03/25/99 THU 11:38 FAX 6305733203 Rosetta Hooker 002

GE International, Inc.
A Subsidiary of General Electric Company - U.S.A.
4200 Wildwood Parkway
4th Floor / West wing
Atlanta, GA 30339

– 1627 Steve Blegen

Hold
Per M. Roll
3/29/99

Send Payment Showing Invoice No. and Invoice Date To:
GE International, Inc.
PO BOX 98749
CHICAGO, IL 60693

INVOICE

PAYMENT DUE:
April 11, 1999

PO#	Order Date	Reference #	Invoice #	Invoice Date	Page
PN4613MM / PN7053MS	6/23/98	401SC9806230	N04G1734	3/12/99	1 of 1

Bill To: ACCOUNTS PAYABLE
NORTHERN STATES POWER
PO BOX 9366
414 NICOLLET NMALL
MINNEAPOLIS, MN 55401-9366

DESCRIPTION		AMOUNT
SHERBURNE COUNTY GENERATING STATION BECKER, MN UNIT #3, TURBINE S/N 170X819 L-1 BUCKET UPGRADE, NON-DESTRUCTIVE ROTOR EXAMINATION, FIELD ENGINEERING SERVICES NDE		
FIRM PRICE :		
MATERIAL PO PN613MM	$1,800,000.00	
LABOR PO PN7053MS	$550,000.00	
*** SEPERATE INVOICE FOR TAX TO BE ISSUED AT COMPLETION OF WORK SCOPE ***		
TO INVOICE FOR PAYMENT #2 UPON SHIPMENT OF BUCKETS		1,300,000.00

COPY

If you have any questions regarding this invoice please contact Rosetta Hooker at (630) 573-3278

TOTAL DUE TO DATE:	1,800,000.00
TOTAL BILLED TO DATE	500,000.00
TOTAL DUE THIS INVOICE:	US $ 1,300,000.00

Dept 04770 Strm 2427 ID DHLD12 Invoice Date 3-12-99
Vendor Code GELC TR13
✓ Needs Line/Receipt ✓
___ Other

Please put an "A" in TT04 when you have taken the action requested. It is not necessary to mail this copy back.

PREPARED BY: J TWEEDDALE
PROJ MGR: MICHELLE TUTTLE (770) 859-6341

DTN	TAX	COLLECTION DISTRICT	OFFICE	SALES DISTRICT	CUST NO	ICN	TOTAL BILLED THIS INVOICE
21	10	60	401	G42	46195	A8213001	US $ 1,300,000.00

Seller represents that the goods covered by this invoice have been produced within the requirements of the Fair Labor Standards Act of 1938, as amended.

Fax to Bob Langer, NSP
330-6534 4/22

TRIAL EXHIBIT
0134
exhibitsticker.com

GE-NSP00083747

TIL 1277-2

GE ENERGY SERVICES

PRODUCT SERVICE

December 2,1999

g

TECHNICAL INFORMATION LETTER

INSPECTION OF LOW PRESSURE ROTOR WHEEL DOVETAILS ON STEAM TURBINES WITH FOSSIL FUELED ONCE-THROUGH BOILERS.

APPLICABLE TO

All US fossil steam turbines with once-through boilers.

PURPOSE

To inform users of need to inspect low pressure rotor wheel dovetails on steam turbines to detect possible Stress Corrosion Cracking.

BACKGROUND / DISCUSSION

Over the past several years cases of intergranular Stress Corrosion Cracking (SCC) have been found in low pressure rotor dovetails of fossil steam turbine units with once through boilers. These rotors had been in service for extended periods. These incidents have involved both Tangential dovetails, figure 1.
And Finger dovetails, figure 2.

SCC has been known to occur with the presence of a Conducive Environment, Applied Stress Levels and a Material that can crack in this environment. The steel used for low-pressure rotors has been in service since the early 1960's due to its superior toughness required for these applications. Subsequent investigations by GE, other suppliers and institutions have found these alloys to have good SCC resistance for the strength levels used. Low-pressure rotors of this composition continue to be the materials of choice for steam turbine manufacturers.

Units operating with Once-Through boilers have a higher susceptibility for SCC. The most vulnerable location in the steam turbine for SCC is believed to be the Wilson Line or the point at which saturation occurs. This region is typically the L-1 or L-2 stage for a conventional reheat steam turbine. There are many factors that influence SCC including condensate polisher and other feed water treatment histories.

Most cases have involved the L-1 and L-2 stages. On rare occasions SCC cracking has also been found further upstream. GE can ultrasonically inspect tangential entry stages, without the need to remove buckets. Meaningful inspection of finger dovetails is not possible without removal of the buckets. SCC of finger dovetail stages has involved the internal fingers with no external indication of cracking and indications have also been found away from dovetail pinholes.

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RECOMMENDATIONS

1. Steam chemistry must be carefully monitored and controlled, to avoid ingestion of harmful contaminants into the turbine. For GE recommendations on steam chemistry control, refer to GEK 72281.

2. Inspect Dovetails for cracking.

   A. All 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. This testing is normally part of a GE in-service rotor evaluation conducted per TIL 956 or it may be conducted as a stand-alone test. GE's Phased Array Dovetail Ultrasonic Test is recommended. If it's decided to remove buckets, the wheel must be tested using florescent magnetic particle testing and a wet continuous method.

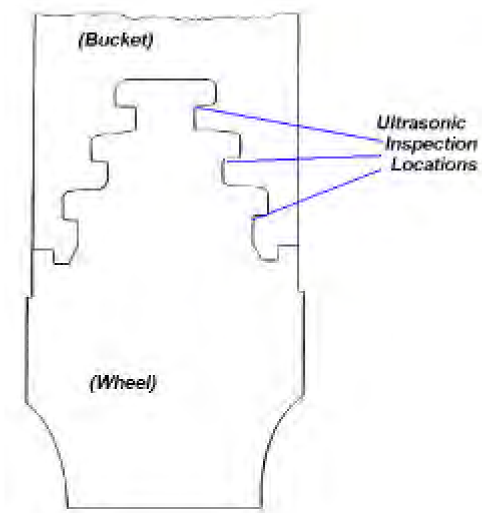


Figure 1. Tangential Dovetail

   B. For inspection of finger dovetails all of the buckets must be removed. Stages with finger dovetails cannot be inspected ultrasonically. For units with once-through boilers and more than 10 years of service, given the possible existence of cracking and the affect on unit reliability, the owner should make preparations for the inspection of all rows of finger dovetails during a convenient maintenance outage.

If buckets are removed, the surfaces must be properly cleaned using approved methods and thoroughly inspected for SCC indications in both the tangential and radial directions using florescent magnetic particle testing and a wet continuous method of testing. Stages with finger dovetails are to be tested in accordance with TIL 1121.

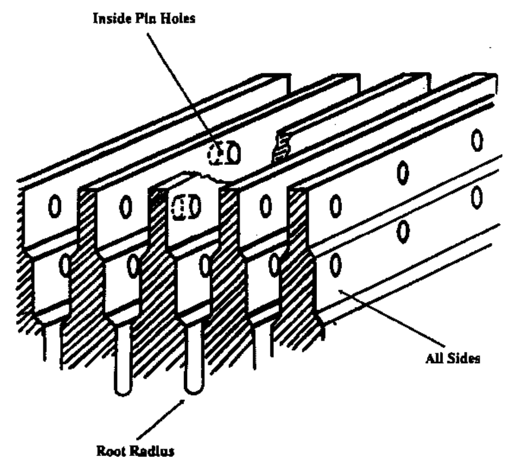


Figure 2. Finger Dovetail

3. Inspection results should be thoroughly documented and forwarded immediately to GE Energy Services for review and recommendation.

In the event that SCC is discovered, initiate repairs at the current outage. Weld repairs, using GE's FineLine weld process, using a forged ring, or GE's weld buildup restoration technology, are the best options. Tangential entry stages may be restored by machining, for either temporary or longer-term service depending on the severity of the cracking found.

For assistance in implementing the above recommendations, contact your local General Electric District Office representative.

GE Power Generation

9999.0024

March 29, 1993

Power Generation Services
General Electric Company
P.O. Box 526440, Salt Lake City, UT 84152-6440
801 463-5713

Mr. Myron Laws
Public Service Co. of Colorado
P.O. Box 857
Brush, CO 80723

Subject: TIL 1121-3AR1
Inspection of Steam Turbine
Rotor Wheel Finger Dovetails
Pawnee #1
TB's.170X742

Dear Mr. Laws:

Attached you will find TIL-1121-3AR1, a revision of TIL 1121-3 issued in 1992. Revision 1 of this TIL was issued to respond to a number of questions received after the original issue, particularly to clarify what is meant by "abnormal operation or unusual operating events."

As with the original TIL, this TIL DOES NOT recommend the removal of buckets for inspection of the rotor wheel finger dovetails, unless abnormal events or operational anomalies are encountered which may increase the risk of stress corrosion and/or fatigue.

This revision includes a detailed inspection procedure and discussion, and a data sheet which will help us in communicating any indications which may be found.

If I can be of further assistance, please let me know.

Sincerely,

Tom D. Varah

Tom D. Varah
Manager, Engineering Services

TDV/kn

TRIAL EXHIBIT
0007

EXHIBIT NO. 74
4.22.15
R. L. KLANDERUD

GE POWER GENERATION
1 RIVER ROAD
SCHENECTADY, NY 12345

GE POWER GENERATION
PARTS & PRODUCT SERVICE

TIL 1121-3AR1

TECHNICAL INFORMATION LETTER

170X742
PUBLIC SERVICE COLOR
PAWNEE 001
COLORADO

February 1, 1993

INSPECTION OF STEAM TURBINE ROTOR WHEEL FINGER DOVETAILS

APPLICABLE TO: All steam turbines with rotors which have buckets attached with finger dovetails.

PURPOSE

Provide complete instructions for nondestructive testing of rotor wheel finger dovetails.

BACKGROUND

Many magnetic particle inspections (MPI) of rotor wheel finger dovetails have been performed by prudent steam turbine owners to detect stress corrosion and/or fatigue cracking. In two instances, out of the hundreds of MPIs performed, cracks which were not discovered during the performance of the inspection procedure were observed. Consequently, GE has examined the MPI procedure for rotor wheel finger dovetails and developed an improved version.

DISCUSSION

Attached to this TIL is an improved magnetic particle inspection procedure for turbine rotor wheel finger dovetails. It allows a more accurate test to be performed in this region whenever the buckets are removed.

The finger dovetail geometry is not conducive to inspection without removing buckets, except for inspection of certain portions of the end fingers. See Figure 1. The most reliable test which clearly identifies the presence of any indications is an MPI when the buckets are removed.

The attached improved MPI procedure was developed by GE Nondestructive Test Engineering to provide a uniform procedure for anyone performing the test.

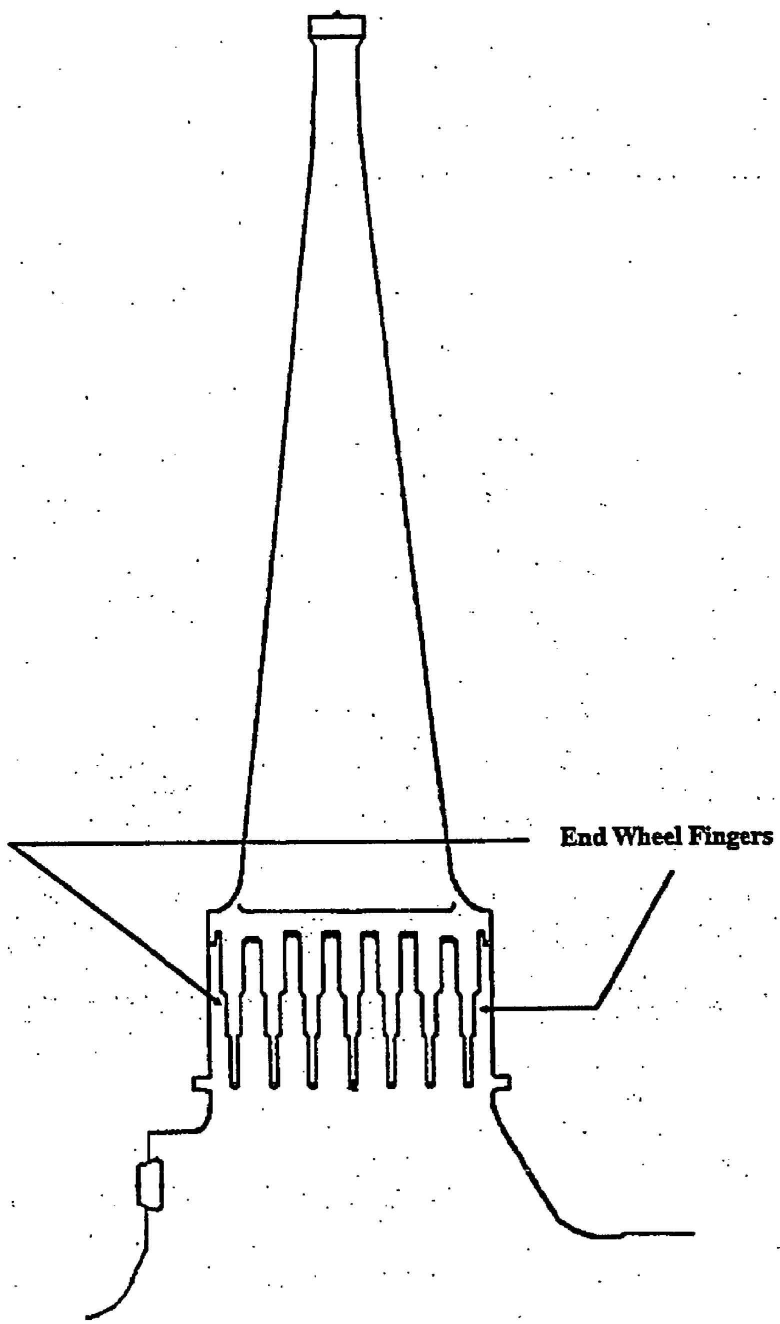


Figure 1
Steam Turbine Rotor Wheel
with Finger Dovetails

RECOMMENDATIONS

1. Whenever buckets are removed, a detailed MPI should be performed on the rotor wheel finger dovetails in accordance with the attached procedure. This inspection should be performed as early as possible within the outage period, and the test results sent immediately to GE for evaluation and recommendations. Your local GE field service representative can forward the data to the proper GE organization, and can also provide assistance with obtaining testing services.

NOTE

Although GE will perform the attached MPI, it is not necessary that GE do so. It is highly recommended that, regardless of who performs the inspection, the attached procedure be followed.

2. Abnormal events or operational anomalies that cause concern for long term reliability of the unit may be reason to consider removal of buckets, before normal replacement, for MPI of the dovetail area. Abnormal events or operational anomalies are any out-of-the-ordinary occurrences, during operation or maintenance, which may increase the risk of stress corrosion and/or fatigue cracking, such as but not limited to the following:

   a. caustic or chemical ingestion or contamination
   b. carryover from boiler
   c. leaking condenser heater tube
   d. overspeeds
   e. water ingestion

   If in doubt, GE will help evaluate the need for additional MPI of the rotor wheel finger dovetail area. Contact your local GE field service representative.

WHEEL FINGER DOVETAIL MAGNETIC PARTICLE INSPECTION (MPI)

SCOPE

This procedure describes the use of wet fluorescent magnetic particle inspection (MPI) to detect stress corrosion cracking (SCC) on steam turbine wheels with finger dovetails. Three different techniques are provided for a thorough examination of the entire surface of the finger. This includes the root radii between fingers and the inside surfaces of the pin holes (Figure 1). A data form is attached, to report the test results to GE for evaluation and recommendations.

NOTE

This test should be completed at the beginning of the outage, to allow time for evaluation of test results and recommendations for any further action.

PREPARATION

1. The rotor must be removed from the unit and the finger dovetail buckets removed from the wheel(s).

2. Surfaces to be tested shall be clean and free of scale, dirt, oil, grease and any other extraneous material that would interfere with the inspection. GE recommends a forceful application of Zircon-M™ sand or equivalent, using dry compressed air as a propellant. An alternative method uses forceful application of glass beads, with dry compressed air as a propellant. However, the use of glass beads is not as effective as the use of Zircon-M sand.

3. The test area shall be covered with a hood or cover to exclude as much ambient white light as possible.

4. Personnel performing the MPI shall be qualified in accordance with the recommendations of ASNT document SNT-TC-1A. They shall be certified to at least NDT Level II Magnetic Particle Testing.

   At least two magnetic particle operators are required at any one time to adequately perform these inspections. The use of two inspection teams simultaneously performing inspections on opposite sides of the wheels will greatly reduce total inspection time.

MATERIALS AND EQUIPMENT

1. Fluorescent MPI material, such as Magnaflux Corporation Magnaglo™ #14AM Prepared Bath, Magnaglo #20B, or equivalent.

2. Power source, with alternating current and either half-wave or full-wave rectified direct current. A 4000 amp minimum magnetizing unit is recommended.

TRADEMARK: Zircon-M is a trademark of the E. I. Dupont De Nemours Company. Magnaglo is a trademark of the Magnaflux Corporation.

MATERIALS AND EQUIPMENT, cont.

3. Welding cables, 4/0, to carry the current.

4. High intensity ultraviolet light with a wavelength of 3200-4000 angstrom units. The black light intensity shall be 5000 microwatts/sq cm, minimum, at a distance of 15 in. (38 cm).

5. Magnaflux Quantitative Quality Indicators (QQIs), or equivalent, to demonstrate adequate magnetic field strength.

6. Mirrors, narrow enough to fit between adjacent dovetails in the region of the innermost pin hole. The mirrors should be as thin as possible; polished stainless steel works well. They should be mounted on a wand long enough to be able to view the entire dovetail surface. The mirrors shall be mounted to achieve a 45 degree angle with the dovetail face for ease of viewing. Two mirrors are required, one looking left and one looking right, to view opposing walls.

7. One piece of magnetic material, 0.25 x 4 x 5 inches (0.64 x 10 x 13 cm), used as a shunt to bridge the fingers and contain the magnetic field during the longitudinal magnetization inspection.

8. Marker with a low halogen and sulphur content (e.g., Marks-a-Lot[R] marker or equivalent) to identify previously inspected positions.

9. Brass or copper rod, smaller in diameter than the pin holes and about twice as long as the total dovetail width.

10. Gauss meter, to read residual magnetism of ±3 Gauss.

INSPECTION TECHNIQUES

GENERAL INSPECTION NOTES AND PRECAUTIONS

1. Areas which are to be inspected with MPI shall be demagnetized before beginning the inspection. Use alternating current (AC). The 4/0 cables should be connected to the ends of the rotor as described in the Direct Circular Magnetization Inspection, paragraph 1.a, below. Adjust the magnetizing unit to the maximum setting, and reduce the current from the maximum value to zero while the magnetizing unit is on. Demagnetization is adequate when the residual magnetism reads within ±3 Gauss on a Gauss meter.

2. The magnetizing unit's maximum current setting shall never be used for any of the inspections described below. The current should be 100-200 amps below the maximum possible so that a higher current can be used for proper demagnetization.

Marks-a-Lot is registered by Dennison Carter.

GENERAL INSPECTION NOTES AND PRECAUTIONS (Continued)

3. All magnetic particle inspections shall be performed using the continuous method. The inspection medium shall be applied to the surface of the dovetail while the magnetizing current is being applied. The magnetizing current remains on after the application of the medium is stopped, about 8-10 seconds, until the draining of medium stops.

4. The Quantitative Quality Indicators (QQIs) are used to demonstrate the adequacy of the magnetizing force for all techniques. Two QQIs shall be placed on the face of the dovetail, grooved side down. The first shall be placed at the extremity of the area of interest, near the outside diameter of the dovetail. The second shall be placed between the middle two fingers, near the bottom of the fingers. This is the area of least accessibility. The QQIs should be carefully taped along their edges to assure tight contact between QQI and dovetail face.

   Current shall be turned on and held constant while the inspection medium is applied to the surface of the QQI. The appearance of a line(s) of fluorescent particles approximately perpendicular to the lines of magnetic flux in the part is the indication of adequate field strength. This demonstration is required at the beginning of each different technique.

5. When inspecting the dovetail surfaces for indications, the black light shall be positioned so that its area of maximum intensity will directly illuminate the specific area being inspected. If the black light has multiple intensity capability, the maximum intensity shall be used.

6. Inspections shall be performed from the lower part of a segment to the upper part of a segment, so that the area being inspected will be clean and free from runoff or residue from previous inspections. Refer to Figure 3.

7. Although indications in the area between the first transition in dovetail thickness and the outside diameter (OD) can be viewed without the use of a mirror, a mirror is required for inspections from the first transition down to the root radius. The mirror shall be held at an angle which will provide a clear view of the dovetail face. The direction of mirror movement shall be from the root radius outward toward the OD (a radial scanning motion). Care shall be taken to avoid allowing the mirror to come in contact with the surface being inspected before the actual scan of that surface, to avoid the potential creation of any false indications.

   Subsequent scans shall assure an overlap of the scanning surface from the previous scan.

8. Between each technique, the dovetail area shall be wiped clean, using acetone or alcohol to remove any residual inspection medium. The surface should be illuminated by black light to verify adequate removal of residual medium.

INSPECTIONS

To obtain coverage for indications in any orientation, magnetic fields shall be generated in the dovetails using at least the first two of the following techniques. These are direct circular magnetization and longitudinal magnetization. A third technique, induced circular magnetization, may also be used, at the discretion of the utility. This method is very sensitive to defects inside the pin holes, and defects oriented radially to each pin hole on the dovetail surface, but is extremely time consuming.

1. **Direct Circular Magnetization**

   The turbine rotor is used as the conductor of current. The magnetic lines of force will be oriented circumferentially with respect to the wheel. The orientation of indications will be in the radial direction on the wheel faces and in the axial direction inside the pin holes.

   a. To generate direct circular magnetization in the wheel dovetails, connect one cable from the power supply to each end of the rotor. For rotors with bore plugs or with tapped holes, connections should be made per Figure 2A. For rotors without tapped end holes, the cable connections may have to be made similar to Figure 2B or 2C.

   CAUTION

   Extreme caution should be taken to assure that all connections are properly tightened. Loose connections could cause arcing to the rotor.

   b. The current setting should be 3500 amps initially. Adjust as required to provide an adequate magnetizing force using QQIs.

   c. Record any indications on the attached data form.

2. **Longitudinal Magnetization**

   The orientation of any indications will be circumferential with respect to the dovetails.

   a. Wind a three turn coil using the 4/0 cable to establish longitudinal magnetization in the dovetails. The turns must be complete. The maximum coil dimension shall be about 48 in. (122 cm). The coil shall be placed in contact with the dovetails so that the upper and lower segments of the coil each intersect all of the dovetails at appproximately a right angle. The sides of the coil shall be laid on the body of the rotor on both sides of the wheel fingers in order to achieve adequate magnetic field strength at the extremities of the dovetails. Refer to Figure 3.

   NOTE

   The optimum positions of the coil for this inspection are the 1:30-4:30 and 7:30-10:30 clock positions. The rotor should then be rotated by 90 degrees and inspected from the new 1:30-4:30 and 7:30-10:30 positions (2.g, below). This allows proper particle flow and runoff without pooling of suspension.

INSPECTIONS (Continued)

2. **Longitudinal Magnetization** (Continued)

   b. The initial current setting shall be 1500 amps (4500 ampere-turns with a three turn coil). Adjust as required to provide an adequate magnetizing force using QQIs.

   c. To contain the magnetism within the dovetails, place the shunt across the outside diameter of the fingers so that all fingers are covered simultaneously. Refer to Figure 3. The shunt shall be left in place for as long as the current remains on.

   d. The magnetic particle suspension shall be sprayed onto the dovetail surfaces underneath the 4 inch (10 cm) height of the shunt. The current is turned on during particle application and shall remain on for about 8-10 seconds following removal of spray suspension.

   e. The inspection area for any one "shot" is limited to the dovetail surfaces within this shunt zone. Care shall be taken to properly mark the areas previously inspected. Successive inspections shall assure a minimum overlap of 0.5 in. (1.3 cm) of the shunt height.

   f. The inspection sequence (movement of the shunt within a given coil position) shall be from the lower end of the coil to the upper end.

   g. Movement of the coil around the outer diameter of the dovetails shall include a minimum overlap of 12 in. (31 cm) from the previous coil position.

   h. Record any indications on the attached data form.

3. **Circular Magnetization** (Optional)

This method uses a central conductor placed through aligned pin holes. It is very sensitive to defects oriented radially to the pin holes and axially to the rotor inside the holes, but is very time consuming.

   a. Pass the brass or copper rod through a set of aligned pin holes. Connect one power cable from the power supply to each end of the rod. While current is flowing, apply magnetic particles to both sides of each pin hole through which the central conductor is located.

   b. The current setting should be 175 amps initially. Adjust the current as required using the QQIs.

   c. Carefully remove the conductor from the holes and inspect the inside of the holes for any indications.

   d. Record any indications on the attached data form.

   e. Care should be taken to mark those sets of pins which have already been inspected.

DEMAGNETIZATION

The unit shall be demagnetized after all inspections have been completed. Use the same procedure described in General Inspection Notes and Precautions, para. 1, above.

RETURN OF DATA FORM

The completed data form should be given to the local GE representative. It will be sent to the main GE office for evaluation and recommendation.

