HYDRO REVIEW®

Corps' Experience with Operating Hydro Turbines with New-Generation Oils

Upon replacing the oil in its hydro turbine-generating units with new-generation oils, the U.S. Army Corps of Engineers experienced operational problems, including sticking valves and plugged filters. The Corps undertook a research project to determine the degree of compatibility of the new and old oils and to develop solutions to the operational issues. The Corps is now upgrading filtration systems and other equipment at several plants to improve unit performance.

By John S. Micetic

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This article has been evaluated and edited in accordance with reviews conducted by two or more professionals who have relevant expertise. These peer reviewers judge manuscripts for technical accuracy, usefulness, and overall importance within the hydroelectric industry.

From 1998 to 2002, several U.S. Army Corps of Engineers hydroelectric powerhouses experienced operational problems following the replacement of worn-out oil with new turbine oils and/or mixing in-service oil with new turbine oils. Problems such as excessive foaming and air entrainment of turbine oil, sticking of governor proportional valves, and plugging of governor pilot in-line filters caused operational difficulties and resulted in increased maintenance and costly unscheduled downtime.

The Corps' 2,620-MW Chief Joseph powerhouse in Bridgeport, Wash. experienced the biggest operational problems. Personnel replaced old oil with new turbine oil during 1999 and 2000. Approximately four months after completing the replacement, personnel observed a significant increase of air entrainment and foaming in governors' oil sumps from what was observed while operating with the old oil. The generating units began experiencing operational problems caused by sticking of governor proportional valves and plugging of governors' pilot in-line filters. Replacement of the plugged filters on all 27 generating units required random stoppage, which increased maintenance efforts and disrupted the operation. Consequently, we in the Corps' Hydroelectric Design Center (HDC) initiated an extensive investigation in 2000, with the goal to determine causes of the observed problems and identify possible solutions.

The investigation included the following tasks:

— Detect possible changes made to the equipment and/or the operational conditions;

— Identify possible changes of the formulation and characteristics of new and old oils;

— Evaluate compatibility of new and old oils; and

— Assess current oil contamination control practices and recommend improvements if needed.

Task 1: detect possible changes to equipment and/or operational conditions

The first step was to determine if any changes were made to the equipment and its operational conditions, which could possibly cause the operational problems with new turbine oil (for example, changing of seals, bearings, and pumps). After interviewing maintenance personnel and reviewing maintenance log books, investigators determined that no such maintenance activities were performed.

Task 2: identify changes to oil formulation and characteristics

To learn more about the characteristics of new turbine oils and their possible contribution to performance deficiencies, we contacted representatives of several oil companies (ExxonMobil, Chevron, Shell, and PetroCanada). Based on feedback, we reached three conclusions:

1) the new-generation turbine oils readily available on the market are generally formulated with Group 2 base oils and nonmetallic or "ashless" additives, while turbine oils historically used at the Corps powerhouses are blends of Group 1 base oils and metallic-based additives;

2) these two additive packages may not be fully compatible with each other; and

3) mixing of the oils with incompatible additives may cause operational difficulties.

We were not able to obtain more specific information about the chemical composition of the additives because they are classified as proprietary information.

Historically, turbine oils used in hydropower equipment in Corps powerhouses were blended with base oils refined from crude oil (accomplished by extracting solvents). These oils exhibited good lubricating properties. They contained various aromatic compounds (referred to as "unsaturates" in tribology literature) in the range of 10 to 30 percent of the volume, which directly affects the percent of saturates (nonreactive portion) present in oil. The amount of aromatics (unsaturates) present in an oil determines the degree of inherent solvency characteristic of base oils. The American Petroleum Institute (API) uses this information as one of the basic parameters to classify base oils (Table 1). According to the API classification (see the range of ratios for saturates-unsaturates), it is safe to conclude that historically used turbine oils are classified as Group 1 oils.

The aromatics are reactive by nature. They have tendency to oxidize in the presence of oxygen (introduced to oil via foaming and the entrained air), thus shortening the oil's service life. The rate of oxidation process increases as the operation temperatures increases. At operating temperatures higher than 80 degrees Celsius (C) , oil starts to thermally degrade, which negatively affects service life by causing oil viscosity to increase above the acceptable limit (usually established at +20 percent of the original viscosity). However, thermal degradation can occur with or without presence of the oxygen.

