OAH 5-2500-38008
MPUC No. E015/GR-21-335

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application by Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota

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In the Matter of the Application by Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS

On November 1, 2021, Minnesota Power (or the Company) filed this general rate case with the Minnesota Public Utilities Commission (Commission), seeking an increase in electric rates of $108.3 million (MN Jurisdictional), or 17.58 percent above present rate revenue of $615.9 million, effective January 1, 2022.

This matter came before Administrative Law Judge Jim Mortenson for an evidentiary hearing on June 13-15, 2022. The hearing was held virtually on Microsoft Teams. Public hearings were held virtually on July 19, 2022, and virtually and in person in Hermantown, Minnesota on July 20, 2022.

David R. Moeller, Senior Regulatory Counsel, Matthew R. Brodin, Senior Attorney, Minnesota Power, and Elizabeth M. Brama, Valerie T. Herring, and Kodi J. Verhalen, Taft Stettinius & Hollister LLP, appeared on behalf of the Applicant, Minnesota Power.

Richard E. Dornfeld, Katherine M. Hinderlie, and Allen Cook Barr, Assistant Attorneys General, appeared on behalf of the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC).

Peter G. Scholtz, Travis Murray, and Joseph C. Meyer, Assistant Attorneys General, appeared on behalf of the Office of the Minnesota Attorney General, Residential Utilities Division (OAG).

Andrew P. Moratzka and Riley A. Conlin, Stoel Rives, LLP, appeared on behalf of the Large Power Intervenors (LPI).

Brian Edstrom, Senior Regulatory Advocate, and Annie Levenson-Falk appeared on behalf of the Citizens Utility Board of Minnesota (CUB).

Pam Marshall, Executive Director, appeared on behalf of the Energy CENTS Coalition (ECC).

Jorge Alonso and Robert Manning appeared on behalf of Commission staff.

STATEMENT OF THE ISSUES

In its Notice of and Order for Hearing,[1] the Commission asked the parties to develop a thorough record on the following issues:

(1) Is the test year revenue increase sought by the Company reasonable or will it result in unreasonable or excessive earnings?

(2) Is the rate design proposed by the Company reasonable?

(3) Is the Company's proposed capital structure and return on equity reasonable?

(4) What are the reasons for the significant changes from the last rate case (E-015/GR-16-664)?

(5) What are the necessary adjustments, if any, regarding the appropriate rate treatment of the following categories:

   (a) Large power incremental production service;

   (b) Economy/non-firm service;

   (c) Replacement firm power service; and

   (d) Pool-within-pool service?

SUMMARY OF CONCLUSIONS

The hearing record demonstrates that Minnesota Power will experience a revenue shortfall. Minnesota Power is entitled to recover this revenue shortfall through an adjustment of its retail electric rates.

The capital structure, cost of debt, and return on equity reflected in the findings below are reasonable and should be used in determining an appropriate rate of return.

Modifying Minnesota Power's retail electric rates in the manner described in the findings and conclusions below, including those related to rate design, will result in just and reasonable rates that serve the public interest.

The hearing record addresses and explains the proposed increases in expenses for production, transmission, customer service and information, sales, and administrative and general activities.

Based on the evidence in the hearing record, the Judge makes the following:

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[1] Notice of and Order for Hearing at 2-3 (Dec. 30, 2021) (eDocket No. 202112-181086-02); First Prehearing Order at 2-3 (Jan. 28, 2022) (eDocket No. 20221-182124-01).

FINDINGS OF FACT

A. Description of the Company

1. Minnesota Power is a public utility operating division of ALLETE. First incorporated in 1906, Minnesota Power has been serving northern Minnesota for over a century and currently provides electricity to more than 145,000 residential and commercial customers, 15 municipal systems, and some of the nation's largest industrial customers across a 26,000 square mile service area located in central and northern Minnesota.[2]

2. Minnesota Power is a division of ALLETE, Inc., and comprises the majority of ALLETE's activities. Net income from Minnesota Power's regulated operations is projected to be 65 percent of budgeted total consolidated ALLETE net income in 2021. The remaining 35 percent of ALLETE's budgeted consolidated net income comes primarily from other wholly owned subsidiaries.[3]

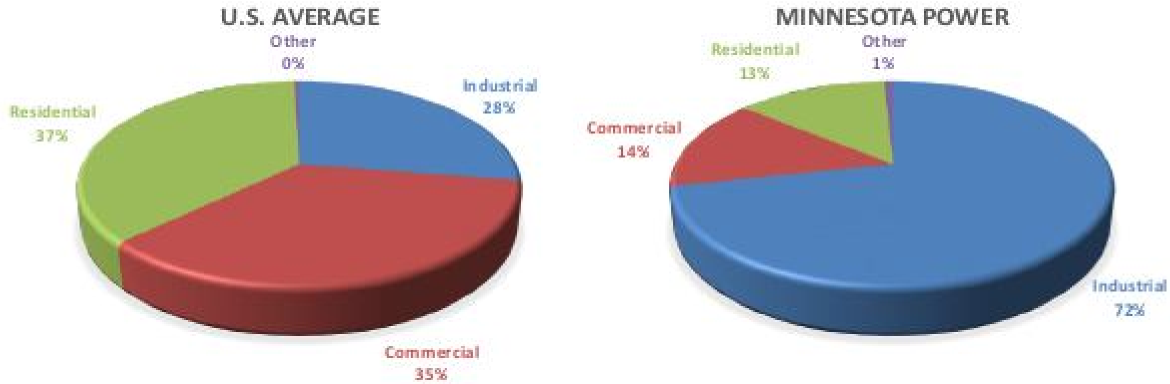
3. Minnesota Power currently utilizes a diverse combination of wind, hydro, solar, coal, biomass, and natural gas generation, totaling nearly 1,800 megawatts (MW). Since 2013, Minnesota Power has decreased its thermal generation through coal plant retirements, idling, or remissioning, while tripling its renewable energy generation. Minnesota Power added two significant and complex renewable power purchases in 2020: Manitoba Hydro and the Nobles 2 wind farm. However, even with these new power supply additions, Minnesota Power's total power supply output (including both purchases and Company-owned generation assets) will be slightly lower in 2022 than in 2010.[4]

4. Minnesota Power serves approximately 123,600 residential, 23,300 commercial, and 400 industrial customers, with programs and services for each customer class.[5]

5. In 2020, approximately 72 percent of retail kilowatt-hour (kWh) energy sales to customers on Minnesota Power's system were delivered to industrial customers alone, while only 13 percent of sales supported the residential class and 14 percent of retail sales were to commercial customers. In contrast, the average utility in the United States sells just 28 percent of retail kWh energy sales to industrial customers and 37 percent and 35 percent of retail kWh energy sales to residential and commercial customers, respectively, as shown in Figure 1 below.[6]

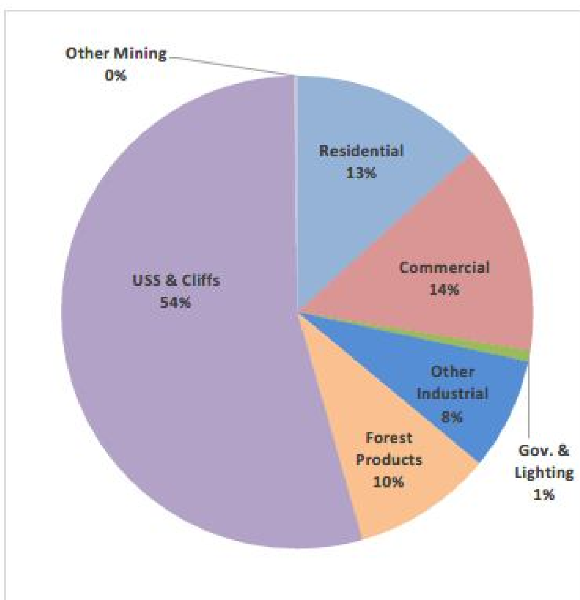
[2] Ex. MP-18 at 8 (Cady Direct).
[3] *Id.* at 7.
[4] *Id.* at 8.
[5] *Id.* at 9.
[6] *Id.*

Figure 1. Minnesota Power's Customer Concentration[7]



6. Minnesota Power's large industrial customers are unique in both their high overall percentage of revenue and kWh energy usage on the system, as well as the individual size of the customers relative to a typical utility. Minnesota Power's large industrial customers, located in northern Minnesota, primarily consist of taconite producers and graphic paper and pulp producers, as depicted in Figure 2 below. These industries, like Minnesota Power itself, are significant components of the regional economy.[8]

Figure 2. Minnesota Power Retail Energy Sales by Customer Class (2020)[9]

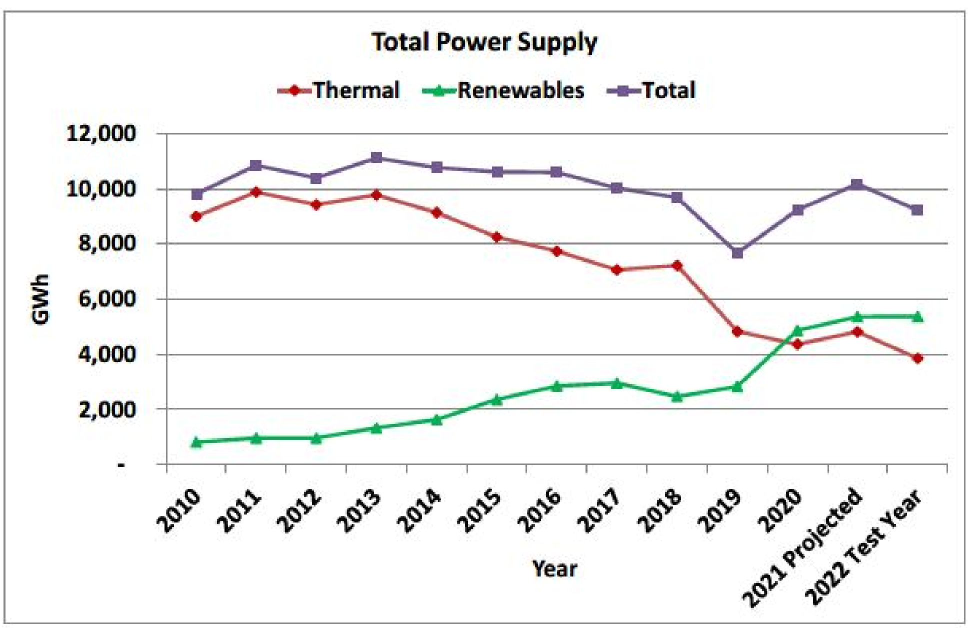


[7] *Id.* at 10.
[8] *Id.*; Ex. MP-30 at 6 (Frederickson Direct).
[9] Ex. MP-18 at 11 (Cady Direct).

7. Minnesota Power's industrial customer operations are unique, as they require large quantities of energy and typically operate around the clock every day of the year. As a result, when the industrial customers are operating, the energy usage pattern of the industrial customer class is relatively stable compared to the other customer classes. This stable usage contributes to more consumption of energy in off-peak hours than other customer classes, which is typically lower cost energy. The size and operations of these industrial customers results in Minnesota Power having one of the highest load factors of any utility in the country, nearly 80 percent, which allows the system to be used efficiently, creating additional value for all Minnesota Power customers. However, the energy usage from this globally competitive and price-sensitive industrial customer class can vary widely from year to year, which dramatically increases the risk profile of Minnesota Power compared to other electric utilities in the state and nation.[10]

8. As shown in Figure 3, Minnesota Power's thermal generation (diamond line) has been decreasing due to retirements, idling, or remissioning since 2013, while the Company has been adding predominantly renewables (triangle line) to augment the power supply. Minnesota Power has tripled its renewable energy since 2014, after meeting the State's Renewable Energy Standard in 2015, a decade early. The Company added two renewable power purchases in 2020: the 250 MW and 133 MW Manitoba Hydro and the 250 MW Nobles 2 wind farm. This power supply transformation has provided 50 percent renewable generation for Minnesota Power customers and has created a new profile of power supply with more renewable generation, but less dispatchable generation, to meet customer needs.[11]

Figure 3. Total Power Supply



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[10] *Id.*

[11] Ex. MP-38 at 7-8 (Pierce Direct).

B. The Company's Present Rates

9. The Company's present rates are the rates authorized by the Commission in its final order in MPUC Docket Nos. E015/GR-16-664 and E015/GR-19-442. In MPUC Docket No. E015/GR-19-442, on December 11, 2020, the Commission issued a Notice and Order Approving Petition to Withdraw Filing. Previously, the Commission had issued its Initial Order Approving Petition and Resolving Rate Case with Conditions on June 30, 2020. It added to these findings in its Order Approving Petition and Resolving Rate Case with Conditions on August 7, 2020. This later Order approved Minnesota Power's petition for approval to move asset-based wholesale sales credits to the Fuel Clause Adjustment (FCA) and to ultimately resolve its pending rate case.[12]

10. Minnesota Power's last fully-litigated rate case was MPUC Docket No. E015/GR-16-664. The Commission issued its Findings of Fact, Conclusions, and Order approving final rates in that proceeding on March 12, 2018 (2016 Rate Case).[13]

C. Jurisdiction

11. The Commission has general jurisdiction over Minnesota Power under Minn. Stat. §§ 216B.01, .02 (2022). The Commission has specific jurisdiction over the rate changes requested by the Company under Minn. Stat. § 216B.16 (2022).

12. The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48-.62 (2022); Minn. R. 1400.5010-.8400 (2021).

D. Procedural History

13. On November 1, 2021, Minnesota Power filed this general rate case by filing an Application for Authority to Increase Rates for Electric Utility Service in Minnesota (Application). It sought an increase in electric rates of $108.3 million (MN Jurisdictional), or 17.58 percent above present rate revenue of $615.9 million, effective January 1, 2022, without suspension. However, the Application included an alternative request for interim rates of $87.3 million (MN Jurisdictional), or approximately 14.23 percent, effective January 1, 2022, with final rates becoming effective within 10 months of the filing date of the Application, if the Commission were to suspend the proposed rate increase.[14]

14. On November 3, 2021, the Commission issued a notice requesting comments on whether the Commission should accept the filing as substantially complete

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[12] In re the Emergency Petition of Minnesota Power for Approval to Move Asset-Based Wholesale Sales Credits to the Fuel Clause Adjustment and Resolve Rate Case, MPUC Docket No. E015/M-20-429.

[13] *In re Application of Minnesota Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E015/GR-16-664, Findings of Fact, Conclusions, and Order (Mar. 12, 2018) (hereinafter, 2016 Rate Case Order). This matter is referred to throughout as the 2016 Rate Case.

[14] Ex. MP-3 (Notice of Change in Rates).

and whether it should refer the case to the Office of Administrative Hearings (OAH) for contested case proceedings.[15]

15. On November 4, 2021, ECC petitioned to intervene.[16]

16. On November 10, 2021, the Department filed Comments recommending that the Commission accept the Application as complete and refer the matter to OAH.[17]

17. On November 10, 2021, the OAG filed Comments regarding the Application.[18]

18. On November 10, 2021, LPI filed Comments regarding the Application.[19]

19. On November 10, 2021, Minnesota Power, ECC, and CUB (Joint Commenters) filed Joint Comments, in which the Joint Commenters agreed to an alternative interim rate proposal that would reduce the interim rate increase for residential customers from 14.23 percent to 7.11 percent.[20]

20. On November 15, 2021, Minnesota Power, LPI, the Department, and OAG filed Reply Comments.[21]

21. On November 23, 2021, CUB petitioned to intervene.[22]

22. On December 30, 2021, the Commission issued three orders in this matter:

(a) a Notice of and Order for Hearing;[23]

(b) an Order Accepting Filing, Suspending Rates, and Extending Timeline;[24] and

(c) an Order Setting Interim Rates.[25]

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[15] Notice of Comment Period on Completeness and Procedures (Nov. 3, 2021) (eDocket No. 202111-179468-01).
[16] Petition to Intervene of the Energy CENTS Coalition (Nov. 4, 2021) (eDocket No. 202111-179505-01).
[17] DOC Comments (Nov. 10, 2021) (eDocket No. 202111-179644-01).
[18] Comments of the Office of the Attorney General (Nov. 10, 2021) (eDocket No. 202111-179670-01).
[19] LPI Comments (Nov. 10, 2021) (eDocket No. 202111-179661-01).
[20] Joint Initial Comments (Nov. 10, 2021) (eDocket No. 202111-179630-01).
[21] Minnesota Power's Reply Comments on Completeness (Nov. 15, 2021) (eDocket No. 202111-179780-01); LPI Reply Comments (Nov. 15, 2021) (eDocket No. 202111-179790-01); DOC Letter (Nov. 15, 2021) (eDocket No. 202111-179779-01); OAG Letter (Nov. 15, 2021) (eDocket No. 202111-179774-01).
[22] Petition to Intervene of the Citizens Utility Board of Minnesota (Nov. 23, 2021) (eDocket No. 202111-180093-01).
[23] Notice of and Order for Hearing (Dec. 30, 2021) (eDocket No. 202112-181086-02). In this filing, the Commission noted that parties to the proceeding are Minnesota Power, DOC, OAG, LPI, ECC, and CUB, and that other parties wishing to intervene must file a notice to intervene with the Administrative Law Judge.
[24] Order Accepting Filing, Suspending Rates, and Extending Timeline (Dec. 30, 2021) (eDocket No. 202112-181086-01).
[25] Order Setting Interim Rates (Dec. 30, 2021) (eDocket No. 202112-181086-03).

23. On January 6, 2022, LPI petitioned to intervene.[26]

24. On January 26, 2022, the Judge issued a Protective Order.[27]

25. On January 28, 2022, the Judge issued the First Prehearing Order that set procedures for parties in the case and established the following schedule:[28]

Document or Event	Due Date
Intervention Deadline	March 18, 2022
Direct Testimony Filing	April 18, 2022
Rebuttal Filing	May 16, 2022
Surrebuttal Filing	June 6, 2022
Settlement Conference	Week of June 6, 2022
Telephone Status Conference	June 10, 2022, at 9:00 a.m.
Evidentiary Hearing	June 13 -16, 2022
Initial Briefs	July 15, 2022
Public Hearings – Virtual	July 19, 2022
Public Hearings – In Person	July 20, 2022
Reply Briefs and Proposed Findings of Fact	August 1, 2022
ALJ Report and Recommendation	September 1, 2022
Exceptions to ALJ Report	September 15, 2022
Commission Order	November 30, 2022

26. On April 18, 2022, the Department, the OAG, LPI, ECC, and CUB filed intervenor Direct Testimony.

27. On May 16, 2022, Minnesota Power, LPI, and ECC filed Rebuttal Testimony. On June 6, 2022, Minnesota Power, the Department, the OAG, LPI, and CUB filed Surrebuttal Testimony.[29]

28. On June 9, 2022, Administrative Law Judge Ann O'Reilly held a Settlement Conference via Microsoft Teams.

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[26] LPI's Petition to Intervene (Jan. 6, 2022) (eDocket No. 20221-181292-02).
[27] Protective Order (Jan. 26, 2022) (eDocket No. 20221-182041-01).
[28] First Prehearing Order (Jan. 28, 2022) (eDocket No. 20221-182124-01).
[29] *See* Master Exhibit List (eDocket No. 20226-186843-01).

29. On June 13, 14, and 15, 2022, Judge Mortenson held a virtual evidentiary hearing via Microsoft Teams.

30. On July 15, 2022, Minnesota Power, the Department, the OAG, LPI, ECC, and CUB filed Initial Briefs. Also on July 15, 2022, the parties filed a Joint Issues Matrix summarizing the issues in this proceeding.

31. On August 1, 2022, Minnesota Power, the Department, the OAG, LPI, ECC, and CUB filed Reply Briefs.

E. Summary of Public Comments

32. The Commission received numerous written comments regarding Minnesota Power's requested rate increase. Many of these customers identified themselves as senior citizens living on a fixed income, who stated that they could not afford the rate increase proposed by the Company. The written comments are summarized below:

- Jeffrey Hammerstrom stated that the Commission should deny Minnesota Power's proposed rate increase and that the proposed 18 percent rate increase is higher than an increase he will receive in Social Security benefits.[30]

- Frank and Susan Bolos questioned whether the rate increase is necessary or if it will just be used for the benefit of Company management and urged the Commission to consider that many customers rely on Social Security and are unable to tolerate frequent cost increases.[31] In a later comment, Frank Bolos stated that "poor people in Northern Minnesota can't handle" additional expenses.[32]

- Matt Pedersen opposes all proposed rate increases for Minnesota Power, especially because he and other customers have responded to the call to use less energy. He stated he is "insulted" and "infuriated" that Minnesota Power is now requesting a rate increase because of falling residential demand.[33]

- Rochelle Pearson submitted comments stating that city, state, county, sales, and federal taxes have all gone up and she is on a very limited income so she does not support a rate increase for Minnesota Power.[34]

[30] Comment by Jeffrey Hammerstrom (Nov. 5, 2021) (eDocket No. 202111-179557-01).
[31] Comment by Frank and Susan Bolos (Nov. 1, 2021) (eDocket No. 202111-179581-01).
[32] Comment by Frank Bolos (June 29, 2022) (eDocket No. 20226-187028-01).
[33] Comment by Matt Pedersen (Nov. 10, 2021) (eDocket No. 202111-179741-01).
[34] Comment by Rochelle Pearson (Dec. 30, 2021) (eDocket No. 20221-181176-01).

- Diana Conway stated the Company was "greedy" and continues to "fleece the consumers" by raising rates. She asked the Commission to reject the proposed rate increase.[35]

- Thomas Johns submitted comments opposing a rate increase. He stated that he lives on Social Security and a small pension and noted that electricity is a necessity. He further noted that the Company showed a profit of $185.6 million in 2019 and that should be enough for operating the utility.[36]

- Donald Johnsen said the full rate increase requested by the Company is too much and the Minnesota Power should only be allowed the amount included in interim rates.[37]

- Mark Roalson suggested instituting a senior discount for senior citizens and pointed out that personal investments in solar to reduce costs are not affordable. He suggested considering a change in salary for executives and moving to a citizen's board.[38] In a later submitted comment, Mr. Roalson suggested that the Company "tighten their belts" and "do a self-evaluation of wages, benefits and expenses to become a more fiscally efficient organization before they enact any more rate increases."[39]

- Aaron Thun recommended rejecting the rate increase at a time when inflation is skyrocketing and the pandemic has been a burden on Minnesotans. He stated that Minnesota Power always asks for "too much" and the burden for business development should be borne by the shareholders and not the customers.[40]

- Tom Hanowski strongly objected to the Company's proposed 17.58 percent increase and instead proposed a rate reduction, since new customers are being added and costs spread across more people. He pointed out that others are not able to simply give themselves a pay increase that is greater than the cost-of-living increases.[41]

- Douglas Hill objected to the rate increase and stated that customers on fixed incomes are already having difficulties and there could not be a worse time for an increase with inflation and the pandemic.[42]

[35] Comment by Diane Conway (Jan. 11, 2022) (eDocket No. 20221-181669-01).
[36] Comment by Thomas Johns (Jan. 18, 2022) (eDocket No. 20221-181646-01).
[37] Comment by Donald Johnsen (Jan. 19, 2022) (eDocket No. 20221-181793-01).
[38] Comment by Mark Roalson (Jan. 20, 2022) (eDocket No. 20221-181783-01).
[39] Comment by Mark Roalson (July 5, 2022) (eDocket No. 20228-188126-01).
[40] Comment by Aaron Thun (Jan. 21, 2022) (eDocket No. 20221-181886-01).
[41] Comment by Tom Hanowski (Jan 22, 2022) (eDocket No. 20221-182001-01).
[42] Comment by Douglas Hill (Feb. 12, 2022) (eDocket No. 20222-182724-01).

- Steven Curtis urged the Commission to disallow rate recovery for expenses that are not directly related to consumer expenses, such as industry dues, lobbying, and advertising.[43]

- The Duluth Public Utilities Commission submitted a letter with support for the Company to charge fair rates to customers but pointed out the magnitude of the requested increase would have a substantial impact on public water utilities, which require large electricity consumption.[44]

- Jared Hoium opposed an increase to his electric bill as he is already stretched thin paying for household expenses.[45]

- ME Elecmetal submitted a detailed letter outlining how the rate increase would impact its business and states it is seeking a reasonable and competitive rate. The customer said its electrical costs in Minnesota have increased 48 percent over the past 10 years and lists several considerations for the Commission.[46]

- Jason Engeldinger stated the rate increase is unacceptable as his heating bill has increased to over $900 per month and is causing a financial hardship.[47]

- Renee Johnson, owner of The Grocery Store in Floodwood, submitted a letter to say her business's electricity bill has gone up $1,000 in the last few months without a change in usage. She urged the Commission to consider the damage a rate increase could do to small businesses in small towns.[48]

- Jim Spreitzer questioned Minnesota Power's commitment to a net carbon zero plan because the solar garden program is full, the residential solar rebate has been reduced, and there is no reduced rate for residential electric vehicle charging.[49]

- Terry Welander commented that Minnesota Power's services have been generally good but suggested auditing the Company's books and finding an example of another electric company that is more efficient and following their lead, rather than increasing rates.[50]

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[43] Comment by Steven Curtis (Feb. 13, 2022) (eDocket No. 20222-182840-04).
[44] Comment by Duluth Public Utilities Commission (Mar. 2, 2022) (eDocket No. 20223-183469-01).
[45] Comment by Jared Hoium (Mar. 22, 2022) (eDocket No. 20224-184470-01).
[46] Comment by ME Elecmetal (Mar. 21, 2022) (eDocket No. 20224-184469-01).
[47] Comment by Jason Engeldinger (Mar. 23, 2022) (eDocket No. 20224-184468-01).
[48] Comment by Renee Johnson (Mar. 23, 2022) (eDocket No. 20224-185046-01).
[49] Comment by Jim Spreitzer (Apr. 28, 2022) (eDocket No. 20224-185309-01).
[50] Comment by Terry Welander (June 24, 2022) (eDocket No. 20226-186954-01).

- Mick and Sandy Justin opposed the rate increase as it would be devastating for the average blue-collar worker who does not qualify for energy assistance.[51]

- Marietta Sutherland objected to the rate increase given the pandemic and challenging economy and noted that others like her are on fixed incomes and can barely make a living.[52]

- Susan Makitalo urged the Commission to not raise rates and to consider seniors who are on fixed incomes. She noted that higher prices are making it difficult to stay in her home.[53]

- A customer whose name was not legible and who identified as a senior citizen on a fixed income, commented that the proposed price increase is met with "bitterness" because other costs are also going up.[54]

- A customer who did not identify themselves questioned why the Company bothered sending a notice about interim rates since those rates are never temporary and the Commission will just give permission to increase rates regardless of what the customer says.[55]

- Ann Miller stated the proposed rate increase would burden residential ratepayers who are already stressed, and the Company should find a way to "stick to their budget."[56]

- David Golen stated he is on a fixed income and called the proposed increase "price gouging." He proposed waiting until things return to normal and President Biden is gone before a lesser increase is granted.[57]

- Stephanie Hemphill submitted a letter opposing the proposed rate increase, stating that residential customers should not be expected to make up for bad economic news affecting cyclical industries of taconite and timber. She stated that she is living on Social Security and suggested shareholders accept a lower rate of return and for the Company to invest in more renewable energy.[58]

- Jeanne Stepun submitted a letter stating she is a retired senior on a fixed income. She asked that consideration be given to the fact that rent,

[51] Comment by Mick and Sandy Justin (June 20, 2022) (eDocket No. 20226-186953-01).
[52] Comment by Marietta Sutherland (June 12, 2022) (eDocket No. 20226-186953-01).
[53] Comment by Susan Makitalo (June 29, 2022) (eDocket No. 20226-187028-01).
[54] Comment (June 29, 2022) (eDocket No. 20226-187028-01).
[55] Comment (June 23, 2022) (eDocket No. 20226-187028-01).
[56] Comment by Ann Miller (July 12, 2022) (eDocket No. 20227-187375-01).
[57] Comment by David Golen (July 13, 2022) (eDocket No. 20227-187394-01).
[58] Comment by Stephanie Hemphill (July 18, 2022) (eDocket No. 20227-187551-01).

groceries, gas, health care insurance, and prescription drug coverage have all increased in cost, and urged for no rate increases to be given.[59]

- Christine Tetzlaff submitted a letter that merely stated: "Greed-flation."[60]

- Andrew Streitz stated that he would be willing to see a "reasonable [rate] increase" but asked that the Commission "require that [the Company] support community solar in exchange for the increase."[61]

- Beth Tamminen, who is retired and on a fixed income, is worried about the rate increase on low- and moderate-income households, especially given inflation and the Company's elimination of its block pricing structure.[62]

- Bret Pence asked that the Company's rate-increase request be denied during this period of "great economic stress and hardship." Mr. Pence also highlighted two structural changes to his bill, namely resource adjustments and the change from an incline block rate structure to a time of use rate. Mr. Pence stated: "I think the real effects and stresses of these structural changes to residential rates need to be considered by the Commission as they decide what a fair rate increase looks like for Minnesota Power residential customers."[63]

- Diane Desotelle argued against the rate increase because the Company simply "want[s] to be compensated for millions in impudent spending." She believes the state should be pushing for "new technology with renewables" instead.[64]

- Tom Thackery, CEO of ERS Utility Solutions, submitted a letter on behalf of Minnesota Power's small and medium commercial and industrial customers. Mr. Thackery alleges that the Company has failed to provide timely and regular rate advice to customers and has rampant demand-billing errors. He therefore requested that "the Commission, as part of this rate case, require Minnesota Power to address these issues in full, including issuing refunds to customers."[65]

- Kathryn Milun, a professor at the University of Minnesota Duluth, noted that her students recently hosted Duluth Power Dialog, a civic conversation for Duluthians about their local electric power sector, during which the students' questions addressed concerns over where Minnesota Power is investing ratepayers' money. Ms. Milun stated: "As you meet to decide on Minnesota

[59] Comment by Jeanne Stepun (July 12, 2022) (eDocket No. 20227-187610-01).
[60] Comment by Christine Tetzlaff (July 3, 2022) (eDocket No. 20228-188126-01).
[61] Comment by Andrew Streitz (July 31, 2022) (eDocket No. 20228-188113-01).
[62] Comment by Beth Tamminen (July 31, 2022) (eDocket No. 20228-188113-01).
[63] Comment by Bret Pence (July 28, 2022) (eDocket No. 20228-188113-01).
[64] Comment by Diane Desotelle (July 30, 2022) (eDocket No. 20228-188113-01).
[65] Comment by Tom Thackery (July 28, 2022) (eDocket No. 20228-188113-01).

Power's proposed rate increase, I hope you will take into account the energy democracy issues that my Minnesota students are themselves researching and putting out there for civic conversation. These facts tell us that Minnesota Power can and should be bringing down customer rates by investing long-term in renewable energy, not building the NTEC plant, and opening our local solar markets to citizen-owned community solar."[66]

- Lora Wedge urged the Commission to reject the rate increase because business-model imbalances should be felt by investors, not residential rate payers. Ms. Wedge noted that the Company has other strategies to reduce costs, whereas rate payers, dealing with pandemic job loss and economic shifts, cannot bear increased rates.[67]

33. Two public hearings were held virtually via Webex on July 19, 2022 — an afternoon and an evening hearing. Both meetings were attended by a handful of customers. One customer provided comments at the afternoon meeting and two customers provided comments at the evening meeting. The following is a summary of their comments:

- Patrick O'Connell, a member of LiUNA 1097, thanked Minnesota Power for providing living wage jobs and careers, especially for those who build and work in the Company's plants.[68]

- Bob Iverson said rates have gone up recently and the Company's stock dividend was increased in March. The proposed rate increase will cause hardship on homeowners in the current financial climate.[69]

- Zach Latimore stated the Company's solar rebate has gone down every year and he would like to see more investment in residential solar and renewables. The proposed rate increase will push more customers into a low-income bracket which will increase the burden on others.[70]

34. Two public hearings were held on July 20, 2022, in Hermantown, Minnesota and virtually via Webex, in the afternoon and in the evening. Approximately six customers attended the afternoon hearing, with five providing comments. The evening hearing was attended by about a dozen customers, with three providing comments. The following is a summary of their comments:

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[66] Comment by Kathryn Milun (Aug. 1, 2022) (eDocket No. 20228-188113-01).
[67] Comment by Lora Wedge (August 1, 2022) (eDocket No. 20228-188113-01).
[68] Webex 2:00 p.m. Tr. at 20 (July 19, 2022) (O'Connell).
[69] Webex 6:00 p.m. Tr. at 19-20 (July 19, 2022) (Iverson).
[70] *Id.* at 21-22 (Latimore).

- Dan Unulock said he did not want customers to pay for Verso's closure.[71]

- Tamara Lowney from the Itasca Economic Development Corporation spoke in favor of Minnesota Power as a partner in the community.[72]

- Matt Baumgartner, who works for the Duluth Area Chamber of Commerce, spoke in support of Minnesota Power as an amazing corporate citizen who supports local initiatives, and provides significant jobs and economic impact in the area.[73]

- Justin Meller, Duluth Plant Manager from ME Elecmetal, who also provided written comments, spoke about how the rate increase would adversely impact the steel foundry business, which is sensitive to global trade and rates in other locations.[74]

- Jim Mitchell spoke about how he has seen a 10 percent increase on his bill in the last year. He stated that the proposed increase is far higher than the rate of inflation, and it is a frustration for customers who have no other options.[75]

- Robert Bassing described how Minnesota Power's renewable options are highly carbon intensive in their creation. He advocated for other options such as modular thorium reactors.[76]

- Linda Herron said the proposed increase was too high based on the current economic situation. She said that 12 percent of Minnesota Power customers cannot pay their bills, and the increase would be a financial burden. She also urged the Company to move faster toward renewables.[77]

- Benjamin Groeschel spoke of some reliability issues he had with his Minnesota Power service in the past. He questioned why the rate increase was needed and advocated for action to address climate change.[78]

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[71] Hermantown 2:00 p.m. Tr. at 21-22 (July 20, 2022) (Unulock). A representative of Minnesota Power responded that Verso has paid for what it owes the Company and that customers will not be charged for amounts owed by Verso. *Id.* at 22-23. (Moeller).
[72] *Id.* at 24-26 (Lowney).
[73] *Id.* at 26-30 (Baumgartner).
[74] *Id.* at 30-33 (Meller).
[75] *Id.* at 33-35 (Mitchell).
[76] Hermantown 6:00 p.m. Tr. at 21-25 (July 20, 2022) (Bassing).
[77] *Id.* at 26-28 (Herron).
[78] *Id.* at 30-33 (Groeschel).

F. Applicable Standards

35. Minnesota law establishes the basic standard for the Commission's determination of utility rates: "Every rate made, demanded, or received by any public utility . . . shall be just and reasonable."[79]

36. The Commission's obligation to determine whether rates are just and reasonable is "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers."[80]

37. This balancing is set forth in Minn. Stat. § 216B.16, subd. 6:

> The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, must give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.

38. A just and reasonable rate must "enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed."[81]

39. The Commission's obligation to set just and reasonable rates must be based on the evidence and record.[82]

40. The Minnesota Supreme Court has recognized that the Commission's authority includes both quasi-judicial and quasi-legislative functions.[83]

41. The term "ratemaking" is often used to describe these two very different rate development functions. For example, the establishment of a rate of return and the resolution of other revenue-related issues are quasi-judicial functions that are subject to the substantial evidence standard.[84]

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[79] Minn. Stat. § 216B.03.
[80] In the Matter of Interstate Power Rates Change Request, 574 N.W.2d 408, 411 (Minn. 1998).
[81] Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 605 (1944).
[82] *Hibbing Taconite Co.*, *Hibbing Taconite Co. v. Minn. P.S.C.,* 302 N.W.2d 5, 11 (Minn. 1981) ("Chapter 216B gives to the PSC the duty as well as the power to set a just and reasonable rate after a full review of evidence and testimony.").
[83] *Hibbing Taconite Co.*, 302 N.W.2d at 9.
[84] *In the Matter of Interstate Power*, 574 N.W.2d at 412-13 ("As the court of appeals properly noted, the legislature has granted the MPUC both legislative and quasi-judicial powers to exercise its statutory authority, and thus when the MPUC acts in a legislative capacity, the standard of review is whether the MPUC exceeded its statutory authority; in contrast, when the MPUC acts in a quasi-judicial capacity, the

42. When it allocates rates among various classes of utility customers (matters of rate design), however, the Commission acts in a quasi-legislative capacity; and enjoys still greater discretion.[85]

43. Minn. Stat. § 216B.16, subd. 4, imposes upon the Company the burden of showing "that the rate change is just and reasonable."[86]

44. This burden is measured based on a preponderance of the evidence standard.[87]

G. Revenue Requirement Issues

45. The revenue requirements portion of a general rate case seeks to determine what additional revenue is needed to meet the utility's required operating income, based upon a "test year" of operations. In this proceeding, Minnesota Power's test year is January 1, 2022, through December 31, 2022.

46. The required operating income is derived from determining the amount of investments in rate base that have been made by the utility's shareholders, and multiplying the approved rate base by the rate of return that is determined to be appropriate for the utility.

47. After determining the required operating income, the utility's test year operating expenses and revenues are evaluated to determine the current operating income for the test year (in this case the 12 months ending December 31, 2022). The difference between the required operating income and the test year operating income is the income deficiency. This income deficiency is then converted into a gross revenue deficiency amount.

48. During the course of the proceeding, the parties resolved certain revenue requirement issues. The revenue requirement issues that remain disputed among the parties are addressed in sections III (H)-(J) of this Report.

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standard of review is the substantial evidence test. "); *Hibbing Taconite Co.,* 302 N.W.2d 9 ("The *St. Paul Chamber* case enunciated the PSC's two functions and the related standards of review. In applying those standards, we now hold that the establishment of a rate of return involves a factual determination which the courts will review under the substantial evidence standard.") (citing *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n,* 251 N.W.2d 350, 357 (Minn. 1977)).

[85] *St. Paul Area Chamber of Commerce,* 251 N.W.2d at 357 ("Once revenue requirements have been determined, it remains to decide how, and from whom, the additional revenue is to be obtained.… It is clear that when the commission acts in this area it is operating in a legislative capacity….").

[86] *See* Minn. Stat. § 216B.16, subd. 4.

[87] *See In re Northern States Power Company*, 416 N.W.2d 719, 722 (Minn. 1987) ("In evaluating the validity of a rate increase application, the Commission should apply the classic burden of proof analysis employed in civil cases in determining whether the utility has established the amount of a claimed cost as a judicial fact").

H. Cost of Capital

49. The calculation of a fair and reasonable rate of return requires a determination of three components: (1) an appropriate capital structure; (2) realistic costs for debt; and (3) a reasonable return on common equity. Each of these components is discussed below.

1. Key Factors Applicable to Determination of Minnesota Power's Rate of Return on Equity (ROE) and Capital Structure

a. Relative Risk Standard

50. To evaluate the comparability of returns and risks, it is necessary to compare Minnesota Power with other, similar utilities.[88]

51. The Commission routinely considers the risk of the utility in relation to the proxy group used to determine the ROE, and as part of the overall analysis of a utility's cost of capital.[89]

52. "Most importantly, the approved ROE must adequately assure a fair and reasonable return in light of the Company's risk profile and costs of obtaining equity investment."[90]

53. The ROE awarded to a utility must (1) be "commensurate with returns on investments in other enterprises having corresponding risks;"[91] and (2) "enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed."[92]

54. The factor of relative risk acknowledges the importance of investors' actual return requirements and the critical role of judgment in selecting the appropriate ROE and overall rate of return. For Minnesota Power, which is not a publicly traded company and whose costs of equity and debt are not entirely set by the market, customer concentration is the biggest and most unique business risk factor identified by both credit rating

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[88] Ex. MP-26 at 33-34 (Bulkley Direct).

[89] 2016 Rate Case Order at 61 ("An ROE of 9.25% is sufficient to establish just and reasonable rates, while adequately assuring a fair and reasonable return in light of the Company's *unique risk profile*, capital structure, and costs of obtaining equity investment." (emphasis added)); *In re the Application of Minn. Energy Resources Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, MPUC Docket No. G-011/GR-15-736, Findings of Fact, Conclusions, and Order at 28 (Oct. 31, 2016) (MERC Order) ("The Commission finds, based on its experience, technical competence, and specialized knowledge in the evaluation of the evidence in the hearing record, that an ROE of 9.70% is sufficient to establish just and reasonable rates, while adequately assuring a fair and reasonable return in light of the Company's *unique risk profile*, capital structure, and costs of obtaining equity investment." (emphasis added)).

[90] 2016 Rate Case Order at 61; MERC Order at 27; *In re Petition by Great Plains Natural Gas Co. for Auth. to Increase Natural Gas Rates in Minn.*, MPUC Docket No. G-004/GR-19-511, Findings of Fact, Conclusions, and Order at 18 (Oct. 26, 2020) (Great Plains Order).

[91] Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944); see also Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 692-93 (1923).

[92] *Hope Natural Gas Co.*, 320 U.S. at 603.

agencies, Moody's and S&P.[93] The applicable regulatory framework, Minnesota Power's small size, service territory, and reduced-price offsets in the Midcontinent Independent System Operator (MISO) market further contribute to Minnesota Power's riskier business profile.[94]

b. Customer Concentration

55. According to Moody's 2021 credit report, ALLETE's exposure to industrial customers is substantial, representing roughly 50 percent of annual sales volume in most years — the highest within the Moody's U.S. regulated utility universe.[95]

56. The Company's industrial customers consist of operating margin sensitive businesses such as iron pellet and taconite producers (69 percent of industrial kWh sold in 2020), paper, pulp and wood products companies (12 percent), and oil pipelines and other industrials (19 percent).[96]

57. Because of the Company's substantial exposure to these cyclical and sensitive industries, Moody's has stated that the Company's credit rating could come under downward pressure if there is lower industrial customer demand and a drop in sales that is not offset by off-system sales or other means.[97]

58. Minnesota Power's revenue from industrial customers was approximately 62 percent and 64 percent of retail revenue in 2020 and 2019, respectively.[98] This compares to an industry average of 16 percent in 2019, making Minnesota Power's percentage of revenue from industrial customers among the highest of investor-owned utilities in the United States.[99]

59. In addition, energy sales to large industrial customers make up approximately 72 percent of the Company's total retail energy sales, while sales to the residential customer class are only 13 percent of total retail energy sales.[100] This industrial customer concentration is a factor that suggests Minnesota Power – ALLETE's largest company - is subject to "significant" earnings volatility risk relative to its peers, according to Table 1 below:[101]

[93] Ex. MP-22 at 17 (Cutshall Direct).
[94] *Id.*
[95] *Id.* at 18, Sch. 2.
[96] *Id.* at 18-19, Sch. 2.
[97] *Id.* at 19, Sch. 2.
[98] *Id.* at 19.
[99] *Id.*
[100] *Id.*
[101] *Id.*

Table 1. LPI Proxy Group – S&P Business and Financial Risk[102]

LPI Proxy Group	Business Risk	Financial Risk	S&P Anchor Credit Rating	S&P Actual Credit Rating	Industrial Sales Percentage
MGE Energy, Inc.	Excellent	Intermediate	A+	AA-	5%
NextEra Energy, Inc.	Excellent	Significant	A-	A-	3%
Pinnacle West Capital Corporation	Excellent	Significant	A-	BBB+	8%
Evergy, Inc.	Excellent	Significant	A-	A-	20%
Ameren Corporation	Excellent	Significant	A-	BBB+	23%
Duke Energy Corporation	Excellent	Significant	A-	BBB+	23%
Portland General Electric Company	Excellent	Significant	A-	BBB+	26%
CMS Energy Corporation	Excellent	Significant	A-	BBB+	28%
Xcel Energy Inc.	Excellent	Significant	A-	A-	31%
The Southern Company	Excellent	Significant	A-	BBB+	33%
American Electric Power Company, Inc.	Excellent	Significant	A-	A-	35%
Entergy Corporation	Excellent	Significant	A-	BBB+	42%
Alliant Energy Corporation	Excellent	Significant	A-	A-	45%
Otter Tail Corporation	Satisfactory	Intermediate	BBB	BBB	21%
Avista Corporation	Strong	Significant	BBB	BBB	23%
NorthWestern Corporation	Strong	Significant	BBB	BBB	34%
IDACORP, Inc.	Strong	Significant	BBB	BBB	36%
ALLETE, Inc.	Strong	Significant	BBB	BBB	72%

60. Minnesota Power's customer makeup is unique in another, important regard. As Moody's noted, Minnesota Power serves a service territory that includes a natural resource-based economy with economic success tied to highly competitive and cyclical industries: taconite processing, paper and wood products manufacturing, and oil pipelines.[103] Taconite processing is highly dependent on economic conditions and the business cycle, because taconite is an input into steel, which is used in durable consumer goods.[104] And two customers control the majority of the Company's taconite customer base. This customer makeup is unlike that of the typical utility, which benefits from a stable base of mostly residential and commercial customers, and it is unlike Minnesota's two other electric investor-owned utilities.[105]

61. Paper manufacturing companies are also facing decreased demand as companies and people are moving away from printed materials and instead are providing information electronically.[106]

62. The continued volatility in the mining industry coupled with the decline in production at the pulp and paper mills, as Company witnesses Mr. Frederickson and Mr. Benjamin S. Levine testified, will have a direct effect on the electric sales of Minnesota Power.[107] For example, the 2020 closure of Verso's Duluth paper mill, one of the

[102] Ex. MP-23 at 17-18 (Cutshall Rebuttal).
[103] Ex. MP-22 at 19 (Cutshall Direct).
[104] *Id.* at 18-20.
[105] *Id.* at 20.
[106] *Id.* at 14-15, 19-21; Ex. MP-26 (Bulkley Direct).
[107] Ex. MP-26 at 43 (Bulkley Direct).

