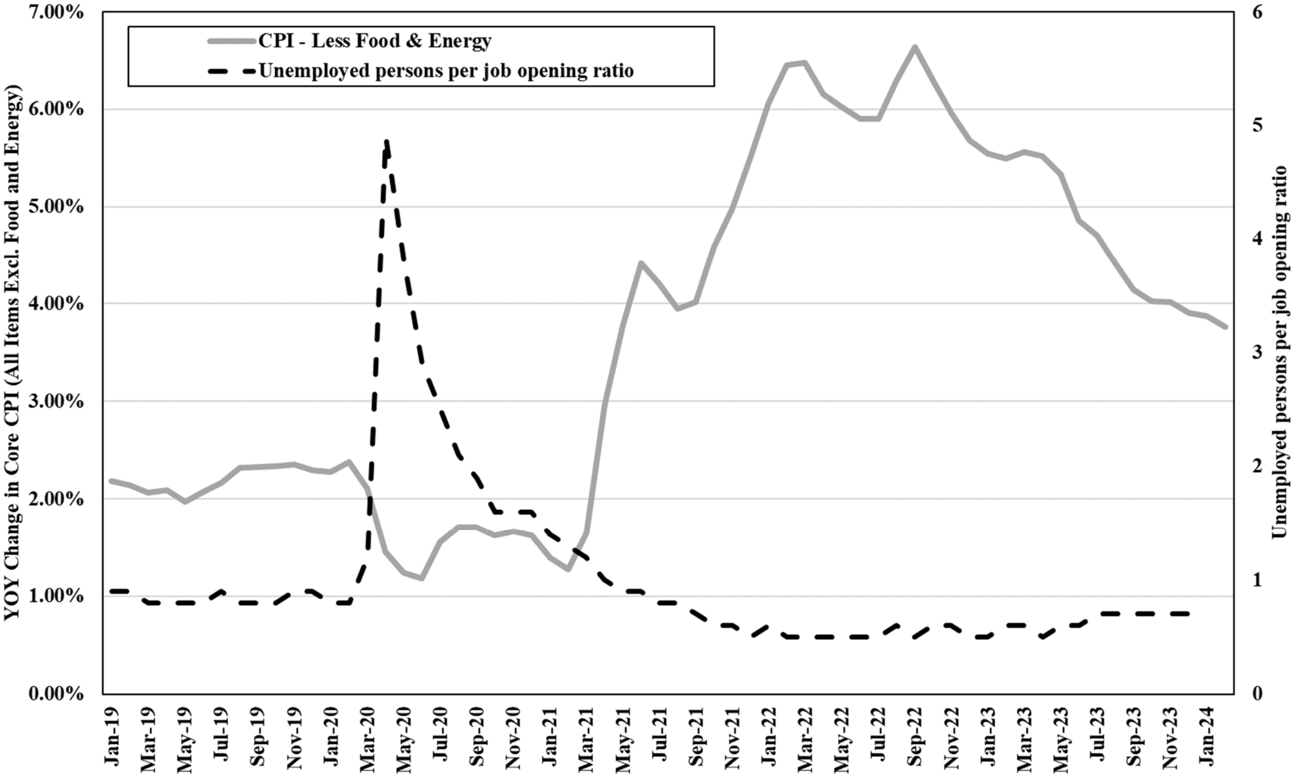
Q. What has the level of inflation been over the past few years?

A. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.40 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982.[19] Since that time, while core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain above the Federal Reserve's target level of 2.0 percent.

In addition, as shown in Figure 2, I have also considered the ratio of unemployed persons per job opening, which is currently 0.7 and has been consistently below 1.0 since 2021, despite the Federal Reserve's accelerated policy normalization. This metric indicates sustained strength in the labor market. Given the Federal Reserve's dual mandate of maximum employment and price stability, the continued increased levels of core inflation coupled with the strength in the labor market has resulted in the Federal Reserve's sustained focus on the priority of reducing inflation.

[19] The year-over-year ("YOY") change in core inflation, as measured by the Consumer Price Index ("CPI") excluding food and energy prices as published by the Bureau of Labor Statistics, is considered because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve because it removes the effect of food and energy prices, which can be highly volatile.

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to February 2023[20]



Q. What are the expectations for inflation over the near-term?

A. The Federal Reserve has indicated that it expects inflation will remain elevated above its target level until 2026 and that the extent to which it maintains the restrictive monetary policy will depend on market indicators going forward. Over the last several months the Federal Open Market Committee ("FOMC") has been clear that they intend to rely on market data before making any changes to interest rates. In the FOMC's meeting on March 20, 2024, Chairman Powell observed that the FOMC will make their decision "meeting by meeting" and while he believes that it will be appropriate to reduce the Federal Funds rate

[20] Bureau of Labor Statistics.

at some point in 2024, the FOMC is prepared to maintain the current Federal Funds rate range higher for longer if needed to reduce inflation:

> We know that reducing policy restraint too soon or too much could result in a reversal of the progress we have seen on inflation and ultimately require even tighter policy to get inflation back to 2 percent. At the same time, reducing policy restraint too late or too little could unduly weaken economic activity and employment. In considering any adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks. The Committee does not expect it will be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably down toward 2 percent. Of course, we are committed to both sides of our dual mandate, and an unexpected weakening in the labor market could also warrant a policy response. We will continue to make our decisions meeting by meeting.[21]

Moreover, Atlanta Federal Reserve President Raphael Bostic, who is a voting member of the FOMC in 2024, recently commented that he expects one rate cut in 2024 but would not rule out the possibility of either two or zero rate cuts depending on the direction of the macroeconomic data.[22] Mr. Bostic's expectations of one rate cut is less than the three that were forecast at the recent FOMC meeting in March 2024. Similarly, Federal Reserve Governor Michelle Bowman, also a voting member of the FOMC, recently noted that while it is not her baseline forecast, there is the possibility that rates will need to increase in 2024 to control inflation as she still sees "a number of potential upside risks to inflation".[23]

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[21] Federal Reserve, Transcript of Chair Powell's Press Conference, March 20, 2024, p. 3.

[22] Schonberger, Jennifer, "Fed's Bostic still expects 1 rate cut in 2024 but doesn't rule out 0 or 2," Yahoo! Finance, April 9, 2024.

[23] Cox, Jeff, "Fed Governor Bowman say additional rate hike could be needed if inflation stays high," CNBC, April 5, 2024.

Q. Have there been economic indicators published since the FOMC published the Summary of Economic Projections on March 20, 2024 that indicate strength in the U.S. economy?

A. Yes. Since that time, the following data has been released demonstrating the unexpected strength in the U.S. economy:

- U.S. employers added 303,000 jobs in March, far exceeding economists' expectation of 200,000.[24]
- The unemployment rate declined from 3.9 percent in February to 3.8 percent in March.[25]
- Average hourly earnings increased 0.3 percent in March 2024, up 4.1 percent year-over-year.[26]
- The year-over-year ("YoY") change in core inflation as measured by the Consumer Price Index ("CPI") excluding food and energy prices was 3.8 percent in March 2024 exceeding economists' estimates of 3.7 percent and equal to the 3.8 percent YoY change in core inflation reported in February 2024.[27]

Q. What is the market's expectation about interest rate cuts since the recent economic data you referenced has been reported?

A. The market has recognized the strength in the economy and the labor market and has tempered its expectations that the FOMC will decrease interest rates in the first quarter of this year. The CME Group, which publishes a "FedWatch" probability chart of FOMC activity, reported on April 8, 2024 that federal funds rate futures contracts reflect expectations of approximately 60 basis points in rate cuts this year which is substantially

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[24] *See, e.g.*, Cox, Jeff, "Job growth zoomed in March as payrolls jumped by 303,000 and unemployment dropped to 3.8%," CNBC, April 5, 2024.

[25] *Id.*

[26] *Id.*

[27] Cox, Jeff, "Consumer prices rose 3.5% from a year ago in March, more than expected," CNBC, April 10, 2024.

lower than the 150 basis points in rate cuts that were expected in January 2024.[28] In summary, the market is expecting that interest rates will remain higher for longer than anticipated in at the beginning of 2024.

B. The Federal Reserve's Monetary Policy to Combat Inflation Has Increased Short- and Long-Term Interest Rates and the Investor-Required Return

Q. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Since the March 2022 meeting, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00 – 0.50 percent to a range of 5.25 percent to 5.50 percent.[29] Further, as noted above, while the Federal Reserve acknowledges that inflation has declined from its peak, it still is well above the Federal Reserve's target of 2 percent. Therefore, the Federal Reserve anticipates the continued need to maintain the federal funds rate at a restrictive level in order to achieve its goal of 2 percent inflation over the long-run.

Q. Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

[28] Reuters, "Fed rate cut expectations for 2024 fall to lowest since October", April 8, 2024.

[29] https://www.federalreserve.gov/monetarypolicy/openmarket.htm.

A. Yes. As the Federal Reserve has substantially increased the federal funds rate and decreased its holdings of Treasury bonds and mortgage-backed securities in response to increased levels of inflation that have persisted for longer than originally projected, longer term interest rates have also increased. For example, as shown in Figure 3, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds have increasing from 1.47 percent on December 15, 2021 to 4.20 percent at the end of March 2024.

Figure 3: 10-Year Treasury Bond Yield, January 2021– March 2024[30]

30 S&P Capital IQ Pro.

Q. How have interest rates and inflation changed since the Company's inception?

A. As shown in Figure 4, both short-term and long-term interest rates have increased since the Company's inception which was January 1, 2017. Specifically, long-term interest rates have increased 130 basis points and the Federal Funds rate has increased 478 basis points. Further inflation is higher by 1.55 percent.[31]

Figure 4: Change in Market Conditions Since the Company's Inception in 2017

Date	Federal Funds Rate	30-Day Avg of 30-Year Treasury Bond Yield	Core Inflation Rate
1/1/2017	0.55%	3.09%	2.25%
3/28/2024	5.33%	4.38%	3.80%
Change	4.78%	1.30%	1.55%

Q. What have equity analysts said about long-term government bond yields?

A. Leading equity analysts have noted that they expect the yields on long-term government bonds to remain elevated. For example, according to the *Blue Chip Financial Forecasts* report, the consensus estimate of the average yields on the 10-year and 30-year Treasury bonds are approximately 3.80 percent and 4.10 percent, respectively, through the first quarter of 2025.[32] Therefore, investors expect interest rates to remain elevated for at least the next 15 months.

[31] S&P Capital IQ Pro.

[32] *Blue Chip Financial Forecasts*, Vol. 43, No. 3, March 1, 2023, at 2.

C. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q. Are utility share prices correlated to changes in the yields on long-term government bonds?

A. Yes. Interest rates and utility share prices are inversely correlated, which means that increases in interest rates result in declines in the share prices of utilities and vice versa. For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over a five-year period. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (*i.e.*, increases in bond yields resulted in the decline of utility share prices).[33]

Q. Has the utility sector underperformed in recent years while long-term government bonds have remained elevated?

A. Yes. Since the beginning of 2023, utility stocks have significantly underperformed the broader market, as Treasury bond yields have increased to levels greater than the dividend yields of utility stocks. For example, as shown in Figure 5, since January 1, 2023, the yield on the 30-year Treasury bond has increased by approximately 44 basis points, while the share prices for the electric utilities included in my proxy group (discussed in the following section) have *declined* by 13.74 percent and the S&P 500 Index has *increased* by more than 36.70 percent. In fact, on October 2, 2023, the utilities sector dropped by 4.7 percent,

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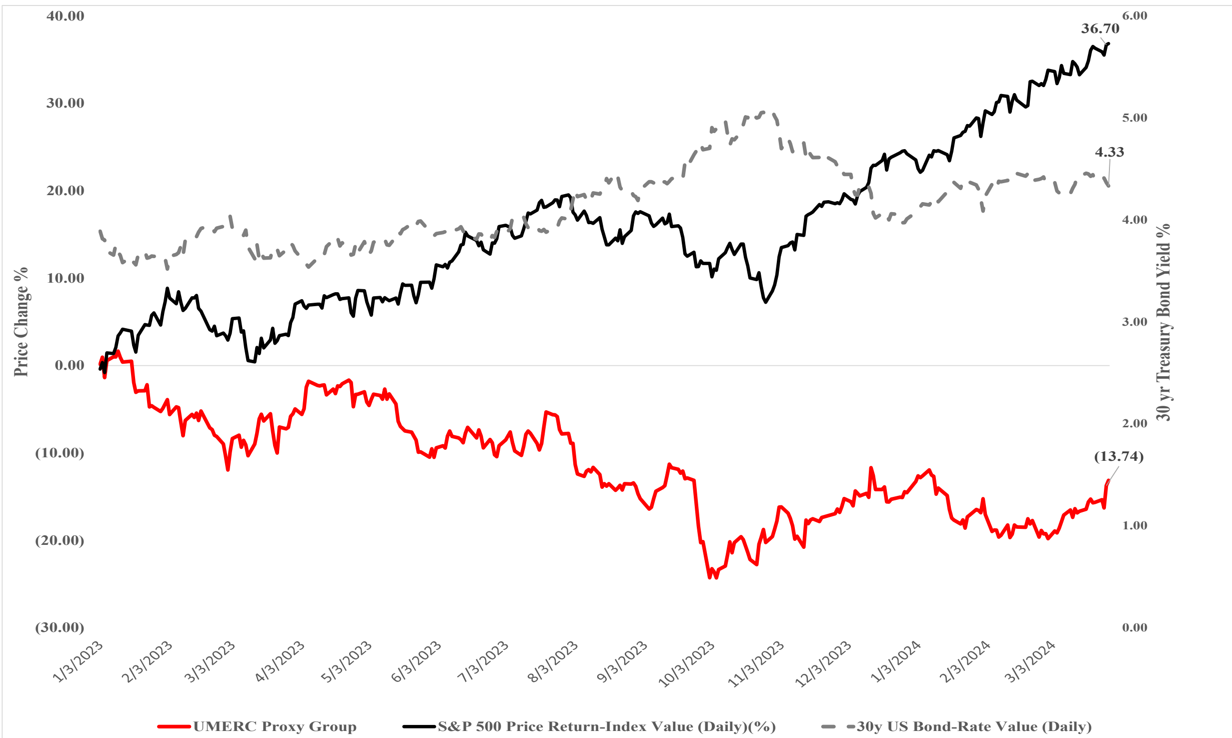
[33] Justina Lee, "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks." Bloomberg.com, March 11, 2021.

its single highest one-day percentage decline since April 2020.[34] The stock price under-performance for the utility sector indicates that the cost of equity has increased since the beginning of 2023.

Figure 5: Relative Performance of the Proxy Group and the S&P 500 Index, January 2023 through March 2024[35]



Q. How do equity analysts expect the utilities sector to perform in 2024?

A. Equity analysts have recently projected the continued underperformance of the utility sector, and have not changed their views on the sector:

- Fidelity Investments classifies the utility sector as underweight;[36]

[34] Caroline Valetkevich, "S&P 500 ends near flat; utilities drop, focus on rate outlook," Reuters, October 2, 2023.

[35] S&P Capital IQ Pro.

[36] Fidelity Investments. "First Quarter 2024 Investment Research Update." January 30, 2024.

- Bank of America recently noted that they are "not so constructive on [u]tilities" given that the dividend yields for utilities are below both the yields available on long- and short-term treasury bonds;[37]

- UBS recently classified the 11 sectors of the S&P 500 as most preferred, natural and least preferred for 2024 with the utility sector being classified as one of UBS's three least preferred sectors (i.e., utilities, materials and real estate;[38] and

- Professional investors surveyed by *Barron's* in its most recent Big Money poll selected the utility sector as one of the four equity sectors that they liked the least over the next twelve months, indicating they are projecting that utilities will underperform the broader market in 2024.[39]

Finally, while Ned Davis Research classified the utility sector as marketweight, they cited risks going forward that could result in a downgrade of their rating to underweight:

> Key drivers: Falling yields have made Utilities' dividend yield more attractive, but the sector still yields less than the 10-year Treasury. At the end of December, only 40% of the sector's stocks yielded more than the 10-year Treasury, 0.6 standard deviations below its long-term average. Lower interest rates or a continuation of the sector's decline in price will be needed to attract dividend-hungry investors.
>
> Indicators to watch: Utilities saw slight sector model score deterioration in December, as one of its relative overbought/oversold indicators flipped from bullish to neutral during the month. Utilities starts 2024 tied with Consumer Staples and Financials for the lowest composite scores among all sectors. We see the possibility for more defensive leadership in the new year, but the sector model has us much closer to a downgrade of the sector than an upgrade.[40]

[37] Julien Dumoulin-Smith, *et. al*., "US Electric Utilities & IPPs: As the leaves fall, preparing for Autumn utility outlook. Macro still has potholes," BofA Securities, September 6, 2023.

[38] Capul, Jason. "UBS Prefers Info Tech, Consumer Staples and Energy in 2024." Seeking Alpha, December 12, 2023, seekingalpha.com/news/4045578-ubs-outlines-its-sector-outlook-and-offers-a-year-end-sp-price-target.

[39] Nicholas Jasinski, "Big Money Pros Are Split on the Outlook for Stocks. But They Are Fans of Bonds," *Barron's*, October 27, 2023.

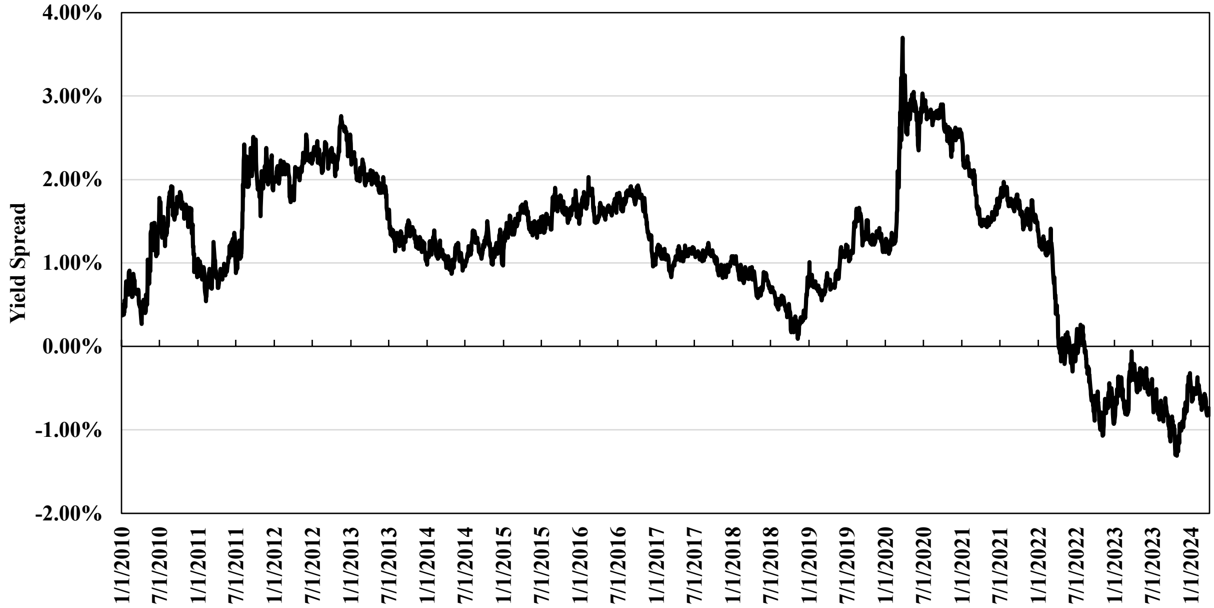
[40] Ned Davis Research, "Risk-on leadership closes out 2023, January 4, 2024, at 18.

