STATE OF MINNESOTA
BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Review of the July 2018-December 2019 Annual Automatic Adjustment Reports	MPUC Docket No. E-999/AA-20-171 OAH Docket No. 82-2500-37082

MINNESOTA POWER'S PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION

July 12, 2021

MINNESOTA POWER

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I. INTRODUCTION

The above-entitled matter came before Administrative Law Judge Barbara J. Case pursuant to the Order Accepting 2018-2019 Electric AAA Reports; Notice of and Order for Hearing ("Order for Hearing") issued by the Minnesota Public Utilities Commission ("Commission") on September 16, 2020.[1] An evidentiary hearing was held on June 3, 2018 via Microsoft Teams. Post-hearing initial briefs were filed by the parties on June 28, 2021, and reply briefs were filed on July 12, 2021. The hearing record closed on July 12, 2021, following receipt of the last responsive briefs.

A. Appearances

Kodi J. Verhalen, Matthew R. Brodin, and Elizabeth M. Brama, Attorneys at Law, Taft Stettinius & Hollister LLP, 2200 IDS Center, 80 South Eighth Street, Minneapolis, Minnesota 55402, and David R. Moeller, Senior Attorney and Director of Regulatory Compliance, 30 West Superior Street, Duluth, Minnesota 55802, appeared on behalf of the Minnesota Power ("Minnesota Power" or the "Company").

Katherine M. Hinderlie and Richard E.B. Dornfeld, Assistant Attorneys General, 445 Minnesota Street, Suite 1800, St. Paul, Minnesota 55101, appeared for and on behalf of the Minnesota Department of Commerce, Division of Energy Resources ("Department" or "DOC").

Andrew P. Moratzka, Sarah J. Phillips, Jessica L. Bayles, and Riley A. Conlin, Attorneys at Law, Stoel Rives, LLP, 33 South Sixth Street, Suite 4200, Minneapolis, Minnesota 55402, appeared for and on behalf of the Large Power Intervenors ("LPI").

Jason Bonnett and Jorge Alonso, Commission staff, 121 Seventh Place East, Suite 350, St. Paul, Minnesota 55101, also participated in the hearing.

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[1] *In the Matter of the Review of the July 2018-December 2019 Annual Automatic Adjustment Reports*, MPUC Docket No. E-999/AA-20-171, ORDER ACCEPTING 2018-2019 ELECTRIC AAA REPORTS; NOTICE OF AND ORDER FOR HEARING at 4-5 (Sept. 16, 2020) (eDocket No. 20209-166630-01). The Order for Hearing was marked and received into the record at the evidentiary hearing as Ex. 1.

B. Statement of Issues

On March 2, 2020, Minnesota Power submitted its Annual Automatic Adjustment of Charges ("AAA") Report – Electric ("2020 AAA Report"). The 2020 AAA Report was submitted pursuant to Minn. R. 7825.2800 through 7825.2840 (2019), which are the Commission's rules governing the required filings of AAA reports and Commission review of these reports. Among other things, electric public utilities are required to submit detailed information in the AAA reports supporting the automatic adjustment of energy-related costs over a certain period, which electric public utilities reflect in an automatic adjustment of charges tariff authorized by the Commission.[2] Specifically, Minnesota Power's tariff contains a fuel adjustment clause ("FAC") that contains a formula for automatically adjusting rates for energy-related costs outside of a general rate case. These automatic adjustments are later subject to Commission review and approval, which the Commission is conducting in the instant docket for the period of July 1, 2018 to December 31, 2019.

The Department reviewed Minnesota Power's AAA report filed in this docket and submitted its own report summarizing its review.[3] While the Department concluded that Minnesota Power had substantially complied with the AAA reporting requirements, the Department ultimately concluded that certain expenditures for unplanned outages incurred by Minnesota Power were not reasonable and prudent, and as a result, the Department recommended that Minnesota Power should reimburse customers for half of these unplanned outage costs.[4] The Company opposed this recommendation.[5]

On September 16, 2020, the Commission issued its Order for Hearing and accepted the AAA reports as substantially in compliance with applicable statutes, rules, and previous Commission orders, but the Commission found a genuine issue of material fact as to whether Minnesota Power's unplanned outage costs for the period were reasonable and prudent and referred this issue to the Office of Administrative Hearings ("OAH") for a contested case proceeding.[6]

In its Order for Hearing, the Commission stated the following regarding the issues to be addressed:

> Over the course of this case, the Commission expects the parties will thoroughly develop a full record addressing, at a minimum, whether Minnesota Power's forced outage costs for the period were reasonable and prudent and, if not, the amount of overcharges (plus interest) that should be returned to ratepayers through the FCA.[7]

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[2] *See* Minn. Stat. § 216B.16, subd. 7 (2020); Minn. R. 7825.2390-.2920 (2019).
[3] REVIEW OF THE JULY 2018-DECEMBER 2019 ANNUAL AUTOMATIC ADJUSTMENT REPORTS, Apr. 15, 2020 (eDocket No. 20204-162132-02).
[4] Ex. 9, Schedule 1 at 10 (Rostollan Direct); Ex. 5, Schedule 4 (Simmons Direct).
[5] Ex. 5, Schedules 3 and 5 (Simmons Direct).
[6] ORDER FOR HEARING at 4-5 (Ex. 1).
[7] ORDER FOR HEARING at 5 (Ex. 1).

In the First Prehearing Order, the Administrative Law Judge summarized the issues as follows:

1. Whether Minnesota Power's forced outage costs for the period of July 2018 through December 2019 were reasonable and prudent, and, if not, the amount of overcharges (plus interest) that should be returned to ratepayers through the Fuel Clause Adjustment Mechanism; and
2. Whether Minnesota Power incurred the forced outage costs reasonably and prudently, applying good utility practices.[8]

Over the course of the proceedings, the parties also provided testimony as to whether Minnesota Power's generation maintenance and inspection practices leading up to the unplanned outages and actions undertaken during the unplanned outages were consistent with good utility practice.

C. Legal Standard

1. Reasonable and Prudent, Applying Good Utility Practices

In the Order for Hearing, the Commission stated that "Minnesota Power will bear the burden of proving that any or all of its forced outage costs were reasonably and prudently incurred, applying good utility practices."[9]

2. Burden of Proof

A public utility like Minnesota Power has the burden of proving by a fair preponderance of the evidence that any proposed change in rates is just and reasonable.[10] A public utility meets its burden of proof by producing affirmative evidence that its costs were prudent and reasonable and that the utility acted reasonably in incurring the costs.[11]

In determining whether to include a claimed cost in rates, the Commission exercises both quasi-judicial and quasi-legislative authority.[12] On the one hand, the Commission acts in a judicial capacity in its fact-finding function to determine the validity of presented facts, and on the other hand, the Commission acts in a legislative function when it balances both cost and non-cost factors in order to arrive at a conclusion among various alternatives.[13] That is, a public utility must demonstrate both the accuracy of costs incurred in serving its customers and that it would be just and reasonable for it to recover these costs from its customers in rates rather than from its shareholders. Once a public utility has presented substantial evidence, establishing by a fair

[8] *In the Matter of the Review of the July 2018-December 2019 Annual Automatic Adjustment Reports*, MPUC Docket No. E-999/AA-20-171, OAH Docket No. 82-2500-37082, FIRST PREHEARING ORDER at 2 ("First Prehearing Order").
[9] ORDER FOR HEARING at 4 (Ex. 1).
[10] Minn. Stat. § 216B.16, subd. 4 (2020); *In re N. States Power Co.*, 416 N.W.2d 719, 722-23 (Minn. 1987).
[11] *See In re N. States Power Co.*, 416 N.W.2d at 723.
[12] *Id.* at 722-23.
[13] *See City of Moorehead v. Minn. Pub. Utils. Comm'n*, 343 N.W.2d 843, 846 (Minn. 1984); *see also St. Paul Area Chamber of Commerce v. Minn. Pub. Utils. Comm'n*, 251 N.W.2d 350, 358 (Minn. 1977).

preponderance of the evidence that its proposed rate change is just and reasonable, then it has met its burdens of production and proof.

D. Summary of Conclusions and Recommendations

As demonstrated by the record, Minnesota Power has provided affirmative evidence, not only that replacement power costs were prudently incurred during the unplanned outages experienced from July 1, 2018 through December 31, 2019, applying good utility practices, but that the Company's generation maintenance programs are consistent with good utility practice.

Because Minnesota Power has met its burdens of production and persuasion, it has demonstrated by a fair preponderance of the evidence that its replacement power costs were prudently incurred during the planned outages experienced from July 1, 2018 through December 31, 2019. The Company has also demonstrated that its generation maintenance programs are consistent with good utility practice.

Therefore, the Administrative Law Judge recommends that the Commission not require the Company to refund any unplanned outage costs through the FAC.

II. FINDINGS OF FACT

A. Parties to the Proceeding

1. Minnesota Power, a public utility operating division of ALLETE, Inc., is an investor-owned utility headquartered in Duluth, Minnesota. Minnesota Power serves about 145,000 retail electric customers and 15 municipal systems across a 26,000-square-mile service area in central and northeastern Minnesota. Minnesota Power has eight Large Power customer contracts, each serving at least 10 megawatts ("MW") of load.

2. The Department advocates for the public interest in utility proceedings before the Commission.[14] The Department staff files testimony and argument addressing the reasonableness of the utility's request.

3. LPI is composed of some of Minnesota Power's largest industrial customers, including: ArcelorMittal USA (Minorca Mine); Blandin Paper Company; Boise Paper, a Packaging Corporation of America company, formerly known as Boise, Inc.; Enbridge Energy Limited Partnership; Gerdau Ameristeel US Inc.; Hibbing Taconite Company; Northern Foundry, LLC; Sappi Cloquet, LLC; USG Interiors, Inc.; United States Steel Corporation (Keetac and Minntac Mines); and United Taconite, LLC.[15] The Administrative Law Judge granted LPI's petition to intervene.[16]

[14] *See* Minn. Stat. § 216A.07, subds. 2-3 (2020).
[15] PETITION TO INTERVENE, Sept. 30, 2020 (eDocket No. 20209-166962-02).
[16] FIRST PREHEARING ORDER at 3 (eDocket No. 202010-167586-02) (Ex. 3).

B. Jurisdiction

4. The Commission has general jurisdiction over Minnesota Power under Minn. Stat. §§ 216B.01, 216B.03, and 216B.04 (2020). The Commission has specific jurisdiction over this matter under Minn. Stat. § 216B.16, subd. 7 and Minn. R. 7825.2390-.2920.

5. This case was properly referred to OAH under Minn. Stat. §§ 14.48-.62 (2020) and Minn. R. 1400.5010-.8400 (2019).

C. Procedural History

6. On March 2, 2020, Minnesota Power filed its 2020 AAA Report.[17]

7. On April 15, 2020, the Department filed its Review of the July 2018-December 2019 Annual Automatic Adjustment Reports.[18]

8. On April 30, 2020, Minnesota Power filed Reply Comments in which it provided additional information requested by the Department in its Report.[19]

9. On May 29, 2020, the Department filed its Response Comments.[20]

10. On June 10, 2020, Minnesota Power filed a supplement to the 2020 AAA Report.[21]

11. On July 1, 2020, Minnesota Power filed Additional Comments in response to the Department's May 29, 2020 Response Comments.[22]

12. On July 24, 2020, the Department filed Additional Response Comments in response to the Company's July 1, 2020 Additional Comments.[23]

13. On July 31, 2020, Minnesota Power filed a letter in response to the Department's Additional Response Comments of July 24, 2020.[24]

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[17] 2020 AAA REPORT (eDocket No. 20203-160872-01).

[18] REVIEW OF THE JULY 2018-DECEMBER 2019 ANNUAL AUTOMATIC ADJUSTMENT REPORTS, Apr. 15, 2020 (eDocket No. 20204-162132-02).

[19] REPLY COMMENTS OF MINNESOTA POWER, Apr. 30, 2020 (eDocket No. 20204-162709-01).

[20] RESPONSE COMMENTS OF THE DEPARTMENT, May 29, 2020 (eDocket No. 20205-163578-01) (Ex. 9, Schedule 1 (Rostollan Direct)).

[21] 2020 AAA REPORT SUPPLEMENT, June 10, 2020 (eDocket No. 20206-163842-01) (Ex. 5, Schedule 2 (Simmons Direct)).

[22] ADDITIONAL COMMENTS OF MINNESOTA POWER, July 1, 2020 (eDocket No. 20207-164474-01) (Ex. 5, Schedule 3 (Simmons Direct)).

[23] ADDITIONAL RESPONSE COMMENTS OF THE DEPARTMENT, July 24, 2020 (eDocket No. 20207-165268-01) (Ex. 5, Schedule 4 (Simmons Direct)).

[24] LETTER OF MINNESOTA POWER, July 31, 2020 (eDocket No. 20207-165493-01) (Ex. 5, Schedule 5 (Simmons Direct)).

14. After meeting on August 20, 2020 to consider Minnesota Power's 2020 AAA Report, on September 16, 2020, the Commission issued the Order for Hearing referring the case to OAH to "thoroughly develop a full record addressing, at a minimum, whether Minnesota Power's forced outage costs for the period were reasonable and prudent and, if not, the amount of overcharges (plus interest) that should be returned to ratepayers through the FCA."[25]

15. The Order for Hearing established Minnesota Power and the Department as parties to this proceeding.[26]

16. On September 30, 2020, LPI petitioned to intervene.[27]

17. On October 14, 2020, LPI moved to admit Jessica L. Bayles pro hac vice.[28]

18. On October 15, 2020 at 10:00 a.m., the Administrative Law Judge held a prehearing conference by telephone.

19. On October 22, 2020, the Administrative Law Judge issued the First Prehearing Order, which, among other things, established an initial schedule for the contested case. The Administrative Law Judge also granted LPI's petition to intervene and Jessica L. Bayles's motion to appear pro hac vice on behalf of LPI. [29]

20. On October 22, 2020, the Administrative Law Judge issued a Protective Order.[30]

21. On December 17, 2020, the Administrative Law Judge issued a Second Prehearing Order,[31] which, among other things, amended the procedural schedule for the contested case, and set the following procedural schedule:

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[25] ORDER FOR HEARING at 4-5 (Ex. 1).
[26] *Id.*
[27] LPI PETITION TO INTERVENE (Sept. 30, 2020) (eDocket No. 20209-166962-02).
[28] LPI MOTION FOR ADMISSION OF JESSICA L. BAYLES PRO HAC VICE (Oct. 14, 2020) (eDocket No. 202010-167280-01).
[29] FIRST PREHEARING ORDER at 2-3 (Ex. 3).
[30] *In the Matter of the Review of the July 2018-December 2019 Annual Automatic Adjustment Reports*, MPUC Docket No. E-999/AA-20-171, OAH Docket No. 82-2500-37082, PROTECTIVE ORDER (eDocket No. 202010-167586-01) (Ex. 2).
[31] *In the Matter of the Review of the July 2018-December 2019 Annual Automatic Adjustment Reports*, MPUC Docket No. E-999/AA-20-171, OAH Docket No. 82-2500-37082, SECOND PREHEARING ORDER (eDocket No. 202012-169108-01) ("Second Prehearing Order") (Ex. 4).

Document or Event	Due Date
Direct Testimony (Minnesota Power)	January 26, 2021
Deadline for Intervention	March 19, 2021
Direct Testimony (Other Parties)	April 19, 2021
Rebuttal Testimony (All Witnesses)	May 24, 2021
Status Conference	May 28, 2021
Evidentiary Hearings	June 3, 2021
Initial Briefs	June 28, 2021
Reply Briefs & Proposed Findings of Fact	July 12, 2021
Administrative Law Judge Report	August 11, 2021

22. On January 26, 2021, Minnesota Power filed the direct testimony and schedules of Todd Z. Simmons, William Poulter, Paul J. Undeland, Leann Oehlerking-Boes, and Joshua G. Rostollan.[32]

23. On April 19, 2021, the Department filed the direct testimony and attachments of Richard A. Polich and Nancy A. Campbell.[33]

24. On May 12, 2021, the Department filed errata to the direct testimony of Richard A. Polich.[34]

25. On May 24, 2021, Minnesota Power filed the rebuttal testimony and schedules of Paul J. Undeland, Leann Oehlerking-Boes, and Joshua G. Rostollan.[35]

26. On May 27, 2021, Minnesota Power filed errata to the direct testimony of Joshua G. Rostollan.[36]

27. On May 28, 2021, the Administrative Law Judge convened a status conference by telephone.

28. On June 3, 2021, the Administrative Law Judge held a one-day evidentiary hearing via Microsoft Teams.

29. On June 2, 2021, Minnesota Power, the Department, and LPI filed initial post-hearing briefs.

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[32] Exs. 5-9 (Simmons, Poulter, Undeland, Oehrlinking-Boes, and Rostollan Direct).
[33] Exs. 10-13 (Campbell and Polich Direct) (Public and Nonpublic).
[34] Exs. 10 and 11 (Polich Direct Errata) (Public and Nonpublic).
[35] Exs. 14-18 (Undeland, Oehlerking-Boes, and Rostollan Rebuttal) (Public and Nonpublic).
[36] Ex. 9 (Rostollan Direct Errata).

