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 EXCEPTIONS TO THE ADMINISTRATIVE LAW JUDGE REPORT

August 31, 2021

MINNESOTA POWER

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I. INTRODUCTION

Minnesota Power (the "Company") respectfully submits these Exceptions to the Administrative Law Judge's ("ALJ") August 11, 2021 Findings of Fact, Conclusions of Law and Recommendation ("ALJ Report").[1] Minnesota Power appreciates the time and effort of the parties and the ALJ in these proceedings, and agrees with the ALJ Report regarding the outages experienced by Minnesota Power during the relevant period other than the ALJ's findings and resulting conclusions and recommendation regarding the Boswell Energy Center ("Boswell") Unit 4 ("BEC4") hot reheat ("HRH") seam-welded steam line outage experienced in the spring of 2019. The HRH seam-welded steam line, which shall hereinafter be referred to as the "HRH line," is an insulated High Energy Piping ("HEP") system that is 640 feet in length and spans 20 floors with limited access within Boswell Energy Center ("Boswell") Unit 4 ("BEC4").[2] The Company takes exception to the ALJ's findings, conclusions, and recommendation surrounding the question of whether Minnesota Power's HEP (which includes the HRH line) inspection program was consistent with good utility practice. Specifically, Minnesota Power takes exception to the ALJ's findings and conclusions that the Company's risk-based, ten-year, inspection cycle for HRH lines was not good utility practice. In her report, the ALJ bases the conclusions and recommendation regarding the HRH line outage on erroneous findings that Minnesota Power's risk-based, ten-year, inspection cycle was not consistent with or approved by a significant portion of the electric utility industry, or, alternatively, reasonable given the facts known at the time of the outage.

This contested case arose as a result of the Department of Commerce's ("Department") recommendation to the Minnesota Public Utilities Commission ("Commission") that Minnesota

[1] Minnesota Power submits with these Exceptions **Attachment A**, which provides the Company's proposed revisions to the ALJ Report.
[2] Ex. 7 at 16 (Undeland Direct).

Power should not be allowed to recover a portion of the unplanned outage replacement power costs included in the Company's AAA report for the period of July 1, 2018 to December 31, 2019. At that time, the Department asserted that the outages occurred due to the Company's lack of generation maintenance expenses in 2018 and 2019, which were each lower than the 2017 test year from the Company's last rate case.[3] In other words, the Department assumed that Minnesota Power's decreased generation maintenance spending compared to the amount approved by the Commission *caused* a higher amount of unplanned outages during the reporting period. Despite Minnesota Power's explanation of the drivers for why maintenance expenses were lower in 2018 and 2019 than the 2017 test year and why correlation does not equate to causation in these instances, the Department maintained its position.[4] The Commission issued an Order for Hearing on September 16, 2020 after finding an issue of material fact as to whether Minnesota Power, applying good utility practice, reasonably and prudently incurred forced outage costs during the AAA evaluation period, and referred the issue to the Office of Administrative Hearings ("OAH") for a contested case proceeding.[5]

Minnesota Power's initial submissions in the contested case demonstrated that the Department's initial premise – that there was a relationship between lower maintenance spending and increased outage costs – was entirely unsupported by the evidence.[6] Most notably, the Company demonstrated that it had not reduced maintenance spending or inspection protocols, compared to those in effect during the last rate case, related to any of the systems that experienced

[3] Ex. 9, Schedule 1 at 10 (Rostollan Direct).
[4] Ex. 5, Schedules 3, 4 at 7-9, and 5 (Simmons Direct).
[5] ORDER FOR HEARING at 8.
[6] Ex. 9 at 4-7, 17, 20-23 (Rostollan Direct). These initial submissions were originally scheduled for December 2020, but were delayed to January 2021 as the Department required more information to retain an engineering expert witness.

unplanned outages during the AAA evaluation period.[7] In other words, Minnesota Power conducted the level of generation maintenance and the methods of inspection approved by the Commission in the last rate case.

Rather than ending the inquiry there, the Department had its engineering expert, Mr. Richard Polich, perform a cursory review of Minnesota Power's maintenance and inspection programs in an attempt to identify potential inconsistencies with good utility practice, including whether he believed that the Company should have conducted more extensive and frequent inspections than were approved in the last rate case. The Department then argued, through Mr. Polich's Direct Testimony, that specific maintenance protocols and actions taken (and not taken) by Company employees were not consistent with good utility practice.[8]

Minnesota Power is concerned with the Department's shift in its basis for recommending that the Company refund any portion of the incurred outage costs to customers. The Company began this contested case defending against allegations that it reduced maintenance and inspection program spending to an extent that it caused increased unplanned outages. After thoroughly disproving that notion, Minnesota Power then defended in detail the decisions it made, and maintenance and inspection program it implemented, from the second-guessing of an expert who never visited the facility and has limited knowledge of both the specific systems that failed and the maintenance and inspection practices utilized and accepted across the industry.[9] If the ALJ Report

[7] Ex. 6 at 6-17 (Poulter Direct); Ex. 5 at 15-20 (Simons Direct); Exs. 14 and 15 at 17 (Undeland Rebuttal) (Public and Nonpublic).
[8] Exs. 10 and 11 (Polich Direct) (Public and Nonpublic).
[9] Mr. Polich has limited experience in power plant operations and maintenance. He did not testify to any experience creating or implementing maintenance and inspection protocols in general or for the components at issue in this proceeding. Exs. 10 and 11 at 1-5, Schedule 1 at 1-5 (Polich Direct) (Public and Nonpublic). Rather, his experience is limited to general familiarity with power plant design and operation, review of the HRH line inspection protocol for two plants with seam welded HRH pipes, and his review of the non-current version of Electric Power Research Institute's

is adopted by the Commission, the precedent it may establish will likely lead to higher maintenance costs for customers as Minnesota Power and other utilities seek to implement "best" utility practice instead of "good utility practice" to minimize the risk of cost recovery disallowance through future proceedings before the Commission based upon misplaced hindsight critiques.

The ALJ correctly determined that the Department's second guessing of what Minnesota Power should have done with respect to the Boswell Unit 3 ("BEC3") hydrogen leak and phase bushing failure, as well as the other 23 unplanned outages during the relevant period were without merit.[10] The ALJ warned of the "difficulty of evaluating maintenance prudence, practice, and expenditures on a case-by-case basis[,]"[11] and indicated that a utility may only be expected to make a reasonable decision based upon the knowledge it had at the time.[12]

With respect to the HRH line seam-weld failure at BEC4, however, the ALJ incorrectly concluded that Minnesota Power failed to meet its burden to demonstrate that its inspection protocol for the HRH line was reasonable, prudent, and consistent with good utility practice. Specifically, Minnesota Power takes exception to the following findings and conclusions:

("EPRI") suggested guidelines for the inspection of seam-welded high-energy-piping ("HEP"), and other EPRI literature. *Id.*; Ev. Hrg. Tr. at 81-82. Mr. Polich demonstrated his lack of experience through his reliance on an inapplicable portion of the American Society of Mechanical Engineers ("ASME") Code, as discussed below, and his conclusions regarding the testing methodology Minnesota Power should have undertaken with respect to the hydrogen leak at Boswell Unit 3 ("BEC3"), for which neither the original equipment manufacturer nor industry experts on that component could devise a meaningful test. *See* Exs. 10 and 11 at 44-45 (Polich Direct) (Public and Nonpublic); Exs. 14 and 15 at 10 (Undeland Rebuttal) (Public and Nonpublic).

[10] ALJ Report at ¶¶ 135, 154.

[11] *Id*. at ¶ 135.

[12] *Id*. at ¶ 154.

ALJ Conclusion	Department Position	Record-Supported Conclusion
ASME B31.1 Non-mandatory Appendix V-8 recommends a minimum 5-year inspection schedule for HRH lines.	ASME Non-mandatory Appendix V-8, which requires a 5-year inspection frequency for corrosive environments, applies to the HRH piping at BEC4.	Non-mandatory Appendix V-8 applies to corrosive environments, which requires the presence of wet steam or liquid. The HRH piping carries only superheated <u>dry</u> steam, which no party disputed, and, therefore, Appendix V-8 does not apply.
Minnesota Power should have followed EPRI's recommended minimum 5-year inspection frequency for HRH lines.	Minnesota Power should have followed EPRI's 5-year 100 percent phased array ultrasonic testing recommendation for HRH lines.	EPRI is a fee-based member industry group that does not set standards. EPRI acknowledged that its HRH inspection recommendations are not followed by a majority of the industry, and are viewed as cost-prohibitive by utilities.
Minnesota Power unreasonably relied upon information from its expert HEP consultant, Thielsch Engineering, which was unreliable hearsay and the product of a feedback loop where Thielsch gave similar advice to all clients.	Minnesota Power unreasonably relied upon Thielsch hearsay that was the product of a feedback loop.	Utilities such as Minnesota Power regularly and reasonably carefully consider verbal advice from recognized industry experts to determine acceptable industry practices when plant personnel develop maintenance programs. Thielsch was vetted and approved by the Company's insurer, FM Global. Requiring multiple experts to address every issue would be wasteful.
Minnesota Power failed to meet its burden of showing that its HRH inspection protocol was reasonable, prudent, and consistent with good utility practice.	Minnesota Power failed to meet its burden of showing that its HRH inspection protocol was reasonable, prudent, and consistent with good utility practice.	Minnesota Power provided ample evidence that its HRH inspection protocol was consistent with good utility practice, including: detailing the Company's process in creating the program; Thielsch's advice based upon its more than 50 other utility clients with similar systems; FM Global's approval of Thielsch and auditing and approval of the HEP inspection program.

For the reasons explained in more detail throughout these Exceptions, Minnesota Power respectfully requests that the Commission adopt the ALJ Report as filed on August 11, 2021, as modified by the revisions provided in **Attachment A** to these Exceptions. While there are certainly other approaches that utilities implement for their seam-welded HEP programs, the ten-year, risk-based inspection cycle for the HRH line, where high-risk runs of such HEP were subject to more frequent inspections, falls well within the acceptable range of good utility practice.

II. EXCEPTIONS

Minnesota Power respectfully takes exception to those portions of the ALJ Report related to the question of whether Minnesota Power's HEP seam-welded steam line inspection program, including that of the HRH lines, at Boswell was consistent with good utility practice.[13] The Company generally takes exception to those portions of the Report that find the HRH line inspection program was not (1) consistent with practices utilized or approved by a significant portion of the electric utility industry, or (2) reasonable and prudent given the information available at the time.

A. Minnesota Power's HRH Line Inspection Protocol Is Consistent with Good Utility Practice

The ALJ concluded that Minnesota Power failed to demonstrate that its HEP inspection program was reasonable and prudent and constituted good utility practice.[14] The ALJ primarily relied upon the Department's testimony that: (1) the HRH line inspection protocol was not consistent with the recommendations from the ASME or EPRI; (2) the Company improperly relied upon the advice of its expert, Thielsch; (3) the safety risks associated with an HRH line failure justify more frequent inspections; and (4) Minnesota Power failed to meet its burden of proof that

[13] Specifically, Minnesota Power takes exception to the following: (i) Summary of Recommendations: 1 and 2; (ii) Findings: 14, 39, 72, 77, 79, 82, 90, 91, 93, 94, 96, 97, 100-102, 104, 107-115, 135, 155, 157-64; (iii) Conclusions: 5-7; and (iv) Recommendations: 1-3.
[14] ALJ Report at ¶ 115.

its HRH line inspection protocol was consistent with good utility practice.[15] These contentions are not, however, supported by the record, as discussed below.

1. ASME B31.1, Appendix V-8 Is Inapplicable

In support of the conclusion that good utility practice required Minnesota Power to inspect 100 percent of its HRH steam pipes at least every five years, the ALJ relied in part upon a non-mandatory appendix of the ASME Code. Specifically, the ALJ concluded that ASME B31.1, Non-mandatory Appendix V-8 – which recommends a five-year inspection interval for "Piping Corrosion" inspections – is applicable to the HRH steam lines (including the BEC4 HRH line that resulted in an unplanned outage in the spring of 2019) at BEC4.[16] This finding, however, is contrary to the plain language of ASME B31.1, as confirmed by EPRI publications that were relied upon by the Department's expert witness in this proceeding.

The Department, through its expert, Mr. Polich, claimed that Appendix V-8 applies to the HRH line at BEC4 because it can develop "rust" that will lead to erosion/corrosion damage.[17] However, Mr. Polich is demonstrably wrong. As explained by Minnesota Power's employees who have worked in the plant for combined decades, erosive/corrosive conditions are not applicable to the HRH line.[18] Rust requires moisture, and the HRH line transports only superheated dry steam (1,015^{o}F) that, due to its temperature, does not contain moisture or cause rust.[19]

Contrary to the ALJ's Report and the Department's position, 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>."[20] Similarly, the ASME

[15] *Id*. at ¶¶ 110 and 112.
[16] *Id*. at ¶¶ 68, 86, 91, and 111.
[17] *Id*. at ¶ 92.
[18] Ex. 7 at 1, Schedule 1 (Undeland Direct).
[19] Exs. 14 and 15 at 21 (Undeland Rebuttal) (Public and Nonpublic).
[20] Ex. 22a at 319 (emphasis added).

Code's list of the "Systems and Components Susceptible to Erosion/Corrosion" does not include the HRH line, and states that "Piping damage due to [Erosion/Corrosion] is not limited to [the listed] systems and may occur in any system of carbon steel or low alloy piping that is exposed to water or wet steam and operates at a temperature greater than 200°F (93°C)."[21] Thus, the ASME Code is clear that erosion/corrosion requires the presence of water or wet steam whereas the HRH line transports only superheated dry steam.

EPRI agrees that corrosion is caused by the flow of "water or wet steam" through pipes.[22] Even more to the point, EPRI states that "[p]iping systems that can be considered immune to [flow accelerated corrosion] (for the most part) include … Superheated steam systems with no moisture content[.]"[23] Additionally, "because corrosion involves the passage of electrons—for corrosion to proceed, there must be a complete electrical circuit which includes … A conductive electrolyte (aqueous solution) that completes the circuit," without which "the circuit is not complete, and corrosion will not occur."[24] As superheated dry steam, the BEC4 HRH line transports a vapor and not an aqueous solution under these conditions.

It is undisputed that the BEC4 HRH line carries superheated dry steam with no moisture content.[25] Thus, the HRH line is not subject to corrosion or erosion due to the lack of wet steam or water in the system. As a result, the ALJ's conclusion that Appendix V-8 (Piping Corrosion) applies to inspection and maintenance of the HRH line is unsupported by both the plain language of the ASME Code and EPRI publications.

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[21] *Id*. (emphasis added).
[22] Ex. 19 at 2-17, 7-46.
[23] *Id*. at 2-18.
[24] *Id*. at 7-59 (emphasis added).
[25] Exs. 14 and 15 at 21 (Undeland Rebuttal) (Public and Nonpublic).

The section of ASME B31.1 that is applicable to the HRH line is Appendix V-12, which covers creep damage like that experienced in the BEC4 HRH line. Section 12 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."[26] In sum, 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 facility operator is responsible for determining the frequency based on facility experience and known conditions of the line.[27] This is consistent with Minnesota Power's HEP maintenance and inspection program, as discussed in more detail below in Section II.A.5.