Q. Why do equity analysts expect the utility sector to underperform over the near-term?

A. Equity analyst expect the utility sector to continue to underperform given that utility dividend yields remain higher than the yields on long-term government bonds. To illustrate this point, I have examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through February 2024 ("yield spread"). I selected the dividend yield on the Standard & Poor's Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds.

As shown in Figure 6, the recent significant increase in long-term government bonds yields has resulted in the yield on long-term government bonds exceeding the dividend yields of utilities. The yield spread as of March 28, 2024 was negative 0.82 percent, meaning that the yield on the 10-year Treasury bond exceeds the dividend yield for the S&P Utilities Index. However, the long-term average yield spread from 2010 to 2023 is 1.19 percent. Therefore, the current yield spread is well below the long-term average. Because of the fact that the yield spread is currently well below the long-term average, and the expectation that interest rates will remain relatively high through at least the next year, it is reasonable to conclude that the utility sector will most likely underperform over the near-term. This is because investors that purchased utility stocks as an alternative to the lower yields on long-term government bonds would otherwise be inclined to rotate back into government bonds, particularly as the yields on long-term government bonds remain elevated, thus resulting in a decrease in the share prices of utilities.

Figure 6: Spread between the S&P Utilities Index Dividend Yield and the 10-year Treasury Bond Yield, January 2010 – March 2024[41]



Q. Has the Commission previously considered capital market conditions in determining authorized ROEs?

A. Yes. For example, in its order in Case No. U-20697, the Commission noted that it is important to consider how a utility's access to capital could be affected in the near-term as a result of market reactions to global events like those that have occurred in the recent past. Specifically, the Commission noted that:

> [i]n setting the ROE at 9.90%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the belief, as stated in the Commission's March 29 order, "that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner." These conditions still hold true based on the evidence in the instant case. The fact that other utilities have been able to access capital despite lower ROEs, as argued by many

[41] S&P Capital IQ Pro and Bloomberg Professional.

> intervenors, is also a relevant consideration. *It is also important to consider how extreme market reactions to global events, as have occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission will continue to monitor a variety of market factors in future rate cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE.*[42]

More recently, in Case No. U-21389, the Commission recognized the importance of considering market conditions in establishing the ROE.

> As the Commission has previously noted, a reasonable ROE must be based on record evidence in the case at hand. Additionally, given significant uncertainty around inflation and interest rates, the Commission finds that the most prudent course of action is to maintain the current ROE. The Commission again notes that it may revisit this determination in future cases as it gains greater insight into the issues currently affecting the financial markets and longer-term macro-economic trends and will continue to seek opportunities to better tie a utility's financial performance to the outcomes experienced by its customers through the ongoing Financial Incentives and Disincentives Workgroup. Therefore, the Commission finds that the record supports an ROE of 9.90%.[43]

D. Conclusion

Q. What are your conclusions regarding the effect of current market conditions on the cost of equity for UMERC?

A. Due to their effect on the estimated cost of equity, it is important that current and projected market conditions be considered in setting the forward-looking ROE in this proceeding. The combination of high inflation and the Federal Reserve's changes in monetary policy indicate that the cost of equity has increased since the Company's inception. Additionally

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[42] MPSC Case No. U-20697, 12/17/2020 Order, at 165-166; emphasis added.

[43] MPSC Case No. U-21389, 3/1/2024 Order, at 65.

as demonstrated above, (i) there is a strong historical inverse correlation between interest rates (*i.e.*, yields on long-term government bonds) and the share prices of utility stocks (*i.e.*, as interest rates increase, utility share prices decline, and thus utility dividend yields increase); and (ii) the yields on long-term government bonds currently exceed the dividend yields of utilities, when historically long-term government bond yields have been lower than the dividend yields of utilities. Because the cost of equity has increased since the Company's inception, cost of equity estimates based in whole or in part on historical or current market conditions, as opposed to projected market conditions, may understate the cost of equity during the future period that the Company's rates will be in effect. Therefore, these current and expected market conditions support consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which better reflect expected market conditions.

V. PROXY GROUP SELECTION

Q. Please provide a brief profile of UMERC.

A. UMERC is an electric generation, transmission, and distribution company that is a wholly-owned subsidiary of WEC Energy. UMERC provides services to approximately 42,000 customers in Michigan's Upper Peninsula.[44] As of December 31, 2023, UMERC's net utility electric plant in Michigan was approximately $394.06 million.[45] In 2022, UMERC

44 UMERC website.

45 Company provided data.

sold approximately 1.71 million MWh to its sales customers and approximately 0.27 million MWh for its customer choice customers.[46]

UMERC is not directly rated by either S&P or Moody's Investors Service ("Moody's"). WEC Energy has a long-term rating of A- (Outlook: Stable) from S&P, BBB+ (Outlook: Stable) from Fitch Ratings ("Fitch"), and Baa1 (Outlook: Stable) from Moody's.[47]

Q. Why have you used a proxy group of publicly traded companies to estimate the cost of equity for UMERC?

A. In this proceeding, I am estimating the cost of equity for UMERC, a rate-regulated subsidy of WEC Energy. Since the cost of equity is a market-based concept and given the fact that UMERC does not make up the entirety of a publicly-traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to UMERC in certain fundamental business and financial respects to serve as its "proxy" for purposes of estimating the cost of equity.

The overall purpose of developing a set of screening criteria is to select a proxy group of companies that aligns with the financial and operational characteristics of UMERC and that investors would view as comparable to the Company. I developed the screens and thresholds for each screen based on judgment with the intention of balancing the need to maintain a proxy group that is of sufficient size with the need to establish a proxy group of companies that are comparable in business and financial risk to UMERC.

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46 *Id*., at 304 and 305.

47 S&P Global Market Intelligence; Fitch Ratings; Moody's Investors Service.

Even if UMERC's regulated electric business made up the entirety of a publicly-traded entity, it is possible that transitory events could bias its market value over a given time period. A significant benefit of using a proxy group is that it mitigates the effects of anomalous events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and financial risk characteristics that are substantially comparable to UMERC, and, therefore, provide a reasonable basis to estimate the appropriate cost of equity for the Company.

Q. How did you select the companies included in your proxy group?

A. I began with the group of 36 companies that *Value Line Investment Survey* ("*Value Line*") classifies as Electric Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, because companies that do not cannot be analyzed using the constant growth DCF model;
- have investment grade long-term issuer ratings from S&P and/or Moody's;
- are covered by more than one utility industry analyst;
- have positive long-term earnings growth forecasts from at least two equity analysts;
- own regulated generation assets that are in rate base;
- derive more than 40.00 percent of its megawatt-hour sales from its owned generation facilities;
- derive more than 60.00 percent of total operating income from regulated electric operations; and,
- were not party to a merger or transformative transaction during the analytical period considered or had a material event that would have affected the market data for the company.

Q. What is the composition of your proxy group?

A. The screening criteria just discussed resulted in a proxy group consisting of the companies shown in Figure 7.

Figure 7: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL

VI. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. The rate of return for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (*i.e.*, book values) in the utility's capital structure. The ROE is the cost rate applied to the equity capital in calculating the rate of return. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required cost of equity determined?

A. A range of the required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns. Within that range, the ROE that is recommended is based on a review of the business, regulatory, and financial risks of the subject utility as compared with the proxy group, including the capital structure of the subject utility. A key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular. Further, it is important that the ROE that is authorized takes into consideration the financial risk resulting from the authorized capital structure of the subject utility. An authorized capital structure that has a greater amount of leverage results in greater risk since equity is the last claimant in the event of the dissolution of a company. Therefore, as the leverage in the capital structure increases, it is necessary for the ROE to increase to recognize the incremental risk to equity holders.

Q. What methods do you use to establish your recommended ROE in this proceeding?

A. I consider the results of the constant growth DCF model, the CAPM, the ECAPM, and a BYRP analysis. A reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Q. Why is it important to use more than one analytical approach to estimate the cost of equity?

A. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[48] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[49] recommend the CAPM, DCF, and BYRP approaches.

Further, the recent changes in market conditions discussed previously highlight the benefit of using multiple models since each model relies on different assumptions, certain of which better reflect current and projected market conditions at different times. For example, the CAPM, ECAPM, and BYRP analyses rely directly on interest rates as an assumption in the models and therefore may more directly reflect the market conditions expected when the Company's rates are in effect. Accordingly, it is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

48 Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies*, New York, McKinsey & Company, Inc., 3rd Ed., 2000, at 214.

49 Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice*, Orlando, Dryden Press, 1994, at 341.

Q. Has the Commission recognized that it is important to consider the results of multiple models?

A. Yes. For example, in its order in Case No. U-18999 for DTE Gas Company, the Commission considered the results of each of the models presented by the witnesses, which included the DCF, CAPM, ECAPM and Risk Premium models, and also considered authorized ROEs in other states, increased volatility in capital markets, and the utility's specific business risks, ultimately authorizing a 10.00 percent ROE. [50]

A. Constant Growth DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D1 \ldots D\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

[50] MPSC Case No. U-18999, 9/13/2018 Order, at 45-47.

Equation [2] is often referred to as the constant growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate (*i.e.*, "*g*").

Q. What assumptions are required for the constant growth DCF model?

A. The constant growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are not objectively valid, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data do you use to calculate the dividend yield in your constant growth DCF model?

A. The dividend yield in my constant growth DCF model is based on the proxy group companies' current annualized dividend and average closing stock prices over the most recent 30, 90, and 180 trading days ended March 28, 2024.

Q. Why do you use 30-, 90-, and 180-day averaging periods?

A. In my constant growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the cost of equity is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long term.

Q. Do you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share ("EPS"), dividends per share and book value per share all grow at the same constant rate. However, over the long run, dividend growth can only be sustained by earnings growth, meaning earnings are the fundamental driver of a company's ability to pay dividends. Therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects. Accordingly, I have incorporated a number of sources of long-term EPS growth rates into the constant growth DCF model.

Q. Which sources of long-term earnings growth rates do you use in your DCF analysis?

A. I incorporate three sources of long-term earnings per share ("EPS") growth rates: (1) *Zacks Investment Research*; (2) Yahoo! Finance; and (3) *Value Line*.

Q. How do you calculate the range of results for the constant growth DCF Models?

A. I calculate the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the *Zacks*, Yahoo! Finance, and *Value Line* projected EPS growth rates) for each of the proxy group companies. I use a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculate results using the average EPS growth rate from all three sources for each proxy group company.

Q. What are the results of your DCF analyses?

A. Figure 8 summarizes the results of my DCF analyses.

Figure 8: Summary of DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.11%	10.54%	11.73%
90-Day Avg. Stock Price	9.08%	10.51%	11.69%
180-Day Avg. Stock Price	9.09%	10.51%	11.70%
Average	9.09%	10.52%	11.71%
Median Results:			
30-Day Avg. Stock Price	9.09%	10.44%	11.53%
90-Day Avg. Stock Price	9.03%	10.43%	11.52%
180-Day Avg. Stock Price	9.03%	10.38%	11.59%
Average	9.05%	10.42%	11.55%

B. CAPM and ECAPM Analyses

Q. Please briefly describe the CAPM.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security.[51] This second component is the product of the market risk premium and the beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components:

$$K_e = r_f + \beta(r_m - r_f) \qquad [3]$$

Where:

K_e = the required market ROE;

β = beta coefficient of an individual security;

r_f = the risk-free rate of return; and

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[51] Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

r_m = the required return on the market.

In this specification, the term (r_m – r_f) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the overall market. Beta is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \qquad [4]$$

Variance (r_m) represents the variance of the market return, which is a measure of the uncertainty of the general market. *Covariance* (r_e, r_m) represents the covariance between the return on a specific security and the general market, which reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q. What risk-free rate do you use in your CAPM analysis?

A. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-yearTreasury bonds;[52] (2) the average projected 30-year Treasury bond yield for the third quarter of 2024 through the third quarter of 2025;[53] and (3) the average projected 30-year Treasury bond yield for 2025 through 2029.[54]

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52 Bloomberg Professional as of March 28, 2024.

53 *Blue Chip Financial Forecasts*, Vol. 43, No. 4, April 1, 2024, at 2.

54 *Blue Chip Financial Forecasts*, Vol. 42, No. 12, December 1, 2023, at 14.

Q. What beta coefficients do you use in your CAPM analysis?

A. As shown on Schedule D9, I use the beta coefficients for the proxy group companies as reported by *Bloomberg Professional* ("*Bloomberg")* and *Value Line*. The beta coefficients reported by *Bloomberg* are calculated using ten years of weekly returns relative to the S&P 500 Index. The beta coefficients reported by *Value Line* are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown on Schedules D9 and D10, I also consider an additional CAPM analysis that relies on the long-term average beta coefficient reported by *Value Line* for the companies in my proxy group from 2013 through 2023.

Q. How do you estimate the market risk premium in the CAPM?

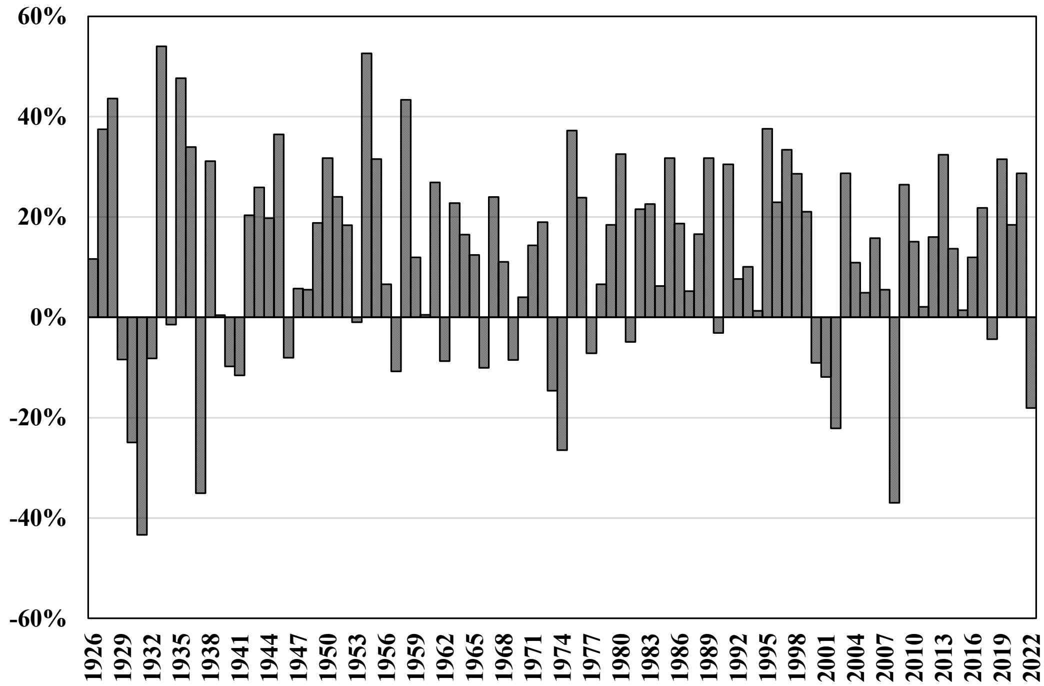
A. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Schedule D11, the expected market return is calculated using the constant growth DCF model discussed earlier in my testimony for the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.57 percent and a weighted long-term growth rate of 11.05 percent, the estimated required market return for the S&P 500 Index as of March 28, 2024 is 12.70 percent.

Q. How does the current expected market return compare to observed historical market returns?

A. As shown in Figure 9, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.70 percent is not unreasonable.

As shown, in 50 out of the past 97 years (or roughly 52 percent of observations), the realized equity market return was 12.70 percent or greater.

Figure 9: Realized U.S. Equity Market Returns (1926-2022)[55]



Q. Do you also consider another form of the CAPM in your analysis?

A. Yes. I have also considered the results of an ECAPM analysis in estimating the cost of equity for UMERC.[56] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

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[55] Depicts total annual returns on large company stocks, as reported in the 2022 *Kroll* SBBI Yearbook.

[56] *See, e.g.*, Roger A. Morin, *New Regulatory Finance*. Public Utilities Reports, Inc., 2006, at 189.

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:

k_e = the required market ROE;

β = adjusted beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[57]

Consistent with my CAPM, my application of the ECAPM uses the same three yields on the 30-year Treasury bonds as the risk-free rate, forward-looking market risk premium estimate, and beta coefficients.

Q. What are the results of your CAPM and ECAPM analyses?

A. The results of my CAPM and ECAPM analyses are summarized in Figure 10, as well as presented in Schedule D9.

[57] *Id.*, at 191.

Figure 10: Summary of CAPM and ECAPM Results

	30-Year Treasury Bond Yield Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	12.04%	12.02%	12.02%
Current Bloomberg Beta	10.96%	10.91%	10.90%
Long-term Avg. *Value Line* Beta	10.72%	10.65%	10.65%
ECAPM:			
Current *Value Line* Beta	12.20%	12.19%	12.19%
Current Bloomberg Beta	11.39%	11.35%	11.35%
Long-term Avg. *Value Line* Beta	11.21%	11.17%	11.16%

C. BYRP Analysis

Q. Please describe the BYRP analysis.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for vertically integrated electric utilities as the historical measure of the cost of equity to determine the risk premium.

Q. What is the fundamental relationship between the equity risk premium and interest rates?

A. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. When the authorized ROEs for vertically integrated electric utilities serve as the measure of required equity returns and the yield on the long-term U.S. Treasury bond is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[58]

Q. Is the BYRP analysis relevant to investors?

A. Yes. Investors are aware of authorized ROEs in other jurisdictions and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. As discussed previously, utilities have experienced credit rating downgrades and been subject to a negative market reaction related to the financial effects of a rate case decision that included a below average authorized ROE. Because my BYRP analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

[58] *See e.g.*, S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2, March, 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also* Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, at 66.

