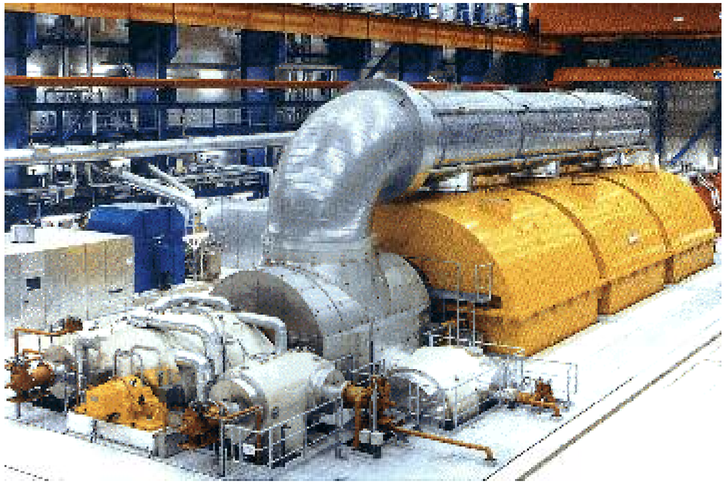
International Association of Engineering Insurers
38th Annual Conference – September 2005, Moscow

Maintenance and Overhaul of Steam Turbines



Working Group

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Discussion Agenda

- Introduction
- Turbine Component Characteristics and Failure Mechanisms
- Steam Turbine Arrangements and Applications
- Monitoring, Operations, Maintenance, and Training Infrastructure
- Steam Turbine Availability and Failure Experience
- Scheduled Maintenance and Overhaul Practices
- Approaches/Methodologies/Criteria for Establishing Longer Time Intervals between Major Overhauls
- Issues with New Steam Turbine Technologies and Applications
- Conclusions/Summary

Introduction

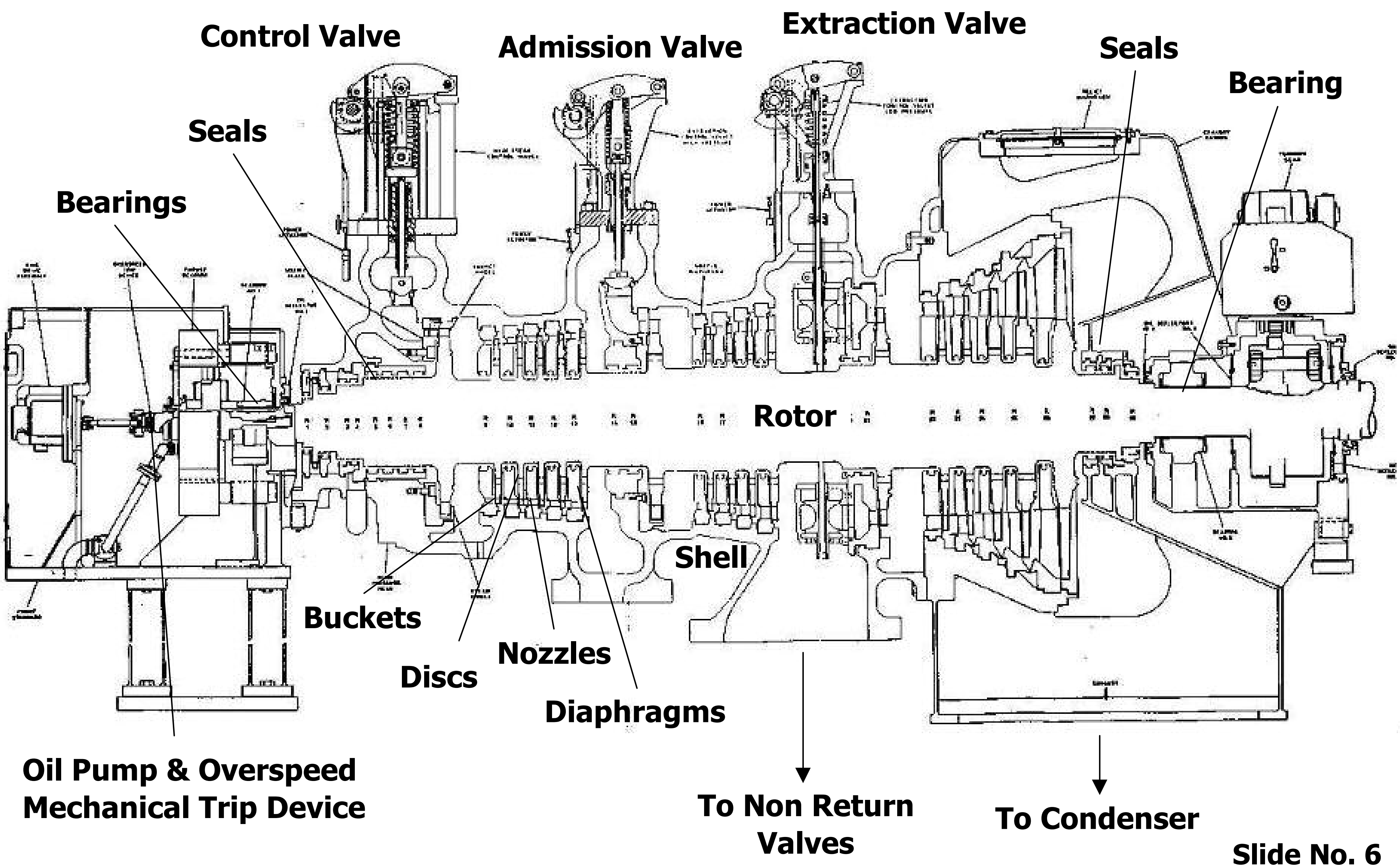
- Steam turbines drive boiler fans, process and chiller compressors, blast furnace blowers, paper mill line shafts, sugar mill grinders, and generators in a variety of industries and applications
- Design/construction range in size from small and simple to highly complex arrangements consisting of multiple sections and multiple shafts
- Maintenance and overhaul considerations need to consider
  - Steam turbine design/construction
  - Application and industry
  - Steam quality
  - Plant infrastructure for monitoring, operations, and maintenance
- Maintenance and overhaul needs for internal turbine components may be different than external turbine components and supporting systems