2. EPRI Recommendations Are Not Followed by a Majority of the Industry

The ALJ concluded that the five-year HRH line inspection program recommended by EPRI might have been consistent with good utility practice.[28] Minnesota Power does not disagree. The Company does, however, take exception to the ALJ's unsupported findings and conclusion that a five-year inspection frequency is required to be consistent with good utility practice.[29] While the five-year phased array ultrasonic inspection frequency and method suggested by EPRI constitutes "best" utility practice at the top end of the range of good utility practice, it is not the only frequency and methodology that are consistent within the range of good utility practice. Rather than evaluating whether the Company's practices fell within the range of good utility practice, the ALJ supplanted Minnesota Power's judgment and decision based upon the information known at the

[26] Exs. 14 and 15 at 21 (Undeland Rebuttal) (Public and Nonpublic); Ex. 15, Rebuttal Schedule 2 at 6 (Undeland Rebuttal) (Nonpublic).
[27] Exs. 14 and 15 at 21 (Undeland Rebuttal) (Public and Nonpublic).
[28] ALJ Report at ¶ 111.
[29] *Id*. at ¶¶ 105-115.

time with the Department's retrospective judgment that the Company should have followed EPRI's recommendations.

As a primary matter, EPRI is not a standard setting organization, but rather is a member utility organization that provides recommendations to its fee-paying members.[30] Thus, in order to access to EPRI's materials and recommendations, a utility must pay annual membership fees or specific publication prices,[31] which are then passed on to customers through rates.[32] Utilities like Minnesota Power must make decisions regarding which industry groups they join, publications they purchase, and suggestions they implement by weighing the potential benefits to maintaining a safe and efficient power supply against the cost of the membership that will be passed on to customers through rates. If member utility organization recommendations equate to industry standards, as suggested by the Department and relied upon by the ALJ, then Minnesota Power and other utilities will to need to give increased consideration to joining every EPRI program and all other relevant member organizations and implement their most stringent suggestions in order to be consistent with this standard of good utility practice.

While EPRI is a 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

[30] Ev. Hrg. Tr. at 75 (Polich).
[31] For example, the Department and its expert declined to purchase or obtain access to the most recent version of EPRI's "Guidelines for the Evaluation of Seam-Welded High-Energy Piping" because it is "really expensive[.]" *Id*. at 81-82.
[32] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 40-41 (Mar. 12, 2018).

consistent with good utility practice.[33] Some of EPRI's guidelines and recommendations are widely adopted within the industry, while others are not.[34]

The parties agree that good utility practice is not "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."[35] This includes "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[.]"[36] Thus, good utility practice is not limited to a single standard unless it is so prevalent that no other standards could be engaged in or approved by a significant portion of the industry.

The ALJ concluded that EPRI's HRH inspection suggestions equated to an industry standard without exploring the evidence regarding whether they were engaged in or approved of by an overwhelming majority of the industry so as to preclude any less stringent practices from being considered good utility practice.[37] This is particularly important considering that EPRI concedes that its HRH inspection recommendations are not followed by the majority of the industry. According to EPRI's 1993 survey,[38] more than half of the 29 utility respondents[39] did not comply with EPRI's creep detection recommendations,[40] and "<u>only 2%</u> of the utilities surveyed

[33] Exs. 14 and 15 at 23 (Undeland Rebuttal) (Public and Nonpublic).
[34] *Id*.
[35] Exs. 10 and 11 at 6-7 (Polich Direct) (Public and Nonpublic).
[36] *Id*.
[37] *See* ALJ Report.
[38] Mr. Polich claims that EPRI told him that its more recent surveys had similar results to the 1993 survey. Exs. 14 and 15, Rebuttal Schedule 1 at 2-3 (Undeland Rebuttal) (Public and Nonpublic).
[39] EPRI's results are also likely skewed given that the "respondent" utilities were prone to be EPRI members and did not include only utilities that operated power generation facilities that used seam-welded pipe for high energy piping applications.
[40] Creep was identified as the likely root cause of the BEC4 HRH line unplanned outage in spring 2019. Ex. 7, Schedule 3 at 4 (Undeland Direct).

complied completely with the EPRI Guidelines[.]"[41] EPRI guidelines cannot be considered the minimum standard for good utility practice if only two percent of the utilities surveyed followed those recommendations completely and less than half complied with creep detection recommendations "for the most part."[42] The ALJ erroneously failed to consider EPRI's own survey demonstrating that its recommendations do not equate to good utility practice to the exclusion of any other standards.

EPRI has more recently acknowledged that its HRH inspection recommendations are far from universally accepted within the electric industry. In a 2017 publication on 30 years of power generation industry seam-weld failures (the "30 Year Report"), EPRI stated, "Increasingly, economic pressure on end-users is necessitating a reevaluation of legacy guidelines for inspection of long-seam welded components. In particular, the [EPRI Guideline] 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."[43] Thus, EPRI has recently acknowledged that its five-year inspection frequency and phased array ultrasonic testing methodology recommendation may have to be reevaluated given its real world economic implications and the actual practices within the industry. Even Mr. Polich, the Department's expert, conceded that "the view of [EPRI's five-year HRH inspection frequency] being cost prohibitive" in the 30 Year Report reflects the views of the utilities.[44]

Mr. Polich also failed to provide sufficient evidence regarding what exactly the EPRI Guidelines recommend. Mr. Polich conceded, "It's one of those things that's a little bit convoluted

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[41] Exs. 14 and 15, Rebuttal Schedule 1 at 33 (Undeland Rebuttal) (Public and Nonpublic) (emphasis added).
[42] *Id*.
[43] *Id*., Rebuttal Schedule 1 at 427.
[44] Ev. Hrg. Tr. at 69-70 (Polich).

throughout [EPRI's Guidelines] because there's a lot of information contained in here . . . ."[45] 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.[46]

Mr. Polich further admitted that he did not inspect BEC4 or its piping or conduct a decision tree analysis for the BEC4 HEP, including the HRH line, to determine what EPRI recommendations would apply.[47] 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.

As discussed in more detail below, Minnesota Power's HRH inspection contractor, Thielsch, informed the Company that none of its approximately 50 utility customers performed phased array ultrasonic testing of 100 percent of their HEP on a five year interval, and that Minnesota Power's ten-year interval was consistent with industry practices.[48] This further demonstrates that EPRI's recommended inspection frequency was not even close to an industry-wide standard.

Ultimately, even EPRI has acknowledged through its 1993 survey and the 30 Year Report that its five-year inspection interval recommendation for HRH lines was, at best, utilized by less than a majority of utilities and is viewed as cost-prohibitive within the industry. Thus, not even

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[45] *Id*. at 66 (Polich).
[46] *Id*. at 67 (Polich).
[47] *Id*. at 67 (Polich).
[48] Ex. 7 at 18 (Undeland Direct).

EPRI supports the ALJ's conclusion that EPRI's recommended five-year inspection interval and phased array ultrasonic testing of HRH lines represents the sole standard for good utility practice.

3. Minnesota Power Reasonably Relied Upon Industry Expert Advice

The Department averred, and the ALJ agreed, that it was unreasonable for Minnesota Power to rely upon advice from its HEP maintenance and inspection expert, Thielsch.[49] The ALJ concluded: "Unsworn claims from [Thielsch] 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 gives similar advice to its other power plant clients."[50]

Sworn testimony from Minnesota Power employees about the information and advice the Company received through discussions with its independent expert consultant, Thielsch, which was used in making decisions about the HEP maintenance and inspection programs does not constitute unreliable hearsay. Pursuant to OAH Rules of Evidence 1400.7300 Subpart 1, the "judge may admit all evidence which possesses probative value, including hearsay, if it is the type of evidence on which reasonable, prudent persons are accustomed to rely in the conduct of their serious affairs." Much of what Minnesota Power must rely upon in determining what practices are common throughout the industry consists of statements from Original Equipment Manufacturers, industry experts, and other utilities that are not always officially documented. The Company submits that it is not only reasonable, it is entirely consistent with good utility practice to take into account industry perspectives provided by outside expert consultants regardless of whether the information is officially documented.

[49] ALJ Report at ¶ 110.
[50] *Id*.

Thielsch is recognized as an expert in the area of HEP maintenance and inspection within the power generation industry.[51] Minnesota Power has worked with Thielsch since approximately 1983, so they are very familiar with Boswell's HEP systems.[52] Based upon Thielsch's widespread knowledge and client-base within the industry, Minnesota Power reasonably relied upon Thielsch's statement regarding its experience with the practices of over 50 other utilities within the industry, even though it was not officially documented at the time.[53]

The Department did not pose any information requests regarding, or raise any objections to, Minnesota Power's Direct Testimony regarding Thielsch's statements until the Department claimed it was unreliable hearsay in initial briefing to the ALJ.[54] If the Department wished to exclude that evidence, it should have made a motion to that effect or given Minnesota Power an opportunity to provide a sworn statement from Thielsch. Waiting until the briefing stage to argue that the Thielsch statements are inadmissible hearsay does little to get to the truth of the matter, and is procedurally objectionable.[55] If the Commission would like a more formal statement from

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[51] Ex. 6 at 15 (Poulter Direct).
[52] *Id*.
[53] Thielsch's statements on this issue were discussed in the Direct Testimony of Mr. Poulter (Ex. 6 at 18-19 (Poulter Direct)) and the Direct Testimony of Mr. Undeland (Ex. 7 at 17 (Undeland Direct)), so the Department was on notice of this statement from the beginning of this contested case. The Department never asked for additional information through an information request or made a motion to exclude this testimony. The Department's tardy request to discount or disallow the Thielsch customer information should be rejected.
[54] INITIAL BRIEF OF THE MINNESOTA DEPARTMENT OF COMMERCE, DIVISION OF ENERGY RESOURCES at 15 (June 28, 2021).
[55] Notably, the Department's expert also relied upon unsworn statements from EPRI regarding whether the 2012 Guidelines, which he did not actually review, materially changed the recommendations contained in the 2003 version of EPRI's Guidelines, upon which he relied. Ev. Hrg. Tr. at 71 (Polich). If unsworn statements are not to be afforded any weight in this proceeding, then the Department failed to provide any reliable testimony regarding EPRI's Guidelines that were in effect during the AAA review period.

Thielsch before the record closes after the hearing, Minnesota Power can certainly facilitate such a filing.

The ALJ's conclusion that Minnesota Power unreasonably relied upon information and advice provided by Thielsch is flawed. The ALJ noted that Thielsch's advice was unreliable because it was the product of a feedback loop where Thielsch is giving the same advice to all of its clients.[56] This reasoning is illogical and would preclude utilities from relying upon advice and information obtained from an independent expert source since, presumably, each entity would give similar advice to all of its clients or members. This is equally true of EPRI's recommendations to its members, which could theoretically be challenged as part of an unreliable feedback loop by another industry expert proposing an even more stringent inspection protocol. If the Commission affirms the ALJ's conclusion regarding the unreliability of industry expert advice, utilities will be forced to seek advice from multiple industry experts and sources regarding every topic and implement the most stringent recommendations in order to avoid being accused of noncompliance with good utility practice.

The ALJ's determination also does not take into account the definition of good utility practice, which includes "<u>any</u> of the practices, methods, and acts engaged in or approved by <u>a significant portion</u> of the electric utility industry during the relevant time period[.]"[57] Thielsch provided Minnesota Power with industry standard information based upon its work with over 50 utility clients, which unquestionably constitutes a significant portion of the industry.[58] At the time of the HRH line seam-weld failure and associated outage in February 2019, Minnesota Power was

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[56] ALJ Report at ¶ 110.
[57] Exs. 10 and 11 at 6-7 (Polich Direct) (Public and Nonpublic) (emphasis added).
[58] Ex. 6 at 18-19 (Poulter Direct)); Ex. 7 at 17 (Undeland Direct). Notably, this sample size is larger than the 29 utilities that responded to EPRI's survey, less than half of which even attempted to comply with EPRI's recommended HEP inspection recommendations.

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.[59] This is in light of Minnesota Power's conversations with other coal-fired power plant operators, various other industry group participation, and the insights of its own licensed professional engineers and plant operators with decades of combined experience.[60] Given that Minnesota Power is unaware of any industry-wide source of information regarding what HEP maintenance and inspection practices are utilized by all national utilities, it was reasonable for the Company to believe that Thielsch's sample of over 50 utilities would be relatively representative of all utilities across the nation.

Further, Minnesota Power's reliance on Thielsch's assessment that the Company's risk-based, iterative HRH inspection protocol was consistent with the programs utilized by Thielsch's other clients was reasonable. In fact, Minnesota Power's insurer, FM Global, approved the use of Thielsch as the Company's external HEP expert and reviewed the HRH line inspection program.[61] Utilities must be able to reasonably rely upon expert advice, especially in highly specialized areas, because it is often the most cost effective, timely, and efficient avenue for learning certain industry or technical information. Indeed, utility industry outside experts exist so that every utility need not develop and maintain knowledge and training for every aspect of its operations, which would be incredibly expensive and unrealistic.

In sum, Thielsch confirmed that Minnesota Power's risk-based HEP inspection protocol that called for inspection of low risk areas such as the vertical HRH line every ten years and

[59] Exs. 14 and 15 at 18 (Undeland Rebuttal) (Public and Nonpublic).
[60] Ex. 7 at 16 (Undeland Direct); Exs. 14 and 15 at 4 (Undeland Rebuttal) (Public and Nonpublic); Ex. 6 at 20-21 (Poulter Direct).
[61] Ex. 7 at 25 and 34, Schedule 3 at 7 and 11 (Undeland Direct); Exs. 14 and 15 at 31 (Undeland Rebuttal) (Public and Nonpublic).

inspection of higher risk areas every two to five years was consistent with the practices of a significant portion of the utility industry. As a result, Minnesota Power's HRH inspection protocol satisfied the Department's requirements for consistency with good utility practice. Moreover, as discussed in more detail below in Section II.A.5, the information and advice received from Thielsch also supports the reasonableness of Minnesota Power's decision to implement the iterative risk-based HEP inspection plan given the information it had at the time, which is an alternative method of demonstrating consistency with good utility practice.

4. Safety is of Paramount Importance for Minnesota Power

The ALJ noted that utility plants have "some inherent dangers that, left unaddressed, can result in injury and death" when determining that the BEC4 HRH line should have been inspected closer to every five years.[62] Safety is of paramount importance in all of Minnesota Power's maintenance, inspection, and operation decisions. Indeed, the primary goals of Minnesota Power's maintenance and inspection programs are ensuring safety and maximizing reliability, while also keeping in mind the need to do so in a cost-effective manner for the benefit of customers.[63] While the ALJ's safety concerns are valid, her reasoning that the potential for catastrophic failure necessitates a higher frequency of inspection ignores that Minnesota Power's HEP inspection protocol took safety into account.

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

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[62] ALJ Report at ¶ 107.
[63] Ex. 5 at 25, 35 (Simmons Direct); Ex. 7 at 38 (Undeland Direct); Ex. 6 at 12-13 (Poulter Direct).

maintenance and inspection cycles using their best judgment based upon the information available at the time.[64]

The Boswell HEP inspection protocol was designed to inspect the higher risk areas, including the risk of unplanned failure as well as the resulting risks to equipment and employee safety,[65] on a more frequent basis than the lower risk areas.[66] One of the core principles for this type of plan is that stress damage, such as creep, is more likely to first appear and show indications in the areas of highest stress.[67] By concentrating more resources on monitoring the areas most likely to first develop wear and damage, the Company would be more likely to catch the first signs of such deterioration and cracking in the system as a whole, which would then inform the Company's inspections and maintenance of the entire HEP system moving forward.[68]

As discussed above, the vertical run of HRH line piping in BEC4 where the spring 2019 failure occurred is one of the lowest stress and lowest risk sections of the HEP system. As a result, and consistent with the practices of a significant portion of other utilities in the industry and advice and review by Thielsch and FM Global, Minnesota Power continued its ten-year inspection frequency for that segment of HEP. Thus, Minnesota Power accounted for safety considerations in its decision regarding the frequency of HRH line inspections, as it does for all maintenance, inspection, and operation decisions.

