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Rebuttal Testimony and Schedules
Herbert J. Sirois

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

IN THE MATTER OF AN APPLICATION OF NORTHERN STATES POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN THE STATE OF MINNESOTA	MPUC Docket Nos. E002/GR-12-961 E002/GR-13-868
IN THE MATTER OF THE REVIEW OF THE ANNUAL AUTOMATIC ADJUSTMENT REPORTS FOR ALL ELECTRIC UTILITIES	E999/AA-13-599 E999/AA-14-579 E999/AA-16-523 E999/AA-17-492 E999/AA-18-373
	OAH Docket No. 65-2500-38476

REBUTTAL TESTIMONY OF

HERBERT J. SIROIS

On Behalf of

NORTHERN STATES POWER COMPANY

September 22, 2023

Exhibit___(HJS-2)

Operations and Maintenance

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND EMPLOYER.

A. My name is Herbert J. Sirois. I am an independent turbomachinery consultant and previously the founder of the now dissolved Foster Cove Engineering, Inc.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes. On June 16, 2023, I filed my Direct Testimony on behalf of Northern States Power Company (Xcel Energy or the Company).

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony responds to the testimony filed by Mr. Richard Polich, of GDS Associates, Inc., on behalf of the Minnesota Department of Commerce (Department). In particular, I respond to Mr. Polich's claim that Xcel Energy did not follow "good utility practice" at Sherco Unit 3.

Q. BEFORE TURNING TO THE SUBSTANCE OF MR. POLICH'S TESTIMONY, DO YOU AGREE WITH MR. POLICH'S USE OF THE TERM "GOOD UTILITY PRACTICE"?

A. I agree only to a point. I agree with Mr. Polich that any analysis of "good utility practices" should consider whether a utility has exercised "reasonable judgment in light of the facts known at the time the decision was made."[1] That description is consistent with Company witness Mr. Allen D. Krug's testimony which discusses the standard to be applied in this proceeding—the prudence standard—which recognizes that a range of actions may be reasonable and that hindsight has no place in a prudence analysis.

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[1] Polich Direct, p. 7.

I disagree with the implication throughout Mr. Polich's testimony that there is some established "good utility practice" standard or standards on the issues he discusses. As Mr. Polich acknowledges, other than his offered definition, there are no other documents that support the definition he provides in his testimony. (*See* the Department of Commerce's (DOC's) Response to Xcel Energy Information Request (IR) No. 25, included as Exhibit___(HJS-2), Schedule 1.) Ultimately, it comes down to reliability, efficiency, and the overall cost to operate the power plant and a range of actions can fall within the realm of "good utility practices," as the prudence standard recognizes. Every utility or plant operator the size of Xcel Energy has the goal of maximizing reliability and thermal and operational efficiency while controlling risks associated with high pressure steam, oil, and rotating equipment, including steam turbine generators, boiler-feed pumps and turbines, fans, complicated hydrogen and lubrication systems, and coal and ash systems.

Finally, I strongly disagree with Mr. Polich's suggestion that *any* reasonable definition of "good utility practice" or prudent utility operation would require major inspections of the steam turbine generator every 3 to 5 years, and that those would routinely and without justification (*i.e.*, abnormal events or operational anomalies) include a blades-off, magnetic particle inspection of the turbine finger dovetails. I have worked with many steam turbine owner/operators and several insurance companies over the course of my 53-year career, and I am not aware of a single operator, equipment manufacturer, or insurance company that would agree with Mr. Polich's assertion that "good utility practice" requires his suggested major inspection frequency of every 3 to 5 years. To the contrary, Xcel Energy and the majority of power plant operators around the world utilize a 9 to 10 year major inspection cycle, with some large utilities using an 18 to 20 year major inspection cycle for low pressure turbines.

II. OVERALL RESPONSE TO WITNESS RICHARD POLICH

Q. WHAT OVERARCHING OBSERVATIONS DO YOU HAVE REGARDING MR. POLICH'S TESTIMONY?

A. As an initial matter, Mr. Polich does not appear to be knowledgeable on the subjects he testifies to. This includes a lack of knowledge of and experience with: (1) a 900 megawatt (MW) steam turbine generator and its steam supply; (2) stress corrosion and stress corrosion cracking of a highly engineered steam turbine steam path; (3) steam quality, including the treatment of feedwater in a subcritical drum boiler and the operational differences between drum and once-through boilers; and (4) the decision-making processes at a large power plant and within the central engineering group of a large utility such as Xcel Energy. Given this lack of knowledge and experience, Mr. Polich misread, misunderstood, and misinterpreted technical guidelines from General Electric (GE), the Sherco 3 steam turbine designer and manufacturer, and the highly technical root-cause analysis of the Sherco 3 L-1 finger dovetail failure completed by Thielsch Engineering (Thielsch Report or Report).

Q. WHAT LEADS YOU TO THESE CONCLUSIONS?

A. A review of Mr. Polich's experience, as set forth in Schedules 1 and 2 to his Direct Testimony, and his responses to discovery in this matter, show that his experience and focus has largely been providing testimony on rates, cost of service, and engineering problems to state regulatory commissions and the Federal Energy Regulatory Commission. (*See* the DOC's Responses to Xcel

Energy IRs 2, 3, and 4, included as Exhibit___(HJS-2), Schedule 2.) While I have no opinions about his suitability to offer testimony in those areas, his education and experience—and, more importantly, his Direct Testimony—demonstrate that he lacks an understanding of highly technical subjects such as water and steam chemistry at a large fossil plant (further discussed by Company expert and witness Mr. David G. Daniels), metallurgical engineering and its role in a proper root cause analysis (further discussed by Company expert and witness Mr. Anthony A. Tipton) or the decision-making processes for fossil turbine outage planning and the risk management exercised by Xcel Energy and the Sherco 3 responsible staff (further discussed by Company experts and witnesses Mr. Timothy P. Murray and Mr. Mark W. Kolb). For example, Mr. Polich has not designed a steam turbine—or any steam path component in any large utility steam turbine—particularly a 900 MW subcritical unit, and appears to have little if any hands on experience operating, maintaining or repairing such a facility.[2] Further, Mr. Polich misstates the conclusion of the Thielsch Report, as discussed by Mr. Tipton, and fails to even mention the Report's *actual* conclusion—that GE's equipment design was the primary causal factor responsible for the November 2011 failure[3] (after analyzing and ruling out maintenance and operations,[4] which included an analysis of water chemistry[5]). Mr. Polich has never been employed by any company to develop inspection techniques—nor has he offered any meaningful review of the inspection

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[2] In response to Xcel Energy Information Request No. 4, Mr. Polich stated: "Mr. Polich (sic) work in Consumers Energy's Engineering Department in 1979 involved coal and natural gas plants." Mr. Polich has identified no other hands on work at such plants.

[3] Thielsch Report, Tipton Direct Exhibit___(AAT-1), Schedule 2 pp. 95-96 (pp. 93-94 of the Report).

[4] Thielsch Report, Tipton Direct Exhibit___(AAT-1), Schedule 2 pp. 67-78, 95-96 (pp. 65-76, 93-94 of the Report).

[5] Thielsch Report, Tipton Direct Exhibit___(AAT-1), Schedule 2 pp. 79-84, 95-96 (pp. 77-82, 93-94 of the Report).

protocol developed by interested parties associated with the failure of the Sherco 3 low-pressure turbine. And Mr. Polich has never worked in a power plant as a water treatment specialist or systems engineer. Simply put, Mr. Polich renders conclusory opinions on issues such as water chemistry and the root cause of the Event, although his testimony reveals that he does not have the qualifications, knowledge, or understanding to make those opinions meaningful.

Q. DO YOU HAVE ANY SPECIFIC EXAMPLES THAT DEMONSTRATE MR. POLICH'S LACK OF STEAM TURBINE EXPERTISE?

A. Yes. Mr. Polich suggests that his opinions are based on his steam turbine expertise, however his testimony is riddled with incorrect information. For example, he represents that Figure 7 in his Direct Testimony (reproduced below), represents the "Sherco LP bucket[6] Attachment Types"—including a tangential entry dovetail:[7]

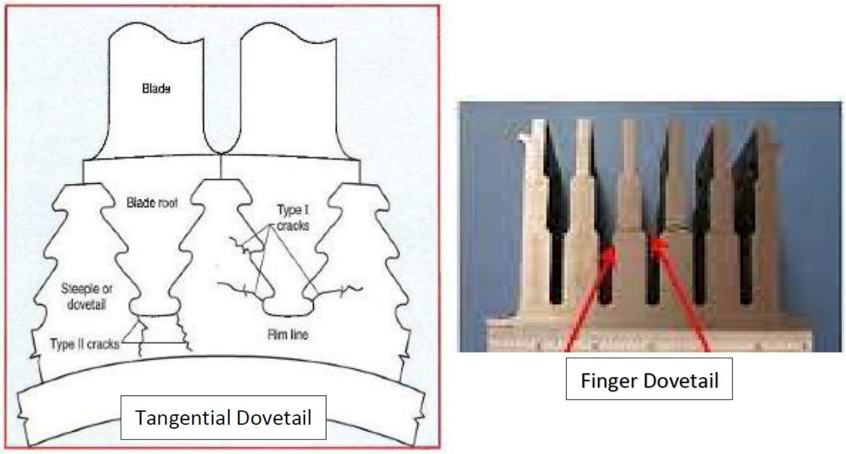

Figure 7 -Sherco LP bucket Attachment Types

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[6] The use of the term "buckets" throughout the parties' testimony is a common industry reference to the turbine "blades." For simplicity, and to minimize industry jargon, I use the term blades throughout my testimony, but the terms are interchangeable.

[7] Polich Direct, p.12.

What is labeled as a "Tangential Dovetail" in Mr. Polich's Figure 7, however, is an ***axial*** entry dovetail—a type of attachment that is not even relevant to this discussion.[8] This is a basic and obvious error that someone with even a modicum of knowledge of steam turbines should not make.

Further, Mr. Polich refers to the "rotor disk to bucket attachment finger dovetail *joint* of the L-1 stage."[9] I have designed steam turbines since 1971 and this is the first time I have seen a reference to the blade (*i.e.*, bucket) attachment to the turbine wheel or disk as a *joint*. Mr. Polich also inexplicably refers to blade tenons as "tendons" throughout his testimony. While these may seem like tedious errors, they are both obvious misstatements that demonstrate Mr. Polich's lack of testimonial precision and expertise with steam turbines.

Q. WHAT ELSE IS PROBLEMATIC ABOUT MR. POLICH'S TESTIMONY?

A. Mr. Polich's testimony is replete with generalities and broad sweeping statements that demonstrate he does not understand the complexity of the Sherco 3 low-pressure turbine wheel finger dovetails and the associated maintenance/inspection practices for this specific attachment configuration. A proper inquiry into the prudency of the Company's operations and maintenance decisions about Sherco 3, however, requires ***precision***—the details inform the entire analysis.

For example, Mr. Polich pronounces that "Xcel personnel were well aware of stress corrosion cracking problems in low pressure turbines long before the

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[8] For an accurate depiction of the Sherco 3 low pressure turbine blade attachment types, see Figure 2 in my Direct Testimony (p. 11).

[9] Polich Direct, p. 38 at line 3.

November 19, 2011 catastrophic failure at Sherco 3." (Polich Direct, p. 6.) Yet this type of general assertion either ignores or fails to understand critical facts, in an effort to blame Xcel Energy for the failure of Unit 3. What Mr. Polich conveniently ignores is that, while there was *general* industry knowledge about the potential for stress corrosion cracking (among other risks) in low pressure turbines, it is important to understand and make distinctions about: (1) in what type of boilers these issues were largely manifesting (*i.e.*, once-through boilers as opposed to the drum boiler in Sherco 3); (2) which types of dovetails had largely been affected (*i.e.*, tangential dovetails versus finger dovetails such as those in the L-0 and L-1 rows of Sherco 3), and—importantly—(3) the type of "inspections" that could be performed to detect *latent* stress corrosion cracking in the L-1 finger dovetails (*e.g.*, a magnetic particle inspection that requires the removal of the turbine blades).

The Sherco 3 failure on November 19, 2011 was the first utility steam turbine generator in a large plant with a *drum boiler* to fail catastrophically when the L-1 blades liberated due to latent stress corrosion cracking in the turbine wheel *finger dovetails*. There was no "industry knowledge" in 2011 that would inform an owner/operator such as Xcel Energy that a blades-off, magnetic particle inspection of the L-1 wheel finger dovetails was warranted *in the absence of abnormal events or operational anomalies*. Mr. Polich appears to utilize 20/20 hindsight—and the fact that something, unfortunately, did go wrong—to impugn the Company for failing to perform a blades-off, magnetic particle inspection of the finger dovetails when there were no abnormal events or operational anomalies (as described in GE's Technical Information Letter (TIL) 1121-3AR1) that justified the added maintenance, duration of outage, expense, and risk to the equipment that performing such an inspection would have entailed.

Q. HOW DO YOU RESPOND TO MR. POLICH'S SUGGESTION THAT A "NON-INVASIVE" INSPECTION DURING THE 2011 MAINTENANCE OUTAGE WOULD HAVE REVEALED THE STRESS CORROSION CRACKING PRESENT IN THE L-1 BLADES (POLICH DIRECT, PP. 25-26)?

A. Mr. Polich is simply wrong once again. With the benefit of hindsight and the post-failure analysis, we know that there was stress corrosion cracking on the internal fingers of the L-1 finger dovetails. Arguably, such cracking would have been visible *if* the blades had been removed. But any suggestion that evidence of the cracking could have been discovered *without* the blades being removed (*i.e.*, a "non-invasive inspection") is flat-out wrong. It is worth emphasizing here that it is not the actual inspection (*i.e.*, the magnetic particle inspection of the finger dovetails) that is an onerous process that must be judiciously performed. As is thoroughly detailed in Mr. Murray's testimony, it is the process of ***removing the blades*** and then ***re-attaching the blades*** that is time-consuming, labor-intensive, and potentially jeopardizes the useful life of the equipment. And unless the blades are being replaced, or there is manufacturer guidance or justification to perform a magnetic particle inspection of the finger dovetails, a prudent utility would not capriciously remove the blades as part of a minor or major inspection. In other words, a prudent utility would never remove the blades from any row on the turbine rotors without justification, and no justification existed here.

As such, the quoted comment in Mr. Polich's Direct Testimony that "cracks in the LP rotors would've been large enough at the time of the 2011 planned outage to be visible with the naked eye, had the buckets been removed"[10] is meaningless. The 2011 planned outage did not include (and did not have justification for) a plan to access the two low-pressure rotors by removing the upper half casing and removing the rotors by disassembling the couplings and then removing the turbine blades, all of which would have been necessary to make those "naked eye" observations referenced by Mr. Polich. And a prudent operator would not undertake the rigorous blade-removal process without manufacturer guidance or the presence of abnormal events or operational anomalies—neither of which was present in 2011. As such, speculations about what might (or might not) have been visible had Xcel Energy removed the blades is irrelevant. Since there was no reasonable basis to remove the blades in 2011, hypothetical scenarios/outcomes do not inform this prudency analysis.

What is relevant, however, is what actually *did* happen during the 2011 inspection. As addressed in Mr. Murray's Rebuttal Testimony, Xcel Energy engaged a qualified contractor, Alstom, to perform this inspection. Notably, Alstom completed a visual inspection of the low pressure turbine rotor last-stage blades—*i.e.*, a non-invasive inspection, the very thing that Mr. Polich opines would have revealed the stress corrosion cracking.[11] Alstom's inspection report confirms that "[n]o corrosion, pitting, cracks, or indications were noted during [sic] in the inspection."[12] In other words, Alstom's inspection demonstrates that—contrary to Mr. Polich's speculation—the stress corrosion

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[10] Polich Direct, p. 26.

[11] Polich Direct, pp. 25-26 ("the cracking was prevalent throughout the LP turbine rotor disk that attach the L-1 buckets to the LP turbine rotor, and would have been found if Xcel had performed non-invasive inspection [sic] during the 2011 maintenance outage.").

[12] Murray Rebuttal, Exhibit___(TPM-2) Schedule 3.

cracking on the L-1 finger dovetails was *not* observable to the naked eye in a non-invasive inspection.

Q. WHAT ELSE DOES MR. POLICH GET WRONG?

A. Mr. Polich suggests throughout his testimony that there was guidance available in 2011 "that identified the potential for steam turbine failure and provided recommended plant maintenance and inspection practices to avoid such a failure." (Polich Direct, p. 5.) Again, if speaking only in *generalities*, this is true: yes, there was guidance available to operators about how to maintain and inspect steam turbines to prevent failures. But the critical and necessary follow-up question is whether there was guidance available in 2011 that was specific to the type of unit present at Sherco 3 that warned and advised about how to prevent the type of failure that occurred on November 19, 2011 in the turbine finger dovetails. The answer to that question is a resounding "no."

Despite the lack of specific advice from GE in the form of a unit-specific, Technical Information Letter (other than TIL 1121-3AR1 which is discussed further in this testimony), Xcel Energy was nevertheless diligent in monitoring for issues and performing necessary maintenance—in addition to scheduling appropriate outages for more detailed inspection/repair work. And as confirmed by Timothy Murray and Mark Kolb, the Company *repeatedly* requested guidance from GE as early as January 15, 2008 for Sherco 3, including seeking unit-specific recommendations associated with the turbine finger dovetails and, as was their practice, constantly engaged with GE to review and discuss planned maintenance decisions. (*See* email included as Schedule 1 in Murray Rebuttal, Exhibit___(TPM-2), Schedule 1.) There is simply no justification for Mr. Polich's claim that Xcel Energy knowingly and unreasonably delayed inspections with the knowledge that such delays would increase the risk of failure. (See Polich Direct, p. 6.) The mere suggestion that Xcel Energy knowingly put its employees and the Sherco 3 turbine, the most substantial unit in its fleet, at risk is absurd.

Q. DOES MR. POLICH ACCURATELY SUMMARIZE GE'S GUIDANCE ON LP TURBINE INSPECTION AND TESTING?

A. No. First, Mr. Polich identifies two Technical Information Letters (TILs) that he indicates "pertain to the Sherco 3 LP turbine failure": TIL 1121-3AR1 and TIL 1277-2.[13] While there is no dispute that TIL 1121-3AR1 is relevant to this inquiry, Mr. Polich is mistaken that TIL 1277-2 relates to this discussion. TIL 1277-2, which—notably—was never issued to Sherco 3, applies to fossil steam turbines with steam supplied by *once-through boilers* (as opposed to Sherco 3's drum boilers). TIL 1277-2, therefore, is not applicable to Sherco 3.

Further, Mr. Polich refers to two General Electric Knowledge bulletins (GEKs) that were issued in the 1970s that purportedly address inspection requirements relevant to this matter: GEK 63355 and GEK 46354.[14] While these GEKs do apply to Sherco 3 and reflect GE's inceptive 3- to 5-year inspection-interval recommendations, these over 40-year old GEKs are outdated and fail to reflect GE's most up-to-date inspection guidance (and industry practices) as of 2011.

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[13] As explained in Mr. Kolb's Direct Testimony, GE, as the Original Equipment Manufacturer, would from time-to-time issue Technical Information Letters (TILs). When GE issued a TIL, it was issued with specific serial numbers and would be applicable *only* to turbines with those serial numbers. For example, Sherco Unit 3's low-pressure B turbine had a serial number of 170X819, and only TILs issued with that serial number would apply to Unit 3's low pressure B turbine. If GE issued a TIL that did not include any Xcel Energy serial numbers, then the Company would not have access to that TIL and it would not apply to any Company turbines.

[14] Polich Direct, pp. 38-39.

As will be discussed further below, Mr. Polich fails to include any reference to or discussion about GEK 111680, which was issued in 2007, applies to Sherco 3, and effectively supplanted the prior GE guidance as it relates to inspection-interval recommendations. GEK 111680 reflects the industry trending towards longer inspection intervals as it recommended *6-year or longer* inspection intervals–directly refuting Mr. Polich's opinion that "GE recommends three-to-five year service interval[sic] for major turbine inspections."[15]

Q. ARE THERE ANY OTHER MISSTATEMENTS IN MR. POLICH'S TESTIMONY THAT WOULD AFFECT THE OUTCOME OF THIS HEARING?

A. Yes. Mr. Polich not only claims that GE recommends a 3 to 5 year "major" inspection cycle for the steam turbine generator, but he further implies that these every-3-to-5 year major inspections should include a blades-off, magnetic particle inspection of the turbine wheel finger dovetails.[16] Whether Mr. Polich is arguing that GE recommends a major inspection every 3 to 5 years, or that GE recommends a major inspection that includes a blades-off, magnetic particle inspection of the finger dovetails every 3 to 5 years, he is wrong on both accounts. First, as will be addressed further below, GE's formal (and informal) written guidance belies Mr. Polich's "every three to five year" inspection suppositions. And GE's involvement in the 1993, 1996, and 2005 major inspections of Sherco Unit 3 debunks Mr. Polich's opinion that GE intended

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[15] Polich Direct, p. 39.

[16] Polich Direct, p. 54: "GE recommends inspection [sic] of the turbine rotor for problems like SCC should be performed every three to five years. The inspection for SCC induced cracks in the LP rotor disk requires removal of the buckets from the rotor. Xcel did not perform this type of inspection within the recommended time period. GE specifically states the buckets need to be removed from the rotor to test for SCC."

all major inspections to include a blades-off, magnetic particle inspection of the turbine wheel finger dovetails.

GE was contracted to perform major inspections on the Sherco 3 LP turbine in 1993 (GE removed and replaced several L-1 blades due to tenon failures but did not perform a full blades-off magnetic particle inspection) and 1996 (GE removed a few blades from each L-1 wheel for thorough inspection of tie wire holes and tenons for cracking but did not perform a full blades-off magnetic particle inspection). And in 2005, Xcel Energy consulted with GE about the scope of the planned major inspection. Further, GE submitted a bid for the work and, while not selected, GE representatives were on-site for the major overhaul/inspection where Mechanical Dynamics & Analysis (MD&A) replaced the turbine end and generator end last stage blade covers. Yet, GE—as the Original Equipment Manufacturer (OEM) and issuer of TIL 1121-3AR1—neither submitted a bid for nor recommended a blades-off, magnetic particle inspection of the turbine finger dovetails during the 2005 major inspection. Why wouldn't GE have pushed for (or suggested/proposed) a blades-off, magnetic particle inspection of the turbine finger dovetails as part of the 1993, 1996, or 2005 major overhauls/inspections if GE's guidance was, as Mr. Polich asserts, to routinely perform such an inspection as part of a major overhaul/inspection? This was not an oversight on GE's part. Such an inspection simply was not viewed as necessary for the Sherco 3 low pressure turbines, given Unit 3's operating history.

