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

PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS

The Minnesota Public Utilities Commission ("Commission") referred this matter to the Office of Administrative Hearings for a contested case proceeding in September 2020. Administrative Law Judge Barbara J. Case ("ALJ") was assigned to the matter. The Commission directed the ALJ to consider whether Minnesota Power's forced outage costs between July 2018 and December 2019 were reasonable and prudent, applying good utility practice—and, if not, the overcharges plus interest that should be returned to ratepayers.

A remote evidentiary hearing was held on June 3, 2021 via Microsoft Teams. Initial briefs were filed on June 23, 2021. Reply briefs were filed on July 12, 2021.

David Moeller, Senior Attorney and Director of Regulatory Compliance, Minnesota Power, and Kodi Verhalen and Matthew Brodin, Taft Stettinius & Hollister LLP, appeared on behalf of Minnesota Power ("Company").

Katherine M. Hinderlie and Richard E.B. Dornfeld, Assistant Attorneys General, appeared on behalf of the Department of Commerce, Division of Energy Resources ("Department").

Andrew P. Moratzka, Sarah J. Phillips, Jessica L. Bayles, and Riley A. Conlin, Stoel Rives LLP, appeared on behalf of the Large Power Intervenors ("LPI").

Jason Bonnett appeared on behalf of the Commission staff.

STATEMENT OF THE ISSUES

1. Whether Minnesota Power's forced outage costs for the period of July 2018 through December 2019 were reasonable and prudent, applying good utility practice; and

2. If not, the amount of overcharges plus interest that Minnesota Power should be required to return to ratepayers through its Fuel Adjustment Clause rider mechanism.

SUMMARY OF RECOMMENDATIONS

1. The ALJ finds that Minnesota Power's maintenance activities and forced outage events relating to Boswell Unit No. 4's hot reheat lines and Boswell Unit No. 3's generator phase bushings were inconsistent with good utility practice. As a result, the Company's forced outage costs associated with these outages were not reasonably and prudently incurred and should be refunded to ratepayers including interest.

2. Based on the evidence in the hearing record, the ALJ makes the following findings:

FINDINGS OF FACT

I. PROCEDURAL HISTORY

1. Minnesota Power filed its Annual Automatic Adjustment of Charges Report in March 2020 pursuant to Minn. R. 7825.2800–.2830 (2019). The AAA Report included a section addressing forced outage events between July 2019 and December 2020 as required by a prior Commission order.[1] In the AAA Report, Minnesota Power identified 26 different forced outage events during the reporting period.[2]

2. A forced outage event is a situation where an electrical generating unit is removed from service for emergency reasons, or due to a component failure or other condition requiring removal outside of a planned maintenance or outage period. The utility will typically incur additional expenses when its own generation facilities are not available for service.[3] In this instance, Minnesota Power reported $7.73 million in replacement power costs associated with these outages that were ultimately charged to retail customers through its Fuel and Purchased Energy Adjustment Rider (Fuel Adjustment Clause Rider or FAC Rider).[4]

3. The Department filed initial comments with the Commission in April 2020 that reviewed the reasonableness of costs charged by utilities to retail customers through automatic

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[1] Minn. Power's 2018-2019 Annual Automatic Adjustment of Charges Report (Mar. 2, 2020) (eDocket Nos. 20203-160872-01, 20203-160872-02).
[2] Minn. Power's 2018-2019 Annual Automatic Adjustment of Charges Report at 206–08 (Mar. 2, 2020) (eDocket Nos. 20203-160872-01, 20203-160872-02) (Attach. No. 15 at 7–9).
[3] DER Ex. 12 at 6–7 (Campbell Direct). Unless otherwise noted, the citations provided are to the public versions of exhibits.
[4] Minn. Power's 2018-2019 Annual Automatic Adjustment of Charges Report at 206–08 (Mar. 2, 2020) (eDocket Nos. 20203-160872-01, 20203-160872-02) (Attach. No. 15 at 7–9).

adjustment mechanisms including Minnesota Power's FAC rider. In its comments, the Department explained that when a power plant "experiences a forced outage, the utility must replace the megawatt hours that plant would have produced if it had been operating, usually through wholesale market purchases. The cost of those purchases flows through the [FAC] directly to ratepayers."[5]

4. After reviewing Minnesota Power's AAA Report, the Department concluded that the Company's purchased power costs had increased significantly in 2019 and 2020. Purchased power is wholesale electricity procured by the utility from a third-party such as an independent power producer or a regional transmission operator such as the Midcontinent Independent System Operator (MISO). Specifically, the Department found that Minnesota Power's total costs per megawatt hour were 10.2% higher in 2019 than 2018.[6] The Department requested that the Company describe the main factors driving these cost increases and provide support for the $13.6 million in MISO charges for February 2019 in its reply comments. The Department also requested that Minnesota Power provide information comparing budgeted to actual generation maintenance expense.[7]

5. In April 2020, Minnesota Power filed reply comments stating that the cost increases were caused by "significant outages" at its Boswell Energy Center in 2019. The Company explained that the coal plant had outages each exceeding twenty days in February, March, June, and July. As a result, Minnesota Power was required to procure power necessary to serve customers from MISO's wholesale energy markets. The Company also provided information regarding actual and budgeted maintenance expenses.[8]

6. In June 2020, Minnesota Power filed a corrected copy of Schedule No. 15. The filing explained that the original Schedule 15 included with its AAA Report incorrectly understated "the Boswell Unit 4 Unplanned Outage related to the Hot Reheat Line Steam Leak . . . by 368,136 MWhs."[9]

7. After reviewing Minnesota Power's filings, the Department shared response comments in July 2020 that found: (1) the Company's forced outage costs were approximately 500% higher between July 2019 and December 2020 than in the two previous AAA reporting periods, (2) Minnesota Power underspent its annual $42 million generation maintenance budget by 21.9% in 2018 and 2019, and (3) the Company passed $7.727 million in forced outage costs onto customers through its FAC Rider.[10]

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[5] Dep't Review of the July 2018-Dec. 2019 Annual Automatic Adjustment Reports at 12 (Apr. 15, 2020) (eDocket Nos. 20204-162132-02, 20204-162132-01).
[6] *Id.* at 22, 51.
[7] *Id.* at 12–13.
[8] Minn. Power Reply Cmts. at 3–4 (Apr. 30, 2020) (eDocket No. 20204-162709-01).
[9] Minn. Power Correction to Attach. No. 15 in the July 2018-Dec. 2019 Annual Automatic Adjustment Report at 1 (June 10, 2020) (eDocket No. 20206-163842-01).
[10] Dep't Additional Response Cmts. at 2, 7–8 (Jul. 24, 2020) (eDocket No. 20207-165268-01).

8. In 2008, the Commission first commented on the relationship between maintenance and unplanned outages, directing utilities "to minimize unplanned facility outages through adequate maintenance and to minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work."[11] Reflecting this past Commission concern, the Department recommended in its July 2020 comments that the Commission require Minnesota Power to refund 50% of the forced outage costs, or approximately $3.864 million, charged to its retail customers.[12]

9. In September 2020, the Commission concluded that further factual development was required to determine "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[.]" As a result, the Commission referred the matter to the Office of Administrative Hearings for a contested case proceeding. The Commission further directed that Minnesota Power should "bear the burden of proving that any or all of its forced outage costs were reasonably and prudently incurred, applying good utility practices."[13]

10. Good utility practice means any 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. Good utility practice is not intended to be limited to the optimum practice, methods, or acts generally accepted in the region in which the Project is located.[14]

11. The Commission also directed the Department to retain an outside engineering expert to assess whether Minnesota Power's maintenance activities and force outage events were consistent with good utility practice.[15] Consistent with this guidance, the Department issued a request for proposal in October 2020 to secure a contractor with engineering expertise to assist in the matter. The Department's first request for proposal was unsuccessful, and the Department reposted the request for proposal in December 2020.[16] To accommodate the need to retain an expert, the parties agreed to modify the procedural schedule.[17] The ALJ issued a Second Prehearing Order with the modified procedural schedule.[18] In February 2021, the Department

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[11] *In re 2006 Annual Automatic Adjustment of Charges for All Elec. & Gas Utils.*, MPUC Docket No. E,G-999/ AA-06-1208, ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS at 5 (Feb. 6, 2008).
[12] Dep't Additional Response Cmts. at 8.
[13] ORDER ACCEPTING 2018–2019 ELECTRIC AAA REPORTS; NOTICE OF AND ORDER FOR HEARING at 4 (Sept. 16, 2020) (eDocket No. 20209-166630-01).
[14] DER Ex. 10 at 7–8 (Polich Direct). Minnesota Power did not dispute the Department's proposed definition of "good utility practice." MP Ex. 14 at 8 (Undeland Rebuttal).
[15] ORDER ACCEPTING 2018–2019 ELECTRIC AAA REPORTS; NOTICE OF AND ORDER FOR HEARING at 4 (Sept. 16, 2020) (eDocket No. 20209-166630-01)
[16] Dep't Extension Request (Dec. 7, 2020) (eDocket No. 202012-168840-01).
[17] Dep't Extension Request (Dec. 7, 2020) (eDocket No. 202012-168840-01).
[18] SECOND PREHEARING ORDER (Dec. 17, 2020) (eDocket No. 202012-169108-01).

informed the Office of Administrative Hearings that it had retained engineering consulting firm GDS Associates, Inc.[19] Mr. Richard Polich of GDS Associates assisted the Department in conducting an independent investigation of the forced outages at Minnesota Power's Clay Boswell coal plant and provided testimony on behalf of the Department in this proceeding.[20]

II. BACKGROUND

12. Utilities are entitled to recover their "revenue requirement" from their customers.[21] The "revenue requirement" is the total amount of money that a utility needs to collect from customers to pay all costs of service including a reasonable return on investment to its investors. The revenue requirement has two main components: return on rate base and operating expenses and revenues. The revenue requirement is set during a general rate case proceeding.[22]

13. During a general rate case, the Commission considers the utility's representative expenses and revenues during a "test year." A test year is typically a recent or forecasted 12-month period selected for purposes of expressing the utility's need for a change in rates.[23] This test year data is then used to determine the utility's revenue requirement and resulting rates charged to ratepayers.