Minnesota Power also accounted for the age of the HEP system in adjusting its maintenance inspection practices over time. In the early years of pipe life, the most likely area of

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[64] Ex. 6 at 4 (Poulter Direct).
[65] *Id*. at 3; Ex. 7 at 38 (Undeland Direct).
[66] Ex. 7 at 16 (Undeland Direct).
[67] *Id*. at 16-18; Ex. 5 at 24-25 (Simmons Direct).
[68] Ex. 7 at 16-18 (Undeland Direct); Ex. 5 at 24-25 (Simmons Direct).

HEP to develop fatigue is at an attachment or bend.[69] As the pipe ages, however, the most common failure mechanism transitions from fatigue to creep. "Creep" is a function of operation at high temperatures, over time and with stress.[70] As Boswell aged, Minnesota Power adapted its HEP inspection protocol to increase frequency at known and additional risk areas and 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.[71]

Minnesota Power maintains rigorous and involved maintenance and inspection programs to ensure the safe and reliable operation of the Boswell facility, while keeping in mind the need to do so in a cost-effective manner for customers. It is just not feasible to prevent every unplanned outage, and the ability of Minnesota Power to maintain Boswell as a reliable resource for its customers for over 40 years speaks to the Company's ability to develop and manage its various maintenance programs.[72]

5. Minnesota Power's Iterative and Risk-Based HRH Line Maintenance and Inspection Program Was Consistent with Good Utility Practice

The ALJ concluded that Minnesota Power's claim that its ten-year HRH inspection schedule was consistent with good utility practice was "supported solely by advice from its contractor, Thielsch."[73] Even if that was the case, as discussed above, it was entirely reasonable for Minnesota Power to rely upon that information and advice and incorporate it into the Company's decisions regarding its maintenance and inspection protocols. The record

[69] Ex. 5 at 24-25 (Simmons Direct).
[70] *Id*. at 25.
[71] *Id*.
[72] *Id*. at 35 (Simmons Direct).
[73] ALJ Report at ¶ 110.

demonstrates, however, that Minnesota Power took much more than only Thielsch's advice into account when developing its HEP maintenance and inspection programs.

Minnesota Power utilizes all of the information available to it to develop inspection plans to determine where, what, how, and how much to inspect.[74] Minnesota Power develops its HEP inspection protocol based on ASME recommendations, past results, known areas of risk, industry bulletins, insurance carrier guidance, plant personnel with decades of experience, and third-party HEP expert recommendations, among many other sources the Company uses in developing its maintenance and inspection programs.[75] Additionally, Boswell employees meet every year with peers from Xcel Energy to discuss issues that have come up in the past year.[76] Minnesota Power's insurance carrier, FM Global, also shares industry issues with the Company and audits the Company's maintenance plans and records and provides recommendations and guidelines to minimize risks.[77] Minnesota Power only implemented its HRH line inspection program after FM Global indicated that it was comfortable in Thielsch's abilities, expertise, and recommendations.[78]

The ALJ determined that, given the known history of HEP failures throughout the industry, Minnesota Power should have implemented an inspection frequency closer to every five years than to every ten years.[79] However, Minnesota Power developed its HEP and HRH risk-based inspection protocols in response to the known history (dating back to the 1980s that have been repeatedly discussed and evaluated), and, in doing so, took into account the <u>applicable</u> ASME recommendations and widely-accepted industry standards for creep detection.

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[74] Ex. 7 at 16 (Undeland Direct).
[75] *Id*. at 16.
[76] Exs. 14 and 15 at 31 (Undeland Rebuttal) (Public and Nonpublic).
[77] Ex. 7 at 25 and 34, Schedule 3 at 7 and 11 (Undeland Direct); Exs. 14 and 15 at 31 (Undeland Rebuttal) (Public and Nonpublic).
[78] *Id*.
[79] ALJ Report at ¶ 107.

As discussed above, ASME B31.1 Appendix V-8 specifically recommends a five-year frequency for inspection of piping that is subject to corrosion, which is not the case for the BEC4 HRH line since it carries only superheated dry steam. If ASME intended to recommend a similar minimum inspection frequency for creep damage, it would have explicitly done so. But ASME B31.1 Appendix V-12 – which relates to creep damage inspection and, thus, is the ASME guideline applicable to the BEC4 HRH line inspection program – does not set forth a minimum frequency for examination. Instead, Appendix V-12.1.1 indicates that operating companies "should periodically select high-priority creep damage areas for examination . . . ."[80] 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."[81] 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."[82] Additionally, these portions of the ASME Code are recommendations for operator consideration and not compliance standards.

Consistent with the recommendations of ASME B31.1 Appendix V-12, and in response to the known history of HRH line failures, Minnesota Power utilized a detailed risk-based analysis to develop the protocol and frequency for inspection of its HEP system, including the HRH line. As recently as 2010, Minnesota Power worked with its expert consultant Sargent & Lundy to identify the amount of stress on all areas of the HEP systems at Boswell.[83] Minnesota Power's

[80] Ex. 15, Rebuttal Schedule 2 at 6 (Undeland Rebuttal) (Nonpublic).
[81] *Id.*
[82] *Id.*, Rebuttal Schedule 2 at 7; Exs. 14 and 15 at 21 (Undeland Rebuttal) (Public and Nonpublic).
[83] Ex. 7 at 17 (Undeland Direct).

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 ASME B31.1 Appendix V-12.5.[84] 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 based upon relative risk.[85] The vertical HRH 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.[86] This method of risk-based inspection scheduling is entirely consistent with the practices recommended in Appendix V-12 of the ASME Code and with the practices of Thielsch's 50 other utility customers.

Minnesota Power utilized the advice of Thielsch, Sargent & Lundy, and FM Global, as well as taking into account past inspection results, the HEP system stress and risk analysis, known areas of concern, and industry bulletins when developing its HRH inspection program.[87] Given this information, Minnesota Power was justified in determining that a ten-year HRH line inspection interval was consistent with good utility practice and would accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition.[88]

The AJL's conclusion that Minnesota Power should have used a five-year inspection frequency for HRH line inspections constitutes a substitution of perfect hindsight judgment for the

[84] *Id*. at 16.
[85] *Id*.
[86] *Id*. at 17.
[87] Exs. 14 and 15 at 22 (Undeland Rebuttal) (Public and Nonpublic).
[88] *Id*. at 18.

decision that Boswell's engineers and managers made given the information it had at the time. That is not the applicable standard of review.

Minnesota Power has demonstrated both: (1) its HEP and HRH inspection protocol was consistent with the practices of a substantial portion of the electric utility industry; and (2) the Company's decision to implement a risk-based HEP inspection program that called for inspection of the low-risk vertical HRH line every ten years, while the higher risk areas of the HEP were inspected between every two to five years, was reasonable given its consistency with ASME guidance, the expert input from consultants like Sargent & Lundy and Thielsch, decades of experience and industry involvement of plant personnel, the review and approval of FM Global, and the information known at the time the decision was made. Accordingly, Minnesota Power's HRH line inspection program was consistent with "good utility practice" under either prong of the parties agreed upon definition of the term.

B. The Cost of Implementing a Five-Year HRH Line Inspection Frequency Would Have Been Significant

The Department argued, and the ALJ agreed, that Minnesota Power did not produce specific evidence to show the additional cost of a five-year HEP inspection protocol would have outweighed the benefits of implementing such a program.[89] As a primary matter, Minnesota Power does not have to demonstrate that a five-year inspection interval would be cost-prohibitive to prove that its ten-year inspection interval (with higher risk areas inspected more often over that period) is consistent with good utility practice. As discussed above, Minnesota Power provided sufficient evidence to show that its HRH line inspection protocol and frequency was consistent with a significant portion of the utility industry. The cost of the inspection protocol is irrelevant to this inquiry.

[89] ALJ Report at ¶¶ 99-101.

Additionally, Minnesota Power did not submit specific estimates or records of third party bids because the Company did not conduct a formal cost-benefit analysis of implementing a five-year phased array ultrasonic 100 percent HRH line inspection at the time the Company's inspection protocol was developed as such a methodology was already known within the industry to not be the absolute expectation, but was merely one approach to a risk-based decision tree analysis.[90] Minnesota Power believed that a formal cost-benefit analysis using a "probabilistic risk analysis" was not necessary or even appropriate because, based upon the experience of the Boswell personnel, it was clear that the cost of implementing a five-year inspection frequency would have been significantly more than the potential benefit.[91] This conclusion is supported by more than sufficient evidence in the record that demonstrates that a significant portion of the industry views EPRI's five-year 100 percent phased array ultrasonic inspection recommendation to be cost-prohibitive, which EPRI openly acknowledged.

1. The $35,000 Quote from Thielsch Did Not Represent the Cost of Implementing EPRI's HRH Line Inspection Recommendations

To cast doubt that inspection of the HRH line on a more frequent basis would have been cost-prohibitive, Mr. Polich claimed in his Direct Testimony that Thielsch "offered to inspect the vertical section of the hot reheat pipe for $35,000."[92] The ALJ found this "quote" from Thielsch to be persuasive.[93] But the $35,000 number came from a few sentence email that does not contain nearly sufficient detail to discern what was covered by the quote, much less to which facility the quote applied.[94] The entirety of the supposed "quote" reads as follows:

> The vertical riser is typically subject to the lowest operational stresses, therefore it is often the lowest priority in the inspection

[90] Exs. 14 and 15 at 29 (Undeland Rebuttal) (Public and Nonpublic).
[91] *Id*. at 15-16, 29.
[92] Exs. 10 and 11 at 15 (Polich Direct) (Public and Nonpublic).
[93] ALJ Report at ¶¶ 99-101.
[94] Exs. 10 and 11, Schedule 3 (Polich Direct) (Public and Nonpublic).

> scheme. Our budgetary proposal focused on the upper horizontal section including the bend at the top of the riser.
>
> If you wanted to include the vertical riser, to get the balance of the system complete, then include and [sic] additional 35 K to the inspection budget.[95]

This so-called "quote" does not identify the type of inspection that was being conducted (i.e. visual, boat samples, phased array ultrasonic testing, etc.), whether it was spot inspections or covered the entire vertical HRH line (or what "balance of the system" referred to in that regard), which Boswell unit was at issue, or even which facility was being inspected. Notably, the four-line email was sent on April 12, 2013, but, as Mr. Polich identified in his Direct Testimony, Thielsch conducted HEP inspections at BEC4 in "September 2010, April 2012, August 2015, and October 2017."[96] Thus, this email did not even apply to the BEC4 HRH line.

Mr. Polich also testified that the inspections performed by Thielsch at BEC4, listed above, did not include the type or extent of inspections that he believed were called for by EPRI's guidelines.[97] The "quote" cited by Mr. Polich was almost certainly not for the type or scope of inspection he believes should have been utilized given that methodology was not used by Minnesota Power at the time. Additionally, the email did not address the costs of scaffolding, removing insulation, surface preparation, reinsulating, removing the scaffolding, and potentially extending an outage to complete the full inspection, which is often five to ten times the cost of the inspection itself.[98]

In sum, the "quote" touted by Mr. Polich is entirely unrelated to what it would actually cost to implement 100 percent phased array ultrasonic testing of all HEP (not just HRH) at BEC4 at

[95] *Id*.
[96] *Id*.; Exs. 10 and 11 at 26 (Polich Direct) (Public and Nonpublic).
[97] Exs. 10 and 11 at 26 (Polich Direct) (Public and Nonpublic).
[98] Exs. 14 and 15 at 28 (Undeland Rebuttal) (Public and Nonpublic); Ev. Hrg. Tr. at 33 (Undeland).

least every five years. The ALJ erred in relying upon the so-called "$35,000 quote" cited by Mr. Polich.

2. EPRI Publication Estimates $5 Million to Implement Five-Year HRH Line Inspection Frequency

EPRI's 2017 30 Year Report describes EPRI research and case studies of historical HEP failures across the industry and discusses changes in the life management approach to long-seam welded piping systems.[99] The 30 Year Report was relied upon by Mr. Polich and cited by the ALJ in discussing the history of HEP failures in seam-welded pipe.[100] Near the end of the 30 Year Report, in a section titled "Future Work and Research Priorities," EPRI acknowledged that many in the industry view its recommended HRH inspection frequency to be too expensive. Specifically, the 30 Year Report states:

> Increasingly, economic pressure on end-users is necessitating a reevaluation of legacy guidelines for inspection of long-seam welded components. In particular, 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.[101]

When asked about this conclusion in EPRI's 30 Year Report, 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."[102] 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

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[99] Exs. 14 and 15, Rebuttal Schedule 1 at 399 (Undeland Rebuttal) (Public and Nonpublic).
[100] ALJ Report at ¶ 68.
[101] Exs. 14 and 15 at 25, Rebuttal Schedule 1 at 427 (Undeland Rebuttal) (Public and Nonpublic).
[102] Ev. Hrg. Tr. at 69-70 (Polich).

standards. The fact that utilities believe that a five-year inspection cycle is cost-prohibitive demonstrates that a significant portion of the industry does not believe that it would be reasonable and prudent to follow that EPRI recommendation.

Minnesota Power does not assert that the cost of implementing EPRI's five-year 100 percent phased array ultrasonic HRH line inspection recommendations would be exactly $5 million. Rather, the Company merely used the estimate published by EPRI to point out the ridiculousness of Mr. Polich's claim that an HRH inspection can be completed for $35,000, and to demonstrate that it was reasonable for Minnesota Power to determine that the costs would outweigh the potential benefits. Further, if EPRI believed that the $5 million estimate was materially incorrect, it is extremely unlikely that it would have published the estimate, or, at a minimum, it would have included such a clarification.

Using EPRI's $5 million estimate as an example, the cost of implementing a five-year HRH inspection cycle using phased array ultrasonic testing would have exceeded ten million dollars within a decade at a single facility.[103] If the same inspection protocol was applied to BEC3 and BEC4, as well as Minnesota Power's former generation facilities with seam welded HRH systems that have recently been retired as part of the Company's transition to renewable energy such as BEC1 and BEC2, the cost of implementation across all of Minnesota Power's applicable generation resources would have been substantial.[104] In fact, using this estimate for only BEC3 and BEC4, alone, the inspections would have totaled approximately $20 million ($5 million for each five-year cycle for each HRH line system) over the last 10 years. By comparison, the Company has incurred $6.6 million[105] inspecting the HRH over the last 10 years and the 2019

[103] Exs. 14 and 15 at 29 (Undeland Rebuttal) (Public and Nonpublic).
[104] *Id.*
[105] *Id.*

unplanned outage required obtaining replacement power at a cost of $4,482,456.[106] As this was the only significant unplanned outage of any of the HRH lines in the four units at Boswell in its 40-years of operation, the EPRI frequency and methodology would dwarf costs incurred to date by Minnesota Power. If the cost estimate published by EPRI in the 30 Year Report is even in the ballpark of the actual costs of implementation, then Minnesota Power's conclusion that the costs would outweigh the potential benefits was certainly reasonable.

C. <u>The ALJ's Recommendation Will Significantly Increase Maintenance Costs</u>

Beyond merely affecting the facilities and systems at issue in this proceeding, the ALJ's conclusions and recommendations would necessarily change how Minnesota Power, and likely other Minnesota utilities, develop and implement maintenance and inspection programs for all generation facilities. If the Company may no longer rely upon information provided by a recognized experts and deeply experienced and educated plant personnel in determining what practices are common and accepted throughout the industry, Minnesota Power will have to either engage multiple experts and implement the most stringent and fulsome recommendations or spend the considerable amount of time and money necessary to develop in-house expertise in all areas affecting its generation fleet. Either of these outcomes would be unnecessarily costly.

