

TRANSFORMER TECHNOLOGY^{MAG}

Monitoring, Diagnostics & Digitalization

Celebrating
the Transformer Technology
Community

The Journey of a Young Transformer Designer:
The Future of the Industry

Power Factor:
Offline, Relative and True

Smart Asset Management:
Digital Power Transformers

Unmatched Versatility



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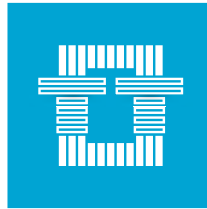
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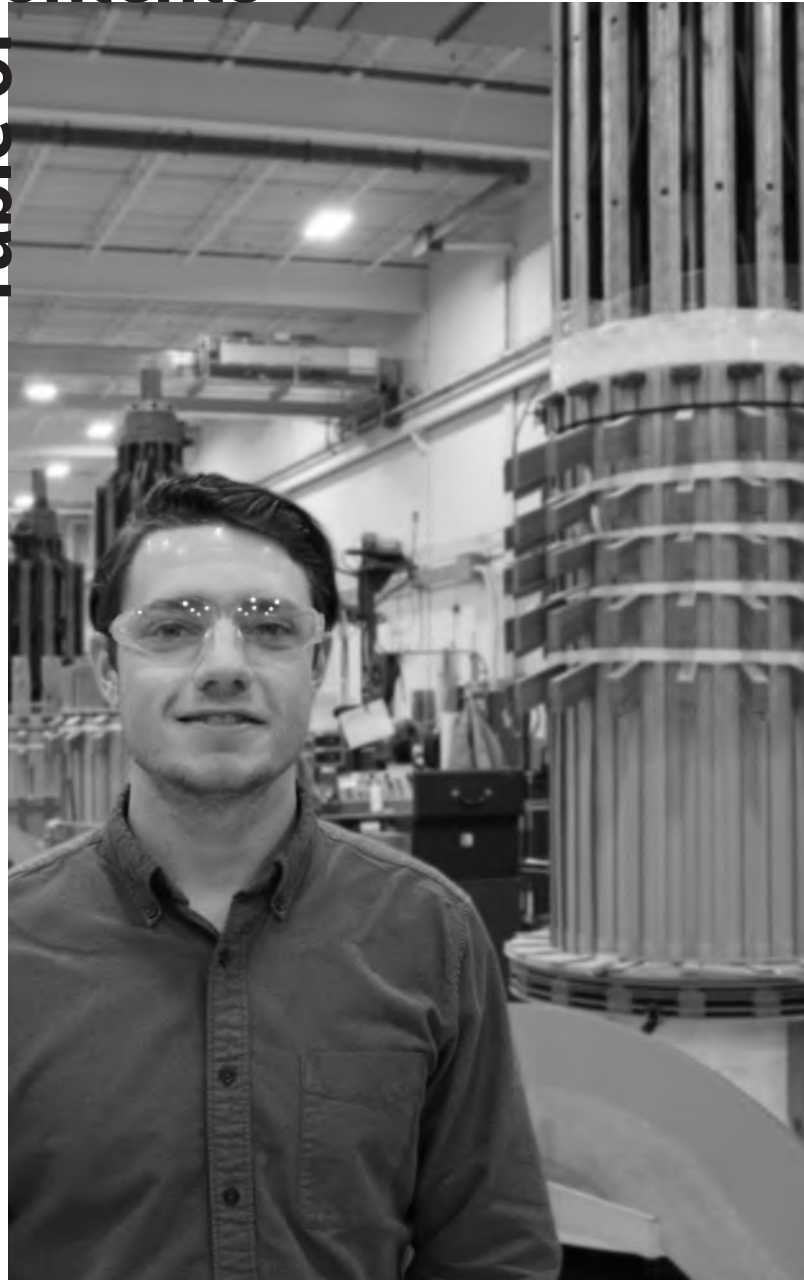
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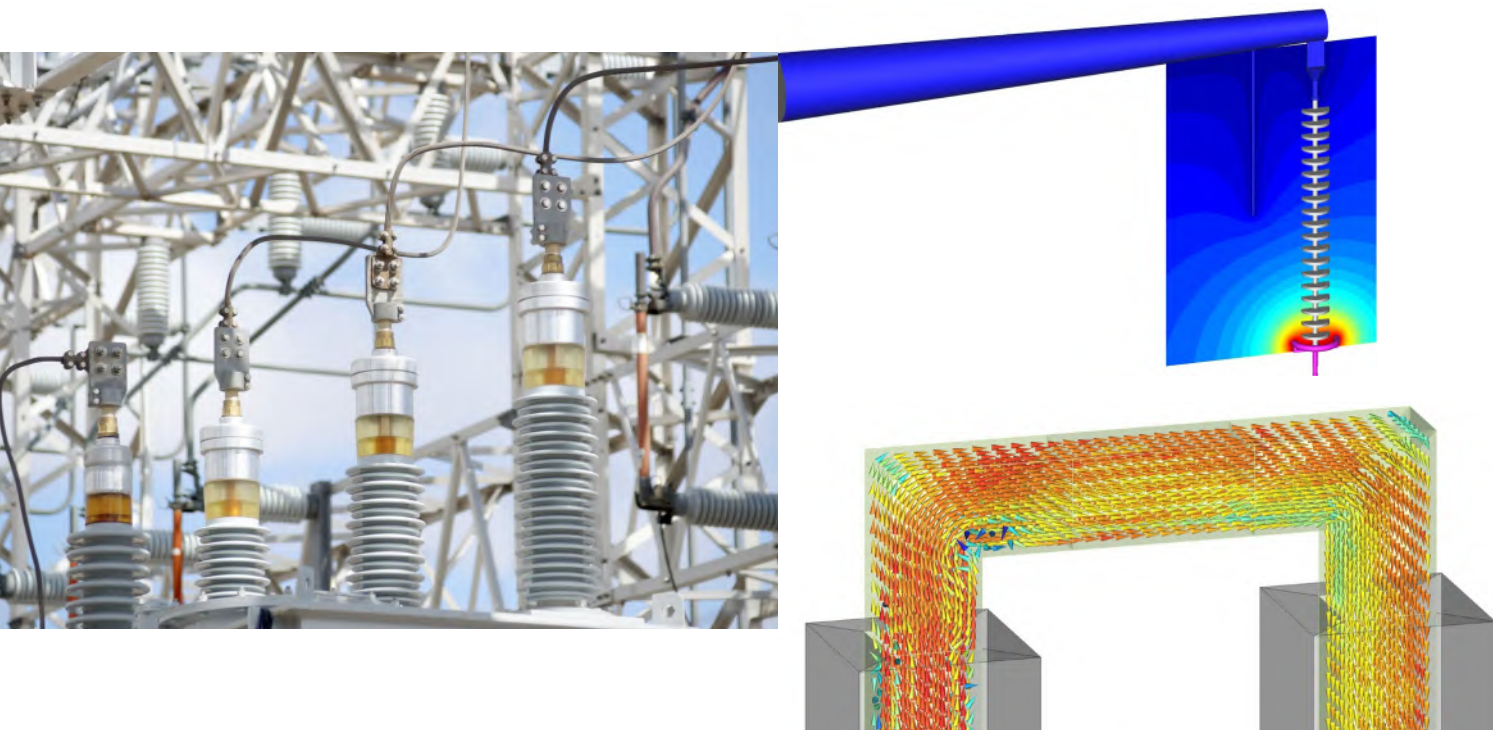
Asset Solutions: by Tony McGrail

Bushings are usually reliable elements of any electric supply system, but all bushings have failure modes and all bushings will eventually fail. In the first article of his new byline Asset Solutions, Tony McGrail reviews the differences between the results of offline bushing testing and online measurements using both relative and true power factor techniques.

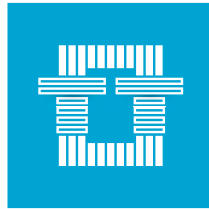
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Some say he is passionate about ultrasound. And they are right. But he is also passionate about helping people get the most from their investment in technologies that create safe workplaces, reduce unplanned downtime, and eliminate waste. Ultrasound just so happens to be that technology. Why? Find out in Allan Rienstra's article on ultrasound testing.



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Impressum

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Dear Readers and Members of TT Community,

Let's take a look at what we accomplished leading up to the publication of this, our Summer Issue of Transformer Technology. First, and more than likely the most important accomplishment the Transformer Technology (TT) team made was making the transformation from a magazine to an on-line community, with a quarterly digital magazine to support that community. Our goal was to engage members of the community, and the most important way to do that was to change our thinking from a subscriber to a member-based community.

It all started with Curtus Duff, a young transformer design engineer who shared his experience and his hope for how he sees the future. His story *The Journey of the Young Transformer Designer* was the first Featured Article under this new format, one that had never been published before and the first of our new community approach: Publishing one great article or interview per week on a key selected topic, weekly news and career features, and special reprints of previous articles or interviews. The goal is to engage the community with as much value as possible. Curtus nailed the challenge.



First, and more than likely the most important accomplishment the TT team made was making the transformation from a magazine to an on-line community, with a quarterly digital magazine to support that community.

Since the selected topic was Digitalization, Diagnostics and Monitoring, it was great to follow up with articles on the key topics. What followed was Chuck Baker's continued story of Kevin, Brian and Andy as they navigated the difficult but critical task of implementing a Reliability Centered Maintenance program for their plant's electrical system. That is near and dear to my heart. As the Founder and President of EPRA, the Electric Power Reliability Alliance, I live and breathe that challenge, and Chuck's continuing saga is as real and raw as it gets. I can't wait to hear what challenges they face next and how they will overcome them. Chuck knows that problem from the perspective of someone who led the development of one of the most ro-

bust transformer maintenance programs I have ever seen.

Great articles from industry professionals like Allan Rienstra, Corné Dames, Dominique Legrand, Tony McGrail and of course the team of Bob Rasor, Hali Moleski and Andy Shkolnik; all were featured week to week and added tremendous value. What we want to create is content that can either be read weekly and/or archived for future use. We want to be and are fast becoming the Body of Knowledge for anything transformer technology related. And, we have only just begun.

Where do we go from here?

In our Fall issue, we start with a preview of what the season ahead brings. I will save more on that for later. But to keep with our ongoing technology themes, we are featuring those tremendously important components of all transformers: Bushings. We already have quite a line-up of articles and interviews for the TT community to access, and much like this Summer issue, we will compile all of those articles into one special Fall Issue, which will be published digitally in October.

With over 7,000 unique connections and very serious daily and weekly engagement, I am pleased to say that the Transformer Technology Community has made that great leap from in-person engagement to digital platforms.

We cannot disregard the elephant in the room - Covid 19. It seemed that the world just stopped as we all tried to grasp what it means to face a global pandemic. Locked down in our homes in a new work-from-home reality made Zoom stock zoom, and before long every technology platform seemed to jump on board: webinars, panels, virtual events and Forums (what we call the every-other-week panel discussion on one select topic at EPRA www.myepra.com/forums). Suddenly everyone was clamoring to make the leap from in-person events to digital platforms. With over 7,000 unique connections and very serious daily and weekly engagement, I am pleased to say that the Transformer Technology Community has made that great leap.

But now for the really fun part, when we create, not one-way communications, but two-way communications with our members. Engage with us! Provide feedback to our authors leaving your comment under the articles and challenge us to deliver new content, not just something to wrap some advertising around. Get involved. Download! Share! Like and post! That is what a community does in the new digital age.

To provide ongoing support for the community we have created a space for *"Allied Members"* who will share, in a unique way, their fundamental values that align with our fundamental values at Transformer Technology. Additionally, we have added the *"Consultants Corner"* featuring those resources that you might need to serve our members in a consultative manner. When you are looking for someone to meet a specific need for professional engagement, look to the Consultants Corner for a list and profile.



Engage with us! Provide feedback to our authors leaving your comment under the articles and challenge us to deliver new content. Get involved. Download! Share! Like and post! That is what a community does in the new digital age.

All of us at Transformer Technology want to thank you, our members of the community for helping us, not only survive this pandemic, but thrive in the midst of it.

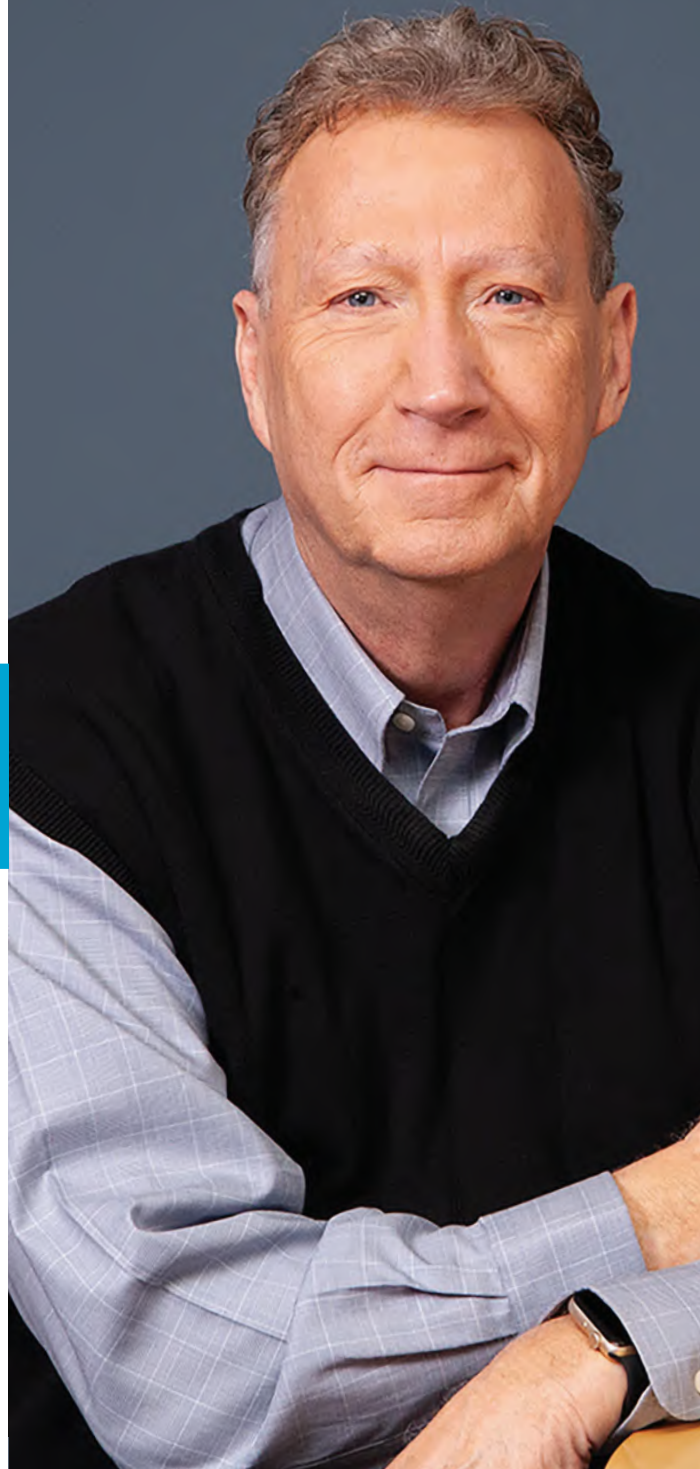
Please feel free to contact me directly at alan.ross@transformer-technology.com, alan.ross@myepra.com or by phone at +1 404-992-5111.