D. The Parties Agreed on the Definition of "Good Utility Practice"

30. Minnesota Power generally agreed with the Department's definition of "good utility practice."[37] According to Department witness Richard A. Polich, "good utility practice" is defined as:

> [A]ny of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition.
>
> I note that "Good Utility Practice" is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to refer to acceptable practices, methods, or acts generally accepted in the region in which the Project is located. "Good Utility Practice" includes, but is not limited to, North American Reliability Corporation (NERC) criteria, rules, guidelines, and standards, Federal Energy Regulatory Commission (FERC) criteria, rules, guidelines, and standards, and Minnesota Public Utilities Commission criteria, rules, guidelines, and standards, where applicable, and as they may be amended from time to time, including the rules, guidelines, and criteria of any predecessor or successor organization to the foregoing entities.[38]

31. The Company agreed that "'Good Utility Practice' is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to refer to acceptable practices, methods, or acts generally accepted in the region in which the Project is located."[39]

32. "Good utility practice" in the context of power producing facilities such as Boswell is the product of many different sources of information, including OEM recommended practice and procedures, accepted standards, hands-on experience with the equipment, continuing education and external training of personnel, information shared through interaction with operators of similar equipment, and relevant information from news outlets and trade articles. Additionally, independent consultants and contractors, especially those who have an expansive client base within the electric utility industry, are a very good source of information regarding the maintenance and inspection programs and practices in place at similar operating units in the region and throughout the country.[40]

33. The Administrative Law Judge agrees with the parties' testimony regarding the definition of "good utility practice." The Administrative Law Judge further finds that "good utility practice" does not require knowing more than industry experts or manufacturers of products used in the utility industry in exercising reasonable judgment.

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[37] Exs. 14 and 15 at 8 (Undeland Rebuttal) (Public and Nonpublic).
[38] Exs. 10 and 11 at 6-7 (Polich Direct) (Public and Nonpublic).
[39] *Id*.
[40] *Id.* at 9.

E. Variations Between Actual and Test Year Generation Maintenance Expenses Are Not Evidence of Failure to Comply with Good Utility Practice

34. In mid-2020, The Department initially recommended in the AAA proceeding that the Commission require a refund of a portion of Minnesota Power's unplanned outage expenses because the Department erroneously drew a causation connection between generation maintenance expense lower than the last-approved test year amounts and the unplanned outages that occurred from July 1, 2018 through December 31, 2019, at Boswell. The Department reached this conclusion without engineering analysis of Minnesota Power's generation maintenance programs.[41]

35. The Department took particular issue with three high-impact outages that occurred in 2019: (1) the hydrogen gas leak outage at Boswell Energy Center ("Boswell") Unit 3 ("BEC3"); (2) the phase bushing failure outage at BEC3; and (3) the hot reheat ("HRH") steam line seam weld failure outage at Boswell Unit 4 ("BEC4").[42]

36. During this contested case proceeding, the Department abandoned its initial argument that the generation maintenance cost levels are evidence that Minnesota Power's maintenance and inspection programs were not consistent with good utility practice.[43]

37. The Department's original justification for recommending a refund assumed that a correlation equated to causation between Minnesota Power's lower-than-test-year generation maintenance expenses in 2018 and 2019 and the number and cost of unplanned outages at Boswell over that period. In doing so, the Department failed to consider the critical factual context or acknowledge that differences between test year and actual maintenance spending are completely normal and expected or, as in this case, can be explained by other factors.[44]

38. Rate cases use the concept of a test year for purposes of establishing just and reasonable base rates for customers. Generally speaking, a test year allows a comparison of a utility's base costs over a defined period (i.e., the test year), including operating expenses, with its total revenues from electricity sales. A future test year uses forecasts of expenses and sales that are intended to be reasonably representative of both actual costs and revenues of a utility but are not intended to match exactly actual costs and revenues.[45] The Commission has previously described the "test year" method as follows:

> Rates that ratepayers pay are based on representative levels of revenue, costs, and investments in a "test year" determined at the time of the most recent rate case. Once rates are set, they are considered to be reasonable until they are changed in the next rate case, or pursuant to any pass-through mechanisms that have been

[41] *See* Ex. 9, Schedule 1 at 10, 14-15 (Rostollan Direct).
[42] Ex. 5, Schedule 4 at 7-8 (Simmons Direct).
[43] Ex. 12 and 13 at 24 (Campbell Direct) (Public and Nonpublic) ("Importantly, these adjustments are ultimately irrelevant to the Commission's directive . . . ."); *see also* Department Initial Brief.
[44] Ex. 5, Schedule 3 at 7-11 (Simmons Direct).
[45] Ex. 9 at 6-7 (Rostollan Direct).

> approved by the Commission. Although individual cost components that were used to develop the rates may vary (increase or decrease) after the rates are set, no adjustment (with the exception of the pass-throughs) is made outside of a rate case for increases or decreases in the individual components of rates.[46]

39. Thus the Commission does not expect that utilities will spend, or will seek to spend, the exact amounts included in the test year, but rather understands that actual spend will vary from year to year for a multitude of reasons.

40. In direct testimony, the Department largely concurred that "expenses approved in the test year are not intended to exactly reflect actual spending levels . . . and "the Commission does not approve generation maintenance expense on a plant-by-plant basis."[47]

41. Rather than using the test year as a basis for budgeting purposes, the Company establishes its maintenance expense budget using a "zero-based" process.[48] This requires building the budget from a baseline, while taking into account historical amounts and activities as well as operational changes.[49] In doing so, the Company evaluates its operating and maintenance needs for that year based on multiple inputs including labor, equipment, tools, and supplies.[50] The amount budgeted in a given year for generation maintenance fluctuates, in part, based on the length and scope of planned outages each year at the Company's generation units according to the long-term outage plan.[51]

42. Consistent with the outage plan, the length and scope of the outages vary each year, which, in turn, causes fluctuations in the generation maintenance expense from year to year.[52] In addition, organizational and operational changes, as well as the evolution of operating and maintenance practices, can impact the amount of a specific expense incurred compared to a given test year. Ultimately, the Company invests in maintenance expenses across the Company where it is needed to best serve customers in any given year, which may or may not match the Company's representative test year budget for a specific maintenance category.

43. In the present proceeding, the differences between the 2017 test year maintenance budget and the actual maintenance expenses for 2018 and 2019 can largely be explained due to the retirement of certain generation facilities in 2018 and 2019, changes to the maintenance expenses of facilities that did not contribute to unplanned outages, and higher than projected capitalization of maintenance projects that unexpectedly grew in scope.[53]

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[46] *In re the Complaint of Myer Shark et al. Regarding Xcel Energy's Income Taxes*, Docket No. E, G-002/C-03-1871, ORDER AMENDING DOCKET TITLE AND DISMISSING COMPLAINT at 4 (Oct. 1, 2004).
[47] Exs. 12 and 13 at 24 (Campbell Direct) (Public and Nonpublic).
[48] Ex. 9 at 4-6 (Rostollan Direct).
[49] *Id*.
[50] *Id*.
[51] *Id*.
[52] *Id*.
[53] *Id.* at 17, 22-23.

44. Taking these explainable differences between the 2017 test year and 2018 to 2019 actual spend into account, the Company's actual maintenance spend for Boswell in 2018 and 2019 was only about $1.9 million, or 5.4 percent (as an average over that period), lower than the test year.[54] That difference, however, is almost entirely due to the fact that the 2017 test year amount included a three-week boiler outage at BEC4, which, consistent with its long-term outage plan, had much shorter planned outages in 2018 and 2019, but would occur again in future years. This difference in length and scope of planned outages, associated with plant systems not the subject of the primary outages the Department raised issues with, contributed to lower generation maintenance expense of approximately $1.5 million in 2018 and $2.2 million in 2019 as compared to the 2017 test year.[55] Thus, the lower amount of maintenance spending in 2018 and 2019 compared to the 2017 test year, which the Department relied upon to justify its initial refund recommendation, was caused by operational differences that are entirely unrelated to the outages at issue in this proceeding.

45. The evidence demonstrates that Minnesota Power has made no reductions in the maintenance and inspection protocols related to the systems affected by unplanned outages during the applicable period.[56] The Department neither produced nor pointed to any evidence of maintenance or inspection program reductions.

46. When comparing Boswell's maintenance expenses to those of other similarly sized coal-fired units across the country, BEC3 and BEC4's maintenance expense per megawatt ("MW") of installed capacity from 2015 to 2019 is slightly higher than the average of the other comparable facilities.[57] More specifically, Boswell's 2019 maintenance expense per MW of installed capacity was approximately eight percent higher than the average of the other comparable facilities over this time period.[58]

47. This demonstrates that the amount of maintenance expenses incurred for BEC3 and BEC4 is consistent with other comparable facilities, which is contrary to the Department's theory that the Company reduced its maintenance spending below industry norms or good utility practice.

48. Several other metrics further demonstrate that Minnesota Power is maintaining its generating facilities consistent with good utility practice. For example, the Department's own analysis of outage costs as a percentage of energy costs for each Minnesota investor-owned utility shows that over the last ten AAA periods (2010 to 2019), Minnesota Power's outage costs as a percentage of energy costs are on par with Xcel Energy's averages.[59] For the 2019 AAA period specifically, outage costs as a percentage of energy costs for Minnesota Power were 2.92 percent.[60] This is nearly 30 percent lower than the Company's 10-year average and is the third lowest

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[54] Ex. 9 at 20 (Rostollan Direct).
[55] *Id.* at 22-23.
[56] Ex. 6 at 11 (Poulter Direct); Ex. 5 at 15-20 (Simmons Direct); Exs. 14 and 15 at 17 (Undeland Rebuttal) (Public and Nonpublic).
[57] Ex. 9 at 12 (Rostollan Direct).
[58] *Id.* at 13.
[59] *Id*.
[60] *Id*. at 13-14.

percentage in that 10-year period.[61] The 2.92 percent during the 2019 AAA period for the Company is also approximately 10 percent lower than Xcel Energy's 3.25 percent for the same period.[62] This analysis indicates that Minnesota Power's outage costs as a percentage of energy costs for the 2019 AAA period were reasonable compared to the Company's historical average as well as Xcel Energy's 2019 AAA period and historical average.

49. The fuel and purchased power costs per megawatt-hour ("MWh") for Minnesota Power customers during the 18-month period were also about six percent lower than the customers of other Minnesota investor-owned utilities.[63] This shows that Minnesota Power's rates for fuel and purchased power are not only reasonable, they are actually lower than the average rates of the other Minnesota utilities over the relevant time period.

F. <u>Minnesota Power's Maintenance and Inspection Programs Were Consistent with Good Utility Practice</u>

1. <u>Minnesota Power's Maintenance and Inspection Programs Were Developed Consistent with Good Utility Practice</u>

50. To ensure that its maintenance and inspection programs are consistent with good utility practice, Minnesota Power utilizes many different sources of information and expertise to develop and analyze its programs. Specifically, Minnesota Power's maintenance programs incorporate applicable OEM recommended practices and procedures, industry-accepted and applicable standards, Minnesota Power's decades of hands-on experience with the equipment, continuing education and external training of maintenance personnel, information shared through trade groups and interaction with operators of similar equipment, recommendations from independent engineering vendors and outside consultants, its own internal learning teams, and relevant information from news outlets and trade articles.[64]

51. The various maintenance programs at Boswell continuously evolve as new procedures and technologies are introduced across the industry and become more economical and practical to use. Minnesota Power also seeks input from independent consultants, contractors, independent consultants, and the Company's insurers to inform Boswell about the programs utilized at other operating units and help evaluate whether those programs (or potions thereof) should be incorporated into Boswell's maintenance program.[65]

52. The Company had its preventative maintenance process audited by third-party consultants Idcon, Reliability Solutions, Genesis Solutions, and RMG approximately a decade ago.[66] The audit concentrated on the Boswell facility but also provided opinions on the other generating facilities including hydro and the renewable energy stations.[67] The audit resulted in

[61] *Id*.
[62] Ex. 9 at 14 (Rostollan Direct).
[63] *Id*.
[64] Exs. 14 and 15 at 9 (Undeland Rebuttal) (Public and Nonpublic).
[65] Ex. 6 at 7 (Poulter Direct).
[66] *Id.* at 14.
[67] *Id.*

additional training in the form of Reliability University, which over 60 engineers, superintendents, and maintenance leads attended and led to modifications of the overall maintenance work process.[68] Minnesota Power's insurance carrier, FM Global, also reviewed the Company's maintenance plans and records and provided recommendations and guidelines to minimize risks.[69]

53. To plan maintenance and inspection activities at Boswell, the Company utilizes a 10-year rolling schedule that corresponds with the OEM and insurer recommended inspection interval for the turbines in each facility.[70] Table 1 provides a generalized turbine and boiler major outage schedule for these units.

Table 1. Generalized Turbine and Boiler Major Outage Schedule[71]

Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Major Outage			Boiler Outage		Half-Major Outage			Boiler Outage		Major Outage
6-8 weeks			3 weeks		6-8 weeks			3 weeks		6-8 weeks

54. Boiler and turbine outages are planned in tandem to minimize facility downtime due to planned outages. In year zero, the Company conducts a six to eight week "Major Outage," which consists of a five-year turbine outage as well as a ten-year major boiler outage. A standard boiler outage, which typically takes approximately three weeks, is scheduled for 30 months after the initial major outage. In year five, the Company conducts a "Half-Major" outage, which consists of a five-year turbine outage along with a standard boiler outage. Another three-week standard boiler outage is scheduled for 30 weeks after the Half-Major outage. Finally, in year 10 the outage schedule starts over again with another six to eight week "Major Outage."[72]

55. Four- to five-day maintenance outages are also scheduled for every spring and fall when there is less demand on the system and replacement power costs are lower. The Company uses these short outages to clean and inspect the boiler and perform balance of plant work that is needed to keep the units operating safely and reliably until the next scheduled boiler or turbine outage.[73] When issues arise between scheduled outages that were not accounted for in existing outage planning, they are added to a "hot list" of items that will be completed at the next practicable scheduled or unscheduled outage.[74]

56. The long-term outage schedule is reviewed and updated at least once a year and outage dates are scheduled with Midcontinent Independent System Operator, Inc. ("MISO") two years in advance. Capital projects are aligned with the outage schedule years in advance. As soon

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[68] *Id.*
[69] Ex. 7 at 25 and 34, Schedule 3 at 7 and 11 (Undeland Direct).
[70] An example long-term outage schedule is included in Ex. 5, Schedule 6 (Simmons Direct).
[71] *Id.* at 7.
[72] *Id.* at 8.
[73] *Id.*
[74] *Id.* at 8-9.

as a scheduled outage is complete, the Company begins detailed preparation for the next planned outage.[75] The outage plan preparation process is detailed in the direct testimony of Company witness Mr. Simmons.[76]

57. Minnesota Power collaborates with third-party consultants to aid in developing outage schedules, inspections, and repair plans when industry expertise in a particular area is necessary or would be beneficial to the planning and implementation of the outages.[77] Minnesota Power does not, however, hire specialty consultants to perform overall outage scheduling and planning for the Company, but rather selectively incorporates the recommendations of contractors into the Company's broader outage planning and scheduling.[78] Minnesota Power's Boswell outage planning team works with consultants and OEMs to efficiently coordinate scheduling and the scope and timing of outage work.[79] The development of the work scope and schedule is the responsibility of the Company's Boswell outage planning team.[80]

58. One of the most significant benefits of collaborating with consultants who work at other facilities around the United States is that their industry-wide experience becomes available to Minnesota Power. OEMs and independent consulting engineers can provide Minnesota Power with valuable information about industry practices and issues that have arisen at other facilities.[81]

59. Minnesota Power also uses information from similar plants around the country when developing its outage plans. For example, the Company is a member of the Association of Edison Illuminating Companies ("AEIC"), which is a working group that serves as a network to compare best practices and lessons learned with other utilities.[82] The Company also currently holds annual benchmark meetings with the Xcel Energy Sherco Station personnel to discuss maintenance, inspection, and operational issues that are being experienced.[83]

60. In sum, Minnesota Power, and specifically Boswell, utilize a variety of resources to ensure its outage plans are consistent with good utility practice. The Company follows OEM guidelines for maintaining inspections, repairs, and upgrades to equipment, and uses those guidelines to drive the maintenance planning schedule.[84] Boswell follows all state guidelines and regulations for the inspections of its boiler piping, welding repairs inspections and HEP lines.[85] Utilizing external and internal experts provides more industry-wide expertise that better informs the Company's maintenance and inspection program planning. And finally, the Company

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75 *Id.* at 9.
76 Ex. 5 at 10-11, Schedule 7 (Simmons Direct).
77 *Id.* at 11.
78 *Id.*; Exs. 14 and 15 at 31 (Undeland Rebuttal) (Public and Nonpublic).
79 Ex. 5 at 12 (Simmons Direct).
80 *Id.*
81 *Id.*; Ex. 6 at 14-16 (Poulter Direct).
82 Ex. 5 at 13 (Simmons Direct).
83 *Id.*
84 *Id*. at 14.
85 *Id*.

leverages the experience gained through decades of operation at the facility and the knowledge and confidence of the staff to implement improvements.[86]