Additionally, if the minimum requirements for good utility practice are determined by the most rigorous recommendations published by a trade group, Minnesota Power will have to become a member of, and pay for all subscriptions from, all applicable trade groups and implement the highest published standard. This will considerably increase the Company's industry group membership and maintenance and inspection budgets going forward.

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[106] *Id.*

Ultimately, the ALJ's conclusions and recommendations have the potential to significantly increase maintenance and inspection costs for Minnesota Power and other Minnesota utilities. The Commission should adopt Minnesota Power's proposed revisions and additions to the findings, conclusions, and recommendations in order to affirm that utilities may rely upon information and advice obtained from industry experts and need not implement "best" industry practices to be consistent with good utility practice.

III. CONCLUSION

Minnesota Power respectfully takes exception to the foregoing Findings of Fact, Conclusions of Law and Recommendation in the ALJ Report. Based on the record and the arguments presented in this proceeding, Minnesota Power requests that the Commission find that Minnesota Power's maintenance and inspection practices were consistent with good utility practice and replacement power costs for the unplanned outages that occurred during the AAA evaluation period of July 1, 2018 through December 31, 2019, were reasonably and prudently incurred for the benefit of Minnesota Power's customers. Minnesota Power has provided as **Attachment A** to this filing a set of proposed revisions to the ALJ Report consistent with these Exceptions.

Dated: August 31, 2021

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OAH Docket No. 82-2500-37082
MPUC Docket No. E999/AA-20-171

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Review of the July 2018–December 2019 Annual Automatic Adjustment Reports

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 was assigned to the matter. The Commission directed the Administrative Law Judge 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.[1]

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. Were Minnesota Power's forced outage costs for July 2018 through December 2019 reasonable and prudent, applying good utility practice?

[1] Ex. 1 (Order Accepting 2018-2019 Electric AAA Reports; Notice of and Order for Hearing at 4 (Sept. 16, 2020) (Order for Hearing)). The exhibits can be found in the Stipulated Exhibit List (eDocket No. 20216-174787-01). Unless otherwise noted, the citations provided are to the public versions of exhibits.

2. If not, what is 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 Administrative Law Judge (ALJ) recommends that the Commission find that the costs of Minnesota Power's maintenance activities and forced outage events ~~relating to hot reheat lines at Boswell Unit No. 4~~ were ~~not reasonably and prudently incurred applying good utility practice. The Administrative Law Judge further recommends the Commission find outages stemming from stopping a hydrogen leak and the subsequent and related replacement of its generator phase bushings at Boswell Unit No. 3's was~~ reasonably and prudently incurred, applying ~~not inconsistent with~~ good utility practices.

2. Based on the above recommendations, the ALJ recommends the Commission order the Company's forced outage costs~~, including interest, associated with Boswell Unit No. 4's hot reheat line outage~~ should not be refunded to ratepayers.

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

FINDINGS OF FACT

I. Procedural History

1. Minn. R. 7825.2800-.2830 (2021) require natural gas and electric utilities implementing automatic adjustments in the recovery of fuel purchases to file annual automatic adjustment reports.[2]

2. Minnesota Power filed its Annual Automatic Adjustment (AAA) of Charges Report on March 2, 2020, pursuant to Minn. R. 7825.2800-.2830.

3. On April 15, 2020, the Department filed its Review of the July 2018-December 2019 Annual Automatic Adjustment Reports.[3]

4. On April 30, 2020, Minnesota Power filed Reply Comments in which it provided additional information requested by the Department in its Report.[4]

5. On May 29, 2020, the Department filed its Response Comments.[5]

[2] Minn. R. 7825.2800-.2830 (2021).
[3] Review of the July 2018-December 2019 Annual Automatic Adjustment Reports (Apr. 15, 2020) (eDocket No. 20204-162132-02).
[4] Minnesota Power Reply Comments (Apr. 30, 2020) (eDocket No. 20204-162709-01).
[5] Department Response Comments (May 29, 2020) (eDocket No. 20205-163578-01).

6. On June 10, 2020, Minnesota Power filed a supplement to the 2020 AAA Report.[6]

7. On July 1, 2020, Minnesota Power filed Additional Comments in response to the Department's May 29, 2020 Response Comments.[7]

8. On July 24, 2020, the Department filed Additional Response Comments in response to the Company's July 1, 2020, Additional Comments.[8]

9. On July 31, 2020, Minnesota Power filed a letter in response to the Department's Additional Response Comments of July 24, 2020.[9]

10. 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 [fuel clause adjustment] (FCA)."[10]

11. The Order for Hearing established Minnesota Power and the Department as parties to this proceeding.[11]

12. The Commission also noted that the Department could seek authorization to retain an outside engineering expert to assess whether Minnesota Power's maintenance activities and force outage events were consistent with good utility practice.[12] 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.[13] To accommodate the need to retain an expert, the parties agreed to modify the procedural schedule.[14] The Administrative Law Judge issued a Second Prehearing Order with the modified procedural schedule.[15]

13. In February 2021, the Department informed the Office of Administrative Hearings that it had retained engineering consulting firm GDS Associates, Inc.[16] Mr. Richard Polich of GDS Associates assisted the Department in conducting an

[6] 2020 AAA Report Supplement (June 10, 2020) (eDocket No. 20206-163842-01).
[7] Minnesota Power Additional Comments (July 1, 2020) (eDocket No. 20207-164474-01).
[8] Department Additional Response Comments (July 24, 2020) (eDocket No. 20207-165268-01).
[9] Minnesota Power Letter (July 31, 2020) (eDocket No. 20207-165493-01).
[10] Ex. 1 at 4-5 (Order for Hearing).
[11] *Id.* at 7.
[12] *See id.* at 5.
[13] Department Extension Request (Dec. 7, 2020) (eDocket No. 202012-168840-01).
[14] *Id.*
[15] Ex. 4 (Second Prehearing Order)
[16] Department Protective Agreement Cover Letter (Feb. 2, 2021) (eDocket No. 20212-170635-01).

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.[17]

14. Mr. Polich is the managing director of GDS Associates, Inc., a consulting and engineering firm. Mr. Polich earned a Bachelor of Science in Mechanical Engineering in 1979, and a Bachelor of Science Nuclear Engineering in 1979, and a Master of Business Administration in 1990, all from the University of Michigan in Ann Arbor, Michigan. He is a registered Professional Engineer in the State of Michigan and has over 40 years of experience in the utility industry and energy sector, performing duties and services for a myriad of companies and organizations.[18]

15. On September 30, 2020, LPI petitioned to intervene.[19]

16. On October 14, 2020, LPI moved to admit Jessica L. Bayles pro hac vice.[20]

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

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

18. On January 26, 2021, Minnesota Power filed the direct testimony and schedules of Todd Z. Simmons,[22] William Poulter,[23] Paul J. Undeland,[24] Leann Oehlerking-Boes,[25] and Joshua G. Rostollan.[26]

[17] Ex. 10 at 1 (Polich Direct).
[18] *Id.* at 1-2, RAP-1.
[19] LPI Petition to Intervene (Sept. 30, 2020) (eDocket No. 20209-166962-02).
[20] LPI Motion for Admission of Jessica L. Bayles Pro Hac Vice (Oct. 14, 2020) (eDocket No. 202010167280-01).
[21] Ex. 4 (Second Prehearing Order).
[22] Ex. 5 (Simmons Direct).
[23] Ex. 6 (Poulter Direct).
[24] Ex. 7 (Undeland Direct).
[25] Ex. 8 (Oehrlinking-Boes Direct).
[26] Ex. 9 (Rostollan Direct).

19. On April 19, 2021, the Department filed the direct testimony and attachments of Richard A. Polich[27] and Nancy A. Campbell.[28]

20. On May 12, 2021, the Department filed errata to the direct testimony of Richard A. Polich.[29]

21. On May 24, 2021, Minnesota Power filed the rebuttal testimony and schedules of Paul J. Undeland,[30] Leann Oehlerking-Boes,[31] and Joshua G. Rostollan.[32]

22. On May 27, 2021, Minnesota Power filed errata to the direct testimony of Joshua G. Rostollan.[33]

23. On May 28, 2021, the Administrative Law Judge convened a status conference by telephone.[34]

24. On June 3, 2021, the Administrative Law Judge held a one-day evidentiary hearing via Microsoft Teams.[35]

25. On June 28, 2021, Minnesota Power, the Department, and LPI filed initial post-hearing briefs.

26. The parties filed reply briefs on July 12, 2021.

II. BACKGROUND

27. Under Minn. Stat. § 216B.16, subd. 7 (2020), and Minn. R. 7825.2390-.2920 (2021), rate-regulated gas and electric utilities may adjust their rates between general rate cases to reflect fluctuations in energy-related costs—that is, the prices they pay for gas or electricity purchased for delivery to ratepayers, or for fuel purchased to generate electricity for ratepayers. These adjustments are called automatic adjustments because a utility generally implements these rate changes in advance of Commission approval.[36]

28. The adjustments automatically affect retail rates and some wholesale transactions. The tariffs of each regulated electric utility contain a fuel clause adjustment (FCA) mechanism setting forth the formula for making adjustments to the utility's retail rates to reflect changes in the utility's energy-related costs. And the terms of each wholesale transaction govern whether and how fluctuations in energy-related costs alter the amount charged to a wholesale customer. Commission rules require utilities to make

[27] Exs. 10, 11 (Polich Direct) (Public and Nonpublic).
[28] Exs. 12, 13 (Campbell Direct) (public and Nonpublic).
[29] Exs. 10, 11 (Polich Direct Errata) (Public and Nonpublic).
[30] Exs. 14, 15 (Undeland Rebuttal) (Public and Nonpublic).
[31] Exs. 16, 17 (Oehlerking-Boes Rebuttal) (Public and Nonpublic).
[32] Ex. 18 (Rostollan Rebuttal).
[33] Ex. 9 (Rostollan Direct Errata).
[34] *See* Ex. 4 (Second Prehearing Order).
[35] *See id.*
[36] Ex. 1 at 2 (Order for Hearing).

detailed filings supporting each automatic adjustment. They also require utilities to make comprehensive annual filings reporting on all automatic adjustments made during a specified twelve-month period.[37]

29. The automatic adjustment rules direct public utilities to make an annual filing (Annual Automatic Adjustment or AAA report) including certain categories of information required in the rules. Over the years, the Commission has ordered utilities to provide reports on other topics, such as costs and revenues related to their interaction with the Midcontinent Independent System Operator (MISO) and certain auxiliary businesses. Most relevant for this matter, the Commission directed Minnesota Power and other Companies to report the amount that each utility spends for maintaining its plant, as well as the maintenance budget that ratepayers provide to each utility, as reflected in the utility's last rate case. The Department then compares this data with data about unplanned (or forced) outages in the utility's plant. When a utility's plant cannot operate, the utility may need to buy replacement energy from the wholesale market—and the FCA causes ratepayers to bear the cost of this replacement energy.[38]

30. Historically, even when there has been evidence of actual mistakes leading to outages, the Commission has not required refunds of forced outage costs.[39] As an example, Minnesota Power cited a case where the Department recommended refunds of forced outage costs resulting from an Allen wrench falling into a duct at a generating station. There the Commission declined to require a refund stating, "[t]he record in this docket does not contain detail sufficient ...to resolve disputes of fact necessary to finally determine the prudence of the utilities' plant operation and maintenance." The Commission further stated, "[t]he prudence of costs related to the forced outages identified by the Department remain subject to review by the Commission at a future date."[40]

31. Commission staff note the Department has been concerned for several years that, because the utilities can automatically recover the cost of replacement power through automatic fuel clause adjustments, utilities may not be adequately spending money budgeted for operation and maintenance of their generating plants and therefore not optimizing the plants' availability.[41]

32. In a February 6, 2008, Order in Docket No. E-999/AA-06-1208 (the 06-1208 Order), the Commission declared that "utilities have a duty 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."[42]

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[37] *Id.*
[38] *Id.* at 2-3.
[39] *See In re Review of the 2010-2011 Annual Automatic Adjustment Reports for all Elec. Utils.*, MPUC Docket No. E-999/AA-11-792, Order Acting on Electric Utilities' Annual Reports at 5 (Aug. 16, 2013).
[40] *Id.*
[41] *See* Staff Briefing Papers at 1 (Aug. 20, 2020) (eDocket No. 20208-165810-01).
[42] *In re Review of the 2006 Annual Automatic Adjustment of Charges for All Electric and Gas Utilities*, MPUC Docket No. E-999/AA-06-1208, Order Acting on Electric Utilities' Annual Reports, Requiring Further Filings,

To 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—the Commission monitors utility expenditures related to maintenance and forced outages.[43]

33. This requirement stems from a noticeable increase in Independently Owned Utilities' (IOUs) outage costs during Fiscal Year (FY) 06 and FY07. When a 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 FCA directly to ratepayers. The high level of outage costs in FYE06 and FYE07 raised the issues of whether plants were being maintained appropriately to prevent forced outages, and whether IOUs were spending as much on plant maintenance as they were charging to their customers in base rates.

34. Also, in the 06-1208 Order, the Commission considered additional reporting on outage issues, developing benchmarks to quantify acceptable outage performance, and creating financial incentives to keep scheduled and unscheduled outages within specified parameters. The Commission noted that while the utilities did not object to providing more detailed data, they did oppose benchmarks, contending that unscheduled outages were situation specific and do not readily fall into a handful of pre-established categories. The utilities also contended that there was no evidence that utilities were not managing outages, scheduled and unscheduled, competently, and resourcefully. The Commission decided it would "require additional 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" to inform the ongoing investigation into the appropriateness of automatic adjustments for electric utilities.[44]

35. Minn. R. 7825.2390-.2920 direct applicable utilities to adjust their FCA amount monthly, and to draft their AAA reports to address the period from July 1 to June 30 (the fiscal year). But in 2018, in a matter titled *In re an Investigation into the Appropriateness of* Continuing *to Permit Electric Energy Cost Adjustments*,[45] the Commission varied its rules and directed the Companies, starting January 1, 2020, to begin making these adjustments annually, and to report these changes on the basis of a calendar year rather than a fiscal year.[46] To transition to this new regulatory regime, the Commission directed the Companies to draft their next AAA report to cover the period July 2018 through December 2019—that is, the final 18 months in which they would make monthly adjustments.[47]

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and Amending Order of December 20, 2006 on Passing MISO Day 2 Costs Through Fuel Clause at 5 (Feb. 6, 2008).

[43] Ex. 1 at 3 (Order for Hearing).

[44] *In re Review of the 2010-2011 Annual Automatic Adjustment Reports for all Elec. Utils.*, MPUC Docket No. E-999/AA-11-792, Order Acting on Electric Utilities' Annual Reports at 5 (Aug. 16, 2013).

[45] *In re an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments*, MPUC Docket No. E-999/CI-03-802, Order Revising Implementation Date, Establishing Procedural Requirements, and Varying Rule (Dec. 12, 2018).

[46] *Id.* at 7.

[47] *Id.*; *see also* Ex. 1 at 3-4 (Order for Hearing).

