

Assess the condition of your oils, prior to the outage

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Oil analysis is one of the most commonly applied predictive-maintenance technologies in today's combined-cycle/cogen plant. For good reason: The technology can provide operators with early indication of abnormal wear, corrosion, or contamination occurring in vital equipment. That's becoming even more important as turbines are built with longer and more massive shafts, and are operating under greater loads and at higher working temperatures. Oil analysis also can help operators assess the oil's chemistry and physical characteristics, to determine its suitability for continued use. Keep in mind that if your oils—whether serving as lubricant or as hydraulic control fluid—fail to perform as intended, your turbines can literally come to a screeching halt.

Oil analysis—sometimes referred to as “tribology”—is important year-round, but particularly so during the planning of a major outage, when operators will have their best opportunity to take corrective actions. Such actions include fluid purification or boosting of additives, topping off or “sweetening” the oil, installing secondary filtration or mediation systems, rebuilding or replacing system drains, and conducting high-velocity flushes followed by drainage, sump wipe-down, and system refill.

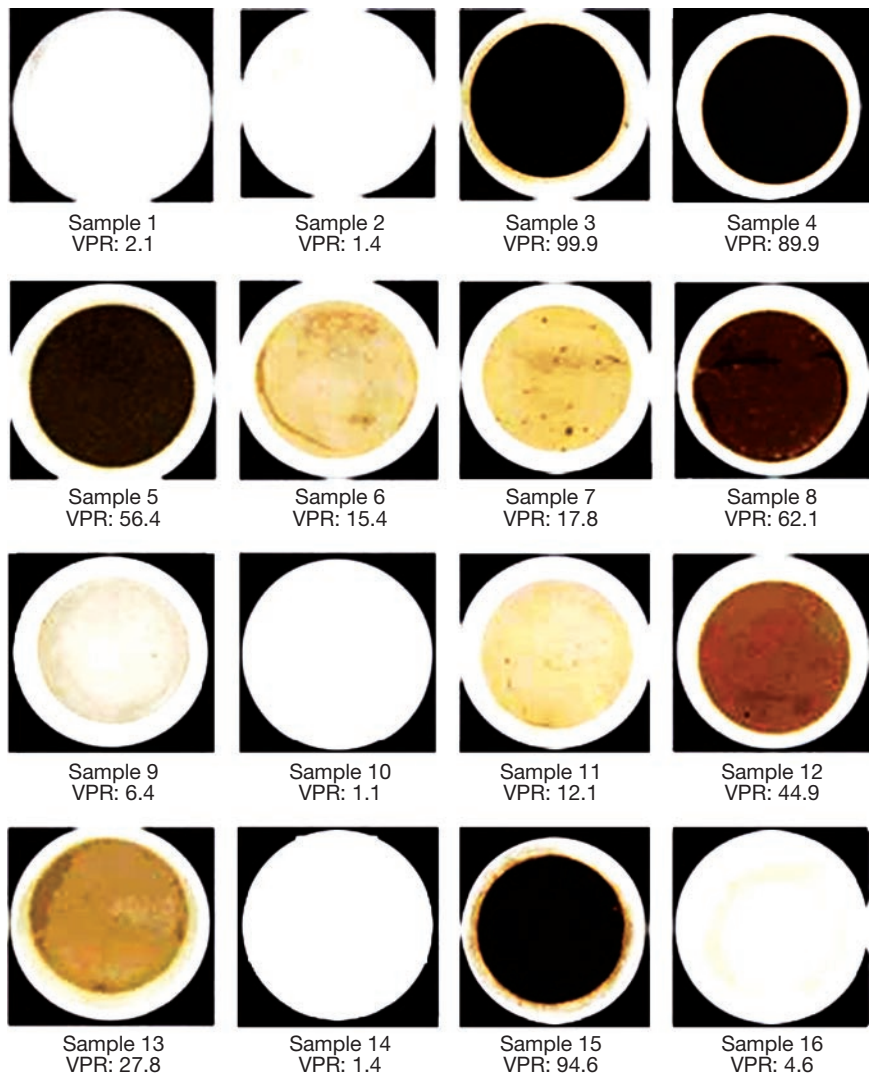
Oil analysis program

An effective oil analysis program should provide operators with three distinct and valuable pieces of information:

1. The condition of the equipment being lubricated or hydraulically controlled—gas turbine (GT), steam turbine, feedwater pump, etc.
2. The physical and chemical suitability of the fluid for future use.
3. The type and level of contamination, if present in the system.

