Condition monitoring of steam turbines by performance analysis

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Abstract *Many power generation steam turbine generators today are required in service well beyond their intended lifetimes. Dismantling for inspection is expensive, and owners need to consider all relevant information in making the decision. Application of condition monitoring in all the applicable methods is justified, with each showing different degradation modes. Performance analysis is less well publicised, yet unlike vibration analysis and oil debris analysis, it will show conditions which reduce machine efficiency and output, such as deposits on blades and erosion of internal clearances. Data obtained from tests before and after overhaul also reveal whether any restorative work achieved the expected improvements in performance. The paper outlines, with examples, some condition monitoring techniques that have contributed to retaining some large fossil machines in service for up to 17 years without opening high-pressure sections.*

Practical implications

The condition monitoring technique of performance analysis is less well known that the other methods, yet it is the only way of detecting and monitoring some modes of machine degradation. Large steam turbines are expensive machines of critical importance, and also expensive to maintain. Maintenance decision makers, therefore, need to take into account the needs of their business, recommendations from the original equipment manufacturer, their own experience and that of other users of similar plant, and information on condition available from the plant.

This paper contains examples of condition monitoring by performance analysis on large steam turbines that are intended to help engineers working in power generation in the application of condition monitoring. Although their effect can be significant, many changes are small and detection requires special test instrumentation. Much useful work can, however, be done with plant instruments. The overall aim is to assist in making the decision to take these machines from service only when justified technically and economically.

Introduction

Steam turbines are the mainstay of electricity production worldwide. Today's competitive electricity generation market has increased the pressure to keep power generation plant online as and when required.

A contributing factor in providing ongoing assurance of acceptable plant condition is the use of condition monitoring. Methods should be applied

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according to the modes of degradation expected. Vibration analysis provides much of this assurance, and has developed such that access to on line vibration data is available to experts who may be located remote from the plant. Damage to blading should be detectable by vibration analysis, but other problems such as deposition, erosion of blading and internal steam leakages require performance analysis.

As other degradation modes can only be detected by visual inspection or non-destructive testing, eventually casings do require to be opened for inspection. This is particularly so for the many large power generation machines continuing in service beyond their intended design life.

Performance analysis can be applied to most plant, rotating and stationary. It is the one condition monitoring technique, which allows the optimum time for restorative maintenance to be determined, where the deterioration results in increased fuel consumption, or in reduced output, or both (Beebe, 1998a).

It should be accepted that a turbine outage after a long time in service would probably take longer than if scheduled more frequently, as internal distortion is likely to have occurred. Also, parts such as casing studs will probably need replacement (Coade and Nowak, 1993). Once a casing is opened and clearance measurements made, it is possible to estimate the performance improvements achievable by refurbishment and so justify the expenditure (Kuehn, 1993; Sanders, 2002). However, it is clearly preferable to try to determine the internal condition first by testing.

The overhaul decision should not be made unless there is a compelling technical or economic reason for opening a casing. A current EPRI project is aimed at extending the accepted interval between overhauls (McCloskey *et al.*, 1995; Roemera *et al.*, 1998; Roemer *et al.*, 2000a, b). Condition monitoring by performance testing has been used to extend time between opening of casings to up to 17 years, making its cost/benefits very favourable (Beebe, 1995; Vetter and Schwiemler, 1989).

Condition monitoring can also be used to evaluate the effect of maintenance or modification work on the steam path. This is of great benefit when justifying future work.

Table I gives some main degradation problems with steam turbine-generators, together with an outline of how condition monitoring can detect them.

Overall condition indicator

The basic method of monitoring steam turbine internal condition is the valves wide open test (ASME, 1985). Essentially, the generator is used as a transducer to measure the power output of the turbine at set datum conditions. For a typical large fossil reheat condensing set:

- The inlet area for steam flow is set to datum by opening the steam control (i.e. governor) valves fully. This should be verified by direct measurement at the valve power servos, rather than relying on control room indicators. Fully open is the only truly repeatable setting.