Today, even with the benefit of hindsight and knowledge of the Sherco 3 event, GE has not issued any guidance recommending either: (1) a major inspection every 3 to 5 years; or (2) a major inspection with the additional blades-off, magnetic particle inspection of the turbine finger dovetails every 3 to 5 years. Mr. Polich's claims to the contrary are not supported by GE guidance and lack merit.

Q. TO CLARIFY, IS A "MAJOR" OVERHAUL/INSPECTION THE SAME THING AS A TIL 1121-3AR1 BLADES-OFF, MAGNETIC PARTICLE INSPECTION OF THE FINGER DOVETAIL ATTACHMENTS?

A. No, these are two entirely separate categories of inspections. GE's manufacturer guidance is instructive to understanding the scope of a major overhaul/inspection. In GEK 111680: Creating an Effective Steam Turbine Maintenance Program (2007), GE explains that a major inspection consists of "[a]ll inspections completed as part of a minor outage/overhaul with exception of borescope inspections."[17] The GEK proceeds to list nine additional recommended scheduled activities, such as "clean[ing] and inspect[ing] stationary and rotating components" and "appropriate non-destructive testing and examinations."[18] Notably, according to this 2007 guidance, the scope of a major overhaul/inspection does ***not*** include a blades-off, magnetic particle inspection of the finger dovetail attachments.

Put differently, the TIL 1121-3AR1 inspection (*i.e.*, blades-off, magnetic particle inspection of the finger dovetail attachments) is a separate, *additional* layer on top of a major inspection that, pursuant to the TIL's recommendations, should only be performed whenever all of the turbine blades are being removed (for

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[17] *See* Sirois Rebuttal, Exhibit___(HJS-2), Schedule 4.

[18] *See* Sirois Rebuttal, Exhibit___(HJS-2), Schedule 4, pp. 14-15.

whatever purpose) *or* if there are abnormal events or operational anomalies that cause concern for the long-term reliability of the unit.

Q. AS OF TODAY, ARE YOU AWARE OF ANY CHANGES GE IMPLEMENTED IN THE DESIGN OF THE FINGER DOVETAIL ATTACHMENT AREAS IN ITS LOW-PRESSURE TURBINE PRODUCTS?

A. Yes. On June 17, 2008, GE was granted United States patent US 7,387,494 B2 titled "Finger Dovetail Attachment Between A Turbine Rotor Wheel and Bucket For Stress Reduction," Yehle et. al. (2008 Patent).[19] The essence of the 2008 Patent is the incorporation of compound radii in the two transition areas (ledges) between varying thicknesses of the wheel fingers and at the bottom radius between adjacent wheel fingers. This design detail is similar to the design process for contouring the side surfaces of steam and gas turbine wheels to produce "constant" or nearly constant stress profile from the hub of the wheel toward outer radius of the wheel but not including the rim of the wheel. The 2008 Patent abstract clearly states: "The fillets on the wheel fingers and slot bottoms have a blend of different radii with the larger radii outward of the smaller radii to reduce stress concentrations and to avoid stress corrosion cracking in steam turbine applications."

Q. AND DOES THIS DESIGN CHANGE FURTHER SUPPORT THE THIELSCH REPORT CONCLUSION REGARDING THE PRIMARY CAUSAL FACTOR BEHIND THE EVENT?

A. Yes. As previously mentioned, Mr. Polich failed to even mention the Thielsch Report's actual conclusion of the root cause of the Event. The Report

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[19] Tipton Direct, Exhibit___(AAT-1), Schedule 3, pp. 450-456.

determined that GE's equipment design was the primary causal factor responsible for stress corrosion cracking and that the design stresses at the LP L-1 finger-pinned blade attachment area of the LP L-1 rotor disks were sufficiently high to render the Sherco 3 low pressure steam turbine rotor material susceptible to stress corrosion cracking *under normal operating conditions*. GE's work on the 2008 Patent confirms the existence of this fundamental design issue.

Q. WHY IS THAT SIGNIFICANT?

A. This is important because prior to the November 2011 Sherco 3 failure event involving the L-1 wheel finger dovetail attachment, and unbeknownst to Xcel Energy, GE sought to improve the design of the finger dovetail attachment to reduce the susceptibility to stress corrosion cracking and applied for and was granted a patent for an improved design. This patent application process was ongoing while Xcel Energy key employees sought guidance from GE in early 2008 about inspections for its low-pressure turbines in the drum boiler plants. GE, however, never disclosed that it had re-designed the finger dovetail attachment to reduce susceptibility for stress corrosion cracking—which would have informed Xcel Energy that its existing design was, in fact, susceptible to such issues.

Q. CAN YOU SUMMARIZE YOUR OVERALL CONCERNS WITH MR. POLICH'S TESTIMONY?

A. Mr. Polich's testimony is based upon his reading of several documents, including the Thielsch Report and various GE technical guidelines, but he has not demonstrated the knowledge or experience to understand them. As I will discuss in greater detail below, Mr. Polich gratuitously "cherry-picks" from those documents and then selectively uses general testimony from the GE trial (where the Company was not a party) to suggest that Xcel Energy knew about the risks, but nevertheless chose not to perform the necessary inspection that could have prevented the 2011 failure. Simply put, it is apparent ***only*** to Mr. Polich, and ***only*** with the benefit of 20/20 hindsight, that this accident should have been prevented by performing a blades-off, magnetic particle inspection of the finger dovetails without any recommendation from GE or other cause to do so.

It does not appear that Mr. Polich clearly understands that a major inspection of a utility-size steam turbine generator involves literally thousands of components and an equal number of repair-replace or use "as is" decisions associated with the steam and feedwater systems, instrumentation, and balance of plant equipment. Tellingly, Mr. Polich ignores (or fails to understand) the difference between an ordinary "major" inspection, such as the one originally planned for 2011 and then deferred to 2014, and a major inspection that would have also included removing the blades to perform a magnetic particle inspection of the finger dovetails as described in TIL 1121-3AR1.

Mr. Polich also ***admits*** (as he must) that the blades-off, magnetic particle inspection in full accordance with TIL 1121-3AR1 is the required inspection to detect latent stress corrosion cracking in the finger dovetails. (See DOC response to XE IR 10 included as Exhibit___(HJS-2, Schedule 3 and Polich Direct, pp. 40-41.) Yet the planned 2011 inspection—the same inspection that Mr. Polich says "would have discovered the extent of the SCC in the LP turbine

L-1"[20] and for which "Xcel's decision to delay that inspection … was directly responsible for the accident"[21]—*did not include, and had no reason to include,* a blades-off, magnetic particle inspection of the turbine finger dovetails. This is why precision is so important when describing what "inspections" occurred—or, as Mr. Polich suggests, *should have* occurred.

In sum, if we take Mr. Polich's generalized opinions and reasoning to their conclusion, he opines that the "buckets off" (*i.e.*, blades off) magnetic particle inspection described in TIL 1121-3AR1 (indisputably, the inspection needed to detect latent stress corrosion cracking) should be performed every 3 to 5 years—without reasonable consideration of the additional outage times, costs, and risk to equipment. There is no guidance from GE (or any industry practice) that in 2011—or even today—supports Mr. Polich's suggestion that the blades-off, magnetic particle inspection should be routinely performed every 3 to 5 years as part of a major inspection.

III. MR. POLICH'S MISCHARACTERIZATION OF THE STATE OF INDUSTRY GUIDANCE IN NOVEMBER 2011

Q. PRIOR TO NOVEMBER 2011, HAD GE PROVIDED GUIDANCE ON LP TURBINE INSPECTION AND TESTING APPLICABLE TO SHERCO 3?

A. Yes. As I discussed in my direct testimony, GE issues technical information letters (TILs) and General Electric Knowledge bulletins (GEKs) to its customers to provide technical advice and guidance for inspecting and maintaining GE-designed and manufactured power plant equipment, including

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[20] Polich Direct, p. 58.

[21] Polich Direct, p. 58.

steam turbines. As it relates to inspection of the LP turbine blades, GE issued two TILs: TIL 1121-3AR1 (1993) and TIL 1277-2 (1999). But of those two, *only TIL 1121-3AR1 applies to Sherco Unit 3* and would only have applied when the L-1 and L-0 blades with finger dovetails were removed from the rotor. TIL 1277-2, which GE did not provide to Xcel Energy for Sherco 3, expressly applies to fossil steam turbines with once-through boilers (as opposed to all the Sherco units' drum boilers) and therefore is not applicable.

As it relates to inspection frequency recommendations, GE issued GEK 63355 and GEK 46354 in the 1970s. However, in 2007, GE issued updated inspection recommendations in GEK 111680: Creating an Effective Steam Turbine Maintenance Program.[22]

Q. DO ANY OF GE'S GEKS OR TILS—INCLUDING TIL 1277-2, WHICH EXPRESSLY APPLIES TO ONCE-THROUGH BOILERS (AS OPPOSED TO SHERCO 3'S DRUM BOILERS)—PRESCRIBE A 3 TO 5 YEAR MAJOR INSPECTION INTERVAL?

A. Neither TIL 1121-3AR1 nor TIL 1277-2 recommend a 3- to 5-year major inspection interval. When GE issued GEK 63355 and GEK 46354, over forty years ago, GE recommended that major inspections should take place every 3 to 5 years. Over time, however, both GE's recommendations and industry practice related to those inspection intervals has changed, to reflect longer intervals.

As noted above, GE issued updated inspection recommendations in 2007 when it issued GEK 111680. This GEK identified a 6-year or longer major inspection

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[22] *See* Sirois Rebuttal, Exhibit___(HJS-2), Schedule 4.

interval, recognizing that inspection intervals could be extended beyond 6 years depending on "fleet experience, testing results, and operational assessment[.]"[23] Notably, GEK 111680 expressly recognized that: "Many of the factors related to the exact timing of inspections are determinable by the owner/operator; other factors draw from empirical knowledge and fleet experience."

In other words, GE's own guidance refutes Mr. Polich's 3 to 5 year major inspection interval opinions. Rather than prescribing specific inspection intervals, GE acknowledged that the owner/operator is in the best position to determine inspection intervals based on numerous factors, including fleet experience. And I am aware that GE gave a PowerPoint presentation in 2006 to Xcel Energy key personnel that confirmed that the industry trend for major inspection intervals had increased from "5 to 7 years" to "10-12" years.[24] In sum, GE's guidance confirms that Mr. Polich is mistaken that there is a "one size fits all" major inspection interval for steam turbines.

Q. DOES MR. POLICH ADDRESS GEK 111680 IN HIS TESTIMONY?

A. No, Mr. Polich does not address GEK 111680, which GE issued in 2007. The only GEKs referenced by Mr. Polich regarding the topic of inspection intervals were GEK 63355 and GEK 46354, which were both issued in the 1970s. Therefore, Mr. Polich ignored the most current GE guidance during the time period prior to the Event.

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[23] *See* Sirois Rebuttal, Exhibit___(HJS-2), Schedule 4.

[24] Murray Rebuttal, Exhibit___(TPM-2), Schedule 2, p. 34.

Q. DO ANY OF GE'S GEKS OR TILS PRESCRIBE A 3 TO 5 YEAR MAJOR INSPECTION INTERVAL THAT WOULD INCLUDE A BLADES-OFF, MAGNETIC PARTICLE INSPECTION OF THE FINGER DOVETAILS?

A. No – not prior to 2011 and not today.

Q. IS GENERAL KNOWLEDGE THAT STRESS CORROSION CRACKING CAN OCCUR IN LP TURBINES THE SAME THING AS HAVING OBJECTIVE FACTS/INFORMATION JUSTIFYING A TIL 1121-3AR1 BLADES-OFF, MAGNETIC PARTICLE INSPECTION OF THE FINGER DOVETAILS FOR A SPECIFIC LP TURBINE?

A. No. Large utility steam turbines such as those installed at Sherco are not standardized within the power generation industry. There are significant design differences between steam turbines operating with similar or even the same conditions but from different manufacturers.

For example, as I stated above, the process for removing and replacing all of the pins and blades from each of the four L-1 finger-dovetail rows (as required to inspect for stress corrosion cracking) is extremely onerous on GE blades. In contrast, while a Westinghouse or Alstom straight or curved axial entry blade is also susceptible to stress corrosion cracking, the inspections for such cracking are less onerous because the blades can easily be removed and the wheel rim can then be inspected using magnetic particle inspection or ultra-sonic inspection techniques.

Similarly, design differences in steam turbines can lead different turbines to be more or less susceptible to stress corrosion cracking. To be sure, no one is disputing that—generally—the power generation industry was fully aware of and appreciated that stress corrosion cracking could occur in low pressure turbines. But because of the differences in operating conditions (steam pressure and temperature, operating speed, duty cycle (load following, base load, cycling), frequency of overspeed trips and many others), differences in design features (such as axial, tangential entry, and finger dovetails), differences in rotor and blade mechanical and chemical properties, and many other factors, the extent and frequency of stress corrosion cracking will vary.

Unfortunately, in the case of Sherco 3—based solely on hindsight and all of the information learned as a result of the 2011 Event—we now know that the GE low pressure turbine L-1 finger dovetail stage was more susceptible to stress corrosion cracking due to its design. Compounding the issue, GE's design of the finger dovetail made inspections difficult. And as explained by Mr. Tipton in both his Direct and Rebuttal Testimony, the GE finger dovetail was also designed in such a way that the as-designed operating stresses were sufficient to result in stress corrosion cracking even in "pure" laboratory water.

In summary, Xcel Energy's general knowledge in 2011 that stress corrosion cracking ***may occur*** in steam turbines was not—by itself—sufficient to warrant an invasive, costly, and time-consuming blades-off, magnetic particle inspection of the L-1 finger wheel dovetails in the Sherco 3 unit. Prior to the Event, there was no general knowledge or industry guidance suggesting that the specific design features and properties of Sherco 3 was more susceptible to stress corrosion cracking.

Q. WOULD IT BE REASONABLE FOR XCEL ENERGY TO SIMPLY "ERR ON THE SIDE OF CAUTION" AND PERFORM A TIL 1121-3AR1 BLADES-OFF, MAGNETIC PARTICLE INSPECTION OF THE FINGER DOVETAILS AS PART OF EVERY MAJOR

OUTAGE EVEN IN THE ABSENCE OF ABNORMAL EVENTS/OPERATIONAL ANOMALIES?

A. No. The TIL 1121-3AR1 magnetic particle inspection is a time consuming, labor intensive, and expensive process that causes long-term wear on the machine and therefore should only be performed in accordance with GE's technical guidance.

As described in more detail in Mr. Murray's Rebuttal Testimony, it is Xcel Energy's experience that such an inspection would add 2 to 4 weeks to a planned major outage, possibly longer depending on the amount of repairs needed to the retaining pin holes in the turbine wheel that were damaged during removal of the pins—and add approximately $1-$2 million to the overall cost of the major outage. Also, as set forth in my Direct Testimony, the repair of retaining pin holes eventually requires a major weld repair of the rotor because the pin holes can only be "oversized" so many times. Accordingly, it would be patently *unreasonable* for an operator to routinely perform a blades-off, TIL 1121-3AR1 magnetic particle inspection without the required justification.

Q. ARE YOU AWARE OF ANY STEAM TURBINE OPERATORS THAT, PRIOR TO THE EVENT, ROUTINELY PERFORMED BLADES-OFF, MAGNETIC PARTICLE INSPECTIONS OF THE TURBINE FINGER DOVETAILS TO DETECT LATENT STRESS CORROSION CRACKING IN THE ABSENCE OF ABNORMAL EVENTS/OPERATIONAL ANOMALIES?

A. No.

Q. CAN YOU PLEASE SUMMARIZE THE STATE OF INDUSTRY KNOWLEDGE IN NOVEMBER 2011 REGARDING THE POTENTIAL THAT STRESS CORROSION

CRACKING COULD LEAD TO THE KIND OF CATASTROPHIC FAILURE THAT WAS EXPERIENCED AT SHERCO 3 THAT WOULD HAVE WARRANTED A BLADES-OFF, MAGNETIC PARTICLE INSPECTION OF THE TURBINE WHEEL FINGER DOVETAIL ATTACHMENTS?

A. The power generation industry where steam is generated with fossil and nuclear fuel has generally been aware of stress corrosion cracking since the 1960s. The Thielsch Report provides a detailed review of "Industry Experience," including an EPRI study conducted in 1997.[25] However, the fact remains that *general* knowledge of the potential for stress corrosion cracking is not a substitute for *specific* knowledge as it relates to a specific steam turbine design operating with conditions outlined previously in this report. The November 2011 Sherco 3 L-1 failure, where the blades liberated from the wheel, was the first in the industry. This event substantially contributed to industry knowledge about the potential of latent stress corrosion cracking in wheel finger dovetails and prompted GE to subsequently issue TIL 1886, technical guidance specific to low pressure turbines with L-1 finger dovetails and operating with steam generated by a drum boiler—*i.e.*, the same type of low pressure turbine and blade attachments present in Sherco 3.

As of November 2011, however, there was no GE guidance recommending a time-based, magnetic particle inspection of the L-1 wheel finger dovetails for power generating plants with drum boilers (in the absence of abnormal events or operational anomalies as set forth in TIL 1121-3AR1).

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[25] Thielsch Report, Tipton Direct Exhibit___(AAT-1), Schedule 2, pp. 85-86 (pp. 83-84 of the Report).

IV. TURBINE INSPECTIONS AND XCEL ENERGY'S GENERAL PRACTICES

Q. DO YOU AGREE WITH MR. POLICH'S SUGGESTION THAT A TIL 1121-3AR1 MAGNETIC PARTICLE INSPECTION, WHICH REQUIRES REMOVAL OF THE BLADES AND SIGNIFICANTLY EXPANDS THE DURATION AND COST OF AN ORDINARY "MAJOR" OVERHAUL/INSPECTION, SHOULD BE PERFORMED EVERY 3 TO 5 YEARS?

A. No. None of the unit-specific technical information letters issued for Sherco 3 (*i.e.*, TIL 1121-31 (1992), TIL 1121-3AR1 (1993), and even TIL 1886 (2013)—which was issued by GE after the Sherco 3 L-1 failure—prescribe a time-based, major overhaul/inspection cycle. And TIL 1277-2 (1999), which is not and never has been applicable to Sherco 3, also fails to recommend a specific time between outages. Further, as addressed earlier in my testimony, GEK 111680 (issued in 2007) unequivocally confirms that Mr. Polich's 3 to 5 year major-inspection-frequency opinions are based on guidance issued more than forty years ago, which is now outdated and inaccurate. Further, GEK 111680 describes the recommended major overhaul/inspection activities and establishes that GE does not consider the TIL 1121-3AR1 blades-off, magnetic particle inspection to be a routine part of such an inspection.

In other words, Mr. Polich is incorrect that GE provided formulaic, time-based directions for performing a blades-off, magnetic particle inspection of the turbine finger dovetails every 3 to 5 years. Mr. Polich has failed to provide, with a specific citation, an up-to-date GE document that in November 2011 (or subsequently) recommends a 3 to 5 year "major" overhaul/inspection cycle. Notably, it would be difficult if not impossible for GE to market utility steam turbines if their recommendation of time between major outages was 3 to 5 years, since GE's competitors recommend time between outages that are more in line with Xcel Energy's and other owner/operators' practices of approximately every 10 years (or longer).

Q. WOULD A BLADES-OFF, MAGNETIC PARTICLE INSPECTION OF THE FINGER DOVETAILS EVERY 3 TO 5 YEARS—AS SUGGESTED BY MR. POLICH—BE PRUDENT OPERATION IN THE ABSENCE OF ANY OBJECTIVE FACTS SUPPORTING SUCH AN INSPECTION?

A. No. Performing a blades-off, magnetic particle inspection of the finger dovetails on a routine, *i.e.*, every three to five years, basis on a large unit such as Sherco 3 would not be prudent for any utility. The cost of the inspection, lost generation revenue (during the 6- to 8-week—or longer—outage) and cost of replacement power for such frequent inspections would certainly be questioned by the regulator. As previously discussed, based on the design of the turbine, the act of removing the finger dovetailed blades consumes some of the life of the low-pressure rotor since many of the blade retaining pins must be drilled out for removal and the corresponding hole must be oversized by drilling and reaming for the fitting of replacement blade retaining pins. In TIL 1886, which was issued approximately two years *after* the Sherco 3 failure, GE confirmed that the wheel finger dovetails should be inspected by removing the blades and performing a magnetic particle inspection in accordance with TIL 1121-3AR1 after ***22 years*** of operation or prior to that whenever the blades are otherwise removed for replacement or inspection. In other words, even with the benefit of hindsight of the 2011 Event, GE's updated (*i.e.*, post-Event) guidance prescribes only three circumstances that would warrant a TIL 1121-3AR1 magnetic particle inspection: (1) the presence of abnormal events or operational anomalies (which I will address below); (2) if the steam turbine has been operational for 22 years; and (3) whenever the blades are otherwise removed for replacement or inspection.

Q. IS THIS CONSISTENT WITH THE COMPANY DID IN 1999?

A. Yes. In 1999, the planned Sherco 3 outage included the removal and replacement of the L-1 blades with an upgraded design. Even though Sherco 3 had only been operational for 12 years, and there were no abnormal events or operational anomalies, Xcel Energy followed the guidance of TIL 1121-3AR1 and contracted with GE to perform a magnetic particle inspection of the turbine finger dovetails as part of that planned major maintenance overhaul because the blades had already been removed. Notably, no issues were detected during this inspection. The inspection report is included as Exhibit___(HJS-2), Schedule 5)

Q. THE IMPLICATION OF MR. POLICH'S TESTIMONY IS THAT XCEL ENERGY DID THE BARE MINIMUM (OR LESS) MAINTENANCE ON ITS LOW PRESSURE STEAM TURBINES—HOW DO YOU RESPOND?