It is time to lead.
It is time for a change.



Alan M Ross
CRL, CMRP
Editor in Chief
Transformer Technology

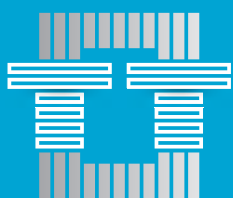
Alan M Ross



**YOUR PASSION
AND KNOWLEDGE
ARE IMPORTANT
TO US**

JOIN OUR
#COLLABORATIVE COMMUNITY

Are you passionate and knowledgeable about your area of business or expertise? Now You can contribute to knowledge sharing in the transformer industry by sharing your field experiences, case studies, research results, or simply your knowledgeable opinion on a topic of interest to the industry.

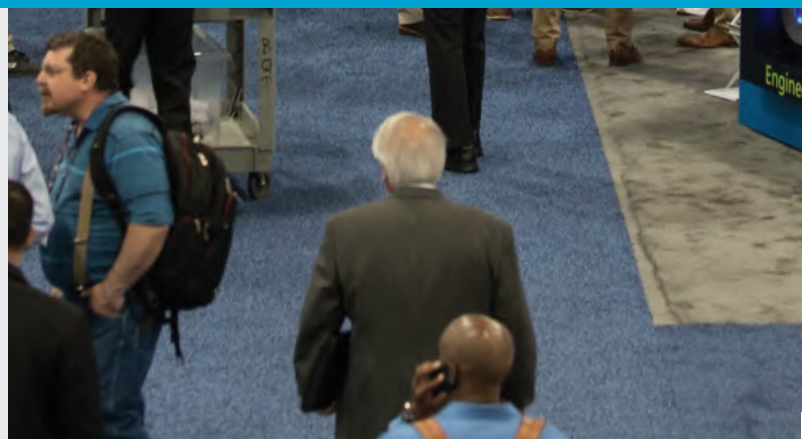
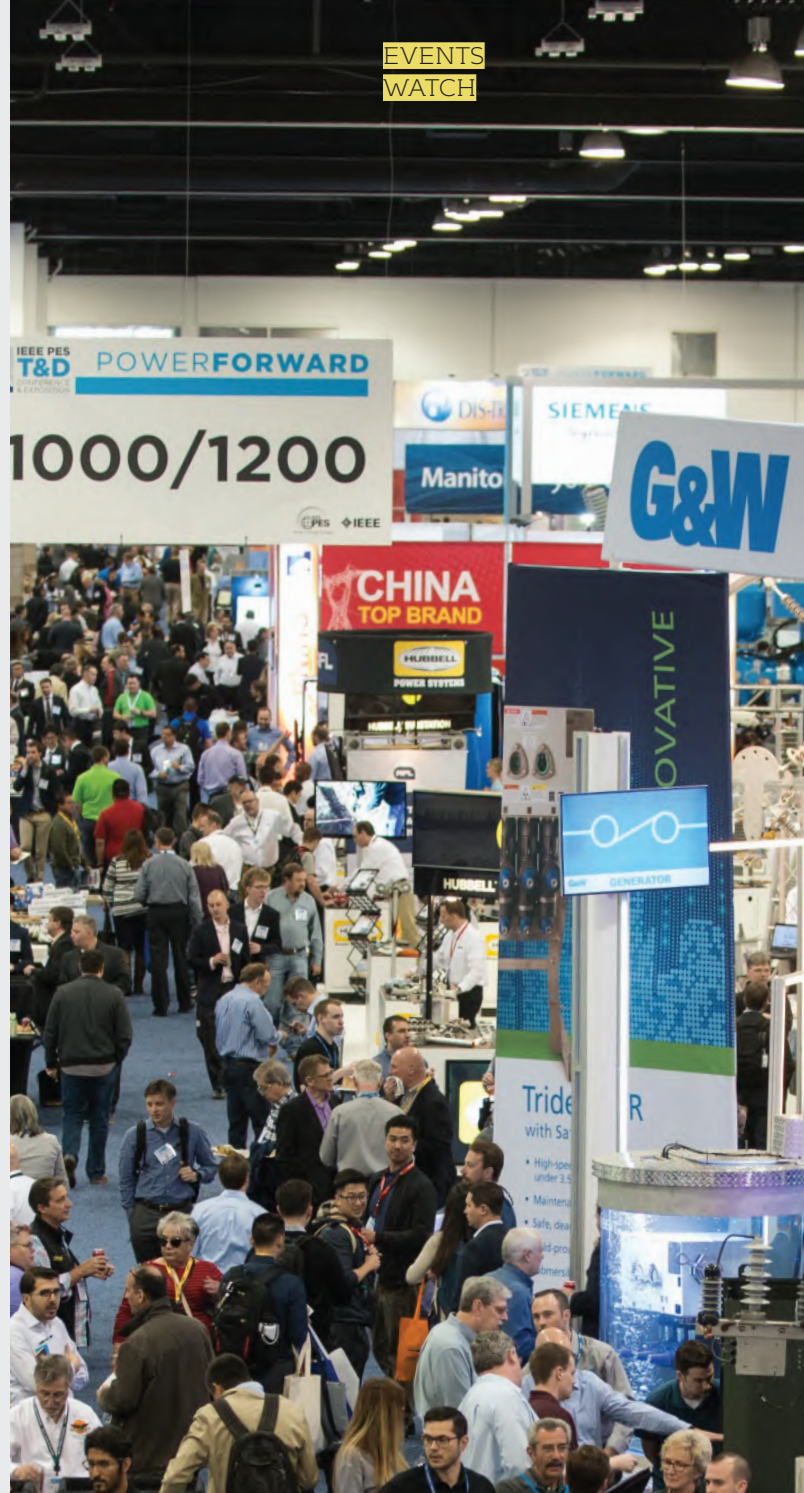


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Contact us at
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to find out how you can
become part of the
Transformer Technology
community.

EVENTS
WATCH



Events Watch



HANNOVER MESSE
Digital Days

July 14 - 15, 2020

<https://hannovermesse.digital/en/>



CWIEME Shanghai

July 29 - 31, 2020

SHANGHAI, CHINA

<http://cn.coilwindingexpo.com/en/>



CIGRE e-session 2020
Technical Exhibition

August 24 - September 3, 2020

[https://www.cigre.org/GB/
events/cigre-e_session](https://www.cigre.org/GB/events/cigre-e_session)



Coiltech 2020

September 23 - 24, 2020

PORDENONE, ITALY

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net/landing.asp?id=97](https://www.quickfairs.net/landing.asp?id=97)



IEEE PES T&D
Conference and
Exhibition 2020

October 12 - 15, 2020

CHICAGO, ILLINOIS

[https://www.ieeeet-d.org/
IEEE20/public/enter.aspx](https://www.ieeeet-d.org/IEEE20/public/enter.aspx)

Editor's Note:

Please note that these event dates were accurate at the time of publication, but schedules may change due to the circumstances related to Covid-19. To get the most updated information about event schedule, please visit the event's webpages or contact the organizers.

The Journey of a Young Transformer Designer: The Future of the Industry

by **Curtus Duff**

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Foreword from the Editor in Chief

When I first met Curtus, I thought about how young he was and how much tribal knowledge he could gain from people in the industry. Over tacos in Texas, and you can't say that often enough, Curtus and I talked about his learning track

to the future. This article is his journey on the track. I cannot thank him enough for his contribution to our community. Curtus is one of the rising stars of our industry and one someone I am delighted to add as a Contributing Editor. Enjoy!



Curtus Duff is an Electrical Design Engineer at SPX Transformer Solutions where he designs medium and large power transformers. He graduated from Purdue University in 2016 with a Bachelor of Science in Electrical Engineering. Upon graduation he started at SPX Transformer Solutions in the Engineering Development Program with six-month rotations each in Design, Testing, Manufacturing, and Application Engineering. Upon completion of the program in 2018, he joined the design team. He is located in Waukesha, Wisconsin where he enjoys the outdoors in activities such as mountain biking and skiing.



Young engineers are eager to learn. Take a young engineer and put him or her in the right environment, and learning will happen.

The power industry currently is that “right environment,” due to its relatively older work force, ripe with experience and knowledge ready to be shared.

I have heard many conversations about plans for retirement, such as fishing or moving to Florida, or both. When the masters of the industry decide to move to Florida, they take their tribal knowledge with them. Now is the time for young engineers to download as much of that knowledge as they can from seasoned engineers. Now is the time for seasoned engineers to teach them. I write this article to take the reader through my own experience as a transformer designer. Many transformer designers will likely share a similar experience. I will go through my story, my process of learning, and explain how I have realized that a culture of passing down tribal knowledge is the key for future success.

During university, I would ask myself, “How much of this stuff am I actually going to use when I get out into the real world?” I jumped all too fast to the conclusion: probably not that much. I was wrong. I recently had a conversation about this topic with a colleague, Doug Reed, a principle design engineer at SPX Transformer Solutions. He told me an interesting story about a time when he had a reunion with some of his college friends. They talked about what they do for a living and about how much of their college education they use in their careers. Doug calls it his “bragging rights” when he makes claims about how much of his college education he actually calls upon when designing transformers. When Doug started listing off his classes, I realized he was onto something. The relevance is quite astounding when you actually think about it!

Here is my list of engineering classes applicable to transformer design:

- Thermodynamics - Cooling
- Statics - Clamping and Tank Structure
- Circuit Analysis - RLC Properties
- Electromagnetics - Flux and Harmonics
- Fields - Magnetic Fields and Dielectric
- Physics - Short Circuit Forces and Winding Strength
- Materials Science - Steel, Oil, Copper, Paper
- Mechanics of Materials - Material strength
- Fluid Dynamics – Flow of Cooling Liquids and Air



Not including the sadistic engineer that takes all of these classes and triple majors in Electrical Engineering, Mechanical Engineering, and Physics, most engineers will take a good percentage of these classes. I personally took the ones my degree required. In my electromagnetics course, we covered transformers for all of one chapter, with a description of a standard, ideal, single-phase transformer as the main takeaway - primary on the left leg and secondary on the right leg. While this was great information for an entry-level position interview, in no way was this information enough to become a good transformer designer.

The point of university was not to teach me exactly what I needed to know in order to be a transformer designer. Instead, my education was meant to be a foundation. While university is certainly not the only way to achieve a solid foundation, going through the brainstorming exercise with Doug made me realize how great of a foundation university was for me. I was challenged daily, and the classes I took taught me how best to learn. For both, I am forever grateful. Exploring transformer

design is like staring through the skinny part of a very wide and very tall traffic cone. The deeper you look, the more opportunities surface to learn. The ability to learn is what guides engineers to travel through this metaphorical traffic cone successfully. Every day that passes is another day to learn something new.



"Exploring transformer design is like staring through the skinny part of a very wide and very tall traffic cone. The deeper you look, the more opportunities surface to learn. The ability to learn is what guides engineers to travel through this metaphorical traffic cone successfully. Every day that passes is another day to learn something new."

Day one of employment in the summer of 2016 began my own exploration through SPX Transformer Solutions's traffic cone of knowledge.

In reality, we orient the primary and secondary windings concentrically. I guess the one chapter discussing transformers in school was not exactly perfect! A new engineer starts out by meeting everyone, exploring the plant, and spending time on weekly learning goals. For me, this learning objective started with reading about Michael Faraday; deriving the volts per turn equation; learning about load loss, core loss, flux density, leakage flux, percent impedance, basic insulation levels, winding types, manufacturing processes, and testing requirements. After the first week, the task ahead of me seemed quite daunting and overwhelming. As I ventured further into the giant traffic cone, the sheer volume of what I did not yet know appeared to be getting bigger and bigger. The light at the end of the...cone seemed so far away. I spent what felt like decades going through internal engineering documentation, vital components to learning the steps of designing and having a central location of company knowledge. These documents are literally a collection of knowledge handed down by many engineers before me. After weeks of training, asking "what is this?" on the shop floor, reading text book after text book, digging through engineering instructions, and examining the details of customer specifications, eventually my boss graced me with the opportunity to fulfill my destiny. By fulfill my destiny, I actually mean my boss said, "Let's start you off with a mock design."

One can read a book about swimming, but that is not going to be enough training to jump into the deep end of a pool. A mock design was essentially me starting to learn to swim in the shallow end. Although I was a little disappointed, because I wanted to make a real contribution to the team, a mock design alleviated the pressure and allowed me to practice designing with no

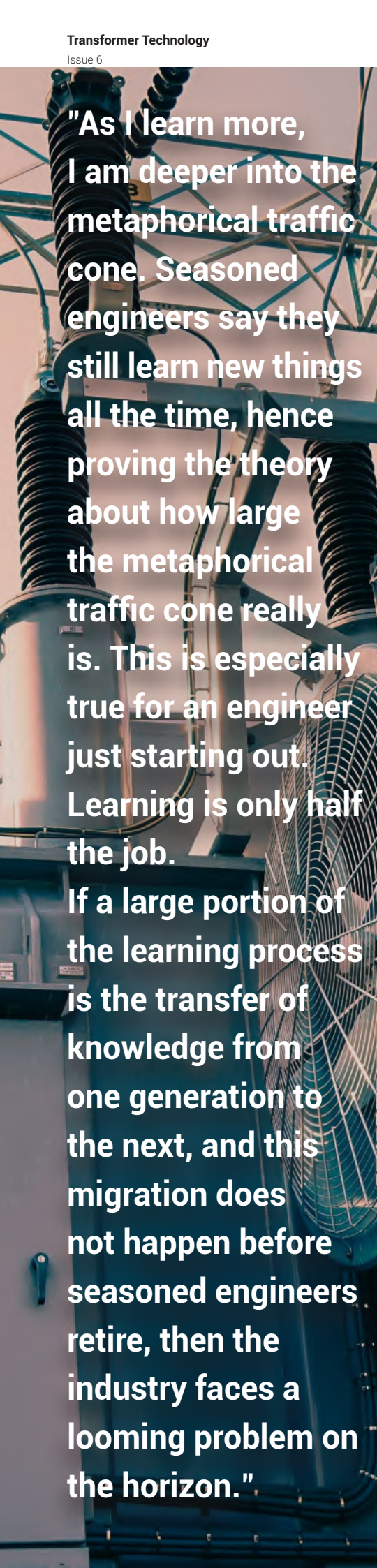
consequences. This would allow me to learn by doing. While all the self-study to get to this point was important, most of the opportunities for learning came about by actually designing a transformer.