Company's Large Industrial customers, equated to about half of the Company's residential sales.[108]

63. Minnesota Power's percentage of retail revenue from its industrial customers of 62 percent in 2020 contrasts with the Minnesota operations at Otter Tail Power Company and Northern States Power Company, which have retail revenue from industrial customers at 26 percent and 14 percent, respectively.[109]

64. It is important to recognize the Company's customer concentration and its effect on the cost of equity, as the Commission has previously recognized.[110] Minnesota Power's customer concentration continues to be riskier than other utilities because of its unique load due to both the dominance of large power customers and the types of industries those customers serve.[111]

65. The Company may not recoup lost sales by selling electricity into the market.[112] The ability to resell in the market to recover decreasing revenue from energy sales is dependent on the relative prices in the market and on the Company's contracts with existing customers.[113] Locational Marginal Prices (LMPs) in MISO have been declining over the past 15 years as new lower variable cost resources have come online. Further, as market sales consist of increasingly variable versus dispatchable resources, utilities have less ability to sell into the market at favorable prices. More variable resources have reduced the average market price due to overall lower prices during periods of high wind generation.[114] As example, while Minnesota Power was able to recover 30 percent of lost net revenues through margins on bilateral sales in 2018, the Company was only able to recover one percent in 2020.[115]

66. The current and expected level of LMPs in the MISO market reduce the likelihood that the Company will be able to offset any reduction in revenue resulting from declines in industrial electric sales through sales into the MISO market. Therefore, the record shows that the risk of eroding revenue resulting from customer concentration is higher for Minnesota Power than other utilities.[116]

67. Along with the Commission, the Department and OAG have each recognized that Minnesota Power faces particular business risk associated with its high degree of customer concentration.[117]

68. A regulated utility must have the opportunity to earn a return that is competitive and would permit it to attract capital. From an investor's perspective, the

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[108] Ex. MP-22 at 19-20 (Cutshall Direct).
[109] *Id.* at 21.
[110] *Id.* at 21.
[111] *Id.* at 10.
[112] *Id.*
[113] *See id.* at 22.
[114] Ex. MP-38 at 14 (Pierce Direct).
[115] Ex. MP-22 at 22 (Cutshall Direct).
[116] *See* Ex. MP-26 at 50 (Bulkley Direct).
[117] Ex. DOC-7 at 38 (Addonizio Surrebuttal); Ex. MP-22 at 23-24 (Cutshall Direct).

operating and credit risk associated with Minnesota Power's large amount of customer concentration is significant and requires a higher return.[118]

c. Company Cash Flows and Credit Metrics

69. In addition to the risk of the Company's customer concentration, the cumulative effect of past events has placed increasing pressures on the Company's cash flows. Since the Company's 2016 Rate Case, ALLETE has experienced: 1) a reduction in its credit rating from both Moody's and Standard & Poor's (S&P); 2) the impacts of the Tax Cuts and Jobs Act; 3) customer load fluctuations, reductions, and loss; and 4) the economic impacts of the COVID-19 pandemic.[119]

70. ALLETE was downgraded in 2019 and 2020 by Moody's and S&P, primarily due to the financial impact of the outcomes in Minnesota Power's last fully-litigated rate case, which had a significant negative effect on the cash flows of the Company.[120] The parent company is currently rated BBB (outlook stable) by S&P and Baa1 (outlook stable) by Moody's.[121] These ratings are only one to two notches above the lowest investment grade rating by each respective agency.[122] A utility's credit rating has a direct effect on both its ability to access capital and the cost for operations and advancing the clean energy transition.[123] The closer ALLETE is to non-investment grade, the higher its cost of debt will be when Minnesota Power looks to issue debt for future regulated projects or to refinance maturing first mortgage bond debt.[124] In addition, if ALLETE were to fall below investment grade, additional costs, such as increases in fees for letters of credit and revolving line of credit facility fees, would be needed to support ALLETE's credit rating when entering into agreements (e.g., with MISO).[125]

71. Key metrics used to evaluate ALLETE's creditworthiness are its ratios of funds from operations to debt (FFO to Debt) and cash flow from operations pre-working capital to debt (CFO to Debt).[126] S&P expects the Company to stay between at least 18 and 20 percent to maintain ALLETE's current credit rating.[127] However, the FFO to Debt ratio for the total Minnesota Power Company is 12.8 percent at current rates with no rate increase; it will be 20.1 percent with the requested equity ratio of 53.81 percent and an ROE of 10.25 percent.[128]

[118] Ex. MP-22 at 27 (Cutshall Direct).
[119] *Id.* at 8.
[120] *Id.* at 10, 25-26, Sch. 4.
[121] *Id.* at 25-26.
[122] *Id.* For comparison, Northern States Power Company-Minnesota is rated A- by S&P (outlook stable) and A2 by Moody's (outlook stable). In addition, Otter Tail Power is rated 2 BBB+ (outlook stable) by S&P and A3 by Moody's (outlook stable).
[123] Ex. MP-24 at 19 (Cutshall Rebuttal).
[124] Ex. MP-22 at 26 (Cutshall Direct).
[125] *Id.*
[126] Ex. MP-24 at 16 (Cutshall Direct).
[127] *Id.*
[128] *Id.* at 16, Sch. 1.

72. Since the credit downgrades in 2019 and 2020, ALLETE has been unable to achieve the CFO to Debt ratio and FFO to Debt ratios that Moody's and S&P respectively require to avoid additional downgrades. If ALLETE remains below the downgrade threshold for an additional year, another downgrade is likely. A downgrade may have cost implications for Minnesota Power and its customers.[129]

73. As shown in Table 2 below, if the intervenors' equity ratio and ROE recommendations were adopted in this proceeding (without any further adjustments from the Company's proposals in the case), the Company would be on the brink of another credit downgrade. The Company's proposal, by contrast, would afford the Company a more reasonable FFO to Debt ratio.

Table 2. FFO to Debt Ratios[130]

FFO to Debt (Rating Agency Threshold: 18 percent)			
	MP ROR	LPI ROR	DOC ROR
Total Company	20.1%	18.3%	19.1%

74. However, the figures in Table 2 account for only the LPI and Department rate of return proposals as compared to the Company's; they do not account for additional reductions in the Company's requested cost recovery in this case. Further, Table 2 assumes there will be no other pandemic, recession, steel industry downturn, or other issue that would cause the Company's revenues to fall below the test year assumptions.[131]

75. Overall, the Company's credit metrics have weakened over the past few years and are not expected to recover over the near-term. The Company maintains that new rates need to be higher in order to access capital and weather a future economic downturn.[132]

d. Regulatory Environment

76. The regulatory environment can also significantly affect both the access to and cost of capital in several ways. Moody's has 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."[133]

77. In making rate of return assessments, Company witness Ms. Bulkley evaluated the regulatory framework in Minnesota considering three factors: 1) cost

[129] *Id.* at 16.
[130] Ex. LPI-5 at 8, Sch. 1 (Walters Surrebuttal).
[131] Evidentiary Hearing Transcript Volume (Tr. Vol.) III at 38 (Walters).
[132] Ex. MP-22 at 9-15 (Cutshall Direct); *see also* Tr. Vol. I at 158 (Cutshall).
[133] *Id.*, Sch. 1.

recovery mechanisms that allow a utility to recover costs in a timely manner between rate cases and provide the utility the opportunity to earn its authorized return; 2) rate design, which if not based on cost causation can result in a significant amount of fixed costs being recovered through the volumetric charge thus increasing cost recovery risk; and 3) comparable return standard, because an awarded rate of return that is significantly below the rate of return awarded to other utilities with comparable risks can affect the ability of a utility to attract capital at reasonable terms.[134]

78. Considering the regulatory adjustment mechanisms and rate design, many of the companies in the proxy group have slightly more timely cost recovery through forecasted test years, year-end rate base, cost recovery trackers and revenue stabilization mechanisms than Minnesota Power has in Minnesota.[135]

79. The Company believes that it should be permitted to utilize a sales true-up mechanism, as most of the proxy group companies do, in order to mitigate financial risk.[136] The Judge does not recommend this mechanism be approved, as discussed below. The Judge does recommend, it order to mitigate the Company's relatively higher financial risk than proxy companies, that its authorized ROE be placed at the higher end of the recommended ROE range.

e. Comparable returns

80. The factor of comparable returns captures the importance of providing a return comparable to returns on alternative investments with commensurate risk. The Commission has stated that it must set rates at a level that permits stockholders an opportunity to earn a fair and reasonable return on their investment.[137]

81. While recent returns authorized in Minnesota have generally been consistent with the average authorized returns for utilities in other jurisdictions across the U.S., the ROE authorized for Minnesota Power of 9.25 percent in 2018 in the 2016 rate case was well below the average authorized ROE for vertically integrated electric utilities across the U.S. at the time.[138]

82. In Otter Tail Power Company's recent rate case proceeding, the Commission authorized a 9.48 percent ROE, inclusive of flotation costs.[139]

83. In addition, the authorized return is not the only consideration — it is important to also consider actual earned returns. Minnesota Power's 2020 unadjusted MN Jurisdictional rate of return was 6.38 percent and the projected 2021 unadjusted MN

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[134] Ex. MP-26 at 54 (Bulkley Direct).
[135] *Id.* at 63-64.
[136] Ex. MP-27 at 60-61 (Bulkley Rebuttal).
[137] Great Plains Order at 14.
[138] Ex. MP-26 at 63-65 (Bulkley Direct).
[139] In re Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn., MPUC Docket No. E-017/GR-20-719, Findings of Fact, Conclusions, and Order at 34-35 (Feb. 1, 2022).

Jurisdictional rate of return is 5.97 percent.[140] These returns are materially below the level authorized by the Commission in 2018. The shortfall was due to incurred costs that were not included in rates as well as a loss of load compared to the sales forecast approved in the last rate case.

f. Market conditions

84. In setting an appropriate overall rate of return, it is also important to take into account the effect of current and expected capital market conditions. Access to capital at reasonable terms is of particular importance if electric utilities are to make transformative investments in their systems to meet demands for a more sustainable power supply.[141]

85. Analysts and regulatory commissions have concluded that current market conditions have affected the results of the ROE estimation models.[142] As a result, it is important to consider the effect of these conditions on the ROE estimation models when determining the appropriate range and recommended ROE for a future period.[143]

86. In the last few years, the interest rate environment has been instrumental in utilities' ability to raise low-cost debt.[144] Given the more recent market volatility and increases in interest rates, however, a positive regulatory framework and supportive credit rating will be needed moving forward to continue to access low-cost capital.[145]

87. During the pendency of this proceeding, the cost of equity for regulated utility companies is being affected by several factors in the capital markets, including: (1) the dramatic shifts in market conditions during 2020, the economic recovery in 2021; (2) the known changes in interest rates and inflation in 2022 and expectations for increased costs over the remainder of 2022; (3) the effect of these changes on the assumptions used in the ROE estimation models; and (4) effects of Federal tax reform on utility cash flows.[146]

88. In a recent rate case for Consumers Energy Company, the Michigan Public Service Commission (Michigan PSC) noted that it is important to consider how a utility's access to capital could be affected by the market.[147] Specifically, the Michigan PSC noted that "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."[148]

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[140] Ex. MP-22 at 9 (Cutshall Direct).
[141] Ex. MP-26 at 11 (Bulkley Direct).
[142] *Id.* at 14-15.
[143] *Id.* at 14.
[144] Ex. MP-22 at 8 (Cutshall Direct).
[145] *Id.* at 8-9.
[146] Ex. MP-26 at 15 (Bulkley Direct); Ex. MP-27 at 24, 115-17 (Bulkley Rebuttal).
[147] Michigan Public Service Commission Order, Cause No. U-20697, *Consumers Energy Company*, December 17, 2020, at 165.
[148] *Id.* at 43.

2. Capital Structure

a. Minnesota Power's Proposed Equity Ratio

89. As the Commission has stated, in order "[t]o determine the Company's cost of capital, it is necessary to determine reasonable ratios of long- and short-term debt and common-stock equity, because the costs of each source of financing are different."[149]

90. The determination of the Company's capital structure must reflect the Company's financial needs, as well as the Company's unique risks.[150]

91. Minnesota Power has proposed a capital structure of 53.81 percent equity and 46.19 percent long-term debt, with a 4.33 percent cost of long-term debt.[151]

92. While the proposed capital structure does not create a near-even split between equity and debt, it follows from the Company's particular circumstances. It is the same as the capital structure from the previously approved rate case; is the level of equity to which the Company presently manages; is within the range of regulated utilities associated with a reasonable proxy group; and is supported by the Department.[152]

93. In Minnesota Power's 2016 Rate Case, the Commission found that an equity ratio of 53.81 percent and a 9.25 percent ROE were appropriate, resulting in an overall rate of return of 7.06 percent.[153] Because Minnesota Power's 2019 Rate Case was withdrawn prior to going through the entire rate case process, its authorized capital structure and rate of return remained unchanged from the 2016 Rate Case.[154] The proposed 2022 test year capital structure is consistent with the methodology that was approved in the Company's 2016 Rate Case.[155]

94. The Company has maintained its capital structure near the allowed capital structure, with slight fluctuations in the ratios due to specific timing of debt and equity issuances and capital expenditures.[156]

95. Since the 2016 Rate Case, Minnesota Power's actual capital structure has been prudently managed close to the 2017 approved capital structure (equity to capital ratio of 53.81 percent) within a reasonable corridor of 52.79 percent to 53.75 percent.[157]

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[149] 2016 Rate Case Order at 55.
[150] Ex. MP-22 at 41 (Cutshall Direct).
[151] *Id.* at 34-35.
[152] *Id.* at 7-8; Tr. Vol. I at 136 (Cutshall); Ex. LPI-3 at 23:1-3 (Walters Direct).
[153] Ex. MP-22 at 8 (Cutshall Direct).
[154] *Id.*
[155] *Id.* at 7.
[156] *Id.* at 7-8.
[157] *Id.* at 9, 35.

96. For the test year, the Company is projected to carry an equity ratio that is slightly higher than what was approved in the last rate case, but requests that the capital structure remain unchanged.[158]

b. Department's Proposed Capital Structure

97. The Department recommended that the Commission approve Minnesota Power's proposed cost of long-term debt and capital structure.[159]

98. The Department, however, maintains that because the Company's proposed equity ratio is somewhat higher than that of other electric utilities, the Company's financial risk is lower than the proxy group. Department witness Mr. Addonizio contended that the Company's proposed common equity ratio of 53.81 percent is higher than the average common equity ratio for the Department's proxy group in 2021 of 42.09 percent, within a range from 29.62 percent to 57.07 percent.[160]

99. On this basis, Mr. Addonizio concluded that a reduction in the authorized ROE of 10 basis points could be justified.[161]

100. Though it does not appear that Mr. Addonizio makes an explicit 10 basis point adjustment to his recommended ROE, he noted that his recommended ROE reflects the difference in financial risk between Minnesota Power and his proxy group.[162]

101. The Company disagrees with Mr. Addonizio's analysis for a number of reasons. First, the Department's proxy group is primarily comprised of parent companies, not utility operating companies.[163] Thus, for certain metrics, a more valid comparison of common equity ratios with a given proxy group would be the operating utility subsidiary or division of the parent companies.[164] This is because the common equity ratios for parent companies are often lower than their operating utility companies, largely because they include non-regulated entities and off-balance sheet debt.[165] The Company believes the equity ratios of the Department proxy group displayed in Mr. Addonizio's Table 8[166] do not provide a reasonable basis to make a ratemaking determination of an optimal common equity ratio for Minnesota Power.[167]

102. When preferrable comparisons are taken into consideration — i.e., when considering the common equity ratios of subsidiary operating utilities — Minnesota

[158] *Id.* at 8.
[159] Tr. Vol. I at 58 (Addonizio).
[160] Ex. DOC-6 at 53, Table 8 (Addonizio Direct).
[161] *Id.* at 55-56.
[162] *Id.* at 53.
[163] Ex. MP-24 at 5 (Cutshall Rebuttal).
[164] *Id.*; *see also* Ex. MP-26, Schedule 13 (Bulkley Direct).
[165] Ex. MP-24 at 4 (Cutshall Rebuttal).
[166] Ex. DOC-6 at 53 (Addonizio Direct).
[167] Ex. MP-24 at 5 (Cutshall Rebuttal).

Power's equity ratio of 53.81 percent is not significantly above the Department's proxy group average.[168]

103. The average common equity for the proxy group at the operating company level is 52.05 percent within a range of 46.90 percent to 59.79 percent.[169] The Administrative Law Judge finds that Minnesota Power's proposed equity ratio of 53.81 percent is only slightly greater than the average, but well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies.

104. The compilation of Mr. Addonizio's proxy group understates the risk faced by the Company.[170] The data provided in Mr. Cutshall's Rebuttal shows Minnesota Power does not have a similar level of business risks compared to the DOC Proxy Group, but rather has among the highest business risks in that group.[171]

c. LPI's Proposed Capital Structure

105. LPI Witness Mr. Walters argued that the Company's proposed equity ratio of 53.81 percent is "excessive" based on a comparison to the book value of common equity for the companies in his proxy group and authorized equity ratios for electric utilities since 2016, which Mr. Walters contended have been in the range of 49.7 percent to 52.00 percent.[172] As a result, Mr. Walters recommended a capital structure consisting of 52.00 percent common equity and 48.00 percent long-term debt for Minnesota Power.[173]

106. However, similar to Mr. Addonizio, Mr. Walters considered the book value of common equity at the holding company level, which would include corporate-level debt that is not part of the regulated or financial capital structure of the operating utilities. The more appropriate comparison for the Company's proposal is a comparison to the capital structures of the utility operating companies of the proxy group, which results in a range for the proxy group at the operating company level of 46.90 percent to 59.79 percent with an average of 52.05.[174]

107. Mr. Walters' review of authorized equity ratios for electric utilities since 2016 also includes authorized equity ratios for transmission and distribution utilities that do not have a similar risk profile as a vertically-integrated electric utility such as Minnesota Power. It also focuses on the mean and median authorized equity ratio in each year since 2016 instead of the range of authorized equity ratios.[175]

[168] Ex. MP-26, Sch. 13 (Bulkley Direct).
[169] *Id.* at 101-02.
[170] Ex. MP-24 at 8 (Cutshall Rebuttal).
[171] *Id.* at 8-9.
[172] Ex. LPI-3 at 23-24 (Walters Direct).
[173] Ex. LPI-5 at 9 (Walters Surrebuttal). LPI did not appear to take a position on the Company's cost of debt.
[174] Ex. MP-27 at 113 (Bulkley Rebuttal); Ex. MP-26, Sch. 13 (Bulkley Direct).
[175] Ex. MP-27 at 113-14 (Bulkley Rebuttal).

108. As shown in Table 3 below, the authorized equity ratios for vertically-integrated electric utilities had a mean range for 2016–2021 of 50.04 percent to 52.33 percent and a median range from 50.00 percent to 52.50 percent.

109. As further shown in Table 3, the maximum authorized equity ratio for vertically-integrated utilities from 2016–2021 ranged from 55.00 percent to 58.18 percent. Minnesota Power's proposed equity ratio is within the range of the actual equity ratios for the proxy group, as well as within the range of the authorized equity ratios for vertically-integrated electric utilities from 2016–2021.[176]

Table 3. Authorized Equity Ratios for Vertically-integrated Electric Utilities 2016–2021[177]

Year	Mean	Median	Minimum	Maximum
2016	50.04%	50.00%	40.25%	57.16%
2017	50.99%	50.03%	48.00%	58.18%
2018	51.38%	52.00%	41.68%	57.10%
2019	52.33%	52.00%	49.38%	57.02%
2020	52.13%	52.50%	46.00%	56.83%
2021	51.16%	51.96%	43.25%	55.00%

110. Finally, Mr. Walters concluded that a 52.0 percent equity ratio and an ROE of 9.40 percent would provide Minnesota Power's retail utility operations an FFO to Debt coverage of 24 percent. However, the Company illustrated that Mr. Walters' FFO to Debt calculation: 1) includes an incorrect inclusion of S&P FFO and debt adjustments, 2) includes allocations to the MN Jurisdictional level that are not S&P calculations, 3) does not include all of Minnesota Power's outstanding debt, and 4) reflects incorrect accounting for income taxes. As a result, Mr. Walters' 24 percent FFO to Debt calculation is unreliable and understates Minnesota Power's ROE and equity needs.[178]

111. When applying a methodology consistent with credit rating agency methodologies, the FFO to Debt ratio for the total Minnesota Power Company is 12.8 percent with no rate increase and 20.1 percent with the Company's requested equity ratio of 53.81 percent and an ROE of 10.25 percent.[179] These results are notably lower

[176] *Id.*
[177] *Id.* at 114.
[178] Ex. MP-24 at 15 (Cutshall Rebuttal).
[179] *Id.* at 16, Sch. 1.

than Mr. Walters' 24 percent FFO to Debt ratio calculated at his recommended 52.0 percent equity ratio and 9.40 percent ROE.

112. Finally, S&P's assessed business and financial risks and credit ratings for the LPI proxy group, along with industrial sales percentages, show that Minnesota Power does not have lower, or similar, risks compared to the proxy group.[180]

113. The Judge finds that a capital structure of 53.8108 percent common equity and 46.1892 percent long-term debt is reasonable. It is consistent with Minnesota Power's past equity ratio determinations by the Commission and with the actual equity ratio maintained by the Company. In addition, it is within the range established by the mean and high equity ratios for the operating companies owned by the proxy group companies. Considering the Company's overall risk profile, setting the equity ratio somewhat above the mean of the proxy group and within this range is reasonable and appropriate.

3. Rate of Return on Equity

114. In setting just and reasonable rates, the Commission is required to:

> [G]ive due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.[181]

115. A "critical component" of "a fair and reasonable return" is the ROE. In addition to debt, these returns finance the Company's infrastructure.[182]

116. A utility's ROE is critical to its financial health. If set reasonably, it is the key to the Company's positive relationships with its investors. The required ROE is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks.[183] An important 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.[184]

117. The proposed ROEs in a rate case are typically based on expert witnesses' modeling methods, which may include:

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[180] *Id.* at 18.
[181] Minn. Stat. § 216B.16, subd. 6.
[182] *See* 2016 Rate Case Order at 57.
[183] Ex. MP-26 at 66 (Bulkley Direct).
[184] *Id.*

(a) Constant Growth Discounted Cash Flow (Constant Growth DCF) method;[185]

(b) Two-Stage Growth DCF method (TGDCF);[186]

(c) Capital Asset Pricing Model (CAPM);[187]

(d) Empirical CAPM (ECAPM);[188] and

(e) Bond Yield Risk Premium Method (Risk Premium or BYRP).[189]

a. The Company's Proposed ROE

118. Minnesota Power proposes an ROE of 10.25 percent.[190]

119. Minnesota Power's expert witness, Ms. Bulkley, presented an analysis of the appropriate return on common equity, developed through the use of several financial models and a review of both qualitative and quantitative factors to determine the appropriate range of ROE, and the recommended 10.25 ROE.

120. First, Ms. Bulkley established a group of comparable companies to serve as a "proxy" for Minnesota Power, reflecting companies with comparable risks and prospects to the extent possible while ensuring there were a sufficient number of companies in the proxy group.[191]

121. Taking these considerations into account, to form the proxy group Ms. Bulkley began with the 36 companies that Value Line classifies as "Electric Utilities,"

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[185] This model is based on the theory that a stock's current price represents the present value of all expected future cash flows, which in turn requires constant growth rates, a stable dividend payout ratio, constant price-to-earnings ratios, and a discount rate greater than the expected growth rate. *See id.* at 70-73.
[186] Also known as the Two-Growth DCF or Two-Stage DCF method. This method smooths the effect of earnings growth rates that are considered too high or too low to be sustainable over the long term. Rather than assuming a single growth rate based on a five-year period into perpetuity like the Constant Growth DCF, the Two-Stage DCF identifies proxy group companies' earnings growth rates that are outside the average growth rate of the proxy group plus or minus one standard deviation and limits those companies' growth rates to the average plus one standard deviation (if they would otherwise be abnormally high) or minus one standard deviation (if they would otherwise be abnormally low). *See id.* at 73-80.
[187] This model estimates the ROE based on the risk-free return, plus a risk premium as needed to compensate investors for risks with a particular security that cannot be offset through diversification. The risk premium is a product of the market risk premium and the Beta Coefficient, which measures the relative riskiness of the security. *See id.* at 89-96.
[188] 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. *See id*. at 94.
[189] This method determines the additional return an investor would require to acquire the more risky equity security rather than a bond. The cost of equity is the sum of the equity risk premium and the yield on a relevant class of bonds. *See id.* at 96-100.
[190] *Id.* at 8.
[191] *Id.* at 34.

and then excluded companies based on ten specified screening criteria.[192] The screening criteria applied by Ms. Bulkley resulted in a proxy group of 17 companies.[193] Ms. Bulkley updated her proxy analysis in Rebuttal, and excluded two companies, ultimately using 15 companies in her proxy group.[194]

122. Next, Ms. Bulkley developed a range of results produced by the CGDCF and TGDCF models, the CAPM and ECAPM, and the BYRP to inform her decision as to where the Company's ROE falls within that range.[195] As shown in Table 4 below, the range of results produced via these models is wide, from 8.81 percent at the low end to 13.53 percent at the high end.

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[192] *Id.* at 34-35. The screening criteria are as follows:

- Pay consistent quarterly cash dividends, because companies that do not pay a dividend cannot be analyzed using the Constant Growth DCF model;
- Are covered by at least two utility industry analysts to provide a broader market perspective and to develop a range of DCF results;
- Have positive long-term earnings growth forecasts from at least two utility industry equity analysts because negative earnings growth rates are inconsistent with the underlying premise of the Constant Growth DCF model;
- Have investment grade long-term issuer ratings from both S&P and Moody's in order to be generally risk comparable to Minnesota Power without compromising the size of the proxy group;
- Own regulated generation assets that are included in rate base to establish a proxy group with similar operating risks as Minnesota Power;
- Have more than 5 percent of owned regulated generation capacity come from regulated coal-fired power plants to recognize the unique risks associated with owning coal-fired generation assets that are consistent with the risks faced by Minnesota Power;
- Derive more than 30 percent of its megawatt-hour sales from its owned generation facilities because of the risks associated with owning and operating generation that differ from the risks faced by distribution utilities;
- Derive more than 60 percent of their total operating income from regulated operations to ensure that the companies included in the proxy group do not derive a majority of their operating income from unregulated operations;
- Derive more than 60 percent of their total regulated operating income from regulated electric operations to ensure that the companies included in the proxy group, like Minnesota Power, derive the predominant share of their operating income from their electric segments; and
- Were not parties to a merger or transformative transaction during the analytical periods relied on because transformative transactions can have a significant effect on the share prices of the firms involved and therefore affect the results of the ROE estimation methodologies.

[193] *Id.* at 38.
[194] Ex. MP-27 at 26 (Bulkley Rebuttal).
[195] Ex. MP-26 at 5-7 (Bulkley Direct).

Table 4. Summary of Analytical Results – Aug. 31, 2021[196]

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average Price	8.94%	9.39%	10.13%
90-Day Average Price	9.20%	9.44%	10.18%
180-Day Average Price	9.15%	9.57%	10.31%
Two-Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average Price	8.81%	9.18%	9.87%
90-Day Average Price	9.06%	9.24%	9.93%
180-Day Average Price	9.03%	9.23%	10.06%
Capital Asset Pricing Model			
	Current Risk-Free Rate (1.91%)	Q4 2021 – Q4 2022 Projected Risk-Free Rate (2.42%)	2023-2027 Projected Risk-Free Rate (3.50%)
Value Line Beta	13.00%	13.06%	13.19%
Bloomberg Beta	11.92%	12.03%	12.25%
Long-term Average Beta	10.90%	11.05%	11.36%
Empirical Capital Asset Pricing Model			
Value Line Beta	13.39%	13.43%	13.53%
Bloomberg Beta	12.58%	12.66%	12.83%
Long-term Average Beta	11.82%	11.93%	12.16%
Bond Yield Plus Risk Premium			
	Current Risk-Free Rate (1.91%)	Q4 2021 – Q4 2022 Projected Risk-Free Rate (2.42%)	2023-2027 Projected Risk-Free Rate (3.50%)
Risk Premium Results	9.50%	9.71%	10.17%

123. Given the current high valuations of utilities and the presumption that the utility sector will underperform over the near term, Ms. Bulkley placed greater weight on the Mean High Constant Growth and Two-Growth DCF results, which ranged from 9.87 percent to 10.31 percent.[197] Further, Ms. Bulkley considered the divergence between the CAPM and DCF model results and the Company's belief that the CAPM results are more reflective of prospective market conditions through the use of projected interest rates and a forward-looking Market Risk Premium. She then concluded that it is reasonable for the high end of the recommended range to exceed the range produced by the DCF model. As a result, Ms. Bulkley supported an ROE range from 9.90 to 10.50 percent.[198]

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[196] *Id.* at 107.
[197] *Id.* at 105.
[198] *Id.* at 106.

124. Ms. Bulkley updated her ROE analysis in Rebuttal Testimony based on market data through March 21, 2022, as shown in Table 5 below.

Table 5. Summary of Updated Analytical Results – March 31, 2022[199]

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average	8.72%	9.48%	10.43%
90-Day Average	8.75%	9.52%	10.47%
180-Day Average	8.81%	9.56%	10.51%
Two Growth DCF			
30-Day Average	8.48%	9.43%	10.35%
90-Day Average	8.52%	9.47%	10.39%
180-Day Average	8.46%	9.51%	10.43%
Capital Asset Pricing Model			
	Current Risk-Free Rate	Q3 2022 – Q3 2023 Projected Risk-Free Rate	2023-2027 Projected Risk-Free Rate
Value Line Beta	11.38%	11.47%	11.51%
Bloomberg Beta	10.53%	10.69%	10.74%
Long-Term Avg. Beta	9.88%	10.08%	10.16%
Empirical Capital Asset Pricing Model			
Value Line Beta	11.70%	11.77%	11.80%
Bloomberg Beta	11.07%	11.18%	11.23%
Long-Term Avg. Beta	10.58%	10.73%	10.79%
Bond Yield Plus Risk Premium			
	Current Risk-Free Rate	Q3 2022 – Q3 2023 Projected Risk-Free Rate	2023-2027 Projected Risk-Free Rate
Risk Premium Results	9.68%	10.00%	10.13%

125. As shown in Table 5, the results of the DCF methodologies as of March 31, 2022, increased since the original analysis for Direct Testimony was performed. In particular the:

- mean results of the CGDCF model increased by 9 basis points from 9.39 percent to 9.48 percent, while the TGDCF results increased by 30 basis points from 9.18 percent to 9.43 percent; [200]

[199] Ex. MP-27 at 26 (Bulkley Rebuttal). The analytical results included in Table 5 reflect the results of the Constant Growth DCF and the Two-Growth DCF analyses excluding the results for individual companies that did not meet the minimum threshold of 7.00 percent.

[200] Based on 30-day average stock prices.

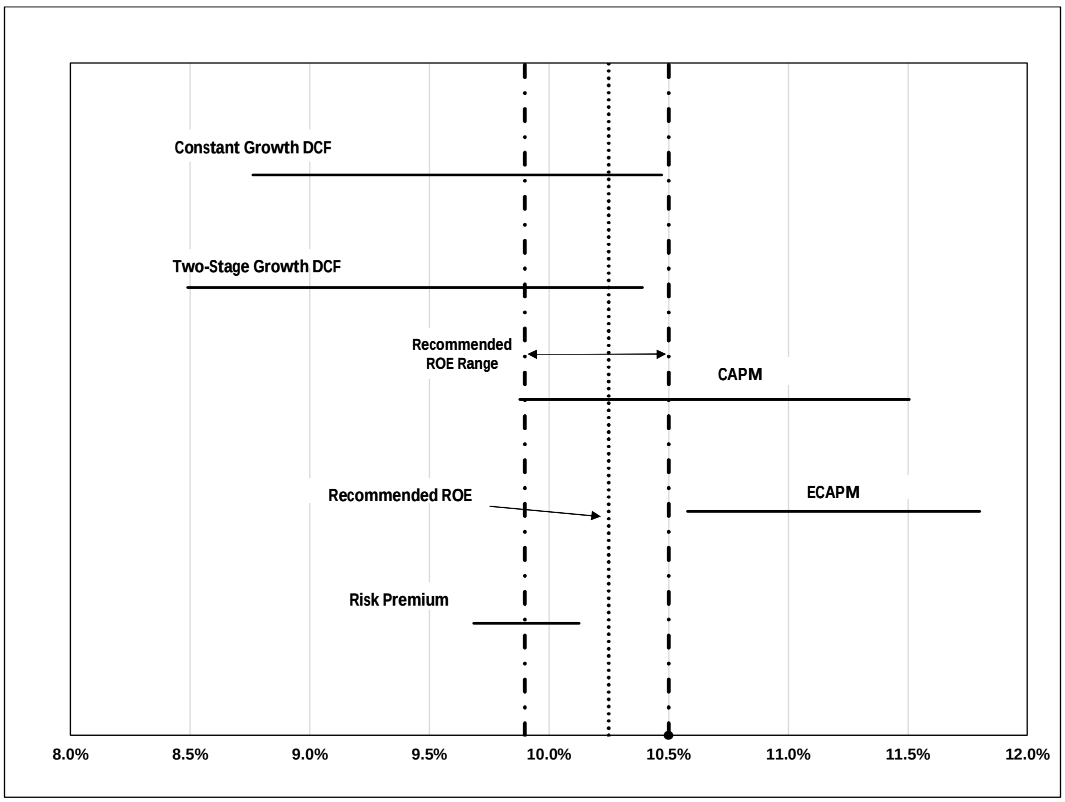
- Mean High results of the CGDCF model increased by 30 basis points from 10.13 percent to 10.43 percent, while the Mean High TGDCF results have increased by 48 basis points from 9.87 percent to 10.35 percent;[201]

- CAPM results using Value Line Betas decreased by 159 basis points from 13.06 percent to 11.47 percent, and the CAPM results using Bloomberg Betas decreased by 134 basis points from 12.03 percent to 10.69 percent;[202]

- Risk Premium results using a near-term projected Treasury bond yield increased by 29 basis points from 9.71 percent to 10.00 percent due to a rise in near term projected Treasury bond yields.[203]

126. Ms. Bulkley's analytical results, updated as of March 31, 2022, are summarized in Figure 4, including the range of results produced by the DCF models and the overall range of results produced by the CAPM, ECAPM, and Risk Premium analyses.

Figure 4. Updated Analytical Results



[201] Based on 30-day average stock prices.
[202] Based on near-term projected Treasury bond yields. The lower CAPM results are primarily due to a change in the way Ms. Bulkley adjusted her methodologies in response to Mr. Addonizio's criticisms of the use of the CGDCF to calculate market return.
[203] Ex. MP-27 at 26-27 (Bulkley Rebuttal).

127. In this instance, Ms. Bulkley noted that the range of the results across all methodologies is wide, from 8.81 percent at the low end to 13.53 percent at the high end.[204] Based on these updated results, Ms. Bulkley continued to support the recommended range of 9.90 percent to 10.50 percent, as well as the Company's requested ROE of 10.25 percent.[205]

128. Ms. Bulkley then took Company-specific risks into consideration, including: (1) customer concentration; (2) current capital market conditions and Company cash flows; (3) the regulatory environment in which the Company operates, including the Company's adjustment mechanisms and rate design; and finally, (4) the Company's proposed capital structure.[206]

129. In addition, the market conditions and model results changed significantly over the course of this proceeding from its initial filing to rebuttal, and surrebuttal.[207] From August 2021 through May 2022, interest rates increased by 118 basis points. From March 2022 to May 2022, the increase was 72 basis points. Inflation increased from 5.20 percent in August 2021 to 8.56 percent in March 2022.[208] The DCF results also increased considerably.

130. Ms. Bulkley narrowed the broad range of ROE results by evaluating current and projected market conditions and the risk of Minnesota Power's operations relative to that of the proxy group companies. Given the current high valuations of utilities and the expectation that the utility sector will underperform over the near term, Ms. Bulkley placed greater weight on the Mean High Constant Growth and Two-Growth DCF results, which ranged from 9.87 percent to 10.31 percent.[209]

b. Department's Proposed ROE

131. The Department recommended that the Commission set an authorized ROE of 9.30 percent and an overall rate of return of 7.00 percent for Minnesota Power. The Department proposed two potential additional adjustments to the ROE. The first proposed adjustment is a reduction to the ROE of 10 basis points to account for Minnesota Power's proposed equity ratio. The second proposed adjustment is an additional 10 basis point reduction to the ROE if the Company's sales true-up mechanism is approved.[210]

132. Mr. Addonizio developed several ROE estimation methodologies including the CGDCF, the TGDCF, the Multi-Stage DCF and the CAPM.[211] Mr. Addonizio, however,

[204] Ex. MP-26 at 6 (Bulkley Direct).
[205] Ex. MP-27 at 118 (Bulkley Rebuttal).
[206] Ex. MP-26 at 3, 37-65 (Bulkley Direct).
[207] Ex. MP-27 at 115-16 (Bulkley Rebuttal); Tr. Vol. I at 115-16 (Bulkley).
[208] Ex. MP-27 at 115-16 (Bulkley Rebuttal); Tr. Vol. I at 115-16, 129-30 (Bulkley).
[209] Ex. MP-26 at 105-06 (Bulkley Direct).
[210] Ex. DOC-6 at 55-56, 97-98 (Addonizio Direct).
[211] More specifically, in developing his ROE recommendation, Mr. Addonizio relied on the multi-stage discounted cash flow analysis and corroborated those estimates using a capital asset pricing model analysis.[211]

admitted he did not use any of his DCF models to select his ROE. Rather, to select his recommended ROE, Mr. Addonizio evaluated the recent authorized ROEs from other jurisdictions and determined that the average authorized ROE of the six fully litigated rate cases for vertically integrated electric utilities in 2021 was 9.41 percent.[212]

133. Mr. Addonizio also did not take into account any particular risk factors unique to Minnesota Power, arguing instead that while his screens did not take into account any of the unique business, financial, or regulatory risks facing Minnesota Power, the proxy group was nonetheless sufficiently reflective of Minnesota Power.[213]

134. The Company believes the Department's approach to determining its recommended ROE departs from its previous methodologies. According to the Company, the Department focused on past outcomes grounded in a Multi-Stage DCF model the Commission recently rejected. The results of the model were significantly below any returns that have been authorized in any jurisdiction and the growth rates were unreliable.[214]

135. Mr. Addonizio's specification of the Multi-Stage DCF model in the current case produces results that are no more reliable than the model that the Commission rejected in the Otter Tail rate case. Further, the Multi-Stage DCF introduces such a level of analyst judgment in when and how to modify growth rates that it is not reliable, unlike the Two-Growth DCF, which calls for a specific adjustment only for results outside the predetermined standard deviation. As a result, the Department's modeling results were significantly below any returns that have been authorized in any jurisdiction.[215]

136. The Commission has specifically found that the Two-Growth DCF is preferable to the Multi-Stage DCF model for estimating ROEs.[216]

137. Moreover, the Multi-Stage DCF introduces additional assumptions, including the estimate of the long-term growth rate, that can bias the results of the model.[217] For good reason, the Commission has previously found the GDP growth rates relied on by the Department to be too low to be used in reasonable ROE modeling.[218] And while Mr. Addonizio claims no utility can exceed the GDP indefinitely, he acknowledges the GDP growth rate reflects the entire economy — not just one utility, let alone one industry — and that the Commission is only setting rates for the next few years. For all these reasons, including his use of an unduly low long-term growth rate of

[212] Ex. DOC-7 at 7 (Addonizio Surrebuttal).
[213] *Id.* at 38-39.
[214] Ex. MP-27 at 39-40 (Bulkley Rebuttal).
[215] *Id.* at 4, 33-34. Though he develops multiple analytical models, Mr. Addonizio suggests that his mean Multi-Stage DCF analyses, which produce results of 7.72 percent and 7.91 percent, "anchor" his ROE recommendation of 9.30 percent. It is not clear how his mean Multi-Stage DCF analysis result "anchors" his recommended ROE when the results produced by these models are 139 to 159 basis points below his recommendation.
[216] *Id.* at 41.
[217] See *id.*
[218] In re Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota, MPUC Docket No. E017/GR-15-1033, Findings of Fact, Conclusions, and Order (May 1, 2017).

3.92 percent, Mr. Addonizio's Multi-Stage DCF model produces results that are far below any returns authorized for a regulated utility. Indeed, Mr. Addonizio's recommendation does not even rely on his Multi-Stage DCF model.[219]

138. The Department's move from a Two Growth DCF to a Multi-Stage DCF model calls its results into question.[220] Mr. Addonizio acknowledged in both pre-filed testimony and at the hearing that he did not rely on the Two-Growth DCF models he developed to prepare his recommendation.[221] He also discussed that his proposed ROE provides "insurance against estimation error."[222]

139. Further, authorized returns are not a measure of the forward-looking cost of equity. Authorized ROEs are historical estimates made by regulators that reflect their views on the investor-required returns based on the data that was available prior to the issuance of the decision. Therefore, it is reasonable to expect that returns authorized in conditions that differ from current and expected market conditions may not reflect the current and expected investor-required return during the period when Minnesota Power's rates will be in effect.[223]

140. As a result, Mr. Addonizio's reliance on the average authorized ROE of the six fully litigated rate cases for vertically integrated electric utilities in 2021 (9.41 percent)[224] is flawed because it is solely backward-looking. It does not take into account rising interest rates and inflationary factors that have changed substantially in 2022. Mr. Addonizio acknowledged that interest rates have increased and he concluded that "recent trends in financial markets may point to a slight increase in the cost of capital" in the last four months as compared to authorized ROEs for electric utilities in fully litigated rate cases since January 2020.[225] Of course, conditions continued to change significantly after intervenor direct was filed in the spring of 2022.

141. The Department's proposal to reduce the ROE by 10 basis points to account for Minnesota Power's proposed equity ratio appears arbitrary. Mr. Addonizio offered scarce evidence that this is a reasonable adjustment.[226]

142. In addition, Mr. Addonizio's proposal to reduce the Company's ROE if a sales forecast true-up is adopted is based on the benefit to the Company of somewhat reduced risk, but is not based on any comparison to proxy group companies' revenue adjustment mechanisms. In contrast, Company witness Ms. Bulkley established that revenue adjustment mechanisms are common within the proxy group, even for

[219] *See* Ex. MP-27 at 37 (Bulkley Rebuttal).
[220] Tr. Vol. II at 89 (Addonizio).
[221] *Id.* at 61-62; Ex. DOC-4 at 24 (Addonizio Direct).
[222] Ex. DOC-6 at 44, 48 (Addonizio Direct).
[223] Ex. MP-27 at 16 (Bulkley Rebuttal).
[224] Ex. DOC-7 at 7 (Addonizio Surrebuttal).
[225] Ex. DOC-6 at 46-48 (Addonizio Direct).
[226] Ex. MP-27 at 68 (Bulkley Rebuttal).

companies without Minnesota Power's level of risk. Further, Ms. Bulkley's proposed ROE assumes the sales forecast true-up is granted.[227]

c. LPI'S Proposed ROE

143. Mr. Walters presented ROE estimation model results ranging from 6.03 percent to 12.15 percent. He used three analytical approaches to produce his results[228] and recommended a 9.40 percent ROE for Minnesota Power within an ROE range of 9.20 to 9.60 percent.[229]

144. Mr. Walters also recommended that if the Company's proposed sales true-up mechanism is approved, the Commission should authorize an ROE towards the low-end of his recommended range to reflect the reduction in risk associated with the sales true-up mechanism as shown in Table 6.[230]

Table 6. Summary of Witness Walters' ROE Estimation Results[231]

ROE Model	Walters' Analytical Results	Walters' Recommended Model ROE Result	Walters' Recommended ROE
Constant Growth DCF Model (Consensus)	9.14%-9.38%	9.20%	ROE: 9.40% (9.20%-9.60%)
Two-Growth DCF	9.16%-9.28%		
Constant Growth DCF Model (Sustainable Growth)	8.00% - 8.19%		
Multi-Stage DCF model	7.79%-7.83%		
Bond Yield Plus Risk Premium analysis	9.15%-9.75%	9.40%	
CAPM	6.03%-12.15%	9.60%	

145. Mr. Walters developed several estimates of the DCF, CAPM and BYRP methodologies, selecting an ROE result from each group of methodologies without explaining his selection rationale. It is not clear from Mr. Walters' analysis how he arrived at the recommended ROE result for each type of model, as his recommendations appear to largely be rounded numbers designed to produce a simple range with 9.40 percent as the simple midpoint. For example, his recommended result for the

[227] *Id.* at 65.
[228] (1) a DCF model (a constant growth version using analyst growth rates, a constant growth version using "sustainable" growth rates, a TGDCF model and a Multi-Stage version); (2) a BYRP analysis, and (3) a CAPM analysis.
[229] Tr. Vol. III at 30 (Walters).
[230] Ex. LPI-3 at 54 (Walters Direct).
[231] *Id.* at 38 (Table CCW-8), 43 (Table CCW-9), 52 (Table CCW-11), 53 (Table CCW-12) (Walters Direct).