A. I disagree with that assertion (and what it incorrectly implies) as my experience and the evidence does not support Mr. Polich's testimony. Aside from his non-specific castigations that the Company failed to follow (outdated) industry guidance (*i.e.*, the over 40-year old GEKs, issued in the 1970s), or apply Technical Information Letters (i.e., TIL 1277-2), that had not been issued to Sherco 3's low pressure turbines, Mr. Polich has not pointed to any maintenance failure by the Company. In addition, there are numerous examples of the Company using available information to make the prudent decisions as to its maintenance program for Unit 3 (and all the Sherco units).

For example, as explained by Mr. Murray in his Rebuttal Testimony, in 2001, at a GE-sponsored conference in Atlanta, a GE representative shared with Xcel Energy representatives (including Murray) that the manufacturer was starting to see *tangential entry dovetail* cracking in low-pressure turbines with drum boilers—in addition to the cracking issues observed with tangential entry dovetails in once-through boilers that was the basis for GE's issuance of TIL 1277-2. Accordingly, despite the absence of written guidance in the form of a Technical Information Letter, GE recommended that utilities with drum boilers (in addition to the utilities that had previously received written guidance specific to units with once-through boilers) conduct phased array ultrasonic inspections of all tangential entry dovetails to look for cracking. The first major overhaul that arose after this conference was the 2005 major overhaul on Sherco Unit 3. Although GE had still not issued any written guidance incorporating their recommendations from the 2001 conference to units with drum boilers, Xcel Energy nevertheless performed a phased array ultrasonic inspection of the L-2 and L-3 tangential entry dovetails on Unit 3.

Next, in 2007, the Company planned a major outage for Sherco Unit 1, which also has a drum boiler. As part of the inspection process for Unit 1, the Company once again performed phased array ultrasonic testing of the tangential entry wheel dovetails even though GE had still not issued any updated written guidance incorporating their informal recommendations conveyed during the 2001 Atlanta conference to units with drum boilers. For Unit 1, this included the L-1 tangential entry dovetail row, in addition to the L-2 and L-3 tangential entry dovetail rows. The vendor performing this inspection detected cracking on the L-1 tangential entry wheel dovetails, which then required machining of the wheel rims followed by a major repair weld. The four L-1 wheels were repaired by Alstom in Richmond, VA and Unit 1 was returned to service.

Based on the issues discovered in Unit 1, Xcel Energy took an unplanned outage in 2008 to also inspect Sherco 2 for L-1 stress corrosion cracking using phased array ultrasonic testing of the tangential entry dovetails. Notably, GE had still not issued any updated written guidance incorporating their recommendations relating to phased array ultrasonic testing of the tangential entry dovetails on units with drum boilers (as first addressed by GE in the 2001 Atlanta conference). The decision to take the unplanned outage to inspect Sherco 2 was based upon reasonable information and evidence at that time: both Unit 1 and Unit 2 had been in service since the 1970s (in contrast to Unit 3, which was put in service in 1987); both Unit 1 and Unit 2 had tangential entry dovetails on the L-1 stage (in contrast to Unit 3, which had *finger* dovetails on the L-1 stage); and Unit 1 and Unit 2 were operated in the exact same fashion—same equipment, same monitoring, and same chemistry team (in contrast, Unit 3 had its own dedicated monitoring and chemistry team). The Company determined that, based upon all these similarities and the findings of stress corrosion cracking on the Unit 1 tangential entry dovetails, it was prudent to inspect Unit 2 to confirm that there was no similar cracking (there wasn't). The 2008 unplanned outage and inspection of Unit 2 was completed without specific guidance from GE, but clearly demonstrates that Xcel Energy was making reasonable, informed, and prudent maintenance decisions based on available data and the training and experience of its key personnel.

V. XCEL ENERGY'S DECISIONS WITH RESPECT TO TURBINE INSPECTIONS UP TO 2011 AND CONSISTENCY WITH INDUSTRY PRACTICES

Q. DO YOU AGREE WITH MR. POLICH'S SUGGESTION THAT XCEL ENERGY "DELAYED" OR "DEFERRED" INSPECTION OF THE LOW PRESSURE TURBINE ROTOR DISK WHEEL DOVETAIL?

A. No. Mr. Polich misconstrues or misunderstands Xcel Energy's decisions as they relate to the 2011 planned inspection of the low-pressure turbine. While Xcel Energy did defer the major inspection of the low-pressure turbine originally planned for 2011 until 2014, at no time did the planned major inspection include a "blades off" TIL 1121-3AR1 magnetic particle inspection of the turbine L-1 and L-0 wheel finger dovetails—a decision based on the fact that there were no objective facts (*i.e.*, abnormal events or operational anomalies) or GE / industry guidance that would have supported such an invasive inspection at that time. At most, during the originally planned 2011 inspection of the low-pressure turbine, Xcel Energy may have inspected the L-2 and L-3 tangential entry dovetails using the phased array ultrasonic inspection technique since this inspection method does not require removal of the blades. But this inspection (or anything less than an inspection that would have removed the blades) would not have detected the latent stress corrosion cracking that was later discovered in the L-1 finger dovetails, an important fact which has not been considered in Mr. Polich's testimony. As discussed by Mr. Murray in his Rebuttal Testimony, Xcel Energy's contractor (Alstom) completed a visual inspection of the low-pressure turbine rotor last-stage blades in 2011 and observed that "[n]o corrosion, pitting, cracks, or indications were noted during [sic] in the inspection."[26]

This is why it is important for witnesses to be precise about what types of inspections they are talking about in their testimony. Here, based upon information that Xcel Energy had in 2011, there was no reason to include a blades-off, TIL 1121-3AR1 magnetic particle inspection of the L-1 and L-0 turbine wheel finger dovetails in either the originally planned 2011 inspection or the "deferred" 2014 inspection.

Q. DO YOU AGREE WITH MR. POLICH'S CONCLUSION THAT XCEL ENERGY'S DECISION TO DELAY OR DEFER INSPECTION OF THE LOW PRESSURE TURBINE ROTOR DISK DOVETAIL WAS THE TRUE ROOT CAUSE OF THE NOVEMBER 19, 2011 ACCIDENT?

A. No. There was no evidence to indicate that the Sherco 3 L-1 finger dovetail had been subjected to operational anomalies or otherwise experienced abnormal events as defined by GE. Also, there was no guidance from GE that would reasonably lead Xcel Energy, or any utility owner/operator for that matter, to perform this invasive and costly TIL 1121-3AR1 inspection.

Instead, I agree with the root cause determinations stated in the Thielsch Report:

> The primary causal factor responsible for the stress corrosion cracking of LP "B" disk was the high static stresses generated

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[26] Murray Rebuttal, Exhibit___(TPM-2), Schedule 3

> during normal operation at the pin holes, ledges and at the base of the fingers of the finger pinned blade attachments in the low pressure turbine L-1 stage disks. These stresses in the finger pinned blade attachments are solely a function of the original design and operation at design conditions.[27]

My over 50 years of experience in the industry, combined with my interviews with key Xcel Energy personnel in January 2016, reviews of their depositions and trial testimony, my review of key documents such as the Thielsch Report, GE documentation such as the TILs, GEKs, and GE internal communications, leads me to conclude that the Company acted in a reasonable and prudent manner in the operation and maintenance of Sherco Unit 3 and its two LP turbines.

Importantly, Xcel Energy is in the business of producing power; as such, it operates large utility-size steam turbine generators. Xcel Energy is not a steam turbine designer and does not have the GE fleet data necessary to understand the nuances of the GE-designed steam turbines. Owners and operators such as Xcel Energy rely on manufacturers—here, GE—for unit-specific guidance about which inspections should be performed on specific design features. And contrary to Mr. Polich's suggestions, GE did not provide any guidance that would have justified the blades-off, TIL 1121-3AR1 magnetic particle inspection of the finger dovetails in the absence of abnormal events or operational anomalies—*i.e.*, the *only* inspection that would have detected the latent stress corrosion cracking of the L-1 finger dovetail in 2011.

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[27] Thielsch Report, Tipton Direct Exhibit___(AAT-1), Schedule 2, pp. 95-96 (pp.93-94 of the Report).

Q. BUT DOESN'T MR. POLICH CLAIM THAT SHERCO UNIT 3 ***DID*** EXPERIENCE ABNORMAL EVENTS OR OPERATIONAL ANOMALIES THAT SHOULD HAVE PROMPTED A TIL 1121-3AR1 MAGNETIC PARTICLE INSPECTION?

A. Mr. Polich did make that claim, generally, and he is simply wrong once again. Mr. Polich did not present any testimony defining or explaining what might have constituted "abnormal events" or "operational anomalies" that would have triggered a TIL 1121-3AR1 magnetic particle inspection. Instead, in response to an Information Request,[28] he pointed to a report from Mr. James Schultz, an expert for GE in the *GE Litigation*, who I understand is not presenting testimony in this case and whose report in the GE Litigation was thoroughly addressed and rebutted by both me and Company witness David Daniels.[29] Despite this direct and specific request for information from the Company, Mr. Polich did not (or could not) identify any specific "abnormal events or operational anomalies."

VI. CONCLUSION

Q. DOES THE FACT THAT A FAILURE HAPPENED DEMONSTRATE THAT THERE WAS IMPRUDENT MAINTENANCE?

A. No, and it would be improper to draw such conclusions based solely on the fact that something did, unfortunately, go wrong (*i.e.*, 20/20 hindsight). The failure happened for the reasons stated in the Thielsch Report (and summarized in Mr.

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[28] See DOC's Response to XE Information Request No. 30, included as Exhibit___(HJS-2), Schedule 6.

[29] For example, regarding the condenser tube leaks discussed by Mr. Schultz and included in the passage relied on by Mr. Polich, I addressed this issue in my rebuttal report "Rebuttal to Expert Witness Report of James D. Schultz" dated April 25, 2016 at paragraph 23. My rebuttal report is included as Exhibit___(HJS-2), Schedule 7.

Tipton's Direct and Rebuttal testimony). But as to prudence, and as explained in this Rebuttal (with evidentiary support), Xcel Energy made prudent, considered, and well-reasoned maintenance decisions related to Unit 3 that were well within the range of reasonable utility practices. Not only were those maintenance decisions reasonable and aligned with industry trends, they were consistent with GE's applicable guidance existing at that time (*i.e.*, GEK 111680 and GE's 2006 PowerPoint confirming industry trend for inspection intervals had increased to "10-12" years).

Q. WAS IT COMMON INDUSTRY PRACTICE IN 2011 TO DO A BLADES-OFF, MAGNETIC PARTICLE INSPECTION OF THE FINGER DOVETAILS TO DETECT LATENT STRESS CORROSION CRACKING IN THE ABSENCE OF ABNORMAL EVENTS/OPERATIONAL ANOMALIES?

A. No, not to my knowledge and based on my 53-years of industry experience. It would be imprudent to perform such an invasive, costly inspection without justification—especially, as Mr. Polich suggests, every 3 to 5 years. At the plant level, the engineering manager and plant manager would likely question this recommendation (and the associated expenditure, as they did for the unplanned outage to inspect the L-1 tangential entry wheel dovetails on Sherco 2 in 2008) without any indication of abnormal events or operational anomalies or manufacturer guidance that the risk would be too great if the steam turbine generator was allowed to continue to operate. The applicable regulators would also likely take issue with such expensive outages that were not required by manufacturer guidance. It is important to keep in mind that the Sherco 3 L-1 finger dovetail failure was the first in the industry. Prior to this event, there was no history of a similar failure where blades were liberated from the rotor, so it would have been uncommon for a plant to perform this inspection in the absence of an abnormal event or operational anomaly.

Q. WHEN THE COMPANY MADE ITS OUTAGE PLAN IN 2011, DID THE COMPANY MAKE REASONABLE DECISIONS BASED ON THE INFORMATION AND MANUFACTURER GUIDANCE THAT THE COMPANY HAD AT THE TIME?

A. Yes. In 2011, there was no specific guidance from GE that would necessitated Xcel Energy to schedule a major inspection of the low pressure turbine—let alone a major inspection that would have included removing the blades to perform a magnetic particle inspection of the L-1 and L-0 finger dovetails. Further, contrary to Mr. Polich's testimony, GE—as the Original Equipment Manufacturer—confirmed in GEK 111680 that owners/operators are in the best position to determine inspection intervals based on numerous factors, including fleet experience. And in a 2006 PowerPoint presentation to Xcel Energy key personnel, GE further confirmed that the industry was trending to "10-12" years between major inspections. This directly disproves Mr. Polich's opinion that "GE recommends three to five year service interval [sic] for major turbine inspections."[30]

Q. IN YOUR EXPERT OPINION, BASED ON YOUR 53-YEARS OF STEAM TURBINE INDUSTRY EXPERIENCE AND REVIEW OF SHERCO 3 MAINTENANCE AND OPERATIONS PRACTICES, DID THE COMPANY PRUDENTLY OPERATE AND MAINTAIN SHERCO 3?

A. Yes. The Company's actions operating and maintaining Sherco 3 were well within the range of reasonable utility actions, based on information available to

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[30] Polich Direct, p. 39.

the Company at the time. Further, the Company's actions operating and maintaining Sherco 3 were well within common industry practice as they existed at the time of the November 2011 event.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Northern States Power Company, doing business as Xcel Energy
Information Request

Docket No.:	E002/GR-12-961, E002/GR-13-868; E999/AA-13-599; E999/AA-14-579; E999/AA-16-523; E999/AA-17-492; E999/AA-18-373; OAH 65-2500-38476 Sherco 3
Requestor:	Xcel Energy - Tara R. Duginske, Assistant General Counsel, Xcel Energy
Requestor email:	Tara.R.Duginske@xcelenergy.com
Requested from:	Minnesota Department of Commerce
Date of Request:	August 14, 2023 Information Request No. 25
Response Due:	August 24, 2023

Reference: Direct Testimony of Mr. Richard Polich

Question:

For each of the following uses of the term "good utility practice," please identify all documents relied on by Mr. Polich to describe or define "good utility practice" as used in the identified testimony:

a. Page 5, Line 12
b. Page 6, Line 8
c. Page 55, Line 15
d. Page 56, line 8
e. Page 56, Line 11

Response:
The term good utility is defined on pages 6 & 7 of Mr. Polich's testimony and no other documents were used to describe or define the term.

Preparer:	Richard A. Polich
Title:	Managing Director
Department:	Power Supply
Telephone:	501-316-9805
Date:	August 24, 2023

Northern States Power Company, doing business as Xcel Energy
Information Request

Docket No.:	E002/GR-12-961, E002/GR-13-868; E999/AA-13-599; E999/AA-14-579; E999/AA-16-523; E999/AA-17-492; E999/AA-18-373; OAH 65-2500-38476 Sherco 3
Requestor:	Xcel Energy - Tara R. Duginske, Assistant General Counsel, Xcel Energy
Requestor email:	Tara.R.Duginske@xcelenergy.com
Requested from:	Minnesota Department of Commerce
Date of Request:	August 9, 2023 Information Request No. 2
Response Due:	August 21, 2023

Question:

State all experience Mr. Polich has with operating or maintaining fossil steam turbines, including but not limited to, and separately identifying, experience with GE manufactured turbine-trains like Sherco Units 1 and 2 (with tangential entry dovetails on the L-1) and experience with GE manufactured turbine-trains like Sherco Unit 3 (with finger dovetails on the L-1).

Response:

Mr. Polich has over 43 years of experience with fossil power plants with steam turbines. In addition, Mr. Polich also has experience with nuclear power plant steam turbines whose low pressure steam turbine has similar operating characteristics to Sherco 3's low pressure steam turbine. Mr. Polich cannot recall which of the units he worked on were GE or other turbine manufacturers. While at Consumers Energy, Mr. Polich worked on all the company's steam turbines during his career. Mr. Polich was also responsible for thermal cycle design of the Midland Cogeneration Venture combined cycle plant. This design required developing a steam cycle that matched the existing steam turbine designed to be used in the Midland Nuclear Plant based on a B&W nuclear steam supply system. Since leaving Consumers Energy, MR. Polich has continued to provide engineering support for coal and natural gas plants support of his clients. This includes coal and natural gas cogeneration facilities, all with steam turbines. Recent plants with steam turbines in which Mr. Polich has worked include Independence Power Plant Unit 2, RS Nelson Power Station Unit 6, Plum Point, John W. Turk, Bartow Combined Cycle Project, and Harrison County. Mr. Polich does not know which of the steam turbines have tangential entry dovetails or finger dovetails.

Preparer:	Richard A. Polich
Title:	Managing Director
Department:	Power Supply
Telephone:	501-316-9805
Date:	August 21, 2023

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Northern States Power Company, doing business as Xcel Energy
Information Request

Docket No.:	E002/GR-12-961, E002/GR-13-868; E999/AA-13-599; E999/AA-14-579; E999/AA-16-523; E999/AA-17-492; E999/AA-18-373; OAH 65-2500-38476 Sherco 3
Requestor:	Xcel Energy - Tara R. Duginske, Assistant General Counsel, Xcel Energy
Requestor email:	Tara.R.Duginske@xcelenergy.com
Requested from:	Minnesota Department of Commerce – Richard A. Polich
Date of Request:	August 9, 2023 Information Request No. 3
Response Due:	August 21, 2023

Reference: Direct Testimony of Mr. Richard Polich

Question:

a) State all education, degrees, coursework, memberships, etc. Mr. Polich has in the area of water chemistry.

b) State all experience Mr. Polich has in operating, monitoring, evaluating, or analyzing water chemistry.

c) State all experience Mr. Polich has in analyzing historical water chemistry data.

d) Provide a list of all matters or cases in which Mr. Polich been offered as an expert in water chemistry.

    i. Indicate if any of these matters or cases in which Mr. Polich has been offered as an expert in water chemistry involved the steam path in a fossil unit.

e) Produce all reports, testimony, opinions and conclusions reached for each matter or case in which Mr. Polich has been offered as an expert in water chemistry.

Response:

a) Mr. Polich does not have any degrees or specific course work in the area of water chemistry. Mr. Polich has taken college courses in chemistry, understands the fundamentals of proper water chemistry, and how it affects materials in the steam turbine. Mr. Polich does not have any memberships in water chemistry.

b) Mr. Polich's experience with steam turbines are discussed in response to Xcel's Information Request No. 2. Some of that experience includes review of water chemistry impacts on plant operations and damage to plant equipment.

c) During the startup of Consumers Energy Campbell 3 power plant, Mr. Polich was part of the team assigned to determine the root cause of the super heater failure. Mr. Polich reviewed the water chemistry data as well as the boiler operational data. The final cause of the super heater failure, which had only been subject to steam conditions for three months, was boiler drum carryover during a power increase and subsequent plant shutdown shortly afterwards. Sodium in the boiler drum was carried over into the super heater and left deposits on the tubes. During the subsequent cooldown and the plant being idle for three days after the carryover, the boiler tubes experienced stress corrosion cracking in the weld areas. Upon startup, the welds failed resulting in the replacement of the superheater. Mr. Polich also analyzed water chemistry data for Plum Point power station as part of assessment of weld failure in the boiler economizer. In assessing the low pressure steam turbine last stage blade failure of Duke Energy Florida's Bartow combined cycle plant, Mr. Polich reviewed historical plant water chemistry data. Mr. Polich has also had discussions with plant personnel at a variety of power plants on water chemistry as it relates to various plant problems.

d) Mr. Polich has not provided direct testimony on water chemistry in regulatory proceedings because the equipment failure presented in his testimony was not related directly to water chemistry. As part of his investigation into equipment failures, Mr. Polich has reviewed water chemistry because of its potential to impact material failure.

e) Not applicable.

Preparer:	Richard A. Polich
Title:	Managing Director
Department:	Power Supply
Telephone:	501-316-9805
Date:	August 21, 2023

26979708v1

Northern States Power Company, doing business as Xcel Energy
Information Request

Docket No.:	E002/GR-12-961, E002/GR-13-868; E999/AA-13-599; E999/AA-14-579; E999/AA-16-523; E999/AA-17-492; E999/AA-18-373; OAH 65-2500-38476 Sherco 3		
Requestor:	Xcel Energy - Tara R. Duginske, Assistant General Counsel, Xcel Energy		
Requestor email:	Tara.R.Duginske@xcelenergy.com		
Requested from:	Minnesota Department of Commerce – Richard A. Polich		
Date of Request:	August 9, 2023	Information Request No.	4
Response Due:	August 21, 2023		

Reference: Direct Testimony of Richard A. Polich, pp. 2-3

Question:

a) What type of power generation equipment was involved when you "provided plant engineering design, project oversight and engineering trouble shooting on [Consumer Powers Inc.'s] existing and new construction power generation fleet" in 1979?

b) Identify each "fossil generation project" for which you provided project development work and state the nature of your work on each project.

c) Identify all instances of assessing, evaluating, or analyzing operations, management, equipment failure or maintenance and repair practices for power generating units with GE turbine-trains in fossil units.

Response:

a) Mr. Polich partially discussed this issue in Discovery Response 2 and 3. Mr. Polich work in Consumers Energy's Engineering Department in 1979 involved coal and natural gas plants. Mr. Polich was responsible for oversight of Midland Nuclear steam cycles system design between during 1980 – 1984. Mr. Polich also was assigned to Palisades Nuclear plant in 1985 as part of a team overseeing design and construction of systems overhaul.
b) Mr. Polich provided project development work on coal plants in Georgia, Michigan and Indiana, none of which were ever built.
c) See DOC's response to XE-002 and Schedule 1 to Mr. Polich's Direct Testimony (RAP-D-1).

Preparer:	Richard A. Polich
Title:	Managing Director
Department:	Power Supply
Telephone:	501-316-9805
Date:	August 21, 2023

Northern States Power Company, doing business as Xcel Energy Information Request

Docket No.:	E002/GR-12-961, E002/GR-13-868; E999/AA-13-599; E999/AA-14-579; E999/AA-16-523; E999/AA-17-492; E999/AA-18-373; OAH 65-2500-38476		
	Sherco 3		
Requestor:	Xcel Energy - Tara R. Duginske, Assistant General Counsel, Xcel Energy		
Requestor email:	Tara.R.Duginske@xcelenergy.com		
Requested from:	Minnesota Department of Commerce – Richard A. Polich		
Date of Request:	August 9, 2023	Information Request No.	10
Response Due:	August 21, 2023		

Reference: Direct Testimony of Richard A. Polich – "Ultrasonic testing provides the ability to detect flaws in parts below the surface due to the penetration of the ultrasonic waves deep into the part and the reflection off cracks in the material. It is often used to detect SCC deep within a part."

