Direct 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

DIRECT TESTIMONY OF

HERBERT J. SIROIS

On Behalf of

NORTHERN STATES POWER COMPANY

June 16, 2023

Exhibit___(HJS-1)

Operations and Maintenance

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Herbert J. Sirois. My business address is 105 Lewis Drive, Davenport, Florida 33837.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am an independent turbomachinery consultant and previously the founder of the now dissolved Foster Cove Engineering, Inc. I have been a turbomachinery consultant since 1993.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy (Xcel Energy or the Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. For over five decades, I have been dedicated to the design, manufacture, and operation of turbomachinery used by the marine, electric utility and process industries. My early experience includes steam turbine and component engineering for large low-, intermediate- and high-pressure steam turbines, nuclear turbines, and engineering for products used within the power generation industry. In 1993, I became an independent turbomachinery consultant, and then in 1998 founded and served as president and technical director of Foster Cove Engineering, Inc. with a focus on failure investigations of steam and gas turbines for power generation plants and insurance companies. In these roles since 1993, I have investigated various turbine-generator failures. My qualifications and experience are more fully described in Exhibit___(HJS-1), Schedule 1 and Exhibit___(HJS-1), Schedule 2, Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony provides opinions regarding Xcel Energy's decades of turbine operation and maintenance preceding the November 2011 failure event (Event) at the third unit (Unit 3) of the Sherburne County Power Generation Plant (Sherco). Specifically, I provide opinions as to the Company's prudency in operating, inspecting, and maintaining Sherco Unit 3, including discussion regarding the turbine manufacturer's advice regarding inspection and maintenance of the Unit 3 low pressure turbines. I explain that the Company's practices were prudent and consistent with industry practices for operating and maintaining this General Electric (GE) steam turbine-generator, that the Company prudently gathered and relied on operational evidence along with equipment-specific technical information to determine the scope of outages, and that the scope of those outages – including the 2011 outage – was reasonable especially given GE's silence in response to the Company's request for additional inspection advice for Unit 3. In whole, the Company took all necessary actions to assure efficient and reliable maintenance on Sherco Unit 3.

Q. PLEASE DESCRIBE THE SCOPE OF WORK YOU PERFORMED IN PREPARATION OF YOUR OPINIONS AND THIS TESTIMONY.

A. I reviewed documentation provided to me by counsel, conducted a site visit to the Sherco plant, and interviewed Sherco plant personnel. The documents reviewed include but are not limited to: a) transcripts of depositions of Company and GE personnel, b) reports of major and minor planned outages conducted on the Sherco Unit 3 steam turbine generator, c) various written communications between and/or within GE/Sherco/Xcel Energy and others. A full list of documents reviewed can be found in Exhibit___(HJS-1), Schedule 2. In addition to my work on behalf of Xcel Energy starting in 2016, I also previously visited Sherco Unit 3 in 2012 on behalf of one of the insurers for Alstom, the company which provided the upgrade to the high- and intermediate-pressure turbine sections on Unit 3 in 2011, just before the failure event. My involvement was to initially survey the damage and review the failure investigation protocols on behalf of Alstom and its insurers.

Q. HAVE YOU PREPARED ANY WRITTEN REFLECTION OF YOUR OPINIONS?

A. Yes. I provided an expert report dated March 1, 2016, and a rebuttal report dated April 25, 2016, in connection with the lawsuit filed by the Company and others against GE, Minnesota District Court Case No. 71-cv-13-1472 (Lawsuit). My expert reports contain opinions consistent with this testimony and are attached as Exhibit___(HJS-1), Schedule 2 and Exhibit___(HJS-1), Schedule 3, respectively. Subsequently, the Company and GE reached a confidential settlement, and I did not testify at trial.

II. SHERCO UNIT 3

A. The Sherburne County Plant, Staff and Resources

Q. PLEASE DESCRIBE THE SHERBURNE COUNTY POWER GENERATION PLANT AND SPECIFICALLY SHERCO UNIT 3.

A. Sherco is a coal-fired, electrical power plant located in Becker, Minnesota. The facility was built in the 1970s and initially comprised two electrical generating units – Sherco Unit 1 and Sherco Unit 2. In 1977, due to increased electrical demand, the Company contracted with GE to design and manufacture an additional steam turbine generator unit – Sherco Unit 3. Unit 3's steam turbine-generator is the largest of the three Sherco units and consists of a high-pressure (HP) turbine, an intermediate-pressure (IP) turbine, two low-pressure (LP) turbines, a generator, and an exciter. Unit 3's steam turbine-generator was delivered to the site in the late 1970s and went into commercial operation in 1987. Further background on the plant and the Company can be found on page 9 of Exhibit___(HJS-1), Schedule 2.

Q. DESCRIBE THE PLANT STAFFING FOR SHERCO UNIT 3.

A. Staffing for the Sherco plant is structured like most multi-unit coal-fired power generation plants of its size. It is organized by discipline and has two lines of responsibility for decisions related to the steam turbine-generators. One line filters down from Plant Director to Manager of Engineering and Technical Services to Superintendent of Engineering. The other filters down from the Plant Director to Manager of Environmental to Chemistry Supervisor for water/steam chemistry. The Sherco Plant is also supported by other resources such as Turbine Overhaul Services, referred to as "centralized engineering." Centralized engineering includes steam turbine and generator experts who understand major issues such as stress corrosion cracking and who can communicate effectively with manufacturers, but who are not steam turbine-generator design engineers.

As a regulated entity, the Company uses these teams of staffing and resources to develop both Sherco's capital and operating budgets within the organization, starting at the plant level by system engineers, with major expenditures often being incurred by the Company and customers such that such expenditures are subject to regulatory review. The work scope and budget for each unit therefore involves input from the system engineer as well as the turbine overhaul services group.

The key technical personnel responsible for safe/reliable operation of Sherco units at the time of the Event were Company witness Mr. Timothy P. Murray, Company witness Mr. Mark W. Kolb and Mr. Duane Wold. A detailed background for each of these three individuals can be found on pages 14 and 15 of Exhibit___(HJS-1), Schedule 2. All three were seasoned experts in their roles.

Mr. Murray, who retired in 2021, served as a Principal Engineer for Xcel Energy's Turbine Overhaul Services Group and had been an Xcel Energy employee since 1984. In his role as Principal Engineer, he provided technical and overhaul planning support to Xcel Energy plants in Minnesota and Wisconsin for both fossil and nuclear facilities. He worked on a fleet of 22 steam turbines in Minnesota and Wisconsin, either individually or collaboratively with Turbine Overhaul Services (centralized engineering). He supported the budgeting process but did not set or develop them, as overall budgeting is set by the individual plants. His group maintained the database of Original Equipment Manufacturer (OEM) and industry technical recommendations for steam turbine-generators.

Mr. Kolb retired in 2018 having worked for Xcel Energy since 1981. Prior to retiring, Mr. Kolb was a systems engineer at Sherco for Units 1, 2, and 3 and was responsible for the steam turbine-generators as well as the condenser and feedwater heaters. He was familiar with OEM technical recommendations but relied on subject matter experts, including Mr. Murray and others in the Turbine

Overhaul Services group. He was also responsible for developing operations and capital expenditure budgets for the systems he managed.

Mr. Wold, who has been retired since 2014, had been the Sherco Plant Chemistry Supervisor since 1982, managing water and steam chemistry for all three Sherco units. He was instrumental in maintaining the operating philosophy of "chemistry first." He started at Sherco after graduation from St. Paul Tech College in 1976 and retired in 2014 after 38 years of continuous employment at Sherco. He regularly attended industry conferences and served as a Target Advisor for one Electric Power Research Institute (EPRI) committee. He had supervisory responsibility for up to five chemical specialists and the two chemistry labs at Sherco.

Q. DOES THE COMPANY RECEIVE ASSISTANCE FROM OUTSIDE RESOURCES AS WELL?

A. Yes. The Company receives technical advice from OEMs as well as other specialty aftermarket service providers such as Mechanical Dynamics & Analysis (MD&A), Alstom (also an OEM), and specialty consultants. That advice is reviewed and disseminated within the Company. For Sherco Unit 3's LP turbines, the Company relied on Turbine Overhaul Services and continues to do so to collect, manage, and disseminate that technical advice. Turbine Overhaul Services maintains an electronic database of OEM notifications, which, for Sherco Unit 3 include GE TILs (technical information letters) and GEKs (General Electric Knowledge bulletins). The Company also relies on access to GE's Outage Optimizer, which includes OEM notifications for units based on each unit's serial number. Until the late 1990s, the Company was receiving and maintaining paper copies of OEM notifications but worked extensively with OEMs to transition to a digital document control system. The Company's current document control system is effective, and well-organized. It has been in existence since 2003.

Q. WHAT ARE YOUR OPINIONS REGARDING THE MAINTENANCE, OPERATIONS, AND RESOURCE-DEDICATION OF SHERCO UNIT 3?

A. The Company has invested in and continues to invest in Unit 3, through appropriate capital expenditures (CAPEX) and operating expenditures (OPEX), proper facilities and technology for feedwater, and the hiring of qualified industry professionals. Based on my knowledge of and extensive experience in the power generation industry, the Company's CAPEX and OPEX budgeting process and budget levels are reasonable for units of this capacity. In addition, the Company has and continues to invest in facilities and technology to ensure that feedwater used for steam generations meets EPRI and GE guidelines. I confirmed that key personnel at Sherco are experienced and knowledgeable in the operations and maintenance of the plant. They operate and maintain the plant with a philosophy of "chemistry first," and have long understood the important safety and reliability issues related to stress corrosion cracking (SCC) in LP turbines. However, as discussed more fully below and in my report on page 4 ¶ f and page 12 (*see* Exhibit___(HJS-1), Schedule 2), owners and operators such as the Company, no matter how knowledgeable, ultimately rely on equipment manufacturers like GE for design-specific technical guidance. That reliance is reasonable and expected for operators such as the Company.

B. Operation, Maintenance, and Inspection History of Sherco Unit 3's Low Pressure Turbines

Q. HOW OFTEN WERE SHERCO UNIT 3'S LP TURBINES INSPECTED?

A. Following installation, a major inspection of Sherco Unit 3 was first performed in 1989, while under warranty. Unit 3's two LP turbines were inspected during this time and showed no indication of defects. Thereafter, subsequent major and minor inspections occurred in 1993 (LP major), 1996 (LP major), 1999 (LP major), 2005 (LP major), and 2008 (LP minor). Outage records can be found at Exhibit___(HJS-1), Schedule 4.

Q. CAN YOU BRIEFLY EXPLAIN THE DIFFERENT TYPES OF INSPECTIONS OF A LP TURBINE?

A. I will discuss these in three groupings: major, minor and detailed inspections. A major inspection of the LP requires removal of the rotors from both LP turbines and detailed inspection of blades, dovetails, rotor bodies, bearing, and stationary casing for erosion and cracking. A major inspection can be completed in approximately 4 to 8 weeks. If defects are found, required repairs would add to this duration. A minor inspection of the LP requires removal and inspection of the bearings and a "crawl thru" of the exhaust hood to inspect for erosion and cracking of casing features and borescopic inspection of the L-0 and possibly the L-1 blade features for erosion and airfoil defects including excessive erosion of the surface. A minor inspection can be completed in approximately 2 to 4 weeks. Again, if defects are found, required repairs may add to this duration. Detailed inspection of the L-0 and L-1 dovetails in accordance with TIL 1121 and TIL 1277 cannot be done without removal of the rotors and blades, a process that goes beyond what is typically included in either a major or minor inspection. These inspections typically require 2 to 4 weeks beyond the duration of a "normal" major inspection. Major repairs to correct oversize dovetail pin holes may require weld repair of the dovetail areas at an off-site specialty facility such as MD&A, Alstom Richmond or one of the GE shops. This would extend a normal major outage by approximately 6 to 8 weeks including weld repair, machining, high speed balance and transportation of one or both Sherco Unit 3 LP rotors.

A noteworthy major LP inspection and repair was conducted in 1999 when four rows of L-1 blades were upgraded to correct a design and operational issue with the tie-wire and airfoil cracking identified by GE. Consistent with TIL 1121-3AR1, when the blades were removed during that upgrade project, the rotor wheel finger dovetails were inspected by GE. *See* Exhibit___(HJS-1), Schedule 4, pages 4-74 and Exhibit___(HJS-1), Schedule 5. For 2011, Unit 3 was originally planned for a major inspection of the LP turbines, but that inspection was changed to a minor inspection, with the major inspection rescheduled for 2014, a decision discussed in more detail later in this testimony.

Q. IN DETERMINING THE SCOPE OF THESE MAJOR AND MINOR OUTAGES, WHAT TECHNICAL ADVICE DID THE COMPANY HAVE TO REFERENCE FOR INSPECTION OF THE LP TURBINE ROTORS?

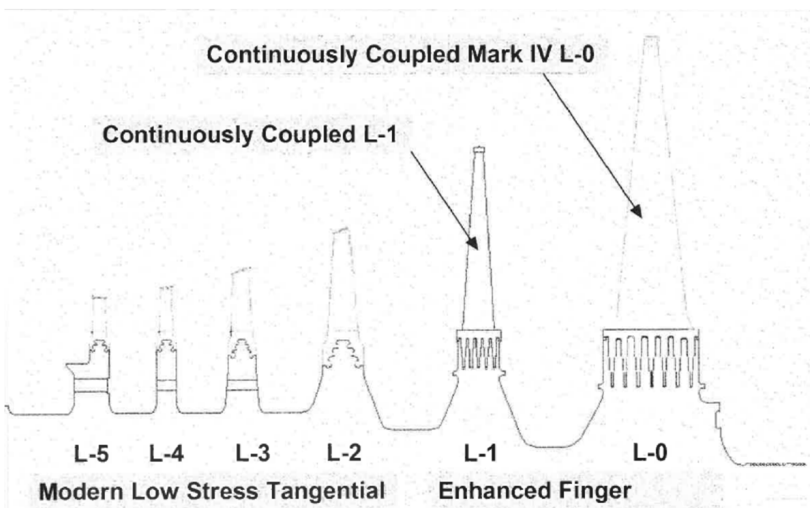
A. GE issues TILs and GEKs to its customers to provide technical advice and guidance for inspecting and maintaining GE equipment. Regarding inspection of the LP turbine blades, GE had issued two TILs: TIL 1121-3AR1 and TIL 1277-2, issued in 1993 and 1999 respectively. See Exhibit___(HJS-1), Schedule 6 and Exhibit___(HJS-1), Schedule 7. Of those two, only TIL 1121-3AR1 expressly applied to Sherco Unit 3's rotors.

Q. DESCRIBE TIL 1121-3AR1 AND HOW IT APPLIED TO THE COMPANY'S INSPECTION PLANS FOR SHERCO UNIT 3.

A. To understand the advice in TIL 1121-3AR1, it is critical to understand the design of the LP turbines for Unit 3. The two LP turbines consist of a series of blade rows (labeled L-5 to L-0 where L-0 is the last and largest blade row on the rotor) through which steam passes to produce power.

Figure 1

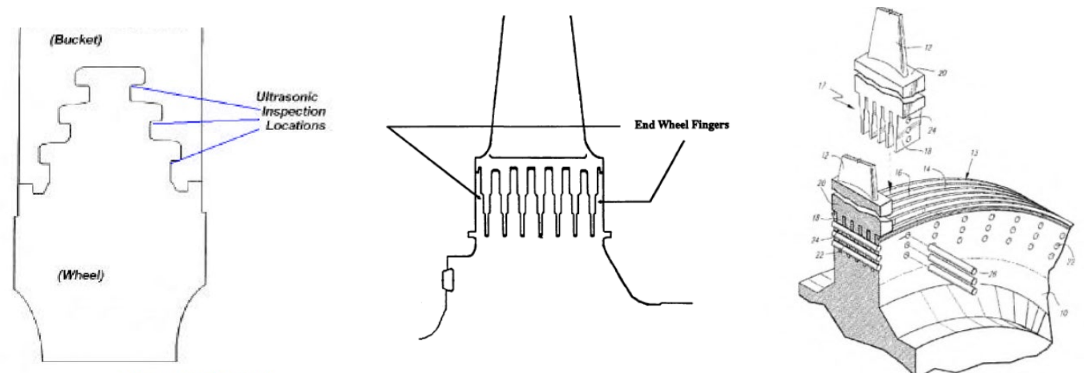
Low Pressure Turbine Blade Rows



Each blade row has a wheel attached to the rotor and each of the blades connects to the rotor wheel by either a "tangential entry" design or a "finger-pinned" design, with the latter using dovetail pins to secure the blade to the rotor wheel's interlocking fingers. Figure 2 shows the differences between these two designs.

Figure 2

Blade Attachment Styles



Tangential Dovetail

Steam Turbine Rotor Wheel with Finger Dovetails

Finger dovetail attachment configuration.

The attachment area for all blades to rotors is referred to as the "dovetail." The design of the attachment is a contributing factor for defects such as stress corrosion cracking. Detection of these defects may be found using inspection techniques developed by the OEM and other specialty companies. The design also determines the complexity of necessary inspection technique to detect defects.

By the early 1990s, GE and other steam turbine manufacturers learned that stress corrosion cracking was a risk for steam turbine rotors, including rotors using what was assumed by GE and other manufacturers and owner/operators to be the robust "finger-pinned" attachment style. It was learned that the cracking could occur on the internal fingers (those features not visible without removal of the blades) of the "finger-pinned" blades and the blade attachment rotor features without detection, because the inspection techniques from the turbine operator's manual were not suitable for examining the internal, unexposed fingers. In 1993, GE supplemented its technical advice for units like

Sherco Unit 3, issuing TIL 1121-3AR1. That technical letter notified operators such as the Company of the possibility of latent, undetected SCC of the internal blade attachment fingers of the finger-pinned dovetail blades and rotors. The letter further provided details for a new form of magnetic particle inspection (MPI) that could detect this type of internal cracking, but noted that the testing procedure required the costly and time-intensive process of disassembling the turbine and then removing one or more groups (random sampling) of finger-pinned blades before the rotor inspection could be performed. TIL 1121, when originally issued, did not specify when or how often the TIL 1121 inspection should be performed. *See* Exhibit___(HJS-1), Schedule 8.

In early 1993, GE revised TIL 1121 and issued TIL 1121-3AR1. *See* Exhibit___(HJS-1), Schedule 7. With that revision, GE added advice as to when an operator should consider performing the "buckets-off" inspection. Briefly, if the buckets (also referred to as "blades" in the industry) are removed for any reason, the rotor should be inspected in accordance with the recommended technique. GE also advised that certain abnormal events or operational anomalies may give reason to consider removal of the buckets to perform the inspection. These events included water chemistry excursions, condenser tube leaks, water ingestion, and turbine-generator overspeed events.

TIL 1121-3AR1 remained in effect until two years after the Sherco Unit 3 failure event in 2011 and was the only technical advice the Company received regarding the need for inspecting for internal latent finger-dovetail stress corrosion cracking on Sherco Unit 3 LP turbines.

Q. DESCRIBE TIL 1277-2 AND HOW IT APPLIED TO THE COMPANY'S INSPECTION PLANS FOR SHERCO UNIT 3.

A. GE issued TIL 1277-2 in 1999. Unlike TIL 1121-3AR1, this new TIL was limited in application to units with once-through boilers, which Sherco did not have. TIL 1277-2 was therefore not directly issued to the Company, which used drum/recirculating boilers to generate steam for the turbines.

TIL 1277-2 recognized that for LP turbine operators with once-through-boiler units, there were industry-wide stress corrosion cracking concerns related to the tangential entry attached blades of LP turbines. The concern was further communicated by GE at a conference which Tim Murray attended in 2001. At that conference, Tim Murray learned of the issues with tangential-entry blade cracking and understood that GE was recommending that even operators with drum boiler units perform the phased array testing of those tangential-entry blades and rotor blade attachment areas as recommended in TIL 1277-2. *See* Exhibit___(HJS-1), Schedule 9.

TIL 1277-2 has two relevant subparts: Section 2(a) advises operators with *tangential entry* L-1 through L-4 wheel dovetails, on units with once-through boilers, with more than 10 years of service should be ultrasonically inspected; Section 2(b) advises that at "a convenient maintenance outage" operators perform a TIL 1121-3AR1 buckets-off MPI of *finger* dovetails for units with once-through boilers and more than 10 years of service.

Though TIL 1277-2 was not formally issued to the Company, following Tim Murray's conference attendance in 2001, he relayed to the Sherco engineers GE's informal recommendation to extend Section 2(a)'s ultrasonic testing to the three Sherco units. *See* Exhibit___(HJS-1), Schedule 9; Exhibit___(HJS-1), Schedule 10; Exhibit___(HJS-1), Schedule 11.

Q. HOW DID SHERCO'S ENGINEERS IMPLEMENT THESE TILS FOR THE THREE UNITS?

A. In 1999, when the L-1 blades were replaced on Unit 3's two LP turbines, the Company hired GE to perform the TIL 1121-3AR1 MPI inspection. *See* Exhibit___(HJS-1), Schedule 5. No stress corrosion crack or other abnormal indications were found. Following the 2001 conference, Mr. Murray communicated internally to Sherco that GE had extended the ultrasonic examination recommended in TIL 1277-2 for tangential entry dovetails to units with drum boilers as well. The Company relied on that recommendation and subsequently inspected Unit 3's tangential entry dovetail rows (L-2 to L-3, as recommended by GE) in 2005 during the major inspection (finding no cracking indications), inspection of Unit 1 in 2007 (finding and repairing cracking found on the L-1 rows, which had tangential entry dovetails), and undertook a costly unplanned outage on Unit 2 in 2008 to conduct the same examination after discovering the cracking on Unit 1. *See* Exhibit___(HJS-1), Schedule 12, Exhibit___(HJS-1), Schedule 13. No abnormal indications were found in Unit 2. The details of GE's conference recommendation and how the Company implemented that recommendation can be found on pages 9 and 10 of Exhibit___(HJS-1), Schedule 2. The Company prudently heeded GE's advice, incorporating TIL 1277-2's ultrasonic inspection into the outage scopes for all three Units.

C. Scope of the 2011 Outage

Q. WAS THE COMPANY AWARE OF THE SCC RISK IN WHEEL DOVETAILS, AND IF SO, SHOULD UNIT 3'S L-1 ROW HAVE BEEN INSPECTED UNDER TIL 1121-3AR1 OR TIL 1277-2 IN 2011?

A. The Company was aware of the risk of stress corrosion cracking in wheel dovetails. Mr. Murray and Mr. Kolb understood the issues with stress corrosion cracking of the LP wheel dovetails based in part on their participation in GE's L-1 users' group, attendance at turbine generator conferences, and the history of inspection with Units 1 and 2. The Company's System Health Reports reflect that knowledge. *See* Exhibit___(HJS-1), Schedule 14. However, those same reports further note that the condition of the Unit 3 LP Turbines was "Green," implying good condition. Moreover, based on the cracking discovery in Unit 1 in a tangential entry wheel dovetail, Mr. Murray inquired to GE in January of 2008 about whether any TILs addressing LP wheel finger dovetail blade attachment cracking on units with drum boilers would be forthcoming. The email exchange that followed showed that despite the GE representative opening an internal case and receiving notice from a GE engineer that instances of SCC have been found on drum boiler units and that TIL 1277 does require revision to include drum boiler units, that information was never shared with the Company prior to the Unit 3 failure in 2011. *See* Exhibit___(HJS-1), Schedule 15. There is no record of the GE representative, or anyone else at GE, sending that information to Mr. Murray or anyone else at the Company. The Company's knowledge and the exchange with GE are detailed more fully on pages 10-12 of Exhibit___(HJS-1), Schedule 2.

Sherco and the supporting Turbine Overhaul Services did not know that GE had fleet experience with stress corrosion cracking of L-1 finger dovetail blade attachments in drum boiler units such as Sherco Unit 3. Without a firm recommendation from GE to perform a L-1 "buckets-off" MPI on Unit 3, the Company reasonably determined that a costly and time-consuming MPI (which itself would involve risks to the unit, as I discuss below) was not warranted in 2011. Mr. Murray and Mr. Kolb both testified that they did not pursue inspection of Sherco Unit 3's LP L-1 and L-0 rows for SCC for many reasons, including: (a) GE had not issued a TIL such as TIL 1277-2 specifically applicable to Sherco Unit 3; (b) GE had been contracted in 1999 to inspect the L-1 wheel finger dovetails and Company records indicate GE found no indications; (c) the design of the Sherco Unit 3 L-1 dovetail is different than that used on Units 1 and 2; (d) no SCC was detected in the 2008 inspection of Unit 2; (e) Sherco Unit 3 never operated with coordinated phosphate water treatment like Units 1 and 2 had; (f) Unit 3's operators did not perceive Unit 3 to have been subject to any abnormal events or operational anomalies which caused concern for the long term reliability of the unit as stated in TIL 1121-3AR1; and (g) GE did not specifically recommend TIL 1277-2 and TIL 1121-3AR1 inspection of the Sherco Unit 3 L-1 dovetails during any of the planning meetings with the Company for the 2011 major outage.

Q. IN PERFORMING TIL 1277-2 INSPECTIONS ON THE TANGENTIAL ENTRY DOVETAILS OF UNITS 1 AND 2, WHAT WERE THE RESULTS AND HOW DID THOSE EVENTS AFFECT THE INSPECTION PLANNING FOR SHERCO UNIT 3?

A. The Company's inspection of Unit 1 in 2007 found indications of SCC which were repaired by Alstom Richmond (Virginia) at a cost of approximately $1.5 million. The Company's inspection of Unit 2 in 2008, which had direct cost of $450,000 plus an estimated additional $1,800,000 in lost revenue, did not detect any SCC damage. Given that the 2008 inspection of Unit 2 showed no evidence of cracking, and for the reasons specified in pages 10-12 of my report (*see* Exhibit___(HJS-1), Schedule 2) and listed in (a) thru (g) above, the Company decided not to pursue inspection of Sherco Unit 3's L-1 blade row dovetails. Even more, Unit 3 had a decade less time in service than Units 1 and 2 and Unit 3's L-1 finger dovetail design was significantly different from the dovetail design of Units 1 and 2 L-1 rows. An experienced electric utility turbine engineer such as Mr. Murray would reasonably conclude that this newer, finger dovetail design in Unit 3 is more robust and less susceptible to cracking, particularly in light of the fact that the manufacturer did not provide a firm recommendation to do additional inspection.

Q. WHY WAS GE'S FAILURE TO FORMALLY EXTEND TIL 1277 OR OTHERWISE ISSUE A FORMAL INSPECTION RECOMMENDATION FOR DRUM BOILER UNITS LIKE SHERCO UNIT 3 SIGNIFICANT?

A. Based on my knowledge of steam turbine design and industry experience, equipment owners and operators rely on the OEMs like GE for technical guidance and support, because OEMs are expected to provide advice which accounts for the unique design of each of their machines in combination with fleet experience. A prudent operator does not assume a "one-size fits all" approach when it comes to technical advice and apply advice issued for one type of equipment (Sherco Unit 1 and Unit 2 steam turbines) to other equipment (Sherco Unit 3 steam turbine) with differing design details, ratings, and operating conditions. Rather, they communicate with the manufacturer to determine what advice applies to their equipment and follow those recommendations. In this case, the Company did exactly that. In 2005, the Company consulted GE on the scope of low pressure turbine wheel inspections for the 2005 major outage, specifically noting that the L-1 row dovetails would not be inspected unless GE recommended otherwise. GE did not make a recommendation to inspect this design feature. And in 2008, Mr. Murray engaged GE once again, asking if a TIL would be issued for units with drum boilers. GE did not issue a new TIL or make any inspection recommendation for finger dovetail wheels. Even though Mr. Murray and Mr. Kolb are experienced and knowledgeable in the operations and maintenance of the Sherco units, they are operators, not turbine designers. They do not have the specialized design knowledge or specific fleet experience outside of Xcel Energy necessary to identify all the technical needs specific to each piece of equipment such as GE's fleet-wide steam turbine history and GE's internal records and research. It is standard and reasonable industry practice for operators to rely on the equipment-specific advice from the manufacturer, and without a GE recommendation advising for a Unit 3 buckets-off MPI of the L-1 finger dovetail wheels, the Company had no basis to support a decision to perform that inspection.

Q. IF A MAJOR INSPECTION OF THE LPS HAD BEEN PERFORMED IN 2011, WOULD THE LATENT CRACKING HAVE BEEN DETECTED?

A. No. Neither major nor minor inspections can effectively detect latent cracking on the internal fingers of an L-1 row. Only the buckets-off MPI described in TIL 1121-3AR1 detects latent internal finger cracking. The Unit 3 low pressure turbines had been rated "green" in Sherco's System Assessment Report (SAR) for several years prior to the 2011 outage. This, combined with the following additional factors, supported the Company's decision not to perform a costly and invasive inspection: (a) the absence of any turbine-harming chemistry and other events as suggested in GE's TILs, (b) the L-1 rotor wheels had been inspected in 1999 with no SCC findings and new blades installed, (c) a borescope inspection of the L-1 blades was performed in 2002 during a "crawl thru" minor inspection, with no L-1 deficiencies found with this limited visual inspection, (d) there were no outstanding TIL recommendations suggesting or recommending MPI inspection of the L-1 wheel/blade finger dovetails, (e) as a corporation, the Company recommended overhaul frequency was 9 years or greater depending on the SAR, (f) deferral of the major inspection of the LP's would have resulted in an 8-1/3 year inspection interval, and (g) conducting a major inspection of the LP concurrently with a major upgrade of the HP and IP turbines would have required two different major contractors working side-by-side, sharing limited work space, overhead cranes, floor space, etc. As referenced above, an L-1 inspection would have required a month-long outage and cost up to $2,000,000. It also would have potentially reduced the usable life of the LP turbines since the finger dovetail blade removal process includes the risk of rotor damage when the dovetail pins are removed. Pins can gall in-place (meaning they weld together due to high contact stress in combination with relative motion between the pin and corresponding finger dovetail surfaces) and must then be machined out thus requiring engineering evaluation and repair. Of course, the risk of SCC would have been minimized with the MPI inspection of the L-1 dovetails, however, the Company did not believe that SCC was a high risk because of the reasons I just listed in (a) thru (g) above. Without concrete indications of SCC risk or a direct recommendation from GE for such an inspection, there was no basis for incurring the costs and risks to the Company and its customers associated with such an inspection.

D. Inspection Cost and Risks

Q. WAS THE POTENTIAL COST OF A TIL 1121-3AR1 BUCKETS-OFF MPI SIGNIFICANTLY DIFFERENT THAN THE COST INCURRED WHEN PERFORMING THE PHASED ARRAY TESTING ON UNIT 2 IN 2008?

A. Yes. Unit 2 is a different type of rotor wheel with tangential entry attachments. Those attachments can be inspected through ultrasonic examination (phased array) which does not require removal of the blades. In contrast, the inspection required to inspect the internal fingers of the finger dovetail rotors is much more complex. I detail the difficulty and cost of this inspection on page 17 of Exhibit___(HJS-1), Schedule 2. In summary, Sherco Unit 3's L-1 wheel dovetails require removal of the blades to perform the MPI. The process requires a 3- to 4-week outage and a cost of $1,000,000 to $2,000,000 in disassembly and inspection costs, and any additional cost to engineer and repair damage to the dovetails caused by removal of the blade dovetail pins. Loss of revenue due to outage extension has not been estimated because, specifically for 2011, the outage length was already determined by the HP and IP upgrade project, and it is possible that a full LP L-1 blade removal and MPI would have fit within the scheduled outage duration.

Experience shows that the process of removing the blades is onerous and causes wear to the machine. Approximately 1,600 dovetail pins must be removed and replaced across the four L-1 rows on the two LP turbines. It is not unusual to have to machine some of those pins for removal, leaving an oversized hole in the blade attachment. There is a limit on how oversized a hole can become before excessive "ligament" stress occurs between adjacent pins. Historically, the oversized condition must be reviewed by GE engineering if the pin diameter must be increased beyond GE's limits. General industry knowledge is that a pin can only be oversized 3 times by .005" each time before an engineering evaluation and a costly weld repair becomes necessary.

These risks were understood by the Company and must be considered when weighing whether an inspection of a particular machine is justified or prudent. Without a manufacturers recommendation or an abnormal operational event which creates a risk of SCC, it would not be prudent for an operator such as the Company to conduct a costly blade removal and inspection which could affect the life of the rotor due to the need for oversizing the finger dovetail pins with each inspection.

Q. IS THERE A LESS COSTLY, LESS INVASIVE METHOD THE COMPANY COULD HAVE USED TO INSPECT FOR THIS INTERNAL-FINGER CRACKING?

A. No. As discussed on page 18 of Exhibit___(HJS-1), Schedule 2, other turbine manufacturers have designed LP blade fasteners (dovetails) with features which may be inspected more easily in comparison to GE's finger-dovetail design. GE's design cannot be thoroughly inspected for SCC without removing the blades, and that process imposes a significant burden on the owner/operator. No alternative inspection exists, and because of inspection cost and the wear on the machine (potential need to engineer and weld repair the dovetail due to damage incurred during removal of the blades for MPI inspection) operators must rely on GE for instructions on when such a burdensome inspection becomes necessary.

Q. DID GE EVER ISSUE TECHNICAL ADVICE SPECIFICALLY TO UNIT 3 REGARDING THESE LEARNED DESIGN ISSUES?

A. GE issued no formal technical advice applicable to the Unit 3 issues prior to the unit's failure in 2011. It wasn't until 2013 that GE issued TIL 1886 (*See* Exhibit___(HJS-1), Schedule 16), which requires major inspections in steam turbines with drum boilers, including units like Sherco Unit 3 with finger dovetails. For units that have 22 years or more of service, TIL 1886 recommends that at the next-scheduled exposure of the LP rotor, the L-1 finger dovetails should be inspected in accordance with TIL 1121-3AR1.

Q. ON WHOLE, WHAT IS YOUR OPINION OF THE OPERATIONS, MAINTENANCE, AND INSPECTION PRACTICES OF THE COMPANY FOR SHERCO UNIT 3?

A. Mr. Murray, Mr. Kolb, and other Company engineers took reasonable and appropriate actions, consistent with sound industry practice, to assure efficient and reliable maintenance on Sherco Unit 3. They acted proactively when Unit 1 was inspected for SCC in 1977, 1985, and 2007, when Unit 2 was inspected in 2008, and when Unit 3 was inspected in 1999. They also carried out comprehensive assessments to determine if Sherco Unit 3 was subject to one or more abnormal events or operational anomalies set forth in TIL 1121, which would have triggered a major inspection. Xcel Energy's System Health Reports, which detail all assessments performed, confirm that no such abnormal events or operational anomalies occurred. Once again, Xcel Energy engineers were knowledgeable about issues surrounding SCC and with that knowledge they appropriately sought out and deferred to the OEM and relied on industry recommendations and experience to determine prudent operation, maintenance, and inspection practices for their specific equipment.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Herbert J. Sirois
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Davenport, FL 33837
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BIOGRAPHICAL INFORMATION
CAREER EXPERIENCE

Herb Sirois' career has been dedicated to the design, manufacture and operation of turbomachinery used by the marine, electric utility and process industries since 1971. He has engineered steam turbine product lines and components while a steam turbine engineer at Westinghouse Electric (Lester, PA) including large second generation low-pressure and high-pressure steam turbines for nuclear power plants (up to 1300 MW) and also while at Terry Corporation (Windsor and Niantic, CT) including steam turbines used to drive auxiliary (emergency) feed pumps in nuclear power stations. In 1993 he formed an independent turbomachinery engineering company, Foster Cove Engineering, Inc. which in 1998, was incorporated in Rhode Island. He has concentrated on failure investigation, project management, and redesign for efficiency and reliability upgrades of turbomachinery – primarily steam and gas turbines used by the electric power generation industry. His extensive design experience has been applied to support the insurance industry with investigation and mitigation of large losses. He has been actively involved in litigation including mediation, arbitration and preparation for trial for matters involving steam and gas turbines and other turbomachinery. Foster Cove Engineering, Inc. was dissolved in 2020 and Herb continues to consult on technical and legal matters involving steam and gas turbines.