TIL 1121-3AR1
Attachment 1
Figure 1

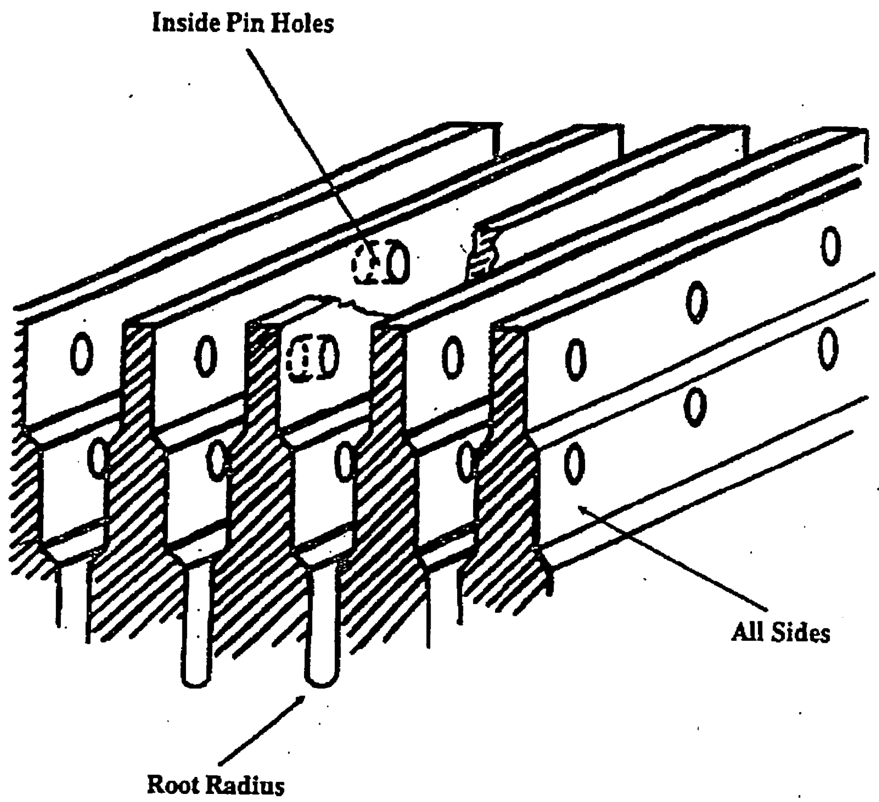


Figure 1
Inspection Locations

TIL 1121-3AR1
Attachment 1
Figure 2

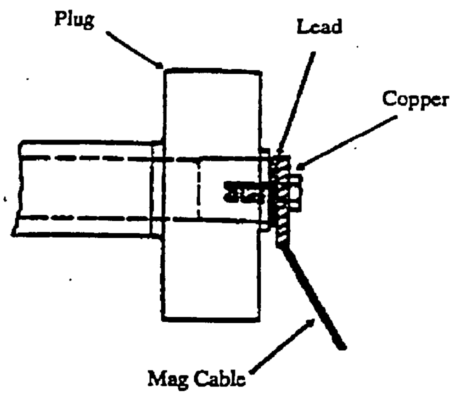


Figure 2A
Bore Plug

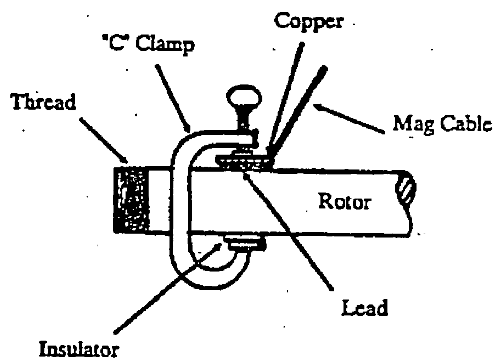


Figure 2B
Governor End of Rotor

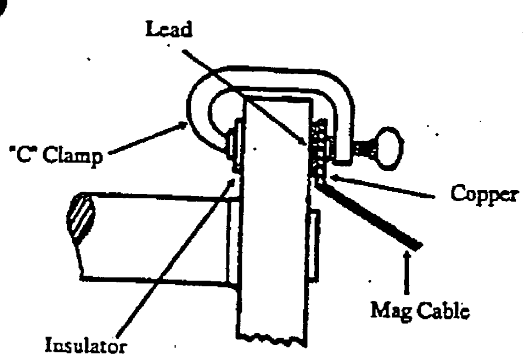


Figure 2C
Coupling Face

Figure 2
Attachment of Cables to Rotor

TIL 1121-3AR1
Attachment 1
Figure 3

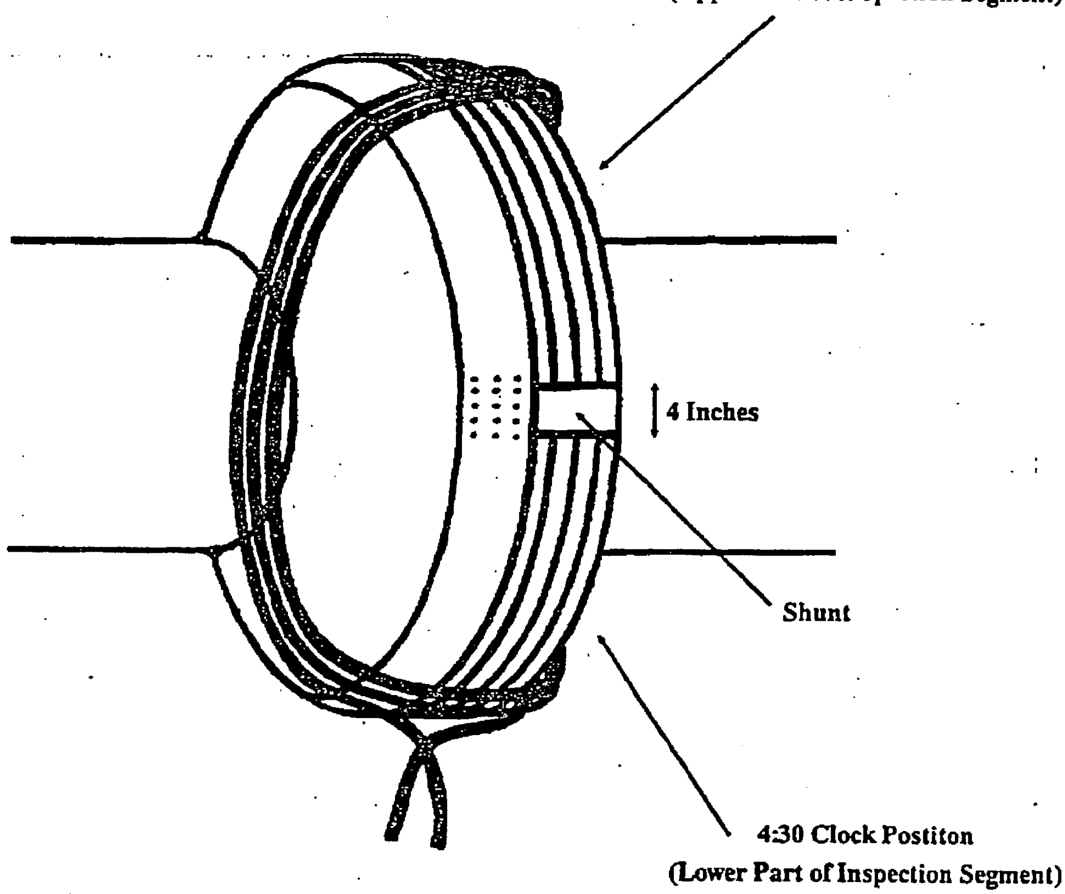


Figure 3
Longitudinal Magnetization
with 3-Turn Coil and Shunt

TIL 1121-3AR1
Attachment 1
Data Sheet 1 of 2

TURBINE WHEEL FINGER DOVETAIL MAGNETIC PARTICLE TEST RESULTS

Turbine number ________________ Inspection date ____________________

Customer ____________________ Station ____________________________

Rotor (LPA, LPB,..) __________ Type of unit ___________________

Rotor S/N _________________ End ______________ Stage ______________

Finger dovetail type: Flat _____ or Nested ______

Mag. particle inspection company ____
Person to contact ____

Describe all indications below and on the attached sketch. Include an accurate description of the location, length and orientation for all indications. Use a separate sketch for indications on each different dovetail face. Include additional sketches as required for indications in other locations.

Dovetails are numbered consecutively, with the #1 dovetail on the admission end of the wheel (see sketch). Rows of pin holes are numbered consecutively in the direction of rotation, with the #1 row located directly below the #1 flat-type dovetail bucket or directly below the back edge of the #1 nested-type dovetail bucket.

Indications detected? Yes _____ No _____

Location of indication(s) (Check all that apply.)

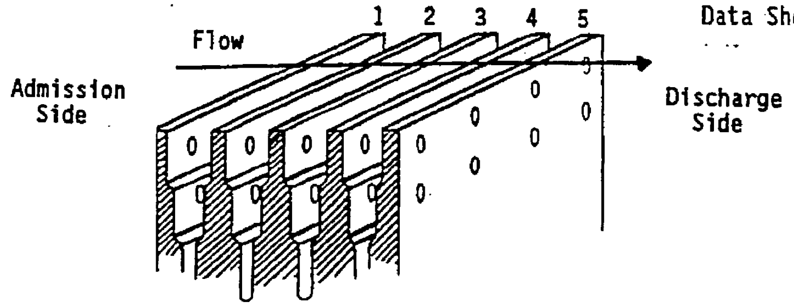
Dovetail number(s) ___________ Pin hole row number(s) ____________
Admission side face ____ Discharge side face ____
Pin hole region: Inner ____ Middle ____ Outer ____
Root radius between dovetail number ____ and number ____
Inside surface of pin hole ____
Wheel/wheel fillet ____
Other (describe) ____

Comments:

SEND IMMEDIATELY TO: Steam Turbine Service Engineering
Bucket and Rotor Service Engineer
GE Company
1 River Road Bldg 37-3C
Schenectady, NY 12345
Phone: (518) 385-9641 Fax: (518) 385-2438

11/91 TVT

TIL 1121-3AR1
Attachment 1
Data Sheet 2 of 2



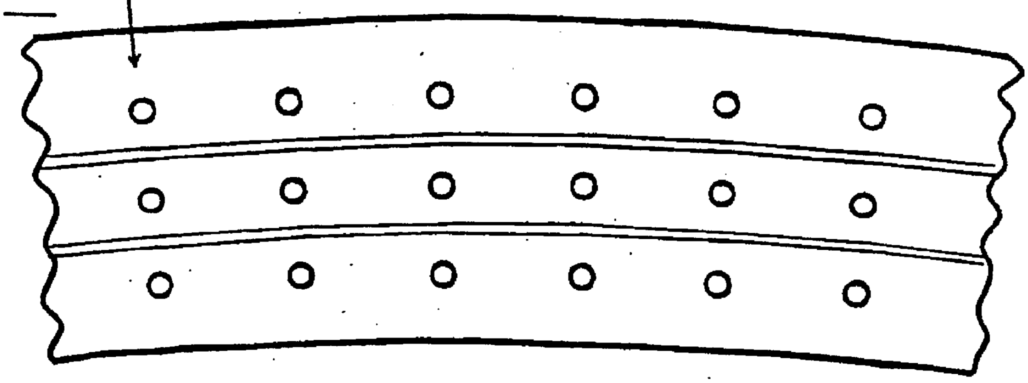
Dovetail Numbering

WHEEL FINGER DOVETAIL MAGNETIC PARTICLE TEST DATA SHEET
(Sketch indications below.)

Rotor ____________ Dovetail # _____ Date ________________________
End ____________ Stage _____ Inspector ________________________

Admission Side

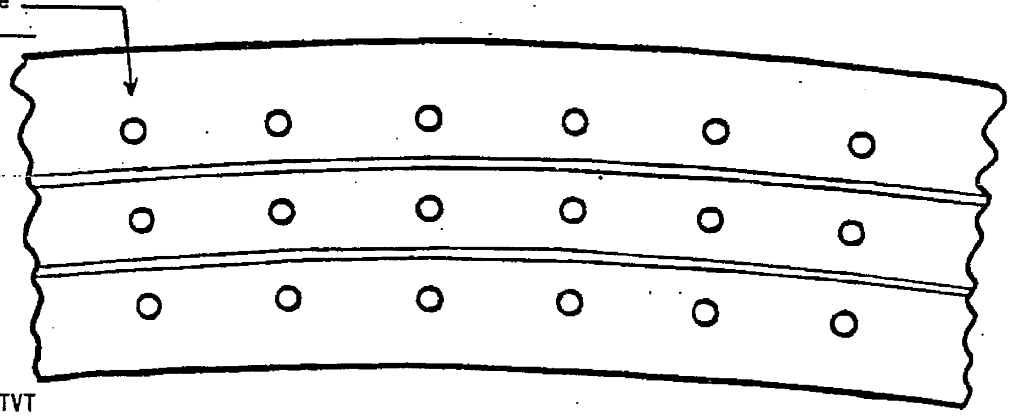
Pin Hole
Row # ____



(Not to scale)

Discharge Side

Pin Hole
Row # ____



11/91 TVT

JUN -9 1992

GE Industry
Sales & Services

Power Generation Services Department
General Electric Company
5353 Gamble Drive, Minneapolis, MN 55416

June 1, 1992

Mr. Steve Kollmann, Mgr.
Operations & Maintenance Support
Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

SUBJECT: TIL 1121-3A, Inspection of Steam Turbine Rotor Wheel Finger Dovetails
TB(s) 170X544, 170X609, 170X819, 170X117, 32357, 32388, 170X361, 118318

Dear Steve:

Enclosed is a copy of Technical Information Letter 1121-3A for your review and implementation. This TIL was written to provide you with GE's latest techniques for nondestructive testing of rotor wheel finger dovetails. These techniques were developed to provide a uniform test procedure for all vendors when performing this inspection.

If you have any questions or comments about this information, please call me.

Sincerely,

J P Force

James P. Force
MGR., ENGINEERING SERVICES
(612) 542-0315

Att.

CC: J.P. Brandt, Sherco
J.L. Hill, Riverside
W. Hill, Monticello
P. Graika, High Bridge

TRIAL EXHIBIT
0005
exhibitsticker.com

EXHIBIT NO. 72
4.22.15
R. L. KLANDERUD

GE POWER GENERATION
1 RIVER ROAD
SCHENECTADY, NY 12345

GE POWER GENERATION
PRODUCT SERVICE

TIL 1121-3A

TECHNICAL INFORMATION LETTER

May 15, 1992

170X117, 032357, 032388
NORTHERN STATES PWR CO
RIVERSIDE 008

INSPECTION OF STEAM TURBINE ROTOR WHEEL FINGER DOVETAILS

APPLICABLE TO: All steam turbine rotors which have buckets attached with finger dovetails.

PURPOSE

Provide complete instructions for nondestructive testing of rotor wheel finger dovetails.

DISCUSSION

GE is continually improving the techniques for inspection of turbine components to help operators extend the life of their units. This TIL presents a new magnetic particle inspection (MPI) procedure for turbine rotor wheel finger dovetails. It allows an accurate test to be performed in this region whenever the buckets are removed.

The finger dovetail geometry is not conducive to inspection without removing buckets, except for inspection of certain portions of the end fingers (Figure 1 of this TIL). The only reliable test which clearly identifies the presence of any indications is an MPI when the buckets are removed.

The MPI procedure attached to the Customer Section of this TIL was developed by the GE Nondestructive Test Engineering group to provide a uniform procedure for all test vendors.

RECOMMENDATIONS

1. Whenever buckets are removed, a detailed MPI should be performed on the rotor wheel finger dovetails. The recommended procedure, with a Test Results form, is provided in Attachment 1. This inspection should be performed as early as possible within the outage period, and the Test Results form sent immediately to GE for evaluation and recommendations. Your local Power Generation Services (PGSD) or International Power Systems (IPSD) representative can provide assistance in sending the data to the proper office. Your PGSD or IPSD representative can also provide assistance in obtaining testing services if the local test vendor is unable to perform the inspection.

2. Abnormal operation or unusual operating events that cause concern for long term reliability of the unit may be reason to consider removal of buckets, before normal replacement, for MPI of the dovetail area.

TIL 1121-3A
Figure 1

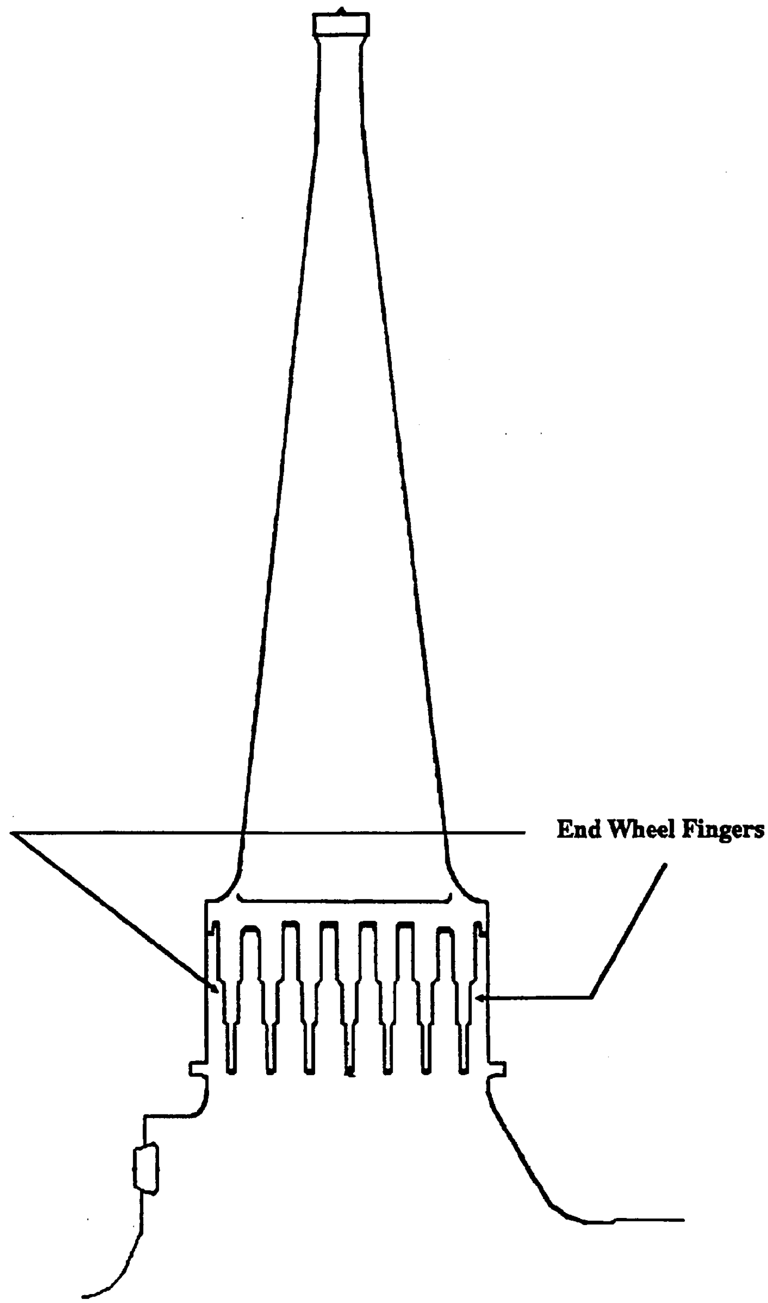


Figure 1
Steam Turbine Rotor Wheel
with Finger Dovetails

WHEEL FINGER DOVETAIL MAGNETIC PARTICLE INSPECTION (MPI)

SCOPE

This procedure describes the use of wet fluorescent magnetic particle inspection (MPI) to detect stress corrosion cracking (SCC) on steam turbine wheels with finger dovetails. Three different techniques are provided for a thorough examination of the entire surface of the finger. This includes the root radii between fingers and the inside surfaces of the pin holes (Figure 1). A data form is attached, to report the test results to GE for evaluation and recommendations.

> **NOTE:** This test should be completed at the beginning of the outage, to allow time for evaluation of test results and recommendations for any further action.

PREPARATION

1. The rotor must be removed from the unit and the finger dovetail buckets removed from the wheel(s).

2. Surfaces to be tested shall be clean and free of scale, dirt, oil, grease and any other extraneous material that would interfere with the inspection. GE recommends a forceful application of Zircon-M™ sand or equivalent, using dry compressed air as a propellant. An alternative method uses forceful application of glass beads, with dry compressed air as a propellant. However, the use of glass beads is not as effective as the use of Zircon-M sand.

3. The test area shall be covered with a hood or cover to exclude as much ambient white light as possible.

4. Personnel performing the MPI shall be qualified in accordance with the recommendations of ASNT document SNT-TC-1A. They shall be certified to at least NDT Level II Magnetic Particle Testing.

At least two magnetic particle operators are required at any one time to adequately perform these inspections. The use of two inspection teams simultaneously performing inspections on opposite sides of the wheels will greatly reduce total inspection time.

MATERIALS AND EQUIPMENT

1. Fluorescent MPI material, such as Magnaflux Corporation Magnaglo™ #14AM Prepared Bath, Magnaglo #20B, or equivalent.

2. Power source, with alternating current and either half-wave or full-wave rectified direct current. A 4000 amp minimum magnetizing unit is recommended.

TRADEMARK: Zircon-M is a trademark of the E. I. Dupont De Nemours Company. Magnaglo is a trademark of the Magnaflux Corporation.

MATERIALS AND EQUIPMENT, cont.

3. Welding cables, 4/0, to carry the current.

4. High intensity ultraviolet light with a wavelength of 3200-4000 angstrom units. The black light intensity shall be 5000 microwatts/sq cm, minimum, at a distance of 15 in. (38 cm).

5. Magnaflux Quantitative Quality Indicators (QQIs), or equivalent, to demonstrate adequate magnetic field strength.

6. Mirrors, narrow enough to fit between adjacent dovetails in the region of the innermost pin hole. The mirrors should be as thin as possible; polished stainless steel works well. They should be mounted on a wand long enough to be able to view the entire dovetail surface. The mirrors shall be mounted to achieve a 45 degree angle with the dovetail face for ease of viewing. Two mirrors are required, one looking left and one looking right, to view opposing walls.

7. One piece of magnetic material, 0.25 x 4 x 5 inches (0.64 x 10 x 13 cm), used as a shunt to bridge the fingers and contain the magnetic field during the longitudinal magnetization inspection.

8. Marker with a low halogen and sulphur content (e.g., Marks-a-Lot[R] marker or equivalent) to identify previously inspected positions.

9. Brass or copper rod, smaller in diameter than the pin holes and about twice as long as the total dovetail width.

10. Gauss meter, to read residual magnetism of ±3 Gauss.

INSPECTION TECHNIQUES

GENERAL INSPECTION NOTES AND PRECAUTIONS

1. Areas which are to be inspected with MPI shall be demagnetized before beginning the inspection. Use alternating current (AC). The 4/0 cables should be connected to the ends of the rotor as described in the Direct Circular Magnetization Inspection, paragraph 1.a, below. Adjust the magnetizing unit to the maximum setting, and reduce the current from the maximum value to zero while the magnetizing unit is on. Demagnetization is adequate when the residual magnetism reads within ±3 Gauss on a Gauss meter.

2. The magnetizing unit's maximum current setting shall never be used for any of the inspections described below. The current should be 100-200 amps below the maximum possible so that a higher current can be used for proper demagnetization.

Marks-a-Lot is registered by Dennison Carter.

GENERAL INSPECTION NOTES AND PRECAUTIONS, cont.

3. All magnetic particle inspections shall be performed using the continuous method. The inspection medium shall be applied to the surface of the dovetail while the magnetizing current is being applied. The magnetizing current remains on after the application of the medium is stopped, about 8-10 seconds, until the draining of medium stops.

4. The Quantitative Quality Indicators (QQIs) are used to demonstrate the adequacy of the magnetizing force for all techniques. Two QQIs shall be placed on the face of the dovetail, grooved side down. The first shall be placed at the extremity of the area of interest, near the outside diameter of the dovetail. The second shall be placed between the middle two fingers, near the bottom of the fingers. This is the area of least accessibility. The QQIs should be carefully taped along their edges to assure tight contact between QQI and dovetail face.

Current shall be turned on and held constant while the inspection medium is applied to the surface of the QQI. The appearance of a line(s) of fluorescent particles approximately perpendicular to the lines of magnetic flux in the part is the indication of adequate field strength. This demonstration is required at the beginning of each different technique.

5. When inspecting the dovetail surfaces for indications, the black light shall be positioned so that its area of maximum intensity will directly illuminate the specific area being inspected. If the black light has multiple intensity capability, the maximum intensity shall be used.

6. Inspections shall be performed from the lower part of a segment to the upper part of a segment, so that the area being inspected will be clean and free from runoff or residue from previous inspections. Refer to Figure 3.

7. Although indications in the area between the first transition in dovetail thickness and the outside diameter (OD) can be viewed without the use of a mirror, a mirror is required for inspections from the first transition down to the root radius. The mirror shall be held at an angle which will provide a clear view of the dovetail face. The direction of mirror movement shall be from the root radius outward toward the OD (a radial scanning motion). Care shall be taken to avoid allowing the mirror to come in contact with the surface being inspected before the actual scan of that surface, to avoid the potential creation of any false indications.

Subsequent scans shall assure an overlap of the scanning surface from the previous scan.

