Technical Topic

Technical Training Guide

Turbine Oil Condition Monitoring

Introduction

Modern steam and gas turbines subject the turbine lubricant to ever greater demands. Higher temperatures are encountered in bearings, smaller reservoirs reduce residence times, and issues with varnish deposits have become critical concerns. Since the oil is the lifeblood of reliable turbine operation, a sound oil condition monitoring is needed to ensure long trouble free operations.

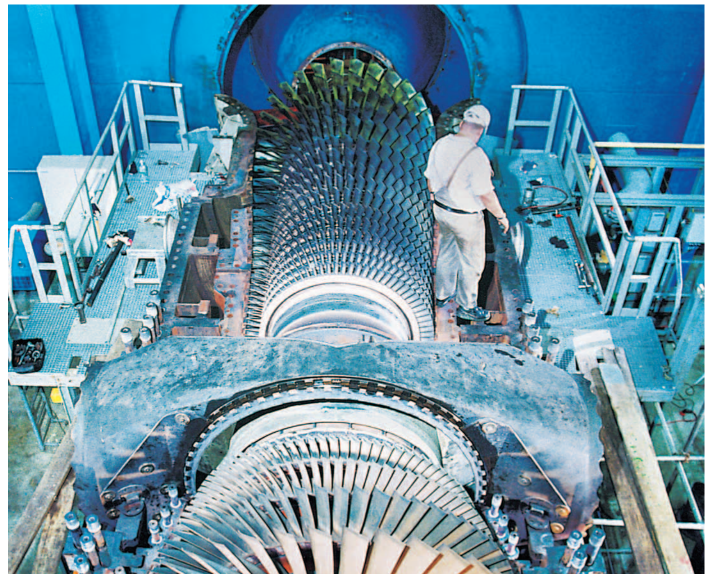
Turbine Oil Degradation

There are four primary reasons that turbine oils degrade in service. First is oxidation. All oils oxidize in service when exposed to oxygen in the atmosphere. And oxidation is not limited to the reservoir as air is dissolved in the oil. With the increasing temperatures found in turbines, increasing flow rates and shorter reservoir residence times, the oxygen and oil have more opportunities to interact.

Second is thermal degradation. The oil can be exposed to temperatures in a turbine that cause base oil and additive molecules to chemically change. The result of this reaction is the formation of materials that are not readily soluble in the oil. The materials then deposit within the oil system causing deposits, and in some cases, equipment failures.

Third is contamination. Turbine oils are subject to a variety of contaminants such as water (especially in steam turbines), dust and other ingress materials, wash down chemicals, and internally derived contamination, such as wear metals. While none of these are a direct result of oil degradation, they often contribute to other degradation issues. Wear metals, such as copper iron and lead, catalyze the oxidation reaction. Water (especially chemically treated water) can have very adverse effects on the ability to dissipate foam and separate from water. Excess foaming can lead to sluggish response from hydraulic control systems, cavitation in pumps and bearings, and safety issues if the foam over fills the reservoir and spills on the floor.

The fourth is additive depletion. Some additive depletion is normal and expected. Anti-oxidant additives are consumed as they perform their function. Demulsifiers help the oil shed water, but if exposed to large amounts of water contamination, the demulsifiers can be removed. Antifoam additives can be removed from ultra fine filtration or can agglomerate when the oil is not circulated for extended periods of time.



Siemens Photo

All of these factors should be consistently monitored throughout the life of the turbine oil. The following describes the tests most commonly used for used turbine oil monitoring. They can be broken into three categories: Physical and Chemical Properties, Contamination Measurements and Performance Properties.

Physical and Chemical Properties

Viscosity ASTM D445

Viscosity is the most important property of any lubricant. Viscosity is defined as the resistance to flow of oil at a given temperature and is measured via the ATSM D445 protocol. As it relates to turbine oils, significant changes to viscosity usually indicate that the oil has become contaminated with another oil. In very severe cases, viscosity will increase as a result of excessive oxidation. Thermal cracking (from excessive heat) of the base oil can cause the viscosity to decrease.

Results of this test are reported as centistokes at 40°C. The typical range of results should be +/- 5 percent of the new oil viscosity.