He has recently been involved with (1) failure investigation of an HP nozzle block in a double auto extraction 33 MW steam turbine generator located in North Carolina, (2) failure investigation of a nozzle block in a 250 MW steam turbine generator located in Canada, (3) failure investigation of a steam turbine HP stop valve stellite seat in a 300 MW combined cycle plant with subsequent foreign object damage resulting located in Texas, and (4) failure investigation of two parallel trip and throttle valves on an 80 MW steam turbine generator resulting in significant property damage, (5) expert witness related to the failure of L-1 steam turbine blades in a 900 MW steam turbine in the US, (6) expert witness related to delayed construction claims involving the power island in an offshore 1600 MW nuclear power plant.

He has contributed to the development of large steam turbines (up to 1300 MW) for the nuclear power generation industry while employed as a design engineer at Westinghouse Electric Corporation. He managed product development programs with responsibility for several new steam turbine product lines while at Terry Corporation. He was associated with Imo Industries from 1988 to 1992 with concentration on engineered components and specific focus on projects related to fluid film bearings, turbomachinery blading, steam turbine repairs and reapplication of turbomachinery in the electric utility industry. He became Product Manager – Steam Turbines for Conmec, Inc., a diversified turbomachinery consulting and manufacturing company in 1998 thru 2000. This additional exposure to large mechanical drive steam turbines has broadened his experience base.

He developed and presents a large steam turbine design and major maintenance seminar designed for electric utility engineers. The seminar has been presented 30 times worldwide. He has also developed a seminar for electric utility engineers and power project developers dealing with ultra-supercritical steam conditions where pressure and temperature exceed 5000 PSIG and 1300F. Emphasis was placed on performance/efficiency, selection of suitable materials and coatings, finite element analysis for heat transfer, distortion control and life prediction.

His diversified interests in the fields of mechanical engineering have resulted in a proven track record dating to 1971.

EDUCATION:

Wentworth Institute of Technology, Mechanical Design Technology, 1966 - 1967
University of Rhode Island, BSME 1971
University of Pennsylvania, MSME graduate courses, 1971 - 1974
University of Rhode Island, MBA, 1988

EMPLOYMENT:

1971 to 1975, Westinghouse Electric Corp, design engineer for new product development used in nuclear power generation plants.

1975 to 1988, Terry Corporation (division of Ingersoll Rand and Dresser Rand), increasing responsibility as (a) design engineer including new product development and testing, failure investigation, (b) Nuclear Products Manager including new product design and qualification, (c) Engineering Manager – Niantic Division, new product design for turbines used by the US Navy, service life extension programs and support of engineering for the Terry GmbH division in Germany, (d) General Manager – Niantic Division including profit and loss responsibility for this vertically integrated steam turbine design and manufacturing facility.

1988 to 1992, Centritech, Imo Industries, regional manager for engineered products sold to the power generation industry. These products included fluid film bearing, steam and gas turbine blades and vanes, upgrade and rerate of steam turbines.

1993 to 2020, Foster Cove Engineering, Inc., president and technical director of an independent turbomachinery consulting company with focus on failure investigations of steam and gas turbines for power generation plants and insurance companies.

1999 to 2000, Conmec (division of Dover Industries), Steam Turbine Manager for steam turbine upgrades and rerates for the petro-chem industry. This was a position I held to increase my knowledge of large mechanical drive steam turbines.

2020 to present, independent turbomachinery consultant.

AFFILIATIONS:
American Society of Mechanical Engineers, ASME Fellow
American Society of Testing and Materials, ASTM, Committee Member for Centrifugal Pumps (prior affiliation, no longer active)
Registered Professional Engineer, RI 5303
Tau Beta Pi and Pi Tau Sigma, Engineering Honor Societies

PATENTS:
Steam Turbine Valve, Ingersoll Rand Company
Exhaust Flow Guide for Steam Turbines, Westinghouse Electric

EXPERT REPORT

In the matter of:

Northern States Power

v.

General Electric

Prepared by:

Herbert J. Sirois, PE

President and Technical Director

Foster Cove Engineering, Inc.

105 Lewis Drive

Davenport, FL 33837

Submitted to:

Tim Thornton

2200 IDS Center

80 South 8th Street

Minneapolis, MN 55402

February 27, 2016
(amended March 1, 2016)

____

Herbert J. Sirois

TABLE OF CONTENTS

1.0 INTRODUCTION

a) My name is Herbert J. Sirois, I was retained by attorneys representing Northern States Power, SMMPA and Interested Insurers on 12/17/2015 to provide expert turbine consulting services including preparation of this expert report and expert testimony related to the issues in dispute between Northern States Power, SMMPA, Interested Insurers and General Electric. A copy of my resume is attached as Appendix A.

b) I have been a registered professional engineer in the State of Rhode Island since 1988. I am the President and Technical Director of Foster Cove Engineering, Inc, a Rhode Island corporation formed in 1998 that specializes in the design and analysis of turbomachinery, including steam and gas turbines. I have specific expertise with the application of turbomachinery in power plants, process industries (such as chemical and pulp/paper), and marine-including commercial and the U.S. Navy. I serve as a consultant to these industries as a specialist involving root cause investigations, design audits for efficiency and reliability, and plant condition assessment specifically involving steam and gas turbines and the evaluation of design and manufacture of domestically and foreign sourced turbomachinery for applications in power plants. I have been qualified as an expert in turbomachinery and provided expert evidence in arbitrations, mediations and trials.

c) I have been previously employed by several turbomachinery design and manufacturing companies since obtaining university degrees (BSME, 1971, MBA, 1988). These companies include Westinghouse Electric Corporation, Terry Corporation – division of Ingersoll Rand, IMO Industries, and Conmec Inc. – now a division of General Electric.

d) I have published technical papers as listed in Appendix C. I am an active member of several professional organizations and have been elected by my peers to the grade of Fellow of the American Society of Mechanical Engineers for my contributions to the turbomachinery industry.

e) I am paid for my time and expertise in accordance with Foster Cove Engineering, Inc. rate schedule in Appendix B.

2.0 SCOPE OF WORK

a) **Purpose**: To review documentation provided to me by counsel, conduct a site visit to the plant, and interview plant personnel to draw conclusions about the operation and maintenance of Sherburne County Unit #3 (Sherco 3) power plant including staff knowledge of the installed steam turbine-generators, planning for major and maintenance outages, CAPEX and OPEX budgeting, culture of the organization, and to draw conclusions about Sherco and NSP/Xcel handling of GE's product notifications (TIL, GEK).

b) **Documents Reviewed and Data Considered in Forming My Opinions**: Documents reviewed are listed in Appendix D and include but are not limited to (a) transcripts of depositions of NSP, Xcel and GE personnel, (b) reports of major and minor outages conducted on the Sherco 3 steam turbine generator, (c) various written communications between and/or within GE/Sherco/Xcel and others as listed.

c) **Evaluation**: Based on my experience with the design, installation, maintenance and operation of steam turbines and the documents mentioned in (b) above, I was able to make observations and reach conclusions about the technical and operational capabilities of Sherco personnel, as well as internal and external communications related to inspection of Sherco's low pressure turbines for stress corrosion cracking.

3. OBSERVATIONS AND CONCLUSIONS:

The following observations and conclusions are based on (a), (b) and (c) above:

a. The owners have invested and continue to invest in Sherco 3 including capital expenditures (“CAPEX”) for the replacement of the HP and IP turbine rotors and diaphragms in 2011.

b. The owners have staffed the engineering and chemistry resources departments with qualified power industry professionals with good operating and maintenance knowledge of the steam turbine generators, water treatment and supporting equipment and systems installed at and operated by Sherco.

c. The maintenance and operating staff at Sherco have historically operated and continue to operate the plant, with a philosophy of “chemistry first”.

d. The owners have and continue to invest in facilities and technology to make sure that the feedwater used for steam generation to generate power via the steam turbine generator meets the guidelines published by EPRI (Electric Power Research Institute) and General Electric. Reference is made to David G. Daniels Expert Report dated January 29, 2016 dealing with this subject.

e. I consider Sherco’s CAPEX and operating expenditure (“OPEX”) budgeting process and budget levels reasonable based on my knowledge of the power generation industry involving due diligence assignments of more than 50 units involving the sale or financing of power generation plants. In reaching this conclusion, I have considered the fact that NSP, a regulated utility and the majority owner (59%) of Sherco 3, is subject to regulatory review of the capital and operating budgets.

f. NSP/Xcel is one of the owners and the operator of Sherburne County power generation plant. Generally, operations and maintenance personnel do not have the specialized knowledge necessary to design critical steam turbine features such as rotors and blades. Owner/operators depend on the original equipment manufacturer for technical guidance and support to assure that the steam turbine-generator will operate in a safe, efficient and reliable manner during its lifetime. General Electric has the required proprietary design data and historical and current fleet experience to notify owner/operators of similar equipment when there is a technical issue which applies to equipment they have designed and manufactured. General Electric failed in its duty to provide Sherco with a firm and unit-specific recommendation to inspect the Unit 3 low pressure turbine rotors for evidence of stress corrosion cracking in the L-1 region of the steam turbine, even after written requests from NSP/Xcel/Sherco responsible engineers.

g. NSP/Xcel inspected for and repaired stress corrosion cracks (SSC) detected in the Unit 1 low pressure turbines L-1 tangential entry dovetails (blade fastener) in 2007 in accordance with the general inspection requirements of General Electric TIL 1277, although this TIL did not specifically apply to the GE steam turbines installed at Sherco1 because Sherco1 is a drum boiler plant and the TIL only applies to only plants with Once Through Boilers (OTB). However, the utility decided to inspect using the phased array ultrasonic (UT) method on the L-1 to L-3 tangential entry dovetails of both low pressure (LP) turbines and detected numerous large indications at the L-1 locations. The LP rotors were repaired by Alstom Richmond (VA) at a cost of approximately $1.5 million. The 2007 inspection was the third since the unit was commissioned in 1976 with UT inspections recommended and conducted by GE in 1977 and 1985 because of contamination due to carryover from the boiler soon after commissioning in 1976. Unit 1 previously operated with coordinated phosphate water chemistry control which resulted in a large amount of carryover and deposits in the steam path. (Exhibit 368, Kolb Deposition)

h. NSP/Xcel inspected Unit 2 low pressure turbines L-1 dovetails in 2008 in accordance with the general inspection requirements of GE TIL 1277 (even though the TIL did not apply) and did not detect stress corrosion cracks (SSC) as previously discovered in Unit 1 in 2007, although TIL 1277 did not specifically apply to Sherco 2 because Sherco 2 is a drum boiler plant and TIL 1277 only applies to Once Through Boilers (OTB) plants. Because of concerns about safety and increasing industry awareness of SCC in tangent entry rotors on units with drum boilers, Sherco decided to inspect the L-1 to L-3 tangential entry dovetails of both LP turbines. The SCC damage detected one year earlier on Unit 1 and the fact that Unit 2 had also operated with coordinated phosphate water chemistry control motivated this inspection. This inspection required NSP/Xcel to take an unplanned outage at a cost of $450,000 plus an estimated additional $1,800,000 in lost revenue.

i. NSP/Xcel considered inspecting Unit 3 L-2 and L-3 wheel tangential entry dovetails using phased array UT in accordance with the general inspection requirements of TIL 1277 during the next planned LP outage after the 2005 major outage, however decided not to perform this inspection in 2011 since (a) the inspection was previously completed in 2005 and no cracks were detected,(checked with Mark Kolb/Tim Murray), (b) the unit had not been subjected to coordinated phosphate water chemistry control, (c) inspection in 2008 of Unit 2 L-1 dovetails did not detect stress corrosion cracking, (d) General Electric had not issued a TIL (similar to TIL 1277 which only applies to steam turbines installed in plants with once through boilers) which specifically applied to the Sherco 3 LP turbines as requested by Xcel and Sherco staff or to any turbine in any other drum boiler plant, (e) GE did not recommend/suggest/advise/mandate Sherco3 to inspect the L-0 to L-4 dovetails even after Sherco requested unit specific advice on this subject in

2008, and (f) Unit 3 performed the best in 2011 as compared to any prior year. (Exhibit 129, Bird Deposition; Exhibit 109, Murray Deposition; Brevig Deposition).

j. Sherco 3 was conducting a planned overspeed test on November 19, 2011 when one partial row of L-1 blade liberated from the wheel dovetail at approximately 3889 RPM. Sherco 3 was operating at speeds less than the GE recommended and industry-standard overspeed RPM when the L-1 blade liberated. GE had recommended a mechanical overspeed trip setting of 4057 to 4093 RPM (112.7 % to 113.7 % of rated speed of 3600 RPM). A normal mechanical overspeed trip setting is 110% of rated speed of 3600 RPM, or 3960 RPM. GE continued to recommend a higher than normal overspeed of the entire turbine generator train even after the 2011 incident. The mechanical overspeed was destroyed during the incident and was replaced with a triple redundant (2 out of 3 voting logic) electric overspeed system supplied by GE. NSP/Sherco engineers requested GE to remove the requirement to perform an actual unit overspeed test every 6 to 12 months and finally succeeded in having this requirement waived and supplanted by test of the electric/hydraulic portion of the system at a reduced ***simulated*** speed of 3852 RPM (107% of rated speed). The industry, including insurance companies, has moved away from actual overspeed testing in favor of simulated overspeed testing as extremely reliable electronic systems became available to eliminate a source of elevated stress and possibly damaging overstress which occurs during an actual overspeed incident. The utility had to drive this issue with General Electric. GE specifically stated in TIL 1121 that “overspeed” is considered an abnormal event or operational anomaly which may increase the risk of stress corrosion cracking and/or corrosion fatigue cracking. GE’s requirement for overspeed testing at 112.7% to 113.7% and every 6 to 12 months induced elevated stress on the L-1 wheel finger dovetail which likely had deleterious effect on the Sherco 3 LP turbines. At the very least, GE’s semi-annual and annual overspeed recommendation creates confusion with one of the abnormal events listed in TIL 1121.

k. Almost two years after the Sherco 3 failure, GE issued TIL 1886 dated October 2, 2013 which applies to GE Steam turbines with fossil fueled drum boilers including combined cycle steam turbines and heat recovery steam generators, which incorporate L-1 buckets with finger dovetails and operate at 3,000 or 3,600 RPM. The TIL has a Compliance Category of “S-Safety”, the highest category and a Timing Code of “5” at scheduled component part repair or replacement. The TIL recommends units that have 22 years (or more) of service on their L-1 wheel finger dovetails, that at the next-scheduled exposure of the LP rotor the L-1 wheel finger dovetails be inspected in accordance with TIL 1121 and that if crack-like indications are detected that the GE Service Manager or Contract Performance Manager be contacted for guidance. (Exhibit 293, Hanson Deposition).

l. GE was granted United States Patent No. US 7,387,494 B2, June 17, 2008 which claims to reduce stress concentration with compound radii at geometric transitions and shot peening of these surfaces will avoid stress corrosion cracking on these features. Although the benefits of these design improvements were available but not yet patented on January 15, 2008 when Tim Murray was requesting GE's Josh Bird for "… feedback from engineering on the drum boiler LP turbine wheel dovetail cracking issues?" (Exhibit 109, Murray Deposition), and then with another email on February 11, 2008 when Tim Murray wrote to Josh Bird, "… I understand from Mark Kolb that GE is not planning on issuing a TIL on this (Subject of email is "RE: LP Turbine Rotor Wheel Dovetail Cracking"). This exhibit also includes the email thread from a GE-PAC case (20080211-0367 created 16:38:45) created by Josh Bird on 2/11/2008. This PAC case was partially resolved on 2/29/2008 at 11:51:00 by GE's James Howenstein when he stated "Although TIL 1277 is written for once through boilers we have been recommending customers with drum boilers follow the recommendations also. We have found instances with SCC on drum boiler units also and will likely continue to find more as the age of the units continues to climb. It has been on my list of TIL's requiring revision for some time now, just hasn't gotten to top of the priority list. I can't promise when we will get it done but we do know that a revision is in order. The customer should also follow the recommendations for inspection as outlined in the following TIL's; TIL-956, TIL 1121, TIL 630. I am sure there are more tht (sic) should be listed in the unit records but these are the few that pertain to the rotating components."

   GE never transmitted to NSP/Xcel Howenstein's recommendation to inspect the LP wheel finger dovetails in accordance with TIL 1277 using the testing procedure defined in TIL 1121 and also never made available to NSP the upgrade of the L-1 dovetails to a more SCC tolerant design as claimed in the referenced US patent issued in 2008.

m. Key NSP/Sherco personnel directly involved in planning and scheduling inspections of the steam turbine generators are experienced and knowledgeable in the operations and maintenance of the Sherco plant. This was confirmed during my visit to Sherco in January 2016. My review of documents involving Sherco and NSP engineer's external communications with GE and others including specialty aftermarket service providers such as MD&A, Alstom and consultants and also internally among themselves confirm a high level of understanding of industry issues with stress corrosion cracking. These engineers (a) were members of several user groups including the GE 33.5" Last Stage Blade group – Sherco 3 has 33.5" last stage blades, (b) participated in GE Large Steam Turbine Conferences where technical topics were presented and discussed, including issues with SCC, (c) participated in industry conferences including assignments on industry committees such as EPRI. These engineers understood the important safety and reliability issues related to stress corrosion cracking in low pressure turbines. At no time did

GE mandate inspection of the Sherco 3 L-1 wheel dovetails since its notification system using TIL's and GEK's did not include power plants with drum boilers. It is noted that if GE had advised inspection of the L-1 dovetails in Unit 3, NSP would have inspected in the unit with the testing method identified in TIL 1121.

Awareness of SCC by the industry started in the 1970's with rotor and disc cracking in nuclear LP steam turbines such as Xcel's own Monticello plant and more recently starting in the 1990's with fossil fired plants throughout the world.

n. NSP/Xcel has used GE for outage support services including planning as recently as 2005 when there was a maintenance and operations agreement utilizing pre-negotiated terms and conditions between the companies from 2005 to 2008. This outage support would typically include identification of spare parts, recommended outage activities including applicable TIL, GEK and other unit specific information, proposal to perform the outage including labor, breakout cost for technical advisor services during the outage. GE also bid the 2011 Sherco 3 HP and IP upgrades including rotors and diaphragms and possibly the inspection of the two LP's. There is no record of GE recommending inspection of the L-1 and L-0 wheel dovetails during this timeframe.

4. DISCUSSION:

Description of Sherco Unit 3 and specific information about the installation and outage history.

The Sherburne County (Sherco) plant is located in Becker, Minnesota. Unit 3 (Sherco 3) went into commercial operation in 1987. The plant also has two similar but lower capacity units, Sherco 1 and 2. Sherco 1 and 2 are 100% owned by Northern States Power (NSP) while Sherco 3 is 59% owned by NSP and the balance of 41% is owned by Southern Minnesota Municipal Power Agency (SMMPA). All three units are operated and maintained by NSP staff with the operating costs for Sherco 3 essentially allocated proportionally based on percentage ownership, output, and use of facilities. NSP is a regulated utility. The Sherco plant is organized similarly to other large coal fired power plants. (*See* Exhibit 213, Farnick Deposition). The Sherco 3 steam turbine-generator unit designed and manufactured by General Electric is a model G3 and was first inspected in 1989 after going into commercial operation in 1987. This first inspection was the warranty inspection. The LP turbines (A and B) were inspected and no indications found by periphery magnetic particle testing of the rotor bodies, no cracked dovetail pins found by ultrasonic testing of the L-0 and L-1 blade rows. Loose tie wires were re-soldered by GE. Further to this first inspection, Exhibit 77 (Murray Deposition) briefly summarizes subsequent major and minor inspections in 1993, 1996, 1999 and 2005. A major LP inspection and repair was conducted in 1999 when four rows of L-1 blades were upgraded to a GE 20.5" blade which corrected design and operational issues with the tie-wire and airfoil cracking. The L-1 wheel finger dovetails were inspected by GE in accordance with GE TIL 1121-3AR1 during the blade upgrade project, although a test report for this inspection was not provided and Exhibit 77 states "…Some of the GE NDE reports are not available at this time."

GE TIL 1277 titled "Inspection of Low Pressure Rotor Wheel Dovetails on Steam Turbines with Fossil Fueled Once-Through Boilers" states the purpose of the TIL is to inform users of need to inspect low pressure rotor wheel dovetails on steam turbines to detect possible Stress Corrosion Cracking." GE had not sent this TIL to Xcel/NSP because none of the Sherco Units had or have once through boilers (OTB). For applicable units, TIL 1277 requires removal of the blades with finger dovetails and that the wheel dovetails be inspected in accordance with TIL 1121.

There is some question as to whether the TIL 1277's finger dovetail inspection includes all wheels or only the L-1 wheels with finger dovetails. In the case of Sherco 3 this could be a total of 8 wheels including 4 L-1 wheels and 4 L-0 wheels.

The other LP wheels including L-2, L-3 and L-4 would be inspected in accordance with TIL 1277 but with a less onerous GE Phased Array Dovetail Ultrasonic Test which does not require removal of blades with tangential entry dovetails.

Tim Murray, in an 8/17/01 email (Exhibit 98, Murray Deposition) to Steven Kollmann and others in the NSP/Xcel organization discusses a trip to GE's Large Steam Turbine Generator Conference in Atlanta. Item 1 states:

> LP Rotor Wheel Dovetail Cracking – Eloy Emeterio provided an update on TIL 1277. Although this TIL only applies to units with once through boilers, GE is now recommending that all LPs be inspected with phased array UT for cracks in the hook fits on the tangential dovetails, L-1 thru L-4 stages. 30% of the LPs on units with once through boilers have been found with cracks. This includes nuclear LPs. 1% of the LPs on drum boilers have been found with cracks.

It is noted that NSP decided to perform phased array inspection of the tangential entry dovetails on the L-1 (and other blade rows) on Unit 1 in 2007 and found many indications which required weld repair of the four L-1 wheels. The rotors were repaired by Alstom Richmond (VA). GE had not issued a unit specific TIL to NSP recommending this inspection. Again, in 2008 without a unit specific TIL, NSP decided to take an unplanned outage on Unit 2 to inspect the L-1 wheel dovetails for cracks. No crack indications were detected during this inspection which cost NSP approximately $450,000 plus an estimated $1,800,000 of lost revenue. Again, the L-1 dovetails for Units 1 and 2 are tangential entry and for Unit 3 they are finger design.

Xcel/NSP was aware of the risk of stress corrosion cracking in wheel dovetails. NSP's System Health Report for Sherco 3, Exhibit 75 (Murray Deposition), mentions this in 2005, 2007, 2009 and twice in 2010. These reports also discuss the time between major turbine overhauls ("TBO") eventually deciding to extend the TBO to 8.75 years from 2005 to 2014 in order to "…fit with the HP/IP/Gen schedule." The 1/5/10 and 12/7/10 System Health Reports (Bates XCEL_Sherco_07_0166826 and …843) under Future Plans, state "…Next major scheduled for 2014." These reports state that the condition of the LP Turbines is (Green) which implies good condition, however, the Xcel/NSP team acknowledge issues with LP dovetails by stating "These LP's also experience dovetail pin cracking problems, erosion damage and may suffer from industry-wide problem with rotor wheel cracking. However, rotor wheel phased array testing in 2005 did not detect any cracking issues." Tim Murray and Mark Kolb understood the issues with stress corrosion cracking of LP wheel dovetails based on their (a) participation in the L-1 user's group, (b) attendance at GE's Large Steam Turbine Generator Conferences, (c) recommendation to inspect

Sherco 1 L-1 in 2007, (d) repair of the Sherco 1 L-1 wheel dovetails based on detection of cracks which were due to stress corrosion cracking, (e) unplanned outage for inspection of Sherco 2 L-1 in 2008 which did not detect cracks. Tim Murray inquired to GE starting January 15, 2008 about any TIL's addressing LP wheel *finger* dovetail cracking on units installed in drum boiler plants. This inquiry addressed the issue of wheel dovetail cracks in plants such as Sherco which did not have supercritical OTB's since TIL 1277, which had not been officially sent to Xcel/NSP/Sherco by GE, specifically applied to OTB plants. The exchange of emails between GE's Josh Bird and Xcel's Tim Murray is shown on Exhibit 109 (Murray Deposition). GE's Josh Bird opened a PAC (Power Answer Center) case within GE on 2/11/08 at 16:38:47 essentially stating that NSP detected SCC and asked if GE will be issuing a TIL addressing SCC on drum boiler units (Exhibit 129, Bird Deposition). The last response to this PAC is dated 2/29/08 at 11:51:00 from James Howenstein to Josh Bird which states

> Although TIL 1277 is written for once through boilers we have been recommending customers with drum boilers follow the recommendations also. We have found instances with SCC on drum boiler units also and will likely continue to find more as the age of the units continues to climb. It has been on my list of TIL's requiring a revision for some time now, just hasn't gotten to the top of the priority list. I can't promise when we will get it done but we do know that a revision is in order.
>
> The customer should also be following the recommendations for inspections as outlined in the following TIL's; TIL-956, TIL-1121, TIL-630. I am sure there are more tht (sic) should be listed in the unit records but these are the few that pertain to the rotating components.

Bird responded to James Howenstein on 2/29/08 at 15:10:59 with "Jim, Thanks for the information. The customer also made reference to TIL-770 for SCC on non-reheat units. This TIL is not (sic) longer available on PS portal. Has TIL 1277 superseded TIL 770 as well?" Other than Jim Howenstein' s response to Josh Bird on 2/29/08 at 15:23:34, the PAC case was closed by Mark Peterson on 6/18/08 at 11:51:00. There is no record of Josh Bird or anyone else at GE sending this response to Tim Murray or anyone else at Xcel/NSP/Sherco.

Xcel/NSP/Sherco, based on its experience, inspected Unit 2 in 2008 and did not detect SCC in the LP's. Tim Murray and Mark Kolb both testified that they did not pursue inspection of Sherco 3 LP L-1 and L-0 for SCC for many reasons, including (a) GE had not issued a TIL such as TIL 1277 which specifically applied to Sherco 3, (b) GE had been contracted in 1999 to inspect the L-1 wheel finger dovetails and NSP records indicate GE found no indications, (c) the design of the Sherco 3 L-1 dovetail is different than that used on Sherco 1 and Sherco 2, (d) no SCC detected in the 2008 inspection of Sherco 2, (e) Sherco 3 never operated with coordinated phosphate water treatment, (f) Sherco 3's operators did not perceive Unit 3 to have been subject to any abnormal events or operational anomalies, such as those stated in TIL 1121-3AR1, that caused concern for the long term reliability of the unit, and (g) GE did not specifically recommend TIL 1277 and 1121 inspection of the Sherco 3 L-1 dovetails during any of the outage planning meetings with NSP/Xcel.

Xcel and NSP engineers, specifically Tim Murray and Mark Kolb respectively, took all necessary actions to assure efficient and reliable maintenance on Sherco 3. They and their predecessors acted proactively when Unit 1 was inspected for SCC in 1977, 1985, and 2007, Unit 2 was inspected for SCC in 2008, and Unit 3 was inspected for SCC in 1999. They have knowledge of the problems which can develop when a steam turbine is subjected to steam chemistry which is not in accordance with EPRI and steam turbine manufacturer's guidelines. Companies such as Xcel and NSP rely on OEMs including General Electric for technical support related to maintenance, operation and inspection of their steam turbines. The utility has technical specialists to assure safe, reliable and efficient operation of the equipment. These specialists depend on General Electric for several reasons, including (a) the OEM possesses the design data necessary to make informed inspect/repair/replace recommendations, (b) the OEM has knowledge of worldwide fleet performance and operating history which becomes the basis for recommendations to inspect/repair/replace, (c) the NSP/Xcel specialists are not turbine designers and do not have the resources necessary to evaluate various designs for suitability. Xcel/NSP requested GE to issue a TIL in 2008 similar to TIL 1277 that would specifically apply to Sherco 3, but this was not done until 2013, nearly 2 years after failure of the Sherco 3 L-1 wheel dovetail.

Tim Murray and Mark Kolb frequently interacted as required by their respective roles. The question about the amount of investigation each did to determine if Sherco 3 has been subjected to one or more abnormal events or operational anomalies has been asked in depositions as well as during my interviews with them at Sherco in January, 2016. The System Health Reports provide a detailed assessment of operational risk, performance parameters, work/outage history, inspection plans and, significant operational events. My review of these reports observed that "abnormal events or operational anomalies" as stated in TIL 1121 would have been recorded not only in the System Health Reports but also in the recording systems which are the basis for these reports. One event discussed with key personnel during my plant visit involved water washing one or both Sherco 3 LP rotors. The stellite shields on one of the blade rows were inspected with liquid penetrant and developer which must be removed after the inspection. The NDE materials were removed by using a pressure washer connected to an untreated water source, possibly not potable. My experience with this process is that since the rotors were not submerged in this water source and that a pressure washer was used to direct the water flow to the stellite shield area which is approximately 1 to 2 feet from the blade dovetail area, it is unlikely that a significant amount of untreated water migrated into the dovetail area during the short amount of time it would have taken to remove the NDE materials.

Discussion of NSP/Xcel and Sherco organizations.

The Sherco plant is organized by discipline as shown on Exhibit 213 (Farnick Deposition). This is similar to most large multi-unit coal fired power generation power plants. There are two lines of responsibility for decisions related to the steam turbine-generators. One would filter down from Plant Director to Manager of Engineering and Technical Services to Superintendent of Engineering and the second filters down from the Plant Director to Manager of Environmental to Chemistry Supervisor for water/steam chemistry. There are two control rooms, one for Sherco 1 and 2, and one for Sherco 3.

The Sherco plant is also supported by Turbine Outage Services, sometimes referred to as “centralized engineering” in other utilities, includes Tim Murray, Jeff Farnick and Victor Scharenbrock. This type of organization appears to be common for similar sized utilities including Dominion (Virginia), Pennsylvania Power and Light and many others. The centralized engineering approach includes subject experts such as steam turbine and generator experts. These individuals are ***not*** designers of these machines. They understand major issues such as stress corrosion cracking and can effectively communicate with the OEM. Exhibit 109 (Murray Deposition) is an example of the level of detail in Tim Murray’s request for information from GE’s Josh Bird – the line of communications that ended without a conclusive recommendation to Tim Murray from Josh Bird to inspect the L-1 wheel dovetails (finger and tangential entry) for SCC in 2008. The recommendation was made within GE but was not communicated to Tim Murray or anyone else in the Xcel/NSP/Sherco organizations.

The utility is regulated and major expenditures are subject to regulatory review. Capital and operating budgets are normally developed within the organization starting at the plant level by system engineers such as Mark Kolb. Input is sought by the systems engineer from the Turbine Outage Services Group, primarily Tim Murray for Sherco 3. An expenditure for a planned outage such as the 2011 Sherco 3 outage which included upgrade of the HP and IP turbines with Alstom designed hardware to replace the original GE hardware but did not include inspection of the LP turbines would fall under regulatory review. The decision regarding the extension of the LP turbines major outage to 2014 was discussed as early as 2008 and confirmed in 2010. It is noted that if the Sherco 3 LP turbine outage had occurred in 2011 that the inspection of the L-1 (and possibly the L-0) wheel finger dovetails in the LP turbines in accordance with TIL 1277 would not have been done because that TIL did not apply to drum boiler plants such as Sherco 1 to 3, and TIL 1121 would not have warranted inspection because none of the events identified in that TIL had occurred. Had there been a concern that the Sherco 3 LP turbines should be inspected for SCC in 2011 as part of the upgrade outage, then the turbines would have been inspected based on a unit-specific recommendation from GE, because there was time during the outage to do a TIL 1121 inspection. (Reference, Steven H. Mills Deposition, pages 61-62, 120-121; Brevig Deposition).

I have concluded that had GE's Josh Bird forwarded James Howenstein' s 2008 recommendation to inspect L-1 wheel finger dovetails in drum boiler units that Xcel/NSP/Sherco would have performed this inspection in 2011 or sooner. However, approval for this inspection within the organization would have required a written recommendation from GE such as a TIL which specifically identified the Sherco 3 unit.

Discussion of key personnel involved with technical decisions for Sherco3

The key technical personnel responsible for the safe and reliable operation of the steam turbine generators at Sherco are Tim Murray, Mark Kolb, and Duane Wold (at the time of the incident in 2011). Review of transcripts of their depositions provided professional biographies of these individuals. To briefly state qualifications:

Tim Murray is a graduate engineer with a Bachelor's Degree in Mechanical Engineering from University of California Berkeley graduating in 1980. He was employed by Bechtel Corporation for 4 years from 1980 to 1984 working on modifications to nuclear power plants related to the Three Mile Island incident, and specifically at Northern States Power (NSP) Monticello Nuclear Station from 1982 to 1984. He became a direct employee of NSP in 1984 assigned as a Systems Engineer to Monticello and maintained that position for approximately 10 years. He transferred to NSP Turbine Overhaul Services Group in 1994 as a Senior Engineer and progressed to Principal Engineer in 2002 and has held that position since then. In this position he provides technical and overhaul planning support to NSP plants in Minnesota and Wisconsin for both fossil and nuclear. He is familiar with steam turbines designed and manufactured by General Electric, Alstom and Allis Chalmers. He works with others in his group, these include Jeff Farnick (former GE technical director), Jerry Brandt and Victor Scharenbrock. Depending on workload, these individuals may join up to form a team or on small assignments they work individually. Tim works on a fleet of 22 steam turbines in Minnesota and Wisconsin. He supports the budgeting process but the individual plants are responsible for overall budgeting, the budget is set at the plant level. He confirmed that his group maintains the database of original equipment manufacturer (OEM) recommendations such as GE technical information letters.

Mark Kolb is a graduate engineer with a Bachelor's Degree in Mechanical Engineering from North Dakota State University (NDSU) graduating in 1980. He was employed for a short period of time with Westinghouse Electric (4 months) after graduating from NDSU. He started with NSP in 1981 as a systems engineer at NSP's Monticello Nuclear Generating Plant and held that position until June 1985. He then moved to NSP's Allen S. King plant as a systems engineer responsible for the Westinghouse steam turbine and other systems including the condenser and feedwater heaters while relying on NSP's technical experts and held that position until November 1994. He moved to Sherco also as a systems engineer for units 1, 2 and 3 with similar responsibilities to those he had at the King plant. He relied on subject matter experts and continues to rely on these experts including Tim Murray and Jeff Farnick. Mark has responsibility for developing operations and capital budgets for the systems he is responsible for including the steam turbine, condenser and feedwater heaters. He is familiar with OEM technical recommendations contained in documents such as GE's TIL's.

Duane Wold has an associate's degree in Chemical Technology from St. Paul Technical College graduating in 1976. He started work at NSP Sherco upon graduating and retired after 38 years of continuous employment in 2014. He started as a chemical specialist and was promoted to Sherco Plant Chemistry Supervisor in 1982. He held that position until his retirement. He had supervisory responsibility for up to 5 chemical specialists and the two chemistry laboratories at Sherco. The details of the water treatment systems installed at Sherco are discussed in David Daniels' expert report dated January 29, 2016. Duane was highly qualified during his employment at Sherco. He attended several industry conferences including those developed by water treatment specialty companies such as Nalco and Betz and EPRI general conferences dealing with the power industry. He served in the role of Target Advisor for one EPRI committee during the mid to late 1990's. He indicated that NSP/Xcel and other Xcel subsidiary companies would share operating information for the various Xcel plants. Duane was instrumental in maintaining the operating philosophy of "chemistry first" to assure that the Sherco units operated in a safe and reliable manner, particularly during start up events which occurred infrequently for these large base loaded units.

Discussion of how OEM notification information (TIL's, GEK's, etc.…) are handled by NSP/Xcel and Sherco staff.

Xcel Turbine Outage Services (TOS) in Minneapolis maintains a database of OEM notifications including GE TILs and GEKs. The utility also relies on GE Outage Optimizer which includes these notifications and which is accessible by the utility for gathering information which is unit specific. This information should have been distributed by mail to the individual plants and others named by the utility until the late 1990's. The distribution system was then changed as a result of more than 12 meetings between GE and NSP/Xcel and also Siemens and NSP/Xcel since these OEM's wanted to update to an electronic distribution system for accuracy and efficiency. The NSP/Xcel document control system is well thought out and has been in existence for more than 13 years. It is used by those involved in outage planning for NSP/Xcel, ensuring all TILs and GEKs sent by GE are available to the specific serial numbered equipment identified by GE.

GE continued to require higher than normal overspeed testing after the Sherco 3 was repaired and recommissioned in 2013.