CGDCF/TGDCF/MSDCF models is entirely outside the range of his CGDCF (Sustainable Growth) and Multi-Stage DCF models.

146. In Surrebuttal, Mr. Walters conducted a regression analysis for comparative purposes, based on the interest rates and risk premiums at the time, intended to show whether his "[risk premium] methodology accurately captures the dynamic relationship between interest rates and the equity risk premium . . . ."[232] Mr. Walters' Direct Testimony showed that the bond yield spreads over Treasury bonds for A rated bonds averaged 1.48 percent over the last 42 years.[233] However, in his Surrebuttal regression analysis Mr. Walters used a spread of 55 basis points based only on the 13-week period ended March 18, 2022, instead of the 148 basis point long-term spread.[234] This short-term yield spread is not reasonable for establishing likely spreads over time. Using a 1.48 percent yield spread for Treasury Bonds produces a 10.08 percent ROE for A-rated utility bonds. This method produces a 9.9 percent ROE if one uses the 1.39 percent spread Mr. Walters used in his Direct Testimony.[235] Both of these ROE outcomes fall within Ms. Bulkley's recommended ROE range, and outside Mr. Walters' range, casting doubt on his analysis.[236]

147. Mr. Walters concluded that his final recommended ROE range is 9.20 percent to 9.60 percent and recommended an ROE of 9.40 percent for Minnesota Power.[237]

148. Mr. Walters concluded that utilities have maintained "robust" valuations and have outperformed the market over the last few months even though there is market uncertainty as a result of the war in Ukraine, inflation has remained elevated, and interest rates have increased.[238]

149. However, S&P continues to maintain a negative outlook for the utility industry in 2022 and noted that downgrades outpaced upgrades for a second consecutive year in 2021.[239]

150. Additionally, Mr. Walters did not adjust his proxy group to remove Pinnacle West Capital Corporation (PNW).[240]

151. It does not appear that Mr. Walters' recommended outcomes adequately reflect current and ongoing market circumstances or Minnesota Power's particular risks and circumstances. As such, Mr. Walters' recommended ROE is less supported by reliable record evidence.

[232] Ex. LPI-5 at 13 (Walters Surrebuttal).
[233] Ex. LPI-3 at 41 (Walters Direct).
[234] Tr. Vol. III at 49-52 (Walters).
[235] *Id.* at 51-52.
[236] *See* Ex. MP-26 at 105-07 (Bulkley Direct).
[237] *Id.*
[238] Ex. LPI-3 at 18 (Walters Direct).
[239] Ex. MP-27 at 71 (Bulkley Rebuttal).
[240] *Id.* at 21-22, 33-34, 76-77.

d. Flotation Costs

152. Consistent with past Commission precedent, Company witness Ms. Bulkley adjusted the results of the DCF analyses to include flotation costs.[241]

153. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.[242]

154. The Department testified that flotation costs are a necessary adjustment to DCF cost of equity estimates, and used a 1.92 percent adjustment to its calculations.[243]

155. The Administrative Law Judge finds that flotation cost adjustments are an appropriate and reasonable adjustment to DCF analyses in this case.

e. Summary of ROE Proposals

156. Figure 5 below shows the authorized returns for vertically-integrated electric utilities in other jurisdictions since January 2018 as compared to the returns of 9.30 percent and 9.40 percent as recommended by Mr. Addonizio and Mr. Walters, respectively.[244]

157. Recent comparable authorized ROEs range from 8.70 percent to 10.60 percent, with an average of 9.66 percent.[245] As shown in Figure 5, the majority of authorized returns for vertically-integrated electric utilities (74 out of 97 decisions or 76 percent) from 2018 through March 2022 have been greater than 9.40 percent. An ROE of 9.40 percent represents the high end of the recommendations for Mr. Walters.[246]

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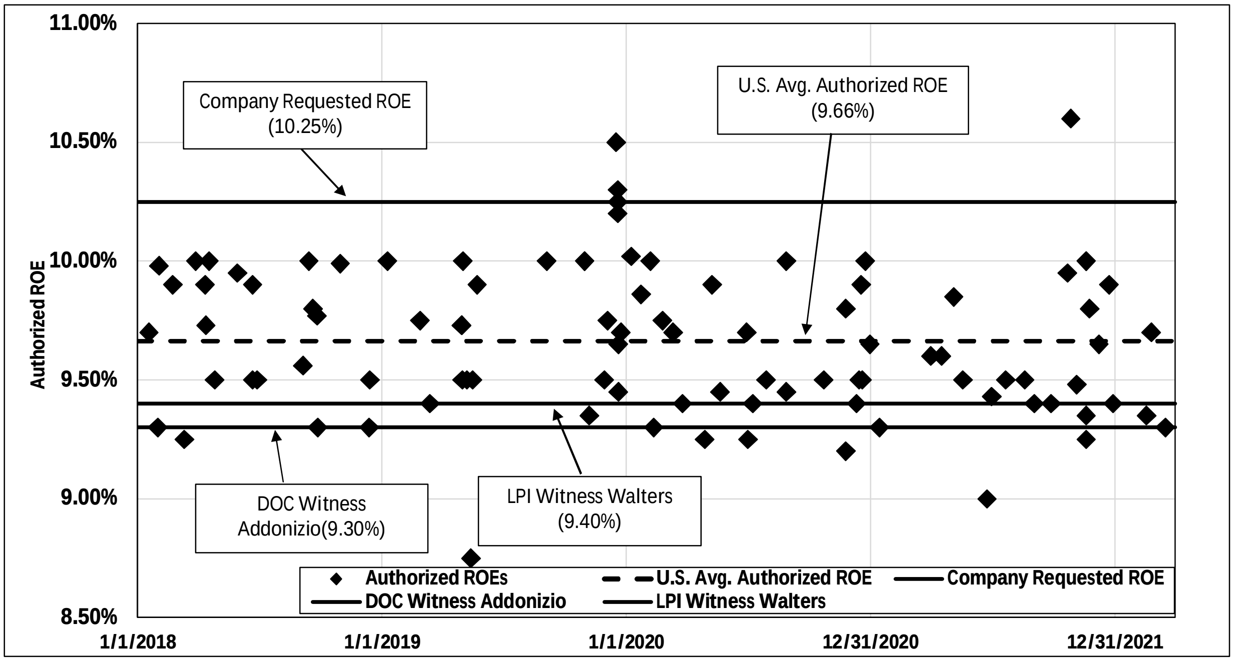
241 Ex. MP-26 at 80-84 (Bulkley Direct).
242 *Id.* at 80.
243 Ex. DOC-6 at 25-27 (Addonizio Direct).
244 *See* Ex. MP-27 at 18-19 (Bulkley Rebuttal).
245 *Id.* at 19.
246 *Id.* at 18-19.

Figure 5. U.S. Authorized ROEs—Vertically-integrated Electric Utilities January 2018 through March 2022[247]



158. Proposing a return below the mean would indicate that both Mr. Walters and Mr. Addonizio believe Minnesota Power has less risk than other comparable vertically-integrated electric utilities across the U.S. Neither Mr. Addonizio nor Mr. Walters provide evidence to support this conclusion, as they instead assume their proxy groups (which consider only certain risk screens) are sufficiently comparable in risk to Minnesota Power.[248]

159. When setting the authorized ROE for Minnesota Power, it is important to consider whether current market conditions are expected to continue over the period during which the rates set in this proceeding will remain in effect. Based on the evidence, market conditions are more likely than not to be worse over the near-term than they were during the trading periods.[249]

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247 *Id.* at 19.
248 *Id.*
249 The following key points support that conclusion:
The Federal Reserve is aggressively normalizing monetary policy in response to sustained elevated levels of inflation. This change has resulted in increases in long-term government bond yields over the past few months and is likely to result in continued increases in long-term government bond yields over the near-term.
1. The share prices of utilities are inversely related to interest rates. Investors expect interest rates to increase over the near-term, which will likely result in a decline in the share prices of utilities. A decline in utility share prices will increase their dividend yield and thus the cost of equity estimate produced by the DCF model. Therefore, current DCF results, which are based on historical data, are likely understating the cost of equity during the period that the Company's rates will be in effect.

160. Based on a comparison of the three analyses offered, the Company's is the most thorough. Additionally, considering the interest inherently motivating each party, the Judge finds that a ROE on the higher end of the range of 9.3 to 10.25 percent (9.8) is reasonable and would fairly balance the interests of customers and shareholders. This ROE would enable the Company to maintain its financial integrity and therefore its ability to attract capital at reasonable rates under a variety of economic and financial market conditions, while continuing to provide safe, reliable and affordable electric utility service to customers in Minnesota.

161. In sum, an authorized ROE of 9.8 is reasonable and appropriate for Minnesota Power. It is the mid-point between the various TGDCF models from March 2022. See Table 5, averages of "mean" and "mean high" numbers: 9.89, 9.93, and 9.97. because it: Further, this number properly recognizes and supports the Company's achievements in leading the State in percentage of renewable generation, exceeding conservation goals, and quality of customer service. It will also support the Company's credit metrics at reasonable levels, thereby supporting maintenance of current credit ratings. Finally, it will support the Company's ability to attract capital to finance investments at reasonable rates, which will provide long-term benefits to ratepayers by limiting the long-term cost of capital.

4. Rate of Return – Overall Recommendation

162. Based on the foregoing discussion and findings, the following rate of return, cost of debt, and capital structure set forth in Table 7 is reasonable for Minnesota Power:

Table 7. Recommended 2022 Test Year Capital Structure and Rate of Return

	Percentage	**Cost**	**Weighted Cost**
Long-Term Debt	46.1892 %	4.3250 %	1.9977 %
Common Equity	53.8108 %	10.2500 %	5.5156 %
Total	**100.0000 %**		**7.5133 %**

2. Current market conditions have affected the results of each of the ROE estimation models, requiring consideration of the results of multiple models and the use of informed judgment.
3. While the ROE estimation models use some historical data (i.e., stock prices and dividends in the DCF model, and bond yields in the CAPM), based on the expectation that interest rates will increase, it is appropriate to also consider near-term projections in the ROE estimation models.
3. The intervenor ROE witnesses in this proceeding have not appropriately considered the effect of a rising interest rate environment or the effects of inflation on the cost of equity for Minnesota Power when developing their respective ROE recommendations.
Id. at 117.

I. Test Year Sales Revenue

163. Energy sales forecasts and customer counts are used to calculate the Company's projected revenue under current rates and projected revenue under the rates proposed for the 2022 test year.[250]

164. Minnesota Power prepared a forecast of retail megawatt-hour (MWh) sales and customer counts for the 2022 test year.[251] The Company forecasted energy use and customer counts for each of its five retail customer classes: Residential, Commercial, Industrial, Public Authorities, and Lighting. Given its size, the Industrial class is further segmented into four sectors for forecasting purposes: Mining and Metals, Forest Products, Pipelines, and Other Industrial sectors.[252]

165. Minnesota Power's 2022 test year sales forecast was produced by combining the Company's 2021 Annual Forecast Report's (2021 AFR)[253] econometric approach to modeling Residential, Commercial, and small Industrial sales with a "bottom-up," customer-by-customer approach to forecasting the Company's large power customers.[254]

166. Minnesota Power's 2022 test year sales forecast is provided below in Table 8.[255]

Table 8. 2022 Test Year Energy Sales and Customer Count[256]

	2022 Test Year	
MWh Sales	**Energy Sales (MWh)**	**Customer Count**
Residential	1,037,401	123,854
Commercial	1,184,475	23,647
Industrial		
Mining and Metals	4,675,529	
Forest Products	607,348	
Pipelines	316,335	
Other Industrial	286,024	
Total Industrial	5,885,236	370
Government & Light	53,626	1,015
Total Retail	**8,160,738**	**148,886**
Municipals	604,042	
SWLP	814,497	
Total Retail and Resale	**9,579,277**	

250 Ex. MP-34 at 41 (Levine Direct).
251 *Id.* at 2.
252 *Id.* at 4.
253 Ex. MP-6, Sch. OS-3.
254 Ex. MP-34 at 33 (Levine Direct).
255 *Id.* at 33-42.
256 *Id.* at 3.

167. The Company's 2022 test year retail sales forecast of 8,160,738 MWh is 3.4 percent higher than 2020 actual retail sales (7,889,945 MWh) and about 5.4 percent lower than a historical five-year average (2016-2020).[257] The Company's 2022 test year energy forecast — which is inclusive of resale energy sales — of 9,579,277 MWh is 3.8 percent higher than 2020 actual retail and resale sales (9,230,235 MWh) and 5.8 percent lower than a five-year historical average of actual retail sales (10,167,369 MWh).[258]

168. Other parties proposed adjustments to the Company's test year sales forecast. The Department preliminarily recommended an increase in the test year sales forecast based on an assumption that all of the taconite mines will operate at full capacity in the 2022 test year, which Department estimated would add 595,938 MWh to test year sales and increase net revenues by $25 million.[259] In Surrebuttal Testimony, the Department reduced its recommended increase to $13.5 million based on the idling of Cleveland-Cliffs Northshore mining operations starting in May 2022.[260]

169. LPI recommended Residential sales be determined based on a 10-year average of Residential use-per-customer multiplied by 2022 customer counts, which LPI estimates would increase revenues by $2.3 million at current rates.[261]

170. The OAG suggested inclusion of sales to ST Paper and the Cenovus Superior Refinery, formerly Husky (Cenovus/Husky) in the 2022 test year, which would add to test year retail sales and also to resales.[262]

1. Mining and Metals Customer Test Year Sales Forecast

171. Test-year sales volumes are integral to calculating a utility's revenue requirement and directly impact both revenues and expenses.[263] The methods used to determine sales levels, therefore, must be reasonable to support a determination of just and reasonable rates.[264] "When sales are under-estimated, a utility's revenue requirement is spread over fewer units (kWh), which means that the utility would collect more revenues per unit sold than is warranted by costs."[265] That is, customers pay a higher rate for energy than is justified by costs.[266]

172. Minnesota Power forecasts sales for its large industrial customers, including its Mining and Metals customers, using a "bottom-up, customer-by-customer

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[257] *Id.*, Sch. 1.
[258] *Id.* at 42.
[259] Ex. DOC-8 at 21 (Shah Direct).
[260] Ex. DOC-9 at 18 (Shah Surrebuttal).
[261] Ex. LPI-1 at 6 (Gorman Direct); Tr. Vol. III at 11 (Gorman) ("The effect of that would be to reduce the residential sales revenue requirement adjustment from $4.3 million down to $2.3 million.").
[262] Ex. MP-34 at 2-7 (Levine Direct); Ex. MP-36 at 2 (Levine Rebuttal).
[263] Ex. DOC-8 at 2 (Shah Direct).
[264] *Id.*
[265] *In re Appl. of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E017/GR-15-1033, Findings of Fact, Conclusions, and Order (May 1, 2017).
[266] *Id.*

approach."[267] That is, projections for each Mining and Metals customer "were developed in cooperation with each customer, taking into account the nuances of the individual customers' operation."[268] Once the individual customer estimates are totaled up for the class, the results are checked against the econometrically produced AFR forecast.[269]

173. The Department contended that Minnesota Power's Mining and Metals forecast for two of its customers, Keetac and Hibtac, is unreasonably low.[270] The Department stated that for the Keetac mine, Minnesota Power attempts to relitigate a determination made by the Commission in its 2016 rate case regarding how revenues from this specific customer should be reflected.[271] For Hibtac, the Department found that Minnesota Power's sales forecast assumes unsupported, historically low levels of taconite production.[272]

174. Minnesota Power argued that changes in the taconite industry as a whole justifies reducing the assumed output from a single customer in the test year because it may be offset by other outages even if the customer is still operating at full capacity.[273]

175. The Commission specifically rejected the argument Minnesota Power puts forth in regards to Keetac in Minnesota Power's 2016 rate case, stating it was unreasonable "to reduce a known test year revenue amount for specific customers as a proxy for a proposed load-factor adjustment for an entire industry."[274] Minnesota Power has not provided evidence in the current rate case that Keetac will be idled at any point during the test year, and it remains unreasonable to reduce Keetac's production as a proxy for speculative reduced production in the entire industry. Instead, test-year sales in this case should reflect Keetac at full production.

176. For Hibtac, Minnesota Power's forecast is lower than all but a handful of the past 46 years that Hibtac has been in operation.[275] Minnesota Power did not provide sufficient support for this departure from the historical data. Hibtac's taconite production level for 2021 was significantly more than what the Company forecasted for the 2022 test year.[276] Minnesota Power has not supported the reasonableness of this large discrepancy between 2021 actual production and the 2022 test year. In addition, Hibtac's recent nominations in 2022 contrast with Minnesota Power's sales forecast, which assumes significantly reduced production or idling.[277]

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[267] Ex. MP-34 at 40 (Levine Direct).
[268] *Id.*
[269] *Id.*
[270] Ex. DOC-8 at 8–17 (Shah Direct).
[271] DOC Initial Br. at 56-57; Ex. DOC-8 at 8-10, 12-15 (Shah Direct).
[272] DOC Initial Br. at 57-58; Ex. DOC-8 at 15-17 (Shah Direct).
[273] *See* Ex. MP-36 at 18 (Levine Rebuttal) (stating that the Department's Keetac adjustment "did not consider the historical operating levels of any other Mining and Metals customers or the class as a whole").
[274] *In re Appl. of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-16-664, Findings of Fact, Conclusions, and Order at 51 (Mar. 12, 2018).
[275] Ex. DOC-8 at 15 (Shah Direct).
[276] *Id.* at 16, SS-D-3.
[277] Ex. DOC-9 at 17, SS-S-6 at 126 (Shah Surrebuttal).

177. The Department submitted an alternative sales forecast that included more reasonable taconite production assumptions for Keetac and Hibtac, in addition to reducing taconite production levels for the Northshore facility, which idled during the test year.[278] Although built using a different, customer-by-customer approach, the Department's number is also consistent with average taconite production for 10-, 15-, and 20-year periods, whereas Minnesota Power's forecasted taconite production levels are significantly lower than even a 3- or 5-year average.[279]

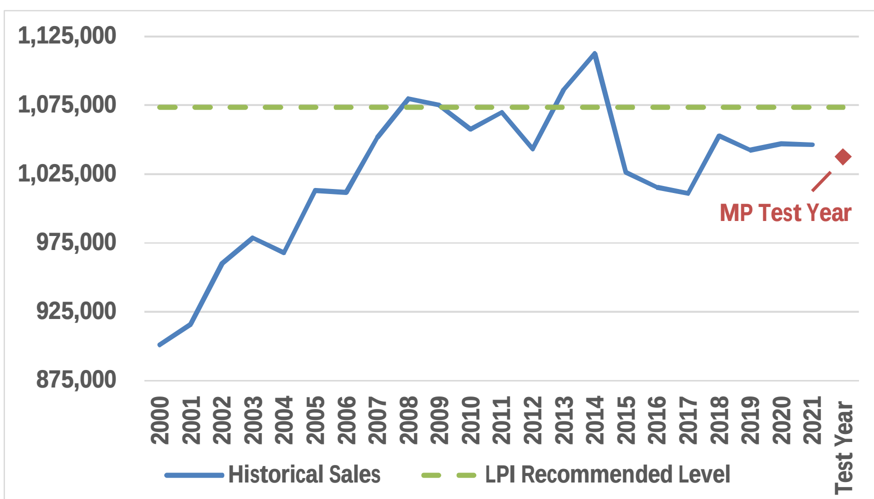
178. The Administrative Law Judge finds that the Company has failed to demonstrate the reasonableness of its test year sales forecast for the Company's Mining and Metals customers, and the Commission should adopt the Department's alternative sales forecast for Minnesota Power's Mining and Metals customers.

2. Residential Customer Test Year Sales Forecast

179. In this case, the Company's forecasted Residential sales of 1,037,401 MWh for an average of 8.38 MWh per Residential customer.[280]

180. The Company's Residential sales forecast is both lower than actual Residential sales since 2017 and lower than the Company's forecasted Residential sales in the 2020 rate case. It is also lower than actual recorded sales between 2017 and 2021.[281]

Figure 6. Residential Sales 2000-2021[282]



[278] Ex. DOC-9 at 18–19 (Shah Surrebuttal).
[279] *See id.*, SS-S-4 at 2.
[280] Ex. LPI-1 at 36 (Gorman Direct).
[281] Ex. LPI-2 at 22-24 (Gorman Surrebuttal); Ex. MP-36 at 7 (Levine Rebuttal).
[282] Ex. MP-36 at 6 (Levine Rebuttal).

181. The COVID-19 pandemic resulted in increased Residential sales due to stay-at- home work.[283]

182. The Company's weather normalization regression analysis contained flaws and "could not fully adjust for the extreme effects of the 2013-14 winter."[284]

183. The Company's forecasting should have included a range that reflected both abnormally high- and low-usage periods.[285]

184. Applying a 10-year, weather-normalized average, results in a forecasted test year value of 8.61 MWh per Residential customer.[286]

185. To meet its burden of proof, the Company must satisfy a two-part test. The first prong of this test requires that the Company establish the amount of a given cost as a judicial fact.[287]

186. Based on the Company's own data and admitted errors with its modeling, the Company failed to satisfy its burden of proof of its proposed Residential sales as a fact.

187. The Judge therefore finds that the Company's revenue requirement should be reduced by $2.3 million.[288]

3. Test Year Sales to ST Paper and Husky/Cenovus

188. The Husky refinery is an oil refinery near Duluth that produces products such as asphalt, gasoline, diesel, and fuel oils.[289] The refinery has been owned by Cenovus Energy since early 2021.[290] There was an explosion at the refinery in April 2018 that "result[ed] in a reduction of resale sales through Minnesota Power's contract with Superior Water Light & Power that will continue until 2023," when the refinery is scheduled to restart following repairs.[291]

189. Verso Corporation operated a paper mill in Duluth until June 2020, when it idled the mill's operations indefinitely.[292] Verso permanently closed the mill in January 2021.[293] The mill was later acquired by ST Paper, which is working to convert the facility to produce tissue paper.[294] ST Paper's equipment supplier has stated that startup of the

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283 Tr. Vol. 1 at 108.
284 Ex. LPI-2 at 25 (Gorman Surrebuttal).
285 Ex. LPI-1 at 40 (Gorman Direct).
286 *Id.* at 38, 40.
287 *N. States Power Co.*, 416 N.W.2d at 722.
288 Tr. Vol. 3 at 11.
289 Ex. OAG-3 at 2 (Lebens Direct).
290 *Id.* at 3.
291 Ex. MP-30 at 39 (Frederickson Direct).
292 *Id.* at 42.
293 *Id.*
294 *Id.* at 37.

new paper machine is planned for the end of 2022.[295] Minnesota Power expects the mill to be operational in early 2023.[296]

190. The test year sales forecast does not reflect sales to either Husky/Cenovus or ST Paper.[297]

191. The OAG recommended that the Commission require the Company to reflect sales to these customers in the test year because failing to do so would unduly benefit shareholders when these customers come online.[298]

192. Minnesota Power responded that sales to Husky/Cenovus and ST Paper should not be included in the test year because their planned startups could be delayed.[299] The Company also argued that its proposed sales true-up mechanism would address the OAG's concerns about shareholders unduly benefitting when these customers resume operations.[300]

193. Minnesota Power has not met its burden to establish that sales to Husky/Cenovus and ST Paper should be excluded from the test year.

194. Both customers will restart by the end of 2022 or early 2023 and can be expected to operate for the foreseeable future once they restart.[301] Failing to reflect these sales, therefore, would unduly benefit Minnesota Power's shareholders by granting them elevated rates that assume these customers are not operating.

195. The Company argued that these customers' plans are not guaranteed. However, it would be unreasonable to assume that these customers' current plans will not come to fruition based on speculation about unknown contingencies that *may* occur.[302] The Company's argument asks the Commission to give it the benefit of the doubt, contrary to the statutory mandate to resolve doubt in favor of the consumer.[303]

196. The Company also argued that its sales true-up proposal would mitigate the OAG's concerns. However, several intervening parties, including the OAG, had valid concerns with the true-up proposal, and even absent these concerns, the true-up mechanism would not address the restart of Cenovus and ST Paper: Under the Company's proposal, a true- up would only be triggered by a $10 million or larger increase in sales revenues, and these two customers' combined sales revenue would not reach

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[295] Ex. OAG-3 at 5 (Lebens Direct).
[296] Ex. MP-34 at 27 (Levine Direct).
[297] *See* Ex. MP-34 at 42 (Levine Direct) (stating that decrease in test year sales was due to closure of Duluth mill and Husky refinery, among other things).
[298] Ex. OAG-3 at 4–7 (Lebens Direct).
[299] *See* Ex. MP-32 at 14 (Frederickson Rebuttal); Ex. MP-36 at 27 (Levine Rebuttal).
[300] Ex. MP-32 at 14 (Frederickson Rebuttal); Ex. MP-36 at 26 (Levine Rebuttal).
[301] Ex. OAG-3 at 4-7 (Lebens Direct).
[302] Ex. OAG-5 at 10 (Lebens Surrebuttal); *see also* Tr. Vol. 1 at 70 (Frederickson) (conceding that he "do[es] not have evidence" that these customers will not start up as planned); *id.* at 105 (Levine) (conceding that he "ha[s] no specific information indicating these customers will not start up next year").
[303] *See* Minn. Stat. § 216B.03.

that threshold.[304] Thus, even if the Commission accepted the Company's proposed true-up mechanism, and both Cenovus and ST Paper restarted, that event would not be sufficient to trigger a true up and flow those revenues back to customers.

197. For the foregoing reasons, the Judge finds that the Commission should require Minnesota Power to reflect sales to Cenovus and ST Paper in the test year.

4. Pipeline and Other Industrial Customer Sales Forecast

198. The Pipeline and Other Industrial sector includes all non-Mining and non-Paper Industrial customers.[305] The Company's 2022 test year forecast for the combined Pipeline and Other Industrial sector is 602,359 MWh.[306]

199. In Direct Testimony, the Department requested that Minnesota Power "provide further supporting data and information for its claimed changes to the energy usage from the Line 3 replacement."[307]

200. In Rebuttal Testimony, the Company provided additional information about its test year forecast for Enbridge, the role the Line 3 replacement is expected to play in those forecasts, and the accuracy of the projections.[308]

201. In Surrebuttal Testimony, the Department testified that the Company's Rebuttal Testimony had resolved its concerns regarding forecasted sales to Enbridge. It stated that the Department did not recommend any adjustment to the test year sales forecast on this issue.[309]

202. The Judge finds that the Company has demonstrated the reasonableness of its test year sales forecast for the Company's Pipelines and Other Industrial customers.

J. Revenue, Expense, and Rate Base Items – Contested Issues

1. Prepaid Pension Asset

203. In this proceeding, the Company requested the 13-month average of its 2022 test year pension plan accumulated contributions in excess of net periodic benefit cost (the "prepaid pension asset") of $80,424,617 (Total Company), $71,506,571 (MN Jurisdictional),[310] be included in the working capital section of rate base. This would result in a net increase to rate base of $43,705,383 (MN Jurisdictional) for accumulated contributions, net of accumulated deferred income taxes (ADIT).[311] The net prepaid

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[304] *See* Ex. OAG-12 (MP trade secret response to OAG IR 5012).
[305] Ex. MP-34 at 28 (Levine Direct).
[306] *Id.* at 30.
[307] Ex. DOC-8 at 19 (Shah Direct). Line 3 is a pipeline that is owned and operated by Enbridge that was retired in late 2021 and replaced with Line 93.
[308] Ex. MP-36 at 29-30 (Levine Rebuttal).
[309] Ex. DOC-9 at 20 (Shah Surrebuttal).
[310] Ex. MP-22, Sch. 13 (Cutshall Direct).
[311] *Id.* at 84; Ex. MP-55 at 13-14 (Turner Rebuttal).

pension asset, minus ADIT, of $43,705,383 (MN Jurisdictional) is the amount on which the Company seeks to earn a return.[312]

204. The prepaid pension asset consists of cumulative contributions Company shareholders (investors) have made to a pension fund, which exceed cumulative annual pension expense paid to employees each year in the form of pension benefits, which are recovered through rates.[313] The additional funding supplied by customers is governed by the Pension Protection Act of 2006 (PPA) and the Employee Retirement Income Security Act of 1974 (ERISA), and helps ensure adequate actual capital is available to fund future benefits.[314] Thus, Minnesota Power contends that the prepaid pension asset consists of investor-supplied capital held to fund future employee retirement benefits. In addition, the returns on the prepaid pension asset reduce the amount of pension expense customers pay through rates.[315]

205. LPI and the Department disputed the inclusion of this asset in rate base. The Department concluded that Minnesota Power "has not demonstrated the reasonableness of including a prepaid pension asset in rate base," and that it should therefore be removed from the 2022 test year working capital rate base.[316]

206. Department witness Ms. Campbell asserted that a prepaid pension asset also does not exist because under generally accepted accounting principles (GAAP), the reported funded status is a liability for the pension plan.[317]

207. In Surrebuttal Testimony, Ms. Campbell stated that she does not dispute that the Company follows GAAP, but that under the FERC Uniform System of Accounts the Company should not have a regulatory asset absent Commission permission.[318] But at the evidentiary hearing, Ms. Campbell admitted she did not look at the FERC directions on accounting for prepaid pension assets and pension expense.[319]

208. Separately, LPI witness Mr. Gorman claimed that approximately 28 percent of the prepaid pension asset was not created by shareholder contributions but was "created by excess earnings on the pension trust and negative pension expense," and should therefore be excluded from the cost of service. In addition, Mr. Gorman argued that the remaining 72 percent should not be permitted to be included in rate base because it "is inconclusive" whether the prepaid pension asset was funded initially by the Company, and to what extent the Company fully recovered its cash contributions from customers and other operations in its non-retail jurisdictions and subsidiaries.[320]

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[312] Ex. MP-22 at 84 (Cutshall Direct).
[313] *Id.* at 42-43, 84.
[314] *Id.* at 43.
[315] *Id.* at 42-43, 84.
[316] Ex. DOC-2 at 28 (Campbell Direct).
[317] *Id.* at 24.
[318] Ex. DOC-3 at 23-24 (Campbell Surrebuttal).
[319] Tr. Vol. II at 191 (Campbell).
[320] Ex. LPI-1 at 16 (Gorman Direct).

a. Background on Pension Funding

209. The Company has defined benefit pension plans, or "DB Plans," for certain employees based on their hiring date. Consistent with industry trends, the Company continues to move away from these plans to the defined contribution model.[321]

210. Minnesota Power's DB Plans are all traditional defined benefit plans that use final average pay and credited service in the benefit calculation. As of Mercer's actuarial analysis performed in 2021, approximately 171 non-bargaining unit employees (approximately 25 percent of all non-bargaining unit employees) and 335 bargaining unit employees (approximately 72 percent) were eligible for the DB Plans.[322]

211. The level of expected expense and necessary contributions to fund the DB Plans are determined based on actuarial calculations involving the Company's actuary, Willis Towers Watson (and previously Mercer), and reviewed for compliance with GAAP by the Company's independent auditor, PricewaterhouseCoopers (PwC).[323]

212. The pension expense component of ratemaking (an income statement item) is included in the Company's rates based on a combination of service costs; interest costs; expected return on plan assets; amortization of prior service costs; and amortization of actuarial gains and losses written off in the period.[324]

213. The Company's request for recovery of the prepaid pension asset arises because over time, the Company has contributed more in terms of actual cash and stock to the pension fund than the expense included in rates.[325]

214. The Company's contribution of these funds reduces the amount of pension expense that is included in customer rates. Minnesota Power provided testimony and a schedule to illustrate that all of the earnings of this prepaid asset reduce the expense that the customer needs to pay.[326]

215. Put differently, the actual funding of the prepaid pension asset earns a return that is applied to reduce annual pension expense for the benefit of customers.[327] Compounded earnings on these contributions go even further to reduce pension expense.[328] Minnesota Power therefore contends that without a return on the prepaid pension asset, this is tantamount to "lending" the investor-supplied funds and the earnings on those funds to customers without compensation to investors.[329]

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[321] Ex. MP-45 at 45 (Krollman Direct).
[322] *Id.* at 48.
[323] *See* Ex. MP-24, Sch. 4, 5 (Cutshall Rebuttal); Ex. MP-26, Sch. 6.
[324] Ex. MP-23 at 48 (Cutshall Direct).
[325] *Id.* at 63; Ex. MP-24 at 36-37, Sch. 3 (Cutshall Rebuttal).
[326] Ex. MP-23 at 56, 77 (Cutshall Direct).
[327] Ex. MP-24 at 36 (Cutshall Rebuttal).
[328] *Id.* at 37.
[329] *Id.* at 36-37.

b. Prepaid Asset – Calculated Value

216. According to Minnesota Power, ALLETE has a prepaid pension asset valued at $108,939,929 as of December 31, 2021.[330] The prepaid pension asset formula (cumulative pension contributions minus cumulative pension expense) is simple for both GAAP and ratemaking purposes. Based on its accounting records going back to 1987, the Company has quantified the total amount of the actuarially calculated contributions and expense.[331] Because the cumulative expenses are less than the cumulative contributions made by the Company, the Company has a prepaid pension asset.

217. ALLETE's pension plan contributions and expense levels are determined under ERISA and the Internal Revenue Code (IRC). The regulatory materials include the provisions of the PPA, as updated, including under the American Rescue Plan Act of 2021, and GAAP set forth by the FASB and accepted by the SEC.[332]

218. The Company has consistently made all contributions required by the IRC, which have exceeded expenses over the life of the plans.[333]

219. As shown in Table 9, beginning in 1994 through 2021 the cumulative amounts for pension expense recovered in rates from customers, actual pension expense, and actual pension contributions are as follows:

Table 9. Total Pension Recovery, Expense and Contributions[334]

Total recovery from customers has been (column Z)	$38 million
Total Jurisdictional expense has been (column W)	$76 million
Total Jurisdictional contributions (column V)	$146 million

220. The Company's actual prepaid pension asset balance has been verified by numerous independent sources. ALLETE's actuary disclosed ALLETE's accumulated contributions in excess of net periodic benefit cost or prepaid pension in its annual disclosure reports.[335] ALLETE's Form 10-K, Note 11 shows the December 21, 2021, prepaid pension asset of $93.2 million.[336] The MN Jurisdictional amount of the prepaid pension asset is $71,506,571.[337] Additionally, ALLETE files audited financial statements with the U.S. Securities and Exchange Commission (SEC) that reflect that it has a prepaid

[330] Ex. MP-24 at 33-34, Sch. 3, 4 (Cutshall Rebuttal); Ex. MP-58 at 9, Sch. 3 (Farrell Rebuttal).
[331] Ex. MP-24 at 36-37; 41 (calculating contributions, GAAP expense and rate recoveries from 2017-2022 (Cutshall Rebuttal); Ex. MP-58 at 9 (Farrell Rebuttal).
[332] Ex. MP-23 at 43-46 (Cutshall Direct).
[333] Ex. MP-24 at 36 (Cutshall Rebuttal).
[334] *Id.*, Sch. 3.
[335] *See id.* for ALLETE's December 31, 2021, prepaid pension asset balance in which the 2021 year-end balance agrees with the 2021 year-end balance in Ex. MP-24 at Schedule 3 and the 2021 beginning balance agrees with the 2020 year-end balance in Ex. MP-24 at Schedule 5.
[336] This is the combination of the $108,939,929 prepaid pension asset plus the prepaid Supplemental Executive Retirement Plan (SERP) balance of a negative $13,496,434 and the prepaid Executive Investment Plan (EIP) balance of a negative $2,265,176. *See* MP-24 at 34, Table 2 (Cutshall Rebuttal).
[337] *See id.*, Sch. 4, 5.

pension asset, and files an audited Federal Energy Regulatory Commission (FERC) Form 1 that reflects a prepaid pension asset.[338]

221. The Company has demonstrated that the prepaid asset exists, and its MN Jurisdictional value is $71,506,571.[339]

c. GAAP Accounting

222. ALLETE's entire accounting, including accounting for its pension plans, is consistent with GAAP. ALLETE (doing business as Minnesota Power) is a New York Stock Exchange publicly-traded entity that is required to have an annual audit of its consolidated financial statements.[340]

223. As part of this annual audit, ALLETE's independent registered public accounting firm, PwC, which is the second largest accounting firm in the world, opines that ALLETE's consolidated financial statements, which are supported by the books and records that also form the basis for this general rate case, are presented fairly — in all material respects — and are "in conformity with accounting principles generally accepted in the United States of America."[341]

224. ALLETE's audited financial statements are also periodically reviewed by the SEC and the FERC. The most recent audits of these entities resulted in no findings or comments related to the Company's accounting for its benefit plans.[342]

225. The Department also asserted that the Company should not be recording accumulated gains and losses for its pension plan in FERC Account 182.3 because the Commission has not allowed the Company to record a prepaid pension asset.[343]

226. Minnesota Power responded that the Department is incorrect in its interpretation of the FERC accounting rules in this instance. Mr. Farrell testified that FERC has directed utilities that recover pension expense in rates according to the Statement of Financial Accounting Standards 87 (i.e., part of GAAP) to record a regulatory asset or liability for the gains and losses in a pension plan that would otherwise be reported as other comprehensive income.[344]

d. Funded Status

227. Minnesota Power further maintains that a plan can be underfunded at the same time it has a prepaid pension asset, because the two concepts measure different things. The prepaid pension asset is the amount by which cumulative past contributions

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338 *See id.*, Sch. 7.
339 *See id.* at 33-34.
340 *Id.* at 28.
341 *Id.*
342 *Id.* at 31-32.
343 Tr. Vol. II at 189 (Campbell).
344 Ex. MP-58 at 4-8 (Farrell Rebuttal); Ex. MP-24, Sch. 7 (Cutshall Rebuttal).

exceed cumulative recognized pension expense. A pension plan is underfunded when its projected pension benefit obligations exceed the value of its assets. These are two different things: The prepaid pension asset is a known and tracked asset that the Company has paid to develop. The Company contributes real cash or stock to the pension that is in excess of the current expenses, that are directly reflected in rates. This creates a tangible prepaid pension asset.[345]

228. The liability (the unfunded portion) is simply an estimate of future expenses, and it is reflected on the balance sheet for transparency purposes, so financial statement users can see what future obligations may be.[346] The reported funded status (in this instance a liability) is irrelevant to determining whether the Company has a prepaid pension asset is valuable.[347]

229. The Commission's past approval of a prepaid pension asset demonstrates that a prepaid pension asset and funded status liability can coexist. In 2015, the Commission permitted Northern States Power Company–Minnesota (NSPM) to recover its prepaid pension asset.[348]

e. Investor-Supplied Funds Benefit Customers

230. The Department also alleged that it would be unreasonable for the Company to earn a return on a prepaid pension asset because the asset was not funded 100 percent from investors. Rather, the Department alleged, "ratepayers already pay for pension expense in their rates, so it is unreasonable to also expect ratepayers to pay a return on a supposed prepaid pension asset."[349] LPI made similar arguments.[350]

231. Minnesota Power provided several arguments in response. First, it is undisputed that all contributions to the pension plan have been funded by ALLETE, either with cash or ALLETE common stock, and not by customers.[351] Customers currently only fund expense based upon an estimate of the test year pension expense.[352] Because the prepaid pension asset is cumulative pension contributions minus cumulative expense, and investors pay for contributions whereas customers pay for expense, the amount by which cumulative contributions exceed expense is by definition an investor-funded asset.[353]

[345] *See* Ex. MP-22 at 78-79 (Cutshall Direct).
[346] Ex. MP-58 at 8-9 (Farrell Rebuttal).
[347] Ex. MP-24 at 24-28 (Cutshall Rebuttal).
[348] In re the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn., MPUC Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order at 20 (May 8, 2015).
[349] Ex. DOC-3 at 26 (Campbell Surrebuttal).
[350] *See* Ex. LPI-2 at 3 (Gorman Surrebuttal).
[351] Ex. MP-24 at 23 (Cutshall Rebuttal).
[352] *Id.* at 24.
[353] *Id.* at 35.

232. Secondly, it is reasonable to include a prepaid pension asset in rate base because these funds help preserve the financial integrity of the pension for the future and are enabled by ALLETE's shareholders.[354]

233. Third, it is also reasonable to include a prepaid pension asset in rate base because the returns earned on the pension plan trust asset are required to be treated as income to the Company under GAAP.[355] Federal law prohibits the withdrawal of any amounts from the pension trust fund except for the payment of benefits and plan expenses. That is, the Company is not able to keep these earnings — customers receive 100 percent of the market return benefits because all of the market returns on the pension plan trust reduce pension expense, which results in lower rates.[356] Therefore, Minnesota Power argues that it is not only reasonable "to also expect ratepayers to pay a return on a supposed prepaid asset," it is necessary to compensate the utility for investor-supplied funds used to provide retirement benefits to utility employees.[357]

f. Consistent Contributions and Negative Expense

234. LPI alleged that because the prepaid pension asset was funded by the pension trust returns and collections from customers, the prepaid asset should be excluded from the Company's rate base and cost of service.[358]

235. LPI's argument disregards the acknowledged formula used to determine the prepaid asset balance: cumulative contributions minus cumulative expense. Given this formula, it is possible for prepaid pension assets to grow even when there have been no contributions.[359]

236. In some years, customers' rates had negative expense embedded in them (2008-2009),[360] and the Company was paying the customer (through negative expense) while the Company was also paying a pension benefit to its employees.[361]

237. It is helpful to keep in mind that many things affect pension expense: pension earnings, discount rates, benefit payments, demographic assumptions (mortality rates, retirement age, and termination rates). Customers benefit from the earnings and

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[354] *Id.* at 36.
[355] *Id.* at 36; Ex. MP-23 at 56, Table 7 (Cutshall Direct).
[356] Ex. MP-23 at 56, Table 7 (Cutshall Direct); Ex. MP-24 at 36-37 (Cutshall Rebuttal).
[357] Ex. MP-22 at 65, 69, 71 (Cutshall Direct).
[358] Ex. LPI-1 at 14 (Gorman Direct).
[359] Ex. MP-24 at 40 (Cutshall Rebuttal).
[360] Ex. LPI-1, Sch. 1 (Gorman Direct).
[361] Mr. Gorman has proof in his own testimony that negative pension expense has been used to set rates. While over 80 percent of the time (including 2022 expected) the pension expense has been positive, it is also clearly shown in Ex. MP-24, Schedule 3 (Cutshall Rebuttal) and in Mr. Gorman's own testimony in Ex. LPI-1, Schedule 1 (Gorman Direct) and related footnotes, that negative expense was used to set rates and the Company had a negative recovery from customers in 2008 and 2009. This proves that the pension pays benefits and the Company paid customers, through negative rates (i.e., offsets to revenue requirement increases), for the pension expense.

infusions of additional capital because all pension earnings reduce expense, and customer rates are set to recover projected pension expense.[362]

238. Intervenors also argued that because negative pension expense contributes to the existence of the asset, the existence of the asset is not certain. As they reason, the amount customers have paid in expense through rates does not match the actual expense each year.[363]

g. Relationship to Other Prepaid Assets in Rate Base

239. The Department also asserted that the prepaid pension asset should not be included in rate base because the asset is temporary.[364]

240. However, the Company demonstrated that the prepaid pension asset is indistinguishable from other utility assets, including prepaids, that are included in rate base, stating: "Any utility asset supporting the provision of utility service (where cash is zero since working capital is included in rate base), no matter the duration, is, or should be, included in rate base. If they are not, the customer would be getting the use of the asset at no cost . . . [.]"[365]

241. The Department confirmed its understanding that an asset's "temporary" nature is not a GAAP term or is otherwise defined by GAAP.[366]

242. More generally for ratemaking purposes, deviations between cash paid and accrued expenses for a given year are very typically included in rate base as prepaid assets.[367] For example, this is true with tax expense, and is the reason why deferred tax liabilities and deferred tax assets (ADIT) are included in rate base. It is also why prepaid expenses are included in the working capital section of rate base. Rate base includes cash working capital, which adds to rate base if shareholders are providing extra net funding and decreases rate base if customers are providing the net funding. If the difference was not included in rate base, either the utility would benefit at the expense of customers or customers would benefit at the expense of the utility — in short, one party would have the use of another party's funds to use for free until the prepayment is recovered.[368]

h. Commission Precedent

243. The Commission does not have a bright-line test to determine whether a prepaid pension asset should be included in rate base. Decisions on this issue have been fact-specific. In the present case, Minnesota Power has focused on establishing that the

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[362] Ex. MP-24 at 40 (Cutshall Rebuttal).
[363] *See* Tr. Vol. II at 168 (Campbell).
[364] Ex. DOC-2 at 25 (Campbell Direct).
[365] Ex. MP-24 at 37-38, 48 (Cutshall Rebuttal).
[366] *Id.*, Sch. 8.
[367] *Id.* at 37-38.
[368] *Id.* at 24, 37-38.

prepaid pension asset consists of investor-supplied funds that support an employee benefit, and that investors are not presently earning any return on their investment.

