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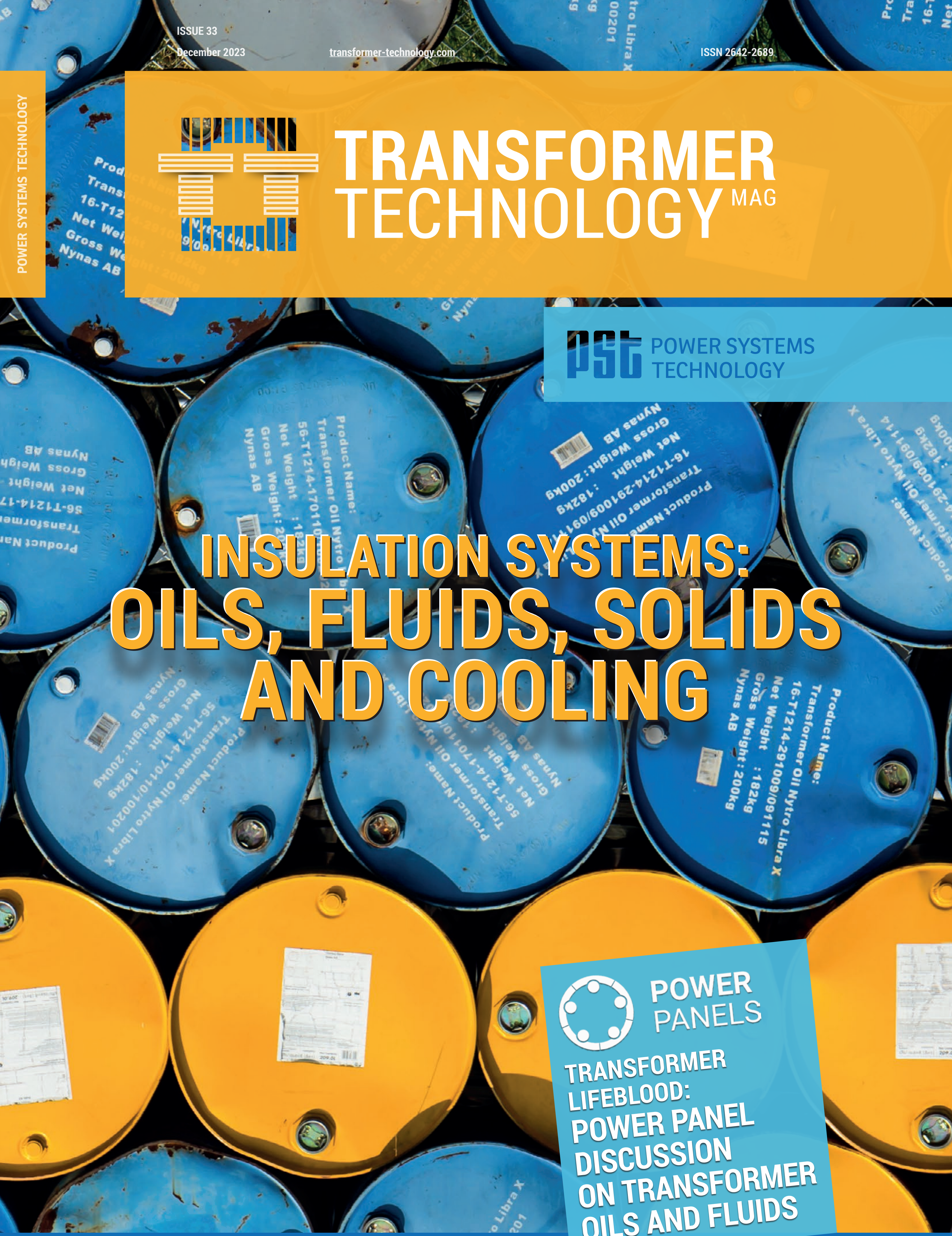

INSULATION SYSTEMS: OILS, FLUIDS, SOLIDS AND COOLING

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TRANSFORMER LIFEBLOOD: POWER PANEL DISCUSSION ON TRANSFORMER OILS AND FLUIDS

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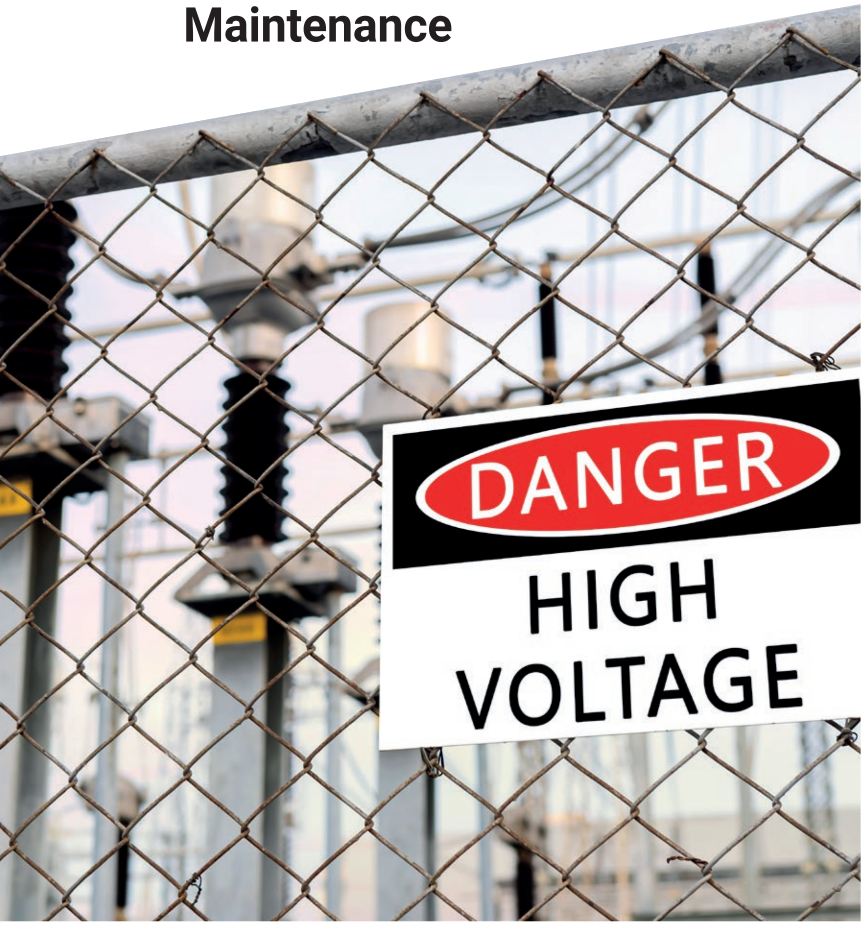
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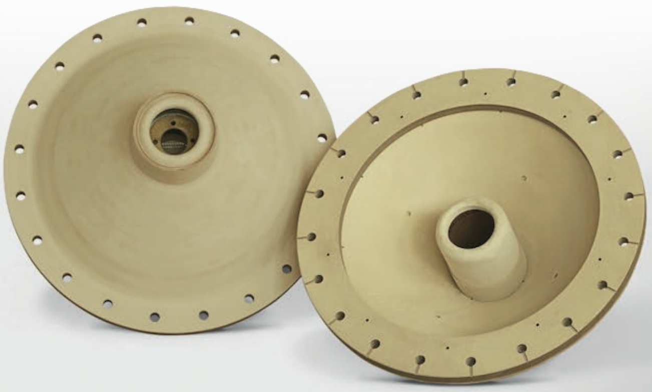

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Evolving Insulation Technologies for Power System Equipment in Response to Higher Operating Demands

As power systems continue to evolve and demand for electricity increases, power system equipment faces higher operating demands. One critical aspect of power system equipment is insulation, which plays a crucial role in ensuring the safe and efficient operation of electrical infrastructure.

In recent years, advancements in insulation technologies have emerged to meet the challenges posed by higher operating demands. Just a few of the changes within insulation for power system equipment and how these advancements are addressing the evolving needs of the industry are below, many of which are featured in some way in this issue.

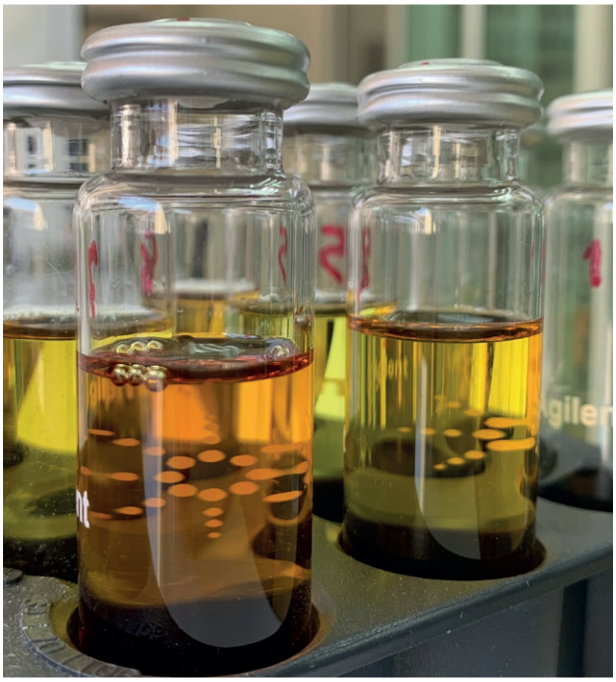
In recent years, advancements in insulation technologies have emerged to meet the challenges posed by higher operating demands.

Understanding the Challenges
Higher operating demands in power systems result from factors such as increased power consumption, renewable energy integration, and the electrification of various sectors. These demands put additional stress on power system equipment, including transformers, cables, and switchgear. Traditional insulation materials may struggle to withstand the increased temperatures, electrical stresses, and environmental conditions associated with these higher operating demands.

Enhanced Thermal Performance
To address the challenges posed by higher operating demands, insulation materials have evolved to offer enhanced thermal performance. New materials, such as advanced polymers and composite insulators, exhibit improved thermal conductivity and can withstand higher temperatures without compromising their insulating properties. These advancements allow power system equipment to operate at higher loads and temperatures, increasing their overall efficiency.

Improved Electrical Insulation
Higher operating demands also require improved electrical insulation to ensure the safe and reliable operation of power system equipment. Insulation materials with higher dielectric strength and lower dielectric losses have been developed to minimize electrical stress and prevent breakdowns. Additionally, advancements in nanotechnology have led to the development of nanocomposite insulation materials, which offer superior electrical insulation properties and enhanced resistance to partial discharges.

Environmental Considerations
As the world becomes more environmentally conscious, insulation technologies for power system equipment have also evolved to address sustainability concerns. Traditional insulation materials, such as oil-based products, are being replaced with eco-friendly alternatives.
For instance, bio-based insulating oils derived from renewable sources are gaining popularity



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due to their reduced environmental impact and improved fire safety characteristics. Our first Power Panel, on Oils and Fluids, has been partly transcribed in the magazine, with the help of technical experts from Cargill, TJH2b, and Ergon. Here is the link to recorded Panel discussion which is a "must watch" presentation.

Enhanced Durability and Reliability:
Higher operating demands necessitate insulation materials that can withstand harsh environmental conditions and prolonged service life. Manufacturers are incorporating additives and modifiers into insulation materials to enhance their durability and resistance to aging. Additionally, advanced testing and monitoring techniques, such as partial discharge measurements and thermal imaging, are being employed to assess the condition of insulation in real-time, allowing for proactive maintenance and replacement strategies.

As the demand for electricity continues to rise, ongoing research and development in insulation technologies will play a crucial role in meeting the evolving needs of the power industry.

While it may seem like the direction of the December edition is not all that different than previous December Oils & Fluids themes, it is clear from the factors above that the insulating properties of all insulation products is advancing rapidly, not just those of Oils & Fluids. These advancements offer enhanced thermal performance, improved electrical insulation, and increased durability, ensuring the safe and efficient operation of power systems. As the demand for electricity continues to rise, ongoing research and development in insulation technologies will play a crucial role in meeting the evolving needs of the power industry.

We hope you enjoy this edition.

Alan M Ross
CRL, CMRP
Managing Editor
APC Media
Technical Director

Alan has decades of experience in the power systems industry and is one of the greatest reliability experts out there.

Dielectric Liquid – A Key to Reliability and Predictive Maintenance

by **Jason Dennison**

When considering the reliable life of transformers, dielectric liquids serve as critical indicators of operational integrity to mitigate risk of failure. The significance of these liquids lies in their ability to provide insights into the current condition of the transformer. Expanding on the foundation laid out in last year's article "Insulating Liquids: The Lifeblood of Transformer Reliability", this article endeavors to delve into further technical context for using liquid analysis as a crucial component of reliability and predictive maintenance.

Predictive Maintenance: A Superior Approach to Transformer Reliability

The choice between predictive and reactive maintenance significantly impacts the reliability and operational longevity of transformers. Reactive maintenance operates on a simple principle: wait for a component to fail, then repair or replace it. While this has strength in simplicity, it carries substantial risks when applied to the reliability of transformers. When a transformer fails unexpectedly, it can lead to extensive downtime, costly repairs, and catastrophic system failures.

Photo: SDMyers

The safety implications to personnel of unplanned power loss, coupled with the financial implications of unplanned downtime, and potential collateral damage to other equipment make reactive maintenance risky as a maintenance strategy.

Predictive maintenance is a strategy to leverage operational knowledge, data collection, and data analysis to monitor the condition of the transformer to provide insight into its condition and trends in the available data to inform decisions to take action to prevent unplanned downtime and sudden system interruptions.

Performing analytical testing on the dielectric liquid has proven to be an effective and cost-effective method to monitor and detect changes within the transformer that can indicate when maintenance may be performed to prevent outage and extend the reliable life of the transformer. The superiority of predictive maintenance is not just its ability to preemptively identify potential faults, but also in its capacity to optimize maintenance activities and schedules to keep costs as low as possible and minimize impacts to operations. To fully realize the benefit, it is imperative to build an understanding of what can be learned from the common dielectric liquid tests.

Jason Dennison is the Director, Diagnostic Analytical Services at SDMyers LLC. Jason leads the world's largest transformer liquid testing laboratory with a team focused on safe operations while generating high volume data analysis and diagnostics. He obtained a bachelor's degree in chemical engineering from the University of Akron with Polymer Specialization and is a Lean/Six Sigma Black Belt with experience spanning industries such as rubber processing, metal machining, petrochemicals, compliance, software development, laboratory chemical hygiene and processing, and data analytics and diagnostics. He is a member of IEEE and ASTM and presents nationally as an authority on transformer fluid analysis.

The superiority of predictive maintenance is not just its ability to preemptively identify potential faults, but also in its capacity to optimize maintenance activities and schedules to keep costs as low as possible and minimize impacts to operations.

Understanding Transformer Health through Liquid Testing

A crucial aspect of predictive maintenance lies in the meticulous analysis of dielectric liquids. There are several common tests that can provide insight into a transformer's condition, enabling reliability and maintenance engineers to make informed decisions regarding operational health and potential maintenance requirements. While the specific results for indicating health of a transformer depend on factors such as dielectric liquid type, transformer size, and transformer voltage class, having a general understanding of the tests and what the results may indicate can expedite maintenance decisions and improve maintenance and reliability outcomes. In all cases, it is important to note that trends over time are essential in helping to understand the health of a transformer. In the US, laboratories generally follow testing procedures defined and governed by ASTM International, while result interpretation comes from other sources including IEEE (The Institute of Electrical and Electronics Engineers) and practical experience. Below, the most common tests will be introduced; there are additional tests that can be performed to gain even deeper insight into transformer health not included here.

Oil Quality "Liquid Screening" Tests

Many tests are generically termed "oil quality" or "liquid screening" tests, which characterize the dielectric liquid's physical properties, indicate evidence of premature aging of the solid or liquid insulation in the transformer, and identify presence of contamination.

Acid Number ASTM D974
This test measures acid content in the dielectric liquid. Acids will form due to liquid and solid insulation oxidation. A higher acid number suggests degradation has occurred, potentially leading to the breakdown of solid insulation. In-service dielectric liquid should have a low acid number if the transformer is healthy.

Interfacial Tension (IFT) ASTM D971
Interfacial tension is a measure of the liquid's integrity, by determining the force required to break the interfacial tension between the liquid and water. This tension force diminishes if contaminants or degradation byproducts, particularly polar compounds, are present in the liquid. In-service dielectric liquid should have a higher IFT measurement if the transformer is healthy. In many cases, IFT has an inverse relationship with Acid Number – as acids increase, the IFT will decrease.

Photo: SDMyers

> In the US, laboratories generally follow testing procedures defined and governed by ASTM International, while result interpretation comes from other sources including IEEE (The Institute of Electrical and Electronics Engineers) and practical experience.

Color Number ASTM D6045/D1500
The color of the dielectric liquid provides visual cues about its condition, though this test alone is not a sufficient analytical tool. Darker liquid can indicate of aging of the insulation, oxidation, or the presence of impurities. This test is often used to corroborate other test results that may indicate premature aging or other fault conditions. In-service dielectric liquid should generally have a low color number, though a higher color number is not necessarily indicative of poor health.

Specific Gravity ASTM D1298
Specific Gravity is a fundamental physical property of the dielectric liquid, related to its density. Major changes to specific gravity suggest the liquid is contaminated. In-service dielectric liquid should maintain a reasonably consistent specific gravity.

Visual & Sediment ASTM D1524
Visual inspection, although seemingly rudimentary, is an important part of liquid screening. Specialists assess the oil's clarity, looking for signs of sediment, carbon particles, or water droplets. Any visual anomalies observed during the inspection can guide further diagnostic interpretation, aiding in the identification of underlying issues. In-service dielectric liquid should be free of particulates, sediment, or observable water droplets.

Dielectric Testing ASTM D877, ASTM D1816

Dielectric liquid testing, as per ASTM standards D877 and D1816, plays a vital role in predictive maintenance. These tests evaluate the oil's breakdown voltage, indicating the dielectric strength of the liquid, which can indicate issues such as contamination, insulation degradation, and in some cases may also highlight elevated moisture content. The D877 dielectric test, which uses flat electrodes submerged in dielectric liquid, was the primary test for breakdown voltage for years. For many years now however, the D1816 dielectric test has grown in adoption as the best dielectric test as it uses rounded electrodes (called "VDE") in dielectric liquid that better approximate conditions inside the transformer related to breakdown voltage and dielectric performance. D1816 is notably more sensitive than D877, and care must be made to get a representative sample. In the diagnosis of results, the presence of elevated dissolved gases and moisture are known to affect D1816 testing, and maintenance decisions based on dielectric results should be made respective of other test data. In-service dielectric liquids in healthy transformers should have high breakdown voltage results.

Karl Fisher Moisture Analysis ASTM D1533

The presence of moisture in transformers is problematic for both the liquid and solid insulation. Moisture in the liquid can increase the risk of dielectric failure. In the solid insulation, when combined with heat, moisture will expedite the aging of the solid insulation and begin to create acids that will harm the integrity of the solid insulation. Moreover, moisture is often a symptom of transformer component failures where seals or gaskets break down and create a path for moisture incursion.

Getting an accurate analysis of moisture content is therefore important and notably, moisture testing is highly dependent on sample accuracy. When sampling, it is crucial to only use approved containers and to fill the container fully to have the highest integrity sample possible. Resources such as ASTM D923 and ASTM D1533 include requirements and procedures to help ensure sampling is properly performed. It is critical at the time of sampling to accurately note the sample temperature as well - moisture is unique in that it will migrate between the liquid and solid insulation depending on temperature.

As temperature increases, some moisture will migrate from the solid insulation to the liquid insulation and will revert as temperature decreases. Recording sample temperature allows a laboratory to report the proper analysis for moisture which includes both the water content in parts-per-million (ppm) and a calculated Percent Saturation (%Sat). Percent Saturation expresses moisture content relative to how much moisture the dielectric liquid is able to hold, which is important to understand based on the significant impact temperature has on moisture content distribution inside the transformer.

The recommended in-service moisture levels depend heavily on liquid type and voltage class of the transformer. Generally, in-service dielectric liquids should have low moisture content, and more importantly, low percent saturation.

Photo: SDMyers

The true power of DGA interpretation lies in the fusion of these diagnostic tools with practical experience and domain expertise.

Photo: SDMyers

The data collected has a direct link to the liquid and solid insulation condition, and the premature aging or degradation of either will have significant impact on the reliability of the transformer.

Dissolved Gas Analysis ASTM D3612

Dissolved Gas Analysis (DGA) is a cornerstone of predictive maintenance in transformers. By analyzing gases dissolved in dielectric liquids from transformers, experts can glean valuable insights into the internal condition of the transformer. Generally, dielectric liquids are tested for 9 gases - atmospheric gases (Oxygen, Nitrogen, Carbon Dioxide) and combustible gases (Carbon Monoxide, Methane, Hydrogen, Ethane, Ethylene, Acetylene) – that may be found in dielectric liquids inside transformers that can be used to determine abnormal conditions in the transformer.

Long term conditions and incipient faults can both be readily seen in DGA data, making it particularly useful in both predictive and reactive maintenance situations. The concentrations of individual gases, the rate of gas generation, and the overall gas profile in a transformer can be interpreted using practical expertise and diagnostic tools such as Duval Triangles, Duval Pentagons, the Key Gas Method, and parameters from standards organizations such as IEEE to determine possible fault conditions inside the transformer. These tools can be of great use in helping to quickly process available data.

However, the true power of DGA interpretation lies in the fusion of these diagnostic tools with practical experience and domain expertise. An experienced practitioner will bring contextual understanding to the analysis, considering factors such as the transformer’s history, nameplate data, operational conditions, and environmental factors. Employing experience, reasoning, and diagnostic tools adds depth to DGA diagnostics, ensuring that maintenance decisions are informed by situational and operational dynamics.

It is difficult to generalize expected gas levels for in-service dielectric liquids. These liquids in normal use may exhibit some amount of some of the combustible gases and will likely have some level of atmospheric gases as well. The expected values also vary greatly with liquid type, transformer size, preservation system type, and operating conditions of a transformer. Generally, gas values should remain reasonably consistent over time in the absence of faults or component failures, so trending is important in establishing a useful diagnosis of the available data. Elevated levels of gases, especially the combustible gases, is likely cause for investigation.

Reliability is About More than Data Analysis

These tests represent the most common tests that can be performed on dielectric liquids inside transformers, though there are other tests that can provide insight into transformer health. Additional tests such as Liquid Power Factor, Inhibitor Content, Furanic Compounds, and Elemental Analysis can be performed to gain even deeper understanding of the condition of the transformer. In the pursuit of predictive maintenance, the data that is available from the dielectric liquid can provide incredible insight into the condition of the transformer. The data collected has a direct link to the liquid and solid insulation condition, and the premature aging or degradation of either will have significant impact on the reliability of the transformer. To extend the reliable life of a transformer, the maintenance approach must move beyond gathering and analyzing data to favor taking more proactive measures to correct deficiencies found in the data early, which has the greatest potential impact to reliability. Doing so can extend the reliable life of a transformer by years, if not decades.

Water promotes the degradation reactions of the insulating paper and damages the oil-paper insulating system, therefore it shortens the lifespan of a transformer, and also reduces the breakdown voltage of the tap-changer oil.