8. Between each technique, the dovetail area shall be wiped clean, using acetone or alcohol to remove any residual inspection medium. The surface should be illuminated by black light to verify adequate removal of residual medium.

INSPECTIONS

To obtain coverage for indications in any orientation, magnetic fields shall be generated in the dovetails using at least the first two of the following techniques. These are direct circular magnetization and longitudinal magnetization. A third technique, induced circular magnetization, may also be used, at the discretion of the utility. This method is very sensitive to defects inside the pin holes, and defects oriented radially to each pin hole on the dovetail surface, but is extremely time consuming.

1. **Direct Circular Magnetization**

The turbine rotor is used as the conductor of current. The magnetic lines of force will be oriented circumferentially with respect to the wheel. The orientation of indications will be in the radial direction on the wheel faces and in the axial direction inside the pin holes.

a. To generate direct circular magnetization in the wheel dovetails, connect one cable from the power supply to each end of the rotor. For rotors with bore plugs or with tapped holes, connections should be made per Figure 2A. For rotors without tapped end holes, the cable connections may have to be made similar to Figure 2B or 2C.

> **CAUTION:** Extreme caution should be taken to assure that all connections are properly tightened. Loose connections could cause arcing to the rotor.

b. The current setting should be 3500 amps initially. Adjust as required to provide an adequate magnetizing force using QQIs.

c. Record any indications on the attached data form.

2. **Longitudinal Magnetization**

The orientation of any indications will be circumferential with respect to the dovetails.

a. Wind a three turn coil using the 4/0 cable to establish longitudinal magnetization in the dovetails. The turns must be complete. The maximum coil dimension shall be about 48 in. (122 cm). The coil shall be placed in contact with the dovetails so that the upper and lower segments of the coil each intersect all of the dovetails at appproximately a right angle. The sides of the coil shall be laid on the body of the rotor on both sides of the wheel fingers in order to achieve adequate magnetic field strength at the extremities of the dovetails. Refer to Figure 3.

NOTE: The optimum positions of the coil for this inspection are the 1:30-4:30 and 7:30-10:30 clock positions. The rotor should then be rotated by 90 degrees and inspected from the new 1:30-4:30 and 7:30-10:30 positions (2.g, below). This allows proper particle flow and runoff without pooling of suspension.

INSPECTIONS, cont.

2. **Longitudinal Magnetization**, cont.

   b. The initial current setting shall be 1500 amps (4500 ampere-turns with a three turn coil). Adjust as required to provide an adequate magnetizing force using QQIs.

   c. To contain the magnetism within the dovetails, place the shunt across the outside diameter of the fingers so that all fingers are covered simultaneously. Refer to Figure 3. The shunt shall be left in place for as long as the current remains on.

   d. The magnetic particle suspension shall be sprayed onto the dovetail surfaces underneath the 4 inch (10 cm) height of the shunt. The current is turned on during particle application and shall remain on for about 8-10 seconds following removal of spray suspension.

   e. The inspection area for any one "shot" is limited to the dovetail surfaces within this shunt zone. Care shall be taken to properly mark the areas previously inspected. Successive inspections shall assure a minimum overlap of 0.5 in. (1.3 cm) of the shunt height.

   f. The inspection sequence (movement of the shunt within a given coil position) shall be from the lower end of the coil to the upper end.

   g. Movement of the coil around the outer diameter of the dovetails shall include a minimum overlap of 12 in. (31 cm) from the previous coil position.

   h. Record any indications on the attached data form.

3. **Circular Magnetization** (Optional)

This method uses a central conductor placed through aligned pin holes. It is very sensitive to defects oriented radially to the pin holes and axially to the rotor inside the holes, but is very time consuming.

   a. Pass the brass or copper rod through a set of aligned pin holes. Connect one power cable from the power supply to each end of the rod. While current is flowing, apply magnetic particles to both sides of each pin hole through which the central conductor is located.

   b. The current setting should be 175 amps initially. Adjust the current as required using the QQIs.

   c. Carefully remove the conductor from the holes and inspect the inside of the holes for any indications

   d. Record any indications on the attached data form.

   e. Care should be taken to mark those sets of pins which have already been inspected.

DEMAGNETIZATION

The unit shall be demagnetized after all inspections have been completed. Use the same procedure described in General Inspection Notes and Precautions, para. 1, above.

RETURN OF DATA FORM

The completed data form should be given to the local GE representative. It will be sent to the main GE office for evaluation and recommendation.

TIL 1121-3A
Attachment 1
Figure 1

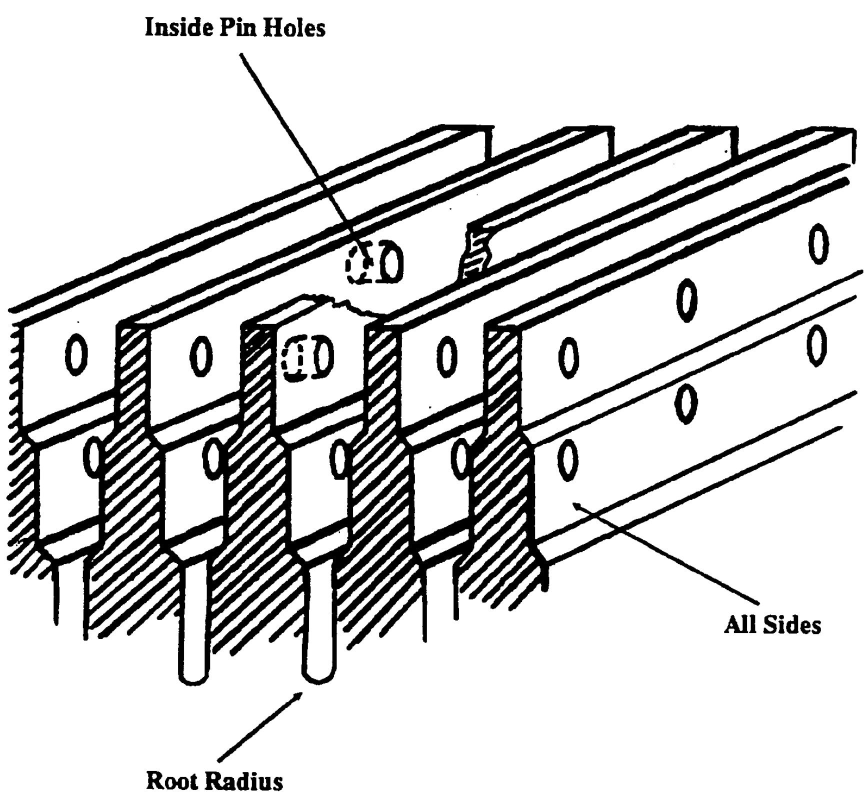


Figure 1
Inspection Locations

TIL 1121-3A
Attachment 1
Figure 2

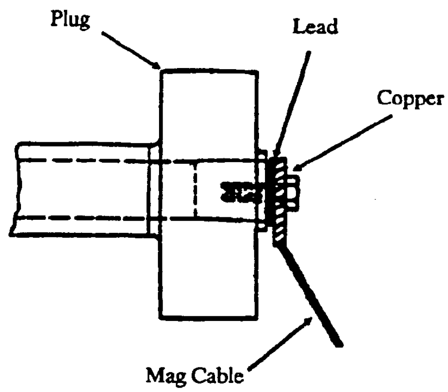


Figure 2A
Bore Plug

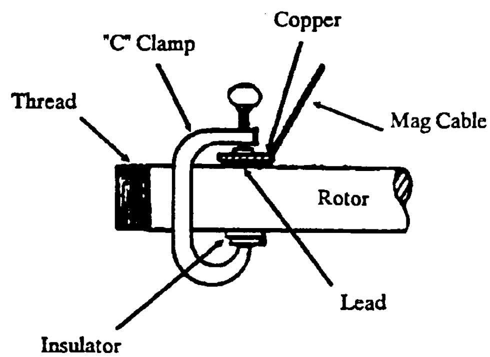


Figure 2B
Governor End of Rotor

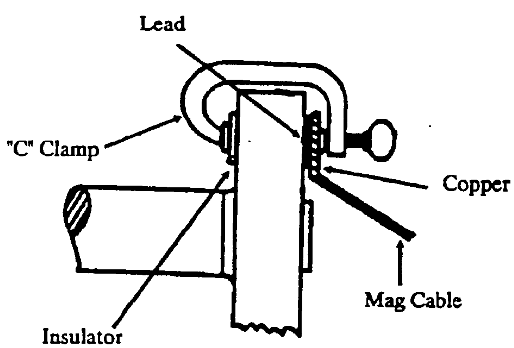


Figure 2C
Coupling Face

Figure 2
Attachment of Cables to Rotor

TIL 1121-3A
Attachment 1
Figure 3

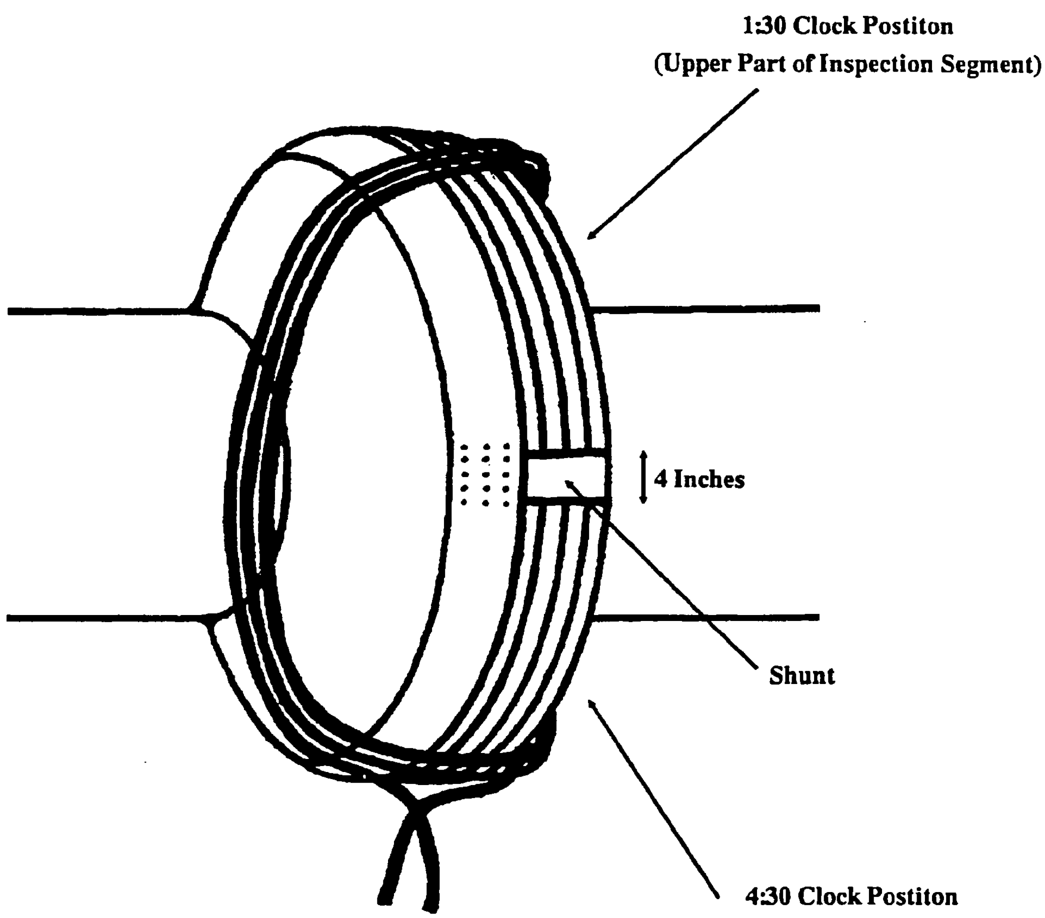


Figure 3
Longitudinal Magnetization
with 3-Turn Coil and Shunt

TIL 1121-3A
Attachment 1
Data Sheet 1 of 2

TURBINE WHEEL FINGER DOVETAIL MAGNETIC PARTICLE TEST RESULTS

Turbine number ________________ Inspection date ______________________

Customer ______________________ Station ______________________________

Rotor (LPA, LPB,..) ____________ Type of unit _________________________

Rotor S/N __________________ End _______________ Stage _________________

Finger dovetail type: Flat ______ or Nested ______

Mag. particle inspection company ____
Person to contact ____

Describe all indications below and on the attached sketch. Include an accurate description of the location, length and orientation for all indications. Use a separate sketch for indications on each different dovetail face. Include additional sketches as required for indications in other locations.

Dovetails are numbered consecutively, with the #1 dovetail on the admission end of the wheel (see sketch). Rows of pin holes are numbered consecutively in the direction of rotation, with the #1 row located directly below the #1 flat-type dovetail bucket or directly below the back edge of the #1 nested-type dovetail bucket.

Indications detected? Yes _____ No _____

Location of indication(s) (Check all that apply.)

Dovetail number(s) ____________ Pin hole row number(s) _____________
Admission side face ____ Discharge side face ____
Pin hole region: Inner ____ Middle ____ Outer ____
Root radius between dovetail number ____ and number ____
Inside surface of pin hole ____
Wheel/wheel fillet ____
Other (describe) ____

Comments:

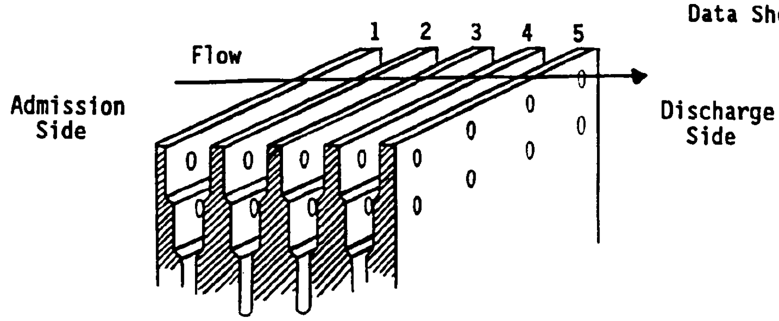
SEND IMMEDIATELY TO:

GE POWER GENERATION SERVICES
5353 GAMBLE DRIVE
MINNEAPOLIS, MN 55416

TEL. (612) 542-0332 FAX (612) 542-0355

11/91 TVT

TIL 1121-3A
Attachment 1
Data Sheet 2 of 2



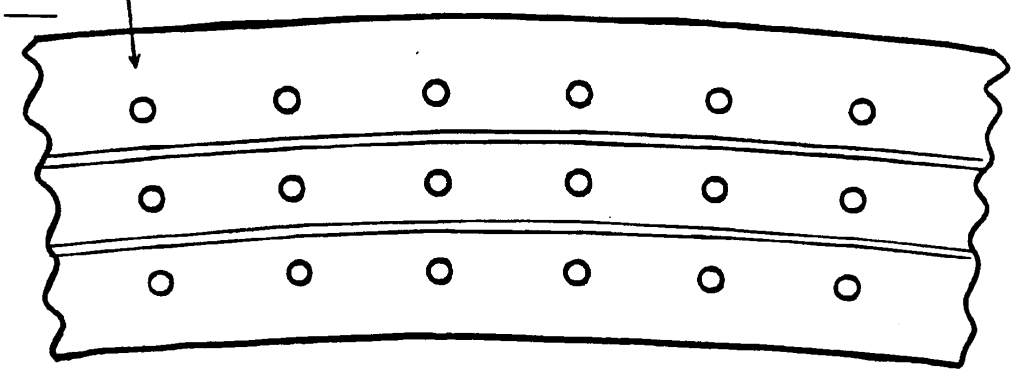
Dovetail Numbering

WHEEL FINGER DOVETAIL MAGNETIC PARTICLE TEST DATA SHEET
(Sketch indications below.)

Rotor ____________ Dovetail # _____ Date ________________________
End ____________ Stage _____ Inspector ________________________

Admission Side

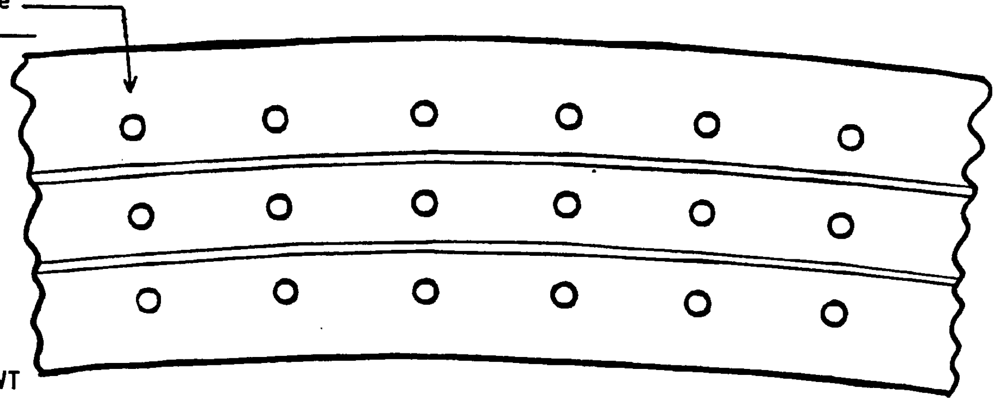
Pin Hole
Row # ___



(Not to scale)

Discharge Side

Pin Hole
Row # ___



11/91 TVT

XCEL_Sherco_07_0171440

From:	Murray, Timothy P
To:	Kollmann, Steven J
CC:	Sowers, Richard E; Farnick, Jeffrey W; Crislip, Michael J; Foerster-Jr, William D; Miller, Michael A; Scharenbroch, Victor J; Brandt, R Jerome; Helmberger, Gary M; Jyrkas, Timothy J; Kral, David S; Gartner, Blaine E; Kolb, Mark W; Amundson, David L; Freborg, James G; Langr, Kenneth F; Tradewell, John; Nordstrom, Kenneth H; Brohlin, Bill; Phelps, Stuart
Sent:	8/17/2001 5:46:07 PM
Subject:	GE Large Steam Turbine Generator Conference Trip Report

Steve, on August 13 thru 16 Jerry Brandt, Blaine Gartner and myself attended GE's LSTG conference in Atlanta. This conference was quite worthwhile as it allowed access to many GE experts and included a vendor fair. Several significant emerging issues were discussed and we picked up some good information on maintenance practices. Note that this is now a combined nuclear and fossil conference. Below is a summary of some of the more significant items of interest.

1. 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 entry 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.

2. Main Stop Valve Bypass Valves, Valve Casings
John Klebaskas presented some new options to reduce bypass valve skirt erosion. Apparently GE has been trying some different seat geometries since 1994 and have come up with some new designs that should significantly improve skirt life. With respect to valve casing inspection GE is still recommending a 4 year inspection interval and they are now also recommending external as well as internal inspections. Cracks up to about 1/2" deep may be ground out. GE is now using a weld repair with local torch stress relief for cracks greater than 1/2" deep.

3. Alignment
Dan Steingraeber discussed some new developments in the laser alignment area. Summary of steam path audit data suggests 'ypical G3 HP running clearances are 40 mils whereas design is 15 on much of the diaphragm and shaft end packing. A flat tooth with 25 mils clearance has the same flow coefficient as a sharp tooth at 40 mils. Study of Bently Nevada prox probe shaft orbit data suggests a journal lift of as much as 10 to 12 mils on the oil wedge whereas they used to believe this was only about 2 to 3 mils. A 3 mil critical at the bearing results in a 10.5 mil deflection at rotor mid span and a 6 mil critical results in a 21 mil midspan deflection. GE is still working on a halfshell (topless) alignment process and they are using this on G3 dense pack installs.

4. Controls Upgrades (Denny Younie)
There is a problem with the EHC Mark I Encore 842 power supply. Apparently age related degradation of the R9 resistor can cause this power supply to fail. A TIL will be issued on this soon. The last chance to buy new components for EHC Mark I & II control systems will be June of 2005. Production of new components will cease on December 31st 2005. GE will still try to support repair of components after this date. GE has a number of controls upgrades available for GE, Westinghouse and Allis Chalmers machines. These range from full MHC to EHC conversions to throttle and governor valve MHC actuator replacements on Westinghouse machines to speed pickup conversions for GE and Westinghouse machines. To date GE has done 27 Westinghouse and 7 Allis Chalmers controls upgrades.

5. Piping Issues (Keith Taylor)
Keith discussed the importance of inspecting LP extraction bellows. Many plants, both fossil and nuclear, are experiencing bellows failures on an increasingly regular basis. These apparently have about a 20 to 25 year life. They strongly suggest stocking at least one of each size bellows. These are not available through GE.
Keith stated that several plants have found BFPT shell drain line orifices missing. Apparently they were never installed or had been removed at initial startup. These should be inspected for since if they are missing a significant performance loss will result. GE is also recommending a modification to nuclear bypass valve 1st leakoff line. A check valve should be added to these lines to prevent crossaround steam from leaking back to the valve at full load operation. This should significantly reduce stem damage from pitting and corrosion by the wet steam constantly leaking back around the stem.

6. Backup Lube Oil System Reliability (Mike Molitor)
Mike discussed the importance of following all GE TILs and recommendations with respect to the emergency bearing oil pump testing and DC electrical supply system. There are about 4 TILs out on this. There have been 5 incidents so far this year alone vhere units have come down without oil as a result of not following GE recommendations.

7. Generator H2 Seals (Jim Flanagan)

TRIAL EXHIBIT
0023
exhibitsticker.com

EXHIBIT NO. 98
4·22·15
R. L. KLANDERUD

Jim stressed the importance of having the correct GEK for the seals on a specific unit. The current GEKs are as follows 46130d, 45934f, and 75520e. Tech manuals should be checked to verify they contain the latest version of the appropriate GEK. The biggest problems they see on H2 seals is with machining or lapping resulting in cutting off oil supply to the oil feed groove on the axial seal face. Another problem area involves use and correct installation of the antirotation devices.

3. Flexible Coupling Failure
Representatives from Duke Energy and KopFlex discussed the generator to exciter coupling failure on Oconee 3. This coupling (KopFlex model 704, same as Monticello I believe) had been installed as per GE TIL 1037 about 8 years ago and recently failed in service. The cause of the failure was attributed to high cycle fatigue of the disc packs resulting from angular misalignment of the coupling. They are recommending stroboscopic inspection of the disc packs for cracking and separation while the unit is on line and thorough visual and MT exams at the next refuel outage. The as found misalignment on the failed coupling was quite small indicating that this design is not tolerant of any misalignment or there is another cause for the failure, disc material?

9. Isophase Bus
Louis Doucet gave an interesting presentation on isophase bus design, inspection, and maintenance. This equipment is still manufactured by GE Canada at the St Augustine plant near Quebec City. Apparently the center phase runs much hotter than the 2 outside phases due to some sort of electrical phenomenon. Periodic thermal scans for hot spots is recommended. The condition of paint is important as unpainted areas will run hotter. There should be low point drains but no breathers to keep moisture out. Cold flow of the silver plated aluminum conductor joints is one of the major concerns. Overtorquing can deform the bolt holes and create hot spots. The condition of the swaged ends of the tin plated flexible copper braids is also important and should be inspected regularly. Insulators and their support hardware should be periodically checked.

10. High Voltage Bushings
Gary Stewart provided some details on high voltage bushing inspection and maintenance. Gary stated that asphalt leakage from the lower seal was not a major concern although the bushing should be checked to ensure the leakage is not the result of a cracked porcelain insulator. The lower seal is not an H2 seal, the upper is. H2 leaks from the flange and terminal plate can be easily repaired without removing the bushing. Magic dust (ground mica) can be added under the viscasil to stop the leak. GE does not consider this a permanent repair but it should last for some time until new bushings can be ordered and installed. GE strongly recommends stocking bushings.

11. Craft Labor/Service Shop Loading
GE is seeing huge increases in demand for craft labor for maintenance and new installations. Last Spring they peaked out at 3000 craft while Spring of '99 was only 1500. More and more customers want there maintenance done and new units running for the Summer peaks. Almost 70% of all service shop work is done in the Spring.

12. Generator Uprates
Karl Tornroos discussed GE's process for generator uprate feasibility studies. These studies typically involve 200 to 600 man hrs and take 8 -12 weeks. They are performed by GE Applications Engineering in Marietta GA. In many cases they find that the stator core end iron is limiting and they have been able to do partial restacks to address these issues. For units in the 150 to 200 MWe range with a number of limiting factors, a complete replacement generator may be a viable option. On liquid cooled winding machines reducing the number of hollow conductors actually allows an increase in MVA rating. Apparently conventionally cooled fields with solid copper can be uprated in some cases by switching to conductor cooled copper.

13. New Products and Technology
GE now has 10 units operating with brush seals, 7 LSTG, 3 medium steam. They are quite pleased with some of results they're seeing. Several units have been opened after months of operation and the brushes are holding up very well. They have only 6 dense pack machines in service and claim to have 21 on order. They claim to have seen 3.5 to 5% increases in section efficiency on these 6.

14. Stator Water Leak Repairs
Karl Tornroos gave an update on water leak repairs. There is a new TIL out on this, GER 3751A. They are now finding water leaks on machines with the serrated clip spacers, pre 1970 machines previously thought immune. I believe this may be Monti's design. 60 full rewinds have been completed on 600 liquid cooled machines. GE is strongly recommending stocking spare bars.