Turbine Component Characteristics and Failure Mechanisms

Major Steam Turbine Components

- Major Internal Components
  - Rotating Blading (Buckets) and Discs/Wheels
  - Shafts, Rotor, Bearings, and Seals
  - Stationary Blading (Nozzles) and Diaphragms
  - Shells, Blade Rings, or Casings
- Major External Components/Supporting Systems
  - Main Stop, Trip & Throttle, Intercept Valves
  - Governor/Control Valves
  - Admissions, Extraction, Non-Return Valves
  - Steam and Drain Connections
  - Overspeed Protection System
  - Lubrication System
  - Electro-hydraulic Control System
  - Water/Steam Chemistry Controls
  - Turbine Control System

Typical Multistage Steam Turbine



Turbine Failure Mechanisms

- Major Turbine Internal Components (Blading, Discs, Rotors, Diaphragms, Shells)
  - Corrosion: Pitting from Corrosive Elements in Steam
  - Creep: Permanent Thermal Distortion Caused By Higher Steam Temperatures and Life Consumption
  - Erosion: Particulate and Water Droplet Damage
  - Fatigue: Vibratory Damage and Life Consumption
  - Foreign/Domestic Object Damage: Debris Damage
  - Stress Corrosion Cracking: High Stress and Corrosive Conditions
  - Thermal Fatigue: Cracks from Thermal Cycling of Thick Parts
- Major Turbine External Components/Systems
  - Valves: Contaminants in Steam, Wear of Mating Parts, Damaged Seats Causing Valve Sticking and Leakage
  - Lube Oil System: Loss of Oil Protection Not Working
  - Water Induction: Water from Steam Lines, Drains, Feedwater Heaters Causing Thermally Distorted Rotors (Bowed) and Shells
  - Contaminated Steam/Water and Particulate from Boilers
  - Turbine Overspeed Protection Not Working