61. There is risk with any maintenance testing and inspection program. For example, while it may be technically possible to test every pipe in the plant every year using outages of sufficient length, such a program would not be fiscally responsible given the low probability of failure. It is the responsibility of the system engineer, in coordination with the external engineers and consultants, the other system engineers, and the plant manager, to establish the appropriate maintenance and inspection cycles.[87] These cycles are based on risk analysis of the HEP.[88]

2. Minnesota Power Implemented its Generation Maintenance and Engineering Programs Consistent with Good Utility Practice

62. The goal of Boswell's maintenance programs is to have the units available for full, reliable production when needed to provide energy to customers. Ideally, this means that a unit is available for full production except for during planned outages.[89]

63. The maintenance programs for BEC3 and BEC4 generally fall within three categories: preventative maintenance ("PM"); predictive maintenance ("PdM"); and corrective maintenance. Minnesota Power leverages several different types of resources to carry out the maintenance programs, including people, tools, parts, Computer Maintenance Management Systems ("CMMS"), and metric collection and analysis.[90]

64. Boswell uses the PM program to inspect and maintain the equipment on a time-based frequency to ensure system reliability and availability.[91] PM includes regular maintenance activities such as lubrications, minor adjustments, etc. that are scheduled based upon the calendar or runtime intervals recommended by the manufacturer or adjusted because of hands on experience with the equipment.[92]

65. The PdM program, which operates in parallel to the PM program, utilizes the latest in technology such as vibration, thermography, motor testing, and other methods to monitor the equipment while it is operating in order to predict and identify when equipment will need maintenance, repair, or replacement.[93] Plant operators utilize the Company's distributed control system ("DCS") with integrated alarms and the Black & Veatch 24/7 Asset 360 Plant System Monitoring to proactively identify abnormalities in equipment operation.[94] When abnormalities are detected, plant staff takes steps to further minimize the risk of unplanned outages with several

[86] *Id.*
[87] Ex. 6 at 4 (Poulter Direct).
[88] Exs. 14 and 15 at 18 (Undeland Rebuttal) (Public and Nonpublic).
[89] Ex. 5 at 15 (Simmons Direct).
[90] Ex. 6 at 6 (Poulter Direct).
[91] Ex. 5 at 15 (Simmons Direct).
[92] Ex. 6 at 6 (Poulter Direct).
[93] *Id.*; Ex. 5 at 15 (Simmons Direct); Ex. 7 at 3 (Undeland Direct).
[94] Ex. 7 at 2-3 (Undeland Direct).

maintenance programs and support technology.[95] Not all failures are detectable by PdM, so the program works in concert with the PM and other programs to improve reliability.[96]

66. Corrective maintenance includes day-to-day maintenance, repairs, and replacements that can occur during planned maintenance outages, unplanned outages, or while the unit is online and there is enough time to execute work prudently and safely.[97]

3. Employee Training and Certification Programs at Boswell are Consistent with Good Utility Practice

67. Minnesota Power requires that Boswell engineers, technicians, and trade employees complete a variety of internal and external training and certifications as a condition of their employment and advancement.[98] The licenses and certifications held by Boswell employees also include various continuing education requirements.[99]

68. Minnesota Power also employs a number of professional engineers ("PE") licensed in the state of Minnesota.[100] A PE license requires a four-year engineering degree, completion of a requisite number of years of engineering experience in various areas, and passing technical competency examinations.[101] Maintaining a PE license requires completion and reporting of continuing education credits.[102] Licensed PEs participate in various aspects of the Boswell maintenance programs.[103]

69. In 2011, Minnesota Power began participating in a training and education program called Reliability University as part of the Company's continued improvements to its PdM, PM, and engineering programs.[104] Reliability University instructors, who are subject matter experts in specific areas, provided training regarding best practices surrounding equipment maintenance, predictive strategies, failure analysis, pumping systems, bearing design, installation, and testing of equipment, along with the use of proactive instead of reactive tools to ensure equipment reliability.[105]

70. As employees learn new information through training and continuing education that is relevant to Boswell's systems, Minnesota Power utilizes it to improve the facility's maintenance and inspection programs.[106]

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[95] *Id.*
[96] Ex. 5 at 15 (Simmons Direct).
[97] Ex. 6 at 6 (Poulter Direct).
[98] *Id.* at 10-12.
[99] Ex. 5 at 22 (Simmons Direct).
[100] Ex. 6 at 11 (Poulter Direct).
[101] *Id.*
[102] *Id.*
[103] *Id.*
[104] Ex. 5 at 22 (Simmons Direct).
[105] *Id.*
[106] Ex. 6 at 11-12 (Poulter Direct).

4. The Occurrence of Unplanned Outages Does not Necessarily Indicate a Deviation from Good Utility Practice

71. Even if a power generation facility uses all available information and technology to create a maintenance and inspection program that applies good utility practice, unplanned outages will still occur.[107]

72. First, it is not possible to predict or avoid all types of defects through testing and monitoring.[108]

73. Second, while increased inspections and testing of almost all systems would likely reduce the overall amount of failures and unplanned outages, such testing may not be operationally or economically practical. For example, it is tremendously difficult to access, or would require a significant amount of labor hours to provide access to, certain system components.[109] These types of labor- and time-intensive inspections can only be completed during longer outages, so they may only be scheduled at the same time as major outages or they would require longer planned outages on a more frequent basis.[110] Other more frequent testing and inspection protocols would be extremely expensive when compared to the potential benefits.[111]

74. As a result, system engineers and plant managers must make judgments to weigh the costs of implementing more frequent or expensive inspection and monitoring with the potential costs associated with an outage that could have been avoided.[112]

5. Minnesota Power's Maintenance and Inspection Programs are Highly Effective

75. Unplanned outages are an unavoidable reality. As a result, Minnesota Power, and the power generation industry in general, assume and plan for a number of unplanned outages at each facility. To track and plan for these unplanned outages, the Company utilizes the Equivalent Unplanned Outage Factor ("EUOF"), which is the fraction (or percentage) of a given period in which a generating unit is not available due to outages or de-ratings.[113] The Company's 2015 Integrated Resource Plan ("IRP") utilized an EUOF of 7.4 percent for BEC3 and 7.2 percent for BEC4.[114] The EUOF calculation method follows the North American Electric Reliability Corporation ("NERC") Generation Availability Data System data reporting instructions.[115] Due to the substantial impact a significant outage can have on an EUOF in a single year or over a short

[107] Ex. 5 at 22 (Simmons Direct).
[108] *See* Ex. 7 at 8 (Undeland Direct) ("It would be extremely difficult and very expensive to eliminate all unplanned outages."); *see also* Exs. 10 and 11 at 14 (Polich Direct) (Public and Nonpublic) ("Yes, some forced outages, such as boiler leaks, are unavoidable even with the best maintenance practices.").
[109] Ex. 5 at 24 (Simmons Direct).
[110] *Id.*
[111] Ex. 7 at 8 (Undeland Direct).
[112] *See* Ex. 5 at 23-24 (Simmons Direct); *see also* Ex. 7 at 8 (Undeland Direct).
[113] Ex. 5 at 31 (Simmons Direct).
[114] *Id.*
[115] *Id.* at 32.

period, Minnesota Power looks at a ten year average for forecasting and budgeting purposes, and often excludes the most significant events from the calculations.[116]

76. To analyze the efficacy Minnesota Power's maintenance and inspection programs, it is necessary to look at a longer period of time because significant outages occur sporadically and skew short term analyses. The fifteen-year history of the actual EUOFs for BEC3 and BEC4 demonstrate trending closely with budget and IRP EUOFs, with some years lower and some years higher than budget and IRP.[117]

77. These historical trends show that, although BEC3 and BEC4's EUOFs are volatile from year to year, they have generally trended downward over time. Additionally, the EUOF levels from 2018 and 2019 are less than some of the EUOFs from prior years, demonstrating that the outages at issue did not fall outside of each facility's historical range.[118]

78. When compared to the industry, BEC3 and BEC4 have considerably outperformed their peers, even when including the outages at issue in this proceeding.[119]

79. Over the six-year period, despite annualized variations, BEC3 operated 36 percent better than the NERC average and BEC4 operated 53 percent better than NERC average.[120]

80. The EUOF history and comparison to industry peers speaks to the actual efficacy of Minnesota Power's maintenance and inspection programs at Boswell, as compared to limiting analysis to an 18-month snapshot in an attempt to define the effectiveness of those programs.[121]

6. <u>The Record Does Not Support the Department's Conclusions that Good Utility Practices Were Not Implemented</u>

81. The record shows that Minnesota Power does not rely exclusively on Thielsch or any other third party consultant to develop maintenance and inspection programs. The development of maintenance schedules, inspection and outage procedures and plans, and repair plans requires a significant collaborative and detailed process.[122]

82. Minnesota Power maximizes the knowledge, capabilities, and experience of Boswell personnel and system engineers by obtaining and incorporating information from OEMs, third-party consultants and contractors, and other outside sources.[123]

83. While the knowledge that outside consultant experts have gained through experience at coal-fired power plants around the country is invaluable, the Company weighs it against all other sources of internal and external information utilized in developing the Company's

[116] *Id.*
[117] *Id.* at 32-33.
[118] Ex. 5 at 33 (Simmons Direct).
[119] *Id.* at 34.
[120] *Id.*
[121] *See id.* at 31-35.
[122] Exs. 14 and 15 at 30-32 (Undeland Rebuttal) (Public and Nonpublic).
[123] *Id.* at 15.

maintenance program.[124] This allows Minnesota Power to leverage information from industry experts while also ensuring the Company maintains knowledge and ultimate control over the maintenance program at Boswell.[125]

84. Obtaining information from industry experts is not contrary to good utility practice. Rather, utilizing industry experts, especially in highly specialized areas, is entirely consistent with good utility practice.[126]

85. Department expert Mr. Polich opines that "a cost benefit analysis on maintenance activities that incorporate[s] probabilistic risk analysis that compares the impact of additional maintenance costs versus cost of forced outage costs on customer rates" is necessary to evaluate risk against expenditure of maintenance costs.[127] That level of analysis, however, is not necessary or even appropriate to justify undertaking or not undertaking every possible maintenance activity.[128]

86. As a primary matter, the term "probabilistic risk analysis" is prevalent in nuclear facilities, but not in coal-fired facilities.[129]

87. The Company completes all maintenance that is necessary to maintain generating units' operations as identified through the collaborative, iterative, and coordinated process. While power production facilities must certainly consider different options, certain proposals are, on their face, not appropriate for further analysis. Other proposals require additional diligence before they are accepted or rejected for the specific system programs at Boswell.[130]

88. The Administrative Law Judge finds that the Company has provided more than sufficient evidence in the record to sustain its burden of proof and establish that its methods for developing and implementing its generation maintenance and inspection programs are consistent with good utility practice.

G. Overview of Unplanned Outages

89. Over the 18-month period of July 2018 through December 2019, the Company experienced twenty-six unplanned outages at Boswell.[131]

90. The Company categorized the unplanned outages as either: 1) low impact; 2) predicted; or 3) high impact outages.[132]

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[124] *Id.* at 30-32.
[125] *Id.* at 15.
[126] *See id.* at 17.
[127] *Id.*
[128] Exs. 14 and 15 at 16 (Undeland Rebuttal) (Public and Nonpublic).
[129] *Id.*
[130] *Id.*
[131] Ex. 7 at 7 (Undeland Direct).
[132] *Id.* at 8.

91. The Company described low impact outages as those outages that have a relatively low impact from an outage time and replacement cost perspective. The Company described these outages, such as boiler water wall tube leaks, as difficult to predict or locate and that developing PM and PdM programs would require many additional weeks of planned outage time a year and a significant increase in the Company's annual generation maintenance expenses. Good utility practice, as developed in coordination with OEMs and independent consulting engineers, is to review the systems on a periodic basis to identify trouble spots and perform maintenance activities, with a more thorough inspection of the boiler tubes during a 10-year turbine overhaul cycle.[133]

92. The Company testified that it is not feasible to inspect 100 percent of the mechanical components of its generating facilities on an annual basis – such level of inspection would not only be well above and beyond good utility practice, but it would be very time consuming and require much longer outages at those generating facilities and would significantly increase generation maintenance expenses for the Company.[134]

93. For these types of systems, good utility practice, as developed in coordination with the Company's OEMs and independent consulting engineers, is to review the systems on a periodic basis to identify trouble spots and perform maintenance activities, with a more thorough inspection of the boiler tubes during Minnesota Power's 10-year turbine overhaul cycle. During the time frame relevant to this proceeding, both BEC3 and BEC4 were approaching the end of their 10-year major maintenance cycles. During these periods, the Company was working diligently to minimize unplanned outage costs for customers by finding ways, when practicable, to delay those outages by hours or days and continue operating the units to a period where Minnesota Power's purchased energy group identified lower replacement energy costs. Such a delay is not always feasible, but the Company testified that it works very hard to try and match unplanned outages to lower replacement energy periods. Minnesota Power is able to efficiently turn around operations in the event of a tube leak, requiring downtime of only 24 to 48 hours on average for the repair.[135]

94. The Company described predicted outages as those outages that were identified prior to an actual outage occurring, but, for a variety of reasons, the Company was not able to delay the maintenance activity to a planned outage. The Company testified that it tries to delay this type of maintenance activity to a planned outage, but that this is not always practicable and an unplanned outage must be taken to address the emergent work.[136]

95. When a predicted outage occurs, the Company also works diligently to try and delay the outage to a time where replacement power is at a more preferential price for customers if the outage occurs during a period of higher cost replacement power. When these types of outages occur, Minnesota Power uses its learning teams to analyze the cause and puts measures in place that can be deployed to minimize the risk of reoccurrence during future operations. These revised or additional measures may include adjusting PMs or PdM routes, adding or modifying alarms, or updating procedures or training. A learning team is a group of people brought together to better

[133] *Id.* at 8-9.
[134] *Id.*
[135] *Id.* at 9.
[136] *Id.*

understand an incident or event and determine solutions and improvements. It is a collaborative approach to solving issues using the people who do the work.[137]

96. High impact outages are those that, while they have a low probability of occurring, occur outside typical PM and PdM maintenance cycles despite performing within expected specification, and require a unit to be taken offline for a significant repair or replacement. All three of the disputed outages were this type of outage. These high impact outages occur infrequently over a facility's operation.[138]

H. The Undisputed Outages Were Reasonably and Prudently Incurred

1. Boiler Tube Leaks

97. Boswell experienced sixteen unplanned outages within the relevant timeframe due to boiler tube leaks. While there were twenty-one total leaks at Boswell during the relevant time period, not all leaks resulted in unplanned outages. The tube leaks were located in random locations throughout the boilers and had various root causes.[139]

98. Boiler tube leaks are the most common cause of outages at coal-fired generating units. It is consistent with historical operations at Boswell to have unplanned outages occur due to tube leaks.[140]

99. The Company testified to the following boiler tube leaks during the relevant time period and explained how it addressed the leaks:[141]

Unit	Leak Location	Number of Leaks[1]	Root Cause
BEC1	Water Wall	2	Corrosion / Ash Erosion
BEC2	Superheater	2	Fatigue / Long Term Overheat
BEC2	Re-Heater	1	Ash Erosion
BEC3	Water Wall	10	Waterside Corrosion / Fatigue / erosion
BEC3	Re-Heater	1	Fatigue
BEC3	Superheater	4	Erosion (1) DMW (2) Fatigue (1)
BEC4	Superheater	1	Fatigue

100. No party disputed that the Company employed good utility practice in addressing boiler tube leaks.

101. The Administrative Law Judge finds that the Company employed good utility practice in addressing the boiler tube leaks.

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[137] Ex. 7 at 9-10 (Undeland Direct).
[138] *Id.* at 10-11.
[139] *Id.*, Schedule 2 at 3-5.
[140] *Id.*, Schedule 2 at 3.
[141] *Id.*, Schedule 2 at 3-5.

2. Condenser Tube Leaks

102. The Company experienced four outages due to condenser tube leaks during the relevant time period.[142]

103. The condensers are large heat exchangers. During normal plant operation, low quality steam from the exhaust of the steam turbine enters the condenser under vacuum pressure. The steam passes around the outside of metal tube bundles that have cool circulating water passing through them. The steam is condensed back into water and reused in the thermal cycle. The subject condenser tubes are a passive equipment with no active or working parts. The BEC3 condenser contains 15,744 tubes and the BEC4 condenser contains 28,376 tubes.[143]

104. The condenser tube leaks experienced during the relevant time period were consistent with historical experiences at Boswell.[144]

105. The condensers are designed to allow half of the condenser to be isolated with large butterfly valves to permit repairs with the unit online. Most condenser leaks start small and are monitored until a repair needs to be completed. Minnesota Power attempts to schedule outages when market conditions are favorable, but sometimes an immediate outage is required to ensure equipment reliability.[145]

106. The Company testified to the following condenser tube leaks during the relevant time period and explained how it addressed the leaks:[146]

BEC3	Condenser Tube Leak	12/22/2018 at 12:10:00 AM
BEC4	Condenser Tube Leak Repair	12/29/2018 at 9:15:00 PM
BEC4	Condenser Tube Leak Repair	01/01/2019 at 12:00:00 AM (Continuation of 12/29/2018 event)
BEC4	Condenser Cleaning	08/16/2019 at 7:17:00 PM

Note: The BEC4 event listed for 01/01/2019 is not a separate outage from the 12/29/2018 outage. The separated line item in the list is to record outage time for different months or year separately due to an overlap.