15. Stator Leak Testing and In Situ Inspection
GE now has a Super HITs skid. They were able to vacuum dry and test a 72 slot unit in 44 1/2hrs. They have a new test for detecting wet bars in addition to capacitance mapping. It is a bound wet bar detector and it looks for a shift in a high frequency RF signal. This is now being offered as part of the HITs skid testing package. Dean Roney discussed GEs MAGIC system for rotor in place generator inspections. They have been using and improving this system for the past 8 years. EPRI has now come out with a paper on Limited Access Inspection and has favorable endorsements for both the GE and Westinghouse systems. NEIL has also approved use of this process in instead of pulling the field provided that the unit is fully equipped with on line monitoring equipment, such as flux probe, PDA, SLMS etc. They have done 117 units with MAGIC and only 2 have required a subsequent field pull to correct problems detected with MAGIC. They can do wedge tap test, El Cid, bar jacking, retaining ring

eddy current and UT all with the rotor in. They are still recommending a 5 to 6 year inspection interval but if all GE TILs and O&M recommendations are implemented including SLMS and MAGIC inspections GE feels that a full blown generator inspection can be pushed out to 10 to 12 years.

16. Generator Field Issues
Ron Zawoysky provided an update on TIL 1292, Generator Rotor Forging Tooth Cracks. This TIL was 1st issued in December 2000 and rev 1 was issued in April of this year. I have not seen either. This TIL applies to more than 1200 water and oil cooled machines. So far 3 units have been found with serious cracking in the #1 and #2 coil slots at the rotor midspan. These are slots with steel wedges. 2 of the rotors had been subjected to motoring and the 3rd had seen extensive turning gear time. Apparently the motoring incidents resulted in localized heating at the wedge to slot tooth interface, changed the material property, and cracked after being subjected to high bending stresses during normal operation. The unit that had high gear time had evidence of extensive fretting and work hardening of the material in the cracked area. GE is very concerned about this in that the cracks found to date could have resulted in a wedge ejection had the units run much longer. GE is recommended that all units be inspected at the next outage. This will require field pull and collector end retaining ring removal.

17. Collector Rings
I discussed with Ron our problems with collector ring replacement and resultant exciter coupling rabbet runout. GE said this was quite common on the larger machines with thin shaft extensions. They said they see this all the time in the shop and it is a result of uneven cooling of the new collector ring and coupling hub after they are put back on. They tend to pinch the shaft and put a kink in it. They have developed a procedure to straighten the shaft prior to machining. It is a controlled jacking processes. Bottom line is that no machining or grinding should be done until the rabbet fit runout is returned to zero as the kink will relieve itself once the unit is at speed and cause vibration problems. Sound familiar? I wonder why our local GE personnel didn't know about this when we discussed this with them on our conference call from Sherco last Spring?

GE repeatedly stated that only National Carbon 634 brushes should be used on collector rings. They also stated that 15 to 20 mils was the minimum spiral groove depth
allowable to return to service. All rings are designed to be able to recut the spiral grooves at least once. 4 months is the average brush life. Collector ring remachining on turning gear is the preferred method. Remachining every 3 to 5 years is normal. 8 micro-inch finish is desired. GE recommends swapping polarity every year to even out ring wear. On 3600 RPM machines 6 mils or less brush vib is acceptable and 6 to 15 is marginal. On 1800 RPM machines 10 mils or less is acceptable and 10 to 20 is marginal. This is provided the frequency is 1X .If 2X, values are much lower.

18. Generator Fleet Issues
When capacitance mapping, the top and bottom bars should be tested separately as well as the turbine and generator ends should be tested separately.
End wedges should be checked for tightness as these are often found loose.
TIL 1226 should be implemented for inspection and or replacement of SWCS strainers.
GE strongly recommends installation of SLMS.
Whenever end winding work is done a bump test to check for natural frequency shift should be done.
Acoustic monitoring can be done to detect changes in core noise. Addition of belly bands can help tighten a loose core.
Rectifier teflon hoses should be replaced every 8 to 10 years.
Low speed balancing of generator rotors should not be performed.

19. Rewinds
GE has a short cycle field rewind that can be done on a 2 pole field in 10 to 14 days onsite and on a 4 pole field in 14 days in the shop. GE did a 72 slot nuclear liquid cooled rewind CP&L Brunswick 2 in 20 days. Refuel outage was 32 days.

20. Vibration and Generator Field Sensitivity (Joe Toth)
Several items can affect generator rotor vibration, shorted turns, blocked cooling passages, mechanical binding of the winding, shifting end turn blocking, alignment. If vibration changes with load it may be related to alignment. If vibration changes with field current at constant load, could be shorted turns. A blocked cooling passage will result in a much longer time for vibration to return to normal when the field current is changed. If vibration changes for no apparent reason it could be something as simple as too tight a clearance on an oil deflector. In any case you need to have both magnitude and phase angle to trouble shoot these types of vibration problems.

21. Preferred Machine
Preferred is now allowed to bid on all work, GE and non GE, provided that they are not asked to bid against GE. They have access to all GE drawings and can make just about anything for GE steam and gas turbines. Frank Schreier is the new president.

Any questions, please call.
Tim
612-520-6806

Xcel Energy

Energy Supply Production Resources Guideline

Number:	Title:	Revision No:	
EPR 5.736G	**Steam Turbine Rotor Wheel Inspection Recommendations for Stress Corrosion Cracking**	1.0	Page 1 of 6

1.0 PURPOSE:

The purpose of this guideline is to provide some background on stress corrosion cracking of steam turbine rotors, summarize current OEM recommendations, and provide inspection recommendations where OEM guidance is lacking.

2.0 APPLICABILITY:

This guideline applies to all reheat steam turbines and a single non-reheat unit, Arapahoe #4.

3.0 RESPONSIBILITIES:

3.1 The facility director is responsible for:

Ensuring station technical and operations personnel are aware of the recommendations in these guidelines.

Planning and budgeting for the inspections and contingencies identified in these guidelines.

3.2 Maintenance Resources is responsible for:

Assisting with outage planning and work scope development to cover the inspections recommended in these guidelines.

EXHIBIT NO. 94
4.22.15
R. L. KLANDERUD

4.0 REQUIREMENTS:

4.1 Background

Stress corrosion cracking in steam turbine rotors has been an issue for every turbine manufacturer for many years. The problem is related to a combination of factors including susceptible materials, high operating stresses, and a corrosive environment. General Electric (GE) low pressure turbines seem to have had the most problems, most likely due to the design of the blade to rotor wheel attachment. In the tangential entry dovetail design commonly used by GE, high stresses in the dovetail radius are present during operation. This condition in combination with the fact that certain corrosive impurities in the steam tend to deposit on the rotor and buckets in the wet steam stages which can lead to corrosion pitting and eventually to stress corrosion cracking.

Author: Tim Murray	Revised by: Original Issue	Approved By: /S/Mark Freeman (Electronic approval on file)
Effective Date: 8/25/08		Approval Date: 8/25/08

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Since the rotor material and design cannot be changed unless costly repairs or replacements are undertaken, the various OEMs have focused on turbine steam purity as one of the primary ways of controlling and minimizing the effects of stress corrosion cracking. The various OEMs issued turbine steam purity recommendations in the late 70s and early 80s primarily to address this issue. These recommendations have been periodically updated and are now more stringent than the original ones. Current steam purity recommendations from Siemens and GE can be found in references 6.2.4 and 6.2.7 respectively.

Most GE nuclear LP turbine rotors have been replaced, primarily as a result of stress corrosion cracking either in the shrunk on wheel disc keyways (as in the case of Xcel Energy Monticello) or in the wheel dovetails themselves. Most GE LP turbine rotors operating on fossil fueled once through boilers (super-critical units) have either been replaced or have had major weld repairs performed as a result of stress corrosion cracking in the wheel dovetails. Over the past several years a growing number of utilities have discovered serious stress corrosion cracks in GE LP turbine rotor dovetails on fossil fueled drum boiler units. This development lead Xcel north to begin performing ultrasonic testing of the wheel dovetails on drum boiler units even though no formal GE recommendations for this inspection exist for drum boiler units.

4.2 Sherburne County Unit #1 Experience

During the Fall 2007 Sherburne County Unit #1 major overhaul, Wesdyne performed phased array UT on the L-1, L-2, and L-3 wheel dovetails on both LP A and LP B rotors. The L-0 rows are the finger dovetail design. Numerous large indications were detected in the wheel dovetails on all 4, L-1 rows. The L-2 and L-3 rows were clean except for some light to moderate pitting. One half of a row of L-1 buckets was removed from the LPA rotor TE to confirm the size and location of the indications. The location and flaw sizes were determined to closely match the Wesdyne data. Due to the severity of the cracking (up to 3/8" deep) both rotors were shipped offsite to the Alstom repair shop in Richmond, VA for a major weld repair restoration of the L-1 wheel dovetails. The cost for these repairs, materials analysis, and failure investigation approached $1,500,000 and extended the scheduled outage by about 4 weeks. The failure analysis confirmed that the root cause of the cracking was stress corrosion. This was the 3rd inspection on these dovetails since the unit entered service in 1976. GE had performed UT exams of the dovetails in 1977 and again in 1985 as a result of rotor contamination due to carryover from the boiler. A coordinated phosphate water chemistry control program was in use during initial start-up of orig 956 2029 5586 field

the unit and problems with chemistry control resulted in a large amount of carryover and deposits on the turbine rotors. Re-inspection of the dovetails is recommended at the next scheduled LP overhaul in 2016.

4.3 General Electric Inspection Recommendations

TIL 770, Stress Corrosion Cracking of Wheel Dovetails on 3600 RPM Non-reheat Machines, was issued in March of 1975 after several in-service failures. This TIL recommends periodic ultrasonic inspection of L-1 and L-2 wheel dovetails on the HP rotor of certain larger non-reheat machines. The only Xcel Energy unit this applies to is Arapahoe unit #4.

TIL 1121, Inspection of Steam Turbine Rotor Wheel Finger Dovetails, was issued in May of 1992. This TIL recommends mag particle inspection of the rotor wheel finger dovetails any time buckets are removed for any reason and applies to all Xcel Energy GE units with finger type dovetails. It does not recommend removal of buckets just to perform the inspection. In most cases this applies to just the L-0 rows, but also to L-1 rows on the larger machines such as Monticello and Sherco 3.

TIL 1277, Inspection of Low Pressure Rotor Wheel Dovetails on Steam Turbines with Fossil Fueled Once-Through Boilers, was issued in the fall of 1999 after it became apparent that a large percentage of units with once through boilers had serious stress corrosion cracking issues. This TIL recommends strict compliance with the turbine steam purity recommendations in GEK 72281. It also recommends performing phased array ultrasonic testing of LP rotor wheel dovetails. This TIL applies only to LP turbine rotors on fossil fueled once through boilers. Technically it does not apply to any Xcel Energy units and was not formally issued to Xcel Energy by General Electric.

4.4 Xcel Energy Fleet Wide Recommendations

4.4.1 All Units

Review and implement, if not already in compliance, the latest OEM or EPRI turbine steam purity recommendations (Cycle Chemistry Guidelines for Fossil Plants: Phosphate Continuum and Caustic Treatment, EPRI, Palo Alto, CA: 2004, 1004188 and Cycle Chemistry Guidelines for Fossil Plants: Oxygenated Treatment, EPRI, Palo Alto, CA: 2005, 1004925), whichever is more stringent, and including monitoring of the reheat steam.

This information is summarized in Xcel Plant Chemistry Control Guidelines manuals (referenced by unit) available at each plant site.

4.4.2 All GE Reheat Steam Turbines

At the next scheduled overhaul where a GE LP turbine is scheduled to be opened for inspection, perform wheel gap checks on the L-1, L-2, and L-3 rows. Seriously consider further investigation of any wheel gaps in excess of 0.005", or greater than 0.010" near the notch opening, as this may indicate distress or yielding in the dovetail.

4.4.3 GE Reheat Steam Turbines with a Known History of Operation Outside of GE Steam Purity Recommendations or With Evidence of Corrosion Pitting

1. At the next scheduled overhaul where a GE LP turbine is scheduled to opened for inspection, perform a phased array ultrasonic examination of the L-1, L-2, and L-3 rotor wheel dovetails.

2. Perform bucket to wheel gap checks on the same rows to check for lifting and dovetail distress.

3. Be prepared to have the inspection results analyzed to determine the need for repairs.

4. Consider contingency planning in the event buckets need to be removed for further inspection and repair. Have steam path repair resources onsite ready for bucket removal. Consider ordering notch groups or set up a PO with vendor to reverse engineer and manufacture notch groups on an expedited basis.

5. Consider contingency planning in the event the rotor(s) need to be shipped offsite for major repairs. Set-up a PO with a repair vendor and have trucks permitted and waiting onsite with shipping skids.

4.4.4 GE Non-Reheat Steam Turbines (Arapahoe 4 Only)

1. At the next scheduled Arapahoe 4 HP turbine outage, perform wheel gap checks and ultrasonic inspection of the L-1 and L-2 wheel dovetails.

2. Consider contingency planning recommendations above.

4.4.5 Siemens, Westinghouse, Allis Chalmers, & Mitsubishi Steam Turbines

Perform inspections of the LP turbine rotor blade attachment grooves in the "wet/dry" regions during scheduled outages on the frequency recommended by the OEM. Note that the rotor blading does NOT require removal in order to inspect these blade attachment grooves. Complete inspections of these grooves including T root, and curved axial entry fir tree designs can be performed using phased array ultrasonic examination techniques.

5.0 REQUIRED RECORDS

The plant and production resources should maintain copies of all inspection results. These inspection results should be incorporated into unit overhaul reports and posted on the production resources website.

6.0 DEFINITIONS & REFERENCES

6.1 Definitions

6.1.1 Stress Corrosion Cracking

A cracking mechanism resulting from a combination of susceptible material, a corrosive environment, and high stress.

6.1.2 Phased Array UT

A non-destructive examination technique utilizing multiple ultrasonic transducers working together to allow inspection of complex geometries for flaws.

6.2 References

6.2.1 Westinghouse OMM 15, Power Plant Water and Steam Sample Service (Steam Purity Recommendations)

6.2.2 Westinghouse OMM 26, L-1R Blade Replacements (Free Standing Blade Design to Address Stress Corrosion Cracking Issues)

6.2.3 Westinghouse AIB 80-11, BB73 L-0 Disc Cracking Inspection Recommendations (Addresses Stress Corrosion Cracking in the L-0 Blade Discs)

6.2.4 Siemens Westinghouse IL 1250-8421, Turbine Steam Purity (Updated Recommendations)

6.2.5 Siemens IB 109, (Allis Chalmers Units) Inspection & Re-machining of LP Steam Turbine Shafts and Shrink Fit Disks

6.2.6 General Electric GEK 63430, Turbine Steam Purity

6.2.7 General Electric GEK 72281c, Steam Purity Recommendations for Utility Steam Turbines. (Updated Recommendations)

6.2.8 General Electric TIL 770, Stress Corrosion Cracking of Wheel Dovetails on 3600 RPM Non-reheat Machines

6.2.9 General Electric TIL 1121, Inspection of Steam Turbine Rotor Wheel Finger Dovetails

6.2.10 General Electric TIL 1277, Inspection of Low Pressure Rotor Wheel Dovetails on Steam Turbines with Fossil Fueled Once-Through Boilers

6.2.11 Mitsubishi MSTB-001, 100,000 Hour Inspections

6.2.12 Mitsubishi MSTB-022, Inspection of Turbine LP Blades & Disc Grooves

6.2.13 Xcel Energy Maintenance Resources Sherburne County Unit #1 Fall '07 Overhaul Report

6.2.14 Wesdyne Power Point Presentation 3-14-08, Inspection of Rotor Blade Attachments Using Phased Array Methodologies

7.0 REVISION HISTORY

Date	Revision	Change
	1.0	Original Issue

From: Murray, Timothy P
To: Kolb, Mark W
Sent: 4/5/2002 11:55:33 AM
Subject: RE: SCC In Sub-critical units

Yes, that's correct, this inspection is done with buckets on. However if significant indications are found, buckets must come off. Typically they've been finding the cracks at the notch area so most of the time only the notch buckets have to be removed. Spare rotors are not out of the question. If short outages are required then you may to want consider a spare LP A and a spare LP B that could possibly be shared between U1 & U2.
Tim

-----Original Message-----
From: Kolb, Mark W
Sent: Friday, April 05, 2002 10:42 AM
To: Murray, Timothy P
Subject: RE: SCC In Sub-critical units

Tim,
This can be done with the buckets on, correct?
Mark
PS I agree with your voice mail about not paying GE for the U3 CV parts that will not arrive in time.

-----Original Message-----
From: Murray, Timothy P
Sent: Thursday, April 04, 2002 3:30 PM
To: Kolb, Mark W
Subject: FW: SCC In Sub-critical units

Mark, we should probably plan on a phased array UT inspection of the L-1 and L-2 wheel dovetails on the next U1 & U2 LP inspections. They are now finding wheel dovetail cracks on the subcritical units.
Tim

-----Original Message-----
From: charles.nordhausen@power.alstom.com [SMTP:charles.nordhausen@power.alstom.com]
Sent: Thursday, April 04, 2002 1:06 PM
To: timothy.p.murray@xcelenergy.com
Cc: ronald.w.elsner@xcelenerg.com.nspco.com; jeffrey.w.farnick@xcelenergy.com; victor.j.scharenbroch@xcelenergy.com
Subject: SCC In Sub-critical units

Tim,

As a follow up to our recent conversation, the two sub-critical units that were found to have Stress Corrosion Cracking are Dayton Power and Light, Killian Station and Ameren, Labadie Station. These are both General Electric LP Turbines. The cracks were discovered during a phased array inspection during the month of March 2002. If you have any questions or would like to talk about inspections and/or repair solutions please contact myself or Bernie Mursch.

Regards,

Chuck Nordhausen
Sales Manager
(651) 653-6668

Bernie Mursch
Customer Services Manager (TSD)
(262) 782-9175

EXHIBIT NO. 100
4·22·15
R. L. KLANDERUD

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From: Kolb, Mark W
To: Murray, Timothy P; Juip, Gary W; Rogers, Peter R
Sent: 1/17/2008 2:11:13 PM
Subject: FW: Sherco LP Dovetails- New Recommendation
Attachments: Stress_Corrosion_Crack_Rate.pdf

Conference call today at 3:30, but I'd like to move it up to 3:00....are you available.

ReGENco write.."

4) By experience of Dr. Don McCann working for about 42 years in this field, it will be very safe measure to inspect these dovetails right away.

Is the recommendation an immediate shut down, or within weeks, months or a year.

We would say within weeks if immediate shutdown is not feasible.

What is the rational for those recommendations, associated risks and failure probabilities with the various delays in inspection.

EPRI guidelines show that stress corrosion crack growth rate can be enhanced between 10 to 100 times with the presence of caustics

-----Original Message-----
From: Gupta, Vikas [mailto:VGupta@regencoservices.com]
Sent: Thursday, January 17, 2008 2:11 PM
To: Kolb, Mark W
Subject: FW: Sherco LP Dovetails- New Recommendation

FYI

EXHIBIT NO. 101
4·22·15
R. L. KLANDERUD

From: Gupta, Vikas
Sent: Thursday, January 17, 2008 2:08 PM
To: 'Johnston III, John G'
Subject: RE: Sherco LP Dovetails- New Recommendation

John,

More definition on we shouldn't wait 2 years to inspect Unit 2 LPs.

1) Unit 1 dovetails had pure stress corrosion type of cracking. Nothing else. We strongly believe that carry over event played big part to it. More specifically, high levels of sodium and cation conductivity played a big role. We have not seen cracking this deep in lot of currently operating 1940-1950 vintage disks/blade attachment areas due to stress corrosion in wetter environment than sherco. This means water chemistry is really major parameter to look at in this case.
2) Unit 2 was never inspected in the past. Our earlier recommendation of 2 year extension was based on the fact that unit 2 was never exposed to high levels of sodium/cation conductivity that cause turbine damage. Data from 1985 to 2007 showed this. However, data obtained from the year 1977-1979 did show that unit 2 was also exposed to higher levels of sodium/cation conductivity though not as severe as unit 1. Therefore, we don't expect cracking to be as severe (if any) in unit 2 dovetails. But it becomes almost mandatory to inspect the dovetails immediately.
3) GE report of deposit analysis (July 20, 1977) did show 2 cases where corrosive damage appeared 8 years after turbines were known to be exposed to caustic carryover.
4) By experience of Dr. Don McCann working for about 42 years in this field, it will be very safe measure to inspect these dovetails right away.

Is the recommendation an immediate shut down, or within weeks, months or a year.

We would say within weeks if immediate shutdown is not feasible.

What is the rational for those recommendations, associated risks and failure probabilities with the various delays in inspection.

EPRI guidelines show that stress corrosion crack growth rate can be enhanced between 10 to 100 times with the presence of caustics. Fred Lyle (A know researcher in this field) pointed out that stress corrosion rate is about 18.5 times in the

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0026

presence of caustics. Using these criteria, probability of failure for unit 2 is same as unit 1 (4.92E-02% more than ReGENco recommended limit of 1E-02%) till year 2007 (and doesn't change by much in next 2 years). This is conservative criteria. Unfortunately, there is only limited literature available which shows change in stress corrosion crack growth rate with change in the percent of caustics (or mostly it's very conservative and done at high sodium levels for short period of time, data extrapolated further). Attached is one common EPRI reference used.

We can discuss more in the conference call.
Regards,
Vikas

From: Johnston III, John G [mailto:john.g.johnston-iii@xcelenergy.com]
Sent: Thursday, January 17, 2008 11:54 AM
To: Gupta, Vikas
Subject: RE: Sherco LP Dovetails- New Recommendation

Hi Vikas -

These seem to be the topics for discussion:

- More definition on we shouldn't wait 2 years to inspect Unit 2 LPs.
- Is the recommendation an immediate shut down, or within weeks, months or a year.
- What is the rational for those recommendations, associated risks and failure probabilities with the various delays in inspection.

Are we prepared to talk in detail about these today on the conference call?

- John

John G Johnston III
Principal Production Engineer - Welding
Xcel Energy
1518 Chestnut Ave
Minneapolis, Minnesota 55403-1292
Office: 612.630.4256
Fax: 612.630.4367
Mobile: 612.247.6906
john.g.johnston-iii@xcelenergy.com
www.xcelenergy.com

-----Original Message-----
From: Gupta, Vikas [mailto:VGupta@regencoservices.com]
Sent: Thursday, January 17, 2008 11:49 AM
To: Johnston III, John G
Subject: RE: Sherco LP Dovetails- New Recommendation

John,
Yes, lets make it about 2 PM (or after) central time if that works with everybody?
Regards,
Vikas
414-475-2859

From: Johnston III, John G [mailto:john.g.johnston-iii@xcelenergy.com]
Sent: Thursday, January 17, 2008 11:41 AM
To: Gupta, Vikas
Subject: RE: Sherco LP Dovetails- New Recommendation

Hi Vikas -

Do you have a time preference today for the call with Sherco?

- John

John G Johnston III
Principal Production Engineer - Welding
Xcel Energy
1518 Chestnut Ave
Minneapolis, Minnesota 55403-1292
Office: 612.630.4256
Fax: 612.630.4367
Mobile: 612.247.6906
john.g.johnston-iii@xcelenergy.com
www.xcelenergy.com

-----Original Message-----
From: Gupta, Vikas [mailto:VGupta@regencoservices.com]
Sent: Thursday, January 17, 2008 10:31 AM
To: Johnston III, John G
Subject: RE: Sherco LP Dovetails- New Recommendation

John,
I'll be available today and tomorrow. Don may not be in until later next week. I'm confident that I can handle most of the questions!
Regards,
Vikas

From: Johnston III, John G [mailto:john.g.johnston-iii@xcelenergy.com]
Sent: Thursday, January 17, 2008 9:49 AM
To: Gupta, Vikas
Subject: RE: Sherco LP Dovetails- New Recommendation

Hi Vikas -

Are you and Don available for a conference call with the plant either today or tomorrow? The plant would like to understand a little more about our new recommendations.

- John

John G Johnston III
Principal Production Engineer - Welding
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john.g.johnston-iii@xcelenergy.com
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-----Original Message-----
From: Gupta, Vikas [mailto:VGupta@regencoservices.com]
Sent: Wednesday, January 16, 2008 3:26 PM
To: Kolb, Mark W; Johnston III, John G
Subject: RE: Sherco LP Dovetails- New Recommendation

Mark,

This is because in the data tabulation you will see that unit 1 went through very poor and high Na / cation conductivity levels in the year 1976. These levels were controlled by the year 1977 but still were high and out of spec. This is the time when unit 2 went to service and had similar levels for about 6 months. (Look at the mean and standard deviations falling out of spec). Then these levels were further controlled in later years and brought down within the spec for both unit 1 and unit 2. (That is why unit 1 operated for almost 30 years).

Therefore, we believe that there could be a damaging effect on the unit 2 dovetails during its first six months in service even though it was not as severe as in case of unit 1. Hence this statement.

Regards,
Vikas

From: Kolb, Mark W [mailto:mark.w.kolb@xcelenergy.com]
Sent: Wednesday, January 16, 2008 2:58 PM
To: Gupta, Vikas; Johnston, John (Xcel Energy)
Subject: RE: Sherco LP Dovetails- New Recommendation

Vikas, John,
Why the statement "...cracking (**if any**) is not expected to be as deep and intense as observed in unit 1. " What is the reasoning?
Thanks,
Mark

-----Original Message-----
From: Gupta, Vikas [mailto:VGupta@regencoservices.com]
Sent: Wednesday, January 16, 2008 2:39 PM
To: Johnston III, John G; Kolb, Mark W
Cc: McCann, Donald
Subject: Sherco LP Dovetails- New Recommendation

Gentlemen,
Based on sodium and cation conductivity levels provided to us from the years 1977 to 1979 for unit 1 and unit 2, the water chemistry of unit 2 was out of specification (recommended by various OEM's) from the dates of Jan 1977 to June 1977.
Generally, there may be some high points during sample measurements but during this period of time, the mean of the data samples and standard deviation were high (and out of spec) as shown in the Attached tabulation.