Approximately 15 to 20 years ago, major oil companies in North America (for example, Chevron, PetroCanada, Mobil, and Shell) introduced and began using new oil-refining technologies. The refining practices consisted of one or a combination of the following technologies: hydrocracking, hydrofinishing, dewaxing, iso-dewaxing, and isomerization. One of the major objectives of these new refining techniques was to minimize or eliminate presence of aromatics in such refined base oils. Decreased amounts of the aromatics from oils resulted in enhancing oils' inherent resistance to oxidation. Their thermal stability thus made them more suitable for applications with higher operating temperatures as well as longer-lasting than the previously used Group 1 oils. However, decreasing the aromatic contents present in oil significantly lowers solvency characteristics of Group 2 oils. Group 2 oils are used almost exclusively in formulating turbine oils currently available on the market.

The most common additives found in Group 1 turbine oils include zinc-based rust and oxidation preventive additives (for example, zinc dialkyldithiophosphates or ZDDP), and silicon-based antifoam additives. Due to good solubility characteristics of Group 1 oils, the zinc-based additives were easily dissolved in oil.

In general, current Group 2 turbine oils are not formulated with the same types of additives. The limited amount of the information received from the representatives of various oil companies surveyed revealed the following: (1) these additives are nonmetallic-based (also called "ashless" additives); (2) there may be instances that some of those additives are incompatible with additives from in-service oils, and (3) mixing of the oils with incompatible additives may cause development of flocks and sludge, stripping of additives from oil, and increased rate of foaming and air entrainment in oil, thus causing operational difficulties. More specific information regarding the chemical composition of the additives used in the process of blending Group 2 turbine oils could not be obtained because they are classified as proprietary information.

Task 3: evaluate compatibility of new and old oils

After learning of the possible additive incompatibility and resulting consequences, we researched a reliable method for independent compatibility testing of old and new oils. The research revealed two major findings. First, the aforementioned oil companies have internal procedures for testing compatibility. Review of these procedures identified differences in the approach and testing techniques, which concerned us about the reliability of the procedure. Secondly, official standard testing organizations such as American Society for Testing and Materials (ASTM) and the International Organization of Standards (ISO) did not have such testing established, which made it difficult for end users to use services of the independent commercial laboratories to test and verify compatibility of new and in-service oils.

In 2000, the Corps learned that Herguth Laboratories, Inc. was providing such services by using its internally developed testing procedure. Discussions regarding the compatibility testing resulted in slight modification of the lab's original method and adopting it as the procedure the lab will follow in testing oil compatibility for all Corps powerhouses. Under the original test procedure, tested oils were mixed in different proportions (for example, 100:0, 85:15, 50:50, 15:85, and 0:100), stored in the oven for one week (168 hours) at 150 degrees Fahrenheit (F), and then visually rated for evidence of incompatibility (such as turbidity, cloudiness, and development of flocks and/or sediments). The added portion of the test procedure consisted of passing the already rated mixtures through a pre-weighted 0.45 micron (μ) filter. The difference in weight of the filter after the pass of mixture determines the presence of filterable residue generated by the incompatibility. Consequently, Corps personnel amended the internal specification for procurement of turbine oils by requiring compatibility testing before new oil is acquired.

From 2001 to 2006, Corps powerhouse staff used Herguth Laboratories for compatibility testing. Lab staff detected incompatibility of the new oil, which enabled personnel at the 525-MW Libby, 810-MW Lower Granite, 115-MW Ozark, and 980-MW McNary hydroelectric facilities to avoid acquiring new oil, thus preventing operational problems.

Late in 2006, ASTM issued a new standard test for compatibility of turbine oils (ASTM D 7155, Standard Practice for Evaluating Compatibility of Mixtures of Turbine Lubricating Oils). This was added to the Corps internal specification and guidance for procurement of turbine oils, with ASTM D 7155 superseding previous references regarding compatibility testing.