Part affected	Mode of degradation	Comments, suitable condition monitoring
Blading	Erosion by solid particles (also erosion by water droplets on latter LP blades)	Usually occurs gradually, worst on inlet blading. Less usual on sets with drum boilers and/or sub-critical inlet steam conditions, or with bypass systems. Performance analysis detects.
Blading	Parts breaking off	Usually sudden. Vibration analysis and performance analysis detects
Bearings	Scoring damage to whitemetal (i.e. Babbitt)	Performance analysis, vibration analysis, wear particles in oil (but representative sampling at each bearing is difficult if not impractical)
Rotors	Rubbing, temporary unbalance, cracking, misalignment	Vibration analysis, and off-line: some NDT (not detailed in this paper)
Valve spindles Shaft and interstage glands (seals, packing) Casing joints LP manhole gaskets Internal steam piping and fittings	Leakage due to wear, distortion, breakage	Likely to occur gradually, but can be sudden. Performance analysis detects Effect of seal wear is relatively greater for HP blading (Cotton, 1993). For impulse blading, the relative lost output for each 25μm increase above design clearance of about 600μm is: HP: blade tips, 5kW; interstage seals, 6kW per stage; end glands 15 to 25kW IP: blade tips, 2.5kW; interstage 2kW per stage; end glands 5kW LP: blade tips and interstage, 1.5kW per stage; end glands 2kW For reaction blading, the effect will be greater
Steam valve strainers Valve spindles Blading	Deposits (more prevalent with base loaded sets as cyclic loading tends to have a blade washing effect)	Likely to occur gradually, mostly in areas around 260°C. Some on-load blade washing occurs with forced steam cooling. Performance analysis detects. Blade surface roughness has biggest effect at higher steam pressures. One case gave 17% drop in output from deposits varying between 250 to 2,300μm in thickness (Cotton, 1993) Permissible roughness for LP blading can be 100 times coarser than for HP blading. One test with surface finish equivalent to 500 grit emery paper caused 5% to 7% less efficiency in HP blading, about 2% in LP (Cotton, 1993, based on work by Forster)

(continued)

Table I.
Some modes of degradation and how detected

Part affected	Mode of degradation	Comments, suitable condition monitoring
Generator rotor, stator	Insulation faults	Electrical plant testing (several techniques (not included in this paper)
Condenser	Air inleakage Tube fouling	Performance analysis (not included in this paper)
Feedwater heaters	Air inleakage, tube fouling by scale or oil	Performance analysis (not included in this paper)
Valves – HP, IP bypass, etc.	Leakage	Performance analysis. Acoustic leakage detection (not included in this paper) is also possible

Table I.

- The temperatures of main inlet and hot reheat steam are set as close to datum as can be achieved. This is usually the same as the rated values.
- The inlet pressure is set to the datum value. As most turbines have capacity beyond their nameplate rating, the standard inlet steam pressure may need to be below the rated value if undesirably high outputs would result (Beebe, 1998c).
- Condenser pressure is largely a function of seasonal conditions and weather, and is usually taken at the best attainable on the day.
- Extractions to feedwater heaters should be all fully open. If feedwater heater unreliability means that some heaters are out of service for long periods, that condition may have to be used as datum, unless a method of allowing for this effect on turbine output can be derived.

Test readings a test run of an hour or so during steady conditions are carefully made using calibrated test instruments, with two separate measurements of each point. Readings of test transducers can be made manually, but it is now usual to use a data logger coupled with a computer. With the exception of some minor flows read from plant instruments and used only in correction factors, test measurements of flow are not required. This simplifies the test considerably and minimises the cost considerably compared with the full heat rate test used for the acceptance tests.

The generator MW output is corrected for any variations from the datum terminal conditions. For example, if the condenser pressure on the test is higher than the datum, then the turbine output will be less that expected at datum condenser pressure. Correction data are usually provided by the manufacturer for use in the acceptance tests but can be obtained using cycle modelling programs or from special tests (Beebe, 1998c). With the instrument calibration information available, the calculations can be performed immediately following the tests.

For some plant items, it is possible to use the normal plant instruments and data processing system to determine condition parameters (Beebe, 1998b). In the case of steam turbines, a more refined method using test quality instruments is needed to give warning well in advance of changes evident from permanent instrumentation systems (Groves, 1996). This may be possible with highly stable transducers of recent design, or with adequate calibration arrangements.