BENEFITS OF A BDV INDICATOR

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Water and moisture are omnipresent in our environment. We encounter it in the form of rain or moist air. In the insulation systems of electrical equipment, however, moisture is undesirable. Excessive moisture in the insulating oil or insulating paper affects their insulation strength. Water promotes the degradation reactions of the insulating paper and damages the oil-paper insulating system, therefore it shortens the lifespan of a transformer, and also reduces the breakdown voltage of the tap-changer oil.

Figure 1: Deterioration of insulating materials because of water

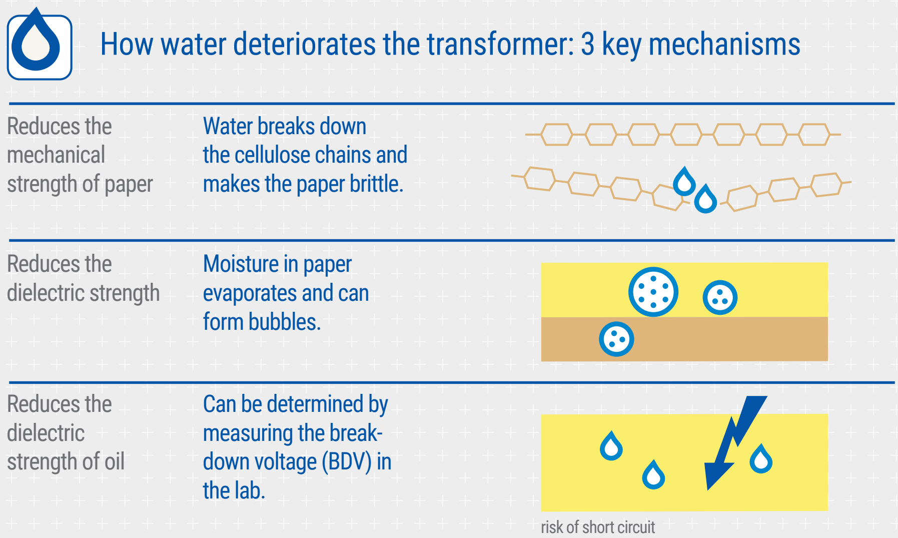
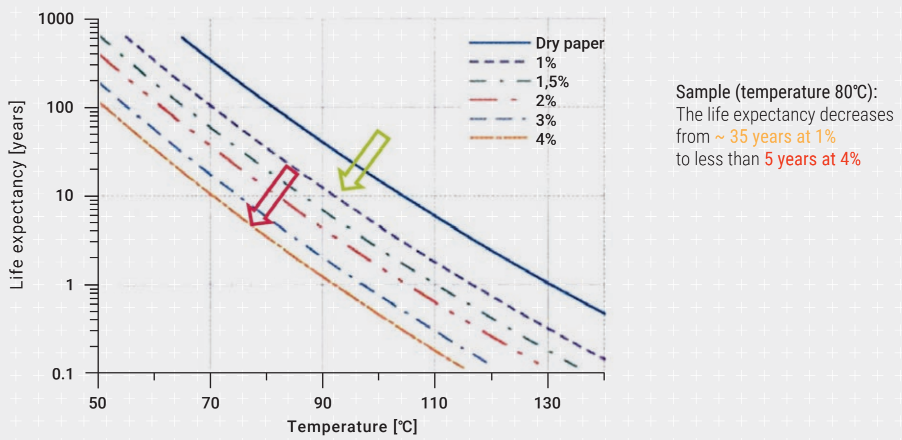


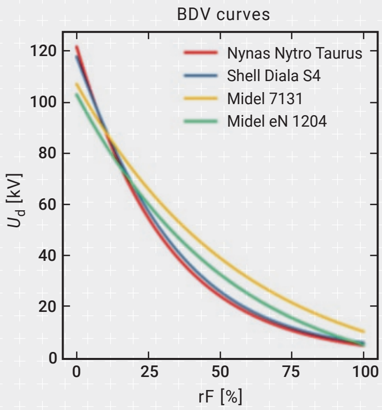
Figure 2: Loss of lifetime because of increased water content



This results in two important aspects regarding moisture:

a. On the one hand, the penetration of moisture into the transformer or tap-changer should be avoided. This is done on the one hand by appropriate handling of the insulating materials and by using dehumidifiers to dry the air inhaled by the transformer or tap-changer.
b. On the other hand, the moisture content of the insulating oil should be continuously monitored. Since it is not possible to directly monitor the moisture content of the insulating paper during ongoing operation of a transformer, this is also done indirectly via the moisture content of the insulating oil.

Figure 3: Resulting BDV models for different oil types



The relationship between relative oil moisture, oil temperature and breakdown voltage can be described using statistical methods from the machine learning toolbox.

A relatively simple way to implement online monitoring of the breakdown voltage is to use the influence of moisture in the insulating oil on the breakdown voltage. The relationship between relative oil moisture, oil temperature and breakdown voltage can be described using statistical methods from the machine learning toolbox. Here, the breakdown voltage data at different oil temperatures and humidity are determined experimentally using a reference method, e.g., IEC 60156. A mathematical model is trained with this data. The model is validated and optimized using test data that is independent of the training data.

Since the test standard used to determine breakdown voltage in the laboratory already has a large measurement uncertainty, it is recommended to divide the results of the BDV calculation into classes based on the IEC 60422[5] standard and the information in the form of a traffic light to represent. This is considered sufficient for long-term trend monitoring.

The advantages of an online moisture sensor with calculation of the breakdown voltage are:

- Continuous monitoring of the moisture content of the insulating oil.
- Continuous monitoring of the insulation strength is possible by calculating the breakdown voltage.
- Calculation of the paper moisture.
- Elimination of the need for regular oil sampling to determine the oil moisture content and the breakdown voltage.
- Timely detection of deviations from the normal or target condition of the transformer and on-load tap-changer.
- Increased operational reliability.

Benefits of a DGA sensor

Evaluation of electrical equipment is an essential but complex process for any asset operator to ensure both operational safety and economic efficiency. As described in detail in CIGRÉ TB 761 [1], the condition of the individual components of the transformer system must be assessed regarding the following aspects:

- Replacement
- Safety
- Maintenance
- Refurbishment / upgrading and
- Oil treatment

This information is condensed, usually in the form of condition indices, and presented for the entire fleet of equipment for decision-making. Over the last 30 years, a very useful method for condition assessment has been the analysis of dissolved gases in the insulating oil. This has been used to evaluate the condition of the active part of a transformer, the tap-changer, and the bushings [6].

Interpretation of the gas patterns for mineral oil-based insulating oils is described for instance in [7, 8], for ester-based insulating oils in [9]. These interpretation approaches found their way into relevant standards [10, 11]. After the establishment of the method in laboratories, more and more online DGA systems of various types appeared on the market – starting from the sum gas sensor system to multigas sensor systems with 8, 9 or more gases [12, 13]. Essentially, available online DGA systems can be divided into two categories:

a. Systems for fault indication and trend analysis.
b. Systems for fault diagnosis as described in [13].

Fault diagnosis is the interpretation of gas patterns according to the methods described in [10, 11]. Usually, gas concentrations are related to each other and assigned to corresponding fault classes. To form different gas ratios, the respective gas components are required as listed in Table 1.

Table 1: Required gas components for formation of the gas ratios according to different interpretation approaches.

Interpretation according to	**Gas Components**								
	H_2	O_2	N_2	CO	CO_2	CH_4	C_2H_6	C_2H_4	C_2H_2
Rogers	X					X	X	X	X
Doernenburg	X					X	X	X	X
Duval Dreieck						X		X	X
Duval Pentagon	X					X	X	X	X
CO_2 / CO				X	X				
O_2 / N_2		X	X						
IEC 60599	X					X	X	X	X

Basically, faults are divided into the following classes according to IEC 60599 [10]:

- PD Partial Discharge
- D1 Low energy discharges
- D2 High energy discharges
- T1 Thermal fault with T < 300°C
- T2 Thermal fault 300°C <= T < 700°C
- T3 Thermal fault 700°C <= T

These classical interpretation approaches show several problems:

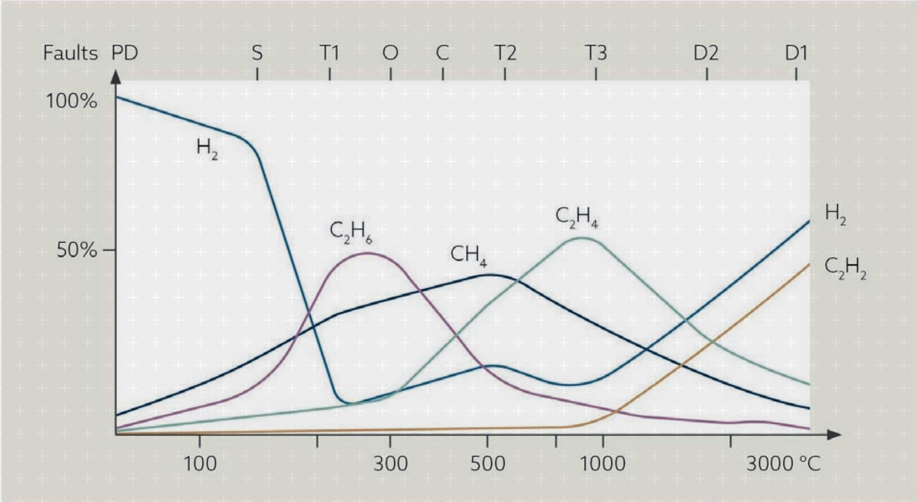
- There is – except for Rogers' gas ratios – no normal range. The gas ratios always indicate a fault.
- The interpretation should be applied only when certain limit concentrations of the gases are exceeded.
- The superposition of different types of faults, which is often the case, is not correctly detected [14].

In recent years, attempts have been made to counteract these disadvantages and improve the reliability of the interpretation results by applying statistical methods from the Artificial Intelligence (AI) toolbox [14-17].

For fault diagnosis, multi-gas online DGA systems are used, which can usually detect > 4 gases and are based on principles of optical spectroscopy (IR or photo-acoustic spectroscopy) or gas chromatography.

Fault indication and trend analysis focus on the relative change of a few gas concentrations. The aim here is to obtain an early indication of deviations from normal or desired operation. Fault classification, as described in the previous chapter, is not the focus. If a corresponding indication is obtained, appropriate measures can be initiated promptly, such as oil sampling with subsequent analysis of various parameters or electrical measurements on site.

Figure 4. Gas formation pattern as a function of temperature [3].



If we look at the development of various gases as a function of temperature and assign them to the typical fault classes as shown in Fig. 4, we can see:

- Hydrogen is present in varying proportions over the entire temperature range.
- The proportion of hydrogen increases sharply during high-energy events (very high temperatures).
- The proportion of acetylene increases sharply during high-energy events (very high temperatures).
- Methane is present in appreciable proportions early in thermally induced faults.

Furthermore, present proportions of carbon monoxide and carbon dioxide indicate possible degradation reactions of the insulating paper, with carbon monoxide forming the precursor to carbon dioxide during paper degradation.

Thus, even with only a few gases, a trend analysis and an early fault indication can be carried out. As shown in Fig. 4, a DGA system detecting the gases hydrogen and carbon monoxide as well as oil moisture can be used for reliable early fault indication and trend analysis. In combination with an extraction unit based on membrane technology, such systems are usually robustly designed and inexpensive, and thus quite suitable for fleet monitoring. The monitoring approach here is rather the large-scale monitoring of the equipment to get a continuous overview of its condition and its development rather than the detailed fault diagnosis of a few critical pieces of equipment.

The advantages of an online DGA sensor with only a few gases for early fault detection are:

- Robust and inexpensive systems.
- Simple handling.
- Early detection of deviations from normal operation.
- Monitoring of a fleet is possible and affordable.

The advantages of a multigas online DGA sensor for fault identification are:

- Fault diagnosis is possible.
- Monitoring of all dissolved gases in critical equipment.
- Gaining knowledge about new and unfamiliar operating equipment.

General advantages of online DGA:

- Continuous monitoring of the oil condition and thus the condition of a transformer and on-load tap-changer.
- Early detection of deviations from normal operation.
- Reduction of regular oil sampling.
- Increased operational reliability (compared to laboratory analysis, the probability of detecting a fault in good time is twice as high [13]).
- Increased predictability of maintenance measures.
- Optimization of operating costs.

Photo: MR

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Jürgen Schübel completed a PhD in physical chemistry in 1991 and worked for 20 years in a major European mineral oil company. His work involved quality control of refinery processes and products, online process control procedures and development of fuels and other oil products. Since 2011 he works for Messko GmbH, a 100% company of Maschinenfabrik Reinhausen GmbH, and his work is focused on the development of measurement systems for electrical equipment and on the dissolved gas analysis. He is senior expert for insulating materials and analytics at Maschinenfabrik Reinhausen GmbH and is an active member of CIGRÉ D1. As product and portfolio manager he is responsible for the DGA and moisture sensor products at Maschinenfabrik Reinhausen GmbH.

A DGA system detecting the gases hydrogen and carbon monoxide as well as oil moisture can be used for reliable early fault indication and trend analysis. In combination with an extraction unit based on membrane technology, such systems are usually robustly designed and inexpensive, and thus quite suitable for fleet monitoring.

What is a High Voltage Engineer? Who are They? Where are They?

By Dr. **Nancy Frost** SMIEEE
Frosty's Zap Lab, LLC

In the last several months I've had a variety of conversations with people and organizations regarding high voltage and dielectrics engineers, and how there appears to be fewer of them than in the past.

How, in our standards working group meetings, there are the same bunch of people, all of us aging together, with fewer and fewer young folks staying around in the industry. We've been puzzling.

Why is this happening? Where are the young engineers being trained? Why are they not coming nto their classic roles in the industry?

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Dr. **Nancy Frost** has been active in the electrical insulation industry for over two decades. She now runs Frosty's Zap Lab, her materials R+D testing laboratory, while working for Gerome Technologies as Materials and Testing Manager. Nancy's education includes a B.S. in Chemistry and M.S. & Ph.D. in E.E. from Clarkson University, finishing her PH.D while working for GE Research. She has given more than 100 papers and short courses in the areas of dielectric materials, aging phenomena, and testing. Through her various roles, she has experienced the points of view of materials suppliers, customers, utilities and manufacturers.

> *WHAT IS A HIGH VOLTAGE ENGINEER? MAYBE THAT'S THE ISSUE. PERHAPS THE DEFINITION HAS GOTTEN LOST. TRADITIONALLY, HIGH VOLTAGE ENGINEERS ARE THE 'KEEPERS' OF THE HIGH VOLTAGE IN A POWER SYSTEM.*

Who is going to pick up the banner and carry forward the high voltage engineering for the next generation? I'm going to share some of my thoughts on this topic with you.

What is a high voltage engineer? Maybe that's the issue. Perhaps the definition has gotten lost. Traditionally, high voltage engineers are the "keepers" of the high voltage in a power system.

They are the ones that design and implement new transmission or distribution lines, so have to keep an eye on the clearances needed to keep the high voltage on the line and not arcing to some tree or tower.

They design substations, with the various equipment, transformers, three phase breakers, grounding schemes, dealing with VAR compensation and other aspects that keep the power flowing smoothly in the transmission or distribution network. They run the power stations, keeping the grid alive and well and functioning smoothly, for example, as lines need to be switched in and out due to changes in grid demand from, say, local outages. They also work on projects underground and undersea, developing cables for transmission and distribution.

But high voltage or dielectric engineers are also the people that make MRIs work. No one wants a false signal or white spot in their MRI! Dielectric engineers also work to design the internal workings of that bone saw that was needed for your loved ones' hip or knee replacement. They design the generator that powers your cruise ship. They help our military by powering our subs and battleships, keeping them functioning safely. And they work undersea, designing and building undersea cables for power transmission over long distances. Someone has to connect those new off-shore generators to the on-shore grids.

HAVING WORKED ON POWER GENERATORS, LARGE MOTORS, SMALL MOTORS, LOCOMOTIVES, TRANSFORMERS, LIGHTING BALLASTS (A SPECIALTY TRANSFORMER), BUSES, MRIS, BONE SAWS, DENTAL DRILLS, POWER CAPACITORS, CABLES OF ALL SIZES AND SHAPES, AUTOMOTIVE IGNITION COILS, TRANSPORTATION ELECTRIFICATION (A MODERN BUZZWORD - THAT ALSO COVERS MANY APPLICATIONS), OUTDOOR INSULATORS, CIRCUIT BREAKERS, ROTOR INSULATION, STATOR INSULATION, TRAINS, PLANES, AND AUTOMOBILES... AND THEY ALL HAVE THE COMMON NEED OF KEEPING THE 'POSITIVE' FROM TOUCHING THE 'NEGATIVE.'

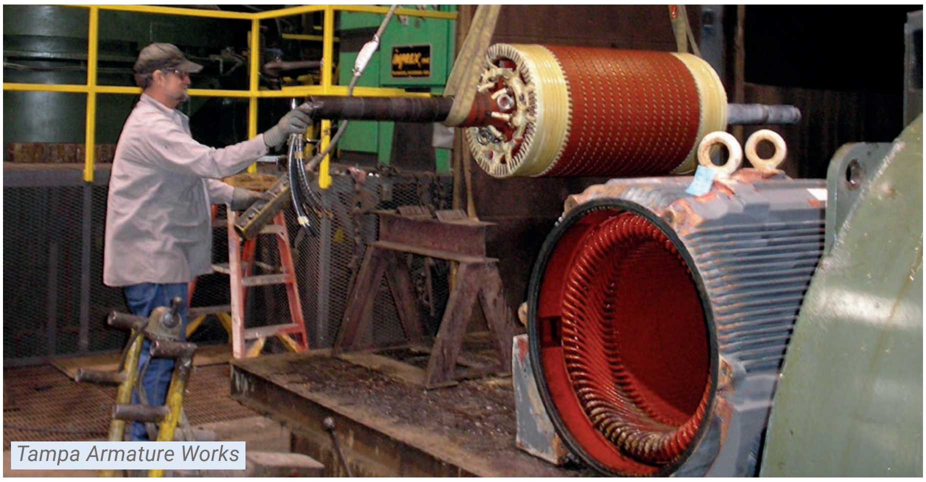
Having worked on power generators, large motors, small motors, locomotives, transformers, lighting ballasts (a specialty transformer), busbars, MRIs, bone saws, dental drills, power capacitors, cables of all sizes and shapes, automotive ignition coils, transportation electrification (modern buzz word - that also covers MANY applications), outdoor insulators, circuit breakers, rotor insulation, stator insulation, trains, planes and automobiles... and they all have the common need of keeping the "positive" from touching the "negative". In other words, having long lasting dielectric materials or insulation that can withstand the electric field, aka the applied voltage, despite the diversity of applications and operating/aging environments. And this diversity may be the key to finding the elusive high voltage engineer and tracking their career path.

What is meant by the applied voltage? For some applications that means 30kV (30,000 volts), and sometimes that means 30V. All depends on the application. It is the electric field that matters. And that's the voltage across a distance (volts per mil, or kV/mm). So, if you have a power line with tens or hundreds of kVs between the line and the ground, that FEELS like it should be different than a wire in a cable that carries a few hundred volts on a submarine. But depending on the distances between the positive and the negative, the basic dielectric properties are very similar. The theory driving the dielectric strength of the materials are similar, despite the diverse extremes in voltage levels.

Where are the next generation dielectrics and high voltage engineers? It seems that they are moving into even newer areas far exceeding the fundamental insulation needs. They are developing the power systems for next generation space applications and travel. They are investigating the influence of nanoparticles and how the laws of physics and chemistry are seemingly different when we get down to that scale; exploring how those materials operate; and if there are really different fundamental laws driving their performance. Of course, they are also diving deeper into the science of the present-day systems and making necessary advances to provide cleaner, greener energy and devices.

What makes a high voltage engineer? High voltage engineering covers a broad swath of skill sets in order to advance the science. They are chemists, and physicists, electrical engineers, and mechanical engineers. They are designers, researchers, development engineers, and yes, those that apply a wrench and get the job done.

Designing a generator is very cool, lots of drafting and computer modeling, considering all aspects of the magnetic as well as electrical field effects of the stator and rotor combination. Power controls, power feeds, plus connections to and from the generator. Never mind the dielectric insulation system and mechanical bracing aspects. Remember, those stator bars will want to fly apart when you turn that rotor. Not to mention the momentum of the rotor itself. Without bracing


Tampa Armature Works

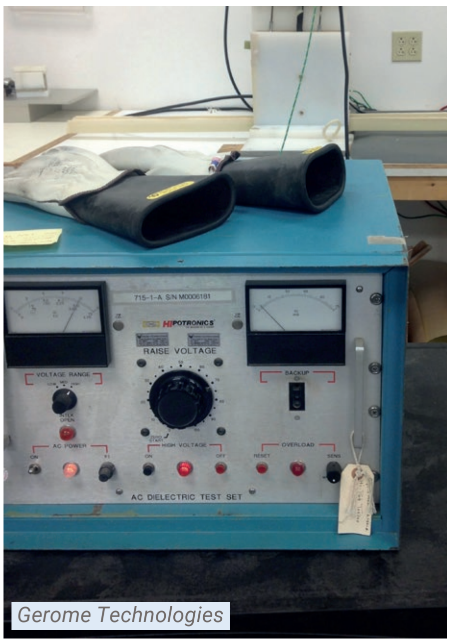
and electrical insulation, the machine won't work.

But generator design isn't all sit in the office and click on your computer to design stator bar sizes and quantities and then hit a button and the generator is made, although some of our young engineers only want to do that when asked, just push computer keys and not touch the real world. The real fun, in my mind, is when one gets to the actual build of the generator; making all the parts fit together, and more, making sure the unit lasts in the field.

Clearances can be designed, but in reality there are measurement errors, and material substitutions may have to be made. Many minute changes that can broadly affect the function and life of the entire generator. That is where the specialist, the dielectrics engineer, comes to play. They understand the materials that are utilized in a generator and how they function individually, as well as together as a system; plus, more critically, how the dielectric materials age and change over time the system is in the operational environment.

That submarine I mentioned - well, the busbars on that system are a critical component to the operation of the sub. Of course, safety is of the utmost concern, both for the personnel as well as for the asset, the sub. But continuous operation is also key! No one wants to be on a sub without power for ANY length of time. So that power system HAS to work, 24/7/365.

For the safety of our military, who risk their lives for us on a daily basis. If an adverse situation should arise, the sub personnel need to be able to access the power bus bar easily and readily tap into it if they need to perform an emergency repair at sea. But yet, they also have to have the busbar safely covered to avoid



Gerome Technologies

Photo: Shutterstock, Frosty's Zap Lab

inadvertent contact. The insulation material on that busbar has multiple requirements, to be robust, yet easy to tap into, and have withstand capability of salt sea air, which has a corrosive effect on metals, to name a few. This involves totally different electrical needs from the power generator, yet similar high voltage and dielectric engineering concepts, that need to be known, understood and properly applied.

So, who is training these high voltage and dielectric engineers? Where do they come from? In addition to the diverse training background of the (way cool) high voltage engineers with which I've worked, those chemists, physicists, and engineers, they have unique and wide-ranging personal backgrounds. Men, women, tall, short, black, white, brown, from all walks of life and all corners of the globe. That is one of the most interesting aspects of this industry in my opinion: the diversity of the high voltage engineer. I believe it comes from our perseverance to solve the problems to make a device function, and function well, and function for a long time. Not only are we a diverse bunch, coming from anywhere in the world, but we also come with a wide variety of educational backgrounds.