GE had recommended mechanical overspeed trip setting of 4057 to 4093 RPM (112.7 % to 113.7 % of rated speed of 3600 RPM). A normal mechanical overspeed trip setting is 110% of rated speed of 3600 RPM, or 3960 RPM. GE continued to recommend a higher than normal overspeed of the entire turbine generator even after the 2011 incident at Sherco 3. The mechanical overspeed was replaced with a triple redundant (2 out of 3 voting logic) electric overspeed system supplied by GE. NSP/Sherco engineers had to be persistent and eventually persuaded GE to remove the requirement to perform ***an actual unit overspeed*** test every 6 to 12 months. Sherco engineering succeeded in having this requirement waived and replaced by testing the electric/hydraulic portion of the system at a reduced ***simulated*** speed of 3852 RPM (107% of rated speed). The power generation industry, including their insurance companies, have moved away from the requirement for actual overspeed testing to simulated overspeed testing with the installation of extremely reliable electronic overspeed systems. This change eliminates a significant source of overstress which occurs during an actual overspeed test or event. The utility had to force this issue with General Electric even though GE states in TIL 1121 that "overspeed" is considered an abnormal event or operational anomaly which may increase the risk of stress corrosion and/or fatigue cracking. Yet GE sought to require NSP to perform these mechanical overspeeds.

Discussion of GE repair of Sherco 3 wheel crown/top hook to remove cracks. This is considered a fairly major repair/excavation which required installation of two titanium blades – (ref. Thielsch RCA, pages 12, 143 – 148).

During repair of the Sherco 3 LP-A and LP-B rotors in the GE Chicago repair facility, defects were discovered by GE in an L-2 rotor. The cause of these large cracks was due to the design of the blade with a sharp corner which initiated localized cracking in the top hook of the wheel tangential entry dovetail. James Howenstein discussed this condition in his deposition (pages 141 – 142). Photos 100 to 103 in the Thielsch report show a substantial excavation to remove the axial/radial crack in one of the L-2 tangential entry dovetails. This excavation was not welded but two lighter titanium blades were installed to compensate for the material removed from the rotor to eliminate the crack and to offset the unbalance which would have resulted from installation of only one titanium blade near the defect. Of particular concern is that Xcel/NSP were not made aware of these defects until the repair had been started. Also, Xcel/NSP had not been and still have not been advised by GE to inspect for this type of defect using a TIL or GEK. James Howenstein testified:

> There was (sic) other ones before Sherco that, as we pulled them apart, we identified those indications. Because you couldn't – you couldn't see those indications with UT.

(Howenstein Deposition, p. 141.) This statement should have led GE to issue another TIL similar to TIL 1277 and TIL 1886 which would have required removal of the blades and NDE inspection using a magnetic particle inspection technique or perhaps a phased array ultrasonic examination similar to that required by TIL 1277 which would not require blade removal. NSP/Xcel were frustrated by GE's lack of notification to inspect for and repair what appears to be a fleet wide issue. NSP engineers have confirmed that GE has still not issued notification to inspect for these defects, however, NSP has developed an inspection method jointly with Structural Integrity Associates.

Discussion of GE's LP turbine design v. other manufacturers' designs.

The inspection of the Sherco 3 L-1 wheel dovetails requires removal of the blades and magnetic particle inspection of the finger dovetails (TIL 1121) and the blades. This whole process, if no additional repairs become necessary such as if cracks are detected which would require weld repair, would require an outage on the order of 3 to 4 weeks. The cost to do the inspection during a planned outage when the LP rotors are removed is estimated to be on the order of ($1,000,000). The cost to do the Sherco 3 L-1 inspection during an unplanned outage is on the order of ($2,000,000) which is approximately three to four times the Sherco 2 cost of an unplanned outage because the blade dovetails are inherently more difficult to inspect and the rotors must be removed from the turbine casing.

Approximately 1600 dovetail pins must be removed and replaced (4 wheels each with 399 pins). It is not unusual to have to machine a small percentage of the pins for removal and the corresponding holes in the blades and wheel must be reamed oversize. There is a limit on the oversize condition, typically .015" on pin diameter and with the number of oversize pins near each other limited so as to not result in excessive "ligament" stress between adjacent pins. The oversize condition must be reviewed by GE engineering if the pin diameter must be increased beyond GE's limits provided to its technicians in the field are doing this type of work. General industry knowledge is that all pins can only be oversized 3 times by .005" each time before (a) an engineering evaluation becomes necessary, (b) the possibility of a weld repair becomes necessary. Owner/operators such as Xcel/NSP understand the risk of (a) operating LP steam turbines with the possibility of developing stress corrosion cracks, and (b) conducting unnecessary inspections which consume the life of the rotor such as the need to oversize the finger dovetail pins with each inspection by a minimum of .005" on diameter. Other manufacturers including Siemens, Westinghouse (now Siemens) and Alstom (now GE) utilize designs for long LP blade fasteners which include straight and curved axial entry features. These are more easily inspected compared to GE's finger dovetail design even though the blades may need to also be removed. The design of wheel and blade dovetails for other manufacturers may also be inspected using phased array ultrasonic methods which has been proven to be reliable for identifying SCC without removing the blades from the rotor. The inability to inspect GE's L-1 finger dovetails (like those on Sherco Unit 3) for SCC without removing the blades imposes an extraordinary burden on the operator and increases reliance on GE to instruct when such inspections are necessary.

APPENDIX A

HERBERT J. SIROIS

EMPLOYMENT:

Upon completion of my BSME at the University of Rhode Island in 1971, I joined Westinghouse Electric Corporation (1972 to 1974) as a steam turbine design engineer. My duties included development of large utility steam turbines with emphasis on structural and fluid flow through stationary components including development of exhaust diffusers, seal design to control leakage and parasitic flows, and extraction openings. I was then employed by Terry Corporation (1975 to 1988) and performed failure investigations of installed critical turbomachinery including steam turbines and developed steam turbine product lines for industrial applications, and the commercial nuclear power industry. I also engineered products applied to the US Navy fossil and nuclear surface fleet and continue to consult these products for the US Navy. I then worked for Centritech/IMO Industries/TurboCare (1988 to 1992) specializing in marketing and sales of engineered bearings, blades and upgrade and re-rate of turbomachinery for the electric utility and petro-chem industries.

I formed Foster Cove Engineering in 1993 as an independent turbomachinery consulting company specializing in failure analysis, troubleshooting, design modification and repair of rotating equipment including steam and gas turbines, compressors and pumps. Foster Cove Engineering, Inc. was incorporated in Rhode Island in 1998. Our client base includes owner/operators of power generation facilities, the US Navy, insurance companies, attorneys and petro-chem and oil refiners. I have investigated insurance losses involving steam and gas turbines including aero-derivative gas turbines manufactured by Solar, General Electric, Westinghouse, Allis Chalmers, Siemens and various Chinese and Japanese designed and manufactured utility steam turbines. I was employed by Conmec in Bethlehem, Pennsylvania (1999 to 2000) as the manager of steam turbine products specializing in the application and upgrading of large mechanical drive steam turbines used in petro-chem and oil refining industries, before returning to Foster Cove Engineering to provide independent turbomachinery consultation.

I conduct training for electric utility engineers and have developed turbomachinery design material for delivering this training.

EDUCATION:

I graduated from the University of Rhode Island with a Bachelor of Science Degree in Mechanical Engineering in January 1971. I received a Master of Science Degree -- Executive MBA, from the University of Rhode Island in 1988. I completed approximately 50% of the course work for a Master's degree in Mechanical Engineering from the University of Pennsylvania prior to relocating for employment in 1975.

PROFESSIONAL AFFILIATIONS:

I am a Registered Professional Engineer in Rhode Island and maintained similar status in Connecticut until 1997. I am an active member of the American Society of Mechanical Engineers and was elected by my peers to the grade of ASME Fellow in 1993. I was nominated for Fellow based on my technical contributions to the turbomachinery industry. I have participated in development of standards for (1) Steam Turbines for the US Navy, (2) Repair of Turbomachinery for the American Petroleum Institute, (3) Centrifugal Pump Standard for American Society of Testing Materials (ASTM). I had been an active member of ASME's Auxiliary Turbine and Generator Committee.

EXPERT EXPERIENCE:

My experience with the design and operation of turbomachinery including steam and gas turbines has been applied to investigation and in some cases the resolution of turbomachinery problems. I have consulted on matters involving design, installation, operation and maintenance of these highly engineered machines. I have provided professional services to attorneys and insurance companies involving (1) failure of a turbine due to overspeed with death resulting and which settled in 2005 before trial, (2) failure of a gas turbine used by an independent power producer where the turbine suffered a major failure, scheduled for arbitration in 2005, (3) failure of a steam turbine due to deficient repair, settled in mediation in 2003, (4) expert testimony for mediation of an overseas power plant construction project where I participated in issues related to the steam turbine, (5) prepared attorneys with questions for depositions. Cases which I provided expert testimony at trial or in arbitration are listed in APPENDIX D.

APPENDIX B

Foster Cove Engineering, Inc.
75 Kingstown Road
Richmond, RI 02898
401-491-9065 tel
fce@fostercove.com

Rates for Professional Services (2014):

Foster Cove Engineering, Inc. (FCE) consultation time and expenses shall be invoiced per the following rates and payment conditions. FCE will commence work upon receipt of one of the following, the client's (a) purchase order, (b) task order for a previously negotiated blanket order, or (c) irrevocable letter of credit.

Hourly Rate: $240/hour for Consulting Engineering including desk studies at FCE facilities, consulting at client's site, report writing, standby and travel. Travel shall be on a "portal to portal" basis.

Overtime Rate: $240/hour (after eight hours) for the same services listed above In "Hourly Rate".

Legal Rate: $280/hour (consulting, depositions, expert testimony and preparation for same, including travel and desk studies at FCE facilities).

Training Rate: $240/hour for travel to and from the assignment and conducting the training assignment using available training materials. Development of new training materials shall be done at the same rate based on FCE's time estimate.

Telephone Consultation: $240/hour, 1 hour minimum.

Offshore Rate:15% premium on the above rates, subject to negotiation.

Long Duration: Negotiated discounts may apply to Contracts exceeding 2 weeks continuous duration.

Expenses: All expenses including performance bonds, travel expenses including mileage (GSA Rate for Privately Owned Vehicles) and others necessary for completion of contracts shall be invoiced at cost. For assignments in the continental US, the CONUS per diem rate shall be used for meals and incidentals; hotel shall be invoiced at cost. For all travel outside of the continental US, Business Class airfare shall apply. Fees for wire transfers and credit card fees for foreign currency conversion shall be included in the currency conversion calculation.

Payment: Due 30 days after submittal of invoice by FCE, payable in US currency. Contracts exceeding 30 days duration shall be invoiced monthly.

APPENDIX C

PUBLICATIONS:

"Steam and Gas Turbine Blade Manufacturing Advances", H. J. Sirois, Power Engineering, 9/03

"Purge Air to Control Contamination of Oil", H. J. Sirois, ASME Power Conference, Denver, CO 1993

APPENDIX D

TESTIMONY PROVIDED AT PROCEEDINGS:

Fluor Daniel Intercontinental, Inc., et al. v. General Electric Company, et al., American Arbitration Association Case No. 50 T 110 00373 99, New York, New York. (2003)

ICC Case No. 15888/JRF - ENEL Produzione, S.p.A. and ENEL Green Power, S.p.A. v. Inversiones Energéticas, Sociedad Anónima de Capital Variable and Comisión Ejecutiva Hidroeléctrica del Río Lempa (2010)

ICC Case No. 15984/JHN/GFG - AREVA GmbH, AREVA NP S.A.S., SIEMENS AKTIENGESELLSCHAFT (Claimants) *v.* TEOLLISUUDEN VOIMA OYJ (Respondent) (2015)

APPENDIX F

DOCUMENTS REVIEWED IN FORMULATING OPINIONS IN THIS EXPERT REPORT:

In addition to all items cited within my report, I reviewed the depositions, documents, and other material identified below. I also visited the Sherburne County Generating Station on January 6, 2016 and interviewed numerous NSP and Xcel personnel including operators, engineers, chemists, and managers.

Depositions, including related exhibits:

Joshua Bird
Jim Force
Brett Hanson
John Heisick
Mark Kolb
Arthur Howenstein
Steven Mills
Tim Murray
Paul Pennington
Duane Wold

Persons interviewed on January 6, 2016 and subsequently by phone include:

Ron Brevig
Darin Schottler
Tim Murray
Mark Kolb
Duane Wold
Adam Henderson
Dave Amundson
Steve Eigen

Documents and Data:

Complaint, *Northern States Power Co. et al v. General Electric Co. et al*, Court File No. 71-cv-13-1472

Root Cause Analysis, Steam Turbine Generator Event of November 19, 2011, Unit No. 3 Sherburne County, Report No. 14439, Thielsch engineering, Inc., dated May 29, 2013

Report of David G. Daniels report dated January 29, 2016

General Electric Company's Instructions GEK-64915, Vols. 1-3 (Turbine Section), *Steam Turbine-Generator Turbine No. 170X819,* Northern States Power Company Sherburne County Generating Station – Unit No. 3 Becker Minnesota

Historical PI Data from 2000 through 2011

TILs 640, 689, 770-3, 949, 956-3R1, 969-3R1, 1008-3, 1024-3, 1121-3A, 1121-3AR1, 1277-2, 1292-1, 1539-2, 1886

GEKs 85280, 111680, 72220, 72281f, 110293a, 111537, 116203, 46488c, 46527b

XCEL_Sherco_01_0000403

XCEL_Sherco_05_0044375 (Unit 3 Overspeed And Valve Tightness Test)

XCEL_Sherco_05_0058044 to 8080 (2011 Unit 3 Infrared Thermography Survey)

XCEL_Sherco_05_0068583 to 8597 (2010 Stop Valve Strainer Inspection)

XCEL_Sherco_05_0068917 to 8937 (2005 Generator Forced Outage Report)

XCEL_Sherco_05_0070585

XCEL_Sherco_05_0075087 to 5091 (2006 CRV Fine Screen Removal & Bearing Inspection Summary Report)

XCEL_Sherco_05_0075423 to 5441 (2008 Minor Inspection)

XCEL_Sherco_05_0093910 to 3966 (2006 Unit 3 Infrared Thermography Survey)

XCEL_Sherco_05_0093981 to 4028 (2007 Unit 3 Infrared Thermography Survey)

XCEL_Sherco_05_0094090 to 4125 (2009 Unit 3 Infrared Thermography Survey)

XCEL_Sherco_05_0094276 to 4342 (2010 Unit 3 Infrared Thermography Survey)

XCEL_Sherco_05_0122529 to 2579 (1999 NDE Inspection Summary)

XCEL_Sherco_05_0122824 to 3141 (1999 Condenser Inspection of Unit 3)

XCEL_Sherco_05_0123142 to 3379 (GE Major Turbine Inspection Report, April 27, 1999)

XCEL_Sherco_05_0123430 to 3454 (1999 LPB Rotor Inspection Report)

XCEL_Sherco_05_0124017 to 4112 (2002 CSI Tube Inspection)

XCEL_Sherco_05_0124120 to 4193 (Sherco Unit 3 Stator Winding Liquid Cooler 31 & 32, EDDY current summary report 2002 outage)

XCEL_Sherco_05_0124194 to 4231 (2002 Unit 3 Turbine-Generator Minor Inspection Report)

XCEL_Sherco_05_0124383 to 4393 (2005 MMR Outage Report)

XCEL_Sherco_05_0124394 to 4421 (2005 Major Inspection)

XCEL_Sherco_05_0124422 to 4502 (2005 Condition Assessment Report)

XCEL_Sherco_05_0124670 to 4681 (2008 MMR Outage Report)

XCEL_Sherco_05_0125344 to 5352 (2011 Unit 3 MMR Outage Summary)

XCEL_Sherco_05_0125627 to 5708 (2011 Capital Projects and Minor Inspections Report)

XCEL_Sherco_05_0127401 to 7447 (1999 MQS Inspection, Inc. Turbine Inspection Report)

XCEL_Sherco_05_0127499

XCEL_Sherco_05_0128365 to 8370 (2002 MMR Inspection Report)

XCEL_Sherco_05_0131099 to 1105

XCEL_Sherco_06_0010858 (Transmittal of TIL 1121)

XCEL_Sherco_06_0011033 (Email re: LP Rotor Cracking Issues)

XCEL_Sherco_06_0011056 (Email re: Unit 1 Turbine & Generator History, Future Outage Plans)

XCEL_Sherco_07_0166405 to 6428 (1999 LPA Rotor Inspection Report)

XCEL_Sherco_08_0111179 to 1405 (Start-Up Report and Checklist Guide)

XCEL_Sherco_09_0001231 (PI Data)

XCEL_Sherco_09_0001573 to 1659, XCEL_Sherco_09_0001660 to 1735, XCEL_Sherco_09_0001736 to 1910, XCEL_Sherco_09_0001911 to 1993 (Chemistry Procedures)

XCEL_Sherco_09_0002142 to 2201

XCEL_Sherco_09_0003952 to 4044, XCEL_Sherco_09_0004045 to 4204, XCEL_Sherco_09_0004205 to 4372 (Sherburne County Generating Plant Chemistry Manual)

XCEL_Sherco_09_0004373 to 4459 (Start up training)

XCEL_Sherco_09_0004460 to 5107 (Plant Management Directives)

XCEL_Sherco_09_0005349 to 5450 (Water Quality Control System)

XCEL_Sherco_09_0005466, 77, and 90 (Boiler Water Samples 2011)

XCEL_Sherco_09_0005531 and XCEL_Sherco_09_0005569 (Unit 3 Circulating Water Data 2011.01-2011.08)

XCEL_Sherco_09_0005575 (Unit 3 Circulating Water Data 2011.09-2011.11.19)

XCEL_Sherco_09_0005582 (Closed Cooling 2011)

XCEL_Sherco_09_0005592 (Condensate Pump Discharge 2001 to 2011)

XCEL_Sherco_09_0005627 (Deaerator 2011)

XCEL_Sherco_09_0005653 (Economizer Inlet 2011)

XCEL_Sherco_09_0005680 (Main Steam 2011)

XCEL_Sherco_09_0005698 (Polisher 31 2011)

XCEL_Sherco_09_0005710 (Polisher 32 2011)

XCEL_Sherco_09_0005732 (Stator Cooling 2011)

XCEL_Sherco_09_0006941 to 7269 (Sherco Unit 3 Chemistry Startup Logs)

XCEL_Sherco_09_0101277 to 526 (Water Chemistry Data)

XCEL_Sherco_3_000211 to 213 and XCEL_Sherco_3_000196-201 (Organizational charts)

XCEL_Sherco_05_0123725 to 3970 (Gen Stat n Field 1999)

XCEL_Sherco_05_0124926 to 4940 (Exciter Bearing Inspection 2008)

XCEL_Sherco_05_0125198 to 5226 (Exciter Bearing Inspection 2010)

XCEL_Sherco_05_0125390 to 5626 (HP IP Turbine Upgrade Report 2011)

XCEL_Sherco_05_0122165 to 2357 (1996 Outage L-1s)

XCEL_Sherco_05_0124319 to 4382 (2005 Dovetail Wesdyne Inspection Report)

XCEL_Sherco_05_0124312 to 4318 (2003 Outage Support Summary)

XCEL_Sherco_05_0122580 to 2823 (Unit Tube Inspection 1999)

XCEL_Sherco_5_0555263 (Email)

XCEL_Sherco_05_0069225 (Email)

XCEL_Sherco_05_0069226 (Email)

XCEL_Sherco_10_0000169 to 170 (Email)

XCEL_Sherco_10_0000175 to 177 (Email)

XCEL_Sherco_10_0000194 to 196 (Email)

XCEL_Sherco_10_0000213 to 214 (Email)

XCEL_Sherco_10_0000171 to 172 (Email)

XCEL_Sherco_10_0000173 to 174 (Email)

XCEL_Sherco_01_0000403 to 408 (Operating Testing Procedures)

XCEL_Sherco_05_0044596 to 4608 (OST Tightness Test)

XCEL_Sherco_05_0044415 to 4506 (2011 Startup Guidelines)

Attached documents numbered SIROIS 00001 to 00084

EXPERT REPORT

Rebuttal to
Expert Witness Report of James D. Schultz

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Summary

This report rebuts opinions presented in a report entitled "Expert Witness Report, Northern States Power, Plaintiffs V. General Electric Company, Defendants" prepared by James D. Schultz, Turbine Generator Expert. The report was signed April 1, 2016.

A brief review of Mr. Schultz's resume and expert qualification shows that his experience is essentially as a field engineer for fossil, nuclear, and industrial turbine generators for General Electric, and as a maintenance manager for FirstEnergy, a utility. He has never worked for a manufacturer as a turbine design engineer, in a power plant, as a water treatment specialist, or systems engineer. He renders expert opinions about the water chemistry and turbine design, although his background suggests he does not have the qualifications to do so.

Throughout his expert report, Mr. Schultz states that General Electric provided technical information in the form of service manuals, GEK's, TIL's, and other documents which advised Northern States Power on how to operate, inspect, and maintain the Sherco 3 steam turbine to prevent the failure of the low pressure turbine due to stress corrosion cracking like that which occurred on November 19, 2011. He also states that NSP's engineers were fully aware of stress corrosion cracking and neglected to perform timely inspections for this, exposed the Sherco 3 steam turbine to contaminants which caused stress corrosion cracking, and neglected to perform even cursory inspections of the L-1 blade attachment which would have demonstrated that the blade attachment was vulnerable to stress corrosion failure.

Mr. Schultz's observations and opinions are not supported by fact. Northern States Power was diligent in performing inspections and maintenance for stress corrosion cracking in spite of General Electric Company's lack of proper advice in the form of a unit specific technical information letter which would have supported the recommendation to inspect the Sherco 3 low pressure turbine and turbine stages for stress corrosion cracking during the major inspection conducted in 2011. The record shows that NSP's repeated requests for this document in 2008 were discussed internally by General Electric; however, the GE engineer's recommendation to advise NSP to inspect all GE units in its fleet with drum boilers in accordance with TIL 1277 which further references TIL 1121-3AR1 were never transmitted to Tim Murray, NSP's subject matter expert, or in writing to anyone else at NSP. In spite of not having this unit specific recommendation from GE, NSP took an unplanned outage in 2008 to inspect Sherco 2 for stress corrosion cracking and found none. This was done at great expense to NSP including the cost of the unplanned outage and the loss of generation revenue. Since Sherco 3 has a different design for the L-1 blade attachment, and due to the fact that GE had not issued a unit specific TIL for Sherco 3, NSP made an informed decision to postpone the major inspection of Sherco 3 LP turbine for approximately 3 years, from the previous 6 year time between outages to 8.33 years. The reasons for this are that (a) the L-1 blades were removed and replaced with upgraded blades in 1999, when the wheel finger dovetails were inspected in accordance with TIL 1121-3AR1 and found acceptable by GE after approximately 12 years of operation, (b) the unit had not been subjected to abnormal chemical events including carryover, as Sherco 1 and 2 had been, and (c) GE had not advised NSP with a unit specific TIL to inspect the L-1 blade attachment areas absent an abnormal event, or listed this inspection in its proposals for major inspection Sherco 3 in 2005, or major upgrade to the HP and IP turbines and inspection of the LP turbines in 2011. NSP has stated that based on the above reasons, the L-1 blades

would not have been removed for inspection of the wheel finger dovetails even if the LP's had been inspected in 2011, there was no reason to.

GE failed to warn NSP of the need to inspect Sherco 3 for stress corrosion cracks in the L-1 blade attachment area. GE claims to have done so in GE and EPRI sponsored conferences, all of which are general and not specific to individual units. NSP's technical staff was fully aware of the risk of operating with stress corrosion cracking; the communications record and documents produced for this litigation are clear and confirm this fact. What is not clear is why GE did not warn NSP with a unit specific technical information letter which should have been issued as requested by NSP. Mr. Schultz does not address this in his expert testimony.

Corrections and Rebuttal to Inaccuracies and Misstatements in Mr. Shultz's Analysis, Opinions and Conclusions

1. Mr. Schultz's experience does not include (a) steam turbine design, (b) large power plant water chemistry, or (c) a record of power plant operations. He has been employed by GE as a field engineer for fossil, nuclear, and industrial turbine generators. He has also been employed by FirstEnergy as Manager of Turbine Generator Maintenance, which does not qualify him to render opinions on stress corrosion failure of a highly stressed L-1 finger dovetail structure. He claims to "… understand the complexity of planning and executing turbine generator work scopes while balancing the budget process with human behaviors that influence a successful, safe outcome, as an expert turbine generator engineer." Mr. Schultz's resume does not support the experience necessary to reach the conclusions he has made about what led to the failure of Sherco 3 L-1 finger dovetail on November 19, 2011 while the steam turbine generator was being overspeed tested.

2. Mr. Schultz claims that NSP subjected Sherco 3 to 2000 load cycle changes from full load to half load including 100 complete stop cycles during the ten years prior to the L-1 failure. This mode of operation is not unusual even for 900 MW units when the manufacturer's loading ramps are adhered to. The statement (page 8) "This type of cycling operation can lead to wetting and drying of contaminants which can accelerate the formation of SCC", implies that all steam turbines which cycle are subject to damage. Manufacturers including Brown Boveri Corporation (now part of General Electric) have designed and manufactured 800 MW to 1300 MW steam turbine generators which operate in similar service as Sherco 3 and have time between major inspections for the low pressure turbines much longer than the 5 or 6 years recommended by GE. This is only possible with proper selection of materials and with operating stresses which are low enough to avoid stress corrosion cracking, as stated in expert reports written by Karen Fuentes and David Daniels.

3. Mr. Schultz claims that General Electric Company publishes service manuals, service bulletins and technical information letters, because "GE recognized the importance of advising owners that it is up to the owners to achieve proper steam purity and maintenance inspections that would preclude the formation of SCC and potential failure." He also states that "In addition, NSP personnel participated in the EPRI 'GE L-1 bucket Users Group' which focused on owner experience and inspection techniques for SCC detection and mitigation." As a point of correction, EPRI did not sponsor or otherwise organize the GE L-1 Bucket Users Group. This group was formed by a small group of individual utilities to address industry wide design issues with the GE L-1 buckets which were not being addressed by GE. GE, with pressure from the L-1 user group, did finally address this design issue and created a new design for the blades which was planned and budgeted for by Sherco for installation in 1999.

4. What Mr. Schultz fails to understand, is that NSP's engineers fully understood the importance of mitigating the risk of operating with SCC, to the extent that NSP, without a unit specific recommendation from GE, performed an unplanned outage on Sherco 2 in 2008. This was to inspect the low pressure rotors with tangentially loaded blades using phased array testing to detect SCC. The reasons for conducting this inspection were the findings of SCC in Sherco 1 in 2007, which required major weld repair of the two LP rotors. This repair was done by Alstom. No SCC indications were discovered during the Sherco 2 inspection in 2008.

5. Mr. Schultz also refers to Technical Information Letter 1121-3AR1 throughout his report. This TIL specifies the inspection method for finger dovetail blades and also states that the inspection should be considered when one or more "abnormal events" occur, as outlined in the TIL. Although this is discussed in M&M Engineering's Karen Fuentes's report "Stress Corrosion Cracking in Turbine Rotors Sherco Unit No. 3", the TIL does not provide sufficient definition of these abnormal events. Measurable parameters such as quantity, time, and frequency would allow a reasonable and experienced person to make a determination if an event is considered abnormal. Small condenser tube leaks that do not contaminate water chemistry and overspeed events including periodic testing of overspeed devices for risk mitigation are not considered abnormal by power plant professionals and manufacturers throughout the industry. Water induction and caustic or chemical ingestion or contamination may be considered abnormal depending on the severity; carryover from the boiler and leaking condenser heater tubes may also be considered abnormal depending on the severity. Unfortunately, GE did not define any measure for what they considered abnormal which then leaves it to the owner to make that determination. NSP determined that Sherco 3 was not subjected to any of the 5 abnormal events outlined in TIL 1121-3AR1.

6. Mr. Schultz does not acknowledge that the trigger for applying the inspection techniques of TIL 1121-3AR1 in the absence of an abnormal event is TIL 1277-2, which only applies to plants with Once Thru Boilers. Again, Sherco 3 is a drum boiler plant. GE did not issue a unit specific TIL equivalent to TIL 1277-2 to NSP for Sherco 3 even after repeated requests from NSP for this. As stated in (4) above, NSP conducted inspections on Sherco 1 and 2 in 2007 and 2008 respectively because these units had previously been subjected to a chemical event or events including carryover. NSP believed this exposure increased the possibility of SCC in the phase transition zone of the LP turbines for those units. Sherco 3 has a different L-1 blade fastener which requires removal of all L-1 and possibly the L-0 blades to inspect the wheel fingers for cracks. With reference to Karen Fuentes's expert report, these cracks originate in the upper and lower shoulders and the pin holes. GE does not provide detailed guidance for which stages must be removed for inspection, although the record indicates that the L-0 buckets do not have a history of SCC so that it is not necessary to inspect the L-0 wheel finger dovetails. The cracks develop in the inner fingers only and not on the two outer fingers which are readily accessible for inspection without removing the blades. He attributes the statement "… there are less invasive ways to look for SCC such as "bucket lift check" where the buckets don't have to be removed" to Tim Murray. This is in conflict with Tim Murray's testimony. Mr. Murray stated that the "bucket lift check" applied only to tangential entry blades. The only inspection method for finger dovetails is magnetic particle inspection as stated in GE's own TIL 1121-3AR1, which requires removal of the buckets.

This inspection is costly in terms of money and time, a characteristic of the GE G-3 design. NSP would balance the need to inspect in accordance with TIL 1121-3AR1 with the risk of continued operation. Since NSP did not believe that Sherco 3 had been subjected to any of the abnormal events in TIL 1121-3AR1, they made the decision in 2005 not to remove the L-1 blades since the LP wheels had previously been inspected in 1999 as part of the blade replacement performed by GE. They then made the decision in 2011 to extend the LP major inspection for another 3 years (approximately) so that the time between major inspections would have been approximately 8.33 years. NSP stated during plant interviews that they would not have performed TIL 1121-3AR1 in 2011 or 2014 unless the unit had been subjected to any of the "abnormal events" listed in the TIL or, if the blades were removed for some other reason such as blade replacement. Sherco 3 had not been subjected to any of abnormal events as of November 2011, nor was it planned to remove the L-1 blades.

7. Mr. Schultz implies that NSP had stopped communicating and awarding work to GE since GE had not received orders since the 1999 major inspection and L-1 blade replacement project. GE was invited to bid and did bid the major inspection for 2005 and was solicited to bid the HP and IP turbine replacement project in 2011. Upgrade of the Sherco 3 HP and IP steam paths was not awarded to GE because the work was awarded based on competitive bidding. GE was high on price for the 2005 and the 2011 projects. It is noteworthy that GE did not indicate in the 2005 and 2011 proposals that they intended to perform the TIL 1121-3AR1 inspection.

With reference to XCEL_Sherco_07_0166486, an email from Tim Murray to GE's Josh Bird and Cathy Petros dated 4/13/2004, where he requested GE to provide budgetary pricing for several items including inspection of the Sherco 3 LP rotor wheel dovetails and he made specific reference to the L-0 and L-1 rows. He states "Additionally all 4 rows of the L-1 blading was replaced by GE in 1999 and wheel dovetails were mag tested at that time with no indications present. This inspection should include engineering evaluation of the test results. This would be onsite work as well." There were two documents associated with this request (a) XCEL_Sherco_05_0052562 which is an email from Josh Bird to Tim Murray quoting the Sherco 3 boresonic inspection, no mention of the inspections of the LP blade dovetails, and (b) XCEL_Sherco_05_0028917 which is an email and proposal from Josh Bird for Linear Phased Array inspection of the L-2 and L-3 wheel dovetails with an option for testing addition rows. These additional rows do not include the L-0 and/or the L-1. GE missed the opportunity to warn NSP that inspection of the L-1 wheel dovetails was necessary as part of the 2005 inspection.

There is a clear record that NSP continued to communicate with GE including, but not limited to Josh Bird, Cathy Petros and others. Specifically, the email thread between Josh Bird and Tim Murray where Tim Murray requested a TIL starting on January 15, 2008 where he requests "… Any feedback from engineering on the drum boiler LP turbine wheel dovetail cracking issue? Any TILs in the works?" XCEL_Sherco_10_0000213-214. This was never resolved by GE, although GE engineer J. Howenstein states in his email to Josh Bird on 2/29/2008 "Although TIL 1277 is written for once through boilers we have been recommending customers with drum boilers follow the recommendations also…." This recommendation was never transmitted to NSP. A TIL triggering the inspection techniques of TIL 1121-3AR1 for Sherco 3 was never issued until TIL 1886 was issued nearly 2 years after the 2011 failure. TIL 1886 differs from TIL 1277 in that it recommends that it apply to units that are operating with greater than 22 years of service on their L-1 wheel dovetails. The inspection interval is not definite, other than it states that "If no dovetail cracking is noted during the inspection, GE believes that continued operation is acceptable before the next inspection, or bucket replacement, dependent on your individual operating strategy. The re-inspect period should be determined at the time of inspection, based on inspection results, inspection method and intended operating profile. Contact your GE Service Manager or Contract Performance Manager for definition of re-inspection interval." It is especially noteworthy that TIL 1886 does not attempt to adjust the inspection period for the number of start/stop cycles or the number of load cycles. Again, there is an absence of measureable quantity, other than time in service.

8. Mr. Schultz indirectly suggests that Sherco should have operated more like a nuclear utility where he states "For example, nuclear power plant operators have tried to reduce human performance issues by allowing workers to create a 'condition report' for anything he/she feels needs attention and evaluation. Then the condition is evaluated by appropriate staff members and resolved or escalated to a 'Problem Solving Team' if the issue is more complex. NSP appears to have lacked such methods for reducing human performance errors." He goes on to suggest "what should have happened" for 8 situations related to Sherco 3 (pages 17 to 19 of his report). He attempts to find fault with NSP's System Health Reports, which is a technically sound system for identifying corrective action and risk. He also attempts to raise the issue of water wash of the L-0 blades and condenser tube leaks as major contributors to SCC of the L-1 finger dovetails. These issues have been completely discounted by Karen Fuentes in her rebuttal of the Veryst report and David Daniels's rebuttals to the Allmon report and most recently Mr. Schultz's report. The last issue refers to "NSP management should not have dressed down the system engineer for strongly recommending a low pressure turbine rotor inspection on Unit two." This completely mischaracterizes the dynamics of the Sherco organization during this time period, and is in fact completely wrong, as noted later in this paragraph. Staff should always be held accountable for their actions in any organization. The risk associated with SCC in Sherco 2 in 2008 was clear to the systems engineer based on the findings in Sherco 1 one year before. Any reasonable person would have strongly recommended the Sherco 2 inspection. The system engineer's recommendation to do the inspection was accepted by NSP management. The system engineer did not stop proposing inspections because no SCC was found in the Sherco 2 LP's in 2008. It is his responsibility to do the best job he can including convincing management to budget for necessary work for unplanned inspections when there is measurable risk. Everyone who has worked in a power plant environment for more than 30 years should have confidence in his or her job function. This was the case with Mark Kolb's recommendation to inspect Sherco 2 LP's for SCC in 2008. The decision to perform the inspection involved many NSP employees, not just Mark Kolb.

Mr. Schultz's attempted portrayal of Mr. Kolb's words on page 200 of his deposition where the expression "dressed down" actually refers to a discussion Mark Kolb he had with GE's technical service manager Brett Hanson. Mr. Hanson "dressed down" Mark because he was being overly conservative in his interpretation of the "abnormal events" TIL 1121-3AR1. Mark Kolb quoted Brett Hanson as saying that this applied to "gross, gross abnormal events beyond what we – we have seen at the plant." (Kolb Depo p.200).

Sherco is not a nuclear plant, but NSP owns and operates Monticello which is a nuclear plant. Ron Brevig, Mark Kolb, and Tim Murray, all NSP senior staff in charge of significant power generation assets at Sherco, previously worked at Monticello and contributed to the development of methods currently used by NSP fossil and nuclear plant staffs so that the best of both are blended together.