107. No party disputed that the Company employed good utility practice in addressing the condenser tube leaks.

108. The Administrative Law Judge finds that the Company employed good utility practice in addressing the condenser tube leaks.

3. BEC3 Boiler Circulation Pump 3C Replacement

109. The BEC3 boiler circulation pump 3C was taken out of service on July 5, 2019.[147]

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[142] *Id.*, Schedule 2 at 6.
[143] Ex. 7, Schedule 2 at 6 (Undeland Direct).
[144] *Id.*
[145] *Id.*
[146] *Id.*
[147] *Id.* at 10.

110. The BEC3 boiler circulation pump that failed was installed in 2013. This boiler circulating pump was taken out of service, and the unit was shut down because of the failure of the pump's mechanical seal. The outage to replace the pump was delayed by one week due to high market pricing conditions at the time.[148]

111. Failure of a mechanical seal accounts for the majority of BEC3's historical boiler circulation pump replacements.[149]

112. BEC3 has three boiler circulating pumps, all of which are required to be in service for the unit to operate at full load. These pumps create a constant movement of water through the boiler waterwalls, ensuring that there is no stagnation in these tubes. Stagnant conditions in a waterwall tube will result in overheating and failure of the tube. Due to the extreme conditions in which the boiler circulation pumps operate, a special system is needed to reduce the pressures and temperature of the water that comes in contact with the mechanical shaft seal. Mechanical seals are not capable of operating at boiler water temperatures and pressures. Therefore, seal water is injected into the pump with some of this water going into the casing and the rest leaking off to the deaerator. This cool seal water forms a thermal barrier which protects the mechanical seal. The two major components of the high pressure breakdown system are a throttling bushing assembly involving a close running tolerance between its rotating and stationary parts, as well as a number of spring loaded floating seal rings. These internal components all wear out over time. And as the pump's internal high pressure breakdown system wears out, the mechanical seal will see elevated pressures and temperatures. Eventually, the mechanical seal will fail, causing water to leak from the pump.[150]

113. The Company has worked with its third-party monitoring consultant to add monitoring points for the boiler circulation leak-off temperature and pressure to identify trends that may be indicative of pending failure. While this had not been an issue in the past, the Company testified that it is comfortable that these new measures will alert the Company of signs that a bushing failure may be forthcoming.[151]

114. There are existing predictive maintenance programs at Boswell for pump and motor vibration that are monitored monthly. Additionally, oil samples are collected from this equipment three to four times per year along with thermography scans. Preventative maintenance is performed on annual and five-year cycles by electrical personnel on the motor. Further, boiler circulating pumps are checked twice daily by operations personnel at Boswell. During these checks, the oil cooler outlet temperature is recorded and lube oil flow and appearance are visually observed along with service water flow. Operations personnel also visually inspect all appurtenant piping and valves for leaks or other abnormalities. None of the auxiliary systems displayed any signs of obvious wear or signs of a pending failure.[152]

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[148] *Id.*, Schedule 2 at 10.
[149] Ex. 7, Schedule 2 at 10 (Undeland Direct).
[150] *Id.*
[151] *Id.*
[152] *Id.*

115. No party disputed that the Company employed good utility practice in addressing the BEC3 boiler circulation pump 3C replacement.

116. The Administrative Law Judge finds that the Company employed good utility practice in addressing the BEC3 boiler circulation pump 3C replacement.

4. BEC4 Intermittent Blowdown Flash Tank Repairs

117. The BEC4 flash tank piping leak outage occurred on October 14, 2018.[153]

118. The Company first noticed a leak of the BEC4 flash tank on August 6, 2018 and a work order was prepared. This work order was added to the hot list (a list of emergent work) to be completed during the planned fall 2018 outage. During the planned outage, the insulation was removed from the piping to the tank. The tank was inspected internally. Dye penetrant was used to try and locate the leak at the tank connection, where the work order identified the leak. The leak was not found, so the connection to the tank was pad welded from the inside as a preventative action.[154]

119. The Company completed the repairs and the repair welds were checked using dye penetrant. Upon startup, the Company found that the pipe was still leaking, but was it was able to identify the leak on a section of piping upstream of the repair area. A repair during startup was not possible. The unit was taken offline and the clearance reapplied, so that the leak could be repaired. The repairs involved replacing an adjacent bad section of piping and adjacent fittings.[155]

120. There were eleven work orders written on the system from 2015-2020. Five work orders were related to valves, four work orders were a result of leaks on the tank or piping, and two work orders were miscellaneous in nature. Prior to the fall 2018 repairs, a leak on the bottom of the tank was repaired in 2015. There was also one work order written in 2019 to repair a leak on the top of the tank at an inlet pipe connection.[156]

121. The flash tank to which the line is connected is vented. So now, if leaks do occur, they are able to be managed so that the repair can wait until the next outage.[157]

122. No party disputed that the Company employed good utility practice in addressing the BEC4 flash tank piping leak outage.

123. The Administrative Law Judge finds that the Company employed good utility practice in addressing the BEC4 flash tank piping leak outage.

[153] *Id.*, Schedule 2 at 11.
[154] *Id.*
[155] Ex. 7, Schedule 2 at 11 (Undeland Direct).
[156] *Id.*
[157] *Id.*

I. Hydrogen Gas System Maintenance, Identification, and Repair Were Consistent with Good Utility Practice

124. During the winter and early spring of 2019, BEC3 experienced two unplanned outages to address a leak in the hydrogen gas system at the facility.[158]

1. Minnesota Power's Hydrogen-Filled Generator Inspection Protocol Was Consistent with Good Utility Practice

125. The Company's PM and PdM programs and inspection and testing protocol for the hydrogen-filled generator system were developed in collaboration with General Electric, the OEM.[159] Specifically, General Electric recommends the inspection of areas where hydrogen leakage is possible during outages that include generator disassembly, which occur once every five years for each unit at Boswell.[160] These inspections include close examination of shaft hydrogen seals, all joints with gaskets, and the float trap.[161]

126. Minnesota Power completed its last inspection of the hydrogen-filled generator components at BEC3 in May of 2014.[162] At that time, none of the gaskets were leaking and an inspection of the original float valve for the system showed no signs of obvious wear, no binding, and no debris that might compromise its operation.[163]

127. The Administrative Law Judge finds that Minnesota Power's inspection protocol of the hydrogen-filled generator components at BEC3 is consistent with good utility practice.

2. Minnesota Power's Handling of the Hydrogen Gas Leak Outages Was Consistent with Good Utility Practice

128. Over the winter of 2018 and 2019, BEC3's generator system engineer identified a high consumption of hydrogen gas in the system.[164] Plant personnel, using a combustible gas detector while BEC3 was operating, narrowed the leak location to somewhere in the leadbox/bushing area.[165] Due to the high voltage and magnetic fields in that area of the leadbox, plant personnel were unable to safely access the area in order to identify the precise location of the leak while the unit was running.[166] During an unplanned outage from the evening of February 2, 2019 until the morning of February 4, 2019, Minnesota Power pressurized the BEC3 hydrogen unit with air and helium gases in an effort to locate the source of the leak.[167] Minnesota Power identified and sealed a substantial leak on a gasket in the leadbox area in order to allow the unit to

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[158] A diagram of the sealed hydrogen generator system is included in Ex. 7, Schedule 4 at 3 (Undeland Direct).
[159] *Id.* at 25.
[160] *Id.*
[161] *Id.* at 25, Schedule 4.
[162] *Id.* at 26.
[163] *Id.*
[164] Ex. 7 at 23 (Undeland Direct).
[165] *Id.*
[166] *Id.* at 23-24.
[167] *Id.* at 23.

continue operating until the leak could be further diagnosed and repaired during the March 30, 2019 planned outage.[168] Prior to that scheduled outage, the system engineer worked with the OEM to develop a plan to complete both the root cause analysis and implement necessary repairs.[169]

129. The BEC3 generator system engineer contacted General Electric's district service manager and generator specialist to discuss the leak and formulate a plan to determine the root cause and repair the leak.[170] Additionally, the Company asked General Electric, the OEM, for advice on how to proceed based upon its experiences with this type of hydrogen leak at other facilities.[171] General Electric recommended installing a dam system in the leadbox.[172] General Electric indicated that the cost of removing and replacing the bushings and gasket system would significantly exceed the cost of the dam system.[173] Minnesota Power contracted with General Electric to implement the repair plan during the planned spring outage.[174]

130. Unfortunately, despite being successful at other General Electric units, the OEM's suggested repairs were unsuccessful during the spring 2019 planned outage and required that the planned outage be extended to finalize the repairs. By using the planned outage for a portion of the root cause analysis, however, the Company was able to reduce the total number of unplanned outage hours than if it had attempted to complete all work during the February 2019 unplanned outage.[175]

131. During the inspections conducted throughout the spring 2019 planned outage, technicians determined that the valve was clean of any debris, moved freely, and showed no sign of wear on the linkage.[176] Additionally, neither the float valve nor "trap" showed any signs of wear, defects, or debris that would be causing a hydrogen leak like the one BEC3 had experienced in the winter of 2018 and 2019.[177] Technicians visually inspected and measured the system components as recommended by the OEM.[178] The Company sent the existing hydrogen seals to a third-party vendor for refurbishment consistent with the OEM's associated specification.[179] Additionally, the Company hired a fabricator to machine shaft surfaces to ensure there were no surface defects that would fail to provide a smooth, sealed surface.[180] General Electric also performed the previously mentioned "dam repair" in the bushing leadbox.[181] After Minnesota Power, General Electric, and third-party contractors completed the inspection and repair work, the

[168] *Id.* at 23, Schedule 4 (The leadbox area is illustrated in Schedule 4).
[169] *Id.* at 23.
[170] Ex. 7 at 24 (Undeland Direct).
[171] *Id.*
[172] *Id.*
[173] *Id.*
[174] *Id.*
[175] *Id.* at 26.
[176] Ex. 7 at 27, Schedule 4 at 4 (Undeland Direct) (Schedule 4 provides a detailed discussion of the inspection and testing process.).
[177] *Id.* at 27.
[178] *Id*.
[179] *Id*.
[180] *Id*.
[181] Ex. 7 at 27, Schedule 4 at 4 (Undeland Direct).

Company reassembled the components to test whether the process that was successful for General Electric at other facilities worked at BEC3.[182]

132. Although the testing and repair processes were time-intensive, the Company had the hydrogen-filled system ready for testing to bring the system online before the end of the original planned outage. When the generator was air-tested in preparation for returning BEC3 to operation, the Company identified a large leak remained in the generator.[183] Using specialized inspection equipment and visual inspections, technicians observed no deviations that would be causing the continued major leak, although they did identify and quickly repair a few minor leaks.[184] The next step in the OEM's protocol included disassembly of the outer oil seals to ensure no leaking was present in the bearing cavity.[185] The Company was able to determine that the leaking was coming from the turbine end, and not the generator end, of the unit, as the OEM and plant personnel had previously established.[186] Based on the location of the leaking, the OEM and site specialists identified two possible sources: The gasket on the hydrogen seal leaking or the hydrogen seal itself leaking.[187] At this point, BEC3 was several days beyond its scheduled planned outage end date.[188]

133. The Company continued further root cause analysis on the various hydrogen-filled system components, testing the system after each reassembly, but could not identify the source of the major leak.[189] Each round of testing and reassembly took approximately four hours to complete.[190]

134. Minnesota Power brought in both General Electric and a contractor that specializes in hydrogen leaks to assist in the iterative root cause analysis to identify and repair the source of the hydrogen leak. Unfortunately, they were also unable to identify the cause of the leak at BEC3.[191] During this time, Minnesota Power began discussions about refurbishing the equipment.[192] The Company continued diagnostic testing by raising the level of oil in the float trap to observe how high the oil had to be to stop the hydrogen leak. Boswell personnel learned that the hydrogen leak stopped when the float trap was completely filled with oil to approximately eight to twelve inches above the valve.[193]

135. During diagnostic testing of the BEC3 hydrogen leak, the Company raised the level of oil in the float trap to determine whether there was an oil level that would stop the hydrogen leak.[194] There is no observation window to see inside of the tank that houses the float trap, so it

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182 *Id.*
183 *Id.*
184 *Id.*
185 *Id*.
186 *Id.*
187 Ex. 7 at 27 (Undeland Direct).
188 *Id.* at 28.
189 *Id.*
190 *Id.*
191 *Id.*
192 *Id.*
193 Ex. 7, Schedule 4 at 9 (Undeland Direct).
194 *Id*.

was not possible to see exactly what was happening inside.[195] The oil level in the float trap was increased using oil from the air detraining tank or the bearing oil header, which, as the diagram of the system shows, also supply oil to other interconnected systems within the facility, including the voluminous vacuum tank.[196] Unbeknownst to the Company at the time, the alarm that would have notified plant personnel that seal oil was reaching the top of the sight glass in the float trap was improperly configured, so the alarm did not provide notice that seal oil was overtopping the sight glass during diagnostic testing.[197]

136. Once Minnesota Power discovered that oil had leaked, it removed the oil from the system using the liquid detector drain valve.[198] Boswell personnel noted no other signs that oil had entered the phase bushings and no further oil was migrating to the liquid detector valve.[199] Further investigation of components that were covered or sealed, such as the phase bushings, to ensure that no oil was present would have required a significant amount of time to take apart, inspect, and reassemble every component.[200] For the phase bushings, this would have required disassembly of components in which there was asbestos containing material.[201] This would have caused a significant extension of the hydrogen leak unplanned outage to inspect equipment that had no indication should have been impacted by migrating oil.[202]

137. After receiving the results of Minnesota Power's float trap testing, General Electric searched internally for any other possible causes of the hydrogen leak, and they were able to identify a single customer that had experienced a similar issue.[203] In that case, despite no visual defects in the float valve, the facility was able to resolve the leak issue by replacing the float valve. General Electric could not provide an explanation why the float valve replacement was necessary or why it eliminated the leak.[204] General Electric informed Minnesota Power that, because failure of float valves is exceedingly rare, it did not have any replacement float valves available, and it would take approximately 15 weeks from procurement to provide that part to the Company.[205]

138. When the Company and the OEM narrowed the root cause of the hydrogen leak to the float valve, BEC3 was about a week beyond the scheduled planned outage end date. Due to the hydrogen leak, however, the Company could not have safely brought the system online while waiting for General Electric to deliver the replacement float valve.[206] At this point, Minnesota Power had two options: leave BEC3 offline until General Electric delivered the replacement float valve fifteen weeks later; or try to find an alternative solution that would allow the unit to safely return to operations.

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[195] *Id.*, Schedule 4 at 6.
[196] *Id.*, Schedule 4 at 3.
[197] Exs. 10 and 11, RAP-15 at 6-7 (Polich Direct) (Public and Nonpublic).
[198] *Id.*, RAP-15 at 5.
[199] Exs. 10 and 11, RAP-15 at 5 (Polich Direct) (Public and Nonpublic).
[200] *See Id.*, RAP-16 at 3-5.
[201] *Id.*
[202] *See id.*
[203] Ex. 7 at 28-29, Schedule 4 at 9 (Undeland Direct).
[204] *Id.*
[205] *Id.* at 29, Schedule 4 at 9.
[206] *Id.* at 29.

139. Minnesota Power's engineers and technicians worked tirelessly and creatively to fabricate an onsite solution that would meet all safety requirements and provide a long term solution to the float valve leak at BEC3.[207] This required purchasing multiple float valves and float balls and testing them in different combinations to determine if an engineered solution would be possible.[208] The Company was able to find a valve that, when used in combination with a new float ball from McMaster-Carr Supply Company, would prevent hydrogen from leaking when the system oil was at operational levels.[209]

140. The Company implemented its self-engineered solution and successfully performed the required air testing, hydrogen system purge, and leak verification. With the successful testing results, the hydrogen-filled system met the criteria for long-term operation, and Minnesota Power returned BEC3 to service on June 20, 2019.[210]

141. The second unplanned outage started at the end of the spring 2019 planned outage after BEC3 failed the original air test on June 3, 2019. The problem was narrowed to the float valve on June 11, 2019. Minnesota Power's engineered solution was completed, and BEC3 was returned to operations, on June 20, 2019.[211] Had Minnesota Power decided to rely solely on General Electric rather than internally engineering a solution, the outage would have lasted fifteen weeks, plus time for installation, from June 11, 2019. Thus, Minnesota Power avoided approximately 14 weeks of unplanned outage by implementing a self-engineered solution.[212]

142. Since the outage, General Electric has not been able to replicate the float valve failure experienced by BEC3, and neither General Electric nor other hydrogen leak specialty contractors were able to definitively identify what caused the BEC3 float valve to leak hydrogen or how to prevent or identify such a leak in the future.[213] This underscores the novelty and complexity of the float valve defect, and speaks to Minnesota Power's ability to identify the problem and implement a self-engineered solution.