36. Minnesota Power's AAA Report, at issue in this matter, included a section addressing forced or unplanned outage events between July 2018 and December 2020 as required by the 06-1208 Order.[48] In the AAA Report, Minnesota Power identified 26 different forced outage events during the reporting period.[49]

37. A forced or unplanned outage event is a situation where an electrical generating unit is removed from service for emergency reasons, for example due to a component failure or other condition requiring removal outside of a planned maintenance or planned outage period. Forced outages may result in a utility incurring forced outage expenses when its own generation facilities are not available for service. These forced outage expenses might include higher replacement power costs.[50] Minnesota Power reported $7.727 million in replacement power costs that were ultimately charged to retail customers through its Fuel and Purchased Energy Adjustment Rider (Fuel Adjustment Clause Rider or FAC Rider) associated with the forced outages.[51]

38. The Department filed a Review of the July 2018-December 2019 Annual Automatic Adjustment Reports with the Commission on April 15, 2020, that assessed the compliance of various filings made by the utilities and the reasonableness of costs charged by utilities to retail customers through automatic 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."[52]

39. After reviewing Minnesota Power's AAA Report, the Department concluded that the Company's purchased power costs had increased significantly in ~~2019~~ 2018 and ~~2020~~2019. 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 percent higher in 2019 than 2018.[53] 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 and provide any plant outages information for February 2019, in its

[48] Minnesota Power's 2018-2019 Annual Automatic Adjustment of Charges Report at 206-08 (Mar. 2, 2020) (eDocket No. 20203-160872-01).
[49] *Id.*
[50] Ex. 12 at 6-7 (Campbell Direct).
[51] Minnesota Power's 2018-2019 Annual Automatic Adjustment of Charges Report at 206-08 (Mar. 2, 2020) (eDocket No. 20203-160872-01).
[52] Review of the July 2018-December 2019 Annual Automatic Adjustment Reports at 12 (Apr. 15, 2020) (eDocket No. 20204-162132-02).
[53] *Id.* at 22, 51.

reply comments.[54] The Department also requested that Minnesota Power provide information comparing budgeted to actual generation maintenance expense.[55]

40. On April 30, 2020, Minnesota Power filed reply comments to the Department's comments, providing actual 2019 Generation and Maintenance Expenses and explaining the cost increases were caused by "significant outages" at its Boswell Energy Center in 2019. The Company explained that the coal plant had outages in February (26 days), March (29 days), June (22 days), and July (20 days). Specifically, in February 2019 Boswell Unit No. 4 had a major unplanned outage to repair a hot reheat line steam leak. As a result, Minnesota Power was required to procure power necessary to serve customers from MISO's wholesale energy markets due to having less company generation to serve load.[56] The Company also provided information regarding actual and budgeted maintenance expenses.[57]

41. On June 10, 2020, Minnesota Power filed a supplement to the 2020 AAA report. The filing explained that the original Schedule 15 included with its AAA Report incorrectly understated "the Boswell Unit No. 4 Unplanned Outage related to the Hot Reheat Line Steam Leak . . . by 368,136 MWhs [(Megawatt hours)]."[58]

42. After reviewing Minnesota Power's filings, the Department shared response comments on July 24, 2020, that found: (1) the Company's forced outage costs were "approximately 500 percent higher in the current AAA compared to the average of the past two AAA filing periods," (2) Minnesota Power underspent its annual $42 million generation maintenance budget by 21.9 percent in 2018 and 2019, and (3) the Company passed $7.727 million in forced outage costs onto customers through its FAC Rider.[59]

43. The Department recommended that the Commission deny recovery of 50 percent of Minnesota Power's forced plant outage costs for a resulting refund of $3.864 million in forced outage costs from the fuel clause adjustment.[60] The Department considered it inequitable for Minnesota Power to keep the lower spending levels of $21.6 million for generation maintenance expenses in 2018 and 2019, at the same time as ratepayers were being charged significantly higher replacement power for forced outages.[61]

44. 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

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[54] *Id.* at 32.
[55] *Id.* at 13.
[56] Minnesota Power Reply Comments at 3-4 (Apr. 30, 2020) (eDocket No. 20204-162709-01).
[57] *Id.* at Attachment A.
[58] 2020 AAA Report Supplement at 1 (June 10, 2020) (eDocket No. 20206-163842-01).
[59] Department Additional Response Comments at 2 (July 24, 2020) (eDocket No. 20207-165268-01).
[60] *Id.*
[61] *Id.*

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."[62]

45. The parties to this matter agree that 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, 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.[63] Furthermore, "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.[64]

46. Utilities are entitled to recover their "revenue requirement" from their customers.[65] 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.[66]

47. 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.[67] This test year data is then used to determine the utility's revenue requirement and resulting rates charged to ratepayers.

48. 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 generation power plant maintenance expense.[68] This amount effectively serves as the Company's annual maintenance budget for

[62] Ex. 1 at 4 (Order for Hearing).
[63] Ex. 10 at 6-7 (Polich Direct); Ex. 14 at 7-8 (Undeland Rebuttal).
[64] Ex. 10 at 7 (Polich Direct).
[65] *See* Minn. Stat. § 216B.16 (2020).
[66] Ex. 12 at 3-4 (Campbell Direct).
[67] Minn. R. 7825.3100, subp. 17 (2021).
[68] Ex. 12 at 8 (Campbell Direct).

generation plants. However, the utility's spending may either drop below or exceed this budgeted amount depending on its actual maintenance needs each year.[69]

49. 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.[70] Permanent cost recovery, however, is not guaranteed. Instead, rider costs are provisionally charged to customers subject to Commission review and possible refund.[71] The Fuel and Purchased Energy Adjustment Rider, for example, allows a utility to recover actual fuel expenses and purchased power costs from customers.[72]

50. 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.[73] Accordingly, the Commission "monitors utility expenditures related to maintenance and forced outages" to "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."[74] 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."[75] The Commission has further explained, "generation-facility outage costs merit careful scrutiny, given their potentially substantial impact on ratepayers."[76]

51. In this case, the Commission found a genuine issue of material fact in dispute about 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. Therefore, the Commission referred this matter to the Minnesota Office of Administrative Hearings for a contested Case proceeding ordering Minnesota Power to bear the burden of proving that any or all of its forced outage costs were reasonably and prudently incurred, applying good utility practices.[77]

III. Minnesota Power's Forced Outages at Boswell

52. Minnesota Power's AAA Report identified 26 different forced outage events during the July 2018 through December 2019 reporting period. All of the forced outages

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[69] *See id.* at 24; Ex. 9 at 23 (Rostollan Direct).
[70] Ex. 12 at 4 (Campbell Direct).
[71] Minn. Stat. § 216B.16, subd. 7(1) (2020) (authorizing rider cost recovery); Minn. R. 7825.2920 (2021) (provisionally approving rider costs subject to further review).
[72] Ex. 12 at 4 (Campbell Direct); *see also* Minn. Stat. § 216B.16, subd. 7(1).
[73] Ex. 12 at 5 (Campbell Direct).
[74] Ex. 1 at 3 (Order for Hearing).
[75] *In re 2006 Annual Automatic Adjustment of Charges for All Elec. & Gas Utils.*, MPUC Docket No. E-999/AA-06-1208, Order Acting on Electric Utilities' Annual Reports at 5 (Feb. 6, 2008).
[76] *Id.*
[77] Ex. 1 at 4 (Order for Hearing).

occurred at Minnesota Power's Boswell coal-fired power plant located in Cohasset, Minnesota. Boswell is Minnesota Power's largest thermal facility and at its peak generated coal-fired power from four operating units, which were constructed between 1958 to 1980. Two of the generating units, Boswell Unit Nos. 1 and 2, were retired from operation in 2018. The two remaining units Boswell Unit Nos. 3 and 4, with a combined generating capacity of approximately 823 MW, have historically provided approximately half the energy needs of Minnesota Power's customers. Boswell Unit No. 3 was commissioned in 1973 and Boswell Unit No. 4 in 1980. Both units have undergone major environmental retrofits, completed in 2009 and 2015 respectively.[78]

53. During the period at issue here, there were 16 forced outages due to boiler tube leaks, two forced outages due to condenser tube leaks, one forced outage to clean the Boswell Unit No. 4 condenser, a forced outage caused by seal failure in a circulating water pump at Boswell Unit No. 3, a forced outage due to a leak in the blowdown flash tank on Boswell Unit No. 4, a forced outage due to hot reheat pipe failure on Boswell Unit No. 4, extension of the spring 2019 Boswell Unit No. 3 outage to complete leak repairs on a generator hydrogen cooling system, and a forced outage to replace oil soaked line-side phase bushings on the "A" phase of the Boswell Unit No. 3 generator.[79]

54. On behalf of the Department, GDS Associates reviewed all of Minnesota Power's forced outages at Boswell Unit Nos. 3 and 4 during the relevant period to determine whether 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.[80] 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.[81]

55. Based on its review GDS did not find any systemic causes, maintenance practices, or commonality trends for the types and frequency of the boiler tube leaks, condenser outages, or the boiler circulating pump outage and found that Minnesota Power's practices concerning these components during the period at issue were consistent with good utility practices.[82] 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

[78] Ex. 6 at 2-3 (Poulter Direct).
[79] Ex. 10 at 16-17 (Polich Direct).
[80] *Id.*
[81] Ex. 1 at 4-5 (Order for Hearing); Ex. 12 at 11 (Campbell Direct).
[82] Ex. 10 at 17-18 (Polich Direct).

and should have noted the frequency of problems in the years leading up to the outage.[83] The Department, however, did not recommend that Minnesota Power refund these outage costs because GDS did not conclude that Minnesota Power's conduct was inconsistent with good utility practice.[84]

56. There were forced outages in each of the 4 Boswell units between July 1, 2018, through December 31, 2019.[85] The Department's concerns are focused on three outages that occurred at Boswell Unit Nos. 3 and 4.[86] GDS 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.[87] 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.[88]

57. Boswell Unit No. 3 was originally constructed by General Electric Company. There are approximately 30 similar units in the United States. In 2009, the Boswell Unit No. 3 High Pressure-Intermediate Pressure (HP-IP) turbine was retrofitted to an "Alstom design." The Low Pressure (LP) turbine and generator remain original. There are not any identical Alstom units in the United States with this retrofit.[89]

58. Boswell Unit No. 4 was originally constructed by Siemens Westinghouse. This unit has a common HP-IP turbine with dozens constructed in the United States. The two LP turbines were less common. In 2010, the entire rotor train was converted to an Alstom design. The generator was refurbished in 2008 and is the only one like it in the United States.[90]

59. Minnesota Power uses a ten-year long-term outage plan for Boswell centered on performing manufacturer recommended major maintenance on boilers and steam turbines.[91] 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.[92] Minnesota Power witness 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 reference when the last turbine overhaul or boiler chemical clean was completed."[93] Outage

[83] *Id.* at 18-19.
[84] Ex. 12 at 17-18 (Campbell Direct).
[85] Ex. 6 at 2 (Poulter Direct).
[86] *Id.* at 3.
[87] Ex. 10 at 48-49 (Polich Direct).
[88] Ex. 12 at 17 (Campbell Direct); Ex. 10 at 45-46 (Polich Direct).
[89] Ex. 6 at 3 (Poulter Direct).
[90] *Id.* at 4.
[91] Ex. 5 at 7 (Simmons Direct).
[92] *Id.* at 13.
[93] *Id.*

schedules may change during an outage plan, however, due to inspections that discover required work that was not previously identified.[94]

60. While 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.[95]

61. Minnesota Power hires consultants to aid in developing schedules, inspections, and repair plans, if equipment specifications or limitations on in-house knowledge require it.[96] Some maintenance and equipment inspection requires consultants to execute the work or inspection.[97] 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.[98]

62. 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.[99] 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.[100]

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

63. The first outage at issue in this proceeding relates to Boswell Unit No. 4's hot reheat line (HRH line). The HRH line is an approximately 33-inch diameter pipe with about 1.5-inch thick walls.[101] The pipe is more than 640 feet long and spans 20 floors with limited access within the unit.[102] It 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.[103] The pipe used on Boswell Unit No. 4's hot reheat line is a longitudinal seam-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.

94 *Id.* at 14.
95 Ex. 10 at 7-8 (Polich Direct).
96 Ex. 5 at 11 (Simmons Direct).
97 *Id.*
98 *Id.*
99 Ex. 10 at 10 (Polich Direct).
100 *Id.*
101 *Id.* at 20.
102 *Id.*; Ex. 7 at 16 (Undeland Direct).
103 Ex. 10 at 20 (Polich Direct).

These specifications include requirements for the thickness, shape, and width of the longitudinal weld—for high pressure service.[104] Longitudinal seam-welded pipe is formed by rolling plate steel into a pipe shape and welding the seam down the length of the pipe.[105]

64. On February 6, 2019, the HRH steam line experienced a seam weld failure which left a 2-foot-long crack, resulting in high-pressure steam release, which necessitated immediate action to begin shutting down Boswell Unit No. 4.[106] Minnesota Power determined that the leak was a failure of the welded seam of the HRH pipe. Because this is a dangerous failure, Boswell management and engineers organized a complete inspection of the HRH pipe which identified another six areas to be repaired.[107] During the shutdown, the Company replaced three sections of the pipe, approximately 20 feet in length, and repaired the other sections. The unit returned to service on March 27, 2019.[108]

65. The section of the HRH line that failed had last been inspected in 2010 and no actionable defects were discovered at that time. Minnesota Power asserts that it is rare, cost-prohibitive and time consuming to perform a complete inspection of the entire (High Energy Piping) HEP system during a single planned outage. Minnesota Power bases its inspection plans on past results, known areas of risk, industry bulletins, insurance carrier and third-party expert recommendations.[109] Specific to the seam rupture here, the vertical run of pipe where the seam rupture occurred is not considered to be a high stress section of the HRH piping. In general, vertical pipe runs experience lower weight loads and hence lower stress levels. For low stress level locations, Minnesota Power inspections are planned to occur every five to ten years. The location of the failure was identified as a low stress area in pipe inspections dating back to 1985. It had a stress test analysis done by Sargent and Lundy in 2010 and was due for inspection in 2020. No operational issues were observed by the unit's system engineers in the meantime. Minnesota Power established its preventive maintenance (PM) and development of maintenance (PdM) programs for HRH piping systems with the assistance of Thielsch Engineering and with third party consultants, such as Sargent and Lundy who has a recognized program for analyzing pipe stress.[110]

66. When asked why Minnesota Power chose a 10-year inspection frequency given a possible frequency between five and ten years, the Company explained that its ten-year inspection cycle for low stress parts of the pipe was informed by their independent consulting engineer telling the Company that none of the 50 U.S. power companies the consultant worked with inspected 100 percent of their low stress longitudinal seam welds on a five-year cycle. Thielsch told Minnesota Power that its

[104] *Id.* at 20-21.
[105] *Id.* at 21.
[106] Ex. 7 at 15 (Undeland Direct); Ex. 10 at 22 (Polich Direct).
[107] Ex. 7 at 15 (Undeland Direct).
[108] Ex. 10 at 22-23 (Polich Direct).
[109] Ex. 7 at 16 (Undeland Direct).
[110] *Id.* at 16-17.

inspection frequency is consistent with good utility practice among the 50 coal-fired generation facility owners for which they work.[111]

1. Industry Experience with Hot Reheat Line Failures

67. 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.[112]

68. Power plants have been using seam-welded pipe for high pressure and temperature steam (considered "high energy" application) transport since at least the 1940s. Documented failures of seam-welded pipe used in high energy piping started in 1970.[113] Since 1985, the Electric Power Research Institute (EPRI) has documented no less than 42 seam welded high energy pipe failures.[114] In 1985, for example, Southern California Edison – Mohave Generation Station's 30-inch diameter hot reheat line failed killing six people, injuring ten others, and causing an estimated $155 million in plant damage.[115] 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.[116] The failure history of seam- welded pipe led EPRI and ASME to recommend that 100 percent of seam-welded pipe used in high energy processes be inspected at least once every five years.[117]