Steam Turbine Arrangements and Applications

Range of Steam Conditions for Turbines

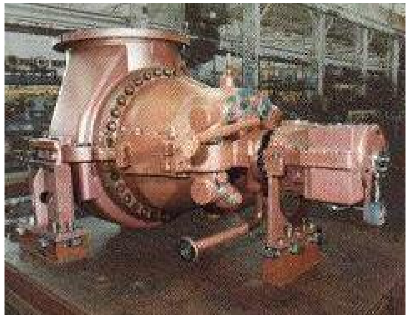
- Type of Steam
  - Saturated: Water Heated to Boiling Point or Vaporization Temperature for a Given Pressure
  - Superheated: Saturated Steam Heated to Higher Temperatures
  - Supercritical: Superheated Steam Increased in Pressure to Thermodynamic Critical Point of Water (3,205 psi/221 bar)
- Typical Steam Conditions
  - Small Units (0.5 - 2 MW): 150-400 psi/500-750°F (10-30 bar/260-400°C)
  - Medium Units (1.5 - 10 MW): 400-600 psi/750-825°F (10-42 bar/400-440°C)
  - Large Units (4 - 100 MW): 600-900 psi/750-900°F (42-62 bar/400-482°C)
  - Large Units (10-1,000 MW): 900-2,400 psi/825-1,050°F (62-166 bar/440-566°C)
  - Supercritical Units (>200 MW): 3,625-5,365 psi/1,010-1,328°F (250-370 bar/540-720°C)

Steam Turbine Arrangements

- High Pressure Section (HP)
- Intermediate Pressure Section (IP)
- Low Pressure Section (LP)
- Double Flow Sections
- Combined Sections (HP/IP, HP/LP, etc.)
- Sections may separated in different casings or installed in a single casing
- Casings may be not be connected directly
- May have single or multiple blading stages
- Most are axial flow turbines (few radial flow)