Q. What does your BYRP analysis reveal?

A. As shown in Figure 11, from 1980 through March 2024, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \qquad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

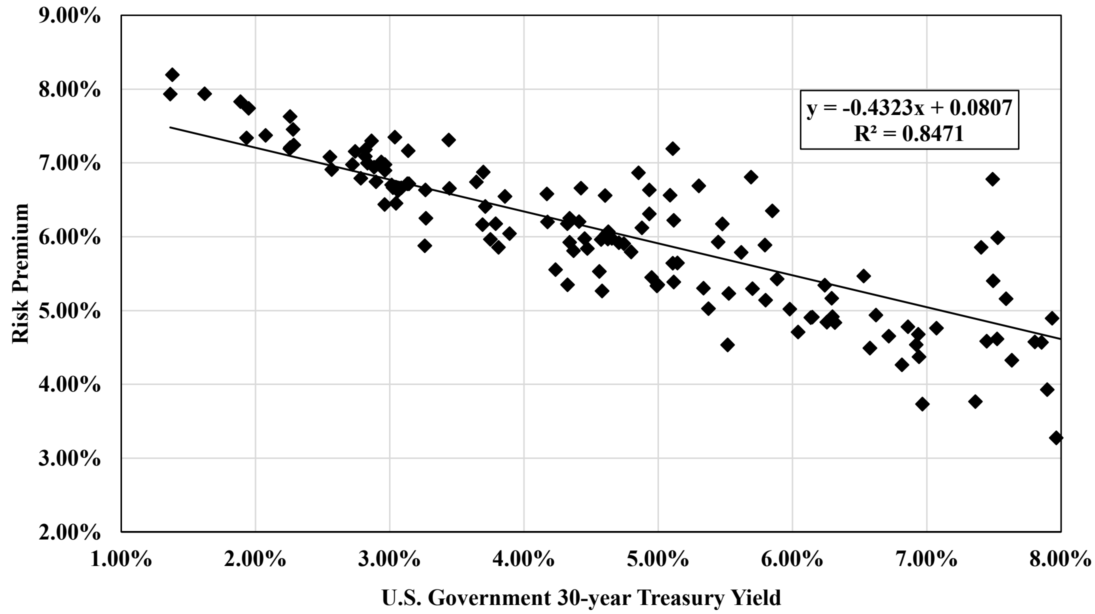
b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding authorized ROEs are derived from all vertically integrated electric utility rate cases over this period as reported by Regulatory Research Associates ("RRA").[59] This equation's coefficients were statistically significant at the 99.00 percent level.

[59] The data was screened to eliminate limited issue rider cases, pipeline transmission cases, and cases that were silent with respect to authorized ROE.

Figure 11: Risk Premium Regression Analysis



Q. What are the results of your BYRP analysis?

A. Figure 12 presents the results of my BYRP analysis, which are also presented in more detail in Schedule D12.

Figure 12: BYRP Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
Bond Yield Risk Premium:	10.56%	10.41%	10.40%

VII. REGULATORY AND BUSINESS RISKS

Q. Do the results of the cost of equity analyses alone provide an appropriate estimate of the cost of equity for the Company?

A. No. The model results provide only a range for the appropriate estimate of the Company's cost of equity. Several additional factors must be considered when determining where the

Company's cost of equity falls within the range of analytical results. These risk factors, discussed below, should be considered with respect to their overall effect on the Company's risk profile relative to the proxy group.

A. Capital Expenditures

Q. Please summarize the Company's capital expenditure requirements.

A. As of December 31, 2023, the Company had net utility plant of approximately $394 million, and the Company currently projects capital expenditures for 2024 through 2028 of approximately $392.3 million.[60] Therefore, the Company's projected capital expenditures represent approximately 99.6 percent of its net utility plant as of December 31, 2023.

Q. How is the Company's risk profile affected by its substantial capital expenditure requirements?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics

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60 Data provided by the Company.

and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[61]

While UMERC is not currently rated by the credit rating agencies, the Company's business risk is also increased as a result of elevated capital expenditures. Therefore, to the extent that UMERC's rates do not permit the opportunity to recover its capital investments on a regular and timely basis, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q. How do UMERC's capital expenditure requirements compare to those of the proxy group companies?

A. As shown on Schedule D13, I calculated the ratio of expected capital expenditures to net utility plant for UMERC and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2024 through 2028 by its total net utility plant as of December 31, 2023. As shown therein, UMERC's ratio of

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[61] S&P Global Ratings. "Assessing U.S. Investor-Owned Utility Regulatory Environments." August 10, 2016, at 7.

capital expenditures as a percentage of net utility plant is 1.94 times the median of the proxy group.

Q. Does the Company currently have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A. No. UMERC still depends on rate case filings for its capital cost recovery.

Q. Are capital investment recovery mechanisms common among electric utilities?

A. Yes. As shown on Schedule D13, approximately 67.5 percent of the proxy group utilities recover costs through capital tracking mechanisms.

Q. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A. The Company's capital expenditure requirements as a percentage of net utility plant are significant relative to the proxy group and are expected to continue over the next few years. UMERC depends on rate case filings to recover the majority of its capital expenditures. The majority of operating subsidiaries held by the proxy group companies have some form of capital tracking mechanism, meaning that this risk mitigation is already reflected in the proxy group companies. Accordingly, I conclude that, all else equal, the Company's risk profile regarding capital expenditures is somewhat greater than that of the proxy group.

B. Regulatory Risk

Q. How does the regulatory environment affect investors' risk assessments?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, and doing so balances the long-term interests of investors and customers. To achieve this balance, the Company must be able to finance its operations assuming a reasonable opportunity to earn an appropriate return on invested capital to maintain an acceptable financial profile. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally-generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

In addition, equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. How do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[62]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[63] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[64]

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62 Moody's Investors Service. Rating Methodology: Regulated Electric and Gas Utilities. June 23, 2017, at 4.

63 Standard & Poor's Global Ratings. Ratings Direct. "Assessing U.S. Investor-Owned Utility Regulatory Environments." August 10, 2016, at 2.

64 *Id.*, at 1.

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

The regulatory environment can significantly affect both the access to, and cost of, capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[65] Moody's has further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[66]

Q. Have you conducted any analysis of the regulatory framework in Michigan relative to the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Michigan on three factors that are important in terms of providing a regulated utility an opportunity to earn its authorized ROE. These are: (1) test year convention (*i.e.*, forecast vs. historical); (2) method for determining rate base (*i.e.*, average vs. year-end); and (3) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Schedule D14 and are summarized as follows:

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65 Moody's Investors Service. Rating Methodology: Regulated Electric and Gas Utilities. June 23, 2017, at 6.
66 *Id*.

Test Year Convention: UMERC uses a forecasted test year, and similarly, nearly half of the utility operating subsidiaries of the companies in the proxy group also use forecasted or partially forecasted test years.

Capital Cost Recovery: As noted previously, UMERC does not have a capital cost recovery mechanism. Approximately 67.5 percent of the utility operating subsidiaries of the proxy group companies have some form of capital cost recovery mechanism.

Volumetric Risk: UMERC does not have protection against volumetric risk through a decoupling or other revenue stabilization mechanism; however, approximately 60.2 percent of the proxy group companies have some protection against volumetric risk.

Q. What is the effect on UMERC not having timely cost recovery mechanisms?

A. The lack of timely cost recovery mechanisms can result in regulatory lag. Regulatory lag occurs when a regulated utility is not able to recover its just and reasonable costs of providing service to customers on a timely basis. Regulatory lag is reflected in a utility's financial performance through earnings attrition, which is the inability of the utility to earn its authorized ROE due to delays in the recovery of allowable costs that have been incurred to provide regulated service to customers.

Q. Is there evidence that UMERC has been unable to earn its ROE?

A. Yes. As shown in

A. Figure 13, UMERC's electricity operations in Michigan has under-earned its ROE in three out of the last five years, with a majority of the under-earnings coming since 2021.

Figure 13: UMERC's Earned ROE Comparison (2019-2023)

	Earned ROE	ROE[67]	Earnings Differential (BPS)
2019	11.35%	10.12%	123
2020	10.80%	10.12%	68
2021	9.84%	10.12%	-28
2022	7.35%	10.12%	-277
2023	7.77%	10.12%	-235

Q. How are credit rating agencies currently viewing the utility sector?

A. Credit rating agencies have (i) indicated that the industry overall has increased risk; (ii) responded with close scrutiny of the financial coverage ratios of the sector; and (iii) maintain a negative outlook on the industry overall for 2023. Therefore, it is critically important to consider these factors and to recognize that the investor-required ROE would be higher today than at the time of Commission decisions in the recent past. As discussed in more detail in Section V, current market conditions demonstrate greater risk than at the time the Commission authorized returns in the recent past.

Q. What are your conclusions regarding the perceived risks related to the Michigan regulatory environment?

A. As discussed, many of the operating subsidiaries of the proxy group companies have relatively more timely cost recovery as compared to UMERC. Both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Therefore, it

67 Data provided by Company. UMERC authorized ROE was calculated as the weighted ROE between last authorized WEPCO and WPSC authorized ROEs, weighted by assets transferred.

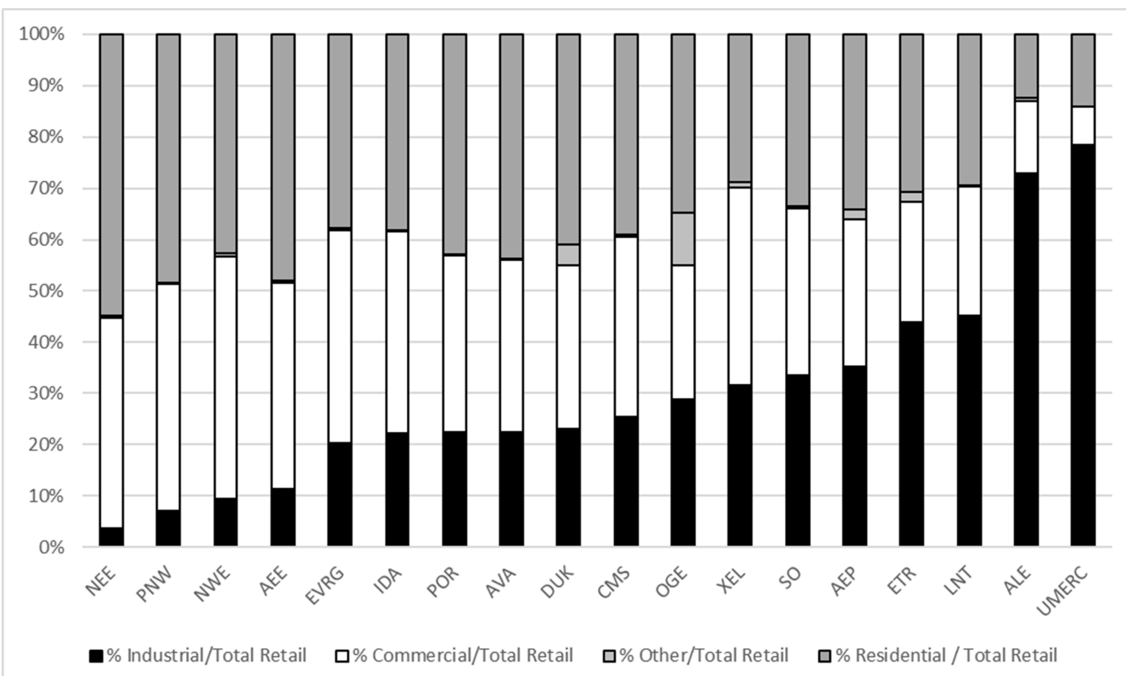
is important that the cost of equity established for UMERC in this proceeding reflect the relative regulatory risk of the Company relative to the proxy group.

C. Customer Concentration

Q. Please summarize UMERC's customer concentration risk.

A. Approximately 78 percent of UMERC's 2022 total retail kWh electric sales were derived from industrial customers.[68] As shown in Figure 14, UMERC's industrial sales volume as a percentage of total retail electric sales was higher than all of the companies in the proxy group by a significant margin.[69]

Figure 14: Customer Concentration[70]



[68] Based on Form FERC Form 1. (2022).

[69] Does not include "other" commercial or residential customers.

[70] S&P Global Market Intelligence - Other sales includes: Total Public Street and Highway Lighting, Other Sales to Public Authorities, Sales to Railroad and Railways, and Interdepartmental Sales.

Q. How does customer concentration affect business risk?

A. An extremely high concentration of industrial customers, operating in only three industries (mining, paper mills, and wood manufacturing), each with the independent ability to create large swings in utility revenues, results in higher business risk. More specifically, over 60 percent of UMERC's 2022 retail kWh industrial electric sales came from one mining facility. While the remaining industrial sales volume came from only four customers in the paper mills and wood manufacturing industries.[71]

Consolidation of load into fewer large customers can create risk because a significant portion of a company's sales could be lost if a customer goes out of business or experiences an economic downturn. As noted by Dhaliwal, Judd, Serfling and Shaikh in their article, *Customer Concentration Risk and the Cost of Equity Capital*:

> Depending on a major customer for a large portion of sales can be risky for a supplier for two primary reasons. First, a supplier faces the risk of losing substantial future sales if a major customer becomes financially distressed or declares bankruptcy, switches to a different supplier, or decides to develop products internally. Consistent with this notion, Hertzel et al. (2008) and Kolay et al. (2015) document negative supplier abnormal stock returns to the announcement that a major customer declares bankruptcy. Further, a customer's weak financial condition or actions could signal inherent problems about the supplier's viability to its remaining customers and lead to compounding losses in sales. Second, a supplier faces the risk of losing anticipated cash flows from being unable to collect outstanding receivables if the customer goes bankrupt. This assertion is consistent with the finding that suppliers offering customers more trade credit experience larger negative abnormal stock returns around the announcement of a customer filing for Chapter 11 bankruptcy (Jorion and Zhang, 2009; Kolay et al., 2015).[72]

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[71] Company provided information.

[72] Dan S. Dhaliwal, J. Scott Judd, Matthew A. Serfling, and Sarah Shaikh, *Customer Concentration Risk and the Cost of Equity Capital*, SSRN Electronic Journal (2016): 1-2. Web.

Therefore, a company that has a high degree of customer concentration will be inherently riskier than a company that derived income from a larger customer base. Furthermore, as Dhaliwal, Judd, Serfling and Shaik detail in the article, the increased risk associated with a more concentrated customer base will have the effect of increasing a company's cost of equity.[73]

Q. Please describe how changes in economic conditions and UMERC's high degree of customer concentration can affect its business risk.

A. UMERC's major industrial customers are engaged in industries such as taconite mining, paper milling, and wood manufacturing. Both taconite mining and wood manufacturing industries, which constitutes over 60 percent of UMERC's retail kWh sales, are highly dependent on economic conditions and the business cycle since lumber and taconite, which is an input into steel, are used in durable consumer goods. Paper mills are also facing decreased demand as companies are moving away from printed materials and instead providing information electronically.

Q. How have mining and logging employment faired in recent economic conditions?

A. As shown in Figure 15, total mining and logging employment in Michigan has been volatile. As a result of COVID-19, mining and logging employment decreased from 7,000 in February 2020 to a low of 5,700 in May 2020 before rebounding to close to pre-recession levels at the end of 2020. Similarly, during the Great Financial crises of 2008/2009, mining

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[73] *Id.* at 4.

and logging employment decreased from a high of 8,000 in 2008 to a low of 6,700 in 2009 and 2010 before rebounding to pre-recession levels in mid-2011.

Figure 15: Michigan Mining and Logging Employment (Thousands)[74]

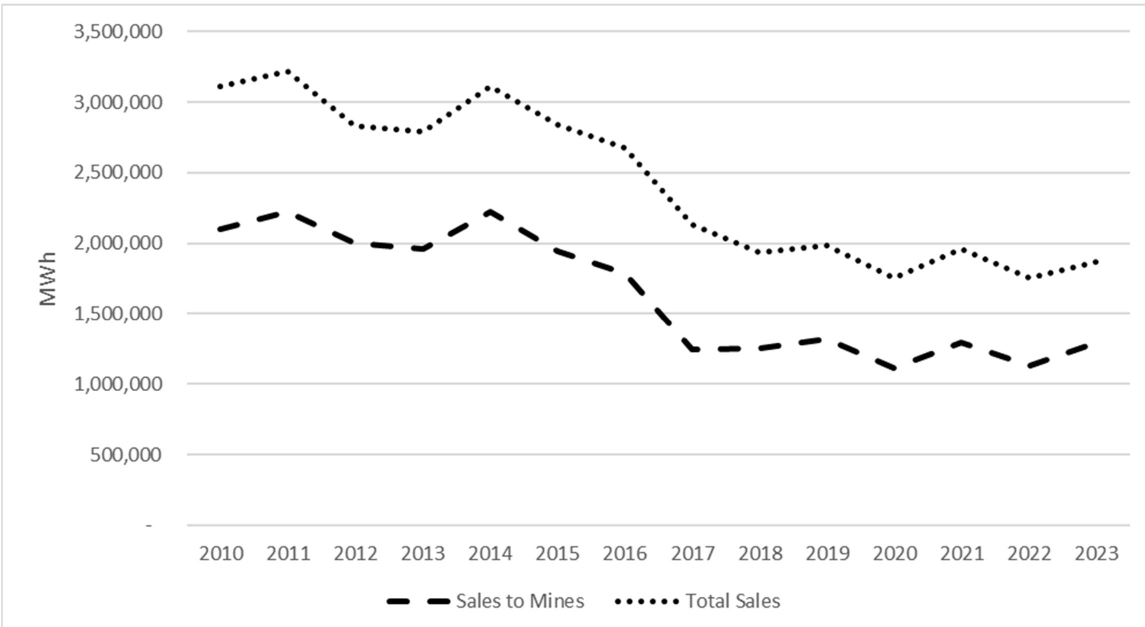
Q. How have the Company's sales been affected by changes in sales of its large industrial customers?

A. As shown in Figure 16, energy sales to mines have driven a lot of the total sales for UMERC. For example, UMERC provided service to two mines, the Tilden and Empire mines, until part way through 2016 when the Empire mining facility was shutdown, leaving the Company serving only the Tilden. This resulted in a 30 percent reduction in sales to mining customers and a 20 percent reduction to total sales from 2016 to 2017. UMERC

[74] U.S. Bureau of Labor Statistics, State and Area Employment, Hours, and Earnings, Minnesota Mining and Logging employment, Series Id: SMS26000001000000001.

has not since recovered to sales levels previous to that of 2017 when it served both mining facilities.

Figure 16: UMERC Total Customer Sales[75]



Q. What is your conclusion regarding the Company's customer concentration and its effect on the cost of equity for UMERC?

A. UMERC is heavily reliant on sales to industrial customers. As noted above, approximately 78 percent of UMERC's total 2022 retail electric sales were to industrial customers. This concentration is higher than all of the proxy group companies, especially when considering that over 60 percent UMERC's total retail electric sales are to one industrial customer. A high degree of customer concentration increases the Company's risk related to customer migration, economic conditions or competition.[76] Therefore, the risk of eroding revenue

[75] Data provided by Company.

[76] Conversely, greater customer diversity decreases the effect that any one customer can have on a company's sales.

resulting from customer concentration is higher for UMERC than the proxy group companies on average. UMERC has significant risk related to its high concentration of sales in a small number of customers that are cyclical businesses, which is greater than the risk faced by the proxy group companies on average.

D. Small Size Risk

Q. Is there a risk to a firm associated with small size?

A. Yes. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect." While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return. [77]

Q. How does the smaller size of a utility affect its business risk?

A. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue

[77] Michael Annin, "Equity and the Small-Stock Effect." Public Utilities Fortnightly, October 15, 1995.

producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies**.**

Q. How do UMERC's electric utility operations in Michigan compare in size to the proxy group companies?

A. The Company's electric utility operations are substantially smaller than the median for the proxy group companies in terms of market capitalization. While UMERC is not publicly-traded on a stand-alone basis, as shown on Schedule D15, UMERC's common equity based on its proposed test year rate base and equity ratio is substantially smaller than the median market capitalization of the proxy group companies.