14. In 2018, the Commission authorized a rate change for Minnesota Power, as part of the Company's last completed general rate case. As part of its decision, the Commission determined that $41,998,904 (approximately $42 million) reasonably represented Minnesota Power's annual power plant generation maintenance expense.[24] This amount effectively serves as the Company's annual maintenance budget for generation plants. However, the utility's spending may either drop below or exceed this budgeted amount depending on its actual maintenance needs each year.[25]

15. In addition to general rate cases, the Commission may adjust utility cost recovery using pass-through mechanisms called "riders." Riders are typically used to charge actual expenses (as opposed to representative amounts set during a test year) such as fuel costs to retail customers.[26] Permanent cost recovery, however, is not guaranteed. Instead, rider costs are provisionally charged to customers subject to Commission review and possible refund.[27] The Fuel

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[19] Dep't Extension Request (Dec. 7, 2020) (eDocket No. 202012-168840-01); Dep't Protective Agreement (Feb. 2, 2021) (eDocket No. 20212-170635-01).
[20] DER Ex. 10 at 1 (Polich Direct).
[21] Minn. Stat. § 216B.16 (2020).
[22] DER Ex. 12 at 3–4 (Campbell Direct).
[23] Minn. R. 7825.3100, subp. 17 (2019).
[24] *In re Appl. of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn*., MPUC Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, & ORDER (Mar. 12, 2018); *In re Appl. of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn*., MPUC Docket No. E-015/GR-16-664, Compliance Filing—Final General Rates § VIII, Compliance Schedule 16 (June 28, 2018).
[25] DER Ex. 12 at 24 (Campbell Direct); MP Ex. 9 at 23 (Rostollan Direct).
[26] DER Ex. 12 at 4 (Campbell Direct).
[27] Minn. Stat. § 216B.16, subd. 7(1) (2020) (authorizing rider cost recovery); Minn. R. 7825.2920 (2019) (provisionally approving rider costs subject to further review).

and Purchased Energy Adjustment Rider, for example, allows a utility to recover actual fuel expenses and purchased power costs from customers.[28]

16. The interplay between costs recovered based on a representative test year amount and those recovered through a rider based on actual spending can create improper financial incentives. Accordingly, the Commission "monitors utility expenditures related to maintenance and forced outages . . . [t]o guard against the possibility that a utility would seek to increase profits by skimping on maintenance—with the expectation that ratepayers would bear any financial consequences."[29] The Commission also requires reporting "to ensure that regulators and the public have the data required to ensure that utilities are managing outages for the maximum protection of ratepayers."[30] The Commission has further explained, "generation facility outage costs merit careful scrutiny, given their potentially substantial impact on ratepayers."[31]

17. In this case, the Commission determined that to assess whether Minnesota Power's forced outage costs were reasonably and prudently incurred, Minnesota Power would have to prove that it applied "good utility practice" relating to the outages.[32]

III. MINNESOTA POWER'S FORCED OUTAGES

18. Minnesota Power's AAA Report identified 26 different forced outage events during the July 2018 through December 2019 reporting period. The Department expressed concern about whether outages associated with three different systems were consistent with good utility practice; and accordingly, whether the costs associated with those outages were "reasonably and prudently" incurred.[33]

19. Minnesota Power uses a ten-year long-term outage plan for Boswell centered on performing manufacturer recommended major maintenance on boilers and steam turbines.[34] Minnesota Power does not generally revise its long-term major outage schedule within the 10-year cycle, but it may modify the scope of work within the plan based on emergent work identified during the execution of the scheduled outage.[35] Minnesota Power witness Mr. Todd Simmons testified that "Generally, the long-term outage plan is only updated to add future years as current year rolls off and to maintain references when the last turbine overhaul or boiler chemical clean

[28] Minn. Stat. § 216B.16, subd. 7(1).
[29] ORDER ACCEPTING 2018–2019 ELECTRIC AAA REPORTS; NOTICE OF AND ORDER FOR HEARING at 3 (Sept. 16, 2020) (eDocket No. 20209-166630-01).
[30] *In re 2006 Annual Automatic Adjustment of Charges for All Elec. & Gas Utils.*, MPUC Docket No. E,G-999/ AA-06-1208, ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS at 5 (Feb. 6, 2008).
[31] *Id.*
[32] ORDER ACCEPTING 2018–2019 ELECTRIC AAA REPORTS; NOTICE OF AND ORDER FOR HEARING at 4 (Sept. 16, 2020) (eDocket No. 20209-166630-01)
[33] AAA Report at 206–08; Ex. DER-2 at 11 (Campbell Direct).
[34] MP Ex. 5 at 7 (Simmons Direct).
[35] MP Ex. 5 at 13 (Simmons Direct).

was completed."[36] Outage schedules may change during an outage plan, however, due to inspections that discover required work.[37]

20. While the Department's engineering expert Mr. Polich generally agreed that Minnesota Power's maintenance and outage planning and timing was consistent with other utilities, he testified that most utilities he has worked with use a five-year long-term outage plan because major maintenance on turbines and the boiler are defined by operating time, number of cycles, and other time-oriented factors, which change from year to year.[38]

21. Minnesota Power hires consultants to aid in developing schedules, inspections, and repair plans, if equipment specifications and or limitations on in-house knowledge require it.[39] Some maintenance and equipment inspection requires consultants to execute the work or inspection.[40] Contractors hired for large jobs will develop their own schedule and then present it to Minnesota Power to consider and incorporate into the plant's broader outage schedule.[41]

22. While equipment manufacturers and industry consultants may often have expertise on the maintenance needs for a power plant, which may provide a critical information base on equipment maintenance requirements and timing, depending on the internal engineering expertise of the plant owner, other consultants may be used to fill in knowledge on proper inspection, maintenance, and timing.[42] Plant owners, however, remain responsible for maintaining plant reliability as part of the regulatory compact.[43] Proper maintenance, therefore, must ensure that the generation asset is available when customer load requires its use.[44]

23. The use of consultants cannot absolve the plant owner of its responsibility to properly perform necessary and required maintenance, adhere to various codes, and comply with permits governing the plant's operation.[45] Power plant owners must therefore maintain knowledge of the American Society of Mechanical Engineers (ASME) Pressure Vessel Code requirements and recommendations, and must have the in-house engineering expertise needed to keep up with the most recent maintenance recommendations set forth by key industry groups such as the Electric Power Research Institute (EPRI), Institute of Electrical and Electronics Engineers (IEEE), equipment user groups, and other like entities.[46]

24. On behalf of the Department, GDS Associates reviewed all Minnesota Power's forced outages at Boswell Unit Nos. 3 and 4 during the relevant period to determine whether

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[36] MP Ex. 5 at 13 (Simmons Direct).
[37] MP Ex. 5 at 14 (Simmons Direct).
[38] DER Ex. 10 at 7–8 (Polich Direct).
[39] MP Ex. 5 at 11 (Simmons Direct).
[40] MP Ex. 5 at 11 (Simmons Direct).
[41] MP Ex. 5 at 11 (Simmons Direct).
[42] DER Ex. 10 at 9–10 (Polich Direct).
[43] DER Ex. 10 at 10 (Polich Direct).
[44] DER Ex. 10 at 10 (Polich Direct).
[45] DER Ex. 10 at 10 (Polich Direct).
[46] DER Ex. 10 at 10 (Polich Direct).

Minnesota Power followed good utility practice. Specifically, GDS Associates reviewed sixteen forced outages from boiler tube leaks, two forced outages from condenser tube leaks, one forced outage to clean a condenser, a forced outage due to a failed water pump, a forced outage due to a leak in the blowdown flash tank, a forced outage due to a hot reheat line failure on Boswell Unit No. 4, the extension of the spring 2019 Boswell Unit No. 3 outage to complete leak repairs on a generator hydrogen cooling system, and a forced outage caused by grounding in the phase bushings of the Boswell Unit No. 3 generator.[47]

25. GDS Associates determined that Minnesota Power followed good utility practices in its maintenance of boiler tubes, condenser tubes, and boiler circulating water pump.[48] GDS Associates determined following its review of the blowdown flash tank outage that Minnesota Power could have done a better job identifying the leak's location both prior to shutting down the plant and during the outage and should have noted the frequency of problems in the years leading up to the outage.[49] The Department, however, did not recommend that Minnesota Power refund these outage costs because its witness Mr. Polich did not conclude that Minnesota Power's conduct was inconsistent with good utility practice.[50]

26. GDS Associates determined that Minnesota Power failed to follow good utility practices related to the hot reheat line outage, the extension of the spring 2019 outage to find and fix the leak in the hydrogen cooling system, and the generator "A" phase bushing failure.[51] Because the failure to follow good utility practice to more expeditiously locate the hydrogen leak did not contribute significantly to the extension of the spring 2019 outage, the Department recommended that Minnesota Power only be required to refund forced outage costs arising from the hot reheat line failure and phase bushing failure.[52]

A. Boswell Unit No. 4's Hot Reheat Line

27. The first outage at issue in this proceeding relates to Boswell Unit No. 4's hot reheat line. The hot reheat line is an approximately 33-inch diameter pipe with about 1.5-inch thick walls. The pipe is more than 640 feet long and is designed to carry approximately 1,000 °F high-pressure steam from the unit's boiler back to the turbine where it is used to generate electricity.[53] The pipe used on Boswell Unit No. 4's hot reheat line is longitudinal welded pipe made of material that conforms with American Society for Testing and Materials Specification A-155, Grade 2-1/4 CR-1 Mo electric fusion welded steel pipe—a technical specification for manufacturing pipe for use in high-temperature applications that includes requirements for the thickness, shape, and width of the longitudinal weld—for high pressure service.[54] Longitudinal seam-welded pipe is formed by rolling plate steel into a pipe shape and welding the seam down the length of the pipe.[55]

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[47] DER Ex. 10 at 16–17 (Polich Direct).
[48] DER Ex. 10 at 17–18 (Polich Direct)
[49] DER Ex. 10 at 18–19 (Polich Direct).
[50] DER Ex. 12 at 17–18 (Campbell Direct).
[51] DER Ex. 10 at 48–49 (Polich Direct).
[52] DER Ex. 12 at 17 (Campbell Direct); DER Ex. 10 at 45–46 (Polich Direct).
[53] DER Ex. 10 at 20 (Polich Direct).
[54] DER Ex. 10 at 20–21 (Polich Direct).
[55] DER Ex. 10 at 21 (Polich Direct).