People with Doctorates, Masters, Bachelors, Associate degrees, and even high school diplomas. I've worked with them all and learned from them all. Many of the traditional educational institutions that pumped out high voltage engineers for classic positions have moved their programs to other areas, many computer based. There are fewer academic programs to directly training high voltage engineers, at least in the USA, leading to a lower number of classically trained high voltage engineers. Although lately I see that there are several solid programs in a few universities, with several young professors starting new programs, I'm pleased to see.

Where do high voltage engineers work these days? I was talking with a colleague recently about candidates for a volunteer opportunity, and we were wondering where the talented young engineers were going for employment. Sadly, many large corporations have closed down their dielectrics groups in the last decade or two. It seems that there have recently come a new group of opportunities for the budding high voltage engineer/scientist. This includes national labs, space programs, military, universities, and colleges.

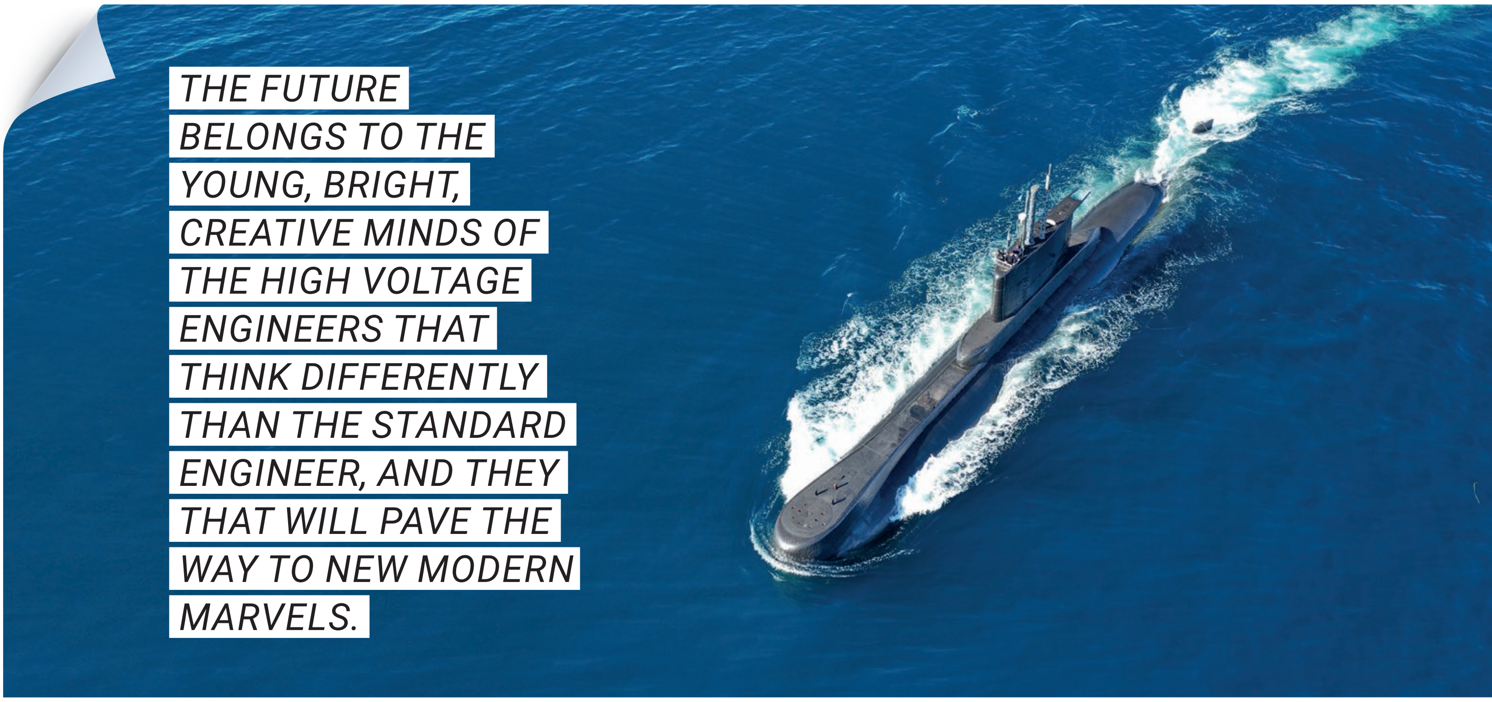
WHAT IS MEANT BY THE APPLIED VOLTAGE? FOR SOME APPLICATIONS THAT MEANS 30KV (30,000 VOLTS), AND SOMETIMES THAT MEANS 30V. ALL DEPENDS ON THE APPLICATION. IT IS THE ELECTRIC FIELD THAT MATTERS. AND THAT'S THE VOLTAGE ACROSS A DISTANCE (VOLTS PER MIL, OR KV/MM).

There is a resurgence of interest beginning in the dielectric engineer for industry, manufacturing companies, and of course utilities once again. Industry is realizing that they need that specialize engineer on their design team for new devices. This wide variety of job types for a small number of young engineers means there are a plethora of opportunities for moving to new jobs that appeal to the mind as well as the pocketbook.

Where can the high voltage engineer gain mentoring? I have been sitting in two days of standards meetings for the IEEE PES EMC Materials Subcommittee, where I have been active for over 25 years. I cannot say how much volunteering on these standards have affected my career. I get to rub elbows with a diverse group of engineers that are responsible for the various aspects of motor and generator insulating materials. These people are from around the world and have a wide variety of backgrounds and areas of expertise. I have learned so much from these shared experiences and the generosity of these people, and have both been mentored and have mentored others. Both are rewarding experiences. For any new young engineers, and those that have a few years or decades under your belt, volunteer. Join your local professional society chapter. Join standards committees. Share, learn, and exchange ideas and experiences.

We all benefit from this. And this is how technical details are transferred from the knowledge base. Sitting over a beer or a cup of coffee, sharing experiences, discussing deep technical concepts and even definitions.

As a final word, I was at a conference last month, listening to keynote lectures on dielectric innovations. Wow, what a wonderful, exciting time to be interested in being a high voltage or dielectrics engineer, as they are reaching into and creating wonderful new areas. Space travel. Nanocomposites and multiple applications. Way cool future there! But to me, the most amazing, and utterly surprising, was that someone was making an artificial muscle! The polymer reacts to a field and shrinks, essentially serving as a muscle. It is a "long" way to real life application but compared to the time of the "war of the currents" of Tesla and Edison, I'm sure the medical application is just around the corner. The future belongs to the young, bright, creative minds of the high voltage engineers that think differently than the standard engineer, and they that will pave the way to new modern marvels.



THE FUTURE BELONGS TO THE YOUNG, BRIGHT, CREATIVE MINDS OF THE HIGH VOLTAGE ENGINEERS THAT THINK DIFFERENTLY THAN THE STANDARD ENGINEER, AND THEY THAT WILL PAVE THE WAY TO NEW MODERN MARVELS.

FROM THE MANAGING EDITOR

Just a word about this author and this article. I admit I am heavily biased, given I think the author Dr. Nancy Frost is a genuine hero of the cause. From the times we lobbied Congress and the White House together on behalf of the Society of Maintenance and Reliability Professionals (SMRP) to the many times we met at conferences and laughed, learned, and shared; every time was memorable. Doc Frosty and her lab Frosty's Zap Lab, LLC (and yes, this is an endorsement, which I rarely do) are the real deal. This is such a great read.

I hope you enjoy it as much as I did. Alan.

Photo: Shutterstock, Frosty's Zap Lab

CHARTER STEEL

THE CASE FOR SAFER TRANSFORMERS WITH DC ELECTRIC ARC FURNACES

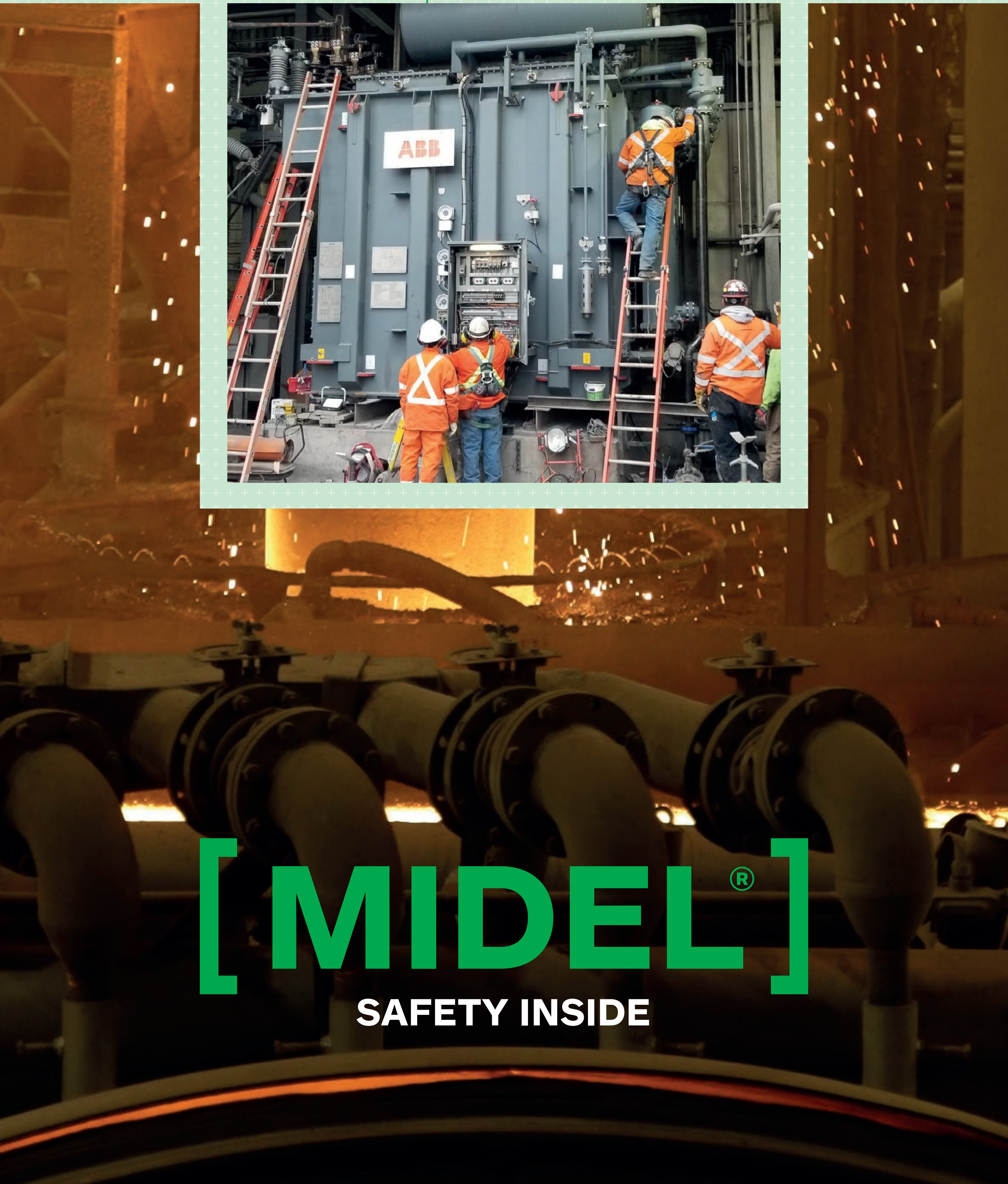


Photo: Charter Steel

Electric arc furnaces (EAFs) have been in use for over two hundred years, with some of the earliest work done in 1810 by Sir Humphrey Davy (inventor of electrochemistry and who, incidentally, gave Nitrous Oxide the label “laughing gas”). An EAF converts electrical energy into thermal energy via an arc; the objective being to melt metals - in this case, steel. In the early 1900s, EAFs emerged commercially in the electrochemistry sector, and the production of electric steel, as it was called, began to take hold, especially with specialty steels and alloys.

An early commercial EAF was patented by Siemens in 1878, and a French inventor Paul Héroult, after discovering the electrolytic aluminum process in 1886, went on to further develop and patent direct electric arc furnaces for steel. The Halcomb Steel Company built and operated the first commercial EAF in the US in Syracuse, NY, using Héroult’s technical advice and design. Further commercial use slowed due to the lack of powerful transformers with higher voltages (which consumed an exorbitant amount of electricity) and improved carbon electrodes that would last longer. After WWII, the use of EAFs for steelmaking expanded rapidly, and was mostly done via alternating current (AC) EAFs. However, the use of direct current (DC) over AC for EAF steelmaking came to the fore with global development and commercialization in the 1970s and 1980s. The technology was quickly enhanced; and while the advantages of DC EAFs over AC EAFs for steel making are numerous, they are too involved to cover in this short article.

Most semi-integrated steel mills or mini mills include an electric meltshop utilizing an EAF for melting scrap. In 1991, US-based Charter Steel built its meltshop in Saukville, WI, one of the USA's first three DC Arc Furnaces. The meltshop created a wholly integrated mini mill at one site and helped set the stage for the rapid growth of mini mills across the USA and many other countries. The original Saukville configuration, designed for scrap steel, featured a 38MW furnace supplied by a single transformer and rectifier. To ensure business continuity, the meltshop also had a spare transformer and later added a spare rectifier. Demand grew, and Charter Steel’s engineers developed a solution to use the spares in tandem with the original units to meet the need for increased production. Saukville Meltshop Electrical Engineer Mike Sauer described it as “a 20% upgrade in power, and the meltshop could always just run on a single rectifier if there were any issues with the other.”

Most semi-integrated steel mills or mini mills include an electric meltshop utilizing an EAF for melting scrap. In 1991, US-based Charter Steel built its meltshop in Saukville, WI, one of the USA's first three DC Arc Furnaces. The meltshop created a wholly integrated mini mill at one site and helped set the stage for the rapid growth of mini mills across the USA and many other countries.

Figures 1 and 2 show the space challenges that formed the constraints of the various proposed solutions.

Figure 1 Overhead View of Charter Steel Rectifier/Transformer Pair

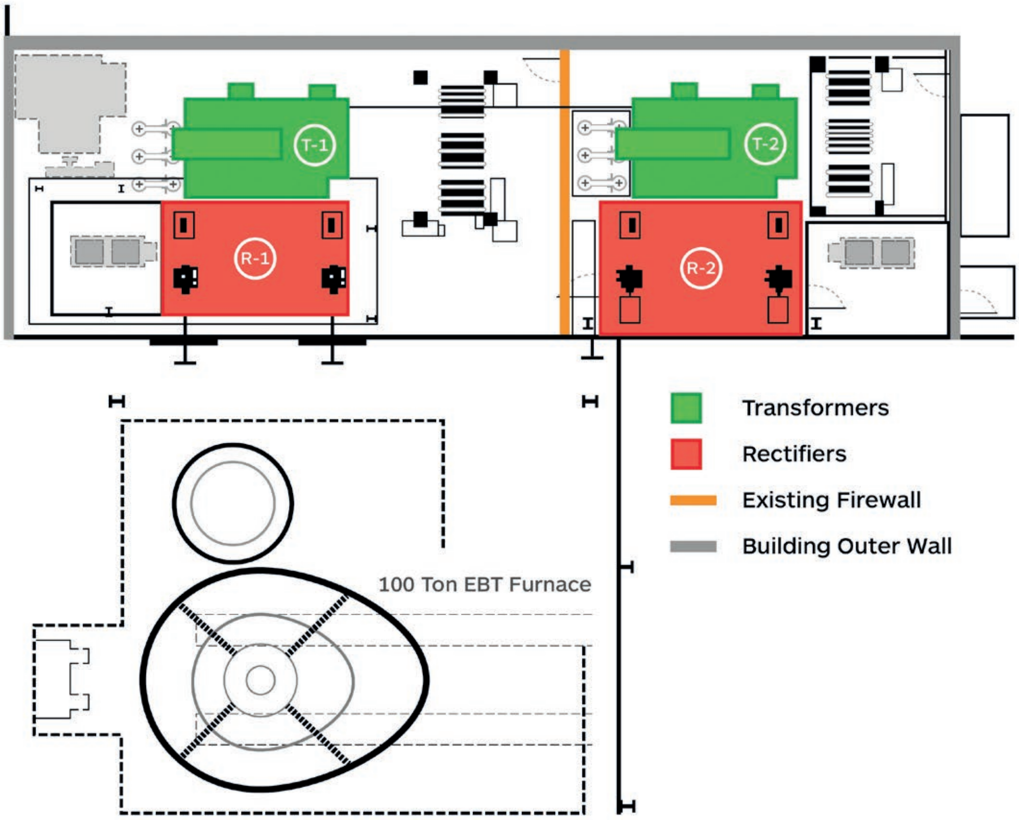


Figure 2 Elevation View of the Rectifier/Transformer Pair

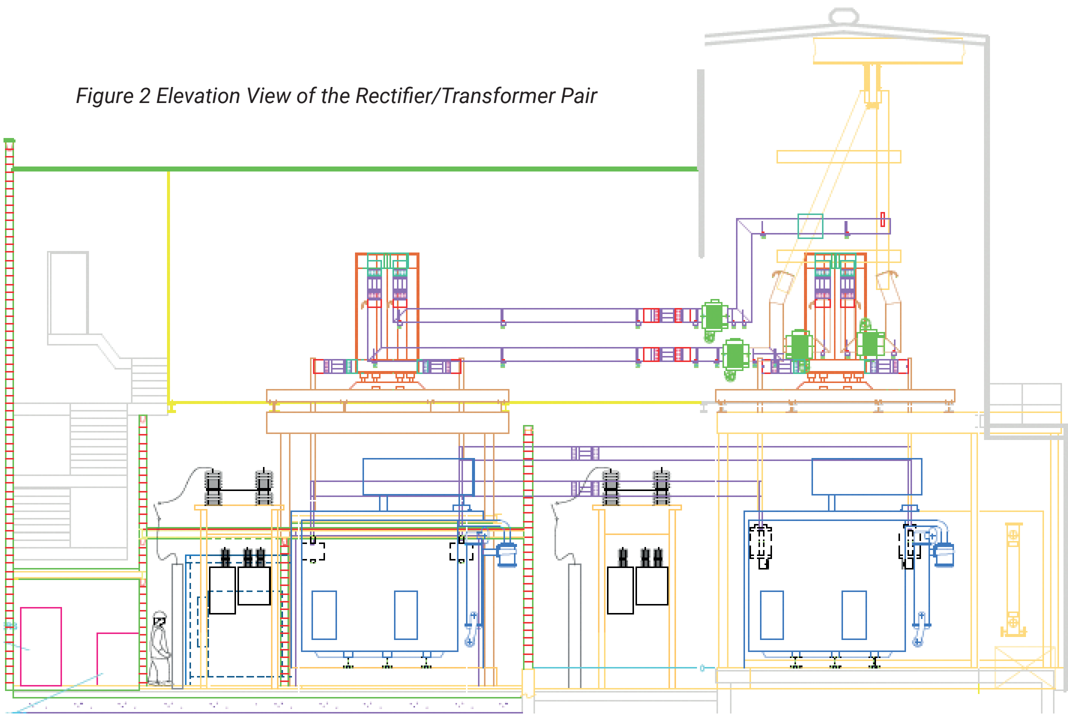
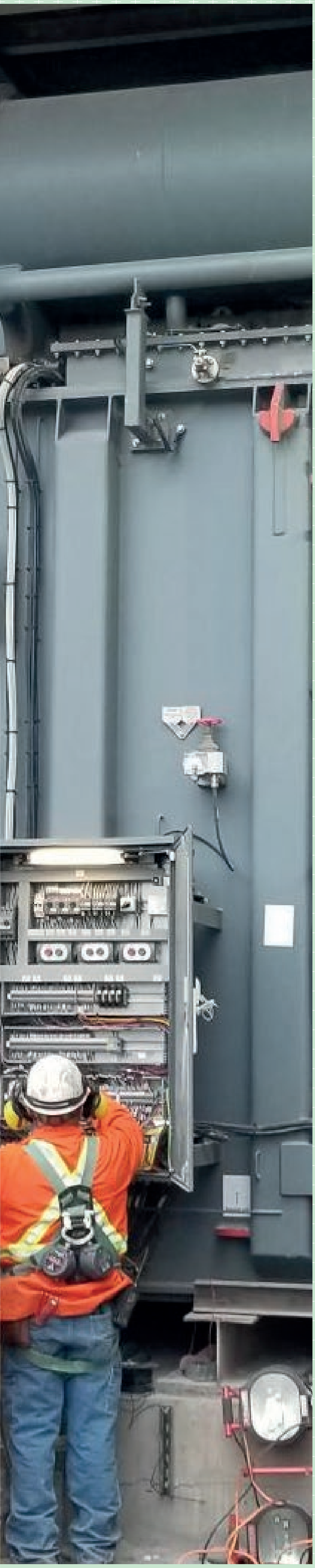


Photo: Charter Steel



The new spare transformer provided a back-up resource to call upon if needed. However, the insurance company's risk experts noted their concern over the pairs of transformers and rectifiers - especially how close they were to each other and the operations of the meltshop. Thus, a concrete block wall was placed between the pairs, but it could not extend to the plant's ceiling due to airflow requirements. To make up for this incomplete fire barrier, it was recommended that Charter add a water-based fire suppression system. A genuinely effective deluge system must cover all four sides and the top of the transformers, meaning a shower of water would hit the rectifier side of the transformer. In effect, this would immediately destroy the rectifier regardless of its involvement in the fire. This water-deluge option created concern within the Charter team; besides the slight but ever-present danger of a false triggering of the water shower, the cold Wisconsin winters could play havoc with the somewhat exposed-to-the-elements transformer vaults. Concern over a burst water pipe led them to consider a dry-type system. Yet, the installation's complexity, its continuous maintenance needs, and high costs (including a new backup power system for the dedicated pumps in case of a power outage) led them to continue searching for a better solution.

Charter evaluated various types of chemical and/or gaseous suppression systems as alternatives. Still, one of the most challenging considerations was the relatively large area (approximately 2,400 cubic meters) containing both pairs of transformer/rectifier power supplies. The ample space, which was not well sealed, would poorly contain the discharge from a suppression system on top of the required extensive volume of fire abatement material.

A new transformer solution was proposed that seemed much more straightforward: replace the potentially flammable mineral oil insulating liquid with an FM Approved "less flammable liquid" which would mitigate the transformer fire risk at a much lower overall cost and reduce the complexity of the required change.

Over several years, all these potential solutions were vetted and rejected. Eventually, the insurer insisted that Charter invest in more spares (rectifiers and transformers) and separate the two operating rectifier/transformer pairs. To accomplish this, at least one of the pairs would have to be moved, requiring a lengthy and costly DC busbar system. This relocation would include an expensive substation construction project and necessitate a long shutdown period. Additionally, the newly located rectifier system would require an exhaustive recommissioning process. The insurer suggested another alternative: simply "exempt" coverage for losses involving the power supplies. However, this option was not acceptable to Charter Steel's management.