Example of VWO tests

350MW reheat turbine

Tests run some years apart and at different seasons gave the results in Table II.

From experience, the reduction observed is significant. Further tests would be performed to ascertain parameters of condition of individual machine components, which can be separately opened. Data for these are often gathered concurrently with the VWO tests. (Note that an increase in VWO output would indicate a different type of degradation.)

200MW non-reheat turbine

An operator of a non-reheat turbine generator normally run at 210MW output on base load noticed that the control oil pressure was higher than usual, indicating that the steam control valves were fully open. Because output was not affected, others had not remarked on this.

A VWO test gave a corrected VWO output of 210MW, a reduction from 216MW at the previous test (new condition). As these monitoring tests were being developed, it was decided to investigate further and perform a more detailed test to include flow measurement.

Unfortunately, the connecting piping to the flow metering assembly leaked, and it was five months before the detailed tests were able to be run to find that the corrected VWO output was 216MW, the same as when new. Further investigation revealed that the unit had been shut down (and started up) 11

Test data	Test A	Correction factor	Test B	Correction factor
Generator output – MW	355.8		349.7	
Steam pressure – main kPa	12,155	1.02285	12,255	1.02053
Steam temperature – main °C	529.5	0.99832	526.7	0.99773
Steam temperature – reheat °C	525.8	1.0101	539.5	0.99873
Reheater pressure drop %	6.76	0.99814	6.03	0.99633
Condenser pressure – kPa	9.34	1.01225	12.44	1.03615
Generator power factor	0.923	1.00012	0.945	1.00064
Steam temperature control spray – main kg/s	6.5	0.99889	24.6	0.99584
Steam temperature control spray – reheater kg/s	0	1	0	1
Final feedwater temperature °C	234.9	1.0005	230.5	0.98957
Combined correction factor		1.04741		1.03521
Corrected VWO output – MW		372.7		362

Table II. Results from two series of tests, 350MW turbine generator times between the tests. It was known that blade deposition rarely occurs on turbines in cyclic loading due to the blade washing effect which results, so the load reducing effect was attributed to blade deposition.

Another message here is the value of close operator surveillance, despite no effect on production being evident in this case.

Section parameters

If routine tests from time to time indicate no change, the steam path can be considered to be unchanged. However, when a changed corrected VWO output is obtained, it is necessary to look further to localise the cause. For instance, a full turbine overhaul is not necessary to open and clean main steam strainers, which may be blocked with weld crud or other material sufficiently to restrict steam flow and so reduce turbine output.

It is also possible that other changes in the steam path may have occurred which do not affect output much, but may be otherwise undesirable. Therefore, it is best to include condition parameters of sections of the turbine at little extra cost during VWO tests.

Parameters obtained from temperature and pressure measurements are shown in Table III.

Enthalpy drop efficiency tests

The enthalpy drop efficiency is the actual enthalpy drop divided by the isentropic enthalpy drop. Figure 1 illustrates this parameter on a section of the Mollier chart. It is usually between 85 per cent and 90 per cent, with typical repeatability for HP casings ± 0.9 per cent; IP casings ± 1.0 per cent.

This can only be determined for the superheated steam sections. For assessment across a turbine section within a casing, stage conditions are usually available in steam extraction lines to feedwater heaters. Naturally, these cannot be used for temperature measurement if the associated feedwater heater is out of service.

The corresponding enthalpy drop efficiencies in the two test series given for the 350MW machine mentioned earlier were:

Test A

- High pressure casing (from main stop valve inlet) 85.5 per cent.
- Intermediate pressure casing (from reheat stop valve inlet) 88.2 per cent.

Text B

- High pressure casing (from main stop valve inlet) 83.8 per cent.
- Intermediate pressure casing (from reheat stop valve inlet) 88.3 per cent.

A relative deterioration in the HP casing is evident. Further study would be made of any other parameters available in this area.