244. In the Company's 2016 Rate Case Order, the Commission adopted the rationale for excluding the prepaid pension asset from rate base that was originally articulated in the 2013 and 2015 rate cases for Minnesota Energy Resources Corporation (MERC).[369] The Commission noted that the circumstances that originally warranted denying a return on the asset in those earlier MERC cases were likewise present in Minnesota Power's 2016 Rate Case.[370]

245. In recent cases involving Minnesota Power, MERC, and Otter Tail Power Company (Otter Tail),[371] the Commission rejected requests to include the utilities' pension and benefit-related assets and liabilities in rate base because:

(1) The utility "recovers its allowable pension expense from ratepayers, and is not being denied recovery of this operating cost";[372]

(2) The pension-plan assets and benefit obligations "go up and down depending on funding, market conditions, or amendments to the plan";[373]

(3) The balances in the prepaid pension asset are "temporary, and fundamentally different than typical rate-based assets on which the Company earns a return on investment";[374]

(4) The asset already earns a return in the form of investment returns;[375] and

(5) It would be "impractical, if not impossible, to equitably separate the prepaid amount attributable solely to [the utility's] contributions from that attributable to ratepayer contributions and market returns."[376]

246. The Commission's approval, however, of a prepaid pension asset in Xcel Energy's 2013 rate case demonstrates that a prepaid pension asset and funded status liability can coexist. NSPM has been allowed recovery of—and currently recovers—its prepaid pension asset based on the Commission's May 8, 2015, rate order:

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369 2016 Rate Case Order at 16 n.22 (citing MERC Order at 8-11; *In re a Petition by Minn. Energy Resources Corp. for Auth. to Increase Natural Gas Rates in Minn.,* MPUC Docket No. G011/GR-13-617, Findings of Fact, Conclusions, and Order at 22-24 (Oct. 28, 2014)).
370 *Id.* at 16.
371 MERC Order at 11; *In re Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E017/GR-15-1033, Findings of Fact, Conclusions, and Order at 25 (May 1, 2017) (Otter Tail Order).
372 2016 Rate Case Order at 16; MERC Order at 11; Otter Tail Order at 25.
373 2016 Rate Case Order at 16; MERC Order at 11; Otter Tail Order at 25.
374 2016 Rate Case Order at 16; MERC Order at 11; Otter Tail Order at 25.
375 2016 Rate Case Order at 16.
376 *Id.* at 17.

> For rate-base purposes, the Commission will require that the pension asset reflect the cumulative difference between actual cash deposits made by the Company reduced by the recognized qualified pension cost determined under the ACM/FAS 87 methods since plan inception, not to exceed the Company's filed request.[377]

247. In previous cases, the Commission has denied the inclusion of the pension asset in rate base because the shareholder funding of the pension contributions could not be determined. That is not the situation in this case. The traceability of the amounts makes this case more like *NSPM* and less like *MERC*.[378] Accordingly, the Judge concludes that the Commission's rationales in prior cases do not apply to the Company in the instant proceeding based upon the record of this case.

248. Here, the Judge finds that the parties have agreed that the prepaid pension asset measures the difference between the cumulative pension contributions and the cumulative recognized pension expense.[379]

249. The Judge finds that the evidence supports the conclusion that the Company's pension plan, and its prepayments, contribute to the service the Company provides. No party argued that the Company's pension plan or benefits are unreasonable. Further, the Company's pension plan and investor contributions to fund the plan help reduce rates for customers and provides an important, promised retirement benefit to employees. Moreover, the Company is required by federal law to maintain a certain level of funding for the pension plan.

i. Prepaid Pension Asset – Overall Recommendation

250. It is a long-standing ratemaking principle that utilities are entitled to an opportunity to earn a reasonable return on investments made for the benefit of customers.[380]

251. The Judge finds that the inclusion of the present pension expense in rates does not compensate investors for the capital they have advanced to fund the pension trust in excess of expenses. The utility and its investors are entitled to recover both the

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[377] *In re the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order at 20 (May 8, 2015) (requiring pension asset reflect the cumulative difference between actual cash deposits made by the Company reduced by the recognized qualified pension cost).

[378] Compare In re the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn., MPUC Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order (May 8, 2015), and In re the Application of Minn. Energy Resources Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn., MPUC Docket No. G-011/GR-15-736, Findings of Fact, Conclusions, and Order at 28 (Oct. 31, 2016).

[379] Tr. Vol. II at 177-80, 185-86 (Campbell); Ex. LPI-1 at 9 (Gorman Direct); Ex. MP-24 at 40 (Cutshall Rebuttal).

[380] See Bluefield, 262 U.S. at 692 (stating that a "public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public.").

O&M expenses associated with an asset and a return on the investments that made the asset possible.

252. All parties agree that the formula for determining whether a prepaid pension asset exists is cumulative contributions to the pension trust minus cumulative expense.[381]

253. The parties agree that shareholders provide cash and stock contributions to the pension fund, whereas customers provide expense recovery through rates, and do not dispute that earnings from plan assets reduce pension expense as shown by Table 7 and Schedules 14 and 15 to Mr. Cutshall's Direct Testimony.[382]

254. The funded pension plan helps attract and retain the employees who provide electric service to customers.

255. The Judge finds that all asset balances are "temporary" in the sense that they rise and fall as new investments are made and depreciation expense is recognized. The Company accounts for the changes in the prepaid pension asset balance by using a 13-month average, as it does for other balances that vary over the year, such as materials and supplies. Additionally, the Company is required by ERISA and the Pension Protection Act to make contributions to the pension trust, just as the Company is required to make investments in physical assets such as transmission and distribution lines to provide service. The dollars contributed to the pension trust are real, out-of-pocket dollars provided by investors, just like dollars spent on physical assets, and investors are entitled to a return on those dollars comparable to the return available on other types of investments.

256. The Judge finds that though the prepaid pension asset earns an investment return, every dollar of that investment return is used to reduce the pension expense charged to customers. Investors receive no direct benefit from the investment return. The fact that customers benefit from the investment return on the prepaid pension assets does not justify denying investors an investment return on the prepaid pension asset, but in fact underscores why investors are entitled to a return.

257. The Judge finds that based on the record of this contested case, to exclude the asset because it is impractical or impossible to separate market returns from the prepaid amount attributed to the Company's contributions from that attributable to customer contributions, is not sufficient reason to exclude the prepaid pension asset from

[381] Ex. DOC-2 at 19 (Campbell Direct) ("The term "prepaid pension asset" describes the amount by which cumulative contributions to a pension trust exceed cumulative pension expense."); Ex. LPI-1 at 9 (Gorman Direct) ("With respect to the pension accounting that creates this PPA, Mr. Cutshall states that a PPA is created when the Company's cumulative cash contributions to the pension trust are in excess of the net annual benefit cost of the pension plan. I agree with Mr. Cutshall's PPA accounting description.").

[382] Ex. MP-23 at 56, Sch. 14 (showing the benefit to customers of Company contributions to the pension fund), and Schedule 15 at 20 (showing how the earned return on assets (EROA) reduces pension expense) (Cutshall Direct).

rate base. The entire prepaid pension asset that the Company seeks to include in rate base resulted from investor contributions.

258. Minnesota Power has also demonstrated that recovery of a return on these contributions will benefit the financial health of the Company's pension fund - an important benefit provided to Minnesota Power employees - and to establishing just and reasonable rates.

259. In sum, Minnesota Power's funding of the accumulated contributions in excess of net periodic pension costs (i.e., the prepaid pension asset) should be included in the working capital section of its rate base for several reasons:

(1) these costs are a necessary cost of providing electric service, which no party has disputed;

(2) a certain level of pension contribution is required by law to fund pension plans, and thus these costs are not discretionary;

(3) cumulative contributions to the pension plan in excess of cumulative pension expense are made by the Company's shareholders and benefit customers by lowering expenses[383] and lowering liabilities;

(4) there is precedent in Minnesota and nationwide for including accumulated contributions in excess of net periodic pension costs in rate base, and many other states have also recognized that a return on this asset is legally required to compensate shareholders for pension funds contributed in excess of amounts included in rates; and

(5) doing so is consistent with standard ratemaking treatment when contributions and expenses differ significantly for any cost of providing utility service, such as with other prepaid amounts.[384]

260. The Judge finds that the record supports that it is both reasonable and necessary to include the Company's request for inclusion of the prepaid pension asset in rate base, net of ADIT, in the amount of $43,705,383 (MN Jurisdictional).

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[383] *See id.*, Sch. 3.
[384] Ex. MP-22 at 65 (Cutshall Direct).

2. Prepaid Other Post-Employment Benefits (OPEB) Assets

a. Background on OPEB Funding

261. ALLETE has two main types of other post-employment benefit (OPEB) plans and ALLETE's OPEB expense reflects employees' post-employment (retirement) medical, dental, and life benefits.[385] ALLETE's 2022 test year OPEB expense is negative $8,409,933 (negative $6,173,505 MP regulated; negative $5,488,944 MN Jurisdictional). For clarity, a negative expense is treated as income.[386]

262. ALLETE's OPEB was an expense from its inception in 1996 through 2012. Then — primarily due to benefit reductions and $145 million of company contributions — the OPEB expense turned to a benefit in 2013. It has remained a negative expense through 2021.[387] The OPEB benefit has been negative since 2013 because Minnesota Power has funded its OPEB plans at the expense level. Minnesota Power's customers have benefitted from negative OPEB expenses since 2013. The negative OPEB expenses have served to both reduce the Company's revenue requirement and provide well-earned benefits to retirees. This negative expense situation is likely to continue in future years.[388]

263. In contrast to pension funding, there is no legal mandate to fund OPEB plans. Utilities have typically funded their OPEB plans as mandated or agreed upon by their governing commissions. On June 27, 2012, the Company requested the ability to determine on an annual basis whether to fund its OPEB trust obligations.[389] The Commission denied this request.[390] One of the reasons for the denial was that the "request would appear to defeat the trust account's purpose, which is to ensure that funds are available to pay benefits when they are due."[391] As with pension funding, by making contributions to the OPEB fund, investors are providing an assurance of future payments of these obligations and reducing annual expense amounts. For test year 2022, the Company's actuary projected that the earnings on these funds will reduce ALLETE's OPEB expense by $9.5 million ($6.2 million MN Jurisdictional).[392]

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[385] Ex. MP-23 at 84-85 (Cutshall Direct).
[386] *Id.* at 85.
[387] *Id.*
[388] *Id.* at 86.
[389] In re Minn. Power's Petition for Approval of Deferred Accounting Related to Pension Plan Contributions and Expenses, MPUC Docket No. E-015/M-11-1264, Reply Comments (Jun. 27, 2012).
[390] In the Matter of Minn. Power's Petition for Approval of Deferred Accounting Related to Pension Plan Contributions and Expenses, Docket No. E-015/M-11-1264, Order Denying Petition (Mar. 11, 2013).
[391] *Id.* at 2.
[392] Ex. MP-23 at 88 (Cutshall Direct).

b. Return on Prepaid OPEB Asset

264. Similar to the pension, the Company requests that the 13-month average of its 2022 test year OPEB plan accumulated contributions in excess of net periodic benefit cost of $19,466,438 (MN Jurisdictional) be included in the working capital section of rate base.[393] This would result in a net increase to rate base of $13,018,104 (MN Jurisdictional) for accumulated contributions, net of ADIT.[394] The ADIT applied to the accumulated contributions in excess of net period benefit cost equals $6,448,334 (MN Jurisdictional) ($7,355,711 Total Company) and consists of $19,466,438 computed at the statutory tax rate of 28.742 percent, plus excess deferred tax of $853,290. The excess deferred tax is a result of the corporate income tax rate change in the Tax Cuts and Jobs Act (TCJA). The net increase, or $13,018,104 (MN Jurisdictional), is the amount on which the Company seeks to earn a return. In other words, Minnesota Power asks to treat these accumulated contributions in the same manner as any other working capital item — all of which similarly fluctuate.[395]

265. The Department argued that the Company has not demonstrated the reasonableness of including a prepaid OPEB asset in rate base, such that it should be removed from the test year amount.[396] As with the Company's prepaid pension asset, the Department reasoned that because customers have already paid for OPEB expense in rates, it is unreasonable to require them to also pay for a return on the prepaid OPEB asset.[397]

266. As with the Company's prepaid pension asset, according to the Company, the Company has a prepaid OPEB asset because the Company has accumulated contributions in excess of net periodic benefit cost OPEB asset because it has contributed more to the OPEB plans than it has expensed since the inception of the plans. The Company highlighted that this is true even when OPEB expense is negative, as has been the case since 2013.[398]

267. As with the prepaid pension asset, the Company stated that it cannot withdraw assets from the OPEB plans other than to pay benefits or plan expenses. According to the Company, this is because the funds are held in a Voluntary Employees Beneficiary Association (VEBA) trust, which is a separate entity from the employer. A 100 percent excise tax is imposed on any funds that reverts back to the employer. Consequently, it is impractical for Minnesota Power to use OPEB assets for anything other than qualified benefits.[399]

268. Minnesota Power argued that it is just and reasonable for customers to pay for a return on Minnesota Power's prepaid OPEB assets because these funds are

[393] *Id.*, Sch. 17.
[394] *Id.* at 94.
[395] *Id.*; Ex. MP-24 at 51 (Cutshall Rebuttal).
[396] Ex. DOC-2 at 28-32 (Campbell Direct).
[397] *Id.* at 31.
[398] Ex. MP-23 at 95 (Cutshall Direct).
[399] *Id.* at 96.

shareholder-supplied funds that are used and useful in utility service. If the Company, through customer rates, funds the expense and the expense is negative, funds should be withdrawn from the OPEB or Voluntary Employees' Beneficiary Association (VEBA) trust to pay the customer (through reduced rates). This would avoid having an asset due to accumulated contributions in excess of net periodic benefit cost asset. Yet, customer rates are not the only consideration in the law. If the Company were to withdraw funds from the VEBA to lower rates tax penalties would be incurred. Consequently, the Company (investors) pays the negative expense to the customers, to avoid the 100 percent excise tax.[400] Thus, the VEBA will continue to have a prepaid OPEB asset, which is expected to grow.

269. As the Company testified, the prepaid OPEB asset is the amount the VEBA owes the Company because the Company paid the negative expense to the customer rather than the VEBA paying the negative expense to the customer. All the earnings on this prepaid OPEB asset will benefit customers by decreasing the OPEB expense. In contrast, the investors' funds are tied up in the VEBA not earning a return until the prepaid OPEB asset balance is at, or below zero, or the VEBA is no longer in existence, which will likely be many decades in the future.[401]

270. The Department also argued that the Company should not recover on its prepaid OPEB asset because the contributions or funds are not investor-supplied funds. As it reasons, annual market returns on the OPEB trust are reinvested into the plan assets, and accumulated earnings on the overall plan asset are included in the actuarially calculated OPEB expense.[402]

271. The Department's position is incorrect. The customer funds the expense, and this level of expense already incorporates all earnings on the trust. Greater earning are remitted to the customer through reduced rates. As the Company illustrated, this can be seen in that a negative expense has already been embedded into rates since 2016 and is the reason the 2022 test year OPEB expense is a negative $5,488,944 (MN Jurisdictional). Because the cash from the earnings cannot be withdrawn, the contributions (or the Company's investment) part of the prepaid OPEB asset remain invested in the plan. Investor-supplied funds that cannot be used by shareholders, and which benefit customers by lowering future rates, should be eligible for a reasonable return.[403]

272. The Department also alleged that the prepaid OPEB assets are temporary and different from typical rate base assets for which the Company is allowed to earn a return on investment.[404]

273. The record, however, does not support the Department's argument. First, temporary assets/liabilities are not GAAP defined terms, as confirmed by the Department

[400] *Id.*
[401] *Id.* at 97.
[402] Ex. DOC-2 at 31-32 (Campbell Direct).
[403] Ex. MP-24 at 47 (Cutshall Rebuttal).
[404] Ex. DOC-2 at 31-32 (Campbell Direct).

in its response to DOC Information Request (IR) 15.[405] Second, the prepaid OPEB asset has been in existence for over three decades. Finally, any utility asset supporting the provision of utility service should be included in rate base.[406]

274. Similar to LPI's arguments with respect to the prepaid pension asset, LPI alleged the negative expense and not the shareholder contribution are creating the OPEB asset, but this is not possible.[407] Minnesota Power stated that it is mandated to contribute the OPEB expense each year.[408] Mathematically, the prepaid OPEB asset equals cumulative contributions minus cumulative expense. When the OPEB expense becomes negative, this means the contributions should be negative (meaning the trust should give cash back to the Company). The funds cannot, however, be withdrawn from the VEBA trust without 100 percent excise tax penalties. Therefore, it is the cumulative contributions that are remaining stable while cumulative expense continues to decrease that is creating the prepaid OPEB asset. This is occurring because funds are being taken from ALLETE to pay customers the negative expense instead of being removed from the trust.[409]

c. Customer Benefits

275. Since the fund's creation, the Company testified that it has honored its obligation to fund OPEB expense. This can be seen in Figure , below, by the cumulative contributions line (circles line) and cumulative expense line (squares line), which closely mirror each other until 2013 when the two begin to diverge. Until that time, Minnesota Power was mandated to fund expense and the customer rates were set at the expense level, so that expense was basically a pass-through obligation. However, when the contributions could no longer follow the expense (because it was negative), plus the Company could not withdraw the negative expense due to the nature of a VEBA trust holding assets for employees, the prepaid OPEB asset was created and began growing. As a result, the Company illustrated that assets in the trust that cannot be removed are creating earnings that flow back through to the customer allowing the customer to benefit at the expense of the Company and its shareholders.[410]

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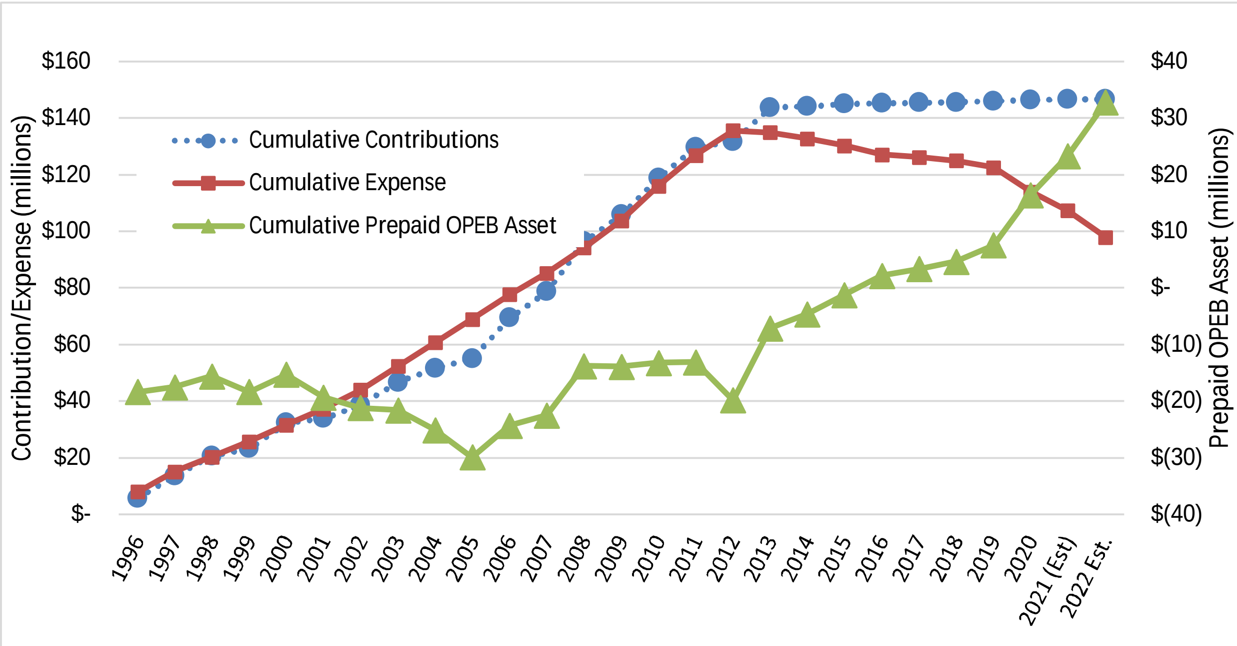
405 Ex. MP-24 at 48, Sch. 8 (Cutshall Rebuttal).
406 *Id.* at 48.
407 Ex. LPI-1 at 20 (Gorman Direct).
408 Ex. MP-24 at 87 (Cutshall Rebuttal).
409 *Id.* at 48-49.
410 *Id.* at 47-50.

Figure 7. ALLETE Cumulative OPEB Activity



d. Potential Outcomes for Prepaid OPEB Asset

276. The Company testified that there are two options to solve the problem of this growing prepaid OPEB asset issue. First, since there are no federal laws and regulations requiring ALLETE to fund the OPEB asset, the Commission could allow the Company to set the recoverable OPEB expense at zero when the expense is calculated as negative.[411] This may be better for customers because it is less risky.

277. The second and most common way commissions handle this issue is to allow the prepaid assets to be placed into rate base; therefore, customers are compensating the shareholders for the use of shareholder-invested funds that support the utility employees who serve customers.[412]

[411] *Id.* at 50. The customer then will neither pay nor receive funds for the OPEB. This will help stop the divergence of the cumulative expense line and the cumulative contributions line.
[412] *Id.*

e. Including the OPEB Asset in Rate Base - Recommendation

278. The Judge finds that denying compensation to shareholders for this use of their money negatively impacts Minnesota Power's financial ratios and was identified by the credit rating agencies as a contributor to Minnesota Power's negative outlook.

279. The Judge finds that denial of a return on the OPEB accumulated contributions in excess of net periodic benefit cost asset precludes the Company from a reasonable opportunity to recover its cost of service and earn its authorized rate of return.

280. The Judge finds that the record supports the Company's request for inclusion of the prepaid OPEB asset in rate base, net of ADIT and would be reasonable for ratemaking purposes.

3. Transmission Capital Project – Beginning of Year Balance

281. An essential component of the rate case calculations is the Company's "plant in service." Plant in service is the cost of the facilities and equipment available and reasonably necessary to provide service. Because the amount of plant in service changes during the test year as the Company as facilities are built or retired, plant in service for the test year is measured by taking the average of two data points: (i) the original cost, depreciated, as of the beginning of the test year (for the 2022 test year, this is the balance as of December 31, 2021) and (ii) the original cost, depreciated, as of the end of the test year (December 31, 2022).[413]

282. Because the rate case filing was submitted before the end of 2021, both beginning- and end-year balances were based on the Company's projections. The Company's projected total plant in service as of the beginning of the 2022 test year was $4,717,517,963 Total Company ($4,088,588,848 MN Jurisdictional); after subtracting depreciation and amortization and adding construction work in progress (CWIP), the Company's projected utility plant as of the beginning of the 2022 test year was $3,118,957,054 Total Company ($2,693,434,132 MN Jurisdictional).[414]

283. To support these projections, the Company provided a detailed explanation of its projected capital investments in 2021 and 2022.[415] The Company explained that it is sometimes necessary to adjust the capital portfolio to respond to changing circumstances; this can even include substituting projects for one another.[416] In particular, the Company maintains that it was experiencing unprecedented uncertainty in the timing of capital projects because of supply chain unpredictability and related issues.[417] Even

[413] Ex. MP-53 at 5 (Turner Direct); *see also* Ex. DOC-4 at 14 (Soderbeck Direct).
[414] Ex. DOC-4, HCS-D-6 at 4-5 (Soderbeck Direct).
[415] *See generally* Ex. MP-42 (Gunderson Direct).
[416] *Id.* at 9-10.
[417] *Id.* at 8.

so, as of the filing of the rate case, the Company was on track to place all capital projects identified in the 2022 test year budget in service in 2022.[418]

284. The Department noted that the Company's actual total plant in service as of the beginning of the 2022 test year was approximately $15.6 million lower than what the Company had projected.[419] The Department identified several projects that were not put in service as projected for 2021, but were moved to 2022.[420] The Department also expressed concern that the Company might not be able to complete the planned 2022 capital additions in 2022.[421] As a result, the Department recommended reducing (i) the utility plant balance as of the beginning of the test year by about $3.5 million to the actual utility plant balance as of December 31, 2021, and (ii) the utility plant balance as of the end of the test year by the same amount.[422]

285. In Rebuttal Testimony, the Company explained why the Department's proposed adjustments were unfounded. First, the Department's recommended adjustment to the test year plant balance was illogically unidirectional: it ignored the fact that the ending test year balance would likely increase (not decrease as the Department assumed) because of increases in labor and materials prices in 2022.[423]

286. Second, the Department did not acknowledge that while the beginning test year balance had been lower than projected, all 2021 projects were on track for completion in 2022. Further, all 2022 projects were on track for completion in 2022, and many were trending above budgeted amounts due to supply chain and procurement environments.[424]

287. Third, the Department's assumptions further failed to recognize that due in part to its northern Minnesota location, and due in part to accounting reasons, the vast majority of the Company's plant additions are placed into service in the third and fourth quarter of the year. This is not abnormal for the Company.[425] The Company testified that it was ahead of the schedule contemplated in its original filing.[426]

288. Finally, the Department's assumption that depreciation and amortization expense would decrease does not appear correct based on the record: the actual expenses were higher than projected.[427] Thus, the overall 2022 test year plant in service

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[418] *Id.* at 10.
[419] Ex. DOC-4 at 14 n. 31 (Soderbeck Direct). This was a very negligible difference: $15.6 million is only about 0.3 percent of the Company's total plant in service.
[420] *Id.* at 15.
[421] *Id.* at 21-22.
[422] *Id.* at 16, 22. Also, recognizing that the movement of a capital addition from plant in service to CWIP can affect certain expenses on the income statement, the Department assumed that the Company's test year depreciation expense would decrease, and it recommended estimated reductions in expenses of $332,863 and $356,695. *Id.* at 18, 23.
[423] Ex. MP-43 at 3 (Gunderson Rebuttal).
[424] *See* Ex. DOC-4, HCS-D-4 (Soderbeck Direct); Ex. MP-43 at 6-7 (Gunderson Rebuttal).
[425] Ex. MP-43 at 5 (Gunderson Rebuttal).
[426] *Id.* at 7
[427] *Id.* at 4, 8.

amount in rate base included in the Company's initial filing remained a reasonable and representative amount for the test year.

289. While the Department dropped its recommended reduction to the ending test year plant balance, the Department increased its proposed adjustment for the beginning test year plant balance from about $3.5 million to about $6,657,334 Total Company ($6,690,538 MN Jurisdictional).[428] Because the test year balance is an average of the beginning balance and the year-end balance, the Department's revised recommendation has nearly the same effect as its original proposal—both proposals reduce the test year plant balance by well over $3 million.[429]

290. The Judge finds that the Company has provided comprehensive evidence concerning its capital additions during the test year. While the beginning test year plant in service amount is lower than initial projections, the ending test year plant in service amount is on track to well exceed initial projections, and the overall average amount proposed by the Company remains reasonable and supported by evidence. Therefore, the Judge recommends rejection of the Department's proposed adjustment.

4. Taconite Harbor Energy Center

291. Taconite Harbor Energy Center (THEC) is a coal-fired generation unit located on the North Shore of Lake Superior near Schroeder, Minnesota.[430] THEC originally had three coal-fired units and an output capability of 225 MW.[431] Minnesota Power ceased coal-fired generation at THEC Unit 3 in 2015, and the unit was retired in place. THEC Unit 1 and Unit 2 were idled in the fall of 2016 with Commission approval.[432]

292. After investigating several options for THEC over the intervening years, the Company anticipated that retirement in 2021 would be appropriate, while maintaining the depreciable life of THEC until 2026 to reduce costs for customers. Minnesota Power submitted a request to retire THEC Units 1 and 2 no later than September 2021, before the end of the facility's Commission approved operating life, to the Commission as part of Minnesota Power's Preferred Plan in its 2021 IRP filed on February 1, 2021 (Docket No. E015/RP-21-33).

293. Minnesota Power has annually offered Unit No. 1 and Unit No. 2 every year between 2015-16 and 2020-21 during the Midcontinent Independent System Operator's (MISO) annual capacity auction, but the units have not been selected for use.[433]

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[428] Ex. DOC-5 at 2, 23-25 (Soderbeck Surrebuttal).
[429] *Id.* at 29-30 (describing averaging effect).
[430] Ex. MP-40 at 33 (Simmons Direct).
[431] *Id.*
[432] *Id.*; Ex. MP-41 at 10 (Simmons Rebuttal).
[433] Ex. DOC-3, NAC-S-7 at 1–2 (Campbell Surrebuttal). A capacity market is a mechanism to provide revenue to a power plant owner to stand ready to supply power when needed. Utilities submit capacity offers. MISO then selects offers starting with the lowest price offers until it meets its demand needs. All selected offers then receive highest price selected.

294. Utility property is only "used and useful" when it "(1) is 'in service'; and (2) is 'reasonably necessary to the efficient and reliable provision of utility service.'"[434] Only property that is "used and useful" may be included in the company's test year rate base.[435] Minnesota Power has been meeting customer needs without Taconite Harbor for the last five or six years and the company will not use Taconite Harbor to provide electricity to customers in 2022.

295. The Department and LPI suggest test-year adjustments for the THEC. The Department recommends adjustments to remove $29.5 million from average rate base and to remove $597,647 Total Company ($518,822 MN Jurisdictional) of O&M expense, on the grounds THEC is no longer used and useful. LPI also recommends that the Commission deny recovery of THEC as it is not "used and useful." However, if the Commission approves a rate of return on the THEC plant costs, then LPI witness Mr. Gorman proposed an adjustment of $1.3 million Total Company ($1.1 million MN Jurisdictional) to the 2022 test year to reflect levelized cost recovery of THEC.[436]

296. At this time, THEC Units 1 and 2 are idle but not retired.[437] The regulatory review process for the 2021 IRP has been prolonged as a result of several extensions to the timeline. Stakeholder Initial Comments did not raise any objection with Minnesota Power's proposed retirement timing for THEC Units Nos. 1 and 2.[438] Due to extensions to comment deadlines in this docket, the Commission has not yet taken action on the Company's request to retire the remaining two units.[439]

297. Mindful of the strong community support for moves away from coal-fired generation, Commission direction to terminate all operations at THEC is likely.[440] Going back to Minnesota Power's 2010 IRP (Docket No. E015/RP-09-1088), the Commission directed the Company to conduct a "continue-to-operate and a shut-down cost analysis" for THEC, including "specific plans for shutting down the . . . Taconite Harbor units in the near future."[441] In its November 12, 2013, Order in Minnesota Power's 2013 IRP (Docket

[434] In re N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn., Docket No. E002/GR-12-961, MPUC FINDINGS OF FACT, CONCLUSIONS, & ORDER at 46 (Sept. 3, 2013) (accepting the ALJ report except as expressly modified); In re N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn., Docket No. E002/GR-12-961, OAH FINDINGS OF FACT, CONCLUSIONS, & ORDER at 23 (July 3, 2013) (citing Senior Citizens Coalition of Northern Minnesota v. MPUC, 355 N.W.2d 295 (Minn. 1984)).
[435] *Id.*
[436] Ex. LPI-1 at 45 (Gorman Direct).
[437] Ex. MP-41 at 10 (Simmons Rebuttal).
[438] *Id*.
[439] *Id.*
[440] *Id.* at 11.
[441] *In re Minnesota Power's 2010-2024 Integrated Res. Plan*, MPUC Docket No. E-015/RP-09-1088, Order Accepting Resource Plan and Requiring Compliance Filings at 5 (May 6, 2011).

No. E015/RP-13-53), the Commission also required the Company to include an analysis of the effects of retiring the remaining THEC generating units in its next IRP.[442]

298. Even though the THEC Units 1 and 2 are not retired, activities at THEC are ongoing and activities to support the environmental compliance activities at the site are included in the 2022 test year O&M budget.[443]

299. The Company continues to maintain the THEC facility as safely and cost effectively as is prudent for a site that is awaiting a retirement decision.[444] During these first few months of 2022, activities at the site include water disposal, ash cell ground water monitoring, asbestos removal, and plowing due to accessibility needs.[445] Internal and external labor expenses include dust control, road maintenance, erosion remediation, electrical needs for the ash cell area, and a variety of leachate disposal and hauling costs along with solid waste and ground water sampling.[446] Periodic inspections are also done to ensure the facility is safe for employees and contracting partners to enter while completing the compliance tasks.[447]

300. The Company is preserving the station in the event the Commission does not approve the facilities' retirement as proposed in the Company's 2021 IRP. Minnesota Power is investigating alternative redevelopment options for the site as well as potential uses for surrounding lands, including new economic and community development that would make use of existing infrastructure.[448]

301. The Judge finds that that while the THEC is idled and has ongoing activities for compliance and safety, the core issue based on prior Commission decision-making is whether the THEC facility is "used and useful" during the 2022 test year. There is no dispute that the facility will not provide service to customers in 2022. Further, there is record evidence demonstrating that THEC has not provided service to customers in at least five years. As such, the Judge finds that THEC is not "necessary" for efficient and reliable provision of utility service and, as result, should be removed from rate base.

302. The Judge recommends that the Commission (1) find Taconite Harbor is not used and useful for the 2022 test year and, therefore, deny Minnesota Power's request to earn a return on it; (2) authorize Minnesota Power to recover its depreciation

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[442] *In re Minnesota Power's 2013-2027 Integrated Res. Plan*, MPUC Docket No. E015/RP-13-53, Order Approving Resource Plan, requiring Filings, and Setting Date for Next Resource Plan at 6 (Nov. 12, 2013). The Commission specifically stated the following in its 2013 order:

The Commission agrees with the Department's analysis and conclusion that the most reasonable plan does not require that [THEC Units 1 and 2] be retired at this time. However, the Commission recognizes that in a number of possible future scenarios, retiring those units is likely to be part of a least-cost plan.

[443] Ex. MP-41 at 13-14 (Simmons Rebuttal).

[444] *Id.* at 14.

[445] *Id.*

[446] *Id.*, Sch. 2.

[447] *Id.*

[448] *Id.* at 10; Ex. MP-40 at 34 (Simmons Direct).

expense through December 31, 2026; and (3) allow recovery of O&M, property tax, and property insurance costs until decommissioning begins.[449]

5. Bad Debt Expense

303. Bad debt expense consists of funds owed by customers that are deemed to be uncollectible for already rendered utility service.[450] The level of bad debt expense included in utility rates is typically estimated for the utility test year using a representative timeframe to arrive at an average.[451] The Department and the Company agree that only a representative bad debt amount should be included in the 2022 test year. The Department and the Company disagree about how to determine the representative amount.[452]

304. Because recent bad debt expense levels in 2019, 2020, and 2021 were influenced by atypical conditions, Minnesota Power recommended a bad debt expense based upon the five-year average from more typical years in 2014 through 2018 and applied a 50 percent increase to account for high arrears accumulated during the COVID-19 pandemic.[453] The result is a proposed test year bad debt expense of $1,255,608.[454]

305. The Department suggested the Company's reference period is unreasonable because it uses information that is more than five years old and includes a 50 percent upward adjustment to the average. The Department instead recommended using a four-year average of 2018 to 2021, or $771,130, resulting in a downward adjustment of $484,478 from Minnesota Power's proposed test year bad debt expense of $1,255,608.[455] In Surrebuttal Testimony, the Department recommended a downward adjustment of $480,505, after applying a MN Jurisdictional allocator of 99.18 percent.[456]

306. Recent factors and events were reflected in the Company's projected bad debt expense. With the significant uncertainty around collectability of arrears that are approximately double the level of a typical year, largely due to the ordered protections for residential customers during the COVID-19 pandemic that spanned over two years, Minnesota Power anticipates higher bad debt expense than observed historical actuals. Further, Minnesota Power and other utilities have been urged by the Commission and various consumer advocates to extend longer-duration payment agreements to residential customers who have arrears. These protections and payment agreements have spanned two Cold Weather Rule periods and balances are likely to span a third.[457]

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[449] Ex. DOC-3 at 83–84 (Campbell Surrebuttal).
[450] Ex. MP-32 at 25 (Frederickson Rebuttal).
[451] *Id.*
[452] Ex. MP-32 at 26–27 (Fredrickson Rebuttal); Ex. DOC-3 at 10 (Campbell Surrebuttal).
[453] Ex. MP-32 at 25-26.
[454] *Id.* at 26.
[455] Ex. DOC-2 at 4-6 (Campbell Direct).
[456] Ex. DOC-3 at 7-8 (Campbell Surrebuttal); Ex. MP-55 at 9 (Turner Rebuttal).
[457] *Id.*

307. Considering all of these factors, Minnesota Power continues to recommend using a five-year average based on a reference period of 2014 to 2018 and applying a 50 percent increase to that average to result in a 2022 test year bad debt expense level of $1,255,608. This is a conservative increase given where arrears balances currently stand and given the reality that the majority of arrears are with residential customer accounts, many of which have been excluded from standard credit and collections processes for over two years. Furthermore, Minnesota Power's actual bad debt expense has exceeded the Department's recommended amount of $771,130 in three of the five reference years, none of which involved the significant events endured since early 2020.[458]

308. The Judge finds that using data from 2014-18 is unlikely to be any more representative of the company's 2022 bad debt expense than the 2018-21 data. In addition, Minnesota Power did not explain how it developed its proposed 50 percent increase factor, or why a 50 percent adjustment would be more reasonable than a different percentage adjustment.[459] Applying a 50 percent adjustment is also inconsistent with Minnesota Power's decision to use 2014-18 data. The Company used older data to avoid the impact of the ongoing COVID-19 pandemic, but then applied the 50 pe increase to account for the pandemic's impact.[460] The Judge finds the Company's approach to be speculative at best.

309. The Judge finds the Department's proposed approach of using a four-year average of recent actuals from 2018-21 is more appropriate than the Company's approach. The Department's approach uses more recent data which is more likely to be representative of customer behavior and relevant economic conditions. It also avoids reliance on an unsupported adjustment factor as Minnesota Power's proposal does. As a result, the Commission should set Minnesota Power's bad debt expense for the 2022 test year at $771,000. This results in an approximately $484,000 adjustment to the company's proposal of about $1,255,000.[461]

6. Employee Count and Compensation

310. To continue providing safe, reliable, and cost-effective electricity, and deliver 100 percent carbon-free electricity by 2050, Minnesota Power needs to ensure that it has a skilled workforce. To attract and maintain this skilled workforce, its compensation and benefits to its employees must remain market-competitive. The Company uses market surveys and similar resources to ensure that the compensation and benefits it offers are market-competitive and reasonable.[462]

311. Minnesota Power's budget for the 2022 test year contemplates 1,063 full-time and part-time employees as of year-end 2022.[463] The Company recognized it was

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[458] *Id.*
[459] DOC Initial Br. at 29; Ex. DOC-3 at 9–10 (Campbell Surrebuttal).
[460] DOC Initial Br. at 29.
[461] Ex. DOC-2 at 6 (Campbell Direct); Ex. DOC-3 at 7–8 (Campbell Surrebuttal).
[462] Ex. MP-44 at 6-7, 32 (Krollman Direct).
[463] Ex. MP-46 at 2 (Krollman Rebuttal).

not possible to increase employee headcount from the year-end 2021 count of 999 employees to 1,063 employees over a short timeframe; instead, the Company budgeted the increase to occur gradually—about five employees a month—throughout 2022.[464] As of the end of May 2022, the Company was on track to meet its 2022 test year headcount, adding employees at this pace: it had 1,024 employees, plus about 15 employees about to start or in pre-screening.[465]

312. The Company's overall number of employees decreased significantly from January 2017 to the 2022 test year, for three reasons: changes in the Company's portfolio of generation resources; the effects of the 2016 Rate Case, which required the Company to undertake significant cost-cutting; and the COVID-19 pandemic.[466] As a result, during 2020 and 2021, the Company was below its budgeted headcount, which stretched employees in a way that is not sustainable over the near-term.[467] The Company undertook a comprehensive workforce review, and it has been engaged in a broad array of efforts and initiatives to recruit and retain employees.[468]

313. The Company's staffing levels have been below the budgeted head count in each of the last five years, with an average understaffing level of around 23 employees.[469] Between 2018 and 2021, the Company over-collected on employment expense by an average of approximately $15 million compared to the 2017 test year.[470]

314. The total cash compensation, for both bargaining unit and non-bargaining unit employees, including Spot Bonuses, that the Company requests for the 2022 test year is $68,437,774 Total Company ($60,806,765 MN Jurisdictional).[471] This figure is based on a total headcount (full-time and part-time, but not temporary staff or interns) of 1,063 employees as of the 2022 test year year-end.[472]

315. Minnesota Power is obtaining at least 11 percent more electricity for its customers via wholesale contracts with third parties than it was in 2017.[473] The company also is generating 33 percent less electricity using its own facilities and retired the labor-intensive coal-fire Boswell Energy Center in Cohasset, since 2017.[474] The openings for which the Company is hiring in 2022, however, are not only at generation facilities, but are in areas such as finance, accounting, and cybersecurity.[475]

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[464] *Id.*
[465] Tr. Vol. 1 at 201 (Krollman); *see also* Ex. MP-46 at 2 (Krollman Rebuttal) (describing how the Company was on pace as of the end of April 2022).
[466] *Id.* at 3-4, 19-22.
[467] Ex. MP-46 at 7 (Krollman Rebuttal).
[468] Ex. MP-44 at 1-14 (Krollman Direct).
[469] Ex. LPI-1 at 23 (Gorman Direct) (the calculation of the average is based upon adding the totals in the difference column of Table 3 and dividing by five).
[470] Department Initial Br. at 35; Ex. DOC-2 at 8 (Campbell Direct).
[471] Ex. MP-44 at 17 (Krollman Direct).
[472] *Id.*
[473] Ex. DOC-2, NAC-D-3 at 2 (Campbell Direct).
[474] Ex. DOC-2 at 10, NAC-D-3 at 2 (Campbell Direct).
[475] *Id.* at 5.

316. Given Minnesota Power is using less labor-intensive resources, the Department and LPI argue that it would be reasonable for the company's workforce to follow these same general trends and recommended that Minnesota Power's 2022 test year compensation expense be set at a 2021 actual spending levels plus a three percent increase to account for inflation anticipated by the company.[476]

317. The Company's 2022 test year budget for total employee compensation and benefits already reflects an overall reduction of approximately $10.6 million Total Company ($8.4 million MN Jurisdictional) as compared to the 2017 actuals. This approach demonstrates that the Company is seeking to right-size its employee expenses in the 2022 test year while also seeking balancing in the other areas that have experienced under-recovery in recent years.[477]

318. The Department's recommendation does not account for additional employees that the Company has identified are necessary for continued operations and does not reflect the market for wage and salary increases.[478] The U.S. Bureau of Labor Statistics identified that consumer prices rose 8.5 percent year-over-year in March 2022.[479] The Department's recommendation does not keep up with year-over-year inflation. The ability for the Company to continue to retain and attract qualified employees while not recognizing these significant market changes would undermine the Company's competitiveness as an employer.[480]

319. LPI also argued that the Company's proposed headcount for the 2022 test year was too high.[481] LPI asserts that because the Company has had challenges hiring in the past, it will be unable to hire the budgeted number of employees.[482] But to date in 2022, the Company is on track to hire the required number of employees, even with the pressures in the labor market that have followed the COVID-19 pandemic.[483]

320. The Judge finds that the record supports the Company's proposed employee headcount and is reasonable for the purpose of determining a reasonable level of employee compensation.