Q. How do you estimate the size premium for UMERC?

A. Given this relative size information, it is possible to estimate the impact of size on the cost of equity for the Company using *Kroll* Cost of Capital Navigator data that estimates the stock risk premia based on the size of a company's market capitalization.[78] As shown in Schedule D15, the median market capitalization of the proxy group is approximately $12.45 billion, which corresponds to the fifth decile of *Kroll's* market capitalization data.[79] Based on *Kroll's* analysis, that decile corresponds to a size premium of 0.61 percent (*i.e.*, 61 basis points). In comparison, UMERC's common equity of approximately $280.05

[78] *Kroll* Cost of Capital Navigator – Size Premium.

[79] *Id*.

million falls within the ninth decile, which corresponds to a size premium of 1.99 percent (*i.e.*, 199 basis points). The difference between the size premium for the Company and the size premium for the proxy group is 138 basis points (*i.e.*, 199 percent minus 61 percent).

Q. Were utility companies included in the small size risk premium study conducted by *Kroll*?

A. Yes. As shown in Exhibit 7.2 of the *Kroll* (formerly *Duff & Phelps*) 2019 Valuation Handbook, OGE Energy Corp. had the largest market capitalization of the companies contained in the fourth decile, which indicates that Kroll has included utility companies in its size risk premium study.[80]

Q. Is the size premium applicable to companies in regulated industries such as electric utilities?

A. Yes. For example, Zepp (2003) provided the results of two studies that showed evidence of the required risk premium for small water utilities. The first study, which was conducted by the Staff of the California Public Utilities Commission, computed proxies for beta risk using accounting data from 1981 through 1991 for 58 water utilities and concluded that smaller water utilities had greater risk and required higher returns on equity than larger water utilities.[81] The second study examined the differences in required returns over the period of 1987 through 1997 for two large and two small water utilities in California. As

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80 *Kroll*, Valuation Handbook: Guide to Cost of Capital, 2019, Exhibit 7.2.

81 Thomas M. Zepp, "Utility Stocks and the Size Effect—Revisited," *The Quarterly Review of Economics and Finance*. Vol. 43, No. 3, 2003, at 578–582.

Zepp (2003) showed, the required return for the two small water utilities calculated using the DCF model was on average 99 basis points higher than the two larger water utilities.[82]

Additionally, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry, and in particular subgroups of utilities.[83] The article considered the CAPM, the Fama-French three-factor model, and a model similar to the ECAPM, which as previously discussed, I have also considered in estimating the cost of equity for the Company. In the study, the Fama-French three-factor model explicitly included an adjustment to the CAPM for risk associated with size. As Chrétien and Coggins (2011) show, the beta coefficient on the size variable for the U.S. natural gas utility group was positive and statistically significant indicating that small size risk was relevant for regulated natural gas utilities.[84]

Q. Have regulators in other jurisdictions made a specific risk adjustment to the cost of equity results based on a company's small size?

A. Yes. For example, in Order No. 15, the Regulatory Commission of Alaska ("RCA") concluded that Alaska Electric Light and Power Company ("AEL&P") was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of ROE analyses in this case, without

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82 *Id*.

83 Stéphane Chrétien and Frank Coggins, "Cost Of Equity For Energy Utilities: Beyond The CAPM," *Energy Studies Review*, Vol. 18, No. 2, 2011.

84 *Id.*

an explicit adjustment, would adequately compensate AEL&P for its greater risk." [85] Thus, the RCA awarded AEL&P an ROE of 12.875 percent, which was 108 basis points above the highest cost of equity estimate from any model presented in the case.[86] Similarly, the RCA has also noted that small size, as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk, geographic isolation and economic conditions, increased the risk of ENSTAR Natural Gas Company.[87] Ultimately, the RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[88]

Additionally, the Minnesota Public Utilities Commission ("Minnesota PUC") authorized an ROE for Otter Tail Power Company ("Otter Tail") above the mean DCF results as a result of multiple factors, including Otter Tail's small size. The Minnesota PUC stated:

> The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments. [89]

[85] Regulatory Commission of Alaska, Docket No. U-10-29, Order No. 15, September 2, 2011, at 37.

[86] *Id.*, at 32 and 37.

[87] Regulatory Commission of Alaska, Docket No. U-16-066, Order No. 19, September 22, 2017, at 50-52.

[88] *Id*.

[89] Minnesota Public Utilities Commission, Docket No. E017/GR-15-1033, Order, August 16, 2016, at 55.

Finally, in Opinion Nos. 569 and 569-A, the Federal Energy Regulatory Commission ("FERC") adopted a size premium adjustment in its CAPM estimates for electric utilities. In those decisions, the FERC noted that "the size adjustment was necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[90]

Q. How have you considered the smaller size of UMERC in your recommendation of the Company's ROE in this proceeding?

A. While I have estimated the effect of UMERC's small size on the cost of equity, I am not proposing a specific adjustment for this risk factor. Rather, I have considered the small size of the Company's utility operations in evaluating where within the range of analytical results that the Company's ROE should fall. All else equal, the additional risk associated with the Company's small size supports an ROE that is above the average of the range of results produced by the cost of equity estimation models.

VIII. CAPITAL STRUCTURE

Q. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility. All else equal, a higher debt ratio increases the risk to investors. For debt holders, higher debt

[90] *Ass'n. of Businesses Advocating Tariff Equity, et. al., v. Midcontinent Indep. Sys. Operator, Inc., et. al.*, 171 FERC ¶ 61,154 (2020), at ¶ 75. The U.S. Court of Appeals recently vacated FERC Order No. 569 decisions that related to its risk premium model and remanded the case to FERC to reopen the proceedings. However, in its decision, the Court did not reject FERC's inclusion of the size premium to estimate the CAPM. (*See*, United States Court of Appeals Case No. 16-1325, Decision No. 16-1325, August 9, 2022 at 20).

ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, whose claim on the cash flow of the Company is secondary to debt holders. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders.

Q. What is the Company's proposed capital structure?

A. The Company proposes to establish a permanent ratemaking capital structure consisting of 50.00 percent common equity and 50.00 percent long-term debt.

Q. Did you conduct any analysis to determine if this requested equity ratio was reasonable?

A. Yes. I compared the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. The cost of equity is estimated based on the return that is derived from companies in the proxy group that are deemed to be comparable in risk to the Company; however, those companies must be publicly-traded in order to apply the cost of equity models. The operating utility subsidiaries of the proxy group companies are most risk-comparable to the Company, and thus it is reasonable to look to the average capital structure of the operating utilities of the proxy group to benchmark the equity ratios for the Company. Specifically, I have calculated the average proportion of common equity, long-term debt, preferred equity and short-term debt for the most recent eight quarters for each of the utility operating subsidiaries of the proxy group companies. As shown in Schedule D16, the common equity ratios for operating subsidiaries of the proxy group companies over the past three years ranged from 45.73 percent to 61.15 percent, with an average of 52.91 percent. Therefore, UMERC's proposed equity ratio is well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies and is well below the average.

Q. Are there other factors to be considered in setting the Company's capital structure?

A. Yes, there are other factors that should be considered in setting the Company's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the credit metrics for utilities.

For example, while Moody's recently revised its outlook for the utility sector from "negative" to "stable", Moody's continues to note that high interest rates and increased capital spending will place pressure on credit metrics. Thus, Moody's highlights constructive regulatory outcomes that promote timely cost recovery as a key factor in supporting utility credit quality.[91]

Likewise, while S&P also recently revised its outlook for the industry from negative to stable,[92] S&P continues to see significant risks in 2024 for the industry as a result of, among other things, inflation and increased levels of capital spending.[93] S&P also recently found that the factors contributing to higher costs (*e.g.*, inflation; deferred commodity costs) and that it will be closely monitoring pressure on the industry's credit quality as a

91 Moody's Investors Service, Outlook, "Outlook turns stable on low prices and credit-supportive regulation," September 7, 2023.

92 S&P Global Ratings, "The Outlook for North American Regulated Utilities Turns Stable," May 18, 2023, at 8.

93 S&P Global Ratings, Industry Credit Outlook 2024 - North American Regulated Utilities, January 9, 2024.

result of its ability to recover these costs on a timely basis and minimize regulatory lag, while at the same time effectively managing regulatory risk and customer rates. [94]

Fitch has stated that it is maintaining a "deteriorating outlook" on the U.S. utility sector in 2024 based on elevated capital spending and continuing higher interest rates that place pressure on credit metrics. Fitch noted that bill affordability will remain a major issue for the industry that could affect future regulatory outcomes, and that while it expects authorized ROEs to start trending up with the increase in interest rates, albeit with a lag, given the uncertain macroeconomic environment and bill pressure on customers, the lag could be longer than in previous cycles.[95]

The credit ratings agencies' continued concerns over the negative effects of inflation, higher interest rates, and increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for the industry as a whole, and UMERC in particular in the context of this proceeding.

Q. Will the capital structure and ROE authorized in this proceeding affect the Company's access to capital at reasonable rates?

A. Yes. The level of earnings authorized by the Commission directly affects the Company's ability to fund its operations with internally generated funds. Both bond investors and rating agencies expect a significant portion of ongoing capital investments to be financed with internally-generated funds. In addition, it is important to recognize that because a

94 S&P Global Ratings, "Regulatory Friction Is Constraining Cost Recovery For North American Investor-Owned Utilities," November 6, 2023, at 8.

95 Fitch Ratings, "North American Utilities, Power & Gas Outlook," S&P Market Intelligence, November 13, 2023.

utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long term financing requirements of the assets placed into service. Those assurances, which often are measured by the relationship between internally generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. As a consequence, both the ROE and capital structure are very important to debt and equity investors, particularly given the capital market conditions discussed previously.

IX. CONCLUSION AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for UMERC?

A. Figure 17 summarizes the results of my cost of equity analyses. Based on the quantitative and qualitative analyses presented in my direct testimony, and the business and financial risks of the Company as compared to the proxy group, the Company's requested ROE of 10.25 percent is at the low end of the range and therefore conservative, particularly when taking into consideration the Company's proposed capital structure, which is more highly leveraged than the proxy group, on average.

Figure 17: Summary of Analytical Results

Constant Growth DCF	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.11%	10.54%	11.73%
90-Day Avg. Stock Price	9.08%	10.51%	11.69%
180-Day Avg. Stock Price	9.09%	10.51%	11.70%
Average	9.09%	10.52%	11.71%
Median Results:			
30-Day Avg. Stock Price	9.09%	10.44%	11.53%
90-Day Avg. Stock Price	9.03%	10.43%	11.52%
180-Day Avg. Stock Price	9.03%	10.38%	11.59%
Average	9.05%	10.42%	11.55%

CAPM / ECAPM / Bond Yield Risk Premium	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	12.04%	12.02%	12.02%
Current Bloomberg Beta	10.96%	10.91%	10.90%
Long-term Avg. *Value Line* Beta	10.72%	10.65%	10.65%
ECAPM:			
Current *Value Line* Beta	12.20%	12.19%	12.19%
Current Bloomberg Beta	11.39%	11.35%	11.35%
Long-term Avg. *Value Line* Beta	11.21%	11.17%	11.16%
Bond Yield Risk Premium:	10.56%	10.41%	10.40%

Q. What is your conclusion with respect to UMERC's proposed capital structure?

A. UMERC's proposal to establish a permanent ratemaking capital structure that is composed of 50.00 percent common equity and 50.00 percent long-term debt is at the low end of the range of actual capital structures of the proxy group companies. Further, taking into consideration the impact of current and projected market conditions on the cash flows of utilities as raised by the credit rating agencies, I conclude that the Company's proposed capital structure is more highly leveraged than the proxy group on average, and therefore has higher overall risk than the proxy group.

Q. Does this conclude your direct testimony?

A. Yes.

Ann E. Bulkley

PRINCIPAL

Boston 508.981.0866 Ann.Bulkley@brattle.com

With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff and prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
PacifiCorp, d/b/a Pacific Power	5/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	01/24	Public Service Company of Colorado	Docket No. 24AL-___G	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
The Southern Connecticut Gas Company	11/23	The Southern Connecticut Gas Company	Docket No. 23-11-02	Return on Equity
Connecticut Natural Gas Corporation	11/23	Connecticut Natural Gas Corporation	Docket No. 23-11-02	Return on Equity
Connecticut Water Company	10/23	Connecticut Water Company	Docket No. 23-08-32	Return on Equity
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	12/23	Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	IURC Cause No. 45990	Return on Equity
Indiana Michigan Power Co.	08/23	Indiana Michigan Power Co.	IURC Cause No. 45933	Return on Equity
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-___	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	04/23	Evergy Kansas	Docket No. 23-EKCE-775-RTS	Return on Equity
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				
Kentucky American Water Company	06/23	Kentucky American Water Company	Docket No. 2023-____	Return on Equity
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	11/23	Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	DPU 23-150	Return on Equity
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Michigan Gas Utilities Corporation	03/24	Michigan Gas Utilities Corporation	Case No. U-21540	Return on Equity
Indiana Michigan Power Co.	09/23	Indiana Michigan Power Co.	Case No. U-21461	Return on Equity
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
ALLETE, Inc. d/b/a Minnesota Power	11/23	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-23-155	Return on Equity
CenterPoint Energy Resources	11/23	CenterPoint Energy Resources	D-G-008/GR-23-173	Return on Equity
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
ALLETE, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Evergy Missouri West	2/24	Evergy Missouri West	File No. ER-2024-0189	Return on Equity
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	1/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire - Board of Tax and Land Appeals				
Liberty Utilities (EnergyNorth Natural Gas)	07/23	Liberty Utilities (EnergyNorth Natural Gas)	Docket No. DG 23-067	Return on Equity
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
Elizabethtown Gas Company	2/24	Elizabethtown Gas Company	GR24020158	Return on Equity
Public Service Electric and Gas Company	11/23	Public Service Electric and Gas Company	ER23120924 GR23120925	Return on Equity
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-W-0235	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Otter Tail Power Company	11/23	Otter Tail Power Company	Case No. PU-23-___	Return on Equity
Montana-Dakota Utilities Co.	11/23	Montana-Dakota Utilities Co.	Case No. PU-23-___	Return on Equity
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/23	Oklahoma Gas & Electric	Cause No. PUD2023-000087	Return on Equity
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	11/23	Pennsylvania-American Water Company	Docket No. R-2023-3043189 (water) Docket No. R-2023-3043190 (wastewater)	Return on Equity
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Texas Public Utility Commission				
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Texas Railroad Commission				
CenterPoint Energy Entex and CenterPoint Energy Texas Gas	10/23	CenterPoint Energy Entex and CenterPoint Energy Texas Gas	2023 Texas Division Rate Case Case No. OS-23-00015513	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/23	Virginia American Water Company, Inc.	Docket No. PUR-2023-00194	Return on Equity
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	03/24	Cascade Natural Gas Corporation	Docket No. UG-24008	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase retail electric rates and for other relief.	)	Case No. U-21541

DIRECT TESTIMONY OF
AARON L. NELSON

FOR

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

May 1 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase retail electric rates and for other relief.	Case No. U-21541

QUALIFICATIONS
OF
AARON L. NELSON
PART I

Q. Please state your name and business address.

A. My name is Aaron Nelson. My business address is WEC Energy Group, 231 West Michigan Street, Milwaukee, Wisconsin 53203.

Q. In what capacity are you employed?

A. I am Senior Project Specialist – State Regulatory Affairs at WEC Energy Group ("WEC"). WEC is the parent company of Upper Michigan Energy Resources Corporation ("UMERC" or the "Company").

Q. What is your educational and business experience?

A. In 2011, I received a Bachelor of Business Administration degree, with specializations in management and information systems, from the University of Wisconsin–Eau Claire. In 2016, I received a Master's of Science in Management degree, with specialization in financial analysis, from the University of Wisconsin-Milwaukee.

In 2011, I was hired by Wisconsin Electric d/b/a We Energies and worked in several areas prior to my current role. In 2016, I became a Project Specialist in State Regulatory Affairs with WBS and in 2019 I was promoted to Senior Project Specialist in the State Regulatory Affairs Department. My responsibilities include preparation of cost of service studies for all WEC utilities, including UMERC. In addition, I am responsible for electric rate development and service and tariff administration for WEC's electric and steam utilities.

Q. On whose behalf are you offering this direct testimony?

A. I am offering this direct testimony on behalf of UMERC.

Q. Have you ever testified before A regulatory agency?

A. Yes. I have provided direct testimony to the Michigan Public Service Commission ("MPSC" or the "Commission") on behalf of UMERC in its Integrated Resource Plan filing in Case No. U-21081. I have also provided direct testimony in Michigan Gas Utilities Company's ("MGUC's") Test Year 2022 and 2024 rate cases in Case Nos. U-20718 and U-21366.

Outside of Michigan, I have provided testimony to the Public Service Commission of Wisconsin on electric, natural gas, and steam rate-making issues in multiple rate cases (Docket Nos. 5-UR-109, 5-UR-110, 6690-UR-126, and 6690-UR-127), to the Minnesota Public Utilities Commission regarding natural gas class cost of service (Docket GR-17-563), and to the Illinois Commerce Commission regarding natural gas class cost of service (Docket Nos. 20-0810, 23-0068, and 23-0069).

AARON L. NELSON
DIRECT TESTIMONY
PART II

Q. What is the purpose of your direct testimony?

A. My direct testimony and exhibits describe and present UMERC's electric class cost of service study ("COSS") for the forecasted 12-month period ending December 31, 2025 ("test year" or "2025TY"), including the request for cost allocation between the Tilden Mining Company, L.C. ("Tilden") and UMERC's other customers. For purposes of this testimony, references to "non-Tilden customers" are to all UMERC retail customers other than Tilden.

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

A. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-16	F1.1	Electric Cost-of-Service Study Version 1 (Established Allocation; w/o RICE)
A-16	F1.2	Electric Cost-of-Service Study Version 2 (Special Contract Allocation; w/o RICE)
A-16	F1.3	Electric Cost-of-Service Study Version 3 (Established Allocation; w/ RICE)
A-16	F1.4	Electric Cost-of-Service Study Version 4 (Special Contract Allocation; w/ RICE)

These exhibits present the 2025TY electric class COSSs prepared for UMERC. The accompanying work papers include associated allocation methodologies, supplemental analyses, and data. Additionally, an Excel class COSS model with formulas intact is being provided as part of the work papers and supports the above exhibits. This testimony explains these studies.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. How many versions of its electric class COSS did UMERC prepare?

