Turbine, Generator & Auxiliaries - Course 234

TURBINE OPERATIONAL PROBLEMS

As steam turbine units increase in size and complexity the operational problems also increase in magnitude. Not only has construction and control become more complex but materials have been pushed closer to their operating limits. As structures have become more massive, thermal gradients and pressure stresses have become more complex. In addition, with the increase in size it is no longer possible to build operational models and test them exhaustively before putting them into commercial operation. Today's turbine units go directly from the drawing board to on-site erection and commissioning.

Problems due to design errors are reasonably rare, but they do occur and because these occurrences are generally catastrophic it is becoming practice to build mathematical models of the system. Computer programs are then used to simulate normal, abnormal and casualty operations so that an assessment of in-service performance can be obtained prior to commissioning. By this method it is often possible to establish operating limitations before the design leaves the drawing board.

Because of the large capital investment in any modern generating station, reliability of the unit becomes a significant concern. This is particularly true of nuclear stations where the cost of alternate electrical energy sources can be truly phenominal. For this reason it is becoming standard practice to assign a dollar value to estimated unreliability and factor this into the initial cost of the unit. This practice hopes to avoid an initial low price which turns out to be no bargain in service.

Despite these precautions, problems do occur particularly in the first year or so following commissioning. Not only do problems more frequently occur with a new plant but the operating and maintenance personnel require some time to familiarize themselves with the station.

The problems discussed in this lesson are derived from significant event reports and operating experience in nuclear and non-nuclear stations. Particular problems are included either because they occur with some frequency or because they represent a significant hazard to the turbine unit. The comments in this lesson are only of a general nature and are not intended as a substitute for design or operating manuals which constitute the manufacturer's specific recommendations on the operation of a specific turbine unit.

Overspeed

The hazards of an unterminated overspeed generally fall into one of four catagories:

(a) speed will rise to a level where the centrifugal forces on the largest diameter wheels will cause tensile failure (rupture) of the wheel,

(b) speed will rise into a critical speed region and remain there long enough for the resulting amplification of vibration to cause failure,

(c) speed will rise to a level where the added stress due to centrifugal force will fail a component which has been weakened through fatigue, erosion or some other long-term phenomena, or,

(d) speed will rise to a level where the centrifugal forces on the generator rotor will rupture the rotor, or will loosen rotating parts which can then contact stationary parts.

The potential for an actual overspeed of the turbine unit occurs from two principle conditions: load rejection and testing of the overspeed trip mechanism. The response of both the mechanical-hydraulic and electrical-hydraulic governing systems to an overspeed following load rejection is discussed in lesson five of this course.

The periodic testing of the operation of the overspeed bolts to trip the unit on an actual overspeed condition places the unit in a condition which can easily result in damage. Because the operation of the overspeed bolts is the last protective feature which functions to limit overspeed, the testing of this trip requires either the disabling of protective features which operate at lower overspeeds or raising the setpoint of these features above the trip point of the overspeed bolts. If the protective features fail to operate properly, the unit speed can be raised to dangerous levels. The testing of overspeed tripping devices is always a hazardous evolution and requires a detailed operating procedure. At least, two independent methods of monitoring turbine speed should be used and personnel conducting the test should be in continuous communication with each other. There should be no question under what conditions the test will be terminated. The raising of speed to the trip point should be smooth and rapid enough to limit the time above operating speed to that required to allow monitors to follow the speed of the unit. Personnel conducting the test should constantly ask themselves if the unit is safe, even if <u>none</u> of the trips function as expected. It should be borne in mind that the vast majority of turbine casualties involving overspeed occur during this type of testing.

Motoring

When the reactor heat production is lost through a reactor trip, the governor steam valves will shut to prevent the turbine steam consumption from lowering heat transport system temperature and pressure. If the generator output breaker is left shut, the turbine generator unit will motor with the turbine being driven by the generator acting as a synchronous motor. There are certain advantages to maintaining the turbine unit motoring during a reactor trip. Keeping the unit at operating speed shortens the time from steam admission to generator loading on the subsequent startup. This enables a faster recovery: first to avoid xenon poison-out and second to return the generator capacity to the grid.