28. On February 6, 2019, a longitudinal seam-weld pipe in Boswell Unit No. 4's hot reheat line ruptured. It left behind an approximately two-foot long crack. This crack allowed high-pressure steam carried in the pipe to escape. Minnesota Power was forced to shut down Boswell Unit No. 4. During the shutdown, the Company inspected the entire hot reheat pipe, replaced the ruptured section, and reinforced other sections which were found to have structural flaws that could lead to failure. The unit did not return to service until March 27.[56]

1. Industry Experience with Hot Reheat Line Failures

29. Hot reheat line failures can have severe consequences because these pipes carry superheated steam under immense pressure. These extreme operating conditions also place pipes under great stress and create a heightened risk of failure absent appropriate inspection and repair procedures. Since 1985, EPRI has documented more than 42 seam welded high energy pipe failures.[57] In 1985, for example, Southern California Edison – Mohave Generation Station's 30-inch diameter hot reheat line failed killing 6 people, injuring 10 others, and causing an estimated $155 million in plant damage.[58] Many other hot reheat line failures on seam welds have been recorded, including failures at power plants in Texas in 1979, Michigan in 1986, and West Virginia in 2014.[59]

30. In this case, despite these risks, Boswell Unit No. 4's hot reheat line rupture did not result in deaths or result in more catastrophic plant damage.

31. Minnesota Power was aware of industry concerns surrounding hot reheat lines and noted in testimony that "HRH piping has been an on-going power generation industry topic for over 30 years."[60] As Minnesota Power witness Mr. William Poulter described, "Starting in the late 1970s the utility industry experienced failures in seam welded pipe."[61] Minnesota Power, however, focused its inspection efforts on what it terms the "high-stress areas," which it describes as those areas "where there are attachments such as pipe hangers or laterals."[62] Minnesota Power claimed that "it is rare for a plant to experience a weld seam failure on a vertical line in a low stress level location."[63]

32. One study notes, although seam-weld failures may be less common than clamshell welds and girth welds, almost all of the very largest outages involved seam welds.[64]

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[56] DER Ex. 10 at 22–23 (Polich Direct).
[57] MP Ex. 14, PJU-1 at 403 (Undeland Rebuttal) (*30-Plus Years of Long-Seam Weld Failures in the Power Generation Industry* (30 Year Report)).
[58] MP Ex. 14, PJU-1 at 411–12, 422 (Undeland Rebuttal) (30 Year Report).
[59] *See* MP Ex. 14, PJU-1 at 399–432 (Undeland Rebuttal).
[60] MP Ex. 6 at 12 (Poulter Direct).
[61] MP Ex. 6 at 13 (Poulter Direct).
[62] MP Ex. 6 at 13 (Poulter Direct).
[63] MP Ex. 6 at 5 (Poulter Direct).
[64] DER Ex. 21 at 4 (MP IR Attach 05.05: Cohn et al, *A Quantitative Approach to a Risk-Based Inspection Methodology of Main Steam and Hot Reheat Piping Systems*).

2. Inspections and Reports Following Boswell Unit No. 4's Hot Reheat Line Failure

33. Following the hot reheat line rupture, Minnesota Power asked Thielsch to assess the failure and determine the extent of the damage.[65] Thielsch began its inspection on February 8 and released it analysis on February 20, 2019.[66]

34. Thielsch's inspection revealed additional damaged or degraded pipe sections, including three 20-foot sections that had to be replaced entirely, and an additional three sections with significant cracking—totaling 140-feet in length—that required welding steel reinforcing patches along the longitudinal seam-welds.[67] Thielsch concluded that the hot reheat line's cracking started in the middle of the pipe wall along the seam weld approximately seven to nine years before the actual rupture.[68] Thielsch also acknowledged that ultrasonic examination would likely reveal similar mid-wall cracking elsewhere in the pipe.[69]

35. After receiving Thielsch's analysis, Minnesota Power concluded that the hot reheat line failed due to a mechanism called "creep."[70] Boswell Unit No. 4's hot-reheat-pipe creep damage was caused by slow developing voids and microcracks in the longitudinal seam-welds that ultimately resulted in pipe failure.[71] These cracks begin in the pipe interior and eventually spread to the outside.[72] At some point, the pipe will fail as the cracks propagate from the inside of the pipe toward the pipe surface through a significant portion of the pipe wall and become long enough that the pipe's strength is compromised and cannot sustain the operating pressure.[73]

36. Phased array ultrasonic examination can locate the voids and microcracks that occur deep within the longitudinal seam-welds of the 1.5-inch thick hot reheat pipe.[74]

37. Thielsch had inspected multiple hot reheat pipe sections in 2012, 2015, and 2017.[75] But these inspections did not include longitudinal seam-weld inspection using ultrasonic examination techniques that would have identified interior cracking or deterioration in the longitudinal seam-welded pipe.[76] Thielsch, instead, relied on "in-situ metallographic

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65 DER Ex. 10 at 29 (Polich Direct).
66 DER Ex. 10 at 29–30, RAP-6 (Polich Direct).
67 MP Ex. 7 at 19–20, PJU-3 at 8 (Undeland Direct); DER Ex. 10 at 22–23 (Polich Direct).
68 DER Ex. 10, RAP-6 at 7 (Polich Direct).
69 DER Ex. 10 at 31–32 (Polich Direct).
70 *Id.*, RAP-12 at 10–11 (MP Power Point).
71 DER Ex. 10 at 33 (Polich Direct).
72 DER Ex. 10 at 33 (Polich Direct). *See also* DER Ex. 19 at 3-22 to 3-23 (EPRI, *Fossil Plant High-Energy Piping Damage: Theory and Practice*).
73 DER Ex. 10 at 33 (Polich Direct).
74 DER Ex. 10 at 33 (Polich Direct); MP Ex. 14, PJU-1 at 31–32 (Undeland Rebuttal) (EPRI Guidelines).
75 DER Ex. 10 at 26 (Polich Direct).
76 DER Ex. 10 at 26–27 (Polich Direct).

examination" and "magnetic particle inspection" techniques.[77] Neither technique, however, can identify cracks or creep deterioration unless they are located near the outside pipe surface.[78]

38. On February 22, EPRI contacted to Minnesota Power to see if they could assist.[79] EPRI recommended, among other things, that Minnesota Power bring in a second entity to perform failure analysis and life assessment of the hot reheat piping.[80] EPRI also requested the failed pipe for their analysis.[81]

39. Later, EPRI provided Minnesota Power with its *High Energy Piping Systems. Still a Clear and Present Danger* presentation, from a generation council meeting, to illustrate the results of its examination.[82] EPRI concluded that there was a basis for more frequent inspection of the seam-welded pipe and that 100% of the hot reheat line should have been examined every four to five years using phased array ultrasonic examination.[83]

40. Following EPRI's recommendation, Minnesota Power hired Structural Integrity Associates to perform additional evaluation of the hot reheat pipe.[84]

41. In its report, Structural Integrity questioned why the hot reheat pipe flaws had not been previously found.[85] Structural Integrity concluded that almost all welds had exceeded their calculated life fraction consumed values.[86] Life fraction consumed values means a portion of the predicted usable life of the pipe that has been used with the pipe in service.[87] For example, if a pipe has a usable life of 100,000 hours and it has been in service for 90,000 hours then the life fraction consumed values would equate to 90% of the pipe's projected usable life that has been consumed.[88]

42. Structural Integrity also found that any repairs to the hot reheat pipe should only be considered temporary and further repair or replacement would be needed within the next year.[89]

43. These inspections revealed six additional areas in need of repair. Three sections of the pipe (totaling about 20 ft.) were replaced and other areas with significate transverse (about 140

[77] DER Ex. 10 at 26 (Polich Direct).
[78] DER Ex. 10 at 27–28 (Polich Direct).
[79] DER Ex. 10 at 30, RAP-8 (Polich Direct).
[80] DER Ex. 10 at 30, RAP-9 (Polich Direct).
[81] DER Ex. 10 at 30, RAP-9 (Polich Direct).
[82] DER Ex. 11, RAP-13 (Polich Direct) (TRADE SECRET). The specific content of the EPRI power point presentation is proprietary and designated as trade secret.
[83] DER Ex. 10 at 28, RAP-13 (Polich Direct).
[84] DER Ex. 10 at 30, RAP-7 (Polich Direct).
[85] DER Ex. 10, RAP-11 at 61 (Polich Direct).
[86] DER Ex. 10 at 34, RAP-11 at 56 (Polich Direct).
[87] DER Ex. 10 at 34 (Polich Direct).
[88] DER Ex. 10 at 34 (Polich Direct).
[89] DER Ex. 10 at 34, RAP-11 at 62 (Polich Direct).