A. UMERC prepared four versions of its electric class COSS.

Q. Why is UMERC submitting multiple versions of its class COSS?

A. First, UMERC has not had a rate case since the Reciprocating Internal Combustion Engine ("RICE") electric generation facilities were placed into service on April 1, 2019. As such, the depreciation rates for those facilities have not been reflected in customer rates. UMERC is submitting two class COSSs that are identical but for the effects of the requested depreciation rate change currently pending in Case U-21542. Second, UMERC is also submitting class COSSs that vary in allocation principles, including: 1) a class COSS that uses established cost allocation principles and 2) a class COSS as modified by cost allocations agreed upon between UMERC and Tilden in Case No. U-18224 on October 25, 2017 ("Tilden Special Contract") in the Tilden Special Contract. UMERC prepared these two versions of its class COSS as support for demonstrating that the contract prices and terms of the Tilden Special Contract are justified on the basis of a cost of service analysis. However, and as I will discuss later in this testimony, UMERC is requesting Commission approval to use its class COSS as modified by cost allocations agreed upon in the Tilden Special Contract for allocating costs to non-Tilden customers in this case. UMERC's class COSS that uses established allocations is being presented as support only for demonstrating that the contract prices and terms of the Tilden Special Contract are justified on the basis of a cost of service analysis and that the ratemaking concerns identified in Case No. U-18224 have been satisfied.

Q. What concerns regarding the ratemaking effects of the Tilden Special Contract were identified in Case No. U-18224?

A. While the Commission approved the Tilden Special Contract, the Commission's order in Case no. U-18224 found that the ratemaking matter should be deferred until UMERC provides a class COSS. UMERC is presenting the requisite cost of service analysis in this case.

Q. Please summarize the versions of class COSS that UMERC prepared.

A. UMERC's four electric class COSSs include:

1. Version 1: Exhibit A-16 Schedule F1.1. This version excludes the effects of the requested depreciation rate change currently pending in Case No. U-21542 and incorporates established cost allocations between Tilden and non-Tilden customers;
2. Version 2: Exhibit A-16 Schedule F1.2. This version excludes the effects of the requested depreciation rate change currently pending in Case No. U-21542 and incorporates UMERC's preferred and agreed upon cost allocations from the Tilden Special Contract between Tilden and non-Tilden customers;
3. Version 3: Exhibit A-16 Schedule F1.3. This version is identical to Version 1 but for changes to the Company's 2025 future test year driven solely by depreciation rates; and
4. Version 4: Exhibit A-16 Schedule F1.4. This is UMERC's preferred class COSS. It is identical to Version 2 but for changes to the Company's 2025 future test year driven solely by depreciation rates.

Q. Please describe Exhibit A-16, Schedule F1.1.

A. Exhibit A-16, Schedule F1.1 Version 1 represents the Base Case COSS. It uses established cost allocation principles between Tilden and the non-Tilden customers, and is similar to those cost of service analyses performed in UMERC's predecessor utilities prior rate cases in Case Nos. U-16830 and U-17669. It does not include the new depreciation rates for the RICE Units. Page 1 of Schedule F1.1 summarizes the development of the allocated rate base, operating income, and revenue deficiency values by rate class at present rates for UMERC's 2025 projected test year Base Case class COSS. Pages 2 and 3 present the same information as Page 1 just at a more disaggregated customer class level using the classes of customers described later in this testimony. Finally, Pages 4 and 5 present the development of total distribution revenue requirements by customer class.

Q. Please describe Exhibit A-16, Schedules F1.2 through F1.4.

A. Schedule F1.2 through F1.4 are organized in the same fashion and present the same information as Schedule F1.1 but for the changes to the Company's 2025 future test year driven solely by depreciation rates and cost allocation principles described earlier. Schedule F1.2 uses the cost allocations from the Tilden Special Contract and does not include the new depreciation rates for the RICE Units. Schedule F1.3 uses the same established cost allocations as Schedule F1.1 and *includes* the new depreciation rates for the RICE Units. Schedule F1.4 uses the cost allocations from the Tilden Special Contract and *includes* the new depreciation rates for the RICE Units. It is noteworthy that all four of the class COSSs demonstrate that UMERC's costs of serving Tilden are fully recovered through the Tilden Special Contract.

Q. Which version of electric class COSS is UMERC recommending be used to set rates for the 2025 projected test year?

A. UMERC recommends that its Version 4 class COSS presented in Exhibit A-16 Schedule F1.4, which incorporates cost allocations agreed upon in the Tilden Special Contract, be used for setting 2025 retail electric non-Tilden rates.

Q. How is the remainder of your direct testimony organized?

A. First I will summarize my conclusions. Second, I will describe and provide a general overview of class cost of service and the processes and procedures I relied on while developing UMERC's test year 2025 electric class COSS. Third, I will provide an overview of the allocation methods used in UMERC's test year 2025 class COSS. Finally, I will describe and summarize the results of UMERC's test year 2025 electric class COSS.

<u>Summary</u>

Q. Can you summarize your recommendations in this proceeding?

A. Yes, the following is a summary of my testimony and recommendations:

1. UMERC's class COSS in this case demonstrates that the Tilden Special Contract prices and terms are justified on the basis of a cost of service analysis, and that the cost to serve Tilden are not being reallocated to other customer classes;
2. The Commission should accept UMERC's cost allocation between Tilden and non-Tilden customers as determined by Exhibit A-16, Schedule F1.4 because this class COSS identifies, quantifies, and assigns all of the specific costs incurred under the contract for which Tilden is responsible for;
3. The Commission should accept UMERC's customer class revenue requirements as determined by Exhibit A-16, Schedule F1.4 for purposes of setting 2025 electric rates; and
4. Including the effect of new depreciation rates as requested in pending Case No. U-21542, UMERC's direct case supports a total revenue increase for non-Tilden customers of $11.1 million, which represents an increase of approximately 13.8% when compared to the Company's revenues at current rates for non-Tilden customers, and including the revenues from RAS customers.

Q. Please summarize the results of UMERC's proposed electric class COSS Version 4.

A. Table 1 summarizes the results of UMERC's electric class COSS with respect to revenue deficiency at present rates by customer class based on UMERC's requested revenue requirement, including revenues from RAS customers, consistent with Exhibit A-16, Schedule F1.4. Present rates are those that the Commission most recently approved.

Table 1
Upper Michigan Energy Resources Corporation
Electric Class Revenue Deficiency at Present Rates

Line No.	Line Description	Present Revenue $	Revenue Deficiency $	Revenue Deficiency %	Revenue Requirement $
1	Retail Non-Tilden Electric Sales				
2	ResFlat	36,267,846	6,795,971	18.7%	43,063,816
3	ResTOU	925,809	211,137	22.8%	1,136,947
4	SecFlat	14,387,956	1,910,800	13.3%	16,298,756
5	SecTOU	896,967	85,357	9.5%	982,324
6	SecDemand	0	0	0.0%	0
7	SecDemandTOU	4,551,196	797,009	17.5%	5,348,205
8	Primary	22,308,359	1,304,721	5.8%	23,613,080
9	Special Contract (U-16967)	423,037	(60,651)	-14.3%	362,386
10	SLO1	1,082,793	118,014	10.9%	1,200,807
11	Total non-Tilden Retail	**80,843,963**	**11,162,357**	**13.8%**	**92,006,320**

General Overview of Class Cost of Service

Q. Does UMERC provide service to multiple rate zones?

A. Yes. As discussed by Mr. Stasik, UMERC was formed effective January 1, 2017 by consolidating the Michigan operations and assets of Wisconsin Electric Power Company ("WEPCO") and Wisconsin Public Service Corporation ("WPS Corp."). UMERC's electric service territory is currently segmented into two rate zones. One rate zone, the WEPCO rate zone for customers previously served by Wisconsin

Electric and one rate zone, the WPSC rate zone for customers previously served by WPS Corp.

Q. Does UMERC's electric class COSS determine cost responsibility for each rate zone?

A. No. UMERC's electric class COSS was prepared at a class level, and each customer class may include individual rate schedules from both legacy rate zones.

Q. What classes of customers are included in UMERC's electric class COSS?

A. UMERC's electric class COSS includes the customer classes under which UMERC currently provides retail service in Michigan. A complete list of the customer classes used in UMERC's class COSS includes:

1. Residential flat;
2. Residential time-of-use;
3. Secondary small flat;
4. Secondary small time-of-use;
5. Secondary medium;
6. Secondary large time-of-use
7. General primary;
8. General primary Special Contract (U-16967);
9. TMSC or Tilden; and
10. Street lighting and other;

Q. Are retail access service customers included in UMERC's electric class COSS?

A. Yes. RAS customers are included with the customer class that they would be assigned to if they were full requirement service customers, since distribution costs are the same across both groups. Loads from RAS customers are included in

UMERC's delivery service allocation factors but excluded from UMERC's power supply service allocation factors. Additionally, electric delivery service revenues from RAS customers are recorded by the Company as other operating revenue in account 456. In the electric COSS, these other operating revenues for delivery service are direct assigned to the customer classes having RAS customers.

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

A. The purpose of a class COSS is to identify the revenues, costs and profitability for each customer class. It assists in determining the reasonableness of each class's present rates, and provides a guide for the development of the proposed cost-based rates using an embedded cost methodology.

Q. How should a class COSS be performed?

A. The most important theoretical principle underlying a class COSS is that cost incurrence should follow historical embedded cost causation. The costs that customers become responsible to pay should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service. Whenever possible, the cost of known components are directly assigned to the cost of service class. By performing a class COSS in this manner, the class COSS can be used to determine how costs should be recovered from customer classes through rate design.

<u>**UMERC 2025TY Electric Base Case COSS (Version 1)**</u>

Q. Please explain the procedures used to develop the class COSSs shown in the Schedules F1.1 to F1.4 of Exhibit A-16 that you are sponsoring.

A. In general, there are three main steps to determining cost responsibility: 1) functionalization, 2) classification, and 3) allocation. Each of these steps is performed on the Company's total cost of service.

Functionalization is the process of categorizing costs based on their function within the utility. Generally, electric costs are functionalized either as production, transmission, or distribution.

Classification is the process of categorizing costs based on whether they are caused by demand, number of customers, or the energy consumed.

Allocation is the process of apportioning each cost item within each classification and for each function to classes of customers. Some costs, particularly general or indirect costs, cannot be directly functionalized or classified. In general, these costs are allocated to functions, classifications, and customer classes based upon the allocated results of other cost items within the class COSS.

Q. What is your process for functionalizing costs?

A. For the most part, the job of functionalizing plant costs is performed by the Plant Accounting Department, which operates in conformance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA"). Similarly, O&M costs are functionalized by our Finance Department, also in conformance with the FERC USOA.

Q. What is your process for classifying costs?

A. Once costs are functionalized, all cost elements are classified by whether they are caused by demand, number of customers, or the energy consumed. Demand-related costs are costs incurred to meet customer demand for electricity. The cost of a peaking power plant a demand-related cost. Customer-related costs are costs associated with customers regardless of the amount of electricity they demand or consume. These are costs incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and bill and maintain the customer's account. The costs to install an electric service drop is an example of customer-related costs. Finally, energy-related costs are costs incurred as customers consume energy. The fuel burned in power plants is an examples of energy-related costs.

In general, production costs that vary with the amount of energy consumed are classified as energy-related. Production costs that do not vary with the amount of energy consumed are classified as demand-related. Transmission costs are considered demand-related. Distribution costs are classified as demand-related or customer-related.

Q. What is your process for allocating costs to customer classes?

A. The purpose of cost allocation is to determine cost responsibility by customer class. The prior steps consisting of functionalization and classification facilitate the allocation of costs to customer classes. In general, costs classified as demand-related are allocated to classes based on a demand allocation factor, costs classified as energy-related are allocated to classes based on an energy allocation factor, and costs classified as customer-related are allocated to classes based on a customer allocation factor. Some costs, such as indirect or general costs, closely follow in proportion with other cost items. These costs are allocated using the allocation results of other cost items, such as plant in service or the labor portion of O&M expense. Whenever possible, the cost of known components are directly assigned to the cost of service class.

Q. Please explain the considerations relied upon in determining the cost allocation methodologies that are used to perform a class COSS.

A. As stated earlier, in order to allocate costs within any class COSS, the factors that cause the costs to be incurred must be identified and understood. Additionally, the cost analyst needs to develop data in a form that is compatible with, and supportive of, rate design proposals. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time. Whenever possible, the cost of known components are directly assigned to the cost of service class.

Q. What is the source of the cost data analyzed in UMERC's class COSS?

A. All cost of service data have been extracted from UMERC's revenue requirements and rate base contained in the instant filing as shown in Witness Reese's Exhibits A-11 through A-14 for the 2025 projected test year. Where more detailed information was required to perform various supplementary analyses related to certain plant and expense elements, the data was taken directly from UMERC's various software systems.

Q. Could you please describe the allocation factors used in UMERC's electric class COSS?

A. Some allocation factors are developed using actual or forecast values that are available prior to performing the class COSS. These are often times referred to as external allocation factors. External allocation factors include data such as number of customers, total energy volumes, and other data being provided as part of this case filing in Workpaper ALN-1. Some allocation factors are generated by the class COSS based on the allocated result of other cost items. These are often times referred to as internal allocation factors. Internal allocation factors include data such as the class allocated amount of total rate base, plant in service, or the labor portion of O&M expenses, to name a few.

Class Loads Analysis

Q Please describe the class loads analysis that is used to derive electric demand allocation factors for cost allocation.

A. Our class load analysis estimates each customer class's load at the time of each monthly system peak (or coincident peak ("CP")), and at the time of each customer class's annual non-coincident peak ("NCP"). The data used for this analysis are derived from interval load data from either a census of customers or statistical samples of customers.

Q What time period is used to derive the electric demand allocation factors?

A. In any given year, weather anomalies can distort the normal relationship between energy and demand. Ideally, averages of the most recently available five years of class load studies would be used to derive demand allocation factors for the test year. However, for this filing, data from 2021 was used. Recently, the Company integrated its load research activities into a standard platform used by all WEC Utilities and current load research work has just begun. Additional historical years will continue to be incorporated into the development of demand allocation factors in future years. Results of UMERC's class load analysis supporting its projected 2025 test year are shown in Workpaper ALN-1.

Q Workpaper ALN-1 also shows loss factors. What are these used for?

A. The metered data used for the class load analysis is at the customer level, while the known system load is at the transmission interface. Distribution losses account for the difference between transmission-level loads and customer-level loads. The same loss factors are used for both energy and demand. The distribution loss factors were originally derived from a comprehensive loss study performed in 2004.

Cost Allocations

Q. What method was used to allocate production plant-related costs to customer classes?

A. UMERC's electric class COSS uses the 12CP 75-0-25 method of cost allocation for production plant-related costs. This method is derived from an average of the 12 monthly system coincident peaks weighted 75% and total energy weighted 25%.

Q. Please describe how transmission costs are allocated to customer classes?

A. Transmission charges from American Transmission Company ("ATC") and the Midcontinent Independent System Operator ("MISO") are treated as O&M expense in our class COSS. These costs are directly passed through to customers and are allocated using the 12CP 100-0-0 method. This method is an average of the 12 monthly system coincident peaks.

Q. How does UMERC classify distribution plant costs in its class COSS?

A. The distribution system is built to meet two criteria. It must connect to all customers and each component must be capable of handling the load of all the customers connected to it at peak demand. The cost of connecting customers to the distribution system are classified as customer-related. There are costs associated with serving all customers even if they only use a minimal amount of energy (or even no energy at all). As noted earlier, these are costs to extend service to and attach a customer to the distribution system, meter any electric usage, and bill and maintain the customer's account. All other costs are incurred to support the load demanded by the customers, so the costs associated with such equipment are classified as demand-related. Currently about 15% of distribution plant is considered customer related (service lines, metering, and lighting) with the remainder assigned as demand related (land, substations, poles, conductors, transformers, and other facilities).

Q. Please describe how distribution demand-related plant costs are allocated to customer classes.

A. As noted earlier, one criteria of the distribution system is that each component must be able to deliver the peak demand of the customers connected to it. Therefore, demand-related distribution costs are allocated to customers classes using the class non-coincident peak ("NCP") method. Because all customer classes do not utilize the full distribution system for electric service, the demand allocation factor used to apportion distribution costs assigns only the portion(s) of the distribution system that is used by each customer class. For example, some customers may take electrical service directly from the transmission system via a customer-owned substation. These transmission level customers utilize no company-owned distribution equipment for electrical service, except a meter to measure their consumption. Some customers may take electrical service directly from the transmission system but via a company-owned substation. These sub-transmission level customers are assigned only the cost of company-owned substations and metering. Some customers may take service directly from the primary distribution system. Primary customers own their own secondary system equipment and therefore are not apportioned the cost of UMERC's secondary distribution system in the electric class COSS. Last, other customers may take service directly from the secondary distribution system. Secondary customers utilize the full distribution system for electric service.

Q. How does UMERC allocate distribution customer-related plant costs to customer classes?

A. As noted earlier, another criteria of the distribution system is that it must connect each customer. Therefore, customer-related distribution costs are allocated to customer classes using a customer allocation factor. Customer-related plant consists of service lines and meters. Because some classes of customers use larger and more costly equipment than other classes, class weighting factors were developed based on a study of historical plant investment by customer class. Development of the allocation factors for service lines and meters is presented in Work paper ALN-1.

Q. Please describe in more detail how service lines (plant account 369) are allocated to customer classes.

A. UMERC can estimate the number of service drops used by each customer class by assuming that customers with the same service address, excluding apartment numbers and suite numbers, share the same service drop. UMERC performs this analysis by customer class rather than by rate schedule because it is possible that a single service drop could serve customers on both flat and time-of-use rates. It is less likely that a single service drop would serve both small and large customers. Costs for plant account 369 are then allocated proportionally to the estimated cost of service drops for each customer class.

Q. Please describe in more detail how meter costs (plant account 370) are allocated to customer classes.

A. Meter costs can be more directly assigned to customer classes because we know which meters serve which customers. UMERC adds up the number of meters serving each class, taking into account that some customers, particularly larger customers, have more than one meter. UMERC's metering department supplied estimates of the unit costs for meters serving different classes. A meter serving a large industrial account costs more than a meter serving a flat-rate residential account. UMERC derived allocation factors for each class by multiplying the number of meters in each class by the estimated unit cost of those meters in each class. Costs are then allocated to customer classes proportionally to these allocation factors.

Q. Please describe how distribution O&M expenses are allocated to customer classes.

A. Distribution O&M expenses are apportioned to customer classes based on their respective plant-related cost. For example, overhead lines maintenance expense (account 593) is allocated to customers classes based on the sum of plan-in-service for poles and fixtures (account 364), overhead conductors (365), and overhead services (369). Whenever possible, the cost of some components (such as street-lighting) are directly assigned to the cost of service class.

Q. How are customer costs categorized?

A. Customer costs are defined by FERC USOA as accounts 901 through 917. UMERC categorizes accounts 901, 902, 903 and 905 as customer accounting costs. Account 904, uncollectibles, is categorized separately for allocation purposes. We have no costs in account 906. Accounts 907 through 910 are categorized as customer service costs. Accounts 911 through 917 are categorized as sales costs.

Q. How does UMERC allocate customer-related O&M costs to each customer class?

A. Customer accounting costs were allocated to customer classes based on the number of customers within each customer class. Expenses in Account 904 uncollectibles, as well as customer services and sales were allocated to customer classes based on a total revenue allocation factor.

Q. Please describe common administrative and general expenses.

A. A&G costs are defined as FERC accounts 920 through 935. Most of these costs are classified based on the allocation results from the labor portion of O&M, as the majority of the A&G costs are related to labor, including pensions and benefits. Property insurance, FERC account 924, is classified based on property, or total net plant in service. Regulatory commission expense, FERC account 928, is classified based on revenue.