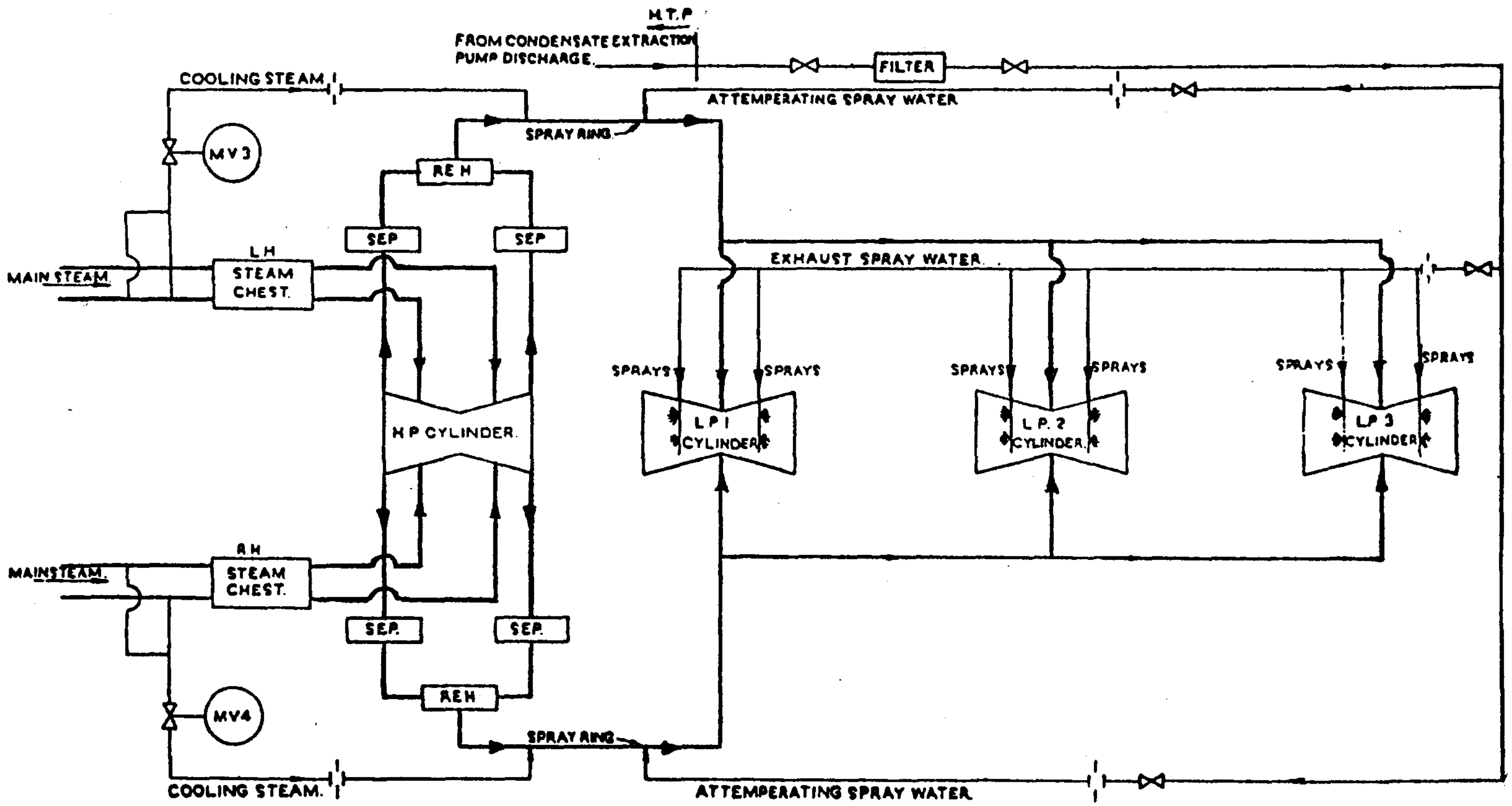
During motoring the turbine blading is turning through dead steam and the friction between the steam and the blading rapidly overheats the long turbine blades at the exhaust end of the low pressure turbine. The problem is made more severe if the vacuum decreases and the blading encounters higher than design steam densities. The problem can be partially alleviated by an exhaust spray system and a cooling steam system as shown in Figure 6.1.