Steam Turbine Arrangements

Single Stage



Multiple Stage

Multiple Stage - Backpressure

Multiple Stage – CC Non-Reheat

Multiple Stage – CC Reheat

Multiple Case, Tandom

Multiple Case, Tandom

Multiple Case, Cross Compound

Monitoring, Operations, Maintenance, and Training Infrastructure

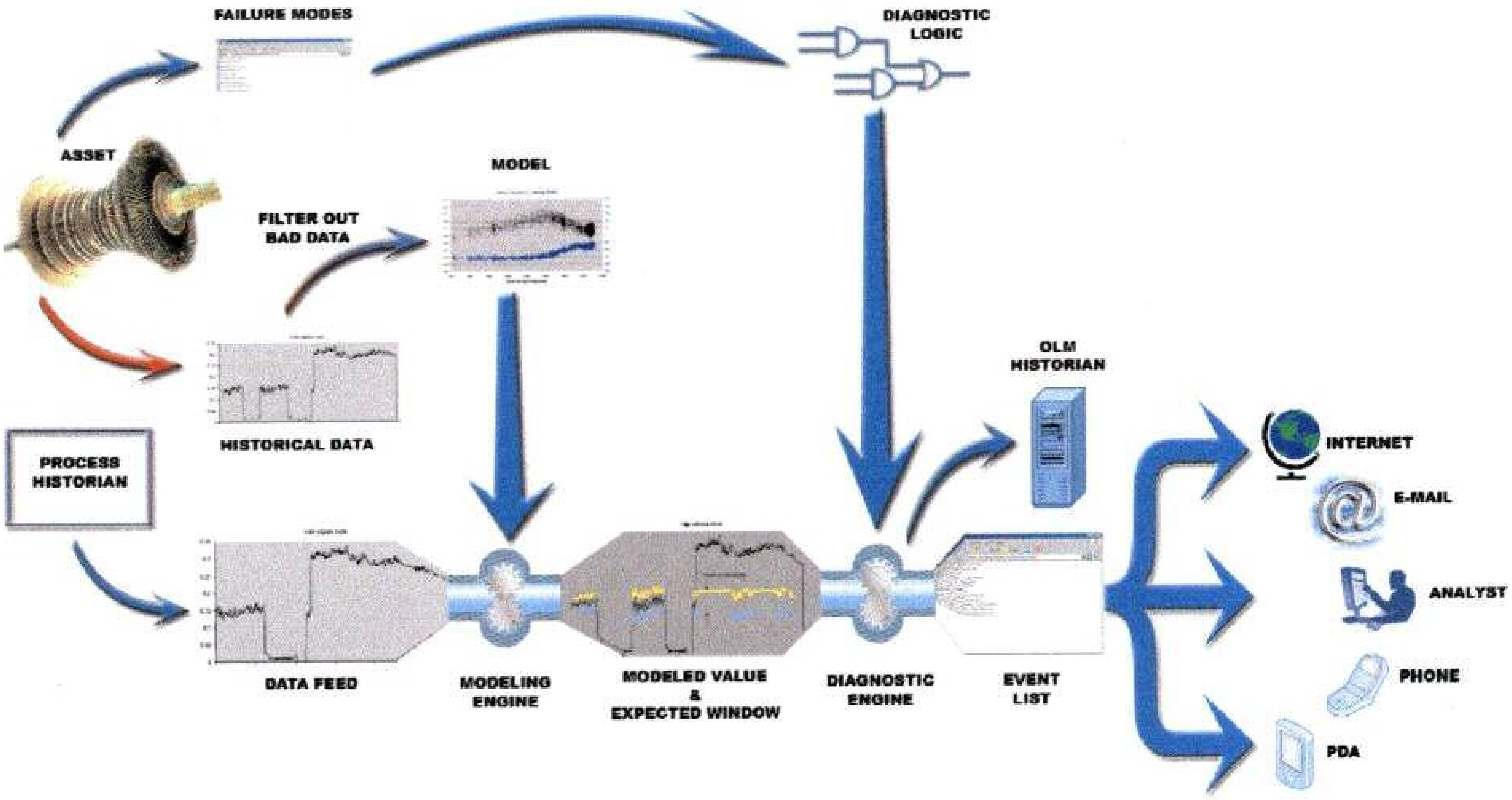
Monitoring

- Needs to be Effective and Tailored by Turbine Size, Type, and Application
- Equipment Monitoring
  - Small Single Stage Units 0.2–2 MW
  - Medium Size Multiple Stage Units 1.5-10 MW
  - Admission/Extraction and Non-Reheat Units <100 MW
  - Combined Cycle Reheat Units
  - Large Reheat Subcritical and Supercritical Units
- Water and Steam Purity Monitoring
- Water Induction Monitoring
- Condition and Trend Monitoring

Basic Turbine Monitoring Parameters

- Speed (RPM) and load (kW/MW, or shaft horsepower (SHP))
- Steam turbine inlet pressure and temperature
- Steam turbine 1st stage pressure and temperature (these are the conditions downstream of the first/large impulse stage before remaining HP section blading, as applicable)
- HP turbine outlet (or cold reheat), IP turbine inlet (or hot reheat), and IP turbine outlet/LP turbine inlet (or crossover) pressures and temperatures for reheat/multiple shell turbines only
- Steam turbine rotor/shell differential expansions (as applicable for large turbines)
- Steam turbine shell and steam chest temperatures/differentials (lower and upper half thermocouples installed in HP and IP turbine sections for large turbines)
- Admission and extraction pressures and temperatures (as applicable)
- Extraction line thermocouples to detect water induction (as applicable)
- Water and steam purity at the main steam inlet and condensate pump discharge
- Sealing steam and exhauster pressures (as applicable)
- Steam turbine exhaust pressure and temperature
- Lube oil and hydraulic fluid supply pressures and temperatures
- Cooling water supply pressures and temperatures for the lube oil and hydraulic fluid systems
- Journal bearing and thrust bearing metal temperatures (or drain temperatures, if applicable) for the turbine and gearbox (as applicable)
- Bearing vibration – seismic, shaft rider, or shaft x-and-y proximity probes measurements for all turbine and gearbox (pinion) bearing locations (as applicable)