9. Mr. Schultz discusses the design of the turbine starting on page 19 of his report. Although he is not a turbine designer, he states that "B9" material is the correct material for the Sherco 3 LP rotors and that this material is not a factor in the failure of the unit. He then relies on the Veryst engineering report to conclude that "… the rotor wheel finger dovetail is robust and not subject to failure within normal operating stresses". Karen Fuentes thoroughly rebuts these claims in her expert report, and I defer to her expertise on this topic. Mr. Schultz's assertion on page 21 that "The GE warnings were

reasonable and timely and no other owner has experienced a catastrophic failure of similar design rotor with finger dovetail on drum type boilers" is without factual basis. GE failed to advise NSP of the need to apply TIL 1121-3AR1 to their LP turbines in drum boiler plants even in the absence of any abnormal events. In fact they did not issue this advice in the form of TIL 1886 until October 2013, nearly 2 years after the Sherco 3 LP failure.

10. The Sherco 3 operations and maintenance manual for the steam turbine generator, GEK 63355, states that cycling generally requires more frequent maintenance. NSP's maintenance program for Sherco 3 is based on GE's technical requirements including the service manual, GEK's, TIL's and others. The maintenance program also accounts for the operating and maintenance history of the unit. Sherco 3 has been inspected many times since going commercial in 1987. The 6 year maintenance period has been the standard for Sherco 3, however, this was extended to 8.33 years in 2009 to be in-line with NSP's requirements to even out expenditures by doing major steam turbine generator inspections in "sections" such as the HP and IP turbines would be done one year and then at some later time, the LP turbines would be inspected. Sherco and NSP made the informed decision to extend the 2011 major inspection for the Sherco 3 LP turbines to 2014 to satisfy the requirement to balance expenditures across years. This decision was also based on the condition of the LP's at that time. The System Health Reports did not show any reliability issues with the LP turbines, if they had then a major inspection would have been conducted at that time. The other significant factor is that the LP L-1 wheel finger pin dovetails would not have been inspected in accordance with TIL 1121-3AR1 even if a major had been conducted in 2011 and 2014. There was no reason to do the inspection based on the facts, as discussed earlier in my expert report and also in this rebuttal to Mr. Schultz's report.

11. Mr. Schultz indirectly implies that attending a GE Users Group conference where SCC is discussed is a substitute for a unit specific TIL requiring a detailed inspection which would cost NSP $1 million or more and possibly cause 2 to 3 weeks of additional lost generation revenue. He claims in his qualifications that he "… understands the complexity of planning and executing turbine generator work scopes while balancing the budget process with human behaviors that influence a successful, safe outcome, as an expert turbine generator engineer." He should fully realize that in his prior role at FirstEnergy as a maintenance manager, that his superiors certainly would have questioned and possibly criticized him had he proposed to conduct an additional $1 million of inspections on a turbine strictly based on some non-specific statements made to him by an original equipment manufacturer with a motivation to upsell inspections and repairs. There were no indications that the L-1 wheel finger dovetails needed to be inspected, GE did not propose this in 2005, and, GE did not issue a unit specific TIL suggesting this inspection. Tim Murray, in requesting a unit specific TIL in 2008 which would recommend inspection of the Sherco 3 L-1 wheel finger dovetails was attempting to obtain from GE a firm recommendation to support the inspection. He never received it.

12. Mr. Schultz implies that GE continued to improve the product with innovation such as the "494 patent" and "fine line welding" "to reduce the susceptibility to SCC". This is not a point of contention, since NSP was fully aware of SCC and the available fine-line weld repair options for SCC because of the repair of the L-1 wheel dovetails in the Sherco 1 LP's in 2007. What NSP was not aware of was the latent susceptibility of the Sherco 3 wheel finger dovetails to SCC and the proper inspection timing to detect it. Tim Murray asked GE for a unit specific TIL in 2008 which would suggest, impose and/or mandate

inspection of the L-1 wheel finger dovetails in accordance with TIL 1121-3AR1. He never received it until TIL 1886 was issued in October 2013, two years after the failure.

13. Mr. Schultz makes the statement in his report "The System Health Report issued in December 2010 acknowledged that 'extending GE recommend (sic) TBO increases risk of failures.' The report recommends a 6-year overhaul frequency. It also noted that the LP inspection interval could possibly be extended to nine years with the proper engineering study. However, notwithstanding NSP's knowledge of the risk of potentially catastrophic failure, NSP extended the LP inspection interval to 2014 without any engineering study or compliance with Xcel Energy Production Resource Guideline EPR 5.713G. Extending the inspection interval from six years to almost nine years should have changed the color coding from green to at least yellow or red, but this was not done. The plant engineer had failed to alert management that additional risk was being taken without a study to determine if this was prudent." These statements by Mr. Schultz are not based on fact.

As Mark Kolb states, "We were not aware of any technical or operational issues that precluded deferring the LP overhaul from 2011 to 2014. The LPs had been rated GREEN in the System Health Report for several years prior to the 2011 outage. Overhaul condition assessment reports suggested the LPs were in generally good condition. The L-1 rotor wheels had been inspected in 1999 by the OEM, and new OEM L-1 buckets were installed. A borescope inspection of the L-1 buckets was performed in 2002. There were not outstanding TIL recommendations suggesting, or requiring, that the L-1 wheel be inspected. As a corporation, NSP's recommended LP overhaul frequency was 9 years, or greater. Sherco had been criticized for being conservative on our 6 year inspection frequency. There was an internal corporate guide that recommended a greater than 6 year overhaul frequency. Our Subject Matter Expert was advocating the LP overhaul deferral to 2014. Other, older, Sherco LPs had gone greater than 6 years between overhaul with success. Deferring the LP overhaul did not preclude a crawl through inspection of the LPs." He also states, "Even if we had performed an LP overhaul in 2011, there was nothing driving us to remove the L-1 buckets and inspect the wheel."

Sherco's system engineer, Mark Kolb, recommended to NSP management that the outage be extended to approximately 9 years (actually 8.33 years) which was and continues to be within NSP's recommended LP overhaul frequency. This recommendation was based on a review of all the available information at the time with Tim Murray. This included the complexities of the planned activities including replacement of the HP and IP steam paths and other normal major outage work. There were concerns about the need to have two separate contractors (GE and Alstom) on site at the same time for the HP and IP and also the LP's in 2011. It would have been necessary for the separate contractors to share crane and available laydown floor capacity since both the HP and IP turbines were being completely torn down for the new Alstom steam paths. The decision to extend the LP outage was fully vetted within NSP and approved by management. Both Mark Kolb and Tim Murray, highly qualified engineers, were involved with evaluating the condition of this unit on a daily basis. Although it appears that neither of them did a formal written report to document the presence or absence of any of the abnormal events referenced in TIL 1121-3AR1, they would have been aware or would have been made aware had any of these events actually occurred. These events would have been highly visible to the Sherco staff including management, specifically the chemistry and operations departments. Planned overspeed tests, which are performed at least annually and possibly semi-annually, as well as small condenser tube and LP feedwater heater tube leaks, do not have such high visibility because that are not unusual in power plants. There would have been some precautionary review for caustic exposure, water induction, and carryover if considered significant. By way of example, the carryover incidents on Sherco 1 and Sherco 2 in the late 1970's had very high visibility to the point of contracting with GE to examine the LP rotors and continued monitoring into the 1980's. In fact, these events led to contaminant deposits in the steam path which then reduced the flow passing capability causing unintended load reduction. So, I am not sure what Mr. Schultz is looking for since the Sherco staff and Tim Murray from NSP's corporate staff, certainly are experienced with all aspects of turbine generator operation and maintenance at the Sherco plant.

14. Mr. Schultz suggests that inspection opportunities of the Sherco 3 L-1 wheel finger dovetails were missed in 2005 and 2011. He again misses the point that NSP was not advised to inspect the L-1 wheel dovetails with a unit specific TIL to trigger TIL 1121-3AR1. It was NSP's belief that (a) because the Sherco 3 L-1 wheel dovetails were different than those on Sherco 1 and 2, they were most likely more conservatively designed than Sherco 1 and 2 tangential entry dovetails, (b) that Sherco 3 had not been subjected to any chemical event that put the turbine at risk, (c) had not been subjected to significant carryover incidents since the unit did not lose load capacity due to the deposits in the HP and IP steam path which would have reduced flow passing capacity, (d) the L-1 blades were replaced in 1999 and the wheel finger dovetails were inspected in accordance with TIL 1121-3AR1 at that time, (e) inspections in 2005 and also in 2011 (after the failure) indicated that the LP had minimal surface pitting and were clean with very little deposits., and (f) GE did not suggest, impose or mandate inspection of the L-1 wheel finger dovetails in its 2005 proposal 94WR0036, XCEL_Sherco_05_006961.

NSP did not take shortcuts or attempt to avoid needed repairs by shopping for non-GE aftermarket providers such as MD&A and Alstom to inspect and repair NSP's turbines. Inspections, upgrades and repairs were competitively bid. GE would lose the bids if its price was higher than the competitor's bids for the same work. This bidding process is common in all industries. Mr. Schultz attempts to use NSP engineer's statements that "GE would recommend overly conservative inspections" to portray NSP and its engineers as willing to take on excessive risk for lower cost, this is not supported by the facts. Inspections performed on Sherco 1 and 2 in 2007 and 2008 respectively confirm that NSP is risk aversive. The inspections performed in the 1970's and 1980's on these same units, after the carryover events which affected the performance of both units also confirm NSP's concern for risk. In 2008, NSP's Tim Murray was looking for a firm recommendation from GE to inspect Sherco 1, 2, and 3 in accordance with a unit specific TIL to trigger TIL 1121-3AR1 so that these inspections could be planned and budgeted for, rather than some non-specific general mention of SCC in a GE User's Group and any other conference. Utilities, regulated utilities in particular, are accountable to ratepayers and the investors. Recommendations to inspect and commit money must be specific and definite. Based on this expert's experience, OEM's such as GE tend to be higher priced for the same services provided by aftermarket suppliers. I have found that there is not much difference in the services provided, in fact many of the inspection and repair techniques for these critical machines have been developed by aftermarket suppliers. However, GE does have the benefit of having the original design data and they also have the availability of fleet wide information including the number of SCC incidents such that it's cost of doing business may be higher than for the aftermarket suppliers for equivalent services. The reality of the situation is that it is not unusual for the same labor force to be used by GE and the aftermarket suppliers to perform maintenance and inspection work such that GE is at a competitive disadvantage for conventional inspections and repairs unless GE (and any other original equipment manufacturer) is willing to accept lower profit margins.

15. Mr. Schultz discusses Sherco's operating practice for Sherco 3 from 1999 to 2011 claiming that for Unit 3 "[t]here were 59 reported stop/start cycles on Unit 3 between 1999 and 2005. There were approximately 2000 load cycles below 66% power from 1999 to the date of the failure, essentially changing this base load unit to a 'peaking' unit." The facts are that stop/start cycles are considered normal for many large units including Sherco 3. Particularly, during the process of recommissioning after a major or even a minor inspection, or in the case of Sherco 3 where there have been forced outages due to boiler tube and condenser tube leaks. The load cycling he refers to appears to be accurate and possibly even understated since discussions with Sherco staff confirmed that Sherco 3 is offered as a "must run" unit to the dispatcher (MISO), with programed load ramps of a maximum of 3 MW/minute from 2009 to the time of failure in 2011. By definition, Sherco operations staff considers any load change greater than 25 MW as a load cycle.

The unit was purchased from GE in the 1970's for load following duty. The technical specification used for the purchase of the Sherco 3 steam turbine generator states that unit must be designed for 200 start/stop cycles per year and that it must operate with unlimited load cycling. A Black and Veatch report written in 1977 (NSP-12-22-77 Rev 1, page 16, paragraph (b), states "The General Electric turbine generator, as currently proposed, is designed to allow variable pressure operation. Pressure can be controlled by varying steam generator drum pressure or by throttling between the primary and secondary superheaters of the steam generator. The steam will be reheated by the secondary superheater so that it enters the turbine at higher temperature and higher enthalpy than for low load operation at full-load throttle pressure. This is a very important feature because it permits the inlet steam temperature to be matched to the turbine metal temperature. Hence thermal differentials and consequent stresses are minimized."

The report goes on to state, "General Electric has developed a detailed set of starting and loading instructions (GEK-46386) for manual turbine start-up which will control the magnitude of the thermal cycles imposed on turbine components. These instructions, in general, contain recommended temperature ramp rates, acceleration rates, temperature soak periods at different speeds, and amount of time of initial loads. The instructions have been established based upon field experience, judgment, laboratory tests, and analytical studies."

There have been no design, reliability, or maintenance issues associated with start/stop and load cycling to which Sherco 3 has been subjected to since it was commissioned in 1987. Although, Sherco may have increased the number of load cycles and start/stop cycles during various time periods for Sherco 3, the fact is that this has not been in excess of the design specification for the steam turbine generator.

16. Budget Constraints – Mr. Schultz states in the last paragraph of this section of his report that it is not likely that anyone would challenge the budget to perform a simple bucket "lift check" during the outage. He does not understand (or chooses to ignore) the fact that the 2005 outage was "rotors out" and that there was no reason to perform TIL 1121-3AR1 because it had been done only 6 years before

(XCEL_Sherco_07_0166486, item 4). There were no plans to do an LP outage in 2011 and certainly not to do a TIL 1121 inspection because there were no indications of SCC and none of the abnormal events listed in TIL 1121 had been observed by Sherco staff or noted in the System Health Reports for the LP turbines. GE never issued a TIL such as TIL 1886 triggering a TIL 1121-3AR1 inspection in the absence of any abnormal events for drum boiler plants (specifically for Sherco 3) and which also included a time based measurement interval until October 2013 – nearly 2 years after the failure. It is also noted that the bucket lift check is not identified in any GE documents; however, it is included in EPRI guidelines but only for tangentially loaded buckets, not for the L-1 wheel finger dovetail buckets design in the Sherco 3 LP turbines.

17. Industry Practices and Recommendations – GE recommends monitoring reheat steam chemistry. This has been addressed and refuted in David Daniels's expert report. Also addressed and refuted in the same report was the impact of the change from AVT to OT.

18. OEM Support and Recommendations – Mr. Schultz states that NSP elected to not have a GE field engineer on site for the LP turbine rotor work from 1999 to 2011. He also states that Sherco transitioned from using GE engineers to utilizing in-house engineers and non-GE vendors for direction and managing the outages starting in 1999. The true facts are that NSP was in frequent contact with GE for bid requests and technical issues, but GE was not price competitive for most of NSP's bid solicitations. NSP found they were not getting significant value from GE, even with GE technical advisors considered better than most by GE. NSP and GE even agreed in 2005 to a fleet wide services agreement (MRO) for maintenance, repair and overhaul work which would be competitively bid. This agreement included technical services and parts for NSP's steam turbine-generators. From 2005 to 2008, GE was requested to bid various work under the MRO. GE proved to be consistently uncompetitive for most of this work and removed themselves from the MRO in 2008. GE did receive purchase orders from NSP for parts during this period. Mr. Schultz also concludes that Xcel, by adding 30 steam turbine generators to the corporate oversight, made it difficult to devote time and skill to support plant maintenance. NSP and Sherco's engineers stated during my plant interview, that the additional 30 steam turbines continued to be maintained by the existing engineers at these plants absorbed by Xcel. For example, Tim Murray maintained, and still maintains, an office at Sherco even after the additional 30 units were incorporated into Xcel's fleet. Mark Kolb maintained his assigned responsibility for the Sherco turbines and actually benefited for these additional engineers now in the XCEL fleet with the ability to share information, when necessary, with his new counterparts at these plants.

19. Environment Factors – Mr. Schultz states that NSP abandoned any plans to spend large amounts of capital dollars at Sherco because of environmental law changes and future requirements to increase the amount of power generation from renewable sources such as wind, solar and hydro. This is not supported by the facts. NSP continued to invest in Sherco with upgrades of the steam paths in the HP and IP turbines. The LP's were considered for similar upgrades; however, since Sherco 3 was commissioned in 1987, the unit had only operated for 24 years by 2011, the age did not justify replacement in 2011. NSP currently has plans to replace the LP turbines in 2026.

20. Mr. Schultz, in Section C. Opinions states that the direct cause of the Sherco 3 L-1 failure in November 2011 is loss of control of steam cycle chemistry. This opinion is not supported by the facts as

discussed and refuted in David Daniels's expert report and also in his rebuttal to the Expert Opinion of William Allmon dated March 25, 2016.

21. Mr. Schultz, in Section C. Opinions states that the L-1 finger style attachment has an approximate 50% over speed capability of a non-damaged finger pin attachment. This opinion is not supported by the facts, as discussed and refuted in Karen Fuentes's expert report and her rebuttal dated March 15, 2016 to Veryst Engineering Report.

22. Mr. Schultz, in Section C. Opinions states that Human Performance was a factor in the eventual damage that occurred on Sherco Unit 3 in 2011. He also states that NSP's System Health Reports for the Sherco 3 LP's should have been coded yellow or red rather than green due to the risk of extending the outage period by 3 years in 2011, without conducting an engineering study. My discussions with NSP's technical staff responsible for the turbine-generators confirmed that the Sherco steam turbines were frequently discussed during daily staff meetings. These daily meetings were conducted at the plant to discuss all aspects of the operation, a completely normal process in the industry. The System Health Reports for Sherco 3 LP's were coded GREEN because those responsible for risk evaluation and reliability of the turbine-generators considered the risk of extending the outage by 3 years to be low.

23. Mr. Schultz, in Section C. Opinions states that NSP's operating and maintenance practices were contributing factors to the November 19, 2011 failure. He states that Sherco did not discuss the impact of TIL 1121-3AR1 in outage planning in 2005 and 2011. What he does not acknowledge is that NSP engineers, as well as engineers I contacted from other utilities, would not consider Sherco 3's operating history as high risk. The unit had not been subjected to any of the abnormal events listed in TIL 1121 3AR1. Issues such as condenser leaks, feedwater heater leaks, and steam path contamination involving chemistry excursions which deviate from pure water and steam, and which Mr. Schultz and GE consider abnormal are far from the realities of operating a 900 MW power generation facility. Condenser and feedwater heater leaks are common in all power generation facilities and are addressed by the operating staff by taking the affected system out of service, or as a minimum, isolating part of the system from the steam cycle. Steam and water chemistry issues are addressed by David Daniels in his expert reports including his rebuttal. He concludes that there were no operational events which would be considered abnormal and which would have led to the 2011 failure. By way of example, exposure of the steam path to carryover incidents such as with Sherco 1 in 1976 led to deposits in the steam path which reduced load capacity of the unit. There has not been any such occurrence with Sherco 3. It was noted in the Thielsch root-cause report that the steam path was clean and free of deposits and excessive pitting.

Draft Rev. B 3-29-12

Sherco 3 Low Pressure Turbine Operation and Inspection History

1979 GE Steam Purity Recommendations Issued
General Electric (GE) GEK 72281 issued defining recommendations for steam purity limits and monitoring.

1987 Commercial Operation.
Unit was started up using an all volatile boiler water treatment (AVT)? Only main steam purity monitored for cation conductivity?

1989 Warranty Inspection.
Rotors out, blast cleaned, standard non-destructive examination (NDE) performed, periphery magnetic particle testing (MT). No indications. Ultrasonic testing (UT) performed on 2nd to last (L-1) and last stage (L-0) dovetail pins. None cracked. Loose L-1 blade tie wires, re-soldered by GE.

1992 TIL 1121 Issued.
GE issued this technical information letter (TIL) for inspection of rotor wheel finger dovetails. Bucket removal is required for this inspection however the TIL does not require bucket removal. GE indicates that these inspections are to be performed only if bucket removal is performed for another reason.

1993 Major Unit Inspection.
Rotors out, blast cleaned, standard NDE performed, periphery MT. No indications. UT performed on L-1 and L-0 dovetail pins. Several cracked L-0 pins replaced by GE. No L-1 pins cracked. Several LPA L-1 buckets and covers replaced by GE due to tenon failures.

1996 L-1 Blade Inspection.
Rotors out, no blast cleaning or NDE other than on blades removed for inspection. A group of 5 blades were removed by GE from each L-1 wheel for thorough inspection of tie wire holes and tenons for cracking.

1999 Major Unit Inspection.
Rotors out, blast cleaned, extensive rotor NDE performed by GE.
All L-1 blades on both rotors were replaced by GE with a new upgraded GE design 20.5" blades. All new dovetail pins. No modifications to wheel attachment, only blade airfoil changes. GE performed boresonic exams, head shot mag exams, and LP blade finger inspections on L-1 rows. Some of the GE NDE reports are not available at this time.
GE also performed phased array UT on L-2 and L-3 rows.

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1999 TIL 1277-2 Issued.
GE issued this TIL for inspection of LP rotor wheel dovetails on fossil fueled once through boilers. It was not issued to Xcel and technically does not apply to any Xcel units. This TIL requires removal of finger dovetail blades for inspection on a periodic basis.

2000 Oxygenated Boiler Water Treatment Started?
Boiler water treatment switched from AVT to oxygenated?

2004 Updated GE Steam Purity Recommendations Issued
GE issued revised steam purity limits and monitoring recommendations GEK 72281c. This GEK Includes a recommendation for monitoring reheat steam purity.

2005 Oxygenated Boiler Water Treatment Terminated?
Boiler water treatment switched back to AVT?

2005 Major Unit Inspection.
Rotors out, blast cleaned, standard NDE performed, periphery MT. No defects noted. MD&A sub Midwest Turbine performed NDE work. UT performed on L-0 pins, many found cracked and replaced. Does not appear that L-1 pins were UT tested. MD&A sub Wesdyne performed L-2 and L-3 wheel dovetail phased array UT.
Heavy L-1 and L-2 deposits noted. Deposit samples taken from LP row 17 (L-2) blading. Some sodium oxide was present in the L-2 row sample.

2008 EPR 5.736 Issued
Energy Supply Production Resources Guideline (EPR) Steam Turbine Rotor Wheel Inspections for stress corrosion cracking (SCC) was issued after Sherco L-1 wheel cracking event to provide inspection recommendations where OEM guidance was lacking.

2008 L-0 Visual
Visual inspections performed on L-0 blade rows only. No defects noted other than some cover fit-up issues from 2005 MD&A L-0 cover replacement work.

2011 L-0 Visual
Visual inspections performed by Alstom on L-0 blade rows only. LP rotors were scheduled for standard overhaul inspection in 2014.
Failure event occurred after start-up during overspeed trip testing.

2012 LP Rotor Repair
GE removed all L-1 and L-0 blading from both LP rotors. Mag testing of rotor wheel dovetails performed including TIL 1121 testing. Mag tests revealed substantial crack indications on all 4 L-1 rows and no indications on the L-0 rows.

References:

1. GE GEK 72281c
2. GE TIL 1121
3. GE TIL 1277
4. 2005 L-2 deposit sample analysis report
5. EPR 5.736
6. MD&A Midwest Turbine 2005 NDE Report

GE Power Generation Services

STEAM TURBINE INSPECTION REPORT

Major Inspection Outage

for

NORTHERN STATES POWER COMPANY
SHERBURNE COUNTY, Unit 3

Equipment Serial #: 170X819

Job Start Date: 2/28/99

Report Issued:

FSR#: 96MP0003

April 27, 1999

Prepared By:
Tom Perkins
Field Engineer

Approved By:
Mark Peterson
Engineering Manager

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HP
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LPA
LPB
GEN

JOB SUMMARY

Customer:	NORTHERN STATES POWER COMPANY		
Station:	SHERBURNE COUNTY		
Unit No.:	3		
Equipment Serial #:	170X819	Rating:	809643 KW
Turbine Type:	G3	Service Year:	1987
Eng. Responsibility:	LST		
Generator Code:	4G4W	Control System:	EHC Mk2
LSB Length:	33.5	Generator Cooling:	Hyd-H2O
Service Type:	Tech Direction		
Steam Conditions:			
Inlet Pressure:	2400 PSI	Inlet Temperature:	1000 Deg F
District Office:	PITTSBURGH (OHIO VALLEY)		
FSR#:	96MP0003		
Engineering Manager:	Mark Peterson		
Account Manager:	Jim Force		
RCT Manager:	Steve Johnson		
Field Engineer:	Tom Perkins		
Job Start Date:	2/28/99	Completion Date:	4/19/99
Job Type:	Major		
Work Scope:	[Y] Turbine [Y] Generator [Y] Valves [N] Auxiliary [N] Other:		

JOB SUMMARY

Sherco unit 3 was removed from service February 26, 1999, for a scheduled seven week complete internal inspection. All turbine sections, valves and lube oil pumps were disassembled and inspected. The generator stator and field were rewound by GE. (See Generator Specialist report.) The Alterrex was disassembled and inspected.

The outage was managed by NSP personnel, with mechanical disassembly and reassembly work performed by Lovegreen under NSP supervision.

The following was performed by GE: Boresonic inspection of all four turbine rotors and the generator field; replacement of the L-1 buckets; modification of the L-1 diaphragms; replacement of the last stage diaphragm spill strips and holders; Field Engineering Services on both 10 hour shifts through most of the outage.

The following was performed by MD&A: Steam path audit, including component condition repair recommendations; diaphragm and nozzle repairs; turbine component laser alignment.

Start-up vibration analysis and balance recommendations were done by CSSI.
Grit blasting and NDT were performed by customer contractors. On site machining repairs were performed by Continental Field Services. The valves were sent to Preferred for inspection and repair.

INSPECTION SUMMARY

Section Component	Location	Description	Action
Main Stop Valve			
Assembly	1,2,3	General Valve Inspection	Routine Valve Inspection Completed
Body		Stripped	Repaired
Body	1,2,3	Non-Destructive Test	No Indications Found
Gasket	Lwr Head,Upr Head		ASSOCIATED PARTS
Strainer Coarse	1,2,3	Preventive Maintenance	Replaced
Stud	Upr Head		ASSOCIATED PARTS
Control Valve			
Assembly		General Valve Inspection	Routine Valve Inspection Completed
Bearing - Rod End	Limit Switch		ASSOCIATED PARTS
Body	1-4	Fit	Machined
Bushing	4 X-head guide	Worn	Replaced
Bushing	Lwr Lever		ASSOCIATED PARTS
Bushing	Upr Lever		ASSOCIATED PARTS
Bushing	Upr Rod		ASSOCIATED PARTS
Chest		Non-Destructive Test	No Indications Found
Gasket	1 1/2 0150,...,...,.		ASSOCIATED PARTS
Gasket	Stand		ASSOCIATED PARTS
Linkage		Worn	Repaired
Pin	Crosshead		ASSOCIATED PARTS
Pin	Pushrod		ASSOCIATED PARTS
Pin	Rear Link		ASSOCIATED PARTS
Pin	Seat	Non-Destructive Test	No Indications Found
Push Rod	1-4	Misadjustment	Used As Is - Warrants Repair
Switch Arm	1-4	Worn	Used As Is - Warrants Repair
Tension Rod	1-4	Misadjustment	Used As Is - Warrants Repair

GE-NSP0027745

INSPECTION SUMMARY

Section Component	Location	Description	Action
<u>Combined Reheat Valve</u>			
Gasket	Lwr Head,Upr Head		ASSOCIATED PARTS
Seat	L,R	Out Of Round	Machined
Strainer Fine	L,R	Preventive Maintenance	Modified
<u>Combined Reheat Int Valve</u>			
Assembly		General Valve Inspection	Routine Valve Inspection Completed
Linkage		Worn	Repaired
<u>Combined Reheat Stop Valve</u>			
Assembly		General Valve Inspection	Routine Valve Inspection Completed
<u>Ventilator Valve</u>			
Disk		Preventive Maintenance	Replaced
Gasket	Outlet,Seat,Upr		ASSOCIATED PARTS
Nut	Disk		ASSOCIATED PARTS
Seat		Worn	Replaced
Stem			ASSOCIATED PARTS
<u>Equalizer Valve</u>			
Assembly		General Valve Inspection	Routine Valve Inspection Completed
Gasket			ASSOCIATED PARTS
<u>Nozzle Box</u>			
Partition		Erosion Spe	Weld Repaired
Ring - Seal	UH	Clearance	Replaced
<u>HP Outer Shell</u>			
Flange	Inlet	Dished	Machined

INSPECTION SUMMARY

Section Component	Location	Description	Action
Gasket	MSI		ASSOCIATED PARTS
Joint	N1,N2	Stripped	Repaired
Key	Center Gib	Cleaned And Inspected	Good Condition - No Visual Defects
Key	Running	Misadjustment	Repaired
Key	Thrust	Misadjustment	Realigned
Nut	MSI		ASSOCIATED PARTS
Ring - Seal	UH	Clearance	Replaced
<u>HP Inner Shell</u>			
Assembly		Blast Clean And NDT	No Indications Found
Fit	Diaphragm	Fretted	Stoned
<u>RHT Outer Shell</u>			
Fit	#1 Inner Shell	Fretted	Stoned
Key	Center Gib	Cleaned And Inspected	Good Condition - No Visual Defects
Key	Running	Misadjustment	Repaired
Key	UH Circ Gib	Clearance	Replaced
Nut	232,234		ASSOCIATED PARTS
Ring - Seal	Pre-warm	Worn	Replaced
Stud	232,234		ASSOCIATED PARTS
<u>RHT Inner Shell</u>			
Assembly		Blast Clean And NDT	No Indications Found
<u>HP Rotor</u>			
Assembly		Blast Clean And NDT	No Indications Found
Assembly		Runout	Balanced
Balance Weight	Shop Plane		ASSOCIATED PARTS
Body		Head Shot Mag	Inspection

INSPECTION SUMMARY

Section Component	Location	Description	Action
Bore		Non-Destructive Test	No Indications Found
Lockplate	A Cplg		ASSOCIATED PARTS
<u>RHT Rotor</u>			
Assembly		Blast Clean And NDT	No Indications Found
Assembly		Runout	Balanced
Balance Weight	Shop End Plane,...		ASSOCIATED PARTS
Body		Head Shot Mag	Inspection
Bore		Non-Destructive Test	No Indications Found
Lockplate	B Cplg		ASSOCIATED PARTS
<u>LP A Rotor</u>			
Assembly		Blast Clean And NDT	No Indications Found
Body		Head Shot Mag	Inspection
Bore		Non-Destructive Test	No Indications Found
Coupling Spacer	B Cplg	Misadjustment	Used As Is - Warrants Replacement
Lockplate	C Cplg		ASSOCIATED PARTS
<u>LP B Rotor</u>			
Assembly		Blast Clean And NDT	No Indications Found
Body		Head Shot Mag	Inspection
Bore		Non-Destructive Test	No Indications Found
Lockplate	D Cplg		ASSOCIATED PARTS
<u>HP Buckets</u>			
Notch Bucket	1T,1G	Lifting	Used As Is - Monitor Condition
<u>RHT Buckets</u>			
Assembly	8G,8T	Erosion Spe	Used As Is - Warrants Replacement

INSPECTION SUMMARY

Section Component	Location	Description	Action
Cover		Deposits	Cleaned
Cover	8G,8T		ASSOCIATED PARTS
<u>LP A Buckets</u>			
Assembly	18GA,18TA	Preventive Maintenance	Replaced
Cover	19GA,19TA	Erosion Water	Used As Is - Warrants Replacement
Pin	19GA,19TA	Cracked	Replaced
<u>LP B Buckets</u>			
Assembly	18GB,18TB	Preventive Maintenance	Replaced
Cover	19GB,19TB	Erosion Water	Used As Is - Warrants Replacement
Pin	19GB,19TB	Cracked	Replaced
<u>HP Diaphragm</u>			
Assembly		Misalignment	Realigned
Assembly	3-7	Blast Clean And NDT	No Indications Found
Partition	2	Erosion Spe	Weld Repaired
Spill Strip	2-7	Worn	Used As Is - Monitor Condition
<u>RHT Diaphragm</u>			
Assembly		Dished	Used As Is - Warrants Repair
Assembly		Misalignment	Realigned
Assembly	9-13, T&G	Blast Clean And NDT	No Indications Found
Horizontal Joint	8	Stripped	Repaired
Horizontal Joint	9T	Stripped	Repaired
Partition	8T,8G	Erosion Spe	Weld Repaired
Spill Strip	8G Inlet,8T Inlet		ASSOCIATED PARTS
<u>LP Diaphragm</u>			

INSPECTION SUMMARY

Section Component	Location	Description	Action
Assembly		Misalignment	Realigned
LP A Diaphragm			
Assembly		Blast Clean And NDT	No Indications Found
Holder - Spill Strip	19GA,19TA	Erosion Water	Replaced
Ring	18GA,18TA	Modification	Replaced
Spill Strip	14GA		ASSOCIATED PARTS
Spill Strip	14TA		ASSOCIATED PARTS
Spill Strip	15TA		ASSOCIATED PARTS
Spill Strip	16GA		ASSOCIATED PARTS
Spill Strip	16TA		ASSOCIATED PARTS
Spill Strip	17GA		ASSOCIATED PARTS
Spill Strip	17TA		ASSOCIATED PARTS
Spill Strip	19GA,19TA		ASSOCIATED PARTS
LP B Diaphragm			
Assembly		Blast Clean And NDT	No Indications Found
Holder - Spill Strip	19GB,19TB	Erosion Water	Replaced
Ring	18GB,18TB	Modification	Replaced
Spill Strip	14TB		ASSOCIATED PARTS
Spill Strip	15GB		ASSOCIATED PARTS
Spill Strip	16GB		ASSOCIATED PARTS
Spill Strip	16TB		ASSOCIATED PARTS
Spill Strip	17GB		ASSOCIATED PARTS
Spill Strip	17TB		ASSOCIATED PARTS
Spill Strip	19GB,19TB		ASSOCIATED PARTS
Crossover			
Gasket	1,2,4,5,6		ASSOCIATED PARTS

INSPECTION SUMMARY

Section Component	Location	Description	Action
Gasket	3		ASSOCIATED PARTS
Gasket	4,6		ASSOCIATED PARTS
LP Hood			
Key	Circular Gib		ASSOCIATED PARTS
LP A Hood			
Key	Circular Gib	Clearance	Used As Is - Warrants Repair
LP B Hood			
Key	Circular Gib	Clearance	Weld Repaired
LP B Inner Casing			
Casing		Cracked	Weld Repaired
Horizontal Joint		Stripped	Repaired
Shaft Packing			
Ring	N1 G1	Damaged	Replaced
Ring	N1 G4-G7	Rubbed	Reconditioned
Ring	N2 G1-G4, G6,G7	Rubbed	Reconditioned
Ring	N3,N4	Preventive Maintenance	Replaced
Ring	N5,N6,N7,N8	Cleaned And Inspected	Good Condition - No Visual Defects
HP Diaphragm Packing			
Ring	2-7	Rubbed	Reconditioned
RHT Diaphragm Packing			
Ring	8-13, T&G	Preventive Maintenance	Replaced

INSPECTION SUMMARY

Section Component	Location	Description	Action
LP A Diaphragm Packing			
Ring	15GA,15TA,16GA,16TA,	Worn	Replaced
LP B Diaphragm Packing			
Ring	15GB,15TB,16TB,17GB,	Worn	Replaced
Packing Casing			
Nut	N1		ASSOCIATED PARTS
Thrust Bearing			
Ball		Sticking	Polished
Dowel	Casing	Loose	Used As Is - Warrants Repair
Pin	TE	Bent	Replaced
Ring - Seal		Worn	Replaced
Thrust Housing		Surface Finish	Polished
Thrust Plates		General Thrust Brg Inspection	Routine Inspection Completed
Thrust Bearing Wear Detector			
Assembly		Disassembled And Inspected	Good Condition - No Visual Defects
Turbine Journal Bearing			
Babbitt	T5,T7,T8	Wiped	Rebabbitt
Babbitt	T6	General Bearing Inspection	Routine Bearing Inspection Completed
Bearing Ring	T1 - T8	Contact Poor	Scraped
Bore	T7	Mis-machined	Rebabbitt
Bushing	T4		ASSOCIATED PARTS
Fit - Ball Seat	T5 - T8	Contact Poor	Scraped
Lock Pin	T4	Fretted	Replaced
Pad	T1	Assembled Improperly	Replaced

INSPECTION SUMMARY

Section Component	Location	Description	Action
Pad	T2	Worn	Replaced
Pad	T3,T4	General Bearing Inspection	Routine Bearing Inspection Completed
Support Pad	T4	Contact Poor	Scraped
Generator Journal Bearing			
Babbitt	T9,T10	Wiped	Rebabbitt
Bearing Ring	T9	Misadjustment	Repaired
Insulation	Inr,Out	Misadjustment	Repaired
Insulation	Inr,Out		ASSOCIATED PARTS
Exciter Journal Bearing			
Babbitt	T11,T12	Clearance	Rebabbitt
Steady Bearing			
Assembly		Steady Bearing Force Check	Required Force Within Guidelines
Oil Deflector			
Assembly		Preventive Maintenance	Reconditioned
Assembly	T10 Inner	Improperly Installed	Repaired
Assembly	T11 Inner,T11 Outer,	Clearance	Used As Is - Warrants Replacement
Emer Brg Oil Pump			
Assembly		Cleaned And Inspected	Good Condition - No Visual Defects
Bearing	Upper		ASSOCIATED PARTS
Motor Suction Pump			
Assembly		Cleaned And Inspected	Good Condition - No Visual Defects
Bearing	Upper		ASSOCIATED PARTS
Seal	Lower,Upper		ASSOCIATED PARTS

INSPECTION SUMMARY

Section Component	Location	Description	Action
Main Oil Pump			
Assembly		Cleaned And Inspected	Good Condition - No Visual Defects
Turning Gear Oil Pump			
Bearing	Upper		ASSOCIATED PARTS
Bushing	Lower	Clearance	Replaced
Seal	Lower,Upper		ASSOCIATED PARTS
Booster Pump			
Assembly		Cleaned And Inspected	Good Condition - No Visual Defects
Shaft		Preventive Maintenance	Used As Is - Warrants Replacement
Turning Gear			
Assembly		Preventive Maintenance	Repaired
Stop	Engagement	Damaged	Repaired
Low Speed Switch			
Assembly		Disassembled And Inspected	Good Condition - No Visual Defects
Standard			
Assembly	Turning Gear	Loose	Tightened
Fit	T4	Pitted	Used As Is - Warrants Repair
PMG			
Assembly		Cleaned And Inspected	Good Condition - No Visual Defects
Trip System			
Insert	Trip Finger		ASSOCIATED PARTS

INSPECTION SUMMARY

Section Component	Location	Description	Action
Latch		Worn	Used As Is - Warrants Repair
Nut	Trip Finger		ASSOCIATED PARTS
Pin	Stem		ASSOCIATED PARTS
Pin - Cotter	Trip Finger		ASSOCIATED PARTS
Shim	Trip Finger		ASSOCIATED PARTS
Trip Finger		Worn	Used As Is - Warrants Repair
Relay Dump Valve			
Assembly		Cleaned And Inspected	Good Condition - No Visual Defects
Seal			ASSOCIATED PARTS
End Shield			
Hydrogen Seal Casing	TE	Clearance	Scraped
Joint	TE,CE	Damaged	Stoned
Ring - Hydrogen Seal		Clearance	Rebabbitt
Cooler			
Assembly	H2	Preventive Maintenance	Replaced
Stator			
Assembly		Generator Air Leakage Test	Results Acceptable
Gas Gap Baffle		Modification	Modified
Oil Deflector	TE Seal Csg		ASSOCIATED PARTS
Winding		Damaged	Rewound
Body			
Body		Head Shot Mag	Inspection
Bore		Non-Destructive Test	No Indications Found

INSPECTION SUMMARY

Section Component	Location	Description	Action
Field			
Assembly		Misadjustment	Used As Is - Warrants Repair
Insulation		Preventive Maintenance	Rewound
Exciter Stator			
Coolers		Preventive Maintenance	Replaced
Exciter Rotor			
Assembly		Disassembled And Inspected	Good Condition - No Visual Defects
Assembly		Runout Check	Good Condition - Runout Acceptable

RECOMMENDATIONS

1. Valve, Control [Sep Chest]; Push Rod; 1-4

The control valve pushrods should be fully disassembled next inspection so adjustments can be made at assembly.