The process started with the task of going through records and finding a unit the company built before that was not too challenging. This way I could pretend I was the original designer, and afterwards, have a design to compare to my own. The unit I was looking for was a 69 kV to 12.47 kV delta-wye transformer with a de-energized tap changer. Something like this typically has a basic insulation level of 350 kV on the high voltage side, 110 kV on the low voltage side and a percent impedance of 8%. I found one with a base rating of 15 MVA and a max of 28 MVA at 65°C degree rise. This was simple enough to get started and perfect for my mock design.

The key to designing a transformer is optimization. My studies had gotten me to the point of understanding the relationships between design and performance. For example, how volts per turn can affect flux density and, therefore, core size. How winding cable geometry can affect stray losses and impedance. How oil flow can affect cooling performance. How insulation design can affect dielectric withstand. How cable dimensions can affect the ability to withstand short circuit forces. The list of design to performance relationships is a long one! The challenge of these many relationships is that they are intermingled. As one design attribute is changed to get a desired outcome, another desirable outcome suffers. Dielectric changes can trade off with cooling performance, while tweaking impedance can trade off with losses. The list of design tradeoffs is also long. Talk to any transformer designer, and they could bore you to death with the tradeoffs. If these design relationships and tradeoffs were not confining enough, they also affect the total cost in a variety of quantities. In many cases, cost is arguably the most important factor for the customer.

Even so, the biggest constraint of them all is that the final design needs to be manufacturable. A designer cannot just do whatever he or she wants. The plant's future manufacturing experience must be considered during the design process. Designing a transformer is the ultimate balancing act. A good designer is one who can optimize amongst all of the variables at play to end up with a design the customer was looking for at the right price. This is exactly what I was trying to achieve with my mock design.

The perfectly optimized design is accomplished through an iterative process. Once I got to where I felt comfortable with my optimized mock design, I ran it through simulation software. Running a model of the design through simulation software is important to prove that the transformer is meeting all performance characteristics, such as losses, impedance, cooling, dielectrics, and short circuit. If any of these simulations fail, a designer must go back to the design and make corrections. If a designer has to make corrections, the design has to be re-optimized around those changes. The re-optimized design needs to be completely re-simulated again because the design is now different and all of variables of the design affect each other. My mock design required a lot of back and forth between designing and simulation.



"As I learn more, I am deeper into the metaphorical traffic cone. Seasoned engineers say they still learn new things all the time, hence proving the theory about how large the metaphorical traffic cone really is. This is especially true for an engineer just starting out. Learning is only half the job. If a large portion of the learning process is the transfer of knowledge from one generation to the next, and this migration does not happen before seasoned engineers retire, then the industry faces a looming problem on the horizon."

Eventually I did it. After what seemed like forever, I came up with a decent design that passed all simulations. I was proud. Next, I decided to compare what I came up with to the design that we actually manufactured. I figured since I worked so hard, the designs would be similar, and they were. While I definitely missed some opportunities for improvement that I did not quite grasp at the time, I had come up with a design that was entirely buildable, would likely pass on the test floor, and would transform voltage as necessary in the field. I considered my mock design – and the entire experience – to be a success.

Now for the message I want to relay, something important that got me to the point of a successful mock design. I have written about the general process and my experience going through that process, but I left something out – the teamwork along the way. Yes, self-study – reading guides and textbooks – was helpful, but having seasoned design engineers around to help was critical to my success. To have engineers around for guidance, ones that remember being in my shoes, but have become masters at their craft, was truly a blessing throughout the whole mock design process.

Fast forward to present time, where I am approaching the "dozen design mark", a team of engineers continues to be available to offer assistance. Thankfully, we have enough experienced people so I can spread my questions out as to not burden one individual too heavily. After I compliment them for being so helpful, they always give me the same response, "The only reason I know what to do is because I've learned what not to do." As humble as they may be, they really know what they are talking about, and I am grateful for the time they take to teach me.

I mentioned the design process is highly iterative, and, because of that, one can use various checkpoints along the way to learn something from an experienced engineer, which helps mold a young engineer into an experienced engineer. Experience is what makes an engineer more

efficient, makes optimizing transformer designs faster, and helps to prevent too many simulation iterations. An experienced engineer can predict what might happen during a modeled simulation before they even run it. Becoming an experienced engineer is something to which I aspire.

As each day passes, I find myself learning more and more. As I learn more, I am deeper into the metaphorical traffic cone. Seasoned engineers say they still learn new things all the time, hence proving the theory about how large the metaphorical traffic cone really is. This is especially true for an engineer just starting out. Learning is only half the job. If a large portion of the learning process is the transfer of knowledge from one generation to the next, and this migration does not happen before seasoned engineers retire, then the industry faces a looming problem on the horizon.

I have been to a few conferences, read articles, and listened to podcasts associated with the power industry in the United States. Frequently a discussion about the aging work force comes up. From my observations, I can see why these discussions are taking place. If you are reading this, you are likely in the power industry, and can probably think of a few people you know with 35 to 45 years of experience that have recently retired. Some of you might witness these retirements often. As these fine individuals join the wonderful "life after work", they take their tribal knowledge with them. As these individuals retire, the average years of experience in the industry decreases. In an industry where knowledge, experience, and know-how are so important, we would be foolish to think that this will not have an impact.

I believe that, as an industry, we have the duty to mitigate the impact of this inevitable "brain drain" right now. Retirees moving to Florida with all of their knowledge is too great of a loss and a true detriment to allow. Of course, we can always hire them back as consultants, but that is not a good solution.

They want to stay retired and young engineers want them to stay retired. Written guides, like those from the IEEE, are great resources that continue to grow each year in an effort to help solve this problem. IEEE also helps in developing the culture of sharing information. This kind of culture is vital for continued advancements, growth, and maintenance of a reliable power network. A culture that converts tribal knowledge into written knowledge helps solidify that knowledge, and ensures that knowledge will not be lost. Companies must emulate this culture of documenting information and create their own internal written engineering documents. When future engineers have access to “lessons learned” from engineers who have “been there, done that”, they can use that information to build their foundation as I did in my early training and continue to do. I cannot stress enough how important written documentation is! I have learned from seasoned engineers through written documentation and in person alike. I believe both are essential parts of teaching young engineers. The passing down of knowledge is something that can never stop and will forever be locked in an eternal pursuit. The torch of knowledge must be passed to the next generations. Those who receive this knowledge must recognize their own responsibility to carry it forward and pass it down, thereby completing the cycle so it can start over again.





**TRANSFORMER
TECHNOLOGY^{COMM}**

BODY OF KNOWLEDGE

Transformer Technology has launched a **keyword searchable library** of the **best information and knowledge** exchanged through our publication and platforms that is made available to all our Members to use, learn from and guide them in their practice or work.

Because we are committed to our **Mission** – to help the **next generation** by capturing the legacy knowledge of the current generation.

Start your search now:
transformer-technology.com/bok

Smart Asset Management: Digital Power Transformers



Corné Dames is the Managing Director of Independent Transformer Consultants, always striving to keep on top of new developments and research. She has expertise as Laboratory Manager in the analysis of transformer oils and as diagnostician identifying problem areas in transformers, as well as profiling of transformers according to available results thus empowering the customer to take preventative steps in maintenance. Corné has vast practical and theoretical knowledge on reliability maintenance programs. Coming from a strong chemical background she has insight in all the chemical processes that is part of the transformer system coupled with technical insight helps customers optimize their reliability maintenance and electrical asset lifetime.

Digitalization is all about managed control.

Power transformers are the key components in the electrical grid and as such they are subjected to various stresses – thermal, mechanical, and electrical. These stresses are the reasons why transformers age. The global population of electrical power transformers is aged.

Currently, if transformers do come equipped with sensors, these sensors can only provide an alarm after the condition of the transformer has already started to deteriorate. This makes evaluation of the transformer's health a complex and challenging task.

Introduction

Digitalization is the addition of remotely connected sensors to a single system. It is the use of unforeseen data relationships from multiple sources to change the value proposition or business model for a specific sector or application.

Digitalization is the cause of large scale and sweeping transformations across multiple aspects of business, providing unparalleled opportunities for value creation and capture, while also representing a major source of risk.[1].

Digitalization is the cause of large scale and sweeping transformations across multiple aspects of business, providing unparalleled opportunities for value creation and capture, while also representing a major source of risk.

In our industry, this route of digitalization is followed to ensure reliability and maximum lifetime – the transformer condition is monitored continuously and evaluated for appropriate asset management decisions. Asset management needs to be both cost-effective and reliable, sensing solutions that provide asset managers with actionable intelligent data.

There is a global consensus to urgently reduce carbon emissions to assist in the fight against global warming. Because the power industry still uses 75% non-renewable sources such as coal, oil, and natural gas, it is an enormous contributor to these dangerous emissions. The energy industry is obligated to decarbonize and to look beyond the conventional fuel sources to sustainable fuel sources.

Because of the de-centralization of the power system, the entire energy value chain must evolve and rely on small scale renewable energy.

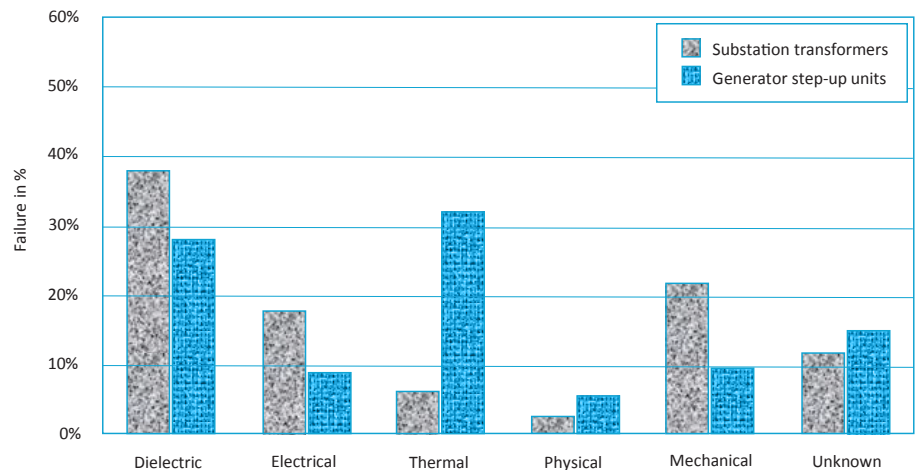
this is vitally important. Transformer failure statistics and historical data must be taken into consideration to provide a failure mode “picture” data model on which recommendations would be based.

In Cigre's failure mode analysis [3], the failure modes were identified as:

1. Dielectric: Partial discharge, arching, etc.
2. Electrical: Short circuit, poor joints, poor contacts
3. Thermal: General overheating, localized hot spot
4. Physical chemistry: Contamination, corrosion etc.

Dielectric failures were the most prominent failures for substation transformers. Thermal and dielectric failures were most common for GSU transformers. This clearly indicates that thermal analysis of transformers can provide critical information about transformer condition and can be used to identify inception of faults or to better manage transformer loading.

Figure 1. Failure mode analysis: Cigre WG A2.37 [3]



Asset life cycle management, grid optimization and aggregation, and integrated customer services will be central to the digital transformation of the energy sector.



Applying the “Lego block” approach [4], temperature monitoring is the first Lego block of the digital power transformer. Electric and thermal faults break down the oil molecule and the insulation paper molecules, resulting in the formation of dissolved gas formation – thus making dissolved gas analysis (DGA) the second Lego block:

1. Temperature monitoring. Using temperature monitoring devices on power transformers is not a recent phenomenon. Most transformers are equipped with a current transformer based winding temperature indicator (WTI) and utilize a PT100 fitted in a pocket to monitor top oil temperature, which usually is the oil temperature (OTI). Please note that temperature varies throughout the transformer, with the hottest part of the transformer being at the top. It is important to take into consideration the ambient temperature to forecast possible overloading and thus overheating, which in turn can decrease the lifetime of the transformer. Other devices like the Buchholz-relay data, oil level, pressure relief device and, if fitted, DGA data should be available to see the whole picture. All of these indicator's data should be taken into consideration to ensure a healthy operating system. This data should be available online to get a real time indication of the situation and to build a picture of what the data should look like when everything is normal. As soon as any deviations are noted, they should be evaluated and a decision should be made, either to monitor the situation if not critical, or to take immediate action if need be to save cost on downtime and maintenance.

2. DGA monitoring. DGA is one of the most common techniques used for fault diagnosis because its non-intrusive and the unit does not need to be de-energized. There are various DGA analysis methods available in the industry. The DGA profile gives us an indication of the transformer condition. It is vitally important that the interpretation of the DGA is done by a technical specialist that can correctly apply all the variants and

relations to come to an accurate indication of the condition of the power transformer. The quality of the testing laboratory and the sample is of the utmost importance as this can cause major inaccuracies leading to inadequate control measures, thus useless data, and a waste of money.

If correctly done, DGA analysis will identify possible faults in the transformer and indicate how serious the problem is. This traditional method leaves a lot up to chance and a lot of expertise is needed to come to the correct answer. If any part of the process does not meet the highest quality, the maintenance manager might end up with the wrong data. This can cause an incorrect action to be implemented and a unit might be lost. Most utilities follow a maintenance strategy requiring them to take an oil sample every 6 to 12 months, which is good enough to build up a history for the unit and to create a unit specific normal profile.