Table 1: American Petroleum Institute's Classification of Base Oils

Group	Impurities (sulfur) weight %		Saturates %	Viscosity Index
1	> 0.03	and/or	< 90	80-120
2	≤ 0.03	and	≥ 90	80-120
3	≤ 0.03	and	≥ 90	> 120
4	All polyalphaolefins (PAO)			
5	All stocks not included in Groups 1-4			

Task 4: assess contamination control, recommend improvements

Our investigation included conducting an efficiency assessment of governors' oil contamination control techniques at Chief Joseph powerhouse. This effort revealed that only a centrifuge located in the oil room was available and used for conditioning of the bulk oil (removing moisture and particles from oil). The practice was to drain oil from sumps of the designated turbine into the main storage tank, demoisturize and clean it via the centrifuge, and return treated oil back to the turbine sumps. Analysis of oil samples from the main storage tank revealed a cleanliness level of ISO 23/19/16(c). Analysis of several randomly chosen governor sumps showed cleanliness in the range of ISO 22/18/14(c) to ISO 23/18/15(c), which is too high for the industry standards of oil used either as a lubricating oil or as a hydraulic oil in governor applications.

Analysis of the sludge that plugged governor pilot in-line filters showed the following components: varnish, 86 percent; wear metals, 7 percent; other debris, 6 percent; and water, 1 percent.

The discovery of an unusually high amount of varnish deposited at governor in-line filter needed an explanation. Therefore, we investigated to gain a better understand the varnish generation.

This effort revealed that the majority of varnish particles in turbine oils used at hydropower facilities are by-products of oil degradation, produced by either oxidation of base oils, additives components, or both. Such generated varnish particles are originally soft, polar, sticky, and small in size (approximately 0.01 micron). Varnish is generated by the operating system at all temperatures. At higher temperatures, varnish is generated due to thermal degradation of turbine oil (for example, a thin film of oil hydrodynamically formed at turbine bearings). Due to its polarity, varnish particles migrate and attach to metal surfaces throughout the system. If those surfaces are hot, varnish particles could harden and coat the surface as a shiny, thin, brownish to amber insoluble layer.

At lower operating temperatures, such as in governor sumps, the oxidation of the oil generates varnish, due to exposure to oxygen from the air . Varnish generation is accelerated in oils which retain foam and entrained air in the oil for longer periods. Those small sticky particles travel with the oil and attach to metal surfaces, including tight oil passages such as proportional valves, causing them to "stick." If the varnish growth is not controlled in oils operating at low temperature, the particles tend to agglomerate to the size of 1 micron or larger. Due to their sticky character, the agglomerated particles became easily deposited at in-line filters and eventually cause them to plug. Accounts from the tribology community suggested that the new-generation Group 2 and possibly Group 3 turbine oils exhibit more tendencies to generate varnish than the old Group 1 turbine oils due to its lower solvency.

The absence of means for continually controlling varnish growth in the governor oil, where all of the previously described problems were observed, convinced the investigator that such conditions are the most likely contributor (if not the cause) for plugging of the small governor pilot in-line filters at a significantly increased rate than before the replacement of the oil (monthly vs. biannually, respectively). Therefore, he concluded that a properly sized off-line filtration system added to governors' sumps could efficiently maintain varnish in oil at the level that is not detrimental and disruptive to the operation of turbines. Chief Joseph powerhouse personnel approved the Corp's Hydroelectric Design Center's intent to validate this conclusion via filtration field tests at their plant.

Field Test

In 2001, Chief Joseph powerhouse staff performed the field test to evaluate the efficiency of filtration systems in conditioning of governors' oils. In this test, two C.C. Jensen Company filtration systems were tested on two separate governors' oil sumps; one system equipped with a low-watt density heater was added to Unit 9, and one without a heater was added to Unit 25. After only a month of filtering governor oils, test results showed improved cleanliness in both sumps; an improved level of ISO 16/15/12 from the initial ISO 20/17/13 for Unit 9, and ISO 17/16/12 from the initial ISO 19/17/14 for Unit 25. As a consequence, governor pilot in-line filters on those units remained clean.