ft.) cracking were repaired with steel patches.[90] Minnesota Power identified other metallurgical conditions calling for less urgent replacement that it planned to replace during a spring 2021 outage.[91]

44. Minnesota Power determined that the cause of the hot reheat line failure was "creep"—a mechanism in which the metal in the pipe deforms, forming voids that weaken the pipe's structural integrity.[92]

45. Minnesota Power concluded that portions of the hot reheat line had reached the end of its serviceable life.[93] Minnesota Power also formed a "Hot Reheat Learning Team" to review the failure, inspections, testing and operations and make recommendations to improve Minnesota Power's high-energy piping program.[94] The Hot Reheat Learning Team compiled a presentation with its findings and recommendations.[95] The team concluded that "a stronger and more formalized inspection program would have decreased the chances of failure."[96]

3. Minnesota Power's High-Energy Piping Program

46. Minnesota Power maintains that its high energy piping program was consistent with industry practice before the hot reheat line failure.[97] Minnesota Power maintained that the good utility practice only requires inspections of "those areas that are most likely to have indications"—a visual or operational deviation from what is expected of the equipment.[98] Minnesota Power stated that in the early years of the pipe, "the most likely area to inspect is at an attachment or discontinuity . . . as a result of fatigue." But as the pipe ages, failure is more likely to occur from "creep" than fatigue. Minnesota Power stated that at this stage inspections include replication and/or boat samples to attempt to detect creep.[99] A "boat sample" or "scoop sample" is a type of destructive testing where a sample is removed from the pipe with a precision cut and that sample is subjected to various laboratory tests to evaluate the microstructure and condition of the pipe.[100]

47. Minnesota Power's witness testified that "Thielsch, confirmed that the Company's inspection frequency is consistent with good utility practice among the more than 50 coal-fired generation facility owners for which they work."[101] Minnesota Power, however, did not provide any documentation from Thielsch that included this statement, nor did it specify to whom at

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[90] MP Ex. 7 at 19–20, PJU-3 at 8 (Undeland Direct).
[91] MP Ex. 7 at 20 (Undeland Direct).
[92] DER Ex. 10 at 35 (Polich Direct).
[93] DER Ex. 10 at 35 (Polich Direct).
[94] DER Ex. 10 at 35 (Polich Direct).
[95] *See* DER Ex. 10 at 25, RAP-12 (Polich Direct).
[96] DER Ex. 10, RAP-12 at 12 (Polich Direct).
[97] MP Ex. 5 at 20 (Simmons Direct).
[98] MP Ex. 5 at 24 (Simmons Direct).
[99] MP Ex. 5 at 25 (Simmons Direct).
[100] MP Ex. 5 at 25 (Simmons Direct).
[101] MP Ex. 7 at 19 (Undeland Direct).

Minnesota Power this statement was made.[102] Given that the statement's lack of support and self-serving nature, the ALJ finds this statement to be unreliable hearsay and will accord it limited weight. In addition to the unreliability of the claim, the ALJ notes that even if all Thielsch customers used a similar inspection schedule, this provides little supports as it is Thielsch who advised Minnesota Power on the appropriate inspection schedule.[103] Minnesota Power's witness admitted that it was reasonable to assume that Thielsch provides similar advice to its clients.[104] Therefore, it is unsurprising and provides little evidence of good utility practice that Thielsch's other clients may have a similarly defective inspection program.

48. Minnesota Power claimed that "It is unknown when, over the nine-year period since the last detailed inspection, the seam weld began to fail."[105] However, Thielsch estimated that the creep deterioration began at approximately 60,000 to 70,000 hours prior to the failure, which assuming annual 90% annual operation equals 7.5 to 8.9 years.[106] The Department's engineering expert testified that the flaws in the hot reheat piping would likely have been found before the pipe ruptured if Minnesota Power had been performing proper inspection techniques.[107]

49. The Department's expert testified that the high failure rate of longitudinal seam-welded piping has been known since the 1980s and each year evidence has accumulated on the potential rupture and/or catastrophic failure risks of this type of pipe when used in high-pressure, high-temperature situations. The history of failures in this type of high energy piping, show that most of these failures occurred in low-stress long vertical and horizontal runs.[108]

50. Previous failure of seam welded high-energy pipe have caused changes in recommended inspection process and frequency in the ASME B31.1 Code and EPRI guidelines.[109]

51. The Department's expert testified that Minnesota Power should have known that the hot reheat pipe's age and hours of operation were beyond the point that only performing 100% inspection of seam-welds once every ten years should have continued.[110] This position is supported by Structural Integrity's finding almost all welds had exceeded their calculated life fraction consumed values.[111]

52. Instead, the Department's expert testified that all longitudinal seam-welded hot reheat piping should have been inspected at least once every five years using phased array ultrasonic examination. The Department's expert based his expert recommendation of a five-year

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[102] Evid. Hrg. Tr. at 24–25 (Undeland); MP Ex. 7 at 19 (Undeland Direct); MP Ex. 14 at 23, 25 (Undeland Rebuttal).
[103] *See* Evid. Hrg. Tr. at 26–28 (Undeland).
[104] Evid. Hrg. Tr. at 29 (Undeland).
[105] MP Ex. 3 at 18 (Undeland Direct).
[106] DER Ex. 10 at 32, RAP-6 at 7 (Polich Direct).
[107] DER Ex. 10 at 38 (Polich Direct).
[108] DER Ex. 10 at 41 (Polich Direct).
[109] DER Ex. 10 at 38 (Polich Direct).
[110] DER Ex. 10 at 38 (Polich Direct).
[111] DER Ex. 10 at 34, RAP-11 at 56 (Polich Direct).

full inspection schedule, not ten years as Minnesota Power had been using since 1999,[112] with guidelines from EPRI and recommendations from the ASME Code B31.1, which addresses high pressure piping.[113]

53. "[Ultrasonic testing] is generally described as the introduction of high-frequency sound waves—generally in the range of 0.5 MHz to 50 MHz—into a component, part, or structure for the purpose of determining some characteristic of the material from which the component, part, or structure is made."[114] "[F]or fossil power plant inspection, ultrasonic inspection is used primarily for flaw detection, classification, and sizing, and for dimensional measurement (thickness)."[115] Phased array ultrasonic testing is a type of advanced ultrasonic testing.[116] "A phased array system permits the inspection of a cross-sectional area of interest with a minimal number of probe positions."[117]

54. Good utility practice dictates that if any evidence of degradation in seam-welded pipe along the longitudinal welds observed with phased array ultrasonic examination, a more rigorous inspection of the entire pipe should be triggered.[118]

55. The ASME Code recommends examining hot reheat lines at intervals not exceeding five years.[119] Section 8 of Appendix V of the ASME code provides the recommendations at issue. Section 8.1 describes the types of power piping subject to ASME's five-year maximum inspection recommendation, which includes critical piping systems subject to internal or external corrosion-erosion:

> 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

112 MP Ex. 3 at 17–18 (Undeland Direct).
113 *See* MP Ex. 22a (ASME Code).
114 DER Ex. 19 at 10–13 (EPRI, *Fossil Plant High-Energy Piping Damage: Theory and Practice*).
115 DER Ex. 19 at 10–13 (EPRI, *Fossil Plant High-Energy Piping Damage: Theory and Practice*).
116 DER Ex. 19 at 10–20 (EPRI, *Fossil Plant High-Energy Piping Damage: Theory and Practice*).
117 DER Ex. 19 at 10–20 (EPRI, *Fossil Plant High-Energy Piping Damage: Theory and Practice*).
118 DER Ex. 10 at 39 (Polich Direct).
119 DER Ex. 10 at 24 (Polich Direct) (discussing ASME Code Section 8 located at MP Ex. 22a at 325, 329 (ASME Code B31.1, Appendix V)).

> 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 of this section. Measures in addition to those listed herein may be required.[120]

56. The Department's expert explained that hot reheat lines generally are covered by Section 8 because they are subject to erosion/corrosion.[121] As stated in the code, "Erosion/corrosion of carbon steel piping may occur at locations where high-fluid velocity exists adjacent to the metal surface."[122] The Department's engineering expert explained that high-energy steam piping systems will develop "certain innate oxide layers on the surface of the piping"—"rust" in lay terms.[123] High-velocity fluids strip rust away exposing bare pipe causing erosion of the piping, which weakens the pipe over time.[124]

57. Minnesota Power agreed that its hot reheat line is a critical piping system.[125] Minnesota Power disagreed that Section 8 of the ASME Code recommendation applied to its hot reheat line.[126] Minnesota Power also argued that the ASME code recommendations did not apply because erosion or corrosion was not the cause of the failure.[127]

58. Minnesota Power argued that Section 12 of the ASME recommendations was the applicable section it specifically discusses creep damage.[128] Section 12.2.2 states that "a procedure should be developed to select piping areas more likely to have greater creep damage" and "[t]he frequency of examination, determined by the Operating Company, should be based on previous evaluation results and industry experience."[129]

59. The ALJ finds credible the expert opinion of Mr. Polich that the ASME Code applies to the hot reheat line. Moreover, the general reason for why the hot reheat line falls under the Code's recommendations need not be the specific cause of the failure in a specific instance. The ASME Code provides evidence that good utility practice requires inspecting all lines subject to erosion or corrosion, including Boswell Unit No. 4's hot reheat line, a maximum of every five years. Minnesota Power's argument that it complied with Appendix V, section 12 of the ASME

[120] MP Ex. 14 at 20 (Undeland Rebuttal). A public version of the relevant section of the ASME code is contained in Mr. Undeland's rebuttal testimony. The code itself is proprietary and designated as Trade Secret. The full version of ASME Code B31.1 is included in the record as MP Ex. 22a.
[121] Evid. Hrg. Tr. at 78 (Polich).
[122] MP Ex. 14 at 20 (Undeland Rebuttal).
[123] Evid. Hrg. Tr. at 78–79 (Polich)
[124] Evid. Hrg. Tr. at 79 (Polich).
[125] Evid. Hrg. Tr. at 31 (Undeland).
[126] MP Ex. 14 at 19–22 (Undeland Rebuttal).
[127] MP Initial Brief at 65.
[128] MP Initial Br. at 65–67.
[129] MP Ex. 15, PJU-2 at 6–7 (Undeland Rebuttal) (ASME Code).

code does not assist it because it ignored industry experience with longitudinal seam-welds. Minnesota Power's failure to follow ASME's recommendations supports the position that it failed to apply good utility practice related to the Boswell Unit No. 4 hot reheat line outage.