Parameter	Comments
Steam strainer pressure drop	Best measured with a differential pressure transducer rather than an upstream and a downstream pair. An increase indicates blockage, possibly from metal particles from boiler tubing, or welding repairs
Corrected first stage pressure	At VWO, proportional to steam flow through the turbine, indicates first stage condition. An increase points to upstream erosion, or downstream blockage, and vice versa
Section enthalpy drop efficiency (superheated steam sections)	Calculated using steam tables computer program. A drop indicates blade fouling, or erosion damage
Section pressure ratios	Stage pressures can be corrected to standard inlet pressure (ASME, 1985), but any error in measuring it is applied to all the stage pressures. Ratios use only the outlet and inlet pressures of each section. Changes show up erosion or deposition
Extraction temperatures to feedheaters in superheated sections	According to design, a higher than expected steam inlet temperature may indicate relative internal bypassing leakage in the turbine upstream of the extraction point
Extraction temperatures to feedheaters in saturated steam sections	Temperatures above saturation temperature indicate leakage of steam from a stage upstream of the extraction point
Drain line temperatures from casings, or from shaft seal (gland, packing) sections	Where available, these may indicate relative leakage, according to design. A similar approach can be used for points before and after pipe junctions of two streams of different temperatures. Pipe surface temperatures are often sufficient for repeatable assessment
Estimated N2 packing leakage (on turbines with combined HP-IP casings)	Test by varying relative inlet steam temperatures and observing effect on IP enthalpy drop efficiency (Cotton, 1993)

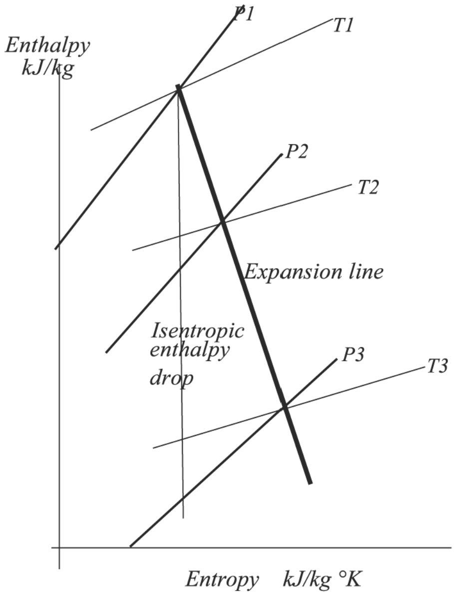
Table III.
Some parameters showing condition of turbine sections

Uses of the expansion line

The plot of the expansion line as shown schematically in Figure 1 is also useful in condition assessment. If a measured stage point does not fall on the line as expected, bypassing of blading would be deduced. Here are two examples.

Reaction turbine HP casing dummy piston leakage

A 200MW machine with a single flow HP casing has a dummy piston on which steam pressure is arranged to act to counteract the axial thrust generated by steam forces on the reaction blading. Steam leaking past the first section of the labyrinth seals around the piston circumference is led through internal piping to join the steam flow from the blading at the first extraction point.



Note: P1, T1 etc. are steam pressure and temperature measured at points of extraction flows in superheated sections

Figure 1.
Section of Mollier chart showing expansion line

As this leakage steam is at a higher temperature then the extraction steam, relative leakage is shown by the temperature difference between the mixture and the normal extraction flow. On one of six machines of this design, even when new this difference was as high as 60°C. The extraction steam temperature can be estimated closely enough from the expansion line. To remove the effect of any blading deterioration of stages upstream, a permanent thermocouple was arranged to fit through the high pressure outer casing to measure the true extraction stage temperature.

LP casing internal steam bypassing

A similar approach can be applied in the low pressure casings. Here the steam at most, if not all, extractions to feedheaters is usually saturated, so the temperature at a stage should be that of saturation for the corresponding pressure. Superheated steam indicates internal steam leakage from an upstream source bypassing the blading. On a 500MW turbine, a burnt area observed on one LP hood was deduced to be due to failure of one of the large expansion bellows in the inlet piping. As test results showed a 27MW drop in VWO output, closer study revealed that steam was entering an LP feedheater at 256°C, rather than the expected 95°C. From careful study of the complex construction details from available drawings, it was deduced that the second bellows in the inlet piping had failed.

Use of stage pressures

Except for the first stage of nozzle-governed turbines, and the last stage, at datum inlet and exhaust conditions, the pressures at stages along a steam turbine are closely proportional to steam flow, and therefore to output. Figure 2 sketches the relationship. Lines 1 to 4 represent stages along the turbine.