Question:

Is it your opinion that the stress corrosion cracking ("SCC") on the internal fingers of finger dovetail rotors can be detected using ultrasonic ("UT") examination?

If yes, provide all documents supporting this contention.

Response:

The portion of Mr. Polich's testimony being quoted was a description of ultrasonic testing. GE's recommendation for finger dovetail rotors inspection was to perform Magnetic Particle Inspection. GE specified in TIL 1121-3AR1

Preparer:	Richard A. Polich
Title:	Managing Director
Department:	Power Supply
Telephone:	501-316-9805
Date:	August 21, 2023

GEK 111680
May 2007

GE Energy

Creating an Effective Steam Turbine Maintenance Program

NSP, et al v GE
EX 724
Date: 7-19-16
Richard G. Stirewalt
Stirewalt & Associates

These instructions do not purport to cover all details or variations in equipment nor to provide for every possible contingency to be met in connection with installation, operation or maintenance. Should further information be desired or should particular problems arise which are not covered sufficiently for the purchaser's purposes the matter should be referred to the GE Company.

The below will be found throughout this publication. It is important that the significance of each is thoroughly understand by those using this document. The definitions are as follows:

NOTE

Highlights an essential element of a procedure to assure correctness.

CAUTION

Indicates a potentially hazardous situation, which, if not avoided, could result in minor or moderate injury or equipment damage.

WARNING

INDICATES A POTENTIALLY HAZARDOUS SITUATION, WHICH, IF NOT AVOIDED, COULD RESULT IN DEATH OR SERIOUS INJURY

*****DANGER*****

INDICATES AN IMMINENTLY HAZARDOUS SITUATION, WHICH, IF NOT AVOIDED WILL RESULT IN DEATH OR SERIOUS INJURY.

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I. BACKGROUND

GE steam turbines have significant differences in the design, application, steam conditions, and output. However, the major components and supporting systems experience similar degradation mechanisms. While it is not possible to exactly forecast the rate of deterioration due to the many unforeseen conditions that a unit may be subjected to during its life (number of start-ups, variation in loading and steam conditions, rubbing of rotating and stationary components, chemical attack, solid particle erosion, water erosion, and water induction etc.), it is understood that proper operation and adherence to starting and loading instructions are vital to sustained performance. Implementing a thorough maintenance and monitoring program is the most effective way to retain reliability, performance and avoid major expenses due to failure of components. As such, GE recommends a comprehensive maintenance management system that incorporates the following elements:

- Monitoring and Diagnostics
- Inspection and Testing
- Maintenance Scope & Frequency

Since the frequency of inspection is dependent upon service duty, system demands, age of the unit, and many other plant requirements, the owner must ultimately determine the exact time intervals between inspections to balance performance, reliability and cost. It is the intent of this instruction to provide information on each of these elements, which will aid the owner/operator to establish a thorough and cost effective maintenance program.

II. MONITORING & DIAGNOSTICS

Between periods of normal maintenance, there are a number of parameters an operator can monitor to detect changes in operating conditions. This facilitates diagnostics in deviation from design conditions to understand the overall condition of the unit and gives capability to predict possible equipment failures in advance.

NOTE

> Several parameters have associated alarm and trip settings based on unit configuration and application. An alarm condition represents any condition exceeding a specified threshold and provides indication of abnormal operating conditions to be investigated. Actions should be taken to remove or clear the condition. A trip condition represents any condition that exceeds a specified threshold and provides automatic action to protect equipment from potential failure. Proper actions are critical to ensure unit longevity and prevent potential component failure, if alarm and trip conditions exist.

The following list of parameters is, as a minimum, recommended to effectively manage the health and performance of a steam turbine.

- Speed (RPM) & Power (MW)
- Bearing vibration – seismic, shaft rider, or shaft x-and-y proximity probes (as applicable)
- Journal bearing and thrust bearing metal temperatures
- Condensate and steam chemistry
- Steam turbine inlet pressure & temperature

- Steam turbine 1st stage pressure & temperature (as applicable)
- HP turbine exhaust pressure & temperature
- IP turbine inlet pressure & temperature
- LP turbine inlet pressures & temperature
- Steam turbine rotor/shell differential expansions (as applicable)
- Steam turbine shell and steam chest temperatures/differentials (as applicable)
- Admission and extraction pressures and temperatures (as applicable)
- Extraction line thermocouples to detect water induction (as applicable)
- Sealing steam and exhauster pressures (as applicable)
- Lube oil and hydraulic fluid supply pressures and temperatures

In addition to the turbine and plant control system capabilities, various systems and software packages are available to compile trends, perform diagnostics, and perform overall condition monitoring. This allows effective analysis of data with the intent of detecting and addressing potential issues in a timely and cost effective manner. It is recommended that employment of one of these systems be considered as part of a comprehensive monitoring program.

A. Vibration Level

The continuous monitoring system for GE steam turbines is referred to as the Turbine Supervisory Instrumentation (TSI) System and includes the typical radial displacement vibration and axial position measurements used for GE steam turbines. Vibration monitoring capability and evaluation is one of the most important portions of the TSI system for trending and predicting changes in turbine health and thermodynamic performance. Overall, vibration monitoring provides the following capabilities:

1. A means of detecting bearing problems. A change in vibration level or erratic vibration reading can be indicative of a wiped bearing and scored journal, as can an increase in bearing metal or oil drain temperature.

2. A means of detecting problems in the rotating parts. Any circumferential variation in weight in the rotating parts will result in an unbalance, which will be reflected in the vibration level at the bearings. Examples are: loss of bucket covers, loss of part or all of a bucket. Step changes in vibration level are indicative of this condition in many cases.

3. A means of detecting bowed rotors. Rubbing of steam path components due to insufficient clearance, created by mis-assembly or mis-operation can create a bow due to uneven heating or cooling of the rotor surfaces. This shift in center of rotation further compounds the rub and increases distortion. Packing, spill strips and bucket covers are the most frequently damaged parts in a bowed rotor event, but permanently bowed rotors may also occur if the localized heating or cooling is sufficient to change material properties of the rotor body. A bow in the rotor of even a few mils will cause a shift in the axis of rotation sufficient to produce a change in vibration level at the bearings. In the low-pressure element of the unit, which contains longer buckets, severe mechanical damage can be caused by water induction and this may be reflected by a change in the vibration level at the bearings. Where applicable, water detection thermocouples can be used to better identify if there is a water induction problem and to help identify the source of the water.

4. A means of detecting a water induction incident. Water backing up from extraction lines and cold reheat lines will cause contraction of the shell lower half, giving a humping effect that can lift the diaphragm packing against the rotor, causing radial rubs and subsequent bowing of the rotor. Another consequence is potential for quenching and localized cooling of the rotor surface. As this occurs the rotor bows away from the area and yields in tension. Dependent on the severity and location, after temperatures equalize, the quenched area may have compressive surface residual stresses resulting in a permanent bow. Where applicable, water detection thermocouples can be used to better identify if there is a water induction problem and to help identify the source of the water. Depending upon the specific characteristics of the unit, including whether water detection thermocouples are installed, additional information on water induction is available either in separate turbine instruction book articles or upon request from General Electric.

5. A means of detecting a cracked rotor. A rotor may crack from repeated excessive thermal stresses or in rare cases, from high cycle fatigue. Thermal cracking (low cycle fatigue) can result from a few incidents of extremely high thermal stresses (such as water induction) or from repeated thermal stresses of lesser but still dangerous magnitude (as in repeated startup and shutdown beyond the recommended starting and loading limits). High cycle fatigue of a shaft or rotor may be produced by periods of operation with adjacent bearings misaligned. As a crack develops, it will change the flexibility of the rotor and hence the vibration level. It may also cause the rotor to react in an erratic manner to normal attempts to balance. Balancing of cracked rotors to achieve operating speed and load is not recommended and should not be attempted.

B. Thermodynamic Performance & Efficiency

An increase in operating pressure within any section of a unit can be indicative of:

- A change in cycle operation
- Internal deposits within the steam path
- Internal damage within the steam path

1. A reduction in operating pressure could be indicative of mechanical damage in which the failed part is digested to the point of not restricting steam flow, but the loss of the part increases the flow capacity of the steam path. Example - loss of or erosion on buckets or partitions.

2. A loss of efficiency in any section of the unit can be indicative of internal deposits or internal damage the same as described above. It should be noted that internal damage, even to the extent of bucket loss might not necessarily be reflected as increased vibration level if the loss occurs in a symmetrical manner.

III. INSPECTION & TESTING

Two methods of inspection are available for better understanding the overall health and performance of a steam turbine, visual and nondestructive testing. Each method can provide enormous amount of information and should be employed at different times during the life of the unit. A good visual examination will quite often reveal the majority of problems that might be encountered, and will generally reveal areas that should be more thoroughly examined by nondestructive testing. Visual examinations should be completed early in an outage or shutdown period, regardless of type, to help recognize priorities and facilitate acquisition of any replacement materials should they be needed, thus helping to assure completion of necessary action within the planned outage time span.

A. Visual Examination

1. *Rubbing* - Rubbing can occur both in the radial and axial direction. Look for rubbing on the covers, packing, wheels and dovetails. Significant rubbing in any of these areas can be critical because of the effect of localized heating. Cover and bucket material, especially in the high temperature stages, is subject to cracking when severely rubbed. On the wheels and rotors, the heat-affected zone may be more significant than the amount of metal removed by rubbing.

2. *Erosion* – Erosion of steam path components can occur due to various sources and in some cases require implementation of extensive repair programs to restore steam path condition to nominal. Proper management of these sources is key to minimizing erosion of the steam path and the effects on lifecycle cost. While a majority of the initiating events that cause erosion conditions are one-time events that can be prevented, sometimes balance of plant equipment operation permits inadequate steam quality to be applied to the steam turbine.

    a. **Water Erosion** - Excessive water erosion can be caused by mis-operation or misdirection of water sprays, running for extended periods with lower than normal reheat temperature, or because of water induction into the steam path from an extraction connection.

    b. **Foreign Particle Erosion** - Excessive foreign particle erosion usually is noted on the governing stage or first stage of the reheat section. The source of particles is an oxide carryover from the boiler and steam pipes or shot peen material left in the steam leads after welding. Photographs and/or casts (R.T.V. rubber, dental compound) can be an invaluable tool for comparison at a future outage.

3. *Cracks* - Close scrutiny can also reveal cracks in covers, vanes, dovetails, or rotors. These cracks can be the results of rubbing, impact damage, fatigue, thermal stresses, or stress corrosion. Early discovery, visually, can lead to proper nondestructive testing and analysis to determine the cause and recommendations for correction.

4. *Stress Corrosion* - Materials and stress levels required to build a unit make various components subject to stress corrosion cracking (SCC) if caustic sulfides or chlorides are introduced. Erosion shields, dovetail pins, buckets, wheels, rotors and shafts are all subject to stress corrosion cracking in the presence of these contaminants. Proper chemistry control is critical to minimizing this effect and is covered in a separate instruction book article. To minimize the possibilities of stress corrosion cracking, proper procedures must be followed when cleaning main steam piping to avoid introducing chemical contaminants into the turbine. The recommended procedures are covered in a separate instruction book article. During operation, chemicals in the boiler may also be carried over by entrainment or in the vapor phase to deposit in specific temperature and pressure regions of the turbine. Even low proportional carryover into the turbine, because of the concentrating mechanism, which exists in the machine, can lead to damaging concentrations of contaminants. Both caustic and chlorides can be carried over in the vapor phase. In plants where

demineralizers are employed, if resins become depleted or regeneration is carried out incorrectly, it is possible for sodium ions or chloride ions to be introduced into the feedwater. Thus, close attention is required in this area.

5. *Deposits* - Deposits that have built up on or in the steam path, should be removed. It is advisable that samples of deposits be taken from the steam path and rotor for laboratory analysis. This analysis can indicate whether contaminants are entering the unit, the possible source of contamination, and result in a recommendation to eliminate, or at least reduce the source of contamination.

6. *Removal of Deposits* - Removal of insoluble deposits from rotors and buckets by blast cleaning has come to be an accepted practice. Tests indicate that the use of 220-mesh aluminum oxide is satisfactory. It produces a soft gray satin finish and slightly increases the fatigue strength of the material. In addition to the relatively pure nature of the product, it also contains a corrosion inhibitor.

   While inherent sturdiness of General Electric turbine buckets has been long recognized, carelessness in cleaning operations may seriously affect the mechanical strength of the part. Hand cleaning with files, scrapers, etc. often produces heavy transverse scratches, which can cause greatly reduced fatigue strength in turbine buckets. Blast cleaning in general is far superior to hand cleaning methods and results in a much quicker, less expensive, and superior job. It reaches fillets and crevices that cannot be reached by hand cleaning methods. Blast cleaning should be done after a complete visual inspection and prior to any nondestructive testing.

CAUTION

Special cleaning instructions and requirements exist for High Velocity Oxygen Fuel (HVOF) or plasma coated diaphragm partitions or buckets. Improper cleaning can result in inadequate removal of deposits or damage to equipment.

   For soluble deposits, various methods are available but the only conclusive way to determine all deposits have been removed from the interior dovetail surfaces is complete removal of buckets with subsequent cleaning, inspection, and testing. Contact your local GE Service Office if more information is required on methods and requirements of cleaning soluble deposits is needed.

   It is important to emphasize that under circumstances of severe contamination with corrosive deposits such as caustic, additional actions are generally required to assess if stress corrosion cracks have initiated, especially in more highly stressed regions such as dovetails or keyways in shrunk on wheels. Ultrasonic examinations can be used effectively in many cases to inspect internal regions without disassembly. However, removal of partial or full rows of buckets may be required in cases where the potential for cracking is particularly high, or where ultrasonic inspections cannot be used effectively due to geometry concerns. For built-up rotors, disassembly of wheels may be required in some cases to inspect wheel bore and keyway surfaces.

7. *Steampath Inspections* – Several visual inspections of both stationary and rotating components are recommended. While some of these can be done through non-intrusive means using a borescope the entire steam path is only viewable during a major outage overhaul and provides the best access to complete these critical checks. Your local GE Service Office can provide detailed process and acceptable measurement criteria. In general the following items should be inspected:

- Visual inspection of the buckets to verify that there are no gaps between adjacent bucket cover shrouds and dovetails as well as no bucket lifting between bucket and wheel
- Inspection for solid particle impingement, with close attention to the first few stages of the HP & IP rows as well as inspection for tenon erosion
- Visual inspection for diaphragm partition damage and contour
- Detailed inspection of sites that indicates rubbing of stationary and rotating components. Localized rubbing can be a precursor to inadequate clearance control during operation and should be investigated prior to re-assembly
- Visual inspection of the buckets should also be performed to verify that the grub screw retention feature at the closure bucket is properly installed. (as applicable)
- For the rotor strip seals a visual inspection should be performed per GEK 110920.

B. Nondestructive Testing

There are several means available to test the soundness of the turbine rotor and buckets; X-ray, ultrasonic test, magnetic particle test, and red-dye penetrant test or Zyglo-test. Each of these tests has its limitations and is more applicable to certain areas.

1. *X-Ray* - X-ray testing is most applicable during manufacture of buckets and has not had widespread usage as an inspection tool for an in service unit, primarily because the defects being tested for are not internal to the part. However, X-ray testing can be used to check the erosion shields on last stage buckets.

2. *Ultrasonic Testing* - The use of ultrasonic testing is widespread. Areas that can be inspected by ultrasonic means are: bucket dovetail pins, bucket and rotor dovetails, integral rotor bodies, and shrunk-on wheels. Special tests have been developed by General Electric to detect cracked dovetail pins, cracked bucket dovetails and wheel dovetails, and to determine the depth of a crack in a rotor surface.

   Ultrasonic testing is available as a test and should be routinely applied to integral (no shrunk-on wheels) rotors during major inspections. It is recommended that all integral rotors have an inspection conducted after 10 years of service. Based on results of the testing performed by GE will specify re-inspection intervals. The details of the inspection depend upon whether the rotor has a bore. On boreless rotors, an ultrasonic inspection is performed from the rotor peripheral surfaces. The extent of coverage is limited by the external geometry of the rotor. A more detailed examination is possible on rotors with a bore. In these cases, the inspection would also include a visual and magnetic particle inspection of the bore surface and an ultrasonic inspection from the rotor bore. Inspection recommendations for nuclear units (1500 and 1800 RPM) differ slightly, and are described in GEK 72178. It is recommended that specially trained General Electric personnel be utilized for these tests.

3. *Magnetic Particle Testing* - Magnetic particle testing has long been established as a reliable and quick means of testing the entire assembled rotor; however, care must be exercised in testing the high temperature stages. The high strength materials can be magnetic particle tested though it is a little more difficult and time consuming than on the more readily magnetized materials used in the lower temperature regions.

CAUTION

Erosion shields are of non-magnetic materials and must be tested by a dye-penetrant or fluorescent penetrant.

4. *Red-Dye Penetrant or Zyglo* - Red-dye penetrant or Zyglo must be utilized in testing non-magnetic materials such as those used in erosion shields. It is also useful in verifying magnetic particle test results. Trained personnel should be used for this test due to the possibilities of mis-interpretation of results.

   Properly applied and interpreted nondestructive testing can do much to eliminate the possibility of a future forced outage. The above discussion, by necessity, is not intended to be a detailed instruction for inspections. The local GE Service Office can supply technical direction and trained personnel to make a complete and thorough inspection. GE will provide repair and operating recommendations upon reporting of the results of any inspection. Upon receipt of a complete description of the problem, GE engineers will describe the repair options available, considering the design parameters on the stage, service experience with other similar designs, and experience obtained with various kinds of repair procedures

C. Last Stage Buckets Inspections

1. A turbine is occasionally shutdown for short durations due to issues with other plant components. At that time, an inspection of the last stage exhaust region can be made with little difficulty through the access manholes. This method of inspection can reveal a number of operational problems, last stage difficulties, or problems related to the internal condition in the machine upstream of the last stage. The following can all be detected by means of last stage inspection.

   a. *Last Stage Erosion* - Excess erosion on the trailing or leading edge of the last stage buckets can be caused by mis-operation or mis-direction of water sprays, running for extended periods with a lower-than-normal reheat temperature, or water induction into the steam path from an extraction connection upstream of the last stage. Erosion measurements should be taken & trended to determine abnormal indications.

   b. *Water Induction* - Serious mechanical damage to the latter stages may result from water induction. Visual inspection of the last stage may reveal if such a problem exists in the unit.

   c. *Stress Corrosion Cracking* – As discussed, stress corrosion cracking is intergranular cracking of components at stress concentrations in the presence of a corrosive agent. The most common corrosive agents are caustic, chlorides, and sulfides that can be introduced into the steam path by carryover in steam, or as a residue left from a cleaning agent. Another factor required for such cracking is a warm, moist atmosphere, which is exactly the condition found in the latter stages of a steam turbine.

   d. *Mechanical Failure* - Mechanical failures of vanes, covers, or tie-wires would be discovered during inspection.

   e. *Foreign Material Damage* – Mechanical damage to vanes, covers, or tie-wires would indicate possible action to prevent failure and loss of efficiency.

2. Considering the value of the information which can be obtained by such an inspection, the ease with which it can be obtained, and the severe consequences that may result from failure of last

stage and/or other low pressure section components, it is recommended that the last stage buckets of all units be inspected at the customer's convenience on an annual basis. As a minimum, the inspection should consist of a thorough visual inspection of parts visible from inside the exhaust hood. Additional non-destructive testing should be considered based on unit history and/or unit age. The following areas should be inspected:

a. *Tie-Wires* - Brazed or welded tie-wires should be visually inspected for cracks in the tie wire, the fillet between tie wire and vane, or in the vane adjacent to the tie wire. Loose tie wires should be inspected for evidence of tie wire cracks. Fretting or other damage in the area of the tie wire hole should also be looked for.

b. *Loose Tie Wire Sleeves* - Some buckets utilize tie wire sleeves held on by bosses. These should be visually inspected for cracks, for missing sleeves, and for sleeves, which may be cocked between adjacent buckets.

c. *Erosion Shields* - Erosion shields, if installed, should be visually and red-dye inspected to uncover evidence of cracking. Visual inspection can also reveal cases of severe erosion or failure of brazed joints.

d. *Bucket Vane* - The vane should be visually inspected for evidence of cracking or pitting, as well as trailing edge erosion. Non-destructive testing is also available.

e. *Peened Covers* - The covers should be inspected for indication of lifting or severe erosion of the covers or tenons. In addition, any missing covers can be discovered.

f. *Inserted Covers* - Several longer buckets employ an inserted cover. Such covers should be inspected for erosion, cracks in the tenon, or cocking of the cover between adjacent buckets. Missing covers would also be detected.

g. *Dovetail* - The accessible area of the bucket dovetail should be inspected for any sign of distress, pitting of the wheel or dovetail pins, or loose pins.

h. *Spill Strips* - The radial spill strips should be inspected for severe rubbing. In the case of a honeycomb spill strip, missing filler material would be discovered

i. *Mechanical Damage* - All accessible rotating and stationary parts should be inspected for evidence of mechanical (impact) damage. Problems in any of the areas described above can possibly lead to future last stage failure, with the possibility of a forced outage. In addition, they may also be symptomatic of other troubles upstream in the machine.

D. Borescope Inspections

An experienced individual performing proper visual inspections will enable detection and disclosure of unit conditions not detected by monitoring equipment or operational analysis. Visual inspections are limited to areas that can be accessed for view, directly or with mirrors, borescope, cameras, etc. In cases where there is a suspicion of internal damage or a build-up of deposits, selected parts may be examined during a short shutdown by means of a borescope. These inspections should be combined with testing to give a more accurate picture of unit health and condition and should include the following areas as a minimum:

Table 1. Visual Inspection Areas

		Foreign Material Damage	Foreign Material Contamination	Cleanliness	Loose or Displaced Parts	Abnormal Movement	Surface Condition	Cracks	Abnormal Wear/Worn Parts	Flow Obstruction	Erosion/Corrosion
Rotor	All Components	X	X	X			X	X			X
	Periphery & Dovetails					X					
	Buckets				X		X		X	X	
	Covers				X	X			X		
Diaphragm	All Components	X	X	X				X			X
	Airfoil						X			X	
	Shell Fit				X	X		X	X		
	Web							X	X		
Valves/Casings	All Components	X	X	X				X			X
	Disc				X	X	X				
	Body						X				
	Drain Lines			X		X				X	
Shell Connections	Weld Connections		X	X			X	X			X
	Drain Lines			X		X				X	

IV. MAINTENANCE SCOPE & FREQUENCY

As detailed in previous sections the purposes of inspections include looking for, minimizing the causes of, and correcting items that occur as the unit ages. Specifically, these include items such as wear, erosion, deposits, distortion, misalignment, mechanical damage, and contamination.