Encouraged by a successful initial trial with C.C. Jensen filtration units, staff expanded the field test to include similar systems from other manufacturers. Two additional commercial mechanical-type off-line filtration systems from different manufacturers (Pacific Fluid Systems Inc. and High Purity Inc.), and a Filter Technologies electrostatic filter were plumbed to four different governor sumps. This field test was set to last three consecutive months.

The characteristics of the mechanical separation-based filtration systems met the Corps' specification requirements set prior to the test. In general, the specification requirements were similar to the initial requirements set for C.C. Jensen units, and included the following characteristics:

— Maximum flow rate of 8.0 gallons per minute (GPM)

— Filtration system to be designed for a 900-gallon oil sump

— A thermostatically controlled heater to be attached to the filter, capable of maintaining oil temperature in the sump at 40°C (105°F)

— The heater element to be a low-watt-density type; not to exceed 12 watts per

A vacuum dehydrator and filter system work to eliminate moisture, oxygen, and gases from transformer oil in Chief Joseph's oil room.

square inch. The heater shall be designed to turn off automatically if the system shuts down for any reason.

— A depth-type cellulose fiber filter element to be rated at 3-micron absolute at minimum Beta 3 ≥ 75.

— The minimum dirt-holding capacity of the filter system shall be 1.1 gallons.

— The filter system to be equipped with oil valves positioned before and after the filter to enable sampling of unfiltered and filtered oil.

The electrostatic-type filtration system with a heater was equipped with a cellulose-type moisture scrubber to remove moisture in oil before the oil enters the electrostatic separation chamber.

Chief Joseph personnel tested the filtered oils monthly, then recorded and tracked results. Collated test results for the first three months showed that both types of filtration systems, mechanical and electrostatic, were efficient in removing varnish and other contaminants from turbine oil. The achieved and maintained cleanliness levels were in the range of ISO 15/13/10(c) and ISO 15/12/9 (c) from the initial cleanliness range from ISO 22/18/14(c) to ISO 23/18/15(c). In addition, maintenance personnel conducted monthly inspections of the pilot in-line filters on the governors included in the test, and reported not seeing any evidence of sludge presence.

Based on research findings, the HDC recommended that all Corps powerhouses add off-line filters to all governors' sumps. Those filters should conform to the above-mentioned guidance for specifying off-line filtration systems intended to filter governor oil. However, the actual size of a particular filtration system will depend on the amount of oil to be treated.

HDC also recommended removing equipment capable of only physically separating water (free and emulsified water) from oil (centrifuges), and replacing it with equipment capable of chemically separating water (free, emulsified, and dissolved water) from oil (vacuum dehydrators). The recommendation also included acquiring appropriately sized off-line, low-flow, depth-type absorbent cellulose filter or an electrostatic oil filter for filtering oil at the main oil storage tanks.

Chief Joseph staff were the first to implement the recommendations. They acquired a new vacuum dehydrator and added an off-line filtration system capable of treating up to 12,000 gallons of bulk oil stored in the oil room.

Using this setup and the new equipment greatly improved the overall cleanliness of the bulk oil at Chief Joseph; typical cleanliness ranges between ISO 15/14/11 and ISO 12/11/10. Currently, Chief Joseph powerhouse staff operates all of its 27 hydro turbines with new-generation turbine oil without experiencing any operational problems to this day.

Conclusions

The new-generation turbine oils are formulated with "ashless" type additives and contain smaller amount of aromatics than previously used oils, making them less susceptible to oxidation and more environmentally friendly.

The results of the field test at Chief Joseph powerhouse and the implementation of recommendations proved that the new-generation turbine oils are suitable for operating hydropower equipment.

The Corps acknowledges that it is important to evaluate the compatibility of any candidate new oil and in-service oil before the new oil is procured. The most reliable compatibility test is ASTM D 7155.