EPRI Condition Monitoring Approach



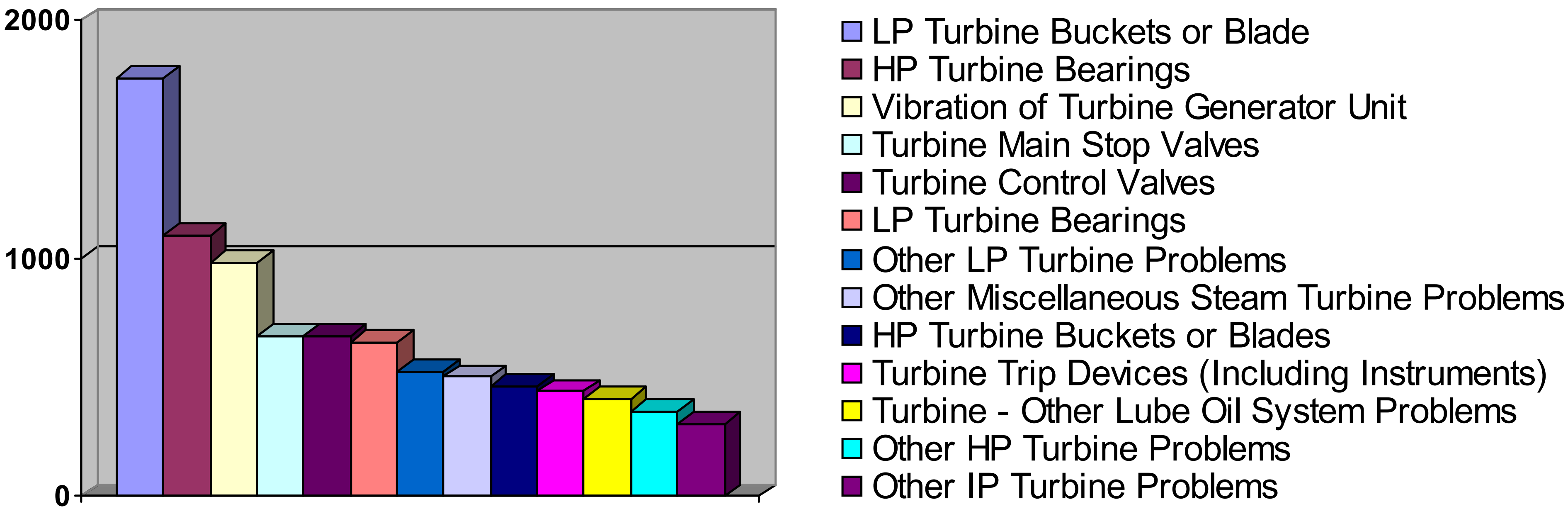
Operations, Maintenance, and Training

- Operations
  - Technical Manuals, Logbooks
  - Procedures (Pre-Start Checklists, Starting, Operation, Shutdown, Casualty, Testing)
  - Operator Knowledge
- Maintenance Management
  - Technical Manuals, Service Bulletins
  - Established Practices on Maintenance Tasks Workscope and Frequency
  - Maintenance Management System (CMM or Equivalent)
  - Lockout/Tagout, Contractor Control, and Emergency Pre-Planning Procedures
- Training
  - Current and Active Training Program
  - Train in the Why as Well as What Needs to be Done
  - Use of Simulators

Steam Turbine Availability and Failure Experience

Steam Turbine Availability

Ranking of Top 15 Failure Causes for Fossil Steam Turbine Lost Availability In MW-Hrs per Year from 1998-2002 (Courtesy NERC and EPRI)



Composite Industry Steam Turbine Failures - Mechanisms and Causes (HSB Files) (Ranking: 1=Highest, 4=Lowest)

Component	Failure Mechanism	Cause(s)	Frequency Rank	Severity Rank
Turbine Rotor and Bearings	Loss of lube oil	1. Pressure switches did not work. 2. Backup lube oil pump did not work. 3. Duplex filter switching problem 4. Oil supply valve leaked 5. Ruptured bearing oil line	1	3
Bucket or Bucket Cover Failure	Fatigue, corrosion, erosion, rubbing, and SCC	1. Blade and/or cover cracked, pitted, thinned or eroded and finally broke. 2. Corrosive chemicals in the steam 3. High backpressure for last turbine stage. 4. Water induction 5. Resonance sensitive bucket design 6. Bowed rotor and/or humped shell	2	2
Turbine Rotor	Overspeed (OS) with or without Water induction	1. NRV stuck open during shutdown. 2. Mechanical OS device did not work. 3. Main Steam Stop/T&T valve stuck partly open. 4. Lost control of test 5. Controls – OS did not work	3	1
Turbine Rotor	Major rubbing, high vibration	1. Quick closing valve did not close properly (broken disk) 2. Direct contact of rotor with buckets, nozzles, seals, and shells 3. Misalignment 4. Protective system did not work	2	2
Nozzle and Buckets, HP and IP Stages	Solid particle erosion	1. Exfoliation – boiler inlet piping. 2. Main Steam Stop/T&T valve inlet strainer broke.	3	4
Nozzle and Buckets, LP Stages	Droplet erosion	1. Saturated steam in the LP turbine. 2. Poor turbine design.	3	4
Nozzles and Buckets, All Stages	Foreign or Domestic Object Damage (FOD/DOD)	1. Debris in inlet line to turbine. 2. Main Steam Stop/T&T valve inlet strainer broke. 3. Parts adrift inside turbine, or broken nozzle partitions or bucket shrouds.	4	3