Q. How are general plant costs allocated to customer classes?

A. General plant consists of assets used to support UMERC's utility services but not readily categorized to a specific utility function. UMERC would not be able to provide electric service without the general plant assets. Communication devices, computer equipment, and vehicles supporting UMERC's utility functions are all examples of general plant. These costs are allocated to customer classes based on the allocation results of all other gross plant in service as these are support costs for the other plant functions. Plant costs related to the implementation of the billing system were directly assigned to the customer classification for allocation to customer classes.

Q. How are depreciation reserve and depreciation expenses allocated to customer classes?

A. Depreciation reserve and depreciation expenses are allocated to customer classes based on the allocated results of the gross plant values of each account.

Q. How are income taxes and deferred income taxes allocated to customer classes?

A. Current and deferred income taxes were allocated to customer classes based upon the allocated results of rate base.

Q. Please Summarize UMERC's Version 1 class COSS.

A. Exhibit A-16, Schedule F1.1 Version 1 represents the Base Case COSS. It uses established cost allocation principles for allocating costs of service between Tilden and the non-Tilden customers, and it is similar to those cost of service analyses performed in UMERC's predecessor utilities prior rate cases in Case Nos. U-16830 and U-17669. It does not include the new depreciation rates for the RICE Units.

<u>UMERC 2025TY Electric Class Cost of Service – Version 2</u>

Q. Please describe Exhibit A-16, Schedule F1.2.

A. Exhibit A-16, Schedule F1.2 is Version 2 of UMERC's class COSSS, which does not include the new depreciation rates for the RICE Units and, where applicable, uses cost allocations from the Tilden Special Contract in lieu of the established allocations from Version 1.

Q. Why did UMERC adjust its cost allocation methods in Version 2?

A. The Tilden Special Contract identified the specific costs for which Tilden would be responsible, including Tilden's portion of the capital costs associated with the RICE units. Because these costs are known, it is appropriate to directly assign those costs to the customer(s) responsible for the cost.

Q. Please summarize the adjustments UMERC made to its class COSS following the Tilden Special Contract.

A. UMERC's Version 2 class COSS incorporates the following adjustments given the particulars of the Tilden Special Contract:

1. Directly assigning 50% of the RICE electric generation facilities capital costs to Tilden, and the remaining 50% to non-Tilden customers;
2. Directly assigning Tilden's fuel and purchased power expenses and associated power supply revenues as an offset of the associated costs to non-Tilden customers;
3. Directly assigning Tilden its portion of the generation A&G expenses of the RICE electric generation facilities;
4. Directly assigning Tilden 100% of the generation operations and maintenance expenses of the RICE electric generation facilities;
5. Directly assigning non-Tilden customers 100% of the property taxes for the RICE electric generation facilities; and
6. Directly assigning non-Tilden customers 100% of other operating revenues, including ancillary services from the RICE electric generation facilities.

These adjustments identify, quantify, and assign to Tilden the costs incurred under the current Tilden Special Contract in UMERC's forecasted 2025 test year electric class COSS.

Q. Please address the capital cost allocation.

A. Approximately 50% of the capital costs of the RICE electric generation facilities were assigned to Tilden with the remainder assigned to non-Tilden customers. Substation costs, based on load ratio share, and metering costs, based on actual costs, were also quantified and assigned to Tilden.

Q. Please address the cost allocation of other operating expenses.

A. Tilden was assigned 100% of the forecasted generation operations and maintenance ("O&M") costs, its load ratio share of transmission and distribution substation expenses, estimated metering expenses, and a proportionate share of administrative and general ("A&G") and income taxes. All property-related taxes were assigned to non-Tilden customers. All fuel-related power supply costs were assigned to non-Tilden customers; however, the fuel-related power supply revenues generated by the Tilden Special Contract were credited to non-Tilden customers as an offset to these costs.

Q. Please Summarize UMERC's Version 2 class COSS.

A. Exhibit A-16, Schedule F1.2 Version 2 uses the cost allocations from the Tilden Special Contract and does not include the new depreciation rates for the RICE Units.

<u>UMERC 2025TY Electric Class Cost of Service – Version 3</u>

Q. Please describe Exhibit A-16, Schedule F1.3.

A. Exhibit A-16, Schedule F1.3 is Version 3 of UMERC's class COSS, which uses established cost allocation principles between Tilden and non-Tilden customers. This version is identical to the Version 1 Base Case COSS but for changes to the Company's 2025 future test year driven solely by depreciation rates for the RICE Units.

Q. Please summarize the results of UMERC's Version 3 class COSS.

A. Including the effect of new depreciation rates as requested in pending Case No. U-21542, UMERC's class COSS Version 3 supports a total revenue increase for non-Tilden customers of $9.6 million, which represents an increase of approximately 11.9% when compared to the Company's revenues at current rates for non-Tilden customers, and including the revenues from RAS customers. As I discussed earlier in this testimony, Version 3 is being presented as support only for demonstrating that the contract prices and terms of the Tilden Special Contract are justified on the basis of a cost of service analysis and that the ratemaking concerns identified in Case No. U-18224 have been satisfied. Version 3 does not consider the specific costs agreed upon in the Tilden Special Contract and therefore should not be used for allocating costs to non-Tilden customers for the 2025 projected test year.

UMERC 2025TY Electric Class Cost of Service – Version 4

Q. Please describe Exhibit A-16, Schedule F1.4.

A. Exhibit A-16, Schedule F1.4 is Version 4 of UMERC's class COSS, which is UMERC's preferred class COSS. This class COSS starts with Version 3 and incorporates the certain known adjustments from the Commission-approved Tilden Special Contract that were utilized in Version 2 (Exhibit A-16, Schedule F1.2) and which were discussed earlier in my testimony.

Q. Please summarize the results of UMERC's class COSS Version 4.

A. Including the effect of new depreciation rates as requested in pending Case No. U-21542, UMERC's class COSS Version 4 supports a total revenue increase for non-Tilden customers of $11.1 million, which represents an increase of approximately 13.8% when compared to the Company's revenues at current rates for non-Tilden customers, and including the revenues from RAS customers.

Q. What is the impact of UMERC's class COSS Version 4?

A. After incorporating the cost allocations agreed upon from the Tilden Special Contract, UMERC's Version 4 class COSS results in a revenue responsibility for non-Tilden customers that is approximately $1.5 million, or 1.9% higher as compared to UMERC's Version 3 class COSS. However, this difference should not be taken to mean that a portion of the cost to serve Tilden is being reallocated to non-Tilden customers through the class COSS. To the contrary, the Version 4 class COSS more directly quantifies and assigns the specific cost to serve Tilden and the costs for which Tilden is responsible to Tilden.

Q. What factors cause the UMERC class COSS to indicate that the Tilden Special Contract generates a revenue sufficiency during the 2025 projected year?

A. As discussed in witness Stasik's direct testimony, the Tilden Special Contract identified the specific costs for which Tilden would be responsible, including Tilden's portion of the capital costs associated with the RICE units, to be levelized over a 20 year period. This framework resulted in a situation that caused UMERC to recover fewer revenues from Tilden than it would have if traditional ratemaking were used during the initial years of the Tilden Special Contract. Conversely, this same framework results in a revenue sufficiency in the later years, as compared to traditional ratemaking. Under this structure, the timing of cost recovery shifts from the early years of the contract to the later years but the total amount of revenue UMERC will recover from Tilden over the term of the contract is the same as it would recover under traditional ratemaking for the same costs.

Q. Will there be an adjustment to the pricing of the Tilden Special Contract to reflect the current cost to serve Tilden as determined by UMERC's class COSS, similar to non-Tilden customers?

A. No. As noted before, the Tilden Special Contract is a 20 year agreement with a levelized cost recovery framework.

Q. Why has UMERC proposed version 4 of the COSS, Exhibit A-16, Schedule F1.4 for allocating costs in this case?

A. First, it is noteworthy that all four versions of the COSS presented in my direct testimony and exhibits demonstrate that the Company is recovering all of the costs of serving Tilden through the Tilden Special Contract in the 2024 test year. Second, as Mr. Stasik describes in his direct testimony, in Case No. U-18224 – the case in which the Commission approved the construction of the RICE Units and the Tilden Special Contract, UMERC set forth substantial evidence that the Tilden Special Contract would provide approximately $161 million net present value benefit to non-Tilden customers as compared to “business as usual” over twenty years, while also providing substantial reliability benefits to the Upper Peninsula. It is appropriate to use the cost allocations from the Tilden Special Contract in the COSS used in this ratemaking proceeding because these are the same cost allocations upon which the benefits of the RICE Units and Tilden Special Contract were based in Case No. U-18224.

<u>Summary and Conclusions</u>

Q. Can you summarize your recommendations in this proceeding?

A. Yes, the following is a summary of my testimony and recommendations:

1. UMERC’s class COSS in this case demonstrates that the Tilden Special Contract prices and terms are justified on the basis of the cost of service, and that the cost to serve Tilden is not being reallocated to other customer classes;
2. The Commission should accept UMERC’s cost allocation between Tilden and non-Tilden customers as determined by Exhibit A-16, Schedule F1.4 because this class COSS identifies, quantifies, and assigns all of the specific costs incurred under the contract for which Tilden is responsible and these same cost allocations were used to demonstrate the benefits to non-Tilden customers in Case No. U-18224;

3. The Commission should accept UMERC's customer class revenue requirements as determined by Exhibit A-16, Schedule F1.4 for use in allocating costs to non-Tilden customers for the 2025 test year; and

4. Including the effect of new depreciation rates for the RICE Units as requested in pending Case No. U-21542, UMERC's direct case supports a total revenue increase for non-Tilden customers of $11.1 million, which represents an increase of approximately 13.8% when compared to the Company's revenues at current rates for non-Tilden customers, and including the revenues from RAS customers.

Q. Does this conclude your direct testimony at this time?

A. Yes it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
****

In the matter of the application of	**)**	
UPPER MICHIGAN ENERGY RESOURCES	**)**	
CORPORATION for authority to increase retail	**)**	Case No. U-21541
electric rates and for other relief.	**)**	

DIRECT TESTIMONY AND EXHIBITS OF

JAMES M BEYER

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

May 1, 2024

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase retail electric rates and for other relief.	))))	Case No. U-21541

I. Introduction and Qualifications

Q. Please state your name and business address.

A. My name is James M. Beyer. My business address is WEC Energy Group ("WEC"), 2830 South Ashland Avenue, Green Bay, WI 54304. I am a Project Specialist in the State Regulatory Affairs Department of WEC. Upper Michigan Energy Resources Corporation ("UMERC" or the "Company") is a wholly owned subsidiary of WEC.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this direct testimony before the Michigan Public Service Commission ("MPSC" or the "Commission") on behalf of UMERC.

Q. Please describe your education and experience.

A. I graduated from Northern Michigan University, Marquette, Michigan, with a Bachelor of Science Degree in Accounting in 2002, and from Lakeland College, Sheboygan, Wisconsin, with a Master of Business Administration ("MBA") degree in 2006. I have been employed by WEC and its predecessors, first as a Pricing Analyst and currently as a Project Specialist since 2004. In that position, I perform and am otherwise involved in rate related studies, service and tariff administration, financial analyses, and rate development and administration.

Q. Have you testified before a regulatory agency?

A. Yes. I have testified before the Public Service Commission of Wisconsin ("PSCW") and the MPSC.

II. Purpose and Overview of Direct Testimony

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

A. The purpose of my direct testimony is to describe UMERC's general approach to electric rate design, and present UMERC's proposed electric rate design for the 2025 test year. Specifically, I will address the following items related to electric rates and rules:

- Development and presentation of UMERC's proposed electric rate design for the 2025 test year;
- Establishment of a new single PSCR Base and PSCR Loss Factor for WEPCO and WPSC Rate Zones;
- State Reliability Mechanism ("SRM") Capacity Charge
- Elimination of the Direct Load Control Program;
- Limiting all non-LED lighting tariffs to current customers;
- Opening the current LED tariff to both the WEPCo and WPSC Rate Zones;
- Adding a Distributed Generation tariff;
- Extension Allowances;
- MCL 460.11(2); and
- Miscellaneous rules, regulations and tariff changes.

Q. Do your direct testimony and exhibits include more than one rate design model?

A. Yes, my direct testimony and rate design exhibits reflect two models that are nearly identical except for changes to the Company's 2025 test year to address the proposed depreciation rates for the RICE Units as requested in pending Case No. U-21542. Exhibits and Schedules labeled as "Base" were developed to include the depreciation rates proposed in Case No. U-21542. Exhibits and Schedules labeled as "Alternate" were developed without the proposed depreciation rates in Case No. U-21542.

Q. Please describe the exhibits that you are sponsoring in connection with your direct testimony.

A. I am sponsoring the following Schedules to Exhibit A-16:

F-2: Summary of Present and Proposed Revenue by Rate Schedule (Base);

F-3: Present and Proposed Revenue Detail (Base);

F-4: Comparison of Present and Proposed Monthly Bills (Base);

F-5: Proposed Tariff Sheets;

F-6: List of Tariff Changes Other than Rate Factors;

F-7: Determination of PSCR Loss and Base Rate Factor;

F-8: State Reliability Mechanism Capacity Charge (Base);

F-9: Rate Realignment for the Purpose of Unifying Rate Zones (Base);

F-10: Summary of Present and Proposed Revenue by Rate Schedule (Alternate);

F-11: Present and Proposed Revenue Detail (Alternate);

F-12: Comparison of Present and Proposed Monthly Bills (Alternate);

F-13: State Reliability Mechanism Capacity Charge (Alternate); and

F-14: Rate Realignment for the Purpose of Unifying Rate Zones (Alternate).

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

A. Yes.

III. Rate Design Principles Utilized

Q. Please give an overview of the rate design philosophy reflected in UMERC's proposed electric rate design.

A. UMERC's basic philosophy is to implement James Bonbright's eight criteria of a desirable rate structure. Mr. Bonbright is the author of the oft-cited "Principles of Public Utility Rates." These criteria are:

1. Simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements.
4. Revenue stability from year to year.
5. Stability of the rates with a minimum of unexpected changes adverse to existing customers.
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate design in discouraging wasteful use of service while promoting all justified types and amounts of use (consideration of energy conservation and load management).

Consistent with these criteria, UMERC follows five general principles when developing rates:

1. A fully-allocated, embedded cost-of-service study should be used as a guide for determining revenue requirements for the individual rate schedules.
2. Both embedded and marginal costs should be used as guides in rate design.
3. Where increases or decreases would be substantial based upon cost of service data, the change in rates should be moderated to incorporate reasonable rate stability.
4. Rate design should reflect cost of service to the extent practical.
5. Rate design should take into consideration the competitive impact on the continued viability of existing business, the ability to attract new businesses to the area, industry restructuring and evolution.

Q. Please summarize UMERC's proposed class revenue increases for base rate design.

A. UMERC's proposed rate class allocation of its proposed annual revenue increase, as developed by Witness Reese and as supported by the cost of service study developed by Witness Nelson (Exhibit A-16, Schedule F1.4), is set forth in Exhibit A-16, Schedule F-2

IV. Description of Exhibit Schedules

Q. Please describe Schedule F-2 and F-10 of Exhibit A-16.

A. All of UMERC's proposed electric rate designs are summarized in Schedule F-2 (Base) and Schedule F-10 (Alternate) of Exhibit A-16.

Q. Please describe Schedule F-3 and F-11 of Exhibit A-16.

A. Schedule F-3 (Base) and Schedule F-11 (Alternate) of Exhibit A-16 contain UMERC's proposed rate design for the test year 2025 with revenue calculations by rate schedule and billing determinants.

Q. Please describe Schedule F-4 and F-12 of Exhibit A-16.

A. Schedule F-4 (Base) and Schedule F-12 (Alternate) of Exhibit A-16 calculate typical monthly bills for customers served at various monthly energy and/or demand levels. Each line shows a typical monthly bill under proposed rates, a typical bill under present rates, the amount of the proposed rate increase, and the percent increase.

Q. Please describe Schedule F-5 of Exhibit A-16.

A. Schedule F-5 of Exhibit A-16 contains red-lined copies of the proposed tariff sheets for 2025 test year. The tariffs represent rates proposed in the Base rate design only.

Q. Please describe Schedule F-6 of Exhibit A-16.

A. Schedule F-6 of Exhibit A-16 contains a list of tariff changes other than rate factors.

Q. Please describe the contents of Schedule F-7 of Exhibit A-16.

A. Schedule F-7 of Exhibit A-16 is the determination of the total company PSCR Loss Factor and Base Rate. Lines 3 through 9 show the forecasted power supply costs and MWh of generation for 2025. Lines 11-13 show the calculation of the proposed single loss factor for both rate zones to be effective with the approval of base rates in this case.

The Loss Factor was calculated by dividing the MWh of generation by the total Company system sales subject to PSCR. Line 15 shows the total company PSCR Base Rate.

Lines 19-31 show the current PSCR loss factors, the current PSCR base rates on net generation, the current PSCR base rates on net sales, as well as the projected 2025 PSCR factor to be requested in the Company's September 2024 plan filing.

Q. Please describe Schedule F-8 and F-13 of Exhibit A-16.

A. Schedule F-8 (Base) and Schedule F-13 (Alternate) of Exhibit A-16 is a calculation of UMERC's SRM revenue requirement and capacity charge by COSS class.

Q. Please describe Schedule F-9 and F-14 of Exhibit A-16.

A. Schedule F-9 (Base) and Schedule F-14 (Alternate) of Exhibit A-16 is the calculation of rate realignment surcharges. The rate realignment surcharges are intended to unify similar rate schedules in the WEPCo and WPSC Rate Zones. The eventual goal is to combine rate zones into a single electric service territory because UMERC operates and provides electric service to its customers on a total company basis. In other words, the only distinction between the rate zones are the rates themselves and this is because at the time of UMERC's formation WEPCO's Michigan approved rates differed from WPS Corp's Michigan approved rates.

V. Revenue Allocation and Rate Design

Q. Could you provide a general overview of the intent of UMERC's proposed revenue allocation?

A. UMERC's proposed revenue allocation provides higher rate increases for schedules in which the existing rate levels do not sufficiently recover the costs of providing service. This was done in an effort to continue to realign and move each of the schedules toward rates that better reflect the cost of providing service.

Q. Do UMERC's proposed rates eliminate subsidizations?

A. Yes. Where possible UMERC proposed rates to collect revenues at COSS. UMERC also has taken into account the future rate zone unification when setting rates. See Schedule F-9 of Exhibit A-16 for more detail. Where appropriate UMERC proposes to set some rate schedules below COSS to quicken the rate unification process. For example, rate schedule Cg3 was set below COSS. UMERC proposes to eliminate the Cg3 rate schedule in the future and move customers to Cp-1M (Secondary). Cp-1M was set higher than COSS for that purpose.