4. Costs of More Frequent Hot-Reheat-Line Inspection.

60. Minnesota Power maintains that there are some equipment components that cannot be fully and frequently inspected economically, so it focuses inspection cycles on areas of known concern.[130] The Company points to its high energy piping system, of which the failed hot reheat line is a component, as an example of this balancing. The high stress areas of the high energy piping system are inspected more frequently than low stress areas.[131]

61. Minnesota Power claimed that performing ultra-sonic phased array examination of the longitudinal seam welds to prevent this type of hot reheat line failure would be prohibitively expensive. In direct testimony, the Company stated that "[a] full inspection of all components and welds of the [hot reheat] line takes four to six weeks of time and costs in excess of one million dollars due to the significant amount of insulation that must be removed prior to, and reinstalled after inspection, as well as accessibility constraints where the [hot reheat] line is located."[132]

62. In rebuttal testimony, Minnesota Power increased its cost claims for a full inspection of the hot reheat line to $5 million dollars. For this proposition, Minnesota Power relied on the following language in a white paper put out by EPRI: "Increasingly, economic pressure on end-users is necessitating a re-evaluation of legacy guidelines for inspection of long-seam welded components. In particular, the recommendation in [8] regarding 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."[133] The "[8]" refers to the *Guidelines for the Evaluation of Seam Welded High-Energy Piping*.

63. Minnesota Power, however, did not provide an estimate the costs that would be associated with performing the recommended inspection procedure and timeline at the Boswell Unit No. 4 facility, stating that it had "not specifically estimated the cost associated with such an inspection protocol because it would be significantly higher than the potential benefits."[134]

64. The Department's expert pointed to Thielsch Engineering, Inc.'s offer to inspect the vertical section of the hot reheat pipe for $35,000 in 2013, as an example of ways that increased maintenance costs may decrease forced-outage costs in the long-run.[135] Mr. Polich noted that "If this this inspection had been performed using industry standard inspection procedures and frequency for longitudinal-welded pipe, it is very likely that the flaws in the HRH pipe would have

[130] MP Ex. 5 at 24 (Simmons Direct).
[131] MP Ex. 5 at 24 (Simmons Direct).
[132] MP Ex. 5 at 24 (Simmons Direct).
[133] MP Ex. 13, PJU-1 at 427 (Undeland Rebuttal).
[134] MP Ex. 14 at 29 (Undeland Rebuttal).
[135] DER Ex. 10 at 15, RAP-3 (Polich Direct).

been found long before the February 2019 hot-reheat pipe rupture and repaired during a planned outage at a much lower cost and avoiding the forced outage."[136]

65. Minnesota Power took issue with this testimony claiming that it misconstrued the costs of such an inspection. Minnesota Power stated that this was "a bid from Thielsch for limited testing of the HRH, and did not include the costs of scaffolding, removing insulation, surface preparation, reinsulating, removing the scaffolding, and potentially extending the outage to complete the full inspection."[137] Minnesota Power, however, did not provide any specific estimates for the individual items that it claimed would increase the costs above the $35,000 quote from Thielsch in 2013.[138]

66. Minnesota Power's claim that following the EPRI guidelines would cost more than $5 million dollars is unsupported. Minnesota Power failed to introduce any more specific cost estimates for this type of inspection than Thielsch's $35,000 quote from 2013 and the generalized statements in the EPRI white paper. Minnesota Power has not explained the wide-gap between the $35,000 actual quote in the record to the $5 million it claims or even $1 million, if the inspections were spread over five years. Minnesota Power has not provided substantial evidence of its claimed costs in the record.

67. The ALJ also finds that Minnesota Power greatly understated the costs associated with a hot reheat line failure that Minnesota Power weighed against its unsupported inspection costs. Mr. Undeland claimed that the inspection costs should be weighed solely against the actual forced outage costs in this proceeding.[139] But Mr. Simmons testified on behalf of Minnesota Power that corrective maintenance, such as that arising from the hot reheat line failure, includes other expenses, including material cost, labor cost, in addition to the replacement power costs noted by Minnesota Power witness Mr. Paul Undeland.[140] Mr. Undeland confirmed Minnesota Power also incurred costs to replace the hot reheat line and conceded that other plants experiencing similar failures have likely incurred costs from injuries that occurred.[141]

5. Conclusions on the Hot Reheat Line Outage

68. Minnesota Power failed to show that its high-energy piping inspection program was consistent with good utility practice.

69. Minnesota Power failed to exhibit good utility practice by relying only on "in-situ metallographic examination" and "magnetic particle inspection" techniques to inspect the longitudinal seam-welds on Boswell Unit No. 4's hot reheat line more often than every ten-

[136] DER Ex. 10 at 15 (Polich Direct).
[137] MP Ex. 13 at 28 (Undeland Rebuttal).
[138] Evid. Hrg. Tr. at 33–35 (Undeland).
[139] MP Ex. 14 at 29–30 (Undeland Rebuttal).
[140] MP Ex. 5 at 27 (Simmons Direct)
[141] Evid. Hrg. Tr. at 36–39.

years.[142] Instead, Minnesota Power's maintenance program should have inspected all longitudinal seam-welded pipe every five years using phased array ultrasonic examination.[143]

70. Minnesota Power's own engineering consultants, Thielsch, calculated the date of when cracks would have first appeared in the failed portion of the hot reheat pipe.[144] Thielsch concluded that the cracks likely began 7.5-8.9 years before the failure.[145] Therefore, even if Minnesota Power had examined the "low stress areas," including the longitudinal seam-welds, once every seven years with appropriate creep detection methods, evidence of pipe degradation would likely have been found and could have been repaired. As shown by the numerous degraded pipe sections that were found during the full inspection following the rupture, if Minnesota Power had been applying good utility practices it would have found at least one of these indications of degradation within the nine years since the last inspection of longitudinal weld seams, which would trigger the need to inspect all the seams.[146]

71. Minnesota Power should also have inspected the hot reheat line more often based on the line's age and the potential for catastrophic failure.[147]

72. Minnesota Power has not met its burden to show that it properly inspected and maintained Boswell Unit No. 4's hot reheat line. Minnesota Power's claim that its ten-year inspection schedule of longitudinal seam-welds is supported solely by advice from its contractor, Thielsch.[148] Minnesota Power retains the responsibility to ensure that advice it accepts from its contractor comports with good utility practice. Unsworn claims from its contractor that other utilities advised by the contractor have similar inspection schedules offers minimal support, because it is unreliable hearsay and the product of a feedback loop where Thielsch's gives similar advice to its thermal power plant clients.[149]

73. In contrast, the Department introduced expert testimony that a five-year inspection program was consistent with good utility practice.[150] The Department's expert supported this opinion with recommendations from ASME, guidelines from a utility trade organization, EPRI, and statements and conclusions from Minnesota Power's own contractors.[151] In addition, the

[142] DER Ex. 10 at 26 (Polich Direct).
[143] DER Ex. 10 at 28 (Polich Direct).
[144] DER Ex. 10, RAP-6 at 7 (Polich Direct).
[145] DER Ex. 10 at 39, RAP-6 at 7 (Polich Direct).
[146] *See* DER Ex. 10 at 15 (Polich Direct).
[147] *See* DER Ex. 10 at 7–8 (Polich Direct) (defining good utility practice); DER Ex. 10 at 32 (Polich Direct); DER Ex. 10, RAP-11 at 56, 61–62 (Polich Direct) (Structural Integrity Report).
MP Ex. 14, PJU 1 at 399–432 (EPRI 30 Year Report).
[148] MP Ex. 7 at 18 (Undeland Direct); MP Ex. 14 at 29 (Undeland Rebuttal); Evid. Hrg. Tr. at 24–29 (Undeland).
[149] Evid. Hrg. Tr. at 29 (Undeland)
[150] DER Ex. 10 at 20–41, RAP-6–RAP-13 (Polich Direct).
[151] Evid. Hrg. Tr. at 52 (Polich); DER Ex. 10 at 20–41, RAP-6–RAP-13 (Polich Direct); MP Ex. 14, PJU-1 (EPRI Guidelines and EPRI 30 Year Report); DER Ex. 21 (MP IR Attach. 05.05 Cohn

Department provided evidence that the high-potential cost of a hot reheat line failure obliged Minnesota Power to perform more frequent inspections.[152] The age of the line, near the end of its life, also supports the Department's position that the line should have been fully inspected more often.[153]

74. Minnesota Power failed to rebut this evidence. Minnesota Power's claims of the high-expense of the Department's proposed inspections were not supported with evidence in the record beyond generalities.[154] As the party with the burden of proof, Minnesota Power must show that the costs would be unreasonable.[155] Instead it assumed that "the cost associated with such an inspection protocol . . . would be significantly higher than the potential benefit."[156]

75. Evidence in the record shows that it is likely that the hot reheat line failure could have been avoided had Minnesota Power inspected more often.[157] The contractor who helped Minnesota Power design its high-energy piping inspection program estimated that the creep damage first appeared at least 7.5 years before the failure.[158]

76. The ALJ notes that, as the party not having the burden of proof, the Department need not prove that an inspection with ultra-sonic phased-array examination every five years constitutes good utility practice for Minnesota Power's inspection program not to conform to good utility practice. An inspection schedule between five and ten years may also have prevented the failure. It is undisputed that Minnesota Power has the burden of proof in this case, and it failed to show that good utility practice allowed it to wait ten years between full hot reheat line inspections for a pipe of this age with a method that can detect creep damage.