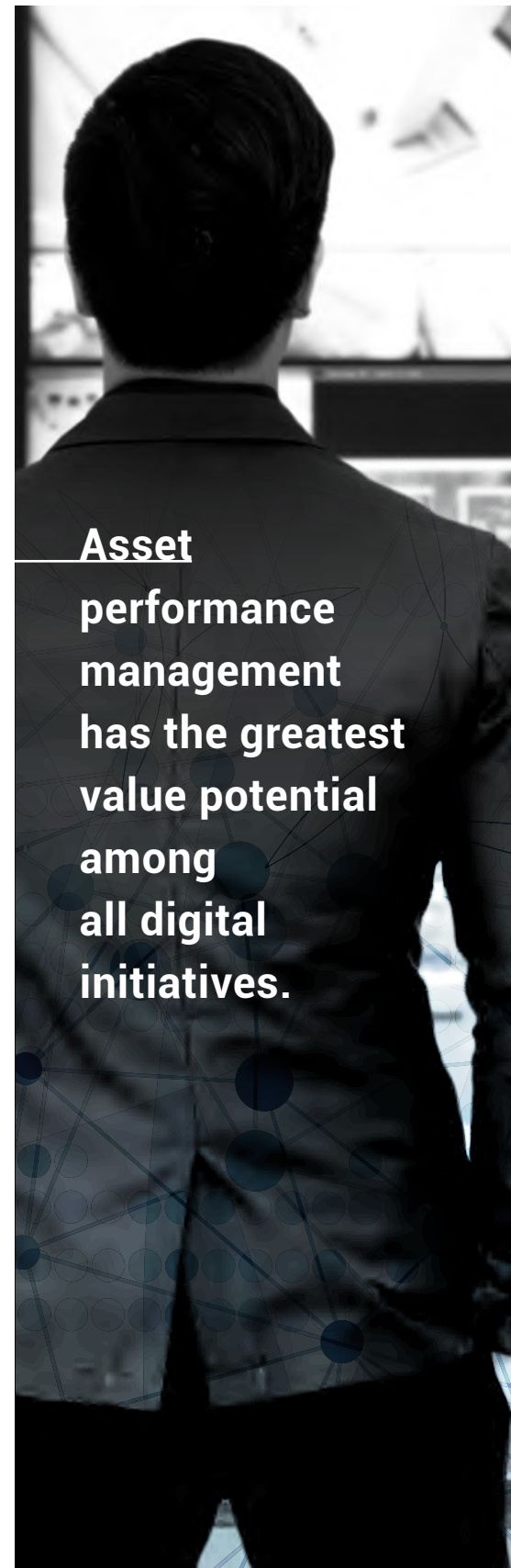
However, since the day-to-day health of the unit is not monitored, if a problem should arise between two sampling cycles, one that is quite serious, within a few days or months the problem might escalate making the repair bill much higher and the repair time consuming. Having real-time data would alert the manager to a problem.

Online DGA can be programmed to sample automatically at pre-set intervals, in a closed-loop measurement system. The system needs to have measurement repeatability, no cross-interference between gases and no calibration required. It needs to detect all the gases for complete transformer analysis and health profile compilation.

Pattern recognition algorithms are built into the software database according to the data in historic database files of transformers that displayed a certain problem, e.g. partial discharge, overheating, discharge fault, or another problem, although expert input might be required for final assessment [4].

Smart asset management

In a study by the U.S. Department of Energy, it was found that 75% of breakdowns have been eliminated by an actively implemented predictive maintenance plan based on digitalization. Asset performance management has the greatest value potential among all digital initiatives.



**Asset
performance
management
has the greatest
value potential
among
all digital
initiatives.**

If digital initiatives like condition monitoring, predictive forecasting, and smart sensors are deployed, it will lead to a marginally lower maintenance costs, lower downtime of assets, and fewer critical breakdowns. Digitalization supplies real-time data by means of connected sensors and algorithms, which enables the maintenance manager to make informed decisions

and take corrective action. Asset managers can identify problems and take action to prevent unplanned downtime. A futuristic approach can be implemented, for instance, "When does it make sense to operate a transformer above its nameplate rating?", rather than the conservative approach of operating at less than half the capacity. This can only be done with continuous data at hand.

Studies found that short time overload conditions (100%-120%) for about 10 hours should not potentially harm the transformer if no partial discharge or hotspots are present in the transformer because there is, in actual fact, no real thermal overload. In comparing load versus temperature versus time, the formation of hydrogen should be monitored as this might be the first indicator of possible electrical faults in the unit.

Traditionally, transformers have been conservatively rated and operated to reduce risk of failure in unforeseen and unpredictable adverse circumstances. However, by continuously and effectively monitoring the load, operating environment and transformer condition in real time, while having control over cooling systems and online tap changers, the typical power transformer can be safely operated by up to 20% above its nameplate value, since it will still be operating within predefined standard design limits, in terms of current and thermal properties. This is known as dynamic rating.

In addition, online condition monitoring devices connected to the online transformer management system permit continuous assessment of condition and can be utilized to provide early warning of deteriorating components or to adjust dynamic rating limits. Most important parameters commonly monitored include fault gases, moisture in oil, bushing power factor, temperature, cooling system functionality, and tap changer utilization. Insulation life consumption can also be monitored on a continuous basis.

Utilization of condition monitoring digitalization also permits condition-based maintenance with attendant benefits in reduced maintenance resource requirements and cost reductions, along with fewer outages.

By combining these capabilities into one Transformer Management System device, we have a "better tool" as required for managing power transformers for maximized output, but in a completely safe and fully controlled manner [3].



How does digitalization apply to utility?

1. System wide data integration and new business models: Provides a system wide view of devices inside the network, as well as analysis of device performances. New business models become possible because of the broad visibility of data and the historical analysed data ensuring maximum application of equipment – optimum use.
2. Fleet level analytics, services and remote management: Improved customer value and experience of the overall product. This enables asset managers to take control of the entire network and ensure maximum potential is reached, creating a wider range of service available to the end user.
3. Station level communication and serviceability: Once the whole base is digitally enabled, cost effective

connectivity and remote managing of equipment becomes a reality.

4. Device level sensing and data acquisition: Data is continuously captured, formatted and analysed from all the devices linked to the system, which makes interpretation and decision making much easier.

Conclusion

The thermal management focus might provide the tools to overcome future challenges of the evolving power grid and the demands placed on the power transformer [5]. According to IEC standards, normal ageing is defined as the loss of 24 hours of life on a power transformer after 24 hours of continued operation. Abnormal ageing occurs when more than 24 hours of lifetime is lost in a power transformer after 24 hours of continued operation. Some studies have shown that under certain conditions, overloading

transformers to 120% did not thermally stress the transformer. The goal should be to overload with acceptable loss of life, and such operations should not pressure design margins of accessories like bushings, tap changers, cable connections, etc. This is only possible under continued monitoring circumstances, getting all the data every second of the day.

Using transformer intelligence enables asset owners to extract all available capacity of transformers; it also helps them reduce investment cost, prevent high over-capacity specs for budgets and tenders, utilize ambient conditions that are favorable for long-term or short-term operation above nameplate rating, monitor vital parameters using smart sensors, and make informed maintenance decisions [6].

Digitalization is all about managed control.

Using transformer intelligence enables asset owners to extract all available capacity of transformers; it also helps them reduce investment cost, prevent high over-capacity specs for budgets and tenders, utilize ambient conditions that are favorable for long-term or short-term operation above nameplate rating, monitor vital parameters using smart sensors, and make informed maintenance decisions.

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Power Factor: Offline, Relative and True





Tony McGrail is Doble Engineering Company's Solutions Director for Asset Management & Monitoring Technology, providing condition, criticality and risk analysis for utility companies. Previously Tony has spent over 10 years with National Grid in the UK and the US; he has been both a substation equipment specialist and subsequently substation asset manager, identifying risks and opportunities for investment in an aged infrastructure. Tony is a Fellow of the IET, a member of the IEEE, CIGRE, ASTM, ISO and the IAM, and is currently active on the Doble Client Committee on Asset and Maintenance Management and a contributor to SFRA, Condition Monitoring and Asset Management standards. His initial degree was in Physics, supplemented by an MS and a PhD in EE followed by an MBA.

Introduction

Bushings are usually reliable elements of any electric supply system, but all bushings have failure modes and all bushings will eventually fail: some relatively slowly, over weeks or months, and some relatively rapidly, over hours [1]. The cause of failure could be a combination of factors such as moisture ingress, the effects of transients, and insulation deterioration. The result is a reduction in the capability of the bushing insulation: power factor (tan delta, dissipation factor) and capacitance may increase, which can be detected through both offline and online measurements. In this paper we review the differences between the results of offline bushing testing and online measurements using both relative and true power factor techniques. We must understand the nature and practicality of offline and online approaches to understand why the results may differ and the value they bring in preventing bushing failures.

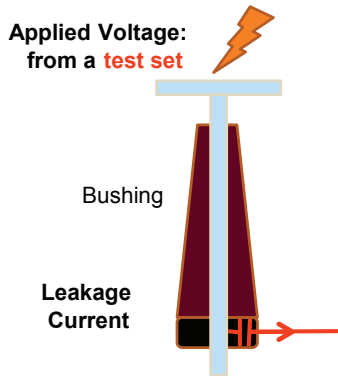
Bushings – Offline Tests

A bushing allows a current carrying conductor to pass through a barrier, which is usually grounded, such as a transformer tank. As the insulation on a bushing is not perfect, the voltage on the conductor will produce a current through the bushing insulation to ground, known as the leakage current, as shown to the left in Figure 1. Measuring the phase angle between the applied voltage and the resulting leakage current allows us to calculate the loss angle, power factor, and capacitance of the bushing insulation, as shown to the right in Figure 1 [2].

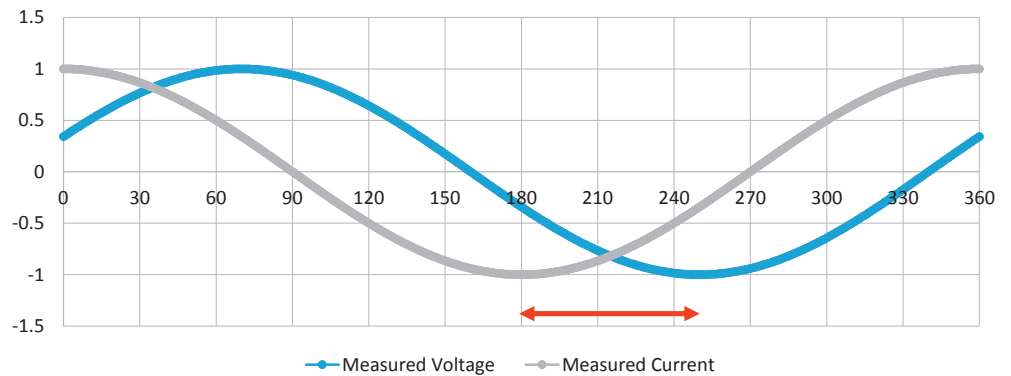
We must understand the nature and practicality of offline and online measurement approaches to understand why the results may differ and the value they bring in preventing bushing failures.

Offline testing of bushings has been performed for many years, with standards such as IEEE C57.29.01 supporting the interpretation of data and providing limits for acceptable results [2]. Each bushing should be factory tested, deriving a 'nameplate value' for the key parameters – power factor and capacitance. Field test results are compared to the nameplate and are trended over time to indicate levels of deterioration [3].

Figure 1.
Offline test overview for bushing
power factor and capacitance



Measured Voltage, Measured Current



Analysis of field results using statistical tools helps identify outliers and anomalous results for bushings which may be at early stages of incipient failure: but we must compare an individual bushing with similar bushings in terms of manufacture and design as results from different bushing 'families' may be very different [3, 4].

In an offline test the voltage is supplied by a test set and is precisely controlled and measured; the resulting leakage current is also precisely measured. These two key parameters are thus well defined and accurately evaluated. In addition, the test object – the bushing – is well defined and consists of everything between the point of voltage application and the point of

current measurement. Given accurate measurements of current and voltage we can then calculate the bushing power factor and capacitance precisely.

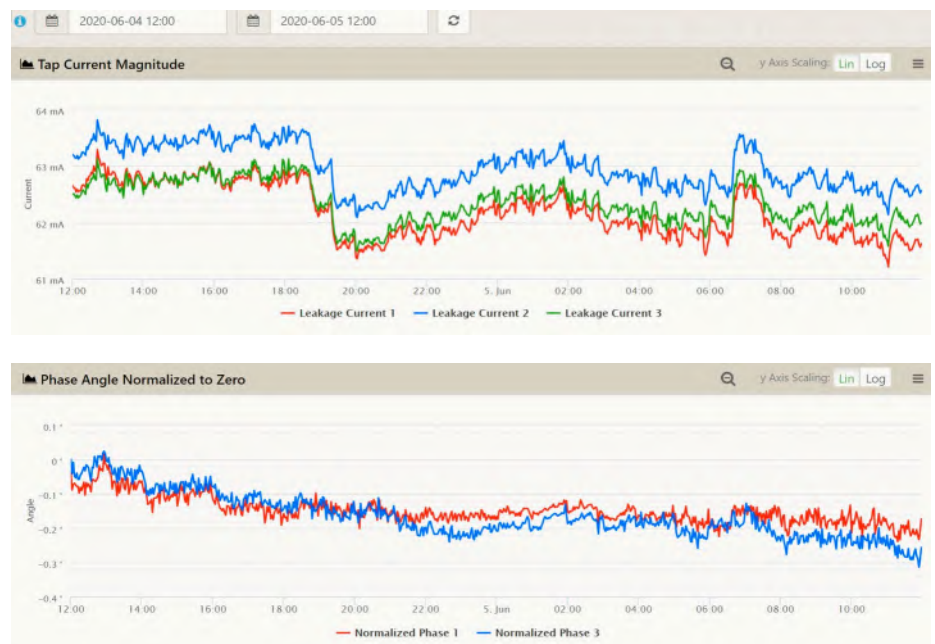
Online Measurements – Early Days

Failure modes of bushings may act over timescales much shorter than the interval between regular offline testing – meaning that incipient failures are missed and possibly catastrophic bushing failures result. The benefit of an online system to monitor bushing condition is clear – prevention of failures, which would otherwise go undetected until the bushing fails [5].

One early approach was to look at the three-phase sum current

as a detector of deterioration. The symmetry of a balanced three-phase system means that when the three sinusoids are added they will sum to zero at any point in time. For the three leakage currents for a set of identical bushings, any non-zero sum *could* be an indicator of deterioration in one of the bushings: this would be a *detector*, rather than a *diagnostic*, as we don't know which bushing is the cause of the non-zero sum, or whether it is a current magnitude or phase variation. In the late 1990s and early 2000s such approaches were used to identify anomaly, but electric supply system variations could lead to too many false positives: minute-by-minute the voltage on each phase is not identical in magnitude across the three phases and the expected 120° phase difference was rarely found.

Figure 2.
Sum Current Chart for a 650 MVA
transformer



The sum current data for a HV set of bushings on a large power transformer is shown on the left in Figure 2; the data covers recordings at 1 minute intervals over 24 hours and is not only non-zero, it also shows phase variation over time which could indicate an incipient failure related to power factor. In fact, this would be a false positive as the raw data, the rms currents and phase angles, are normal for this bushing set. The charts at right in Figure 2, cover the same time period as the sum current and the variations seen in rms current and phase are typical and reflect the individual application of the bushings [3].

It was the tendency to provide too many false positives which led Doble to move away from sum current as a detector almost 20 years ago, and move to actual power factor data and capacitances for each bushing.