2. Shell, HP Inner; Fit; Diaphragm

Fretted HP inner shell to diaphragm fits should be repaired next inspection.

3. Rotor, RHT; Assembly;

Factory/shop plane balance weights should be stocked for the next internal inspection.

4. Buckets, HP; Notch Bucket; 1T,1G

Notch bucket lifting should be monitored next inspection.

5. Buckets, LP B; Cover; 19GB,19TB

Plans should be made to replace the last stage bucket covers next inspection.

6. Trip System [EHC]; Trip Finger;

A new trip finger insert, shim, nut and pin should be ordered for the next inspection.

7. Valve, Control [Sep Chest]; Linkage;

Plans should be made to repair worn pin holes in linkage clevises next inspection.

RECOMMENDATIONS

8. Valve, Control [Sep Chest]; Switch Arm; 1-4

The actuator limit switch arms should be repaired or replaced next inspection.

9. Valve, Control [Sep Chest]; Tension Rod; 1-4

Control valve tension rods should be fully disassembled next inspection in order to adjust rod lengths at assembly.

10. Shell, HP Outer; Key; Thrust

HP rotor axial clearances should be analyzed at disassembly next inspection to determine if any corrections should be made. NOTE: It is necessary to have the midstandard cover in place to determine axial position of the thrust bearing since the locating fit has buttons for load cells.

11. Shell, RHT Outer; Fit; #1 Inner Shell

Fretted/eroded reheat inner to outer shell fits should be repaired next outage.

12. Rotor, HP; Assembly;

Factory/shop plane balance weights should be stocked for the next internal inspection.

13. Rotor, LP A; Coupling Spacer; B Cplg

A new B coupling (reheat to LP A) spacer with extra thickness should be ordered for the next inspection to restore the axial position of both LP rotors. The standard new spacer thickness is 1.625. The new spacer ordered should be at least 1.750 thick.

RECOMMENDATIONS

14. Buckets, RHT; Assembly; 8G,8T

The covers and/or buckets should be replaced next inspection. There is an increasing risk of cover failure beyond a normal 6 year run.

15. Buckets, LP A; Cover; 19GA,19TA

Plans should be made to replace the last stage bucket covers next inspection.

16. Diaphragm, RHT; Assembly;

Modifications should be performed next inspection to restore axial clearances. These may include a combination of rotor machining, diaphragm repositioning or modification, and diaphragm replacement. An engineering study should be performed prior to the next outage.

17. Hood, LP A; Key; Circular Gib

The upper LP A circular gib keys should be replaced next inspection.

18. Hood, LP B; Key; Circular Gib

The upper LP B circular gib keys should be replaced next inspection.

19. Bearing, Thrust; Dowel; Casing

The thrust ball dowels and holes should be inspected and repaired as necessary next inspection.

20. Bearing, Thrust; Thrust Housing;

The thrust ball seal ring sliding surfaces should be remachined next inspection if the rings show wear.

RECOMMENDATIONS

21. Bearing, Generator Journal; Insulation; Inr,Out

New inner and outer bearing ring insulating kits should be ordered for the next inspection. These kits will include the shims and retaining spacers.

22. Oil Deflector; Assembly; T11 Inner,T11 Outer,

New Alterrex oil deflectors should be ordered for the next inspection.

23. Pump, Booster; Shaft;

A new shaft should be ordered for the next inspection.

24. Standard; Fit; T4

The bearing support bore should be repaired next inspection. The support pads should be remachined to match.

25. Trip System [EHC]; Latch;

The incorrectly machined trip latch stem should be returned for replacement. The stem and finger should be replaced next inspection.

26. End Shield; Hydrogen Seal Casing; TE

A new turbine end bolt on oil deflector should be ordered for the next generator inspection.

27. Field; Assembly;

Axial clearances should be checked against the field clearance drawing at disassembly next inspection, to ensure there are no problems increasing the B coupling spacer thickness.

PARTS USED AND RECOMMENDED

Item	PU	RI	RO	QTY	UM	Parts Description	Cust Stk #	Catalog #	Drawing #
1	X			3	Each	Main Stop Valve,Gasket,Lwr Head		8029	U336W075D1050
2	X			3	Each	Main Stop Valve,Gasket,Upr Head		8051	303A5841P0132
3	X			3	Kit	Main Stop Valve,Strainer Coarse,1,2,3		8044	0993D812G0002
4	X			1	Each	Main Stop Valve,Stud,Upr Head		8053	U606P321L2387
5	X			4	Each	Control Valve,Bearing - Rod End,Limit Switch		729JA58	
6	X			1	Each	Control Valve,Bushing,4 X-head guide		720J	222A2928P0101
7	X			4	Each	Control Valve,Bushing,Lwr Lever		7264	It 85
8	X			8	Each	Control Valve,Bushing,Upr Lever		7274	It 84
9	X			8	Each	Control Valve,Bushing,Upr Rod		7274	It 312
10	X			8	Each	Control Valve,Gasket,1 1/2 0150		302120	U160X000P0357
11	X			1	Each	Control Valve,Gasket,1 1/2 1500		302135	U160X000P0577
12	X			8	Each	Control Valve,Gasket,1/2 1500		3021122	U160X000P0573
13	X			1	Each	Control Valve,Gasket,3 0150		302197	U160X000P0360
14	X			4	Each	Control Valve,Gasket,Stand		7235	303A5842P0126
15	X			1	Each	Control Valve,Pin,Crosshead		7200	It 86
16	X			1	Each	Control Valve,Pin,Pushrod		7200	It 301
17	X			1	Each	Control Valve,Pin,Rear Link		721Y	It 59
18			X	4	Each	Control Valve,Switch Arm,1-4		729JA06	
19	X			2	Each	Combined Reheat Valve,Gasket,Lwr Head		6921	U336W125D1950
20	X			2	Each	Combined Reheat Valve,Gasket,Upr Head		6962	303A5842P0134
21	X			2	Kit	Combined Reheat Valve,Strainer Fine,L,R		6943	117D7090G0002
22	X			1	Each	Ventilator Valve,Disk,			Non-GE
23	X			1	Each	Ventilator Valve,Gasket,Outlet		9203	303A5841P0038
24	X			1	Each	Ventilator Valve,Gasket,Seat		9202	303A5839P0007
25	X			1	Each	Ventilator Valve,Gasket,Upr		9201	303A5839P0022
26	X			1	Each	Ventilator Valve,Nut,Disk		9200	Non-GE
27	X			1	Each	Ventilator Valve,Seat,		9200	
28	X			1	Each	Ventilator Valve,Stem,		9200	Non-GE
29	X			1	Each	Equalizer Valve,Gasket,		7002	303A5841P0008
30	X			2	Sets	Nozzle Box,Ring - Seal,UH		1600	Non-GE

PU=Part Used During the Inspection RI=Part Recommended for Immediate Restock RO=Part Recommended for the Next Inspection

PARTS USED AND RECOMMENDED

Item	PU	RI	RO	QTY	UM	Parts Description	Cust Stk #	Catalog #	Drawing #
31	X			2	Each	HP Outer Shell,Gasket,MSI		5266	303A5841P0066
32	X			8	Each	HP Outer Shell,Nut,MSI		5269	U615X000P0218
33	X			2	Sets	HP Outer Shell,Ring - Seal,UH		5200	Non-GE
34	X			3	Each	RHT Outer Shell,Key,UH Circ Gib		5800	111B8945P0002
35	X			2	Each	RHT Outer Shell,Nut,232,234		5825	U615X000P0224
36	X			1	Set	RHT Outer Shell,Ring - Seal,Pre-warm		5800	
37	X			2	Each	RHT Outer Shell,Stud,232,234		582S	U605P324L5137
38			X	20	Each	HP Rotor,Balance Weight,Shop Plane			128Y303
39	X			14	Each	HP Rotor,Lockplate,A Cplg		0896	234A6376P0005
40			X	20	Each	RHT Rotor,Balance Weight,Shop End Plane			0879A775G0017
41			X	12	Each	RHT Rotor,Balance Weight,Shop Mispan			323B7410G0001
42	X			16	Each	RHT Rotor,Lockplate,B Cplg		0804	234A6376P0007
43			X	1	Each	LP A Rotor,Coupling Spacer,B Cplg		0800	Extra Thick
44	X			16	Each	LP A Rotor,Lockplate,C Cplg		0856	234A6376P0008
45	X			16	Each	LP B Rotor,Lockplate,D Cplg		0866	234A6376P0009
46			X	1	Set	RHT Buckets,Assembly,8G		070F	000E0000P0000
47			X	1	Set	RHT Buckets,Assembly,8T		070D	000E0000P0000
48			X	1	Set	RHT Buckets,Cover,8G		070G	000B0000P0000
49			X	1	Set	RHT Buckets,Cover,8T		070E	000B0000P0000
50	X			1	Set	LP A Buckets,Assembly,18GA		0700	
51	X			1	Set	LP A Buckets,Assembly,18TA		0700	
52			X	1	Set	LP A Buckets,Cover,19GA		0717	000B0000P0000
53			X	1	Set	LP A Buckets,Cover,19TA		0715	000B0000P0000
54	X			33	Each	LP A Buckets,Pin,19TA		0700	
55	X			1	Set	LP A Buckets,Pin,8-13, T&G		2400	Non-GE
56	X			1	Set	LP B Buckets,Assembly,18GB		0700	
57	X			1	Set	LP B Buckets,Assembly,18TB		0700	
58			X	1	Set	LP B Buckets,Cover,19GB		071D	000B0000P0000
59			X	1	Set	LP B Buckets,Cover,19TB		071B	000B0000P0000
60	X			55	Each	LP B Buckets,Pin,19GB		0700	

PU=Part Used During the Inspection RI=Part Recommended for Immediate Restock RO=Part Recommended for the Next Inspection

PARTS USED AND RECOMMENDED

Item	PU	RI	RO	QTY	UM	Parts Description	Cust Stk #	Catalog #	Drawing #
61	X			1	Each	LP B Buckets,Pin,19TB		0700	
62	X			24	Each	RHT Diaphragm,Spill Strip,8G Inlet		603B4	294A5401P0001
63	X			24	Each	RHT Diaphragm,Spill Strip,8T Inlet		602B1	294A5401P0001
64	X			1	Set	LP A Diaphragm,Holder - Spill Strip,19GA		0900	
65	X			1	Set	LP A Diaphragm,Holder - Spill Strip,19TA		0900	
66	X			26	Each	LP A Diaphragm,Ring,18GA		605B6	New Mod
67	X			26	Each	LP A Diaphragm,Ring,18TA		605B	New Mod
68	X			30	Each	LP A Diaphragm,Spill Strip,14GA		605B6	U699R070B0650
69	X			30	Each	LP A Diaphragm,Spill Strip,14TA		605B	U699P070B0650
70	X			32	Each	LP A Diaphragm,Spill Strip,15TA		605B	U699R069B0680
71	X			34	Each	LP A Diaphragm,Spill Strip,16GA		605B6	U699K070B0725
72	X			34	Each	LP A Diaphragm,Spill Strip,16TA		605B	U699H070B0725
73	X			20	Each	LP A Diaphragm,Spill Strip,17GA		605B6	U699J132B0820
74	X			20	Each	LP A Diaphragm,Spill Strip,17TA		605B	U699H132B0820
75	X			56	Each	LP A Diaphragm,Spill Strip,19GA		605B6	155B1130P0001
76	X			56	Each	LP A Diaphragm,Spill Strip,19TA		605B	155B1130P0001
77	X			1	Set	LP B Diaphragm,Holder - Spill Strip,19GB		0900	
78	X			1	Set	LP B Diaphragm,Holder - Spill Strip,19TB		0900	
79	X			26	Each	LP B Diaphragm,Ring,18GB		604B	U699M122B0990
80	X			26	Each	LP B Diaphragm,Ring,18TB		604B1	New Mod
81	X			30	Each	LP B Diaphragm,Spill Strip,14TB		604B1	U699V070B0650
82	X			32	Each	LP B Diaphragm,Spill Strip,15GB		604B	U699V069B0680
83	X			34	Each	LP B Diaphragm,Spill Strip,16GB		604B	U699M070B0725
84	X			34	Each	LP B Diaphragm,Spill Strip,16TB		604B1	U699L070B0725
85	X			20	Each	LP B Diaphragm,Spill Strip,17GB		604B	U699M132B0820
86	X			20	Each	LP B Diaphragm,Spill Strip,17TB		604B1	U699L132B0820
87	X			56	Each	LP B Diaphragm,Spill Strip,19GB		604B	155B1130P0001
88	X			56	Each	LP B Diaphragm,Spill Strip,19TB		604B1	155B1130P0001
89	X			5	Each	Crossover,Gasket,1,2,4,5,6		322234	341A2968P0060
90	X			1	Each	Crossover,Gasket,3		322246	341A2968P0092

PU=Part Used During the Inspection RI=Part Recommended for Immediate Restock RO=Part Recommended for the Next Inspection

GE-NSP00227763

TR.EX.NSP0061.024

GE Power Generation Services

PARTS USED AND RECOMMENDED

Item	PU	RI	RO	QTY	UM	Parts Description	Cust Stk #	Catalog #	Drawing #
91	X			2	Each	Crossover,Gasket,4,6		322236	341A2968P0064
92			X	4	Each	LP Hood,Key,Circular Gib		5700	0232A634P0001
93	X			1	Set	Shaft Packing,Ring,N1 G1		2611	U841B225L0668
94	X			1	Set	Shaft Packing,Ring,N3		2600	
95	X			1	Set	Shaft Packing,Ring,N4		2600	
96	X			1	Set	RHT Diaphragm Packing,Ring,8-13, T&G		2400	
97	X			1	Set	LP A Diaphragm Packing,Ring,15GA		2400	Non-GE
98	X			1	Set	LP A Diaphragm Packing,Ring,15TA		2400	Non-GE
99	X			1	Set	LP A Diaphragm Packing,Ring,16GA		2400	Non-GE
100	X			1	Set	LP A Diaphragm Packing,Ring,16TA		2400	Non-GE
101	X			1	Set	LP A Diaphragm Packing,Ring,17GA		2400	Non-GE
102	X			1	Set	LP A Diaphragm Packing,Ring,17TA		2400	Non-GE
103	X			1	Set	LP B Diaphragm Packing,Ring,15GB		2400	Non-GE
104	X			1	Set	LP B Diaphragm Packing,Ring,15TB		2400	Non-GE
105	X			1	Set	LP B Diaphragm Packing,Ring,16TB		2400	Non-GE
106	X			1	Set	LP B Diaphragm Packing,Ring,17GB		2400	Non-GE
107	X			1	Set	LP B Diaphragm Packing,Ring,17TB		2400	Non-GE
108	X			2	Each	Packing Casing,Nut,N1		5287	U614X000P0212
109	X			1	Each	Thrust Bearing,Pin,TE		0601A25	182A8449P0008
110	X			2	Each	Thrust Bearing,Ring - Seal,		0619	U820G006K0100
111	X			2	Each	Turbine Journal Bearing,Bushing,T4		062FA21	182A4939P0008
112	X			2	Each	Turbine Journal Bearing,Lock Pin,T4		062D	U727P003L0550
113	X			1	Set	Turbine Journal Bearing,Pad,T1		0622	169C2596G0006
114	X			1	Set	Turbine Journal Bearing,Pad,T2		0622	169C2588G0003
115			X	1	Kit	Generator Journal Bearing,Insulation,Inr		950VA25	
116	X			1	Each	Generator Journal Bearing,Insulation,Inr		9500	Non-GE
117	X			1	Each	Generator Journal Bearing,Insulation,Out		9500	Non-GE
118			X	1	Kit	Generator Journal Bearing,Insulation,Out		950TA75	
119			X	1	Set	Oil Deflector,Assembly,T11 Inner		2200	
120			X	1	Set	Oil Deflector,Assembly,T11 Outer		2200	

PU=Part Used During the Inspection RI=Part Recommended for Immediate Restock RO=Part Recommended for the Next Inspection

GE-NSP0027764

PARTS USED AND RECOMMENDED

Item	PU	RI	RO	QTY	UM	Parts Description	Cust Stk #	Catalog #	Drawing #
121			X	1	Set	Oil Deflector,Assembly,T12 Inner		2200	
122			X	1	Set	Oil Deflector,Assembly,T12 Outer		2200	
123	X			1	Each	Emer Brg Oil Pump,Bearing,Upper			MRC5411C
124	X			1	Each	Motor Suction Pump,Bearing,Upper			BCA5312W
125	X			1	Each	Motor Suction Pump,Seal,Lower			#416664
126	X			1	Each	Motor Suction Pump,Seal,Upper			#471341
127	X			1	Each	Turning Gear Oil Pump,Bearing,Upper			BCA5312W
128	X			1	Each	Turning Gear Oil Pump,Bushing,Lower		4020	
129	X			1	Each	Turning Gear Oil Pump,Seal,Lower			#416664
130	X			1	Each	Turning Gear Oil Pump,Seal,Upper			#471341
131			X	1	Each	Booster Pump,Shaft,		412E	
132			X	1	Each	Trip System,Insert,Trip Finger		1718B2G	
133			X	1	Each	Trip System,Nut,Trip Finger		1718B2J	
134			X	1	Each	Trip System,Pin,Stem		1718B1V	U408A206L0275
135			X	1	Each	Trip System,Pin - Cotter,Trip Finger		1718B2K	
136			X	1	Each	Trip System,Shim,Trip Finger		1718B2H	
137	X			1	Kit	Relay Dump Valve,Seal,			0892E851G0002
138	X			2	Ass'y	Cooler,Assembly,H2		9700	
139			X	1	Ass'y	Stator,Oil Deflector,TE Seal Csg		978FA06	
140	X			2	Ass'y	Exciter Stator,Coolers,			

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MAIN STOP VALVES

Main Stop Valve

Assembly: 1,2,3

The main stop valve subassemblies were sent to Preferred for inspection. The main seats were lapped and contact checked.

Main Stop Valve

Body:

Three upper head stud holes were in poor condition and were repaired by CFS with threaded inserts.

Main Stop Valve

Strainer Coarse: 1,2,3

The strainer screens were starting to dimple into the strainer holes. The coarse mesh was replaced. Spare strainers were installed with fine mesh at assembly.

Main Stop Valve

Body: 1,2,3

The internal surfaces of the main stop valve bodies were blast cleaned and NDT'd. No indications were found. Seat stellite was penetrant tested and no indications were found.

GE Energy Services

Rotor

INSPECTION REPORT

for

Northern States Power Company
Sherburne County #3
LPB Rotor

TRIAL EXHIBIT
0062
exhibitsticker.com

NSP, et al v GE
PLF EX 202
Date: 7-15-15
Richard G. Stirewalt
Stirewalt & Associates

GE-NSP00228052

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Engineering Evaluation

GE Energy Services

April 2, 1999

Global Inspection & Repair Services
General Electric International, Inc.

SUBJECT: IN-SERVICE TURBINE ROTOR INSPECTION

NORTHERN STATES POWER COMPANY
SHERBURNE COUNTY #3
TURBINE #170X819
LP-B ROTOR, SERIAL #3567V1

INSPECTION HISTORY AND COMPARISON OF RESULTS

This is the first in-service NDT inspection performed by GE Company on the subject rotor. A comparison of the original acceptance ultrasonic tests with the current tests shows the results to be within GE Company's repeatability limits and implies that no internal change has occurred in this rotor between tests.

CURRENT RECOMMENDATIONS

The recent evaluation of the structural integrity of this rotor included the original and the current NDT results, material properties, and the temperature and stress exposures. The evaluation also included an analysis of an assumed crack on the bore surface under each stage. The results of this evaluation were reviewed at a meeting on March 22, 1999. The resulting recommendations for this rotor are:

> Continue service in accordance with current GE Company prewarming, starting, and loading recommendations. The rotor should be completely reinspected after not more than ten (10) additional years of service. The primary purpose of the reinspection is to reduce the probability of a catastrophic failure by detecting the initiation or propagation of crack-like discontinuities near the bore and performing corrective action before critical conditions are reached. The probability of failure from other degradation such as periphery or dovetail cracking is also reduced by early detection and appropriate action. In addition, routine inspections provide periodic reevaluations of the rotor integrity with the latest techniques that may permit the identification of conditions not previously recognized.

NON-DESTRUCTIVE TESTS PERFORMED

The standard tests performed on this rotor during the recent inspection are listed below. A description of each of these tests is provided in the attached appendix.

- Bore visual examination
- Bore magnetic particle test
- Radial beam boresonic test
- Angle beam boresonic test
- Periphery ultrasonic test
- Axial ultrasonic test
- Rotor dovetail ultrasonic test
- Bucket to rotor gap measurements
- Periphery magnetic particle test

NORTHERN STATES POWER COMPANY
SHERBURNE COUNTY #3
TURBINE #170X819
LP-B ROTOR, SERIAL #3567V1

BORE SURFACE EXAMINATION

The bore surface of this rotor was prepared for testing by light honing immediately prior to the recent inspection. The visual inspection and subsequent magnetic particle test of the bore surface disclosed no indications.

RADIAL BEAM BORESONIC AND PERIPHERY ULTRASONIC TEST

The radial beam boresonic and the periphery ultrasonic tests revealed only one indication. The size and coordinates of this indication are provided on an attached tabulation. Graphic displays of the indication are provided on an attached layout that shows the location of the indication relative to the rotor geometry. The layout includes an axial-radial outline of the rotor with the indication plotted at its proper location. The circumferential location of the indication is displayed with an axial-circumferential view.

ANGLE BEAM BORESONIC TEST

The angle beam boresonic test performed on this rotor revealed no radial-axial type patterns of indications that fulfill the established crack-like criteria.

The purpose of the angle beam boresonic test is to identify radial-axial patterns of indications that could represent crack-like discontinuities near the bore of the rotor. The test operates at or near the acoustic and electronic noise thresholds of the inspection and consequently detects many reflectors that may include material structure as well as inclusions or real cracks. The indications detected are scanned by applying an algorithm that identifies radial-axial patterns and lists those with sufficient point density to qualify as a potential crack. In addition, a visual study of all the test data combined with experienced judgment is required to ensure the proper conclusions concerning the presence, nature, and overall size of any significant discontinuities.

AXIAL ULTRASONIC TEST

The straight beam axial ultrasonic test performed from the ends of the rotor revealed no indications.

ROTOR DOVETAIL ULTRASONIC TESTS

An ultrasonic test of the accessible wheel dovetail hooks was performed on stages L-2 and L-3 of both the turbine and generator ends of this rotor. Point source type indications, some of which were reported as levels, were detected in both L-2 stages. None of the indications showed evidence of continuity in the circumferential direction and there was no loss of the reference reflections. These indications did not warrant bucket removal for further investigation.

It should be noted that the dovetail test is a detection test only and does not size the indications. In addition, there have been cases where cracks existed in locations where no wheel dovetail ultrasonic indications were revealed. As a result, there may be conditions that were not revealed or evaluated that could limit the serviceability of the wheels.

NORTHERN STATES POWER COMPANY
SHERBURNE COUNTY #3
TURBINE #170X819
LP-B ROTOR, SERIAL #3567V1

BUCKET TO ROTOR GAP MEASUREMENTS

The gap between the bucket and wheel tangs was measured around the entire circumference on both the admission and discharge sides of stages L-2 and L-3 on both the turbine and generator ends of this rotor. A measurable gap was reported at the notch closure on all four of these stages. The maximum values ranged from 0.007" to 0.016". There were no measurable gaps at the regular buckets on any of the stages examined and further action due to the above reported values is not warranted at this time.

PERIPHERY MAGNETIC PARTICLE TEST

It has been reported that a magnetic particle test of the external surfaces of this rotor revealed no indications. This test was not performed by GE Life Extension Services.

ROTOR OUTLINE

A 1/5 scale outline of the rotor is provided with this report. The outline serves as a model for stress calculations and also shows the location of any reported bore surface and internal indications relative to the rotor geometry.

MATERIAL PROPERTIES

The material properties of this rotor are listed on an attached table. At the time of manufacture, the FATT measured from the transverse core samples was -60°F. An embrittlement of 65°F is estimated for the first stage region and 15°F for the second stage region of this rotor due to service conditions which raises the FATT of those portions to 5°F and -45°F respectively. No embrittlement is predicted for the remainder of the rotor.

NORTHERN STATES POWER COMPANY
SHERBURNE COUNTY #3
TURBINE #170X819
LP-B ROTOR, SERIAL #3567V1

The recommendations provided in this report represent our best judgment in light of the information available to us. In evaluating the above recommendations, the owner should recognize that there are many operating practices and conditions including, but not limited to, those mentioned above which affect continued satisfactory operation of which GE has no control. It is the owner's responsibility to determine whether or not the rotor should continue to be used in light of the information furnished above and his own operating practices and conditions. No warranty, either expressly or by implication, is being made in regards to these recommendations, and GE expressly disclaims any liability for any damages allegedly incurred as a result or consequence of their application whether it is claimed that these recommendations resulted from GE's negligence or that it is strictly responsible for the damages claimed to have been sustained. GE's responsibility in connection with furnishing this report is as set forth in the contract under which this report is furnished.

Prepared by

G. S. Bullock 4/2/99

G.S. Bullock, Senior Engineer
Life Extension Services
GE International Inc.
Schenectady, New York 12345

NORTHERN STATES POWER COMPANY
SHERBURNE COUNTY #3
TURBINE #170X819
LP-B ROTOR, SERIAL #3567V1

MATERIAL PROPERTIES

SIMILAR TO ASTM	A 470 Class 7	
TENSILE PROPERTIES		
Tensile Strength	128.8 - 135.3	ksi
0.02% Yield Strength	106.1 - 114.8	ksi
Elongation	18.0 - 22.0	%
Reduction of Area	61.0 - 70.0	%
IMPACT ENERGY		
Charpy V-notch @ R.T.	50 - 100 ft. lb.	

50% FRACTURE APPEARANCE TRANSITION TEMPERATURE (FATT)

*As Received	-60°F
*Embrittled	5°F

* See text for further description.

CRACK GROWTH

da/dn vs. ΔK see appendix

TOUGHNESS

K_{Ic} vs. T_e see appendix

Inspection Report

Tabulation and Plots of Test Results

Definitions for Turbine Rotors

The tables constitute a summary of the results of standard non-destructive tests which could be performed on any given rotor. The results of those tests which apply to the subject rotor are noted and comparisons to any previous test results are made. In general, the following comments apply to the test procedures and results.

- Generally, all tests conducted on or from the bore are performed after any necessary conditioning and cleaning to the bore.
- The bore visual examination is conducted prior to the bore magnetic particle and boresonic test, as well as before and after any local grinding.
- The bore magnetic particle test is conducted along the entire length of the bore for 360° circumferentially.
- The Field of View (F.O.V.) of the borescope used for the bore visual and magnetic particle tests is equal to approximately half of the bore diameter.
- Additional bore magnetic particle tests are conducted if grinding is performed on a representative area (or areas) of indications, as revealed by the above Bore Visual Examination or Bore Magnetic Particle Test. The variation on the number of indications in the F.O.V. and changes in their respective axial lengths are noted during grinding operations in each area. Generally, grinding is performed in 1/16 inch increments to a maximum depth of 1/4 inch.
- The Axial Ultrasonic Test is conducted from one or both end faces of the rotor.
- The DATAQ™ boresonic examination is performed by a computerized system comprised of a radial beam test and two or more angle beam tests.
- The Peripheral Ultrasonic Test (2.25 Mhz) is a radial test conducted from all accessible peripheral surfaces of the rotor.
- Radial locations are referenced from the bore surface or from the centerline of a solid rotor. Axial locations are referenced from the Generator End (GE) of the rotor. Circumferential locations are referenced from an identifiable mark on the rotor, such as the boresonic calibration hole.
- Cylindrical coordinates are used to describe the locations of ultrasonic indications. The accuracy of these measurements is defined as the maximum distance between the reported location of an indication and the actual location within reasonable confidence. The coordinates of an indication are, therefore, normally considered to be within repeatable limits between tests when the reported locations are within twice the accuracy. The accuracy of the three coordinates are as follows: Axial $\pm$ 1/4 inch; Radial $\pm$ 1/8 inch; Circumferential $\pm$ 10 minutes (5°).
- Equivalent Flat bottom Hole (EFBH) diameter is the diameter of a flat bottom hole, oriented normal to the ultrasonic beam, that would reflect the same amount of energy as the ultrasonic indication at its reported location. Actual indication sizes may be larger or smaller than calculated EFBH diameters.
- A level of indications consists of a large number of closely spaced indications, such that their individual sizes and spacing cannot be clearly determined.

- An area of indications is similar to a level but consists of fewer indications.
- A Holding Indication is an indication or group of indications for which the ultrasonic reflection implies a continuous extent greater than that of a point source.
- A Traveling Indication is an indication for which the ultrasonic reflection may imply an orientation other than normal to the ultrasonic beam.
- Tabulation of Test Results includes all indications revealed by radial beam boresonic, radial beam peripheral and angle beam boresonic tests.

3567V1

INDIVIDUAL ULTRASONIC INDICATIONS
(COMPOSITE OF BORE & PERIPHERY TEST RESULTS-03/21/99)

	---------LOCATION---------			EFBH	AXIAL
IND	AXIAL	RADIAL	ANGULAR	SIZE	HOLD
NO.	(IN)	(IN)	(DEG)	(IN)	(IN)
1	216.94	1.26	164	<.03	

Inspection Report

Appendix

Appendix

I. History of Rotor Inspection Program

The General Electric Company has long been a pioneer in the development of improved non-destructive testing equipment and procedures, particularly for application to rotating turbine and generator components.

The impetus for this effort has been the desire to enhance the reliability and availability of rotating components, the failure of which could prove catastrophic.

In the early 1950's, the peripheral ultrasonic test of turbine and generator rotors was introduced. This test, although crude when compared to today's practices, did permit a limited evaluation of rotors. The test undoubtedly prevented many, but not all, major failures during a time when rotor sizes, stresses and temperatures were increasing rapidly.

In recognition of the fact that the region near the bore of a rotor is highly stressed, and because it is also the region most likely to contain metallurgical imperfections, bore ultrasonic testing equipment was developed in the late 1950's to permit a more thorough evaluation of this critical region. Beginning in 1959, this testing procedure has regularly been applied to turbine and generator rotors. During the years since the peripheral and boresonic tests were introduced, continual improvements have been made in equipment, testing techniques and evaluation procedures.

GE has attempted to provide continuing surveillance of turbine and generator components during the entire life of a machine. Improved non-destructive testing procedures for evaluating in-service rotors have been introduced at various times as our experience and development work have indicated the need for this testing.

The first major large steam turbine in-service bore inspection program was initiated in 1968 by a recommendation that a class of CrMoV rotors shipped in the early 1950's be inspected. These were rotors heat treated to provide high rupture strength ("1850 F grade"). The heat treatment that produced the higher rupture strength also produced low long-time rupture ductility, lower than acceptable by current standards. Conventional, relatively short time parametric high temperature tests conducted prior to the introduction of this grade indicated adequate rupture strength and ductility. Although subsequent long-term (years) service experience and laboratory tests confirmed the rupture strength obtained from the parametric tests, they also revealed substantially less long-term rupture ductility than was predicted. This low rupture ductility caused a number of service troubles, including dovetail and balance groove rupture cracking.

These occurrences of peripheral cracking in rotors made from this material, and the fact that these cracks could progress relatively rapidly, caused concern that undetected bore cracks might initiate and propagate to critical size, thus causing catastrophic failures. Therefore, a program of inspecting the bores, as well as peripheries and dovetails of these rotors, was put in place. A total of 183 of these rotors were shipped and all have been inspected. Since 1968, approximately 2/3 of these rotors have been retired.

Although some were removed from service because the unit was retired, most were replaced because of conditions, such as peripheral cracking or internal discontinuities, revealed during an inspection.

Based on this experience, the program was expanded in 1974 to include the integral rotors (those whose wheels are an integral part of the rotor forging) of all fossil utility turbine-generators shipped before 1959, and hence before boresonic testing equipment and the discipline of fracture mechanics were in existence. The program was further expanded in 1979 to include all 3000 and 3600 rpm turbine rotors with 10 years or more service.

The expanded program is well along; more than 1,500 turbine rotors have had an in-service inspection and evaluation performed at least once. Generally, the aim of the program has been to inspect the more critical rotors first. Correspondingly, the percentage of more restrictive recommendations, such as replace or reinspect in three years or less, was higher in the early period. A more recent sample of rotors inspected show that the recommendation for more than 80% is to reinspect after six years of additional service or 10 years for the newer rotors. The annual percentage of replacement recommendations has declined to less than 2%. In all cases where rotor replacement was recommended, the units were permitted to continue in operation until a new rotor was obtained. However, in one case, a spare rotor had to be installed before returning the unit to service.