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[476] Ex. DOC-3 at 14–15 (Campbell Surrebuttal).
[477] Ex. MP-46 11.
[478] *Id.* at 2-3; Tr. Vol. 1 at 192, 201 (Krollman) ("I do believe that we are on pace to hit head count as we demonstrated throughout 2020 to (sic) so far this year.").
[479] Ex. MP-46 at 9-10 (Krollman Rebuttal).
[480] *Id.* at 10.
[481] Ex. LPI-1 at 22 (Gorman Direct).
[482] *Id.*
[483] Ex. MP-46 at 2, 7 (Krollman Rebuttal); Tr. Vol. 1 at 201 (Krollman) (Ms. Krollman confirming that the Company is "on pace to continue to hit headcount" in the 2022 test year and that evaluation takes into account attrition.).

a. Base Compensation

321. The Company's Adjusted Test Year includes $68,384,774 (Total Company) of Employee Compensation Expense.[484]

322. The Department opposed the Company's budget for total cash compensation of $68.4 million, arguing that the Company has "over-recovered" on employee base compensation during the period covering 2017 through 2021. First, the Department proposed that the total compensation should be $62.8 million, the average of the Company's total compensation for 2018 to 2021.[485] In Surrebuttal Testimony, the Department revised its recommendation, and stated that the total compensation should be $64.8 million, the actual 2021 compensation expense plus a three percent inflation factor.[486]

323. The Department's use of a four-year average to establish the Company's employee base compensation does not take into account the Company's headcount needs, the downsizing the Company undertook during the averaging time period and the unforeseen global pandemic.[487] The Department's proposed increase for inflation also ignores the actual inflation and market conditions experienced by the Company, which demonstrate March 2022 year-over-year inflation of 8.5 percent and market increases of at least 4.5 percent to base compensation.[488]

324. The Judge finds that the record supports the Company's proposed level of base compensation and is reasonable for setting rates.

b. High Performance Awards Expense

325. High Performance Awards are performance-based pay that are designed to reward the top ten percent of non-bargaining unit, non-management employees, who have exhibited exceptional performance. The performance must contribute in a material way to achievement of ALLETE's strategic goals.[489]

326. The Company's 2022 test year budget includes $350,880 (Total Company) for High Performance Awards expense.[490]

327. The Department did not challenge recoverability of High Performance Awards, but argued that the 2022 test year amount for High Performance Awards should be based on the average of the Company's actual High Performance Awards expenses for 2018 to 2021.[491]

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[484] Ex. MP-55 at 10 (Turner Rebuttal).
[485] Ex. DOC-2 at 12 (Campbell Direct).
[486] Ex. DOC-3 at 15 (Campbell Surrebuttal).
[487] *Id.* at 9.
[488] *Id.* at 9-11.
[489] Ex. MP-44 at 28 (Krollman Direct).
[490] *Id.* at 29; Ex. MP-55 at 10 (Turner Rebuttal).
[491] Ex. DOC-2 at 13 (Campbell Direct).

328. But during 2018 to 2021, Company witness Ms. Krollman testified that the Company was understaffed and the COVID-19 pandemic affected headcount, causing actual High Performance Awards to be lower than anticipated.[492]

329. Use of an average from past years makes little sense where the past years are factually dissimilar from the test year. In addition, the budget for High Performance Awards is set as a percentage of total employee salaries—because the Company will have a higher employee count in 2022, and wages are increasing rapidly in 2022 because of macroeconomic factors, High Performance Awards should increase in a commensurate manner.[493]

330. High Performance Awards are essential to attracting and retaining qualified and talented employees.[494]

331. If High Performance Awards were arbitrarily reduced as the Department proposes, the Company would have to increase base compensation for non-bargaining, non-management employees so that it could remain market-competitive.[495]

332. The Judge finds that the test year reflects a reasonable level of High Performance Awards expense.

c. Defined Contribution Plan Expense

333. The Company's defined contribution plan (DC Plan) has features of both an employee stock ownership plan and a 401(k)-retirement savings account. It covers both non-bargaining unit and bargaining unit employees.[496] The Company's contribution and contribution match vary, depending on when the employee was hired.[497] The Company's budget for the 2022 test year for the DC Plan costs is $6,828,196 Total Company.[498]

334. The Department argued that the 2022 test year amount for the Company's DC Plan costs should be based on the average of the Company's actual DC Plan expenses for 2018 to 2021, about $6.2 million.[499]

335. Using an average from 2018 to 2021 is not reasonable in this context, because the Company's employee count (which drives the DC Plan costs) during that period was not sustainable and is not representative of 2022 circumstances.[500] For

[492] Ex. MP-46 at 14 (Krollman Rebuttal).
[493] *Id.* at 15.
[494] *Id.* at 16.
[495] *Id.*
[496] Ex. MP-44 at 45 (Krollman Direct).
[497] *Id.* at 45-46.
[498] *Id.* at 46.
[499] Ex. DOC-2 at 13 (Campbell Direct).
[500] Ex. MP-46 at 20 (Krollman Rebuttal).

example, in 2022 (unlike 2018-2021), inflation is causing employees' wages to increase rapidly, which in turn causes the DC Plan costs to increase.[501]

336. In addition, the Company is continuing to transition from a defined benefit plan system to the DC Plan system.[502] As Minnesota Power undergoes attrition from employee retirements and other departures, generally the employees departing the Company are members of the defined benefit plan, while the replacements are eligible for only the DC Plan.[503] This factor alone accounts for at least $800,000 Total Company in the Company's DC Plan expense in 2022.[504]

337. The Department's four-year average does not take into account the changing plan design.[505]

338. The Administrative Law Judge finds that the test year reflects a reasonable level of DC Plan expense.

d. Health Care Plans Expense

339. The Department recommended that the Company's 2022 test year expense for health care plans should be set using the Company's average actual health care plan expenses from 2018 to 2021.[506]

340. The Company proposed that the amount for health care plans should be $7,963,722 Total Company; under the Department's averaged approach, the amount would be $7,474,761 Total Company.[507]

341. The Company's proposal is consistent with PricewaterhouseCoopers Health Research Institute's estimates of health care costs in the United States.[508]

342. Medical expenses in 2020 and 2021 were lower than expected because of the COVID-19 pandemic—executive orders and fear of infection caused people to not seek, or be unable to obtain, medical care other than care for COVID-19.[509]

343. In contrast, the Company testified that medical care expense is expected to increase in 2022, because of increased service availability, a reversion to prior health care habits, deferred care from 2020 and 2021, and increases in mental and behavioral health treatment.[510] Also, medical expenses are undergoing rapid inflation, and will be

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[501] *Id.*
[502] *Id.*
[503] *Id.*
[504] *Id.*
[505] *Id.*
[506] Ex. DOC-2 at 13 (Campbell Direct).
[507] Ex. MP-46 at 17 (Krollman Rebuttal); Ex. MP-55 at 12 (Turner Rebuttal).
[508] Ex. MP-44 at 39 (Krollman Direct); DOC Initial Br. at 32-33; Ex. DOC-2, NAC-D-2 at 2 (Campbell Direct).
[509] Ex. MP-46 at 17 (Krollman Rebuttal).
[510] *Id.*

higher in 2022 than they were in 2017-2020.[511] Perhaps most importantly, the Company's health care plan expense is driven substantially by its number of employees, which, as explained above, was at an unsustainably low number from 2017 to 2021.

344. The Administrative Law Judge finds that the test year reflects a reasonable level of health care plan expense.

7. FERC Accounts 923, 924, and 925

345. The Department recommended that FERC Accounts 923 (outside services expense) and 924 (property insurance) be set according to a four-year average and that FERC Account 925 (injuries and damages insurance) be set at a five percent increase above 2021 actual expense.[512]

346. The Company did not agree that the use of a four-year average in this case would result in a reasonable level of expenses for FERC Accounts 923 and 924. The arbitrary use of multi-year averages for setting test year expenses is not reasonable, especially given the anomalous nature of 2020.[513] Rather, the Company's 2022 test year O&M forecast is the best reflection of the anticipated O&M expenses for 2022 based on Minnesota Power's current expectations for operations and costs.[514] When creating the budget for the 2022 test year, the Company carefully considered system and Company needs, as well as known impacts, that multi-year averages (both in general but also any specifically that include 2020) proposed by the Department do not reasonably capture.[515] That is, incorporating a multi-year average would disconnect the amount of O&M to be collected through rates from the costs that Minnesota Power expects to experience.[516]

347. The Company did not agree that the Department's analysis comparing actual spending to recovery through base rates was sound. First, the Department's analysis assumed that retail sales during each year equal the approved test year forecast. Minnesota Power retail sales were lower, however, than the 2017 test year: on average 7.4 percent lower from 2017 through 2021.[517] This means that the Company did not actually recover all of the costs approved in the 2017 test year.[518] Second, the Department's argument overly simplified the ratemaking process, since it considers only one expense when in actuality the Commission approves an overall revenue requirement. The test year is meant to be representative of the Company's overall costs and required returns but may change in the future based on actuals. That is, cost savings in one area may be offset by increases in other areas, the timing lag of earning a return on prudent

[511] *Id.* at 18-19.
[512] Ex. DOC-1 at 16-26 (Miltich Direct).
[513] Ex. MP-29 at 26 (Rostollan Rebuttal).
[514] *Id.* at 27.
[515] *Id.* at 26.
[516] *Id.* at 27.
[517] *Id.* at 27, Table 1.
[518] *Id.*

capital additions subsequent to the test year, or lower revenue if sales are below levels assumed for the test year.[519]

a. Outside Services Expense (FERC Account 923)

348. The Company's Adjusted Test Year includes $9,220,139 (Total Company) of FERC Account 923 – Outside Services Employed expenses.[520]

349. The Department recommended adjusting FERC Account 923 expenses to the four-year average of 2018-2021 resulting in an adjustment to the 2022 test year of $848,214 (Total Company). The Department argued that actual "annual expenses have fluctuated up and down with no steady trend apparent" and that Minnesota Power "has not provided compelling rationale or substantive evidence to demonstrate that the extent of its requested increases . . . is justified."[521]

350. The Company considered its system and Company needs as well as known impacts, including consulting industry resources and its own experience in market trends, which the Department's four-year average does not account for.[522]

351. The Judge finds that the record supports the Company's forecasted FERC Account 923 expenses for Outside Services Employed. The Department's four-year average does not accurately account for these expenses forecasted to be incurred during the test year and to be reflected in rates going forward.

b. Property Insurance (FERC Account 924)

352. The Company's Adjusted Test Year includes $7,509,492 (Total Company) of FERC Account 924 – Property Insurance.[523]

353. The Department recommended an adjustment of $2,087,029 (Total Company to FERC Account 924 – Property Insurance amounts.[524] Similar to the Department's recommendation for FERC Account 923, Outside Services Employed, the Department's recommendation is based on a four-year average of 2018 – 2021. The Department argues that actual "annual expenses have fluctuated up and down with no steady trend apparent."[525]

354. The Department's proposed adjustment also results in a lower expense for the 2022 test year than the 2021 actual expense for property insurance. The Company's budget witness testified that it is reasonable to expect that property insurance premiums, assuming similar coverage and deductibles, will rise in the future, not decrease.

[519] *Id.* at 27.
[520] Ex. MP-55 at 20 (Turner Rebuttal).
[521] Ex. DOC-1 at 23 (Miltich Direct).
[522] Ex. MP-29 at 28 (Rostollan Rebuttal).
[523] *Id.*, Sch. 2 at 3.
[524] Ex. DOC-1 at 24 (Miltich Direct).
[525] *Id.* at 23-24.

Minnesota Power has budgeted for an increase in its property insurance premiums in 2022 compared to 2021 based on its recent history with property insurance premiums and expectations for continued premium increases. These projections are based upon actual conversations with insurance providers and brokers, resulting in the Company budgeting higher test year expense compared to 2021.[526]

355. The Judge finds the Company has demonstrated reasonable estimated trends in the insurance market which support the Company's budgeted level of FERC Account 924 – Property Insurance expense. It is reasonable for purposes of setting rates.

c. Injuries and Damages (FERC Account 925)

356. The primary expense included in FERC Account 925 is for insurance premiums, other than property insurance; such as excess liability, executive risk program (directors and officers, fiduciary, crime, etc.), and cyber liability insurance.[527]

357. For the 2022 test year, the Company proposes $3,463,097 (Total Company) in FERC Account 925 expenses.[528]

358. Compared to the Department's recommendations for FERC Accounts 923 and 924, which it recommends be set based on a four-year average, the Department recommended that FERC Account 925 expenses be set at 2021 actual expense plus a five percent increase.[529]

359. The Company testified that the Department's percentage is not grounded in actual industry information and would be an insufficient amount based on Minnesota Power's past experience and expectations for future rates. From 2019 to 2021, actual expenses for FERC Account 925 increased approximately eight percent on average, despite the Company's ongoing efforts to find market competitive insurance premiums. Indications for 2022 are 10 to 15 percent increases for excess liability from the Company's industry mutual insurance providers. These firms have largely shielded Minnesota Power from an even more difficult commercial market.[530]

360. The Company's Executive Risk insurance program was renewed on May 1, 2022, with an eight percent overall premium increase. Cyber liability renewal premiums with the Company's industry mutual insurers are now trending to follow the broader commercial market of 20 to 30 percent increases. Breach claims and social engineering losses across insurers' books in 2022 have impacted insurance rates. In addition, Risk Strategies forecasts a rate increase for liability insurance of five percent to ten percent for liability insurance and 30 percent or higher for cyber insurance in 2022. Taking these forecasts at the mid-point for liability insurance and the low end for cyber insurance would

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[526] Ex. MP-29 at 29-30 (Rostollan Rebuttal).
[527] *Id.* at 31.
[528] Ex. DOC-1 at 19, GJM-D-4 at 3 (Miltich Direct); Ex. MP-28, Sch. 2 at 3 (Rostollan Direct); Ex. MP-55 at 21-22 (Turner Rebuttal).
[529] Ex. MP-29 at 26 (Rostollan Rebuttal); Ex. DOC-1 at 24 (Miltich Direct).
[530] Ex. MP-29 at 31-32 (Rostollan Rebuttal).

alone increase Minnesota Power's rates by 15 percent over 2021 actuals. These data points highlight why the Department's proposal is not reasonable and should not be accepted.[531]

361. The Judge finds that the record supports the Company's proposed level of expense within FERC Account 925 and is reasonable for setting rates.

8. Dues and Memberships

362. The Company included costs associated with memberships and dues in its employee expenses for the test year. The Company argues the membership and dues amounts it included in its rate request each provide value to Minnesota Power's customers.[532]

363. During discovery, the Company discovered an error in the calculation of the Organizational Dues adjustment applied to the Adjusted Test Year. The Company incorporated the $1,086 decrease to O&M Expense – Other Administrative and General.[533] After accounting for the correction, the Adjusted Test Year includes $817,797 (Total Company) of Organizational Dues.[534]

364. Under Minnesota law, the Commission must not permit recovery of a utility's travel, entertainment, and related employee expenses, including "dues and expenses for memberships in organizations or clubs," if the Commission finds these expenses unreasonable and unnecessary for the provision of utility service.[535] The burden to establish reasonableness is on the utility.[536]

365. The Commission recently affirmed that, where a utility has not clearly established how membership dues connect to the provision of utility service or that service would be impaired without those dues, dues are not recoverable from ratepayers.[537]

366. The OAG argued that dues for four specific organizations were unreasonable and unnecessary for the provision of electric service in Minnesota. Specifically, the OAG recommended the following disallowances:

- $266,662 (Total Company) for Edison Electric Institute (EEI) dues;

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531 *Id.*
532 Ex. MP-28 at 39-40 (Rostollan Direct).
533 Ex. MP-55 at 7 (Turner Rebuttal).
534 *Id.* at 25.
535 Minn. Stat. § 216B.16, subd. 17.
536 *Id.* at subd. 4.
537 In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, MPUC Docket No. E-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 24–25 (Feb. 1, 2022).

- $55,000 (Total Company) for Western Coal Traffic League (Western Coal) dues;

- $29,981 (Total Company) for Minnesota Utility Investors (MUI) dues;

- $1,250 (Total Company) for American Gas Association (AGA) dues; and

- $67,655 (MN jurisdiction) to normalize the level of organizational dues in the Test Year.[538]

367. Because the OAG's recommendation to normalize the level of organizational dues was stated as a MN Jurisdictional figure, the Company re-calculated the OAG's recommended adjustment in Total Company dollars. After that adjustment, the grand total adjustment sought by the OAG is $441,498 (Total Company).[539]

368. In the Company's last rate case, the Commission approved inclusion of membership dues for EEI and Western Coal Traffic League, excluding the lobbying-related portion of dues as identified by the organizations on their invoices. The Company used the same method in this current case. The Commission found the non-lobbying portion of membership dues for EEI and the Western Coal Traffic League, as well as nine other organizations, to be "reasonable and necessary to the provision of utility service." [540]

369. For the reasons set forth below, the Judge recommends that the Commission disallow $31,231 (Total Company) for MUI and AGA. The Judge further recommends that the jurisdictional and total company amounts be recalculated based on these adjustments to the OAG recommendation.

a. Edison Electric Institute and Western Coal Traffic League Dues

370. EEI and Western Coal are both trade associations that engage in lobbying and related policy advocacy on behalf of their members. EEI "represents all U.S. investor-owned electric companies" while Western Coal "was founded to advocate the interests of consumers of western coal."[541]

371. On the invoices Minnesota Power receives from organizations such as EEI, the organization itself divides and clarifies dues used for lobbying expenses and dues that are unrelated to lobbying expenses. Employees make a good faith effort to ensure dues related to lobbying expenses are recorded to FERC Account 426.4 and are excluded from the test year. In addition, as part of the Company's review of employee expenses, it also looks for lobbying-related expenses and exclude these items when identified. The

[538] Ex. OAG-2 at 13 (Lee Surrebuttal).
[539] Ex. MP-55 at 25-26 (Turner Rebuttal).
[540] In re Application of Minnesota Power for Auth. to Increase Rates for Elec. Util. Serv. in Minn., MPUC Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 41 (Mar. 12, 2018).
[541] Ex. OAG-1 at 5 (Lee Direct).

Company does not audit or otherwise investigate the activities of these organizations.[542] Company witness Mr. Rostollan testified that the Company's method is consistent with Commission precedent.[543]

372. The OAG argued that EEI and Western Coal dues should be excluded from the test year because the Company failed to demonstrate that it had removed all lobbying-related amounts. The OAG contended that the Company had not shown that these organizations' self-reported lobbying percentages capture the full extent of their policy-advocacy efforts or that their non-lobbying activities benefit ratepayers.[544]

373. The OAG pointed to three regulatory developments since Minnesota Power's last rate case that it argued support giving these organizations' dues greater scrutiny. First, in 2019, the U.S. House Energy and Commerce Committee opened an investigation into the Utility Air Regulatory Group (UARG), an EEI-affiliated advocacy group that was involved in efforts to roll back air-quality regulations. This development prompted UARG's member utilities, including Minnesota Power, to withdraw their support and funding, and resulted in UARG disbanding.[545] While the Company has not expressly included UARG dues in the test year in this case, it has requested recovery of EEI dues, and EEI had funded UARG before the latter disbanded.[546] According to the OAG, this suggests that Minnesota Power's test year EEI dues continue to fund policy advocacy that does not benefit ratepayers.[547]

374. Second, in December 2021, the Federal Energy Regulatory Commission (FERC) opened an inquiry into the rate recoverability of industry association dues in response to a petition highlighting these groups' political activities.[548] While FERC has not yet made a final decision in that case, the OAG argued that this proceeding demonstrates that there is nationwide concern about the lack of transparency into the activities of trade associations, and specifically, whether these activities benefit ratepayers.[549]

375. Finally, in a June 2021 rate-case decision, the Kentucky Public Service Commission (KPSC) did not permit the utility to recover any EEI dues, reasoning that "[m]erely identifying a portion of costs incurred that a utility does not seek recovery of does not meet the threshold of reasonableness as to the remainder of expenses."[550]

376. Minnesota Power responded that (1) it had removed the lobbying costs identified by EEI and Western Coal,[551] (2) its membership in these organizations benefits

[542] Ex. OAG-1 at 5 (Lee Direct).
[543] *Id.* at 14-15.
[544] *Id.* at 13.
[545] *Id.* at 11-12.
[546] Ex. OAG-2 at 9 (Lee Surrebuttal).
[547] OAG Initial Br. at 8.
[548] Ex. OAG-1 at 10 (Lee Direct).
[549] *Id.* at 11.
[550] *Id.* at 9.
[551] Ex. MP-29 at 12–14 (Rostollan Rebuttal).

ratepayers,[552] and (3) its treatment of organizational dues is consistent with its last rate case and the regulatory developments cited by the OAG are not relevant to Minnesota.[553]

377. The Judge finds the Company has properly adjusted the allowable dues for EEI and Western Coal for the 2022 test year, in accordance with the decision in Minnesota Power's prior rate case.

b. American Gas Association dues

378. Minnesota Power's test year dues request includes dues for the American Gas Association (AGA). AGA is an organization that "represents more than 200 local energy companies that deliver clean natural gas throughout the United States."[554]

379. The OAG argued that these dues should be disallowed because the AGA does not represent electric utilities like Minnesota Power and there appears to be no direct benefit to Minnesota Power's ratepayers.[555]

380. The Company responded that it uses natural gas at two of its power plants and that its membership allows it to stay up-to-date on industry issues.[556]

381. The Judge finds that Minnesota Power has not established that its membership in AGA is reasonable and necessary for the provision of utility service. The AGA's own website states that it represents companies that deliver natural gas. Therefore, it does not represent the interests of ratepayers and its dues should not be included in Minnesota Power's rates. For these reasons, the Commission should disallow recovery of AGA dues.

c. Minnesota Utility Investors dues

382. Minnesota Power's proposed test year includes dues paid to Minnesota Utility Investors (MUI), an organization whose "activities focus on empowering shareholders in the legislative and regulatory processes to advance policies that benefit shareholders, not ratepayers."[557]

383. The OAG argued that MUI dues should be disallowed because MUI's activities are intended to benefit shareholders and the Company had not established any benefit to ratepayers. The OAG also noted that the Commission has disallowed MUI dues in other recent rate cases where their recoverability was challenged.[558]

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[552] *Id.* at 19-21.
[553] *Id.* at 14-17.
[554] Ex. OAG-1 at 14 (Lee Direct) (citing AGA website).
[555] OAG Initial Br. at 10.
[556] Ex. MP-29 at 23 (Rostollan Rebuttal).
[557] In the Matter of the Petition by Great Plains Natural Gas Co. for Authority to Increase Natural Gas Rates in Minnesota, MPUC Docket No. G-004/GR-19-511, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 9 (Oct. 26, 2020).
[558] Ex. OAG-1 at 13–14 (Lee Direct).

384. The Company responded that its membership in MUI helps attract capital that is needed to operate the utility.[559]

385. The Judge finds that Minnesota Power has not established that the benefits it receives from MUI are sufficient to support rate recovery of its dues. MUI exists solely to represent utility shareholders,[560] and the Commission has disallowed MUI dues in other cases where their recoverability was challenged.[561]

d. Employee Expenses

386. The Employee Expense Statute[562] requires the Commission to prohibit allowing "as operating expenses a public utility's travel, entertainment, and related employee expenses that the commission deems unreasonable and unnecessary for the provision of utility service."[563] Employee expenses include membership dues like those discussed in the preceding section, as well as things like travel and lodging expenses, food and beverage expenses, recreational and entertainment expenses, and gift expenses, among others.[564]

387. The Company provided testimony regarding the reasonableness of amounts in the test year that are commonly referred to as "employee expenses" and which included those expenses enumerated in the Employee Expense Statute. The Company explained how it budgeted for $4,739,674 to be included in the 2022 test year for employee expenses.[565]

388. Employee expenses are tracked in the Company's employee expense reporting system.[566] Employee expenses include expenditures for airfare, hotel stays, car rentals, parking, meals for business purposes, or recognition for the work performed by Company employees to provide safe and reliable service to customers.[567]

389. Employee expenses included in the Company's 2022 test year are necessary for the provision of utility service as such expenses are often incurred when Company employees work in the field, meet with customers and other stakeholders, attend conferences and trainings that support their work, or work at remote locations.[568]

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[559] Ex. MP-29 at 22 (Rostollan Rebuttal).
[560] Ex. OAG-2 at 11 (Lee Surrebuttal).
[561] In the Matter of the Petition by Great Plains Natural Gas Co. for Authority to Increase Natural Gas Rates in Minnesota, MPUC Docket No. G-004/GR-19-511, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 9 (Oct. 26, 2020).
[562] Minn. Stat. § 216B.16, subd. 17.
[563] *Id.* subd. 17(a).
[564] *Id*.
[565] Ex. MP-28 at 29-39, Sch. 10 (Rostollan Direct).
[566] *Id.*
[567] *Id.* at 29-30.
[568] *Id.* at 30.

390. The Company has policies in place to ensure compliance with employee expense requirements, which also includes trainings on such policies and expense documentation procedures.[569]

391. The Company testified to how it met the requirements of Employee Expense Statute by providing itemized employee expenses for 2020, the most recently-completed fiscal year.[570] Company witness Mr. Rostollan described the software the Company uses to process all employee expenses, how it extracts such data, and how it queries such data to create the employee expense schedules to comply with the Employee Expense Statute. These procedures are consistent with the Company's last rate case.[571]

392. To develop a budget for employee expenses, the Company employs a zero-based budgeting philosophy for O&M expenses that are not labor related.[572] This approach requires building the budget from a baseline, while reviewing historical amounts and activities as well as expected operational changes in the business to inform the budgeting process.[573] Minnesota Power budgeted its employee expenses for 2022 based on the assumption that the meeting and travel restrictions related to COVID-19 that drastically reduced employee expenses in 2020 and 2021 have largely been lifted.[574] Minnesota Power testified that overall, its budgeting process, including that for employee expenses, has been very accurate.[575]

393. The process of developing a test year budget involves the calculation of an "employee expense adjustment," which is an amount that is typically not recoverable as employee expenses in rates and should be excluded from the test year.[576]

394. Traditionally, the proposed employee expense adjustment is based on a review of employee expenses for the most recently completed fiscal year (which would have been 2020 for this filing). In this rate case, however, the Company calculated the adjustment to the 2022 test year employee expenses on a prorated basis using its analysis of 2018 actual employee expenses due to the unique and unprecedented financial impacts faced by the Company and the world in 2020 due to the COVID-19 pandemic.[577]

395. There is nothing in the Employee Expense Statute that requires the Company's 2022 test year amount be based on its most recently completed fiscal year — the Employee Expense Statute requires only that such data be provided with the filing.[578]

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[569] *Id.*
[570] *Id.* at 31-33.
[571] *Id.* at 34-35.
[572] *Id.* at 5, 36.
[573] *Id.* at 36.
[574] *Id.*
[575] *Id.* at 8.
[576] *Id.* at 36-39.
[577] *Id.* at 36.
[578] Minn. Stat. § 216B.16, subd. 17.

396. The Company testified that the process of developing an employee expense adjustment is time consuming and is completed manually, requiring review of each line of employee expense data and a determination of whether or not the expense is necessary for the provision of utility service.[579]

397. For the 2022 test year, the Company identified a test-year employee expense adjustment of $547,300 (Total Company), or $486,614 (MN Jurisdictional) based on the prorated amount developed through its analysis of the 2018 actual employee expenses.[580]

398. The Judge finds that this amount represents a reasonable employee expense adjustment for the 2022 test year.

399. The OAG reviewed the Company's proposed test year level of employee expenses and recommended that the Company's 2022 test year amount be reduced by approximately $2,120,741 (MN Jurisdictional).[581] This amount includes two categories of reductions. First, the OAG recommended a reduction of approximately $2.06 million based on a 2020 representative year. In supporting 2020 as a representative year of employee expense for ratemaking purposes, OAG witness Mr. Lebens argued that the Company did not itemize its 2022 test year budget and that work styles that have evolved over the past few years, including "face-to-face video conversations," have "eliminate[ed] travel" and decreased associated employee expenses.[582] Second, the OAG recommended certain reductions totaling approximately $61,000 for specific expenses it did not believe were necessary for the provision of utility service.[583] These expenses include certain board of directors' costs, newspaper subscriptions, and other costs that the Company did not include in the employee expense adjustment.[584] In addition, the OAG recommended an adjustment for costs related to an ALLETE executive.[585]

400. The standard under Minnesota law is that the Commission may not allow in rates employee expenses that it "deems unreasonable and unnecessary for the provision of utility service."[586] The Employee Expense Statute does not require a finding that such expenses be deemed "essential" to the provision of utility service, as OAG witness Mr. Lebens appears to recommend.[587]

401. The Judge finds that the OAG's recommendations, both to use 2020 as a basis for developing the overall 2022 test year budget for employee expenses and its specific recommendations for certain items, would result in a budget for employee

[579] Ex. MP-28 at 36-39 (Rostollan Direct).
[580] *Id.* at 36.
[581] Ex. OAG-3 at 16-17 (Lebens Direct).
[582] *Id.* at 12-14.
[583] *Id.* at 16-17.
[584] *Id.* at 15-16.
[585] *Id.* at 16.
[586] Minn. Stat. § 216B.16, subd. 17(a).
[587] Ex. OAG-5 at 3 (Lebens Surrebuttal) ("Q. Should the Commission only allow the Company to recover essential expenses from its customers? A. Yes.").

expenses that is far too low to be reasonable and be used to set rates on a going-forward basis.

402. Company witness Mr. Rostollan testified that it is not appropriate to use 2020 as representative of a typical year for employee expenses, which would unreasonably penalize the Company for taking thoughtful actions in 2020 to protect the health and welfare of its employees and society.[588] The COVID-19 pandemic resulted in meeting, travel, and other restrictions — which drastically reduced employee expenses during 2020, resulting in the year not being representative of a typical year.[589] 2020 was the first year of the global pandemic and was markedly different than the past, present, and foreseeable future in terms of business and travel activity.[590] It is therefore not reasonable to assume — as the OAG has done — that the way business was done in 2020 is the way it will continue in perpetuity.[591]

403. Additionally, Company witness Mr. Rostollan explained that the Company develops its budgets from the bottom up using zero-based budgeting.[592] This means that the Company budgets from a baseline, while reviewing historical amounts and activities in addition to expected operational changes in the business to inform the budgeting process for employee expenses.[593] And, in years the Company is preparing a rate case test year, the employee expenses used in the test year are adjusted downward based on analysis of a recent and representative year before Minnesota Power finalizes its test year budget for employee expenses.[594] The Company did not use the 2018 data to build the 2022 test year budget for employee expenses — the 2018 data was used solely to make an adjustment to the 2022 budget for ratemaking purposes.

404. OAG witness Mr. Lebens maintained that Minnesota Power employees could be more productive going forward due to changing work styles.[595] For instance, Mr. Lebens claimed that Minnesota Power employees could be "twice as productive" if those employees did not need to occasionally drive from Duluth to St. Paul to attend Commission meetings.[596] The Judge finds that this is conjecture and is not supported by the hearing record.

405. There is also no requirement, as the OAG asserts, that the Company should only recover an amount of employee expense that has been itemized in order to comply with the Employee Expense Statute.[597] The OAG's assertion is also contrary to Minnesota

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[588] Ex. MP-28 at 5 (Rostollan Rebuttal).
[589] *Id.*
[590] *Id.*
[591] *Id.*
[592] *Id.* at 3.
[593] *Id.* at 5, 36.
[594] *Id.* at 36.
[595] Ex. OAG-3 at 14 (Lebens Direct).
[596] *Id.*
[597] *Id.* at 12-14.

law, which requires the Company to provide itemized detail for the most recently completed fiscal year, not the test year.[598]

406. The Company testified that the OAG's second proposed adjustment of $61,217.83 (MN Jurisdictional) for employee expenses not included in the employee expense adjustment is also not reasonable.[599] Company witness Mr. Rostollan was particularly concerned by the proposed adjustment including employee service awards paid out in gift cards, gifts to employees for recognition of safety contributions, a cell phone case, subscriptions to news organizations, and expenses for a meeting of the Board of Directors.[600] Gifts to employees are part of the Company's overall employment benefits; they recognize employees for safety contributions and also help retain employees, which benefits both customers and the Company.[601] Safety is an important part of providing safe and reliable electric service, and the Company considers gifts to employees recognizing those contributions and promoting safety as necessary to providing utility service.[602] Regarding the cell phone case that Mr. Lebens points out, certain employees are issued cell phones in order for those employees to carry out their responsibilities on behalf of providing electric service to customers.[603] The OAG believes that these particular items should not be included in employee expenses.[604] The Company testified that these costs are reasonable to include in the 2022 test year.[605]

407. The Company also testified that Mr. Lebens' recommendations related to a Board of Directors meeting at Minnesuing Acres by citing to website marketing for this establishment, which is located in northern Wisconsin, should be rejected.[606] The Board of Directors serves as the key oversight for the Company, and a utility cannot function without a board of directors or other management body.[607] On occasion, the Board of Directors will hold an off-site meeting as an alternative to on-site and virtual meetings.[608] These off-site meetings allow the Board to conduct business in person free of distraction and interruptions that can happen when meetings are on-site, which enables the Board to more effectively conduct its business and carry out its oversight role for the Company.[609]

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[598] Minn. Stat. § 216B.16, subd. 17(b). Mr. Lebens acknowledges this in his Direct Testimony. Ex. OAG-3 at 10 (Lebens Direct).
[599] Ex. MP-29 at 9 (Rostollan Rebuttal).
[600] *Id.*
[601] *Id.* at 9-10.
[602] *Id.* at 10.
[603] *Id.*
[604] Ex. OAG-3 at 16 (Lebens Direct).
[605] Ex. MP-29 at 9-11 (Rostollan Rebuttal).
[606] Ex. OAG-3 at 16 (Lebens Direct).
[607] Ex. MP-29 at 11 (Rostollan Rebuttal).
[608] *Id.*
[609] *Id.*

408. The Company agreed to remove $1,500 in costs (Total Company) from the test year related to an executive of a separate ALLETE subsidiary.[610] The Administrative Law Judge finds this reasonable.

409. The gift cards included in Minnesota Power's itemized 2020 expenses are not analogous to the "spot bonuses" allowed in the Company's 2016 rate case. Spot bonuses are "performance-based incentive compensation, paid through payroll or, if small in amount, as gift cards."[611] The gift cards at issue in this case, however, are not performance-based bonuses; they are employee-recognition gifts provided "for years of service with the Company."[612] The Commission recently denied rate recovery of similar employee-recognition gifts in another utility's rate case, finding that "[t]hese types of expenses have historically been disallowed in rate cases and the Commission sees no compelling reason offered on this record to deviate from past practice."[613] Minnesota Power has not identified a compelling reason that the claimed gift-card expenses should be included in the test year.

410. Overall, the Judge finds that the Company's budget for employee expenses is reasonable and should be approved, except for expenses related to awards for years-of-service to the Company. All other costs have been shown necessary for the provision of utility service.

411. The Judge also finds that the Company has complied with the Employee Expense Statute by providing such data for the most recently completed fiscal year (2020).

9. Economic Development Expenses

412. The Company seeks recovery of $384,531 (Total Company) in the test year, which represents 100 percent of its economic development expenses.[614]

413. Minnesota law permits recovery of economic development expenses: "The commission may allow a public utility to recover from ratepayers the expenses incurred for economic and community development."[615]

414. The Commission's practice has been to allow utilities to recover half of their economic development costs though rates. This practice reflects the Commission's

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[610] *Id.*
[611] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, MPUC Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 34 (Mar. 12, 2018).
[612] Ex. MP-29 at 9 (Rostollan Rebuttal).
[613] In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, MPUC Docket No. E-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 27 (Feb. 1, 2022).
[614] Ex. MP-55 at 4-5 (Turner Rebuttal).
[615] Minn. Stat. § 216B.16, subd. 13.

judgment that, because both ratepayers and shareholders benefit from the increased economic activity that results from this spending, they also should share the costs.[616]

415. Minnesota Power argues that while the Commission's decisions in the Company's recent past rate case have allowed 50 percent recovery through rates, circumstances have changed. First, the Company described its efforts to promote economic development to facilitate customer and job growth — especially to support a Just Transition in host communities where employment in Minnesota Power's coal fired generating facilities is declining as the state of Minnesota transitions away from fossil fuel generation.[617] The focus on Just Transition for the fossil generation host communities in the Company's region, which benefits electric service customers, warrants a more robust support for economic development.[618]

416. Second, the Company actively supports economic development in the region through partnerships with public and private sector entities. The partnerships champion technological research and development advances that one day may help transform the resource-based industries. The goal of these efforts is to enable them to expand their markets beyond the paper and integrated steel industries into which they now sell almost all of their products. Membership in organizations like the Itasca Economic Development Corporation and Area Partnership for Economic Expansion are more examples of regional development priorities for the Company.[619]

417. Third, the Company's economic development efforts seek to diversify the regional economy to buffer cyclical economic downturns in any one sector. Minnesota Power focuses its efforts supporting growth in manufacturing, value added minerals, nonferrous minerals, biofuel and biochemical production, technology services, and building products.[620]

418. Examples of the Company's successful economic development efforts include the attraction of a $439 million wood-based manufacturing project to Cohasset, Minnesota on land currently used as buffer for the Boswell Energy Center. According to the Company, the 800,000+ square foot project will create 158 direct jobs, 300-400 construction jobs, and significant tax base for the city, county, school district, and state. This success will help the community balance the future potential loss of tax revenue and jobs from the Boswell Energy Center when it ceases coal operations and will enable Minnesota Power to grow electric load. The Company also recently aided in the effort to

[616] In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, MPUC Docket No. E-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 21 ("Shareholders as well as customers benefit from economic development activities, because increased economic activity in the Company's service territory is likely to result in increased energy usage to fuel these activities. Because only a portion of the activity's benefit accrues to customers, it is appropriate for the Company to only recover a portion of the total economic development cost.").
[617] Ex. MP-30 at 2, 82-85 (Frederickson Direct).
[618] *Id.* at 84.
[619] *Id.* at 82.
[620] *Id.* at 83.

find a new buyer for the Duluth paper mill, which will be converted to manufacture tissue and preserve over 80 high-paying manufacturing jobs. Minnesota Power also claims to have attracted a 1,000+ employee aviation manufacturing company, a $20 million co-location data center, a large-scale pet food manufacturing facility, a rotomold plastics facility, and a biotechnology firm.[621]

419. The Department and OAG recommended recovery of 50 percent of the Company's economic development expenses based on past Commission decisions and how Company shareholders, in addition to customers, benefit from economic development expenses.[622]

420. The Company argues that its contribution to Just Transition for the fossil generation host communities in Itasca County and St. Louis County warrants 100 percent recovery for economic development costs.[623]

421. The Company's economic development staff spend considerable time and effort on initiatives like the Company's Community Advisory Panels (CAPs), which prioritizes community outreach in host communities, as well as opportunities to leverage additional resources for host communities like spearheading and financially sponsoring the regional application for up to $60 million in Build Back Better funding submitted to the U.S. Economic Development Administration in 2021.[624]

422. The Judge finds that Minnesota Power's economic development investments have been valuable to the region, will be increasingly important as the clean energy transition continues, and are appropriate for cost recovery in this proceeding. The Administrative Law Judge finds that the record supports 50 percent cost recovery of economic development expenses as routinely adopted by the Commission.

423. The Company makes a good argument that its unique efforts help the northern Minnesota region and warrant distinguishing past Commission cost recovery decisions that have only permitted 50 percent recovery of economic development expenses. The proposed development work aims to bring customers who are not legacy industries into the Company's portfolio, which is a policy warranting reasonable recovery for the Company because of the likely positive impact to the community and rate-payers in general. But the record lacks the evidence for the Judge to make a true comparison to how other utilities' economic development efforts have bene orchestrated and their impact. The Commission, which has the necessary expertise and perspective, is in the best position to determine whether Minnesota Power's activities warrant a change to past practice.

[621] *Id.* at 84.
[622] Ex. DOC-1 at 12-16 (Miltich Direct); Ex. OAG-1 at 18-20 (Lee Direct).
[623] Ex. MP-32 at 25 (Frederickson Rebuttal).
[624] *Id.*

10. Production Tax Credits

424. Production Tax Credits (PTCs) are federal tax credits that are earned from the generation of electricity using renewable resources.[625] PTCs are provided for the first ten years of a renewable energy facility's operation.[626] Minnesota Power generates PTCs through its operation of the Bison Wind Energy Center (Bison) and the Taconite Ridge Wind Energy Center (Taconite Ridge) (including the recent "repowering" of Taconite Ridge).[627]

425. Since the Company's 2016 Rate Case, the PTC benefit has been incorporated in base rates, with an annual true-up through the Company's Renewable Resource Rider (RRR).[628] This approach is used because it is difficult to predict annual wind generation and also because the Internal Revenue Service (IRS) changes the PTC rate each year.[629] The Company proposed to continue with this methodology.[630]

426. No party disagreed with the Company's proposal as to this methodology.[631] The Company's estimated PTC benefit for the 2022 test year, which would be incorporated into base rates, is $32,001,832 Total Company ($28,052,710 MN Jurisdictional).[632]

427. The Department proposed that the PTC benefit to be incorporated into rate base should be $39,924,985 Total Company.[633] The Department's figure is the average of the Company's actual PTCs earned from 2018 to 2021.[634]

428. The ten-year period for Bison I ended in 2021; the ten-year period for Bison II and III ends in 2022; and the ten-year period for Bison IV ends in 2024.[635] As a result, the Company's generation of PTCs will be lower in 2022 than it was previously, and will be decreasing substantially in the years immediately thereafter, as shown in the following Table.[636]

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[625] Ex. MP-47 at 8 (Armbruster Direct).
[626] *Id.*
[627] *Id.*; *see also* Ex. MP-40 at 36 (Simmons Direct) (describing repowering).
[628] Ex. MP-47 at 8 (Armbruster Direct).
[629] *Id.*
[630] *Id.* at 9.
[631] *See* Ex. DOC-4 at 4 (Soderbeck Direct) (agreeing to same).
[632] Ex. MP-47 at 9 (Armbruster Direct); Ex. MP-48 at 7 (Armbruster Rebuttal).
[633] Ex. DOC-4 at 6 (Soderbeck Direct).
[634] *Id.*
[635] *Id.*
[636] Ex. MP-48 at 4-5 (Armbruster Rebuttal).

Table 10. PTCs Earned and Expected to be Earned[637]

Production Tax Credits Earned and Expected to be Earned							
Year	Taconite Ridge	Taconite Ridge Repower	Bison I	Bison II	Bison III	Bison IV	Total
2017	$ 1,358,256	$ -	$ 6,523,560	$ 7,894,152	$ 8,011,584	$ 20,182,080	$ 43,969,632
2018	$ 537,261	$ 393,326	$ 5,489,562	$ 6,629,405	$ 6,684,603	$ 17,103,579	$ 36,837,736
2019	$ -	$ 857,096	$ 6,108,903	$ 7,123,042	$ 7,270,723	$ 18,773,463	$ 40,133,226
2020	$ -	$ 1,319,513	$ 6,133,362	$ 7,907,464	$ 8,018,792	$ 20,149,913	$ 43,529,043
2021*	$ -	$ 1,223,393	$ 2,956,925	$ 7,457,522	$ 7,482,393	$ 18,065,338	$ 37,185,571
2022	$ -	$ 1,057,317	$ -	$ 5,905,032	$ 5,990,901	$ 19,048,583	$ 32,001,832
2023	$ -	$ 1,350,000	$ -	$ -	$ -	$ 22,550,626	$ 23,900,626
2024	$ -	$ 1,350,000	$ -	$ -	$ -	$ 22,607,009	$ 23,957,009
2025	$ -	$ 1,400,000	$ -	$ -	$ -	$ -	$ 1,400,000
2026	$ -	$ 1,241,968	$ -	$ -	$ -	$ -	$ 1,241,968
2027	$ -	$ 589,541	$ -	$ -	$ -	$ -	$ 589,541
2028	$ -	$ 580,000	$ -	$ -	$ -	$ -	$ 580,000
2029	$ -	$ 408,900	$ -	$ -	$ -	$ -	$ 408,900

* 2021 projected fiscal year

429. The Judge finds that it would be appropriate to use an average in the way the Department proposes when the activity during the test year is expected to consistent with the activity in previous years. But the average PTCs generated from 2018-2021, when Bison I was generating PTCs, are not reflective of the 2022 test year, in which Bison I will not be generating PTCs.

430. The Department also argued that the 2018-2021 average PTCs should be used because "an accurate estimate ensures ratepayers are not subject to dramatic changes in rates as the amount is trued-up."[638] But the Company's original proposal was an accurate estimate of the PTCs to be generated during the 2022 test year, based on the anticipated activity of Bison II, III, IV, and Taconite Ridge.