The exhaust spray system uses water off the discharge of the condensate extraction pump which is sprayed into the exhaust annulus of the turbine. This spray helps cool the dead steam as it is circulated by the rotation of the final low pressure turbine stages. To aid this system, steam is taken from the high pressure steam line ahead of the governor valves and routed to the inlet to the LP turbine. This "cooling steam" keeps a positive direction of steam flow through the LP turbine stages which helps to remove the windage heat.

Even with both cooling steam and exhaust sprays in operation, the final stage LP blading will overheat in something like an hour. This will require stopping the motoring of the unit. However, since the reactor will poison-out in about the same time frame, there would be little advantage in extending this limit.

Low Condenser Vacuum

When condenser vacuum decreases below design values, the turbine unit is subjected to a variety of unusual stimuli. Heat rate increases as less work is extracted from each kilogram of steam; the turbine internal pressure profile changes; extraction steam pressure and temperature change; the distribution of work between the high and low pressure turbine changes. However, the most immediate problem associated with vacuum decreasing below design is that the condenser will



Schematic Arrangement of LP Cylinder Exhaust Spray Cooling System and Cooling Steam System

Figure 6.1

eventually not be able to condense all the steam being exhausted to it. In order to restore equilibrium to the condenser, the amount of steam rejected to it must be decreased. For this reason when vacuum has fallen below the minimum at which full power can be handled, the turbine will automatically begin to unload to a power level where the condenser can again reach equilibrium. With a design vacuum of 720 mm of Hg [5 kPa(a)], unloading will start at around 705 mm of Hg and will continue until either vacuum stops decreasing or 10% power is reached at 575 mm of Hg. If the vacuum decreases further the emergency stop valve will trip shut at 560 mm of Hg.

The combination of a low power level and low condenser vacuum imposes particularly severe conditions on the low pressure turbine blading. Not only do the long blades have to pass through a high density steam-air mixture but the absence of adequate steam flow through the turbine decreases the rate of heat removal. The adverse effect of low vacuum, low steam flow is the reason for terminating vacuum unloading before the governor steam valve fully shuts off steam. This effect also explains why, on a startup, vacuum should be the best obtainable before rolling the turbine with steam. It is desirable to maintain condenser vacuum on a shutdown until the turbine speed has decreased to about 50-60% of synchronous, to avoid a no steam flow, low vacuum condition.

Water Induction

Water damage to modern saturated steam turbines can be roughly divided into two categories: long term erosion by wet steam and catastrophic damage due to ingress of large quantities of water. The former cause of turbine damage is covered in lesson 1 and elsewhere in this lesson.

Slugs of water can enter the turbine through a number of places, however, the two most common sources of turbine damage are due to water induction through the governor steam valve and through the extraction steam lines. Water induction causes damage in three principle ways:

(a) direct impact damage on turbine components such as blading, diaphragms and blade wheels,

(b) excessive thrust caused by water impingement leading to thrust bearing failure or hard rubbing between components, and

(c) thermal damage to components due to quenching by water which may result in excessive thermal stresses, thermal distortion, or permanent warping. This is particularly true in the superheated section of the low pressure turbine.

Slugs of water which enter a turbine at high velocity will take the shortest path through the turbine, possibly clearing out both fixed and moving blades in the process. Because of the greater fluid density and the resulting impact on the rotor, induction of water from the steam generator may result in thrust loads much higher than design values. A failure of the thrust bearing can result in excessive axial travel of the rotor and subsequent severe rubbing damage to blading, blade wheels, diaphragms, glands and other components. Because of its high heat capacity, water contacting hot turbine parts can cause severe thermal stresses and distortion. This distortion can cause secondary damage if a turbine is restarted before the distortion has dissipated. While thermal distortion is not particularly severe in saturated steam portions of the turbine, it can be a significant cause of damage in the superheated sections.