B. Boswell Unit No. 3's Hydrogen Cooling System

77. The second outage relates to Boswell Unit No. 3's hydrogen cooling system. Electric power generators produce significant heat that must be removed to maintain operating efficiency. Hydrogen gas is typically used as a coolant for large generators including Boswell Unit No. 3. Hydrogen's low density, high specific heat, and thermal conductivity make it a superior coolant relative to other options such as air, water, and oil. Hydrogen's flammability, however, means that plant operators must exercise vigilance to ensure that hydrogen does not escape from the generator where it could cause an explosion or fire.[159] Boswell Unit No. 3 uses

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et al, *A Quantitative Approach to a Risk-Based Inspection Methodology of Main Steam and Hot Reheat Piping Systems*); MP Ex. 22a (ASME Code).

[152] DER Ex. 10 at 20–41 (Polich Direct); MP Ex. 14, PJU–2 at 399–432 (Undeland Rebuttal) (EPRI 30 Year Report).

[153] DER Ex. 10 at 33–34, 38, RAP-11 at 56 (Polich Direct) (Structural Integrity Report).

[154] *See* Evid. Hrg. Tr. at 33–35.

[155] DER Ex. 10 at 8–9 (Polich Direct) (defining "good utility practice").

[156] MP Ex. 14 at

[157] DER Ex. 10 at 48–49 (Polich Direct).

[158] DER Ex. 10 at 38–39 (Polich Direct).

[159] DER Ex.10 at 41–42 (Polich Direct).

an oil system to seal hydrogen gas within the generator shaft and avoid leaks into surrounding areas.[160]

78. During the 2018-2019 winter, Minnesota Power discovered that Boswell Unit No. 3's generator was leaking hydrogen gas. Minnesota Power first believed that the leak was in the lead box, a section under the generator. Minnesota Power sealed the lead box leaks sufficiently during a weekend outage to allow continued operation until the planned spring maintenance outage scheduled to start on March 20, 2019.[161] Minnesota Power hired General Electric, the original equipment manufacturer, to perform repairs and consult how to address the leak.[162]

1. Minnesota Power's Diagnosis of the Hydrogen Leak Cause

79. During the March planned outage, Minnesota Power working with General Electric performed repairs of much of the equipment in the generator area.[163] Once complete, Minnesota Power tested the system, around the time of the end of the original scheduled outage, but the generator failed the test still indicating a sizable leak.[164] The outage, therefore, was extended beyond the initial end date to address ongoing repair issues.[165] Therefore, the final days of the hydrogen leak repair were classified as an "unplanned" outage.[166]

80. At that time, further analysis was done which indicated that the leaking was focused on the turbine end, not the generator end of the unit as Minnesota Power originally believed.[167]

81. Minnesota Power continued to perform further root cause analysis but was still unable to locate the source of the major leak. Minnesota Power brought back General Electric to assist in the root cause analysis and hired another contractor that specializes in hydrogen leaks.[168]

82. At some point during Minnesota Power's attempts to locate the hydrogen leak, the testing resulted in filling the seal oil system to see how much oil was needed to stop the leak.[169] This procedure stopped the leak but also flooded the float trap with oil, which led Minnesota Power to discover that the valve in the float trap was leaking.[170]

83. While replacement of the float trap ultimately resolved the hydrogen leak, Minnesota Power did not keep track of the amount of additional seal oil it flooded into the system versus the amount of oil it took out before putting the hydrogen cooling system back online.

[160] DER Ex.10 at 42 (Polich Direct).
[161] MP Ex. 7 at 23 (Undeland Direct).
[162] MP Ex. 7 at 24 (Undeland Direct).
[163] MP Ex. 7 at 27 PJU-4 (Undeland Direct).
[164] MP Ex. 3 at 27 (Undeland Direct).
[165] MP Ex. 3 at 29 (Undeland Direct).
[166] MP Ex. 3 at 29 (Undeland Direct).
[167] MP Ex. 3 at 27 (Undeland Direct).
[168] MP Ex. 3 at 28 (Undeland Direct).
[169] DER Ex. 10 at 43 (Polich Direct).
[170] DER Ex. 10 at 43 (Polich Direct).

Minnesota Power stated in response to a Department information request: "several barrels of oil were required to perform the testing, although the specific number was not recorded."[171] Regarding the seal oil's removal, Minnesota Power stated, "several barrels of oil were drained from the generator liquid detector. The precise amount of drained oil was not recorded."[172]

84. Minnesota Power also did not adequately inspect whether additional oil remained in the generator after completion of the hydrogen leak repairs.[173] Minnesota Power stated, "Once a solution was found to the float trap problem around June 20, 2019, the only additional check that was made was to verify that no oil was coming from valve H-72 (liquid detector drain)."[174] It also stated that it performed a visual inspection of the leadbox, but it is unclear what that constituted.[175]

85. The Department's expert concluded that Minnesota Power did not apply good utility practice in how it addressed and repaired the generator hydrogen leak. He emphasized the amount of time that it took Minnesota Power to recognize that the float valve could have been the cause and stated that all potential sources of the leak should have been identified and tested in the first root cause analysis.[176] However, because Minnesota Power's roundabout method of diagnosing the leak only resulted in a small and undeterminable extension of the planned outage,[177] the Department did not recommend that Minnesota Power be disallowed from recovering those costs.[178]

86. The Department's expert also emphasized that the way in which Minnesota Power ultimately determined the cause of the leak was not consistent with good utility practice.[179] Minnesota Power's improper overfilling of the hydrogen seal oil system likely led to seal oil leaking into the generator.[180] "Good utility practice would be to keep track of the amount of seal oil used in any testing process, track any leakage, and clean up any leaked seal oil so it does not cause damage to other components of the generator."[181]

2. Conclusions on Hydrogen Leak Outage

87. Minnesota Power failed to follow good utility practice in two ways in addressing the hydrogen leak, only one of which is material.

88. First, Minnesota Power's failure to efficiently conduct a root cause analysis delayed bringing the plant online but for an unknowable amount of time. Therefore, the ALJ agrees with

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[171] DER Ex. 10, RAP-15 at 5 (Polich Direct).
[172] DER Ex. 10, RAP-15 at 5 (Polich Direct).
[173] DER Ex. 10 at 43 (Polich Direct).
[174] DER Ex. 10, RAP-15 at 5 (Polich Direct).
[175] DER Ex. 10, RAP-15 at 4 (Polich Direct).
[176] DER Ex. 10 at 44–45 (Polich Direct).
[177] DER Ex. 10 at 45 (Polich Direct).
[178] DER Ex. 12 at 17 (Campbell Direct).
[179] DER Ex. 10 at 44 (Polich Direct).
[180] DER Ex. 10 at 44 (Polich Direct).
[181] DER Ex. 10 at 44 (Polich Direct).

the Department that Minnesota Power need not refund the forced outage costs for this unknown amount of time.

89. Second, Minnesota Power's introduction of additional seal oil into the system and subsequent failure to record the amount of additional oil introduced and failure to investigate whether any leaked seal oil ended up inside the generator and failure to clean up the leaked seal oil did not follow good utility practice. Failure to follow good utility practice in this instance was material, because the seal oil ultimately contaminated the phase bushings, contributing to their failure as discussed below.

C. Boswell Unit No. 3's Phase Bushings

90. The third outage relates to Boswell Unit No. 3's phase bushings. Bushings are cylindrical structures that insulate a conductor carrying electric current at high voltage. Bushings are needed to prevent the electric field created by the electric current flowing through the conductor from causing excess current leakage or a flashover event that could, in turn, start a fire or damage the facility. Boswell Unit No. 3 has a total of six bushings. They consist of three line-side bushings (A, B, and C phases) and one neutral bushing for each of the three phases on the generator.[182]

91. On July 8, 2019, a relay on the generator "A" phase detected a ground fault and operators took the plant off-line. The Company investigated the ground fault and determined that the ground fault occurred in the "A" phase of the system, but were unable to determine the specific component that had failed.[183] Electricity is transmitted in three phases (A, B, and C), and the generator in question has six bushings, two bushings per phase.[184] Minnesota Power hired General Electric to provided more specialized personnel to investigate, and General Electric determined on July 14, 2019 that the failure was on the A phase line side bushing and they would need to be replaced.[185] The Company and General Electric ultimately decided to replace all six bushings.[186]

92. These six phase bushings had all been tested at a scheduled outage three months earlier on April 18, 2019. As Mr. Undeland testified "During that inspection and testing, 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 that was performed was within acceptable criteria with no other indication to support further investigation, allowing the equipment to be returned to service."[187]

93. Minnesota Power stated that it does not know the age of the bushings that failed, and they could either have been installed in 1970 or 2001.[188] Minnesota Power claimed, "This outage was not only unplanned, but also beyond any foreseeable protocols that could have been

[182] *Id.* at 46.
[183] *Id.* at 33.
[184] *Id.* at 32.
[185] *Id.* at 33.
[186] *Id.* at 33-34.
[187] MP Ex. 3 at 32 (Undeland Direct).
[188] MP Ex. 3 at 35 (Undeland Direct).

put in place to prevent this outage."[189] Minnesota Power focused on the recent inspection and that increasing the time between inspection would not have prevented the outage because the inspection occurred only three months earlier.[190]