69. Minnesota Power was aware of industry concerns surrounding hot reheat lines and noted that "HRH piping has been an on-going power generation industry topic for over 30 years."[118] Minnesota Power focused "more direct attention on the high-stress areas," which it describes as those areas "where there are attachments such as pipe hangers or laterals."[119] Minnesota Power indicated that "it is rare for a plant to experience a weld seam failure on a vertical line in a low stress level location."[120]

70. One study noted that, although seam-weld failures may be less common than clamshell welds and girth welds, almost all of the very largest outages involved seam welds.[121]

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[111] *Id.* at 18-19.
[112] *See* Ex. 14, PJU-1 at 401 (Undeland Rebuttal) (*30-Plus Years of Long-Seam Weld Failures in the Power Generation Industry* (30 Year Report)).
[113] Ex. 10 at 22 (Polich Direct).
[114] Ex. 14, PJU-1 at 403 (Undeland Rebuttal) (30 Year Report).
[115] *Id.*, PJU-1 at 405, 410-12, 422.
[116] *See id.* at 399-432.
[117] Ex. 10 at 22 (Polich Direct).
[118] Ex. 6 at 12 (Poulter Direct).
[119] *Id.* at 13.
[120] *Id.* at 5.
[121] Ex. 21 at 4 (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

71. Minnesota Power has had its longest on-going consulting relationship for piping systems and headers with Thielsch Engineering.[122] Following the hot reheat line rupture, Minnesota Power asked Thielsch to assess the failure and determine the extent of the damage.[123] Thielsch began its inspection on February 8, 2019, and released it analysis on February 20, 2019.[124]

72. Thielsch's inspection revealed six additional damaged or degraded pipe sections. Three sections, approximately 20 feet in length, had to be replaced entirely, and an additional three sections with significant transverse cracking were repaired with steel patches that ran along the welded seam of the pipe, 140 feet in length.[125] Thielsch concluded that the hot reheat line's cracking started approximately seven to nine years before the actual rupture.[126]

73. After receiving Thielsch's analysis, Minnesota Power concluded that the hot reheat line failed due to a mechanism called "creep."[127] 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.[128] These cracks begin in the pipe interior and eventually spread to the outside.[129] 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.[130]

74. Phased array ultrasonic examination can locate the voids and microcracks that occur deep within the longitudinal seam-welds of a hot reheat pipe.[131]

75. Thielsch had inspected multiple hot reheat pipe sections in 2012, 2015, and 2017.[132] But these inspections did not include longitudinal seam-weld inspection using ultrasonic examination techniques that could have identified interior cracking or deterioration in the longitudinal seam-welded pipe.[133] In those inspections, Thielsch, used "in-situ metallographic examination" and "magnetic particle inspection" techniques.[134]

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[122] Ex. 6 at 14 (Poulter Direct).
[123] Ex. 10 at 29 (Polich Direct).
[124] *Id.* at 29-30, RAP-6.
[125] *Id.* at 22-23.
[126] *Id.* at 38.
[127] *Id.* at 30, 32-33.
[128] *Id.* at 33
[129] *Id.*; *see also* Ex. 19 at 3-22, 3-23 (EPRI, *Fossil Plant High-Energy Piping Damage: Theory and Practice*).
[130] Ex. 10 at 33 (Polich Direct).
[131] *Id.*; Ex. 14, PJU-1 at 31-32 (Undeland Rebuttal) (EPRI Guidelines).
[132] Ex. 10 at 26 (Polich Direct).
[133] *Id.*
[134] *Id.*

Neither technique, however, can identify cracks or creep deterioration unless those defects are located near the outside pipe surface.[135]

76. On February 22, 2019, EPRI, having learned of the seam rupture, contacted Minnesota Power to see if they could assist.[136] 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.[137] EPRI also requested the failed pipe for their analysis.[138]

77. Later, EPRI provided Minnesota Power with its *High Energy Piping Systems. Still a Clear and Present Danger* presentation.[139] In this presentation to its members, EPRI ~~concluded~~ stated that there was a basis for more frequent inspection of the seam-welded pipe and that 100 percent of the hot reheat line should have been examined at least every five years using phased array ultrasonic examination, which is consistent with EPRI's own recommendations and prior reports.[140]

78. Following EPRI's recommendation, Minnesota Power hired Structural Integrity Associates to perform additional evaluation of the hot reheat pipe.[141]

79. In its report, Structural Integrity questioned why the hot reheat pipe flaws had not been previously found.[142] Structural Integrity concluded that almost all welds had exceeded their calculated life fraction consumed values, but that the model indicated at least some level of continued operation in the pipe.[143] Life fraction consumed values means the portion of the predicted usable life of the pipe that has been used with the pipe in service.[144] 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 percent of the pipe's projected usable life that has been consumed.[145] Structural Integrity also acknowledged that the particular flaws identified in the pipe after the outage occurred "are well outside of SI's experience base. Simply stated, we have not seen this condition previously in what amounts to many miles of seam weld examinations."[146]

80. 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.[147]

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135 *Id.* at 27-28.
136 *Id.* at 30, RAP-8.
137 *Id.* at 30, RAP-9; Ex. 7, PJU-3 at 7 (Undeland).
138 Ex. 10 at 30, RAP-9 (Polich Direct).
139 Ex. 11, RAP-13 (Polich Direct) (Trade Secret). The specific content of the EPRI power point presentation is proprietary and designated as trade secret.
140 Ex. 10 at 22, 28, RAP-13 (Polich Direct).
141 *Id.* at 30, RAP-7.
142 *Id.*, RAP-11 at 61.
143 *Id.* at 34, RAP-11 at 56 and 62.
144 *Id.* at 34.
145 *Id.*
146 Ex. 10 at RAP-11 at 62.
147 ~~*Id.*,~~ Ex. 10 at 34, RAP-11 at 62.

81. Minnesota Power planned to replace the HRH pipe during a spring 2021 outage.[148]

82. Minnesota Power also formed a "Hot Reheat Learning Team" to review the failure, inspections, testing and operation prior to the failure and make recommendations to improve Minnesota Power's high-energy piping program.[149] The Hot Reheat Learning Team compiled a presentation with its findings and recommendations.[150] The team ~~concluded~~ opined that "a stronger and more formalized inspection program would have decreased the chances of failure, however, it is recognized that even with a high quality inspection program, we cannot guarantee that we would have prevented this failure."[151]

3. Minnesota Power's High-Energy Piping Program

83. Minnesota Power maintains that its high energy piping program was consistent with industry practice before the hot reheat line failure.[152] Minnesota Power stated that good utility practice only requires inspections of "those areas that are most likely to have indications," which are visual or operational deviations from what is expected of the equipment.[153] 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. As the pipe ages, the failure mechanism transitions from fatigue into creep." According to Minnesota Power, over time inspections include replication and/or boat samples to detect creep in its earliest stages.[154] 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.[155]

84. Minnesota Power asserts that "[i]t is unknown when, over the nine-year period since the last detailed inspection, the seam weld began to fail."[156]

85. Mr. Polich 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.[157] He also stated 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.[158]

[148] Ex. 7 at 20 (Undeland Direct).
[149] Ex. 10 at 35 (Polich Direct).
[150] *See id.*, RAP-12.
[151] *Id.*, RAP-12 at 12.
[152] Ex. 5 at 20 (Simmons Direct).
[153] *Id.* at 24.
[154] *Id.* at 24-25.
[155] *Id.* at 25.
[156] Ex. 7 at 18 (Undeland Direct).
[157] Ex. 10 at 38 (Polich Direct).
[158] *Id.* at 38, 41.

86. 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.[159]

87. According to Mr. Polich, Minnesota Power should have known that the hot reheat pipe's age and hours of operation were beyond the point that only performing 100 percent inspection of seam-welds once every ten years should have continued.[160] This position is supported by Structural Integrity's finding almost all welds had exceeded their calculated life fraction consumed values.[161]

88. Mr. Polich asserted that all longitudinal seam-welded hot reheat piping should have been inspected at least once every five years using phased array ultrasonic examination.[162] The Department's expert based his recommendation of a five-year full inspection schedule, not ten years as Minnesota Power had been using since 1999,[163] with guidelines from EPRI and recommendations from the ASME Code B31.1, which addresses high pressure piping.[164]

89. "[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."[165] "[F]or fossil power plant inspection, ultrasonic inspection is used primarily for flaw detection, classification, and sizing, and for dimensional measurement (thickness)."[166] Phased array ultrasonic testing is a type of advanced ultrasonic testing.[167] "A phased array system permits the inspection of a cross-sectional area of interest with a minimal number of probe positions."[168]

90. Good utility practice dictates that any evidence of degradation in seam-welded pipe along the longitudinal welds should automatically trigger a more rigorous inspection of the entire pipe.[169]

90a. Mr. Polich asserted that EPRI, a member organization, recommends a five-year 100 percent phased array ultrasonic inspection of all HEP.[170] Mr. Polich, however, clarified this when asked to identify where EPRI's *Guidelines for the Evaluation of Seam Welded High-Energy Piping*, which he cited, is "one of those things that's a bit convoluted

[159] *Id.* at 38.
[160] *Id.*
[161] *Id.* at 34, RAP-11 at 56.
[162] *Id.* at 28.
[163] Ex. 7 at 17-18 (Undeland Direct).
[164] *See* Ex. 22a (ASME Code) (Nonpublic).
[165] Ex. 19 at 10-13 (EPRI, *Fossil Plant High-Energy Piping Damage: Theory and Practice*).
[166] *Id.*
[167] *Id.* at 10-15, 10-20.
[168] *Id.* at 10-20.
[169] Ex. 10 at 39 (Polich Direct).
[170] *Id.* at 37 (Polich Direct); Ex. 14 at PJU-1 at 427 (Undeland Rebuttal).

throughout this document . . . and it's part of a decision tree that you go through to come to this conclusion."[171]

90b. EPRI's own survey of 29 utilities indicated that less than 50 percent of those responding followed EPRI's recommendations stated in its *Guidelines for the Evaluation of Seam Welded High-Energy Piping*.[172]

91. The ASME Code on which Mr. Polich relies recommends examining hot reheat lines at intervals not exceeding five years.[173] Section 8 of Non-Mandatory Appendix V of the ASME code, which covers "Piping Corrosion," 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 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.[174]

92. The Department's expert explained that hot reheat lines generally are covered by Section 8 because they are subject to erosion/corrosion.[175] As stated in the code, "Erosion/corrosion of carbon steel piping may occur at locations where high-fluid velocity

[171] Evid. Hrg. Tr. at 66-67 (Polich).
[172] Ex. 19 at PJU-1 at 33 and 87 (Undeland Rebuttal). "However, . . . it was discovered that only 2% of the respondents actually followed the Guidelines completely and 41% had followed the Guidelines for the most part." *Id.* at PJU-1 at 87.
[173] ~~Id.~~Ex. 10 at 24 (discussing ASME Code Section 8 located at MP Ex. 22a at 325, 329 (ASME Code B31.1, Appendix V)).
[174] 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.
[175] Evid. Hrg. Tr. at 78-79 (Polich).

exists adjacent to the metal surface."[176] 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.[177] High-velocity fluids strip rust away exposing bare pipe causing erosion of the piping, which weakens the pipe over time.[178]

93. Minnesota Power agreed that its hot reheat line is a critical piping system.[179] Minnesota Power disagreed that Section 8 of the ASME Code recommendation applied to its hot reheat line.[180] Minnesota Power averred that corrosion and erosion require water or wet steam, and that the hot reheat line transports only superheated dry steam. The Company cited the ASME Code's definition of "erosion/corrosion" as "a flow-accelerated corrosion process that leads to loss of wall thickness in carbon or low alloy steel pipe exposed to water or wet steam."[181] The Company further indicated that the ASME Code did not list hot reheat system as one of the "Systems and Components Susceptible to Erosion/Corrosion," which noted that erosion/corrosion could occur in an unlisted system that is "exposed to water or wet steam."[182] Minnesota Power also argued that the ASME code recommendations did not apply because erosion or corrosion was not the cause of the failure.[183]

93a. EPRI's publication "Fossil Plant High-Energy Piping Damage: Theory and Practice" states that "[p]iping systems that can be considered immune to [flow accelerated corrosion] (for the most part) include … Superheated steam systems with no moisture content[.]"[184] The 30 Year Report also states that "because corrosion involves the passage of electrons—for corrosion to proceed, there must be a complete electrical circuit which includes … A conductive electrolyte (aqueous solution) that completes the circuit," without which "the circuit is not complete, and corrosion will not occur."[185]

94. Minnesota Power argued that Section 12 of the ASME ~~recommendations~~ Non-Mandatory Appendix V was the applicable section because it specifically ~~discusses~~ covers creep damage.[186] Section 12 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."[187]

95. 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.[188] The Company points to its high energy piping system, of

[176] Ex. 14 at 20 (Undeland Rebuttal).
[177] Evid. Hrg. Tr. at 78-79 (Polich)
[178] *Id.* at 79 (Polich).
[179] *Id.* at 31 (Undeland).
[180] Ex. 14 at 19-21 (Undeland Rebuttal).
[181] Ex. 22a at 319.
[182] *Id.*
[183] MP Initial Brief at 65 (June 28, 2021).
[184] Ex. 19 at 2-18.
[185] *Id.* at 7-59.
[186] *Id.* at 65-67.
[187] *Id.* at 66.
[188] Ex. 5 at 24 (Simmons Direct).

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.[189]

96. Minnesota Power claimed that performing ultra-sonic phased array examination of the longitudinal seam welds at least every five years to prevent this type of hot reheat line failure would be prohibitively expensive. 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."[190]

97. Minnesota Power ~~later revised its cost claims for~~stated that, according to EPRI, the 100 percent phased array ultrasonic inspection advocated for by EPRI and Mr. Polich would cost ~~a full inspection of the hot reheat line to~~ $5 million dollars.[191] For this proposition, Minnesota Power relied on the following language in ~~a white paper~~the 30 Year Report 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."[192] The "[8]" refers to the *Guidelines for the Evaluation of Seam Welded High-Energy Piping*.