The primary objective of these rotor bore inspection programs is to reduce the probability of rotor bursts. Rotor inspections have revealed a few rotors with a bore crack of sufficient size that it could have burst on the next start-up. The recommendation subsequent to that inspection was that the rotor should not be returned to service. Since then, the rotor has been cut apart to reveal the crack, whose size and shape agree very well with the NDT measured values.

In addition, several other rotors have been found to contain bore cracks that could have grown to critical size during subsequent service, had they not been detected early and removed by enlarging the bore. A number of rotors, although they did not yet have bore cracks, contained numerous, large internal indications that were judged to be of sufficient severity to warrant recommending replacement, bottleboring, or more frequent inspections.

The experience gained from the rotor inspections conducted to date and the improved understanding of material behavior which has accrued in recent years have confirmed the advisability of performing periodic rotor inspections in order to limit probability of rotor bursting.. Our current judgment is that all rotors should be thoroughly inspected about every six years (10 years for newer rotors with no indications), with more frequent inspections of those judged to be more critical.

II. NDE Test Descriptions

In preparation for the normal in-service rotor inspection, the turbine owner removes the rotor from the turbine and places it in an appropriate location in the station to provide access for non-destructive testing. The periphery surfaces are prepared for inspection by aluminum oxide blasting and a visual and magnetic particle inspection of the peripheral surfaces is performed. This can be accomplished by GE customer personnel or an independent testing laboratory.

The tests normally conducted by GE personnel on in-service rotors include the following:

1. Bore Visual Inspection

   All visual surface indications or irregularities are described and their axial and circumferential locations are recorded. Representative indications are normally photographed.

2. Bore Magnetic Particle Test

   All indications are described and their axial and circumferential locations recorded. Representative indications are normally photographed. The purpose of this test is to identify bore surface and near surface indications.

3. Bore Ultrasonic Tests

   Straight Beam
   A 2.25 MHz longitudinal wave ultrasonic test is conducted throughout the entire length of the bore except over surface irregularities. The test is performed with GE's computerized DATAQ™ system that automatically records the amplitudes and axial, radial and circumferential locations of all indications. The purpose of this test is to detect and track volumetric or non radial-axial planar indications.

   Circumferential Angle Beam
   A 5 MHz shear wave ultrasonic test in two directions is conducted throughout the entire length of the bore except over surface irregularities. The test is performed with the DATAQ™ computerized system in conjunction with the straight beam test and automatically records the locations of individual reflectors. The purpose of the test is to recognize radial-axial type patterns of indications near the bore.

4. Periphery Ultrasonic Test

   A 2.25 MHz radial longitudinal beam ultrasonic test is performed from as many of the cylindrical-shaped periphery surfaces as possible. Special ultrasonic contoured shoes are used to permit testing from some of the otherwise inaccessible locations, such as between interstage packing teeth. Indication amplitudes and their axial, circumferential and radial locations are recorded. Unusual indication patterns, sizes or characteristics which might give evidence of radial extent are noted. The purpose of this test is to supplement the boresonic test in the detection of indications and to provide data in solid portions of rotors.

5. Axial Ultrasonic Test

   An ultrasonic test is performed in the axial direction from accessible rotor end faces. The purpose of the test is to detect discontinuities with significant reflective area in the radial-tangential plane. The amplitude and location of all indications detected are recorded.

6. Rotor Dovetail Ultrasonic Test

   Ultrasonic testing is performed on selected rotor dovetails that experience has shown coul develop cracks during service. Geometry limitations may prevent inspection of the entir dovetail, partic ly the outermost hook. The radial m ment of the buckets relative to the rotor is measured on the same selected dovetails. If the ultrasonic inspection reveals evidence of cracking and/or unusual amounts of relative movement are measured, it may be recommended that buckets be removed for further examination of the rotor dovetail.

7. Supplementary Tests

In addition to the above standard tests, supplementary tests may be conducted in order to help clarify specific situations. For example, a high resolution periphery test may be conducted to better define the sizes and spacings of indications within levels. A special "near surface" test may be performed to more accurately determine the proximity of the ultrasonic profile to the outer surface. Depending on the type of rotor, a high-saturation bore magnetic particle test may be conducted to identify possible regions of severe chemical segregation.

III. Characterization of Indications and Their Effect on Mechanical Properties

Ultrasonic indications are reflections of acoustic energy from discontinuities in the material. In addition to actual cracks, such reflections have been detected from various other discontinuities such as non-metallic inclusions, porosity, oxides, forging tears and even grain boundaries. The nature and size of the ultrasonic indications (discontinuities) generally cannot, at the present time, be deduced accurately from ultrasonic tests alone. Further, the effects of the indications on the rotor material properties, if any, obviously cannot be determined solely by ultrasonic testing.

A dual effort program was thus initiated a number of years ago to provide necessary information of this type. One objective was to relate the size and type of the indications to the reported ultrasonic data. The other objective was to determine the influence of these indications on the rotor material properties.

Numerous studies, which included the precise mapping of ultrasonic indications in rotors, wheels and other turbine parts, coupled with subsequent sectioning, metallographic investigation and measurement of actual indication sizes, have produced valuable information for analysis of discontinuities in rotor steels. As expected, certain types of ultrasonic indications tend to be unique to rotor type (e.g., high temperature vs. lower temperature) and location within the rotor.

Sufficient empirical data was obtained to relate the amplitude of reported indications to actual physical sizes of indications isolated destructively. This work has revealed that the actual size of a discontinuity can be several times that implied by ultrasonic testing. As these studies progressed, it was found that a correction factor of two is sufficiently conservative for most cases. Unless other test data indicate the need for a larger correction factor, a value of two is used in the rotor evaluation.

Finally, these studies have shown that most ultrasonic discontinuities are not cracks. Some have been identified as porosity, non-metallic inclusions, forging tears, etc.

The second part of the dual effort program mentioned earlier was a parallel investigation of the effects of the different types of indications on the rotor material properties. This program, which also has been underway a number of years, has produced data on the effects of various types of ultrasonic and magnetic particle indications on the rupture, low-cycle fatigue, high-cycle fatigue and fracture toughness properties of rotor materials.

IV. Rotor Evaluation Procedures

A. Bore Surface Indications

Bore surface indications detected visually or by magnetic particle test are generally considered one of the more serious conditions found in a rotor. A bore surface indication is much more likely to produce a failure than the same size indication located internally. Indications in rotor forgings are seldom actual cracks; however, cracks have been found and other indications can become cracks. Identification of indications is therefore very important. Bore surface indications may consist of pitting, porosity, non-metallic inclusions, alloy segregation, forging tears, actual cracks due to rupture or low-cycle fatigue or combinations of these conditions. The visual examination, magnetic particle inspection and grinding are used to help identify these indications. Other information, such as material properties, service conditions (time, temperature and stress) and the individual ultrasonic profiles are also used to identify bore surface indications.

Bore surface or very near surface indications found either visually or by magnetic particle test are generally explored by grinding. The bore grinding performed by the NDT technician is limited to either a 360° grind where very little material is removed or a very local grind where the maximum depth is about 1/4". Local grinding on a specific indication is performed in increments of about 1/16" with a visual or magnetic particle inspection after each grind. The axial extent and the general appearance (photographed or described) is recorded at each increment. Frequently, shallow grinding (about 1/16") will completely remove an indication or group of indications; however, others may appear. Local grinding is performed only when necessary to evaluate surface indications and usually only the largest or typical indications in critical regions are selected for exploration. After the grinding is completed, the region is well blended to reduce any stress concentration effects. It must be recognized that future boresonic inspections in areas of significant local grinding are not possible.

For evaluation purposes, the non-crack-like bore surface indications are assumed to be cracks and their effect on the integrity of the rotor is analyzed in the same manner as ultrasonic indications. The size of the assumed crack is defined by the axial extent observed on the surface and the radial extent found by grinding.

In those relatively rare cases where crack-like indications are observed on the bore surface, they should be removed before the rotor is returned to service. If these indications have been removed by local grinding, it is usually assumed for evaluation purposes that sub-surface cracks of similar size exist in the vicinity of the ground-out indications. If these more serious surface indications are too deep or numerous to be removed by local grinding, a recommendation is made that the rotor be overbored or bottlebored before it is returned to service.

B. Ultrasonic Indications

1. Comprehensive Data Review

Each of the various ultrasonic tests conducted has a specific range over which it is most effective in detecting internal discontinuities. For example, the boresonic test is most effective in testing material near the bore (approximately 1/8" to 3" from the bore surface) while the periphery ultrasonic test can detect indications only between wheels, etc. Some indications are detectable by several ultrasonic tests, others by only one. Thus, before rotor evaluation starts, the indications revealed by the radial beam boresonic and the radial beam periphery ultrasonic tests are combined into a single composite listing that properly accounts for those indications detected by both tests. Additionally, the individual plots from the clockwise and counter-clockwise angle beam boresonic tests are also separately reviewed.

2. <u>Size Correction</u>

Material discontinuities produce reflections during an ultrasonic test. The amplitude of each reflection is converted into an "Equivalent Flat Bottom Hole" (EFBH) diameter. This is the diameter of a flat bottom hole that would reflect the same amount of ultrasonic energy as the indication, if it were in the same location, in a plane perpendicular to the ultrasonic beam. Depending on the type of indications, spacing, orientation, etc., the actual discontinuity may be larger or smaller than the EFBH. A size correction factor is applied which was derived from data obtained by cutting up rotors and examining the discontinuity that caused the ultrasonic indications (Described in Section III). The current conservative size correction factor is two; that is, the reported EFBH is doubled for evaluation purposes.

3. <u>Fracture Mechanics Approach</u>

A fracture mechanics approach is used to evaluate the indications in a rotor. An assumption inherent in this approach is that all indications are cracks. This is generally conservative, since prior defect characterization work has shown that the vast majority of indications are **not** cracks. However, since the most sophisticated ultrasonic equipment currently available cannot determine conclusively that an internal indication is not a crack and the consequences of misinterpretation could lead to a rotor burst, the conservative assumption is generally made that every indication is a crack unless there is convincing evidence to the contrary. It is further assumed that these cracks are oriented in a plane perpendicular to the limiting local stress. It should be pointed out that a fracture mechanics approach assumes that the cracks being analyzed are contained in otherwise sound material. That is, the material adjacent to an assumed crack is free of defects and has the crack growth and toughness properties of "clean" materials. Material containing many identified ultrasonic indications is likely to contain additional undetected discontinuities, such as segregation or other undetectable conditions, that may produce a degradation of material properties. Laboratory tests have shown that crack growth through such material can be erratic. As an example, classic fracture mechanics does not explain the most recent turbine rotor burst in Gallatin.[14] Awareness of this somewhat unpredictable behavior occasionally requires judgments to be made that would otherwise appear more conservative than necessary.

4. <u>Crack Growth</u>

Using a fracture mechanics approach, where indications are assumed to be cracks, an estimate of the crack growth due to typical* turbine operating cycles is made. A conservative number of start-up cycles (usually 1,000) is assumed to occur between inspections. In addition, in the HP section, major load changes produce a less severe cycle with a mean load, and 1,000 of these cycles are also assumed. The centrifugal and thermal stresses and temperature local to each indication are used in the crack growth calculations. The proximity effect and "link-up" among or between indications and the bore surface is accounted for as the indications grow. Fatigue crack growth data for turbine rotor materials is shown in Figure 1. There are many factors that affect crack growth, all of which are not fully understood and which may account for a scatterband that exceeds an order of magnitude. The scatterband includes data generated by GE and others over the past several years. The material included are NiCrMoV, CrMoV, NiMoV and 12Cr with tests conducted at both room and elevated temperature. Most of the rotor evaluated in the inspection program are low alloy forgings of either NiCrMoV or NiMoV composition. Crack growth data for these materials is similar and the mean value for CrMoV is used. Since crack growth varies with temperature, the range of the mean value from room temperature to 1000 F/538 C is shown in Figure 1.

5. Critical Crack Size

The indications which were assumed to be cracks and "grown" according to the above procedure are compared to the critical crack size at the same location in the rotor as the indication. Another measure used to judge the severity of an indication is to calculate the rotational speed the rotor must reach for "grown" indication to be critical. In both cases, a severe cycle is used. The rotor is assumed to be pre-warmed according to the published starting and loading recommendations for that unit and then the loading is assumed to be at the "bore limit" rate. The temperature and the combined thermal and centrifugal stresses at the location of each indication are calculated as a function of time to find the most limiting conditions. The critical combination of stress and crack size is established by the critical stress intensity factor (fracture toughness, K_{IC}). A correlation between fracture toughness and excess temperature is shown in Figure 2. Again, a wide scatterband of data exists which would permit a wide variation in the selection of K_{IC} and the resulting critical combination of stress and crack size. Since fracture toughness data normally is not available for the specific rotor being evaluated, the bottom of the scatterband is normally assumed. Excess temperature is defined as the temperature of the material minus its fracture appearance transition temperature (FATT)**. A measured value of FATT may not be available either; however, an estimate can be made. This estimate is based on the original mechanical properties, chemistry and heat treatment, all of which are available. The current FATT of a rotor is estimated by first calculating the original, as-received value, then adding the estimated embrittlement caused by exposure to high temperature. The tolerance that a rotor has against failure due to discontinuities decreases with time because of embrittlement.

V. Summary

The in-service rotor inspection experience accumulated by GE clearly indicates the desirability of conducting periodic inspections. While effective in-service rotor inspection programs cannot absolutely guarantee the prevention of bursts, the probability is significantly reduced.

Technical publications which contain additional pertinent data are referenced.

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* Operation of the unit is assumed to be in accordance with published starting and loading recommendations. Cycles of average severity (0.2% surface life expenditure/cycle) are assumed.

** FATT is the temperature at which the fracture of a Charpy specimen is 50% ductile and 50% brittle.

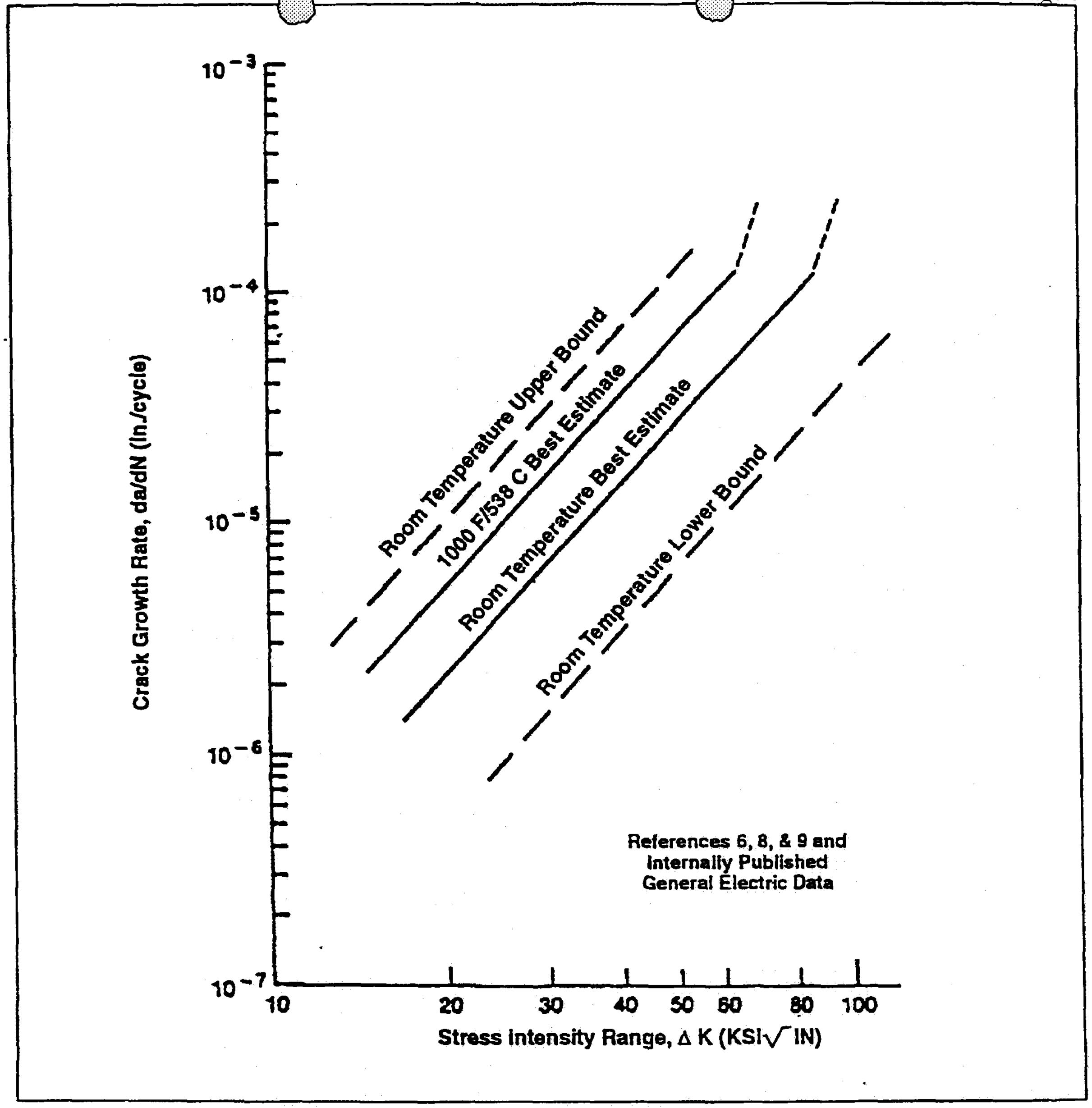

Figure 1. Crack growth rates

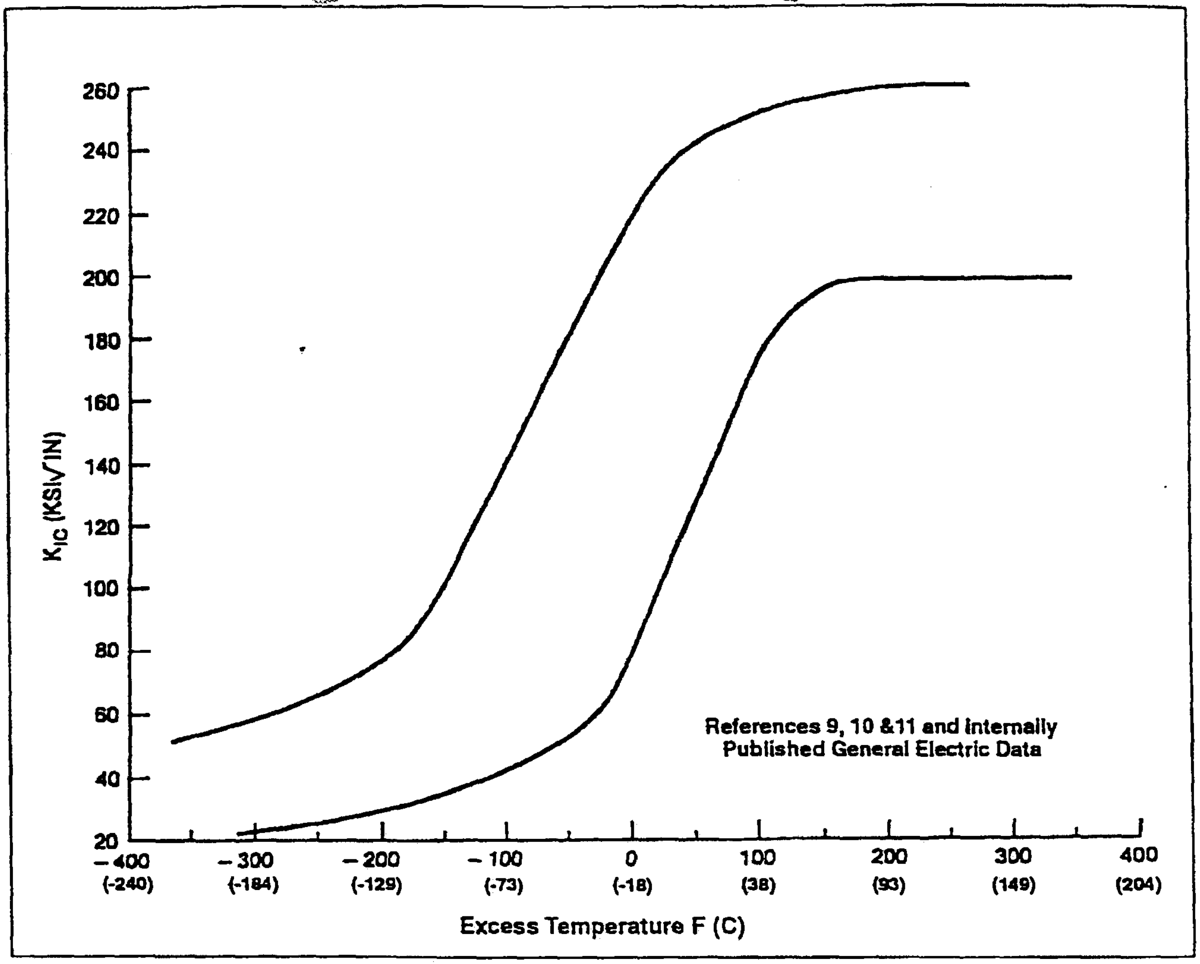

Figure 2. Rotor toughness data

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TURBINE ROTOR

HP Rotor

Assembly:

HP rotor runout readings were taken by MD&A in their balance machine. The maximum runout was 6 1/2 mils at the midspan. The rotor was low speed balanced by MD&A on site.

Factory/shop plane balance weights should be stocked for the next internal inspection.

HP Rotor

Assembly:

The HP turbine rotor and buckets were blast cleaned and NDT'd by customer vendors. No indications were found.

HP Rotor

Body:

A "head shot" mag-particle inspection was performed on the HP rotor by GE technicians. No indications were found.

HP Rotor

Bore:

Boresonic and selected wheel dovetail inspection was performed on the HP rotor by GE Life Extension Services. See separate report.

RHT Rotor

Assembly:

Reheat rotor runout readings were taken by MD&A in their balance machine. The maximum runout was 12 mils at the midspan. The rotor was low speed balanced by MD&A on site.

Factory/shop plane balance weights should be stocked for the next internal inspection.

TURBINE ROTOR

RHT Rotor

Assembly:

The reheat turbine rotor and buckets were blast cleaned and NDT'd by customer vendors. No indications were found.

RHT Rotor

Body:

A "head shot" mag-particle inspection was performed on the reheat rotor by GE technicians. No indications were found.

RHT Rotor

Bore:

Boresonic and selected wheel dovetail inspection was performed on the reheat rotor by GE Life Extension Services. See separate report.

LP A Rotor

Coupling Spacer: B Cplg

The axial position of both LP rotors is about 1/4" too far toward the turbine end, based on wheel and diaphragm clearances. (The first inspection report confirms this axial position.) A light axial rub was found on the 16GB bucket cover. Factory engineering advised that under normal operating procedures, there should be no rotor short rubbing as-is, but a new B coupling spacer should be ordered for the next outage. No adjustments were made this outage. The existing B spacer is 1.412" thick.

A new B coupling (reheat to LP A) spacer with extra thickness should be ordered for the next inspection to restore the axial position of both LP rotors. The standard new spacer thickness is 1.625. The new spacer ordered should be at least 1.750 thick.

LP A Rotor

Assembly:

The LP A turbine rotor and buckets were blast cleaned and NDT'd by customer vendors. No indications were found.

TURBINE ROTOR

LP A Rotor

Body:
A "head shot" mag-particle inspection was performed on the LP A rotor by GE technicians. No indications were found.

LP A Rotor

Bore:
Boresonic and selected wheel dovetail inspection was performed on the LP A rotor by GE Life Extension Services. See separate report.

LP B Rotor

Assembly:
The LP B turbine rotor and buckets were blast cleaned and NDT'd by customer vendors. No indications were found.

LP B Rotor

Body:
A "head shot" mag-particle inspection was performed on the LP B rotor by GE technicians. No indications were found.

LP B Rotor

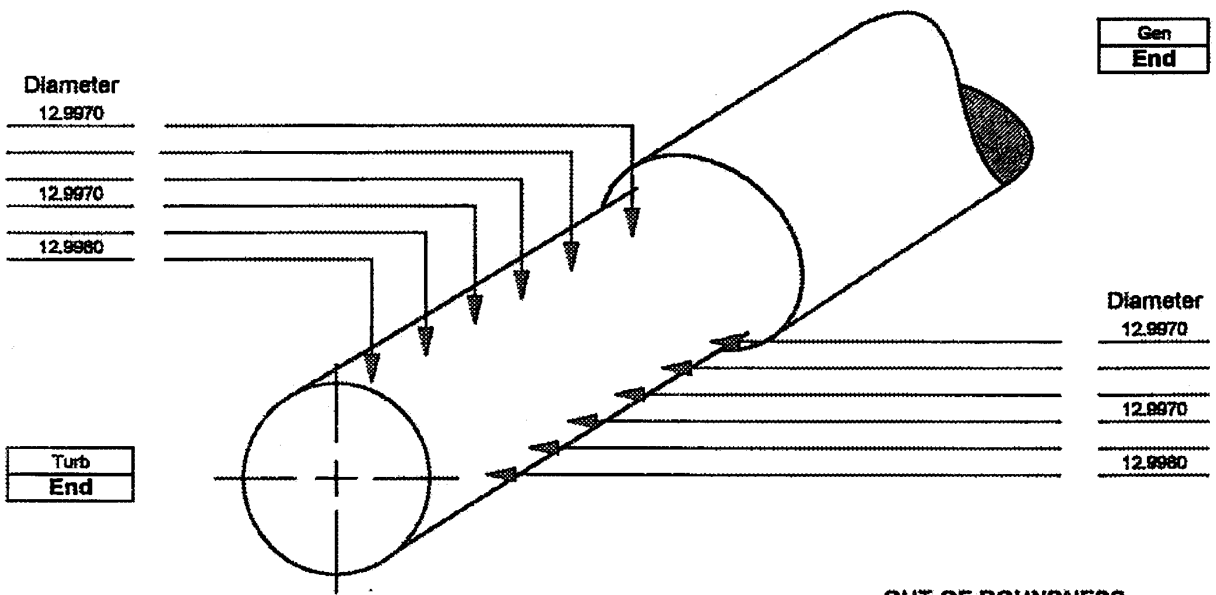
Bore:
Boresonic and selected wheel dovetail inspection was performed on the LP B rotor by GE Life Extension Services. See separate report.

Rotor Journal Condition

Date(m/d/y 3/3/99 Turbine Serial No. 170X819 Prepared by Joe Gonzalez

Journal Number 1

NOTE: **Mark on sketch to show grooving, discoloration, carbon inclusions, or irregularities in the journal surface.**



JOURNAL SIZES

	0°	90°	All
Maximum	12.9980	12.9980	12.9980
Minimum	12.9970	12.9970	12.9970
Difference	0.0010	0.0010	0.0000
Average	12.9973	12.9973	12.9973

OUT OF ROUNDNESS

Diameters		Out of Round
0°	90°	
12.997	12.997	0.000
12.997	12.997	0.000
12.998	12.998	0.000

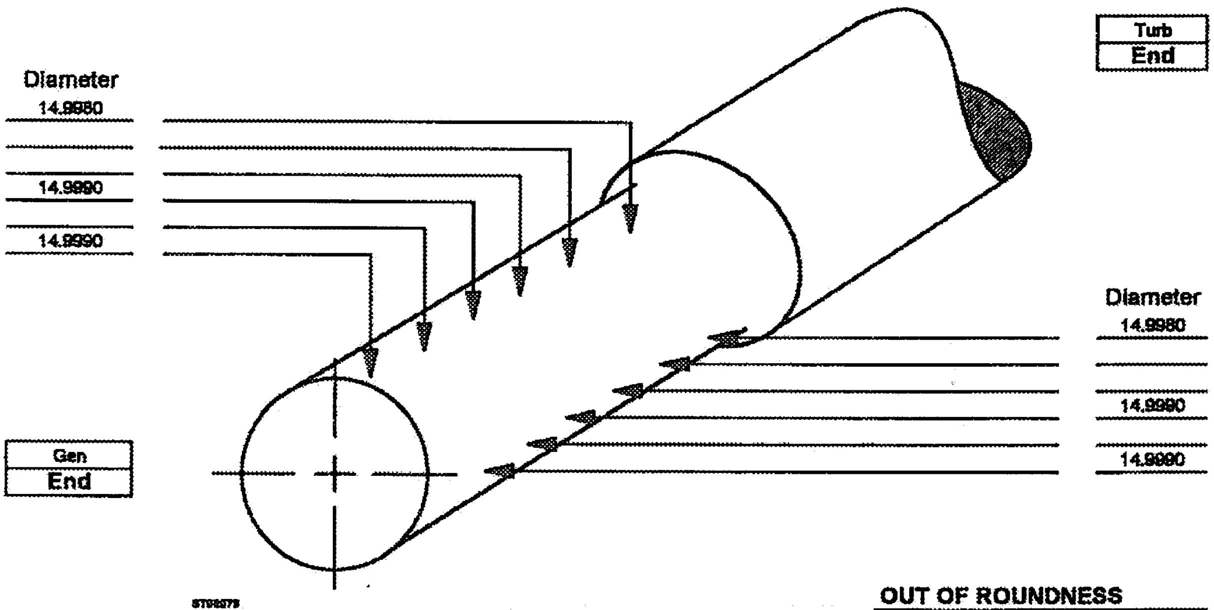
Comments:

Rotor Journal Condition

Date(m/d/y 3/3/99 Turbine Serial No. 170X819 Prepared by Joe Gonzalez

Journal Number 2

NOTE: Mark on sketch to show grooving, discoloration, carbon inclusions, or irregularities in the journal surface.



JOURNAL SIZES

	0°	90°	All
Maximum	14.9990	14.9990	14.9990
Minimum	14.9980	14.9980	14.9980
Difference	0.0010	0.0010	0.0000
Average	14.9987	14.9987	14.9987

OUT OF ROUNDNESS

Diameters 0°	Diameters 90°	Out of Round
14.998	14.998	0.000
14.999	14.999	0.000
14.999	14.999	0.000

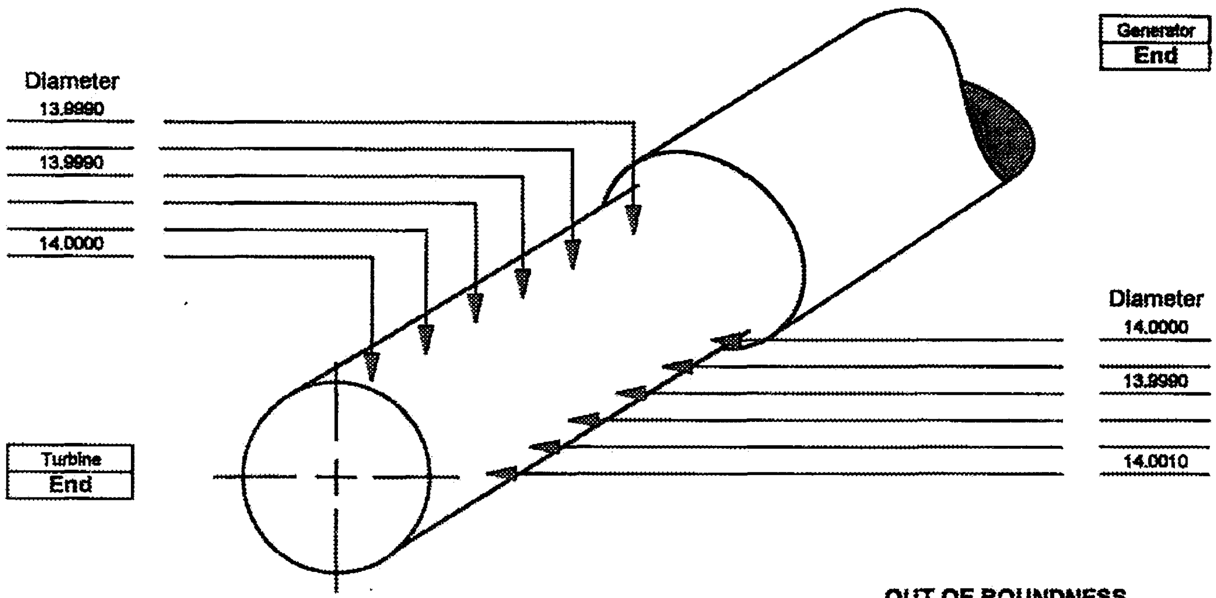
Comments:

Rotor Journal Condition

Date(m/d/y 3/4/99 Turbine Serial No. 170X819 Prepared by Joe Gonzalez

Journal Number 3

NOTE: Mark on sketch to show grooving, discoloration, carbon inclusions, or irregularities in the journal surface.



JOURNAL SIZES

	0°	90°	All
Maximum	14.0000	14.0010	14.0010
Minimum	13.9990	13.9990	13.9990
Difference	0.0010	0.0020	-0.0010
Average	13.9993	14.0000	13.9997

OUT OF ROUNDNESS

Diameters		Out of Round
0°	90°	
13.999	14.000	-0.001
13.999	13.999	0.000
14.000	14.001	-0.001

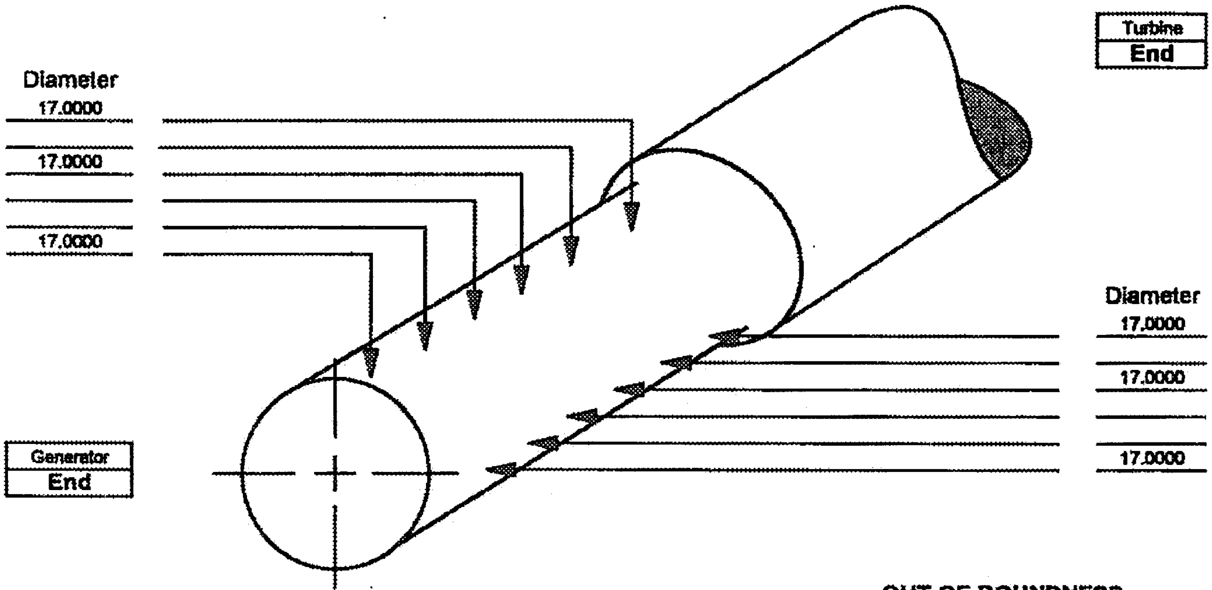
Comments:

Rotor Journal Condition

Date(m/d/y 3/4/99 Turbine Serial No. 170X819 Prepared by Joe Gonzalez

Journal Number 4

NOTE: Mark on sketch to show grooving, discoloration, carbon inclusions, or irregularities in the journal surface.