Since we have seen that cracking in unit 1 was purely due to stress corrosion phenomenon with effect of caustics, the high levels of sodium and cation conductivity may have helped initiate (and possibly grow) cracks at the dovetails of unit 2. Nevertheless, cracking (**if any**) is not expected to be as deep and intense as observed in unit 1.

Therefore, it is now our recommendation to inspect unit 2 LP dovetails as a safe measure. We don't feel comfortable in extending the inspection interval to 2 more years in the light of new evidence.

Please let me know if you have any questions.

Best Regards,
Vikas

Vikas Gupta
Condition Assessment Analyst
Materials & Analysis
Phone: 414-475-2859
FAX: 414-475-2858
Email: VGupta@regencoservices.com

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LP ROTOR CRACKING

- L-1 Dovetail Region
- Due to Stress Corrosion Cracking (SCC)

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R. L. KLANDERUD

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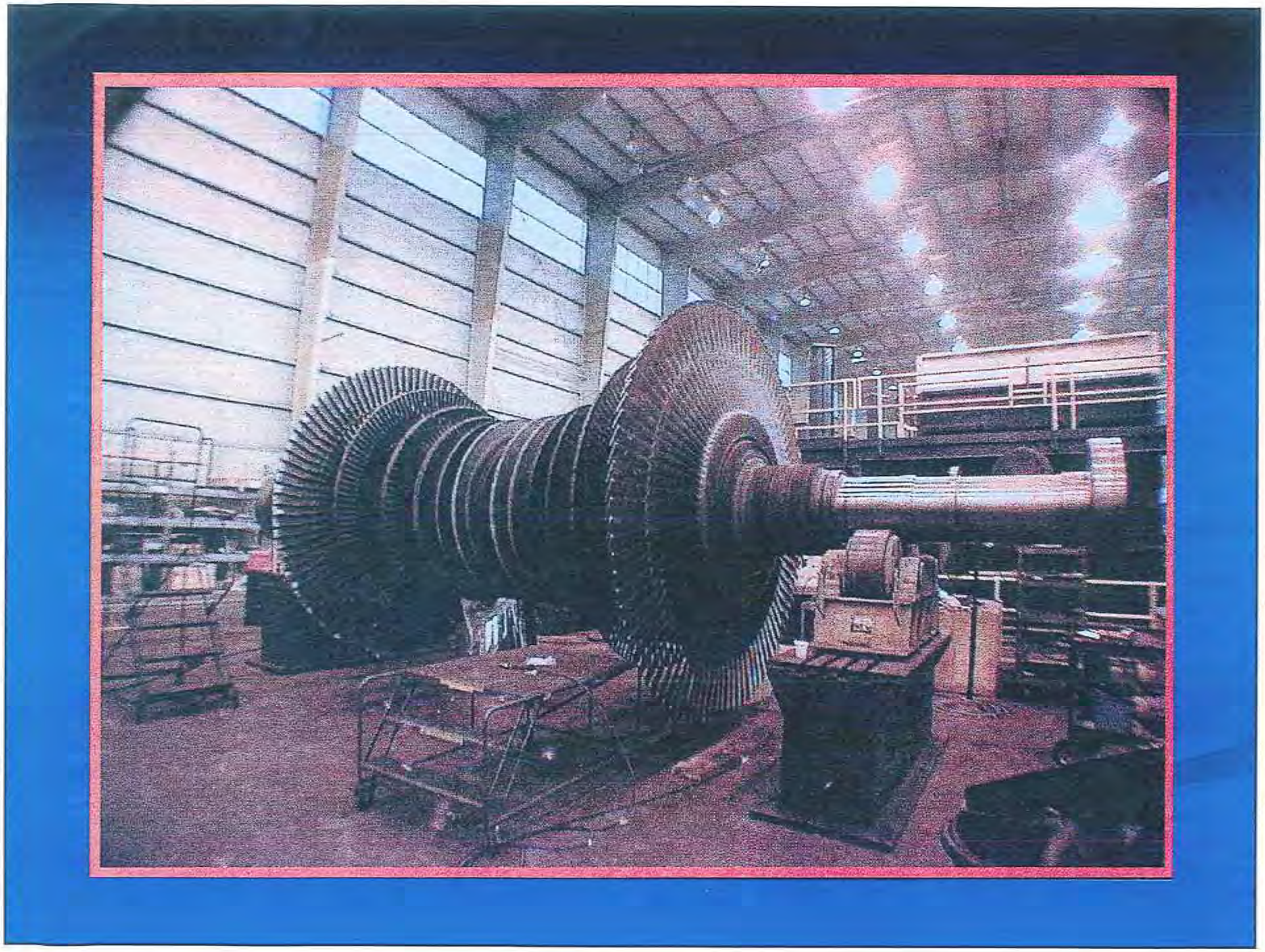


HISTORY

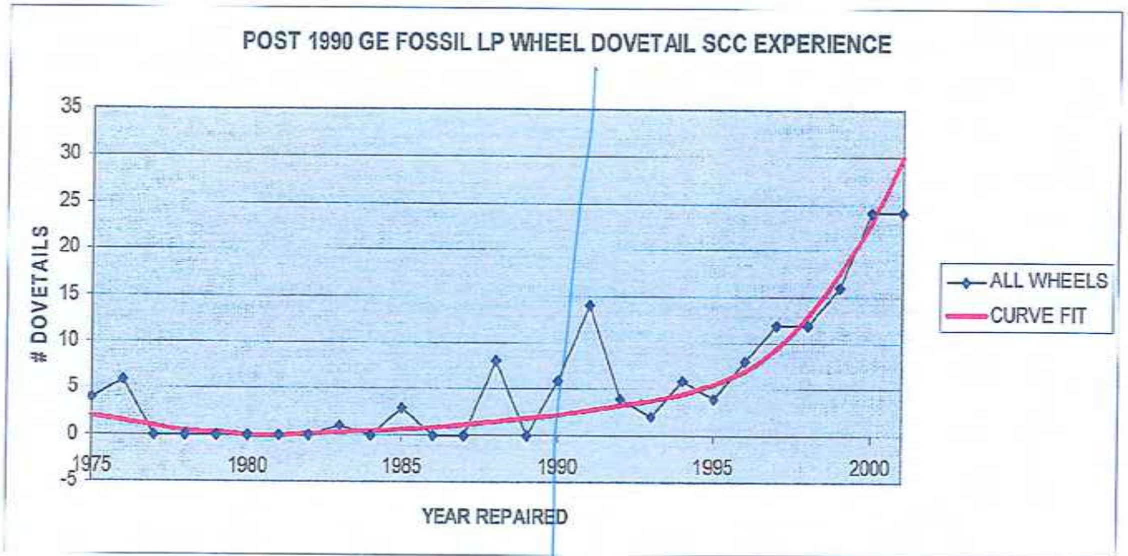
- Nuclear Units
  - Virtually all rotors replaced
  - Monticello replaced in 1984
- Once-Through Boilers
  - 30% of rotors replaced
  - 25% risk per GE
  - TILL 1277 issued
- Drum Type Boilers
  - 1% of rotors repaired by 2003
  - < 1% risk per GE
  - No TILL issued, no plans to issue

when was this, info from

??
LSTG conference
ask for update

LP ROTOR 12% CHROME WELD REPAIRS

PRE & POST 1990 GE FOSSIL LP INDUSTRY SCC EXPERIENCE:



wheeled yrs Cap for

includes drum Dsdes

ALSTOM

INDUSTRY EXPERIENCE

- > 5% of all drum units
- Teco Energy - Currently at GE
  - Close to "critical failure"
- Miller - 4 wheels, 2007/2008
- Southern – 2 rotors inspected/cracked, will look at remaining 6
- Rocksboro (C.E., G3 same vintage)
  - Exposed to Na per C.E.
  - Alstom repaired, 23 days in 2006
- Bruce Mansfield – 2002
- Consumers/Campbell 3 – 4 of 6 rotors in 2000
- Navajo/Salt River – 4 rotors

⇨ **Trend is increasing frequency**

⇨ **Still no plans for TILL**

⇨ **Fleet implications for Xcel – Larger than Sherco issue**

SHERCO HISTORY – UNIT 1

- Unit startup in 1976
- Water chemistry - Coordinated Phosphate Treatment (CPT)
  - Driver for SCC
- Unit lost capacity, early 1977
- Opened turbine, heavy deposits
- Attributed to carry over
- 6/77 switched to All Volatile Treatment (AVT)
  - Damage Done
- GE recommended inspections in 1977 and 1985
  - No crack indications found

- **Unit Exposed to Na - SCC driver**

SHERCO HISTORY – UNIT 2

- Unit start up in 1977
- Same water chemistry as U1 - 6 months
- Same turbine deposits as U1 found in 1978
- 1977 switched to AVT
- Boiler chemical cleaning incident, required Couton bottom replacement….carry over?
- GE recommended inspections in 1978 and 1983
  - No crack indications found

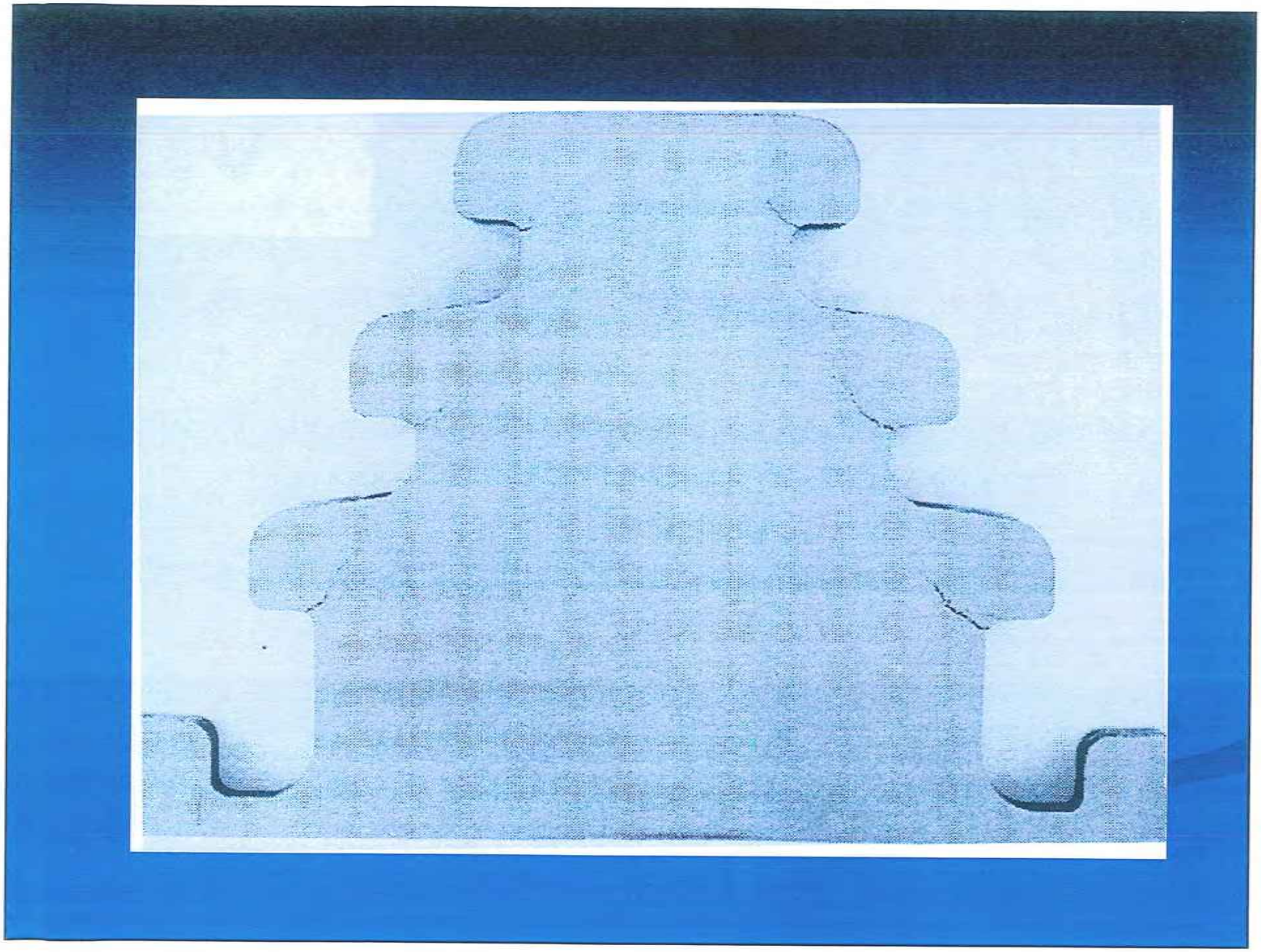
- **Unit exposed to Na - SCC driver**

SHERCO HISTORY

- 2003: < 1 % of fleet effected
- 2004: More incidents in drum boiler fleet
  New Tool/phased array testing
  Proactively decided to inspect Sherco units.
- 2005: U3 Inspected – no indications
- 2006: U2 Inspection cut – budget
- 2007: U1 Unbudgeted inspection – cracking found

what is unit 3

B.S.L-1
not gotten

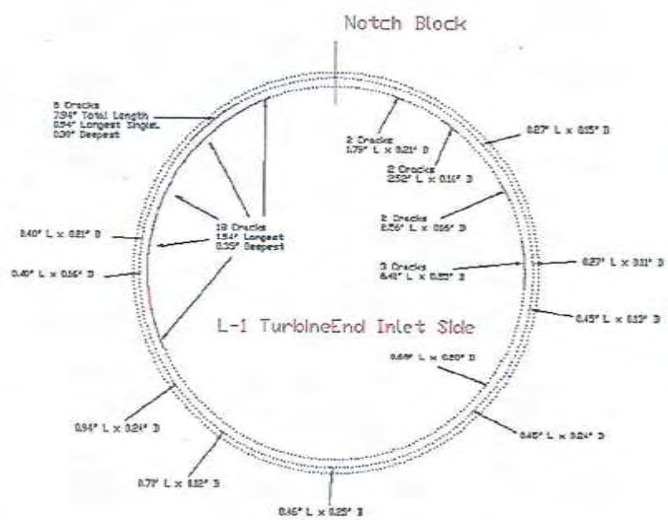


WESDYNE INTERNATIONAL

POLARIZED ZIEW

LP A TURBINE END

INLET SIDE



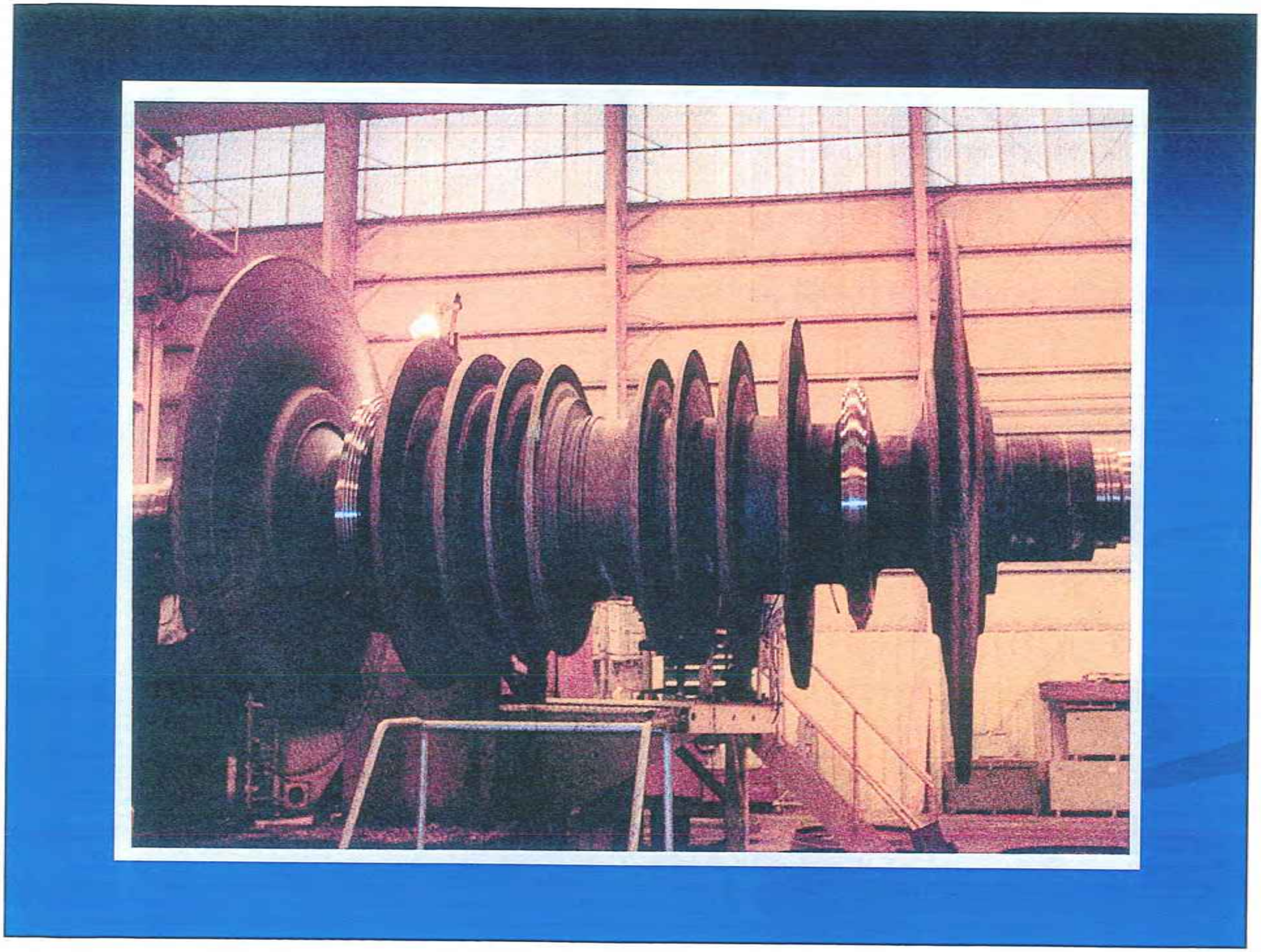
UNIT 1 – 2007 INSPECTION

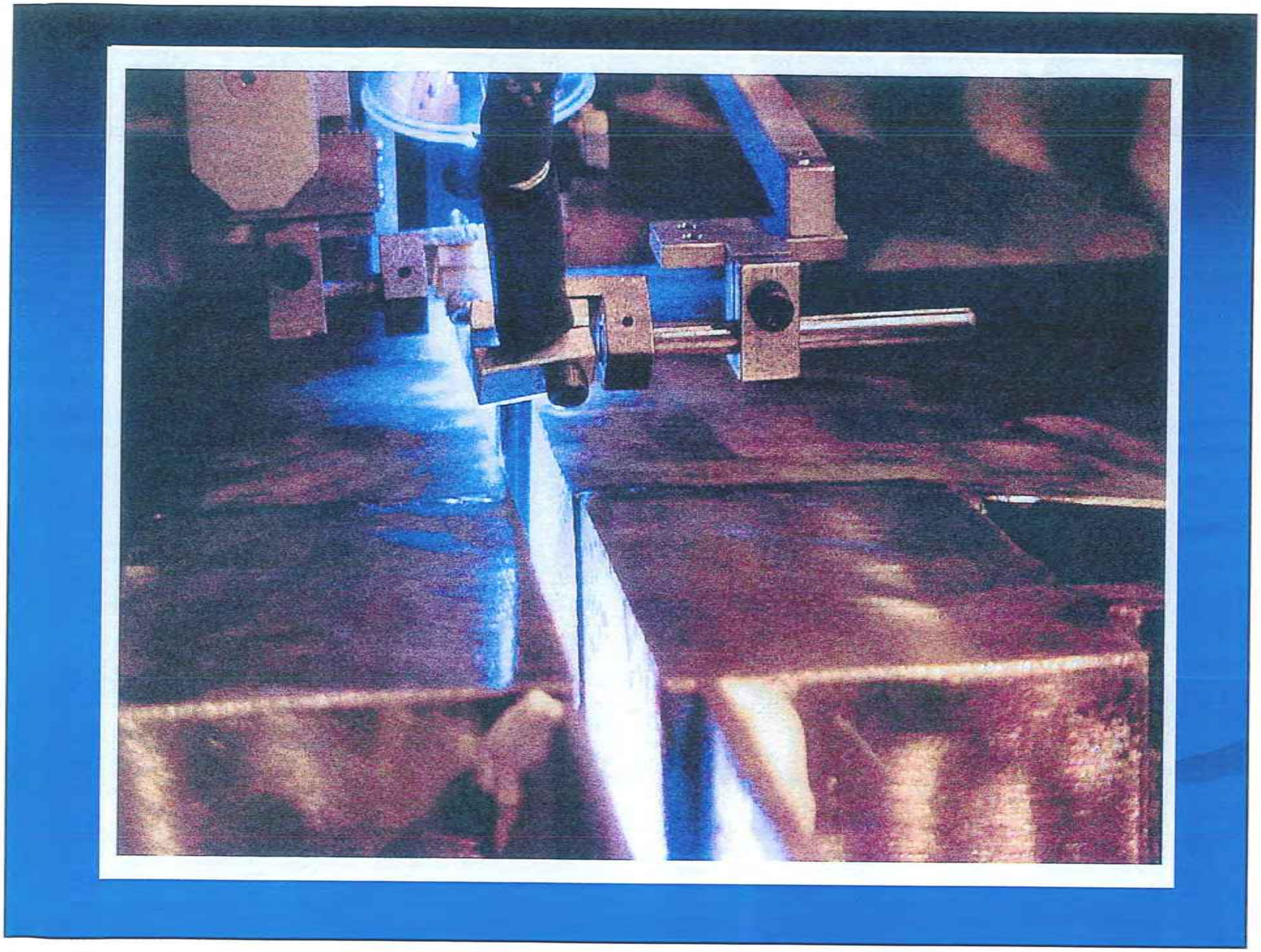
- Cracking - all four wheels, all hooks
  - Unit 2 implications
  - Parallel paths to evaluate U1 and U2
  - Contacted vendors
    - GE, ReGENco, MD&A, SIA, Alstom, Turbine Masters, FOMIS (emergency request)
  - Multiple parallel paths to:
    - Verify WesDyne data
    - Investigate repair options (schedule, cost, service life)
    - Failure analysis U1 & U2
    - Gather U2 data (chemistry, operations, overspeeds, geometry, etc.)
    - Obtain industry data (FOMIS, vendors, other utilities)

- **All agreed repair required, 0.375" cracks**
- **Alstom weld build-up selected**

// what info ask for vendors

// industry data





UNIT 2

- Initial ReGENco report (Dec. 2007)
  - Fall 2009 inspection
- Revise ReGENco report (mid Jan 2008)
  - High Na values - 1st six months of service
  - Inspect "…within weeks if immediate shutdown not feasible."