Total Acid Number (ASTM D974)

Total Acid Number (TAN) is the measure of the oil's acidity and is measured by titrating the oil with a base material (KOH) and determining the amount of base required to neutralize the acids in the oil. The results are reported as mg KOH/g of the oil being tested. TAN measures the acidic by products formed during the oxidation process.

ASTM D4378 (In Service Monitoring of Mineral Turbine Oils for Steam and Gas Turbines) recommends that a 0.3 to 0.4 mg KOH/g rise above the new oil value as the warning limit. Any significant change in TAN should be investigated as the acids in the oil can cause corrosion of bearing surfaces that result in irreparable damage.

However, care should be taken in reacting to a single high TAN result. The TAN test is not a precise method (+/- 40 percent by ASTM Standard) and is subject to variability of operators. Poor maintenance of the buffer solution or electrodes used in the titration can also yield false results.

Oxidation Stability by Rotary Pressure Vessel Oxidation Test (ASTM D2272)

Rotary Pressure Vessel Oxidation Test (RPVOT and formerly known as RBOT) is a measure of remaining oxidation life when compared to new oil. The test is not intended to draw comparisons between two different new oils or oils of different chemistries. In fact, oils with very high new oil RPVOT values have been seen to have the shortest life in laboratory rig testing.

ASTM D4378 defines 25 percent of the new oil RPVOT value as the lower limit. When the oil is approaching the 25 percent of new oil value in conjunction with an increasing TAN, ASTM D4378 recommends that plans should be made to replace the charge of oil.

Contamination Measurements

Water Content – (Visual and ASTM D1744)

Turbine oils are subject to water contamination from several sources. Steam turbines can have leaking gland seals or steam joints. All turbines can become contaminated with water from atmospheric condensation in the reservoir or leaking heat exchangers.

The turbine oil should be inspected daily for water. Looking at the sample, it should be clear and bright. A cloudy or hazy appearance indicates that water may be present. An on-site water test can be performed such as the hot plate crackle test where the subject oil is dropped on a heated metal surface. Bubbling and crackling indicate that water is present.

In the laboratory, water is typically measured by Karl Fischer Titration (ASTM D1744) and reported as a percent or in parts per million. ASTM D4378 identifies 1,000 ppm or 0.1 percent water as a warning limit. However, some OEM's have defined 500 ppm as the warning limit. Keep in mind that the Karl Fisher method does not measure free water, so daily visual inspections of the turbine oil are recommended.

Metals by Inductively Coupled Plasma (ICP)

Metals concentration in a turbine oil can give early warning of wear conditions, changes in equipment operation or potential contamination issues. Keep in mind however, that the size of the metals detected by this method is limited to very small metal particles, typically less than 8 microns in size. That means catastrophic failures can occur where large pieces of wear metal are generated and not detected by this test.

There is no specific limit on the amount of metals for turbine oils. The trend of metals concentration is often the most important aspect of this test.

Ultra Centrifuge Rating

The Ultra Centrifuge test detects finely dispersed or suspended particles in the oil. The subject oil sample is centrifuged at 17,500 rpm for 30 minutes. At the end of this period, the test tube is drained and the remaining sediment is rated against a standard as shown in Figure 1.

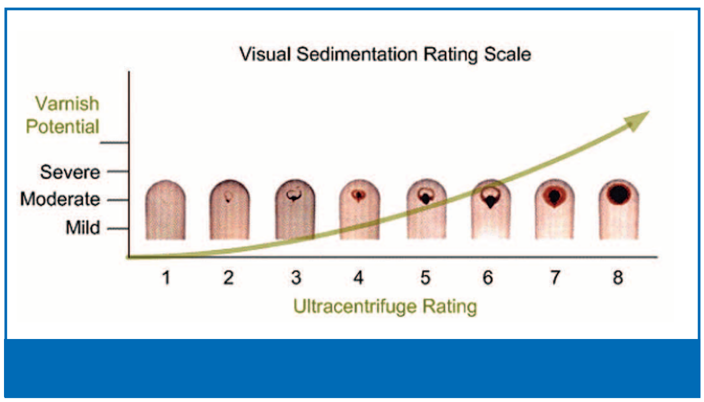


Figure 1

The primary use of this test is to give an early indication of deposit precursors in the oil. The results of the test are reported on a scale of 1 to 8, where 8 indicates the largest amount of residual sediment. A result of 4 to 6 is cause for concern that the oil in service has the potential to lay down performance-robbing deposits in the system.