Prevention of water induction requires both proper operation of protective features and careful avoidance of operating errors. The induction of water from the main steam line is minimized by the steam generator level control system, the high level alarm and by closure of the governor steam valve on high water level. However, improper or inadequate draining of steam lines during startup and subsequent loading can result in slugs of water being accelerated down the steam lines and into the turbine.

Water induction into the turbine can have particularly severe consequences on startup. While running under load, the steam flow can be of some benefit in absorbing water and minimizing thermal distortion, particularly in superheated sections of the turbine. Moreover, damage from rubbing can be increased when rotor speed is in the critical speed range.

If high vibration or other serious problems necessitate shutting down the turbine, the unit should not be restarted until all the water has been drained from the unit and the cause of water entry found and corrected. In addition, sufficient time should be allowed for relief of thermal distortion of the casing and rotor. Experience has shown that the most serious damage from water induction often occurs considerably after the first indication of water induction and attempting to restart may result in extensive damage due to rubbing between fixed and moving parts.

Moisture Carryover

Carryover is the continuous entrainment of liquid boiler water in the steam leaving the steam generators. The cyclone separators and steam scrubbers in the steam generators are designed to remove virtually all of the liquid water and under normal conditions, the steam leaving the steam generators is less than .2% liquid water (moisture). Both design and operating engineers are very sloppy in their use of the term "carryover". This is because these people are concerned not only with the quantity of liquid boiler water leaving the steam generators but also with the quantity of chemicals which is carried along in the water droplets. A water droplet is a mini-sample of boiler water and its makeup is more or less representative of boiler chemistry. Depending on boiler chemistry, the moisture entrained in the steam may contain SiO_2, Cl^-, Na^+, soluable and insoluable calcium and magnesium salts, OH^- and a wide variety of other chemicals. The water which leaves a steam generator can thus cause damage in three ways:

(a) moisture erosion which would occur even if the water were pure,

(b) chemical corrosion from active ions carried with the water, and

(c) chemical deposits on valve seats and stems and on turbine blades.

Depending on which of these effects we are concerned about, one may talk about carryover as the amount of moisture or as the amount of dissolved and undissolved solids in this moisture. You can see that if the amount of solids in the boiler water increases, more solids will leave the boiler, even if no more water leaves the boiler. The point of all this is that when one discusses the causes of increased carryover you have to know whether he is talking about the increase in the quantity of water leaving the steam generator or the increase in chemicals leaving in that water. It is not the purpose of this lesson to solve the problems of the world. Suffice it to say that in this lesson carryover will be defined as the amount of <u>water</u> leaving with the steam. The reader is cautioned, however, that this definition is not universal.

Carryover can be increased by two methods: mechanical and chemical.

Mechanical methods which increase carryover are generally those which decrease the effectiveness of the cyclone separators and/or steam scrubbers. <u>High boiler level</u> can physically flood the separators and decrease their effectiveness. Under certain conditions, <u>low boiler level</u> can cause carryover. If boiler level drops below the bottom of the separator columns, level oscillations can cause overloading of some separators with resultant carryover. <u>Rapid power increases</u> can increase carryover not only through swell flooding the separators but through temporarily overloading the separators as steam rushes from the steam generators. If steam flow is above design either from one steam generator or all steam generators, increased carryover can result. The moisture separators are intended to produce dry steam at some maximum power level. If the steam generator is forced to supply more than this design maximum, steam quality will suffer. This method of inducing carryover can be a particular problem if one steam generator is isolated, possibly forcing the others to operate at higher power levels.

The turbine can be protected against mechanical carryover by:

(a) monitoring boiler level,

(b) adherence to specified loading rates, and

(c) high boiler level closure of the steam admission valves.