The Corps recommends making a one-time investment at its hydro plants to upgrade equipment and contamination control practices, including:

— Adding to each governor sump a dedicated off-line, low-flow, depth-type absorbent-type filter or the electrostatic oil filters with low-watt density heaters;

— Adding properly sized similar type of off-line filter (without heaters) to the main oil storage tanks;

— Acquiring a vacuum dehydration equipment for improved removal of moisture from oil; and

— Scheduling periodic treatment/conditioning of all the oil from each turbine.

Wear and varnish particles in the oil promote further wear and varnish generation. Maintaining oil as clean and dry as possible extends the service life of the equipment and the lubricant, minimizes maintenance efforts, and eliminates unscheduled downtime. ■

Reference

Micetic, John, "Operating Hydro Turbines with New Generation Turbine Oils," Waterpower XVI Technical Papers CD, PennWell Corporation, Tulsa, Oklahoma, 2009.

CLEAN OIL
BRIGHT IDEAS

Turbine Oil
Hydro Power, Governor and Thrust Bearing Systems

CJC™ Application Study

Application Study written by:

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C.C.JENSEN INC.
USA

2006

CUSTOMER

Hydro Power Plant operated by the leading producer of hydroelectric energy in the United States.

THE SYSTEM

7 x 53 MW Francis Turbines.
Governor Oil / Thrust Bearing Systems.
Manufacturer: Voith Siemens Hydro
Oil Type: Turbine Oil, ISO VG 68
Oil Volume: 1,000 gallons (approx. 3,785 L)

THE PROBLEM

Management embarked on a multi-year project to rehab the 48 year old hydro power plant. Life extension and the use of environmentally friendly Francis runners were the key objectives. The replacement contract included 7 turbines with new digital governors.
Project Engineers understood from experience that the new digital governors would be more sensitive to fine particles and the potential for varnish would be greatly increased when using Group II oils.

THE SOLUTION

A **CJC™ Fine Filter HDU 27/54 MZ-EH1PT**, processing 5 gpm (approx. 19 L/min.) with an MZ-16-4 Pump. This system was selected for its efficiency in maintaining the oil free of particle and varnish in the commissioning and operation phases. The system features 2 **CJC™ Filter Inserts B 27/27**, rated at 3-micron absolute. The Filter Inserts also have the capability of removing varnish by adsorption, approximately 16 pounds per set.

THE RESULT

The contamination level on one turbine prior to commissioning and start up was ISO 20/15. Afterwards the level improved by 8 ISO Codes to ISO 11/7. **This translates into a life extension factor of 9 and the cleanliness level improved by a factor of 256.** No significant levels of varnish have been detected in the oil since start up.

OIL SAMPLES

TEST SAMPLE	BEFORE	AFTER
ISO Code	20/15	11/7

View of Power House from Observation Deck

CJC™ Fine Filter HDU 27/54 MZ-EH1PT

Varnish Removal from Governor System

This picture illustrates how effectively the CJC™ Filter Inserts remove varnish and particles from the oil

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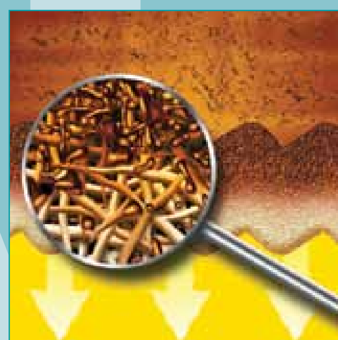

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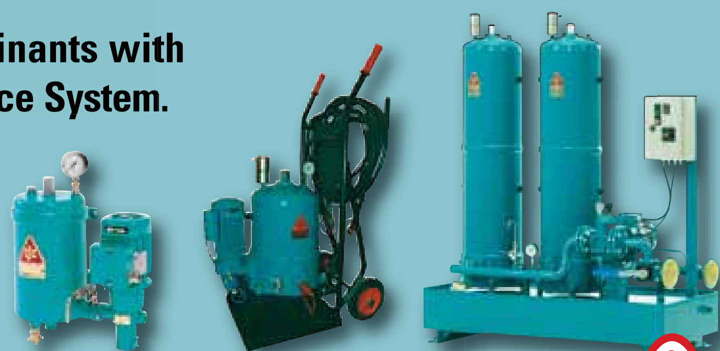

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