For the purposes of discussion, scheduled outages will be referred to as (1) Minor Maintenance Overhauls and (2) Major Maintenance Overhauls. The difference in these inspections is the magnitude of disassembly and testing performed. Minor outages primarily consist of bearing, valve, and minor steam path inspections with the unit assembled while a major outage primarily consists of complete unit disassembly and inspection. Additionally, GE recommends a detailed steam path audit be completed during major outage overhauls to help understand performance degradation characteristics as well as any potential reliability concerns for planning of next major outage.

There are a number of auxiliary and support systems, which require routine maintenance or inspection between scheduled outages. The owner/operator will find these recommendations in various operating instructions within the O&M manual and should also include additional maintenance tasks as operating experience and inspections indicates. Results of this routine maintenance should be retained in well-organized files readily available for reference. These routine maintenance records coupled with the information from the monitored operating data are a good indicator of pending service or operating problems that should be addressed at the next scheduled outage.

A. Factors

While many items need to be considered when determining exact outage frequency, unit specific influence factors should be one of the major considerations. In general the factors that should be considered when determining exact timing of your scheduled outage are:

- Performance and health trend monitoring results
- Operational compliance & maintenance practices, procedures, and personnel
- Inspections and testing completed between major overhaul outages
- Previous NDE inspection results completed during scheduled outages
- Operational events/incidents since last scheduled outage
- General problems based on empirical data and specific fleet issues
- Past history of problems
- Water and steam purity monitoring capability & compliance
- Service Duty – starts/hours per year (base-load, mid-range, cyclic)
- Unit age and design life concerns

Many of the factors related to the exact timing of inspections are determinable by the owner/operator; other factors draw from empirical knowledge and fleet experience. GE monitors operating experience, inspection results, and in-service operating issues of the installed base to the degree that the information is available. This is used to analyze and identify potential issues specific to similar units across the fleet with subsequent recommendations to owners on specific matters forwarded by means of Technical Information Letters (TIL) so applicable action can be taken to obtain maximum reliability, availability, and maintainability.

B. Scope

During an outage, the full scope of maintenance activities varies based on operational assessment as well as previous inspection and testing results. In addition scheduled maintenance activities are recommended to ensure the highest reliability and availability. The following guidelines are recommended scheduled activities for steam turbine maintenance.

Table 2. Periphery Maintenance

TEST / INSPECTION	Daily	Weekly	Monthly	Annually
Visual inspection of unit and auxiliary equipment for leaks and abnormal noise	X			
Unit performance & health trend with Turbine Supervisory Instrumentation		X		
Visual inspection and greasing of all sliding surfaces		X	X	
Testing of turbine protection systems & devices per GEK requirements		X	X	X
Analyze lube & hydraulic oil per GEK requirements			X	
Visual inspection of Stop and Control Valve operation			X	
Functional testing of emergency lube oil systems per GEK requirements		X	X	X
Visual inspection of pipe hangers and piping support systems			X	
Visual inspection of all leak off lines and drain valves for proper operation			X	
Visual inspection of lube oil system and components				X
Low Pressure section last stage inspection				X
Mechanical & electrical checkout of instrumentation, protection & control systems				X
Test mechanical over-speed (as applicable)				X

1. Minor Maintenance Overhaul
    - Borescope inspection of accessible parts of the steam path and shell connections
    - Actuator & steam side inspection of all stop, control, and bypass valves
    - Checkout/Calibrate all alarms, trips, and protective devices and/or instrumentation
    - Inspect all journal and thrust bearing for wear and clearances
    - Remove and inspect steam strainers
    - Inspect spray water systems including bypass systems and condenser interior
    - Visual inspection of all drain system piping, fitting, and traps
    - Visual inspection of filters and fluid pipes for damage including functional testing of lubrication and drain system piping and components
    - If installed, visual examination of condensing and feed-heating systems
    - Inspections of foundation slide surfaces and anchor locations
    - Additional checks based on unit history and individual operational observations
2. Major Maintenance Overhaul
    - All inspections completed as part of a minor outage/overhaul with exception of borescope inspections
    - Opening of turbine casings and steam path inspection

- Opening clearance and alignment
- Clean and inspect stationary and rotating components
- Complete examination of couplings, including axial run-out test
- Close consideration should be made for performance of a steam path audit to best understand performance degradation and definition of recoverable and unrecoverable losses
- Appropriate non-destructive testing and examinations
- Inspection of all shell/casing piping connections
- As appropriate, NDE of all parts should be done to checks for both surface and sub-surface cracking and/or indications
- Detailed inspection of lubrication and drain system piping and components

C. Intervals

While the exact timing of inspections depends on the factors mentioned above, they can be made to correspond to periods of shutdown for work on, or inspection of, other power plant components. Scheduled maintenance outages should be planned well in advance of the actual outage date, and preparation for the outage should begin early. An important part of that is to review operational logs, previous inspection reports for any indication of work needed, and review recommendations from GE communicated by letter or TIL to integrate those items into your scope in addition to that described above.

In general, it is recommended that turbine-generators that have been operated in accordance with the Company's specific operating instructions or, in the absence thereof, in accordance with generally accepted operating practices of the electric power producing industry, be inspected in accordance with the approximate timelines defined in Table 2.

Table 3. Inspection Interval Matrix

	Interval (Service Years)	**Comments**
Minor Maintenance Overhaul	3 years*	Inspections may be required more or less frequent depending on fleet experience, testing results, and operational assessment completed as part of comprehensive maintenance management program.
Major Maintenance Overhaul	6 years*	Inspections may be required more or less frequent depending on fleet experience, testing results, and operational assessment completed as part of comprehensive maintenance management program.
*Influence factors are unit specific and need to be considered when determining exact outage interval. Timing should also consider balance of plant and other power generation equipment outage requirements.		

Materials expected during an outage, should be ordered such that they are available at the start of the outage to avoid risk of costly delays waiting for material. A sound maintenance program should reflect the level of acceptable risk for the unit. This will vary from unit to unit and plant to plant, and will change over time as the economic importance of the unit changes. In addition, new technologies are constantly being developed to improve unit reliability, performance, monitoring and inspection equipment, and otherwise provide more cost effective means for maintaining your unit. The owner/operator should be aware of the developments and modify the maintenance program accordingly. While this should be a continuous process, the maintenance outage planning review is an appropriate checkpoint.

D. Interval Extensions

The previous discussions are general guidance and recommendations and do not purport to cover all details nor to provide for every possible contingency to be met in connection with maintenance. Should further information be desired or should particular problems arise which are not covered sufficiently for the owner/operators purposes the matter should be referred to your local GE Service Office.

A maintenance program should reflect the level of acceptable risk for the unit, which will vary from unit to unit, plant to plant and fleet to fleet and will probably change over time as the importance of the unit to the power system changes. In addition, new technologies are constantly being developed to improve unit reliability, performance, monitoring and inspections, and otherwise provide more cost effective means for maintaining the unit

It is recognized that some customers desire to have longer or shorter intervals where it makes sense. GE has unique capability to help assist in this evaluation and analysis on a single unit or an entire fleet in the form of a customized reliability analysis to optimize unit availability and lifecycle cost. This type of engineering assessment is completed for units that are serviced under a Long Term Service Agreement managed by GE. For other customers, your local GE Service Office can assist you in your maintenance planning, and review of your overall maintenance program, incorporating any appropriate new maintenance, repair and upgrade technologies available.

GE Energy
General Electric Company
www.gepower.com

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18,702.50

COPY

Form No: 27.300

MQS INSPECTION, INC.

TURBINE INSPECTION REPORT

OWNER: Northern States Power CLIENT: Northern States Power

LOCATION: Sherco Plant CONTACT: Lanny Dahlman
Becker, MN

TURBINE:

Manufacturer: General Electric Serial Number: 170X819

Unit Number: 3 Rating: 850 MW RPM: 3600

INSPECTION:

Date Inspected: 3-4-99 thru 3-18-99 Technician: Mike Christensen
Technician: Doug Gertner

P.O. #: PN4205MT

W/O#: 07F3389

Report Date: 3-15-99

(X) Complete ( ) Partial Inspection

Auxl. Comp. Inspected:

This report details the conditions noted during our inspection of the above unit. The disposition of all deficiencies noted shall be the responsibility of the owner.

NSP, et al v GE
EX 276
Date: 11-24-15
Richard G. Stirewalt
Stirewalt & Associates

MQS INSPECTION, INC.

Form: 27.302

Turbine #: 170X819

Work Order #: 07F3389

HIGH PRESSURE (H.P.) SECTIONS

Component	Insp. Req'd Yes	Insp. Req'd No	Method Cleaned	MT	UT	PT	VT	ET	RT	Deficiency Noted Yes	Deficiency Noted No
Outer Shell/Cylinders											
Inlet Sleeve Trepans Westinghouse)	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Positioning Grooves	(✓)	( )	sandblast	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Horizontal Joint	(✓)	( )	"	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Studs/Bolts	(✓)	( )	NA	( )	(✓)	( )	(✓)	( )	( )	( )	(✓)
Inlet Steam Flanges	(✓)	( )	sandblast	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Bell Seals (Westinghouse)	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Steam Chest											
Steam Flange Bolts	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Chest Seats	(✓)	( )	solvent	( )	( )	(✓)	(✓)	( )	( )	( )	(✓)
Studs	(✓)	( )	stoned	( )	(✓)	( )	(✓)	( )	( )	( )	(✓)
Covers	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Cover Studs	( )	(✓)	"	( )	( )	( )	( )	( )	( )	( )	( )
Body	(✓)	( )	"	( )	( )	( )	(✓)	( )	( )	( )	(✓)
Rotor/Spindle											
Shaft	(✓)	( )	sandblasted	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Buckets/Blades	(✓)	( )	"	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Covers/Shroud Bands	(✓)	( )	"	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Wheels/Discs	(✓)	( )	"	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Coupling	(✓)	( )	solvent	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Coupling Bolts	(✓)	( )	NA	( )	(✓)	( )	(✓)	( )	( )	( )	(✓)
Thrust Collar.....(IP rotor)	(✓)	( )	solvent	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Bearing Journal	(✓)	( )	"	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Babbitt Bearing Bond	(✓)	( )	"	( )	(✓)	(✓)	(✓)	( )	( )	(✓)	( )
Thrust bearing Bond (Babbitt)	(✓)	( )	"	( )	(✓)	(✓)	(✓)	( )	( )	(✓)	( )
Diaphragms/Stationary Blade Rings											
Partitions/Blades	(✓)	( )	sandblasted	(✓)	( )	( )	(✓)	( )	( )	(✓)	( )
I.D. Rings/Sets	(✓)	( )	"	(✓)	( )	( )	(✓)	( )	( )	(✓)	( )
O.D. Rings/Sets	(✓)	( )	"	(✓)	( )	( )	(✓)	( )	( )	(✓)	( )
Inner Shells/Cylinders											
Nozzle Block	(✓)	( )	sandblasted	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Port Way	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Nozzle Row (Row of Partitions)	(✓)	( )	sandblasted	(✓)	( )	( )	(✓)	( )	( )	(✓)	( )
Steam Shield/Steam Deflector	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Horizontal Joints	(✓)	( )	sandblasted	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Positioning Grooves	(✓)	( )	"	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Studs/Bolts	(✓)	( )	stoned	( )	(✓)	( )	(✓)	( )	( )	( )	(✓)
Other Components											
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )

MQS INSPECTION, INC.

Form: 27.304

Turbine #: 170X819 **Work Order #:** 07F3389

INTERMEDIATE PRESSURE (L.P.) SECTIONS

Component	Insp. Req'd Yes	Insp. Req'd No	Method Cleaned	MT	UT	PT	VT	ET	RT	Deficiency Noted Yes	Deficiency Noted No
Outer Shell/Cylinders											
Positioning Grooves	☑	☐	sandblasted	☑	☐	☐	☑	☐	☐	☑	☐
Horizontal Joint	☑	☐	“	☑	☐	☐	☑	☐	☐	☐	☑
Studs/Bolts	☑	☐	NA	☐	☑	☐	☑	☐	☐	☐	☑
Inlet Steam Flanges	☐	☑	“	☐	☐	☐	☐	☐	☐	☐	☑
Rotor/Spindle											
Shaft	☑	☐	sandblasted	☑	☐	☐	☑	☐	☐	☐	☑
Buckets/Blades	☑	☐	“	☑	☐	☐	☑	☐	☐	☐	☑
Covers/Shroud Bands	☑	☐	“	☑	☐	☐	☑	☐	☐	☐	☑
Wheels/Discs	☑	☐	“	☑	☐	☐	☑	☐	☐	☐	☑
Couplings	☑	☐	solvent	☑	☐	☐	☑	☐	☐	☐	☑
Bearing Journal	☑	☐	“	☐	☑	☑	☑	☐	☐	☐	☑
Babbitt Bearing Bond	☑	☐	“	☐	☑	☑	☑	☐	☐	☑	☐
Diaphragms/Stationary Blade Rings											
Partitions/Blades	☑	☐	sandblasted	☑	☐	☐	☑	☐	☐	☑	☐
I.D. rings/Sets	☑	☐	“	☑	☐	☐	☑	☐	☐	☑	☐
O.D. Rings/Sets	☑	☐	NA	☑	☐	☐	☑	☐	☐	☑	☐
Inner Shells/Cylinders											
Horizontal Joints	☑	☐		☐	☐	☐	☐	☐	☐	☑	☐
Positioning Grooves	☑	☐		☐	☐	☐	☐	☐	☐	☐	☑
Studs/Bolts	☐	☐		☐	☐	☐	☐	☐	☐	☐	☐
Other Components											
	☐	☐		☐	☐	☐	☐	☐	☐	☐	☐
	☐	☐		☐	☐	☐	☐	☐	☐	☐	☐
	☐	☐		☐	☐	☐	☐	☐	☐	☐	☐
	☐	☐		☐	☐	☐	☐	☐	☐	☐	☐

MQS INSPECTION, INC. **27.303**

Turbine #: 170X819 **Work Order #:** 07F3389

LOW PRESSURE (L.P.) SECTIONS

	Insp. Req'd		Method							Deficiency Noted	
Component	**Yes**	**No**	**Cleaned**	**MT**	**UT**	**PT**	**VT**	**ET**	**RT**	**Yes**	**No**
Rotor/Spindle											
Buckets/Blades	(✓)	( )	sandblasted	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Covers/Shroud Bands	(✓)	( )	“	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Wheels/Disc	(✓)	( )	“	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Shaft	(✓)	( )	“	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Bearing Journal	(✓)	( )	solvent	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Tie Wires/Lashing Wire Lugs	( )	( )	NA	( )	( )	( )	( )	( )	( )	( )	( )
Couplings	(✓)	( )	solvent	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Bucket Pins/Steeples	(✓)	( )	sandblasted	( )	(✓)	( )	( )	( )	( )	(✓)	( )
Erosion Strips/Stellite Strips	(✓)	( )	“	( )	( )	(✓)	(✓)	( )	( )	(✓)	( )
Babbitt Bearing Bond	(✓)	( )	solvent	( )	(✓)	(✓)	(✓)	( )	( )	(✓)	( )
Shells/Cylinders											
Positioning Grooves	(✓)	( )	sandblasted	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Horizontal Joint	(✓)	( )	“	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Support Tube Welds	(✓)	( )	“	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Bridge Supports	(✓)	( )	“	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Studs/Bolts	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Crossover Pipe System											
Crossover Studs and Bolts	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Crossover Diaphragm	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Expansion Diaphragm	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Steam Deflectors	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Support Welds	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Other Components											
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )
	( )	( )		( )	( )	( )	( )	( )	( )	( )	( )

MQS INSPECTION, INC.

27.306

Turbine #: 170X819

Work Order #: 07F3389

GENERATOR SECTION

Component	Insp. Req'd Yes	Insp. Req'd No	Method Cleaned	MT	UT	PT	VT	ET	RT	Deficiency Noted Yes	Deficiency Noted No
Rotating Field											
Retaining Rings.....ID only..........	(✓)	( )	solvent	( )	( )	(✓)	(✓)	( )	( )	( )	(✓)
Fan Blades....................................	(✓)	( )	"	( )	( )	(✓)	(✓)	( )	( )	( )	(✓)
Fan Blade Bolts...........................	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Shaft (Exposed Areas)..................	( )	(✓)	"	( )	( )	( )	( )	( )	( )	( )	( )
Couplings..	( )	(✓)	"	( )	( )	( )	( )	( )	( )	( )	( )
Bearing (Babbitt Bond)................	(✓)	( )	solvent	( )	(✓)	(✓)	(✓)	( )	( )	(✓)	( )

(Note: Plugging and sealing of the generator shall be the responsibility of the client)

Other Components

______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )
______	( )	( )	______	( )	( )	( )	( )	( )	( )	( )	( )

MQS INSPECTION, INC. 27.301

Turbine #: 170X819

Work Order #: 07F3389

VALVES

Component	Insp. Req'd Yes	Insp. Req'd No	Method Cleaned	MT	UT	PT	VT	ET	RT	Deficiency Noted Yes	Deficiency Noted No
Stop Valves											
H.P. Seal Head	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Bonnet	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
H.P. Seal Head Seat	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Disc/Plug	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Anti-Rotation Pins	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Screen/Strainer	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Valve Body	(✓)	( )	NA	( )	( )	( )	(✓)	( )	( )	( )	(✓)
Valve Body Seat	(✓)	( )	solvent	( )	( )	(✓)	(✓)	( )	( )	( )	(✓)
Head	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Support Yoke	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Studs	(✓)	( )	wire brush	( )	(✓)	( )	(✓)	( )	( )	( )	(✓)
Disc Seat/Plug Seat	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Studs	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Control Valve/Governing Valves											
Stem	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Bonnet	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Disc/Plug	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Disc Seat/Plug Seat	( )	(✓)	NA	( )	( )	( )	( )	( )	( )	( )	( )
Valve Body	(✓)	( )	NA	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Valve Body Seat	(✓)	( )	solvent	( )	( )	(✓)	(✓)	( )	( )	( )	(✓)
Studs	(✓)	( )	wire brush	( )	(✓)	( )	(✓)	( )	( )	( )	(✓)
Intercept Valves or Combination Intercept/Reheat Valves											
Stems	( )	( )	NA	( )	( )	( )	( )	( )	( )	( )	( )
Discs/Plugs	( )	( )	NA	( )	( )	( )	( )	( )	( )	( )	( )
Disc Seat/Plug Seat	( )	( )	NA	( )	( )	( )	( )	( )	( )	( )	( )
Screen	( )	( )	NA	(✓)	( )	( )	(✓)	( )	( )	(✓)	( )
Valve Body....& seat	( )	( )	NA	( )	( )	(✓)	(✓)	( )	( )	( )	(✓)
H.P. Seal Head	( )	( )	solvent	( )	( )	( )	( )	( )	( )	( )	( )
Studs	( )	( )	wire brush	( )	(✓)	( )	(✓)	( )	( )	( )	(✓)
Equalizer Valve											
Stem	( )	( )	solvent	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Disc	( )	( )	solvent	(✓)	( )	( )	(✓)	( )	( )	( )	(✓)
Disc Seat	( )	( )	solvent	( )	( )	(✓)	(✓)	( )	( )	( )	(✓)
Valve Body	( )	( )	NA	( )	( )	( )	( )	( )	( )	( )	( )
Valve Body Seat	( )	( )	solvent	( )	( )	(✓)	(✓)	( )	( )	( )	(✓)
Studs	( )	( )	NA	( )	( )	( )	( )	( )	( )	( )	( )

MQS INSPECTION, INC. **Record of Turbine Blade or Bucket Inspection**

Date: 3-15-99 Unit No.: 3

Form No. 27.308

Station Sherco Turbine No.: 170X819 HIGH PRESSURE ROTOR

Stage No.	Total No. Blades	No. Groups	Blades / Group	Blade Length	Notch Plugs	Blade / Bucket No.	Inspection Method	Distance from Shroud	Defect Length	Defect Entirely thru (Y or N)	Entrance or Dischg. Side (E or D)	Remarks
Gov-1	80	20	4	6-1/4"	1	NA	mt/vt					Light erosion & pitting to blading
Turb-1	80	20	4	6-1/4"	1	"	"					Light erosion & pitting to blading
2	92	23	4	7"	1	"	"					Light erosion & pitting to blading
3	88	22	4	7-3/4"	1	"	"					Light erosion & pitting to blading
4	84	21	4	8-3/4"	1	"	"					No defects noted
5	76	19	4	9-1/4"	1	"	"					No defects noted
6	68	17	4	19"	1	"	"					No defects noted
7	62	15	4/5	11-1/4	1	"	"					No defects noted

MQS INSPECTION, INC.