98. Minnesota Power, however, did not provide an estimate of 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 benefit."[193]

99. Mr. Polich pointed to Thielsch'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.[194] Mr. Polich noted that:

> [I]f 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 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.[195]

100. This four-line email correspondence from Thielsh does not identify what portions are included in its statement to "include the vertical riser" or what type of inspection would

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[189] *Id.*
[190] *Id.*
[191] ~~MP Initial Brief at 72.~~Ex. 14 at 29 (Undeland Rebuttal).
[192] ~~*Ex. 14*~~*Id.*, PJU-1 at 427 (Undeland Rebuttal).
[193] *Id.* at 29.
[194] Ex. 10 at 15, RAP-3 (Polich Direct).
[195] *Id.* at 15.

be completed.[196] As Minnesota Power did not use phased array ultrasonic testing, it is reasonably assumed that it does not include the inspection methodology that EPRI and Mr. Polich recommend.[197] ~~In response,~~ Minnesota Power also 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 an outage to complete the full inspection."[198] 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.[199]

101. Minnesota Power's claim that following the EPRI guidelines ~~would~~ could cost more than $5 million dollars is ~~un~~supported by EPRI's own documentation. ~~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.~~

102. Mr. Undeland claimed that the inspection costs should be weighed solely against the actual forced outage costs in this proceeding.[200] ~~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 and labor cost, in addition to the replacement power costs noted by Minnesota Power witness Mr. Paul Undeland.[201] Mr. Undeland confirmed Minnesota Power also incurred capital costs to replace the hot reheat line and conceded that other plants experiencing similar failures have likely incurred costs from injuries that occurred.[202]

103. Mr. Undeland testified that "[w]hile more planned outage time, longer planned outages, and additional equipment disassembly and testing could reduce the number of outages, it would significantly increase the Company's generation maintenance expense, in turn providing a reasonable basis to increase customer rates to a level that outweighs the benefit of such practices in excess of good utility practice."[203]

104. Mr. Polich agreed that some forced outages are unavoidable but stated that some of the forced outages at issue here could have been avoided. In particular, he disagreed that increased planned outages will increase costs forcing an increase in rates. He noted that during the period at issue and prior, Minnesota Power's maintenance costs were below the maintenance costs the Commission approved in the Company's last rate case. So additional maintenance would not have caused increases.[204] He also notes that many

[196] *Id.*
[197] *Id.*
[198] Ex. 14 at 28 (Undeland Rebuttal).
[199] Evid. Hrg. Tr. at 33-35 (Undeland).
[200] *See* Ex. 14 at 29-30 (Undeland Rebuttal).
[201] Ex. 5 at 27 (Simmons Direct)
[202] Evid. Hrg. Tr. at 36-39 (Undeland).
[203] Ex. 7 at 8 (Undeland Direct).
[204] Ex. 10 at 14-15 (Polich Direct).

equipment inspections can be planned, scheduled, and accomplished within the period of a planned maintenance outage. Furthermore, unless a probabilistic risk analysis comparing the impact of additional maintenance costs versus forced outage costs on customer rates is performed it is unknown whether the costs would outweigh the benefits. He posits that the HRH pipe failure is an example of a situation where inspection would have been more cost effective than the forced outage that occurred.[205] Mr. Polich, however, testified that he had neither inspected the piping at Boswell nor completed a decision tree analysis of risk for Boswell Unit No. 4.[206]

4. Conclusions on the Hot Reheat Line Outage

105. The Commission asked whether Minnesota Power's forced outage in its HRH line was consistent with good utility practice. As agreed by the parties, 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, 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.[207]

106. More simply, the Commission asked whether Minnesota Power's practices related to this forced outage were reasonable and prudent. Prudent is defined as exercising good judgement or common sense and characterized by or resulting from care or wisdom in practical matters or in planning for the future.[208]

107. At even the level of nonexpert understanding, a utility plant is a complicated system with some inherent dangers that, left unaddressed, can result in injury and death. Moreover, for all the reasons explained in this matter, lack of maintenance can lead to forced outages and higher consumer costs. The outside parameter for inspection of the HRH is, at the most, every ten years with ~~expert~~ the EPRI member organization recommending five years~~technical organizations recommending a shorter five-year period~~. Taking into consideration the critical nature of the HRH, the known history of such failures throughout the industry, the potential consequences of its failure and considering the age, the various analyses performed over decades of experience by plant personnel and hired third-party experts, and peculiarities of the Boswell plant, ~~a~~ the range of reasonable and prudent maintenance schedules included inspecting the vertical HRH line ~~should have been closer to every five years than to~~ every ten years, with more frequent inspections occurring on higher-stress portions of the HEP. These inspections are ~~It is reasonable and prudent to anticipate more frequent, not regular or lessening, inspection~~

[205] *Id.* at 15.
[206] Evid. Hrg. Tr. at 66-67 (Polich).
[207] *Id.* at 6-7. Minnesota Power does not dispute the Department's proposed definition of "good utility practice." Ex. 14 at 8 (Undeland Rebuttal).
[208] *American Dictionary Online* (July 29, 2021) https://www.ahdictionary.com/word/search.html?q=prudent.

~~and maintenance of any complexly engineered system for which good working order is~~ critical for reliability and safety.

108. Minnesota Power's inspection schedule was reasonable and prudent based on the information known at the time, including additional structural analysis performed in 2010. ~~should have inspected the hot reheat line more frequently based on the line's age and potential for catastrophic failure.~~[209] Additionally, Minnesota Power has provided evidence that its HRH inspection protocol was consistent with at least 50 other utilities, which constitutes a significant portion of the utility industry as opposed to the more limited sample set of 29 utilities surveyed by EPRI.

109. After the failure occurred, Minnesota Power's own engineering consultants, Thielsch, calculated the date when cracks would have first appeared in the failed portion of the hot reheat pipe. Thielsch concluded that the cracks likely began 7.5-8.9 years before the failure.[210] At that time, Structural Integrity, a second piping consulting firm recommended to Minnesota Power by EPRI inspected the line and concluded that its model indicated that the piping showed some level of continued operation.[211] Therefore, it is unknown whether a different inspection method or shorter frequency would have definitively identified the metallography conditions (or whether they would have been of sufficient size for identification) on an increased inspection frequency. ~~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. This would have triggered the need to inspect all the seams.~~[212]

110. It is undisputed that Minnesota Power has the burden of proof in this case to show that it properly inspected and maintained Boswell Unit No. 4's hot reheat line. Minnesota Power's claim that its ten-year HRH inspection schedule was consistent with the practices of a significant portion of the utility industry is supported by sworn testimony from its employees about information the Company received from its external HRH expert, Thielsch, regarding the practices of over 50 other utilities, which constitutes a significant portion of the utility industry. Minnesota Power's claim that its ten-year inspection schedule of longitudinal seam-welds was reasonable and prudent based upon information available at the time is supported ~~solely~~ by advice from its contractor, Thielsch, stress and risk testing performed by Sargent and Lundy in 2010, audits by the Company's insurer – FM Global – of Thielsch and Minnesota Power's inspection programs, past inspection results, and through decades of plant personnel experience and education on these

[209] ~~Ex. 10 at 38-41 (Polich Direct).~~Ex. 7 at 17 (Undeland Direct).
[210] *Id.* at 39.
[211] *Id.* at RAP-11 at 62.
[212] ~~*See id.* at 15.~~

issues.[213] 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 gives similar advice to its other power plant clients.[214]~~ It is reasonable for Minnesota Power to carefully consider the information learned after the 2019 hot reheat outage in establishing its future HEP inspection frequency and approach to prioritizing various portions of the HEP.

111. In contrast, the Department introduced expert testimony that a five-year inspection program was consistent with good utility practice.[215] The Department's expert supported his informed opinion with recommendations from ASME, guidelines from a utility trade organization, EPRI, and statements and conclusions from Minnesota Power's own contractors.[216] The ASME recommendations on which the Department's expert relies are for corrosive/erosive environments, which require the presence of water or wet steam that are not present in the superheated dry steam transported by the hot reheat line at issue in this proceeding.[217] EPRI has been studying and documenting identical failure of seam-welded pipe as occurred here.[218] While EPRI has been studying seam-welded pipe failures for decades, their own documentation indicates a less than 50 percent adoption rate of their recommendations (from the sample set of 29 utilities) in the industry and concerns that incorporation of the recommendations would be cost-prohibitive.[219] Thus, while the Department has demonstrated that the EPRI-recommended five-year inspection protocol is consistent with good utility practice, it has not demonstrated that this standard represents the minimum threshold for good utility practice. ~~In addition, the Department provided evidence that the high-potential cost of a hot reheat line failure obliged Minnesota Power to perform more frequent inspections.[220] 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.[221]~~

112. As the party with the burden of proof, Minnesota Power need not prove that all other inspection protocols are inconsistent with good utility practice to demonstrate that its inspection programs were within the range of good utility practice. Rather, the Company must show that either (1) its hot reheat inspection protocol was utilized or approved of by a significant portion of the utility industry, or (2) the actions it took are reasonable and prudent with the information available at the time it made its decisions for the HRH inspections. Minnesota Power has met both alternatives for satisfying this

[213] Ex. 6 at 4; Ex. 7 at 18 (Undeland Direct); Ex. 14 at 23, 27 (Undeland Rebuttal); Evid. Hrg. Tr. at 24-29 (Undeland).
~~[214] Evid. Hrg. Tr. at 29 (Undeland).~~
[215] Ex. 10 at 24-41 (Polich Direct).
[216] Evid. Hrg. Tr. at 52 (Polich); Ex. 10 at 24-41 (Polich Direct).
[217] Ex. 19 at 20-21 (Undeland Rebuttal).
[218] *See* Ex. 14, PJU–2 at 399-432 (Undeland Rebuttal) (EPRI 30 Year Report).
[219] Ex. 19 at PJU-1 at 33 and 87 and PJU-2 at 29 (Undeland Rebuttal). "However, . . . it was discovered that only 2% of the respondents actually followed the Guidelines completely and 41% had followed the Guidelines for the most part." *Id.* at PJU-1 at 87.
~~[220] Ex. 10 at 24-41 (Polich Direct).~~
~~[221] *Id.* at 38-39.~~

burden by demonstrating that its risk-based approach was consistent with good utility practice. ~~Minnesota Power failed to rebut the Department's evidence. Minnesota Power's claims of the high expense of the Department's proposed inspections were unsupported with specific evidence in the record.[222] As the party with the burden of proof, Minnesota Power must show that the costs would be unreasonable.[223] Instead it claimed, without support, that "the cost associated with such an inspection protocol . . . would be significantly higher than the potential benefit."[224] This is especially concerning when the dangers of an HRH failure are not merely an unplanned outage, but possible loss of life or significant injury.~~

113. Evidence in the record ~~shows~~ does not show that by employing a more-frequent inspection protocol or a different inspection methodology Minnesota Power would have ~~that it is likely that the hot reheat line failure could have been avoided had Minnesota Power inspected it more often~~avoided the hot reheat line failure.~~[225]~~

114. Minnesota Power has ~~not~~ met its burden to show that good utility practice allowed it to ~~wait~~ develop a risk-based, 10-year, inspection cycle for the hot reheat line based upon the information available at the time~~ten years between full hot reheat line inspections for a pipe of this age with a method that can detect creep damage~~. Minnesota Power has further demonstrated that its hot reheat line inspection frequency was consistent with the practices utilized or approved of by a significant portion of the utility industry.

115. Minnesota Power ~~failed to show that its high-energy~~has demonstrated that its HEP inspection program was reasonable and prudent and constituted good utility practice.

B. 2019 Hydrogen Leak Repair at Boswell Unit No. 3

116. The second forced outage at issue was caused by the hydrogen cooling system at Boswell Unit No. 3. 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.[226]

117. Boswell Unit No. 3 uses an oil system to seal hydrogen gas within the generator shaft and avoid leaks into surrounding areas. The shaft penetration is sealed with a shaft hydrogen seal. This relies on seal oil to provide the seal between the seal and the rotating shaft. For that reason, the seal oil vacuum tank and float trap are inspected once every

~~[222] *See* Evid. Hrg. Tr. at 33-35.~~
~~[223] Ex. 1 at 4 (Order for Hearing).~~
~~[224] Ex. 14 at 29 (Undeland Rebuttal).~~
~~[225] Ex. 10 at 48-49 (Polich Direct).~~
[226] *Id.* at 41-42.

five years for any accumulated dirt or debris. The float trap valve is removed from the housing to inspect the valve for any debris or binding in the linkage.[227]

118. Boswell Unit No. 3 is a fully sealed generator system that is filled with hydrogen gas. The original equipment manufacturer (OEM) of this generator is General Electric (GE). The generator is filled with hydrogen gas for three primary reasons: (1) hydrogen gas (when pressurized) is a better insulator than air, (2) the density of hydrogen gas is one tenth the density of air, resulting in less rotating losses in the generator during operation, and (3) hydrogen has far superior heat transfer characteristics than air. Hydrogen gas is, however, a very flammable gas that can self-ignite when it leaks from a pressure vessel under specific conditions. It is an invisible gas that can accumulate in unseen areas and create an explosive atmosphere if not properly contained or vented. Because of these considerations, significant repairs to the hydrogen gas system require that the unit be taken offline.[228]

119. The system also relies on the integrity of the float trap for purposes of operating the hydrogen-filled system. From past experience at Boswell Unit No. 3, the valve (a double seated 1.25-inch brass valve) has to be removed from the float trap housing and inspected every five years. The Company had an experience in 1989 where debris caused the valve to malfunction. The Company has also had an experience at another plant where a similar valve had wear in the linkage resulting in malfunction. During operation, the valve is always open, so tight shutoff is not necessary. For that reason, the valve seats are not checked for 100 percent contact.[229]

120. Boswell Unit No. 3 noted high hydrogen gas consumption in November 2018. After checking common locations and doing several operational tests, a weekend outage was scheduled for February 2 and 3, 2019. During that short outage, the unit was purged of hydrogen and pressurized with air and helium in an effort to locate the source of the leak. This test identified a substantial leak on the terminal plate to leadbox gasket. An epoxy was used to seal the leak from an external location until a planned spring 2019 outage, when a full investigation could be undertaken, and repairs could be made.[230]

121. After the spring 2019 outage commenced, the repair and associated inspections were initiated. The leadbox dam was installed according to the pre-outage plan developed with GE. As part of the spring outage, the inspection technicians undertook an inspection of the float valve and the hydrogen seal at the generator shaft was sent to Power Plant Services for full refurbishment. These measures were intended to restore the system and minimize the risk of future hydrogen gas leaks. During the inspections of the float valve and float trap, the inspection technicians determined that the valve was clean of any debris and moved freely and showed no sign of wear on the linkage. Additionally, neither the float valve nor "trap" showed any signs of wear, defects, or debris that would be causing

[227] Ex. 7, PJU-4 at 2 (Undeland Direct).
[228] *Id.*
[229] *Id.*
[230] *Id.*, PJU-4 at 4, 7.

a hydrogen leak like the one Boswell Unit No. 3 had experienced in the winter of 2018 and 2019.[231]

122. During the March planned outage, Minnesota Power working with GE, performed repairs of much of the equipment in the generator area.[232] New gaskets were used, as was a gasket sealant that has been effective and in use for 20 years on hydrogen and oil gaskets.[233]

123. On June 4, 2019, Minnesota Power tested the system, around the time of the end of the original scheduled outage, but the generator failed the test and still indicated a sizable leak, about ten times the amount considered acceptable for the test.[234] The outage was extended beyond the initial end date to address ongoing repair issues.[235] Therefore, the final days of the hydrogen leak repair were classified as an "unplanned" outage.[236]

124. 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.[237] To reach this conclusion, Minnesota Power, in consultation with GE and others, performed multiple protocols to isolate the cause of the leak. Theses protocols are described in detail in Schedule 4 of Mr. Undeland's direct testimony.[238]

125. Minnesota Power continued to perform further root cause analysis but was still unable to locate the source of the major leak. Minnesota Power again contacted GE to assist in the root cause analysis and hired another contractor that specializes in hydrogen leaks.[239]

126. Also, in early June, as part of the troubleshooting effort, the oil level in the float trap tank was raised using the manual isolation and bypass valves. Once the oil level went well above normal operating level, the leak stopped.[240] Boswell personnel discovered that the float trap had to be completely flooded for the leak to stop. This was about 8-12 inches above the valve. The normal oil level was controlled about 3-4 inches above the valve suction under normal operating conditions for the system. The results of this oil test were communicated back to GE and Power Plant Services. While neither company had an answer, they offered to reach out to their contacts at other generating units. As part of this effort, they identified a customer that had a similar problem.[241]

127. Without Minnesota Power, GE or Power Plant Services being able to identify the root cause of the issue, Minnesota Power solved the problem by replacing the valve itself.