1. General Electric's Report on Phase Bushing Failure

94. General Electric, however, produced a report replete with references to seal oil that it located in the phase bushings and the potential of oil-soaked bushings to overheat and cause a ground fault. As the General Electric report notes in the second paragraph of the Executive Summary:

> This unit had been inspected in the spring of this year, and the customer described incidents where large amounts of oil had ingressed into the unit after restart involving the hydrogen seals and the float trap. This oil ingress included large amounts of oil in the lower frame extension including the cooling passages through the high voltage bushings.[191]

95. The General Electric report includes the following passages regarding the presence of oil in the both the bushing insulation and the phase bushings themselves:

> "Because of the possibility that the oil had blocked the cooling passages and overheated a bushing, it was decided to strip the bushing clamshells on the A-phase . . . ."[192]
>
> "As the insulation was removed from these two bushings, it was seen that there was no putty on the T4 bushing. It was also seen that the insulation *was soaked with oil completely through the thickness of the layers of insulation. Oil was also found in the insulation of the T1 bushing, but it was not saturated as it was on T4.*"[193]
>
> "A crew of millwrights working for the customer removed the isophase box and the T4 bus[h]ing from the unit. *The bushing was seen to be full of oil.*"[194]
>
> "All of the bushings on this unit were full of oil. Oil will block the cooling passage through these bushings and can cause the bushings to overheat. A small pump was used to pump as much oil as possible

[189] MP Ex. 3 at 35 (Undeland Direct).
[190] MP Ex. 3 at 32–38 (Undeland Direct).
[191] DER Ex. 10, RAP-16 at 3 (Polich Direct).
[192] DER Ex. 10, RAP-16 at 4 (Polich Direct).
[193] DER Ex. 10, RAP-16 at 4 (Polich Direct) (emphasis added).
[194] DER Ex. 10, RAP-16 at 4 (Polich Direct) (emphasis added).

> out of the 5 bushings still in the unit. An estimated 5 gallons of oil was pumped out of each of the bushings."[195]

96. Minnesota Power stated that it replaced all six bushings, indicating a rationale that six had arrived instead of the three that the Company ordered and because "General Electric did not know why the A phase line side bushing failed."[196] According to the GE report, however, "The customer originally planned to replace only the T4 bushing, which had gone to ground. But with 6 new bushings on hand, as well as higher than expected DC microamp leakage on the T1 HBV, and the knowledge that all 6 of the in-service bushings had been filled with oil, it was decided to replace all six HVBs."[197]

2. Department Testimony on Phase Bushing Failure

97. The Department's engineering expert testified that oil in the bushings can cause them to fail due to the oil blocking the cooling passages, which causes the bushings to overheat.[198] In response to a Department information request, Minnesota Power admitted that the oil in the bushings was seal oil: "It was apparent to plant personnel and our third-party expert consultants that the oil was seal oil. This oil was introduced into this area during the float trap valve testing and repairs . . . ."[199]

98. The Department's engineering expert concluded that Minnesota Power should have followed good utility practice by investigating whether seal oil leaked into the generator when trying to locate the hydrogen leak.[200] And if that investigation had found seal oil leakage, Minnesota Power should have cleaned up the oil.[201] The Department's expert concluded that these simple steps would have prevented the phase bushings from being filled with seal oil or have found the seal oil prior to restarting the plant.[202] This would have avoided the bushing failure and the need to purchase replacement bushings and a roughly two-week unplanned outage.[203]

3. Cause of the Phase Bushing Failure

99. Minnesota Power did not dispute that the oil in the bushings was from its testing of the hydrogen gas leak. Minnesota Power also did not appear to dispute that failing to monitor the amount of oil introduced into the system or check for leaked seal oil was consistent with good utility practice.

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[195] DER Ex. 10, RAP-16 at 5 (Polich Direct)
[196] MP Ex. 3 at 33–34 (Undeland Direct).
[197] DER Ex. 10, RAP-16 at 12 (Polich Direct).
[198] DER Ex. 10 at 47 (Polich Direct).
[199] DER Ex. 10, RAP-15 at 4 (Polich Direct).
[200] DER Ex. 10 at 47 (Polich Direct).
[201] DER Ex. 10 at 47–48 (Polich Direct)
[202] DER Ex. 10 at 48 (Polich Direct).
[203] DER Ex. 10 at 48 (Polich Direct).

100. Instead, Minnesota Power faulted the Department for presenting "no evidence that the phase bushing failure was due to the presence of seal oil in the phase bushing."[204] Minnesota Power stated that "General Electric was unable to conclude whether the presence of oil did or did not contribute to the failure."[205]

101. Among the alternative causes that Minnesota Power pointed to in its rebuttal testimony were sudden load changes, excessive vibration, overheating, overheating of the leads, and normal vibration over long periods of time.[206] Minnesota Power confirmed, however, that General Electric did not find any of these alternative potential causes to be the cause the phase bushings failure.[207] Moreover, scant mention of these other potential causes, besides overheating caused by the bushings being soaked in oil, is mentioned in General Electric's report.[208]

102. One of the alternative causes focused on by Minnesota Power was that vibrations over time caused the outage as evidenced by a tar like substance on the mounting flange.[209] However, Mr. Undeland acknowledged that he was not aware of General Electric noting concerns about tar had during the April 2019 inspection.[210]

103. Minnesota Power also emphasized that the bushings "could have been approximately 50 years old," but Minnesota Power admitted they did not know whether these bushings had been replaced as recently as 2001.[211] The ALJ will not allow Minnesota Power to benefit from failing to keep accurate records of its bushing replacements.

104. Minnesota Power ultimately acknowledged that General Electric stated that the bushings could have failed from overheating due to the seal oil blocking proper cooling.[212]

105. Minnesota Power also blamed its failure to detect the oil leakage on an alarm that was not properly configured.[213] But Minnesota Power admitted that it was responsible for the improper configuration.[214]

4. Conclusions on Phase Bushing Outage

106. Minnesota Power has not shown that it followed good utility practice. Minnesota Power's alternative theories of what caused the phase bushing failure are unpersuasive. Clear indications in the General Electric report and the timing of the failure soon after the bushings'

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[204] MP Ex. 14 at 34 (Undeland Rebuttal).
[205] MP Ex. 14 at 35 (Undeland Rebuttal).
[206] MP Ex. 14 at 35 (Undeland Rebuttal)
[207] Evid Hrg. Tr. at 39–43.
[208] DER Ex. 10, RAP-16 (Polich Direct).
[209] Evid. Hrg. Tr. at 40 (Undeland).
[210] Evid. Hrg. Tr. at 41 (Undeland)
[211] MP Ex. 14 at 35 (Undeland Rebuttal).
[212] Evid. Hrg. Tr. at 43 (Undeland).
[213] MP Initial Br. at 8, 50, 53.
[214] *Id.*

passed inspection shows that the phase bushings failed because they overheated after being soaked with oil.[215] Minnesota Power admitted that following the repairs to address the hydrogen leak, it failed to monitor the amount of oil it introduced into the system.[216] Minnesota Power also admitted that the oil in the generator was seal oil that had been introduced while trying to locate the hydrogen leak.[217] Minnesota Power's new theory in briefing that the phase bushing failure was the result of an improperly configured alarm does not assist it, because Minnesota Power was also required to follow good utility practice in configuring any system alarms.[218]

107. Good utility practice and commonsense dictate that Minnesota Power should have monitored the amount of additional oil it flooded into the system to ensure all excess oil was removed before restarting the generator. Minnesota Power's failure to do so contributed to the failure of the phase bushings and it should not be allowed to retain the forced outage costs that were not reasonably and prudently incurred as a result.

D. Conclusions

108. Based on the above findings the ALJ finds that Minnesota Power's maintenance and inspection programs for Boswell Unit No. 4's hot reheat line, Boswell Unit No. 3's hydrogen cooling system, Boswell Unit No. 3's phase bushing were inconsistent with good utility practice.

a. **Boswell Unit No. 4's Hot Reheat Line**. Minnesota Power failed to show that its ten-year inspection period comported with good utility practice. Good utility practice instead dictated that Minnesota Power should have fully inspected the unit's hot reheat line more frequently than every ten years using methods that can detect creep damage such as phased array ultrasonic examination. More frequent inspection is consistent with guidance produced by industry organizations. More frequent inspections were also prudent based on the well-known high consequence of failures and the potential for worker injuries or deaths. Given this potential for catastrophic failure, Minnesota Power failed to show that more frequent inspections would have unreasonable costs. More frequent inspection would likely have avoided this outage as reports by Minnesota Power's consultant Structural Integrity Associates concluded. As the plant operator, Minnesota Power must retain sufficient internal expertise to ensure that its maintenance program is properly administered. The Company cannot, therefore, rely on purported statements from its consultants regarding common industry practice of other consultant customers.

b. **Boswell Unit No. 3's Hydrogen Cooling System.** In determining the source of the hydrogen leak, Minnesota Power's decision to flood the generator's seal oil system was not consistent with good utility practice. The ALJ agrees that the Company should have removed the float valve and performed a leak test on the float valve to see if it was sealing properly to determine if it was the cause of the hydrogen leak. Further, even if flooding the seal oil system was an appropriate testing technique, good utility practice

[215] DER Ex. 10, RAP-16 (Polich Direct)
[216] DER Ex. 10, RAP-15 (Polich Direct).
[217] DER Ex. 10, RAP-15 (Polich Direct).
[218] MP Initial Br. at 41–44

dictates that Minnesota Power should have at least tracked the amount of seal oil used in any testing process, tracked any leakage, and cleaned up any leaked seal oil.[219]

c. **Boswell Unit No. 3's Phase Bushings.** Minnesota Power's failure to record the amount of seal oil and check for leakage after pumping several barrels of oil into Boswell Unit No. 3's hydrogen cooling system was not consistent with good utility practice. The Company should have carefully tracked the amount of oil it was using and ensured that oil was fully accounted for after completing its testing. In a setting like a power plant where equipment failures can have deadly consequences, common sense dictates that excess oil should be tracked, cleaned up, and kept from contaminating other machinery. Here, Minnesota Power's failure to track and subsequently investigate possible seal oil leakage and clean up seal oil that leaked onto Boswell Unit No. 3's phase bushing was inconsistent with good utility practice. Minnesota Power's alternative causation theories for the phase bushing failure are unpersuasive in light of the bushings' recent inspection and General Electric's report consistently flagging the seal oil as the central potential cause.