Online Measurements – Relative Power Factor

We must note that a key difference between online and offline measurements: in online measurements we do not supply the voltage, and must find a way to measure it, or account for it, which is what happened initially with 'Relative Power Factor'. The approach is to measure the three leakage currents, as shown in Figure 3, and calculate the phase difference between each pair of bushings.

We are interested in power factor and capacitance, but we must start with the basic measurements: the raw waveforms at each bushing test tap, as shown in Figure 4, as these are what we use to determine the leakage current rms and phase values. We would theoretically expect a pure sinusoid at each tap, but this is not often the case. The data in Figure 4 shows the three HV bushings, to the left, and the three LV bushings to the right, all of which contain harmonic content.

The curves in Figure 4, for a transformer at a windfarm location, show the actual signals are neither pure sine waves nor equal in magnitude. The recordings are used to calculate the actual system

The benefit of an online system to monitor bushing condition is clear – prevention of failures, which would otherwise go undetected until the bushing fails.

Figure 3.
Relative Power Factor basic measurements

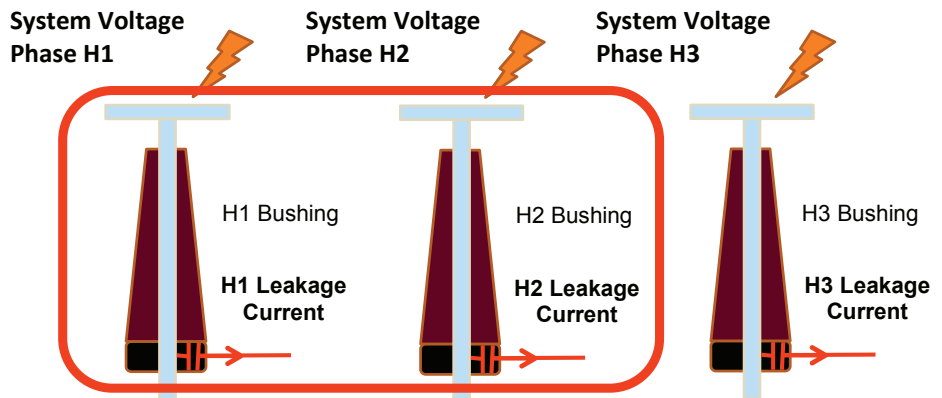
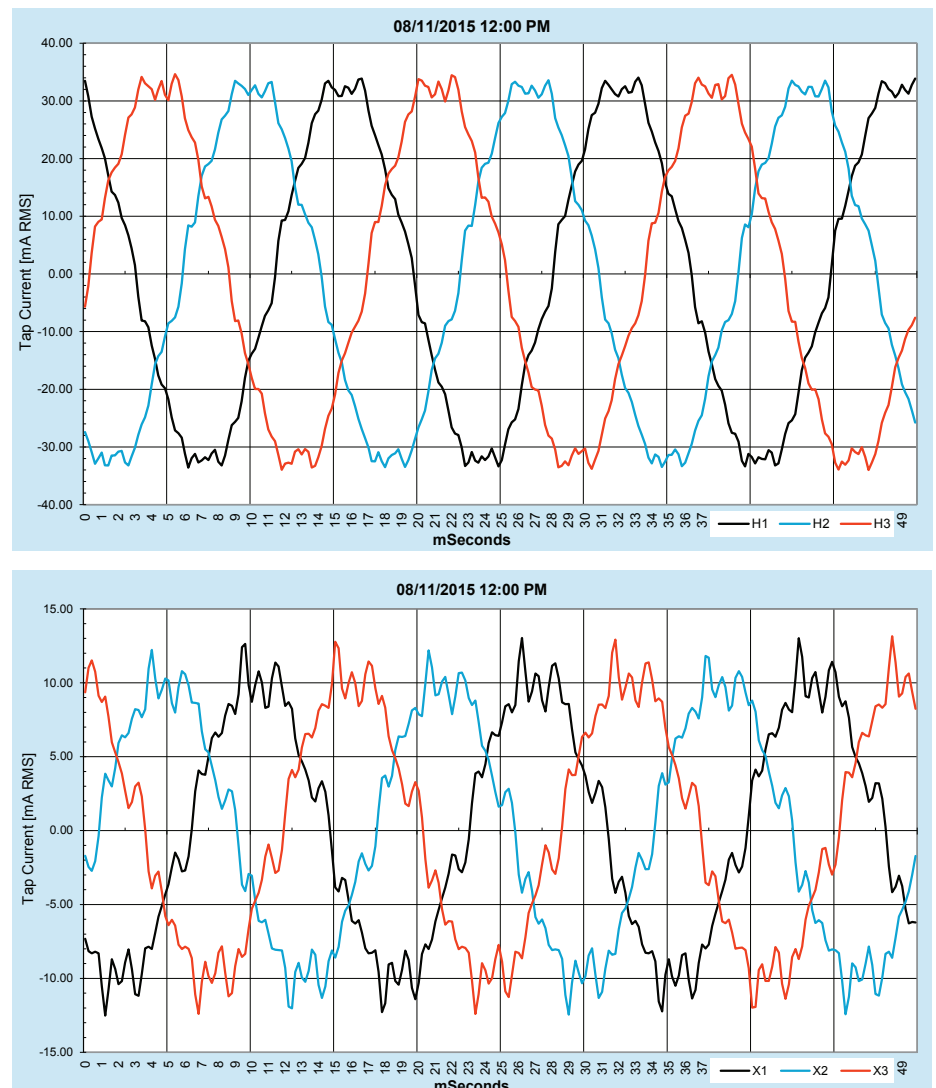


Figure 4.
Raw waveforms at a windfarm transformer



frequency – which is usually close to but not exactly equal to 50 or 60 Hz. An early approach to determine waveform frequency was to count zero crossings, but this could lead to incorrect results as harmonic content means more crossings may be counted than are present at the fundamental system frequency. A far better method is auto-correlation of the sinusoid, followed by digital power sinusoid generation and cross correlation, which has the benefit of also giving the harmonic content of the raw waveform.

Once we have the raw waveforms we can accurately calculate the key initial values, which are shown in Figure 2: current magnitudes and relative phase. In practice, all three currents have a phase angle measured against an arbitrary time reference given by the data acquisition system. These angles are used to calculate the relative phase angle between any two bushings; the phase angle chart in Figure 2 shows just two values as the third value is always 360° minus the sum of the two given, as A relative to B, B relative to C and C relative to A will always add to 360° .

In Figure 3, we can measure the relative phase between H1 leakage current and H2 leakage current: this relative phase angle will be derived from contributions of the two bushing power factors and the phase difference between H1-H2, which is nominally 120° . We can use the three relative values to calculate the power factor of each bushing, noting that variation in system voltage phase from 120° is a significant impact. Capacitance is calculated from the leakage current and nameplate bushing voltage. It is clear from the approach that there are several sources of variation: as can be seen in Figure 2 the voltage on the system is not a constant magnitude, as we can see all three rms current magnitudes changing in unison, and the relative phase is not constant at 120° .

In practice, many of the effects of system variation can be removed by averaging the power factor and capacitance values to remove some of the system-imposed effects. The Relative Power Factor

technique has been successful in identifying deteriorating bushings and preventing their failure for more than two decades: relative power factor has saved a variety of bushing types including Trench, GE and Westinghouse and prevented catastrophic failures [3, 6].

As an example, Figure 5 shows the recorded rms currents and weekly power factor for a set of 3 bushings. The variation was such that alerts were triggered for a weekly power factor at 2.5%, compared to a nameplate value of 0.32%. The transformer was taken offline and bushing tests confirmed the deteriorated state of the bushing.

Without appropriate condition monitoring, the true condition of the bushing would have only been found after it had deteriorated to the point of failure. Note that alerts should be able to be set based on instantaneous rms current and phase values, as well as daily, weekly and monthly values.

If a temperature measurement for each individual bushing is available, that should be used to 'correct' the resulting power factor and capacitance values for comparison to manufacturer tables stored within the monitor; where necessary, a user should be able to enter correction factors for their individual bushings.

A key difference between online and offline measurements is that in online measurements we do not supply the voltage, and must find a way to measure it, or account for it.

Figure 5.
Leakage Current and Relative Power factor for failing bushing



Online Measurements – True Power Factor

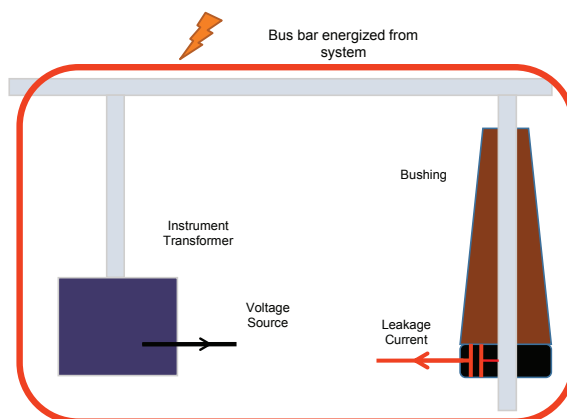
True Power Factor (TPF) is called 'True' as it looks at the phase angle between a voltage and a current, by using a voltage reference, as shown in Figure 6, where a bushing and an Instrument Transformer (IT) are on the same bus bar. As with Relative Power Factor, everything between the two measurement points is now part of the 'device under test': the bushing and the instrument transformer.

If the IT and the bushing are on different sides of a transformer – say an HV bushing and an LV IT – then the whole transformer is also part of the 'object under test' and could be a cause of variation in the final power factor or capacitance values. As in the case of Relative Power Factor, the raw waveforms for both current and voltage are recorded and used to derive rms and phase values. To provide a valid voltage reference, the voltage and current measurements need to be either made simultaneously on a single monitor or referenced to GPS timing to allow for calculation of the loss angle and power factor.

The individual current magnitude and phase for a set of three bushings and three ITs recorded over a four-week period are shown in Figure 7. Alerts may be set on voltage or current rms magnitude and/or phase. The relative phase between current and voltage yields the loss angle, which is used to determine the True Power. It is clear that there is variation in the resulting rms values over time – the results shown, however, are normal for this location. Alerts can be set on the instantaneous True Power Factor and Capacitance values, but it should also be possible to set alerts on the smoothed variation calculated on a 24-hour moving average of all available results, with the data shown in Figure 8. The daily variation is much smoother than the instantaneous values shown in Figure 7, but still reflects some of the system voltage variations.

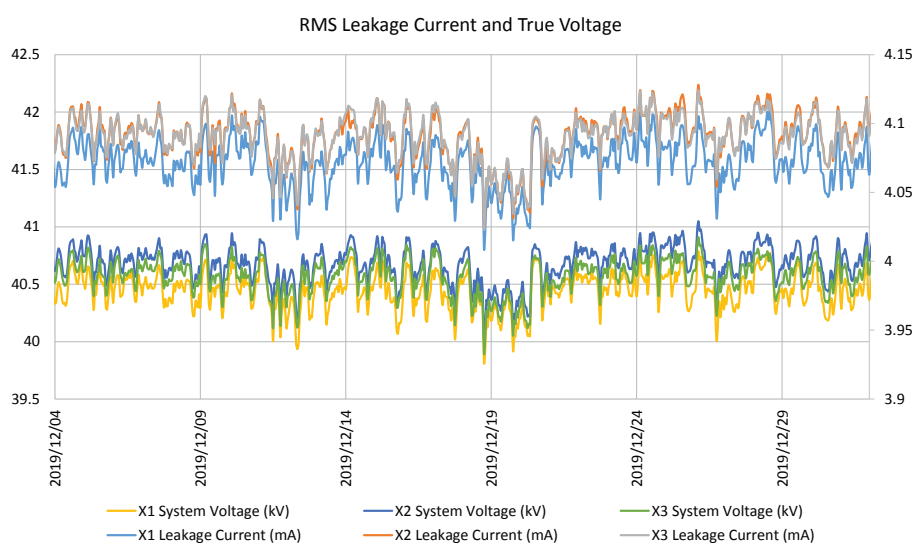
Unlike the relative power factor, there is no need to account for the system 120° contribution if the bushing and IT are on the same HV bar. We can also 'calibrate' the calculated power factor

Figure 6.
Set up for True Power Factor



The Relative Power Factor technique has been successful in identifying deteriorating bushings and preventing their failure for more than two decades, saving a variety of bushing types and preventing catastrophic failures.

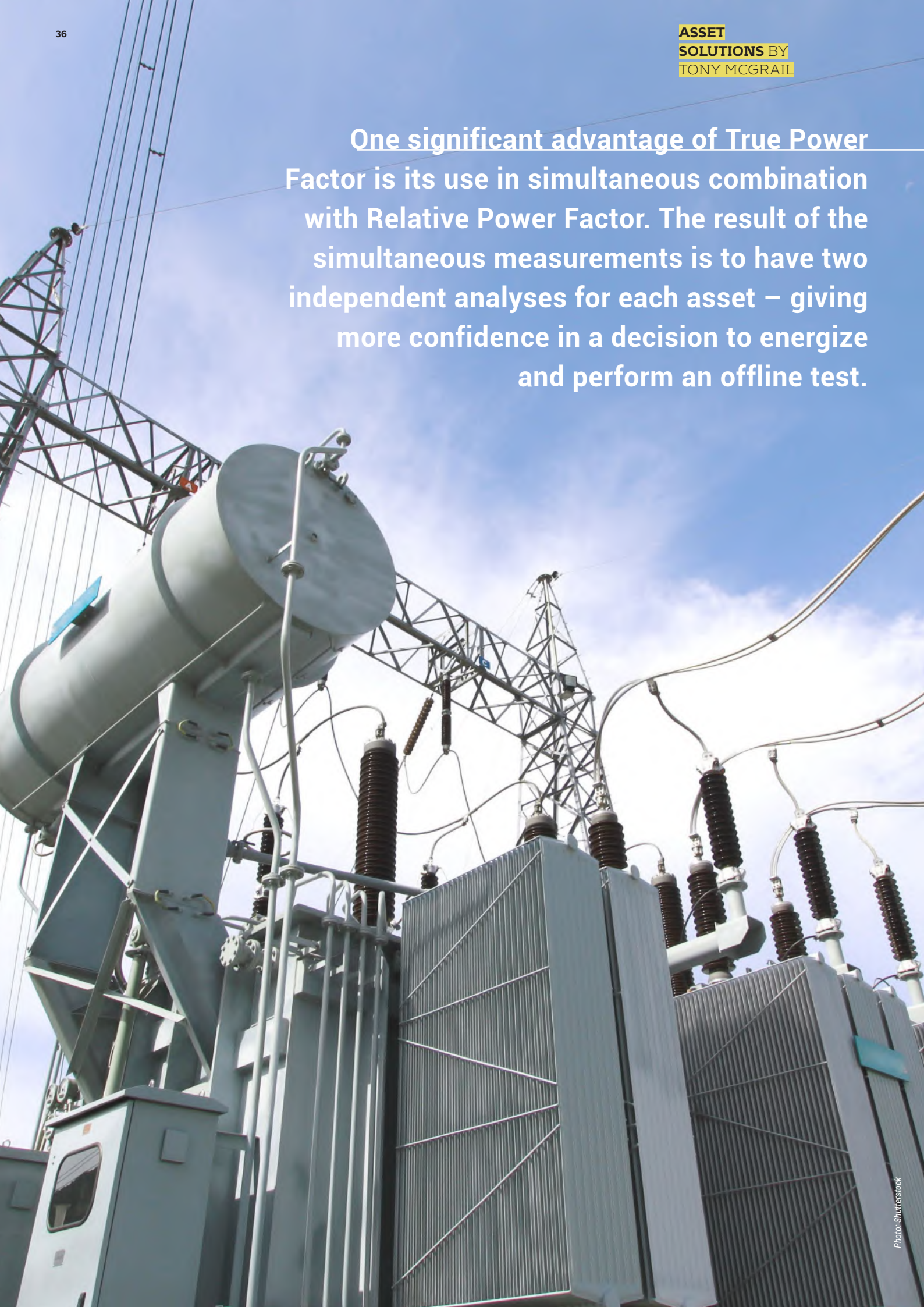
Figure 7.
Simultaneous current and voltage measurements in a True Power Factor application



in software by setting an offset for the IT to give the final results as the expected power factor for the bushing, but remembering that any variation may not be caused by the bushing,

but be a result of changes in the IT: we are, in fact, monitoring both assets. Again, harmonic content of the raw waveforms is calculated for monitoring and diagnostic purposes.