- **Unit 2 at same, potentially higher, risk as Unit 1**

FUTURE OUTAGE – UNIT 2

- Inspections
  - 14 days
  - $450K
    - (MD&A, Millwrights, TFA, WesDyne, grit blasters, NDE, carpenters, shipping contingency, parts, maintenance support, SIA)
- Repairs
  - Do nothing
  - Enhanced dovetail
  - Blend cracks
  - Remove bucket groups
  - Long shank buckets
  - Titanium row
  - Pressure plate
  - Weld repair
    - Alstom - weld build-up
    - GE - Fineline

	Alstom	GE
Shop	$1,200K / 32 Days	$1,700K / 30 Days
Ship	$95K / 10 Days	$60K / 6 Days
Total Outage (min)	60 Days	56 Days

Outage Options

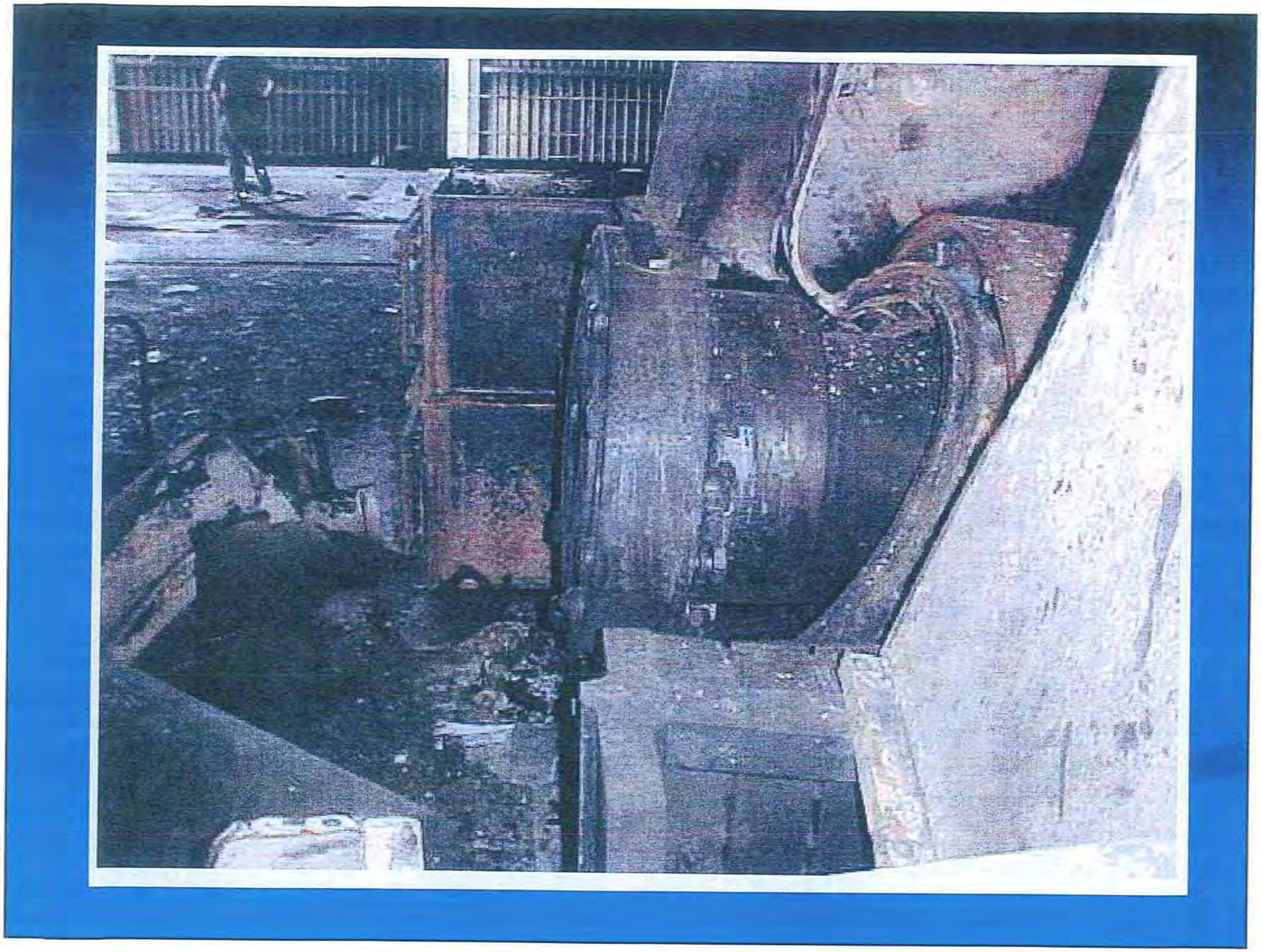
- Immediate
  - Preferred Option
  - Shop space unavailable
  - Overlap with PI Outage
- March-May
  - Shop and resources available
  - Unit available for summer
  - Partially avoids PI outage
  - Minimizes risk
- Fall 2008
  - Replace unit 3 outage
    - Multiple capital projects scheduled
    - Unit 3 Partnership – discussion and consent required
  - Risk too high
- Fall 2009
  - Risk too high
- **Plant recommends March-May Outage**

Unit 2 Turbine Outage

- Inspect L-1, L-2 and L-3 rows
- MD&A
  - Available
  - Developing schedule, cost estimates
  - Checking resource availability
- WesDyne
  - Key people available
  - Ability to inspect with rotors in/out
- Alstom
  - Shop available late March, April
  - Potential conflict w/ other rotor repairs
    - Shut down: March 7th - no conflict; March 14th - 5 day delay, March 21st – 10 day delay
  - Shipping: Stage trucks, permits. Frost restrictions and Easter potential impact
- Crack analysis
  - ReGENco and SIA
  - Models built, fast turnaround
- Parts - List developed, order soon
- Purchasing – T&C's issues w/ Alstom and WesDyne, Working w/ Linda Holz
- Duration – 14 ~60+ days

Unit 2 B.O.P. Outage

- Inspect and repair boiler slope refractory ($40k)
- Inspect and repair boiler corner tubes ($25k)
- Clean boiler burners, SOFA ports, & back pass ($18k)
- Inspect & repair 21 air heater ($17k)
- Install 21 ID fan motor rotor ($8k)
- Install 21 Main station aux transformer, if repairs complete ($8k)
- Complete forced outage work scope, 42 work orders ($180k)
- Total Cost $296K



RISKS

- In-service Failure
  - 8 weeks minimum to 2+ years, total destruction
- Other plants at same or higher risk as Sherco
- Bigger issue is the Xcel fleet implication

issues which impacts U3

Name of Component or System - System Health Report
Assigned Budget Team: TS
Maximo System/Subsystem: TS/LP

Plant & Unit	Component	Code	Date
Sherco Unit 3	LP Turbine	☒ Green ☐ Yellow ☐ Red	2/1/2005

Team members: Budget Team Lead: Dan McConnell
System Engineer: Mark Kolb
TOS Engineer: Tim Murray
I&C Technician: Dan McConnell

(I) Description of condition(s) that substantiate a "Green", "Yellow" or "Red" Code.

LP Turbines (Green): Contingent upon maintaining current levels of maintenance and 6-year T.B.O. Also require that the L-0 covers be replaced in 2005. There is a potential industry-wide problem with rotor wheel cracking.

(II) Risk(s) associated with a "Yellow" or "Red" Code.

Risks associated with wheel cracking involve wheel failure and buckets departing the rotor. Resulting collateral damage could be severe (i.e. due to mass imbalance).

(III) Corrective actions that could minimize or mitigate the risks identified above, or allow reclassification of the code to "Yellow" or "Green".

Perform inspections and repairs if required during the 2005 outage.

TRIAL EXHIBIT
0008
exhibitsticker.com

EXHIBIT NO. 75
4.22.15
R. L. KLANDERUD

XCEL_Sherco_07_0167418

TR.EX.NSP0008.001

System Description

- General Electric G3, dual flow, low pressure turbines (2)
  - S/N 170X819
  - 1987
  - GEK 64915
  - NX-23221-3900-0,1,2

Key System Design information

- Turbine train (HP/IP/LP) nameplate: 2400 psig, 1000°F, 1000°F reheat, 1.5" Hg Abs. Exhaust pressure.
- (2) Double flow LP's, with (6) stages (12) rows per LP turbine, 33.5" last stage buckets, extraction steam for feed water heating
- See NX-23221-3900-0, 1, 2

Key Performance Parameters

- Bearing vibrations
- URGE rating
- Performance and efficiency values
- Years since major overhaul
- Type of operation base/load following
- Number of starts cold/hot
- Any water induction incidents
- Any off-frequency events
- Starting & loading charts followed
- Proper pre-warming
- Weekly/annual trip testing results
- Bearing metal temperatures per OEM

Significant Work History

- 1993 Major inspection
- 1996 L-1 tie-wire holes inspected for cracking
- 1999 Major inspection
  - L-1 buckets replaced by GE continuous coupled buckets and L-1 diaphragms modified.
  - Rotor "head-shot" exam by GE, no indications found
  - Boresonic exam of LPA and LPB (GE approved a 10 year re-inspection interval)
  - Replace L-0 diaphragm spill strips and holders with erosion resistant materials
  - L-0 bucket pins replaced by GE due to cracking
    - LPA: 33 on TE and 170 on GE
    - LPB: 1 on TE and 50 on GE
  - Bearings 5,7, and 8 had slight wiping and excess clearances. Sent out for repairs.
  - LP's are out of position axially by ¼" (too far toward turbine end)
  - Rotors low speed balanced
- 2002
  - LPA and LPB cross-over expansion bellows replaced (due to cracking)

- Bearing 6 inspected and returned to service without rebabitting. (Note: This bearing has been running at a higher temperature than the other LP bearings since the 1999 outage.
- Borescopic exam of L-1 buckets. Only light water erosion of covers and tenons noted.
- L-0 visual exam, heavy cover erosion. Up to 1/16", due to water erosion. Covers should be replaced at next opportunity.

Inspection Plans

- Maintain 6 year inspection frequency
- Rotor boresonic exams at OEM frequencies or as allowed by data results and analysis. Working with an independent vendor to extend bore inspection intervals beyond OEM recommendations
- Annual heat rate testing
- Annual URGE testing
- Oil analysis (quarterly)
- Annual vibration survey and frequency analysis
- Consider stripping the insulation off of the crossover piping to allow visual and NDE exams. (Infrared images reveal possible steam leak at some locations)
- Crawl through inspections every 3 years during boiler outages.

Future Plans

- The LP inspection interval could possibly be extended to 9 years to fit with the HP/IP/Gen schedule if required (based on 2005 inspection results). Otherwise maintain 6-year overhaul frequency.
- Crawl through inspection during boiler outages
- Replacement of L-0 bucket covers (scheduled for 2005)
- Perform phased array ultrasonic inspection of LP rotor wheel dovetails
- Replace ruptured discs

Name of Component or System - System Health Report
Assigned Budget Team: TS
Maximo System/Subsystem: TS/LP

Plant & Unit	Component	Code	Date
Sherco Unit 3	LP Turbine	☒ Green ☒ Yellow ☐ Red	2/22/2007 1030

Team members: Budget Team Lead: Duane Wold
System Engineer: Mark Kolb
TOS Engineer: Tim Murray,
I&C Technician: Dan McConnell

(I) Description of condition(s) that substantiate a "Green", "Yellow" or "Red" Code.

LP Turbines (Green): Contingent upon maintaining current levels of maintenance and 6-year T.B.O. These LP's experience dovetail pin cracking problems, erosion damage and may suffer from an industry-wide problem with rotor wheel cracking. Based on as-found condition of LP's during the 2005 outage, and repairs performed, a Green rating is justified. Unit 3 LP's could probably go 9 years and still maintain a Green rating. The rating could be changed to Yellow based on the unknown condition of the bearings. They were all found with wiped Babbitt during the 2005 outage. The root cause is still questionable. They experienced high metal temperatures during the Significant Operational Events discussed at the end of this report.

(II) Risk(s) associated with a "Yellow" or "Red" Code.

Risks associated with wheel cracking involve wheel failure and buckets departing the rotor. Resulting collateral damage could be severe (i.e. due to mass imbalance and projectiles). Erosion damage may allow components to separate and contact other rotating and stationary components. Cracked dovetail pins may allow buckets to separate from the rotor (low probability). Bearing Babbitt failures can lead to high vibrations, unit trip and failed unit re-starts. In an extreme case it can lead to catastrophic turbine failures.

(III) Corrective actions that could minimize or mitigate the risks identified above, or allow reclassification of the code to "Yellow" or "Green".

The LP's may be replaced as part of the uprate project (2011). This would improve the option of a 9 year inspection interval and maintaining a Green rating with even less risk. Perform phased array testing. Perform bearing inspections and monitor bearing operation and metal temperatures.

System Description

- General Electric G3, dual flow, low pressure turbines (2)
  - S/N 170X819
  - 1987
  - GEK 64915
  - NX-23221-3900-0, 1,2

Key System Design information

- Turbine train (HP/IP/LP) nameplate: 2400 psig, 1000°F, 1000°F reheat, 1.5" Hg Abs. Exhaust pressure.
- (2) Double flow LP's, with (6) stages (12) rows per LP turbine, 33.5" last stage buckets, extraction steam for feed water heating
- See NX-23221-3900-0, 1, 2

Key Performance Parameters

- Bearing vibrations
- URGE rating
- Performance and efficiency values
- Years since major overhaul
- Type of operation base/load following
- Number of starts cold/hot
- Any water induction incidents
- Any off-frequency events
- Starting & loading charts followed
- Proper pre-warming
- Weekly/annual trip testing results
- Bearing metal temperatures per OEM

Significant Work History

- 1993 Major inspection
- 1996 L-1 tie-wire holes inspected for cracking
- 1999 Major inspection
  - L-1 buckets replaced by GE continuous coupled buckets and L-1 diaphragms modified.
  - Rotor "head-shot" exam by GE, no indications found
  - Boresonic exam of LPA and LPB (GE approved a 10 year re-inspection interval)

  - Replace L-0 diaphragm spill strips and holders with erosion resistant materials
  - L-0 bucket pins replaced by GE due to cracking
    - LPA: 33 on TE and 170 on GE
    - LPB: 1 on TE and 50 on GE
  - Bearings 5,7, and 8 had slight wiping and excess clearances. Sent out for repairs.
  - LP's are out of position axially by ¼" (too far toward turbine end)
  - Rotors low speed balanced
- 2002
  - LPA and LPB cross-over expansion bellows replaced (due to cracking)
  - Bearing 6 inspected and returned to service without rebabitting. (Note: This bearing has been running at a higher temperature than the other LP bearings since the 1999 outage.
  - Borescopic exam of L-1 buckets. Only light water erosion of covers and tenons noted.
  - L-0 visual exam, heavy cover erosion. Up to 1/16", due to water erosion. Covers should be replaced at next opportunity.
- 2005 Major Inspection
  - Turbines found in generally good condition, other than unexpected bearing repairs on T-5,6,7,8 and previously planned L-0 cover replacement, minimal/normal repairs were required. Virtually no SPE damage but some water erosion on last few stages, slight FOD heaviest toward the inlet stages, heavy deposits toward the back (deposits less than last major overhaul).
  - New LPA/B L-0 covers installed by MD&S, supplied by GE.
  - Babbitt damage to all 4 LP bearings. Damage had the appearance of arc-type damage, blown out babbit. Sent out for repair at RPM.
  - Broken dovetail pins replaced (190 pins)
  - D-coupling spacer disc found slipped since the last outage, realigned and re-doweled.
  - Rotors were low speed balanced
  - LP rotors were repositioned 0.230" toward the generator to improve internal clearances.
  - LPA bearing move for alignment reasons.
  - T6,7 oil deflectors rebuilt by RPM
  - Phased Array (NDE) testing on LP rotors. Indication found on LPA (generator end). Analysis determined that the indication was probably there from original construction. Re-inspection interval of 10 years specified, (2015). It is highly recommended that spare closure group components be on-hand for the next inspection as bucket removal is a possibility when Phased Array testing is performed.

Inspection Plans

- Maintain 6 year inspection frequency, consider extending to 9 years
- Rotor boresonic due in 2049 (per Dr. McCann)
- Annual heat rate testing
- Annual URGE testing
- Oil analysis (quarterly)
- Annual vibration survey and frequency analysis
- Consider stripping the insulation off of the crossover piping to allow visual and NDE exams. (Infrared images reveal possible steam leak at some locations)

- Crawl through inspections every 3 years during boiler outages.

Future Plans

- The LP inspection interval could possibly be extended to 9 years to fit with the HP/IP/Gen schedule if required (based on 2005 inspection results). Otherwise maintain 6-year overhaul frequency.
- Crawl through inspection during boiler outages
- Perform phased array ultrasonic inspection of LP rotor wheel dovetails, 2015 due
- Replace rupture discs
- Uprate project plans to replace LPs in 2011.

Significant Operational Events

1. Following the major outage, the #4 and #5 bearing metal temperatures climbed over a period of weeks and were sensitive to load and condenser pressure. In early 2006 an outage was planned for temporary valve screen removal and to address the hot bearing root cause. IP bearing #4 was found to be set ~0.0065" to low with some assembly errors. The pinch on both #4 and #5 bearings was found to be excessive, (0.005"~0.006"), which did not allow the bearings to self-align. MD&A corrected the errors under warrantee. The bearings were not required to be sent out for repair. Unit startup went well and the turbine continues to operate satisfactorily.
2. Full load trip and startup incident 7/23/06: During a plant trip, due to non-turbine related reasons, the turbine ventilator valve stuck open for over four hours, unnoticed. Once discovered, the valve was helped closed, by hand, as the valve operator spring did not have sufficient force to close the valve. During the unit restart, several oil pumps were shut down in error, eventually causing another trip. During the next restart the #6 bearing reached 336 deg F, #7 reached 274 deg F and #10 reached 241 deg F. The unit was placed on line. The upstream detraining tank screens were checked for the presence of babbit and none was found. There appears to be very little change in the rotor vibration due to this event. Bearing metal temperatures are similar to, and in some cases better than before the event. There is a slight shift in shaft oil pump suction pressure. This suggests the possibility of a change in oil flow through the system, (bearing geometry or rotor position change possibly). The unit has been running at high loads for an extended period of time, and been cycled off-line several times since the event and exhibits no unusual symptoms that suggest major bearing damage. This is not to say that there is no damage. Units have operated with significant bearing damage for months and years without any operational indications. The bearings may well have been damaged. They may function properly until the next major overhaul, but are probably more at risk for wiping than a "new" bearing.

Name of Component or System - System Health Report
Assigned Budget Team: TS
Maximo System/Subsystem: TS/LP

Plant & Unit	Component	Code	Date
Sherco Unit 3	LP Turbine	☒ Green ☐ Yellow ☐ Red	2/12/2009, 13:30

Team members: System Engineer: Mark Kolb
Budget Team Lead: Dan McConnell
TOS Engineer: Tim Murray,
I&C Technician: Dan McConnell

(I) Description of condition(s) that substantiate a "Green", "Yellow" or "Red" Code.

LP Turbines (Green): During the 2005 outage all the LP bearings were found with various degrees of wiped babbitt. The root cause for the wiping is still in question, (i.e. prior repair quality, overloading, electrolysis, other?). All bearings were repaired and returned to service. In 2006 the unit experienced a Significant Operational Event discussed at the end of this report, resulting in high bearing metal temperatures. Since that time the bearings have performed with out incident. In 2008, inspection of bearings #6 and #7 found the bearings in good condition other than small amounts of electrolysis damage present.

These LP's also experience dovetail pin cracking problems, erosion damage and may suffer from an industry-wide problem with rotor wheel cracking. However, rotor wheel phased array testing in 2005 did not detect any cracking issues.

Other than the current bearing issue, the turbines were found in generally good condition both during the 2005 outage, and during the very limited non-disassembly inspection in 2008.

(II) Risk(s) associated with a "Yellow" or "Red" Code.

Risks associated with wheel cracking involve wheel failure and buckets departing the rotor. Resulting collateral damage could be severe (i.e. due to mass imbalance and projectiles). Erosion damage may allow components to separate and contact other rotating and stationary components. Cracked dovetail pins may allow buckets to separate from the rotor (low probability). Bearing babbitt failures can lead to high vibrations, unit trip and failed unit re-starts. In an extreme case it can lead to catastrophic turbine failures.

(III) Corrective actions that could minimize or mitigate the risks identified above, or allow reclassification of the code to "Yellow" or "Green".

The LP's will not be replaced as part of the uprate project (2011). Perform phased array testing next major inspection. Perform bearing inspections in 2008 (Update, completed inspections on #6 and #7 bearings only in 2008) and monitor bearing operation and metal temperatures. Major overhaul in 2011.

System Description

- General Electric G3, dual flow, low pressure turbines (2)
  - S/N 170X819
  - 1987
  - GEK 64915
  - NX-23221-3900-0, 1,2

Key System Design information

- Turbine train (HP/IP/LP) nameplate: 2400 psig, 1000°F, 1000°F reheat, 1.5" Hg Abs. Exhaust pressure.
- (2) Double flow LP's, with (6) stages (12) rows per LP turbine, 33.5" last stage buckets, extraction steam for feed water heating
- See NX-23221-3900-0, 1, 2

Key Performance Parameters

- Bearing vibrations
- URGE rating
- Performance and efficiency values
- Years since major overhaul
- Type of operation base/load following
- Number of starts cold/hot
- Any water induction incidents
- Any off-frequency events
- Starting & loading charts followed
- Proper pre-warming
- Weekly/annual trip testing results
- Bearing metal temperatures per OEM

Significant Work History

- 1993 Major inspection
- 1996 L-1 tie-wire holes inspected for cracking
- 1999 Major inspection
  - L-1 buckets replaced by GE continuous coupled buckets and L-1 diaphragms modified.
  - Rotor "head-shot" exam by GE, no indications found
  - Boresonic exam of LPA and LPB (GE approved a 10 year re-inspection interval)

  - Replace L-0 diaphragm spill strips and holders with erosion resistant materials
  - L-0 bucket pins replaced by GE due to cracking
    - LPA: 33 on TE and 170 on GE
    - LPB: 1 on TE and 50 on GE
  - Bearings 5,7, and 8 had slight wiping and excess clearances. Sent out for repairs.
  - LP's are out of position axially by ¼" (too far toward turbine end)
  - Rotors low speed balanced
- 2002
  - LPA and LPB cross-over expansion bellows replaced (due to cracking)
  - Bearing 6 inspected and returned to service without rebabitting. (Note: This bearing has been running at a higher temperature than the other LP bearings since the 1999 outage.
  - Borescopic exam of L-1 buckets. Only light water erosion of covers and tenons noted.
  - L-0 visual exam, heavy cover erosion. Up to 1/16", due to water erosion. Covers should be replaced at next opportunity.
- 2005 Major Inspection
  - Turbines found in generally good condition, other than unexpected bearing repairs on T-5,6,7,8 and previously planned L-0 cover replacement, minimal/normal repairs were required. Virtually no SPE damage but some water erosion on last few stages, slight FOD heaviest toward the inlet stages, heavy deposits toward the back (deposits less than last major overhaul).
  - New LPA/B L-0 covers installed by MD&A, supplied by GE.
  - Babbitt damage to all 4 LP bearings. Damage had the appearance of arc-type damage, blown out babbit. Sent out for repair at RPM.
  - Broken dovetail pins replaced (190 pins)
  - D-coupling spacer disc found slipped since the last outage, realigned and re-doweled.
  - Rotors were low speed balanced
  - LP rotors were repositioned 0.230" toward the generator to improve internal clearances.
  - LPA bearing move for alignment reasons.
  - T6,7 oil deflectors rebuilt by RPM
  - Phased Array (NDE) testing on LP rotors. Indication found on LPA (generator end). Analysis determined that the indication was probably there from original construction. Re-inspection interval of 10 years specified, (2015). It is highly recommended that spare closure group components be on-hand for the next inspection as bucket removal is a possibility when Phased Array testing is performed.
- 2008 Minor Inspections:
  - Inspection of bearings #6 and #7 found the bearings in good condition other than small amounts of electrolysis damage present. #6 bearing had excessive pinch due to a missing shim, this was corrected.
  - L-0: Cover inspection noted slight gap between covers and blade tips, gaps dimensions documented. Appears to be an assembly error from 2005. L-0 blades in good visual condition, light deposits present.
  - T7 Bearing Cone Extension: Extension was making contact with the exhaust hood. 2 of 6 joint bolts found cracked. This is probably the cause of the LP buzz noise experienced at low loads. Replaced all joint bolting with new grade 8 bolts. Should be replaced with B-16 bolts next major overhaul.

Inspection Plans

- Maintain 6 year inspection frequency, consider extending to 9 years
- Rotor boresonic due in 2049 (per Dr. McCann)
- Annual heat rate testing
- Annual URGE testing
- Oil analysis (quarterly)
- Annual vibration survey and frequency analysis
- Crawl through inspections every 3 years during boiler outages.
- Inspect bearing in 2008 for mechanical or electrical damage. UPDATE: Completed inspection of #6 and #7 in 2008. Continue to monitor operation of LP bearings.
- Inspect L-0 cover-to-blade tip gaps.

Future Plans

- The LP inspection interval could possibly be extended to 9 years to fit with the HP/IP/Gen schedule if required (based on 2005 and 2011 inspection results). Otherwise maintain 6-year overhaul frequency.
- Crawl through inspection during boiler outages, inspect L-0 covers, cone extensions.
- Perform phased array ultrasonic inspection of LP rotor wheel dovetails, 2011.
- Replace rupture discs next major.
- Replace all cone extension joint bolting with B-16 bolts.

Significant Operational Events

1. Following the major outage, the #4 and #5 bearing metal temperatures climbed over a period of weeks and were sensitive to load and condenser pressure. In early 2006 an outage was planned for temporary valve screen removal and to address the hot bearing root cause. IP bearing #4 was found to be set ~0.0065" to low with some assembly errors. The pinch on both #4 and #5 bearings was found to be excessive, (0.005"~0.006"), which did not allow the bearings to self-align. MD&A corrected the errors under warrantee. The bearings were not required to be sent out for repair. Unit startup went well and the turbine continues to operate satisfactorily.
2. Full load trip and startup incident 7/23/06: During a plant trip, due to non-turbine related reasons, the turbine ventilator valve stuck open for over four hours, unnoticed. Once discovered, the valve was helped closed, by hand, as the valve operator spring did not have sufficient force to close the valve. During the unit restart, several oil pumps were shut down in error, eventually causing another trip. During the next restart the #6 bearing reached 336 deg F, #7 reached 274 deg F and #10 reached 241 deg F. The unit was placed on line. The upstream detraining tank screens were checked for the presence of babbit and none was found. There appears to be very little change in the rotor vibration due to this event. Bearing metal temperatures are similar to, and in some cases better than before the event. There is a slight shift in shaft oil pump suction pressure. This suggests the possibility of a change in oil flow through the system, (bearing geometry or rotor position change possibly). The unit has been running at high loads for an extended period of time, and been cycled off-line several times since the event and exhibits no unusual symptoms that suggest major bearing damage. This is not to say that there is no damage. Units have operated with significant bearing damage

for months and years without any operational indications. The bearings may well have been damaged. They may function properly until the next major overhaul, but are probably more at risk for wiping than a "new" bearing.