Particle Count (ISO 4406)

Particle Counting and ISO Cleanliness ratings define the concentration of particles in the oil and relate this back to the ISO Cleanliness scale. The results are reported as the number of particles greater than 4 microns/6 microns/14 microns per ml of fluid. The ISO

Cleanliness Code relates the number of particles per ml to a logarithmic scale with code number for each range. A typical result would look like 18/16/13 where 18 means there is 1,300 to 2,500 particles per ml greater than 4 microns in size, 320 to 640 greater than or equal to 6 microns, and 40 to 80 greater than 14 microns. Refer to Table 1.

Particle counts are subject to a wide range of variability due to sample preparation, oil formulations, contamination of the sample container, and location and method of sampling. There are also differences in the equipment used to measure particle counts between light dispersion techniques and filter pore blockage methods.

Care should be taken to ensure that the samples used for Particle Counts are representative and consistent. The particle count results are only good as a relative measure of contamination and no ASTM standard exists for this test. Ultimately, particle count does give a good indication of overall system cleanliness. OEMs do offer some guidelines for new and used oils, but in general an ISO Cleanliness code of 18/15/13 or lower is an acceptable result.

ISO Cleanliness Particle Count Ratings

Range Code	Number of Particles per ml	
	More Than	Up to & Including
24	80,000	160,000
23	40,000	80,000
22	20,000	40,000
21	10,000	20,000
20	5,000	10,000
19	2,500	5,000
18	1,300	2,500
17	640	1,300
16	320	640
15	160	320
14	80	160
13	40	80
12	20	40
11	10	20
10	5	10
9	2.5	5
8	1.3	2.5
7	0.64	1.3
6	0.32	0.64
5	0.16	0.32
4	0.08	0.16
3	0.04	0.08
2	0.02	0.04
1	0.01	0.02
0	0.005	0.01
00	0.0025	0.005

Table 1

Colorimetric Analysis

Colorimetric analysis is designed to measure the insoluble materials in the turbine oil which often lead to varnish deposits. The process includes treating the lubricant sample with a specific chemical mixture designed to isolate and agglomerate insoluble by-product material, and collect this material on a filter patch. The color spectra of the collected material is then evaluated and depending on the intensity of specific colors or color ranges, a varnish potential rating may be derived. The filter patch may also be weighed as a means to determine insoluble concentration in the lubricant. Several commercial labs utilize this technique, each with their own specific method. Currently, this is not covered by an ASTM standard, but an ASTM method is currently being developed based on this concept. See Figure 2 for an example of colorimetric patch test results.

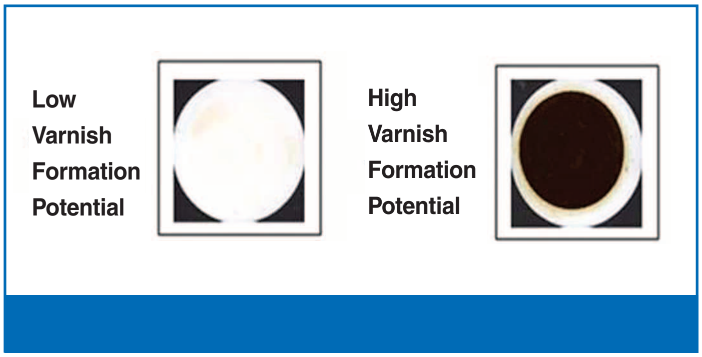


Figure 2

Performance Properties

Corrosion Inhibition (ASTM D665 A and B)

ASTM D665A uses distilled water and a steel test spindle at 60°C. ASTM D665B uses synthetic seawater and is a more severe test not commonly used for turbine oils. If rust is detected on the steel test spindle in the test, the test is considered a failure. However, a failing ASTM D665 test does always correlate to a rust issue in the system.

Demulsibility (ASTM D1401)

Demulsibility is a measure of the oil's ability to separate from water. The 40 ml of the subject oil and 40 ml of distilled water are mixed and then allowed to settle. The amount of time for full separation of the oil and water is recorded or after 30 minutes, the amounts of oil water and emulsion are recorded. ASTM does not offer a warning limit for demulsibility, but a result of 15 ml or greater of emulsion after 30 minutes is a fair warning limit. Contamination and oil age are factors that negatively effect demulsibility.