431. No party has questioned the Company's estimation process or suggested that the Company's estimate was incorrect.

432. In April 2022, the IRS changed the rate for PTC generation from $25 per MWh to $27 per MWh, which was later corrected to $26 per MWh.[639] Although this causes the Company's estimated PTCs to be earned in 2022 to increase from $32,001,832 Total Company to $33,281,906 Total Company, the Company's position is that this change does not require a change in the PTC amount to be included in base rates.[640]

[637] *Id.* at 4.
[638] Ex. DOC-4 at 6 (Soderbeck Direct).
[639] Ex. MP-48 at 6 (Armbruster Rebuttal).
[640] *Id.* at 7.

433. Any difference between the 2022 test year amount of PTCs and the actual PTCs generated will be trued up in the RRR each month, such that customers will receive the full benefit of any PTCs generated by the Company.[641]

434. The Judge finds that the Company's proposal for the amount of PTCs to be included in base rates for the 2022 test year is reasonable and should be adopted.

11. UIPlanner

435. A class cost of service study (CCOSS) is used to identify the responsibility of each customer class for each cost incurred by the utility in providing service as accurately as possible.[642] The CCOSS is then used as one input to help determine how costs should be recovered from customers through rate design.[643] A CCOSS should be based on cost causation principles, which means that costs should be allocated to each customer class based on an approximation of whether and how much each class caused costs to be incurred by the utility.[644]

436. UIPlanner is the software that was used by Minnesota Power to prepare its CCOSS model in this proceeding. UIPlanner was purchased from UI Solutions Group (formerly Utilities International, Inc.). UIPlanner gathers data for the CCOSS model directly from Minnesota Power's internal data sources and then uses this data to create models based on actual data, projections, and budgets.[645]

437. Minnesota Power began the process of evaluating alternative CCOSS models following the Company's 2016 Rate Case. In that case concerns were raised in that case about the transparency and accuracy of the Company's prior Excel-based CCOSS model.[646]

438. The Commission's order from the 2016 Rate Case required Minnesota Power to work with parties to either improve the transparency of the existing Excel-based model or adopt a new CCOSS model.[647]

439. Minnesota Power complied with the Commission's order from the 2016 Rate Case. After an extensive evaluation process that took into account input from Commission staff, the Department, the OAG, and LPI, Minnesota Power decided to acquire and implement the UIPlanner software in 2019.[648]

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[641] *Id.*; *see also* Tr. Vol. II at 104 (Ms. Soderbeck acknowledging that if the Commission adopts the Company's proposal for the amount of PTCs to include in base rates, the Company's customers will still receive the benefit of any PTCs generated above those levels, because they will be reflected in the RRR).
[642] Ex. DOC-10 at 4 (Zajicek Direct).
[643] *Id.*
[644] *Id.* at 5.
[645] Ex. MP-49 at 3-12 (Shimmin Direct); Ex. MP-50 at 56 (Shimmin Rebuttal).
[646] Ex. MP-50 at 56 (Shimmin Rebuttal).
[647] 2016 Rate Case Order at 113.
[648] Ex. MP-49 at 4-5 (Shimmin Direct); Ex. MP-50 at 56 (Shimmin Rebuttal).

440. CUB was the only party to this proceeding that questioned the prudency of the Company's investment in the UIPlanner software. CUB witness Mr. Nelson raised three arguments related to the Company's procurement process for UIPlanner: (1) Minnesota Power did not conduct a formal business case to analyze the costs and benefits of UIPlanner, (2) the Company did not adequately evaluate alternatives to UIPlanner, and (3) the Company did not adequately explain the changes in the cost estimates for UIPlanner.[649]

441. Company witness Mr. Shimmin testified that he is not aware that the Commission has ever required a public utility to prepare a business case analysis prior to purchasing new software.[650] CUB was also unable to identify any prior Commission order requiring a utility to prepare a business case analysis prior to acquiring new software.[651]

442. While a business case has not been required prior to procuring new software, Minnesota Power provided testimony describing the significant due diligence that the Company performed prior to procuring UIPlanner.[652] This due diligence included an analysis of the benefits, costs, and alternatives to UIPlanner that are three of the key elements of a business case that CUB identified. The Company's due diligence efforts also included a four-day workshop with UI Solutions Group personnel to determine whether the functions of UIPlanner would meet the Company's CCOSS needs and requirements.[653]

443. The Company also provided testimony related to its efforts to evaluate alternatives to UIPlanner.[654] The Company evaluated three primary alternatives: (1) continue use of the existing Excel-based CCOSS model; (2) develop a new CCOSS modeling system in-house; and (3) acquire a new CCOSS modeling system from an outside vendor.[655] The Company provided testimony summarizing its analysis of these three alternatives.[656] After evaluating these three alternatives, Minnesota Power concluded that acquiring a new CCOSS modeling software was the superior alternative.[657] Prior to purchasing UIPlanner, the Company also consulted with other utilities that use UIPlanner and determined that other utilities were very satisfied with UIPlanner.[658]

444. CUB also criticized the Company's procurement process for failing to contact other CCOSS model vendors or issuing a Request for Proposal (RFP) prior to

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[649] Ex. CUB-1 at 5-14 (Nelson Direct).
[650] Ex. MP-50 at 59 (Shimmin Rebuttal).
[651] *Id.*, Sch. 1 at 17.
[652] *Id.* at 57-58.
[653] *Id.*
[654] *Id.* at 59-61.
[655] *Id.* at 57-58; Ex. MP-49 at 9 (Shimmin Direct).
[656] Ex. MP-49 at 9-10 (Shimmin Direct); Ex. MP-50 at 59-60 (Shimmin Rebuttal).
[657] Ex. MP-50 at 58 (Shimmin Rebuttal).
[658] *Id.*

selecting UIPlanner.[659] Company witness Mr. Shimmin explained that after researching CCOSS software alternatives, the Company concluded that "UIPlanner was the only software modeling option available at the time that was designed to develop a CCOSS model."[660] During the course of the proceeding, CUB did not offer the name of any other CCOSS software vendor. Due to the unavailability of other software vendors, it was reasonable that Minnesota Power did not contact other software vendors or issue an RFP prior to selecting UIPlanner.

445. CUB also questioned why the costs for UIPlanner changed from the evaluation process to final costs.[661] The Company explained that the initial cost estimate was a high-level cost estimate prepared prior to obtaining an estimate from UI Solutions Group. After discussing a Statement of Work with UI Solutions Group, Minnesota Power revised its implementation (consulting fees) cost estimate to $750,000.[662] This amount only included consulting fees and did not include the other costs associated with implementing UIPlanner.

446. The Company provided a detailed breakdown of the $1.9 million that the Company spent to implement UIPlanner.[663] These costs included consulting fees, software license fees, travel costs, post-production support, Company software and hardware costs, internal labor costs, and external consultant costs.[664]

447. Minnesota Power also provided testimony regarding how the Company was able to reduce the final costs for implementing UIPlanner by undertaking several cost mitigation measures.[665]

448. The Company's procurement process and project management was prudent and the Company was able to reduce costs for implementing UIPlanner through several cost minimization measures.[666]

449. Minnesota Power's procurement of UIPlanner was reasonable and prudent and Minnesota Power should be permitted to recover the $1.9 million associated with this software purchase. The need to replace the Company's prior Excel-based CCOSS model, that had been in use since 1996, was discussed at some length in the Company's 2016 Rate Case and not challenged. The Commission directed the Company to update its CCOSS in some manner. Further, Minnesota Power conducted extensive due diligence and evaluated several alternatives prior to selecting the UIPlanner software. In addition, after selecting the UIPlanner software, Minnesota Power took steps to minimize the costs

[659] Ex. CUB-1 at 11 (Nelson Direct).
[660] Ex. MP-50 at 58 (Shimmin Rebuttal).
[661] Ex. CUB-1 at 12-13 (Nelson Direct).
[662] Ex. MP-50 at 61 (Shimmin Rebuttal).
[663] *Id.* at 62.
[664] *Id.*
[665] *Id.*
[666] *Id.* at 62-64.

associated with implementing this new software such that the final costs for this project came in under the original budgeted amount.

450. The Judge finds that the record supports the Company's prudent and reasonable procurement of the UIPlanner software to meet its CCOSS modeling needs. Minnesota Power should be allowed to recovery of its $1.9 million in costs for UIPlanner.

K. Rate Design – Contested Issues

1. Class Cost of Service Study (CCOSS)

451. The National Association of Regulatory Utility Commissioners' (NARUC) electric cost allocation manual (NARUC Electric Manual) is a leading authority on CCOSS for electric utilities.[667] As provided in the NARUC Electric Manual, there are three steps in performing a CCOSS. First, costs are functionalized, or grouped according to the major function or purpose they serve in enabling the overall system to provide service to customers.[668] These functions include: production or purchased power, transmission, and distribution.[669]

452. Second, after costs are recognized for their separate functions in providing service, costs are classified into three basic categories based on how they are incurred: (1) customer costs, (2) energy or commodity costs, and (3) demand or capacity costs.[670] Customer costs are those costs that are directly related to the number of customers served, energy costs are costs that vary with the energy or kWh that the utility provides to customers, and demand costs vary with the kilowatt (kW) demand imposed by the customer during specific peak hours.[671]

453. After costs have been functionalized and classified, the next step is to allocate them among the customer classes. To accomplish this, the customers served by the utility are separated into several groups based on the nature of the service provided and load characteristics.[672] Once customer classes have been designated, the functionalized and classified costs are allocated among the classes as follows: (1) demand-related costs are allocated among customer classes on the basis of demands (kW) imposed on system during specific peak hours; (2) energy-related costs are allocated among the customer classes on the basis of the energy which the system must supply to serve the customers; and (3) customer-related costs are allocated among the customer classes on the basis of the number of customers or the weighted number of customers.[673]

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[667] *Id.* at 6.
[668] *Id.*, MZ-D-1 at 18.
[669] *Id.*, MZ-D-1 at 18-19.
[670] *Id.*, MZ-D-1 at 4.
[671] *Id.*
[672] *Id.*, MZ-D-1 at 22.
[673] *Id.*

a. Overview of CCOSS Results

454. Minnesota Power's 2022 CCOSS proposed new allocation methodologies for production demand-related costs and transmission costs. Apart from these proposed changes and other minor refinements, the Company's 2022 CCOSS uses the same major classifications and allocation methodologies considered by the Commission in the Company's 2016 Rate Case.[674] They are also the same methods approved by the Commission in Minnesota Power's 2008 and 2009 rate cases.[675]

455. The two new allocation methods are to replace the Peak & Average (P&A) method, used to allocate fixed production demand-related costs, with the Four Coincident Peak Average and Excess (4CP A&E) method.[676] For transmission costs, the Company's 2022 CCOSS replaces the previously used P&A allocator with the Twelve Monthly Coincident Peak (12CP) method.[677]

456. The Company is proposing to use the 4CP A&E allocator to allocate fixed production demand-related costs for a number of reasons, including the following:

- The 4CP A&E method results in more equitable allocation of costs;
- The 4CP A&E method better reflects cost-causation;
- The A&E method is a common and well-established method; and
- The 4CP A&E method would provide better cost signals needed for utility of the future initiatives.[678]

457. The Company is proposing to use the 12CP allocator to allocate transmission costs because it is a better allocator compared to the P&A method for a number of reasons, including the following:

- The 12CP method results in fairer and more equitable allocation of costs;
- The 12CP method aligns with how other transmission cost are incurred and allocated by Minnesota Power;
- The 12CP method is a common and well-established method; and
- The 12CP method would improve transparency in price signals to customers.[679]

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[674] Ex. MP-49 at 15 (Shimmin Direct).
[675] *Id.* These changes are reflected in the Guide to Minnesota Power's CCOSS. *Id.*, Sch. 1; *see also* Ex. MP-4 (Public); Ex. MP-5 (Trade Secret) (Volume 3, Direct Schedules B-16 to B-19 and C-13 to C-16).
[676] Ex. MP-49 at 15 (Shimmin Direct).
[677] *Id.* at 16.
[678] *Id.* at 22.
[679] *Id.* at 27.

458. The results of the Company's 2022 CCOSS at a class level are summarized in Table 10 below. Table 10 shows the class cost revenue requirement outcomes by class and show the change from present rate revenues that would be required for each class to cover its respective cost of service as determined by Minnesota Power's 2022 CCOSS.

Table 10. Test Year 2022 CCOSS Required Revenue Increase by Customer Class Including Dual Fuel (MN Jurisdictional)[680]

Customer Class	Increase/ (Decrease) to Revenues Required	% Increase/ (Decrease)
Residential	$58,652,160	51.68%
General Service	$11,010,021	14.11%
Large Light & Power	$19,669,749	17.99%
Large Power	$18,405,124	5.91%
Lighting	$521,939	13.64%
Total Retail	**$108,258,993**	**17.58%**

b. Classification and Allocation of Fixed Production Costs

i. Classification of Fixed Production Costs

459. Almost 74 percent or $535.8 million of Minnesota Power's total MN Jurisdictional revenue requirement is functionalized as production costs.[681] Minnesota Power classifies its production costs following the long-established fixed variable method. Minnesota Power classifies all of its fixed production costs as demand-related and all variable production costs are classified as energy-related.[682] Fixed production costs are those costs that do not vary with the amount of electricity that is produced or consumed whereas variable production costs are those costs that do vary with the amount of electricity produced.[683] The variable production costs primarily include fuel costs that are recovered in the fuel adjustment charge (FAC) and other variable operation and maintenance costs that are primarily recovered through base rates.[684] The Company has used this approved methodology since its 2008 rate case and it has been the foundation of the Company's rate design since then.[685] Table2 below shows that the Company's classification of production costs results in a split of 56 percent demand-related costs and 44 percent energy-related costs.

680 *Id.* at 12.
681 Ex. MP-50 at 6 (Shimmin Rebuttal).
682 *Id.* at 3.
683 *Id.* at 5-6; Ex. DOC-10 at 34 (Zajicek Direct).
684 Ex. MP-50 at 6 (Shimmin Rebuttal).
685 *Id.*

Table 12. Minnesota Power's Classification and Jurisdictional Allocation of Production Costs

Total Production Revenue Requirements	Classification		MN Jurisdiction Revenue Requirements	Percent
Fixed Production Revenue Requirements	100% Demand	1/	299,961,752	56%
Variable Production Revenue Requirements	100% Energy	1/	235,834,738	44%
Total			535,796,490	100%

1/ Direct Testimony of Mr. Shimmin, Table 3, page 14.

460. Minnesota Power's classification assumes that no costs, zero percent of the dollar value, of fixed production vary with the energy used while holding demand and customers constant.[686] But Minnesota Power has invested in production facilities with higher capital costs to reduce energy costs. As Minnesota Power explained in its 2015 IRP "Energy requirements continue to dominate the Company's supply picture" and Minnesota Power's high system load factor "drives the need for efficient energy intensive resources to serve customer requirements."[687] Minnesota Power, therefore, has spent more on fixed production plant than it would otherwise have needed by building base load power plants, which have higher fixed costs but lower variable costs, rather than peaking power plants, which provide service for short periods of time and have relatively lower fixed costs.[688]

461. As a result, the Department recommended classifying fixed production costs into demand-related and energy-related costs based on a system load factor.[689] The Department recommended Minnesota Power use its system load factor as the percentage of fixed production costs that is energy-related, and 1 minus the system load factor as the percentage that is demand-related.[690] The Department argues that using a system load factor is more consistent with cost causation. As it reasons, the system load factor approximates the percentage of Minnesota Power's net fixed production costs that vary with energy while holding demand and customers constant.[691] Table 13 below shows that the Department's classification of production costs results in the Company's Minnesota Jurisdiction revenue requirements for production costs being split into 13 percent demand-related and 87 percent energy-related costs. In addition, the Department's recommendation would result in $6.2 million in 2022 test year costs moving out of the Minnesota Jurisdiction.[692]

[686] Ex. DOC-10 at 34 (Zajicek Direct).
[687] Ex. OAG-9 at 4 (Twite Rebuttal) (quoting In re Minn. Power's Appl. for Approval of its 2015- 2029 Resources Plan, Docket No. E015/RP-15-690, Initial Filing at 27 (Sept. 1, 2015) (eDocket No. 20159-113710-01)).
[688] Ex. DOC-11 at 6 (Zajicek Surrebuttal).
[689] Ex. DOC-10 at 34 (Zajicek Direct).
[690] *Id.*
[691] *Id.*
[692] Ex. MP-50 at 7 (Shimmin Rebuttal).

Table 13. Department's Classification and Jurisdictional Allocation of Production Costs[693]

Total Production Revenue Requirements	Classification	MN Jurisdiction Revenue Requirements		Percent
Production Revenue Requirements	16.369 % Demand	71,102,521	1/	13%
Production Revenue Requirements	83.631% Energy	458,481,290	1/	87%
Total		529,583,811		100%
Jurisdictional Cost Shifting		(6,212,679)	2/	

1/ DOC IR 709 as attached to Direct Testimony of Mr. Zajicek, DOC Ex. ___MZ-D-6.

2/ Total Compared to Table 2 above.

462. Minnesota Power opposes the Department's recommendation to classify fixed production costs using the system load factor for a number of reasons. It asserts that the Department's recommendation is based on a false premise — that fixed production costs vary with the amount of energy produced or consumed. Minnesota Power witness Mr. Shimmin explained that by definition, the Company's fixed production costs in the test year are fixed and will not vary with the amount of energy produced.[694]

463. Minnesota Power also argues that classifying fixed production costs based on a load factor would result in volatile rates, because the Company's load factor is not consistent from year-to-year. Minnesota Power witness Mr. Shimmin explained that since 2015, the Company's retail load factor has never been the same from one year to the next.[695] Minnesota Power provided evidence to show that if the load factor would have been used to classify fixed production costs in the 2017 test year from the 2016 Rate Case and again in the 2022 test year, the result would have been five percent less being assigned to energy-related costs and over 35 percent more being assigned to demand-related costs in the 2022 test year as compared to the 2017 test year.[696]

464. The Department has not identified any changes in customer use of the Company's electric system that warrant the recommended change.[697]

465. Minnesota Power also opposed the Department's recommendation because it would result in significant harm to the Company by shifting $6,212,679 in 2022 test year costs out of the Minnesota Jurisdiction. Minnesota Power explained that these test year revenue requirements would not be able to be recovered by the Company from FERC customers and would present immediate and lasting harm.[698]

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693 *Id.*
694 *Id.* at 4.
695 *Id.*
696 *Id.* at 4-5.
697 *Id* at 6-7.
698 *Id.* at 7.

466. According to the Department, Minnesota Power's inability to recover costs caused by its FERC/Wholesale class from that class due to the structure of its contracts is not the Minnesota Commission's concern. If costs are not being caused by the Minnesota Jurisdiction, ratepayers in the Minnesota jurisdiction should not pay for them.[699]

467. LPI testified that if the Commission adopts the Department's proposed allocation of fixed production costs as energy-related and demand-related, that the Commission should allocate the energy-related fixed production costs using average demand, rather than energy as recommended by the Department. LPI's approach, however, is not reasonable because it fails to take into consideration the jurisdictional shift that results when moving from 100 percent demand-related classification to 83.631 percent energy-related and 16.369 percent demand-related.

468. The OAG took issue with the Company's classification of wind generation costs as entirely demand-related.[700] OAG witness Mr. Twite testified that wind generation "tends to receive a very low-capacity accreditation" which Mr. Twite contends means that wind contributes relatively little to the Company's Resource Adequacy requirements.[701]

469. Minnesota Power's classification of wind plant as demand-related is the same classification that has been used in the Company's last three rate cases and is consistent with the classification approved in the Company's Renewable Resources Rider.[702]

470. The Judge finds that the record supports the Company's classification of fixed production costs, including wind generation, as demand-related costs.

ii. Allocation of Fixed Production Costs

471. Minnesota Power is proposing to use the Four Coincident Peak Average and Excess (4CP A&E) method to develop a composite demand allocator to allocate fixed production costs that are classified as demand-related or capacity-related.[703] The 4CP A&E method will replace the Peak & Average method the Company used previously. The 4CP A&E method allocates costs in proportion to each class's average demand and their contribution to the system peaks that are in excess of their average demand.[704] Simultaneously, the 4CP A&E method also allocates costs to each class based on the average demand they place on the system.[705]

472. The Department supports the Company's proposal to use the 4CP A&E method noting that this method "is generally supported by the NARUC Electric Manual"

[699] T. Tr. Vol. 2 at 20 (Shimmin).
[700] Ex. OAG-10 at 6 (Twite Surrebuttal).
[701] *Id.*
[702] Ex. MP-49, Sch. 1 at 11 (Shimmin Direct).
[703] *Id.* at 16.
[704] Ex. MP-50 at 8 (Shimmin Rebuttal).
[705] Ex. MP-49 at 24 (Shimmin Direct).

and "fits well with the Company's situation."[706] Department witness Mr. Zajicek testified that because Minnesota Power does not have peaking generation facilities that other allocation methods are not appropriate.[707] Mr. Zajicek also testified that because the 4CP A&E method uses one peak from each of the four highest peak months that this method fits the Company's unique load profile of having a winter peak but also high summer peaks.[708]

473. LPI also supports the Company's use of the 4CP A&E method to allocate fixed production costs.[709] LPI witness Ms. York stated that "the P&A allocation method does not accurately reflect cost-causation, penalizes high load factor customers, is inherently flawed due to the double counting of average demand, and is generally out of favor in the electric industry."[710] Ms. York also stated that "[t]he 4 CP A&E allocation of production demand-related costs is more reasonable and improves the accuracy of MP's CCOSS relative to the Peak & Average method."[711]

474. The OAG and CUB recommended that the Company continue to use its P&A method to allocate fixed production demand-related costs.[712]

475. Minnesota Power witness Mr. Shimmin provided several reasons why the P&A method is no longer the best method to allocate fixed production costs: (1) the Peak & Average method will result in an inequitable allocation of costs, (2) the Peak & Average method will penalize efficient, high load customers, (3) the Peak & Average method has an inherent double counting flaw, and (4) the Peak & Average method will not provide good cost signals needed for future initiatives.[713]

476. Minnesota Power also provided evidence to show that the 4CPA&E method results in a more equitable allocation of costs as compared to the Peak & Average method. Figure 6 and Figure 7 show production demand revenue requirements for these two methods.

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[706] Ex. DOC-10 at 32 (Zajicek Direct).
[707] *Id.* at 32-33.
[708] *Id.* at 33.
[709] Ex. LPI-6 at 8 (York Direct). LPI, however, testified that if the Commission adopts the Department's proposed allocation of fixed production costs as energy- and demand-related, that the Commission should allocate the energy-related fixed production costs using average demand, rather than energy as recommended by the Department. This approach, however, is not reasonable because it fails to take into consideration the jurisdictional shift that results when moving from 100 percent demand-related classification to 83.631 percent energy-related and 16.369 percent demand-related. Ex. MP-52 at 2-3 (Shimmin Surrebuttal).
[710] Ex. LPI-6 at 8 (York Direct) (citing Ex. MP-49 at 17-18 (Shimmin Direct)).
[711] *Id.*
[712] Ex. OAG-6 at 15-19 (Twite Direct); Ex. CUB-1 at 20-26 (Nelson Direct).
[713] Ex. MP-49 at 14 (Shimmin Direct).

Figure 6. Peak & Average Method: Index of Production Demand Revenue Requirement[714]

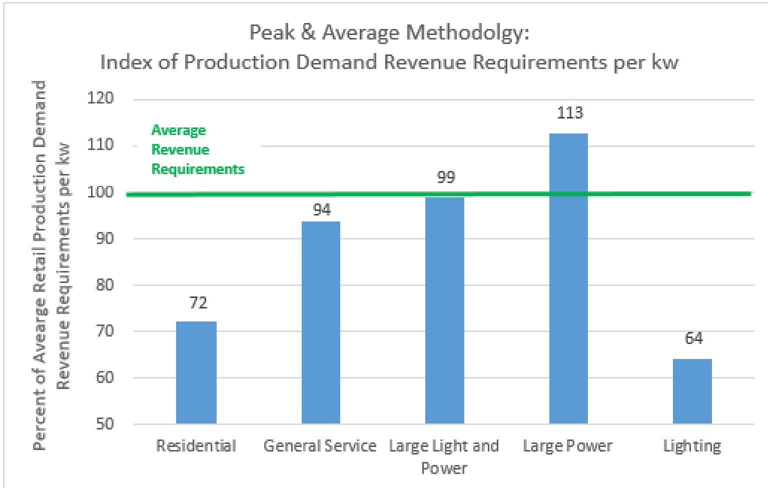
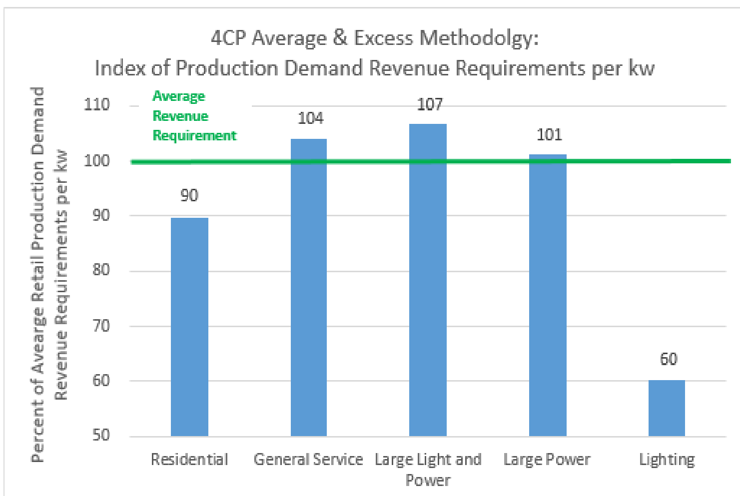


Figure 7. 4CP A&E Method Index of Production Demand Revenue Requirement[715]



477. As shown in these figures, the Residential class cost index is much closer to the system average under the 4CP A&E method than under the Peak & Average method, illustrating a fairer and more equitable cost allocation.[716] Similarly, the Large Power class cost index is much closer to, or at the system average, with the 4CP A&E method as compared to the Peak & Average method. Company witness Mr. Shimming

[714] *Id.* at 19, 24. These figures were developed using the production demand revenue requirements allocated to each class using either the Peak & Average or 4CP A&E allocators. The revenue requirements were then divided by each class's contribution to the coincident peak to estimate a unit revenue requirements per kW. The total Minnesota Jurisdictional system average unit revenue requirement per kW is set as 100 in the index. The other classes are then indexed comparing to the system average.
[715] *Id.*
[716] *Id.* at 23.

explained that because the Large Power class is by far the largest class on the Company's system, it makes sense that it should be just about at the average.[717] The figure above also shows the Peak & Average method's excess cost allocation to the Large Power class penalizes these customers and burdens them with additional costs which do not accurately reflect cost causation.[718]

478. Minnesota Power witness Mr. Shimmin also explained that the 4CP A&E method is superior to the Peak & Average method because it does not have an inherent double counting flaw.[719] The Peak & Average method calculation uses each class's contribution to the single coincident peak in the peak demand factor portion of the composite allocator. In this calculation, the average demand portion of the peak demand is double counted and is included in the peak demand factors of the composite allocator.[720]

479. The Company's 4CP Average and Excess method allocates these costs based on the average of each class's usage during the Company's four coincident peaks. The OAG recommends allocating demand-related production costs based on class usage during MISO's summer coincident peak.[721]

480. Minnesota Power opposed the OAG's recommendation as oversimplifying the relationship between Minnesota Power's peak and MISO's peak.[722] The OAG's recommendation presumes that because the Company is required to demonstrate it has adequate resources to serve its load, plus MISO's resource adequacy reserve margin, during the Company's one hour peak coincident with MISO's peak, then each customer class should bear total annual capacity costs in proportion to its share or contribution to that one hour peak.[723] However, the Company explained that in the Company's IRP process and in MISO's Annual Planning Resource Auction (PRA) process, the Company's projected and estimated single peak plus a reserve margin that is coincident with MISO's expected peak, does not dictate or determine a set generation resource level.[724] Rather, the Company noted that these are very complex resource planning processes that serve important short, medium, and long-term regional reliability needs.[725] The Company explained that Minnesota Power does not immediately build new fixed generation resources at the completion of each IRP planning cycle, and certainly not after every annual PRA exercise.[726] As such it would be inappropriate to allocate production costs based on the MISO peak.

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[717] *Id.*
[718] *Id.* at 19.
[719] *Id.*
[720] *Id.* at 20.
[721] Ex. OAG-7 at 25 (Twite Direct).
[722] Ex. MP-50 at 13 (Shimmin Rebuttal).
[723] *Id.* at 14.
[724] *Id.*
[725] *Id.*
[726] *Id.*

481. Company witness Mr. Shimmin also testified that the OAG's recommendation of allocating production capacity costs coincident with MISO's peak would also lead to poor cost signals and be confusing for customers. This is because the Company manages its unique, high load factor system based on the Company system peak not MISO's peaks.[727] For instance, when the Company calls on customers to interrupt their service, it does so based on its system needs not MISO peaks.[728]

482. The Judge finds that the record supports the Company's proposed 4CP A&E method for allocating fixed production costs and that the Company's four coincident peaks, not MISO's summer coincident peak, should be used as part of the 4CP A&E method.

c. Classification and Allocation of Transmission Costs

483. Minnesota Power classifies transmission costs as demand-related and is proposing to use the 12CP method for allocating transmission costs in this proceeding.[729] The 12CP method allocates costs based on the relationship between the total of all class loads at the time of Minnesota Power's 12 monthly system peaks.[730] The Company had previously allocated transmission costs using the P&A method.

484. The Company explained that it is reasonable to use the 12CP method for allocating transmission costs because it plans and invests in transmission facilities to meet the needs of all customers' peak demands each month of the year. This cost experience aligns with the 12CP method.[731] In addition, MISO transmission revenue and expenses are allocated on the 12CP method so using the 12CP for purposes of the CCOSS aligns with how these expenses are incurred and received by the Company.[732]

485. The Department recommended that transmission costs should be allocated using both the 12 CP allocator and the 1CP method.[733] The inclusion of the 1CP method is recommended because the Company's transmission system was built, and costs incurred, before the Company relied on MISO requirements.[734] The 1CP method uses a single annual system peak to allocate customer responsibility, which is what the Company's system planning relied on before changing to MISO requirements.[735] The result is that customers that heavily contribute to the single peak will pay a proportionally larger portion of the transmission costs.[736]

486. Minnesota Power witness Mr. Shimmin testified that the 1CP method is inconsistent with how the Company plans and invests in transmission facilities as the

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727 *Id.* at 15.
728 *Id.*
729 *Id.* at 18-21; Ex. MP-49 at 27-31 (Shimmin Direct).
730 Ex. MP-50, Sch. 1 at 9 (Shimmin Rebuttal).
731 *Id.*, Sch. 1 at 14.
732 *Id.*
733 *See* Ex. Ex. DOC-10 at 42 (Zajicek Direct); Ex. DOC-11 at 4 (Zajicek Surrebuttal).
734 Ex. DOC-10 at 36-37 (Zajicek Direct).
735 *Id.*
736 *Id.*

transmission system must be sufficiently robust to meet customer needs every month of the year rather than a single month.[737] Minnesota Power also noted that, as shown in Table below, as compared to the Company's proposed 12CP method, the 1 CP method increased the transmission costs allocated to the Residential class by over 30 percent.

Table 14. Comparison of 12CP and 1CP allocations for Transmission Costs[738]

Total Transmission Revenue Requirements	Total Minnesota Jurisdiction	Residential	General Service	Large Light and Power	Large Power	Lighting
1 MP's Recommendation /1						
2 Transmission 12CP	$ 71,699,367	$ 11,166,578	$ 7,311,421	$ 13,081,755	$ 40,048,092	$ 91,521
3 DOC's Recommendation /2						
4 Transmission 1CP	$ 71,968,825	$ 14,594,511	$ 7,306,324	$ 12,324,685	$ 37,491,405	$ 251,899
5 DOC's Cost Shifting	$ 269,458	$ 3,427,933	$ (5,097)	$ (757,070)	$ (2,556,687)	$ 160,378
6 Change %	0.4%	30.7%	-0.1%	-5.8%	-6.4%	175.2%

1/ Direct Testimony of Mr. Shimmin, Table 3, page 14.

2/ DOC IR 710 as attached to Direct Testimony of Mr. Zajicek, DOC Ex. ___ MZ-D-7.

487. Minnesota Power also explained that allocating transmission costs on the 1CP method would create a disconnect between cost allocation and third-party MISO expenses and revenues, which are calculated or allocated based on the 12CP method.[739]

488. LPI agreed with the Company's 12CP allocation method for transmission costs noting that the 12CP method "aligns with how transmission costing is done in the wholesale market."[740]

489. While Minnesota Power proposes to classify all transmission costs as demand-related, the OAG recommended that a "portion" of transmission costs should be classified as energy-related. [741]

490. Minnesota Power opposed the OAG's recommendation as inconsistent with cost causation principles. Minnesota Power participates in the annual MISO Transmission Expansion Planning (MTEP) process where Minnesota Power and MISO ensure that the transmission system has sufficient load-serving capacity to meet the needs of all customers over a range of potential system conditions.[742] The relevant metric in ensuring reliability is demand, not energy.[743] The Company's transmission facilities are designed based on capacity and reliability metrics; the costs are fixed and the costs do not vary

[737] Ex. MP-50 at 19 (Shimmin Rebuttal).
[738] *Id.* at 20.
[739] *Id.* at 19.
[740] Ex. LPI-7 at 24 (York Rebuttal).
[741] Ex. OAG-6 at 29 (Twite Direct).
[742] Ex. MP-50 at 20 (Shimmin Rebuttal).
[743] *Id.*

with energy.[744] Minnesota Power also criticized the OAG for failing to recommend a specific percentage of transmission costs that should be classified as energy-related.[745]

491. The Judge finds that the record supports the Company's proposed allocation of transmission costs using the 12CP method. The Judge also finds that the record supports the Company's classification of transmission costs as demand-related.

d. Classification and Allocation of Distribution Costs

492. Minnesota Power proposes to classify the distribution system into customer-related and demand-related components using the Minimum System method.[746] The Company's Minimum System method classifies distribution facilities between demand-related and customer-related costs based on the Company's Distribution Plant Study.[747] The Minimum System method is one of two methods recognized by NARUC and it has been used in the Company's last three rate cases.[748] The Company's classification of its distribution assets based on the Distribution Plant Study is shown in Table below.

Table 15. Classification of Distribution Plant Based on Minimum System Method[749]

Plant	FERC Account *Function Code*	Function	Customer Classification Minimum System %	Demand Classification %
Poles , Towers	364, 365	Primary Overhead Lines	37.55%	62.45%
OH Conductors	*D300*	Secondary Overhead Lines	49.44%	50.56%
UG Conduits, &	366, 367	Primary Underground Lines	24.20%	75.80%
Conductors	*D400*	Secondary Underground Lines	10.43%	89.57%
Line	368	Overhead Transformers	26.34%	73.66%
Transformers	*D500*	Underground Transformers	49.38%	50.62%
Services	3691	Overhead Services	53.75%	46.25%
	3692	Underground Services	27.57%	72.43%
	D600			

493. The Department reviewed the Company's Minimum System study and found it to be acceptable, as long as the Company included a demand adjustment.[750] In Rebuttal, Company witness Mr. Shimmin explained that Minnesota Power's Minimum System study included a demand adjustment.[751] In Surrebuttal Testimony, the

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744 *Id.*
745 *Id.* at 20-21.
746 *Id.* at 21; Ex. MP-49 at 40-42 (Shimmin Direct).
747 Ex. MP-6, Vol. 4, OS-1, Distribution Plant Study.
748 Ex. MP-49 at 40-41, Sch. 1 (Shimmin Direct); Ex. MP-50 at 22 (Shimmin Rebuttal).
749 Ex. MP-49, Sch. 1 at 15 (Shimmin Direct).
750 Ex. DOC-10 at 37 (Zajicek Direct).
751 Ex. MP-50 at 22 (Shimmin Rebuttal).

Department confirmed its agreement that the Company's Minimum System study included a demand adjustment.[752]

494. The Commission stated in its most recent rate case order, "No single cost-study method can be judged superior to all others in all contexts, and the choice among methods involves disputes over assumptions, applications, and data. . . . While evaluating data from a variety of studies will not eliminate any study's weaknesses, it provides a broader range of perspectives from which to evaluate each study and can reduce the impact of any particular study's flaws."[753] The Department recommends that the Commission use a range of CCOSS results that are analytically sound and supported by the record to inform its rate design determinations. Using a range of CCOSS results is consistent with the Commission's practice and clearly expressed preference in several recent rate cases including Minnesota Power's last rate case.[754] The Department's recommended CCOSS range is in Table 16 as follows:[755]

Table 16. Department of Commerce CCOSS Ranges

Class	Basic Customer CCOSS	Minimum Size 12 CP CCOSS	Minimum Size 1 CP CCOSS
Residential	21.94%	22.82%	23.30%
General Service	12.41%	12.13%	12.12%
Large Light and Power	18.11%	17.40%	17.29%
Large Power	47.06%	47.06%	46.68%
Lighting	0.49%	0.59%	0.61%
Total Minnesota Jurisdiction	100.00%	100.00%	100.00%

[752] Ex. DOC-11 at 21 (Zajicek Surrebuttal).
[753] In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota, MPUC Docket No. E-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 43-44 (Feb. 1, 2022).
[754] *See In re Appl. of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn*., MPUC Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, & ORDER at 71 (Mar. 12, 2018) (eDocket No. 20183-140963-01) ("The Commission . . . will instead continue its practice of considering a range of models to classify FERC accounts 364-69 [service lines] [T]his practice allows the Commission to consider a range of accepted economic theories to develop a better outcome."); *In re Appl. of Otter Tail Power Co. for Authority to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 62 (May 1, 2017) ("However, the Commission also concurs with the OAG on the merits of considering more than one cost study. The Electric Manual indicates that no single cost study method can be judged superior to all others in all contexts, and the choice among methods is fraught with disputes over assumptions, applications, and data."); *In re Appl. of N. States Power Co., d/b/a Xcel Energy for Authority to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 44–45 (June 12, 2017) ("All of this is consistent with the NARUC Manual's conclusion that no single cost-study method can be judged superior to others in all contexts. For these reasons, the Commission will consider a range of classification methods for purposes of allocating responsibility for the necessary revenues among Xcel's various customer classes.").
[755] Ex. DOC-10 at 42 (Zajicek Direct).

495. The OAG recommended adoption of the Basic Customer method to classify distribution system costs. The Department recommended that the Basic Customer method be considered by the Commission as part of the multiple CCOS studies the Department offers. [756]

496. Minnesota Power agreed against considering the Basic Customer method, as it reasons that this method is not aligned with cost causation. The Company noted that the Basic Customer method over-classifies demand-related costs and under-classifies customer-related costs.[757] Table 17 below summarizes the allocation of distribution costs into demand-related and customer-related components based on the Basic Customer method.

Table 17. Basic Customer Method Classification of Distribution Costs[758]

FERC Account	Description	Demand Related	Customer Related
364	Poles, Towers, & Fixtures	100%	-
365	Overhead Conductors & Devices	100%	-
366	Underground Conduit	100%	-
367	Underground Conductors & Devices	100%	-
368	Line Transformers	100%	-
369	Services	-	100%
370	Meters	-	100%

497. As shown in the table above, under the Basic Customer method, FERC Accounts 364 to 368 (poles, conductors, underground cable, and transformers) are classified as entirely demand-related costs. This allocation is inconsistent with the NARUC Manual which states that these FERC Accounts should be classified as both demand-related and customer-related costs.[759] This is because the costs of these facilities is driven, at least in part, by the number of customers.[760]

498. Minnesota Power also noted that adoption of the Basic Customer method would also result in a substantial cost shift from Residential customers and to other customer classes. This is depicted in Table 11 below that provides a comparison of the Distribution Primary and Secondary revenue requirements under the Company's Minimum System method as compared to the Basic Customer method.[761]

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[756] Ex. OAG-6 at 30-35 (Twite Direct); Ex. DOC-10 at 42 (Zajicek Direct).
[757] Ex. MP-50 at 45 (Shimmin Rebuttal).
[758] *Id.*
[759] *Id.*; Ex. DOC-10, Sch. 1 at 12 (Zajicek Direct).
[760] Ex. MP-50 at 45-46 (Shimmin Rebuttal).
[761] *Id.* at 50.

Table 11. Primary and Secondary Distribution Revenue Requirement Implication of Basic Customer Method[762]

	Revenue Requirements by Function & Classification	Total Minnesota Jurisdiction	Residential	General Service	Large Light and Power	Large Power	Lighting
1	**MP's Minimum System /1**						
2	**Distribution Primary**	$ 48,086,677	$ 23,971,114	$ 11,461,115	$ 12,082,851	$ -	$ 571,597
3	Demand	$ 36,823,499	$ 14,855,598	$ 9,769,817	$ 12,047,554	$ -	$ 150,530
4	Customer	$ 11,263,178	$ 9,115,516	$ 1,691,298	$ 35,297	$ -	$ 421,067
5	**Distribution Secondary**	$ 30,985,820	$ 20,009,153	$ 6,064,015	$ 2,452,012	$ -	$ 2,460,640
6	Demand	$ 17,696,670	$ 11,048,481	$ 4,186,476	$ 2,415,807	$ -	$ 45,906
7	Customer	$ 13,289,150	$ 8,960,672	$ 1,877,539	$ 36,205	$ -	$ 2,414,734
8	**Total**	$ 79,072,497	$ 43,980,267	$ 17,525,130	$ 14,534,863	$ -	$ 3,032,237
9	**DOC's IR 712 /2**						
10	**Distribution Primary**	$ 48,089,356	$ 19,400,312	$ 12,758,904	$ 15,733,553	$ -	$ 196,587
11	Demand	$ 48,089,356	$ 19,400,312	$ 12,758,904	$ 15,733,553	$ -	$ 196,587
12	Energy	$ -	$ -	$ -	$ -	$ -	$ -
13	Customer	$ -	$ -	$ -	$ -	$ -	$ -
14	**Distribution Secondary**	$ 30,984,677	$ 18,247,117	$ 6,766,069	$ 3,856,086	$ -	$ 2,115,405
15	Demand	$ 27,917,315	$ 17,410,780	$ 6,581,940	$ 3,852,000	$ -	$ 72,596
16	Energy	$ -	$ -	$ -	$ -	$ -	$ -
17	Customer	$ 3,067,362	$ 836,337	$ 184,130	$ 4,087	$ -	$ 2,042,809
18	**Total**	$ 79,074,033	$ 37,647,429	$ 19,524,974	$ 19,589,639	$ -	$ 2,311,992
19	**Change $ (DOC less MP)**	$ 1,536	$ (6,332,838)	$ 1,999,844	$ 5,054,776	$ -	$ (720,245)
20	**Change %**	0%	-14.4%	11.4%	34.8%	N/A	-23.8%

1/ Direct Testimony of Mr. Shimmin, Table 3, page 14.

2/ DOC IR 712 as attached to Direct Testimony of Mr. Zajicek, DOC Ex. ___ MZ-D-5.

499. The Judge recommends the Commission use a range of CCOSS results that are analytically sound and supported by the record to inform its rate design determinations, consistent with the Department's recommendation.

e. Classification of Advanced Metering Infrastructure (AMI) Meters

500. Minnesota Power is currently in the process of installing advanced metering infrastructure (AMI) meters that have additional functionality and benefits as compared to traditional meters.[763] The Company proposed to classify AMI meter-related costs as 100 percent customer related.[764] The Company classifies meter costs as 100 percent customer-related because each customer must have a meter, and because the number of meters, and therefore total meter costs, are not driven by and do not fluctuate with the demand or energy usage of the customer once the meter is installed.[765]

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762 *Id.*
763 *Id.* at 23. The Company is expected to complete its AMI meter deployment by the end of 2023. Ex. MP-42 at 101 (Gunderson Direct).
764 Ex. MP-50 at 23-27 (Shimmin Rebuttal).
765 *Id.* at 24.

501. Given the additional functionality and benefits provided by the AMI meters, the OAG recommended that AMI meter-related costs be classified as 1/3 customer-related, 1/3 demand-related and 1/3 energy-related.[766] This is consistent with a Commission decision in 2017, which stated that "added meter costs borne by subscribers to the Residential–Controlled Demand service offered by Otter Tail Power are more appropriately understood as demand or energy costs. These costs are incurred to benefit Otter Tail's system as a whole, not just the customer receiving electricity through the meter."[767]

502. The Company recommended rejection of the OAG's recommendation regarding classification of AMI meter-related costs. Company witness Mr. Shimmin testified that the OAG has not conducted a formal analysis of the benefits of AMI meters and that such an analysis is needed to ensure that the benefits of AMI meters are not double counted or already embedded in programs, rates, and actual O&M expense.[768] Company witness Mr. Shimmin also explained that the OAG's classification would result in significant cost shifts among both jurisdictions and customer classes as shown in Table 12 below.