JOURNAL SIZES

	0°	90°	All
Maximum	17.0000	17.0000	17.0000
Minimum	17.0000	17.0000	17.0000
Difference	0.0000	0.0000	0.0000
Average	17.0000	17.0000	17.0000

OUT OF ROUNDNESS

Diameters		Out of Round
0°	90°	
17.000	17.000	0.000
17.000	17.000	0.000
17.000	17.000	0.000

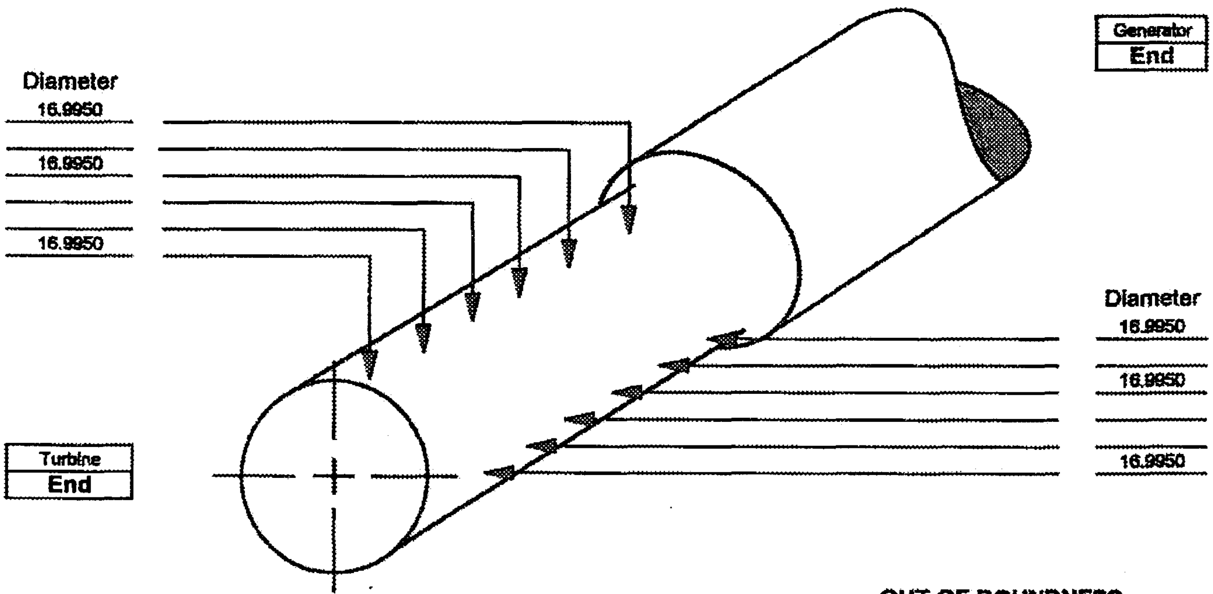
Comments:

Rotor Journal Condition

Date(m/d/y 3/12/99 Turbine Serial No. 170X819 Prepared by Joe Gonzalez

Journal Number 5

NOTE: **Mark on sketch to show grooving, discoloration, carbon inclusions, or irregularities in the journal surface.**



ST8807R

JOURNAL SIZES

	0°	90°	All
Maximum	16.9950	16.9950	16.9950
Minimum	16.9950	16.9950	16.9950
Difference	0.0000	0.0000	0.0000
Average	16.9950	16.9950	16.9950

OUT OF ROUNDNESS

Diameters		Out of Round
0°	90°	
16.995	16.995	0.000
16.995	16.995	0.000
16.995	16.995	0.000

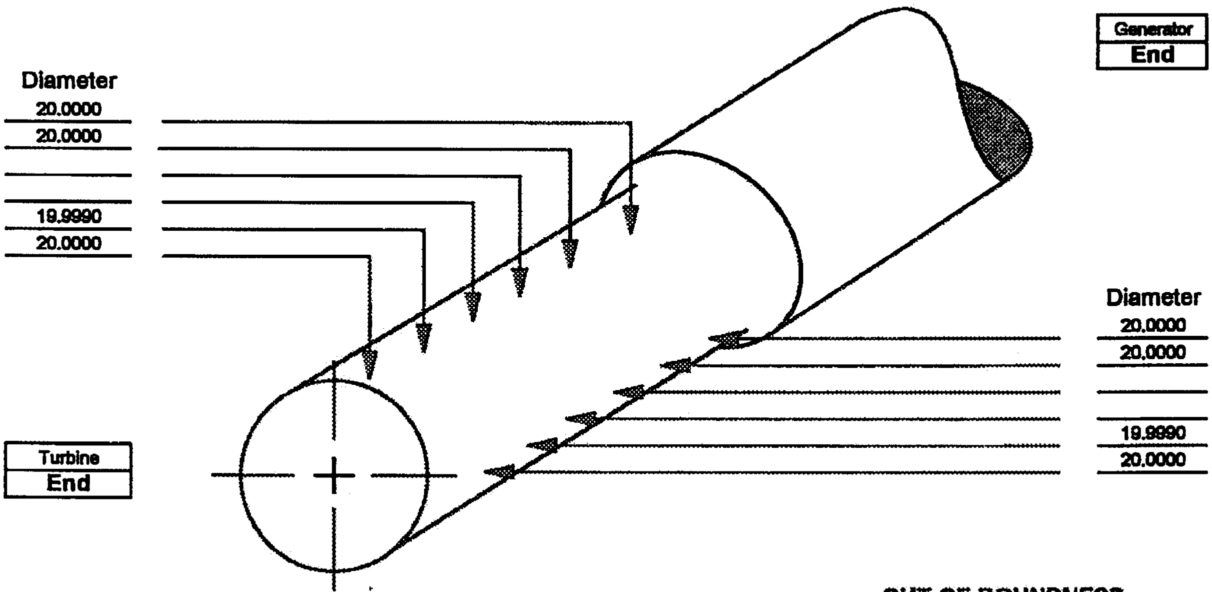
Comments:

Rotor Journal Condition

Date(m/d/y 3/5/99 Turbine Serial No. 170X819 Prepared by Joe Gonzalez

Journal Number 6

NOTE: **Mark on sketch to show grooving, discoloration, carbon inclusions, or irregularities in the journal surface.**



JOURNAL SIZES

	0°	90°	All
Maximum	20.0000	20.0000	20.0000
Minimum	19.9990	19.9990	19.9990
Difference	0.0010	0.0010	0.0000
Average	19.9998	19.9998	19.9998

OUT OF ROUNDNESS

Diameters		Out of Round
0°	90°	
20.000	20.000	0.000
20.000	20.000	0.000
19.999	19.999	0.000
20.000	20.000	0.000

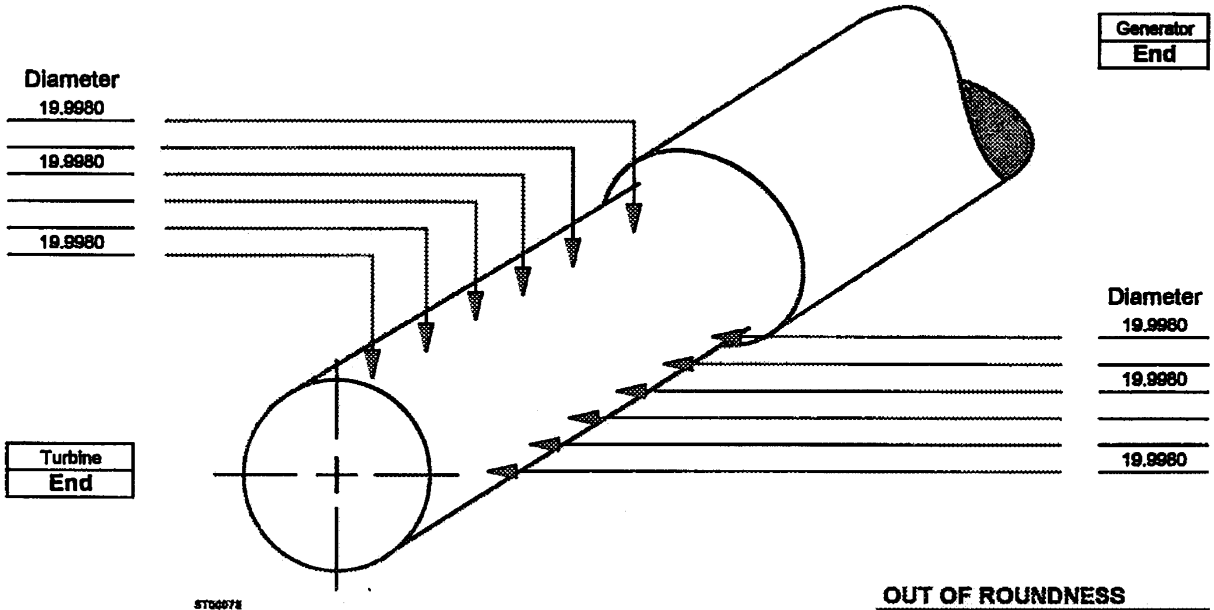
Comments:

Rotor Journal Condition

Date(m/d/y 4/5/99 Turbine Serial No. 170X819 Prepared by Joe Gonzalez

Journal Number 7

NOTE: **Mark on sketch to show grooving, discoloration, carbon inclusions, or irregularities in the journal surface.**



OUT OF ROUNDNESS

Diameters 0°	Diameters 90°	Out of Round
19.998	19.998	0.000
19.998	19.998	0.000
19.998	19.998	0.000

JOURNAL SIZES

	0°	90°	All
Maximum	19.9980	19.9980	19.9980
Minimum	19.9980	19.9980	19.9980
Difference	0.0000	0.0000	0.0000
Average	19.9980	19.9980	19.9980

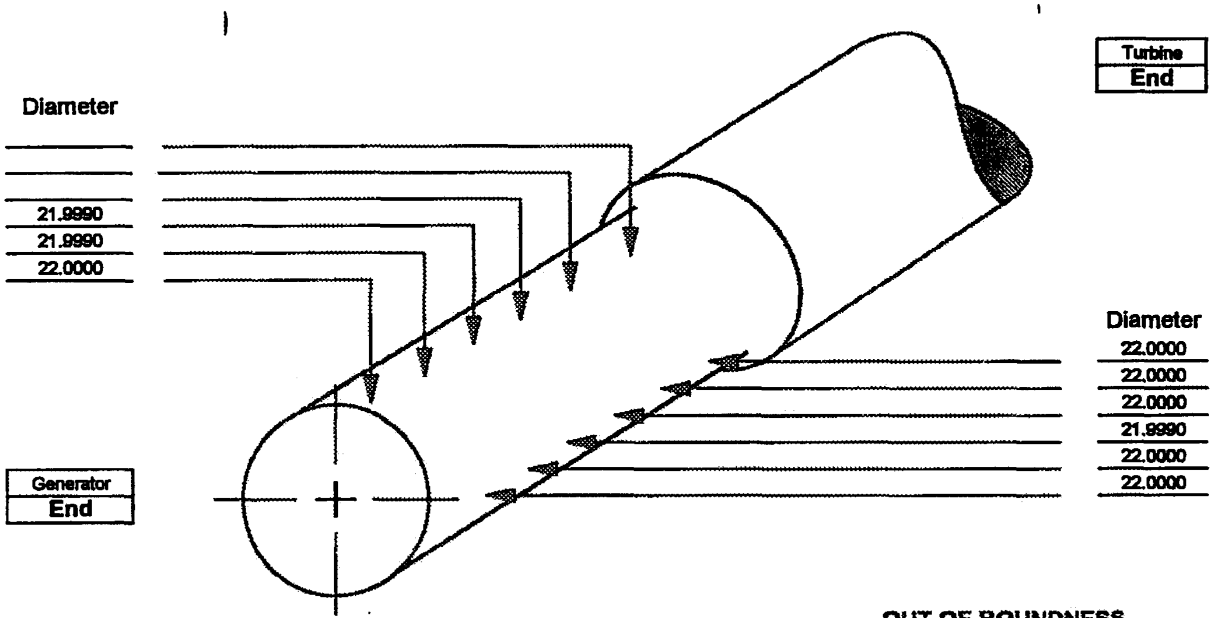
Comments:

Rotor Journal Condition

Date(m/d/y 3/5/99 Turbine Serial No. 170X819 Prepared by Joe Gonzalez

Journal Number 8

NOTE: **Mark on sketch to show grooving, discoloration, carbon inclusions, or irregularities in the journal surface.**



JOURNAL SIZES

	0°	90°	All
Maximum	22.0000	22.0000	22.0000
Minimum	21.9990	21.9990	21.9990
Difference	0.0010	0.0010	0.0000
Average	21.9993	21.9998	21.9996

OUT OF ROUNDNESS

Diameters		Out of Round
0°	90°	
	22.000	
	22.000	
	22.000	
21.999	21.999	0.000
21.999	22.000	-0.001
22.000	22.000	0.000

Comments:
Readings were taken 1 inch apart starting from the Turbine end.

Rotor Radial Runout Checks

Turbine Rotor and Shaft In-Service Runout Form

Date(m/d/y) 3/17/99 Turbine Serial No. 170X819 Prepared by T. Perkins

Rotor Identification HP

Rotor Checked Out
(In Unit or Out of Unit)

Which end of rotor is at face plate if placed in lathe? ______ *(Turbine End or Generator End)*

Describe location of rotor supports. Turb End Journal Gen End Journal

NOTE:
1. Mark position 1-8 to agree with stamped degree marks on rotor as shown in Fig. 1.
2. Set indicator to zero at number 1 position.
3. Indicate both journals and five planes along body (between stages) of each rotor. See Figs. 2, 3, & 4.

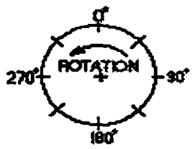


Fig.1

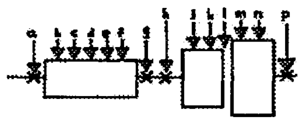


Fig.2

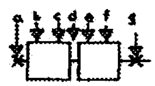


Fig.3

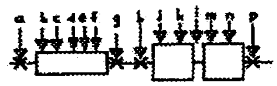


Fig.4

ROTOR RUNOUTS

Area Indicated	Position Number (Readings are in Mils)									Maximum
Journal or Stage No.	1 0°	2 45°	3 90°	4 135°	5 180°	6 225°	7 270°	8 315°	1 0°	Run Out
TE CR Hub	0.0	-1.0	0.0	2.0	5.0	6.5	5.0	4.0	0.0	7.5
OS Gov	0.0	1.0	5.0	8.0	12.0	14.0	11.0	5.0	0.0	14.0
SB Jrnl	0.0	-1.0	-1.0	0.0	1.0	2.0	2.5	2.0	0.0	3.5
TE MOP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.0	0.0	1.0
GE MOP	0.0	0.0	0.0	0.5	1.0	1.0	1.0	1.0	0.0	1.0
GE CR	0.0	-0.5	-0.5	-0.5	1.0	1.0	1.5	1.0	0.0	2.0
TE Jrnl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Midspan	-3.0	-2.0	0.0	-1.5	-3.0	-5.0	-6.5	-5.5	-3.0	6.5
GE Jrnl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GE Cplg	0.0	0.0	0.0	0.5	1.0	0.5	0.5	0.5	0.0	1.0
Rim										
GE Cplg	0.0	-1.0	-1.0	-0.5	0.0	0.0	0.0	0.0	0.0	1.0
Rabbet										

Comments

Rotor Radial Runout Checks

Turbine Rotor and Shaft In-Service Runout Form

Date(m/d/y) 3/24/99 Turbine Serial No. 170X819 Prepared by T. Perkins

Rotor Identification Reheat

Rotor Checked Out
(In Unit or Out of Unit)

Which end of rotor is at face plate if placed in lathe? ______ *(Turbine End or Generator End)*

Describe location of rotor supports. Turb End Journal Gen End Journal

NOTE:
1. Mark position 1-8 to agree with stamped degree marks on rotor as shown in Fig. 1.
2. Set indicator to zero at number 1 position.
3. Indicate both journals and five planes along body (between stages) of each rotor. See Figs. 2, 3, & 4.

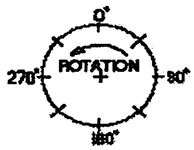


Fig.1

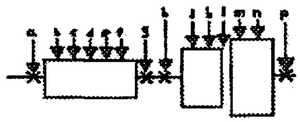


Fig.2

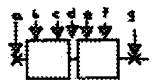


Fig.3

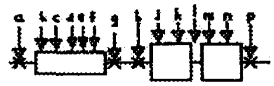


Fig.4

ROTOR RUNOUTS

Area Indicated Journal or Stage No.	Position Number (Readings are in Mils) 1 0°	2 45°	3 90°	4 135°	5 180°	6 225°	7 270°	8 315°	1 0°	Maximum Run Out
TE Cplg	0.0	-2.0	-3.0	-4.5	-4.5	-2.0	1.0	2.0	0.0	6.5
Rim										
TE Cplg	0.0	-1.0	-2.0	-2.0	-2.0	-1.0	-0.5	-0.5	0.0	2.0
Hub										
TE Jrnl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Midspan	0.0	4.0	7.0	10.0	8.0	5.0	-2.0	-3.0	0.0	13.0
GE Jrnl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GE Cplg	0.0	-2.0	-3.0	-4.0	-4.0	-3.0	-1.0	-0.5	0.0	4.0
Rim										

Comments

Bolt Extension Report
For Use With Extensiometer

Date (m/d/y) 4/12/99 Turbine S/N 170X819 Prepared by T. Perkins

Component * A Coupling

Location	Extension Required (In Mils)	DIAL READING Before Tightening	DIAL READING After Tightening	Extension Obtained (In Mils)	Rod No.
1	18-21	256	236	20	
2		262	243	19	
3		271	252	19	
4		278	258	20	
5		226	208	18	
6		256	234	22	
7		291	271	20	
8		284	263	21	
9		302	280	22	
10		262	243	19	
11		291	271	20	
12		287	266	21	
13		287	265	22	
14		283	261	22	

Component * B Coupling

Location	Extension Required (In Mils)	DIAL READING Before Tightening	DIAL READING After Tightening	Extension Obtained (In Mils)	Rod No.
1	24-27	383	357	26	
2		291	265	26	
3		452	426	26	
4		361	335	26	
5		372	346	26	
6		476	449	27	
7		488	462	26	
8		364	338	26	
9		415	391	24	
10		441	416	25	
11		364	335	29	
12		391	363	28	
13		392	365	27	
14		398	373	25	
15		382	356	26	
16		417	391	26	

* Indicate Valve, Shell, or Flange Identification.

Bolt Extension Report
For Use With Extensiometer

Date (m/d/y) 4/13/99 Turbine S/N 170X819 Prepared by T. Perkins

Component * C Coupling

Location	Extension Required (in Mils)	DIAL READING Before Tightening	DIAL READING After Tightening	Extension Obtained (in Mils)	Rod No.
1	25-29	514	487	27	
2		554	528	26	
3		506	478	28	
4		481	452	29	
5		542	517	25	
6		546	520	26	
7		524	498	26	
8		516	491	25	
9		508	481	27	
10		500	474	26	
11		505	476	29	
12		472	447	25	
13		505	479	26	
14		524	497	27	
15		487	460	27	
16		557	532	25	

Component * D Coupling

Location	Extension Required (in Mils)	DIAL READING Before Tightening	DIAL READING After Tightening	Extension Obtained (in Mils)	Rod No.
1	37-42	321	279	42	
2		296	255	41	
3		173	131	42	
4		283	243	40	
5		278	236	42	
6		303	263	40	
7		303	261	42	
8		235	193	42	
9		256	215	41	
10		325	284	41	
11		257	218	39	
12		293	253	40	
13		280	241	39	
14		291	252	39	
15		248	210	38	
16		210	168	42	

* Indicate Valve, Shell, or Flange identification.

Coupling Assembly Checks
With Intergral Rabbets

Date 4/10/99 Turbine Serial No. 170X819 Prepared by T. Perkins

oupling A

Data Final
(as found/final)

NOTES:
(1) For radial runout set indicator to read "0" at the number 1 position.
(2) Mark positions 1-8 to agree with factory stamped degree marks on rotor as shown on Fig. 1.

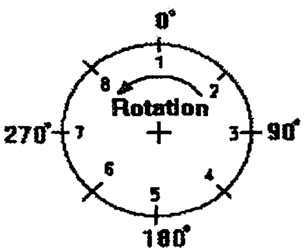


Fig. 1.

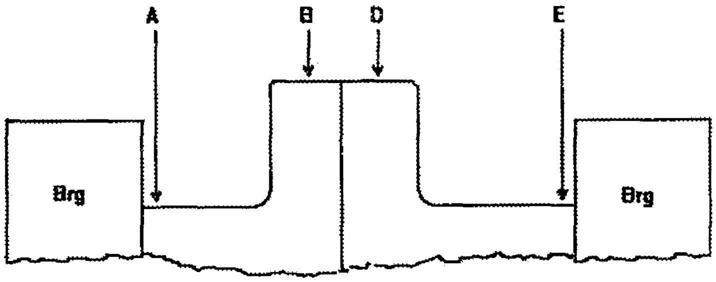


Fig. 2.

Coupling Runouts (Readings are in Mils)

Area Indicated		Position Number 1 0°	2 45°	3 90°	4 135°	5 180°	6 225°	7 270°	8 315°	1 0°
TE Journal	A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TE Cplg. Periph	B	0.0	0.5	0.0	1.0	0.5	0.5	0.5	0.0	0.0
GE Cplg. Periph	D	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GE Journal	E	-1.0	-0.5	-1.0	-2.0	-2.0	-2.0	-2.0	-2.0	-1.0

Differential Runouts

Journals	A-E	1.0	0.5	1.0	2.0	2.0	2.0	2.0	2.0	1.0
Cplg. Periphery	B-D	0.0	0.5	0.0	1.0	0.5	0.5	0.5	0.0	0.0

Maximum Runouts

Area Indicated		Data Check	TIR Runout	TIR Check
TE Journal	A	OK	0.0	OK
TE Cplg. Periph	B	OK	1.0	OK
GE Cplg. Periph	D	OK	0.0	OK
GE Journal	E	Check	1.5	Check

Maximum Differential Runouts

		Max. Diff.	Diff. Check
Journals	A-E	1.5	Check
Cplg. Periphery	B-D	1.0	OK

Coupling Assembly Checks
Without Integral Rabbets

Date 4/12/99 Turbine Serial No. 170X819 Prepared by T. Perkins

Coupling: B

Data: Final
(as found/final)

NOTES:
(1) For radial runout set indicator to read "0" at the number 1 position.
(2) Mark positions 1-8 to agree with factory stamped degree marks on rotor as shown on Fig. 1.

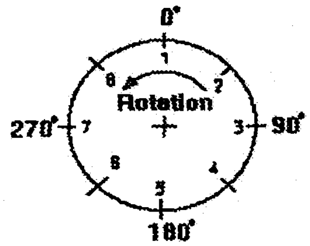


Fig. 1.

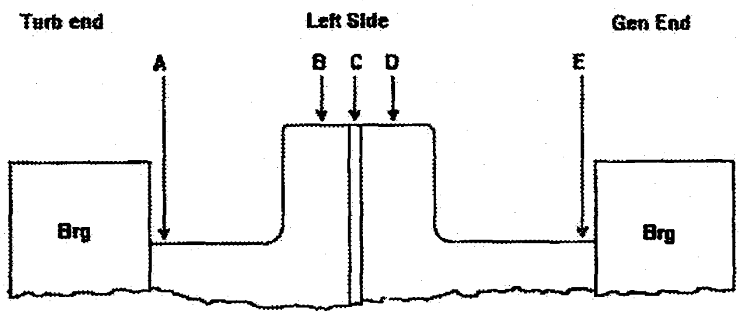


Fig. 2

Coupling Runouts (Readings are in Mils)

Area Indicated		Position Number 1 0°	2 45°	3 90°	4 135°	5 180°	6 225°	7 270°	8 315°	1 0°
TE Journal	A	0.0	-1.0	-1.5	-2.0	-2.0	-1.0	-0.5	-1.0	-1.0
TE Cplg. Periphery	B	0.0	0.0	0.0	-1.0	-1.0	-1.0	-0.5	0.0	0.0
Spacer	C	0.0	0.0	-1.0	-1.5	-2.0	-2.0	-1.0	0.0	0.0
GE Cplg. Periphery	D	0.0	-1.5	-1.5	-3.5	-2.5	-1.5	-0.5	0.0	0.0
GE Journal	E	0.0	0.0	-0.5	-1.0	-1.0	-0.5	-1.0	-0.5	0.0

Differential Runouts

Journals	A-E	0.0	-1.0	-1.0	-1.0	-1.0	-0.5	0.5	-0.5	-1.0
Cplg. Periphery	B-D	0.0	1.5	1.5	2.5	1.5	0.5	0.0	0.0	0.0
Spacer to Cplg	C-B	0.0	0.0	-1.0	-0.5	-1.0	-1.0	-0.5	0.0	0.0
Spacer to Cplg	C-D	0.0	1.5	0.5	2.0	0.5	-0.5	-0.5	0.0	0.0

Maximum Runouts

Area Indicated		Data Check	TIR Runout	TIR Check
TE Journal	A	Check	2.0	Check
TE Cplg. Periphery	B	OK	1.0	OK
Spacer	C	OK	2.0	OK
GE Cplg. Periphery	D	OK	3.5	Check
GE Journal	E	OK	1.0	OK

Maximum Differential Runouts

		Max. Diff.	Diff. Check
Journals	A-E	1.5	Check
Cplg. Periphery	B-D	2.5	Check
Spacer to Cplg	C-B	1.0	OK
Spacer to Cplg	C-D	2.5	OK

Coupling Assembly Checks
Without Integral Rabbets

Date 4/13/99 Turbine Serial No. 170X819 Prepared by T. Perkins

Coupling: C

Data: Final (as found/final)

NOTES:
(1) For radial runout set indicator to read "0" at the number 1 position.
(2) Mark positions 1-8 to agree with factory stamped degree marks on rotor as shown on Fig. 1.

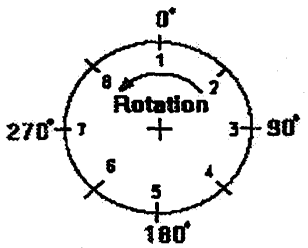


Fig. 1.

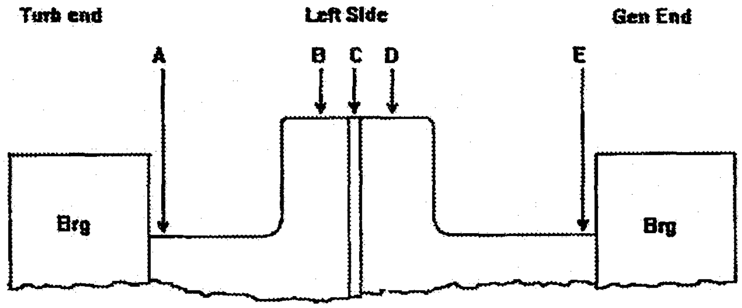


Fig. 2.

Coupling Runouts (Readings are in Mils)

Area Indicated		Position Number 1 0°	2 45°	3 90°	4 135°	5 180°	6 225°	7 270°	8 315°	1 0°
TE Journal	A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TE Cplg. Periphery	B	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	0.0
Spacer	C	0.0	1.0	1.5	2.0	2.0	2.0	1.0	1.0	0.0
GE Cplg. Periphery	D	0.0	0.0	0.0	1.5	2.0	2.0	1.5	1.0	0.0
GE Journal	E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Differential Runouts

Journals	A-E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cplg. Periphery	B-D	0.0	0.0	0.0	-1.5	-1.0	-1.0	-0.5	0.0	0.0
Spacer to Cplg	C-B	0.0	1.0	1.5	2.0	1.0	1.0	0.0	0.0	0.0
Spacer to Cplg	C-D	0.0	1.0	1.5	0.5	0.0	0.0	-0.5	0.0	0.0

Maximum Runouts

Area Indicated		Data Check	TIR Runout	TIR Check
TE Journal	A	OK	0.0	OK
TE Cplg. Periphery	B	OK	1.0	OK
Spacer	C	OK	2.0	OK
GE Cplg. Periphery	D	OK	2.0	OK
GE Journal	E	OK	0.0	OK

Maximum Differential Runouts

		Max. Diff.	Diff. Check
Journals	A-E	0.0	OK
Cplg. Periphery	B-D	1.5	OK
Spacer to Cplg	C-B	2.0	OK
Spacer to Cplg	C-D	2.0	OK

Coupling Assembly Checks
With Intergral Rabbets

Date 4/13/99 Turbine Serial No. 170X819 Prepared by T. Perkins

oupling D

Data Final
(as found/final)

NOTES:
(1) For radial runout set indicator to read "0" at the number 1 position.
(2) Mark positions 1-8 to agree with factory stamped degree marks on rotor as shown on Fig. 1.

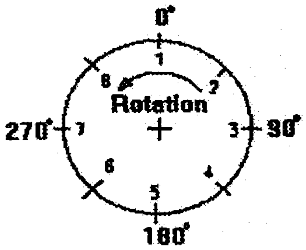


Fig. 1.

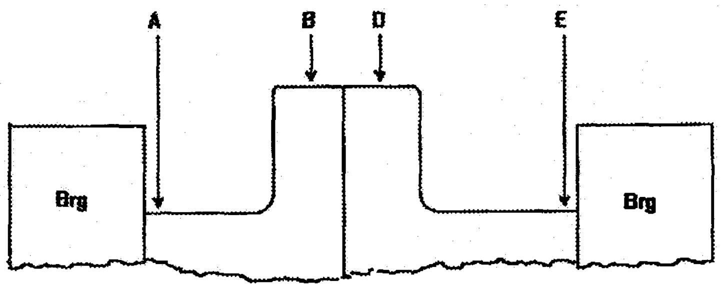


Fig 2

Coupling Runouts (Readings are in Mils)

Area Indicated		Position Number 1 0°	2 45°	3 90°	4 135°	5 180°	6 225°	7 270°	8 315°	1 0°
TE Journal	A									
TE Cplg. Periph	B	0.0	-0.5	-0.5	0.0	-1.0	-0.5	1.0	0.5	0.0
GE Cplg. Periph	D	0.0	0.0	-0.5	0.5	-0.5	-0.5	-0.5	-0.5	0.0
GE Journal	E									

Differential Runouts

Journals	A-E									
Cplg. Periphery	B-D	0.0	-0.5	0.0	-0.5	-0.5	0.0	1.5	1.0	0.0

Maximum Runouts

Area Indicated		Data Check	TIR Runout	TIR Check
TE Journal	A			
TE Cplg. Periph	B	OK	2.0	Check
GE Cplg. Periph	D	OK	1.0	OK
GE Journal	E			

Maximum Differential Runouts

		Max. Diff.	Diff. Check
Journals	A-E		
Cplg. Periphery	B-D	2.0	Check

Coupling Assembly Checks
With Intergral Rabbets

Date 4/13/99 Turbine Serial No. 170X819 Prepared by T. Perkins

oupling E

Data Final
(as found/final)

NOTES:
(1) For radial runout set indicator to read "0" at the number 1 position.
(2) Mark positions 1-8 to agree with factory stamped degree marks on rotor as shown on Fig. 1.

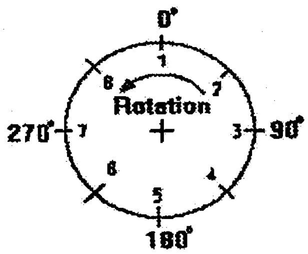


Fig. 1.

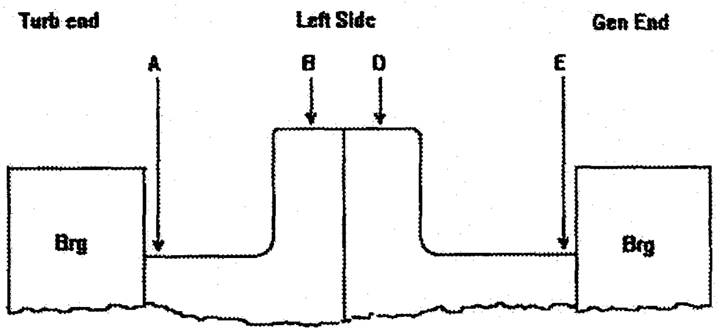


Fig 2.