Care should be taken when evaluating demulsibility as the preparation of the glassware and the quality of the water used can yield false or failing results.

Foam Tendency and Stability (D892, Sequence I)

The presence of some foam in the reservoir is normal and not a cause for concern. Excessive foaming is generally not related to the oil, but rather to mechanical issues that cause excessive amounts of air to be introduced to the oil. Contamination and oil oxidation can also have an effect on the foaming tendency and stability.

Excessive amounts of foam are a concern to the turbine operator for two reasons. First is a safety and housekeeping issue if the foam overflows the reservoir. Second, excessive amounts of air in the oil can lead to more rapid oxidation and a phenomenon know as micro-dieseling. Micro-dieseling is caused when an air bubble in the oil is rapidly and adiabatically compressed causing extreme local temperature increases. These large temperature increases are known to cause thermal and oxidative degradation of the oil leading to deposit formation.

ASTM D4378 offers the guideline of 450 ml of foaming tendency and 10 ml of stability in Sequence I test.

How, Where and When to Sample

There is no correct answer as to how and where to sample turbine oil. The selection of sample location is dependent on what data is required from the oil analysis. For example, if information about wear metals is the primary concern, sampling after the filter is not a good location since the desired data would have been lost through the filtration process. A better sample point in this case would be prior to the filters or the bearing return line. If information about contamination is the primary concern, pre and post filter samples can be useful. Comparing the ISO Cleanliness code of a sample before and after the sample gives specific insight into the effectiveness of the employed filtration and the degree of contamination ingress. For most purposes, a sample obtained prior to the filters is most desirable for general testing.

While there are many appropriate locations to obtain a sample, there is almost universal agreement on how to sample. To get representative oil samples, the unit should be up to normal temperature and operating condition or just following shut-down. The sampling point should be clean and purged of all stagnant or dirty oil that may be in the line and valve. Make sure the sample container is clean and dry. Correctly and completely fill in the sample labels and mail as soon as possible to the appropriate lab. Delays in sending samples can add variability to test results, especially those concerned with insoluble content in the oil.

A suggested schedule for oil analysis is shown in Table 2.

Conclusion

The reliable operation of a power generating turbine and its associated equipment is dependent on the health and well being of the lubricant in use. Regular oil analysis and condition monitoring is one tool that should be used to maintain the turbine in peak operating condition. The oil analysis program should include the basic tests outlined in this document to asses the physical and chemical properties, contamination issues and performance characteristics of the fluid. Operators should consult with the equipment manufacturer for further guidance on the interpretation of the used oil analysis data.

Suggested Schedule for Oil Analysis of Turbine Systems

Test	Steam	Gas	New Oil - Base Line	Frequency - Used Oil	Suggested Limit
Viscosity - ASTM D445	X	X	X	Monthly	+/- 5% of new oil value
Total Acid Number - ASTM D664	X	X	X	Monthly	Caution = 0.1 to 0.2 mg KOH/g over new oil value; Warning = 0.3 to 0.4 over new oil value and check against RPVOT value
RPVOT - ASTM D2272	X	X	X	Quarterly	25% of new oil value; If close to 25%, increase frequency of test
Water Content (visual)	X	X	X	Daily	Check for haziness
Water Content - ASTM D1744	X	X	X	Monthly	Greater than 0.1% in steam turbines; Greater than 0.05% in gas turbines
ISO Cleanliness	X	X	X	Monthly	Target 18/16/13 or better
Rust Test - ASTM D665 A	X	X	X	Only if corrossion issues	Pass
Foam - ASTM D892, Seq I	X	X	X	Only if foam is an issue	Seq I exceeds 450 tendency, 10 ml stability
Demulsibility - ASTM D1401	X	X	X	Only if water separation is a concern	15 ml of emulsion after 30 mintues
Ultra Centrifuge		X	X	Monthly to Quarterly	UC rating of 4 to 6
Varnish Potential Rating		X	X (Gas Turbine Only)	Monthly to Quarterly	Varnish potential rating of 50 or more

Table 2 ***Taken from ASTM D 4378***

Appendix 1 –
Analysis Interpretation Guideline

Analysis Data Interpretation Guide

(Note, this should be used only as a general guide. Specific corrective actions should be taken only with guidance from the OEM and/or your lubricants supplier.)