503. The Company also argues that the OAG's classification would shift a large percentage of AMI costs to the Large Light & Power and Large Power classes and over $822,780 would be shifted out of the Minnesota jurisdiction.[769] Further, according to Minnesota Power, the OAG's recommendation would also require the Company to recover over $480,000 in annual revenue requirements from each Large Power customer for AMI meter costs when considering the actual installed costs per AMI meter for each customer is significantly lower.[770]

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[766] Ex. OAG-6 at 38 (Twite Direct).
[767] Ex. OAG-6 at 37 (Twite Direct); *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E-017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 75 (May 1, 2017). This quotation refers specifically to the treatment of advanced metering costs in marginal customer cost calculations, but the underlying concept is equally relevant to embedded CCOSSs.
[768] Ex. MP-50 at 26 (Shimmin Rebuttal).
[769] *Id.*
[770] *Id.*; Ex. OAG-7, Sch. AT-D-3 at 1 (Twite Direct).

Table 12. Revenue Requirement Impact of OAG's AMI Meter Allocation[771]

Customer Class	Company's Customer Meter Revenue Requirements /1		OAG's Arbitrary Allocation /2		OAG's Unsubstantiated Cost Shifting	
	$	%	$	%	$	% Δ
Residential	7,755,717	75.80%	3,570,686	34.90%	(4,185,031)	-53.96%
General Service	1,948,760	19.05%	1,258,452	12.30%	(690,308)	-35.42%
Large Light & Power	126,605	1.24%	1,086,021	10.61%	959,416	757.80%
Large Power	265,876	2.60%	3,360,354	32.84%	3,094,478	1163.88%
Lighting	18,988	0.19%	17,653	0.17%	(1,335)	-7.03%
Total Retail	10,115,946	98.87%	9,293,166	90.83%	(822,780)	-8.13%
FERC	115,569	1.13%	938,349	9.17%	822,780	711.94%
Total	10,231,515	100.00%	10,231,515	100.00%	-	0.00%

1/ Refer to Shimmin Direct Testimony, Table 3 for Meters - Customer revenue requirements. FERC amount added here.

2/ Allocated on composite factors in Shimmin Rebuttal, Table 5: 1/3 Customer Meter, 1/3 Demand, 1/3 Energy.

504. LPI also opposes the OAG's proposed allocation of AMI meter costs.[772] LPI witness Ms. York testified that the additional functionality provided by AMI meters is only useful and only improves the efficiency of the system if customers use the meters to improve their consumption decisions and behaviors.[773] Ms. York noted that the additional functionality will result in lower overall costs to the customer to which the meter is connected.[774] Ms. York concluded that because customers with AMI meters receive direct benefits from the improved functionality and service reliability that they should therefore pay the full AMI meter costs.[775]

505. Consistent with the Commission's reasoning in E-017/GR-15-1033, the Administrative Law Judge recommends that the Commission adopt the classification recommended by the OAG: 1/3 energy- related, 1/3 demand-related, and 1/3 customer-related.

f. E8760 Energy Cost Allocator

506. The E8760 allocator is an energy-cost allocator based on the time-of-use concept. The allocator recognizes the importance of linking the time when a customer consumes electricity to the cost of providing electricity at that time.[776] A customer class that consumes proportionately more of its energy during periods of high or peak demand, when the market price for electricity is higher, should be expected to be charged more than a customer who consumes energy during off peak times. The E8760 is based on Minnesota Power's system Locational Marginal Price (LMP) hourly cost and the hourly

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[771] Ex. MP-50 at 26 (Shimmin Rebuttal).
[772] Ex. LPI-7 at 26-27 (York Rebuttal).
[773] *Id.* at 27.
[774] *Id.*
[775] *Id.*
[776] Ex. MP-49, Sch. 1 (Shimmin Direct).

energy use of each class.[777] The Company's E8760 allocator was used and approved in all three of the Company's last completed rate cases.[778]

507. To create the E8760 allocator, Minnesota Power used the most recent hourly load data that it had available for each customer class to scale the 2022 test year energy load shapes. For Large Power customers, the most recent hourly load data was 2020 and for all other customer classes, the most recent hourly load data was 2013-2014 load research data.[779]

508. Both the Department and LPI recommend that the Company update its E8760 allocator using more recent load data for all customer classes prior to filing its next rate case.[780]

509. The Company stated that it plans to update its E8760 energy allocator data using the hourly load data that will be available once the Company completes its full AMI deployment in December 2023.[781]

510. The OAG took issue with the Company's use of the 2020 LMP and applying these prices to 2013-2014 load data. It recommended instead that the Company use an unweighted energy allocator.[782] In response to the OAG's critique, the Company provided evidence to demonstrate that the 2013/2014 load shapes are a reasonable proxy to scale the 2022 test year energy by class.[783] The Company also provided evidence to show that due to falling market MISO prices in recent years, the LMP has less of an impact as a weight in the calculation, such that use of 2020 LMP data did not have much of an impact on the calculation of the E8760 allocator.[784] Minnesota Power also explained that using an unweighted energy allocator does not reflect the time-of-use differences in allocating energy costs across customer classes.[785]

511. The Judge finds that the Company's proposed calculation of the E8760 allocator in this case is reasonable and that the Company's E8760 allocator should be used in this proceeding to allocate energy costs.

512. The Administrative Law Judge also finds it reasonable to for the Company to be required to use then-current data for this allocator in its next rate case filed after full AMI deployment is complete.

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[777] *Id.*; Ex. MP-50 at 28 (Shimmin Rebuttal).
[778] Ex. MP-49, Sch. 1 at 10-11 (Shimmin Direct).
[779] Ex. MP-50 at 28 (Shimmin Rebuttal).
[780] Ex. DOC-10 at 40 (Zajicek Direct); Ex. LPI-8 at 24 (York Surrebuttal).
[781] Ex. MP-50 at 29 (Shimmin Rebuttal).
[782] Ex. OAG-6 at 22-25 (Twite Direct).
[783] Ex. MP-50 at 29 (Shimmin Rebuttal).
[784] *Id.*
[785] *Id.* at 44.

g. Multiple CCOSS

513. The Department recommends that the Commission consider three different CCOSS results: (1) a minimum-size method CCOSS that classifies fixed production costs based on system load factor and using a 1CP method for allocating transmission costs (Minimum Size 1 CP CCOSS); (2) a minimum-size method CCOSS that classifies fixed production costs based on the system load factor but using the 12CP method to allocate transmission costs (Minimum Size 12CP CCOSS); and (3) a Basic Customer method CCOSS that classifies fixed production costs based on the system load factor and using the Company's recommended 12CP method for allocation of transmission costs (Basic Customer CCOSS).[786]

514. A comparison of these CCOSS, as well as the other CCOSS discussed in this proceeding, is provided in Table from LPI witness Ms. York's Surrebuttal Testimony. Minnesota Power's proposed CCOSS is shown in column (4) below.

Table 20. Required Revenue Increase/Decrease by Customer Class Based on Different CCOSS[787]

Line	Customer Class	P&A[1]	4CP A&E Only[1]	12CP Only[1]	4CP A&E and 12CP[1]	Basic Customer[2]	Minimum Size 12CP[2]	Minimum Size 1CP[2]
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Residential	41.57%	51.10%	42.16%	51.69%	38.87%	44.45%	47.43%
2	General Service	9.43%	13.49%	10.05%	14.12%	14.22%	11.65%	11.61%
3	Large Light & Power (LLP)	13.46%	17.14%	14.32%	18.00%	18.97%	14.35%	13.61%
4	Large Power (LP)	12.35%	6.57%	11.69%	5.92%	8.60%	8.60%	7.72%
5	Lighting	16.56%	15.49%	14.73%	13.66%	-7.90%	10.92%	15.11%
6	Total Retail	17.58%	17.58%	17.58%	17.58%	16.63%	16.63%	16.62%

Sources and Notes

[1] Direct testimony of Stewart Shimmin at Table 4.

[2] Zajicek Workpaper 1.

515. Minnesota Power disagrees with the Department's recommendation to use multiple CCOSS recommendations: Company witness Mr. Shimmin believes that doing so could lead to inconsistent CCOSS recommendations when different classification and allocation methods are combined.[788] Instead, the Company urges adoption of a single CCOSS, the Company's 2022 CCOSS, in this case.[789]

[786] Ex. DOC-10 at 42 (Zajicek Direct).
[787] Ex. LPI-8 at 5 (York Surrebuttal).
[788] Ex. MP-49 at 53 (Shimmin Rebuttal).
[789] *Id.* at 56.

516. Using a range of CCOSS results is consistent with the Commission's practice and clearly expressed preference in several recent rate cases including Minnesota Power's last rate case.[790] As the Commission stated in its most recent rate case order, "No single cost-study method can be judged superior to all others in all contexts, and the choice among methods involves disputes over assumptions, applications, and data. . . . While evaluating data from a variety of studies will not eliminate any study's weaknesses, it provides a broader range of perspectives from which to evaluate each study and can reduce the impact of any particular study's flaws."[791]

517. The Judge finds that the Department's recommendation of using a range of CCOSS results based on sound methodologies is an appropriate basis for rate design determinations in this proceeding.

h. Using Customer Class Specific ROEs in CCOSS

518. CUB witness Mr. Nelson recommended that the Commission increase the revenue requirement apportioned to the Large Power class by increasing the Large Power class's ROE within the CCOSS.[792]

519. Company witness Mr. Shimmin testified that from a practical standpoint, CUB's recommendation would introduce distortions to the CCOSS that would erode the usefulness of the results. The Company also testified that it would also be nearly impossible in a single rate case, let alone between cases, to develop and agree upon unequal class ROEs.[793]

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[790] *See In re Appl. of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, & ORDER at 71 (Mar. 12, 2018) (eDocket No. 20183-140963-01) ("The Commission . . . will instead continue its practice of considering a range of models to classify FERC accounts 364-69 [service lines] [T]his practice allows the Commission to consider a range of accepted economic theories to develop a better outcome."); *In re Appl. of Otter Tail Power Co. for Authority to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 62 (May 1, 2017) ("However, the Commission also concurs with the OAG on the merits of considering more than one cost study. The Electric Manual indicates that no single cost study method can be judged superior to all others in all contexts, and the choice among methods is fraught with disputes over assumptions, applications, and data."); *In re Appl. of N. States Power Co., d/b/a Xcel Energy for Authority to Increase Rates for Elec. Serv. in the State of Minn*., MPUC Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 44–45 (June 12, 2017) ("All of this is consistent with the NARUC Manual's conclusion that no single cost-study method can be judged superior to others in all contexts. For these reasons, the Commission will consider a range of classification methods for purposes of allocating responsibility for the necessary revenues among Xcel's various customer classes.").

[791] In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota, MPUC Docket No. E-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 43-44 (Feb. 1, 2022).

[792] Ex. CUB-1 at 36 (Nelson Direct).

[793] Ex. MP-50 at 55-56 (Shimmin Rebuttal).

520. Company witness Mr. Shimmin also noted that by having standard CCOSS results using equal class ROEs, the Commission has an unbiased starting point from which to make apportionment decisions.[794]

521. LPI also opposed CUB's proposal to use class-specific ROEs in the CCOSS.[795] LPI witness Ms. York pointed out that CUB acknowledged that accurately quantifying a specific increase in the LP class ROE is difficult to do.[796] LPI also noted the Company's overall risk assessment for purposes of determining its ROE is based on the Company's overall revenue stability which does not distinguish between rate classes such that there is no way differentiate class-specific risk factors.[797]

522. While CUB's overall concern about the subsidization of costs for a small number of large power customers is legitimate (just as the Company's concern about the high proportion of its sales being dependent on those same customers is legitimate), the Administrative Law Judge finds that the record does not support CUB's recommendation to use customer class specific ROEs in the CCOSS.

i. Jurisdictional Allocation

523. Jurisdictional allocation is the step in the CCOSS whereby the costs are allocated between Minnesota Power's FERC and Minnesota jurisdictions.[798] In this case, Minnesota Power used the same jurisdictional allocation procedures as those approved in the Company's last three rate cases.[799] Company witness Mr. Shimmin recommended the Commission approve all of the Company's 2022 jurisdictional allocation factors.

524. The Company testified that there are certain major changes that have impacted the Company's jurisdictional allocations since the 2016 Rate Case. There were a combination of a number of changes that decreased Minnesota Power's non-retail load relative to the Company's retail load: 1) the Husky Refinery explosion and shutdown in mid-2018 caused a decrease in Superior Water Light & Power load, which is a firm Municipal customer; 2) in mid-2019, Minnesota Power lost Brainerd as a firm Municipal customer; 3) the COVID-19 pandemic's effect on customer energy sales; and 4) revised and extended contracts with several Minnesota Municipal customers reduced their firm load and energy.[800]

525. The Company also explained that there have also been a number of changes that have decreased Minnesota Power's retail load: 1) the Verso paper mill shutdown; 2) the reduction in load at the Blandin paper mill when Paper Machine #5 was

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[794] *Id.*
[795] Ex. LPI-7 at 17 (York Rebuttal).
[796] *Id.* at 18.
[797] *Id.*
[798] Ex. MP-50 at 32 (Shimmin Rebuttal).
[799] Ex. MP-50 at 32 (Shimmin Rebuttal). While the Department had initially recommended using 2020 jurisdictional allocators, in Surrebuttal Testimony, based on additional information provided by the Company, the Department now supports the Company's 2022 jurisdictional allocators. Ex. DOC-11 at 17 (Zajicek Surrebuttal).
[800] Ex. MP-50 at 35-36 (Shimmin Rebuttal).

permanently shut down in 2017; and 3) the COVID-19 pandemic's effect on customer energy sales, which are somewhat offset by increased sales through a non-firm retail supply agreement with Silver Bay Power Company. In addition, since the Company's 2016 Rate Case, the Company has added Brainerd and Dahlberg as wheeling customers.[801]

526. The Department initially recommended that the Company use 2020 jurisdictional allocation factors rather than 2022 jurisdictional allocation factors but supported the Company's use of its 2022 jurisdictional allocation factors in Surrebuttal Testimony.[802]

527. While the Department agreed with the Company's proposed use of the 2022 jurisdictional allocation factors, the OAG continued to press for use of the 2020 jurisdictional allocations in this case.[803]

528. However, the Company put forth evidence demonstrating that use of the 2020 jurisdictional allocation factors would cause financial harm to the Company, would not represent test year cost causation and rate design principles, and would result in dislocation of revenue requirements. These effects distort just and reasonable rate design to all classes, and particularly harm the Large Power class.

529. As shown below in Table 21, using the 2020 jurisdictional allocation factors would shift $5,128,433 out of the Minnesota Jurisdiction, and the Company would not have an opportunity to recover these costs from its FERC/Wholesale customers.[804]

[801] Ex. MP-50 at 35-36 (Shimmin Rebuttal).
[802] Ex. DOC-10 at 44-47 (Zajicek Direct); Ex. DOC-11 at 15-20 (Zajicek Surrebuttal).
[803] OAG Initial Brief at 15-16.
[804] Ex. MP-50 at 38 (Shimmin Rebuttal). The Company explained that it would not be able to recover these costs from FERC/Wholesale customers because these customers are served through service agreements that cannot be renegotiated until their term is expired which for many of these contracts is at the end of the decade. Ex. MP-50 at 38 (Shimmin Rebuttal).

Table 21. Cost Shifting Implications of Using Out-Of-Period 2020 Allocation Factors per Minnesota Power's Response to Department Information Request No. 711

	Total Revenue Requirements	Total Minnesota Jurisdiction	Residential	General Service	Large Light and Power	Large Power	Lighting
1	Minnesota Power's Recommendation /1						
2	Total	$ 724,263,534	$172,169,623	$89,042,387	$129,006,642	$329,697,105	$4,347,777
3	Demand	$ 438,702,209	$ 96,440,831	$56,078,271	$86,561,642	$198,651,254	$ 970,211
4	Energy	$ 235,834,738	$ 37,937,386	$25,188,357	$41,656,541	$130,613,430	$ 439,024
5	Customer	$ 49,726,587	$ 37,791,406	$7,775,759	$788,459	$432,421	$2,938,542
6	2022 COSS using 2020 Allocators per DOC/2						
7	Total	$ 719,135,101	$163,000,737	$82,680,535	$121,504,582	$347,059,951	$4,889,296
8	Demand	$ 436,081,730	$ 86,741,578	$50,703,337	$79,326,433	$217,923,757	$1,386,625
9	Energy	$ 233,319,256	$ 38,602,340	$24,107,885	$41,365,889	$128,685,256	$ 557,886
10	Customer	$ 49,734,114	$ 37,656,819	$7,869,312	$812,260	$450,937	$2,944,786
11	DOC's Cost Shifting						
12	Total	$ (5,128,433)	$ (9,168,886)	$ (6,361,852)	$ (7,502,060)	$ 17,362,846	$ 541,519
13	Demand	$ (2,620,479)	$ (9,699,253)	$ (5,374,934)	$ (7,235,209)	$ 19,272,503	$ 416,414
14	Energy	$ (2,515,482)	$ 664,954	$ (1,080,472)	$ (290,652)	$ (1,928,174)	$ 118,862
15	Customer	$ 7,527	$ (134,587)	$ 93,553	$ 23,801	$ 18,516	$ 6,244

1/ Direct Testimony of Mr. Shimmin, Table 3, page 14.

2/ Summarized from results of DOC IR 711.

530. LPI questioned the Company's treatment of its revised wholesale municipal customer contracts in calculating the 2022 jurisdictional factors.[805] These wholesale municipal contracts were revised from full requirements contracts to a combination of base and incremental capacity contracts. LPI takes issue with the fact that the Company excluded the non-firm incremental demand and energy portion of these revised contracts from the calculation of the 2022 test jurisdictional allocations factors.[806]

531. Minnesota Power provided testimony that exclusion of the non-firm incremental demand and energy portion of these wholesale municipal contracts is proper. Minnesota Power witness Mr. Shimmin explained that similar to other Large Power non-firm products, the incremental portions of the revised municipal contracts are essentially market pass-through products for the municipal customers.[807] As these products are non-firm products, it would be inappropriate to allocate costs in the firm FERC/Wholesale jurisdictional allocations.[808]

532. Company witnesses Mr. Shimmin and Mr. Frederickson also noted that retail customers are provided the benefits from these non-firm municipal contracts. The revenues associated with the municipal non-firm incremental demand and energy products are treated as revenue credits and are allocated across both jurisdictions and all classes in the CCOSS.[809] The demand-related revenue is an offset for the capacity purchases for these contracts and the energy-related revenue offsets fuel costs in the fuel adjustment clause (FAC), creating a net margin in the FAC that benefits all retail

[805] Ex. MP-50 at 41 (Shimmin Rebuttal).
[806] Ex. MP-50 at 41 (Shimmin Rebuttal).
[807] Ex. MP-50 at 41 (Shimmin Rebuttal).
[808] Ex. MP-50 at 41-42 (Shimmin Rebuttal).
[809] Ex. MP-50 at 42 (Shimmin Rebuttal).

customers.[810] Given the nature of these contracts, and to match the allocation of the benefits of these contracts, it is appropriate to exclude the non-firm incremental demand and energy portion of the contracts from the allocation factors.

533. The Judge finds the Company's proposed 2022 jurisdictional allocation factors to be reasonable and recommends their use in this case.

2. Customer Class Revenue Apportionment

534. Once the CCOSS analysis is complete, the Commission evaluates how to apportion the approved revenue requirement among the various customer classes. Revenue apportionment is important because it ultimately determines the base rate customers are charged for their electrical service.

535. The Company is proposing an equal increase adjustment of 18.22 percent across all General Rates for sales by rate class, as shown in Table .

Table 22. Proposed Rate Increase Across Customer Classes[811]

Rate Class	General Rate Class Cost of Service Study	Proposed General Rate Increase
Residential	51.68%	18.22%
General Service	14.11%	18.22%
Large Light & Power	17.99%	18.22%
Large Power	5.91%	18.22%
Lighting	13.64%	18.22%

536. Typically, Minnesota Power attempts to follow the CCOSS results to align rates with the CCOSS.[812] In this case, however, strict adherence to the CCOSS would require a 51.68 percent increase for the Residential customer class.[813] An increase of this magnitude could have an adverse impact on the Residential customer class.[814] With this in mind, the Company considered the magnitude of the overall MN Jurisdictional rate increase indicated by the CCOSS and determined that an equal percentage increase across all customer classes was a more reasonable proposal at this time.[815]

537. The proposed 18.22 percent increase for all rate classes is higher than the total retail rate class percentage to be at cost, which was 17.58 percent.[816] This is

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[810] Ex. MP-50 at 42 (Shimmin Rebuttal).
[811] Ex. MP-56 at 13 at Table 2 (Peterson Direct); Ex. MP-55, Schedule 4, Updated Direct Schedule E-3, Part 1 at 1 (Turner Rebuttal) (the Company's Class Cost of Service Study was updated in Rebuttal Testimony).
[812] Ex. MP-56 at 6 (Peterson Direct).
[813] Ex. MP-56 at 6-7 (Peterson Direct); Ex. MP-55, Schedule 4, Updated Direct Schedule E-3, Part 1 at 1 (Turner Rebuttal).
[814] Ex. MP-56 at 6 (Peterson Direct).
[815] Ex. MP-56 at 6 (Peterson Direct).
[816] Ex. MP-56 at 6 (Peterson Direct).

because a decrease to Dual Fuel rates, which are determined outside the CCOSS, is necessary to increase competitiveness with alternative fuels.[817] As the Company explained, the Dual Fuel recommendation affected the overall proposed revenue apportionment for all other customer classes so there would be a tie to total revenue requirements.[818] In addition, Minnesota Power also made an adjustment related to demand response that was necessary to account for recently approved and proposed changes to LP Demand Response (DR).[819] Overall, with these adjustments, Minnesota Power proposes an 18.22 percent increase for all General rate classes.

538. The Department, the OAG, ECC, CUB, and LPI addressed the Company's proposed allocation of revenue responsibility and gave a range of responses. The Department recommends that the Commission moderate Minnesota Power's proposed revenue responsibility apportionment. The Department agreed that moving customers closer to their actual services costs was an appropriate goal. However, the Department is concerned that Minnesota Power's proposal moves residential customers too aggressively and creates "rate shock." The Department maintains that these risks are heightened in light of the approval Minnesota Power received - outside of this rate case - to move those customers from inverted block rates to time-of-day rates.[820] Accordingly, using the Department's initial revenue requirement determination of an overall 6.7 percent increase, the Department recommends moderating the increase to the residential class by only increasing that class's rates by 6.0 percent and increasing the remaining customer classes rates by 6.8 percent.[821]

539. The Department further recommends that if a different revenue requirement increase were adopted, that the customer classes revenue responsibility should be adjusted in proportion to that 6.0:6.8 ratio.[822]

540. The OAG argues that if there are significant reductions to the Company's requested revenue requirement, the Commission will have more flexibility to modify class revenue apportionment in accordance with policy considerations.[823] The OAG's class revenue apportionment recommendation, which was calculated using the Department's proposed revenue requirement, calls for specific percentage increases to all customer classes—with the exception of the Company's Dual Fuel customers—and the recommended increases are shown in Figure 15, below:

[817] Ex. MP-56 at 6 (Peterson Direct).
[818] Ex. MP-56 at 5-6 (Peterson Direct).
[819] Ex. MP-56 at 6 (Peterson Direct).
[820] Ex. DOC-12 at 6–8 (Peirce Direct).
[821] *Id.* at 13.
[822] Ex. DOC-13, at 2 (Peirce Surrebuttal).
[823] Ex. OAG-9 at 11–12 (Twite Rebuttal).

Figure 15: OAG class revenue apportionment (at DOC revenue requirement)[824]

		MP proposed		OAG proposed	
Customer class	**Current revenue**	**Revenue**	**Increase**	**Revenue**	**Increase**
Residential	$111,948,172	$132,346,366	18.2%	$118,261,504	5.6%
General Service	$76,999,163	$91,029,262	18.2%	$81,931,330	6.4%
Large Light & Power	$107,584,315	$127,187,366	18.2%	$114,475,608	6.4%
Large Power	$337,791,239	$391,406,171	15.9%	$357,763,806	5.9%
Lighting	$3,807,678	$4,501,479	18.2%	$4,051,578	6.4%
Dual Fuel	$10,245,080	$10,219,139	-0.3%	$10,219,139	-0.3%

541. The OAG also argues that if the Commission adopts a different revenue requirement, the percentages recommended by the OAG should be adjusted proportionally.[825]

542. CUB argues that the exigent circumstances the Commission identified when the interim rates were set have persisted or worsened for the residential class.[826] Inflation, in particular, has worsened in the months since the Commission set interim rates.[827]

543. LPI argues that large power customers subsidize the residential class and that the gap between large power and residential has persisted for nearly 30 years.[828] Further, Industrial customers paid approximately five percent above the national average in 2020 and the Residential class paid rates that were 15 percent below the national average in 2020.[829] LPI proposes a revenue allocation that brings all classes to cost of service, but gradually increases rates for the Residential class over three years, so as to avoid rate shock, as shown in Table 23:[830]

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[824] *Id.* at 13, fig.5 (Twite Rebuttal).
[825] *Id.*
[826] CUB Ex. 1 at 42 (Nelson Direct); ECC Ex. 1 at 7 (Fair Direct); DOC Ex. 12 at 13-14 (Peirce Direct); OAG Initial Brief, 20- 25.
[827] CUB Ex. 1 at 42 (Nelson Direct).
[828] LPI Initial Br. at 30.
[829] MP-18 at 16:15-21 (Cady Direct).
[830] Ex. LPI-6 at 10, T. 1 (York Direct).

Table 23

LPI Proposed Revenue Allocation
Based on Mr. Gorman's Proposed Revenue Requirement
($ Thousands)

Line	Customer Class	Present Base + Fuel Revenue[1]	Phase 1 Increase from Present		Phase 2 Increase from Phase 1		Phase 3 Increase from Phase 2		Total Increase	
			Amount[2]	Percent	Amount	Percent	Amount	Percent	Amount[3]	Percent
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Residential	$113,500	$20,361	17.9%	$7,694	5.7%	$7,694	5.4%	$35,750	31.5%
2	General Service	$78,025	$6,714	8.6%	0	0.0%	0	0.0%	6,714	8.6%
3	Large Light & Power (LLP)	$109,328	$11,991	11.0%	0	0.0%	0	0.0%	11,991	11.0%
4	Large Power (LP)	$311,272	$11,227	3.6%	0	0.0%	0	0.0%	11,227	3.6%
5	Lighting	$3,825	$318	8.3%	0	0.0%	0	0.0%	318	8.3%
6	Total	$615,949	$50,611	8.2%	$7,694	1.2%	$7,694	1.1%	$66,000	10.7%

Sources & Notes:
[1] Includes dual fuel revenues by rate class from Direct Schedule E-3, Part 1, page 1 of 4.
[2] Includes MP's proposed Residential increase of $20.398 million, and proposed decrease of $37,000 for Residential Dual Fuel.
[3] Reflects a revenue deficiency of $66.0 million from Table 1 of Mr. Gorman's direct testimony.

544. The Company asserts that it understands the challenges faced by the Residential rate class, particularly low-income customers, and agrees that balancing the overall impact between rate classes is important.[831] During the interim rate time period, Residential customers are paying a 7.11 percent interim rate increase, and gradualism upward from that percentage should be considered in the overall apportionment.[832]

545. The Company does not believe that it is reasonable to increase the Residential rate by 51.68 percent,[833] or the full cost to serve, indicated in the CCOSS.[834] That is, the Company does not agree with moving the Residential class, and, correspondingly, all customer classes, to its full cost to serve as recommended by LPI witness Ms. York.[835] When considering the ability to pay - an important factor in the ratemaking process - moving the Residential class to the full cost of service is not reasonable.[836]

546. Furthermore, Minnesota Power neither agrees with ECC witness Ms. Fair, who states that the proposed Residential rate increase would be too high,[837] nor with CUB witness Mr. Nelson, who specifically recommends increasing rates for the Residential customer class by half of the overall percentage increase to other customer classes.[838]

[831] Ex. MP-57 at 5 (Peterson Rebuttal).
[832] Ex. MP-57 at 5 (Peterson Rebuttal).
[833] This percentage was updated by Company witness Ms. Turner in the updated CCOSS, from 51.69 percent. Ex. MP-55, Schedule 4, Updated Direct Schedule E-3, Part 1 at 1 (Turner Rebuttal).
[834] Ex. MP-57 at 6-7 (Peterson Rebuttal); Ex. LPI-6 at 17-19 (York Direct).
[835] Ex. MP-57 at 7 (Peterson Rebuttal).
[836] Minn. Stat. § 216B.16, subd. 15(a).
[837] Ex. MP-57 at 5 (Peterson Rebuttal); Ex. ECC-1 at 5-8 (Fair Direct).
[838] Ex. MP-57 at 5 (Peterson Rebuttal); Ex. CUB-1 at 42-43 (Nelson Direct).

547. The Company also disagrees with OAG's recommendation to include the Dual Fuel or certain types of Large Power – Other Energy revenue adjustments in an equal percentage increase.[839] The Company testified to its efforts to work with Dual Fuel customers on improving services and ensuring customers do not leave the program.[840] In addition, the Company testified to the reasonableness of using previously-approved apportionment methodology for certain types of Large Power – Other Energy revenues.[841]

548. The Company also testified to additional reasons as to the reasonableness of its proposed revenue apportionment. The Company's proposed rates more accurately reflect the costs of reliable and safe energy serving Minnesota Power's customers as the Company transitions its fleet to incorporate more renewable energy.[842] Moreover, the Company has not had a complete rate case decision from the Commission since the 2016 Rate Case, and permitting the recovery of increased costs since the last rate case is necessary.[843] Minnesota Power currently offers one of the lowest residential electric rates in the State of Minnesota and is well below the national average.[844] Despite the seemingly large increase for a single rate case, Minnesota Power's Residential overall customer bills remain well below the actual cost of providing service, comparable to Minnesota and national averages, and continue to offer affordable rates for low-income customers.[845]

549. The Judge agrees with the Department that moderating the rate increase to the residential class is necessary to prevent rate shock in light of the other changes that classes' rates are currently undergoing. Accordingly, the Commission should proportionally adjust Minnesota Power's rate increases for each class in accordance with the ratio proposed by the Department.

3. Residential Service Charge

550. The Company initially proposed to increase the Residential service charge from its current level of $8.00 per month to $10.00 per month.[846]

551. The $8.00 per month Residential customer charge is currently the lowest residential fixed charge as compared to investor-owned electric utilities in Minnesota and the proposed increase would be the first increase since the Company's 2008 rate case.[847] This increase is well below what the charge would have been if it had been updated with

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839 Ex. MP-57 at 7-9 (Peterson Rebuttal).
840 Ex. MP-57 at 7-8 (Peterson (Rebuttal).
841 Ex. MP-57 at 8-9 (Peterson Rebuttal).
842 Ex. MP-56 at 13 (Peterson Direct).
843 Ex. MP-56 at 13 (Peterson Direct).
844 Ex. MP-56 at 13 (Peterson Direct).
845 Ex. MP-56 at 13 (Peterson Direct).
846 Ex. MP-56 at 19 (Peterson Direct).
847 *Id.*

inflation over the past 12 years since Minnesota Power's last increase, and is also much lower than all neighboring distribution cooperatives.[848]

552. The Company testified that while it is true that neighboring municipals and cooperatives are not rate-regulated by the Commission, they nevertheless provide a good comparison to the Company's proposed fixed residential charges because these utilities serve customers that are in adjacent areas in northern, rural parts of Minnesota, and who experience similar demographics, economic conditions, and income levels.[849]

553. The Company, CUB, and ECC are party to a partial settlement agreement. Under the partial settlement agreement, Minnesota Power agreed to (i) increase the budget of its Customer Affordability of Residential Electricity (CARE) program, and (ii) to increase the amount of its existing low-income, usage-qualified discount from 35 percent to 40 percent of the standard residential rate on the first 600 kWh.[850] In exchange, CUB and ECC agreed not to oppose a $1.00 increase to a fixed, Residential Service Charge.[851] While the Department continues to support its primary recommendation, the Department also does not object to this resolution to increase the monthly Residential customer charge to $9.00.[852]

554. The Company disagreed that OAG's recommended reduction to $6.50 Residential customer charge was reasonable. The OAG's recommendation does not include all appropriate customer-related costs and results in a higher volumetric rate compared to the Company's.[853]

555. The Judge finds that an increase of the Residential service charge from $8.00 to $9.00 is reasonable and should be approved. The change reflects a reasonable resolution of this issue between the Company, ECC, and CUB, which will also result in improvements to the CARE program.

4. Other Customer Charges

556. The Company also proposed certain changes to customer charges for other customer classes besides the Residential class. These proposals are summarized in Table .

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[848] Ex. MP-57 at 14 (Peterson Rebuttal) (concluding that if Minnesota Power's charge had followed inflation since the last increase, the charge would be $10.57); *see also* Ex. MP-56 at 19-21 (Peterson Direct) (highlighting the Residential Service Charges for neighboring electric utilities in Northeastern Minnesota ranges from $24.00 per month to $46.00 per month).
[849] Ex. MP-57 at 13 (Peterson Rebuttal).
[850] MP Ex. 20 at 11 (Cady Surrebuttal).
[851] Ex. MP-20 at 11-12, Sch. 2 (Cady Surrebuttal); see also Ex. ECC-2 at 7 (Fair Rebuttal) (stating "if the Company agrees to recommended funding and credit amounts I included in my Direct Testimony, I would be inclined to support a customer service charge increase from $8.00 to $9.00").
[852] Ex. MP-59 (DOC Response to Minnesota Power IR No. 39).
[853] Ex. MP-57 at 14-15 (Peterson Rebuttal).

Table 24. Summary of Customer Charges[854]

Customer Class	Current Customer Charge	Proposed Customer Charge
Residential – Seasonal	$10.00	$15.00
Residential EV	$4.25	$4.25
General Service	$12.00	$15.00
Commercial EV	$12.00	$15.00

557. The Department recommended that the Company's proposed monthly service charges should be approved for all classes, except for the Residential service charge as discussed above.[855]

558. Only the OAG recommended that the proposed General Service customer charge should not be approved, and in fact recommended a reduction to $9.00 per month for General Service.[856]

559. No other party took a position with respect to the monthly service charges summarized in Table .

560. The Company did not agree that the OAG's recommendation was appropriate.[857] Like its recommendation on the Residential service charge discussed above, the OAG fails to include all costs in its recommendation and its recommendation, therefore, is not reasonable. The OAG's methodology does not account for all customer costs, compared to the Company's minimum system calculation approach to calculate the service charge, which is supported by NARUC Electric Utility Cost Allocation Manual, and also reflects a gradual increase.[858]

561. The Judge recommends approval of all proposed monthly service charges for all classes as just and reasonable.

5. General Service and Large Light and Power (LL&P) Interruptible Rider

562. The Company proposed certain revisions to the General Service and LL&P rates, as discussed in the Direct Testimony of Company witness Leah Peterson.[859] The Department and LPI addressed Company proposals and in certain instances made further recommended changes to these rate classes.

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[854] Ex. MP-56 at 15-35 (Peterson Direct); Ex. DOC-12 at 15 (Peirce Direct).
[855] Ex. DOC-12 at 14-16 (Peirce Direct).
[856] Ex. OAG-6 at 42-56 (Twite Direct).
[857] Ex. MP-57 at 16 (Peterson Rebuttal).
[858] *Id.* at 15-16, Sch. 3.
[859] Ex. MP-56 at 34-42 (Peterson Direct).

563. The Company proposed certain updates to the rider language to reflect current market parameters for interruptible service.[860]

564. The General Service and LL&P Interruptible service is a short-term capacity product.[861]

565. The Company currently provides an 11 percent discount to the base rate demand and energy charges, and fuel costs applicable to interruptible demand and energy for certain LLP customers.[862] The Company's 11 percent discount is smaller than either short- or long-term products.[863] The Company did not compare the 11% discount to shorter-term products during this proceeding.

566. The Department and LPI both provided testimony regarding the General Service and LL&P Interruptible Rider. The Department agreed with Minnesota Power's proposed tariff updates to better define the parameters of interruptible service.[864]

567. LPI recommended that the Company increase the LL&P interruptible credit to be aligned with the MISO Zone 1 auction clearing price.[865] The Company did not address this, only arguing against the basis for LPI's initial position which relied on a comparison with long-term combustion engines.[866]

568. Minn. Stat. § 216B.03 requires that any doubt as to the reasonableness of rates should be resolved in favor of the consumer.

569. The Company failed to meet its burden of proof to justify maintaining the smaller 11 percent discount. Therefore, the Judge recommends the Commission require the Company's LL&P interruptible credit be aligned with the MISO Zone 1 auction clearing price, currently approximately $7.20 per kW-month.

6. Rider for Fuel and Purchased Energy

570. The Company proposed certain changes to the Fuel and Purchased Energy Rider. Effective with final rates, Minnesota Power proposes to show the FPE Charge as a separate line item on customer bills, as allowed by the Commission in the Fuel Clause Docket Order. Because the Department of Commerce was previously concerned about having the conservation program adjustment (CPA) as a stand-alone line item on customer bills, Minnesota Power also proposes to combine its other existing state energy policy-related cost recovery rider line items with the CPA effective with final rates.[867] The other currently applicable cost recovery riders include the Rider for Transmission Cost Recovery, Rider for Renewable Resources, and Rider for Solar Energy Adjustment, which

[860] *Id.* at 56.
[861] Ex. MP-57 at 21 (Peterson Rebuttal).
[862] Ex. LPI-8 at 13:12-15 (York Surrebuttal).
[863] *Id.* at 13:14 – 14:17.
[864] Ex. DOC-12 at 20-21 (Peirce Direct).
[865] Ex. LPI-8 at 14:8 - 17 (York Surrebuttal); LPI Initial Br. at 40.
[866] MP Initial Br. at 204.
[867] Ex. MP-56 at 54-55 (Peterson Direct).

would be combined with the CPA and shown on customer bills as the Minnesota Policy Adjustment. These rider adjustment line items recover a portion of the total costs for their respective categories, similar to the CPA, making it logical to combine them rather than continuing to show them separately. Conversely, part of the purpose of the fuel clause forecast and projected FPE costs is to allow for more customer transparency for these costs. This increased visibility is promoted by showing the FPE Charge as a separate line item rather than combining it in the Resource Adjustment.[868]

571. The Commission's November 5, 2019, Order Approving Compliance Filings in Docket No. E999/CI-03-802 required that in the initial filings for their next rate cases, each utility shall demonstrate that its proposed base rates exclude FCA related costs. Because the Company needs to consider fuel costs as part of customer bill impacts, Minnesota Power met this requirement by including all fuel clause revenues, as well as fuel and purchased energy costs, in the calculation of the revenue deficiency. Volume 3, Direct Schedule E-2, page 77 shows the monthly fuel clause factor by customer class for both present rates and general rates. Because the fuel clause factors for present rates — in which there was zero cost of fuel in base rates — and general rates are identical, it shows that there were no changes to the FAC that impacted the revenue deficiency calculation. It also demonstrates that the Company's zero-base cost of fuel is unchanged.[869]

572. LPI recommended developing a separate on-peak and off-peak Fuel and Purchased Energy rates for the LL&P Time-of-Use customer class.[870]

573. The Company, however, did not agree with LPI's recommendation. Any changes recommended for the Rider for Fuel and Purchased Energy should be handled in a Fuel Adjustment Clause related docket, and not as part of the rate case.[871] In addition, this change would be an administrative burden due to fuel and purchased energy true-up calculations. Any customer that takes service on the LL&P Time-of-Use tariff would require additional configuration in Minnesota Power's billing system.[872] Minnesota Power's efforts to give customers accurate price signals that are reflective of costs must be balanced with the objectives of simplicity and avoiding unnecessary administrative complexity. This is particularly true in a case like this in which there is currently only one customer that utilizes this time-of-use tariff.[873]

574. The Judge agrees with the Company's position that LPI's proposed changes to the Fuel and Purchased Energy rates for the LL&P Time-of-Use customer class are best developed in a Fuel Adjustment Clause related docket.

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[868] Ex. MP-56 at 53-56 (Peterson Direct).
[869] *Id.* at 55-56.
[870] Ex. LPI-6 at 25 (York Direct).
[871] Ex. MP-57 at 21-22 (Peterson Rebuttal).
[872] *Id.* at 22.
[873] *Id.*

575. The Judge finds that the Company's proposed changes to the Fuel and Purchased Energy Rider are reasonable and has met all compliance requirements.

7. Large Power – Other Energy Revenues[874]

576. Large Power – Other Energy revenues consist of charges and credits for various customer programs including: Pool within Pool Service Fee, Economy/Non-Firm Energy, Incremental Production Service, Replacement Firm Power Service, Fixed Price Contract, and several demand response programs.[875]

577. The Company explained that it accounts for Large Power – Other Energy revenues as a revenue credit in the CCOSS when determining customer class revenue apportionment.[876]

578. The OAG challenged the reasonableness of the Company's treatment of certain kinds of Large Power – Other Energy Revenues for the purpose of setting rates in this rate case.[877]

579. The Company provided justification for the reasonableness of how it treats these revenues. In Rebuttal Testimony, the Company provided four specific reasons for why the Company excludes certain types of Large Power – Other Energy revenues (Pool within Pool Service Fee, Economy/Non-Firm Energy, Incremental Production Service, Replacement Firm Power Service, and Fixed Price Contract) from its proposed revenue apportionment among customer rate classes. These reasons are:

- Economy Energy, Replacement Firm Power Service, and the Pool Service fee, along with the Fixed Price Contract Revenue, are based on charges established in separate agreements that do not change in a retail rate case.

- A portion of Large Power – Other Energy revenue is based on incremental energy costs that vary monthly and even hourly and is associated with service for non-firm energy products.

- Revenues from these Large Power – Other Energy products are treated as revenue credits to all customer classes within the CCOSS rather than Large Power rate class revenue.

- Customers being charged for the Economy, Replacement Firm Power Service, and the Pool Service fee have their own generation, which they use to serve a portion of their load. Minnesota Power accredits this

[874] In re the Application by Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, MPUC Docket No. E015/GR-21-335, Notice of and Order for Hearing at 2-3 (Dec. 30, 2021).
[875] Ex. MP-57 at 8 (Peterson Rebuttal).
[876] *Id.* at 3, 8-9.
[877] Ex. OAG-7 at 8-10 (Twite Direct); Ex. OAG-10 at 14-17 (Twite Surrebuttal).

generation with the MISO under the requirements of MISO's Module E Resource Adequacy Program.[878]

580. The Company's rationale demonstrates the reasonableness of the Company's approach to treating Large Power – Other Energy revenues for purposes of revenue apportionment. This approach is consistent with the Company's previous apportionment methodology for Large Power – Other Energy revenues.

581. The OAG did not address the demand response revenue credits that are included in Large Power – Other Energy revenues.

582. The OAG did not address that electric service agreements are agreements that are reviewed and approved by the Commission outside rate cases. Therefore, in order to accept the OAG's recommendation, the Company stated that it would need to renegotiate several electric service agreements with its customers. Further, this renegotiation would require Commission approval to account for increases to fixed cost portions of the applicable charges.[879]

583. As the OAG noted in testimony, "most of these revenues appear to change throughout the term of the agreements." The Company responded that a portion of Large Power – Other Energy revenues are due to non-fixed cost components that are subject to change based on MISO market prices. These market changes can cause the Company's incremental cost of energy to change by hour.[880] While some of the fixed cost components of Large Power – Other Energy revenue could be changed during a rate case, there are multiple factors that would need to be considered, along with consideration for the non-fixed energy component and demand response credits.

584. The OAG's assumption that Large Power – Other Energy revenues should be included in the overall revenue apportionment because there is a fixed cost component that could be impacted by the results of this rate case is not supported on the record.

585. The Judge finds that the Company has demonstrated that it is reasonable and consistent with past practice to exclude certain Large Power – Other Energy revenues from the overall revenue apportionment.

L. Revenue Mechanisms – Contested Issues

1. Large Power Sales True-Up

586. The Company proposed a sales true-up mechanism to symmetrically manage the risks and benefits of LP sales volatility that occur between rate cases. Specifically, following the conclusion of the current rate case, Minnesota Power would track base rate revenues annually for the entire LP class compared to a baseline level established for the 2022 test year. It would then add to this variance any margins the

[878] Ex. MP-57 at 8-9 (Peterson Rebuttal).
[879] Ex. OAG-10, Sch. AT-S-1 at 1-2 (Twite Surrebuttal) (Company's response to OAG No. 3010).
[880] *Id.* at 15, Sch. AT-S-1 at 2; Ex. MP-57 at 8-9 (Peterson Rebuttal).