Finally, a new transformer solution was proposed that seemed much more straightforward: replace the potentially flammable mineral oil insulating liquid with an FM Approved "less flammable liquid" which would mitigate the transformer fire risk at a much lower overall cost and reduce the complexity of the required change. Charter Steel's engineering team was familiar with the fire risk mitigation properties of ester liquids in new, smaller transformers, however, the high cost and lead times for multiple new rectifier transformers presented a sizeable economic obstacle.

The electrical engineering team at Charter needed to determine which transformer OEMs currently make a 48 MW rectifier transformer using FM Approved alternative liquids. Also, could their existing mineral oil-filled transformers be converted from mineral oil to an alternative lower flammability liquid through a process known as retrofilling? Would the units be in good enough condition to warrant a retrofill? With three transformers, one spare, and two in-service, how many new units would they require? Since each unit had a different history of load profiles and differing ages, an engineering study for each transformer was required. Noting that the ester liquids would have different dielectric and thermal properties from mineral oil, such as viscosity, also meant that a study would determine which units could be safely retrofilled and if any modifications or derating would be required.

At this time, the two operating transformers and the one spare were five (5), seventeen (17), and twenty-seven (27) years old. The engineering study determined that the five and 17-year-old transformers could be safely retrofilled with synthetic ester transformer liquid. The 27-year-old transformer was considered an unsuitable candidate to be retrofilled.

Based on a thorough analysis of commercially available less flammable FM Approved liquids, Charter engineers began to look more closely at MIDEL 7131. It was developed over 40 years ago, a synthetic ester liquid with its earliest application in a retrofill at British Steel Company in the UK in the late 1970s. It seemed particularly well suited for the cold northern Wisconsin climate, having one of the lowest cold temperature pour points (-56˚C) of any less flammable ester and an oxidation resistance that outclasses FM Approved natural esters. These characteristics meant that not only would MIDEL 7131 be more fire-safe, but it could take the cold weather and be easy to process during retrofills without the worry of thin film polymerization (a phenomenon occurring much more readily with natural esters when exposed to air).

Charter engineers began to look more closely at MIDEL 7131. It seemed particularly well suited for the cold northern Wisconsin climate, having one of the lowest cold temperature pour points (-56˚C) of any less flammable ester and an oxidation resistance that outclasses FM Approved natural esters. These characteristics meant that not only would MIDEL 7131 be more fire-safe, but it could take the cold weather and be easy to process during retrofills without the worry of thin film polymerization

Accordingly, Charter ordered a new MIDEL 7131-filled transformer to meet the FM-approved standards. This unit would be installed first; then, the two other units would be retrofilled with MIDEL 7131. This staging would also mean there would be minimal downtime. Tamini Transformers was chosen to supply the new MIDEL unit based on the Italian firm's strong track record with rectifier transformers and their experience with MIDEL synthetic ester designs. Additionally, Tamini agreed to perform the retrofill evaluations and manage the retrofilling process. The MIDEL applications engineering team was also consulted to support Tamini's retrofill evaluation and, eventually, worked directly with Charter Steel at no extra cost.

Charter closely compared the operating temperatures between the retrofilled MIDEL transformer and the new MIDEL one. They found no more than a 2°C temperature difference between them.

Once the new Tamini MIDEL unit was installed in April 2021, a side-by-side comparison could be made with its older twin (mineral oil-filled) unit. Because the two units paired with rectifiers operate so that each supplies half of the required furnace power, an accurate apples-to-apples analysis of oil and winding temperatures could occur. Charter engineers found no perceptible differences in the operating temperatures of the two transformers. Approximately four months later, the five-year-old transformer was retrofilled with MIDEL and installed in place of the mineral oil-filled unit During the next several months, Charter closely compared the operating temperatures between the retrofilled MIDEL transformer and the new MIDEL one They found no more than a 2°C temperature difference between them. With excellent results, Charter Steel in late 2022 retrofilled the 17-year-old transformer and put it into operation in place of the first retrofilled unit. In this instance, because the second unit had a different set of oil coolers than the first retrofilled transformer and even the new transformer, up to a 5°C difference in operating temperature was recorded between the operating pairs. However, this was not of concern to the engineering teams as it was still well within the specifications based on the load profile analysis. The transformers are regularly sampled* and there have been no issues with the transformers, both new and retrofilled with MIDEL 7131 ester. Oil test reports have all looked favorable, as seen in Tables 1-3. Charter Steel's engineering team and the company's insurance firm were fully satisfied with the final risk reduction solution.

Photo: Charter Steel

TAMINI TRANSFORMER 49.6 MVA, 26.4kV

	ASTM Test Method	Units	*IEEE C57.166 Standard Limit "Liquid in New Transformers"	Post Energization	*IEEE C57.166 Standard Limit "In-service"	In-Service		
Sample date				Apr 2021		Jul 2021	Jun 2023	Sep 2023
Dielectric breakdown (1mm)	D1816	kV	≥25	27	≥23		26.5	30.3
Interfacial Tension	D971	mN/m			≥11		22.1	22.7
Color	D2129[A]/ D1500[B]		≤200[A]	125	<1.5[B]		0.5	0.5
Acid number	D974	mg KOH/g	≤0.03	0.02	≤0.5		0.03	0.02
Water Content	D1533	mg/kg	≤200	40	≤450	72	114	49.3

Table 1a *Limits are from the draft standard IEEE C57.166 and are subjected to change.*

		IEEE C57.155 Guide Limit	Post Energization	In-Service		
Sample date			Apr 2021	Jul 2021	Jun 2023	Sep 2023
Hydrogen (H_2)	ppm	64	6.1	3.9	8	22
Methane (CH_4)	ppm	104	8.9	1.2	0.5	4.5
Ethane (C_2H_6)	ppm	124	2.8	0.3	1.2	2.7
Ethylene (C_2H_4)	ppm	150	21.9	1.8	4.1	6.4
Acetylene (C_2H_2)	ppm	13	5.6	0.4	0.6	1.2
Carbon Monoxide	ppm	1344	58.8	36.4	275	522

Table 1b

2003 RETROFILLED TRANSFORMER 51.1 MVA, 26.4kV

	ASTM Test Method	Units	*IEEE C57.166 Standard "Liquid in New Transformers"	Post Energization	*IEEE C57.166 Standard "In-service"	In-Service	
Sample date				Dec 2021		Jun 2023	Sep 2023
Dielectric breakdown (1mm)	D1816	kV	≥25	27.7	≥23	27.5	35.4
Interfacial Tension	D971	mN/m		21.8	≥11	22.5	22.8
Color	D2129[A]/ D1500[B]		≤200[A]	125	<1.5[B]	0.5	0.5
Acid number	D974	mg KOH/g	≤0.03	0.02	≤0.5	0.02	0.03
Water Content	D1533	mg/kg	≤200	39.8	≤450	47.3	106

Table 2a *Limits are from the draft standard IEEE C57.166 and are subjected to change.*

		IEEE C57.155 Guide Limit	Post Energization	In-Service	
Sample date			Dec 2021	Jun 2023	Oct 2023
Hydrogen (H_2)	ppm	64	9	14	13
Methane (CH_4)	ppm	104	0.9	0.7	4.1
Ethane (C_2H_6)	ppm	124	1.2	1.7	1.6
Ethylene (C_2H_4)	ppm	150	2	3.5	5.4
Acetylene (C_2H_2)	ppm	13	0.3	1.1	0.3
Carbon Monoxide	ppm	1344	76	205	508

Table 2b

2015 RETROFILLED TRANSFORMER 51.1 MVA, 26.4kV

	ASTM Test Method	Units	*IEEE C57.166 Standard Limit "Liquid in New Transformers"	Post Energization	*IEEE C57.166 Standard Limit "In-service"	In-Service	
Sample date				Nov 2021		Jul 2022	Oct 2022
Dielectric breakdown (1mm)	D1816	kV	≥25	28	≥23	31	29.8
Interfacial Tension	D971	mN/m			≥11		
Color	D2129[A]/ D1500[B]		≤200[A]	125	<1.5[B]	0.5	0.5
Acid number	D974	mg KOH/g	≤0.03	0.03	≤0.5	0.067	
Water Content	D1533	mg/kg	≤200	96	≤450	38	42.7

Table 3a

**Limits are from the draft standard IEEE C57.166 and are subjected to change.*

		IEEE C57.155 Guide Limit	Post Energization	In-Service	
Sample date			Nov 2021	Jul 2022	Oct 2022
Hydrogen (H_2)	ppm	64	0.1	7	9
Methane (CH_4)	ppm	104	0.5	4	2.8
Ethane (C_2H_6)	ppm	124	0.1	1	1.3
Ethylene (C_2H_4)	ppm	150	0.9	4.6	4.6
Acetylene (C_2H_2)	ppm	13	0.3	0.9	1.1
Carbon Monoxide	ppm	1344	14.1	200	229

Table 3b

The fire point of the retrofilled 2003 and 2015 transformers was 304˚C and 302˚C respectively, thus achieving K class/less flammable status in contrast to the O class rating of the original mineral oil

EAFS CRITICAL FACTOR IN STEEL DECARBONIZATION

Steel Manufacturers Association Emissions Report Conclusions

- **Scope 1 & 2**: Domestic EAF steelmakers emit 78% less carbon emissions in crude steelmaking than their integrated counterparts in the US. At the hot-rolled steel level, the emissions standing between US EAFs and BOFs narrows to 74%
- **Scope 3:** Scope 3 emissions for EAFs were similar to or lower than BOFs, and do not close the absolute gap between the two steelmaking routes
- The carbon footprint for slab rerollers that use imported slab is higher than most US BOFs and significantly higher than all domestic EAF-based flat producers
- Direct emissions for US pig iron production reached 1.47 t CO2 / thm, 15% lower than the average among Russian, Ukrainian and Brazilian peers. However, when the carbon footprint of upstream iron ore mining is included, the performance gap narrows to just 5% since US iron ore mining companies have higher emissions than their global seaborne peers
- For integrated steelmaking, CRU has identified a clear relationship between iron ore quality, pellet rates, and BF steelmaking emissions. However, when all scope 3 emissions are considered, there is no overall impact on carbon intensity between domestic BFs and sheet EAFs using imported raw material. Sheet mill EAFs maintain a substantial advantage

Photo: Charter Steel

Michael Sauer is the Electrical Project Manager at Charter Steel, Melting Division, in Saukville, Wisconsin. He has been with Charter Steel in Saukville since they tapped their first HEAT in 1991. With both BSEE and MSBA degrees from Michigan Technological University, Michael is also a Licensed Professional Engineer. As a member of the Association for Iron & Steel Technology for 22 years, he has served on both the Crane and Electrical subcommittees.

Anthony Coker leads M&I Materials' MIDEL business for the Americas. He is in the Academy of Distinguished Engineering Alumni at Georgia Tech, has a Chemical Engineering degree and serves on their Chemical & Biomolecular Engineering Advisory Board. He graduated from the Institute for Georgia Environmental Leadership and serves on the Sustainable Business Advisory Board at the Scheller College of Business. He is Board Chair for cleantech incubator Green House Accelerator and was Board Chair for the Georgia Solar Energy Association. Previously, he worked with a regional solar design/build firm, a start-up solar cell company, General Electric, Dow Chemical and Accenture.

*The new Tamini transformer and the retrofilled 2003 transformers are sampled and analyzed monthly. The tables presented in this article have data on the transformers post energization along with recently analyzed samples. For the new Tamini MIDEL 7131 unit, Table 1a shows the liquid quality data and Table 1b shows the DGA. Table 2a shows the liquid quality data and Table 2b shows the DGA for the retrofilled 2003 transformer. Since the retrofilled 2015 transformer was in operation for few months while 2003 unit was being retrofilled, data presented in this article includes the post energized sample and the last two analyzed samples in 2022. The transformer is now analyzed annually, and the next sample data will be available towards the end of 2023. All the post energization and in-service samples analyzed have values below the upper specification limits, hence all the units are in good operating condition.

Electric Arc Furnaces Emit 78% Less Carbon

The steel industry is the largest manufacturing sector for global emissions, producing approximately 7-9% of all man-made CO_2 emissions, and global steel demand is projected to increase 30% by 2050. As part of a multipronged approach to decarbonizing steel making, EAFs can reduce carbon dioxide emissions by up to 78% over traditional and highly fossil (coal/coke) intensive process such as Blast or Basic Oxygen Furnaces (BOFs).

The Steel Manufacturers Association Steelmaking Emissions Report 2022* captured these figures in its conclusions (insert 1). Though EAFs form a critical piece to the current decarbonization of steelmaking and can displace substantial quantities of "primary" steel, there is not an unlimited supply of high-quality scrap steel (produced via primary steelmaking) to replace the need to decarbonize the primary furnaces fueled by coal. However, look for an increased share of EAF made steel in the near term.

POWER PANEL DISCUSSIONS
Oils and Fluids

Bruce Forsyth
Global Application Engineering Manager, Cargill

Claude Beauchamin
Director of Technical Development and Director of Quality Assurance, TJH2b Analytical Services

Edward Casserly
Senior Scientist, Ergon

Alan M Ross
Managing Editor, APC Media

Alan Ross: Hi, my name is Alan Ross. I am the Managing Editor of APC Media. Welcome to our Power Panel on Oils & Fluids, one of our most popular topics in our digital magazines. My guests for this panel are Edward Casserly from Ergon, Bruce Forsyth, with Cargill, and Claude Beauchamin, from TJ|H2b.

Claude Beauchamin: Good day, everyone. Thank you for this opportunity to share with you our collective experience. I'm Claude Beauchamin from TJ|H2b Analytical Services. I'm a chemist by training and formation, but I've been in contact with electrical engineering all my life. I'm almost an engineer by sympathy. I graduated from Montreal University in '76. In my previous life, for almost 30 years, I was involved in transformer online monitoring both for gas and other parameters. I joined TJ|H2b in 2011, so I've already been Director of Technical Development for 12 years. I'm also a member for the IEEE, and more particularly today for the C57104, the DGA Guide. But I'm also a member of other organizations such as CIGRE, IEC, ASTM, and Canadian Council for Standards. I'm a member of the Ordre des chimistes here in Quebec.

Edward Casserly: I'm Ed Casserly. I received my PhD in organic chemistry from Rice University and began my career as a research chemist with Pennzoil, and I'm currently the senior scientist for Ergon Refining in Mississippi. I've been involved with R&D and technical support for specialty petroleum products for 39 years now. I've got seven US patents with Pennzoil and additional seven patents with Ergon. I'm a member of all the same organizations that Claude mentioned, IEEE, CGRE, IEC. Within ASTM, I am the Vice Chair, and this year I received the IEC 1906 Award.

Bruce Forsyth: My name is Bruce Forsyth. I'm an Electrical Engineer, and I've been working in the transformer industry for just about 36 years. Most of my career has been in the design and manufacturing of distribution and power transformers. I've had the opportunity to be involved in transformers as small as 25kV and 34.5kV class, and as large as 500MVA.

> Our hope is to educate the industry as to what the options are, and then let them make the educated choice of what best fits their application and their current needs.
>
> **Edward Casserly**

I'm a member of several industry organizations, including CIGRE, NFPA, and EEE. I had the honor of serving as chair of the IEEE Transformers Committee for the 2020 to 2021 term. I am currently the Global Application Engineering Manager for Cargill Bioindustrial.

BETTER APPLICATIONS OF DIFFERENT FLUIDS

AR Gentlemen, thank you so much for joining us on this important panel. One of the reasons that we were delighted that the three of you could join us is the expertise that you have demonstrated within the industry. I love the fact that you're all involved with all of different organizations that we're involved with, IEEE, CIGRE, ASTM and others.

For our first topic, where would you advise a new engineer coming into a utility, specifying new products for different classes of transformer, on which oil to specify? Is there a simple rule that she can apply, or is it just, "it depends"? Ed, let's start with you.

EC Thanks, Alan. First off, let's talk about either naphthenic or iso-paraffinic. You have to realize there's a full range of mineral oils out there. The original ones were the naphthenic, and then there were paraffinic oils, which had wax in them, so they had high pour points, and then there were iso-paraffinic oils. In the last few years, we had the bio-based, hydrocarbons. There's a lot of different types of molecules that are parts of mineral oils.

In addition, there's several different levels of inhibition. So, you have totally uninhibited versus high-grade inhibited. Those give you different levels of oxidation and stability.
So basically, mineral oils have been around for the last century since the late 1800s, and so they've been used successfully in all applications and voltage types, including free breathing application. If you want to look at what's been used historically, it's been the mineral oils because those are the only thing that have been available. The uninhibited mineral oils are generally used in less severe, lower voltage

Photo: Shutterstock

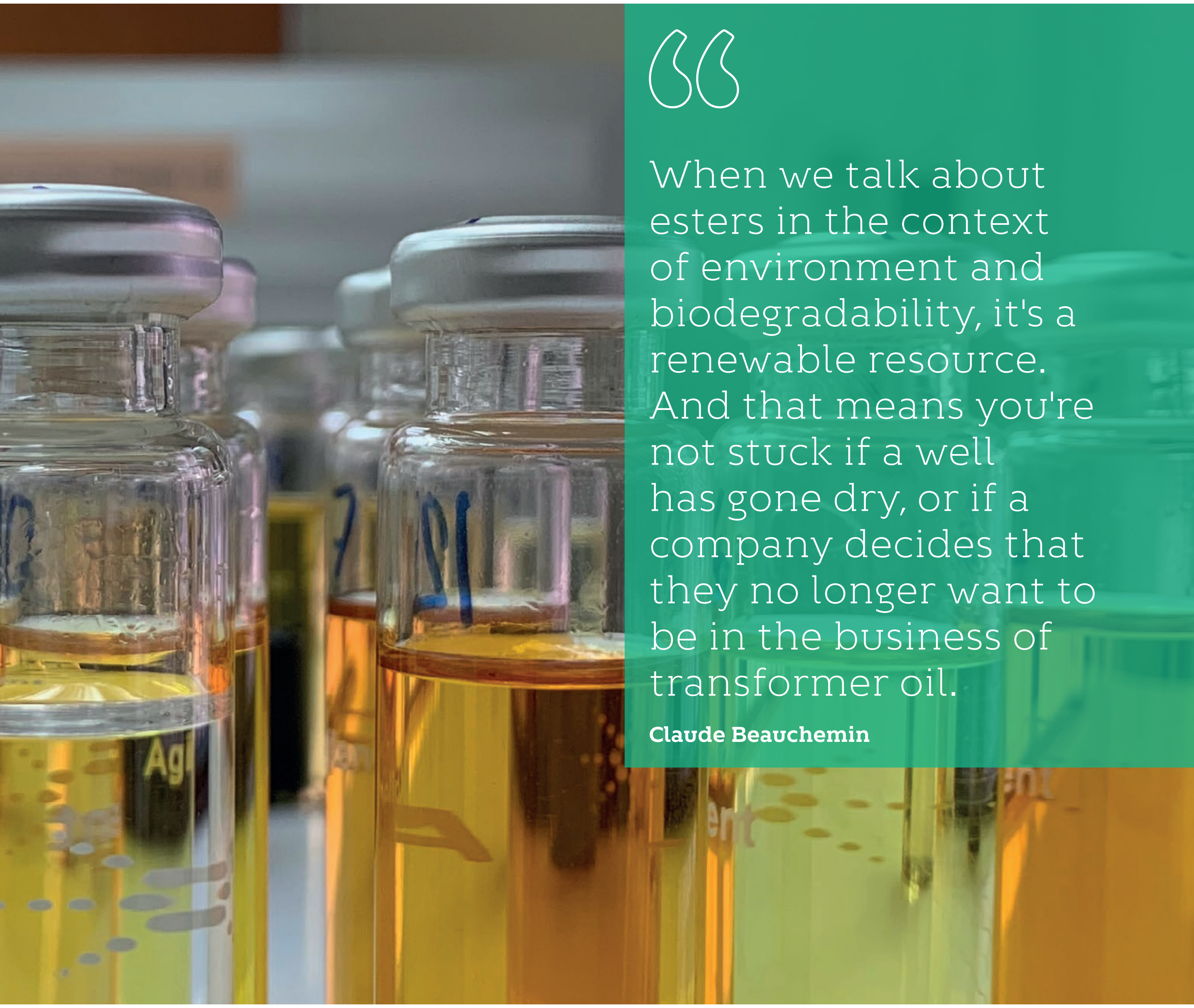
> For life extension reasons, natural esters have a tendency to keep the insulation a little bit drier if customers are looking to extend the life of a transformer.
>
> **Bruce Forsyth**

applications, because they don't have the same oxidation stability as the inhibited ones.

But there's a few applications where they are not suitable. Recently they haven't been used as much due to non-electrical considerations. They do have a relatively low pour point, and so they're not used in buildings where high pour point liquids are being used. The use of sprinklers and fire suppression can help mitigate the risk and potential damage of fires. But if you want to be safer, you'd put in a high fire point liquid, such as the esters. They're not typically readily biodegradable, so if you're next to water or an environmentally sensitive areas, you want to shy away from the mineral oils and use the natural synthetic esters, since they are. Our hope is to educate the industry as to what the options are, and then let them make the educated choice of what best fits their application and their current needs. There's a wide range for them to choose from. I don't want to say buyer beware, but it's the buyer's choice.

AR *Buyer beware*. I like that. Specify the wrong oil in a transformer and be aware of the consequences. Bruce, if you could take the same question.

BF Motivation is a tricky thing, and what Ed alluded to is that at the end of the day, it's up to the buyer to decide what's right for their application. But I will emphasize that the fire risk is important, the natural esters have a much higher fire point. If a transformer is going to be placed indoors, or is in close proximity to other structures, natural esters are a good option to consider. In those cases, Ed mentioned the proximity to waterways, if there's a risk of a spill of any sort, the natural esters are 99% readily biodegradable and generally non-toxic to the environment. If there was a spill, there would still be issues related to preventing it, but it would prevent some of the long-term environmental damages. Moreover, for life extension reasons, and I'll mention that, again, maybe at some point, the natural esters have a tendency to



> When we talk about esters in the context of environment and biodegradability, it's a renewable resource. And that means you're not stuck if a well has gone dry, or if a company decides that they no longer want to be in the business of transformer oil.
>
> **Claude Beauchemin**

Photo: Shutterstock

keep the insulation a little bit drier if customers are looking to extend the life of a transformer- If a certain amount of overloading is required, natural esters have some characteristics that benefit that application as well.

AR Claude, TJ|H2b is very utility-focused, correct? I mean, a lot of your customers are utility-focused, so talk a little bit about what you've seen in your career, as it relates to either of these from a specification standpoint. You're a member of organizations that write standards, so talk a little bit about that.

CB Ed and Bruce did a nice job describing the pros and cons of both families of products, esters and mineral oils. I've been there long enough to remember the time when an ester-based oil was simply a research project somewhere. Today, it has become a choice depending on preference. As Ed pointed out, there are some criteria to follow. We do see an increase in the use of non-mineral oil in the industry very clearly. We do see new liquids, like gas-to-liquid, synthetic, synthetic materials, synthetic esters, and synthetic hydrocarbons. There is a lot of activity there.