Residential Flat Rate Design

Q. Please describe UMERC's proposed Base rate design for the Rg1 and Rg-1M rate schedules.

A. The Rg1 and Rg-1M rate schedules for the WEPCO and WPSC Rate Zones consist of fixed and energy charges. The existing rate levels are forecasted to under-recover the revenue requirement for this rate schedule by approximately 18.74%. For Rg1, UMERC is proposing to increase energy charges by approximately 20.3% while leaving the fixed charges flat. A typical customer using 500 kWh per month currently pays approximately 16.9 cents per kWh. The proposed rate design would increase this to approximately 19.9 cents per kWh. For Rg-1M, UMERC is proposing to increase energy charges by approximately 22.7% while leaving the fixed charges flat. A typical customer using 500 kWh per month currently pays approximately 16.5 cents per kWh. The proposed rate design would increase this to approximately 19.6 cents per kWh. A slightly higher increase in Rg-1M will also assist UMERC's plan to unify the WEPCo and WPSC Rate Zones. Details of the rate design proposal can be found on page 1 and 2 of Schedule F-3 of Exhibit A-16. The above summary is related to the Base rate design proposal only. The Alternate rate design uses the same methodology. Details can be found on page 1 and 2 of Schedule F-11 of Exhibit A-16.

<u>Residential Time-of-Use Rate Design</u>

Q. Please describe UMERC's proposed Base rate design for the Rg2 and Rg-OTOU-1M rate schedules.

A. The Rg2 and Rg-OTOU-1M rate schedules for the WEPCO and WPSC Rate Zones consist of fixed and energy charges. The existing rate levels are forecasted to under-recover the revenue requirement for this rate schedule by approximately 22.81%. For Rg2, UMERC is proposing to increase energy charges by approximately 25.6% while leaving the fixed charges flat. A typical customer using 500 kWh per month currently pays approximately 14.2 cents per kWh. The proposed rate design would increase this to approximately 17.4 cents per kWh. For Rg-OTOU-1M, UMERC is proposing to increase energy charges by approximately 22.4% while leaving the fixed charges flat. A typical customer using 500 kWh per month currently pays approximately 14.7 cents per kWh. The proposed rate design would increase this to approximately 17.4 cents per kWh. A slightly higher increase in Rg2 will also assist UMERC's plan to unify the

WEPCo and WPS Rate Zones. On/Off-Peak price ratios were also held steady for both rate schedules. Details of the rate design proposal can be found on pages 3 and 4 of Schedule F-3 of Exhibit A-16. The above summary is related to the Base rate design proposal only. The Alternate rate design uses the same methodology with a reduced revenue requirement. Details can be found on pages 3 and 4 of Schedule F-11 of Exhibit A-16.

<u>Secondary Flat Rate Design</u>

Q. Please describe UMERC's proposed Base rate design for the Cg1, Cg-1M, TssM, TssU, Cg2, Cg-3M and Mp-1M rate schedules.

A. The Cg1 and Cg-1M rate schedules for the WEPCO and WPSC Rate Zones consist of fixed and energy charges. The existing rate levels are forecasted to under-recover the revenue requirement for this rate schedule by approximately 13.28%. For Cg1, UMERC is proposing to increase energy charges by approximately 13.6% while leaving the fixed charges flat. A typical customer using 2,200 kWh per month currently pays approximately 16.3 cents per kWh. The proposed rate design would increase this to approximately 18.4 cents per kWh. For Cg-1M, UMERC is proposing to increase energy charges by approximately 17.0% while leaving the fixed charges flat. A typical customer using 2,200 kWh per month currently pays approximately 12.7 cents per kWh. The proposed rate design would increase this to approximately 14.7 cents per kWh. A slightly higher increase in Cg-1M will also assist UMERC's plan to unify the WEPCo and WPSC. Details of the rate design proposal can be found on pages 5 and 6 of Schedule F-3 of Exhibit A-16.

UMERC currently has no customers being served under rate schedules TssM and TssU. Rates under these rate schedules are linked to the Cg1 rate schedule. Details of the rate design proposal can be found on pages 7 and 8 of Schedule F-3 of Exhibit A-16.

The Cg2 and Cg-3M rate schedules consist of fixed and energy charges. The existing rate levels are forecasted to under-recover the revenue requirement for this rate schedule by approximately 13.28%. For Cg2, UMERC is proposing to increase energy charges by approximately 14.2% while leaving the fixed charges flat. A typical customer using 2,200 kWh per month currently pays approximately 15.4 cents per kWh. The proposed rate design would increase this to approximately 17.5 cents per kWh. For Cg-3M, UMERC is proposing to increase energy charges by approximately 15.0% while leaving the fixed charges flat. A typical customer using 20,000 kWh per month currently pays approximately 12.5 cents per kWh. The proposed rate design would increase this to approximately 14.3 cents per kWh. Rates for Mp-1M were linked to Cg-3M. This results in a 19.34% increase for the Mp-1M rate schedule. There are only 4 customers on this rate schedule and UMERC will propose to cancel Mp-1M and move the customers to Cg-3M in a future rate case. A typical customer using 14,000 kWh per month currently pays 12.1 cents per kWh. The proposed rate design would increase this to approximately 14.4 cents per kWh. A slightly higher increase in Cg-3M will also assist UMERC's plan to unify the WEPCo and WPSC rate zones. This subject is discussed later in testimony and also shown on Schedule F-9 of Exhibit A-16. Details of the rate design proposal can be found on pages 9 and 10 of Schedule F-3 of Exhibit A-16. The above summary is related to the Base rate design proposal only. The Alternate rate design uses the same methodology with a reduced revenue requirement. Details can be found on pages 5 through 10 and 29 of Schedule F-11 of Exhibit A-16.

Secondary Time-of-Use Rate Design

Q. Please describe UMERC's proposed Base rate design for the Cg5 and Cg-OTOU-1M rate schedules.

A. The Cg5 and Cg-OTOU-1M rate schedules for the WEPCO and WPSC Rate Zones consist of fixed and energy charges. The existing rate levels are forecasted to under-recover the revenue requirement for this rate schedule by approximately 9.52%. For Cg5, UMERC is proposing to increase energy charges by approximately 12.0% while leaving the fixed charges flat. A typical customer using 4,400 kWh per month currently pays approximately 13.9 cents per kWh. The proposed rate design would increase this to approximately 15.6 cents per kWh. For Cg-OTOU-1M, UMERC is proposing to increase energy charges by approximately 14.3% while leaving the fixed charges flat. A typical customer using 2,200 kWh per month currently pays approximately 10.8 cents per kWh. The proposed rate design would increase this to approximately 12.2 cents per kWh. A slightly higher increase in Cg5 will also assist UMERC's plan to unify the WEPCo and WPSC Rate Zones. This subject is discussed later in testimony and also shown on Schedule F-9 of Exhibit A-16. On/Off-Peak price ratios were also held steady for both rate schedules. Details of the rate design proposal can be found on pages 11 and 12 of Schedule F-3 of Exhibit A-16. The above summary is related to the Base rate design proposal only. The Alternate rate design uses the same methodology with a reduced revenue requirement. Details can be found on pages 11 and 12 of Schedule F-11 of Exhibit A-16.

<u>Secondary Demand Time-of-Use Rate Design</u>

Q. Please describe UMERC's proposed Base rate design for the Cg3 and Cg3C rate schedules.

A. The Cg3 and Cg3C rate schedules for the WEPCO and WPSC Rate Zones consist of fixed, demand and energy charges. The existing rate levels are forecasted to under-recover the revenue requirement for this rate schedule by approximately 17.51%. For Cg3, UMERC is proposing to increase energy charges by approximately 12.2% and demand charges by approximately 11.8% while leaving the fixed charges flat. A typical customer with a demand of 210 kW using 70,000 kWh per month currently pays approximately 13.7 cents per kWh. The proposed rate design would increase this to approximately 15.0 cents per kWh. There are currently no customers taking service under the Cg-3C rate schedule. All rates for Cg-3C are linked to Cg3 with the exception of the Curtailable Demand Credit. UMERC is not proposing to change the credit for 2025. A slightly lower increase to Cg3 will also assist UMERC's plan to unify the WEPCo and WPSC Rate Zones in the future. This subject is discussed later in testimony and also shown on Schedule F-9 of Exhibit A-16. The ratio of revenues to fixed, demand and energy were held steady with the proposed rate design. Details of the rate design proposal can be found on pages 13 and 14 of Schedule F-3 of Exhibit A-16. The above summary is related to the Base rate design proposal only. The alternate rate design uses the same methodology with a reduced revenue requirement. Details can be found on pages 13 and 14 of Schedule F-11 of Exhibit A-16.

Primary Rate Design

Q. Please describe UMERC's proposed Base rate design for the Cp1, Cp-1M, Cp2, Cp3, Cp4 and Schedule A rate schedules.

A. The Cp1, Cp-1M and Cp3 rate schedules for the WEPCO and WPSC Rate Zones consist of fixed, demand and energy charges. The existing rate levels are forecasted to under-recover the revenue requirement for this rate schedule by approximately 5.85%. For Cp1, UMERC is proposing to increase energy charges by approximately 2.6% and demand charges by approximately 5.3% while leaving the fixed charges flat. A typical customer with a demand of 1,200 kW using 490,000 kWh per month currently pays approximately 11.9 cents per kWh. The proposed rate design would increase this to approximately 12.2 cents per kWh. For Cp-1M, UMERC is proposing to increase energy charges by approximately 8.1% and demand charges by approximately 8.9% while leaving the fixed charges flat. A typical customer with a demand of 900 kW using 320,000 kWh per month currently pays approximately 7.1 cents per kWh. The proposed rate design would increase this to approximately 8.0 cents per kWh. For Cp3, UMERC is proposing to increase energy charges by approximately 5.3% and demand charges by approximately 6.0% while leaving the fixed charges flat. A typical customer with a demand of 7,600 kW using 4,200,000 kWh per month currently pays approximately 10.5 cents per kWh. The proposed rate design would increase this to approximately 10.7 cents per kWh. For Schedule A, UMERC is proposing to increase energy charges by approximately 1.5% and demand charges by approximately 1.6% while leaving the fixed charges flat. The one customer on this rate schedule takes service under the Retail Access Service tariff and therefore pays only distribution rates through UMERC. There are currently no customers taking service under the Cp2 or Cp4 rate schedules. All rates for the Cp2 and Cp4 rate schedules are linked to Cp1. A slightly lower increase to Cp1 and Cp3 will also assist UMERC's plan to unify the WEPCo and WPSC Rate Zones. The ratio of revenues to fixed, demand and energy were held steady with the proposed rate design. Details of the rate design proposal can be found on pages 15 through 19 of Schedule F-3 of Exhibit A-16. The above summary is related to the Base rate design proposal only. The Alternate rate design uses the same methodology with a reduced revenue requirement. Details can be found on pages 15 through 19 of Schedule F-11 of Exhibit A-16.

Special Contract (U-16967) Rate Design

Q. Please describe UMERC's proposed Base rate design for the rate schedule associated with Special Contract (U-16967).

A. The rate schedule associated with Special Contract (U-16967) consists of fixed, demand and energy charges. The existing rate levels are forecasted to over-recover the revenue requirement for this rate schedule by approximately 14.34%. Due to the special contract UMERC is not proposing to change the customer's base rates. Details of the rate design proposal can be found on page 20 of Schedule F-3 of Exhibit A-16. The Alternate rate design uses the same methodology with a reduced revenue requirement. Details can be found on page 20 of Schedule F-11 of Exhibit A-16.

Outdoor and Overhead Lighting Rate Design

Q. Please describe UMERC's proposed Base rate design for the Gl1, Ms2, Ms3, LED, Ls-1M and Mg1 rate schedules.

A. UMERC is proposing to increase all non-LED lighting schedules by approximately 16.5%, while LED is increasing by 2.16%. This is proposed to better align LED and non-LED lighting schedules. All non-LED lighting schedules are to be closed to new customers. As LED replaces existing lighting facilities, UMERC's historic pricing for LED has been much higher than the non-LED counterpart. For example, currently a 100 watt high pressure sodium ("HPS") lamp is $11.54 per month. The equivalent LED is a total of $16.05 per month. The LED lamp monthly cost is 39% higher than the HPS equivalent. In the proposed rate design the 100 watt HPS is $14.31 per month while the LED equivalent is $17.76 per month. In the proposed rate design the LED lamp monthly cost is 24% higher than the HPS equivalent. This rate design brings them closer together. There are currently no customers being served under the Mg1 tariff. Details of the rate design proposal can be found on pages 22 through 28 of Schedule F-3 of Exhibit A-16. The Alternate rate design uses the same methodology with a reduced revenue requirement. Details can be found on pages 22 through 28 of Schedule F-11 of Exhibit A-16.

<u>Power Supply Cost Recovery</u>

Q. Please describe the power supply cost recovery line item in rate design.

A. The current fuel surcharges of $0.01167/kWh and $0.01594/kWh included in the WEPCo and WPSC Rate Zones, respectively, are shown in present rates but all fuel cost recovery in the test year is built into the base rates and thus there is no fuel adjustment needed in the proposed rates.

Q. How does UMERC propose to determine the new PSCR Base Rate for its WEPCo and WPSC Rate Zones?

A. UMERC proposes to establish a new single PSCR base rate for both rate zones by dividing the net PSCR costs, by the MWhs of generation plus purchased power, less opportunity sales, less MISO sales, less renewable energy as forecasted for 2025 in the instant general rate case proceeding. UMERC further proposes that all future PSCR factors be calculated using the new PSCR Base Rate as UMERC provides power supply on a total company basis. This calculation can be found on Schedule F-7 of Exhibit A-16.

Q. What is the proposed new PSCR Base Rate for the WEPCo and WPSC Rate Zones?

A. The proposed new PSCR Base for the WEPCo and WPSC Rate Zones is $57.10/MWh, as shown on line 15.

Q. How does UMERC propose to determine the new PSCR Loss Factor for its WEPCo and WPS Rate Zones?

A. UMERC proposes to establish a new PSCR Loss Factor that reflects distribution line losses only. The Loss Factor is determined by dividing the net MWh of generation by the MWh of system sales subject to PSCR. UMERC proposes that all future PSCR plans and reconciliations use this new proposed PSCR Loss Factor.

Q. What is the proposed new PSCR Loss Factor for the WEPCo and WPSC Rate Zones?

A. The proposed new PSCR Loss Factor for is 1.0391 for both the WEPCo and WPSC

Rate Zones.

Q. Please describe page 7 of Schedule F-5 Exhibit A-16.

A. Page 7 of Schedule F-5 Exhibit A-16 is an updated tariff sheet reflecting the proposed new PSCR Base and the proposed new PSCR Loss Factor for both the WEPCo and WPSC Rate Zones. UMERC proposes the implementation of the proposed new PSCR Base Rate and PSCR Loss Factor starting with the first business month immediately following the issuance of a final MPSC order in the instant general rate case proceeding.

Q. Is the preliminary 2025 PSCR Plan presented in the instant general rate case proceeding identical to the 2025 PSCR Plan that will be filed in September 2024?

A. The 2025 PSCR Plan presented in the instant general rate case proceeding is only a preliminary estimate of the power supply costs. A 2025 PSCR Plan will be filed in late September 2024. Fuel and purchased power costs and sales will be updated to reflect the latest cost estimates and sales forecast as part of that filing.

State Reliability Mechanism Capacity Charge

Q. Is UMERC proposing any changes to its SRM capacity charge at this time?

A. Yes it is. UMERC's current capacity charges were established in Case No. U-18253 and have been effective since June 1, 2018. In its August 30, 2023 Order in Case No. U-21370 the Commission indicated that the next annual review of the Company's SRM capacity charge would coincide with its next general rate case.

Q. Please describe the resources relied upon by UMERC to derive the total capacity related generation costs included in the utility's base rates.

A. UMERC relied upon the output from the class Cost of Service Study ("COSS") as sponsored by Witness Aaron Nelson in Exhibit A-16, Schedule F1.4.

Q. Please explain the SRM capacity charge calculation found on Exhibit A-16, Schedule F-8.

A. UMERC's total SRM capacity costs were derived by subtracting total production variable costs and energy sales revenue net of fuel from total power supply costs.

Total power supply costs (row 1) were calculated by subtracting the total distribution revenue of $32,180,912 found on page 3 column B row 62 of Nelson's Schedule F1.4 from UMERC's Total Retail revenue requirement of $165,777,111 found on page 2 column B row 62 of Nelson's Schedule F1.4. The resulting total power supply costs equal $133,596,199.

Total production variable costs (rows 2-7) were calculated by summing transmission expense, fuel expense, purchased power and variable operations and maintenance. Transmission expense of $24,516,499 can be found on page 2 of Nelson's Schedule F1.4 column B, row 28. Fuel expense of $25,948,404 can be found on page 2 of Nelson's Schedule F1.4 column B, row 28. Purchased power of $35,121,871 can be found on Nelson's Schedule 13 column B, row 85. Variable operations and maintenance of $692,192 can be found on Nelson's Schedule 13 column c, row 89. The sum of the above values equals $86,278,966.

Row 8 opportunity sales of $4,950,725 can be found on Nelson's Schedule 13, column B, row 61.

The SRM production capacity cost is then calculated by subtracting the total production variable costs and energy sales revenue net of fuel from the total power supply costs for a value of $42,366,508. The non-mines portion of this value is $23,513,418. This is calculated by dividing the total non-mine revenue requirement by the total revenue requirement. This equals 56%. This value is then allocated to each COSS class on a 12CP Demand basis. Energy only and lighting classes are charged on a per kWh basis while classes with a demand component are charged on a per kW basis.

Q. How does UMERC's proposed capacity charge compare to the current capacity charge?

A. UMERC's current capacity charge is $229,523 per megawatt-year ($629 per megawatt-day). UMERC's proposed capacity charge found on Exhibit A-16, Schedule F-8 rows 13 and 14 is $224,161 per megawatt-year ($614 per megawatt-day).

<u>Customer-owned Generation</u>

Q. Is UMERC proposing any changes to its customer-owned generation service offerings at this time?

A. UMERC is proposing a distributed generation tariff to replace the Company's current net metering tariffs. In Case U-18383, the Commission ordered the implementation of Inflow/Outflow tariffs for utilities in any rate case filed after June 1, 2018. Commission

Staff found this method to be of better design than the current net metering tariffs and recommended the Inflow/Outflow method as the preferred design for replacing the current net metering tariffs.

Q. Please describe the Inflow/Outflow method.

A. The Inflow/Outflow method separates the power inflows from the power outflows, allowing distinct and independent sets of metering data that can be utilized to establish appropriate cost of service allocators and billing determinants. The currently established method of net metering nets the billing determinants together.

Q. Please describe the Company's proposed Inflow/Outflow tariffs.

A. The Company's proposed tariff is consistent with Staff's template Distributed Generation Tariff identified on Exhibit A of the Commission's April 18, 2028 Order issued in Case No. U-18383.

Q. How will the Company compensate distributed generation customers for excess power?

A. The Company is proposing to credit customers for excess power with a credit equal to the Power Supply Energy rate and the PSCR factor.

Q. Will distributed generation customers retain rights and ownership to any environmental credits?

A. Yes. Customers will retain the rights and ownership to any environmental credits (including any Renewable Energy Credits, methane offsets, carbon credits, etc.)

associated with excess generation purchased under this tariff unless separately contracted for by the Company and Customer.