Company received from sales due to lost LP load. This information would be submitted in annual compliance filings with the Commission.[881]

587. If the base rate revenue in future years is at least $10 million higher or lower than the 2022 test year baseline level, including any margins on sales due to lost LP load, the Company would request Commission approval to implement changes. These changes would occur in the first year or in subsequent years. The Company proposes a new tariff that would include a rider on all customer bills to credit or charge customers for the amount of the variance compared to the 2022 test year baseline. The rider amount would apply as an equal percentage to all customer classes. The rider amount would be calculated to be in effect for one year (12 monthly bills) and would then revert to zero once the sales true-up balance reaches zero, unless and until another rider request is approved. If the true-up variance is less than $10 million higher or lower than the 2022 baseline, the rider would revert to or remain at zero. The true-up mechanism would continue and be reconsidered in the Company's next general rate case.[882]

588. The company argues that the mechanism will allow customers to benefit when large power operations increase beyond the baseline set in the test year and results in less risk of choosing a test year that is unrepresentative of future years. Minnesota Power also claims that it would help the company stay out of future rate cases that are triggered solely by changes in large power operations.[883]

589. The Department, OAG, and LPI all recommend that the Commission reject Minnesota Power's large power sales true-up proposal. The Department argued first that the proposal was inconsistent with ratemaking principles. The Department asserted that Minnesota Power's proposal inappropriately guarantees that even if sales to certain industrial customers decline, the company can simply surcharge customers to make up the difference. The Department also suggested the proposal was one-sided. According to the Department, if residential customer sales increased or the company acquired a new large power wholesale customer via a third party or a new municipal customer, for example, Minnesota Power would not be required to include these higher sales revenues in the large power sales true-up.[884]

590. The Department also argues that the proposal is a bad deal for customers. Minnesota Power's experience over the past decade suggests that it is unlikely large power revenues will exceed the 2022 test year amount by more than $10 million in any given year. In fact, there was not a single year from 2009 to 2021 in which customers would have benefited from the true-up mechanism had it existed.[885] Minnesota Power's customers would have been surcharged $55.68 million over the ten-year period, while the company's actual deviation from the test-year baseline would have only been $32.65 million, a $23.01 million swing in the company's favor.

[881] Ex. MP-32 at 15 (Frederickson Rebuttal).
[882] *Id.*
[883] Ex. MP-30 at 80 (Frederickson Direct).
[884] Ex. DOC-2 at 40 (Campbell Surrebuttal).
[885] Ex. OAG-6 at 59–60 (Twite Direct).

Year	Large Power Revenue Change from Baseline	Customer Refund or Surcharge
2010	$5.13 million	$0
2011	$8.47 million	$0
2012	$9.52 million	$0
2013	$9.31 million	$0
2014	$4.82 million	$0
2015	$1.95 million	$0
2016	($7.55 million)	$0
2017	($0.89 million)	$0
2018	($1.86 million)	$0
2019	($5.87 million)	$0
2020	($27.49 million)	($27.49 million)
2021	($28.19 million)	($28.19 million)
Total	($32.65 million)	($55.68 million)[229]

591. Finally, the Department asserted that the proposal aggravates the situation it is intended to address. Minnesota Power's large power class is comprised of industrial customers; including taconite mining and processing facilities, pulp and paper industry production facilities, and other manufacturing.[886] These industries are energy-intensive, highly competitive, and sensitive to economic conditions. Accordingly, a mechanism that shifts the burden of one plant closure onto the remaining large power customers (along with other customers) could cause a domino effect that prompts additional closures.[887]

592. Implementation of a sales true-up shifts cost recovery risk from the Company and its shareholders to ratepayers.[888]

593. The Company has not met its burden to show its proposed sales true-up is reasonable for ratepayers. The Judge concurs with the Department and other intervenors that the Commission should reject Minnesota Power's large power sales true-up proposal. The company's proposal inappropriately shifts business and operations risks properly borne by the shareholders to the customers. Minnesota Power's investors receive a rate of return as compensation for bearing these risks. In addition, the Judge is persuaded that proposal, like other rider proposals, would undermine the utility ratemaking framework and disincentivize efficient management by the company. Finally, the Judge notes the significant downside risk presented to other customers in the form of large and unexpected surcharges.

2. Property Tax True Up

594. The Company requested recovery of its forecasted property tax expense for the 2022 test year. The forecasted property tax expense is $55,237,907 (Total

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[886] Ex. DOC-2 at 33 (Campbell Direct).
[887] *Id.* at 36-37.
[888] Ex. LPI-6 at 26:4-5 (York Direct).

Company), the bulk of which is assessed by the State of Minnesota. The Minnesota adjusted amount is $36,121,983, and the MN Jurisdictional amount is $32,214,885.[889]

595. The Company explained how it estimates the amount of property tax expense, and how it undertakes an annual "administrative appeal" with the Minnesota Department of Revenue (DOR) as well as other advocacy to keep its property tax burden as low as reasonably possible.[890]

596. The Company committed that in August 2022, when the DOR is expected to issue the Company's final 2022 Apportionable Market Value, it would submit supplemental testimony.[891]

597. No party opposed the Company's estimate, its recovery of the forecasted property tax expense, or its proposed update process.

598. The Company also requested an annual true-up for its property tax expense.[892] Through this mechanism, each year (once the Company's actual property tax obligations for that year are known in sufficient detail), the Company would submit a compliance filing in this docket.[893]

599. For example, the compliance filing for the 2022 test year would be submitted in the third quarter of 2023.[894] This compliance filing would identify the amount by which the actual property tax obligations were over or under the amount for property taxes established in this rate case (the "baseline").[895] If the property tax obligations were lower than the baseline, the Company would refund the difference to customers (with interest at a rate established by the Commission equivalent to the Company's short-term borrowing rate), and if the property tax obligations were higher than the baseline, the Company would charge customers through a bill surcharge or similar mechanism.[896]

600. The Company explained that its proposed true-up would be useful because various parts of the valuation analysis are highly discretionary with the DOR, rendering the property tax expense somewhat unpredictable. Additionally, there is a long lag—around 18 months—between the estimation of the property tax expense and when the Company receives its actual property tax bills.[897]

601. The true-up the Company proposes is consistent with the true-up process that Xcel Energy uses.[898]

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889 Ex. MP-47 at 10 (Armbruster Direct).
890 *Id.* at 11-12.
891 *Id.* at 12.
892 *Id.* at 12-13.
893 *Id.* at 13.
894 *Id.*
895 *Id.*
896 *Id.*
897 *Id.* at 11-12.
898 *Id.* at 13.

602. The Department opposes the Company's proposed true-up. The starting point of the Department's opposition to the true-up is its position that the Company's property tax expense is not unpredictable. The Department argued that the annual increases in the Company's property tax expense are correlated to increases in the original cost of the Company's operating property in service.[899]

603. But the original cost of the Company's operating property is only one variable the DOR uses to develop its valuation of the Company. Other variables, such as the Capitalization Rate and the weighting of the Cost and Income Approaches, are highly discretionary with the DOR and even small changes in them can cause significant swings in the Company's property tax burden.[900]

604. The Department argued that if the Company's property tax expense is different in future years than anticipated, the Company can just file another rate case.[901]

605. Although property taxes are a significant expense for the Company, it is not reasonable to maintain that the Company can file a rate case when and if the DOR causes an unexpected jump in the Company's property taxes.[902]

606. At the hearing, the Department emphasized that its opposition to the Company's proposed property tax true-up stems from the concern that such a true-up can hinder a utility's incentive to mitigate costs between rate cases.[903]

607. The Company has strong incentives to prudently manage and mitigate its property tax expense—it is accountable to its customers and its shareholders, as well as the Commission.[904] The Company advocates and negotiates with the DOR every year to ensure it pays the lowest property taxes possible.[905]

608. The Judge finds that the Company's test year level of property tax expense is reasonable.

609. The Judge finds that the Company's property tax true up is supported by the record, is reasonable, and should be approved.

M. Interim Rates

610. The Commission approved an interim rate increase of $87.3 million, or 14.23 percent, effective January 1, 2022. The increase is subject to an adjustment for Residential customers such that Residential customers, would only see an interim rate

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[899] Ex. DOC-5 at 15-16 (Soderbeck Surrebuttal).
[900] Ex. MP-48 at 9-11 (Armbruster Rebuttal); *see also* Ex. MP-47 at 10-11 (Armbruster Direct).
[901] Ex. DOC-4 at 8 (Soderbeck Direct); Ex. DOC-5 at 11, 14 (Soderbeck Surrebuttal).
[902] Ex. MP-48 at 9 (Armbruster Rebuttal).
[903] Tr. Vol. II at 106 (Soderbeck).
[904] Ex. MP-48 at 8 (Armbruster Rebuttal).
[905] *Id.*; *see also* Ex. MP-47 at 11 (Armbruster Direct) (describing advocacy and administrative appeal process).

increase of 7.11 percent, subject to possible adjustment. The Commission found exigent circumstances to adjust the Residential interim rate increase percentage.[906]

611. Separately, LPI witness Ms. York and OAG witness Mr. Twite raised questions about the Company's ultimate recovery of the amount by which the Commission reduced interim rates for the Residential class.[907] Minn. Stat. § 216B.16, subd. 3, specifies that the Commission establishes interim rates ex parte, and the Commission did not refer this matter to the Office of Administrative Hearings. As such, this issue is not ripe for a recommendation. Depending on the final revenue requirement in this proceeding, it will be a decision solely for the Commission without recommendation from the Judge.[908]

N. Uncontested or Resolved Issues

1. Revenue, Expense, and Rate Base Items

a. Transmission Capital Project – End of Year Balance

612. Company witness Mr. Daniel W. Gunderson testified to the reasonableness of the Company's capital investments and projects, including how the Company plans for and manages its capital investments budget.[909]

613. The capital budget undergoes a bottom-up, multi-level gated process. This review confirms that capital projects are required within a specific year for the Transmission, Distribution, Facilities, Security, Cyber Technology Services, Land Management, and Fleet work areas. Each of these areas maintain individual long-range plans based on identified needs and priorities and are used to build each year's capital budgets.[910]

614. Mr. Gunderson testified that each month the capital additions portfolio is reviewed. The actuals are compared to budget at the project level, from both a financial perspective and performance perspective. Any variances that might impact a project are immediately addressed and communicated to leadership. Project forecasts are reviewed monthly to maintain a steady and dependable flow of financial information regarding capital expenditures. This process of monitoring the capital budget throughout the year ensures prudent management of Company resources.[911]

615. Department witness Ms. Soderbeck questioned the Company's test year plant balances, and initially recommended a reduction of ending test year balances by $3,566,948 Total Company ($3,566,948 MN Jurisdictional) and plant-related expenses

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[906] Order Setting Interim Rates at 3-8 (eDocket No. 202112-181086-03).
[907] Ex. LPI-6 at 4-6 (York Direct); OAG-9 at Section IV (Twite Rebuttal).
[908] *See* Order Setting Interim Rates at 5 (Dec. 30, 2021) (eDocket No. 202112-181086-03) ("While Minnesota Power may track its forgone revenues, the issue of cost recovery must wait until the end of the rate case.").
[909] Ex. MP-42 at 4-60 (Gunderson Direct).
[910] *Id.* at 5.
[911] *Id.* at 6-7.

by $356,695 Total Company ($356,695 MN Jurisdictional). Ms. Soderbeck also requested additional information regarding actual 2021 plant balances and proposed capital projects included in the 2022 test year.[912]

616. In Surrebuttal Testimony, however, the Department no longer recommended an adjustment for 2022 capital plant additions based upon information the Company provided in Rebuttal. In Rebuttal Testimony, the Company demonstrated that its 2022 capital additions in the test year were reasonable and that the Company expects all capital additions included in the 2022 test year to be placed into service before the end of the year.[913]

617. The Judge agrees that the Company has demonstrated that its 2022 test year plant balances are reasonable.

b. Pension Expense

618. Company witness Mr. Patrick L. Cutshall explained how the Company calculated a reasonable level of pension expense to be reflected in the 2022 test year.[914]

619. The 2022 pension expense is projected to be $5,574,892 for ALLETE ($3,588,541 MP regulated), which equates to $3,190,618 (MN Jurisdictional) pension expense in the 2022 test year. This is a reduction of $2,038,730 from the MN Jurisdictional amount included in the Company's last approved 2017 rate case test year. The Company recommended including the actual 2022 pension expense based on a December 31, 2021, measurement date (which will be known by the end of January 2022), which is the same approach approved in the 2016 Rate Case.[915]

620. The Department reviewed the Company's proposed pension expense and recommended that the Commission approve the Company's proposed level of pension expense for the test year.[916]

621. The Judge finds that the Company's recommended level of pension expense for the 2022 test year is reasonable.

c. Service Center Sales Adjustment (Regulatory Liability Calculation)

622. The Service Center Sales Adjustment represents the value of several asset sales and transactions. These include sales of the Aurora, Crosby, and Chisholm service centers, sale of land and buildings near the Boswell Energy Center, and the transfer of a

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[912] Ex DOC-4 at 18-23 (Soderbeck Direct).
[913] Ex. DOC-5 at 3 (Soderbeck Surrebuttal); Ex. MP-43 at 2-8 (Gunderson Rebuttal).
[914] Ex. MP-22 at 46-60 (Cutshall Direct).
[915] *Id.* at 46.
[916] Ex. DOC-2 at 14-19 (Campbell Direct).

loader from the Laskin Energy Center to the Rapids Energy Center. The value of these sales creates a regulatory liability that acts as a credit to customers in this rate case.[917]

623. The Department recommended a correction to the Service Center Sales Adjustment of $60,949 on a Total Company basis or $54,190 on a MN Jurisdictional basis.[918]

624. The Company agreed with the Department's recommendation and reflected this correction in the test year.[919] After review, the Department testified that this issue is resolved.[920]

625. The Administrative Law Judge agrees that the amount of Service Center Sales Adjustment, as corrected, is reasonable.

d. Thomson Restoration Project

626. The Thomson Restoration Project was a large hydroelectric construction project. The purpose of the Project was to restore substantial damage that occurred to the facility in June 2012 due to record rainfall and flooding. The project included the forebay canal reconstruction, electrical restoration, mechanical and general civil rehabilitation, upgrades to the water conveyance system, construction of additional spillway facilities, and refurbishment of Dam 6. The Company sought and received approval to recover costs for this project through the Company's Rider for Renewable Resources (RRR) (Docket No. E015/M-14-577). In the Company's 2016 Rate Case (Docket No. E015/GR-16-664), all completed portions of the restoration project were moved into base rates. This included all projects except for the Thomson Spillway and Dam 6.[921]

627. The Company testified to the reasonableness of all Thomson Restoration Project costs, including the use of insurance proceeds received for the project, which benefited customers. The Company testified that a majority of the costs for the Thomson Restoration Project are already in rate base, with the remaining requested to be recovered in this rate case.[922]

628. The Company testified that projects often have lagging costs after they are put into service. These types of expenses relate to site clean-up or related matters, address disputed costs with contractors, or relate to project clean-up — because each occur after a project has been put into use for Minnesota Power's customers. The pace at which these projects was being designed, permitted, procured, and constructed led the

[917] Ex. DOC-1 at 3-7 (Miltich Direct).
[918] *Id.* at 6-7.
[919] Ex. MP-55 at 18-19 (Turner Rebuttal).
[920] Ex. DOC-3 at 3-4 (Campbell Surrebuttal).
[921] Ex. MP-41 at 3 (Simmons Rebuttal).
[922] *Id.* at 3-9.

Company to ensure the facility was returned to use as soon as practicable while finishing up other aspects of the sub-projects.[923]

629. In Surrebuttal Testimony, the OAG testified that it no longer recommended that remaining Thomson Restoration Project costs be excluded from the test year based upon the additional information the Company provided.[924]

630. The Judge agrees and recommends no adjustment to the test year on this issue.

e. Huber Engineered Wood Products Land Sale

631. Huber is a private company that has proposed to purchase approximately 400 acres of land held by the Company for the Boswell Energy Center. Huber plans to use the site for an oriented strand board (OSB) plant.[925]

632. Mr. Frederickson testified that the proposed Huber OSB plant is not expected to start up and be at full production until 2024.[926]

633. The Company testified that there is currently no sales agreement between the Company and Huber for the sale of any property and that Huber is currently working toward obtaining necessary permits for the proposed facility before development may proceed.[927]

634. The OAG initially requested additional information about the potential land sale, but ultimately recommended no adjustment to the test year to account for this sale given the current status of the potential development.[928]

635. The Judge agrees and recommends no adjustment to the test year on this issue.

f. Sunset Provisions for Test Year Expense and Revenue Amortizations

636. The Company proposed to amortize certain one-time expenses and revenues over a three-year period. These items are: 1) the Boswell Energy Center 1 & 2 Regulatory Asset (expense); 2) Rate Case Regulatory Asset (expense); 3) Credit Card Fees Regulatory Liability (revenue); and 4) Service Center Sales Regulatory Liabilities.[929]

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[923] *Id.* at 8.
[924] Ex. OAG-2 at 18 (Lee Surrebuttal).
[925] Ex. MP-30 at 36-37, 73 (Frederickson Direct); Ex. MP-41 at 2-3 (Simmons Rebuttal).
[926] Ex. MP-30 at 73 (Frederickson Direct).
[927] Ex. MP-41 at 2-3 (Simmons Rebuttal).
[928] Ex. OAG-1 at 21-25 (Lee Direct); Ex. OAG-2 at 15-16 (Lee Surrebuttal).
[929] Ex. MP-53 at 14, 23-27, 31-32 (Turner Direct).

637. The Department agreed with the Company's proposal to amortize these regulatory assets and liabilities over three years, but also recommended a sunset provision for each amortization after three years.[930]

638. The Department noted that the Company did not object to a sunset provision for each amortized expense or revenue item and considered this issue resolved.[931]

639. The Administrative Law Judge recommends that the Commission accept the amortization periods for the requested regulatory liabilities and assets with a sunset provision.

2. Rate Design

a. Residential Low-Income Usage Qualified Discount

640. As part of partial settlement agreement among Minnesota Power, ECC, and CUB, Minnesota Power requests that the low-income, usage-qualified discount under the Residential Rate Schedule be increased to 40 percent of the standard residential rate on the first 600 kWh.[932]

641. The partial settlement agreement on this issue is consistent with ECC's recommendation. ECC witness Ms. Fair recommended an increase to the current discount for low-income, low-usage customers from the proposed 35 percent to 40 percent.[933]

642. The Judge finds that the parties' proposed settlement to be reasonable and in the public interest and should be adopted. The Judge finds that increasing the low-income, usage-qualified discount under the Residential Rate Schedule from 35 percent as proposed by the Company to 40 percent of the standard residential rate on the first 600 kWh is reasonable.

b. Dual Fuel and Controlled Access Rates

643. The Company proposed to modify the Residential and Commercial/Industrial Service Schedules for Dual Fuel and Controlled Access by separating service under each of the schedules into Small Service and Large Service. These changes are described by Company witness Ms. Peterson, which also include modifications to the current off-peak energizing period to the period 10:00 p.m. to 6:00 a.m. and an update to the name of the Residential and Commercial/Industrial Controlled Access Service.[934]

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[930] Ex. DOC-1 at 7-11 (Miltich Direct).
[931] Ex. DOC-3 at 5 (Campbell Surrebuttal).
[932] Ex. MP-20 at 11-12, Schedule 2 (Cady Surrebuttal).
[933] Ex. ECC-1 at 14-16 (Fair Direct).
[934] Ex. MP-56 at 25-28 (Peterson Direct).

644. Dual Fuel is an interruptible electric service available to customers who have non-electric sources of energy available to satisfy energy requirements during periods of interruption.[935]

645. Controlled Access is a service for controlled energy storage or controlled loads, which are energized only for a specific daily period.[936]

646. The metering and load control technology for both services have changed since these rates were first developed. The meters originally required a separate hardware from the control hardware, which utilized an entirely different communication network and, thus, added costs. Today, this additional communication system, as well as the extra hardware, has become obsolete. Customers, depending on their load size, require different equipment. The technology for the control system for customers with small service no longer requires external equipment but is now an internal part of the meters.[937]

647. The Company proposed to modify the Residential and Commercial/Industrial Service Schedules to offer two Dual Fuel rate options for customers to select - either standard Dual Fuel or Dual Fuel Plus.[938]

648. The Company proposed to add clarifying language for how the Residential Dual Fuel Interruptible Tariff applies to customers with a qualified Air Source Heat Pump. In particular, the proposed changes are more descriptive of what months these customers may choose to be exempt from Dual Fuel interruptions (June through September) and, during this time, would pay the standard Residential energy charge.[939]

649. The Company proposed a 300-hour limit on annual interruptions. Additionally, the service would limit physical interruptions to two times per day for up to four hours at a time for Dual Fuel customers, and a 1,000-hour limit on interruption on annual interruptions for 20 hours of interruptions per calendar day, for Dual Fuel Plus customers.[940]

650. The Company also proposed to clarify how the tariff applies to customers with a qualified Air Source Heat Pump.[941]

651. The Department reviewed the Company's proposed changes to Dual Fuel rates and recommended approval of the Company's recommended changes.[942]

652. Similar to Dual Fuel Plus, Minnesota Power has proposed that the energy charge for Residential and low voltage Commercial/Industrial Controlled Access service

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[935] *Id.* at 25.
[936] *Id.*
[937] *Id.*
[938] *Id.* at 28-33.
[939] *Id.* at 33.
[940] *Id.* at 28-29; Ex. DOC-12 at 17, SLP-D-8 (Peirce Direct).
[941] Ex. MP-56 at 33 (Peterson Direct).
[942] Ex. DOC-12 at 16-18 (Peirce Direct).

be set at 4.710¢ per kWh. For high voltage Commercial/Industrial customers, the energy rate will be set at 4.052¢ per kWh. The Company proposes Controlled Access monthly Service Charges of $6.00 for Small Service and $16.00 for Large Service.[943]

653. The Judge finds the Company's proposed changes to Dual Fuel and Controlled Access rate structures and rates to be just and reasonable and should be approved.

c. Municipal Pumping

654. Minnesota Power proposed to eliminate the Municipal Pumping schedule from its rate book. Company witness Ms. Peterson testified that the transition of all customers on this rate to the General Service rate schedule began with the implementation of the 2016 Rate Case final rates and was completed in 2019.[944]

655. The Department recommended approval of the Company's proposal to eliminate the Municipal Pumping schedule.[945]

656. The Judge finds that the record supports eliminating the Municipal Pumping schedule from the Company's rate book.

d. General Service

657. The Company proposed certain changes to General Service rates, which were presented by Company witness Ms. Peterson. In addition to a change to the monthly customer charge, the Company proposed to change the Energy Charge from 6.054 cents per kWh to 7.647 cents per kWh and to increase the on-peak Demand Charge from $6.50 to $8.00 per kW per month.[946]

658. The Company's proposed changes also include changes to the Pilot for Commercial Electric Vehicle Charging Service, including the monthly customer charge, energy charge, and demand charge.[947]

659. No party opposed the Company's proposed changes to General Service rates.

660. The Judge recommends approval of the Company's proposed changes as just and reasonable.

[943] Ex. MP-56 at 33 (Peterson Direct).
[944] *Id.* at 35.
[945] Ex. DOC-12 at 21 (Peirce Direct).
[946] Ex. MP-56 at 34-35 (Peterson Direct).
[947] *Id.*

e. Large Light and Power (LL&P)

i. Proposed LL&P Rate Structure

661. The Department recommended approval of the Company's proposal to split the demand charge into a distribution demand charge and transmission demand charge, which is a resolved issue.[948]

662. The Company's proposed change would provide additional transparency to customers regarding cost drivers.[949]

663. The Judge agrees that this proposal is reasonable and should be approved.

ii. Proposed LL&P Rates

664. Minnesota Power has proposed to change both the Demand Charge and Energy Charge for LL&P Service. The Demand Charge for the first 100 kW of billing demand is proposed to stay at $1,200 per month. The Demand Charge for all additional billing demand is proposed to decrease from $10.50 per kW-month to $10.00 per kW-month, with the addition of Transmission Demand of $4.69 per kW-month. The same Demand Charge changes are also incorporated in the LL&P Rider for Schools, which has a lower minimum billing demand. The Energy Charge is proposed to change from 4.148¢ per kWh to 4.945¢ per kWh.[950]

665. Aside from certain issues related to voltage discounts raised by LPI, no party opposed the Company's proposed changes to LL&P rates.

666. The Judge recommends that all proposed rate changes for LL&P not opposed by any party be approved as just and reasonable.

iii. Voltage Discounts

667. LPI expressed concerns that the Company's proposed voltage discounts do not reflect the LL&P class cost of service.[951] To that end, LPI recommended increasing the voltage discounts for primary voltage and higher to make greater movement toward cost of service.[952]

668. Specifically, LPI recommended increasing the demand charge discount to $2.45/kW to fully reflect cost of service for customers served at primary voltage.[953] In addition, LPI recommended increasing the transmission voltage energy discount to approximately 40 percent of the cost-based rate, which results in a credit of $0.008/kWh.

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[948] *Id.* at 36-37; Ex. DOC-12 at 19 (Peirce Direct).
[949] Ex. MP-56 at 36 (Peterson Direct).
[950] *Id.* at 38.
[951] Ex. LPI-6 at 19-22 (York Direct).
[952] *Id.* at 21-22.
[953] *Id.*

669. Finally, LPI recommended modifying the LL&P tariff to include an additional energy discount of $0.00153/kWh for customers served at subtransmission voltage.[954]

670. The Company testified that it is not opposed to increasing the voltage discounts for primary and transmission voltage as LPI recommends.[955] Moreover, the Company did not oppose modifying the LL&P tariff to include an energy discount of $0.00153/kWh for customers served at subtransmission voltage, subject to any additional discount being recovered within the LL&P customer class.[956]

671. The Judge recommends that LPI's proposed increases to voltage discounts be approved as recommended.

iv. LL&P Time-of-Use Rider

672. The Commission approved a Pilot Rider for Large Light and Power Time-of-Use Service (LL&P TOU Rider) on August 8, 2011.[957]

673. Enbridge is the only customer currently taking service under the LL&P TOU Rider. It began taking service under the Rider on July 1, 2019. Service under the Rider is currently restricted to LL&P customers with total power requirements in excess of 10,000 kW, which limits the customers eligible for the current pilot.[958]

674. To expand the number of customers who can participate in the pilot, Minnesota Power proposed to lower the customer's total power requirements from 10,000 kW to 3,000 kW. Currently, the text of the LL&P TOU Rider states the customer's power requirement is "in excess of 10,000 kW"; the Company would update this to "at least 3,000 kW."[959]

675. Due to the Company's proposed changes, nine additional customers would be eligible to take service under the LL&P TOU Rider.[960]

676. Minnesota Power proposed to add a super off-peak period with an energy rate of 3.475¢ per kWh and no corresponding demand charge.[961]

677. Minnesota Power also proposed to have on-peak hours of 3:00 p.m. to 8:00 p.m. Central Time Monday through Friday, excluding holidays (currently 7:00 a.m. to 10:00 p.m.); super off-peak hours of 11:00 p.m. to 5:00 a.m. Central Time (current

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[954] *Id.* at 22.
[955] Ex. MP-57 at 20 (Peterson Rebuttal).
[956] *Id.* at 20.
[957] In re Minnesota Power's Petition for Approval of a Pilot Rider for Large Light and Power Time-of-Use Service, MPUC Docket No. E015/M-11-311, Order (Aug. 8, 2011).
[958] Ex. MP-56 at 39 (Peterson Direct).
[959] *Id.* at 40
[960] *Id.*
[961] *Id.* at 41.

LL&P TOU Pilot does not have a super off-peak period); and off-peak hours of all other hours (current is also all other hours).[962]

678. The Department reviewed the Company's proposed changes to the LL&P TOU Rider and recommended approval.[963]

679. The Judge agrees and recommends approval of all proposed changes to the LL&P TOU Rider as just and reasonable.

v. Foundry, Forging, and Melting Rider

680. The Company proposed certain updates to the LL&P rider designed for foundry, forging, and melting customers.[964]

681. No party opposed the Company's proposed changes.

682. The Judge recommends approval of the Company's proposed updates as just and reasonable.

vi. Non-Metered Service

683. The Company proposed certain changes to its Rider for Non-Metered Service.[965]

684. No party opposed the Company's proposed changes.

685. The Judge recommends approval of the Company's proposed changes as just and reasonable.

f. Lighting

686. Minnesota Power testified to certain proposed changes to its Lighting tariffs, which would simplify application of the tariff. The Company's proposed changes include changes to individual Lighting rates and changes to Outdoor and Area Lighting Service as well as Street and Highway Lighting service. The Company's proposed changes also include a phase out of rate Options 2 and 3 under the Company's Lighting tariffs.[966]

687. The Department reviewed the Company's proposed changes to Lighting tariffs and recommended approval.[967]

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[962] *Id.*
[963] Ex. DOC-12 at 19-21 (Peirce Direct).
[964] Ex. MP-56 at 38-39 (Peterson Direct).
[965] *Id.* at 56-57.
[966] *Id.* at 42-44.
[967] Ex. DOC-12 at 21-22 (Peirce Direct).

688. The Judge finds that the Company's proposed changes to Lighting tariffs are just and reasonable and should be approved.

g. Large Power

i. Large Power Rate Structure

689. The Company proposed changes to the Large Power rate structure. The Company requested the addition of a line item labeled "Transmission Demand Charge" as a separate demand charge line item on the customer bills. Minnesota Power is requesting to split out the Transmission component within the current Demand Charge and list it as its own line item on the customer bill. As a result of the change to the Transmission component, the remaining Demand Charge will only contain charges for generation and distribution.[968]

690. The Company's proposed change increases transparency regarding the existing Demand Charges and does not affect current Electric Service Agreements. Separating the current demand charges into their constituent components will create more transparency regarding the drivers of system costs and provide a cost-effective alignment with the evolving power markets.[969]

691. The Department reviewed the Company's proposed changes to the Large Power rate structure and recommended they be approved.[970]

692. The Judge finds that the Company's proposed LP rate structure is reasonable and should be approved.

ii. Proposed LP Rates

693. Minnesota Power proposed to increase the Demand Charge for the first 10,000 kW or less of Billing Demand from $250,087 to $251,204, decrease the Demand Charge for all additional Firm Demand from $24.96 to $23.50 per kW-month, and add the Transmission Demand Charge of $6.24 per kW-month. The LP Firm Energy rate is proposed to increase from 1.041¢ per kWh to 1.364¢ per kWh.

694. No party contested the Company's proposed LP rates.

695. The Judge finds that the Company's proposed LP rates are reasonable and should be approved.

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[968] Ex. MP-56 at 44-46 (Peterson Direct).
[969] *Id.*
[970] Ex. DOC-12 at 22-23 (Peirce Direct).

iii. Large Power Interruptible Service Rider

696. Minnesota Power proposed to replace the Large Power Interruptible Service Rider with the Large Power Demand Response Rider. The Company is making this proposal because of the difficulties administering the features of this outdated rider.[971]

697. The Department agreed that this proposal is reasonable.[972]

698. The Judge finds that the Company's proposal to replace the Large Power Interruptible Service Rider with the Large Power Demand Response Rider reasonable and should be approved.

iv. Non-Contract Large Power Service

699. The Non-Contract LP demand charges have historically been set 20 percent higher than standard LP demand charges as a strong incentive for these large customers to continue making long-term contractual commitments under the standard LP Service Schedule.[973]

700. Minnesota Power has proposed to continue this precedent and again set the Non-Contract LP demand and Transmission Demand charges 20 percent higher than the standard demand charges. This charge is $301,445 for the first 10,000 kW, $28.20 per kW for all additional Billing Demand, and $7.49 per kW for Transmission Demand.[974]

701. No party opposed the Company's proposed changes.

702. The Judge finds that the Company's proposed changes to Non-Contract Large Power Service are reasonable.

v. Incremental Production Service Rider

703. Minnesota Power proposed changes to the Rider for LP Incremental Product Service (IPS). The proposed changes involve:

- Changing the base price structure from an incremental cost-based price to the greater of the MISO Day Ahead LMP or the current year average LP forecasted fuel and purchased energy rate;

- Granting Minnesota Power to the ability to curtail IPS usage in times of low renewable energy conditions or high LMP pricing conditions; and

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[971] Ex. MP-56 at 60 (Peterson Direct).
[972] Ex. DOC-12 at 23-24 (Peirce Direct).
[973] Ex. MP-56 at 48 (Peterson Direct).
[974] *Id.*

- Allowing LP customers to exceed the current 110 percent threshold on IPS usage during times of high renewable energy availability, low system loads, or low LMP pricing conditions.[975]

704. The Company testified to why these proposed changes are reasonable.[976]

705. No party opposed the Company's proposed changes.

706. The Judge finds that the Company's proposed changes to LP IPS are reasonable.

vi. Large Power Demand Response Rider

707. The Company proposes an allocation, demand credit discount change, and quantity update related to the LP DR "Product A," and the "Curtailable product." LP DR products are similar to a capacity purchase that MP utilizes to satisfy MISO capacity requirements for its system. Therefore, the Company requests that, effective with final rates and for future rate proceedings, the credits paid to participating LP customers be treated like purchased power demand and allocated accordingly.[977]

708. In addition, Minnesota Power proposes to increase the Product A demand credit discount to $1.20 per kW (versus the existing $0.60 per kW). This change aligns with evolving MISO requirements to accredit demand response capacity within the MISO system, requiring customers to accept double the interruptions per year.[978]

709. The Department reviewed the Company's proposed changes to the Large Power Demand Response Rider and recommended that they be approved.[979]

710. The Judge agrees that the Company's proposed changes to Large Power Demand Response are reasonable and should be approved.

h. Advanced Metering Infrastructure (AMI) Opt-Out Charge

711. The Company has proposed to implement an AMI Opt-Out Charge of $20.00 per month. This would be in addition to the monthly Residential Service Charge and Residential energy rate.[980]

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975 *Id.* at 49.
976 *Id.* at 48-51.
977 *Id.* at 51-53. The Commission approved Product A in MPUC Docket E015/M-18-735 and the Curtailable product in MPUC Docket E015/M-16-534. LP DR Product A and the curtailable product are emergency curtailment only, Load Modifying Resource – Demand Resource that Minnesota Power accredits with MISO under the requirements of MISO's Resource Adequacy.
978 *Id.* at 51-52.
979 Ex. DOC-12 at 22-25 (Peirce Direct). The OAG also supported the Company's proposal to recover demand response credits from all customers. Ex. OAG-6 at 10 (Twite Direct).
980 Ex. MP-56 at 23 (Peterson Direct).

712. The AMI Opt-Out Charge will apply to residential customers who opt-out of having electric consumption metered through AMI and who provide reasonable access to their electric meter.[981]

713. While the Department initially recommended rejection of the Company's proposed AMI Opt-Out Charge of $20.00 per month, the Department later agreed in Surrebuttal Testimony.[982]

714. In addition to approving the Company's proposal, the Department recommended that "MP be directed to report on the number of residential customers opting out of AMI meter use and the costs associated with that opt-out as part of its ongoing compliance reporting on the transition to TOD rates."[983]

715. The Judge agrees that the Company's proposed AMI Opt-Out Charge of $20.00 per month is reasonable. The Judge also agrees that the Department's proposed compliance requirement is reasonable and recommends approval.

i. Tariff Eliminations

716. The Company proposed to eliminate the following tariffs, in addition to eliminating the Large Power Interruptible Service Rider and the Energy-Intensive Trade-Exposed (EITE) Tariff:

- General Service/Large Light & Power Area Development Rider;
- Large Power Area Development Rider; and
- Miscellaneous Electric Revenue Charges Transformer Rentals.[984]

717. The Department reviewed the Company's proposed tariff eliminations and recommended approval.[985]

718. The Judge recommends approval of the Company's proposed tariff eliminations, as agreed to by the Department.

j. Extension Rules

719. Minnesota Power proposed some clarifications in the following sections: General, Contributions, Basis for Making Extensions for Permanent Service Where Extension Costs are $30,000 or less, and Reapportionment and Refunds.[986]

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[981] *Id.* at 24.
[982] Ex. DOC-12 at 25-29 (Peirce Direct); Ex. DOC-13 at 7-9 (Peirce Surrebuttal).
[983] Ex. DOC-13 at 8-9 (Peirce Surrebuttal).
[984] Ex. MP-56 at 60-61 (Peterson Direct).
[985] Ex. DOC-12 at 29 (Peirce Direct).
[986] Ex. MP-56 at 57-59 (Peterson Direct).

720. These sections of the tariff have not been modified since the Company's Extension Rules were revamped in Docket No. E015/M-12-1359. The revised language is shown in redlined and clean format in Volume 3, Tariff Pages for Change in Rates, Minnesota Power Electric Rate Book, Section VI, Page No. 4, Extension Rules.[987]

721. The Department reviewed the Company's proposed changes to Extension Rules and found them reasonable and recommended approval.[988]

722. The Judge agrees that the Company's proposed changes to Extension Rules are reasonable and should be approved.

k. Business Development Incentive

723. Minnesota Power proposed certain changes to the Rider for Business Development Incentive.[989]

724. No party opposed the Company's proposed changes.

725. The Judge finds that the Company's proposed changes are reasonable.

l. Released Energy and Voluntary Energy Buyback

726. Minnesota Power proposed certain changes to the Rider for Released Energy and the Rider for Voluntary Energy Buyback.[990]

727. No party opposed the Company's proposed changes.

728. The Judge finds that the Company's proposed changes are reasonable.

m. Other Rider Proposals

729. Minnesota Power proposed two minor tariff modifications:

- Pilot Rider for Residential Time-Of-Day Service. The changes are shown in redlined format in Volume 3, Tariff Pages for Change in Rates, Minnesota Power Electric Rate Book, Section V, Page No. 91, Pilot Rider for Residential Time-Of-Day Service; and

- In the Community-Based Energy Development (C-BED) tariff, the Company is requesting to have service closed to new customers because Minn. Stat. § 216B.1612 was repealed. The change is shown in redlined format in Volume 3, Tariff Pages for Change in Rates, Minnesota Power Electric Rate

[987] *Id.* at 57.
[988] Ex. DOC-12 at 29-30 (Peirce Direct).
[989] Ex. MP-56 at 59-60 (Peterson Direct).
[990] *Id.* at 60.

Book, Section IX, Page No. 1, Community-Based Energy Development (C-BED).

730. No party opposed these minor tariff modifications.

731. The Judge agrees that the Company's proposed changes are reasonable and should be approved.

3. Revenue Mechanisms - Wholesale Customer Outlook – Hibbing Public Utilities

732. The Company's 2022 test year forecast for the required resale customer class, which includes sales to Superior Water, Light and Power (SWLP) and Minnesota Power's municipal customers, is 1,418,539 MWh.[991]

733. The forecast accounts for several substantial changes, including: (1) the Husky Oil Refinery explosion and subsequent idling that affects sales to SWLP, (2) the termination of Xcel Energy's agreement with Laurentian Energy Authority and subsequent changes in Hibbing Public Utilities' and Virginia Public Utilities' generation, which has reduced purchases from Minnesota Power, and (3) the expiration of Public Utilities of Brainerd's contract with Minnesota Power on July 1, 2019.[992]

734. As reported in Minnesota Power's Compliance Report to the Commission filed on May 11, 2022, in Docket No. E015/M-21-28, Minnesota Power entered into a new Long-Term Boswell Power Purchase and Market Energy Services Agreement with Hibbing Public Utilities (HPU) on April 11, 2022. This agreement replaces all requirements ESA that was entered into by the parties in 2015 (2015 ESA).[993]

735. The Department and MP agreed to address the HPU Agreement in the fuel and purchased energy filing. In addition, MP agreed to remove impacts from the new HPU Agreement in the rate case.[994]

736. The Judge finds the resolution on this issue reasonable and should be accepted.

4. Products and Services – Resolved Issues - Customer Affordability of Residential Electricity (CARE) Program

737. Pursuant to the partial settlement agreement between the Company, ECC, and CUB, the Company will request Commission approval to increase the annual Customer Affordability of Residential Electricity (CARE) program budget under Docket

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[991] Ex. MP-30 at 80-82 (Frederickson Direct).
[992] *Id.*
[993] Ex. MP-32 at 28, Sch. 15 (Frederickson Rebuttal); *In the Petition by Minnesota Power for Approval of its Industrial Demand Response Produce C Contracts*, MPUC Docket No. E015/M-21-28, Compliance Report (May 11, 2022).
[994] Ex. DOC-3 at 42-43, NAC-S-4 (Campbell Surrebuttal).

No. E015/M-11-409. This agreement provides for proposed increases to the CARE flat discount and extension of the CARE flat discount/affordability credit to non-LIEHAP, low-income customers.[995]

738. Specifically, the Company will request the following changes to the CARE program:

- Increase, up to $429,303, the annual budget for the CARE Program. The CARE budget increase is based on three proposed program changes and related assumptions: 1) increasing the amount of the current CARE flat discount from $15 to $20/month, 2) extending the CARE flat discount to an estimated 80 percent of the anticipated additional 12,447 non-LIHEAP, low-income customers, and 3) extending the CARE affordability credit to an estimated 20 percent of the anticipated additional 12,447 non-LIHEAP, low-income customers. Items 2 and 3 would be a CARE qualification exception for those who initially self-declare as low-income, using a process approved in Docket No. E015/M-20-850. Continued eligibility for the CARE program, beyond the initial exception, would be subject to customers requesting and being approved for LIHEAP within one-year of their low-income self-declaration.

- The CARE program changes will be submitted as a program modification request through Docket No. E015/M-11-409 and subject to Commission approval.[996]

739. The Judge finds that the partial settlement agreement is reasonable and in the public interest regarding the Company's commitments to changing the CARE program. The Judge recommends that it be adopted.

CONCLUSIONS OF LAW

1. The Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. § 14.50 (2022) and Chapter 216B.

2. The public and parties received proper and timely notice of the hearing and Minnesota Power complied with all procedural requirements of statute and rule.

3. Every rate made, demanded, or received by any public utility shall be just and reasonable.[997] Rates must not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but rather, must be sufficient, equitable, and consistent in application to a class of customers. In addition, to the maximum reasonable extent, the

[995] Ex. MP-20 at 11-13, Schedule 2 (Cady Surrebuttal).
[996] *Id.*, Sch. 2.
[997] Minn. Stat. § 216B.03.

Commission must set rates to encourage energy conservation and renewable energy use and to further the goals of Minn. Stat. §§ 216B.164, 216B.241, and 216C.05 (2022).[998]

4. The burden of proof is on the public utility to show that a rate change is just and reasonable.[999]

5. The record supports the resolution of the settled, resolved, and uncontested matters set forth in this Report and Minnesota Power's initial filing. These matters have been resolved in the public interest and are supported by substantial evidence.

6. The rates set in accordance with this Report would be just and reasonable.

7. Any of the foregoing findings of fact that are more properly characterized as conclusions of law are hereby adopted as conclusions of law.

RECOMMENDATION

Based on the foregoing findings of fact and conclusions of law, the Administrative Law Judge makes the following recommendations:

1. The Commission should determine that Minnesota Power is entitled to increase gross annual revenues in the manner and in the amount consistent with the findings and conclusions of this Report.

2. The concepts set forth in these findings and conclusions should govern the mathematical and computational aspects of the findings and conclusions. The computations should be adjusted so as to conform to the conclusions of the Report.

Dated: September 1, 2022

JIM MORTENSON
Administrative Law Judge

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.1275, .2700 (2021), unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Minn. R. 7829.2700, subp. 3. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

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[998] *Id.*
[999] Minn. Stat. § 216.16, subd. 4.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge’s recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

MINNESOTA
OFFICE OF
ADMINISTRATIVE
HEARINGS

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September 1, 2022

See Attached Service List

Re: ***In re the Application by Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota***

OAH 5-2500-38008
MPUC No. E015/GR-21-335

To All Persons on the Attached Service List:

Enclosed and served upon you is the Administrative Law Judge's **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS** in the above-entitled matter.

If you have any questions, please contact me at (651) 361-7874, michelle.severson@state.mn.us, or via facsimile at (651) 539-0310.

Sincerely,

Michelle Severson

MICHELLE SEVERSON
Legal Assistant

Enclosure
cc: Docket Coordinator

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
PO BOX 64620
600 NORTH ROBERT STREET
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CERTIFICATE OF SERVICE

In re the Application by Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota	OAH Docket No.: 5-2500-38008

On September 1, 2022, a true and correct copy of the **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS** was served by eService, and United States mail, (in the manner indicated below) to the following individuals:

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