143. Minnesota Power's handling of the hydrogen leak was not only consistent with good utility practice: it exceeded that standard. Prior to and during the outage, Minnesota Power followed the proper maintenance practices suggested by General Electric (the OEM). Even since the outage, General Electric has not suggested any changes to the Company's PM or PdM programs for this system.[214] The Company completed all maintenance and inspections

[207] *Id.*
[208] *Id.*, Schedule 4 at 10.
[209] Ex. 7 at 29 (Undeland Direct).
[210] *Id.*
[211] *Id.* at 30.
[212] *See* Ex. 7 at 28-32 (Undeland Direct); *see also* Exs. 14 and 15 at 11 (Undeland Rebuttal) (Public and Nonpublic) ("General Electric did not provide any suggestions, other than trying a new valve that would take 15 weeks to procure, to test whether the float valve was the cause of the hydrogen leak.").

[213] Ex. 7 at 31-32 (Undeland Direct).
[214] *Id.* at 31.

recommended by the OEM, and worked as quickly as possible to return the unit to long-term operation safely and efficiently for the benefit of customers.[215]

144. Given these circumstances, Minnesota Power did exceptionally well to return BEC3 to service months earlier than it would have had the Company relied exclusively on the solution offered by General Electric.

145. The Administrative Law Judge finds that the Company employed good utility practice in addressing the hydrogen gas leak outages.

146. The Administrative Law Judge recommends that the Commission not order Minnesota Power to refund any replacement power costs related to the hydrogen gas leak outages.

3. The Department's Criticisms Are Unsupported by Evidence

147. The Department's expert, Mr. Polich, suggests in his direct testimony that Minnesota Power did not apply good utility practices in how it investigated and repaired the hydrogen leak in the BEC3 generator. Specifically, Mr. Polich contends that Minnesota Power should have "removed and tested the float valve for leakage . . . ."[216] He further opines that the failure to immediately test the float valve led to other testing that resulted in the overfilling of hydrogen seal oil in the system.[217]

148. Mr. Polich's testimony does not cite to any information or evidence indicating that Minnesota Power should have known, without the benefit of hindsight, to start its investigation and testing with the float valve. Additionally, Mr. Polich does not explain how the float valve could have been tested for leakage to identify the defect, which is notable because neither General Electric nor other hydrogen system expert consultants have been able to devise a testing methodology for the float valve.[218] Also, the float valve operates in an open position and is never closed during operation, so testing for leakage, as Mr. Polich suggested, would not have provided any information regarding the functionality of the float valve.[219]

149. Mr. Polich also fails to acknowledge that, months prior to the outage, Minnesota Power worked with General Electric, the OEM, to formulate a plan to determine the root cause and repair the hydrogen leak.[220] As the OEM, General Electric had the best information in the industry regarding both what could have caused the hydrogen leak as well as the processes and testing that Minnesota power could undertake to identify the root cause. Minnesota Power sought expertise and assistance from the industry experts and followed their recommendations in attempting to address the hydrogen leak, which is wholly consistent with good utility practice.[221]

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[215] *Id.*
[216] Exs. 10 and 11 at 44 (Polich Direct) (Public and Nonpublic).
[217] *Id.*
[218] *See id.* at 44-45.
[219] Exs. 14 and 15 at 10 (Undeland Rebuttal) (Public and Nonpublic).
[220] *Id.*
[221] *Id.*

150. The Company also testified that undetectable float valve defects are exceedingly rare, and the OEM and other hydrogen leak experts were unaware of any testing that would confirm the float valve as the root cause other than completely replacing it, which, given the availability of that part, would have taken fifteen weeks to procure.[222]

151. The Administrative Law Judge agrees that there is no factual basis for Mr. Polich's suggestion that Minnesota Power should have immediately determined that the float valve was a likely cause of the hydrogen leak.

152. The Administrative Law Judge agrees that Mr. Polich's standard is not consistent with good utility practice, and, in fact, *exceeds* even optimum utility practice because it would have required Minnesota Power to know more than the OEM and industry experts. Based on what the Company knew about the system, its operation, and likely failure conditions at the time of the leak, the methodical and iterative testing, repair, and engineering process was consistent with good utility practice.

153. The Department concluded that any potential deviations from good utility practice by Minnesota Power did not cause or materially lengthen the outage.[223] As a result, the Department does not recommend that the Commission order Minnesota Power to refund any replacement power costs related to this outage.[224]

J. Phase Bushing Maintenance, Identification, and Repair Were Consistent with Good Utility Practice

1. Minnesota Power's Phase Bushing Inspection and Maintenance Protocol Was Consistent with Good Utility Practice

154. Electricity is transmitted in three phases (A, B, C) and there are two bushings per phase (line and neutral), totaling six bushings in BEC3's system.[225] Minnesota Power tests all unit phase bushings every five years pursuant to the recommendation of the OEM, General Electric.[226] The Company tests the bushings using a hi-pot, or overpotential, test, which is an electrical test that measures the amount of leakage current an insulated system has to ground when a high voltage is applied to the winding.[227] The test procedure is consistent with Institute of Electrical and Electronics Engineers ("IEEE") standards, the OEM's suggested practices, and FM Global's insurance guidance, which are all consistent in their testing frequency and protocol recommendations.[228] The Company has followed these recommendations since the unit was constructed in 1970.[229]

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[222] *Id.* at 11.
[223] Exs. 12 and 13 at 17 (Campbell Direct) (Public and Nonpublic).
[224] *Id.*
[225] Ex. 7 at 32 (Undeland Direct).
[226] *Id.* at 34.
[227] *Id.*
[228] *Id.*
[229] *Id.*

155. On April 18, 2019, the Company's contractor (General Electric) completed the five-year testing and inspections on BEC3's six bushings and three windings.[230] The General Electric generator specialist reported that all six phase bushings installed on BEC3 were operating within General Electric's acceptable limits. The direct-current ("DC") leakage test indicated that all bushings performed within acceptable criteria with no other indication to support further investigation.[231] The report noted, however, that the DC leakage test indicated a higher rate of leakage for the A phase bushing, even though its operation was within limits of testing.[232]

2. Minnesota Power's Handling of the Phase Bushing Outage Was Consistent with Good Utility Practice

156. On July 8, 2019, a relay in BEC3 was tripped offline due to a ground fault alarm.[233] To investigate the cause of the relay's safety response, the Company conducted additional analysis of the electrical circuit consisting of the isophase bus, the step-up transformer, three generator windings, and six phase bushings.[234]

157. Minnesota Power utilized employees who specialized in circuit system failures from the Boswell relay work area as well as the Company's transmission construction and maintenance work areas to assist in isolating the equipment that caused the ground fault alarm.[235] The Company disconnected the system components at the generator and then tested the isophase bus and step-up transformer in order to eliminate them as potential causes of the ground fault alarm.[236] Boswell electricians then separated the three phase systems at the generator and, based upon further testing, they were able to determine that the ground fault occurred on the A phase of the system.[237] This discovery indicated that the root cause was likely a failure of an A phase bushing, the neutral side bushing, or the winding in the generator itself.[238] The Company determined that specialized personnel would be necessary to assist in the investigation effort and remove asbestos containing materials prior to further investigation. On July 10, 2019, the Company contacted General Electric to assist with diagnosing and repairing the A phase bushings.[239]

158. On July 12, 2019, General Electric began working in cooperation with Boswell personnel to identify the cause of the relay fault. On July 14, 2019, General Electric's engineer determined that the failure was on the A phase line side bushing, which would need to be replaced.[240]

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[230] *Id.* at 32. The Company provides a detailed summary related to this outage in Ex. 7, Schedule 5 (Undeland Direct).
[231] Ex. 7 at 32 (Undeland Direct).
[232] Exs. 14 and 15 at 35 (Undeland Rebuttal) (Public and Nonpublic).
[233] Ex. 7 at 32 (Undeland Direct).
[234] *Id.*
[235] *Id.* at 33.
[236] *Id.*
[237] *Id.*
[238] *Id.*
[239] Ex. 7 at 33 (Undeland Direct).
[240] *Id.*

159. Minnesota Power does not keep spare phase bushings in stock because they do not have a history of frequent failure.[241] As a result, the Company contacted General Electric to procure three replacement bushings, which General Electric indicated could be delivered to BEC3 on July 16, 2019.[242] While the bushings were en route to Boswell, the Company had General Electric remove the asbestos containing insulation in all six of the phase bushings at BEC3 to allow for the flex leads inspection that General Electric recommends when phase bushings are replaced.[243] No defects were found in the leads.[244]

160. When the replacement bushings arrived on July 16, 2019, the shipment included six bushings instead of the three bushings that the Company had ordered.[245] Minnesota Power decided that it was most prudent to replace all six bushings given that General Electric did not know why the A phase line side bushing failed and because of the overall age of the bushings.[246] Additionally, much of the preparation necessary to replace six bushings would be the same as that which would be required even if only three bushings were replaced. General Electric installed six new bushings on July 18 and 19, 2019.[247] Final inspections and testing were completed on July 21, 2019, and the unit was brought online on July 22, 2019.[248] The unit returned to service on July 26, 2019.[249]

161. Minnesota Power's phase bushing maintenance and inspection program, as well as its response to the BEC3 phase bushing outage in 2019, were consistent with good utility practice. The Company has utilized the same phase bushing inspection methods and testing schedule, which are consistent with OEM and industry recommendations, since the construction of the unit in 1970.[250] The Company has made no reductions in its phase bushing maintenance expenses during the evaluation period.

162. The Company worked as quickly as possible, while maintaining safety and ensuring that the repair would be sufficient for continued operations, to return the unit to operation for the benefit of customers. The Company was not able to take any steps to try and delay the outage because when a ground fault occurs, the unit must be taken offline.[251]

163. The Company was following industry practice, OEM recommendations, and IEEE guidelines. Further, the Company consulted with the OEM after this outage and the OEM has not suggested any changes to its instructive maintenance and inspection guidelines. Instead, the Company is adding to its five-year inspection and testing procedure for the circuit system that the Company be provided with the raw test results while the Engineer, technicians, and test equipment

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[241] *Id*.
[242] *Id.*
[243] *Id.*
[244] *Id.*
[245] Ex. 7 at 33 (Undeland Direct).
[246] *Id*.
[247] *Id*.
[248] *Id.* at 33-34.
[249] *Id.* at 37.
[250] *Id.* at 35.
[251] Ex. 7 at 37 (Undeland Direct).

are still on site. That allows sufficient time for any re-inspection or re-testing the Company may request.[252]

164. The Administrative Law Judge finds that the Company employed good utility practice in addressing the phase bushing outage.

165. The Administrative Law Judge recommends that the Commission not order Minnesota Power to refund any replacement power costs related to the phase bushing outage.

3. <u>General Electric Could Not Identify the Proximate Cause of the Bushing Failure</u>

166. Minnesota Power asked General Electric if it could determine the root cause of the phase bushing failure. While General Electric identified a couple of potential causes, it did not make an ultimate determination regarding the actual cause of the A phase bushing failure.[253]

167. One potential cause listed by General Electric in its Ground Fault Investigation report was the presence of oil in the phase bushings, which can block cooling passages and cause the bushings to overheat.[254] When the phase bushings were opened up after the unit was shut down during the outage, the Company and General Electric found that oil had ingressed into the phase bushings after the testing and restart associated with the hydrogen gas leak outage.

168. Pursuant to the testing procedures suggested by General Electric for the spring 2019 hydrogen gas leak repair, Minnesota Power varied the oil levels in the hydrogen gas system in order to help diagnose the cause of the leak and identify potential solutions.[255] Unfortunately, the alarm that would have notified BEC3 personnel regarding the overflow of oil was not properly configured at the time, so it did not alert plant personnel when oil overtopped the sight glass during hydrogen leak testing.[256] When Minnesota Power discovered the overflow, it removed oil from the system using the liquid detector drain valve and no other evidence of oil migration was observed.[257] General Electric did not recommend or suggest any additional inspections or verifications related to the hydrogen leak testing that would have included removing the insulation in order to visually inspect the phase bushings.[258] As a result, Minnesota Power was not aware of the presence of oil in the phase bushings until after the outage.

169. Given the presence of oil in the phase bushings, Minnesota Power specifically asked General Electric whether the oil could have caused the A phase bushing failure. Although General Electric indicated that the presence of oil could lead to overheating, it could not determine whether the presence of oil in the BEC3 phase bushings contributed to the A phase failure, and

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[252] *Id.* at 37-38.
[253] *See generally* Exs. 10 and 11, RAP-16 (Polich Direct) (Public and Nonpublic).
[254] *Id.*, RAP-16 at 3, 5.
[255] *Id.*, RAP-15 at 4-6.
[256] *Id.*, RAP-15 at 6-7.
[257] *Id.*, RAP-15 at 5.
[258] Exs. 10 and 11, RAP-15 at 4 (Polich Direct) (Public and Nonpublic).

was unable to identify any testing that would be determinative of the root cause of the bushing failure.[259]

170. General Electric's Ground Fault Investigation report also indicated that, although no definitive physical damage was apparent on the bushing, "there were tell-tale signs of a black tar-like substance seen on the porcelain at the flange just above the ferrule. This might be a sign that the bushing failure is under the mounting flange."[260] If the unit experienced vibration, either short term or long term, the greatest point of distress would be the mounting flange.[261] General Electric issued technical bulletins in 2013 and 2017 in response to units experiencing bushing failures due to natural frequency (resonance) vibration.[262]

171. Ultimately, neither General Electric nor Minnesota Power were able to make a definitive determination of the root cause of the phase bushing failure. General Electric also indicated that it was unaware of any testing that would provide a definitive result.[263]

4. **The Department's Conclusions Are Unsupported by Evidence**

172. Mr. Polich contends that Minnesota Power failed to follow good utility practice by not investigating whether seal oil had leaked into the bushings when it was addressing the hydrogen gas leak earlier in 2019, and that the presence of seal oil caused the bushings to overheat and fail.[264]

173. The Administrative Law Judge finds that Mr. Polich's arguments fail on two fronts. First, there is insufficient evidence in the record to determine that the seal oil was the cause of the phase bushing failure. Second, Minnesota Power did not deviate from good utility practice.

174. Mr. Polich contends, without citing to any reports or evidence, that had Minnesota Power removed the seal oil from around the phase bushings immediately, it "would have avoided the bushing failure, having to purchase replacement bushings and the roughly two-week outage."[265] This conclusion, however, assumes that the oil present in the phase bushings definitely caused the failure, which the record shows not even the OEM could determine.

175. Mr. Polich also failed to acknowledge the numerous reasons a phase bushing could fail. Phase bushings may be damaged by sudden load changes, excessive vibration, overheating, overheating of the leads, and normal vibration over long periods of time.[266] In this case, the A phase bushing could have been the original from 1970 or a replacement from 2001, so it could have been approximately 50 years old at the time it failed.[267] Additionally, the DC leakage test performed during the Spring 2019 outage indicated a higher rate of leakage for the A phase

[259] *Id.*, RAP-15 at 7-8.
[260] *Id.*, RAP-16 at 4.
[261] Exs. 14 and 15 at 35-36 (Undeland Rebuttal) (Public and Nonpublic).
[262] Ex. 7, Schedule 5 at 9 (Undeland Direct).
[263] Exs. 14 and 15 at 36 (Undeland Rebuttal) (Public and Nonpublic).
[264] Exs. 10 and 11 at 48 (Polich Direct) (Public and Nonpublic).
[265] *Id.*
[266] Exs. 14 and 15 at 35 (Undeland Rebuttal) (Public and Nonpublic).
[267] *Id.*

bushing, which suggests that there could have been some underlying issues that later caused the failure.[268] General Electric's finding of a tar-like substance on the porcelain at the flange suggests that the failure might have occurred under the mounting flange as a result of either short or long term vibration.[269]

176. There are multiple possible causes of the phase bushing failure, but it is impossible to determine with any certainty what the actual cause was. As a result, Mr. Polich's contention that the phase bushing failure would not have occurred but for the presence of seal oil constitutes a guess regarding the root cause rather than a definitive, evidence-based conclusion.

177. Mr. Polich's conclusion that Minnesota Power failed to follow good utility practice by not immediately finding and removing the seal oil from the phase bushings after the hydrogen leak testing similarly lacks an evidentiary basis. Minnesota Power was unaware that seal oil had overtopped the sight glass on the hydrogen system due to an alarm failure.[270] After it became aware of the spill, Minnesota Power drained the oil from the system.[271] Because such an overflow of oil had never happened in the past, Minnesota Power did not know that oil would make its way into the phase bushings.[272] And absent removing the insulation from and observing the bushings, which is a time and labor intensive process involving asbestos, Minnesota Power would not have been able to discover the oil.[273]

178. It is also important to acknowledge that the testing Minnesota Power conducted to identify the hydrogen leak was far from a standard process. In fact, General Electric identified only one other facility that experienced the same float valve failure as BEC3.[274] Given the novelty of the testing procedures, there really is no established good utility practice or even any suggested protocols from the OEM or industry experts.[275] Instead, BEC3 personnel were required to move forward using their best judgment given the information available at the time.[276]

179. Minnesota Power's innovative testing and repair of the hydrogen leak reduced that outage by approximately 14 weeks compared to if Minnesota Power had just waited for a new float valve from General Electric to be manufactured.[277] That type of ingenuity should not be punished by denying Company recovery of replacement energy expenses from a much shorter outage that only may have been caused because employees did not design a perfect testing protocol on the fly, as Mr. Polich suggests should have happened. Ultimately, given the extremely novel circumstances and without the benefit of hindsight, Minnesota Power's efforts to identify and fix the hydrogen leak and return the unit to operation and then address the relatively short phase bushing outage were consistent with good utility practice.