Q. How does the Company propose to transition current net metering customers?

A. The Company requests to close the current net metering tariffs (CGS-1, CGS-2, CGS Large, CGS Biogas, PG-1M, PG-1AM and PG-1BM) to new customers and proposes that current net metering customers remain on the existing tariff for a period of 10 years from the date of meter installation for the net metering service as prescribed under MCL 460.1183. There are currently 80 customers under the category 1 net metering tariffs and 3 customers under the category 2 net metering tariffs.

<u>NatureWise and Energy for Tomorrow</u>

Q. Is UMERC proposing changes to the NatureWise and/or Energy for Tomorrow premium rate?

A. No. Updates to the premium rate for both NatureWise and Energy for Tomorrow are handled with the annual voluntary green pricing filing. The most recent case (U-18356) was filed on September 22, 2023 and approved on December 21, 2023. No changes to the premium were proposed in the filing.

<u>Direct Load Control</u>

Q. Please describe the Direct Load Control ("DLC") Programs available in UMERC's WPSC Rate Zone.

A. The DLC programs consist of the following tariffs, which UMERC is proposing to eliminate.

- Rg-DCM – A shed and cycling program for central air conditioners and/or water heaters that provides a fixed monthly credit of $8/month for 4 months per year to residential customers on their bill. This program serves approximately 56 customers in combination with the Cg-DCM program.
- Cg-DCM - A shed and cycling program for central air conditioners and/or water heaters that provides a monthly credit of $8/month for 4 months per year to commercial and industrial customers on their bill.

Q. Why is UMERC proposing to eliminate the residential and commercial direct load control programs.

A. Customer load on the Rg-DCM and Cg-DCM tariffs was controlled using a load control device that is installed on the customer's air conditioner and/or water heater. During a load control event, the WEC System Operations center would initiate an FM or paging signal, which was sent to towers around the service territory. The towers would transmit the signal to the load control devices to disengage or engage the unit. The technology is outdated and individual control units are failing. The individual FM and paging units have been discontinued and are no longer being manufactured. The Company has purchased excess or used equipment from other utilities and has been recycling and repairing units for years. This practice is no longer sustainable. The program was last used in 2019. UMERC's sister company, Wisconsin Public Service Corporation, filed and received approval from the PSCW to eliminate the same direct load control programs in docket 6690-UR-126 effective January 1, 2020.

Residential Income Allowance and Senior Bill Assistance program

Q. Does UMERC plan to address MCL 460.11(6) in this rate case?

A. Yes. MCL 460.11(2) states that a rate increase request shall include proposed eligible low-income customer and eligible senior citizen customer rates. In this case, UMERC is proposing to adopt versions of Michigan Gas Utilities Corporation's Residential Income Allowance ("RIA") and Senior Bill Assistance programs. In connection therewith, the Company is not seeking to impose customer participation caps, but is requesting deferred accounting treatment for revenue impacts of higher or lower participation compared to estimated participation.

Q. Is the Company sponsoring proposed tariff sheets relating to this request?

A. No, not at this time. UMERC believes that Staff's guidance and projections on customer participation levels is required. UMERC believes that after it works with Staff it will be able to produce the necessary tariff sheets.

<u>Cancellation of Tax Cut and Job Act 2017 ("TCJA") Credits</u>

Q. Are you sponsoring tariff sheets that reflects the cancellation of the TCJA credits?

A. Yes. All impacts from the TCJA, including those referred to as Credit A and Calculation C, as established in the Commission's orders in Case Nos. U-20110 and U-20314, are fully reflected in the proposed base rates. Consequently, the Company is sponsoring a tariff sheet that reflects the cancellation/termination of the credits effective with the approval of the base rates in this case.

<u>Rate Realignment</u>

Q. Please explain UMERC's proposed rate realignment plan.

A. UMERC is proposing a rate realignment plan as shown on Schedule F-9 of Exhibit A-16. The initial goal of the rate realignment plan is to gradually combine similar rate schedules between the WEPCo and WPSC Rate Zones. The ultimate goal of the rate realignment plan is to bring similar rate schedules to equal average rates and subsequently combine rate schedules to eliminate rate zones under UMERC. The rate schedules that UMERC is proposing to unify are shown in the table below.

WEPCo Rate Zone	**WPSC Rate Zone**
Residential Flat Rate - Rg1	Residential Flat Rate - Rg-1M
Residential TOU - Rg2	Residential TOU - Rg-OTOU-1M
General Secondary Flat Rate - Cg1	General Secondary Flat Rate - Cg-1M
General Secondary Flat Rate - Cg2	General Secondary Flat Rate - Cg-3M
General Secondary TOU - Cg5	General Secondary TOU - Cg-OTOU-1M
General Secondary Large TOU - Cg3	General Primary TOU - Cp-1M (Secondary)
General Primary TOU - Cp1 (Medium)	General Primary TOU - Cp-1M (Primary)
General Primary TOU Curtailable - Cp3	General Primary TOU - Cp-1M (Transmission)

Q. Please explain how UMERC is proposing to realign customer rates under similar rate schedules.

A. UMERC is proposing an annual $/kWh adjustment to the affected rate schedules. The annual adjustment was calculated by dividing the proposed revenue increase or decrease by the forecasted kWh sales for each rate schedule. The revenue requirement is held constant while the $/kWh adjustments are set as either a credit or charge to bring the average $/kWh equal.

Q. Please explain when these adjustments would go into effect.

A. These annual $/kWh adjustments would be modified annually, on a service rendered basis, on the anniversary of the effective date of the Commission's order in the instant general rate case proceeding.

VI. Rules and Regulations

Q. Have you calculated the values for extension allowances for expansion of the electric distribution system?

A. Yes. The calculated values of extension allowances for expansion of the electric distribution system are shown on pages 3 and 4 of Exhibit A-16, Schedule F-5.

Q. How were the extension allowances calculated?

A. UMERC proposes to increase extension allowances by the percentage increase in total distribution costs from present to proposed. Present distribution costs from the COSS are $30,683,321 and proposed distribution costs are $32,180,912. This represents an increase of approximately 5%. Extension allowances were increased approximately 5% to coincide with the change in total distribution costs. See Witness Nelson's Schedule

F1.4 page 3 for detail. Below is a table containing present and proposed extension allowances.

Customer Class	Present	Proposed
Residential	$535	$561
C&I Energy Only 0-15kW	$535	$561
C&I Energy Only 0-15kW	$814	$854
C&I Energy Only 0-15kW	$2,531	$2,655
C&I Demand	$56	$59

VII. Miscellaneous Electric Rate Sheet Changes

Q. Is UMERC proposing any changes to the lighting rate sheets?

A. Yes. UMERC is proposing to close all non-LED lighting tariffs to new customers beginning January 1, 2025. The Company is no longer able to obtain new non-LED lights for installation. UMERC is proposing to make the current LED tariff in the WEPCo Rate Zone available to those customers in the WPSC Rate Zone.

Q. Is UMERC proposing any changes to the Large Commercial and Industrial Service – Interruptible Rider ("Cp-I")?

A. Yes. Currently customers participating on the Cp-I rider are required to revise annual demand nominations for the succeeding calendar year by April 15th. UMERC is proposing to change the requirement date to January 15th of each year. The proposed date better aligns with the Midwest Independent System Operator's ("MISO") shift to a seasonal resource adequacy requirement. UMERC also files capacity demonstrations each year on March 1st.

Q. Is UMERC proposing any other changes to the rate sheets?

A. Yes. UMERC is proposing numerous minor changes (other than pricing changes) as reflected in Schedule F-6 of Exhibit A-16. These proposed changes include many minor administrative changes and clarifications in addition to the more noteworthy changes addressed in my testimony.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase electric rates and for other relief.	)	Case No. U-21541

PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material that Upper Michigan Energy Resources Corporation ("Applicant") or any other Party discloses to another Party during the course of this proceeding. The Applicant or other Party disclosing Protected Material is referred to as the "Disclosing Party"; the recipient is the "Receiving Party" (defined further below). The intent of this Protective Order is to protect non-public, confidential information and materials so designated by the Applicant or by any other party, which information and materials contain confidential, proprietary, or commercially sensitive information. This Protective Order defines "Protected Material" and describes the manner in which Protected Material is to be identified and treated. Accordingly, it is ordered:

I. "Protected Material" and Other Definitions

A. For the purposes of this Protective Order, "Protected Material" consists of trade secrets or confidential, proprietary, or commercially sensitive information to be provided by Disclosing Party's materials responsive to Part III of the Commission's rate case filing requirements approved in Case No. U-18238 and any testimony, exhibits, workpapers, discovery, audit responses, any witness' related exhibits and testimony, and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material shall 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. Trade secrets or confidential, proprietary, or commercially sensitive information provided in response to discovery, in response to an order issued by the presiding officer or the Michigan Public Service Commission ("MPSC" or the "Commission"), in testimony or exhibits filed later in this case, or in arguments of counsel;

2. 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;

3. Information that could identify the bidders and bids, including the winning bid, in a competitive solicitation for a power purchase agreement or in a competitively bid engineering, procurement, or construction contract at any stage of the selection process (i.e., before the Disclosing Party has entered into a power purchase agreement or selected a contractor); and

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

5. 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. "Party" refers to the Applicant, MPSC Staff ("Staff"), the Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in this Case No. U-21541 under the Commission's Rules of Practice and Procedure, Mich Admin Code, R 792.10401 et al.

D. "Receiving Party" means any Party to this proceeding who requests or receives access to Protected Material, subject to the requirement that each Reviewing Representative sign a Nondisclosure Certificate attached to this Protective Order as Attachment 1.

E. "Reviewing Representative" means a person who has signed a Nondisclosure Certificate and 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.E.1;

3. an expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or

4. an employee or other representative of a Receiving Party with significant responsibility in this case.

A Reviewing Representative is responsible for assuring that persons under his or her supervision and control comply with this Protective Order.

F. "Nondisclosure Certificate" means the certificate attached to this Protective Order as Attachment 1, which is signed by a Reviewing Representative who has been granted access to Protected Material and agreed 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 Protected Material that is marked as required by Paragraph III.A and made available for review by the Disclosing Party to any Receiving Party or Reviewing Representative. This Protective Order protects: 1) the Protected Material; 2) any copy or reproduction of the Protected Material made by any person; and 3) 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 shall be maintained in a secure place. Access to Protected Material shall be limited to persons authorized to have access subject to the provisions of this Protective Order.

B. Protected Material shall be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party may authorize access to and use of Protected Material by a Reviewing Representative identified by the Receiving Party, subject to Paragraphs III and V below, only as necessary to 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. These individuals 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 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, the Disclosing Party and the Receiving Party will attempt to reach an agreement to accommodate that Receiving Party's request to review Protected Material. If no agreement is reached, then either the Disclosing Party or the Receiving Party may submit the dispute to the presiding officer. 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 officer.

D. Before reviewing any Protected Material, including copies, reproductions, and copies of notes of Protected Material, a Receiving Party and Reviewing Representative shall sign a copy of the Nondisclosure Certificate (Attachment 1 to this Protective Order) agreeing to be bound by the terms of this Protective Order. The Reviewing Representative shall also provide a copy of the executed Nondisclosure Certificate to the Disclosing Party.

E. Even if no longer engaged in this proceeding, every person who has signed a Nondisclosure Certificate continues to be bound by the provisions of this Protective Order. The obligations under this Protective Order are not extinguished or nullified 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.

F. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding officer and any other administrative law judge ("ALJ") or ALJ staff member working on this matter shall have access to all Protected Material that is submitted to the Commission under seal without the need to sign the Nondisclosure Certificate.

G. 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.

H. 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 mark any information that it considers confidential as "CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21541." 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-21541." 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 or a court of competent jurisdiction, which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, must be sealed and maintained in the MPSC's or court's files with a copy of the Protective Order attached.

C. It is intended that the Protected Material subject to this Protective Order should be shielded from disclosure by a Receiving Party only to the extent permitted by law. If any person files a request under the Freedom of Information Act with a governmental agency participating in this proceeding, including, but not limited to, the MPSC, the MPSC Staff, and the Michigan Attorney General, seeking access to documents subject to this Protective Order, the governmental agency 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 governmental agency grants the request in full or in part.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. In response to a motion, the Commission or the presiding officer in this case may revoke a document's protected status after notice and hearing. If the presiding 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 to the Commission within that time period. Any Party opposing the application for leave to appeal shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. If an application is filed, then the information will continue to be protected from disclosure until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired.

B. If a document's protected status is challenged under Paragraph IV.A, the Receiving Party challenging the protected status of the document shall explicitly state its reason for challenging the confidential designation. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

V. Retention of Documents

A. Protected Material remains the property of the Disclosing Party. The Protected Material only remains available to the Receiving Party, unless the Receiving Party is an agency/public official of the State of Michigan subject to state documentation retention schedules, until the time expires for petitions for rehearing of a final MPSC order in this Case No. U-21541 or until the MPSC has ruled on all petitions for rehearing in this case (if any). Should the Receiving Party be an agency/public official of the State of Michigan who retains the Protected Material to comply with applicable state documentation retention schedules, it is acknowledged that this Order will continue in effect and said Receiving Party will be required to retain the Protected Material in accordance with this Order. On or before the time specified by the preceding sentences, the Receiving Party shall return to the Disclosing Party all Protected Material in its possession or in the possession of its Reviewing Representatives—including all copies and notes of Protected Material—or destroy the Protected Material and, at the request of the Disclosing Party, certify in writing that it has done so.

B. Notwithstanding the preceding paragraph, Counsel for a Receiving Party may maintain confidential files of Protected Material beyond the resolution of this proceeding, provided that this Order will continue in effect with respect to the Protected Material for so long as it is retained by counsel for any requesting Party. For purposes of this paragraph, the "resolution" of a case means the expiration of the period of judicial review of a final order of the Commission. Counsel for a Requesting Party shall have the right to retain copies of the pleadings, orders, transcripts, briefs, comments, and exhibits in these proceedings, but this protective order will continue in effect with respect to the Protected Material contained in these documents. If the Protected Material is relevant or reasonably calculated to lead to admissible evidence in another Commission proceeding relating to and involving the Disclosing Party, then it may be used subject to the issuing of a new protective order in that case.

VI. Limitations and Disclosures

The provisions of this Protective Order do 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.l through I.B.5. 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: 1) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or 2) 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. The preceding sentence shall not apply to disclosures required under the Freedom of Information Act. Paragraph III C of this Order addresses the procedures for Freedom of Information Act disclosures.

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 the MPSC, the presiding officer, and the Disclosing Party, in writing, of the identity of 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.

____
Administrative Law Judge

Attachment 1

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*****

In the matter of the application of	)	
UPPER MICHIGAN ENERGY RESOURCES	)	
CORPORATION for authority to increase its	)	Case No. U-21541
electric rates and for other relief.	)	
______________________________________	)	

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 issued in Case No. U-21541, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by the terms of the Protective Order. I understand that the substance of the Protected Material (as defined in the Protective Order), any notes from Protected Material, or any other form of information that copies or discloses Protected Material, shall be maintained as confidential and shall not be disclosed to anyone other than in accordance with the Protective Order.

Reviewing Representative

Date: ____________________ ____________________________________

Title:
Representing:

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 Michigan Energy Resources Corporation Docket No. U- 21541

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Michigan Energy Resources Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Sherri A. Wellman

Address Miller Canfield

One Michigan Avenue, Suite 900

City Lansing State MI

Zip 48933 Phone 517-483-4954

Email wellmans@millercanfield.com

Date 05/01/2024

Signature: Sherri A. Wellman Digitally signed by: Sherri A. Wellman DN: CN = Sherri A. Wellman email = wellmans@millercanfield.com C = AD O = Miller Canfield Date: 2024.05.01 15:24:00 -04'00'

○ I am not an attorney

◉ I am an attorney whose:

Michigan Bar # is P- 38989

________ Bar # is: ________
(state)

EAHR1 - 09/29/2016

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

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THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Upper Michigan Energy Resources Corporation Docket No. U- 21541

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Michigan Energy Resources Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Paul M. Collins
Address Miller Canfield
One Michigan Avenue, Suite 900
City Lansing State MI
Zip 48933 Phone 517-483-4908
Email collinsp@millercanfield.com
Date 05/01/2024
Signature: Paul M. Collins Digitally signed by: Paul M. Collins DN: CN = Paul M. Collins email = Collinsp@MillerCanfield.com C = US O = Miller, Canfield, Paddock and Stone, P.L.C. OU = Attorney at Law Date: 2024.05.01 15:23:46 -04'00'

○ I am not an attorney

◉ I am an attorney whose:

Michigan Bar # is P-69719

__________ Bar # is: __________
(state)

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.

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THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Upper Michigan Energy Resources Corporation Docket No. U- 21541

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Michigan Energy Resources Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Benjamin J. Holwerda

Address Miller Canfield

One Michigan Avenue, Suite 900

City Lansing State MI

Zip 48933 Phone 517-483-4949

Email holwerda@millercanfield.com

Date 05/01/2024

Signature: Benjamin J. Holwerda

Digitally signed by: Benjamin J. Holwerda
DN: CN = Benjamin J. Holwerda email = holwerda@millercanfield.com C = US O = Miller Canfield OU = Attorney at Law
Date: 2024.05.01 15:22:52 -04'00'

○ I am not an attorney

◉ I am an attorney whose:

Michigan Bar # is P- 82110

________ Bar # is: ________
(state)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase electric rates and for related relief.	)))))	Case No. U-21541

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF INGHAM)

Victoria J. Seyfried, being first duly sworn, deposes and states that on May 1, 2024, she served a copy of the following, together with this Proof of Service upon the parties set forth on the attached Service List via electronic mail:

1. Application of Upper Michigan Energy Resources Corporation for authority to increase electric rates and for related relief;
2. Proposed Notice of Hearing;
3. Certification of Filing Requirements;
4. Direct Testimonies and Exhibits of Richard F. Stasik, Anthony Reese, Jared J. Peccarelli, Ann E. Bulkley, Aaron L. Nelson, and James M. Beyer;
5. Non-Confidential Documentation that complies with Part II and Part III of the Rate Case Filing Requirements;
6. Proposed Protective Order; and
7. Appearances of Sherri A. Wellman, Paul M. Collins, and Benjamin J. Holwerda

Victoria J. Seyfried

Digitally signed by: Victoria J. Seyfried
DN: CN = Victoria J. Seyfried email = Seyfriend@millercanfield.com C = US O = Miller Canfield OU = Legal Assistant
Date: 2024.05.01 15:22:37 -04'00'

Victoria J. Seyfried

Subscribed and sworn to before me
on this 1st day of May, 2024.

Kacey O'Neill

Digitally signed by: Kacey O'Neill
DN: CN = Kacey O'Neill email = oneill@millercanfield.com C = AD
Date: 2024.05.01 15:22:23 -04'00'

Kacey O'Neill, Notary Public
State of Michigan, County of Livingston
My Commission Expires: 12/26/26
Acting in the County of Ingham

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **UPPER MICHIGAN ENERGY RESOURCES CORPORATION** for authority to increase electric rates and for related relief.	)))))	Case No. U-21541

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