[231] *Id.*, PJU-4 at 5.
[232] *Id.* at 27.
[233] *Id.*, PJU-4 at 7.
[234] *Id.* at 27, PJU-4 at 8.
[235] *Id.* at 29.
[236] *Id.* at 14, 29.
[237] *Id.* at 27.
[238] *Id.*, PJU-4 at 8.
[239] *Id.* at 28.
[240] *Id.*, PJU-4 at 9.
[241] *Id.*

Replacing the valve was a convoluted process because GE was unable to provide a replacement valve for 15 weeks.[242]

128. After testing many different designs, Minnesota Power found a valve that solved the problem, and the unit was put back into service. Minnesota Power then inquired of GE and Power Plant Services about what other issues to look for or systems to inspect. The companies had no suggestions other than to replace the valve. The limited experience they had (one plant for each) with similar situations, was that the problem was on an older unit and there was nothing to explain a root cause of the problem or why it was remedied by replacing the valve.[243]

129. 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 allowed into the system versus the amount of oil it took out before putting the hydrogen cooling system back online. 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."[244] 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."[245]

130. Minnesota Power also did not inspect whether additional oil remained in the generator after completion of the hydrogen leak repairs.[246] 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)."[247] It also stated that it performed a visual inspection of the leadbox, which was "clean and dry."[248]

131. Mr. Polich 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.[249] However, in Mr. Polich's opinion, because Minnesota Power's roundabout method of diagnosing the leak only resulted in a small extension of the planned outage,[250] the Department did not recommend that Minnesota Power be disallowed from recovering those costs.[251]

132. The Department's expert asserts that the way in which Minnesota Power ultimately determined the cause of the leak was not consistent with good utility practice.[252]

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[242] *Id.*
[243] *Id.*, PJU-4 at 9-10.
[244] Ex. 10 at 43, RAP-15 at 5 (Polich Direct).
[245] *Id.*, RAP-15 at 5.
[246] *Id.* at 43.
[247] *Id.*, RAP-15 at 5.
[248] *Id.*, RAP-15 at 4.
[249] *Id.* at 44-45.
[250] *Id.* at 45.
[251] Ex. 12 at 17 (Campbell Direct).
[252] Ex. 10 at 44 (Polich Direct).

Minnesota Power's improper overfilling of the hydrogen seal oil system likely led to seal oil leaking into the generator.[253] According to the Department expert, "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."[254] Thus, while the Department does not seek to disallow Minnesota Power's costs related to the Hydrogen Leak, it asserts that Minnesota Power's actions are material to this matter because the alleged overuse of seal oil spilled over into the third and final forced outage in this matter.

133. Minnesota Power's forced outage costs related to the hydrogen leak were reasonable and prudent.

134. The Department that Minnesota Power has not shown that Minnesota Power did not efficiently conduct a root cause analysis and so delayed bringing the plant online for an excessive amount of time.

135. The problems, analysis and actions related to the hydrogen gas leak provide an object lesson in the difficulty of evaluating maintenance prudence, practice, and expenditures on a case-by-case basis. The parties agree that hydrogen leaks are dangerous and require immediate action. The hydrogen leak presented a unique puzzle such that GE, the original OEM, Power Plant Services with an ex-GE engineer on staff, and an external contractor that specializes in hydrogen leak location were not able to troubleshoot the source of the problem. These facts illustrate the lack of a template for prudent, good utility practice in certain situations. ~~Unlike, for example, the frequency of certain system inspections, s~~Seldom seen problems cannot be deemed to have a common industry practice. In hindsight, it would have been better practice to measure the amount of oil that was pumped into the system. But in the moment, knowing that the barrier between dangerous hydrogen gas and the plant was seal oil, that seal oil resolved the leak, and without an industry or OEM protocol for the problem, it is reasonable to find that Minnesota Power made reasonable and prudent decisions in attempting to resolve the problem.

C. Boswell Unit No. 3's 2019 Phase Bushing Failure

136. 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.

137. 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.[255]

[253] *Id.*
[254] *Id.*
[255] Ex. 7, PJU-5 at 2 (Undeland Direct).

138. The generator has a water-cooled stator winding that requires vacuum dehydration prior to testing. Minnesota Power has always used GE, the OEM, to test the generator because GE has the necessary equipment to do the dehydration. Another benefit of using GE is that the water-cooled windings have a fleet history of water leakage and GE is best equipped to deal with those leaks. Minnesota Power historically experienced leaks, which culminated in a generator stator rewind in 2001. There had been no problems since then.[256]

139. On July 8, 2019, a relay on the generator "A" phase detected a ground fault and operators took the plant off-line.[257] Electricity is transmitted in three phases (A, B, and C), and the generator in question has six bushings, two bushings per phase.[258] 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.[259] Minnesota Power hired General Electric to provide more specialized personnel to investigate, and General Electric determined on July 14, 2019 that the failure was on the A phase line side bushing which would need to be replaced.[260] Minnesota Power and General Electric ultimately decided to replace all six bushings.[261]

140. These six phase bushings had all been tested at a scheduled outage three months earlier on April 18, 2019. As Mr. Undeland testified "[d]uring 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."[262]

141. Minnesota Power does not know the age of the bushings that failed; they could either have been installed in 1970 or 2001.[263] Minnesota Power claimed, "This outage was not only unplanned, but also beyond any foreseeable protocols that could have been put in place to prevent this outage."[264] Minnesota Power focused on the recent inspection, noting that increasing the time between inspections would not have prevented the outage because the inspection occurred only three months earlier.[265]

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

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[256] *Id.*
[257] Ex. 10 at 46 (Polich Direct).
[258] Ex. 7 at 32 (Undeland Direct).
[259] *Id.* at 33.
[260] *Id.*
[261] *Id.* at 33-34.
[262] *Id.* at 32.
[263] *Id.* at 35.
[264] *Id.*
[265] *Id.* at 36.

> 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 (HVB).[266]

143. 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 . . . ."[267]

> "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."[268]

> "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.*"[269]

> "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 out of the five bushings still in the unit. An estimated five gallons of oil was pumped out of each of the bushings."[270]

144. Minnesota Power stated that it replaced all six bushings, because 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."[271] According to the GE report, however, "The customer originally planned to replace only the T4 bushing, which had gone to ground. But with six new bushings on hand, as well as higher than expected DC microamp leakage on the T1 HVB, and the knowledge that all six of the in-service bushings had been filled with oil, it was decided to replace all six HVBs."[272]

[266] Ex. 10, RAP-16 at 3 (Polich Direct).
[267] *Id.*, RAP-16 at 4.
[268] *Id.* (emphasis added).
[269] *Id.* (emphasis added).
[270] *Id.*, RAP-16 at 5.
[271] Ex. 7 at 33-34 (Undeland Direct).
[272] Ex. 10, RAP-16 at 12 (Polich Direct).

145. Mr. Polich 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.[273] Minnesota Power agrees that the oil in the bushings was seal oil: "[I]t was apparent to plant personnel and our third-party expert consultants that the oil present in the phase bushings was seal oil. This oil was introduced into this area during the float trap valve testing and repairs . . . ."[274]

146. Mr. Polich 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.[275] And if that investigation had found seal oil leakage, Minnesota Power should have cleaned up the oil.[276] He concluded that these steps would have prevented the phase bushings from being filled with seal oil or would have found the seal oil prior to restarting the plant.[277] This would have avoided the bushing failure and the need to purchase replacement bushings and a roughly two-week unplanned outage.[278]

147. Minnesota Power did not dispute that the oil in the bushings was from its testing of the hydrogen gas leak. 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."[279] Minnesota Power stated that "General Electric was unable to conclude whether the presence of oil did or did not contribute to the failure."[280]

148. Among the alternative causes that Minnesota Power pointed to were sudden load changes, excessive vibration, overheating, overheating of the leads, and normal vibration over long periods of time.[281] Minnesota Power confirmed, however, that General Electric did not find any of these alternative potential causes to be the cause of the phase bushings failure.[282] Moreover, there is little mention of these other potential causes, besides overheating caused by the bushings being soaked in oil, in General Electric's report.[283]

149. 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.[284] However, Mr. Undeland acknowledged that he was not aware of General Electric noting concerns about tar during the April 2019 inspection.[285]

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[273] *Id.* at 47.
[274] *Id.*, RAP-15 at 4.
[275] *Id.* at 47.
[276] *Id.* at 47-48.
[277] *Id.* at 48.
[278] *Id.*
[279] Ex. 14 at 34 (Undeland Rebuttal)
[280] *Id.* at 35.
[281] *Id.*
[282] Evid Hrg. Tr. at 39-43.
[283] Ex. 10, RAP-16 (Polich Direct).
[284] Evid. Hrg. Tr. at 40 (Undeland).
[285] *Id.* at 41 (Undeland)

150. 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.[286]

151. Minnesota Power ultimately acknowledged that General Electric stated that the bushings could have failed from overheating due to the seal oil blocking proper cooling.[287]

152. Minnesota Power also blamed its failure to detect the oil leakage on an alarm that was not properly configured.[288] But Minnesota Power admitted that it was responsible for the improper configuration.[289]

153. Minnesota Power's alternative theories of what caused the phase bushing failure are unpersuasive. The Administrative Law Judge notes that it is unlikely that three bushings would have suddenly failed simultaneously for any of the reasons theorized by Minnesota Power. Furthermore, statements in the General Electric report, and the timing of the failure soon after the bushings passed inspection makes a conclusion that the phase bushings failed because they overheated after being soaked with oil more likely than any of the potential causes posited by Minnesota Power.[290]

154. The Administrative Law Judge concludes that Minnesota Power made reasonable and prudent decisions in addressing the phase bushing failure. The Administrative Law Judge agrees that the phase bushing failure was a consequence of the oil that was added to the float valve to address the hydrogen gas leak. However, with regard to the phase bushings, just as in responding to the hydrogen leak, the Company made the best decisions it was able to make based on the knowledge it had at the time. There was no evidence that there was an industry standard for testing of the improperly configured alarm or a specific schedule for anything related to the bushings' failure. The problem resulted from a failure to consider every possible undesired consequence of the hydrogen leak repair but not from a failure to perform advised maintenance or failure to adhere to industry standards.

IV. Conclusions

155. Based on the above findings, the Administrative Law Judge finds that Minnesota Power's maintenance and inspection programs for Boswell Unit No. 4's hot reheat line were not inconsistent with good utility practice.

156. Based on the findings above, the Administrative Law Judge finds that Minnesota Power's maintenance and inspection of the hydrogen gas leak and bushings failures were not the result of a failure to adhere to good utility practice.

[286] Ex. 14 at 35 (Undeland Rebuttal).
[287] Ev. Hrg. Tr. at 43 (Undeland).
[288] MP Initial Br. at 8, 50, 53.
[289] *Id.* at 8, 50.
[290] Ex. 10, RAP-16 (Polich Direct)

157. Having concluded that Minnesota Power's maintenance and inspection programs associated with those systems at Boswell that experienced unplanned outages from July 1, 2018 through December 31, 2019, were within acceptable good utility practice, there are no ~~the hot reheat line outage was not consistent with good utility practice, the Administrative Law Judge concludes that the~~ expenses associated with the outage that 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~~.

~~158. Minnesota Power's incremental forced outage costs associated with Boswell Unit No. 4's hot reheat line 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, 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.~~

~~159. The Department and Minnesota Power agree on the amount of incremental costs associated with Boswell Unit No. 4's hot reheat line.~~

~~160. 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.[291] 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."[292]~~

~~161. 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.[293] The Department agreed that this methodology would produce reasonable results.[294] 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 to ensure that customers are repaid where a utility either overcharged them or imprudently incurred the expense.[295] This matter implicates the second situation. As previously discussed, Minnesota Power incurred incremental forced outage costs by failing to observe good utility practice.~~

~~162. In a similar situation, the Commission ordered 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~~

~~[291] Ex. 12 at 19-20 (Campbell Direct); Ex. 16 at 3 (Oehlerking-Boes Rebuttal).~~
~~[292] Ex. 16 at 3 (Oehlerking-Boes Rebuttal).~~
~~[293] *Id.* at 3-4.~~
~~[294] DER Initial Br. at 26-27 (June 28, 2021).~~
~~[295] Ex. 12 at 26-28 (Campbell Direct).~~

~~penalize ratepayers for imprudent actions that resulted in otherwise preventable outages."~~[296]

~~163. In addition, the Administrative Law Judge 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 Administrative Law Judge 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. In summary, riders are the appropriate 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.~~[297]

~~164~~158. Based on the foregoing Findings of Fact and the record in this proceeding, the Administrative Law Judge makes the following:

CONCLUSIONS OF LAW

1. The Commission and the Administrative Law Judge have jurisdiction over the subject of the proceeding pursuant to Minn. Stat. §§ 216B.03, .16, subd. 7 (2020), Minn. R. 7825.2900, .2920 (2021), 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 is properly before the Administrative Law Judge.

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.[298]

4. The utility always retains the burden of proving the reasonableness of costs the utility seeks to charge ratepayers.[285299] Submitting evidence on an issue does not create a rebuttable presumption of reasonableness.[300]

5. Based on the findings above and the record in this proceeding, Minnesota Power ~~did not demonstrate~~has demonstrated by a preponderance of the evidence that its maintenance and inspection practices implemented ahead of and during the relevant period of unplanned outages from July 1, 2018 through December 31, 2019,~~for its Hot~~

~~[296] *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).~~
~~[297] Ex. 12 at 4, 25-28 (Campbell Direct).~~
[298] Ex. 1 at 4 (Order for Hearing); Minn. R. 1400.7300, subp. 5 (2021).
[299] *In re N. States Power Co.*, 416 N.W.2d 721, 726 (Minn. 1987).
[300] *Id.* at 725-26.

~~Reheat Line~~ were consistent with good utility practice, or that any deviation from good utility practice did not contribute to the outage.

~~5. The Administrative Law Judge concludes that Minnesota Power did not reasonably and prudently incur forced outage costs resulting from the Hot Reheat Line at issue in this proceeding. The Company and the Department agree on the refund owed to customers.[301] Interest should be calculated using the U.S. Federal Reserve Prime Rate.[302]~~

~~6. Utility rate riders are pass-through mechanisms used to adjust utility rates outside of a general rate case.[303] Costs paid by customers through a rider are provisionally authorized subject to subsequent Commission review and adjustment.[304] The Commission has repeatedly used rate riders to refund overcharges and imprudently incurred utility costs.[305]~~

~~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.[306]~~

~~8~~6. Any of the forgoing Findings of Fact more properly designated as Conclusions of Law are hereby adopted as such.

RECOMMENDATIONS

Based on these Findings of Fact and Conclusions of Law, the Administrative Law Judge recommends:

1. The Commission find that ~~the Hot Reheat Line forced outage at the Boswell Energy Center was inconsistent~~Minnesota Power's generation maintenance and inspection practices implemented ahead of and during the relevant period of unplanned outages from July 1, 2019 through December 31, 2019, were consistent with good utility practice or that any deviation from good utility practice did not contribute to the outage, and that Minnesota Power's incremental costs arising from ~~that~~ those unplanned outages were ~~not~~ reasonably and prudently incurred.

~~[301] Ex. 12 at 17 (Campbell Direct); Ex. 16 at 2 (Oehlerking-Boes Rebuttal).~~
~~[302] Ex. 12 at 19-20 (Campbell Direct); Ex. 16 at 3 (Oehlerking-Boes Rebuttal).~~
~~[303] Ex. 12 at 4, 25-28 (Campbell Direct); *see also* Minn. Stat. § 216B.16, subd. 7.~~
~~[304] Minn. R. 7825.2920.~~
~~[305] *See*, *e.g.*, *In re Xcel Energy's Pet. for Affirmation that MISO Day 2 Costs are Recoverable*, 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).~~
~~[306] Ex. 16 at 3-4 (Oehlerking-Boes Rebuttal).~~

~~2. Minnesota Power refund the 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.~~

~~3~~2. The Administrative Law Judge respectfully recommends that the Commission should adopt the Findings of Fact, Conclusions of Law, and Recommendations set forth above.