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268 *Id.*
269 *Id.* at 35-36.
270 Exs. 10 and 11, RAP-15 at 4-7 (Polich Direct) (Public and Nonpublic).
271 *Id*.
272 *Id*.
273 Ex. 7 at 33, 35-36, Schedule 4 at 9 (Undeland Direct).
274 *Id.* at 28-29, Schedule 4 at 9.
275 *Id.*
276 *Id.*
277 *Id*.

K. HRH Maintenance, Identification, and Repair Were Consistent with Good Utility Practice

1. Minnesota Power's HRH Steam Line Inspection and Maintenance Program Was Consistent with Good Utility Practice

180. The HRH steam line is an insulated HEP system that is 640 feet in length and spans 20 floors with limited access within the unit.[278] It is rare to perform a complete inspection of an entire HRH system during a single planned outage because it is cost-prohibitive and time-consuming.[279] Minnesota Power plans inspections based on past results, known areas of risk, industry bulletins, insurance carrier guidance, and third-party HEP expert recommendations among the many other sources the Company uses in developing its maintenance and inspection programs.[280] Minnesota Power utilizes all of the information available to it, including recommendations from the last inspection and the input of third-party HEP experts, to develop inspection plans prior to planned outages to determine where, what, how, and how much to inspect.[281]

181. Minnesota Power inspects high stress and high risk sections of each of Boswell's HEP systems every two to five years, with low stress level areas (such as the vertical section of HRH steam line where the seam weld failed) due for inspection every five to ten years based upon relative risk.[282] Minnesota Power inspected sections of the BEC4 HRH steam line in 2017 prior to the 2019 failure, but not the particular section that failed. The HRH steam line was scheduled for inspection every ten years due to its relatively low stress and risk, and was last inspected in 2010 with no actionable defects noted at that time.[283]

182. Piping experiences a combination of stresses due to internal pressure, weight loads, and bending/torsion caused by thermal expansion.[284] In general, vertical pipe runs like the HRH steam line experience lower stress levels because they have lower weight loads than horizontal and hanging pipe.[285] For horizontal runs, bending stresses are present in the unsupported sections between the hangers, and valves and protective insulation add to the weight and stress of those sections.[286] As a result, horizontal runs have much higher risk of failure than vertical runs, and Minnesota Power plans its inspection protocol to account for these different risk levels.[287]

183. The vertical HRH steam line has been identified as a low stress area in all pipe inspections dating back to 1985, including in a Sargent & Lundy stress analysis performed in 2010.[288] Because the HRH steam line was last inspected in 2010, it was due for inspection in 2020.

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[278] *Id.* at 16.
[279] Ex. 7 at 16 (Undeland Direct).
[280] *Id.*
[281] *Id.*
[282] *Id.*
[283] *Id.*
[284] *Id.* at 17.
[285] Ex. 7 at 17 (Undeland Direct).
[286] *Id.*
[287] *See id.* at 16-17.
[288] *Id.*

Since 2010, the Company observed no operational issues that would have caused BEC4's systems engineer to accelerate the inspection and testing schedule for the HRH steam line seam weld.[289]

184. Minnesota Power selected the 10-year inspection frequency for the HRH steam line based on input from its independent consulting engineer, the relative risk and stress in that section of the piping, and historic operating and metallurgical knowledge, among other sources.[290] According to Thielsch, Minnesota Power's longest and most often used independent consulting engineer for HEP maintenance and inspection, over the past 30 years, none of the approximately 50 U.S. power companies they have worked for have inspected 100 percent of their low stress longitudinal seam welds on a five-year cycle.[291] Thielsch confirmed that Minnesota Power's HRH inspection protocol is similar to those of the other power companies with which Thielsch has decades of experience.[292]

185. It is entirely consistent with good utility practice to focus more inspection resources on those areas that are most likely to have indications, which are visual or operational deviations from what is expected of the equipment.[293] In the early years of pipe life, the most likely area to develop fatigue is at an attachment or discontinuity, which can include any equipment geometry besides that which is round or straight.[294] As the pipe ages, the most common failure mechanism transitions from fatigue to creep. "Creep" is a function of operation at high temperatures, over time and with stress.[295]

186. Over time, the inspections begin to include replication and boat sample testing to detect creep in its earliest stages. A "boat sample" is a type of destructive testing where a sample is removed from the pipe with a precision cut and that sample is then subjected to various laboratory tests to evaluate the microstructure and condition of the pipe.[296] Minnesota Power has continually adapted its HEP inspection protocol in order to focus on the areas of the system most likely to first show signs of damage to the overall system.[297]

187. In order to ensure consistency with good utility practice, Minnesota Power develops inspection program scope and frequency protocols based upon many different sources of information including past results, known areas of risk, industry groups, insurance carrier recommendations, and third-party expert recommendations. [298] Additionally, Boswell employees meet every year with peers from Xcel Energy to discuss issues that have arisen over the past year.[299] Minnesota Power's insurance carrier, FM Global, also shares industry issues with the

[289] *Id.*
[290] *Id.* at 18.
[291] Ex. 7 at 18 (Undeland Direct).
[292] Ex. 7 at 18-19 (Undeland Direct); Exs. 14 and 15 at 26-27 (Undeland Rebuttal) (Public and Nonpublic).
[293] Ex. 5 at 24 (Simmons Direct).
[294] *Id.* at 24-25.
[295] *Id.* at 25.
[296] *Id.*
[297] *Id.* at 20
[298] Exs. 14 and 15 at 31 (Undeland Rebuttal Public and Nonpublic).
[299] *Id.*

Company and prompts changes to the protocol or frequency of inspections when applicable.[300] The Company uses all of the above-described resources, as well the decades of experience of many of Boswell's employees, to ensure that its maintenance and inspection programs are, at a minimum, on par with other coal-fired power plants.

188. The Administrative Law Judge finds that Minnesota's Power's HRH steam line inspection and maintenance program was consistent with good utility practice.

2. **Minnesota Power's Handling of the HRH Steam Line Outage Was Consistent with Good Utility Practice**

189. On February 6, 2019, the HRH steam line at BEC4 experienced a seam weld failure, resulting in a steam release that required Minnesota Power to shut BEC4 down.[301] The Company safely brought BEC4 offline within two hours of the failure to facilitate a detailed inspection.[302] BEC4 personnel determined that the leak was caused by a two-foot failure of the welded seam of the HRH steam line.[303] Due to the nature of the seam weld failure, Boswell management and engineers decided to conduct a complete and thorough inspection of the HRH steam line.[304]

190. Minnesota Power had Thielsch mobilize to Boswell to conduct a comprehensive investigation of the HEP at BEC4 and help determine next steps.[305] Thielsch took boat samples from above and below the HRH steam line seam weld that had failed.[306] The results showed that there was substantial and widespread creep within the HRH piping, indicating that it was at the end of its usable life.[307]

191. The type of longitudinal seam welded piping used in power plant HEP is almost exclusively manufactured for specific jobs.[308] As a result, Minnesota Power had to order piping that would be manufactured to meet the specifications of the HRH steam line segment that needed to be immediately replaced. The steam line material was ordered on February 15, 2019, and delivered to BEC4 on March 12, 2019.[309]

192. While the steam line was being manufactured, Minnesota Power decided to inspect 100 percent of the HEP system at BEC4 to determine if there was additional damage that would require repair.[310] The inspection identified six additional areas of the existing steam line that required reinforcement.[311] Additionally, Thielsch found transverse cracking in many steam line

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[300] *Id.*
[301] Ex. 7 at 15 (Undeland Direct). A more detailed description of the HRH line outage is provided in Ex. 7, Schedule 3 (Undeland Direct).
[302] *Id.* at 15.
[303] *Id.*
[304] *Id.*
[305] *Id.*, Schedule 3 at 4.
[306] *Id.*
[307] Ex. 7, Schedule 3 at 4 (Undeland Direct).
[308] *Id.*
[309] *Id.*
[310] *Id.*, Schedule 3 at 4-5.
[311] *Id.*, Schedule 3 at 5.

spools that was determined to not be service related, but rather were likely cracks from the manufacturing of the plate that would not likely create additional risk.[312] In order to eliminate the possibility that the transverse cracks could cause a failure, however, Minnesota Power had Thielsch design patches that were installed by Moorhead Machinery & Boiler Company ("MMBCO").[313]

193. During the analysis of the HRH system, Minnesota Power contacted EPRI to discuss the failure. EPRI suggested that Minnesota Power: (1) perform a 100 percent inspection of the system; (2) repair damaged areas discovered through the inspection; (3) hire a second inspection company to identify high risk locations in the piping system; and (4) have the second inspection company verify Thielsch's results for high risk areas.[314] Minnesota Power brought in Structural Integrity to identify and inspect high risk areas of the HEP.[315]

194. Minnesota Power hired MMBCO to make the necessary repairs to the HRH steam line. Removal and replacement of very large HRH steam line is not a simple process, especially given that the three sections that required replacement were located near the top of the boiler building, 17 or more stories up, and were in difficult to access areas.[316] MMBCO also installed 140 feet of reinforcement patches over areas with a lot of transverse cracking.[317]

195. The repairs were complete on March 25, 2019.[318] A State of Minnesota High Pressure Piping Inspector reviewed the repairs and determined that it was safe to restart the facility.[319] Minnesota Power safely put the HRH steam line back in service seven weeks after the failure.[320]

196. Although the repairs made it safe to put BEC4's HRH steam line back in service, Boswell engineers concluded that a complete replacement of the piping system should be conducted during the next major planned outage in April 2020.[321] Due to the COVID-19 pandemic, however, that outage was delayed until the spring of 2021.[322]

197. The Administrative Law Judge finds that the Company employed good utility practice in addressing the HRH steam line outage.

198. The Administrative Law Judge recommends that the Commission not order Minnesota Power to refund any replacement power costs related to HRH steam line outage.

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[312] *Id.*
[313] Ex. 7, Schedule 3 at 5 (Undeland Direct).
[314] *Id.*, Schedule 3 at 7.
[315] *Id.*
[316] *Id.*
[317] *Id.*
[318] *Id.*, Schedule 3 at 10.
[319] Ex. 7 at 21 (Undeland Direct).
[320] *Id.* at 15-16.
[321] *Id.*, Schedule 3 at 11.
[322] *Id.* at 20.

3. Minnesota Power's Learning Team Provided Recommendations to Improve the HEP Maintenance and Inspection Program

199. Whenever a Minnesota Power facility experiences a significant failure or outage, the Company uses a learning team to analyze the causes and put measures into place to minimize risk of reoccurrence.[323] The learning team is a collaborative approach using a group of individuals who are most familiar with the equipment and operations at issue. A trained coach or facilitator leads the learning team through a process that involves learning about the incident, reflection, and developing recommended solutions.[324] When a high impact outage occurs, such as the HRH failure, the Company evaluates the PM and PdM programs to determine if improvements could be made in light of the information learned as a result of the outage.[325] Minnesota Power established a learning team to review the HRH steam line seam weld failure and provide suggested changes to its operations, PM program, and PdM program.[326]

200. Minnesota Power's learning team and its expert consultants concluded that the Company's PM and PdM programs and HEP inspection protocol were consistent with good utility practice.[327] In light of the information learned through the steam leak investigation about the extent of creep in BEC4's HRH, Minnesota Power established four steps intended to reduce the risk of similar failure from occurring in the future: (1) inspect and repair the entire BEC4 HRH piping system; (2) accelerate inspections of the BEC3 HRH piping; (3) completely replace the BEC4 HRH piping system; and (4) revise BEC's HEP inspection program.[328]

201. Through an internal review of the HEP program, and consultation with third-party engineering firms, the Company elected to revisit the standardized test methods for specific areas of the steam lines.[329] The Company created a formalized HEP program document as a reference that outlines the quality control procedures, inspection frequency, inspection methods, and required inspector qualifications.[330]

202. The Administrative Law Judge finds that Minnesota Power's convening of a learning team to evaluate the BEC4 HRH steam line seam weld failure and the associated overall HEP program at Boswell is consistent with good utility practice and should be an approach that is encouraged at these facilities.

4. The Department's Position Is Unsupported By Evidence

203. The Department, through its expert Mr. Polich, opined that Minnesota Power did not follow good utility practice with regard to its maintenance and inspection of the HRH steam

[323] Exs. 14 and 15 at 32 (Undeland Rebuttal) (Public and Nonpublic).
[324] *Id.*
[325] *Id.*
[326] *Id.*
[327] *Id.*
[328] *Id.*
[329] Ex. 7 at 22 (Undeland Direct).
[330] *Id.*

line at BEC4, and that failure to do so caused the failure of the HRH and the unplanned outage in February 2019.[331]

204. Mr. Polich contends that Minnesota Power diverted from good utility practice in two ways. First, he suggests that Minnesota Power should have created a program that would inspect 100 percent of all seam welded steam line using phased array ultrasonic examination at least every five years, as recommended by EPRI.[332] Second, Mr. Polich contends that Minnesota Power overly relied upon its vendor Thielsch in creating its HEP maintenance and inspection program, and should have questioned Thielsch's suggestions and been aware of the potential issues with seam-welded HEP steam line.[333]

205. Based on the following findings, the Administrative Law Judge finds that the Department's assertions are not supported by any evidence or even by the sources upon which Mr. Polich purports to rely.

a. *100 Percent Phased Array Ultrasonic Inspection of HEP Every Five Years is not Common Utility Practice*

206. At the time of the HRH steam line seam weld failure and associated outage in February 2019, Minnesota Power was not aware of any other power companies that had implemented 100 percent inspections using phased array ultrasonic examination of all seam-welded HEP at least every five years.[334] Based on common practice in the industry and the information available to Minnesota Power at that time, the Company's inspection program for seam-welded HEP was on the upper end of the range of good utility practice.[335] Additionally, Minnesota Power utilized a detailed risk-based analysis to establish inspection frequency of all HEP. Minnesota Power's protocol of inspecting its low stress seam-welded HEP between every five to ten years depending on the level of risk for each area was considered good utility practice. The vertical section of HRH at BEC4 is one of the areas of least stress, so it was scheduled for inspection on a ten-year frequency.[336]

207. In support of his position that good utility practice rigidly requires phased array ultrasonic examination of 100 percent of the HEP within a facility at least every five years, Mr. Polich indicated that he knew of two power plants that complied with that standard.[337] But he admitted that his knowledge regarding what HEP maintenance practices are employed by utilities across the country is limited to "the three power plants HEP inspection programs he has

[331] Exs. 14 and 15 at 17 (Undeland Rebuttal) (Public and Nonpublic).
[332] Exs. 10 and 11 at 39-40 (Polich Direct). Notably, Mr. Polich did not list EPRI as one of the standard setting organizations in his definition of "good utility practice." *See id.* at 7.
[333] *Id.* at 40-41.
[334] Exs. 14 and 15 at 18 (Undeland Rebuttal) (Public and Nonpublic).
[335] *Id.*
[336] *Id.*
[337] *Id.*, Rebuttal Schedule 1 at 5, response to MP IR 05(b). Although Mr. Polich states in testimony that he knows of three facilities that follow EPRI's guidelines, he clarified during the Hearing that only two of the three facilities have longitudinal seam-welded HEP for which EPRI's guidelines would be applicable. Ev. Hrg. Tr. at 59-60 (Polich). Thus, Mr. Polich's conclusions about industry practice are really based upon two facilities.

reviewed[.]"[338] Mr. Polich's definition of good utility practice requires that a "significant portion" of the electric utility industry must accept a practice or method.[339] Thus, by his own standard, Mr. Polich's invocation of a grand total of two facilities falls immeasurably short of establishing the threshold for good utility practice.