109. Having concluded that these outages were not consistent with good utility practice, the ALJ concludes that the expenses associated with these outage events were not reasonably and prudently incurred as set forth in the Commission's referral order and as a result should be refunded to customers as discussed further below.

IV. FINANCIAL ADJUSTMENTS

110. Minnesota Power's incremental forced outage costs associated with Boswell Unit No. 4's hot reheat lines and Boswell Unit No. 3's phase bushings were not reasonably and prudently incurred because they resulted from outages that likely could been avoided with maintenance and inspection programs aligned with good utility practices. Accordingly, these the expenses relating to the purchase of replacement power from third parties over and above Boswell's own generation costs should not be charged to customers and should be refunded along with interest.

111. The Department and Minnesota Power agree that the incremental costs associated with Boswell Unit No. 4's hot reheat lines and Boswell Unit No. 3's phase bushings outages, respectively, equal $4,482,456 and $1,764,695. As a result, the ALJ finds that the total refund or credit owed to ratepayers is $6,247,151 not including interest.[220] The ALJ further concludes that no refund is owed to ratepayers for incremental outage costs associated with Boswell Unit No. 3's hydrogen cooling system or Boswell Unit No. 4's blowdown flash tank. While it is possible that Minnesota Power could have employed better maintenance or inspection practices for these facilities, the Company's conduct was not necessarily inconsistent with good utility practices. As a result, no additional adjustment is necessary.[221]

[219] *Id.* at 44–45.
[220] Ex. DER-2 at 17 (Campbell Direct).
[221] DER-1 at 45–46 (Polich Direct); Ex. DER-2 at 17–18 (Campbell Direct).

112. Minnesota Power and the Department agree that the Company should apply the U.S. Federal Reserve prime rates that were applicable during the refund period to calculate the required interest.[222] Minnesota Power states it would 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."[223] Using this methodology, assuming an October 2021 refund, Minnesota Power calculates that the total refund including interest equals $6,845,234.[224]

113. Minnesota Power stated that it would calculate specific refund amounts for the eight Large Power customers and seventeen Municipal customers based on their actual kilowatt hour usage. For its other customers, Minnesota Power stated that it would calculate the refund 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.[225] The Department agreed that this methodology would produce reasonable results.[226] The ALJ agrees that this approach—agreed upon by the parties—represents an appropriate method for refunding overcharges.

V. PRUDENCY OF RIDER ADJUSTMENTS

114. The Commission has ordered utilities to provide rider refunds or credits to ratepayers for overcharges in the past. The Commission typically has used rider adjustments ensure that customers are repaid where utility either overcharged them or imprudently incurred the expense.[227] This matter implicates the second situation. As previously discussed, Minnesota Power has incurred incremental forced outage costs imprudently by failing to observe good utility practice.

115. In a similar situation, the Commission order another utility to refund replacement power costs that were charged to ratepayers. The Commission concluded that these costs were caused by the utility's failure to observe industry procedures. The Commission, accordingly, reasoned that allowing the utility to "retain recovery of these costs would penalize ratepayers for imprudent actions that resulted in otherwise preventable outages."[228]

116. In addition, the ALJ notes that riders are a common tool for adjusting utility rates outside of a rate case and that these incremental costs were originally charged to ratepayers using a rider. The ALJ finds that it is appropriate to use an accounting tool intended to make financial adjustments outside of the rate case to provide a prompt refund to Minnesota Power's customers. This is further true, here, where it maintains the symmetry with how customers were originally charged for these imprudently incurred expenses. In summary, riders are the appropriate

[222] DER Ex. 12 at 19–20 (Campbell Direct); MP Ex. 17 at 3 (Oehlerking-Boes Rebuttal).
[223] MP Ex. 17 at 3 (Oehlerking-Boes Rebuttal).
[224] MP Ex. 17, LOB-1 at 1 (Oehlerking-Boes Rebuttal).
[225] *Id.* at 3–4.
[226] DER Initial Br. at 26–27.
[227] DER Ex. 12 at 26–38 (Campbell Direct).
[228] *In re Review of the 2014-2015 Annual Automatic Adjustment Reports for all Elec. Utils.*, MPUC Docket No. E-999/AA-15-611, ORDER ACCEPTING REPORTS, REQUIRING REFUND, & SETTING ADDITIONAL REQUIREMENTS at 5 (July 21, 2017).

accounting tool for providing timely refunds or credits to ratepayers. Riders are simply pass-through mechanisms that can be used to correct for either past overcharges or undercharges.[229]

117. Based on the foregoing Findings of Fact and the record in this proceeding, the Commission makes the following:

CONCLUSIONS OF LAW

1. The Commission and the ALJ have jurisdiction over the subject of the proceeding pursuant to Minn. Stat. §§ 216B.03, .16, subd. 7 (2020), Minn. R. 7825.2900, .2920 (2019), and Minn. Stat. §§ 14.57–.62 (2020).

2. Proper notice was timely given and all relevant substantive and procedural requirements of law or rule have been fulfilled and, therefore, the matter was properly before the ALJ.

3. Pursuant to the Commission's Order, Minnesota Power bore the burden to demonstrate by a preponderance of the evidence that its maintenance practices were consistent with good utility practice, and that any deviation from this standard did not contribute to the forced outage events at issue in this proceeding.[230]

4. The utility always retains the burden of proving the reasonableness of costs the utility seeks to charge ratepayers.[231] Submitting evidence on an issue does not create a rebuttable presumption of reasonableness.[232]

5. Based on the findings above and the record in this proceeding, Minnesota Power did not demonstrate by a preponderance of the evidence that its maintenance practices for its Hot Reheat Line and Phase Bushing facilities were consistent with good utility practice, or that any deviation from good utility practice did not contribute to the outage events at issue in this proceeding.

5. The ALJ concludes that Minnesota Power did not reasonably and prudently incur forced outage costs resulting from the Hot Reheat Line rupture and Phase Bushing failure at issue in this proceeding. The Company and the Department agree that the refund owed to customers equals $6,247,151.[233] Interest should be calculated using the U.S. Federal Reserve Prime Rate.[234]

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229 Ex. DER-2 at 4, 25–28 (Campbell Direct)
230 ORDER ACCEPTING 2018–2019 ELECTRIC AAA REPORTS; NOTICE OF AND ORDER FOR HEARING at 4 (Sept. 16, 2020) (eDocket No. 20209-166630-01); Minn. R. 1400.7300, subp. 5 (2019).
231 *In re N. States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987).
232 *Id.* at 725–26.
233 DER Ex. 12 at 17 (Campbell Direct); MP Ex. 17 at 2 (Oehlerking-Boes Rebuttal).
234 DER Ex. 12 at 19– 20 (Campbell Direct); MP Ex. 17 at 3 (Oehlerking-Boes Rebuttal).

6. Utility rate riders are pass-through mechanisms used to adjust utility rates outside of a general rate case.[235] Costs paid by customers through a rider are provisionally authorized subject to subsequent Commission review and adjustment.[236] The Commission has repeatedly used rate riders to refund overcharges and imprudently incurred utility costs.[237]

7. Because rider refunds are authorized by law and consistent with Commission practice, it is appropriate for Minnesota Power to refund imprudently and unreasonably incurred incremental forced outage expenses in this proceeding via its Fuel Adjustment Clause rider. Minnesota Power should calculate specific refund or credit amounts using the procedures agreed upon by the Department and the Company.[238]

8. Any of the forgoing Findings of Fact more properly designated as Conclusions of Law are hereby adopted as such.

RECOMMENDATIONS

Based upon these Findings of Fact and Conclusions of Law, the ALJ recommends:

1. The Commission find that the Hot Reheat Line and Phase Bushing forced outages at the Boswell Energy Center were inconsistent with good utility practice, and that Minnesota Power's incremental costs arising from the outages involving these facilities were not reasonably and prudently incurred.

2. Minnesota Power refund $6,247,151 in incremental forced outage costs plus interest calculated and distributed to customers using the methodologies agreed upon by the parties and described in the Findings of Fact above. Assuming an October 2021 refund, this methodology would require Minnesota Power to refund $6,845,234.

3. The Commission should adopt the Findings of Fact, Conclusions of Law, and Recommendations set forth above.

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[235] Minn. Stat. § 216B.16, subd. 7.

[236] Minn. R. 7825.2920.

[237] *See, e.g.*, *In re Xcel Energy's Pet. for Affirmation that MISO Day 2 Costs are Recoverable Under the Fuel Clause Rules & Associated Variances*, MPUC Docket No. E-002/M-04-1970, ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS at 7, 17 (Dec. 20, 2006); *In re Minn. Power's Pet. for Approval of Credits to Customers*, MPUC Docket No. E-015/M-15-875, ORDER APPROVING REFUND & REQUIRING FILINGS at 2–3 (May 26, 2016); *In re Review of the 2014-2015 Annual Automatic Adjustment Reports for all Elec. Utils.*, MPUC Docket No. E- 999/AA-15-611, ORDER ACCEPTING REPORTS, REQUIRING REFUND, & SETTING ADDITIONAL REQUIREMENTS at 5 (July 21, 2017).

[238] MP Ex. 17 at 3–4 (Oehlerking-Boes Rebuttal).