One significant advantage of True Power Factor is its use in simultaneous combination with Relative Power Factor. The result of the simultaneous measurements is to have two independent analyses for each asset – giving more confidence in a decision to energize and perform an offline test.





One significant advantage of True Power Factor is its use in simultaneous combination with Relative Power Factor: as shown using the outlines in Figure 9 where the measurements provide a view of condition of all assets involved, and build on the strength of each measurement:

- The orange outlines identify individual bushing/IT combination monitored using True Power Factor and identify a problem on a particular phase.
- The green outline covers the use of Relative Power Factor to monitor the performance of each bushing
- The blue outline covers the use of Relative Power Factor to monitor the performance of each IT

The result of the simultaneous True and Relative Power Factor measurements is to have two independent analyses for each asset – giving more confidence in a decision to de-energize and perform an offline test.

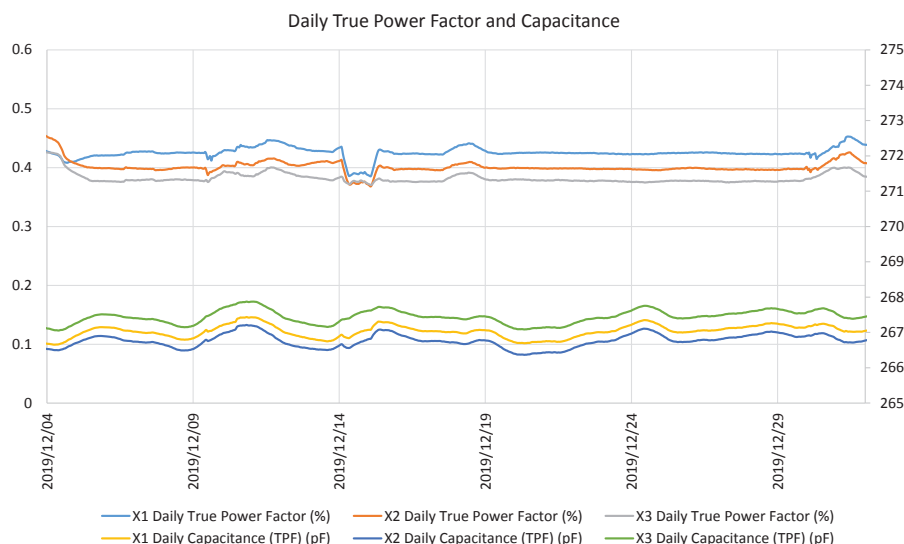
Discussion

A monitor should provide individual bushing power factors and capacitances, at an interval suitable for the failure modes of the specific bushing monitored. Recordings of the raw sinusoid waveforms should be available, and correlation techniques used to derive the fundamental system frequency and the harmonic content of currents/voltages. Alerts should be set based on knowledge of the bushing failure modes likely to be in operation and the specific application, and include alerts for temperature corrected:

- instantaneous current and voltage values
- relative and true phase angles and loss angles
- relative and true power factor and capacitance
- harmonic content
- any data value of interest to the user

Bushing condition monitoring has been developed over several years to the point where monitoring systems may replicate offline tests. The increase in available data supports asset risk management, effectively

Figure 8.
True Power and Capacitance daily variations



Bushing condition monitoring has been developed over several years to the point where monitoring systems may replicate offline tests. The increase in available data supports asset risk management, effectively providing usable information in a timely manner.

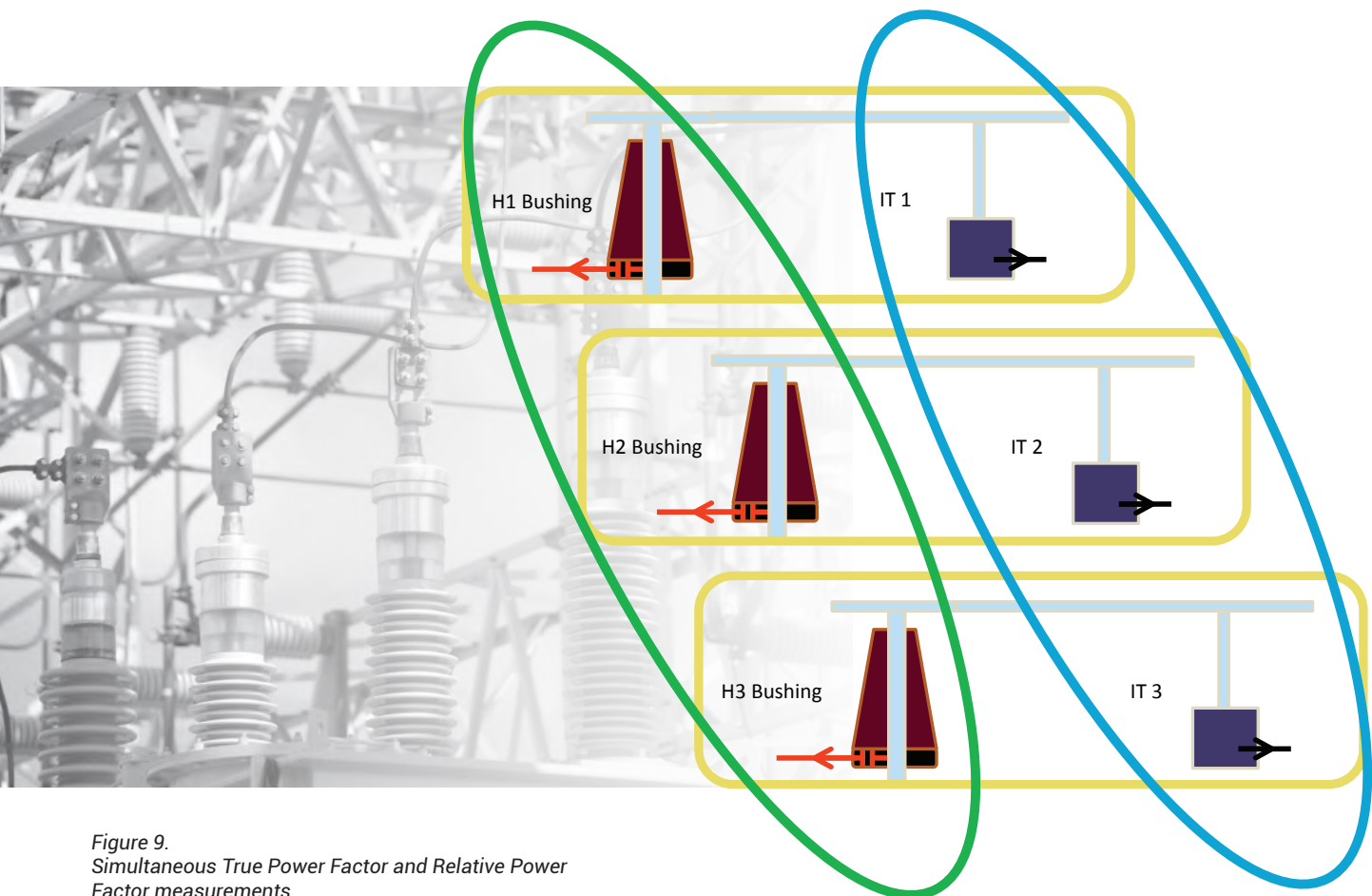


Figure 9.
Simultaneous True Power Factor and Relative Power Factor measurements

providing usable information in a timely manner. Of course, there is a need to embed the monitoring system and the management of alerts into the organizational structure and culture, or the benefits of condition monitoring may not be realized.

Acknowledgements

The author would like to thank his many colleagues for the many discussions of the theory, practices and benefits of bushing monitoring over many years.

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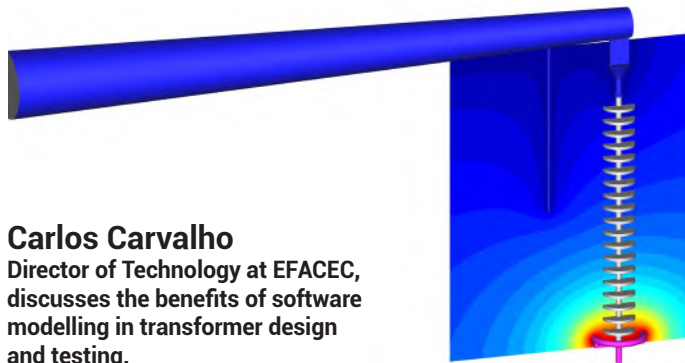
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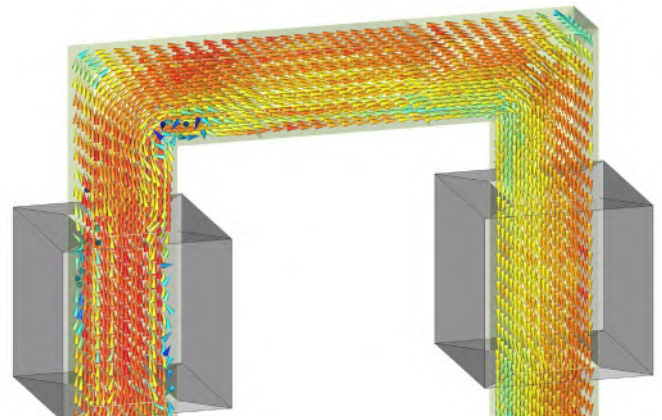
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THE BENEFITS OF SOFTWARE MODELLING IN TRANSFORMER DESIGN AND TESTING: EFACEC Case Study



Carlos Carvalho

Director of Technology at EFACEC, discusses the benefits of software modelling in transformer design and testing.



The EFACEC Group is leading the supply of integrated solutions and equipment in the market of power generation, transmission and distribution. The Group forms a complete value chain, from building turnkey projects to equipment manufacture, where integrated solutions are developed and designed in accordance with clients' needs. The Group offers a comprehensive range of activities including Power Generation, Transmission and Distribution, Automation and Telecontrol Systems, Electric Mobility Power Supply Systems as well as Maintenance and Technical Assistance Services.

The director of Technology, Carlos Carvalho, leads a strong engineering team of 120 in the EFACEC Power Transformers Business Unit: "Our division has the capability to design and manufacture core and shell type power transformers up to 1,500 MVA and 525 kV, mobile substations up to 90 MVA, and immersed and dry type distribution transformers. This makes the design and manufacture of power transformers the core of EFACEC's business. In the current market, transformers need to be ever more effective and competitively priced. To do this, we at EFACEC employ simulation software to build virtual prototypes of the system prior to manufacture, to avoid wasting time on costly mistakes."

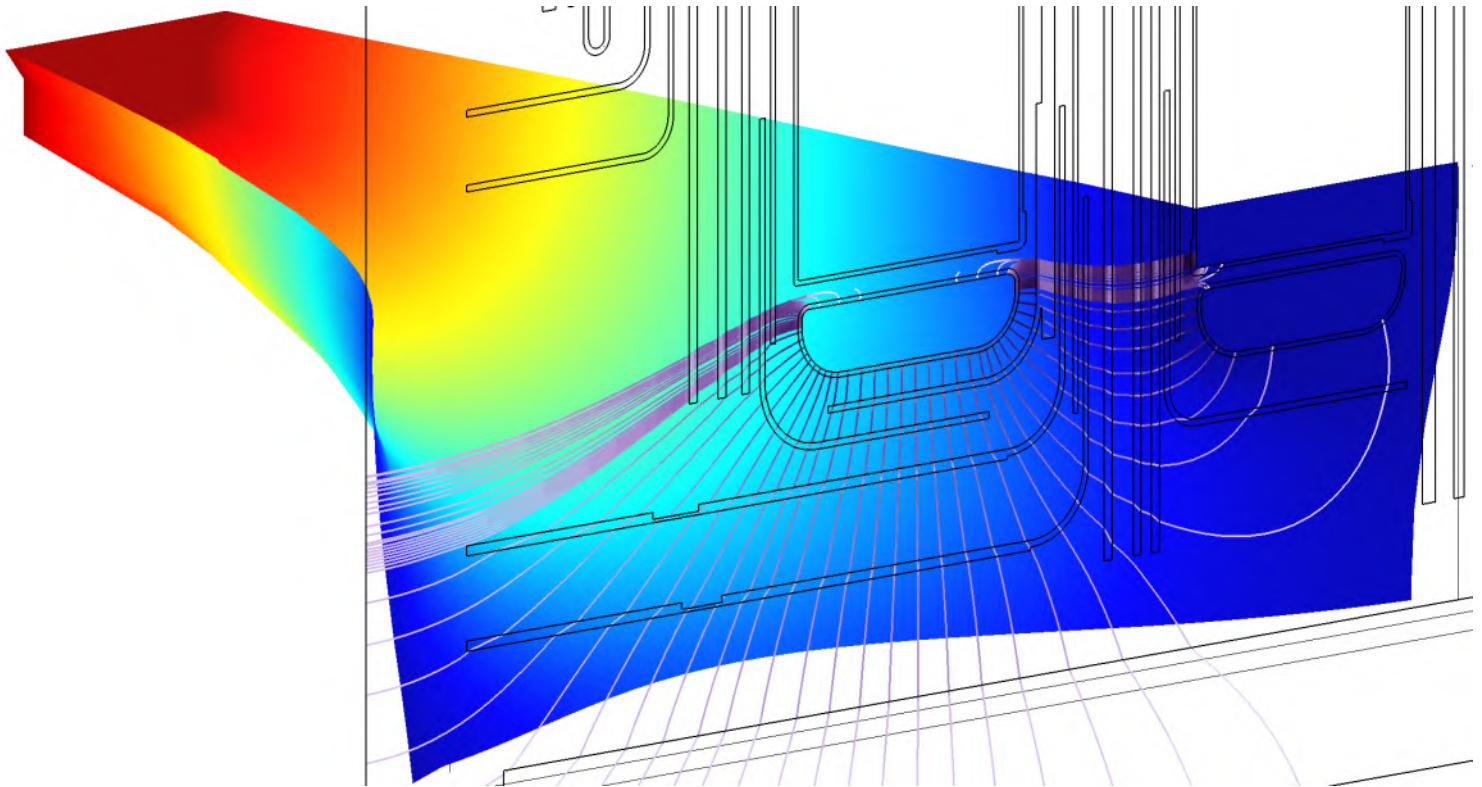
In the current market, transformers need to be ever more effective and competitively priced. To do this, we at EFACEC employ simulation software to build virtual prototypes of the system prior to manufacture, to avoid wasting time on costly mistakes.