208. Rather than providing evidence of the common practices of a significant portion of utilities, Mr. Polich relies exclusively on the recommendations and guidelines set forth by the American Society of Mechanical Engineers ("ASME") and EPRI to support his position.[340]

209. Mr. Polich first cites to Appendix V, "Recommended Practice for Operation," of the ASME Code for Pressure Piping, B31.1 (2016).[341] Specifically, Mr. Polich quoted the following provision:

> *V-8.5.2 Continued examination shall be made at intervals based upon the results of the initial inspection, but not to exceed 5 yr with corrective measures being taken each time that active corrosion is found.*[342]

210. Section 8.1.1 of Appendix V ("V-8.1.1") sets forth the types of piping systems to which that particular appendix applies:

> V-8.1.1 This section pertains to the requirements for inspection of critical piping systems that may be subject to internal or external corrosion-erosion, such as buried pipe, piping in a corrosive atmosphere, or piping having corrosive or erosive contents. Requirements for inspection of piping systems to detect wall thinning of piping and piping components due to erosion/corrosion, or flow-assisted corrosion, are also included. Erosion/corrosion of carbon steel piping may occur at locations where high fluid velocity exists adjacent to the metal surface, either due to high velocity or the presence of some flow discontinuity (elbow, reducer, expander, tee, control valve, etc.) causing high levels of local turbulence. The erosion/corrosion process may be associated with wet steam or high purity, low oxygen content water systems. Damage may occur under both single and two phase flow conditions. Piping systems that may be damaged by erosion/corrosion include, but are not limited to, feedwater, condensate, heater drains, and wet steam extraction lines. Maintenance of corrosion control equipment and devices is also part

[338] Exs. 14 and 15 at 4, Rebuttal Schedule 1 at 2, response to MP IR 04(c) (Undeland Rebuttal) (Public and Nonpublic).
[339] Exs. 10 and 11 at 6 (Polich Direct) (Public and Nonpublic).
[340] *Id.* at 19. It is worth noting that Mr. Polich, in defining "good utility practice" did not cite to ASME's Code or EPRI's recommendations, but did include "acts generally accepted in the region in which the project is located." *See* Exs. 10 and 11 at 6-7 (Polich Direct) (Public and Nonpublic).
[341] Exs. 10 and 11 at 24 (Polich Direct) (Public and Nonpublic).
[342] *Id.* (emphasis in Polich Direct).

of this section. Measures in addition to those listed herein may be required.[343]

211. The BEC4 HRH seam-welded piping does not fall within any of the categories of piping systems set forth in V-8.1.1.[344] The BEC4 HRH system is not buried, is not located in a corrosive atmosphere, and does not carry corrosive or erosive contents. Further, the BEC4 HRH system is not a part of the "feedwater, condensate, heater drains, and wet steam extraction lines" systems. Finally, the BEC4 HRH system does not carry wet steam; it carries dry superheated steam.[345] Consequently, V-8.1.1 does not apply to the BEC4 HRH, and Mr. Polich's reliance on this section is misplaced.

212. The Department's expert, Mr. Polich, testified that HEP systems can develop "rust" that will cause erosion/corrosion damage.[346] But as Company witness Mr. Undeland testified, the BEC4 HRH system is not in corrosive environment in that it does not carry wet steam, only dry, superheated steam.[347]

213. Importantly, none of the pre- or post-outage inspections of the HRH steam line indicated findings of any erosion or corrosion of the pipes (which is the subject of Section V-8), much less that it was the cause of the failure.[348] This further demonstrates that the HRH steam lines are not, by their nature, a corrosive or erosive environment that would be subject to V-8.

214. Most importantly, however, the ASME Code explicitly defines "erosion/corrosion" as "a flow-accelerated corrosion process that leads to loss of wall thickness in carbon or low alloy steel pipe exposed to <u>water or wet steam</u>."[349] Similarly, the ASME Code's list of the "Systems and Components Susceptible to Erosion/Corrosion" does not include the HRH steam line, and states that "Piping damage due to [Erosion/Corrosion] is not limited to these systems and may occur in any system of carbon steel or low alloy piping that is exposed to <u>water or wet steam</u> and operates at a temperature greater than 200°F (93°C)."[350] Thus, pursuant to the express terms of the ASME code, a corrosive/erosive environment requires the presence of water or wet steam. Because the HRH steam line carries only superheated dry steam, it does not create a corrosive/erosive environment that would be subject to Nonmandatory Appendix V-8 of the ASME Code.

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343 Exs. 14 and 15 at 20 (Undeland Rebuttal) (Public and Nonpublic) (emphasis added); Ex. 15, Rebuttal Schedule 2 at 4 (Undeland Rebuttal) (Nonpublic) (emphasis added).
344 Exs. 14 and 15 at 21 (Undeland Rebuttal) (Public and Nonpublic).
345 *Id.*
346 Ev. Hrg. Tr. at 78 (Polich).
347 Exs. 14 and 15 at 20-21 (Undeland Rebuttal) (Public and Nonpublic).

348 *See, generally* Ex. 7, Schedule 3 (Undeland Direct) (discussing inspections of the welded seam failure of the HRH line).
349 Ex. 22a at 319 (emphasis added).
350 *Id*. (emphasis added).

215. Further, the cause of the HRH steam line seam weld failure was determined to be creep, not corrosion.[351] In the 2016 version of the ASME Code for Pressure Piping, B31.1, which was applicable to active inspections and maintenance procedures developed ahead of the February 2019 unplanned HRH outage in question, section V-12, titled "Creep," would have been the section of Appendix V that applied to BEC4's HRH piping.[352] V-12.1.1 indicates that operating companies "should periodically select high-priority creep damage areas for examination . . . ."[353] V-12.2.2 states that a "procedure should be developed to select piping system areas more likely to have greater creep damage. . . . The procedure should establish a prioritized examination schedule based on the evaluation process."[354] Additionally, Section V-12 does not set forth a specific period for examinations. Instead, V-12.5 notes that "[t]he frequency of examination, determined by the Operating Company, should be based on previous evaluation results and industry experience. Particular consideration should be given to the selected high-priority weldments."[355]

216. In other words, Section V-12 does not call for 100 percent inspection of all piping on a set schedule, but rather indicates that areas of high stress or that have a history of creep should be targeted for periodic evaluation and that the Company was responsible for determining the frequency based on facility experience and known conditions of the line.[356] This is consistent with Minnesota Power's HEP maintenance and inspection program.

217. Minnesota Power worked with expert consultants to identify the amount of stress on all areas of the HEP systems at Boswell.[357] Minnesota Power's system engineers used this information, along with past inspection results, known areas of concern, third-party expert recommendations, industry bulletins, and insurance carrier recommendations to identify the areas of the HEP system that were at a higher risk for creep, as laid out in Section V-12.5.[358] Higher stress and risk areas were inspected every two to five years, while the areas of least stress, such as the vertical section of HRH at BEC4, were inspected on a ten-year frequency.[359] This method of risk-based inspection scheduling is entirely consistent with the practices recommended in Section V-12 of the ASME code.

218. Ultimately, Mr. Polich's reliance on the ASME code to support a rigid five-year inspection frequency requirement is misplaced.

219. Minnesota Power's maintenance and inspection program is consistent with Section V-12, which addresses creep damage inspections – the type of damage at issue in the BEC4 HRH.

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[351] Exs. 14 and 15 at 20-21, 32-33 (Undeland Rebuttal) (Public and Nonpublic); *see also* Ex. 7, Schedule 3 (Undeland Direct).
[352] Exs. 14 and 15 at 21 (Undeland Rebuttal) (Public and Nonpublic); Ex. 15, Rebuttal Schedule 2 at 6 (Undeland Rebuttal) (Nonpublic).
[353] Ex. 15, Rebuttal Schedule 2 at 6 (Undeland Rebuttal) (Nonpublic).
[354] *Id.*
[355] Exs. 14 and 15 at 21 (Undeland Rebuttal) (Public and Nonpublic); Ex. 15, Rebuttal Schedule 2 at 7 (Undeland Rebuttal) (Nonpublic).
[356] Exs. 14 and 15 at 21 (Undeland Rebuttal) (Public and Nonpublic).
[357] *Id.* at 22.
[358] *Id.*
[359] *Id.*

On the other hand, Section V-8 applies only to inspections for damage caused by erosion or corrosion, which was not identified as being present in any of the HRH inspection reports and is inapplicable because the piping does not contain water or wet steam.

220. Mr. Polich also cites to EPRI's 2003 "Guidelines for the Evaluation of Seam-Welded High-Energy Piping" to support his argument that phased array ultrasonic testing of 100 percent of seam-welded HEP every four to five years is required to comply with good utility practice.[360] But EPRI is not a standard creating entity; it is a member utility organization that provides suggested practices and procedures to its members for a fee.[361]

221. Mr. Polich indicates that he relied upon the 2003 edition of this EPRI document. However, that version does not explicitly recommend phased array ultrasonic testing on 100 percent of seam-welded HEP on a four- to five-year cycle. Instead, the 2003 document cited by Mr. Polich recommends a risk-based analysis of HEP for purposes of establishing an inspection program for seam-welded piping, which Minnesota Power used in developing its HEP program, including increased inspections, like those performed as recently as 2018, on high-risk areas.[362]

222. Although Mr. Polich claims that compliance with good utility practice requires all seam-welded HEP inspection programs to include phased array ultrasonic testing of 100 percent of HEP at least every five years, he acknowledged that the EPRI recommendations do not state that conclusion with any clarity. Instead, after being unable to point to the places in the document supporting his position, Mr. Polich conceded that "It's one of those things that's a little bit convoluted throughout this document because there's a lot of information contained in here . . . ."[363] Mr. Polich continued:

> [I]t's part of a decision tree that you go through to come to this conclusion. And so it's not the type of thing where it just simply says 100 percent over five years. You actually have to follow the passes through the flow diagram and look at how the piping has performed and things like that. So there's not a single specific place within this document you could find it, it's related to the overall scope in which this document points out how you should address the evaluation of seam-welded high-energy piping.[364]

223. Mr. Polich further admitted that he did not inspect or conduct a decision tree analysis for the BEC4 HRH to determine what EPRI recommendations would apply.[365] Thus, the EPRI recommendations are not nearly as straightforward as Mr. Polich initially claimed, and he has admittedly not performed the analysis necessary to determine what maintenance practices EPRI would suggest for BEC4's HRH.

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[360] Exs. 10 and 11 at 25 (Polich Direct) (Public and Nonpublic).
[361] Ev. Hrg. Tr. at 75 (Polich).
[362] *Id.* at 71-73.
[363] *Id.* at 66.
[364] *Id.* at 67.
[365] *Id.*

224. While EPRI is a very useful resource and Minnesota Power takes its guidelines and recommendations into consideration when creating and updating maintenance and inspection programs, EPRI recommendations do not alone set forth the range of programs that would be consistent with good utility practice.[366] Rather, EPRI's recommendations often represent the optimum utility practice. Some of EPRI's guidelines and recommendations are widely adopted within the industry, while others are not.[367]

225. In addition to taking into account any recommendations from trade groups such as EPRI, the range of maintenance and inspection programs that fall within good utility practice is also informed by OEM recommended practices and procedures, IEEE standards, historical experience, the common practices of other utilities and plant operators, continuing education and external training of personnel, and recommendations from independent engineering vendors and outside consultants, among other sources.[368] Hence, EPRI recommendations are only one data point among many that must be taken into account in establishing the parameters of good utility practice.[369]

226. Thielsch informed Minnesota Power that none of their approximately 50 utility clients, many of which have multiple coal-fired facilities, follow the EPRI recommendation for 100 percent ultrasonic inspection of seam-welded HEP at least every five years, including those clients that consistently subscribe to EPRI's applicable programs.[370]

227. This is fairly consistent with EPRI's own survey results. In response to Minnesota Power's IR No. 04(c), which asked Mr. Polich to identify all utilities of which he is aware that have had a policy of 100 percent compliance with all EPRI guidelines and recommendations, the Department responded, in part:

> EPRI has also conducted surveys of the utility industry on applying the recommendations contained in "Guidelines for the Evaluation of Seam-Welded High-Energy Piping." While the Department was not able to obtain a copy of EPRI's most recent survey due to cost-constraints, Mr. Polich was informed by EPRI that the most recent results are very similar to the 1993 survey, which are contained in the 2003 EPRI report, "Guidelines for the Evaluation of Seam-Welded High-Energy Piping," page 1-47 through page 1-60 . . . .[371]

The Department contended that EPRI's survey, which included responses from 29 utilities, "concluded that 50% of the utilities responding to the 1993 survey were applying EPRI guidelines . . . ."[372]

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[366] Exs. 14 and 15 at 23 (Undeland Rebuttal) (Public and Nonpublic).
[367] *Id.*
[368] *Id.*
[369] *Id.*
[370] *Id.*
[371] *Id.*, Rebuttal Schedule 1 at 2-3, response to MP IR 04(c).
[372] Exs. 14 and 15, Rebuttal Schedule 1 at 2-3, response to MP IR 04(c) (Undeland Rebuttal) (Public and Nonpublic).

228. In EPRI's own words:

> Although our survey indicated that only 2% of the utilities surveyed complied completely with the EPRI Guidelines, 50% of the utilities thought that they had followed the procedures completely, and another 17% believed that they were following the Guidelines procedures in part. EPRI review of these claims showed that in fact 41% had followed the Guidelines for the most part.[373]

Two percent compliance means that, at most, only a couple of the power plants from the 29 utilities surveyed were actually following all of EPRI's suggested procedures for HEP inspections. At best, less than 50 percent of respondents thought that they had followed EPRI's guidelines. That means that more than half of respondents believed that they were not strictly following EPRI's guidelines.[374]

229. More recently, EPRI has acknowledged that its five-year inspection interval recommendation is not generally followed within the industry and may be cost prohibitive. Specifically, in 2017 EPRI conceded that "the recommendation in [the Guidelines for the Evaluation of Seam-Welded High-Energy Piping] regarding a five-year inspection interval is viewed as cost-prohibitive with the estimated cost for a single HRH piping system to be on the order of $5 million."[375]

230. When asked about this conclusion in EPRI's 2017 publication, Mr. Polich attempted to deflect by stating that "[t]his is not EPRI's opinion" . . . "the view of being cost prohibitive is not by EPRI, but by the utilities."[376] However, the EPRI publication does not attribute the statement as the opinion of utilities or indicate that EPRI disagrees – that is solely how Mr. Polich has chosen to interpret the document. In any event, this is a distinction without a difference because good utility practice is established by the actual practices of utilities, not by EPRI recommended standards. The fact that utilities believe that a five-year inspection cycle is cost prohibitive demonstrates that a significant portion of the utility industry does not follow that EPRI recommendation.[377]

231. In defending the potential cost of compliance with EPRI guidelines, Mr. Polich concludes that if Minnesota Power had undertaken an inspection of the vertical section of HRH steam line in 2013 at a cost $35,000 "it is very likely that the flaws in the HRH steam line would have been found . . . ."[378] But Mr. Polich significantly misconstrues the cost of such an inspection as $35,000. That was a bid from Thielsch for limited testing of the HRH at BEC3 (not BEC4), and did not include the costs of scaffolding, removing insulation, surface preparation, reinsulating,

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[373] *Id.*, Rebuttal Schedule 1 at 33 (emphasis in original).
[374] *See id.* at 24; *see also* Exs. 10 and 11 at 6-7 (Polich Direct)(Public and Nonpublic) (noting that "good utility practice" refers to the practices of a "significant portion of the electric utility industry").
[375] Exs. 14 and 15 at 25, Rebuttal Schedule 1 at 427 (Undeland Rebuttal) (Public and Nonpublic).
[376] Ev. Hrg. Tr. at 69-70 (Polich).
[377] *See* Exs. 10 and 11 at 6-7 (Polich Direct) (Public and Nonpublic).
[378] Exs. 10 and 11 at 15 (Polich Direct) (Public and Nonpublic).

removing the scaffolding, and potentially extending an outage to complete the full inspection.[379] Additionally, the scope of the Thielsch bid was for a portion of the HRH, far less than the type of testing Mr. Polich claims Minnesota Power should have employed, which included 100 percent phased array ultrasonic testing of the entire HEP system and not just a small section of the HRH steam line.[380]

232. Given the $5 million estimate included in ERPI's 2017 publication, the Administrative Law Judge agrees that it is clear that Mr. Polich's claim that it would have cost Minnesota Power only $35,000 to comply with EPRI's HEP inspection guidelines is meritless.

233. Minnesota Power has not specifically estimated the cost associated with such an inspection protocol because it would be significantly higher than the potential benefit.[381] Using EPRI's own estimate of $5 million, however, the total cost from 2010 to 2020 would have been $10 million for BEC3 (assuming two cycles of 100 percent inspection were completed over the two five-year periods), and another $10 million for BEC4, for a total of $20 million. That amount would cover inspections on only the HRH piping systems of these two units, not those of Boswell Units 1 and 2, which were also in operation over this 10-year period. Additionally, this amount would not include costs for the remainder of the HEP, which Mr. Polich concludes should also fall under this inspection protocol.[382]

234. In the approximately forty years of operation at BEC4, there has been only one outage caused by a high impact failure of the HRH piping; the 2019 outage at issue in this proceeding.[383] The Department estimates an incremental cost increase of $4,482,456 for the replacement power for the 2019 HRH steam line failure outage at BEC4. Based upon the estimate for implementing EPRI's inspection protocol that was included in its 2017 publication, the cost for BEC3 and BEC4 would have been approximately $20 million over just the period from 2010 to 2020.[384] During that same period, the actual costs to implement Minnesota Power's current program were approximately $6.6 million.[385] Adding to this amount the cost of the replacement power required in 2019 would bring the total to just over $11 million, nearly half of the cost of the inspection protocol Mr. Polich recommends.

235. Even limiting the evaluation period to ten years and two facilities, the costs of implementing Mr. Polich's suggested inspection protocol would be significantly more than the cost to customers for the inspections actually performed plus the 2019 outage. If the comparison period was extended back to 2003 (the date of the EPRI report relied upon by Mr. Polich) and all of Minnesota Power's facilities that have HRH systems were included in the analysis, the costs of Mr. Polich's inspection protocol would dwarf the cost of the 2019 outage.[386]

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[379] Exs. 14 and 15 at 28 (Undeland Rebuttal) (Public and Nonpublic).
[380] *Id.*
[381] *Id.*
[382] *Id.* at 29.
[383] *Id.*
[384] *Id.*
[385] Exs. 14 and 15 at 29 (Undeland Rebuttal) (Public and Nonpublic).
[386] *Id.* at 29-30.