Steam Turbine Failures

Fatigue Failure Compounded by Condenser Extraction Line Backflow

Water Induction Rub Compounded by Attempts to Turn Thermally Locked Rotor

Rotor/Seals Welded to Inner Shell from Rub

SCC Failure in LP Blade LE

Scheduled Maintenance and Overhaul Practices

Turbine Maintenance Tasks and Frequencies

- Tasks and Frequencies Defined Based on Past Experience By:
  - Turbine Manufacturers
  - Consultants
  - Industry Organizations (EPRI, VGB)
  - Plant Personnel Based on Experience
  - Plant Process Requirements
  - Criticality to Application
  - Insurers
- Task Frequency Requirements May Include Daily, Weekly, Monthly, Annually, Minor Outages (3-5 Years), Major Outages (3-9 Years, 9-12 Years), and Every 25,000 or 100,000 Equivalent Operating Hours (EOH)
- U.S./European Tasks and Frequencies Nearly the Same and Not Subject to Any Regulatory Requirements
- Japan Tasks and Frequencies Are Subject to Regulatory Periodic Maintenance Requirements and Periodic Self Maintenance Requirements Which Were Initiated in 1995. Adherence to Both Requirements is Mandatory
- Special Outages – Conducted for Special Inspections, Life Analyses, Etc.

Approaches/Methodologies/Criteria For Establishing Longer Time Intervals Between Major Overhauls

Approaches Used to Establish Longer Time Intervals Between Steam Turbine Major Outages

- Management Directed Interval
- Process and Criticality Driven Intervals
- Turbine Manufacturer's Intervals
- Electric Power Research Institute (EPRI) Methodologies
- VGB Standards
- Risk-Based Methodologies
  - HSB Risk Based Analysis Programs (TOOP and STRAP)
  - Japan Programs
- Reliability Centered or Condition Based Maintenance (RCM or CBM)

EPRI Methodologies

- Initially Utilized Decision Analysis Methodology Coupled with Probability/Consequence Information Provided by the User to Determine the Change in Net Present Value (NPV) with Time. When NPV is Negative, Time to Overhaul
- Changed to a Condition Assessment Approach
  - Overhauls Should Be Conducted Every 80,000 EOH
  - Color Code (Blue, Yellow, Red, or Green) Level of Degradation (Some, Significant, Severe, or Good Condition) or Major Turbine Components or Systems
  - No Defined Standards for Level of Coding
  - No Increments/Decrements in EOH Based on Coding
  - Levels Established by Whoever is Doing Assessment

VGB Standards

- First Overhaul May be Conducted After 100,000 EOH
- Subsequent 100,000 EOH Overhauls May be Conducted Based on Following Criteria:
  - Type of turbine (condensing with high steam wetness, turbine sections with austenitic steel, geared turbines, etc.)
  - Mode of operation (continuous duty, off-load operation, starting/loading mode, sliding/fix pressure operation, etc.)
  - Observations during operation (vibration, steam and oil temperatures and pressures, leakages, alignments, changes in service fluids, etc.)
  - Special measurements (internal efficiency, vibration analysis, heat rate, foundation distortion)
  - Functional tests (protective and control equipment)
  - Life assessment calculations
  - Turbine life expenditure
  - Inspection interval of other unit components (steam generator and generator)
  - Manufacturer and insurer recommendations
  - Exchange of information with other utilities (weaknesses and breakdowns)
  - Influence of downtime
- Between major overhauls, minor or intermediate overhauls may be scheduled every 25,000 EOH