When we talk about esters fin the context of environment and biodegradability, it's a renewable resource. And that means you're not stuck if a well has gone dry, or if a company decides that they no longer want to be in the business of transformer oil. Now, of course, as far as the lab is concerned, this presents a lot of challenges. Mercifully, the tests are the same for all types of liquid. If you do a DGA, you do a DGA, it's the same gas. But the interpretation and sometimes the analysis process are slightly different, or sometimes quite different. We also must take that into account. When we receive a sample, it's important to know what it is, because you don't process a DGA for mineral oil in the same manner that you process it for an ester-based oil. As far as a specification is concerned, again, Ed rightly pointed out that at the end of the day, this is the customer's decision. And of course, the manufacturer of the transformer must know in advance what you want.

WHY DOES IT TAKE SO LONG FOR EXPERTS TO MAKE DECISIONS?

AR I love the fact that you set me up for the next question. I think DGA is the number one test that everybody runs, right? In the utility industry, certainly, DGA is the number one fluid diagnostic they base their decisions on. I've mentioned that it took six years to update the DGA guide from the transformer committee. All of you have been involved in that. Six years is a long time to be able to upgrade the guide. There's a reason why it took six years. So, Bruce, why six years?

BF Why does it take so long? That's a great question. It takes so long because one of the great things about the IEEE and the IEC documents is they're developed by volunteers. These are people that are involved in the industry and dedicate their time to come together and analyze the information that's available and try to come, as a community, to the best technical decisions that benefit the industry as a whole. There's a lot of different opinions involved. It takes time to aggregate data. One of the issues that took a long time with this most recent gas guide is gathering the latest and greatest information.

Data that's available is key to making these decisions. Interpreting data, and Claude is an expert on this more than I am, but interpreting the DGA data is not a simple process. There's a lot of things that go on in a transformer that affect what's in that oil. And pulling these things together, getting the data to have statistically reliable results is a challenge and takes time. And then once we have it, as I said, aggregating it, and analyzing it, and coming up with the right information, understanding what that data is telling us, it takes time. There are a lot of different opinions involved sometimes and it takes time for all of those experts to express those opinions, to work them out, and to find that common story that best represents the state of technology today.

AR Excellent. Great. Claude, he set you up now, because you see it. You see it in all of the results. And a lot of it depends on interpreting the data. As an engineer, I want to know - give me some data, but give me an interpretation so I know what it means, but more importantly, so that I know what to do, right?

CB First of all, Alan, I unfortunately have to correct you. It was not six years; it was more like 15.

AR I knew that, but I didn't want to say that.

CB The work started in or around 2003 for the revision of the guide, and it got stuck. And as Bruce highlighted, it's all volunteers who work on this and the work is long. In 2006, there was a vote at the meeting, I think it was in Montreal, where they decided to simply reiterate the guide as is with some minor corrections, because they were not ready to put something new out. We voted on it in 2018 and it got published in 2019. Depending on where I put my starting point, it's more like 15 or 16 years. One of the difficulties is it is developed by volunteers, so the time that people could share with us is a limiting factor.

By the way, I want to personally thank Dave Hanson, my boss, who gave me the opportunity to volunteer. The amount of time I sank into that guide, it was just insane. Any other boss would have simply pulled the plug and said, *Claude, you have a day job, don't forget it.* He let me work on it, and I have to thank him for that.

The other item that is a bit of a corollary to the fact that we're all volunteers is that it is very much like herding cats. We have a lot of different opinions, a lot of different points of view, and it becomes a bit of horse trading. *Yes, we said that, but no, you could not say this*, and so on, and so forth.

The data we collected, over a million and a half points of data had to accounted for. By the way, thank you for the paper that Transformer Technology published years ago on this topic. Just the work to collect the data, clean it, because you could not use the raw data as is, then process it, and then ask the question, "okay, we got this result, is it meaningful, is It is useful?" Now we have the discussion and then start the computation again if we're not happy with it. Plus. there is the complication that you might have a supplier that has various requirements in terms of privacy of the data. That was a major undertaking and I'm glad that we managed it.

AR Excellent, Claude, thank you. Ed, you get to sum up all of that, and you can just say "ditto", or give us your thoughts. As the vice chair of ASTM, which is also a standards organization, talk a little bit about why it takes as much time, whether it is an ASTM standard, or an IEEE, or an IEC?

> Interpreting the DGA data is not a simple process. There's a lot of things that go on in a transformer that affect what's in that oil.
>
> **Bruce Forsyth**

> "The data, we collected, over a million and a half points of data had to be accounted for. Just the work to collect the data, clean it, because you could not use the raw data as is, then process it, and then ask the question, 'okay, we got this result, is it meaningful, is it useful?'
>
> **Claude Beauchemin**

Photo: Shutterstock

EC There are four different international committees that work on insulating liquids. You got ASTM and IEEE, which are based in the US, IEC and CIGRE in the EU. ASTM and IEC develop standards - specifications for insulated liquids. IEEE and CIGRE publish guides, like the maintenance guides. You have experts, as both the gentlemen mentioned, from around the world and from different disciplines. You have chemists and local chemists talking to organic chemists, talking to electrical engineers, talking to mechanical engineers and we don't all speak the same language. There's that. There's the education between the different experts for them to understand your point of view. It takes a while. For the specifications, we want the things to be very exact. What is the flash point? What is the pour point? We can do that and say these are all the tests that are important, but then we have to come up with a value to use. That's a little like Claude said, a little bit of horse trading as to "is the flash going to be 140 or is it going to be 145?". And everybody has their own opinions. And it all comes down to compromise and consensus. You must work together.

BF Let me add that when the standards are developed, it never ends. It's not like it's over. Our standards are constantly under development. The challenge is deciding when to publish whatever is available today. We're not very good at drawing a line and saying, "let's publish what we've got today". The engineers always want to say, "no, we've got one more paragraph we need to add. We need to do one more little thing." We're not as good as the cell phone manufacturers that every September have a new model coming out. We tend to want to try to make that document perfect before it gets published. And sometimes that takes a little longer than it should. But that's an important thing. So, once it's published, a lot of times these documents are immediately open for revision, because new information becomes available.

EC Within IEC, we recently added a requirement for straight gassing for the inhibited high-grade oils within IEC 60296, which is a specification for mineral insulating liquids. It's only required for that one product, not for the uninhibited or the trace inhibited products, but it's something that the end users were asking about. They were always asking about straight gassing. They wanted some performance testing, and so it took a considerable amount of testing to define the test parameters that we used and to put in the limits for the high-grade mineral oils. There's a lot of discussion these days for performance-based parameters. One last thing is that there's a growing number of liquids and other components with the different types of paper. The whole system must be compatible with all the other parts of all the other components. You have to look at it as a system and not just a collection of different components. You just can't say, "well, this is the best mineral, or this is the best ester". You must say, "this is the system", be it mineral and paper, and all the different other components as a whole. You must make sure that everything works together.

AR Excellent. And thank you. We do have a question from the audience. Is there an undue influence from suppliers in developing these standards?

BF Let me add that when the standards are developed, it never ends. It's not like it's over. Our standards are constantly under development. The challenge is deciding when to publish whatever is available today. We're not very good at drawing a line and saying, "let's publish what we've got today". The engineers always want to say, "no, we've got one more paragraph we need to add. We need to do one more little thing." We're not as good as the cell phone manufacturers that every September have a new model coming out. We tend to want to try to make that document perfect before it gets published. And sometimes that takes a little longer than it should. But that's an important thing. So, once it's published, a lot of times these documents are immediately open for revision, because new information becomes available.

EC Well, the ASTM D27 and IEC TC 10 are both the committees for insulating liquids and fluids. And so, by default, they're going to be dominated by the insulating people, the liquids people and the gas people. There are other com-mittees within ASTM and IEC that deal with the transformers or the components of transformers, and those are dominated by the end users, the manufacturers and end users. But you're right in that we need more cross pollination between the liquid people and the manufacturers of the transformers and the end users. We would love to have more utilities within the ASTM D27. We have a few, but we definitely would love more. Same thing within IEC. We get pigeonholed into different groups because of the scope of that particular committee, but we welcome everybody to come in and give their input.

POWER PANELS

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Understanding Oil Specifications

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The chosen fluid must serve multiple functions, including preventing flashover, acting as a heat transfer medium, preserving the core and coil assembly, and reducing aging of the insulation by restricting oxygen and moisture ingress.

Eileen Finnan, currently holds the position of Senior Director, Professional Services at Doble Engineering where she is responsible for transformer consulting, field testing, and insulating and high voltage laboratory services in the US. She has participated for many years in cross-functional teams that deliver in-depth condition assessments of critical electrical assets and large-scale fleet assessment services. Her previous roles include Manager at Doble Engineering Materials Laboratory which provides routine and specialized testing on insulating fluids from electric power equipment. Eileen currently has responsibility for issuing the Doble Annual Survey which evaluates commercially available domestic and international transformer oils. She is a frequent presenter of Doble's Laboratory Diagnostics Seminar. Eileen received her Bachelor of Science degree in Physics and Chemistry from Trinity College in Dublin, Ireland.

Mineral oil plays a crucial role in the insulation system of vital transformers on the electric grid. Transformers facilitate energy transfer between electrical circuits without any moving parts, through inductively coupled conductors. The insulation, primarily composed of cellulose, is enhanced by a liquid dielectric. The chosen fluid must serve multiple functions, including preventing flashover, acting as a heat transfer medium, preserving the core and coil assembly, and reducing aging of the insulation by restricting oxygen and moisture ingress. Achieving the right mix of properties involves balancing considerations such as dielectric strength, viscosity, density, volatility, flash point, and chemical stability—all at a reasonable cost and without compromising environmental or safety concerns.

Specifications

There are several specifications available today that can be used to assure quality of mineral insulating transformer oils. Doble Transformer Purchase Specifications (TOPS) was one of the first specifications in North America, having been first published in 1961 and updated over the years to reflect the changing needs of the industry. Organizations such as IEC, IEEE, and ASTM have similar specifications.

Oxidation inhibitors, such as synthetic additives like DBPC/BHT and DBP, slow down this process by competing for available oxygen. Specifications typically separate oils into classification based on the amount of added antioxidant.

All of these specification standards essentially evaluate the same properties of the oils, differing somewhat in the particular tests included or the methods required; physical, electrical and chemical properties that relate to the functioning of the oil, its composition, purity, and stability. Additional properties, additives and behavior may also be included in these specification documents, for example stray gassing is a mandatory test in TOPS while it is not part of some other specifications. Figure 1 lists some of the properties typically included in oil specifications and the significance in practice of those characteristics.

Mineral oils are oxidatively unstable, which can lead to the formation of acidic by-products and eventually sludge deposition in transformer cooler areas. Oxidation inhibitors, such as synthetic additives like DBPC/BHT and DBP, slow down this process by competing for available oxygen. Specifications typically separate oils into classification based on the amount of added antioxidant, as shown in Table 1. In TOPS, oil with passivators which act as metal deactivators is evaluated as inhibited Type II.

Many commercially available oils have been evaluated against TOPS by Doble Engineering laboratories since the first such report was published in 1953. Reviewing the historical data shows the move away from uninhibited to inhibited oils, shown in Table 2, as refining processes developed and demand for the fully uninhibited oils receded. The oils tested as part of the survey are from refiners globally and include oils from the Americas, Europe and Asia.

Table 1: Inhibitor Classifications

TOPS 3 Classes by Inhibitor Content	ASTM 2 Classes by Inhibitor Content	CAN/CSA C50 3 Classes by Application 4 Classes by Inhibitor Content			IEC 60296 2 Classes by Application	
		A(<25°C)	B(>25°C)	S(OCB)	Xfrms	Low T Switchgear
Uninhibited					Type U	Type U
Inhibited Type I **0.08% max**	Inhibited Type I **0.08% max**	Type I **0.08% max**	Type I **0.08% max**	Type I **0.08% max**	Type I **0.08% max**	Type I **0.08% max**
Inhibited Type II **0.3% max**	Inhibited Type II **0.3% max**	Type II **0.4% max**	Type II **0.4% max**			
		Type III **0.4% max** Extended performance	Type III **0.4% max** Extended performance			
		Type IV **0.4% max** Extended performance	Type IV **0.4% max** Extended performance			

Table 2: Inhibited Oils Over the Years

Survey No	Year	Total Number of Oils Tested	Number of Uninhibited Oils	Uninhibited Oils, % of Survey Oils Tested
32	1969	13	13	100
41	1973	10	10	100
61	1983	18	7	38.9
100	2007	41	6	14.6
108	2015	37	1	2.7
110	2017	46	5	11
113	2020	43	3	7
115	2022	64	8	13

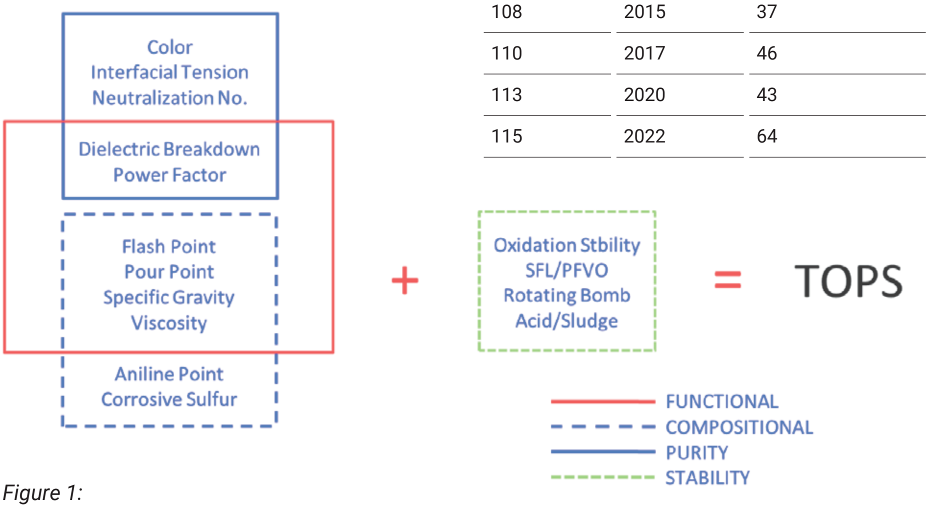

Figure 1: Relevance of Common Specification Tests

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Mineral insulating oils are thermally stable and can withstand temperatures as high as 700°C in low oxygen environments. They are, however, oxidatively unstable, especially at high temperatures. All oxidation stability testing is essentially the same – the oil is aged in an accelerated manner using heat, oxygen, and a copper catalyst. Natural and added inhibitors will slow the aging process and therefore less stringent limits are allowed for uninhibited and less inhibited oils. Maximum concentrations of inhibitors are specified to avoid poor performance of the base oil being masked by the presence of excessive retardants. A typical aging test, ASTM D2440, calls for the heating of the oil at 110°C in the presence of sanded copper wire, which acts as a catalyst, while oxygen is fed to the oil through a thin tube throughout the 64 and 120hour aging periods. At the end of each period, the acidic byproducts and any sludge formed are quantified,

Mineral insulating oils are thermally stable and can withstand temperatures as high as 700°C in low oxygen environments. They are, however, oxidatively unstable, especially at high temperatures.

Electrical Properties

To ensure the oil can satisfy the demands of an effective dielectric, several electrical tests are included in TOPS. The dielectric breakdown volage, measured using ASTM D1816, involves a voltage being applied across spherically shaped electrodes with a defined gap of 1mm or 2mm, until a flashover between the electrodes occurs (Figure 3). The limits given in TOPS apply to a fluid that has been filtered and dried, which is generally done with new oil prior to filling in an electrical asset. Typical data for new oil is shown in Table 3.

Power factor, also referred to as dissipation factor, is a test used to measure the dielectric losses of the fluid at room temperature and at 100°C. Testing at both temperatures helps qualify the type of material causing the losses. A high reading at room temperature not reflected in the higher temperature measurement is an indication of moisture or conducting particles that are driven off in the heating process. A high reading at 100°C suggests the cause is contamination of the new fluid with polar compounds.

The impulse breakdown test is carried out using the cell shown in Figure 4, which is a negative needle to sphere configuration. It is an indicator of the oil's ability to resist lightning voltage stresses and is influenced by the concentration of polycyclic aromatics. The TOPS limit for this test is 145kV minimum.

Table 3:
ASTM D1816

Product From Refiner	Dielectric Breakdown Voltage D1816 1mm Electrode Gap kV	Dielectric Breakdown Voltage D1816 2mm electrode gap kV
Oil 1-As received	12	18
Oil 1-After Filtering and Drying	39	73
Oil 2-As received	41	70
Oil 3-As received	23	48
Oil 4-As received	17	30
Oil 4-After Filtering and Drying	35	64

Figure 2:
Accelerated Aging Testing ASTM D2440

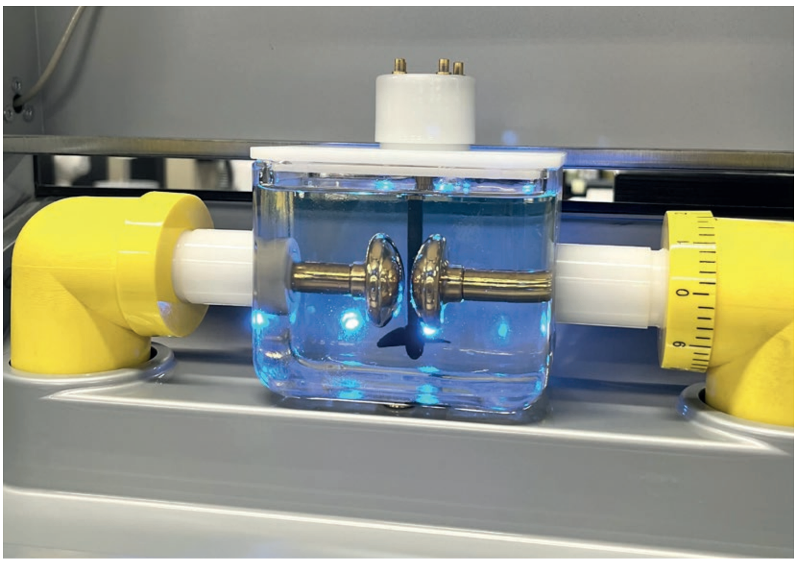


Figure 3:
Dielectric Breakdown ASTM D1816

The gassing tendency (ASTM D2300) is a measure of the ability of an oil to absorb or evolve gas over a set period after the oil has been saturated with hydrogen and has had voltage applied to the oil/gas interface. The resultant ionic bombardment of the oil molecules results in some hydrogen gas being released from saturated hydrocarbon molecules in the oil and some gas absorbed by unsaturated aromatics. The resultant net absorption or evolution under these conditions will determine whether the oil is deemed positive or negative, and the latter can be important under certain high-stress applications.

Physical Properties

Properties such as color and interfacial tension are an indicator of oil purity, with new oils typically having a clear appearance with little color noticeable. Exposure to light can cause darkening due to photodegradation reactions, and contamination or contact with incompatible materials will similarly cause new oils to exceed the 0.5 maximum color allowed.

Figure 4:
Impulse Breakdown Voltage

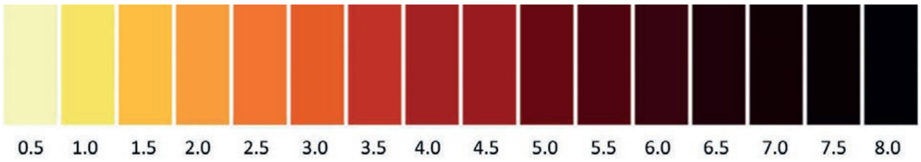


Figure 5:
Color

The number refers to a standard color scale that increases in increments of 0.5 as shown in Figure 5.

The interfacial tension (IFT) of an oil is the amount of force needed to break the oil water interface with a fine platinum ring (Figure 6) and is a measure of the polar compounds left in an oil. Clean new oil should easily meet the minimum of 40 mN/m specified by TOPS. Figure 7 plots the data from 2019 survey report and all easily satisfy the requirements. Given the consistently high recent values in IFT which are likely a reflection of more modern refining, an increase in the IFT minimum is under consideration for the next revision of TOPS.

Pour point, relative density and viscosity are indicators of flow characteristics and the oil's suitability as a heat dissipation medium.

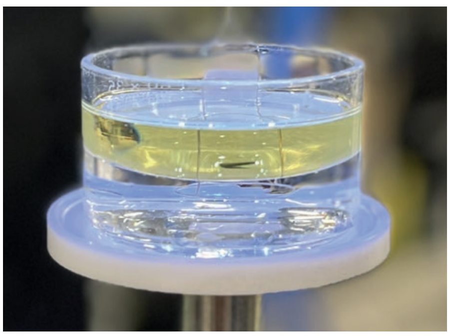


Figure 6:
Interfacial tension

Viscosity is measured at 0°C, 40°C and 100°C to ensure it can perform adequately over the range of temperatures likely to be encountered in service. The pour point is a measure of the oil's ability to flow at very low temperatures and can be of importance for cold start up conditions. These properties should not change over the service life of the oil and any significant change would indicate contamination or very advanced aging where sludge has precipitated from the oil.

Corrosive Sulfur and Additives

Corrosive sulfur compounds, if present in an oil, will attack copper and silver leaving deposits of metal sulfides on the metal and paper surfaces inside a transformer in service, and can contribute to failure. This has been an ongoing issue in service since the early 2000s and in response, oil specifications, including TOPS, updated the requirements to include more rigorous testing to aid in detecting problematic oils. Corrosive sulfur testing by ASTM D1275 and Doble Covered Copper Deposition (CCD) must both be passed for an oil to be deemed non-corrosive by TOPS. Testing for dibenzyl disulfide and elemental or free sulfur were added as mandatory tests to help reduce the incidence of corrosive sulfur in service. Figure 8 shows copper sulfide deposits on conductor paper insulation from a transformer winding and on the conductor in an in-service bushing.