Viscosity: +/- 5 percent of new oil value cSt at 40°C

Low Viscosity

- Low viscosity oil used as make-up
- Mechanical shear in VI improved oils
- Contamination with solvents
- Thermal cracking from excessive heat (such as electric tank heaters)
- Bad or mis-labeled sample

High Viscosity

- Higher viscosity oil used as make-up
- Excessive oxidation
- Hot spots within the system
- Over extended oil drain interval
- Contamination
- Bad or mis-labeled sample

Total Acid Number

- Increasing or high oxidation
- Wrong oil
- Contamination with a different fluid
- Testing variability

RPVOT

- Decreasing RPVOT indicates consumption of anti-oxidant compounds in the oil
- Increasing RPVOT – rare but can be the result of specific oil formulation reactions
- Testing variability – typically a low value due to a leak in the pressure vessel

Water

- Atmospheric condensation
- Leaking oil coolers
- Ingress of water wash
- Steam leaks
- Poor oil demulsibility
- Oil conditioning equipment not functioning properly
- Vapor extractor not working
- Inaccurate sample (bottom samples)

Metals

- Inaccurate sample (bottom sample)
- Component wear
- Wrong oil
- Sealants
- Thread compounds
- Contaminants
- Assembly lubes

Ultra Centrifuge

- Accumulation of insoluble materials in the oil
- Inaccurate sample
- Indication of increasing potential to form deposits

Particle Count

- Inaccurate sample
- Filtration equipment not operating properly
- Poor storage and handling procedures

Metals Interpretation Guidelines

For guidance only. Consult OEM for specific guidance on metal content interpretation.

Total Acid Number

- Contaminant and Additive metals can come from a number of sources.
  - Barium - lubricant detergent
  - Boron - process/cooling water additive, gear oil additive
  - Calcium - lubricant detergent, hard water
  - Magnesium - lubricant detergent, hard water, process/cooling water additive
  - Molybdenum - lubricant friction modifier; possible alloying element
  - Phosphorus - lubricant antiwear additive
  - Silicon - low levels may be antifoam additive, excess is typically external contaminant
  - Sodium - lubricant detergent, hard water, process/cooling water additive
  - Zinc - lubricant antiwear additive, may be wear metal also

- Wear metals
  - Aluminum - structural components, bearings, bushings
  - Chromium - bearings, may be alloyed with iron
  - Copper - bearings, bushings
  - Iron - structural components
  - Lead - bearings
  - Manganese - usually part of steel alloy - low levels typically seen when iron levels are very high
  - Nickel - bearings, structural components, may be alloyed with iron
  - Tin - bearings, bushings - typically seen with copper
  - Titanium - turbine blades

Appendix 2 -
ASTM and OEM Used Oil Limits

	ASTM D4378	Ahlstom - Gas and Steam	GE - Gas	GE - Steam	Solar	MHI - Steam & Gas	Siemens/ Westinghouse
Source	ASTM D4378	HTGD901117	GEK 32568f	GEK 46506D	ES9-224	MS04-MA-CL001 and CL002	K-8962-11
Viscosity @ 40°C	+/- 5% of new oil	Exceeds ISO VG Class	25 to 41	29.6 to 36.3	+20% or -10% of new oil	26 to 39	+/- 10% of new oil
TAN	0.3 to 0.4 over new oil	0.2 rise above new oil	0.4	0.5	0.6 max for mineral oils; 0.8 for SHC	0.4 increase over new	0.3 to 0.4 over new oil
RPVOT	< 25%		< 25% of new	> 50 minutes	> 25% of new oil	> 25% of original	25% of new oil
Water	> 0.1%	500 ppm		0.1% max	2,000 ppm max		200 ppm max
Flash Point - ASTM D92	30°F drop from original			375°F (191°C) minimum			
Rust Prevention - ASTM D665	light fail in D665A			Pass			
Cleanliness		17/14		16/14	Abrupt Change		17/14 max
Demulsibility		30 minutes max					<20 minutes
Metals		15-25 ppm; >30 ppm limit					Trend/consult
Air Release		8 minutes for ISO VG 32			10 minutes max (guideline)		4 minutes max
Foam	Seq I exceeds 450/10				Seq I - 300/10; Seq II - 300/10 (guideline)		Seq I - 400/10

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