Chemical induced carryover results when the chemicals in the boiler water break the surface tension of the water or allow foaming to occur. The presence of oil in steam generators causes foaming to occur on the water surface. This foaming can cause severe carryover and oil in the boilers is an extremely serious problem. Because of this, however, designers have made it virtually impossible for oil to enter the steam/feedwater system. Although it requires a certain creative incompetance to get oil into the boilers, it is certainly possible. One not unlikely way is through leaking or standing oil being sucked into sub-atmospheric piping in the condensate or makeup water system.

Both high undissolved solids and high dissolved solids, particularly the former, can promote carryover through breaking the surface tension of the water. This promotes liquid water being carried off with the steam. In addition, such high solids will be carried over with the moisture and may foul blading and cause control valve sticking and leakage.

Blade Failure

If there is a complete failure of a turbine blade in operation the effects may be disastrous as sections of blades get stuck between rows of fixed and moving blades and can strip the blade wheel. The resulting vibration can completely wreck the turbine. This type of failure due to metal failure is extremely rare due to advanced metallurgical developments and methods of blade fixing. However, because of the high stresses imposed on rotating blades and shroud bands, even minor errors during installation or replacement of blading may lead to early blade vibration, cracking and ultimate failure.

Probably the most significant source of blade failure is damage induced by water impact and erosion. Not only is the quality of steam entering the turbine important but in addition the ability of the blade to shed water can influence blade life. Use of cantilevered blades without shrouds is becoming reasonably widespread in nuclear steam HP turbines as the shroud tends to restrict the centrifuging of water droplets off of the blade. There have also been cases of blade tip and shroud band erosion and failure due to inadequately sized stage drains which resulted in standing water in the turbine casing.

Water erosion in the exhaust end of the HP and LP turbines has caused failure of lacing wires and damage to the leading edges of the blading. The erosion of blading causes pieces of metal to break off which may cause damage to fixed and moving blades in subsequent stages. Defects of this kind are minimized by having a very hard stellite or chrome steel insert welded to the leading edge of LP turbine blades. In cases of extreme water erosion, however, these inserts may become undercut and themselves break loose to become a source of impact damage.

In operation, centrifugal stresses, bending stresses and thermal stresses may ultimately cause fatigue cracking of the blade roots. These cracks can only be detected during shutdown by non-destructive testing. Any evidence of blade cracking should be treated with caution as it is not only indicative of an abnormality within the turbine but also can lead to catastrophic blade failure.

Expansion Bellows Failure

Expansion bellows are used extensively in large turbines on LP pipework and between LP turbines and the condenser when the main condenser is being used as a reject or dump condenser.

In practice the bellows develop hairline cracks due mainly to thermal cycling as a result of load changes. Failure may also be caused by overload, for example, if an expansion bellows is fitted between the LP turbine and the condenser, the bellows may become strained if the condenser is over-filled without supporting jacks in position to take the weight.

Bearing Failure or Deterioration

Recent experience indicates that approximately half of all major turbine problems involved the bearings and lubricating oil system. With only a few exceptions most bearing problems can be traced directly to malfunctioning or maloperation of the lube oil system. Provided the lube oil system performs its primary function of supplying clean lube oil at the proper temperature and pressure to the bearings at all times when the turbine/generator shaft is rotating, there is usually little problem with the bearings.

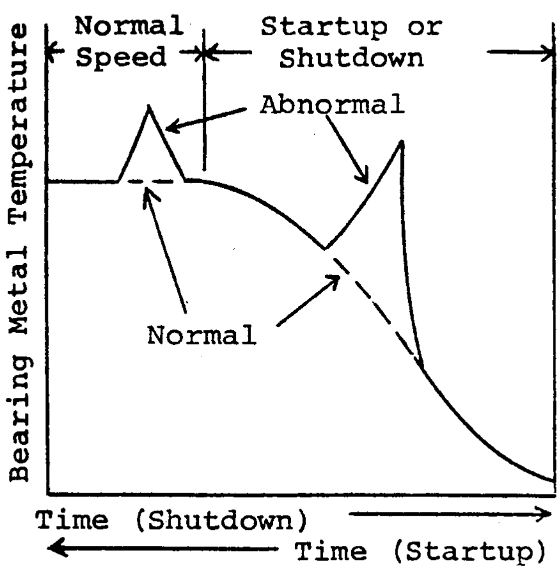
Since even a brief failure of the lube oil flow to the bearings can result in considerable damage to the unit, the system is designed to provide continuous oil flow under a variety of pump shutdowns and power failures. The automatic features which provide the backup lube oil supply must be tested frequently to insure satisfactory operation. In particular the pressure switches which indicate low lube oil pressure should be tested not only for proper annunciation but also to insure that they are capable of starting the appropriate backup pump. In addition the response time of backup pumps should be tested to insure that continuity of lube oil flow is maintained. Testing should be conducted with consideration given to the consequences of a failure of the system to operate as designed. For example, if the starting of the dc emergency lube oil pump is tested by turning off the auxiliary oil pump, with the unit on the turning gear, the shaft will be left rotating with no oil flow if the dc pump fails to start.