To get this info, operators should

QSA correlation investigation ISO 32 GT lubricant samples—varnish potential rating (VPR)



1. Insoluble contaminants are generated from degraded base oil and spent additives. This form of contamination serves as building blocks for sludge and varnish deposits. The varnish potential rating helps operators assess the risk of developing such problems, by rating the severity of the condition on a 1-100 scale

work with a laboratory that has experience with the application and types of fluids used in their powerplant. The laboratory should be able to not only perform the required tests, but

also to provide a thorough interpretation of all test data and to make facility-specific recommendations. Ask about the experience of the lab analysts, and if they are certified by a

professional society such as the Society for Tribologists and Lubrication Engineers (STLE).

GT lubricants typically are manufactured from the naturally occurring hydrocarbons present in petroleum as it is pumped from underground or extracted from geological tar sands. Traditionally, base oils were solvent-refined to remove impurities. This class of fluids is defined as Group I.

Group II oils have become the

dominant product in today's lubricant business. Sometimes referred to as "hydroprocessed," Group II oils are superior to Group I as turbine lubricants because of their lower sulfur and aromatic content, which makes them more oxidation-resistant. Note that while these properties are highly desirable, the degradation byproducts of Group II oils are less soluble than Group I oils, thus they tend to precipitate more readily. This char-

acteristic can lead to the formation of varnish—a serious issue that GT users must contend with (see "Gas-turbine valve sticking. . .the plot thickens," elsewhere in this issue).

Control fluids. Phosphate esters typically are used in the hydraulic control systems of steam turbines, because of their superior fire-resistance compared to mineral oils. Differences in the chemistries between phosphate esters and mineral oil call

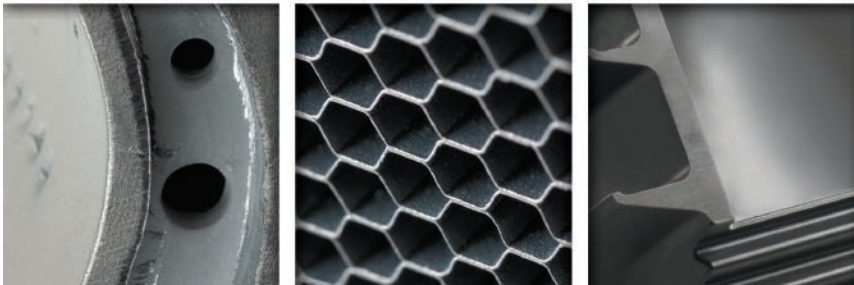
Oil analysis parameters

Property	Test method	Sampling frequency	Lube	Control	Description
Acidity	ASTM D974	Q	Y	Y	A measure of the acidic content of the oil usually expressed in mg KOH/g. All lubricants will have an intrinsic acid number that is determined by the chemical constituents of the oil
Air release	ASTM D3427	Q	Y	Y	Measures the ability of the air to release entrained air
Antioxidants	ASTM D6971	A	Y	Y	Antioxidants are used to increase the useful life of the oil. Once the AOs are depleted the oil is more susceptible to degradation (see RPVOT below)
Appearance	Visual	M	Y	Y	Visual examination of the sample appearance. Look for abnormalities such as cloudiness, visible debris, separation, or water
Chlorine content	ASTM D808	Q	N	Y	Chlorine content should be monitored because it may cause valve corrosion and etching. Chlorine content should be maintained at less than 100 ppm
Cleanliness level	ISO4406:1999	M	Y	Y	The number of particles within a specified size range is counted for a specified fluid volume. The cleanliness level may be thought of as a particle density/distribution measurement
Color	ASTM D1500	M	Y	Y	Fluids tend to darken with age. However, rapid darkening of the fluid may indicate fluid degradation or contamination
Corrosive tendency	ASTM D130	A	Y	N	High corrosive tendency leaves soft metals such as copper susceptible to attack
Foaming characteristics	ASTM D892	Q	Y	N	An excessive foam tendency may indicate additive depletion, contamination, improper reservoir level or excessive mechanical agitation of the fluid
Mineral-oil content	ASTM D1399	Q	N	Y	Mineral-oil contamination may attack certain seal materials, reduce the flame resistance of the fluid and above certain levels result in a hazy mixture because of mineral-oil insolubility
Resistivity	ASTM D1169	M	N	Y	Measures the resistance of the fluid to conduct an electric current
RPVOT	ASTM D2272				Measures the ability of the oil to resist oxidation under controlled conditions
Rust tendency	ASTM D665	A	Y	N	Tests the fluid's ability to resist rust formation
Spectro-chemical	ASTM D6595	M	Y	Y	Measures the elemental, metallic, content of the lubricant. The elements may originate from wear, contamination, or oil additives
Water content	ASTM D1744	M	Y	Y	The water content of the oil usually is reported in ppm (1 ppm=0.0001%)
Varnish	QSA SM	Q	Y	Y	Byproduct of oil degradation, which tends to be insoluble in the oil
Water separability	ASTM D1401	Q	Y	N	The ability of the oil to readily separate from water
Viscosity	ASTM D445	M	Y	Y	Viscosity is the resistance of a fluid to flow. Oil film thickness is dependent on the viscosity