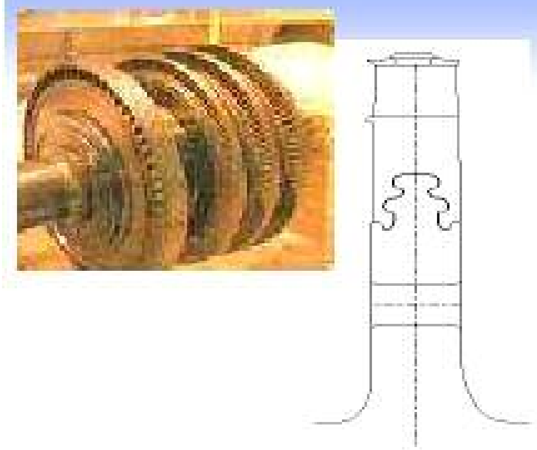
Risk-Based Methodologies

- Hartford Steam Boiler Experience
  - Established Risk-Based Algorithms to Calculate Steam Turbine and Generator Risks from Probability of Failures, Failure Consequences, and Engineering Modifying Factors Developed with Industry Input
  - Developed 2 Programs Based on ASME Risk-Based Guidelines
    - Turbine Outage Optimization Program (TOOP) for Power Generation and Utility Steam Turbines and Generators
    - Steam Turbine Risk Assessment Program (STRAP) for Steam Turbines in Process Applications (<100,000 HP)
  - Grounded/Correlated Program Outage Interval Levels with Units that Have Successfully Run Longer Outage Intervals
  - Analyzed 90 TOOP Steam Turbines, 130 STRAP-Size Steam Turbines, and 100 Generators to Date
- Japan Experience
  - Deregulation Caused Machinery Manufacturers and Electricity Producers to Adopt Risk-Based Methodology (RBM) Approach
  - Plants Are Utilizing Machinery Data and Past Operations To Develop Maintenance Plans for Their Respective Steam Turbine Generators

Issues with New Steam Turbine Technologies and Applications

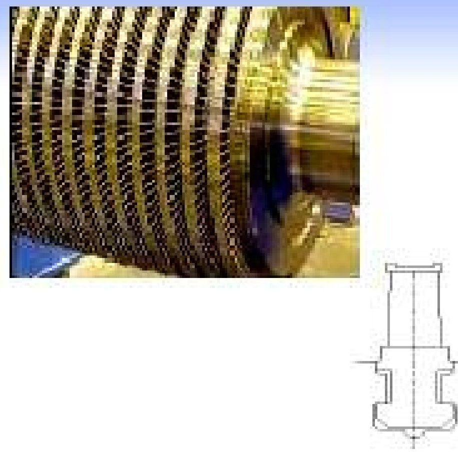
New Steam Turbine Trends

- More Reaction Blading, More Stages in HP and LP, and Smaller Clearances
- Larger LP Blades
- High Pressures and Temperatures
- Higher Efficiencies