Photo: Shutterstock, Doble

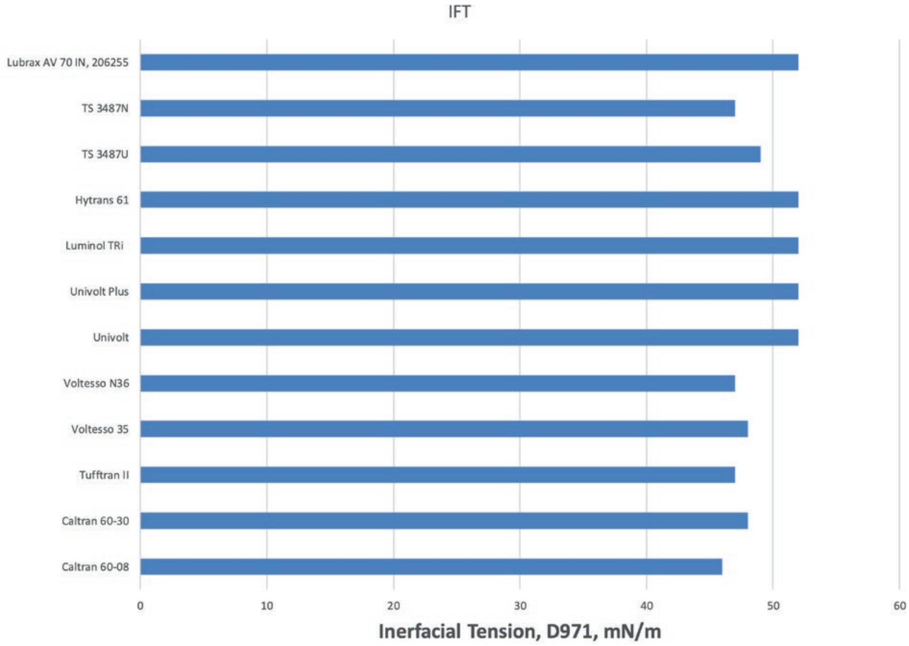
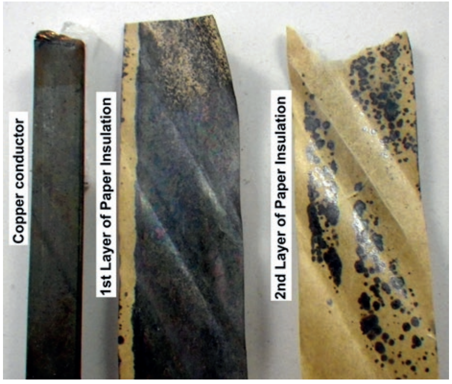


Figure 7:
IFT of North American Oils from Survey Report 2019



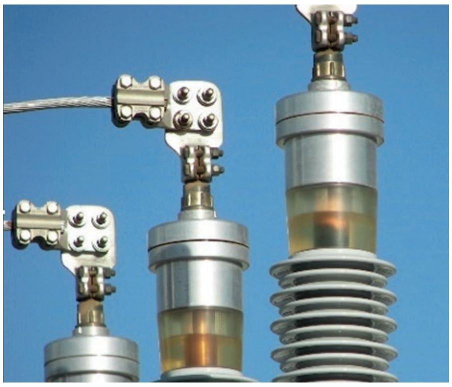


Figure 8:
Copper Sulfide Deposits In Service

Testing by ASTM D1275 involves heating the oil with a small copper strip for 48hours at 150°C and comparing the tarnish level to a standard corrosion chart, as shown in Figure 9. The oil is considered to have failed if the tarnish level is 4a or darker.

The Doble CCD evaluates both the copper strip and a layer of paper aged with it, in both a low and high oxygen environment, to mimic both sealed and free-breathing conservator conditions in the field. Again, the copper is compared to the corrosion chart, and the paper is examined for deposition of copper sulfide, a characteristically shiny deposit on the copper-facing side of the paper wrap (Figure 10). If any one of the paper or metal strips fails, the oil is deemed corrosive.

Passivators

Passivators, also known as metal deactivators, are sometimes added to an oil to improve oxidation stability and can also mitigate corrosive sulfur by reducing the rate of metal sulfide reactions. These passivators attach to the metal surfaces thereby reducing the number of reaction sites available for the corrosive sulfur compounds from the oil, as depicted in Figure 11. TOPS specifies there should be no detectable passivator unless agreed otherwise by the buyer.

Figure 9:
ASTM D1275 Corrosive Sulfur Testing

Figure 10:
Covered Copper Deposition Testing

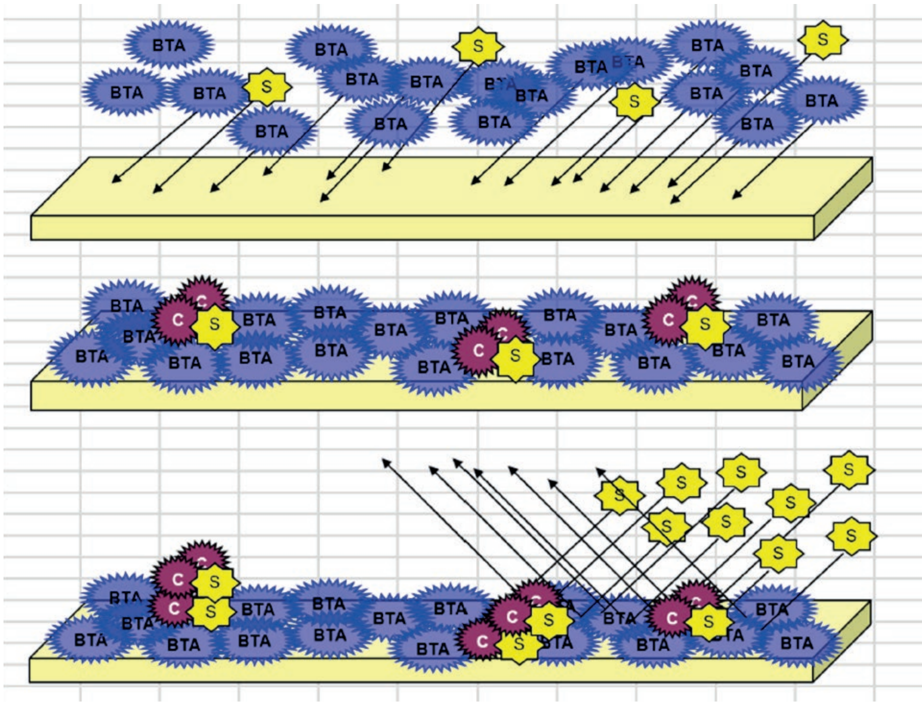


Figure 11:
Passivator Action

Stray Gassing

Dissolved Gas Analysis (DGA) is a crucial test for monitoring electrical asset performance during service. Gases generated from oil and insulation breakdown offer insights into asset management and grid reliability. Stray gassing, caused by the fluid or additives like passivators, should be considered to avoid misinterpreting in-service data. Table 4 presents norms based on survey data, helping identify oils prone to stray gassing through tests in high oxygen and high nitrogen environments simulating different service conditions.

Dissolved Gas Analysis (DGA) is a crucial test for monitoring electrical asset performance during service. Gases generated from oil and insulation breakdown offer insights into asset management and grid reliability.

Oils with passivator added can show a greater tendency to produce higher than normal concentrations of some gases, typically hydrogen and carbon monoxide, which are formed at lower temperatures. Concentrations of Hydrogen from survey oils tested is shown in Figures 12, with the concentration of passivator shown for any oil that had detectable concentrations of BTA or Irgamet 39.

Table 4:
Stray Gassing Norms TOPS

Typical Stray Gassing Values 95% Norms Determined by Doble over 3 years (with outliers removed)		
	Concentration, ppm (ul/l)	
GAS	Air Sparged	Nitrogen Sparged
Hydrogen	590	250
Methane	120	80
Carbon Monoxide	450	115
Ethane	120	36
Carbon Dioxide	1580	385
Ethylene	8	6
Acetylene	0	0

Note:
Analysis performed by ASTM D3612C after aging

Composition

Mineral transformer oils can be sourced from naphthenic, paraffinic, or natural gas, each with distinct properties due to the hydrocarbon composition. Naphthenic oils have fewer waxy compounds and are refined using solvent extraction and hydrotreating, which produces a base oil that is receptive to oxidation inhibitor additives. The refining process needs to allow some aromatics,

Photo: Shutterstock, Doble

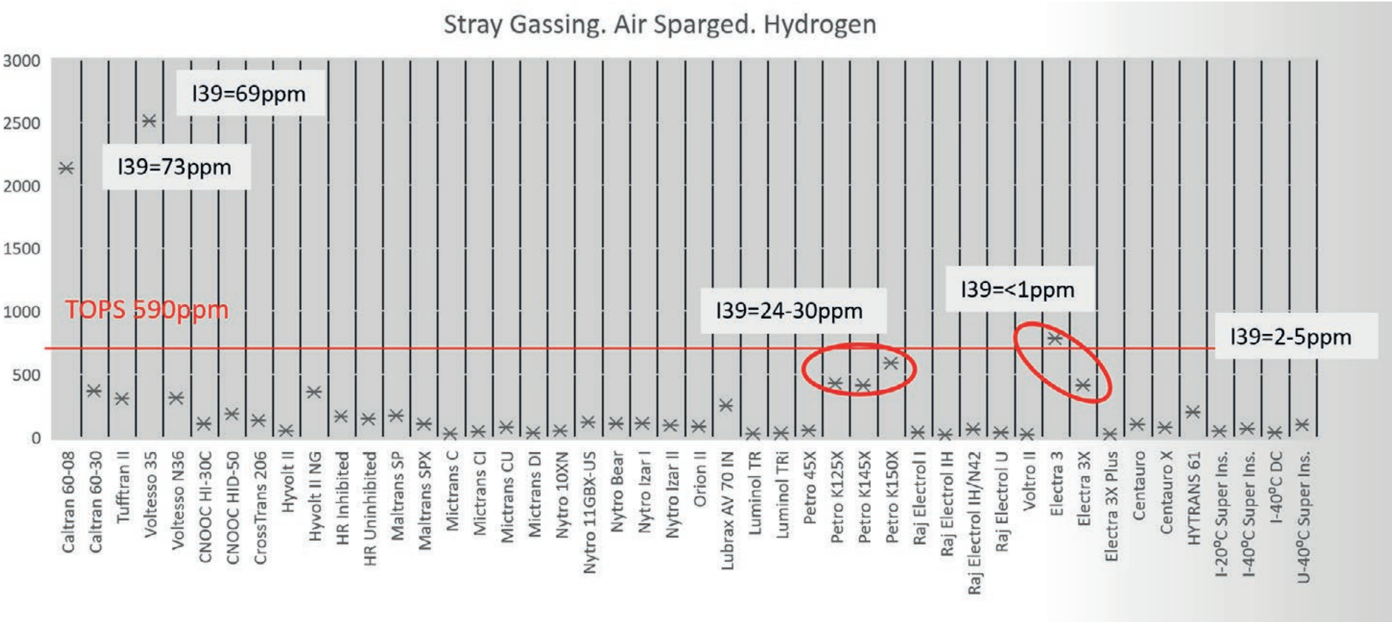


Figure 12:
Stray Gassing Hydrogen Air Sparged

which are natural inhibitors, to be retained in those oils that will not have synthetic inhibitors added (Uninhibited products). Highly refined paraffinic oils produced using hydroprocessing, which removes waxy components and undesirable compounds such as sulfur and nitrogen, have very low aromatic contents and typically have lower specific gravity and viscosity than naphthenic oil. This lower viscosity can be most evident at lower temperatures.

Gas-to-liquid (GTL) oils, derived from methane, are almost entirely isoparaffinic and without added aromatics have very high gassing tendency values. Flash point is influenced by the volatile compounds in an oil and iso-paraffins tend to be well in excess of the 145°C minimum specified by TOPS. This limit may be reviewed in the next revision of TOPS. Extended rotating pressure vessel times are also a typical feature of iso-paraffin oils.

Properties of oils from various sources are detailed in Table 5.

Summary

In summary, there are many oils in the market from different crude sources and specifications should be employed to help you evaluate them. Advances in refining processes result in changes over time and specifications need to keep up with these changes so that they remain relevant. Oils from these various sources are generally fully miscible and compatible with one another, with the caveat that when replacing an oil in service with one that has a significantly different aromatic content, may lead to gasket issues, impacting seal effectiveness.

In summary, there are many oils in the market from different crude sources and specifications should be employed to help you evaluate them. Advances in refining processes result in changes over time, and specifications need to keep up with these changes so that they remain relevant.

Table 5:
Properties of oils from different sources

Doble 2022 Survey Report No. 115	Aniline Point	Flash Point	Interfacial Tension	Neutralization Number	Pour Point	Power Factor at 100°C	Power Factor at 25oC	Relative Density 60/60	Viscosity at 0C	Viscosity at 100C	Viscosity at 40°C	Viscosity at 40°C	Oxidation Inhibitor Content	Sludge-Free Life	Oxidation Stability D2440				Rotary Bomb	Gassing Tendency at 80°C	Impulse Breakdown Voltage	Carbon Type Composition, C_A	Carbon Type Composition, C_N	Carbon Type Composition, C_P
															72		164							
Units	°C	°C	mN/m	mg KOH/g	°C	%	%		KIN cSt	KIN cSt	KIN cSt	SUS	% wt.	Hrs	% wt.	mg KOH/g	% wt.	mg KOH/g	Min.	microL/min	kV	%	%	%
Product	D611	D92	D971	D974	D97	D924	D924	D4052	D445	D445	D445	D2161	D2668	Doble (b)	None	D974	None	D974	D2112	D2300	D3300	D2140	D2140	D2140
Naphthenic NA	80.7	154	51	<0.01	-66	0.057	0.002	0.879	62.77	2.44	9.71	57.8	0.27	>88	<0.01	<0.01	<0.01	<0.01	315	32.8	>300	4.0	47.0	49.0
Isoparaffin-NA	103.3	181	49	<0.01	-57	0.070	0.005	0.824	50.14	2.55	9.20	56.1	0.23	>88	<0.01	<0.01	<0.01	<0.01	604	19.8	>300	1.1	26.6	72.3
Isoparaffin-Asia	105.1	188	51	<0.01	-51	0.016	0.002	0.835	59.34	2.89	11.41	63.8	0.35	>88	<0.01	<0.01	<0.01	<0.01	640	35.7	>300	0.0	27.5	72.5
GTL	112.1	194	55	<0.01	-48	0.010	0.001	0.808	54.80	2.70	9.29	58.40	0.26	>88	<0.01	<0.01	<0.01	<0.01	678	52.6	>300	No value registered		

Q&A

POWER TRANSFORMER DRYING: VAISALA

TRANSFORMER TECHNOLOGY Q&A WITH PAUL KOESTINGER, OWNER, RETRANOL GMBH, AND SENJA LEIVO, SENIOR INDUSTRY EXPERT, VAISALA

Photo: Vaisala, Shutterstock

VAISALA

Transformers are critical components in electrical transmission systems. However, moisture can degrade transformers and reduce their lifetime. In this Q&A article with transformer drying experts Paul Koestinger, owner of Retranol GmbH, and Senja Leivo, Senior Industry Expert at Vaisala, we will explore common questions about moisture in transformers, its effects and key drying methods to remove moisture and extend transformer life.

What is the purpose of drying a power transformer — and why do it?

Concerning drying power transformers, there are three main points:

1. **Life expectancy:** The moisture in the transformer governs the degradation of the paper. The more moisture you accumulate in the paper, the shorter the lifetime of the transformer. Keeping average paper moisture content to 1% or below optimizes insulation life. But normal levels of around 2% still allow decades of safe operation before the end of life.
2. **Dielectric breakdown:** When a transformer cools down, cold oil can contain less moisture than hot oil, which may result in free water in the oil and in the transformer in the dielectric field, which can lead to a cascading flashover and insulation failure.
3. **Overload capability:** Overloaded transformers can create bubbles due to the evaporation of moisture in the transformer. The higher the moisture content, the lower the temperature where these bubbles form. Since bubbles immediately precipitate dielectric failure, the overload capacity is reduced with high moisture.

Temperature dictates paper degradation. The higher the transformer's temperature, the faster the paper degradation. Moisture also has a significant influence on the speed of degradation. The more moisture in a transformer, the quicker the paper will degrade.

Once a power transformer's insulation paper becomes brittle, the transformer approaches the end of its lifetime. Degraded paper does not mean the transformer will fail immediately, but a short circuit in the grid will result in significant movement on the windings. If the insulation paper around the copper winding starts breaking off, the transformer can short circuit.

Once a power transformer's insulation paper becomes brittle, the transformer approaches the end of its lifetime.

What are the primary sources of moisture in power transformers?

Moisture can make its way into transformers through several routes, even in units that should theoretically operate moisture-free:

- **Breathing:** As transformers operate, the bulk oil expands and contracts with temperature fluctuations. This causes the tank to breathe, with the oil level rising and falling in the conservator. To replace the volume, the space is designed to breathe through a silica gel breather that dries the incoming air. However, the gel cannot dry air down to the deficient moisture levels inside the tank. Slow ingress still occurs over decades of breathing, especially in industrial transformers with frequent load cycling and oil movement.
- **Broken gaskets:** Any external oil leaks around gaskets, valves or seals allow moisture to migrate into the tank while oil leaks out. The concentration gradient in power transformers drives moisture into the paper insulation. Even tiny leaks allow moisture accumulation over months or years of operation.
- **Paper degradation:** Over decades of continuous operation, the cellulosic paper insulation slowly degrades through thermal aging, oxidation and hydrolysis from small amounts of accumulated moisture. This degradation process produces water as a byproduct, gradually increasing the overall moisture content within the transformer over its lifetime.

Another crucial topic when discussing drying is moisture distribution in a transformer. While small amounts of water vapor and droplets dissolve or suspend within the insulating mineral oil, the vast majority of moisture in a transformer migrates into the solid cellulose-based insulation around windings.

Over 99.8% of the total moisture content within a transformer resides in the cellulose paper insulation, not the bulk oil.

For example, consider a 400 MVA transformer containing 15 tons (33,000 lbs.) of cellulosic insulation and 60 tons (132,000 lbs.) of mineral oil. An average insulation moisture content of 3% would contain approximately 450 liters (120 gallons) of moisture bound in the solid insulation and only 0.6 liters (0.16 gallons) dissolved in the oil (at 30°C). The moisture distribution is not entirely even throughout. Thicker blocks and barriers are less accessible and absorb less over time. About 50% of the total cellulose interacts more actively with the oil, exchanging moisture.

Over 99.8% of the total moisture content within a transformer resides in the cellulose paper insulation, not the bulk oil.

Ester fluids can contain roughly 20 times more moisture than mineral oil before becoming saturated. But even with esters, over 97% of total moisture remains concentrated in the paper insulation.

Moisture can infiltrate transformers from several sources over decades of operation.

When does moisture accumulation warrant drying a unit?

While no moisture should be present in new transformers, ambient humidity, leaks and degradation gradually increase moisture.

Three common scenarios call for a complete transformer drying process:

1. The first and the most common is following any major internal maintenance or repairs. After exposing the core and windings to ambient air and moisture, a drying process helps remove any moisture. The longer the exposure period with oil removed, the more critical a complete drying becomes. A few days of exposure introduces minimal moisture, while repairs taking weeks or months cause severe moisture increases.
2. When sampling and testing indicate high moisture content in oil and insulation, general guidelines — like the IEC standard 60422 — suggest drying is beneficial above 20 PPM moisture in mineral oil. Online monitoring provides the best trend data to identify increasing moisture over time.

Photo: Shutterstock, Vaisala, Retranol GmbH

3. Proactively planned midlife service — at around 25-30 years of operation for most transformers — can help remove any moisture accumulated from small leaks or degradation, extending the unit's remaining useful life. Scheduled midlife drying provides best condition with regards to degradation from moisture or oxidation.

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When it comes to drying itself, the main factor is the diffusion speed. The more moisture we remove in one hour, the better the drying efficiency. This diffusion speed or drying speed is influenced mainly by temperature. The hotter you heat some material, the easier it is to remove moisture.

And because humidity is a significant factor, drying a transformer from 4% to 3% is much easier than from 2% to 1%. The lower the moisture content, the harder removing moisture from the transformer becomes. When extracting moisture from a material, we have to create a pressure difference between the inside of the material and the outside. Applying vacuum is always an excellent idea whenever you want to dry transformers. Also, the material properties are fundamental to understand because drying thin paper around the copper winding is much easier than the thick blocks on the material. Speaking of drying in the field, the issue of oil impregnation exists. Under-standing your material is essential because when you dry it in the factory, there is no oil on the paper. In the field, you always have oil-impregnated material that blocks the moisture going in but also prevents the moisture from coming out. So, more powerful systems are necessary to remove the same amount of mois-ture as in the factory.

Consequently, vacuum is a critical issue in the drying process. A perfect drying situation demands higher temperatures and vacuum simultaneously.

Reaching a specific temperature is vital. The higher the temperature in the drying process, the faster it is. So, your drying time will be shorter, but you also have temperature-dependent paper degradation. You cannot heat a transformer to 200 degrees and finish within one day. You must have an equilibrium between perfect temperature and what kind of degradation you have in the process.

Determining when to proactively dry transformers depends on various factors, but what practical methods can be applied once drying is deemed necessary, and which is the most efficient?

Transformer drying techniques range from relatively simple processes to highly engineered solutions for large units.

Factory vapor phase drying: Considered the gold standard for the lowest moisture content, vapor-phase drying heats the transformer active part to 130° using va-porized solvents without oxygen. This facilitates deep drying over three to five days. Factory systems use sealed chambers and hydrocarbon vapor, achieving residual moisture levels below 0.5% in insulation. New large units are all dried this way, but bringing vapor-phase ovens into the field is not due to explosion risks.

On-site vacuum drying: Mild heat is applied through hot oil circulation and then pulling a strong vacuum on the tank. This removes moisture directly from the windings and paper by vaporization. As energy is consumed by evaporating mois-ture, the process cools down over time. Depending on the transformer size, multiple vacuum cycles with heating phases may be required to reach target moisture levels.

Hot oil spray technique: Hot oil is sprayed directly onto windings while vacuum is held. This way evaporation of moisture can happen at the same time as heating the insulation. This approach is often used in shell-type transformer designs.

Low-frequency drying: A low-frequency power source runs a current directly through transformer windings to generate internal heating from 20-50% of a nominal current. With no oxygen present, high temperatures safely dry paper. This process is often combined with hot oil spray and presents the most powerful drying technique on site.

Online oil drying/degassing: Continuously circulate a side stream of oil through an external vacuum dehydration unit and return degassed oil to the tank. Although very slow, the gradient between dry oil and wet windings during this process allows gradual moisture removal over months or years and keeps the oil clean.

Molecular sieve dryers: Install temporary molecular sieve filters that continuously circulate a portion of the oil volume, slowly reducing moisture levels in the circulating oil. Gradual paper drying occurs over months or years.

What technique is the most efficient?

That depends on transformer size and your needs. Let's compare the different methods with our example unit, the 400-MVA transformer, with 3% moisture.

Controlling the moisture extraction rate helps provide the most valuable data to guide drying process control and determine when satisfactory dryness has been achieved.

Drying this transformer in the factory, its vapor phase will take some days. This transformer needs a week to dry if we use the low-frequency technique. In the method with hot oil and vacuum, that's a month of drying time. If we go to oil circulations, even with high temperatures, consider a year or much more with small drying machines with minimal oil circulation. So, with a smaller transformer, consider more straightforward techniques. With big transformers, adopt a more advanced approach.

Numerous drying techniques can be applied in the field to remove moisture from transformer insulation and oil.

After completing an on-site drying process, how can utilities confirm that the drying process was successful?

Controlling the drying process is a complex task. However, controlling the moisture extraction rate helps provide the most valuable data to guide drying process control and determine when satisfactory dryness has been achieved.

Measure hourly moisture extraction rate

By installing dew-point sensors on vacuum lines or measuring moisture at the exhaust of the vacuum pump, the moisture extraction rate can be calculated in grams per hour or ton of insulation.

Target 5-20 g/hr-ton initially in factory vapor. Expect substantially lower extraction rates in the field due to oil impregnation effects and lower process temperatures. But higher rates indicate the presence of higher levels of moisture.

Monitor vacuum level evolution

The magnitude of vacuum pull provides the driving force to remove moisture from insulation by vaporization. As moisture decreases over time, vapor pressure drops and vacuum increases. When the vacuum level flattens out, the air ingress and the suction capacity are equalized.

Check measurements after oil filling

Final dryness validation relies on methods like Dielectric Frequency Response (DFR, DIRANA, PDC). However, these are not useful during the actual heating process. To get a good understanding through a moisture in oil sample will take months.

Extraction rate and vacuum trends are the best real-time guides for controlling on-site drying processes.

Photo: Shutterstock

The difficulty with esters, especially natural esters, is that they tend to polymerize when they are exposed to heat and oxygen at the same time.