Symbols: A=Annually, M=Monthly, N=No, Q=Quarterly, Y=Yes



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for the application of different laboratory testing methodologies and condition limits.

Oil analysis reports

A good place to start when assessing the condition of your oils is to review all of the tribology reports since the last outage. These questions should be addressed:

- Are there abnormal results or values that deviate from the trend?
- If there are nonconforming results, what actions should be taken?
- Does additional analysis need to be performed prior to the outage?
- Are samples being taken from the appropriate locations and at the appropriate time intervals?
- Is the testing that's being performed relevant and in keeping with current standards?

The table provides a summary of the tests often used in oil analysis programs. What follows is a discussion of some of the seven most common oil problems encountered at combined-cycle/cogen plants and ways you can combat them.

High varnish potential rating (VPR) indicates that the fluid contains sufficient levels of insoluble contaminants to promote the formation of deposits (Fig 1). Unfortunately,

these deposits generally form in critical areas of the system—such as sensitive servo valves, tight mechanical filters, journal bearings or other high-pressure, high-temperature zones, heat exchangers or sump warmers, sight glasses, and the splash zone within a reservoir.

If your VPR is high, check for the following:

- Sluggish or sticking valves and actuators.
- Elevated lubricant or system temperatures.
- Deposits in or plugging of filters (monitor differential pressures).
- Visible indicators of deposit formation—for example, hazy sight glasses or “bathtub rings” in reservoirs.

Plant operators also can take several preventive steps to reduce the rate at which the VPR degrades. For instance, air entrainment can be minimized by ensuring that fluid return lines do not dump into the reservoir with excessive turbulence. Also, ensuring that fluids are maintained at the recommended levels will promote longer residence time, which facilitates the release of trapped air in the fluid. Reservoir warmers or heating elements should be appropriately sized for the application and environment, so they do not create excessive hot spots within the system.

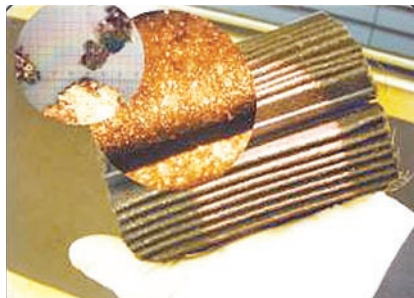
Corrective actions for high VPR include the installation of electrostatic separation or agglomeration technologies, or reactive media depth filtration systems. A partial drain and refill may dilute the concentration of insoluble contamination to safer levels. Additionally, additives—which can become depleted as a result of stress and aging—may need a boost. Note that the addition of new fluid may have only a minimal impact on varnish that has already been deposited in the system.

Poor water separability. A lubricant that displays poor water separability will be more difficult to purify using traditional methods—such as gravity, centrifuge, or coalescing. The presence of water can result in sludge formation, corrosion, fluid degradation, and/or additive washout. Rust and oxidation inhibitors are known to be susceptible to washout. Polar compounds, which may be a sign of fluid degradation, also impact the water separability. Polar compounds may be removed by electrostatic filtration or other similar technologies.