Record of Turbine Blade or Bucket Inspection

Date: 3-15-99 Unit No.: 3

Form No. 27.308

Station Sherco Turbine No.: 170X819 INTERMEDIATE PRESSURE ROTOR

Stage No.	Total No. Blades	No. Groups	Blades / Group	Blade Length	Notch Plugs	Blade / Bucket No.	Inspection Method	Distance from Shroud	Defect Length	Defect Entirely thru (Y or N)	Entrance or Dischg. Side (E or D)	Remarks
8	100	25	4	9-3/4	1	NA	mt/vt					Light foreign object damage with heavy erosion to blading.
												Foreign material wedged on ID of covers.
9	108	27	4	9"	1	"	"					Light foreign object damage with heavy erosion to blading.
												Foreign material wedged on ID of covers.
10	104	26	4	9-3/4	1	"	"					Light erosion with sporadic foreign material wedged on the ID
												of the covers.
11	104	26	4	10.5"	1	"	"					Sporadic foreign material wedged on the ID of the covers.
12	80	20	4		1	"	"					No defects noted
13	72	18	4	14"	1	"	"					No defects noted

MQS INSPECTION, INC. **Record of Turbine Blade or Bucket Inspection**

Date: 3-15-99 Unit No.: 3

Form No. 27.308

Station Sherco Turbine No.: 170X819 LOW PRESSURE ROTOR"A"

Stage No.	Total No. Blades	No. Groups	Blades / Group	Blade Length	Notch Plugs	Blade / Bucket No.	Inspection Method	Distance from Shroud	Defect Length	Defect Entirely thru (Y or N)	Entrance or Dischg. Side (E or D)	Remarks
14	198	40	4/5	6-1/8"	1	NA	mt/vt					Light pitting on blading both the generator and turbine ends
15	200	40	5	7.5"	1	"	"					Light pitting on blading both the generator and turbine ends
16	128	32	4	10-5/8	1	"	"					Light pitting on blading both the generator and turbine ends
17	94	13	4/5	16-5/8	1	"	"					Light pitting on blading both the generator and turbine ends
L-1 18												Blading removed to be replaced
L-0 19	94	NA	NA	39-3/4	1	"	"					Moderate erosion to the erosion strips blade area adjacent to strips
												and insert blocks. 171 bucket pins found to be rejected; 33 pins
												on the turbine end and 138 pins on the generator end.
												NOTE: Stage #17 notch plug blade is a titanium blade.
												(non-magnetic)

MQS INSPECTION, INC. **Record of Turbine Blade or Bucket Inspection**

Date: 3-15-99 Unit No.: 3

Form No. 27.308

Station Sherco Turbine No.: 170X819 LOW PRESSURE ROTOR "B"

Stage No.	Total No. Blades	No. Groups	Blades / Group	Blade Length	Notch Plugs	Blade / Bucket No.	Inspection Method	Distance from Shroud	Defect Length	Defect Entirely thru (Y or N)	Entrance or Dischg. Side (E or D)	Remarks
14	198	40	4/5	6-1/8"	1	NA	mt/vt					Light pitting on blading both the generator and turbine ends
15	200	40	5	7.5"	1	"	"					Light pitting on blading both the generator and turbine ends
16	128	32	4	10-5/8	1	"	"					Light pitting on blading both the generator and turbine ends
17	94	13	4/5	16-5/8	1	"	"					Light pitting on blading both the generator and turbine ends
L-1 18												Blading removed to be replaced
L-0 19	94	NA	NA	39-3/4	1	"	"					Moderate erosion to the erosion strips, blade area, adjacent to
												strips and insert blocks 56 bucket pins found to be rejected
												one pin on the turbine end and 55 pins on the generator end.
												NOTE: Stage #17 notch plug blade is a titanium blade.
												(non-magnetic)

MQS Inspection, Inc. 1920 Oakcrest Avenue, Roseville, MN 55113

Form 27.309

IDENTIFICATION OF DIAPHRAGM BLADING DEFECTS

Sketch is looking at steam inlet side of diaphragm. First blade on left side would be No. 1-T on top half and No. 1-B on bottom half. Also, show total number of blades as their total number in either top or bottom, not total number in top and bottom.

NB= Nozzle Block
FOD = Foreign object damage

Since the defects are found in about the same location on either the inside diameter or outside diameter, and usually on the discharge side we only need to indicate with "X" where the crack or defect occurred, in proper column and the length of the defect.

Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage #	Total # of Blades	# of Defects	Inspection Method	Blade #	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	Type Defects
Gen										
NB-T	84		Vt/mt	All			X	X		Light FOD severe erosion
"	"	9	"	–	X			X		1-4, 41,44,81-83 missing part of blade due to erosion
"	"	2	"	–	X			X		29, 64 have cracks
"	"	25	"	–		X		X		5,7,8,15,16,18,19,22,24,26-28,31,35,39,42,48,50,69,73,75-77,80,81 have cracks
Gen.										
NB-B	84		Vt/mt	All			X	X		Light FOD, severe erosion
"	"	8	"	–	X			X		2-4, 44, 80-83 are missing part of blade due to erosion
"	"	4	"	–		X		X		4,6,14,15,17,26,29,46,56,60 have cracks
Turb										
NB-T	84		Vt/mt	All			X	X		Light FOD severe erosion
"	"	12	"	–	X			X		1-5, 40-42,44,81-83 are missing part of blade due to erosion
"	"	21	"	–		X		X		1,3,4,6,13,14,19,21,39,41,42,44,48,51,53,55,56,60,65,71,79 have cracks
Turb										
NB-B	84		Vt/mt	All			X	X		Light FOD severe erosion
"	"	10	"	–	X			X		1-4, 44, 78, 80-84 are missing part of blade due to erosion
"	"	2	"	–	X			X		59,77 have cracks
"	"	11	"	–		X		X		1,38,39,45,47,71,72,74,81-83 have cracks
2-T	36		"	All			X	X		Heavy FOD light erosion
"	"	1	"	5	X			X		Has tear

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Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage #	Total # of Blades	# of Defects	Inspection Method	Blade #	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	Type Defects
2-T	• 36	1	Vt/mt	11	X			X		Has hole
"	"	1	"	21	X			X		Has crack
"	"	1	"	22		X		X		Has crack
2B	36		"	All			X	X		FOD and light erosion
"	"	4	"	--	X	X		X		Previous weld repair area cracked on 1,4,19,20
"	"	1	"	18	X			X		Has crack
3-T	60		"	All			X	X		Light FOD light erosion
"	"		"	--		X	X			Weld cracked on brace between blades 59 and 60
"	"	4	"	--		X		X		47,53,57,58 have cracks
"	"	1	"	49	X			X		Has crack
3-B	60		"	All			X	X		Light erosion FOD
"	"	8	"	--	X			X		3-5,8,9,14,52,60 have cracks
"	"	4	"		X			X		33,48,55,57 are missing piece of blade due to FOD
4-T	50		"	All			X	X		Light erosion light FOD
"	"	2	"	–		X		X		3, 25 have cracks
4-B	50		"	All			X	X		Light FOD erosion
"	"	1	"	--		X	X			Crack on brace which is between blades 49 and 50
"	"	2	"	--	X			X		11, 13 have cracks
"	"	1	"	--		X		X		23 has crack
5-T	47		"	All			X	X		Light erosion
"	"	2	"	--	X		X			8, 27 have cracks

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Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage #	Total # of Blades	# of Defects	Inspection Method	Blade #	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	Type Defects
5-T	47	1	Vt/mt	--	X			X		24 has crack
"	"	1	"	--		X		X		35 is separating in the weld repair area
"	"	3	"	--		X		X		39, 44, 46 have cracks
5-B	47		"	All			X	X		Light erosion
"	"	1	"	--		X		X		44 has crack
6-T	57		"	All			X	X		Light erosion
"	"	1	"	--	X	X		X		57 has crack
"	"	2	"	--		X		X		11, 13 have cracks
6-B	57		"	All			X	X		Light erosion
"	"	10	"	--		X		X		2,12,32,33,39,41,47,50,51,53 have cracks
"	"	3	"	--	X			X		9,11,13 have cracks
7-T	39	4	"	--	X			X		13, 16, 18, 26 have cracks
"	"	2	"	--	X	X	X			Weld cracked on braces which are between blades 38 and 39
7-B	39	1	"	--	X			X		#1 has crack
Gen										
8-T	61		Vt/mt	All			X	X		Severe erosion, FOD
"	"	14	"	--		X		X		1,14,19,21,22,24,28,31-33,46,48,50,52 have cracks
"	"	1	"	--		X	X			Weld cracks on brace which is between blades 60 and 61

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Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage	Total # of Blades	# of Defects	Inspection Method	Blade #	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	[illegible]
Gen										
8-B	61		Vt/mt	All			X	X		Erosion FOD
"	"	12	"	--		X		X		2,6,13,15,23,27,28,32,39,40,47,50 have cracks
"	"	1	"	--	X		X			Weld cracked on brace which is between blading 60 and 61
Turb.										
8-T	61		"	All			X	X		Heavy FOD, severe erosion
"	"	3	"	--	X			X		3,8,15 are missing part of blade due to erosion
"	"	20	"	--		X		X		6,8,11,14,17,19,20,24-29,36,49-53,55 have cracks
"	"	3	"	--	X			X		30,31,58 have cracks
Turb										
8-B	61		"	All			X	X		Erosion FOD
"	"	23	"	--		X		X		1-5,8,10,11,13,27,28,30-34,36,39,40,57-60 have cracks
"	"	1	"	--	X			X		46 has crack
Gen										
9-T	43		"	All			X	X		FOD erosion
"	"	2	"	--	X		X			5,38 have cracks
"	"	1	"	--		X	X			32 has crack
"	"	3	"	--		X		X		3,19,27 have tears
"	"	4	"	--		X		X		5,11,36,40 have cracks
"	"	2	"	--	X			X		9,12 have cracks

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IDENTIFICATION OF DIAPHRAGM BLADING DEFECTS

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Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage #	Total # of Blades	# of Defects	Inspection Method	Blade #	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	Type Defects
Gen.										
9-B	43		Vt/mt	All			X	X		FOD erosion
"	"	4	"	--	X			X		4,11,12,25 have cracks
"	"	1	"	--		X		X		15 has crack
"	"	1	"	--		X	X			Web cracked in previous weld repair area at blade #32
Turb.										
9-T	43		"	All			X	X		Light erosion, FOD
"	"	2	"	--	X			X		19, 21 have holes
"	"	7	"	--		X		X		2,5,17,25,34,33,38 have cracks
"	"	6	"	--	X			X		13,19,29,33,40,42 have cracks
"	"	2	"	--	X	X	X			Welds cracked on braces between blades 42 and 43
Turb.										
9-B	43		"	All			X	X		Erosion FOD
"	"	1	"	--		X		X		14 has crack
"	"	1	"	--	X			X		36 has crack
"	"	3	"	--				X		7,9,13,22 previous repair areas cracked
"	"	1	"	--			X			Inner web cracking between blades
Gen.										
10-T	37		"	All			X	X		Light FOD
"	"	1	"	--	X		X			Weld on brace has severe erosion between blades 36,37

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IDENTIFICATION OF DIAPHRAGM BLADING DEFECTS

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FOD = Foreign Object Damage

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Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage #	Total # of Blades	# of Defects	Inspection Method	Blade #	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	[illegible]
Gen.										
10-B	37		Vt/mt	All			X	X		Light FOD
"	"	6	"	--		X		X		3,28,30,31,34,36 have cracks
Turb										
10-T	37		"	All			X	X		Erosion light FOD
"	"	2	"	--		X		X		1, 16 have holes
Turb.										
10-B	37		"	All			X	X		FOD
"	"	1	"	--		X		X		1 has crack
"	"	2	"	--				X		11, 35 have holes in blade
Gen.										
11-T	63		"	All			X	X		Light erosion
"	"	2	"	--	X	X		X		63 has cracks
Gen.										
11-B	63		"	All			X	X		Light erosion
"	"	1	"	--	X			X		5 has crack
"	"	1	"	--		X		X		11 has crack
Turb.										
11-T	63		"	All			X	X		Light erosion, FOD
"	"	1	"	--	X			X		#52 has crack

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IDENTIFICATION OF DIAPHRAGM BLADING DEFECTS

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Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage #	Total # of Blades	# of Defects	Inspection Method	Blade #	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	[illegible]
Turb.										
11-T	63	1	Vt/mt	--			X			63 weld is separating from brace
11-B	63			All			X	X		FOD light erosion
"	"	2	"	--				X		1, 63 have holes in blade
Gen.										
12-T	52		"	All			X	X		Light erosion
12-B	"	1	"	--	X			X		23 has holes
"	"	1	"	--		X		X		42 has crack
Turb.										
12-T	52		"	All			X	X		Light erosion
"	"	1	"	--		X		X		1 has hole
12-B	52		"	All			X	X		Light erosion
"	"	2	"	--				X		16, 40 have holes
"	"	1	"	--	X			X		42 has crack
Gen.										
13-T	60		"	All						Good
13-B	"	2	"	--	X			X		5,7 have cracks
"	"	1	"	--						Outer web cracked at blade #41
Turb										
13-T	60		"	All			X	X		Light erosion, light FOD
13-B	"	1	"	--		X		X		26 has crack

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Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage #	Total # of Blades	# of Defects	Inspection Method	Blade #	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	Type Defects
Turb.										
13-B	60	1	Vt/mt	All	X			X		Web cracked at #3 blade
LPA	GEN									
14-T	71		"	All			X	X		Light erosion
14-B	71		"	"			X	X		Light erosion
LPA	TURB									
14-T	71		"	All			X	X		Light erosion
"	71	1	"	--	X			X		17 has tear
"	"	1	"	--	X			X		18 has crack
LPA	TURB									
14-B	71		"	All			X	X		Light erosion
"	"	1	"	--		X	X			71 has crack
"	"	1	"	--	X			X		70 has crack
LPA	GEN									
15-T	79	2	"	--	X			X		68, 79 have cracks
15-B	"	1	"	--		X		X		19 has crack
"	"	1	"	--	X			X		44 has crack
LPA	TURB									
15-T	79		"	All			X	X		FOD
"	"	1	"	--	X			X		79 has tear

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Form 27.309

IDENTIFICATION OF DIAPHRAGM BLADING DEFECTS

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Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage [illegible]	Total # of Blades	# of Defects	Inspection Method	Blade #	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	[illegible]
LPA	TURB									
15-B	79		Vt/mt	All			X	X		FOD
"	"	5	"	--	X			X		Previous weld repair area cracked
LPA	GEN									
16-T	36		"	All			X	X		Light pitting
"	"	1	"	--	X			X		36 has crack
LPA	GEN									
16-B	36		"	All			X	X		Light pitting
LPA	TURB									
16-T	36		"	All			X	X		Light pitting
16-B	36		"	--		X		X		Light pitting
"	"	1	"	--		X		X		29 has crack
LPA	GEN									
17-T	40			"	All					Good
17-B	40	1	"	--		X		X		14 has crack
"	"	1	"	--	X			X		22 has crack
LPA	TURB									
17-T	40	1	"	--	X			X		1 has crack
"	"	4	"	--		X		X		24,25,26,27 have cracks
17-B	40		"	--		X		X		Good

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NB= Nozzle Block
FOD = Foreign object damage

Since the defects are found in about the same location on either the inside diameter or outside diameter, and usually on the discharge side we only need to indicate with "X" where the crack or defect occurred, in proper column and the length of the defect.

Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage #	Total # of Blades	# of Defects	Inspection Method	Blade #	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	[illegible] Type Defects
LPA	GEN									
18-T	40	1	Vt/mt	--		X		X		22 has crack
"	"	1	"	--	X			X		32 has crack
"	"	1	"	--	X					Right side horizontal joint cracked in weld area
18-B	40	1	"	--	X			X		37 previous repair area separating
"	"	1	"	--	X					Left side horizontal joint cracked in weld area
LPA	TURB									
18-T	40	1	"	--	X			X		Web cracked at blade #40
"	"	1	"	--	X					Right side horizontal joint cracked in weld area
18-B	40	1	"	--	X			X		18 has crack
"	"	1	"	--		X		X		35 has crack
"	"	1	"	--	X					Left side horizontal joint cracked in weld area
"	"	1	"	--		X				Left side fit key racked
LPA	GEN									
19-T	30	7	"	--		X	X			16,17,19,20,23-25 welds cracked
"	"	3	"	--	X		X			6,7,29 welds cracked
19-B	30	1	"	--	X			X		1 weld cracked
"	30	4	"	--		X		X		23-25, 27 welds cracked
LPA	TURB									
19-T	30	2	"	--		X		X		17,24 welds cracked
"	"	2	"	--	X			X		19,2 23 welds cracked

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MQS Inspection, Inc. 1920 Oakcrest Avenue, Roseville, MN 55113

Form 27.309

IDENTIFICATION OF DIAPHRAGM BLADING DEFECTS

Sketch is looking at steam inlet side of diaphragm. First blade on left side would be No. 1-T on top half and No. 1-B on bottom half. Also, show total number of blades as their total number in either top or bottom, not total number in top and bottom.

NB = Nozzle Block
FOD = Foreign Object Damage

Since the defects are found in about the same location on either the inside diameter or outside diameter, and usually on the discharge side we only need to indicate with "X" where the crack or defect occurred, in proper column and the length of the defect.

Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stages [illegible]	Total # of Blades	# of Defects	Inspection Method	Blade [illegible]	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	[illegible]
LPA	TURB									
19-T	30	4	Vt/mt	--	X		X			10,14,22,25 welds cracked
19-B	30	3	"	--	X			X		2,3,5 welds cracked
LPB	GEN									
14-T	71		"	All			X	X		Light erosion, light FOD
14-B	71		"	All			X	X		Light erosion, light FOD
"	"	1	"	--	X			X		Previous weld repair separately at 57
LPB	TURB									
14-T	71		"	All			X	X		Light erosion, light FOD
"	"	1	"	--	X			X		63 has crack
14-B	71		"	All			X	X		Light FOD light erosion
LPB	GEN									
15-T	79		"	All			X	X		FOD erosion
"	79		"	--				X		Previous weld repair areas bending and rolling over
15-B	79	2	"	--				X		2, 76 have holes
"	"	1	"	--	X			X		74 has crack
"	"	1	"	--		X		X		52 has crack
LPB	TURB									
15-T	79		"	--						Good
15-B	79		"	--						Good

MQS Inspection, Inc. 1920 Oakcrest Avenue, Roseville, MN 55113

Form 27.309

IDENTIFICATION OF DIAPHRAGM BLADING DEFECTS

Sketch is looking at steam inlet side of diaphragm. First blade on left side would be No. 1-T on top half and No. 1-B on bottom half. Also, show total number of blades as their total number in either top or bottom, not total number in top and bottom.

NB= Nozzle Block
FOD = Foreign object damage

Since the defects are found in about the same location on either the inside diameter or outside diameter, and usually on the discharge side we only need to indicate with "X" where the crack or defect occurred, in proper column and the length of the defect.

Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage #	Total # of Blades	# of Defects	Inspection Method	Blade #	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	Type Defects
LPB	GEN									
16-T	36		Vt/mt	All			X	X		Light pitting
16-B	36		"	"			X	X		Light pitting
LPB	TURB									
16-T	36		"	All			X	X		Light pitting
16-B	36		"	All			X	X		Light pitting
17-T	40		"	--						Good
17-B	40	1	"	--	X					Lift side horizontal joint cracked in weld area
"	"	1	"	--	X		X			Web cracked at blade #13
LPB	TURB									
17-T	40	1	"	--	X			X		33 has crack
17-B	40	1	"	--	X			X		10 has crack
LPB	GEN									
18-T	40	1	"	--	X					Right side horizontal joint cracked in weld area
18-B	40	1	"	--	X					Left side horizontal joint cracked in weld area
"	"	1	"	--		X		X		Repair area separating at Blade #1
LPB	TURB									
18-T	40	1	"	--	X					Right side horizontal joint cracked in weld area
18-B	40	1	"	--	X					Left side horizontal joint cracked in weld area

MQS Inspection, Inc. 1920 Oakcrest Avenue, Roseville, MN 55113

Form 27.309

IDENTIFICATION OF DIAPHRAGM BLADING DEFECTS

Sketch is looking at steam inlet side of diaphragm. First blade on left side would be No. 1-T on top half and No. 1-B on bottom half. Also, show total number of blades as their total number in either top or bottom, not total number in top and bottom.

NB = Nozzle Block
FOD = Foreign Object Damage

Since the defects are found in about the same location on either the inside diameter or outside diameter, and usually on the discharge side we only need to indicate with "X" where the crack or defect occurred, in proper column and the length of the defect.

Date: 3-15-99 Station: Sherco WO# 07-F3389

Turbine #: 170X819 Unit No. 3 Technician: Michael T. Christensen, Level II, Doug Gertner, Level II

Stage [illegible]	Total # of Blades	# of Defects	Inspection Method	Blade [illegible]	From OD Ring	From ID Ring	Inlet Side	Discharge Side	Length of defect	[illegible]
LPA	GEN									
19-T	30	1	Vt/mt	–	X			X		2 weld cracked
"	"	8	"	--	X		X			3,8,11,12,14,26-28 welds cracked
"	"	5	"	--		X	X			3,21,8,24,26 welds cracked
19-B	30	2	"	–	X			X		25,27 have cracks
"	"	1	"	–		X		X		26 weld cracked
"	"	20	"	--	X		X			1,2,4-7,9-11,14,16-18,21,22,26-30 welds cracked
"	"	8	"	–		X	X			6,8-11,23,24,29 welds cracked
LPB	TURB									
19-T	30	9	"	–	X		X			1,6,10,16,18,20,21,27,28 welds cracked
"	"	1	"	–		X	X			11 weld cracked
19-B	30	5	"	--	X	X	X			4,9,21,26,29 welds cracked
"	"	8	"	--	X		X			1,2,10,11,16,19,27,30 welds cracked
"	"	1	"	--		X	X			24 weld cracked
"	"	5	"	–		X		X		10,11,19,20,30 welds cracked
"	"	11	"	--	X			X		3,5,13,14,16,17,22-24, 26,28 welds cracked
"	"	4	"	--	X	X		X		9,12,15,19 welds cracked

MQS Inspection, Inc.

Form: 27.311

TURBINE COMPONENT REPORT

Client: NSP **Turbine #** 170X819 **Unit #:** 3 **Item:** Packing Glands
Station: Sherco **Date:** 3-15-99 **Technician:** Michael T. Christensen, Level II

Description or Area	VT	MT	PT	UT	Damage	Location/Comments
N-1	X	X				Both halves inner & outer revealed no recordable indications
N-2	X	X				Both halves inner & outer revealed no recordable indications
N-3	X	X				Both halves revealed no recordable indications.
N-4	X	X				Both halves revealed no recordable indications.
N-5	X	X				Both halves revealed no recordable indications.
N-6	X	X				Both halves revealed no recordable indications.
N-7	X	X				Both halves revealed no recordable indications.
N-8	X	X				Both halves revealed no recordable indications.

MQS Inspection, Inc.