236. The Administrative Law Judge finds that Mr. Polich's conclusion is not consistent with the common practice in the industry, which was to inspect seam-welded HEP between every five to ten years, with lower stress and lower risk areas such as the BEC4 HRH being inspected on the less frequent end of that range. But Mr. Polich does not really address, much less disprove, Minnesota Power's position that its HEP inspection program was consistent with the common practice in the industry at the time. Thus, while Mr. Polich's testimony addresses what EPRI suggests as the most *optimal* HEP inspection protocol, it does not establish the full range of good utility practices.

b. *Minnesota Power Did Not Unreasonably Rely upon Thielsch*

237. Mr. Polich concludes that Minnesota Power "heavily relied upon Thielsch and essentially turned over the HEP inspection program to Thielsch."[387] He concludes that Minnesota Power should have taken more control and questioned Thielsch's recommended inspection protocol. The Administrative Law Judge does not agree.

238. Thielsch has provided independent consulting services for the HEP systems in Boswell facilities for decades, and has significant experience with coal fired power plants across the country.[388] Minnesota Power values Thielsch's expertise within the industry and extensive knowledge of the Boswell facilities, including BEC4.[389]

239. There is significant value in having the same expert consultants inspect a HEP system over a long period. They gain valuable first-hand knowledge on the health of the system, have consistent access to the historical reports from past inspections, have the ability to trend findings throughout the years and predict potential future problem areas, and provide more informed recommendations for future inspections.[390] Third-party experts also provide specialized knowledge in areas where it would be cost-prohibitive for Minnesota Power to train its employees and purchase the equipment necessary to perform the inspections and testing.[391]

240. Mr. Polich's conclusion that Minnesota Power overly relied upon Thielsch's advice and counsel is not reasonable considering he relies almost entirely on EPRI's recommended guidelines, which he admits are considered cost prohibitive by utilities. And while EPRI's guidelines are based upon its opinion about what the practices should be, Thielsch informed Minnesota Power regarding the practices actually employed by approximately 50 other utilities across the country.[392]

241. In any event, Minnesota Power did not simply turn over the responsibility for the HEP inspection protocol to Thielsch, as suggested by Mr. Polich. Thielsch offers comprehensive and continuing oversight for piping and boiler inspection programs through a master services agreement relationship with some of its clients.[393] Minnesota Power does not have a master

[387] Exs. 10 and 11 at 40-41 (Polich Direct) (Public and Nonpublic).
[388] Exs. 14 and 15 at 30 (Undeland Rebuttal) (Public and Nonpublic).
[389] *Id.*
[390] *Id.*
[391] *Id.*
[392] *See id.* at 23, 30-32.
[393] *Id.* at 31.

services agreement with Thielsch, but rather utilizes Thielsch and its expertise on more of a project by project basis.[394]

242. Although Minnesota Power certainly accepted and incorporated many of Thielsch's recommendations, they were one of many sources of information considered by the Company in creating the final HEP maintenance and inspection program.[395] Minnesota Power develops inspection program scope and frequency protocols based upon many different sources of information including past results, known areas of risk, industry groups, insurance carrier recommendations, and third-party expert recommendations.[396] Inspection protocol development involves a collaborative process with several parties utilizing information from a variety of internal and external sources.[397] While Thielsch has been a key contributor supporting development of Minnesota Power's HEP program over the years, the Company has also relied upon internal expertise and other third-party experts for additional inputs and recommendations for the program.[398]

243. In the end, the Administrative Law Judge agrees that it is good utility practice for a utility to consult with industry experts when developing an inspection and maintenance program.

c. *Learning Team Recommendations Are Not Evidence that Past Practices Were Not Consistent with Good Utility Practice*

244. Mr. Polich attempts to use the recommendation of Minnesota Power's learning team to improve its HEP inspection program as evidence that its historical program was not consistent with good utility practice.[399] The fact that Minnesota Power chose to make changes to its PM and PdM programs related to HEP inspections in no way indicates that the prior programs fell short of good utility practice.[400] To the contrary, it is good utility practice to learn from equipment failures and make improvements to prevent similar failures in the future.[401] The term "continuous improvement" is often used in in the industry as a means of expressing the desire to build upon the programs and systems already in place as a good utility practice.[402] The recommendations of the HRH learning team were aimed at continuous improvement and building additional defenses against recurrence of similar events. The recommendations do not mean there was fault or that good utility practices were not being followed.[403]

245. A number of inputs determines the level to which any particular topic, piece of equipment, or system is provided resources to maintain reliability.[404] There is a spectrum, and good utility practice that thoughtfully plans additional maintenance, inspection, and testing falls

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394 Exs. 14 and 15 at 31 (Undeland Rebuttal) (Public and Nonpublic).
395 *Id.*
396 *Id.*
397 *Id.* at 32.
398 *Id.*
399 Exs. 10 and 11 at 39-40 (Polich Direct) (Public and Nonpublic).
400 Exs. 14 and 15 at 33 (Undeland Rebuttal) (Public and Nonpublic).
401 *Id*.
402 *Id*.
403 *Id.*
404 *Id.*

appropriately in the middle. Balance between resources and the level of risk is never perfect, and adjustments are often needed to continuously improve.[405]

246. The ability to convene a learning team is very important for utilities, like Minnesota Power, to self-evaluate whether its programs require revisions.[406] If these learning teams are used against utilities in the way Mr. Polich has used the HRH learning team analysis, such self-reflective and open discussion activities may be discouraged in the future.[407]

L. No Unplanned Outage Replacement Power Costs Should Be Refunded Because Minnesota Power Followed Good Utility Practice

247. LPI argues in its Initial Brief that Minnesota Power should be required to refund the costs of the unplanned outages during the 18-month AAA review period even if its actions are deemed consistent with good utility practice.[408] This argument is based upon the Department's initial oversimplified conclusion that because Minnesota Power spent $12.4 million less in generation maintenance expenses in 2019 than was included in the 2017 test year, and collected $7.727 million in unplanned outage costs during the 18-month AAA evaluation period in 2018 and 2019, the Company must have "pocketed" the maintenance savings while passing the increased unplanned outage costs on to customers.[409]

248. As discussed in detail in Sections II.E and II.F above, the intent of test year budgets is not to set a rigid spending amount by line item for future years. It is understood and expected that the individual cost components used to develop the rates will vary from year to year.[410] In this case, the lower generation maintenance spending in 2019 compared to the test year can be explained by the retirement of several generation facilities in 2018 and 2019, changes to the maintenance expenses of facilities other than Boswell, higher than projected capitalization of maintenance projects, and different points in the long-term outage plan (2017 had a three week planned boiler outage at BEC4, with shorter outages planned for 2018 and 2019).[411] Importantly, Minnesota Power did not reduce maintenance or inspection activity or spending on any of the Boswell systems at issue in this proceeding.[412] There has been no evidence presented by any party in this proceeding that would suggest that reduced maintenance spending was even a contributing cause of any of the unplanned outages during the 18-month evaluation period.

249. LPI's assertion that Minnesota Power gets to "keep" the cost savings due to reduced generation maintenance expenses is overly simplistic and inaccurate.[413] Generation maintenance

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[405] *Id.*
[406] Exs. 14 and 15 at 34 (Undeland Rebuttal) (Public and Nonpublic).
[407] *Id.*
[408] LPI Initial Brief at 13.
[409] *Id*. LPI did not submit any independent evidence or testimony in this contested case proceeding.
[410] *In re the Complaint of Myer Shark et al. Regarding Xcel Energy's Income Taxes*, Docket No. E, G-002/C-03-1871, ORDER AMENDING DOCKET TITLE AND DISMISSING COMPLAINT at 4 (Oct. 1, 2004).
[411] Ex. 9 at 17, 20, 22-23 (Rostollan Direct).
[412] Ex. 6 at 11 (Poulter Direct); Ex. 5 at 15-20 (Simmons Direct); Exs. 14 and 15 at 17 (Undeland Rebuttal) (Public and Nonpublic).
[413] LPI Initial Brief at 13-14.

costs are highly cyclical based upon what types of outages are scheduled each year. In years where no significant outages are scheduled in the long-term outage plan, like in 2018 and 2019, generation maintenance expenses are typically lower than the test year.[414] When scheduled major outages occur, the Company's generation maintenance expenses typically exceed the test year amount.[415] Moreover, when there are actual savings in one area, they are often offset by cost increases in other areas.[416] Despite these variations, "no adjustment (with the exception of the pass-throughs) is made outside of a rate case for increases or decreases in the individual components of rates.[417]

250. The "netting adjustment" sought by LPI would constitute ratemaking outside of a rate case because it would be based solely upon differences in spending levels, not on whether the replacement energy costs were reasonably and prudently incurred. Commission precedent is clear that this would be inappropriate ratemaking.[418]

M. Replacement Power Costs Were Reasonable and Prudent

251. If Minnesota Power determines that it needs additional power to meet customer needs during the unplanned outage, the Company purchases replacement power for the unplanned outage.[419]

252. Replacement power costs are the costs incurred to purchase power to make up for the generation lost as a result of either a planned or unplanned outage at one of the Company's generation facilities.[420]

253. When an unplanned outage occurs or is imminent, Minnesota Power looks at multiple factors to determine whether to procure replacement energy during the outage timeframe. Those factors include projected load, MISO resource availability, renewable forecast, weather in MISO as well as in the Minnesota Power territory, Minnesota Power load forecast, power supply expectation (both baseload and variable generation plus purchases and sales), and MISO market and bilateral market price expectations.[421]

254. These factors help the Company determine whether the least cost option would be to procure replacement energy bilaterally from a counterparty, to purchase the energy from the MISO Day-Ahead or Real-Time market, or to do both. For example, if the bilateral market is higher than the expected MISO market price, the decision may be made to purchase some or all of the energy needed from the MISO market.[422]

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[414] Ex. 9 at 23-26 (Rostollan Direct).
[415] *Id*.
[416] *Id*.
[417] *In re the Complaint of Myer Shark et al. Regarding Xcel Energy's Income Taxes*, Docket No. E, G-002/C-03-1871, ORDER AMENDING DOCKET TITLE AND DISMISSING COMPLAINT at 4 (Oct. 1, 2004).
[418] *Id*.
[419] Ex. 8 at 2-3 (Oehlerking-Boes Direct).
[420] *Id.* at 2
[421] *Id.*
[422] *Id.* at 3.

255. Whenever possible, Minnesota Power seeks to determine the best timing to take an unplanned outage in order to minimize replacement power costs. When an outage need is identified, the condition of the equipment is evaluated to determine whether the unit needs to immediately come down to avoid further damage to plant equipment or creates an unsafe environment. If the unplanned outage can be delayed, Minnesota Power arranges for the outage to occur during the next least cost time period for procuring replacement power.[423]

256. The incremental replacement power costs for unplanned outages at Boswell included in Minnesota Power's FAC from July 1, 2018 through December 31, 2019, were $7,728,000.[424] These are defined as incremental costs because they are the replacement power costs over and above Boswell's power costs.[425] Using the process to utilize bilateral purchases and MISO market purchases to minimize replacement energy costs, Minnesota Power paid approximately $606,000 less than it would have had it utilized only MISO Day-Ahead Market purchases.[426]

257. The Department has not provided any testimony or evidence challenging whether Minnesota Power's process for procuring replacement power is consistent with good utility practice.

258. Overall, the Administrative Law Judge finds that Minnesota Power's process to evaluate and procure replacement power for unplanned outages exhibited good utility practice.

N. Minnesota Power's Proposed Refund Methodology Should Be Used if a Refund is Ordered

259. While the Administrative Law Judge does not recommend that the Commission require Minnesota Power to refund any unplanned outage costs through the FAC to customers, should the Commission order a refund, the record demonstrates that Minnesota Power's proposed refund methodology is reasonable.

260. Replacement power costs related to planned and unplanned outages are recovered from customers through the Rider for Fuel and Purchased Energy Charge. Minnesota Power included actual replacement power costs in its monthly FAC calculation, which was used to adjust rates monthly and in subsequently filed monthly and annual reports, which were reviewed for accuracy and prudence.[427] The adjustments reflected, on a per kilowatt hour basis, deviations from the base cost of energy established in the utility's most recent general rate case.[428]

261. Minnesota Power's maintenance practices were consistent with good utility practice and no refund of replacement power costs for unplanned outages from July 1, 2018

[423] *Id.*
[424] *Id.* at 5.
[425] Ex. 8 at 5 (Oehlerking-Boes Direct).
[426] *Id.* at 6.
[427] *Id.*
[428] *Id.*

through December 31, 2019 is appropriate. If the Commission finds that an adjustment is appropriate for the unplanned outage costs associated with BEC4's HRH steam leak and BEC3's Generator Bushing failure, however, Minnesota Power agrees that the Department's calculation of the adjustment amount is accurate for these two unplanned outages. Minnesota Power also agrees that it would be appropriate to include interest in the adjustment, and proposes to use the prime interest rate in effect from the month the outage costs were charged to the customers until the month that customers would receive the refund.[429]

262. If the Commission orders a refund of unplanned outage costs to customers, the Company is proposing to calculate specific refund amounts for the eight Large Power customers and seventeen Municipal customers based on their actual kilowatt hour usage to which the unplanned outage costs were applied.[430] Minnesota Power proposes to calculate the specific refund amount for Large Power and Municipal customers by calculating what the applicable FAC rates would have been without the proposed disallowed outage costs (and interest), determining a reduction in the FAC rate, and applying that rate change to the actual usage for the months affected by the outage costs.[431] If any of these Large Power customers or Municipal customers are in arrears, Minnesota Power will first apply this refund amount as a credit to the amount in arrears before issuing any refund.[432]

263. For the remaining customer classes, the potential refund amount (total potential refund plus interest less the amount to be refunded to the Large Power and Municipal customers) could be refunded in the month following receipt of a final order from the Commission.[433] Minnesota Power proposes to calculate the refund for these customers by taking the remaining refund amount divided by the forecasted sales for the applicable remaining customer classes. This rate would be applied to actual usage in the refund month.[434]

264. The Company recognizes that there could be a difference in the forecasted versus actual usage in the refund month. Similar to the treatment of the "fuel cost reduction credit" issued by the Company in 2016, the Company will track the over or under refund amount.[435] If the Company over refunds, that will become a shareholder expense; if the Company under refunds, the under refund amount will be donated to HeatShare.[436]

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[429] Exs. 16 and 17 at 2-3 (Oehlerking-Boes Rebuttal) (Public and Nonpublic). The applicable interest rates by month are included in Exs. 16 and 17, Rebuttal Schedule 1 at 2-4 (Oehlerking-Boes Rebuttal) (Public and Nonpublic).
[430] *Id.* at 3.
[431] *Id.* at 3-4.
[432] *Id.* at 4.
[433] *Id.*
[434] *Id.*
[435] *In the Matter of Minnesota Power's Petition for Approval of Credits to Customers*, MINNESOTA POWER'S REPLY COMMENTS at 1-2, Docket No. E015/M-15-875 (Feb. 15, 2016). The Commission approved the Company's proposed refund methodology, aside from an offset for legal fees, in a May 26, 2016 Order Approving Refund and Requiring Filings.
[436] Exs. 16 and 17 at 4 (Oehlerking-Boes Rebuttal) (Public and Nonpublic).

265. Any Conclusions of Law more properly designed as Findings of Fact are hereby adopted as such.

III. CONCLUSIONS OF LAW

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. §§ 14.50 and Chapter 216B (2020).

2. The parties and the public received proper and timely notice of the hearings in this matter.

3. Minnesota Power is a "public utility" as defined by Minn. Stat. § 216B.02, subd. 4, because it operates facilities for furnishing electric service at retail to the public in Minnesota.[437]

4. Public utilities are required by Minn. Stat. § 216B.04 to provide safe, adequate, efficient, and reasonable service.

5. Minnesota Power has the burden of proof to show that the unplanned outage costs were reasonably and prudently incurred, applying good utility practices.

6. Minnesota Power has demonstrated by a fair preponderance of the evidence that the unplanned outage costs were reasonably and prudently incurred, applying good utility practices.

7. Minnesota Power has demonstrated by a fair preponderance of the evidence that its generation and maintenance programs, and actions taken during the unplanned outages occurring July 1, 2018 through December 31, 2019, were consistent with good utility practice.

8. Any Findings of Fact more properly designed as Conclusions of Law are hereby adopted as such.

Based on the foregoing Findings of Fact and Conclusions of Law, the Administrative Law Judge makes the following:

[437] Minn. Stat. § 216B.02, subd. 4 (2020).

IV. RECOMMENDATION

IT IS RECOMMENDED that the Minnesota Public Utilities Commission order that:

1. Minnesota Power has demonstrated that the unplanned outage costs were reasonably and prudently incurred, applying good utility practices.

2. Because Minnesota Power has met its burden that the unplanned outage costs were reasonably and prudently incurred, applying good utility practices, that Minnesota Power is not required to refund any unplanned outage costs through the FAC.

Dated: _______________

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BARBARA J. CASE
Administrative Law Judge