He continues: "For the past 26 years EFACEC has been using simulation software from INTEGRATED Engineering Software to help iron out any design issues in the early stages, before they prolong the design lifecycle. The software we use at EFACEC are the ELECTRO, COULOMB, FARADAY and INDUCTO products. ELECTRO is a 2D/RS electric field solver designed specifically for applications such as transformers. ELECTRO can calculate electric field strength, transmission line parameters and capacitance. Our designers can automatically vary and experiment with geometry, materials and sources, therefore reducing the tedious, repetitive task of fine tuning multiple design parameters. COULOMB is, by contrast, a 3D electric field solver used for calculations such as electric field strength, transmission line parameters and capacitance. Finally, FARADAY is a 3D eddy current field solver which can calculate force, torque, displacement current, flux linkage, induced voltage, power and impedance."

Despite using software simulation, a yet unsolved problem in the design of transformers came to light. The weak link theory was adapted to the design of the insulating structures inside oil immersed power transformers. The stratified insulation media is composed by pressboard barriers and oil channels. The dielectric permittivity of the pressboard is twice that of the oil and so the electric field accumulates in the oil channels. The oil dielectric strength is also much lower than that of the pressboard, so, in theory, if you can guarantee the dielectric strength of the weak oil, then the whole insulating structure will withstand the electric stress.

For the past 26 years EFACEC has been using simulation software from INTEGRATED Engineering Software to help iron out any design issues in the early stages, before they prolong the design lifecycle.

This empirical knowledge was developed initially by some power transformer manufacturers, and later, became public knowledge through technical papers published by Weidmann, a major supplier of pressboard to the power transformer industry. Weidmann carried out several research experiments to set-



the oil curves, a group of decaying exponential E-field strength versus length curves that are accepted as almost the standard in the transformer industry.

Carlos continues: "We at EFACEC came across this theory and requested that INTEGRATED develop it into a software solution for inclusion in its programs. INTEGRATED wrote a pro-

"The Partial Inception dialog feature helps us in our modelling and design phase by enabling us to simulate the dielectric tests and to evaluate the dielectric strength of the insulating structures between the windings, the leads, the bushing tails and the tank turrets, etc. In the power transformer industry, we can say that each transformer produced is unique, therefore during the design phase, each transformer is like a prototype and so there are constantly new challenges to analyze," says Jacomo.

There are many other applications for which the PD inception analysis may be useful, as it does not impose the base and the exponent of exponential oil curves. Therefore, users can replace these oil curves with their own air curves, silicon

The Partial Inception dialog feature helps us in our modelling and design phase by enabling us to simulate the dielectric tests and to evaluate the dielectric strength of the insulating structures between the windings, the leads, the bushing tails and the tank turrets.

We at EFACEC strongly advocate the use of modeling software to test designs as it cuts costs and supplies real flexibility, particularly where a product range comprises of major elements, large transformers in this case, which are always slightly different from the last one manufactured. Even with our very specialized applications we have been able to achieve all the capabilities we require from software simulation."

gram which was capable of this feature, effectively turning theory into reality." In less than a month, EFACEC had a custom-made solution to its problem, known as the partial discharge (PD) inception dialog feature.

curves, tangential to porcelain curves, or similar. Carlos concludes: "We at EFACEC strongly advocate the use of modeling software to test designs as it cuts costs and supplies real flexibility, particularly where a product range comprises of major elements, large transformers in this case, which are always slightly different from the last one manufactured. Even with our very specialized applications we have been able to achieve all the capabilities we require from software simulation."

For more information about EFACEC and INTEGRATED, please visit:

http://www.efacec.pt/PresentationLayer/efacec_competencias_00.aspx?idioma=2&area=2
<http://www.integratedsoft.com/products/electro.aspx>

Moisture in Transformer Insulation

by **Bob Rasor**
Hali Moleski
and **Andy Shkolnik**

EXPERTS GRAPPLE NOT SO MUCH ON THE DESIRABLE MOISTURE LEVELS FOR THE SOLID INSULATION, BUT RATHER WITH THE EXACTNESS OF ESTIMATING THE WETNESS OF IN-SERVICE UNITS.

Intuitively it is agreeable to all that moisture in transformers is not desirable. This article has as its goal to offer a very practical and experience-based profile that addresses several commonly asked questions with answers and opinions from both our industry and experience with having dried more than 500 transformers with moisture issues.



What are some of the most commonly asked questions?

1. What are the different moisture levels to be aware of and how is a transformer evaluated as slightly, moderately or extremely wet?
2. Is the moisture that shows up in the oil a reliable indicator of the condition of the solid insulation?
3. What are the accepted methods of drying insulation? Conversely, what has shown to be ineffective in drying a transformer?
4. How does moisture affect aging and reliability?
5. What can be said for the economic effects of moisture on a transformer and the costs for restoration to reliability?



Bob Rasor PE has over 40 years of service in this industry. He has been active in IEEE and recent chair of the 2015 revision to C57.106, an IEEE Guide for Acceptance and Maintenance of Insulating Mineral Oil in Electrical Equipment. He is also currently serving on several Working Groups including a new moisture guide where he is chairing one of the task forces. Bob is the Technical Director for SDMyers LLC.



Hali Moleski is a chemical engineer, with 14 years of experience in oil processing equipment. She is the Manager of Engineered Products at SDMyers and leads the design and performance for oil processing equipment. Hali's current responsibilities include project management, product design, technical report writing, and research and development projects.



Andy Shkolnik graduated from the University of Akron with bachelor's degrees in Physics, Math, and Secondary Education. He is a Technical Support Scientist at SDMyers LLC, an international leader in the field of insulating liquid analysis, engineered products & services, and training & education. He has co-authored papers on paper insulation aging and remaining life estimation, and on transformer maintenance and reliability. Andy is a member of ASTM Committee D27 on Electrical Insulating Liquids and Gases.

What are the different moisture levels to be aware of and how is a transformer evaluated as slightly, moderately or extremely wet?

Experts grapple not so much on the desirable moisture levels for the solid insulation, but rather with the exactness of estimating the wetness of in-service units. Again, if the question is what is considered dry insulation, there are few disputes.

A new, dry transformer with under 0.5% moisture in the insulation is the norm. How much of the total moisture is in the paper insulation and how much is in the oil? Only about 1%, or even less of this water is in the oil. An interesting way to show this involves considering a 1,000-gallon transformer with an estimated 1,100 or so pounds of porous/paper insulation. If one-half percent of this weight is moisture, and if completely in the oil, it would be just over 5 pounds of water dissolved in 1,000 gallons (7,500 pounds) of oil. This would mean a perfectly dry transformer would have 780 ppm of moisture in the oil! But we can see how it is the reverse, as depending upon the temperature, often under 10 ppm, but, no more than 10 to 25 ppm of water is the typical expected water content in a dry transformer.

What about a transformer starting to show signs of moisture issues? How wet is too wet? And first of all, how did it get wet? There are three basic ways a transformer can become wet:

1. The unit somehow came from the factory improperly dried. This is not all that common. With factory testing including an Insulation Power Factor test before shipping, a value around 0.5% indicates dryness. Lesser Basic Insulation Limits (BIL) can tolerate 1%, and some distribution units reportedly allow 2%. In a general sense, the Insulation Power Factor values at lower levels like these align well the % Moisture by Dry Weight in the solid insulation (%MBDW).
2. The next cause of moisture in a transformer comes from aging of both the oil and the paper insulation, because moisture is a by-product of the chemical reaction of both oil and paper with oxygen, heat and even minute levels of moisture. Copper is also a catalyst for oil oxidation, making the control of moisture, heat and oxygen even more desirable. If there are no rising acid levels, no indication of the creation of furans (a chemical byproduct of the

breakdown of the paper insulation) and a good D1816 dielectric strength, this cause becomes less likely.

3. Lastly, and most commonly, moisture enters transformers by ingress. The oil level in a transformer will rise and fall due to changes in temperature based on changes in load and ambient. With these changes, the oil may vary in volume as much as 4-5% a day. If a unit is not sealed properly, the oil preservation system will allow moisture to be drawn in as the oil cools and decreases in volume. Once in, it dissolves and does not reverse migrate.

Once a unit is showing elevated moisture levels in the oil, the paper insulation is also affected. Figure 1 shows the variation experienced due to temperature and the migration of water from the insulation to the oil, and vice-versa. This transformer was dry for about 10 years and sampled twice a year – once in the summer and once in the colder months. The warmer the oil, the more the moisture migrates. At year 10 or so, the unit developed a leak and moisture levels became unacceptable. More on this in the next section.

Figure 1. Moisture and field dry-out - 138 kV transformer 8,400 gallons [1]

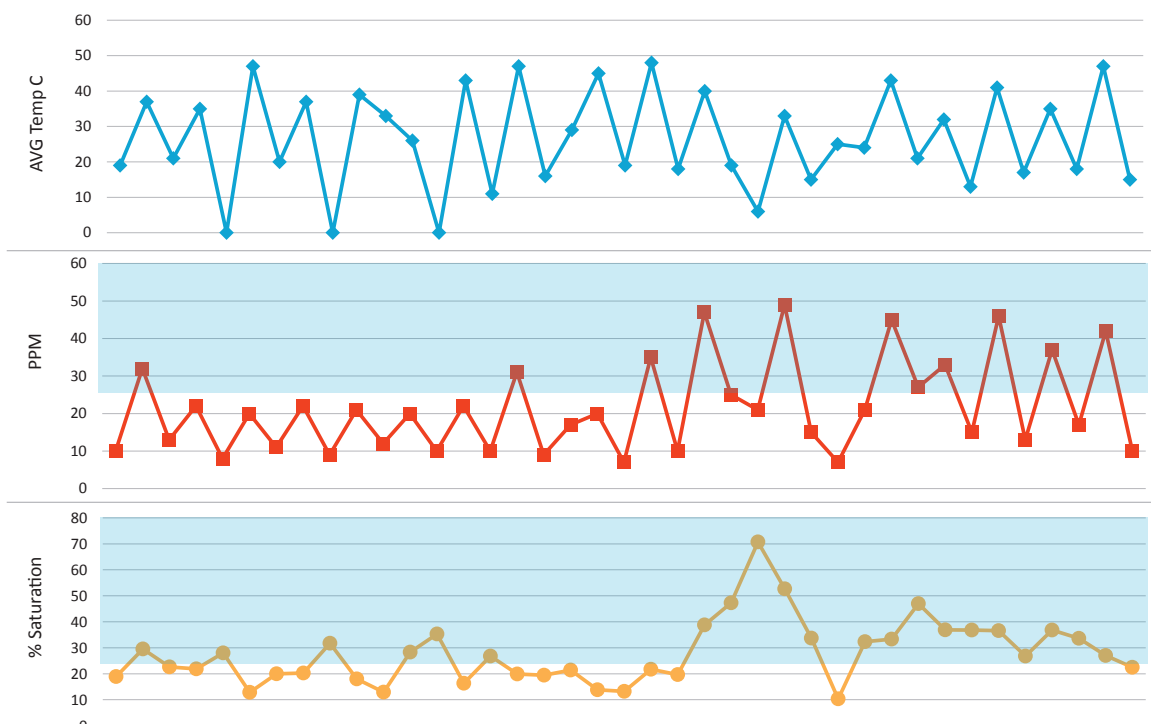
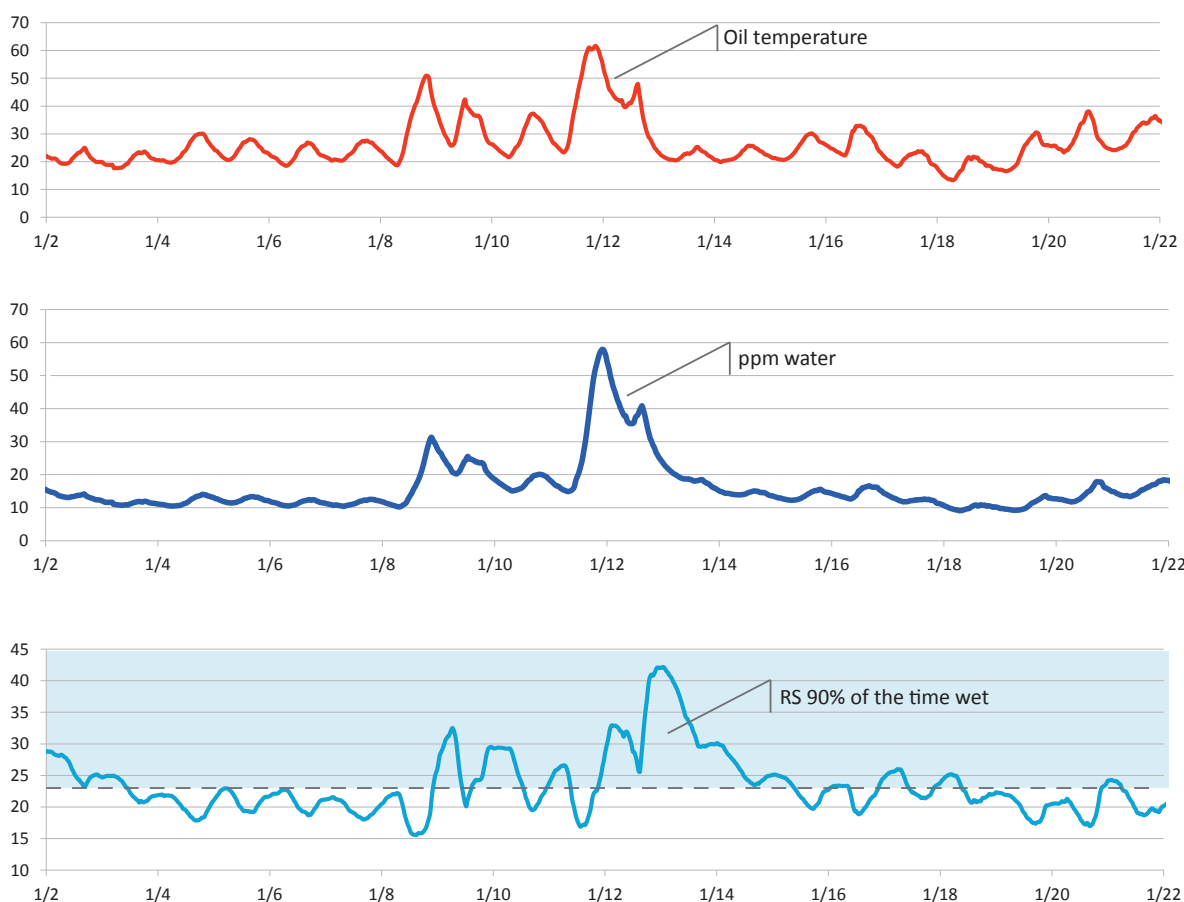


Figure 2. Migration of moisture in and out of the oil in a transformer with changes in temperature [2]



Is the moisture that shows up in the oil a reliable indicator of the condition of the insulation?