Form: 27.311

TURBINE COMPONENT REPORT

Client: NSP Turbine # 170X819 Unit #: 3 Item: Casings
Station: Sherco Date: 3-15-99 Technician: Michael T. Christensen, Level II

Description or Area	VT	MT	PT	UT	Damage	Location/Comments
H.P. Outer casing	X	X				Upper & lower casing halves revealed no recordable indications.
I.P. outer casing	X	X				Lower casing half revealed no recordable indications, upper half #2
						Fit on gen. End has a 2-1/8" long crack at 61" from right side horz. Joint
L.P.-A casings	X	X				Diaphragm fits show physical damage (rubbing)
L.P.-B casings	X	X				Diaphragm fits show physical damage. (rubbing) inner (upper half)
						#2 access cover weld is cracked in base metal. 5.25" on the turbine
						End, 13.5" long crack at 61" from access cover described previously,
						Crack is in base metal on the turbine end. Lower half revealed no
						Indications
H.P. Inner casing	X	X	X			No recordable indications noted.
I.P. #1 Inner casing	X	X				Lower halves for the turbine and generator ends revealed no recordable
						Indications. Upper halves for the turbine and generator ends have
						Cracking on the left and right hand horizontal joints.
I.P. #2 Inner casing	X	X				Lower halves for the turbine & generator endsd revealed no recordable
						Indications Upper half generator end revealed cracking on the left
						And right hand side horizontal joints, upper half turbine end revealed
						No recordable indications.

MQS Inspection, Inc.

Form: 27.311

TURBINE COMPONENT REPORT

Client: NSP **Turbine #** 170X819 **Unit #:** 3 **Item:** Valve Comp.
Station: Sherco **Date:** 3-15-99 **Technician:** Michael T. Christensen, Level II

Area Description or Area #	VT	MT	PT	UT	Damage	Location/Comments
Equalizer valve	X	X	X			Body seat, disc & seat, and the stem revealed no recordable indications.
Control Valve	X	X	X	X		Springs & valve body seats revealed no recordable indications. Valve
						Seats, pins, 4 per valve revealed no recordable indications including
						Valve body.
Stop valve	X	X	X			Valve body seats revealed no recordable indications, including the valve
						Body.
Intercept valve	X	X	X			Valve screen welds are cracked in the corners and the welds show
						Undercutting. Valve body seats revealed no indications.

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Form: 27.311

TURBINE COMPONENT REPORT

Client: NSP **Turbine #** 170X819 **Unit #:** 3 **Item:** Misc.

Station: Sherco **Date:** 3-15-99 **Technician:** Michael T. Christensen, Level II

Description/or Area	VT	MT	PT	UT	Damage	Location/Comments
Gen. For blades (60)	X		X			No defects noted.
Misc. turning gear pieces	X		X			No defects noted.
Generator retaining rings	X		X			No defects noted.

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Form: 27.311

TURBINE COMPONENT REPORT

Client: NSP **Turbine #** 170X819 **Unit #:** 3 **Item:** Exciter
Station: Sherco **Date:** 3-15-99 **Technician:** Michael T. Christensen, Level II

Description or Area	VT	MT	PT	UT	Damage	Location/Comments
Exciter retaining rings	X		X			O.D. of rings examined, no defects noted.
Bearing	X		X	X		Collector end (lwr.) – excessive rubbing.
	X		X	X		Collector end (upper) – excessive rubbing with a ¼" long crack on the
						Bottom of the inboard side.
"	X		X	X		Turbine end (lwr.) – light sporadic disbond around edges.
						Turbine end (upper) – light sporadic disbond around edges, with a crack
						7/16" long, 4-3/8" from left horizontal joint and 1-1/4" from inboard
						Side, another crack 3/8" long, 1/16" from right side horizontal joint ¼"
						From inboard side and a 3/8" long crack, 7/8" from right horizontal
						Joint at the outboard side.
Seal assemblies (4)	X	X				3 assemblies NDE'd acceptable, #33 inboard has a 2-3/4" long crack
(boiler feed pump port)						In the webbing.
Rings (4)	X	X				NDE acceptable
(boiler feed pump port)						
Exciter shaft	X	X				No defects noted on excisable shaft, journals & coupling

MQS Inspection, Inc.

Form: 27.311

TURBINE COMPONENT REPORT

Client: NSP Turbine # 170X819 Unit #: 3 Item: Bearings
Station: Sherco Date: 3-15-99 Technician: Michael T. Christensen, Level II

Description or Area	VT	MT	PT	UT	Damage	Location/Comments
Thrust Bearings	X		X	X		Light sporadic disbond around edges of bearings, light pitting.
#1 Bearing	X		X	X		Upper half bearing has randomly isolated 1/8" diameter areas of disbond
						#4 pad one area and #5 pad twelve areas.
"	X		X	X		Lower half bearing has light sporadic disbond around edges of bearing
						Pad #6l has a 1.5" diameter area of disbond and pads 7 and 6R have
						Cracks in babbit, see attached sketch for locations.
#2 Bearing	X		X	X		Upper half bearing has light sporadic disbond around edges of bearing
						Pads. Pads #3, #4 and #5 have disbond see attached sketch for
						Locations. #3 and #4 pads have cuts in babbit near the governor end
"	X		X	X		Lower half bearing has light sporadic disbond around edges of bearing
						Pads. Pads #6L, #7 and #6R have disbond. See attached sketch.
#3 Bearing	X		X	X		Upper half bearing #3 pad m;issing a ½"X1/4" piece of material on the
						Generator end.
"	X		X	X		Lower half bearing #6L pad and #7 pad have light sporadic disbond
						Around edges

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Form: 27.311

TURBINE COMPONENT REPORT

Client: NSP Turbine # 170X819 Unit #: 3 Item: Bearings (contd.)
Station: Sherco Date: 3-15-99 Technician: Michael T. Christensen, Level II

Description or Area	VT	MT	PT	UT	Damage	Location/Comments
#4 Bearing	X		X	X		Upper half bearing #3 & #5 pad have light sporadic disbond around
						Edges, light pitting on governor end of the #5 pad.
"	X		X	X		Lower half bearing #6L & #7 have disbond on the governor end
						See attached sketch.
#5 Bearing	X		X	X		Upper half bearing has light sporadic disbond around the edges with light
						Pitting in the middle of the pad. Pad also has disbond and cracking
						See attached sketch.
"	X		X	X		Lower half bearing has light sporadic disbond around the edges with
						Cracking and disbond, see attached sketch.
#6 Bearing	X		X	X		Upper ;half bearing hs light sporadic disbond around the edgees of the
						Generator and governor ends only. Bearing also has one area of disbond
						See attached sketch.
"	X		X	X		Lower half bearing has light sporadic disbond on the left and right
						Horizontal joints, with other areas of disbond in center of pad,
						See attached sketch.

MQS Inspection, Inc.

Form: 27.311

TURBINE COMPONENT REPORT

Client: NSP **Turbine #** 170X819 **Unit #:** 3 **Item:** Bearings (contd.)
Station: Sherco **Date:** 3-15-99 **Technician:** Michael T. Christensen, Level II

Description/Area	VT	MT	PT	UT	Damage	Location/Comments
#4 Bearing	X		X	X		Upper half bearing #3 & #5 pad have light sporadic disbond around
						Edges, light pitting on governor end of the #5 pad.
"	X		X	X		Lower half bearing #6L & #7 have disbond on the governor end
						See attached sketch.
#5 Bearing	X		X	X		Upper half bearing has light sporadic disbond around the edges with light
						Pitting in the middle of the pad. Pad also has disbond and cracking
						See attached sketch.
"	X		X	X		Lower half bearing has light sporadic disbond around the edges with
						Cracking and disbond, see attached sketch.
#6 Bearing	X		X	X		Upper ;half bearing hs light sporadic disbond around the edgees of the
						Generator and governor ends only. Bearing also has one area of disbond
						See attached sketch.
"	X		X	X		Lower half bearing has light sporadic disbond on the left and right
						Horizontal joints, with other areas of disbond in center of pad,
						See attached sketch.

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Turbine Component Report

Client: NSP

Station: Sherco

Unit: 3

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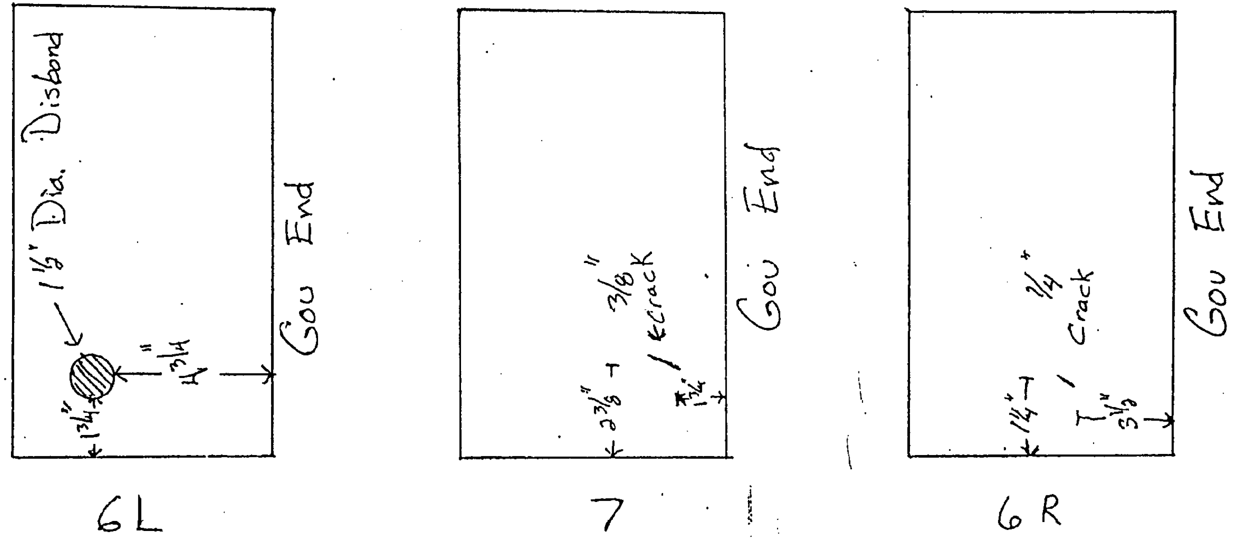
Sheet 1 of 10

Date: 3-15-99

#1 Bearing Pads (Lower)



Technician: Mel T. Chr Level II Date: 3-15-99

Technician: Doug Greth Level II Date: 3-15-99

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MQS Turbine Inspection Program

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Turbine Component Report

Client: NSP
Station: Sherco
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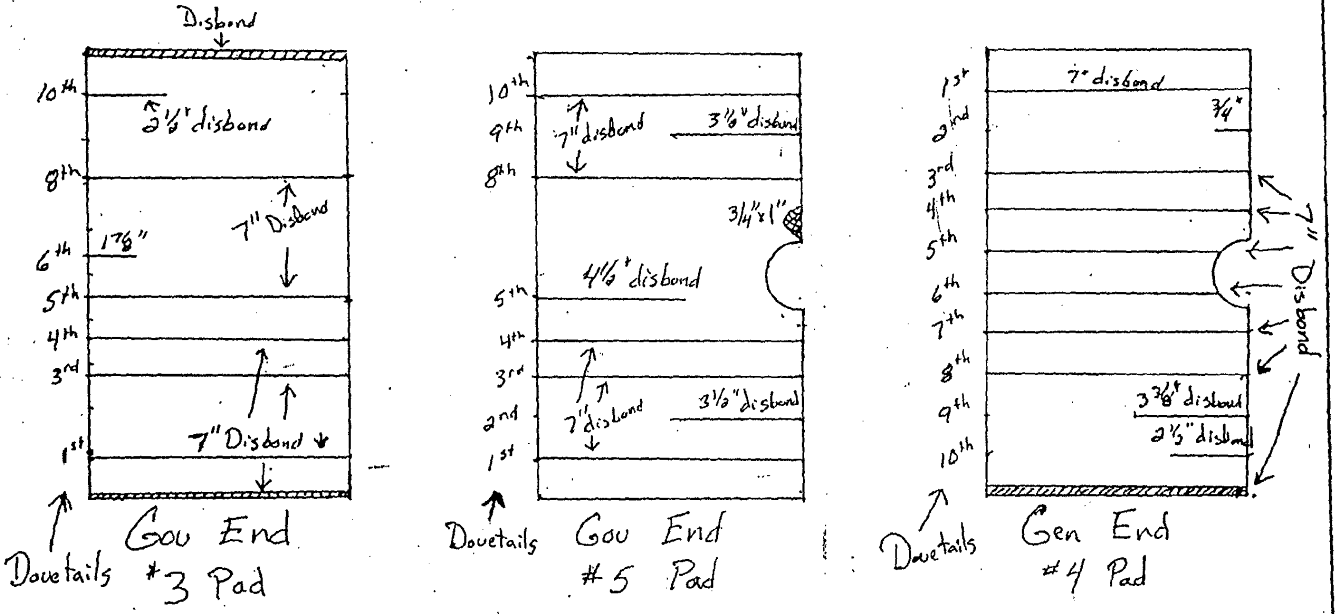
Date: 3-15-99

#2 Bearing Pads (Upper)



Technician: Level II Date: 3-15-99
Technician: Level II Date: 3-15-99

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Turbine Component Report

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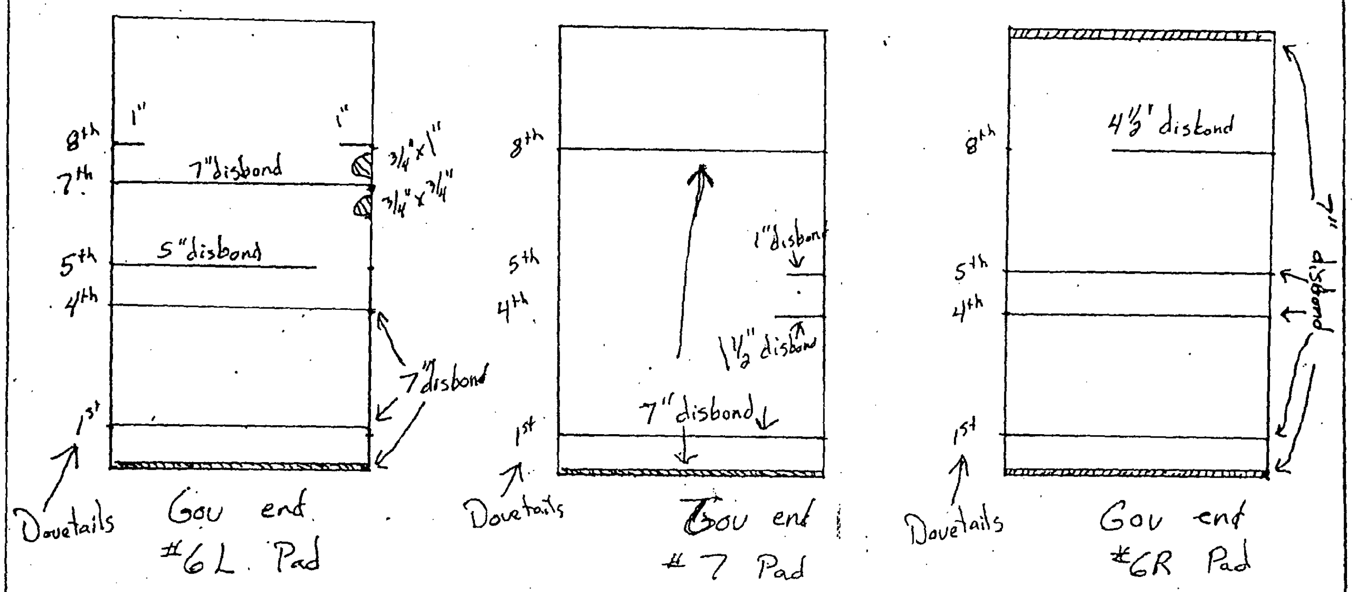
#2 Bearing Pads (Lower)



Technician: Level II Date: 3-15-99
Technician: Level II Date: 3-15-99

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Turbine Component Report

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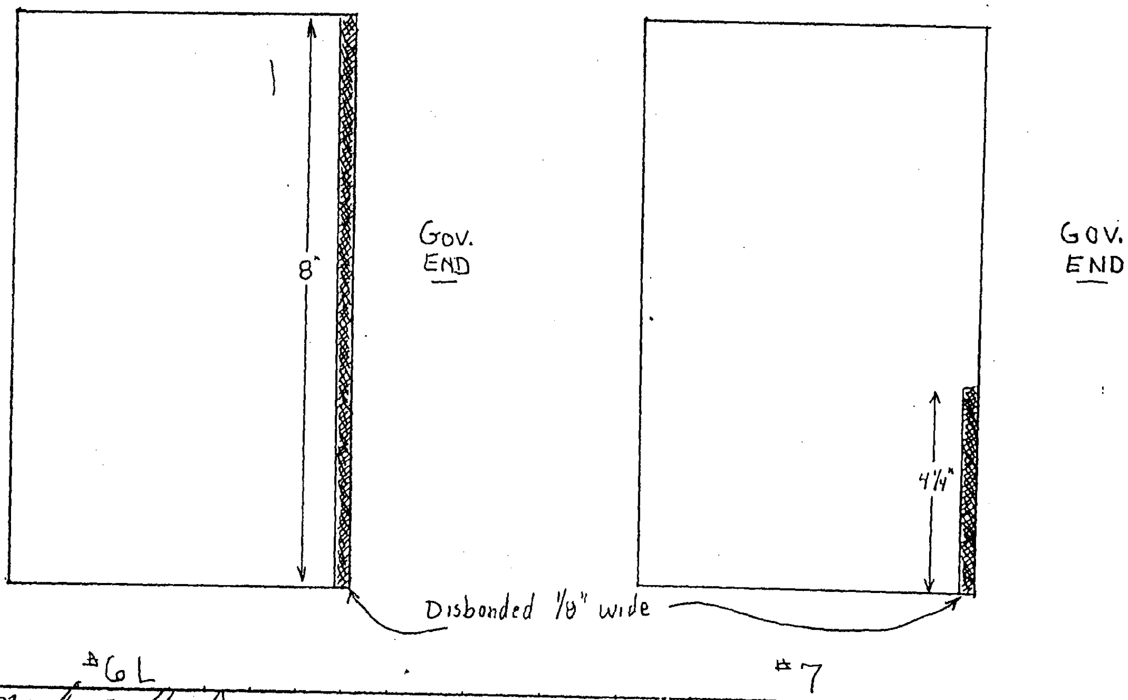
#4 LOWER



Technician: Level II Date: 3-15-99
Technician: Doug Level I Date: 3-15-99

MQS Turbine Inspection Program

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Turbine Component Report

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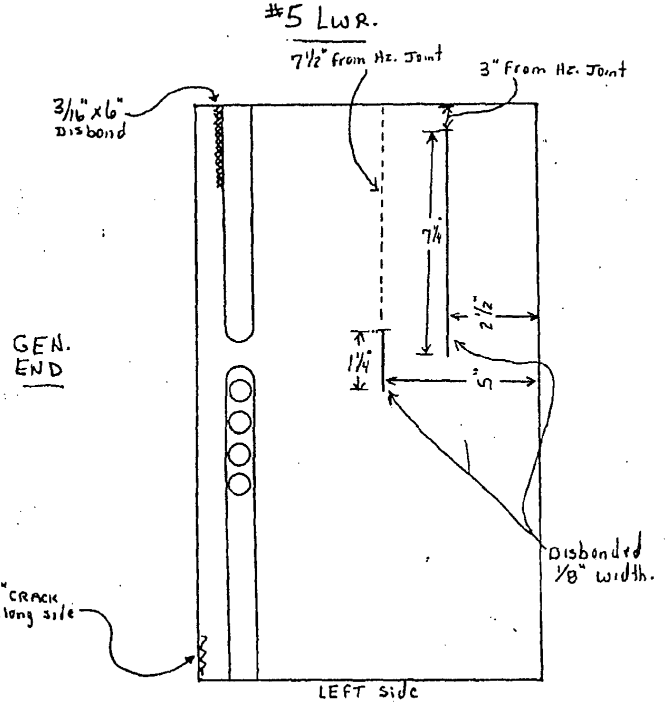
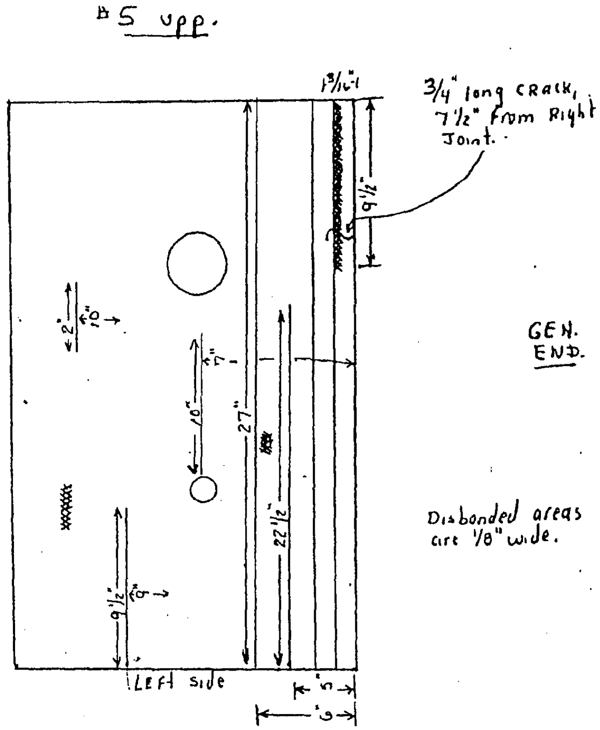
Unit: 3
Date: 3-15-99





Disbonded areas are 1/8" wide.

XXXX - Represents Heavily pitted areas.