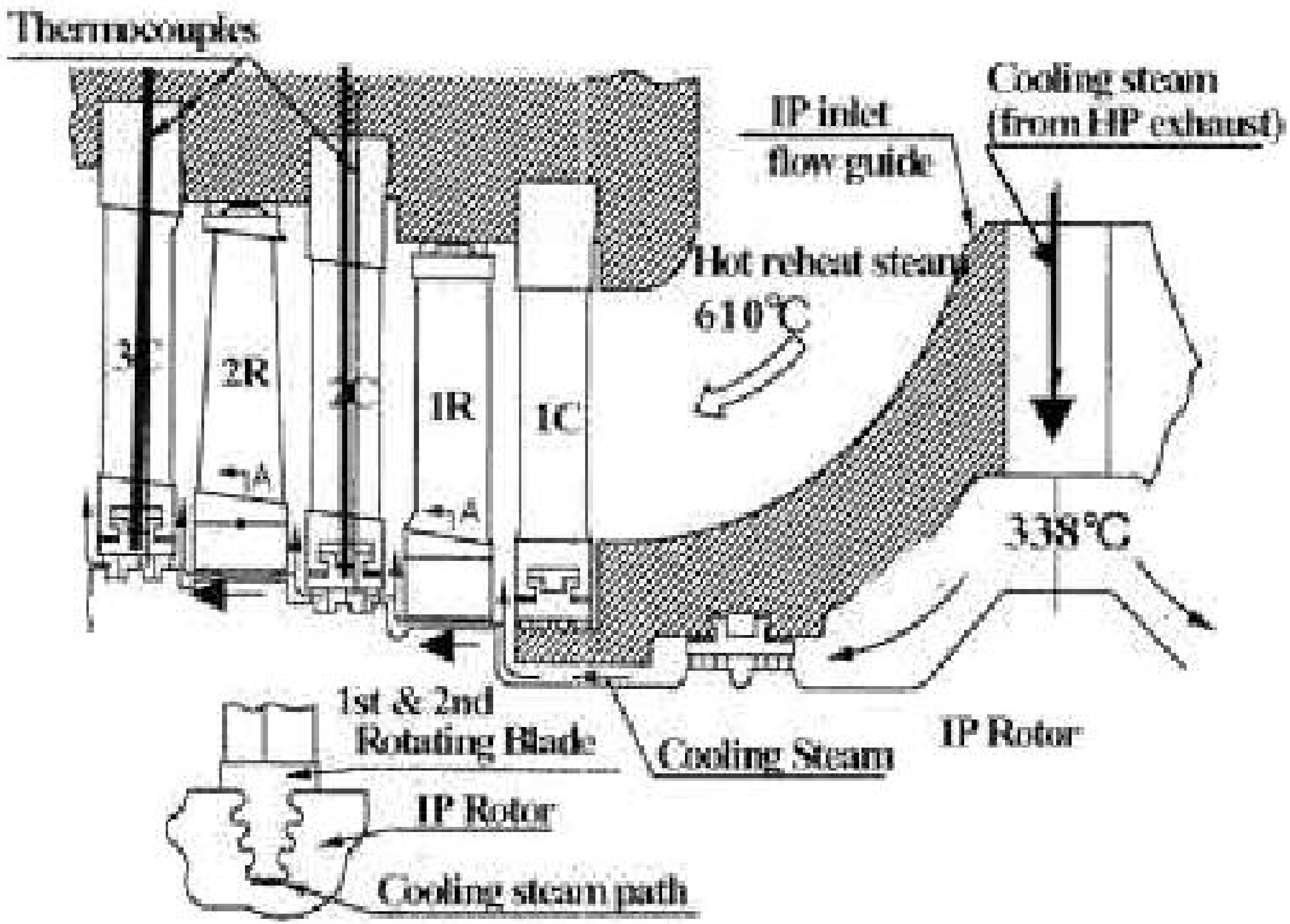
Impulse Stages
Fewer Rows
Wide Clearances

Increased Reaction
Content/More Rows
Reduced Clearances



Substantially Increased Reaction
Content/Even More Rows
Further Reduced Clearances

Advanced Steam Turbines



Conclusions/Summary

- While steam turbines differ in design, complexity, application, steam conditions, and size, they all are fundamentally the same. Consequently, the maintenance and overhaul efforts are similar, although tailored to the specific unit and application
- There needs to be an infrastructure in place for steam turbine monitoring, operations, maintenance, and training. The infrastructure is equally important as the equipment.
- There have been numerous causes of steam turbine failures worldwide at both the component and system level. As such, steam turbine maintenance and overhaul efforts should be directed toward diagnosing and mitigating those types of events.
- The maintenance practices in North America and Europe are not subject to regulatory requirements while they are in Japan. Regardless of the area of the world, the recommended scheduled maintenance requirements are quite similar.
- There are a number of different approaches which are utilized today for establishing longer time intervals between major overhaul outages. Regardless of the approach, it is important that the methodologies effectively establish the overhaul intervals based on the highest risk portions of the steam turbine.
- The technologies being incorporated into new steam turbines are more sophisticated, require operation at higher pressures and temperatures, and generally have smaller clearances to improve efficiency. Continued vigilance with regards to monitoring the reliability and availability of these new units is needed.

In summary, what is important to insurers is that the maintenance tasks and frequencies should be prioritized towards the portion of the steam turbine that have the highest risks- the highest probability and consequence of failure. That usually means:

- *Protecting the steam turbine from overspeeds, water induction, loss of lube oil, corrosive steam, and sticking valves that could cause major damage to the turbine*
- *Conducting internal inspections of the turbine flowpath, shells and rotors in order to detect damage early enough to prevent a subsequent major failure.*