During starting up of a 200MW turbine, great difficulty was experienced with extremely high in-leakage into its condenser. Despite all the air removal pumps running, condenser pressure was still well above normal. As load was increased, the problem disappeared above 40 per cent load (L in Figure 2).

By examining the stage pressure vs. load curves, it was noticed that the pressure to LP2 feedheater was below atmospheric (A in Figure 2) until above 40 per cent load, when it became positive. The air leak was suspected to be somewhere in the turbine system connected to that point. Meticulous study of piping drawings and inspection of the machine revealed a sprung joint in a flange joint in the leakoff piping from a shaft end gland. This piping led to the LP2 feedheater.

Such investigations are not necessarily easy – few drawings may be available, the piping and connections may be under lagging, access is required to areas of the machine which are probably dark, noisy, certainly hot, and special staging may need to be built.

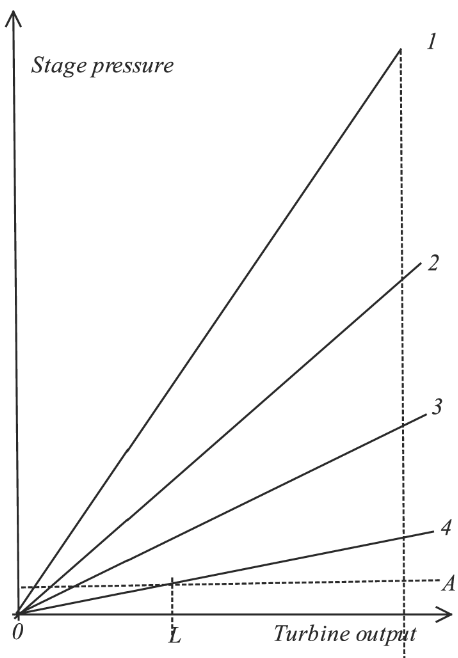


Figure 2.
Stage pressures along turbine

Application of all paremeters

A 350MW turbine as shown earlier above showed a significant reduction in corrected VWO output. As this was only the second series of tests on this new machine, further investigation proceeded (Beebe, 1978, 2001).

Calculation of enthalpy drop efficiency and pressure ratio for each section localised the cause of the reduction as the intermediate pressure section. As this base load machine had been in continuous service for six months, it was postulated that blade deposition had occurred.

During coming off line for the next planned outage, a steam forced cool was conducted. Here the steam temperatures at main inlet and reheat inlet are reduced in steps as load is reduced over a few hours, taking care to observe operating limits such as the margin above saturation temperature. This practice is common where prompt access is required to the turbine, as it can save many hours over cooling at the natural rate.

Tests repeated after the outage revealed that the corrected VWO output had returned to its original value, and the section parameters had also reverted. Learnt here is that steam forced cooling should be standard practice before outages on machines which have long steady load service. The condensate should be sampled and tested for signs of deposits from the blading.

Comparative tests

Where steam flows through blading sections can be found, further parameters of condition are available.

Measurement of cycle flow is expensive, often requiring several flow measurements in the cycle. Some plants have a high accuracy flow element for final feedwater flow, with some having a removable inspection port, but these are not common. In some situations, a comparative flow measurement is useful, even without a high accuracy element.

Blades of a new design were installed in the last stage sections of a turbine. Significant improvements in efficiency and output were promised.

Testing at VWO was run immediately before and after the outage. Flow was calculated using the permanent feed flow element, which is welded in the line. Test quality transducers were installed to measure its differential pressure output. The condition of the flow element was assumed to be unchanged during the outage period.

Test results showed that VWO output and efficiency had increased in the order predicted, however, some of this may have been due to other work done during the outage. Some casing joint distortion was found and the joint was remachined on one casing. Some changes in section parameters in this casing were observed (Beebe, 2000).

This case does highlight the difficulty of distinguishing between the effects of two or more maintenance/modification jobs, both of which should have an impact on performance. However, in the future, similar deterioration in this area should be detectable in advance of proposed work, and the improvements in performance used to justify maintenance action.

Conclusion

From the cases described, it is concluded that condition monitoring by performance analysis is a most valuable input in assuring continued operation, and when deciding and justifying major maintenance actions.

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