Of almost equal importance to bearing well-being is the cleanliness of the lube oil. Contamination of the turbine lube oil with water, fibers, particulates, dirt, rust and sludge can not only destroy the lubricating properties of the oil but also can cause accelerated bearing wear due to deposition of grit between the bearing and shaft journal. The lubricating oil should be sampled frequently. The results can be used to assess the quality of the oil and the efficiency of the purification system. Sample points should be chosen to insure samples represent not only the oil in the sump but also the oil samples or the strainers should receive particular attention as they may indicate bearing, journal or pump deterioration.

One of the most effective ways to monitor proper bearing performance is through bearing metal temperature. A gradual increase in metal temperature over a period of several weeks or months can indicate a gradual deterioration of the bearing. Bearing metal temperature is influenced primarily by load, shaft speed and the type of bearing. Of a lesser importance under normal conditions are bearing journal surface, alignment, oil flow and inlet oil temperature. With the shaft at rated speed and oil flow and temperature normal, an upward trend in bearing metal temperature indicates a change in bearing load, alignment or journal surface condition. Temperature spikes of the type shown in Figure 6.2 can be excellent indicators of bearing deterioration. High spots on the journal or bearing can cause metal to metal rubbing until wear has eliminated the contact. This is particularly true on shutdown or startup when the oil film in the bearing is thinner and, therefore, there is more susceptibility to scoring.

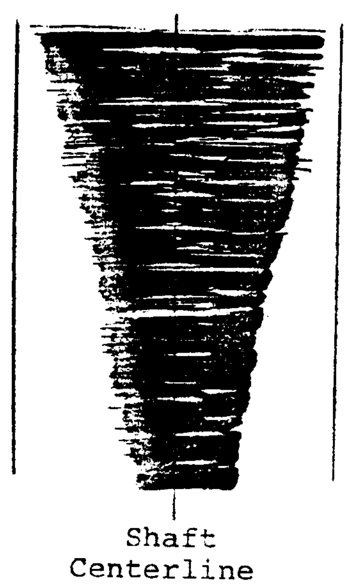
Bearings should be inspected for wear and alignment at least each time the turbine unit undergoes a major overhaul. Journals should be checked for smoothness and uniform roundness and diameter from one end to the other. Journals should be inspected for scoring or an uneven surface which occurs from scoring and self-lapping over an extended period. A bearing metal wear pattern such as shown in Figure 6.3 is indicative of journal to bearing misalignment.

There is a popular and untrue notion that spherical seated journal bearings are self aligning during operation. Bearings must be properly aligned to prevent deterioration. Additionally, the ball seats must be tight to prevent wear of the ball seats from causing vibration of the bearing.



Abnormal Bearing
Metal Temperature

Figure 6.2



Misaligned Bearing
Wear Pattern

Figure 6.3

ASSIGNMENT

1. Discuss the factors affecting the severity of the following operational problems. Include in your discussion the possible consequences and the design and operational considerations which minimize their frequency or effect.

    (a) overspeed
    (b) motoring
    (c) low condenser vacuum
    (d) water induction
    (e) moisture carryover
    (f) blade failure
    (g) expansion bellows failure
    (h) bearing failure

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