What special considerations apply when drying ester-filled transformers?

Ester fluids can absorb and dissolve far higher quantities of moisture than traditional mineral oils. This increased solubility allows faster surface moisture removal on wet insulation and more effective drying by circulating oil through a dehydrator.

Despite the liquid's high moisture capacity, most moisture remains trapped within the cellulose paper insulation, not the bulk fluid. Simply changing the liquid without internal drying does not dry the transformer.

The difficulty with esters, especially natural esters, is that they tend to polymerize when they are exposed to heat and oxygen at the same time. This needs to be considered when selecting the drying technique. Hermetic sealing systems are far more critical with ester fluids since external leaks allow much faster moisture ingress compared to mineral oil.

Ester-based fluids present unique drying considerations compared to traditional mineral oil-filled transformers. However, another critical transformer design factor also warrants attention during drying — the compression force clamping windings and core steel.

How critical is monitoring winding clamping pressure changes during drying?

Removing moisture from paper insulation can lead to some loss of clamping pressure on transformer windings.

Normal operation leads to gradual loss of the original clamping force over decades of thermal cycling, material degradation and mechanical vibrations. Limiting the target residual moisture minimizes drying-related clamping loss based on field experience. Re-clamping before drying showed to be sufficient in most cases on old units.

Moisture accumulation presents a vexing challenge in maintaining power transformers. While drying requires care and expertise, moisture reduction will extend the safe operating lifetime of these critical assets. When faced with moisture issues, transformer owners can leverage established drying methods to return transformers to optimal dryness, managing transformer life cycles for decades of safe operation.

Download the definitive Vaisala eBook on Moisture in Transformers. This companion to our renowned webinar series is full of the latest practical and scientific advice on measuring moisture in power transformers.

Limiting the target residual moisture minimizes drying-related clamping loss based on field experience.

Cattie Liang

CATTIE LIANG *is the Commercial Director of Power Systems overseeing the China FR3® fluid team at Cargill. Cargill's FR3 fluid, derived from over 95% vegetable oil, is the original, most tested natural ester in the world. FR3 fluid outperforms mineral oil in overall cost savings, grid resiliency, transformer performance and fire safety providing a better way to power how our communities live, play, work and thrive.*

In her extensive 15-year career in the energy industry across Denmark and China, Cattie has passionately advocated for clean and green energy solutions and products. Having worked in wind turbine manufacturers and energy consulting firms, she has played a pivotal role in advancing clean energy and providing advisory to power industry investors. Cattie's expertise spans across supply chain management, strategies, and business development. Now leading the commercial team in China, Cattie is dedicated to propelling FR3 fluid to the China power market.

Drawing from her experiences in the power and energy industries, Cattie recognizes the vital role women can play and the great achievements women can potentially make in the power systems industry.

Aligned with China's 2060 Carbon Neutrality policy, Cattie firmly advocates for natural ester over mineral oil.

Her leadership aims to expand natural ester application in solar and wind markets in China, contributing to the nation's commitment in renewable energy, as well as paving the way to prove women's power in power systems.

Cattie studied in Denmark and holds a MSc in Economics and Business Administration.

Find more inspiring stories in our online edition of the Women in Power Systems.

Drawing from her experiences in the power and energy industries, Cattie recognizes the vital role women can play and the great achievements women can potentially make in the power systems industry.

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The Transition to Green Transformer Insulating Oils – Yes or No?

In this month's issue of Transformer Technology, there is a well-informed podcast presentation on the current state of power transformer insulating fluids. This included, among other topics, their availability and technical aspects. The major suppliers of these fluids were all contributors to the presentation. It also includes a question-and-answer segment at the end.

IF WE LOOK AT THESE PRODUCTS STRICTLY FROM A MARKETPLACE USE PERSPECTIVE, HYDROCARBON NAPHTHENIC-BASED OIL TYPE AND NATURAL SOY ESTER FLUIDS COMPRISE MOST OILS USED TO FILL POWER TRANSFORMERS.

by **Chris Kenney** President
Clover Oil and Chemical Company LLC

Photo: Shutterstock

A short recap of the products discussed were hydrocarbon naphthenic-based oils as well as natural ester vegetable oil-based fluids. To drill down a little deeper as to the availability of hydrocarbon type fluids, we should mention a paraffinic chemical composition type of hydrocarbon fluid is also marketed to the transformer industry. Ester fluids can be obtained as either a natural ester derived from seed oils such as soy, canola, rapeseed, sunflower etc. The synthetic esters are derived from a selection of alcohols and acids through a chemical reaction of esterification.

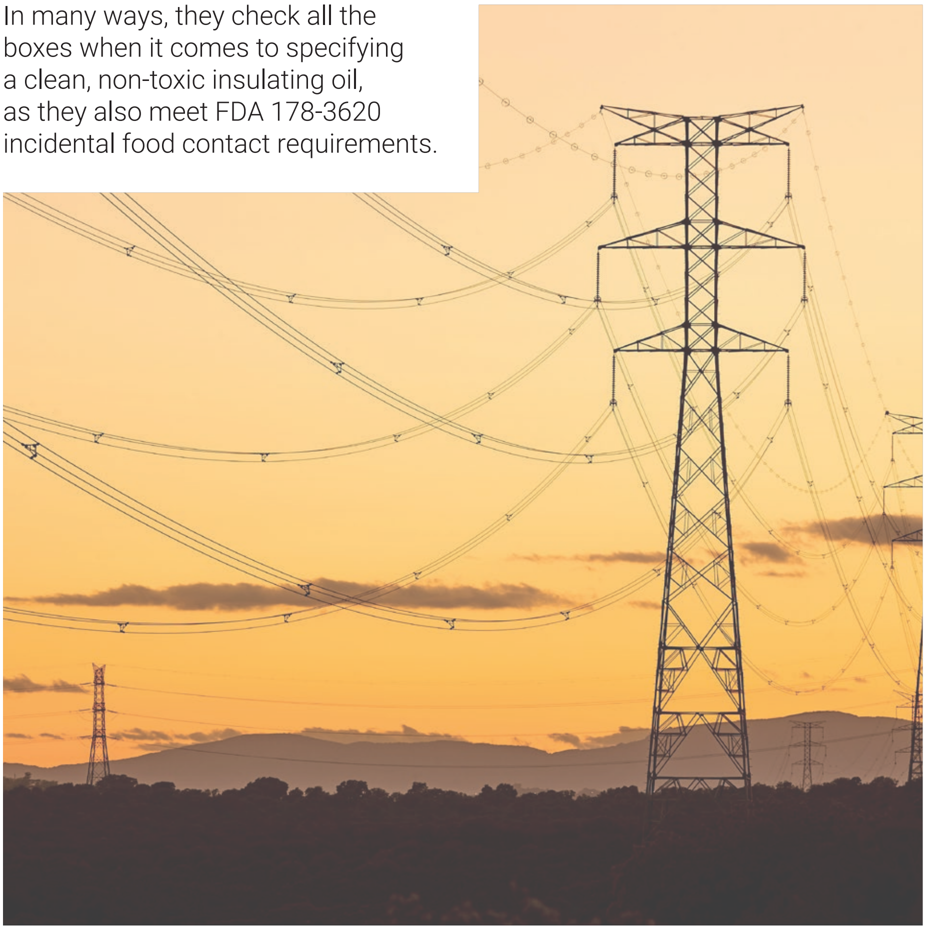
If we look at these products strictly from a marketplace use perspective, hydrocarbon naphthenic-based oil type and natural soy ester fluids comprise most oils used to fill power transformers. If we segment naphthenic-based oils and esters, I will estimate the hydrocarbons fill out approximately 98% of the market.

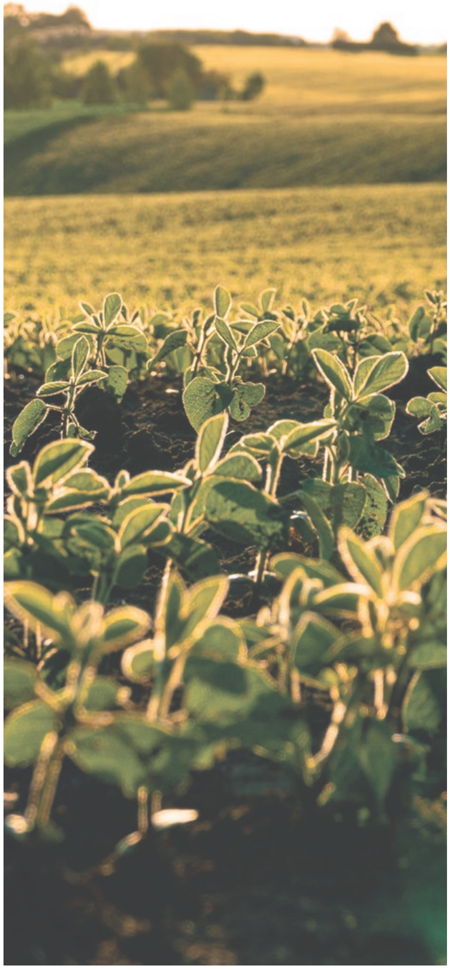
Chris Kenney spent the majority of his time in the refining industry in the sales and marketing of specialty hydrocarbon fluids, more specifically in transformer oil sales. Chris has worked in sales and sales management with Ergon Refining, Cross Oil, Petro Canada and Calumet Specialty Products. In all these assignments, he was at the forefront in business development roles dedicated to developing net new transformer oil market share. Chris is an expert in the technical aspects of both naphthenic and paraffinic transformer oils and has established worldwide contacts in the power transformer industry and US utility industry. Chris holds a Bachelor of Arts from St. Joseph's University, and currently resides in Acworth, GA with his wife Karen. Chris is available for either full, or part-time consultation arrangements regarding the sales and marketing of transformer oils.

We can say a few words about paraffin-based fluids, their characteristics, and ultimately why they lag so far behind naphthenic-based oil products among users. Paraffin-based oils make excellent insulating oils. Paraffin-based oils, because of their natural chemical composition, are in some ways superior to the naphthenic oils. Paraffin-based oils are the overwhelming choice to blend almost all lubricant formulations. 50% of the lubricant market in the US falls into the motor oil category. Apart for synthetic motor oil formulations, paraffin-based oils are 100% exclusively specified as the preferred base stock. Many of the technical aspects of paraffin-based oils, primarily oxidation stability, translate well when used as a transformer oil. The current technology used to make current generation motor oil is known as hydrocracking. Hydrocracking produces low pour points, very low Sulphur, and aromatic content, as well as low polynuclear hydrocarbons, which are considered hazardous to people's health. They require no passivators when blending transformer oils to make type 1 or 2 transformer oils. In many ways, they check all the boxes when it comes to specifying a clean, non-toxic insulating oil, as they also meet FDA 178-3620 incidental food contact requirements.

Amidst all this, they have failed to make any dent in the macro market consumption percentage, because the pricing of these products is simply not competitive with their cousin, naphthenic-based oils. This price question will come up again when we talk about the ester products. It is not that the marketers of paraffin-based oil insulation fluids have not tried to make their case as to the value add of these oils. They have. I have personal experience going down this road. It is just the value proposition has been inadequate to make many potential customers make the switch to the higher priced product.

PARAFFIN-BASED OILS MAKE EXCELLENT INSULATING OILS. PARAFFIN-BASED OILS, BECAUSE OF THEIR NATURAL CHEMICAL COMPOSITION, ARE IN SOME WAYS SUPERIOR TO THE NAPHTHENIC OILS.





The natural ester product has run into the same resistance in the marketplace as the paraffin-based oil. The natural soy ester fluids exhibit chemical properties when subjected to ASTM 3487 requirements and show them to be excellent candidates to make power transformer insulating fluids. They especially shine when it comes to flash and fire point.
The natural soy ester material has a flashpoint of 330°C and a fire point of 360°C. The naphthenic-based oil has a flash point of 145°C and a fire point of 160°C. They can also boast of being biodegradable and rated non-hazardous in soil and water. Mineral oil is not readily biodegradable and has the potential for toxicity. Natural soy ester fluids do not exhibit sludge formation. Mineral oils, when subjected to overheating, begin to oxidize. This oxidation causes a buildup of acids which will lead to sludge formation and eventually begin to destroy the cellulose inside the transformer. The synthetic ester oils are used in much lower quantity than the natural vegetable seed oil product. They are also much more expensive than the natural ester.

Photo: Shutterstock

They have a more specialized application field as well: marine transformers, underground transformers, and rail and traction transformers. As it stands today, only one producer of natural soy ester oil supplies the American market. This presents a difficulty for other companies which might want to enter this market. The distribution and medium power oil insulated transformer manufactures who use this product by application will have one tank from which to feed their plant fill. Currently, as far as I can tell, the ester product is not being used in any large power transformer field fills. I am not making any technical claims as to why this is true. I am involved in the sale and marketing of insulation fluids to the North American field fill market. My company represents the mineral oil products, as well as a new entry into the natural soy ester insulating fluid market. I simply see no demand in the substation type large power transformer space for ester fluids.

THE NATURAL SOY ESTER FLUIDS EXHIBIT CHEMICAL PROPERTIES WHEN SUBJECTED TO ASTM 3487 REQUIREMENTS AND SHOW THEM TO BE EXCELLENT CANDIDATES TO MAKE POWER TRANSFORMER INSULATING FLUIDS.

Lastly, we can talk a little more about the who, why and where of these various fluids and what the future holds for them in the future. We are all aware of the scientific and cultural demands for heavy industry and consumer products in the transition to a green economy. Mostly this revolves around climate change. I'm not a scientist, but I am aware of some of the conflicting claims entered by the proponents both for and against the path to follow to achieve such a monumental task. As pertains to transformer oils, the effort to replace hydrocarbons as insulating fluids has been affected by this movement as well… but with little success. As I mentioned earlier, naphthenic-based oils fulfill approximately 98% of the macro market for new power transformer fill. The green ester products have made some inroads, but is very small sliver of the market. The esters, as I have said, make excellent insulating oils. One of characteristics most often mentioned is their high flash and fire points. Their biodegradability is often touted as one their most important benefits. These benefits are real and can, in those cases where relevant, make a big difference in an outcome where a potential fire or explosion would take place. I suppose the question should be what is the incidence of this occurrence? According to T&D World, the average probability of a serious transformer fire is on the order of 0.06% and 0.1% per service year, or one fire per 1000 to 1500 transformer service years. Thankfully, large power transformer fires are rare.

The high price of ester transformer fluid like paraffin-based oil transformer fluids when compared to green benefits is slowing the sales and usage of these fluids. The other consideration is the fact that the acceptance specifications for transformer oils have been established over the years to accommodate the hydrocarbon mineral oil products. They are what they are because the standards committees who have established the specifications have agreed they were adequate to fulfill the demands of transformer operating conditions to insure a long and trouble-free life. The green and technical data used to promote the higher price has not proven to cause a large industry-wide migration to the green product slate. It must be noted a major manufacturer of both natural and synthetic ester insulation fluids recently sold this segment of their business to a major oil company.

I BELIEVE GREEN PRODUCTS, WHERE APPLICABLE, SHOULD ALWAYS BE THE FIRST CHOICE TO INSURE A SAFE ENVIRONMENT FOR US ALL TO LIVE IN. BY THE SAME TOKEN, THEY MUST BE ABLE TO COMPETE VALUE-WISE WITH THE PRODUCTS THEY REPLACE.

I believe green products, where applicable, should always be the first choice to insure a safe environment for us all to live in. By the same token, they must be able to compete value-wise with the products they replace. It seems at the present time the dominant fluid will be the naphthenic-based oil hydrocarbon. Until competing products, be they other hydrocarbon-based oil fluids, or natural or synthetic ester prices come more in line with conventional hydrocarbon fluids, the transition to green products will remain slow.

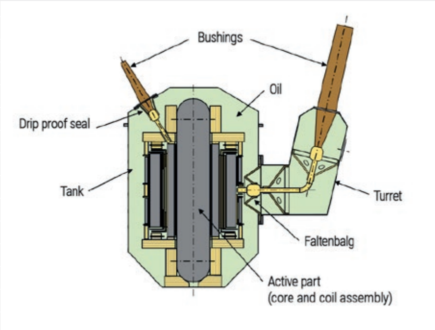
MAKING YOUR
TRANSFORMERS
BETTER

WEIDMANN FALTENBALG

Technology

The Weidmann Faltenbalg is a diaphragm made of Transformerboard providing a drip-proof separation of the oil in the main tank from the oil in the bushing turret. The Faltenbalg is used in oil-filled transformers where current-carrying leads run from the sealed main tank into an adjacent compartment containing, for example, a bushing, a connection to a series transformer, or a regulator.

For decades, Weidmann has been helping transformer manufacturers and utility companies add value to their transformers. Using our advanced manufacturing technology, the Faltenbalg is a reliable insulation structure made from our superior insulation material and is shaped like 'folded bellows'.



Features & Benefits

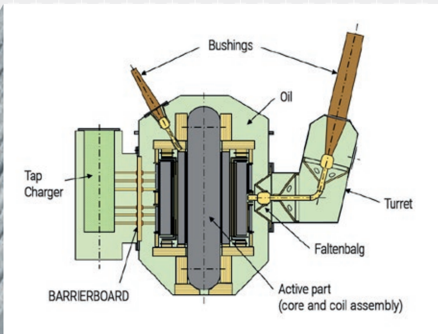
- Protects the core and coil assembly against the ingress of moisture and dirt during the bushing assembly.
- More accurate location of PD sources as DGA tests can be taken from the main tanks and the other compartment (e.g. the bushing turret) separately.
- Protects the windings during the dismantling of the bushing for servicing.
- Provides an optimized design for the mid-winding lead passing through the tank wall; a benefit when there are weight or road/rail clearance restrictions.
- Reduction in commissioning time due to the on-site oil filling operations being limited to a small amount at the bushing turrets.
- Standard designs available for AC power transformers up to 500 kV (≤ 1,5 bar) and special, customized designs available for DC applications (convertor transformers).
- Each production series of Faltenbalgs is over-pressure tested in Weidmann's special test tank.
- Using our significant experience in the design and manufacture of hundreds of Faltenbalgs for installation in transformers around the world, our customers can be assured of safe installation and use of this crucial insulation component.

Photo: Wiedmann

WEIDMANN BARRIERBOARD

MAKING YOUR TRANSFORMERS BETTER

Over 60 years ago, Weidmann, the inventor of precompressed Transformerboard, developed polyester laminated board. Its unique characteristics of high electric and mechanical strength and dimensional stability make it the best choice of material for Barrierboards.



Technology

Weidmann Barrierboards provide a leakproof separation of the oil in the transformer tank from the oil in the tap changer chamber. The separation of these elements provides a range of benefits:

- Maintenance on the tap changer can be done without emptying the main tank.
- Significantly reduced risk of a tap changer failure impacting the transformer's active part.
- Possible to conduct separate oil sampling in the main and the tap changer tanks.

Using laminated board of a thickness of 50mm and more, Barrierboards are designed in various forms to meet specific installation requirements. Typical voltage and current requirements range from U_N = 70 to 420 kV; I_N = 50 to 4400 A (≤ 1,5 bar).

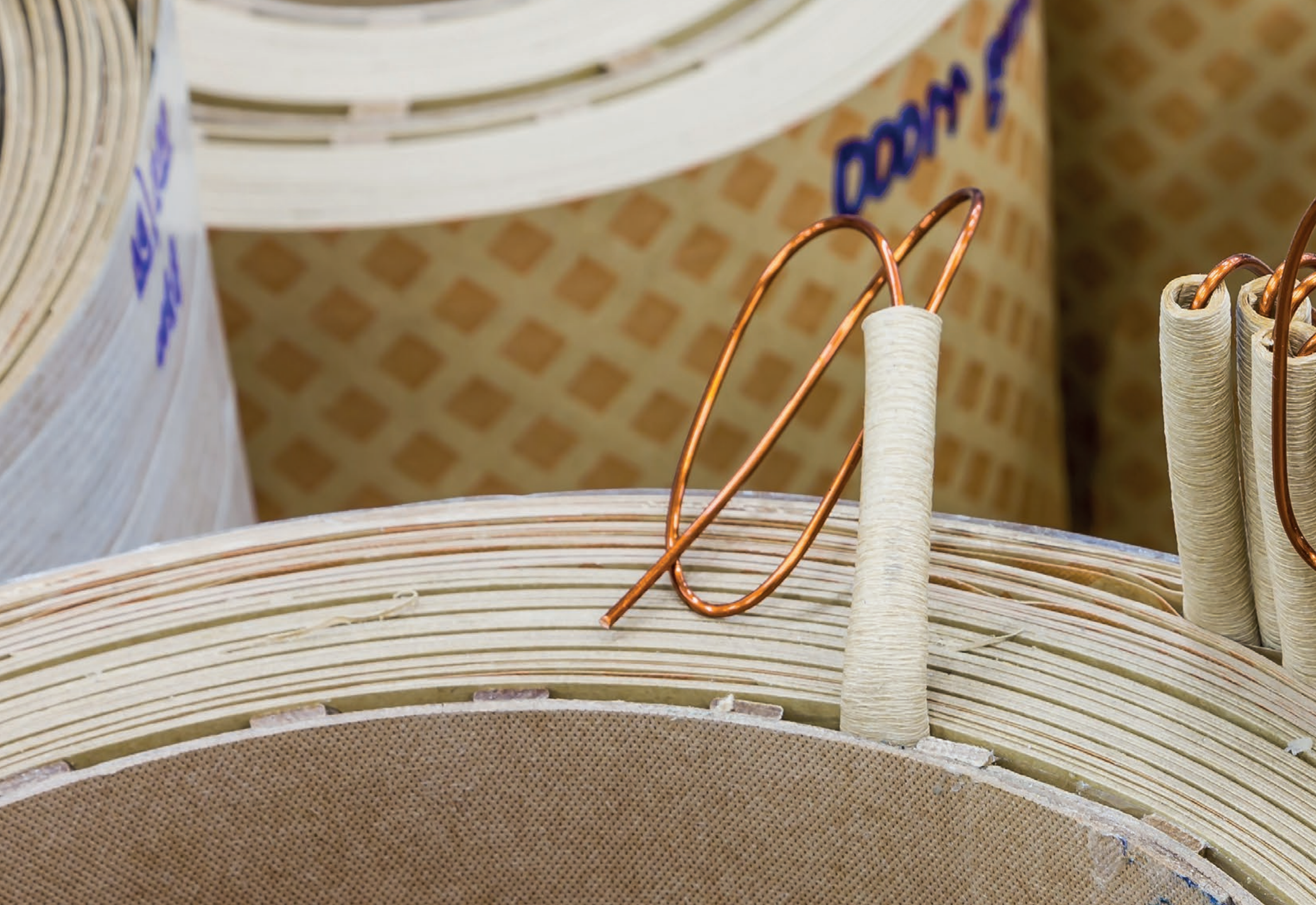
The cylindrical shapes of the contact sockets or pins are designed to cope with often high electrical voltage stresses. The contacts are designed for connecting at both ends so that the tap connections can be easily attached.