Name of Component or System - System Health Report
Assigned Budget Team: TS
Maximo System/Subsystem: TS/LP

Plant & Unit	Component	Code	Date
Sherco Unit 3	LP Turbine	☒ Green ☐ Yellow ☐ Red	1/5/2010

Team members: System Engineer: Mark Kolb
TOS Engineer: Tim Murray,
I&C Technician: Dan McConnell

(I) Description of condition(s) that substantiate a "Green", "Yellow" or "Red" Code.

LP Turbines (Green): During the 2005 outage all the LP bearings were found with various degrees of wiped babbitt. The root cause for the wiping is still in question, (i.e. prior repair quality, overloading, electrolysis, other?). All bearings were repaired and returned to service. In 2006 the unit experienced a Significant Operational Event discussed at the end of this report, resulting in high bearing metal temperatures. Since that time the bearings have performed with out incident. In 2008, inspection of bearings #6 and #7 found the bearings in good condition other than small amounts of electrolysis damage present.

These LP's also experience dovetail pin cracking problems, erosion damage and may suffer from an industry-wide problem with rotor wheel cracking. However, rotor wheel phased array testing in 2005 did not detect any cracking issues.

Other than the current bearing issue, the turbines were found in generally good condition both during the 2005 outage, and during the very limited non-disassembly inspection in 2008.

(II) Risk(s) associated with a "Yellow" or "Red" Code.

Risks associated with wheel cracking involve wheel failure and buckets departing the rotor. Resulting collateral damage could be severe (i.e. due to mass imbalance and projectiles). Erosion damage may allow components to separate and contact other rotating and stationary components. Cracked dovetail pins may allow buckets to separate from the rotor (low probability). Bearing babbitt failures can lead to high vibrations, unit trip and failed unit re-starts. In an extreme case it can lead to catastrophic turbine failures.

(III) Corrective actions that could minimize or mitigate the risks identified above, or allow reclassification of the code to "Yellow" or "Green".

The LP's will not be replaced as part of the uprate project (2011). Perform phased array testing next major inspection. Perform bearing inspections in 2008 (Update, completed inspections on #6 and #7 bearings only in 2008) and monitor bearing operation and metal temperatures. Major overhaul in 2011 or 2014.

System Description

- General Electric G3, dual flow, low pressure turbines (2)
  - S/N 170X819
  - 1987
  - GEK 64915
  - NX-23221-3900-0, 1,2

Key System Design information

- Turbine train (HP/IP/LP) nameplate: 2400 psig, 1000°F, 1000°F reheat, 1.5" Hg Abs. Exhaust pressure.
- (2) Double flow LP's, with (6) stages (12) rows per LP turbine, 33.5" last stage buckets, extraction steam for feed water heating
- See NX-23221-3900-0, 1, 2

Key Performance Parameters

- Bearing vibrations
- URGE rating
- Performance and efficiency values
- Years since major overhaul
- Type of operation base/load following
- Number of starts cold/hot
- Any water induction incidents
- Any off-frequency events
- Starting & loading charts followed
- Proper pre-warming
- Weekly/annual trip testing results
- Bearing metal temperatures per OEM

Significant Work History

- 1993 Major inspection
- 1996 L-1 tie-wire holes inspected for cracking
- 1999 Major inspection
  - L-1 buckets replaced by GE continuous coupled buckets and L-1 diaphragms modified.
  - Rotor "head-shot" exam by GE, no indications found
  - Boresonic exam of LPA and LPB (GE approved a 10 year re-inspection interval)

  - Replace L-0 diaphragm spill strips and holders with erosion resistant materials
  - L-0 bucket pins replaced by GE due to cracking
    - LPA: 33 on TE and 170 on GE
    - LPB: 1 on TE and 50 on GE
  - Bearings 5,7, and 8 had slight wiping and excess clearances. Sent out for repairs.
  - LP's are out of position axially by ¼" (too far toward turbine end)
  - Rotors low speed balanced
- 2002
  - LPA and LPB cross-over expansion bellows replaced (due to cracking)
  - Bearing 6 inspected and returned to service without rebabitting. (Note: This bearing has been running at a higher temperature than the other LP bearings since the 1999 outage.
  - Borescopic exam of L-1 buckets. Only light water erosion of covers and tenons noted.
  - L-0 visual exam, heavy cover erosion. Up to 1/16", due to water erosion. Covers should be replaced at next opportunity.
- 2005 Major Inspection
  - Turbines found in generally good condition, other than unexpected bearing repairs on T-5,6,7,8 and previously planned L-0 cover replacement, minimal/normal repairs were required. Virtually no SPE damage but some water erosion on last few stages, slight FOD heaviest toward the inlet stages, heavy deposits toward the back (deposits less than last major overhaul).
  - New LPA/B L-0 covers installed by MD&A, supplied by GE.
  - Babbitt damage to all 4 LP bearings. Damage had the appearance of arc-type damage, blown out babbit. Sent out for repair at RPM.
  - Broken dovetail pins replaced (190 pins)
  - D-coupling spacer disc found slipped since the last outage, realigned and re-doweled.
  - Rotors were low speed balanced
  - LP rotors were repositioned 0.230" toward the generator to improve internal clearances.
  - LPA bearing move for alignment reasons.
  - T6,7 oil deflectors rebuilt by RPM
  - Phased Array (NDE) testing on LP rotors. Indication found on LPA (generator end). Analysis determined that the indication was probably there from original construction. Re-inspection interval of 10 years specified, (2015). It is highly recommended that spare closure group components be on-hand for the next inspection as bucket removal is a possibility when Phased Array testing is performed.
- 2008 Minor Inspections:
  - Inspection of bearings #6 and #7 found the bearings in good condition other than small amounts of electrolysis damage present. #6 bearing had excessive pinch due to a missing shim, this was corrected.
  - L-0: Cover inspection noted slight gap between covers and blade tips, gaps dimensions documented. Appears to be an assembly error from 2005. L-0 blades in good visual condition, light deposits present.
  - T7 Bearing Cone Extension: Extension was making contact with the exhaust hood. 2 of 6 joint bolts found cracked. This is probably the cause of the LP buzz noise experienced at low loads. Replaced all joint bolting with new grade 8 bolts. Should be replaced with B-16 bolts next major overhaul.

Inspection Plans

- Maintain 6 year inspection frequency, consider extending to 9 years
- Rotor boresonic due in 2049 (per Dr. McCann)
- Annual heat rate testing
- Annual URGE testing
- Oil analysis (quarterly)
- Annual vibration survey and frequency analysis
- Crawl through inspections every 3 years during boiler outages.
- Inspect bearing in 2008 for mechanical or electrical damage. UPDATE: Completed inspection of #6 and #7 in 2008. Continue to monitor operation of LP bearings.
- Inspect L-0 cover-to-blade tip gaps.

Future Plans

- The LP inspection interval could possibly be extended to 9 years to fit with the HP/IP/Gen schedule if required (based on 2005 and 2011 inspection results). Otherwise maintain 6-year overhaul frequency. Next major scheduled for 2014.
- Crawl through inspection during boiler outages, inspect L-0 covers, cone extensions.
- Perform phased array ultrasonic inspection of LP rotor wheel dovetails, next major.
- Replace rupture discs next major.
- Replace all cone extension joint bolting with B-16 bolts.

Significant Operational Events

1. Following the major outage, the #4 and #5 bearing metal temperatures climbed over a period of weeks and were sensitive to load and condenser pressure. In early 2006 an outage was planned for temporary valve screen removal and to address the hot bearing root cause. IP bearing #4 was found to be set ~0.0065" to low with some assembly errors. The pinch on both #4 and #5 bearings was found to be excessive, (0.005"~0.006"), which did not allow the bearings to self-align. MD&A corrected the errors under warrantee. The bearings were not required to be sent out for repair. Unit startup went well and the turbine continues to operate satisfactorily.
2. Full load trip and startup incident 7/23/06: During a plant trip, due to non-turbine related reasons, the turbine ventilator valve stuck open for over four hours, unnoticed. Once discovered, the valve was helped closed, by hand, as the valve operator spring did not have sufficient force to close the valve. During the unit restart, several oil pumps were shut down in error, eventually causing another trip. During the next restart the #6 bearing reached 336 deg F, #7 reached 274 deg F and #10 reached 241 deg F. The unit was placed on line. The upstream detraining tank screens were checked for the presence of babbit and none was found. There appears to be very little change in the rotor vibration due to this event. Bearing metal temperatures are similar to, and in some cases better than before the event. There is a slight shift in shaft oil pump suction pressure. This suggests the possibility of a change in oil flow through the system, (bearing geometry or rotor position change possibly). The unit has been running at high loads for an extended period of time, and been cycled off-line several times since the event and exhibits no unusual symptoms that suggest major bearing damage. This is not to say that there is no damage. Units have operated with significant bearing damage

for months and years without any operational indications. The bearings may well have been damaged. They may function properly until the next major overhaul, but are probably more at risk for wiping than a “new” bearing.

Name of Component or System - System Health Report
Assigned Budget Team: TS
Maximo System/Subsystem: TS/LP

Plant & Unit	Component	Code	Date
Sherco Unit 3	LP Turbine	☒ Green ☐ Yellow ☐ Red	12/7/2010

Team members: System Engineer: Mark Kolb
TOS Engineer: Tim Murray,
I&C Technician: Dan McConnell

(I) Description of condition(s) that substantiate a "Green", "Yellow" or "Red" Code.

LP Turbines (Green): During the 2005 outage all the LP bearings were found with various degrees of wiped babbitt. The root cause for the wiping is still in question, (i.e. prior repair quality, overloading, electrolysis, other?). All bearings were repaired and returned to service. In 2006 the unit experienced a Significant Operational Event discussed at the end of this report, resulting in high bearing metal temperatures. Since that time the bearings have performed with out incident. In 2008, inspection of bearings #6 and #7 found the bearings in good condition other than small amounts of electrolysis damage present.

L-0 bucket end of life issue, replacement scheduled for 2020.

These LP's also experience dovetail pin cracking problems, erosion damage and may suffer from an industry-wide problem with rotor wheel cracking. However, rotor wheel phased array testing in 2005 did not detect any cracking issues.

GE recommends TBO of 5 years. Increasing inspection interval adds risk. Currently scheduled for a 8-1/3 year TBO this cycle.

Other than the current bearing issue, the turbines were found in generally good condition both during the 2005 outage, and during the very limited non-disassembly inspection in 2008.

(II) Risk(s) associated with a "Yellow" or "Red" Code.

Risks associated with wheel cracking involve wheel failure and buckets departing the rotor. Resulting collateral damage could be severe (i.e. due to mass imbalance and projectiles). Erosion damage may allow components to separate and contact other rotating and stationary components. Cracked dovetail pins may allow buckets to separate from the rotor (low probability). Bearing babbitt failures can lead to high vibrations, unit trip and failed unit re-starts. In an extreme case it can lead to catastrophic turbine failures. Extending GE recommend TBO increases risk of failures.

(III) Corrective actions that could minimize or mitigate the risks identified above, or allow reclassification of the code to "Yellow" or "Green".

The LP's will not be replaced as part of the uprate project (2011). Perform phased array testing next, 2014. Perform bearing inspections in 2008 (Update, completed inspections on #6 and #7 bearings only in 2008) and monitor bearing operation and metal temperatures. Major overhaul in 2014.

System Description

- General Electric G3, dual flow, low pressure turbines (2)
  - S/N 170X819
  - 1987
  - GEK 64915
  - NX-23221-3900-0, 1,2

Key System Design information

- Turbine train (HP/IP/LP) nameplate: 2400 psig, 1000°F, 1000°F reheat, 1.5" Hg Abs. Exhaust pressure.
- (2) Double flow LP's, with (6) stages (12) rows per LP turbine, 33.5" last stage buckets, extraction steam for feed water heating
- See NX-23221-3900-0, 1, 2

Key Performance Parameters

- Bearing vibrations
- URGE rating
- Performance and efficiency values
- Years since major overhaul
- Type of operation base/load following
- Number of starts cold/hot
- Any water induction incidents
- Any off-frequency events
- Starting & loading charts followed

- Proper pre-warming
- Weekly/annual trip testing results
- Bearing metal temperatures per OEM

<u>Significant Work History</u>

- 1993 Major inspection
- 1996 L-1 tie-wire holes inspected for cracking
- 1999 Major inspection
  - L-1 buckets replaced by GE continuous coupled buckets and L-1 diaphragms modified.
  - Rotor "head-shot" exam by GE, no indications found
  - Boresonic exam of LPA and LPB (GE approved a 10 year re-inspection interval)
  - Replace L-0 diaphragm spill strips and holders with erosion resistant materials
  - L-0 bucket pins replaced by GE due to cracking
    - LPA: 33 on TE and 170 on GE
    - LPB: 1 on TE and 50 on GE
  - Bearings 5,7, and 8 had slight wiping and excess clearances. Sent out for repairs.
  - LP's are out of position axially by ¼" (too far toward turbine end)
  - Rotors low speed balanced
- 2002
  - LPA and LPB cross-over expansion bellows replaced (due to cracking)
  - Bearing 6 inspected and returned to service without rebabitting. (Note: This bearing has been running at a higher temperature than the other LP bearings since the 1999 outage.
  - Borescopic exam of L-1 buckets. Only light water erosion of covers and tenons noted.
  - L-0 visual exam, heavy cover erosion. Up to 1/16", due to water erosion. Covers should be replaced at next opportunity.
- 2005 Major Inspection
  - Turbines found in generally good condition, other than unexpected bearing repairs on T-5,6,7,8 and previously planned L-0 cover replacement, minimal/normal repairs were required. Virtually no SPE damage but some water erosion on last few stages, slight FOD heaviest toward the inlet stages, heavy deposits toward the back (deposits less than last major overhaul).
  - New LPA/B L-0 covers installed by MD&A, supplied by GE.
  - Babbitt damage to all 4 LP bearings. Damage had the appearance of arc-type damage, blown out babbit. Sent out for repair at RPM.
  - Broken dovetail pins replaced (190 pins)
  - D-coupling spacer disc found slipped since the last outage, realigned and re-doweled.
  - Rotors were low speed balanced
  - LP rotors were repositioned 0.230" toward the generator to improve internal clearances.
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- Inspection of bearings #6 and #7 found the bearings in good condition other than small amounts of electrolysis damage present. #6 bearing had excessive pinch due to a missing shim, this was corrected.
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Inspection Plans

- Maintain 6 year inspection frequency, consider extending to 9 years
- Rotor boresonic due in 2049 (per Dr. McCann)
- Annual heat rate testing
- Annual URGE testing
- Oil analysis (quarterly)
- Annual vibration survey and frequency analysis
- Crawl through inspections every 3 years during boiler outages.
- Inspect bearing in 2008 for mechanical or electrical damage. UPDATE: Completed inspection of #6 and #7 in 2008. Continue to monitor operation of LP bearings.
- Inspect L-0 cover-to-blade tip gaps.

Future Plans

- With the proper engineering study the LP inspection interval could possibly be extended to 9 years to fit with the HP/IP/Gen schedule if required. Otherwise maintain 6-year overhaul frequency. Next major scheduled for 2014.
- Crawl through inspection during boiler outages, inspect L-0 covers, cone extensions.
- Perform phased array ultrasonic inspection of LP rotor wheel dovetails, next major.
- Replace rupture discs next major.
- Replace all cone extension joint bolting with B-16 bolts.

Significant Operational Events

1. Following the major outage, the #4 and #5 bearing metal temperatures climbed over a period of weeks and were sensitive to load and condenser pressure. In early 2006 an outage was planned for temporary valve screen removal and to address the hot bearing root cause. IP bearing #4 was found to be set ~0.0065" to low with some assembly errors. The pinch on both #4 and #5 bearings was found to be excessive, (0.005"~0.006"), which did not allow the bearings to self-align. MD&A corrected the errors under warrantee. The bearings were not required to be sent out for repair. Unit startup went well and the turbine continues to operate satisfactorily.
2. Full load trip and startup incident 7/23/06: During a plant trip, due to non-turbine related reasons, the turbine ventilator valve stuck open for over four hours, unnoticed. Once

discovered, the valve was helped closed, by hand, as the valve operator spring did not have sufficient force to close the valve. During the unit restart, several oil pumps were shut down in error, eventually causing another trip. During the next restart the #6 bearing reached 336 deg F, #7 reached 274 deg F and #10 reached 241 deg F. The unit was placed on line. The upstream detraining tank screens were checked for the presence of babbit and none was found. There appears to be very little change in the rotor vibration due to this event. Bearing metal temperatures are similar to, and in some cases better than before the event. There is a slight shift in shaft oil pump suction pressure. This suggests the possibility of a change in oil flow through the system, (bearing geometry or rotor position change possibly). The unit has been running at high loads for an extended period of time, and been cycled off-line several times since the event and exhibits no unusual symptoms that suggest major bearing damage. This is not to say that there is no damage. Units have operated with significant bearing damage for months and years without any operational indications. The bearings may well have been damaged. They may function properly until the next major overhaul, but are probably more at risk for wiping than a "new" bearing.

Legacy Clarify Case

ID Number:	20071006-0080	Site ID:	T170X544
Parent ID Number:		Site Name:	NORTHERN STATES POWER COMP/
Serial No.:	170X544	Type 1:	Planned Outage- Tech. As
Instance Name:	Large Steam	Status:	Complete
Group:	Turbine Rotor	Priority:	Emergency
Section:	Rotor, LP A	Severity:	...
Component:	Dovetail	Customer Want Date:	2007-10-08 23:31:12
Created:	2007-10-06 14:35:28		
Title:	STM--170X544--LPA TE L-1 dovetail cracking.		

Case Details

Main Unit:	PG1-Steam Turbine	Submitter First Name:	MARK
Initiator:	Customer	Submitter Last Name:	PETERSON
Queue:		Submitter Phone:	(612)520-3707 OR *323-3
Owner:	howensja	Submitter SSO:	204013859
Owner Emp No:		Contact First Name:	MARK
Owner Work Group:	PS-Steam	Contact Last Name:	PETERSON
Owner First Name:	James	Contact Phone:	(612)520-3707 OR *323-3
Owner Last Name:	Howenstein	Contact SSO:	204013859
Type 2:	Not Applicable	Documentation Only:	☒
Type 3:	Not Applicable		
Potential Safety Issue:	☒		
CCLIST1:	joshua.bird@ge.com,mark.peterson@ps.ge.com		
CCLIST2:	joshua.bird@ge.com,mark.peterson@ps.ge.com		

NSP, et al v GE
PLF EX 128
Date: 6-26-15
Richard G. Stirewalt
Stirewalt & Associates

Subcase

Legacy Clarify Subcases Parent ID = 20071006-0080

0 Legacy Clarify Subcases

ID number	Site ID	Serial No.	Site Name	Title	Owner Last Name	Owner First Name	Created	Owner Emp No	Customer Want Date	Close Date	Close Notes	Group	Section	Component	Resolution Code	Type

Case History

Please sort the header to view expanded notes.

Legacy Clarify Case Histories ID Number = 20071006-0080

5 Legacy Clarify Case Histories

Entry	Type	Entered By	Notes

TRIAL EXHIBIT
0037

GE-NSP00358430

TR.EX.NSP0037.001

Date	Type	Entered By	Notes
2008-06-18 11:05:45	Case Close	sa	Close Requested By Mark Peterson (mark.peterson@ps.ge.com) using eField Service logged in as petersma
2007-10-09 08:58:06	Notes	howensja	See the information in the case notes. James Howenstein - TL Steam Turbine Prodcust Service DialComm : 8*421-6007 PhoneNo : 678-844-6007 Email ID : james.howenstein@ps.ge.com Fax : 678-844-6739
2007-10-09 08:57:01	Notes	howensja	We cannot comment on the test performed by Wesdyne and have no idea if the indications are severe enough to warrant removal of the buckets for further investigation and/or what repairs we might recommend if we had performed the test. As far as removal of the L-1 buckets and operation of the unit; They could remove the buckets and operate but this would require the installation of a pressure plate. We would probably recommend the removal of the TE and GE for thrust considerations. The reduction in output would be approximately 12,800KW per end.
2007-10-06 14:41:27	Phone Log	gaitheram	spoke to mark he does not an answer til moday afternoon.
2007-10-06 14:35:29	Email Log	emailclerk	Unit in a major inspection. A phased array examination has been completed and WestDyne and there are 33 indications on the inlet side of the TE LPA rotor; 25 on the bottom hook and 8 on the middle hook. On the outlet side there are 25 identified on the middle hook. Desired Deliverable: Customer is considering repair options and timing. They have asked: Is it possible to remove the LPA TE buckets and run until a later time so that they can more efficiently plan the repairs. If so, they would like to know approximate losses. PROFILE INFORMATION: NAME: Mark Peterson ADDRESS: GE Energy Servicec 2025 49th Avenue North Minneapolis, MN 55430 USA PHONE: (612)520-3707 FAX: (612)520-3737 CELL PHONE: (612)804-7569 EMAIL ADDRESS: mark.peterson@ps.ge.com Emergency Criteria: Planned outage, last minute return to service problem. Extensive cracking found in the LPA TE L-1 dovetails. Supporting Details:

Activity Summary

Legacy Activity Summaries

ID Number = 20071006-0080 — 15 Legacy Activity Summaries

Entry Date	Action Name	Entry By	Additional Info
2008-06-18 11:07:21	Rule Action	sa	Action email of rule Case Closed Notification fired
2008-06-18 11:05:45	Case Close	sa	Status = Complete, Resolution Code = Verbal Resp.Provided, State = Open.
2007-10-09 08:59:27	Rule Action	sa	Action res_email_to_field of rule Case Resolved Notification fired
2007-10-09 08:58:09	Chg Status	howensja	from status In Process to status Resolution Issued

2007-10-09 08:58:06	Notes	howensja	See the information in the case notes. James Howenstein - TL Steam Turbine Prodcust Service Dial
2007-10-09 08:57:01	Notes	howensja	We cannot comment on the test performed by Wesdyne and have no idea if the indications are severe en
2007-10-06 22:34:07	Accept	howensja	from Queue GPTS Steam to WIP default.
2007-10-06 14:41:33	Dispatch	gaitheram	from WIP AMBER'S to Queue GPTS Steam.
2007-10-06 14:41:27	Phone Log	gaitheram	Start = 10/06/2007 02:41:10 PM, End = 10/06/2007 02:41:27 PM, Contact = MARK PETERSON.
2007-10-06 14:36:50	Rule Action	sa	Action email of rule New Case Opened fired
2007-10-06 14:36:49	Accept	gaitheram	from Queue PAC Front Line to WIP AMBER'S.
2007-10-06 14:35:29	Dispatch	emailclerk	from WIP Planned Outage- Tech. Assist. to Queue PAC Front Line.
2007-10-06 14:35:29	Email In	emailclerk	Email received from mark.peterson@ps.ge.com.
2007-10-06 14:35:28	Create	emailclerk	Contact = MARK PETERSON, Priority = Respond as Necessary, Status = In Process.
2007-10-06 14:35:28	Commit	emailclerk	Made to MARK PETERSON due 2007-10-08 23:31:12

Closure Information

Resolution Category: ...

Field Action Taken:

Resolution Date: 2007-10-09 08:58:06

Closed Date: 2008-06-18 11:05:45

Resolution Notes:

09-OCT-07
See the information in the case notes.

James Howenstein - TL
Steam Turbine Prodcust Service
DialComm : 8*421-6007
PhoneNo : 678-844-6007
Email ID : james.howenstein@ps.ge.com
Fax : 678-844-6739

Other Details

Aero

Unauthorized Hw Repair: ☐

Gasification

Customer Issue: ☐

Shop Order No.:

Recurring Issue: ☐

Prob Code L1:

Customer Requested RCA:

Prob Code L2:

Customer Answer Time: 1753-01-01 00:00:00

Industrial

Late Reason:

Warranty Flag:

Invoice PO No.:

Warranty Start Date: 1976-03-16 12:00:00

Market: MINNEAPOLIS WEST 94

Customer Request Date:

Requisition No.:

Customer Problem Detected Date:

SR No.: web_petersma_11916957(

Solution Identified Date:

Segment:

FE Assigned Date:

Technology:

GE commit Date:

Application:

GE Contacted Date:

Ship To No.:

Motors

Service Shop/Vendor Cost:

Replacement Part Req#:

Quantity:

Replacement Part Cost:

RMS Tag Number:

Concession Cost:

Date Code:

Motors Serial No.:

Product Type:

Motors Model No.:

Failure Code 1:

Motors Manufacturing Loc.:

Failure Code 2:

Failure Code 3:

Remote Services

Exclude from ETTR:

Contract No.:

Final Solution Provided:

Initial Solution Provided:

Solution Verified by Customer:

PowerGen

Drawing Part#:

Potential Security Vulnerability:

Punchlist:

Trip Related:

Component Failure:

Legacy Clarify Attachments Legacy Main Case = 20071006-0080 0 Legacy Clarify Attachments

File Name	Attachment GE Link	Folder URL

Legacy Clarify Case

ID Number:	20080211-0467	Site ID:	T170X544
Parent ID Number:		Site Name:	NORTHERN STATES POWER COMPANY - SHERBURNE GENERATING S
Serial No.:	170X544	Type 1:	In Svc.- Post Warr.- Tech
Instance Name:	Large Steam	Status:	Complete
Group:	Turbine Rotor	Priority:	Respond as Necessary
Section:	Rotor, LP	Severity:	...
Component:	Dovetail	Customer Want Date:	2008-02-29 23:31:12
Created:	2008-02-11 16:38:45		
Title:	STM–170X544–LP dovetail Stress Corrosion Cracking - Drum Boiler ST		

Case Details

Main Unit:	PG1-Steam Turbine	Submitter First Name:	JOSHUA
Initiator:	Customer		
Queue:		Submitter Last Name:	BIRD
Owner:	howensja	Submitter Phone:	-678-844-4464
Owner Emp No:		Submitter SSO:	204027199
Owner Work Group:	PS-Steam	Contact First Name:	MARK
Owner First Name:	James	Contact Last Name:	PETERSON
Owner Last Name:	Howenstein	Contact Phone:	(612)520-3707 OR *323-
Type 2:	Not Applicable	Contact SSO:	204013859
Type 3:	Not Applicable	Documentation Only:	☐
Potential Safety Issue:	☐		
CCLIST1:	joshua.bird@ge.com,mark.peterson@ps.ge.com,joshua.bird@ps.ge.com		
CCLIST2:	joshua.bird@ge.com,mark.peterson@ps.ge.c		

Subcase

Legacy Clarify Subcases Parent ID = 20080211-0467

0 Legacy Clarify Subcases

ID number	Site ID	Serial No.	Site Name	Title	Owner Last Name	Owner First Name	Created	Owner Emp No	Customer Want Date	Close Date	Close Notes	Group	Section	Component	Resolution Code	Type

Case History

Please sort the header to view expanded notes.