Technician: Level II Date: 3-15-99
Technician: Doug Level II Date: 3-15-99

MQS Turbine Inspection Program

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Turbine Component Report

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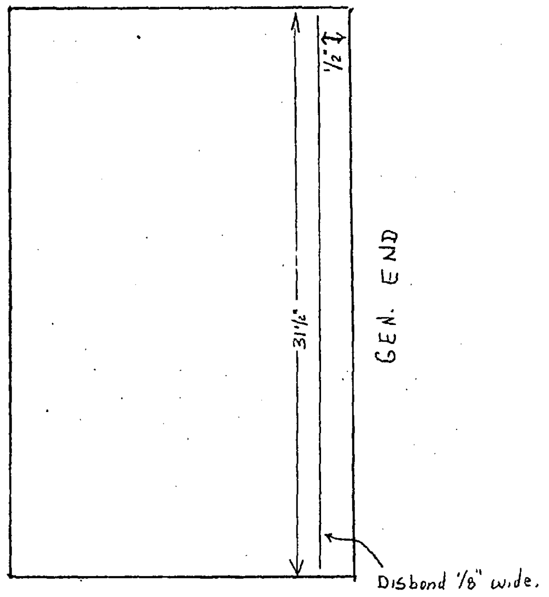
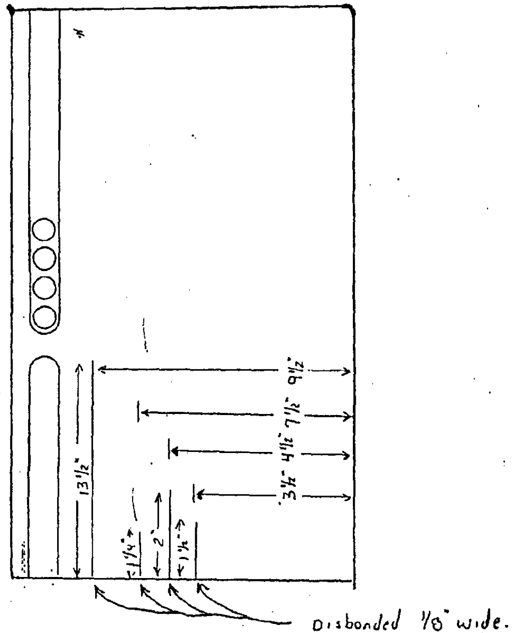


#6 upper



#6 Lower

Technician: Matt T. Christ Level II Date: 3-15-99
Technician: Doug Becker Level II Date: 3-15-99

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Turbine Component Report

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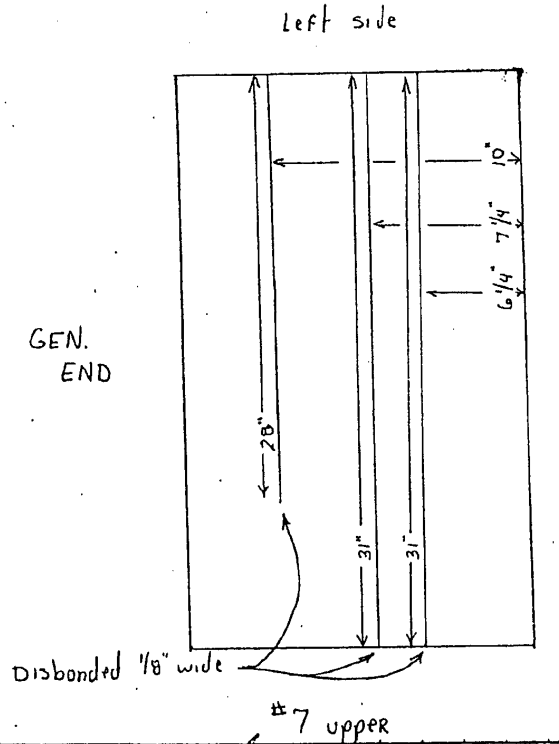

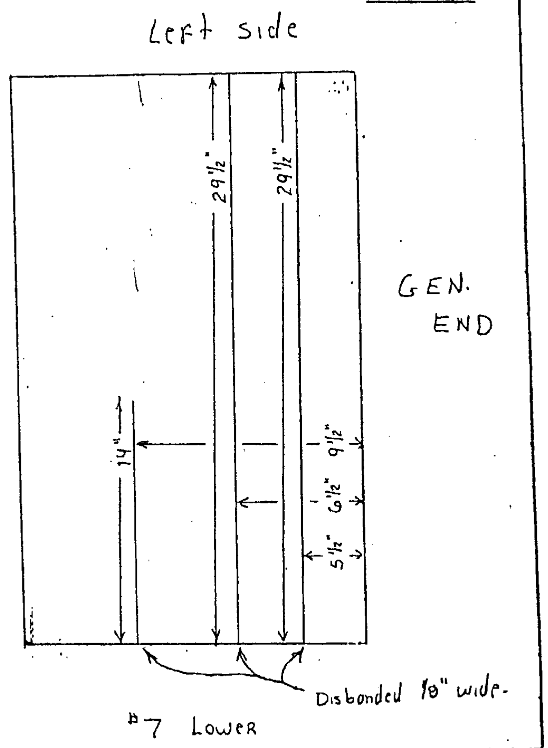

Technician: Level II Date: 3-15-99

Technician: Level II Date: 3-15-99

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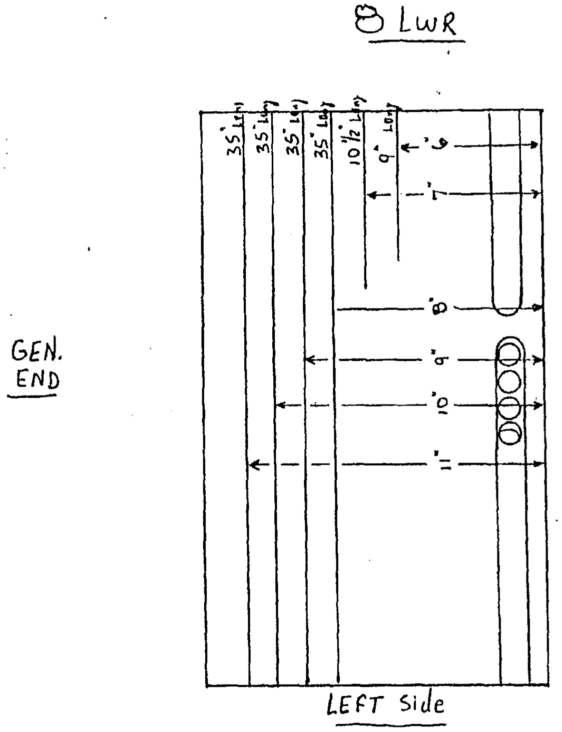

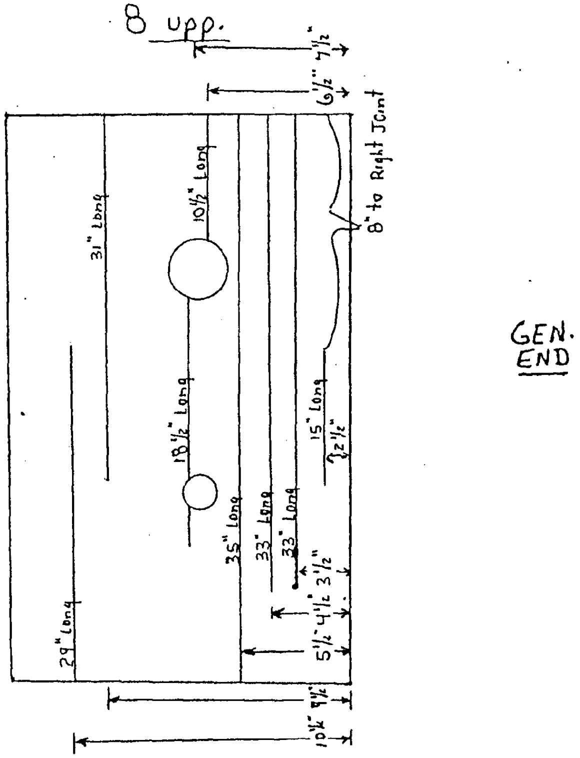

Technician: Level II Date: 3-15-99
Technician: Doug Level II Date: 3-15-99

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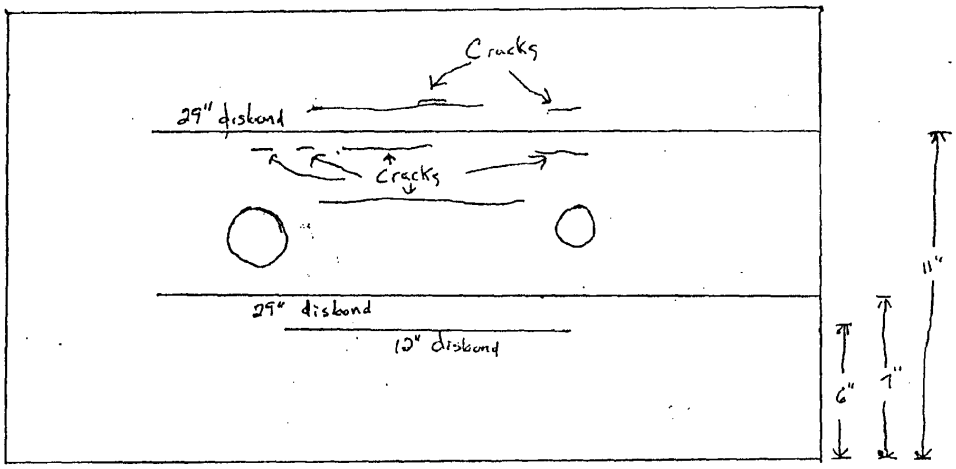
#9 Bearing (Top)



Gov End

Technician:
Technician: Doug
Level II Date: 3-15-99
Level I Date: 3-15-99

MQS Turbine Inspection Program

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Turbine Component Report

Client: NSP
Station: Sherco
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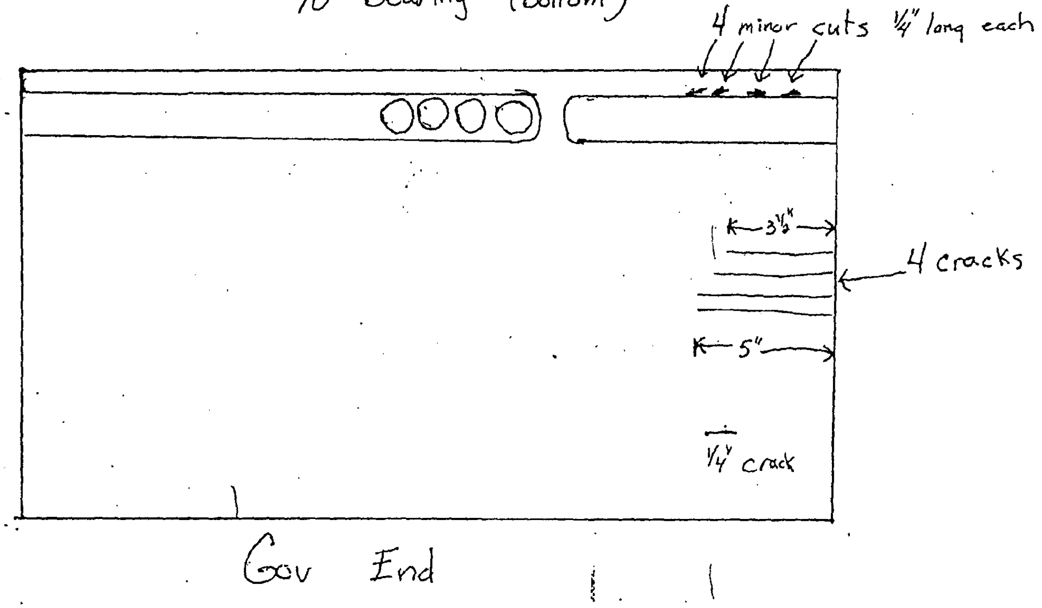
Date: 3-15-99

#10 Bearing (bottom)



Technician: Mick T. Christ Level II Date: 3-15-99
Technician: Doug Getus Level II Date: 3-15-99

MQS Inspection, Inc. 1920 Oakcrest Avenue, Roseville, MN 55113

FORM 27.315

TURBINE INSPECTION PROGRAM

Ultrasonic Examination of Bolts & Studs

Client: Northern States Power MQS Work Order #: 07F3389
Station: Sherco Unit 3 Turbine No. 170X819 Date: 3-15-99

Component	Total # of Items	# Inspected	# Accept	# Reject	Dimensions L D	In Place	Defect Location
HP Outer							
Cyl. Studs	44	44	0			No	
IP Outer							
Cyl. Studs	64	64	0			No	
CRV Studs	72	72	0			Yes	
Control							
Valve Studs	48	48	0			Yes/No	
Stop Valve							
Studs	48	48	0			Yes/No	
A Coupling							
Bolts	16	16	0			No	
B Coupling							
Bolts	16	16	0			No	
C Coupling							
Bolts	16	16	0			No	
D Coupling							
Bolts	16	16	0			No	
Ventilation							
Valve	18	18	0			Yes	
HP Inner							
Cylinder	26	16	0			No	

Technician: Michael T. Christensen, Level II, Douglas Gertner, Level II Date: 3-15-99

MQS INSPECTION, INC. **TURBINE INSPECTION PROGRAM**

NDE TECHNIQUE RECORD / MAGNETIC PARTICLE

Form: 21.07A Rev. Org.

DATE: 3-15-99

PAGE of

CLIENT: Northern States Power

WORK ORDER No 07F3389

STATION: Sherco

UNIT 3

TURBINE No 170X819

SPECIFICATION: MQS INSPECTION, INC.

PROCEDURE: 27.D.300 Rev.0 - Section 4

PRECLEAN:

MATERIAL: NA

METHOD NA

BATCH No: NA

EQUIPMENT: **MAGNAFLUX** [✓ M500] P500 (CIRCLE ONE) S/N: 78108

AMPS:

CURRENT:

Head Shot NA	Coil Shot: 1500 amps	Other Info:	
Contact Material: COPPER	4/0 Cable		

RATED MAXIMUM AMPERAGE: 4,000

METHOD: CONTINUOUS

YOKE: PARKER / [✓ MAGNAFLUX] S/N: 6007-Y9

CURRENT: AC DC FIXED AMPERAGE

MAGNETIC FIELDS ARE VERIFIED WITH A MAGNETIC FIELD INDICATOR (PIE GUAGE)

MATERIAL:

MAGNAFLUX 14A (Redi-Bath) BATCH No: 98C074 APPLICATION: Spray

CARRIER II BATCH No: NA

14AM BATCH No: 97F09K

GREY DRY POWDER: TYPE: #1 Grey BATCH No: 91F050

RED DRY POWDER: TYPE: 8A Red BATCH No: 95D009

DEMAG: METHOD: AUTOMATIC REOSTAT DEMAG with INFINITE CONTROL RESIDUAL: +/- 2 GAUS

METHOD: Withdrawal RESIDUAL: +/- 2 GAUSS

POSTCLEAN:

MATERIAL: NA

METHOD NA

BATCH No: NA

NOTE: If any of the above parameters change make note of them below.

Record results on appropriate Turbine Inspection form.

Attach sketches or additional information as applicable.

LEVEL III APPROVAL: Kenneth J. Olson	TECHNICIAN / Level: Michael T. Christensen, Doug Gertner	DATE: 3-15-99

MQS . INSPECTION, INC. **TURBINE INSPECTION PROGRAM**

NDE TECHNIQUE RECORD/LIQUID PENETRANT Form: 23.08A Rev. Org.

DATE: 3-15-99 PAGE of

CLIENT: Northern States Power WORK ORDER No: 07F3389

STATION: Sherco UNIT 3

TURBINE No 170X819

SPECIFICATION: MQS INSPECTION PROCEDURE: 27.D.300 Rev.0 - Section 9

PRECLEAN:

MATERIAL: NA METHOD NA BATCH No: NA

DRYING TIME: NA

PENETRANT:

MATERIAL: SKL-SP BATCH No: 98M02K APPLIED BY: Spray/ brush

DWELL:

MATERIAL: ZL-60D BATCH No: 98L108 APPLIED BY: Spray

DWELL: 30 min.

EXCESS PENETRANT REMOVAL:

MATERIAL: SKC-S METHOD: Wipe BATCH No: 98L08K DRYING TIME: 5 min.

MATERIAL: Denatured Alcohol METHOD: wipe BATCH No: NA DRYING TIME: 5 min.

DEVELOPER:

MATERIAL: SKD-S2 BATCH No: 98B04K APPLIED BY: Spray

DEV. TIME 10 min.

POSTCLEAN:

MATERIAL: NA METHOD BATCH No:

NOTE: If any of the above parameters change make note of them below.

Record results on appropriate Turbine Inspection form. Attach sketches or additional information as applicable.

LEVEL III APPROVAL: Kenenth J. Olson	TECHNICIAN / Level: Michael T. Christensen, Doug Gertner	DATE: 3-15-99

MQS INSPECTION, INC. **TURBINE INSPECTION PROGRAM**

NDE TECHNIQUE RECORD / ULTRASONIC

Form: 22.15A Rev. Org.

DATE: 3-15-99

PAGE of

CLIENT: Northern States Power

WORK ORDER No: 07-F3389

STATION: Sherco

UNIT: 3

TURBINE No 170X819

SPECIFICATION:

BABBIT BEARINGS MQS INSPECTION, INC. PROCEDURE: **27.D.300 Rev.0 - Section 7**

STUDS / BOLTING MQS INSPECTION, INC. PROCEDURE: **27.D.300 Rev.0 - Section 8**

EQUIPMENT

Unit Mfg.: Krautkramer Model: USK-7B S/N: 2732

Transducer Mfg.: Panametrics Model: contact S/N: 191046

Frequency: 5.0 mhz Angle: 0 degrees Size: .25" dia. Type: contact

Transducer Mfg.: Panametrics Model: contact S/N: 126536

Frequency: 2.25 mhz Angle: 0 degrees Size: .50" dia. Type: contact

CABLE: LENGTH: 6 ft TYPE: [✓ BNC / BNC] [✓ BNC / MD] * (CIRCLE ONE)

Calibration Block: IIW Block S/N: A01515

Babbit bearing cal. Std. S/N: GTM-31

Couplant: Aquasonic 100 Batch No.: H-386

Turbine Oil Batch No.: NA

PROCESS

Method: CONTACT Scanning: MANUAL Inches / Second: < 6"/sec. Overlap 25%

Special Instructions:

Record results on appropriate Turbine Inspection form. Attach sketches or additional information as applicable.

LEVEL III APPROVAL: Patrick J. Haggenmiller

TECHNICIAN / Level: Doug Gertner, Lv II
Michael T. Christensen, Level II

DATE: 3-15-99

MQS INSPECTION, INC. **TURBINE INSPECTION PROGRAM**

NDE TECHNIQUE RECORD / VISUAL EXAMINATION Form: 26.03 Rev. 2

DATE: 3-15-99
PAGE of

CLIENT: Northern States Power
WORK ORDER No: 07F3389

STATION: Sherco
UNIT 3

TURBINE N 170X819

SPECIFICATION: MQS INSPECTION
PROCEDURE: 27.D.300 Rev.0 - All Sections

EQUIPMENT:(List all insp.equipment and visual aids used (include S/N's and/or cal. dates when applicable)

RESULTS:

Bearings showing disbond and cracking

Diaphragms and nozzle blading have cracking and foreign object damage

IP inner casings have cracks on the horizontal joints

IP outer casings has a #2 positioning groove cracked.

Intecept valve screen has cracked weldds and undercutting of welds

LP-B inner cylinder has 2 cracks in the parent metal

Cracked bucket pins on both LP-A and LP-B rotors

Boiler feed pump #33 inboard seal assy. Haas a cracked web

Record results on appropriate Turbine Inspection form.
Attach sketches or additional information as applicable.

LEVEL III APPROVAL: Kenneth J. Olson	TECHNICIAN / Level: Doug Gertner, Lvl.II Michael T. Christensen, Level II	DATE: 3-15-99

MQS
MQS Inspection, Inc.

1920 Oakcrest Avenue
Roseville, MN 55113

Phone (612)633-7616
Fax (612)633-4928

CERTIFICATION OF INSPECTION

Northern States Power
ATTN: Accounts Payable
P.O. Box 9366
Minneapolis, MN 55440

(612) 520-6896

CERTIFICATION # 07-F3389
Customer # 073310
Lab # 07
Customer Job#
Shipping Doc #
Customer PO #
Date Completed 03/19/99

Description of Parts:

Their Count	Our Count	Part Number	Description
1	1	FWO GENERAL ELECTRIC TURBINE UNIT #3 AT SHERCO STATION, BECKER, MN	

Method .... MAGNETIC PARTICLE, LIQUID PENETRANT

Specification MQS INSPECTION

Procedure .... 27.D.300 REV 0
Acceptance Criteria REPORT ALL FINDINGS TO CLIENT

Remarks:
See report.

MQS Inspection, Inc.

Title

Northern States Power Company, doing business as Xcel Energy
Information Request

Docket No.:	E002/GR-12-961, E002/GR-13-868; E999/AA-13-599; E999/AA-14-579; E999/AA-16-523; E999/AA-17-492; E999/AA-18-373; OAH 65-2500-38476 Sherco 3		
Requestor:	Xcel Energy - Tara R. Duginske, Assistant General Counsel, Xcel Energy		
Requestor email:	Tara.R.Duginske@xcelenergy.com		
Requested from:	Minnesota Department of Commerce		
Date of Request:	August 29, 2023	Information Request No.	30
Response Due:	September 11, 2023		

<u>Reference:</u> DOC Response to Xcel Energy Information Request 21 (a) states:

> "TIL 1121-3AR1 does not prescribe a specific interval for performing inspection of the finger dovetails but it does identify abnormal events or operational anomalies that should trigger the inspection and Sherco 3 did experience these <u>events</u>." (emphasis added)

<u>Question:</u>
Identify with specificity the "events" referred to in this response, including the date of any such events.

<u>Response:</u>
The Sherco 3 operating abnormalities referred to in my testimony can be found in GE's expert witness James D. Schultz's "Expert Witness Report", pages 13 – 15. See GE Litigation Deposition Exhibit 686.

Preparer:
Title:
Department:
Telephone:
Date:

27095696v1

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Schedule 7

Exhibit___(HJS-2), Schedule 7 has been marked Not-Public in its entirety. This Schedule was prepared by Mr. Herb Sirois directly in response to a report prepared by Mr. James D. Schultz (Schultz Report) on behalf of General Electric (GE), and provided to Xcel Energy by GE, subject to a confidentiality agreement. GE considers the Schultz Report to include confidential and proprietary information to GE. Therefore, the Company considers this Schedule to be trade secret data as defined by Minn. Stat. § 13.37(1)(b) and Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Expert Report – Rebuttal to Expert Witness Report of James D. Schultz
2. **Authors:** Herbert J. Sirois, PE, Foster Cove Engineering, Inc.
3. **Importance:** Includes confidential and proprietary information of GE that is subject to a confidentiality agreement between the Company and GE.
4. **Date the Information was Prepared:** April 25, 2016