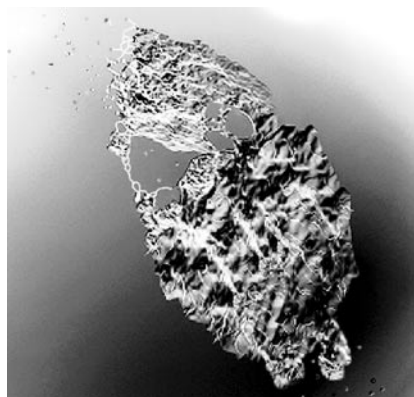
Poor water separability may not be a critical issue if the system is not prone to water ingress. However, systems that are susceptible to water ingress—such as steam turbines—may require additional measures to



2. Sludge found in this main reduction gear system was no surprise, because oil analysis of samples had revealed high water contamination



3. Filter media should be examined for unusual contaminants at the time it is serviced



4. Microscopic evaluation of metal particulates can provide valuable clues about their origin, cause, and relative severity



5. Gels or slime may develop from reactions between incompatible fluids or from certain contaminants. Here's a gel layer that formed in a contaminated system that uses phosphate ester as a hydraulic control fluid. Sample acid number was greater than 4.0

maintain acceptable water content. The measures include installing an online vacuum dehydrator or air stripping to control water content.

Elevated particle count. High levels of hard contaminants can produce an increase in wear. Hence it is critical to maintain system cleanliness to prolong equipment life and reduce failures. A plant outage provides the opportunity to inspect the system for sources of contaminant ingress, as well as to evaluate the filtration system.

Traditionally, the particle count is expressed as the number of particles present greater than a given micron size, per unit volume of fluid. Cleanliness levels also are represented by the ISO 4406 classification system to classify the particles larger than 4, 6, and 14 microns per milliliter of fluid. In addition to monitoring contamination levels, particle counts and the associated cleanliness codes are used to evaluate filter efficiency. The results reflect the solid contaminants present in the system, but do not identify composition or source.

Hard contaminants may be generated from abnormal wear, corrosion, or fatigue. As the element within a mechanical filter ages, the intertwined fibers that make up the filter may begin to fatigue and break off, thereby releasing material into the system (Fig 3). Many associate hard contamination with dirt and environmental debris. Dirt may enter a lubrication or hydraulic system through faulty breathers, malfunctioning seals, or routine maintenance. Another less recognizable source of hard contamination is new fluid.

Abnormal foaming characteristics can be caused by polar contaminants—such as degradation byproduct. If this is occurring, operators need to closely monitor the situation. Inspect the top of the reservoir for foam. Frequency fluctuations of the reservoir-cooling fan may indicate that foam is being sucked into the fan.

If foam is present, operators should first investigate mechanical fixes—such as ensuring the oil return line releases fluid below the liquid level, ensuring the maximum amount of fluid is kept in the reservoir, subjecting the reservoir to a slight vacuum (if not already done so), reducing turbulence in the return line, and/or installing additional baffling to prohibit air migration to the suction side of the reservoir.

If mechanical fixes are not successful, investigate sweetening the oil by “bleed and feed” to reintroduce foam inhibitor. The reformulation of foam inhibitor in the field is possible, but

difficult. Too much foam inhibitor will accelerate the problem and it is difficult to know the exact volume of turbine oil in an operating system.

Metal particulates. A properly functioning lubricating or control system will rarely generate metal particulates, and the fluids used in these systems are specially formulated with additives to protect against surface corrosion. Therefore, any sudden increase in the concentration of metal particulates indicated in the elemental analysis is cause for concern and immediate action. The abnormal conditions that either cause or accelerate corrosion and wear can occur quickly, as in the case of contamination with an ingested foreign matter. Particles detected are typically 8 microns in size and less and results are reported in parts per million (ppm) by weight.

If abnormal levels of wear debris are found, advanced testing methodologies—such as analytical ferrography or microscopic evaluation—can be employed to identify the source and severity of the condition (Fig 4).

Elevated acid number in control fluid. The degradation byproducts of an electrohydraulic control fluid are acidic; an increase in that fluid's acid number indicates that the fluid is starting to deteriorate (Fig 5). These systems typically use a purification media of Fuller's Earth, Selexsorb, activated alumina, zeolite, or ion-exchange resin. The purification media should be changed whenever the acid number starts to increase. Purification media also should be checked for proper flow rate.

Poor resistivity in control fluid. The electrical resistivity of an electrohydraulic control fluid must be maintained at acceptable levels, otherwise the system will be prone to electrical erosion. The precision metering edges on servo-controlled valves are especially susceptible to this form of wear.

There are two primary causes for low resistivity: (1) the purification media is not being changed often enough, or (2) flow rate through the media is incorrect. If the acidity is being maintained at sufficiently low levels and the resistivity is low, this could be an indicator that the flow rate through the purification media is too high. If the flow rate is too high, a high resistivity will not be maintained, although the acidity will be controlled. Operators should consult the OEM and filter supplier to ensure that the filter media is being sufficiently maintained and that flow rates are within acceptable limits. CCJ OH