Legacy Clarify Case Histories ID Number = 20080211-0467

6 Legacy Clarify Case Histories

Entry Date	Type	Entered By	Notes
2008-02-11 16:38:47	Email Log	emailclerk	The customer found and repaired cracks on the L-1 dovetails during their major inspection in fall 2007. They performed two separate RCA's, and both confirmed that the cracking was due to stress corrosion. The customer has heard that there have been other GE steam turbines with drum boilers that have found stress corrosion cracking (SCC) in the LP dovetails. TIL 1277 addresses SCC for steam turbines with once-through boilers, but does not pertain to this steam turbine, which has a drum boiler. Desired Deliverable: The customer is asking if GE will be issuing a TIL addressing SCC on steam turbines with drum boilers, similar to TIL 1277 issued for steam turbines with once-through boilers. If not, are there any other maintenance recommendations that the customer should be following for other drum boiler steam turbines in their fleet?

TRIAL EXHIBIT
0038
exhibitsticker.com

NSP, et al v GE
PLF EX 129
Date: 6-26-16
Richard G. Stirewalt
Stirewalt & Associates

GE-NSP00044508

Entry Date	Type	Entered By	Notes
			Thanks, Josh PROFILE INFORMATION: NAME: Josh Bird ADDRESS: 2025 49th Ave N Minneapolis, MN 55430 USA PHONE: 612-520-3713 FAX: 612-520-3737 CELL PHONE: 651-238-5154 EMAIL ADDRESS: joshua.bird@ps.ge.com
2008-06-18 11:04:40	Case Close	sa	Close Requested By Mark Peterson (mark.peterson@ps.ge.com) using eField Service logged in as petersma
2008-02-29 11:51:00	Notes	howensja	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 recommendations for inspections as outlined in the following TIL's; TIL-956, TIL-1121, TIL-630. I am sure there are more tht should be listed in the unit records but these are the few that pertain to the rotating components.
2008-02-29 15:10:59	Email Log	emailclerk	(Reply-to-sender return email from joshua.bird@ge.com) From: "Bird, Joshua \(GE Infra, Energy\)" <joshua.bird@ge.com> To: "Energy Clarify Pac \(GE Infra, Energy, Non-GE\)" <pacclarify@alppsa009.energy.tsg.ge.com> X-MIME-Autoconverted: from quoted-printable to 8bit by alppsa009.energy.ge.com id m1TKAQ213697 Jim, Thanks for the information. The customer also made reference to a TIL-770 for SCC on non-reheat units. This TIL is not longer available on the PS portal. Has TIL 1277 superceded TIL 770 as well? Thanks, Josh
2008-02-29 11:51:35	Notes	howensja	See the information in the case notes. James Howenstein - TI Steam Turbine Product Service DialComm : 8*421-6007 PhoneNo : 678-844-6007 Email ID : james.howenstein@ps.ge.com Fax : 678-844-6739
2008-02-29 15:23:34	Notes	howensja	Actually TIL 956 replaces TIL 770 . If you read through the GE section of TIL 956 it does in fact reference TIL 770 among others that are now considered part of TIL 956.

Activity Summary

Legacy Activity Summaries ID Number = 20080211-0467

19 Legacy Activity Summaries

Entry Date	Action Name	Entry By	Additional Info
2008-02-12 15:40:09	Accept	howensja	from Queue GPTS Steam to WIP default.
2008-02-11 16:59:28	Dispatch	tuckert1	from WIP TONYA'S WIP to Queue PAC Info.Support.
2008-02-11 16:38:45	Create	emailclerk	Contact = MARK PETERSON, Priority = Respond as Necessary, Status = In Process.
2008-06-18 11:04:40	Case Close	sa	Status = Complete, Resolution Code = Verbal Resp.Provided, State = Open.
2008-02-29 11:53:17	Rule Action	sa	Action res_email_to_field of rule Case Resolved Notification fired
2008-02-11 16:58:00	Accept	tuckert1	from Queue PAC Front Line to WIP TONYA'S WIP.
2008-02-11 16:38:46	Commit	emailclerk	Made to MARK PETERSON due 2008-02-29 23:31:12
2008-02-29 15:12:18	Rule Action	sa	Action Info added to open case of rule Email/Research added to Open Case fired
2008-02-29	Notes	howensja	See the information in the case notes.

Entry Date	Action Name	Entry By	Additional Info
11:51:35			
			James Howenstein - TI Steam Turbine Product Service DialCo
2008-02-12 07:15:30	Dispatch	cavach	from WIP Cava - default to Queue GPTS Steam.
2008-02-29 15:23:34	Notes	howensja	Actually TIL 956 replaces TIL 770 . If you read through the GE section of TIL 956 it does in fact re
2008-02-29 11:51:38	Chg Status	howensja	from status In Process to status Resolution Issued
2008-02-12 07:10:17	Accept	cavach	from Queue PAC Info.Support to WIP Cava - default.
2008-02-11 16:38:47	Email In	emailclerk	Email received from joshua.bird@ps.ge.com.
2008-02-29 11:51:00	Notes	howensja	Although TIL 1277 is written for once through boilers we have been recommending customers with drum
2008-02-11 16:40:36	Rule Action	sa	Action email of rule New Case Opened fired
2008-02-11 16:38:47	Dispatch	emailclerk	from WIP In Svc.- Post Warr.- Tech. Assist. to Queue PAC Front Line.
2008-06-18 11:06:30	Rule Action	sa	Action email of rule Case Closed Notification fired
2008-02-29 15:10:59	Email In	emailclerk	Email received from joshua.bird@ge.com.

Closure Information

Resolution Category:

Resolution Date: 2008-02-29 11:51:35

Field Action Taken:

Closed Date: 2008-06-18 11:04:40

Resolution Notes:

29-FEB-08
See the information in the case notes.

James Howenstein - TI
Steam Turbine Product Service
DialComm : 8*421-6007
PhoneNo : 678-844-6007
Email ID : james.howenstein@ps.ge.com
Fax : 678-844-6739

Other Details

Aero

Unauthorized Hw Repair: ☐

Gasification

Customer Issue: ☐

Recurring Issue: ☐

Customer Requested RCA: ☐

Shop Order No.:

Prob Code L1:

Prob Code L2:

Customer Answer Time: 1753-01-01 00:00:00

Industrial

Late Reason:

Invoice PO No.:

Market: MINNEAPOLIS WEST 9

Requisition No.:

Warranty Flag: ☐

Warranty Start Date: 1976-03-16 12:00:00

Customer Request Date:

SR No.: web_birdj1_12027659036

Segment:

Technology:

Application:

Ship To No.:

Customer Problem Detected Date:

Solution Identified Date:

FE Assigned Date:

GE commit Date:

GE Contacted Date:

Motors

Service Shop/Vendor Cost:

Quantity:

RMS Tag Number:

Date Code:

Product Type:

Failure Code 1:

Failure Code 2:

Failure Code 3:

Replacement Part Req#:

Replacement Part Cost:

Concession Cost:

Motors Serial No.:

Motors Model No.:

Motors Manufacturing Loc.:

Remote Services

Exclude from ETTR: ☐

Contract No.:

Final Solution Provided:

Initial Solution Provided:

Solution Verified by Customer:

PowerGen

Drawing Part#:

Potential Security Vulnerability: ☐

Punchlist: ☐

Trip Related: ☐

Component Failure: ☐

Legacy Clarify Attachments Legacy Main Case = 20080211-0467 0 Legacy Clarify Attachments

File Name	Attachment GE Link	Folder URL

From: Bird, Joshua (GE Infra, Energy)
To: Murray, Timothy P
Sent: 2/26/2008 4:02:54 PM
Subject: RE: LP Turbine Rotor Wheel Dovetail Cracking
Attachments: GEK72281c.pdf

Hi Tim,

I am having a tough time finding you some of these other documents as well. I've attached GEK 72281, but none of the GER's you referenced show up in the system. Since they are not in the database, I'm not really sure where to go to get these three GER's.

As for TIL 770, I'll check with engineering to see what I can find out about this one.

Thanks,

Josh

-----Original Message-----
From: Murray, Timothy P [mailto:timothy.p.murray@xcelenergy.com]
Sent: Tuesday, February 26, 2008 1:43 PM
To: Bird, Joshua (GE Infra, Energy)
Subject: RE: LP Turbine Rotor Wheel Dovetail Cracking

Josh,
Another follow-up. Still no response to my request to fix the link within optimizer. Also, I found another reference to TIL 770, this time in a GE Stress Corrosion Cracking presentation made at the 2003 LSTG conference in Atlanta. Apparently it does in fact exist. In this same presentation there were references to the following GE documents also related to turbine rotor stress corrosion cracking;
GEK 72281
GER 2883
GER 3086
GER 3253
I tried locating these within optimizer as well. No luck. Could you provide copies of each? I'm working on Xcel fleet wide inspection recommendations. These documents should provide some valuable background info. I would really appreciate some help on this.
Thanks
Tim

-----Original Message-----
From: Murray, Timothy P
Sent: Thursday, February 21, 2008 9:26 AM
To: 'Bird, Joshua (GE Infra, Energy)'
Subject: RE: LP Turbine Rotor Wheel Dovetail Cracking

Josh,
As a follow-up to this. I did locate TIL 0770-3 on outage optimizer. It was issued against our Arapahoe Unit#4, turbine S/N 101604. The only problem is the link within optimizer is bad, it links up with the wrong TIL, TIL 550, something totally different. I did submit a TIL dispute through the optimizer web page asking to correct the link problem so I can view TIL 770. Maybe something will happen.
Tim

-----Original Message-----
From: Murray, Timothy P
Sent: Monday, February 11, 2008 3:28 PM
To: 'Bird, Joshua (GE Infra, Energy)'
Subject: RE: LP Turbine Rotor Wheel Dovetail Cracking

NSP, et al v GE
PLF EX 130
Date: 6-26-15
Richard G. Stirewalt
Stirewalt & Associates

TRIAL EXHIBIT
0039
exhibitsticker.com

Josh,
Thanks for checking on this. It is a mystery to me as to why this TIL shows up in our database. It is listed as TIL 770-3. Also when I was searching in outage optimizer I noticed that the older TILs show up as "0772", etc. I also have a reference to it from a 3rd party, they list it as TIL 770-2 issued in March 1975. If there are any special inspection recommendations for stress corrosion cracking on our non-reheat machines we would certainly be interested in finding out. Our Bayfront 5 outage starts next month. So if you could do some more checking we would certainly appreciate it.
Thanks again.
Tim

-----Original Message-----
From: Bird, Joshua (GE Infra, Energy) [mailto:joshua.bird@ge.com]
Sent: Monday, February 11, 2008 3:17 PM
To: Murray, Timothy P
Subject: RE: LP Turbine Rotor Wheel Dovetail Cracking

Hi Tim,

I could not find TIL 770 in the records... there was a TIL 769 and 771, but 770 was not in there. I also did a search by title using various keywords ("stress", "dovetails", etc.), and could not find a TIL specifically for SCC on non-reheat machines. The best I could find was TIL 1277 for SCC on once-through boiler machines, which you are familiar with.

Typically, the TIL's are removed from the database when they are either supreceded or obsolete. Unfortunately there is not a placeholder or ID that says why a TIL is unavailable... even if the TIL is superceded, only sometimes does the new TIL note that it superceded an old TIL. Either way, I don't know what happened to TIL 770, but I could try to chase down an answer if you wish.

As for the SCC at Sherco, I still haven't heard an official word one way or the other on the issuance of a TIL for SCC on drum-boiler units. Its been a few weeks since I last bugged engineering on this, so I figure its time for me to ask again. We'll see what they say.

Thanks,

Josh

-----Original Message-----
From: Murray, Timothy P [mailto:timothy.p.murray@xcelenergy.com]
Sent: Monday, February 11, 2008 2:29 PM
To: Bird, Joshua (GE Infra, Energy)
Subject: RE: LP Turbine Rotor Wheel Dovetail Cracking

Hi Josh,
I understand from Mark Kolb that GE is not planning on issuing a TIL on this. Be that as it may I'm wondering if you could help me out on a related issue? I'm looking for a copy of GE TIL 770, Stress Corrosion Cracking of Wheel Dovetails on 3600 Non-reheat Machines. I'm thinking that this would apply to a number of our machines such as Bayfront 4&5, Red Wing 1&2, and a some of our Colorado and Texas units. I can not locate a copy within outage optimizer for any of our units. If you could forward a PDF version I would appreciate it.
Thanks Josh.
Tim

-----Original Message-----
From: Bird, Joshua (GE Infra, Energy) [mailto:joshua.bird@ge.com]
Sent: Tuesday, January 15, 2008 2:56 PM
To: Murray, Timothy P
Subject: RE: LP Turbine Rotor Wheel Dovetail Cracking

Hi Tim,

I have not received any feedback yet from engineering regarding the dovetail cracking. Let me circle back with them, and see what they have. I'll also pass on the confirmation that the Sherco 1's cracking was stress corrosion.

Thanks,
Josh

-----Original Message-----
From: Murray, Timothy P [mailto:timothy.p.murray@xcelenergy.com]
Sent: Tuesday, January 15, 2008 2:52 PM
To: Bird, Joshua (GE Infra, Energy)
Subject: LP Turbine Rotor Wheel Dovetail Cracking

Josh,
Any feedback from engineering on the drum boiler LP turbine wheel dovetail cracking issue? Any TILs in the works? We just heard about several more drum boiler LPs that have been found with serious cracking in the wheel dovetails. By the way, we did get 2 independent failure analysis that indicate the root cause of the Sherco 1 wheel cracks is stress corrosion. Any feedback you can provide regarding inspection recommendations for the rest of our drum boiler fleet would be appreciated.
Thanks
Tim
763-261-3204

GE Power & Water

THERMAL ENGINEERING
PRODUCT SERVICE

TIL 1886
02 OCTOBER 2013
Compliance Category – S
Timing Code - 5

TECHNICAL INFORMATION LETTER

INSPECTION OF LOW PRESSURE ROTOR WHEEL DOVETAILS ON STEAM TURBINES WITH FOSSIL FUELED DRUM BOILERS

APPLICATION

This TIL applies to select GE Steam Turbines with fossil fueled drum boilers including combined cycle steam turbines with heat recovery steam generators, which incorporate L-1 buckets with finger dovetails and operate at 3,000 or 3,600 rpm.

PURPOSE

To inform users of the need to inspect L-1 wheel finger dovetails on steam turbines to detect possible stress corrosion cracking. Discontinuities or other service related damage in L-1 wheel finger dovetails may develop into cracks of a "critical" size. Under continued operation such "critical" flaws could lead to a bucket liberation, which, in addition to resulting in extensive damage to the turbine, may also result in substantial damage to adjacent equipment and in some circumstances, possibly serious injury to any nearby personnel.

Compliance Category

O - Optional	Identifies changes that may be beneficial to some, but not necessarily all, operators. Accomplishment is at customer's discretion.
M - Maintenance	Identifies maintenance guidelines or best practices for reliable equipment operation.
C - Compliance Required	Identifies the need for action to correct a condition that, if left uncorrected, may result in reduced equipment reliability or efficiency. Compliance may be required within a specific operating time.
A - Alert	Failure to comply with the TIL could result in equipment damage or facility damage. Compliance is mandated within a specific operating time.
S – Safety	Failure to comply with this TIL could result in personal injury. Compliance is mandated within a specific operating time.

Timing Code

1	Prior to Unit Startup / Prior to Continued Operation (forced outage condition)
2	At First Opportunity (next shutdown)
3	Prior to Operation of Affected System
4	At First Exposure of Component
5	At Scheduled Component Part Repair or Replacement
6	Next Scheduled Outage

BACKGROUND DISCUSSION

The L-1 stage is the second to last row of rotating components on a low pressure steam turbine rotor. L-1 stages come in various vane lengths and dovetail configurations dependent on the application and the size of the machine. Several offerings in the GE fleet feature a finger dovetail bucket attachment configuration for the L-1 stage.

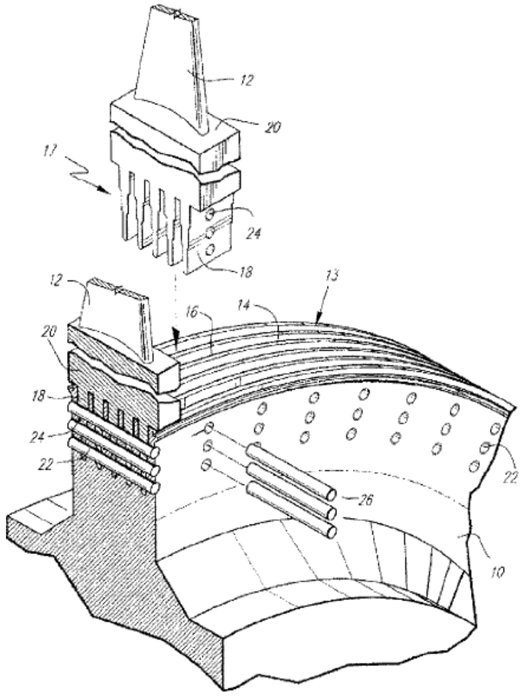

Figure 1: Finger dovetail attachment configuration.

Over the past several years, cases of Intergranular Stress Corrosion Cracking (SCC) have been observed in low pressure dovetails of fossil fueled steam turbine units with drum boilers. These rotors had been in service for extended periods. Several of the cases have involved L-1 stage finger dovetails, Figure 1.

SCC has been known to occur in the presence of a conductive environment, a rotor material that may crack in this environment, and applied stress levels. SCC is a time dependent phenomena that has been observed in wheel dovetails in as few as 9.5 years.

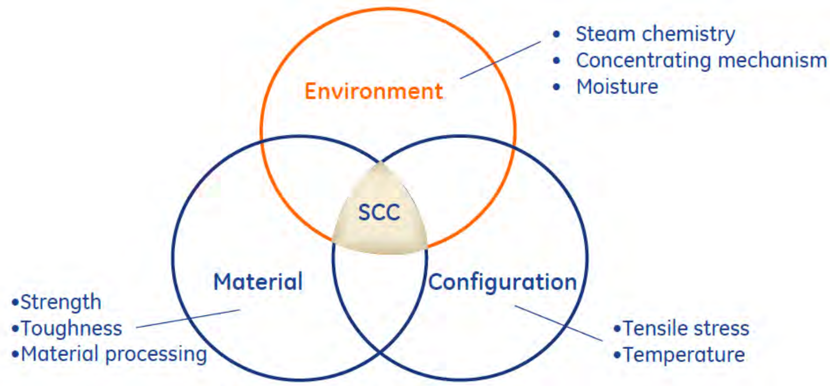

Figure 2: Conditions typically necessary for stress corrosion cracking to occur.

Units with drum boilers, including heat recovery steam generators, may be susceptible to SCC. There are many factors that influence SCC, including condensate polisher type and feed water treatment histories. Specific recommendations for maintenance of steam chemistry may be found in GEK 72281. The most vulnerable location in the steam turbine for SCC is believed to be the Wilson line, or the point at which saturation occurs. This region is typically the L-1 or L-2 stage for conventional reheat steam turbines. The quality of the steam, or moisture level, at the L-0 stage is typically such that water droplets preclude the formation of corrosive deposits on the wheel dovetail surfaces. For these reasons, incidents of SCC in L-0 wheel finger dovetails are extremely limited whereas multiple incidents of SCC in L-1 wheel finger dovetails have been observed.

The particular steel alloy used for low-pressure rotors has been employed in steam turbines since the 1960's due to its enhanced toughness required for these applications. Subsequent investigations by GE, other suppliers and institutions have found these alloys to have good SCC resistance for the strength levels used. Low-pressure rotors of this composition continue to be the material of choice for steam turbine manufacturers.

The finger dovetail bucket attachment configuration was introduced in the 1950's to enable larger active length, higher performing low pressure buckets, while managing stress levels, relative to tangential entry (pine tree) dovetails. Using available inspection data on the fleet of GE steam turbines, including over 60 incidents of stress corrosion cracking in low pressure rotor dovetails, GE has conducted thorough statistical analysis to understand the probability of SCC being observed in L-1 wheel finger dovetails. Given that dovetail stresses are a function of centrifugal load, 1,500 and 1,800 rpm rated speed units typically maintain lower stresses in finger dovetails than 3,000 and 3,600 rpm units. As a result of lower stresses, the incident rate of finger cracking in 1,500 and 1,800 rpm units has not warranted a specific communication regarding inspection of wheel finger dovetails. Note that TIL 1121 recommends magnetic particle inspection of all wheel finger dovetails whenever buckets are removed.

Inspection of wheel finger dovetails for SCC indications is not possible without removal of the buckets. SCC of finger dovetail stages has involved the internal fingers with no external indication of cracking. Also, indications have been observed away from dovetail pin holes. Note that inspection recommendations for tangential entry dovetails are provided in TIL 956 and GEK 11680.

Figure 3: Example of stress corrosion cracking at the step down regions of a wheel finger.

RECOMMENDATIONS

The following recommendations apply to units that are operating with greater than 22 years of service on their L-1 wheel dovetails:

1. At the next scheduled exposure of the low pressure rotor, perform non-destructive examination (NDE) on the L-1 wheel dovetail. The current GE recommended inspection method requires that the buckets be removed from the wheel and for all dovetail fingers to be inspected using MPI. It is recommended to work with your local GE Service Manager or Contract Performance Manager (CPM) to determine appropriate NDE methods and any updated and recommended inspection technologies to be employed.

2. If crack-like indications in the wheel dovetail are revealed during inspection, customers should contact their GE Service Manager or CPM for further guidance regarding repairs.

For units with less than about 22 years of service on their L-1 wheel dovetails, the steps above should be included at the closest scheduled major inspection to the time in which the L-1 wheel dovetail is expected to exceed 22 years of service.

If no dovetail cracking is noted during inspection, GE believes that continued operation is acceptable before the next inspection, or bucket replacement, dependent on your individual operating strategy. The re-inspect interval 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.

PLANNING INFORMATION

Compliance

- Compliance Category: **S**
- Timing Code: **5**

Manpower Skills

In addition to normal major outage personnel, GE Bucket specialists for removal and re-installation of L-1 buckets, GE Life Extension Services (LES) specialists for specific dovetail inspection, GE Inspection Services specialists for rotor, bucket and stationary component inspections.

Parts

Oversized finger dovetail pin and reamer kits
Bucket covers

Special Tooling

Low speed balance capability
Finger dovetail bucket pin removal and installation tooling
Finger dovetail bucket installation tooling
Finger dovetail non-destructive evaluation equipment

Reference Documents

GEK 72281: Steam Purity Recommendations for Steam Turbines
GEK 111680: Creating and Effective Steam Turbine Maintenance Program
TIL 1121: Inspection of Steam Turbine Rotor Wheel Finger Dovetails

Previous Modifications

None

Scope of Work

Inspection + Bucket Re-Installation: 4 weeks

Contact your local GE Service Manager or Contract Performance Manager for assistance or for additional information.

Contact your local GE Service Manager or Contract Performance Manager in order to update GE unit record sheets or to submit as-built drawings for changes incurred by this TIL.

NOTE: *If you would like to receive future TILs by email, contact your local GE Service Manager or Contract Performance Manager for assistance.*

TIL COMPLIANCE RECORD

Compliance with this TIL must be entered in local records. GE requests that the customer notify GE upon compliance of this TIL.

Complete the following *TIL Compliance Record* and FAX it to:

TIL Compliance
FAX: (678) 844-3451

TIL COMPLIANCE RECORD	For Internal Records Only # ____________
Site Name:	Customer Name:
Customer Contact Information	**GE Contact Information**
Contact Name:	Contact Name:
Address:	Address:
Email:	Email:
Phone:	Phone:
FAX:	FAX:
Turbine Serial Number(s):	

INSTALLED EQUIPMENT

TIL Completed Date: ____________

100% TIL Completed: ____________

Description:

Unit Numbers:	Part Description:	Part Number	MLI Number

Comments:

NOTE: *If there are any redlined drawings that pertain to this TIL implementation, please FAX the drawings along with this TIL Compliance Record.*

FAX this form to: **TIL Compliance**
FAX: (678) 844-3451