Features & Benefits

- Oil in the main tank does not need to be drained during maintenance of the tap changer ensuring the transformer's active part remains protected from moisture and dust pollution.
- Quick and efficient drying, vacuum treatment, and oil filling of the tap changer compartment, keeping outage times to a minimum.
- Plug-in connections are available to significantly reduce the transformer assembly time.
- The configuration of the terminals creates a smooth field pattern and facilitates minimum clearances to earth and consequently reduces overall dimensions.
- Flexible designs (rectangular, round, oval) to meet specific installation requirements.
- Weidmann's 40+ years of experience designing and manufacturing hundreds of crucial Barrierboards guarantees our customers proven safe installation and high performance over many years of use in transformers around the world.

WEIDMANN

website: weidmann-electrical.com e-mail: electrical@weidmann-group.com



How Wet Is My Transformer, and What Should I Do About It?

by **Brian Sparling**

The most important piece of information needed (and often ignored at the time of sampling) is the temperature of the oil sample when it is taken. Without this temperature being noted, the value of the moisture-in-oil test is meaningless.

Brian Sparling, SMIEEE (a Senior member of IEEE), is the Senior Transformer Technical Advisor with Kinectrics Inc. Brian has over 20 years of experience in the field of power and distribution transformers. For the past 30 years, he has been involved in all aspects of monitoring, diagnostics, and condition assessment of power transformers. He has authored and co-authored more than 34 technical papers on various topics dealing with monitoring and diagnostics of transformers. He has contributed to many guides and standards with the Canadian Electricity Association, IEEE Transformers Committee, and the Cigré A2 Transformers Committee.

Moisture assessment in transformers is often determined using equilibrium diagrams, where the moisture content in the solid insulation (paper, pressboard) is derived from the moisture content in oil (ppm). This method fails for several reasons, a primary one being that aging of oil has a major impact on the moisture titration assay. Furthermore, the Karl Fischer Titration (KFT) method suffers from moisture ingress into the sample during transportation to the laboratory, and different processes utilized during transportation and improperly sealed sample containers can also lead to the release of water from the sample leading to unsatisfactory results. The most important piece of information needed (and often ignored at the time of sampling) is the temperature of the oil sample when it is taken. Without this temperature being noted, the value of the moisture-in-oil test is meaningless.

Photo: Shutterstock

To illustrate this point, the graph shown in Figure 1 reveals the situation for a hypothetical Karl Fischer test result of 50ppm. The curves at different temperatures represent the saturation curves up to 100%. Assuming the oil temperature of the sample was 30℃ then the RS is 60%. This result indicates the transformer unit needs to be dried. If the sample temperature was instead 63℃, then the RS would be 20%, which is considered acceptable for service. If the sample temperature was 20℃. the RS is 100%, which suggests a high moisture content symbolic of “raining” inside the transformer. In this case, the unit should be removed from service, and consideration for a complete and effective dry out of both solid and liquid insulation should be mandated.

Research has demonstrated that the key to understanding the moisture condition is to gain knowledge of the % RS (relative saturation) of moisture dissolved in the oil. The Karl Fischer test measures the absolute water content in oil, which is composed of:

(1) free water,

(2) bound water (to particles and other polar compounds) and

(3) dissolved water in the oil known as % RS.

The previously published equilibrium curves used with the PPM measurement of moisture in oil therefore neglects to consider the following:

- Sampling process and (in many cases) lack of temperature of the sample
- Uncertainty of the KFT testing
- Equilibrium conditions in the transformer
- Absorption capacity of the oil
- Aging of oil and paper

The relative saturation of moisture in oil can be measured with a sensor permanently installed on the transformer, in an area with good oil circulation. It measures directly and continuously the % RS and temperature of the oil at the sensor location.

The question then becomes at what point should I seriously consider drying my transformer?

Answer:

1) When the % RS moisture in oil consistently exceeds 18%. At this point, the dielectric breakdown strength of the oil has decreased by 20 to 30%.[2]

2) When the moisture content in paper consistently exceeds 2% wt./wt. for units < 69 kV class.[3]

3) For EHV transformers the limit for moisture in paper may be lower at 2% wt./wt.

The moisture in power transformers using dielectric response methods and equilibrium diagrams can provide the user with information on the condition such as:

- Dielectric diagnostic methods deduce moisture in the solid insulation from dielectric properties like polarization/depolarization currents and dissipation factor as a function of frequency of applied voltage.
- Improved technology for de-energized testing combines time-domain (PDC) and frequency-domain (FDS) measurements and thus substantially shortens the measurement duration.
- The analysis algorithm compensates for the influence of conductive aging by-products.
- The updated software has been successfully utilized[1] for onsite measurements that compare favorably to other measurement and analysis methods.
- The conventional application of equilibrium diagrams to derive moisture in cellulose (%) from moisture in oil (ppm) are affected by substantial errors.

Photo: Shutterstock, Kinetrics

Figure 1.

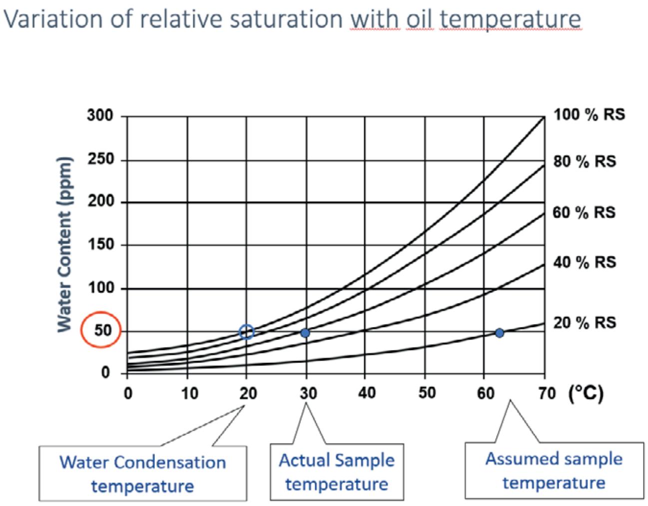
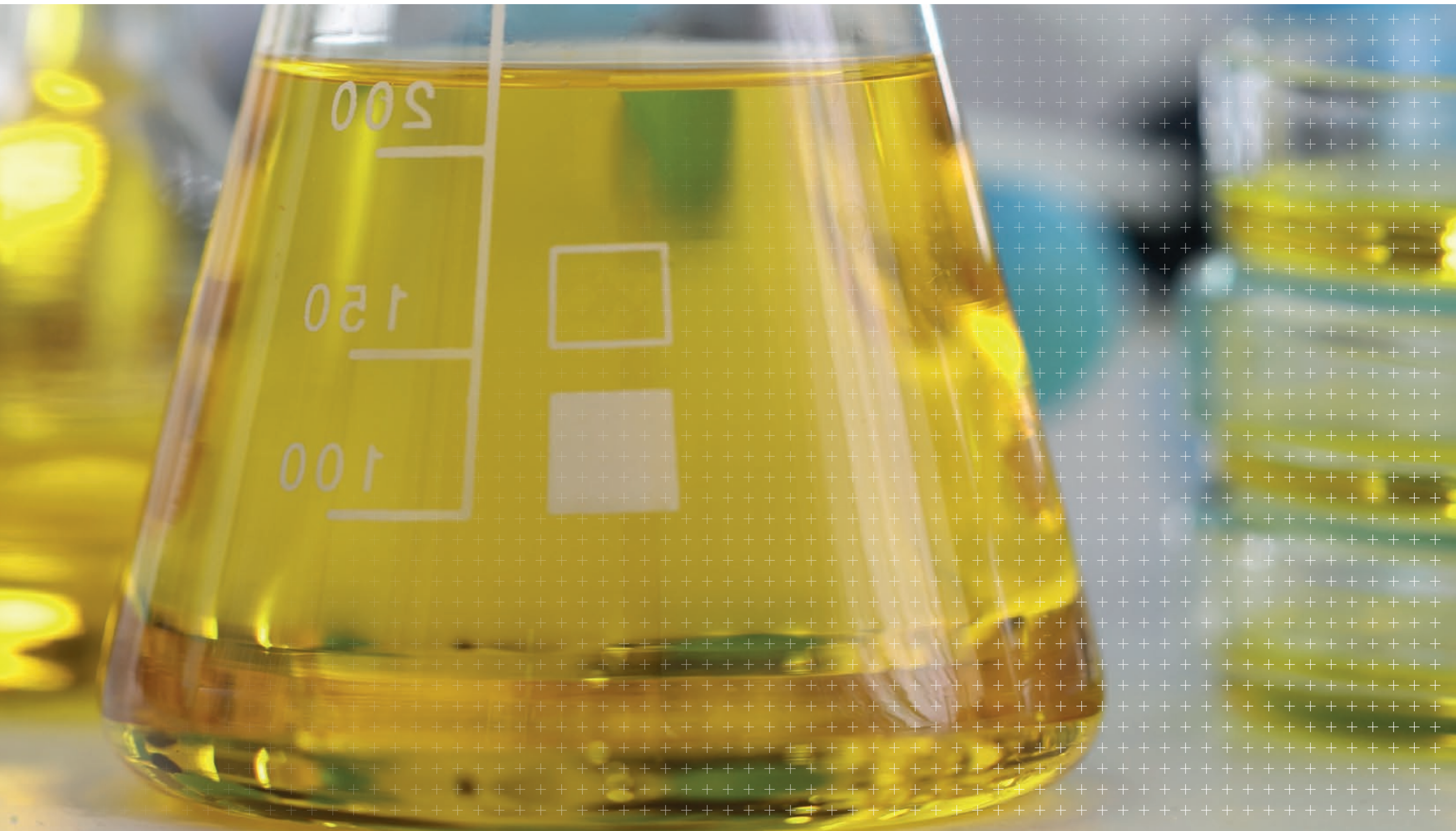


Figure 2. A Single Phase GSU with excessive moisture in the paper, and puncture from HV to LV through the barrier [4]

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- To exclude the interference due to oil aging, the moisture in oil relative to saturation level is more appropriate than moisture in oil in ppm.

- Updated equilibrium curves using % RS of dissolved moisture in oil have been produced, and when used provide a realistic view of the overall moisture condition of the transformer.

- One step forward constitutes the use of moisture relative saturation in oil sensors. This measurement is easy to perform on a continual basis, with accurate and repeatable measurements. These data points should be then integrated into an on-line monitoring system, where the values can be computed, and alarms set accordingly.

Where does all this water come from?

A primary source for this accumulation of moisture inside the tank is via leaks due to deteriorated gaskets. When oil leaks out from gasketed joints, it is possible for moisture and ambient air to enter. Another major source of moisture is from the paper itself as it naturally ages due to the chemical reactions induced by heat, moisture in the paper and acids found in the oil. The byproducts of this continuous chemical reaction are water, carbon monoxide and carbon dioxide, as well as Furanic compounds. All these chemicals dissolve into the oil. The oil gives up the water, and the paper absorbs it, and feeds the chemical reaction.

Why should I be concerned about this?

Excessive moisture in the oil and paper insulation can lead to the following:

- Dielectric breakdown of the oil and paper leading to partial discharges and dielectric breakdown.

- Accelerated aging of the winding insulation, reducing its tensile strength and its useful remaining life.

- The risk of 'bubble formation' between turns and sections of the winding insulation under heavy loading leading to sudden failure.

When oil leaks out from gasketed joints, it is possible for moisture and ambient air to enter. Another major source of moisture is from the paper itself as it naturally ages due to the chemical reactions induced by heat, moisture in the paper and acids found in the oil.

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[2] Cigre Technical Brochure No. 741, Moisture Measurement and Assessment in Transformer Insulation, August 2018

[3] Cigre technical Brochure No. 445, Guide for Transformer Maintenance, February 2011.

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Underground MV Switchgear Market and the Rise of Solid Insulation in the US

by **Saad Habib**

DRIVING THE FUTURE

- The US has set ambitious goals to shift 50% of its distribution network underground by 2040, driving the demand for underground MV switchgear upwards.
- The growth drivers for the MV switchgear industry are increasing grid resilience and reliability requirements, integrating renewable energy resources, grid expansion of EVs and DERs, and the Inflation Reduction Act (IRA).
- Solid insulation offers robust protection against environmental factors with compact designs and reduced maintenance requirements, making it an ideal choice for underground electrical distribution network.

Photo: Adobe Stock

> The US has set ambitious goals to shift 50% of its distribution network underground by 2040. This shift will increase the demand for MV switchgear, enhance the reliability and resilience requirements of the electrical grid, and pave the way for innovations in technologies like solid insulated switchgear (SIS).

Saad Habib works as a Research Analyst, specialized in High Voltage (HV) and Medium Voltage (MV) switchgear within the power systems field. His expertise focuses on MV and HV switchgear market dynamics, with a keen eye on emerging trends, such as the adoption of SF6 alternative solutions that are poised to reshape the global switchgear market. Saad has an extensive track record, engaging in both tailored projects for leading global companies and providing off-the-shelf services. Armed with a background in Electrical Engineering from FAST and an MBA from CBM, Saad seamlessly blends technical prowess with business acumen. With over five years of Project Management experience, he is celebrated for delivering invaluable insights into the ever-evolving power grid industry, contributing to a more sustainable and efficient future.

As the United States continues to modernize its electrical infrastructure, one of the most notable trends in the energy sector is the increasing adoption of underground electrical distribution networks. This transformative approach to electricity distribution and management is particularly prominent in urban and densely populated areas. The US has set ambitious goals to shift 50% of its distribution network underground by 2040. This shift will increase the demand for MV switchgear, enhance the reliability and resilience requirements of the electrical grid, and pave the way for innovations in technologies like solid insulated switchgear (SIS). This article delves into the market of MV switchgear and the future of SIS MV switchgear in the US.

DRIVING THE FUTURE

As the MV switchgear industry grows, new technologies, such as solid insulated switchgear (SIS), are gaining popularity.

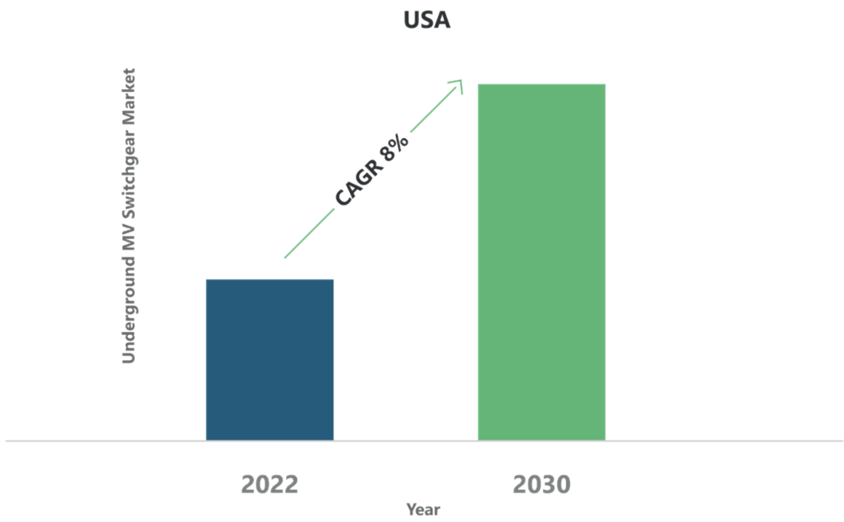

Figure 1: Expected CAGR of Underground MV Switchgear Market from 2022 to 2030. Source: PTR Inc.

Growth Drivers for the MV Switchgear Market

The US underground MV switchgear market is poised for significant growth, projected to achieve a compound annual growth rate (CAGR) of approximately 8% from 2022-2030.

There are several drivers of growth in the MV switchgear market including grid resilience and reliability requirements, integration of renewable energy resources, distribution grid expansion, and the Inflation Reduction Act.

Increasing grid resilience and reliability requirements

As the grid landscape evolves, the emphasis on grid resilience and reliability drives the demand upward for advanced MV switchgear solutions that can withstand various challenges, including extreme weather events and cyber security threats.

Integration of renewable energy resources

Integrating renewable energy sources like solar and wind into the grid requires flexible and reliable MV switchgear systems capable of managing variable power flows.

Distribution grid expansion for EVs and DERs

As EVs and DERs are gaining traction, distribution grids are expanding to accommodate these new energy sources. This growth requires new MV switchgear capable of handling increased capacity and ensuring smooth integration.

Inflation Reduction Act (IRA)

By promoting economic stability, reducing interest rates, and potentially increasing infrastructure investments, the Inflation Reduction Act is creating a conducive environment for sustained growth and innovation in the MV switchgear industry. Moreover, the focus on sustainability and energy efficiency aligns with the broader goals of modernizing the electrical grid, further improving the prospects of the MV switchgear industry. As the MV switchgear industry grows, new technologies, such as solid insulated switchgear (SIS), are gaining popularity.

Photo: Shutterstock

DRIVING THE FUTURE

Future of SIS MV Switchgear in the US

Modernizing the electrical grid infrastructure has become crucial due to climate change-induced extreme weather events and increasing demand for uninterrupted power supply in urban and rural areas. This has led to multiple advancements in the MV switchgear technology. Firstly, there is a substantial uptick in demand for pad-mounted underground switchgear, which offers a more resilient and secure solution than traditional overhead systems.

Secondly, there is a preference for solid insulation in these systems. Solid insulated switchgear (SIS) is favorable due to its properties for safeguarding underground networks. Solid insulation offers superior protection against moisture, contaminants, and other environmental factors, making it a dependable choice for underground installations. Moreover, SIS technology provides compact and maintenance-free solutions, further enhancing its appeal to the evolving needs of the underground MV switchgear market. As the industry continues to innovate and adapt to the changing landscape of the energy sector, solid insulation is expected to be at the forefront of this journey towards a more resilient and reliable underground electrical grid.

Apart from solid insulation, other insulation technologies include gas-insulated switchgear (GIS) and dry air technology. Some key aspects to consider when opting for different types of MV insulation are dielectric strength, environmental impact, maintenance requirements, safety, longevity and reliability, regulatory compliance, and application-specific requirements. Figure 2 and Figure 3 show the comparison of dielectric strength and maintenance requirements between different types of insulation technologies, respectively.

SIS generally has lower maintenance requirements than GIS, mainly due to the absence of SF_6 gas handling and associated concerns. Different OEMs use SIS in the US due to its properties, which are favorable for underground installations.

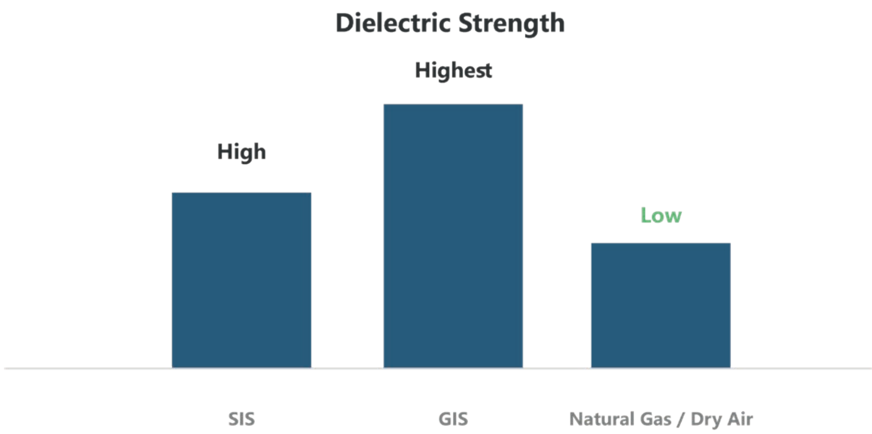

Figure 2: Comparison of Dielectric Strength between Different Insulation Types. Source: PTR Inc.

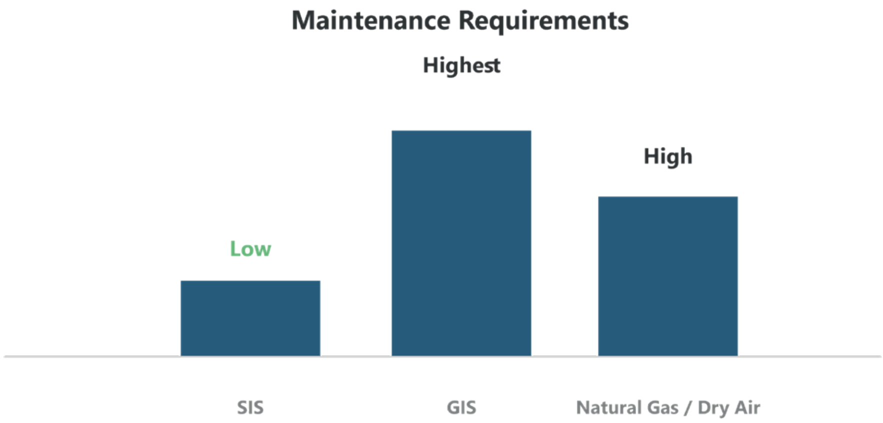

Figure 3: Maintenance Requirements as per Insulation Type. Source: PTR Inc.

SF_6 gas, generally used in GIS, has an exceptionally high dielectric strength. The environmental concerns associated with it have urged the exploration of alternative material insulation. Solid insulated switchgear (SIS) provides a viable option, particularly in medium voltage applications, offering good dielectric properties and environmental benefits. Gaseous alternatives like nitrogen and dry air are also being considered, especially for air-insulated switchgear (AIS), due to their lower environmental impact. However, they may have lower dielectric strength than SF_6.

SIS generally has lower maintenance requirements than GIS, mainly due to the absence of SF_6 gas handling and associated concerns. Natural gas MV switchgear falls between SIS and GIS in terms of maintenance requirements, with a focus on gas quality, leak detection, and some mechanical components. Different OEMs use SIS in the US due to its properties, which are favorable for underground installations.

Looking Ahead

Technological advancements are set to shape the future of underground switchgear, with SIS technology expected to take the lead. Solid insulation offers robust protection against environmental factors with compact designs and reduced maintenance requirements, making it an ideal choice.

Considerations such as dielectric strength, environmental impact, safety, longevity, and regulatory compliance are significant in choosing medium voltage insulation. While SF_6 has long been the go-to dielectric medium, alternatives like solid insulation, nitrogen, and dry air are gaining traction, with solid insulation standing out as a viable option, especially for underground electrical distribution networks.

With these considerations, the US MV switchgear market is poised for a sustainable and resilient future, aligning with global efforts to reduce greenhouse gas emissions and enhance the electrical grid's overall reliability and sustainability.

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GREEN ENERGY TECHNOLOGY: SOLAR, WIND AND RE+2023

In February 2024 edition of the Power Systems Technology and Transformer Technology magazine we invite you to embark on a journey delving into the forefront of renewable energy, one of the most relevant topics today, when we are at a brink of green energy revolution! We present a thorough exploration of the most recent advancements and groundbreaking innovations that have unfolded in the areas of solar and wind energy, as well as energy storage and asset life extension, and bring you exclusive interviews with innovators, engineers, and thought leaders from the 2023 Renewable Energy Conference (RE+). We imagine this edition as a beacon illuminating the path toward a sustainable future powered by renewable resources.

We extend an invitation to authors and industry experts to contribute their valuable insights, research findings, and thought leadership to enrich the discourse. If you have compelling contributions that align with our mission to drive innovation and progress in the field of renewable energy, we encourage you to reach out to our editor, Alan Ross, at alan.ross@apc.media. Together, let us amplify the dialogue and propel the renewable energy landscape into new dimensions.

COMING IN FEBRUARY ISSUE