Coupling Runouts (Readings are in Mils)

Area Indicated		Position Number 1 0°	2 45°	3 90°	4 135°	5 180°	6 225°	7 270°	8 315°	1 0°
TE Journal	A	0.0	0.0	1.0	1.0	0.0	0.0	0.0	1.0	0.0
TE Cplg. Periph	B	0.0	0.0	1.0	3.0	3.0	1.0	-1.0	1.0	0.0
GE Cplg. Periph	D	0.0	0.0	0.0	1.0	1.0	1.0	1.0	0.0	0.0
GE Journal	E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Differential Runouts

Journals	A-E	0.0	0.0	1.0	1.0	0.0	0.0	0.0	1.0	0.0
Cplg. Periphery	B-D	0.0	0.0	1.0	2.0	2.0	0.0	-2.0	1.0	0.0

Maximum Runouts

Area Indicated		Data Check	TIR Runout	TIR Check
TE Journal	A	OK	1.0	OK
TE Cplg. Periph	B	OK	4.0	Check
GE Cplg. Periph	D	OK	1.0	OK
GE Journal	E	OK	0.0	OK

Maximum Differential Runouts

		Max. Diff.	Diff. Check
Journals	A-E	1.0	OK
Cplg. Periphery	B-D	4.0	Check

March 4, 1999 to March 25, 1999

M & SP NDE Inspection Summary

Report Date: 4-5-99

Prepared By: [signature]
L. C. Dahlman
NDE Specialist

Reviewed By Tom Jones
T.M. Jones, Level III

TRIAL EXHIBIT
0074
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NSP, et al v GE
EX 275
Date: 11-24-15
Richard G. Stirewalt
Stirewalt & Associates

Sherburne County Generating Station
Unit 3
M & SP NDE Inspection Summary

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Sherburne County Generating Station
Unit 3
M & SP NDE Inspection Summary

Introduction

DESCRIPTION:

Sherco Unit 3 is a General Electric Turbine consisting of four double-shell sections: a high-pressure section, a double-flow reheat section, and two double-flow low-pressure sections. Operating at 2400 PSIG at 1000F and exhaust pressure of 1.5" HG. ABS. with a rating of 809643 KW at 3600 RPM

Turbine No. 170X819
Generator S/N: 180X819
Exciter S/N: 316X270

Major observations/modifications this outage:	
Bearings showing disbond and cracking	Some sent out for repair
Diaphragms & nozzle blading have cracking and FOD	See MDA report
IP Inner casing has cracks on the Horizontal Joints	Leave "AS IS"
IP Outer casing has a #2 positioning groove cracked	Leave "AS IS"
Intercept valve screen has cracked welds and undercutting of welds	Leave "AS IS"
LP-B Inner cylinder has 2 cracks in parent material	Need Repair
Cracked bucket pins on both LPA & LPB rotors	Replaced
Boiler Feed Pump #33 inboard seal assembly has cracked web.	Leave "AS IS"

GE performed the following inspections:

Generator Rotor inspection (MT)
Head Shots on HP, IP, LP rotors
Boresonic inspection of HP, IP, LP rotors
LP Blade Finger Inspection on L-1 Rows

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

BEARINGS

Component	Item	Method		
		PT	VT	UT
Bearings				
	#1 Upper Half Pads	NAD	NAD	Randomly isolated areas of debond 1/8" dia.; #4 pad , 1 area; #5 pad, 12 areas
	#1 Lower Half Pads	Sporadic debond around edge; #7 pad 3/8" crack 1-7/8" from gen end near middle; #6 pad ¼" crack 3-3/8" from gen end	NAD	Spot debond on pad 6L
	#2 Upper Half Pads	Sporadic debond around edge	#3 pad ¼" cut 7/8" from gov end; #4 pad 3/8" cut 7/8" from gov end	Debond at dovetail grooves on pads 3,4,5 most full length
	#2 Lower Half Pads	Sporadic debond around edge	NAD	Debond at dovetail grooves
	#3 Upper Half	NAD	1 spot heavy gouging on all pads; #3 pad ¼" x½" piece missing on gen end	NAD
	#3 Lower Half	#7 pad minor debond around edge; #6L pad minor debond on edge	1 spot heavy gouging on all 3 pads	NAD
Four Section Bearing (Thrust)				
	Pads 1,2,3,4	Tight fine cracks along edges	Light pitting, very minor debond, tight fine cracks around edges	Debond along dovetail grooves
	#4 Upper Half	#5 pad minor debond around edges; #3 pad minor debond	#5 light pitting on gov end surface	Debond along edge
	#4 Lower Half	#7 pad minor debond on one edge; #6L pad debond on gov end	NAD	NAD

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

BEARINGS

Component	Item	Method		
		PT	VT	UT
Bearings				
	#5 Upper Half	Sporadic minor debond around edges; tight fine cracking from horizontal joint down 9½" on gen side, most approx. ¼" L; ¾" long; crack into oil groove 7" down from horiz. joint right side	Minor pitting in middle right side	Debond along dove tail grooves 2", 9½", 10", 27", 22½" lengths
	#5 Lower Half	Sporadic minor debond around edges; tight fine cracking from horiz. joint down 6" on gen side, most approx. ¼" long next to oil groove; 7/8" long crack on side of bearing and comes 1/8" into the bearing 3" down from horiz. joint on gen side	NAD	Debond along dove tail grooves 1¼", 7¼"
	#6 Upper Half	Sporadic debond around edges	NAD	Debond along one groove 31½"
	#6 Lower Half	NAD	NAD	Debond along dovetail grooves 1½", 2", 1¼", 13¼"
	#7 Upper Half	Sporadic debond around edges on both ends	Light physical damage on bearing surface	Debond along dovetail grooves 31", 31", 28"
	#7 Lower Half	Sporadic debond around edges on gov. end	Light physical damage on bearing surface	Debond along dovetail grooves 14", 29½", 29½"
	#8 Upper Half	Sporadic debond on edges, gov. end	Physical damage on bearing surface @ right side	Debond along Dovetail grooves 29", 31", 18½", 10½", 33", 33", 15"
	#8 Lower Half	Sporadic debond on edges	Physical damage on bearing surface	Debond along dovetail grooves 15", 15", 18", 38", 10½", 9"

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

BEARINGS

Component	Item	Method		
		PT	VT	UT
Bearings				
	#9 Upper Half	Tight fine cracks, sporadic debond along edges	NAD	Debond along dovetail grooves
	#9 Lower Half	Sporadic debond along edges	Minor cuts on surface less than 1/8"	NAD
	#10 Upper Half	Sporadic debond around edges	Minor pitting	NAD
	#10 Lower Half	Sporadic debond around edges	Minor pitting, 4 cracks 1¼"L	NAD

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

HIGH PRESSURE ROTOR

Component	Item	Method			
		MT	PT	VT	UT
Turbine End					
	MOP Impeller			NAD	
	Oil Pump			NAD	
	#1 Journal	NAD		NAD	
	N-1 Packing Grooves	NAD		NAD	
	Wheel Row #7	NAD		NAD	
	Wheel Row #6	NAD		NAD	
	Wheel Row #5	NAD		NAD	
	Wheel Row #4	NAD		NAD	
	Wheel Row #3	NAD		NAD	
	Wheel Row #2	NAD		NAD	
	Bucket Row #7 – 11¼"L (15 gp of 4/5)	NAD		NAD	
	Bucket Row #6 – 10"L (17 gp of 4)	NAD		NAD	
	Bucket Row #5 – 9¼"L (19 gp of 4)	NAD		NAD	
	Bucket Row #4 – 8-3/8"L (21 gp of 4)	NAD		NAD	
	Bucket Row #3 – 7¾"L (22 gp of 4)	NAD		Light pitting	
	Bucket Row #2 – 7"L (23 gp of 4)	NAD		Light pitting	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

HIGH PRESSURE ROTOR

Component	Item	Method			
		MT	PT	VT	UT
	Shroud Covers Row #7	NAD		NAD	
	Shroud Covers Row #6	NAD		NAD	
	Shroud Covers Row #5	NAD		NAD	
	Shroud Covers Row #4	NAD		NAD	
	Shroud Covers Row #3	NAD		NAD	
	Shroud Covers Row #2	NAD		NAD	
	Impulse Stage Row 2 (20 gp of 4 – 6¼"L)	NAD		Light erosion	
	Impulse Stage Row 1 (20 gp of 4 – 6¼"L)	NAD		Light erosion	
	N-2 Packing Grooves	NAD		NAD	
	#2 Journal	NAD		NAD	
	A Coupling	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

HIGH PRESSURE STATIONARY LOWER

Component	Item	Method			
		MT	PT	VT	UT
	N-1 Packing Outer	NAD		NAD	
	N-1 Packing Inner	NAD		NAD	
	#7 Diaphragm (39)	#1 crack OD		Light sporadic FOD	
	#6 Diaphragm (57)	#2,12,32, 33,39,41, 47,50,51,53 crack ID; #9,11,31 crack OD		Light erosion	
	#5 Diaphragm (47)	#44 crack ID		Light erosion	
	#4 Diaphragm (50)	#11,13 crack OD; #23 crack ID		Light FOD & erosion; Crack on ID brace between #49	
	#3 Diaphragm (61)	#3-5,8,9,14, 52,60 crack OD; #33,48,55, 57 missing part of blade from FOD		Light erosion, FOD	
	#2 Diaphragm (36)	#1,4,14,20 previous weld repair crack; #18 OD crack TE		Moderate FOD & light erosion	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

HIGH PRESSURE STATIONARY LOWER

Component	Item	Method			
		MT	PT	VT	UT
Outer Casing	#1 Gib Key Fit (slot)	NAD		NAD	
	#2 Gib Key Fit	NAD		NAD	
	Horizontal Flange	NAD		NAD	
#1 Inner Shell		NAD		NAD	
	#7 Gib Key Fit	NAD		NAD	
	#6 Gib Key Fit	NAD		NAD	
	#5 Gib Key Fit	NAD		NAD	
	#4 Gib Key Fit	NAD		NAD	
	#3 Gib Key Fit	NAD		NAD	
	#2 Gib Key Fit	NAD		NAD	
New	Stellite Ring Outer		NAD	NAD	
New	Stellite Ring Inner		NAD	NAD	
	Lower Gib	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

HIGH PRESSURE STATIONARY LOWER

Component	Item	Method			
		MT	PT	VT	UT
#2 Inner Shell		NAD		NAD	
	Nozzle Block	NAD		NAD	
	Row #1 Blading (84)	#4,6,14,15, 17,26,29,46 ,56,60 crack ID; #19,20,29, 67 crack OD		Light FOD, sever erosion; #2-4,44, 80-83 missing part of blade from erosion OD	
	Row #2 Blading (84)	#1,38,39, 45,47,71, 72, 74,81, 82, 83 crack ID; #59,77 crack OD		Light FOD, sever erosion #1-4,44, 78, 80-84 missing part of blade from erosion OD	
	N-2 Packing Inner	NAD		NAD	
	N-2 Packing Outer	NAD		NAD	
Outers	Shell Bolts (44)			NAD	NAD
Inners	Shell Bolts (16)			NAD	NAD

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

HIGH PRESSURE STATIONARY UPPER

Component	Item	Method			
		MT	PT	VT	UT
	N-1 Packing Inner	NAD		NAD	
	N-1 Packing Outer	NAD		NAD	
	#7 Diaphragm (39)	#13,16,18, 26 crack OD		ID & OD braces cracked between 38 & 39	
	#6 Diaphragm (57)	#57 crack ID & OD, #11,13 crack ID		Light erosion	
	#5 Diaphragm (47)	#24 crack OD; #39, 44,46 Crack ID; #8, 27 crack leading edge OD		Light erosion, #35 repair area separating ID	
	#4 Diaphragm (50)	#3,25 crack ID		Light erosion	
	#3 Diaphragm (60)	#47,53,57, 58 crack ID, #49 crack OD		Light FOD, Light erosion, ID brace crack between 59,60	
	#2 Diaphragm (36)	#50 tear, #11 hole OD, #21 crack OD, #22 crack ID		Heavy FOD, light erosion	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

HIGH PRESSURE STATIONARY UPPER

Component	Item	Method			
		MT	PT	VT	UT
Outer casing	#1 Gib Key Fit (slot)	NAD		NAD	
	#2 Gib Key Fit	NAD		NAD	
	Horizontal Flange	NAD		NAD	
# 1 Inner Shell		NAD		NAD	
	#7 Fit	NAD		NAD	
	#6 Fit	NAD		NAD	
	#5 Fit	NAD		NAD	
	#4 Fit	NAD		NAD	
	#3 Fit	NAD		NAD	
	#2 Fit	NAD		NAD	
New	Stellite Ring Outer		NAD	NAD	
New	Stellite Ring Inner		NAD	NAD	
# 1 Inner Shell	Upper Gib	NAD		NAD	
#2 Inner Shell		NAD		NAD	
	Nozzle Block	NAD		NAD	
	Row #1 Blading (84)	#5,7,8,15, 16,18,19, 22,24,26-28,31,35, 39,42,48, 50,69,73, 75,77,80,81 crack ID; #29, 64 crack OD		Light FOD, sever erosion; #1-4,41, 44, 81-83 missing part of blade from erosion OD	
	Row #2 Blading (84)	#1,3,4,6,13, 14,19,21, 39,41,42, 44,48,51, 53,55,56, 60,65,71,79 crack ID		Light FOD, severe erosion; #1-5,40-42,44,81-83 missing part of blade from erosion	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

HIGH PRESSURE STATIONARY UPPER

Component	Item	Method			
		MT	PT	VT	UT
	N-2 Packing Inner	NAD		NAD	
	N-2 Packing Outer	NAD		NAD	
	Main Steam Outboard Flange	NAD		NAD	
	Main Steam Inboard Flange	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE ROTOR TURBINE END

Component	Item	Method			
		MT	PT	VT	UT
	A Coupling	NAD		NAD	
	Thrust Bearing Collars	NAD		NAD	
	#3 Journal	NAD		NAD	
	Packing Grooves	NAD		NAD	
	Shaft	NAD		NAD	
(72)	#13 Bucket Row (14")	NAD		NAD	
(80)	#12 Bucket Row (12")	NAD		NAD	
(104)	#11 Bucket Row (10½")	NAD		NAD	
(104)	#10 Bucket Row (9¾")	NAD		Light erosion	
(108)	#9 Bucket Row (9")	NAD		Light erosion	
(100)	#8 Bucket Row (9¾")	NAD		Light FOD, Heavy erosion	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE ROTOR TURBINE END

Component	Item	Method			
		MT	PT	VT	UT
	#13 Shroud	NAD		NAD	
	#12 Shroud	NAD		NAD	
	#11 Shroud	NAD		Sporadic FOD on inside covers	
	#10 Shroud	NAD		Sporadic FOD on inside covers	
	#9 Shroud	NAD		Sporadic FOD on inside covers	
	#8 Shroud	NAD		Sporadic FOD on inside covers	
	#13 Wheel	NAD		NAD	
	#12 Wheel	NAD		NAD	
	#11 Wheel	NAD		NAD	
	#10 Wheel	NAD		NAD	
	#9 Wheel	NAD		NAD	
	#8 Wheel	NAD		NAD	
	Balance Weights	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE ROTOR GENERATOR END

Component	Item	Method			
		MT	PT	VT	UT
	Shaft	NAD		NAD	
	#8 Bucket Row 9¾" (25 gp of 4	NAD		Light FOD, Heavy erosion	
	#9 Bucket Row 9" (27 gp of 4)	NAD		Light erosion	
	#10 Bucket Row 9¾" (26 gp of 4)	NAD		Light erosion	
	#11 Bucket Row 10-½" (26 gp of 4)	NAD		NAD	
	#12 Bucket Row 12" (20 gp of 4)	NAD		NAD	
	#13 Bucket Row 14" (18 gp of 4)	NAD		NAD	
	#8 Shroud	NAD		Sporadic FOD on inside covers	
	#9 Shroud	NAD		Sporadic FOD on inside covers	
	#10 Shroud	NAD		Sporadic FOD on inside covers	
	#11 Shroud	NAD		Sporadic FOD on inside covers	
	#12 Shroud	NAD		NAD	
	#13 Shroud	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE ROTOR GENERATOR END

Component	Item	Method			
		MT	PT	VT	UT
	#8 Wheel	NAD		NAD	
	#9 Wheel	NAD		NAD	
	#10 Wheel	NAD		NAD	
	#11 Wheel	NAD		NAD	
	#12 Wheel	NAD		NAD	
	#13 Wheel	NAD		NAD	
	Packing Grooves	NAD		NAD	
	#4 Journal	NAD		NAD	
	B Coupling	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE STATIONARY TURBINE END LOWER

Component	Item	Method			
		MT	PT	VT	UT
Turbine End Lower					
	N-3 Outer Lower	NAD		NAD	
Outer Casing	#1 Fit (Slot)	NAD		NAD	
	#2 Fit	NAD		NAD	
	Horizontal Flange	NAD		NAD	
#2 Inner Shell		NAD		NAD	
	#13 Gib Key Fit	NAD		NAD	
	#12 Gib Key Fit	NAD		NAD	
	#11 Gib Key Fit	NAD		NAD	
#2 Inner Shell	Gib Key Fit	NAD		NAD	
	#13 Diaphragm (60)	#26 crack ID, #3 OD web crack TE		NAD	
	#12 Diaphragm (52)	#16,40 hole in blade, #42 crack OD		Light erosion	
	#11 Diaphragm (63)	#1, 63 hole in blade		Sporadic FOD with light erosion	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE STATIONARY TURBINE END LOWER

Component	Item	Method			
		MT	PT	VT	UT
#1 Inner Shell		NAD		NAD	
	#10 Gib Key Fit	NAD		NAD	
	#9 Gib Key Fit	NAD		NAD	
	#8 Gib Key Fit	NAD		NAD	
#1 Inner Shell	Fit	NAD		NAD	
	#10 Diaphragm (37)	#1 crack ID, #11,35 hole in blade		Sporadic FOD	
	#9 Diaphragm (43)	#7,9,13,22 Cracked repair area; #14 ID crack; #36 OD crack		Sporadic FOD & erosion	
	#8 Diaphragm (61)	#1-5,8,10, 11,13,27, 28,30-34, 36,39,40, 57-60 crack ID		Erosion, FOD, #46 crack OD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE STATIONARY GENERATOR END LOWER

Component	Item	Method			
		MT	PT	VT	UT
Generator End Lower					
#1 Inner Shell		NAD		NAD	
	#8 Gib Key Fit	NAD		NAD	
	#9 Gib Key Fit	NAD		NAD	
	#10 Gib Key Fit	NAD		NAD	
#1 Inner Shell	Gib Key Fit	NAD		NAD	
#1 Inner Shell	Fit	NAD		NAD	
	#8 Diaphragm (61)	#2,6,13,15, 23,27,28, 32,39,40, 47,50 crack ID		Erosion, FOD, Crack of brace OD between 60 & 61	
	#9 Diaphragm (43)	#4,11,12,25 OD crack; #15 ID crack; Inner web cracked in previous weld repair area on LE @ blade #32		Sporadic FOD & erosion	
	#10 Diaphragm (37)	#3,28,30, 31,34,36 ID crack		Light sporadic FOD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE STATIONARY GENERATOR END LOWER

Component	Item	Method			
		MT	PT	VT	UT
Generator End Lower					
#2 Inner Shell		NAD		NAD	
#2 Inner Shell	Fit	NAD		NAD	
	#11 Gib Key Fit	NAD		NAD	
	#12 Gib Key Fit	NAD		NAD	
	#13 Gib Key Fit	NAD		NAD	
	#11 Diaphragm (63)	#5 crack OD; #11 crack ID		Light erosion	
	#12 Diaphragm (52)	#23 hole in blade OD; #42 ID crack		NAD	
	#13 Diaphragm (60)	#5,7 OD blade crack; Outer web cracked @ blade #41		NAD	
Outer Casing	#2 Fit	NAD		NAD	
	#1 Fit (Slot)	NAD		NAD	
	N-4 Outer Lower	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE STATIONARY TURBINE END UPPER

Component	Item	Method			
		MT	PT	VT	UT
Turbine End Upper					
	N-3 Outer Upper	NAD		NAD	
Outer Casing	#1 Fit	NAD		NAD	
	#2 Fit	2-1/8" crack 61" from RS horiz TE of fit		NAD	
	Horizontal Flange	NAD		NAD	
#2 Inner Shell					
#2 Inner Shell	Gib Key Fit				
	#13 Gib Key Fit	NAD		NAD	
	#12 Gib Key Fit	NAD		NAD	
	#11 Gib Key Fit	NAD		NAD	
	#13 Diaphragm (60)	NAD		Light FOD & erosion	
	#12 Diaphragm (52)	#1 hole ID		Light erosion	
	#11 Diaphragm (63)	#52 crack OD, #63 weld separating from brace		Light erosion & FOD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE STATIONARY TURBINE END UPPER

Component	Item	Method			
		MT	PT	VT	UT
Turbine End Upper					
#1 Inner Shell		12 cracks on left side of horiz. Longest 5/8"		NAD	
	#10 Gib Key Fit	NAD		NAD	
	#9 Gib Key Fit	NAD		NAD	
	#8 Gib Key Fit	NAD		NAD	
#1 Inner Shell	Fit	NAD		NAD	
	Horizontal Flange	NAD		NAD	
	#10 Diaphragm (37)	#1, 16 holes OD		Light erosion, FOD	
	#9 Diaphragm (43)	#2,5,17,25, 33,34,38 crack ID, #13,19,29, 33,40,42 crack OD		Light FOD both braces crack between #42 & 43, #19,21 holes OD	
	#8 Diaphragm (61)	#6,8,11,14, 17,19,20, 24-29,36, 49-53,55 crack ID; #30,31,58 crack OD		Heavy FOD, severe erosion #3,8,15 missing part of blade	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE STATIONARY GENERATOR END UPPER

Component	Item	Method			
		MT	PT	VT	UT
Generator End Lower					
#1 Inner Shell		Left & right horiz. joint have small numerous cracks		NAD	
	#8 Gib Key Fit	NAD		NAD	
	#9 Gib Key Fit	NAD		NAD	
	#10 Gib Key Fit	NAD		NAD	
#1 Inner Shell	Gib Key Fit	NAD		NAD	
#1 Inner Shell	Fit	NAD		NAD	
	#8 Diaphragm (61)	#1,14,19, 21,22,24, 28,31-33, 46,48,50, 52 crack ID		Severe erosion, FOD, crack of brace ID between 60 & 61	
	#9 Diaphragm (43)	#5,38, crack LE OD, #32 crack LE ID, #3,18, 27 tear ID, #5,11,36,40 crack ID, #9,12 crack OD		FOD, erosion	
	#10 Diaphragm (37)	NAD		Light sporadic FOD; OD brace severe erosion	
Outer Casing	#1 Fit	NAD		NAD	
	#2 Fit	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

INTERMEDIATE PRESSURE STATIONARY GENERATOR END UPPER

Component	Item	Method			
		MT	PT	VT	UT
Generator End Lower					
#2 Inner Shell		Left & right horiz. joint have small numerous cracks		NAD	
#2 Inner Shell	Fit	NAD		NAD	
	#11 Gib Key Fit	NAD		NAD	
	#12 Gib Key Fit	NAD		NAD	
	#13 Gib Key Fit	NAD		NAD	
	#11 Diaphragm (63)	#63 crack ID & OD		Light erosion	
	#12 Diaphragm (52)	NAD		Light erosion	
	#13 Diaphragm (60)	NAD		NAD	
	N-4 Outer Upper	NAD		NAD	
Outer	Shell Bolts (64)			NAD	NAD

SHERCO UINT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE ROTOR "A"

Component	Item	Method			
		MT	PT	VT	UT
Turbine End					
	B Coupling	NAD		NAD	
	#5 Journal	NAD		NAD	
	Packing Grooves	NAD		NAD	
	Shaft	NAD		NAD	
	L-0 Dovetail Pins				33 Pins cracked
	L-0 Tie Wires	NAD		NAD	
	L-0 Wheel	NAD		NAD	
	L-0 Stellite		NAD	NAD	
	Row (L-0) Buckets (94) 39-¾"	NAD		Light erosion on all blading, erosion to strip and blade area adjacent to strip	
	Row (L-0) Shroud	NAD		NAD	
	L-1 Dovetail Pins				N/A
	L-1 Tie Wires	N/A		N/A	
	L-1 Wheel	NAD		NAD	
	Row (L-1) Buckets	N/A		N/A	
	Row (L-1) Shroud	N/A		N/A	
	Row 17 Wheel	NAD		NAD	
	Row 16 Wheel	NAD		NAD	
	Row 15 Wheel	NAD		NAD	
	Row 14 Wheel	NAD		NAD	

SHERCO UINT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE ROTOR "A"

Component	Item	Method			
		MT	PT	VT	UT
Turbine End					
	Row 17 Buckets (13 gp of 4/5) 16-5/8"	NAD		Light pitting	
Titanium	Row 17 Notch Blade		NAD	NAD	
	Row 16 Buckets (32 gp of 4) 10-5/8"	NAD		Light pitting	
	Row 15 Buckets (40 gp of 5) 7½"	NAD		Light pitting	
	Row 14 Buckets (40 gp of 4/5) 6-1/8"	NAD		Light pitting	
	Row 17 Shroud	NAD		NAD	
	Row 16 Shroud	NAD		NAD	
	Row 15 Shroud	NAD		NAD	
	Row 14 Shroud	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE ROTOR "A"

Component	Item	Method			
		MT	PT	VT	UT
Generator End					
	Row 14 Wheel	NAD		NAD	
	Row 15 Wheel	NAD		NAD	
	Row 16 Wheel	NAD		NAD	
	Row 17 Wheel	NAD		NAD	
	Row 14 Buckets	NAD		Light pitting	
	Row 15 Buckets	NAD		Light pitting	
	Row 16 Buckets	NAD		Light pitting	
	Row 17 Buckets	NAD		Light pitting	
Titanium	Row 17 Notch Blade		NAD	NAD	
	Row 14 Shroud	NAD		NAD	
	Row 15 Shroud	NAD		NAD	
	Row 16 Shroud	NAD		NAD	
	Row 17 Shroud	NAD		NAD	
	L-1 Dovetail Pins	N/A		N/A	N/A
	L-1 Tie Wires	N/A		N/A	
	L-1 Wheel	NAD		NAD	
	Row (L-1) Buckets	N/A		N/A	
	Row (L-1) Shroud	N/A		N/A	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE ROTOR "A"

Component	Item	Method			
		MT	PT	VT	UT
Generator End					
	L-0 Dovetail Pins	NAD		NAD	140 pins cracked
	L-0 Tie Wires	NAD		NAD	
	L-0 Wheel	NAD		NAD	
	L-0 Stellite		NAD	NAD	
	Row (L-0) Buckets	NAD		Light erosion on all blading, erosion to strip and blade area adjacent to strip	
	Row (L-0) Shroud	NAD		NAD	
	Packing Grooves	NAD		NAD	
	#6 Journal	NAD		NAD	
	C Coupling	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE STATIONARY "A" TURBINE END LOWER

Component	Item	Method			
		MT	PT	VT	UT
	N-5 Packing Outer	NAD		NAD	
Lower Inner Cylinder					
	#19 Keys & Gib Alignment	NAD		NAD	
	#18 Keys & Gib Alignment	NAD		NAD	
	#17 Keys & Gib Alignment	NAD		NAD	
	#16 Keys & Gib Alignment	NAD		NAD	
	#15 Keys & Gib Alignment	NAD		NAD	
	#14 Keys & Gib Alignment	NAD		NAD	
	#19 Diaphragm (30)	#2,3,5 OD weld cracked TE		NAD	
	#18 Diaphragm (40)	LS Horiz. joint crack & Key way crack; #18 crack OD TE; #35 ID crack TE.		NAD	
	#17 Diaphragm (40)	NAD		NAD	
	#16 Diaphragm (36)	#29 cracked center of blade		Light pitting	
	#15 Diaphragm (79)	#52,53,59, 73,70 weld repair cracked		Sporadic FOD	
	#14 Diaphragm (71)	#70 crack OD TE; #71 crack ID LE		Light erosion	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE STATIONARY "A" GENERATOR END LOWER

Component	Item	Method			
		MT	PT	VT	UT
Generator End Lower					
	#14 Keys & Gib Alignment	NAD		NAD	
	#15 Keys & Gib Alignment	NAD		NAD	
	#16 Keys & Gib Alignment	NAD		NAD	
	#17 Keys & Gib Alignment	NAD		NAD	
	#18 Keys & Gib Alignment	NAD		NAD	
	#19 Keys & Gib Alignment	NAD		NAD	
	#14 Diaphragm (71)	NAD		Light erosion	
	#15 Diaphragm (79)	#19 Crack ID, #44 Crack OD		NAD	
	#16 Diaphragm (36)	NAD		Light pitting	
	#17 Diaphragm (40)	#14 crack ID, #22 crack OD		NAD	
	#18 Diaphragm (40)	LS Horiz. joint cracked; #37 OD repair area separating		NAD	
	#19 Diaphragm (30)	#1 OD crack; #23,24,25, 27 ID weld cracked		NAD	
	N-6 Packing Outer	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE STATIONARY "A" TURBINE END UPPER

Component	Item	Method			
		MT	PT	VT	UT
	N-5 Packing Outer	NAD		NAD	
Upper Inner Cylinder		NAD			
	#19 Keys & Gib Alignment	NAD		NAD	
	#18 Keys & Gib Alignment	NAD		NAD	
	#17 Keys & Gib Alignment	NAD		NAD	
	#16 Keys & Gib Alignment	NAD		NAD	
	#15 Keys & Gib Alignment	NAD		NAD	
	#14 Keys & Gib Alignment	NAD		NAD	
	#19 Diaphragm (30)	#17,24 ID weld cracked TE; #19,23 OD weld cracked TE; #10,14,22, 25 OD weld cracked LE		NAD	
	#18 Diaphragm (40)	RS horiz. joint OD web crack; OD web crack @ blade #40		NAD	
	#17 Diaphragm (40)	#1 crack OD, #24, 25,26,27 crack ID		NAD	
	#16 Diaphragm (36)	NAD		Light pitting	
	#15 Diaphragm (79)	#79 tear in center		Sporadic FOD	
	#14 Diaphragm (71)	#17 tear OD, #18 crack OD		Light erosion	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE STATIONARY "A" GENERATOR END UPPER

Component	Item	Method			
		MT	PT	VT	UT
Generator End Upper		NAD			
	#14 Keys & Gib Alignment	NAD		NAD	
	#15 Keys & Gib Alignment	NAD		NAD	
	#16 Keys & Gib Alignment	NAD		NAD	
	#17 Keys & Gib Alignment	NAD		NAD	
	#18 Keys & Gib Alignment	NAD		NAD	
	#19 Keys & Gib Alignment	NAD		NAD	
	#14 Diaphragm (71)	NAD		Light erosion	
	#15 Diaphragm (79)	#68,79 crack OD		NAD	
	#16 Diaphragm (36)	#36 crack OD		Light pitting	
	#17 Diaphragm (40)	NAD		NAD	
	#18 Diaphragm (40)	#22 ID crack, #32 OD crack		RS Hoiz. Joint OD cracked	
	#19 Diaphragm (30)	#16,17,19, 20,23,24,25 ID weld cracked LE; #6,7,29 OD weld cracked		NAD	
	N-6 Packing Outer	NAD		NAD	

SHERCO UINT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE ROTOR "B"

Component	Item	Method			
		MT	PT	VT	UT
Turbine End					
	C Coupling	NAD		NAD	
	#7 Journal	NAD		NAD	
	Packing Grooves	NAD		NAD	
	Shaft	NAD		NAD	
	L-0 Dovetail Pins	NAD		NAD	1 Pin cracked
	L-0 Tie Wires	NAD		NAD	
	L-0 Wheel	NAD		NAD	
	L-0 Stellite		NAD	NAD	
	Row (L-0) Buckets	NAD		NAD	
	Row (L-0) Shroud	NAD		NAD	
	L-1 Dovetail Pins	N/A		N/A	N/A
	L-1 Tie Wires	N/A		N/A	
	L-1 Wheel	NAD		NAD	
	Row (L-1) Buckets	N/A		N/A	
	Row (L-1) Shroud	N/A		N/A	
	Row 17 Wheel	NAD		NAD	
	Row 16 Wheel	NAD		NAD	
	Row 15 Wheel	NAD		NAD	
	Row 14 Wheel	NAD		NAD	

SHERCO UINT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE ROTOR "B"

Component	Item	Method			
		MT	PT	VT	UT
	Row 17 Buckets	NAD		NAD	
Titanium	Row 17 Notch Blade		NAD	NAD	
	Row 16 Buckets	NAD		NAD	
	Row 15 Buckets	NAD		NAD	
	Row 14 Buckets	NAD		NAD	
	Row 17 Shroud	NAD		NAD	
	Row 16 Shroud	NAD		NAD	
	Row 15 Shroud	NAD		NAD	
	Row 14 Shroud	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE ROTOR "B"

Component	Item	Method			
		MT	PT	VT	UT
Generator End					
	Row 14 Wheel	NAD		NAD	
	Row 15 Wheel	NAD		NAD	
	Row 16 Wheel	NAD		NAD	
	Row 17 Wheel	NAD		NAD	
	Row 14 Buckets	NAD		NAD	
	Row 15 Buckets	NAD		NAD	
	Row 16 Buckets	NAD		NAD	
	Row 17 Buckets	NAD		NAD	
Titanium	Row 17 Notch Blade		NAD	NAD	
	Row 14 Shroud	NAD		NAD	
	Row 15 Shroud	NAD		NAD	
	Row 16 Shroud	NAD		NAD	
	Row 17 Shroud	NAD		NAD	
	L-1 Dovetail Pins	N/A		N/A	N/A
	L-1 Tie Wires	N/A		N/A	
	L-1 Wheel	NAD		NAD	
	Row (L-1) Buckets	N/A		N/A	
	Row (L-1) Shroud	N/A		N/A	
	L-0 Dovetail Pins	NAD		NAD	55 Pins Cracked
	L-0 Tie Wires	NAD		NAD	
	L-0 Wheel	NAD		NAD	
	L-0 Stellite		NAD	NAD	
	Row (L-0) Buckets	NAD		NAD	
	Row (L-0) Shroud	NAD		NAD	
	Packing Grooves	NAD		NAD	
	#8 Journal	NAD		NAD	
	D Coupling	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE STATIONARY "B" TURBINE END LOWER

Component	Item	Method			
		MT	PT	VT	UT
	N-7 Packing Outer	NAD		NAD	
Lower Inner Cylinder					
	#19 Keys & Gib Alignment	NAD		NAD	
	#18 Keys & Gib Alignment	NAD		NAD	
	#17 Keys & Gib Alignment	NAD		NAD	
	#16 Keys & Gib Alignment	NAD		NAD	
	#15 Keys & Gib Alignment	NAD		NAD	
	#14 Keys & Gib Alignment	NAD		NAD	
	#19 Diaphragm (30)	#1,2,4,9,10, 11,16,19, 21,26,27, 29,30 OD weld cracked LE; # 4,9,21,24, 26,29 ID weld cracked LE; #9,10,11, 12,15,18, 19, 20,30 ID weld cracked TE: #3,5,9,12, 13,14-17, 22-24,26,28 OD weld cracked TE		NAD	
	#18 Diaphragm (40)	NAD		LS Horiz. Joint crack	
	#17 Diaphragm (40)	#10 crack OD		NAD	
	#16 Diaphragm (36)	NAD		Light pitting	
	#15 Diaphragm (79)	NAD		NAD	
	#14 Diaphragm (71)	NAD		Light erosion	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE STATIONARY "B" GENERATOR END LOWER

Component	Item	Method			
		MT	PT	VT	UT
Generator End Lower					
	#14 Keys & Gib Alignment	NAD		NAD	
	#15 Keys & Gib Alignment	NAD		NAD	
	#16 Keys & Gib Alignment	NAD		NAD	
	#17 Keys & Gib Alignment	NAD		NAD	
	#18 Keys & Gib Alignment	NAD		NAD	
	#19 Keys & Gib Alignment	NAD		NAD	
	#14 Diaphragm (71)	#57 OD weld repair separating		Light FOD, light erosion	
	#15 Diaphragm (79)	#2,76 hole in blade, #74 crack OD, #52 crack ID		NAD	
	#16 Diaphragm (36)	NAD		Light pitting	
	#17 Diaphragm (40)	LS horiz. joint crack, #13 LE OD crack		NAD	
	#18 Diaphragm (40)	LS Horiz. joint cracked; #1 repair area separating		NAD	
	#19 Diaphragm (30)	#1,2,4-7, 9-11,14, 16-18,21, 22, 26-30 OD weld cracked LE; # 6,8-11,23, 24, 29 ID weld cracked LE; #26 ID weld cracked TE; #19 blade crack ID TE; #25,27 blade crack OD TE		NAD	
	N-8 Packing Outer	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE STATIONARY "B" TURBINE END UPPER

Component	Item	Method			
		MT	PT	VT	UT
	N-7 Packing Outer	NAD		NAD	
Upper Inner Cylinder		Crack at #2 access cover 5¼"L; crack corner of LS outer end plate 13½"L			
	#19 Keys & Gib Alignment	NAD		NAD	
	#18 Keys & Gib Alignment	NAD		NAD	
	#17 Keys & Gib Alignment	NAD		NAD	
	#16 Keys & Gib Alignment	NAD		NAD	
	#15 Keys & Gib Alignment	NAD		NAD	
	#14 Keys & Gib Alignment	NAD		NAD	
	#19 Diaphragm 30 blades	#1,6,10,16, 18,20,21, 27,28 OD weld cracked LE; #11 ID weld cracked LE		NAD	
	#18 Diaphragm (40)	NAD		RS Horiz. joint OD crack	
	#17 Diaphragm (40)	#33 crack OD		NAD	
	#16 Diaphragm (36)	NAD		Light pitting	
	#15 Diaphragm (79)	NAD		NAD	
	#14 Diaphragm(71)	#63 crack OD		Light erosion, Light FOD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

LOW PRESSURE STATIONARY "B" GENERATOR END UPPER

Component	Item	Method			
		MT	PT	VT	UT
Generator End Upper		NAD			
	#14 Keys & Gib Alignment	NAD		NAD	
	#15 Keys & Gib Alignment	NAD		NAD	
	#16 Keys & Gib Alignment	NAD		NAD	
	#17 Keys & Gib Alignment	NAD		NAD	
	#18 Keys & Gib Alignment	NAD		NAD	
	#19 Keys & Gib Alignment	NAD		NAD	
	#14 Diaphragm (71)	NAD		Light erosion, Light FOD	
	#15 Diaphragm	NAD		Sporadic FOD blades rolled over, LE erosion at OD of web	
	#16 Diaphragm	NAD		Light pitting	
	#17 Diaphragm	NAD		NAD	
	#18 Diaphragm (40)	LS Horiz. joint cracked		NAD	
	#19 Diaphragm (30)	#2 OD weld cracked TE: #3,8,11,12, 14,26,27,28 OD weld cracked LE; #3,8,21,24, 26 ID weld cracked LE		NAD	
	N-8 Packing Outer	NAD		NAD	

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

BOLTING

Component	Item	Method			
		MT	PT	VT	UT
A Coupling					
	Bolts (16)	NAD		NAD	NAD
	Nuts (32)	NAD		NAD	
	Washers (32)	NAD		NAD	
B Coupling					
	Bolts (16)	NAD		NAD	NAD
	Nuts (32)	NAD		NAD	
	Washers (32)	NAD		NAD	
C Coupling					
	Bolts (16)	NAD		NAD	NAD
	Nuts (32)	NAD		NAD	
	Washers (32)	NAD		NAD	
D Coupling					
	Bolts (16)	NAD		NAD	NAD
	Nuts (32)	NAD		NAD	
	Washers (32)	NAD		NAD	
HP Outer	Bolts (44)			NAD	NAD
IP Outer	Bolts (64)			NAD	NAD
HP Inner	Bolts (26)			NAD	NAD
LP Inner	Bolts (16)			3 with indications	NAD

SHERCO UNIT 3 OUTAGE
SUMMARY LISITING

VALVES

Component	Item	Method			
		MT	PT	VT	UT
#1 CONTROL VALVE					
	Body (TIL 943)		NAD	NAD	
	Seat		NAD	NAD	
	Seat Pins (4)				NAD
	Bolts (12)			NAD	NAD
#2 CONTROL VALVE					
	Body (TIL 943)		NAD	NAD	
	Seat		NAD	NAD	
	Seat Pins (4)				NAD
	Bolts (12)			NAD	NAD
#3 CONTROL VALVE					
	Body (TIL 943)		NAD	NAD	
	Seat		NAD	NAD	
	Seat Pins (4)				NAD
	Bolts (12)			NAD	NAD
#4 CONTROL VALVE					
	Body (TIL 943)		NAD	NAD	
	Seat		NAD	NAD	
	Seat Pins (4)				NAD
	Bolts (12)			NAD	NAD