It was stated earlier that most of the moisture in a transformer is NOT in the oil. However, the water in the oil is still a reliable indicator of moisture in a transformer.

How wet does the oil become if the biggest "holder" of the moisture is the porous insulation? There are several methods that have been developed to relate moisture levels in the oil to the moisture in the solid insulation. They have some variation, but most involve having some measurement of temperature and a graphical or numerical relationship between the ppm of moisture in the oil and the % Moisture in the paper insulation. The results of these methods are used as estimates. In studying the different methods, even though they vary and can have differing results, they can all identify a wet transformer. And the useful aspect of % Saturation is that it stays elevated even if the moisture

retreats back out of the oil and into the insulation when temperatures drop.

In Figure 2, from IEEE and EPRI studies, a transformer studied in Australia shows the dramatic migration of moisture in and out of the oil in a transformer, with changes in temperature.

If only a Parts per Million (PPM) reading is used, it will vary to where even a wet transformer can give an apparent dry PPM result if the oil is cool enough. In both figures, where the current IEEE Guide C57.106 [3] has a 25 PPM limit for a 138 kV class transformer, readings varied from 15 to 50 ppm in Figure 1 and 10 to 60 ppm in Figure 2, solely based on the oil temperature. The same charts show that the % Saturation was elevated independent of temperature.

Opinions vary on where the limits are set to determine wet versus not-so-wet versus dry. Based on our experiencing these opinions first-hand, at 30% Saturation most would

agree the transformer is becoming a concern.

There is also another factor that can affect how representative an oil sample can be to judge the wetness of the insulation. Most oil samples are drawn from the bottom valve of the electrical equipment. These valves are known to collect moisture that can be higher than the water content of the oil in the main tank. Several articles have been written on this, and other oil service companies have determined that this happens. The valve, sticking out into the cooler ambient air, tends to have moisture condense inside the valve, and then it gets trapped in the valve since most are globe valves and do not have a straight, open path into the main tank. SDMyers profiled over 500 samples that tested high in moisture. When resampled with extra flushing, only 70% of them were actually wet. It should be routine to verify first-time high moisture levels with a sample that has at least one gallon of oil flushed for every inch of valve size.

What are the accepted methods of drying insulation? Conversely, what has shown to be ineffective in drying a transformer?

This portion of the paper has the least amount of controversial opinions. IEEE C57.140 Guide for Evaluation and Reconditioning of Liquid Immersed Power Transformers [4] has in several revisions expanded upon only a few methods for drying wet insulation.

1. Factory drying is perhaps the most effective, but the least practical for owners – and most costly. Once taken out of service and shipped to a repair facility, there are at least three methods for drying, with most including untanking the core and coil assembly. Baking, vacuum drying, or a process known as Vapor Phase Drying are the ways repair shops can remove moisture from the insulation. Typically, electrical testing is a follow-up means to verify a good outcome.

2. Next in terms of cost, are the field vacuum dry-out methods, of which there are several. This procedure will require a vacuum rated transformer and an outage for one to two weeks, as well as around the clock vacuum drying, usually with a cold trap and then a dew point check before filling – also costly. From basic physics, when vacuum is applied to wet paper insulation, once the vapor pressures are satisfied for vaporization, a transformer can be dried. There are field details to this in as much as many wet units that are vacuum rated have thousands of gallons of oil and coils needing to be heated with sometimes hundreds of thousands of pounds of mass. If the oil is the means to heat the core, it can be heated in bulk and then quickly drained or hot-oil-sprayed.

Alternatively, the windings can be heated by DC current or new magnetic induction methods, but regardless, the vacuum from a field processor flashes off the moisture and it can be trapped and measured or electrically tested to confirm an endpoint. There are indeed several ways to help confirm a field dryout endpoint:

The Piper Chart

Once the dryout is completed, and the transformer is still empty, vacuum is applied at a known winding temperature, and the Piper Chart is read for an estimation of dryness. The Piper Chart, shown in Figure 3, from IEEE C57.93 Guide for Installation and Maintenance of Liquid Immersed Power Transformers [5], has lines of %MBDW with respect to temperature on the x-axis and vacuum on the y-axis. During a vacuum dry-out, it is important to know the temperature of the insulation.

Cold Trap Measurement

If drying by attaining a heated core and coil, and then pulling vacuum with a cold trap, IEEE guides point out that collecting diminishing moisture and then only 2 ounces of moisture per hour in a cold trap is an indication of the completion of moisture removal (provided there is at least 40°C in core temperature). Some cold traps use very efficient refrigerants and a fast cycle defrost. It is still not uncommon for liquid nitrogen or even dry ice and acetone to be used to attain the minus 80°C temperatures ideal to sublime moisture to a frozen state.

Dew Point Test

After drying, with the drained transformer, dry air or nitrogen is applied to the transformer at minus 60°C dewpoint or dryer, and to a pressure of 2 psi. After 24 hours, the slightly pressurized dry gas is relieved through a dew point meter. If the transformer is dry, the dew point of the gas will have stayed around minus 50°C. Charts like the one shown in Figure 4 have been developed and used by Original Equipment Manufacturers for decades to estimate a dry transformer. Again, as with most moisture related metrics, temperature plays an important role.

Electrical Testing

Lastly, after filling, confirmation of dryness can be estimated by electrical testing. The insulation power/dissipation factor is used, or newer to the industry, a test called Dielectric Frequency Response.

One additional noteworthy discussion comes from the notion that a wet transformer can be efficiently dried

by dehydration “passes” of hot, dry oil in the transformer. While a hot oil circulation treatment will indeed dry the oil, the migration of the other 99% of the moisture into the oil is much too slow to achieve complete moisture reduction in the windings.

There are many case studies where the oil is dried (even with up to 10 circulation passes) with great final oil results, only to realize the leach-back effects of 99% of the water, having the oil again show high readings of moisture, because the paper insulation is still wet. Only surface moisture from the insulation is believed to be removed with hot oil circulations. Also, IEEE C57.140 [4] limits this processing to only surface moisture for the insulation, stating the following:

7.1. Off-line de-energized processing methods. For non-vacuum rated transformers:

b) Hot liquid method consists of heating the entire volume of liquid in the transformer and passing it through a vacuum degasifier/dehydrator to remove the moisture from the liquid and reheating the liquid as it is returned to the transformer. The hot dry liquid will pick up moisture from the surface of the active parts of the transformer and that moisture is removed from the liquid using the vacuum dehydrator/degasifier. This is also a slow process because moisture deep within the active part must migrate to the surface areas to be removed by the hot liquid.*

ON-LINE DRYERS USE A SLOW CIRCULATION METHOD WITH DRYING MEDIA TO REMOVE THE MOISTURE AS THE TRANSFORMER WINDING RELEASES IT.



3. **On-line (energized) Transformer Drying** is another method that has been shown to be successful. This method is especially useful for field moisture reduction for non-vacuum rated transformers. IEEE C57.140 [4] states the following:

7.2. On-line energized liquid dry-out method

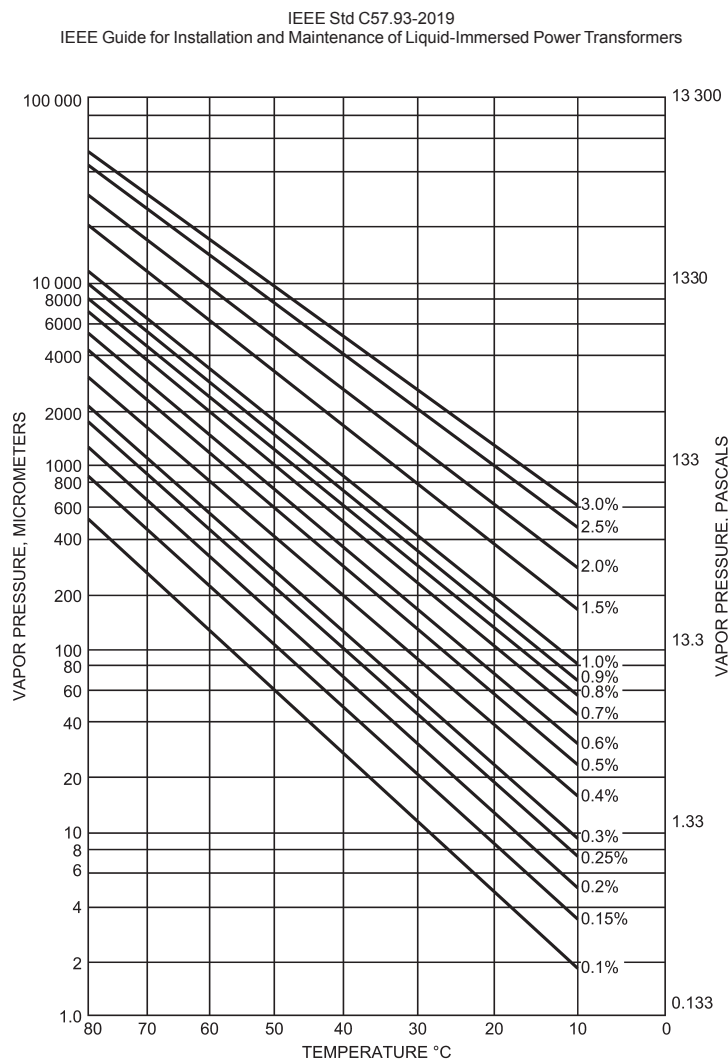
On-line transformer moisture removal systems have become increasingly popular to extend the operating period of a transformer that has had an increase in moisture level or may be gassing and needs to remain in service until a scheduled outage can occur.*

On-line dryers use a slow circulation method with drying media to remove the moisture as the transformer winding releases it. Temperature again plays a role as the increased solubility of the oil will allow moisture to migrate out of the insulation where the dryer can remove it. This process can take upwards of a year in some cases, while other smaller transformers may dry somewhat faster.

In Figure 5, a dryer was equipped with moisture sensors, and a transmitter and posts data for viewing and recommendations.

As the moisture leaves the paper and other porous materials, the transformer slowly dries. In this example, as the transformer

Figure 3. Moisture equilibrium chart Piper [5]



NOTE—This chart was prepared using information from a Piper Chart, which was extrapolated and interpolated from published data on cotton paper. Piper gave a multiplication factor of 1.7 to use for Kraft paper (non-thermally upgraded). This chart incorporates the 1.7 factor, and the values obtained need to be corrected. It should be noted that equilibrium moisture content of cellulose is dependent on whether equilibrium is approached by absorption or desorption, since there is a hysteresis effect.

Figure B.2—Moisture equilibrium chart (with moisture content in percent of dry weight of insulation) Piper [B23]



ELEVATED MOISTURE LEVELS, BEING MORE PROBLEMATIC IN LARGER TRANSFORMERS, HAVE A COMPONENT OF SERVICE COST VERSUS OUTAGE COST TO CONSIDER.

* IEEE C57.140-2017 – Adapted and reprinted with permission from IEEE. Copyright IEEE 2017. All rights reserved.

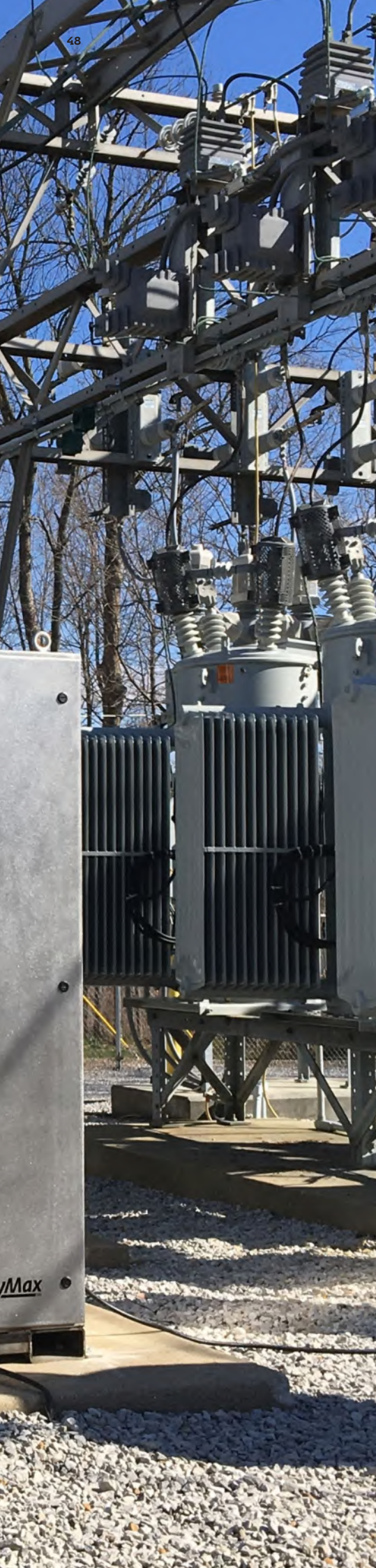


Figure 4. Dew point chart

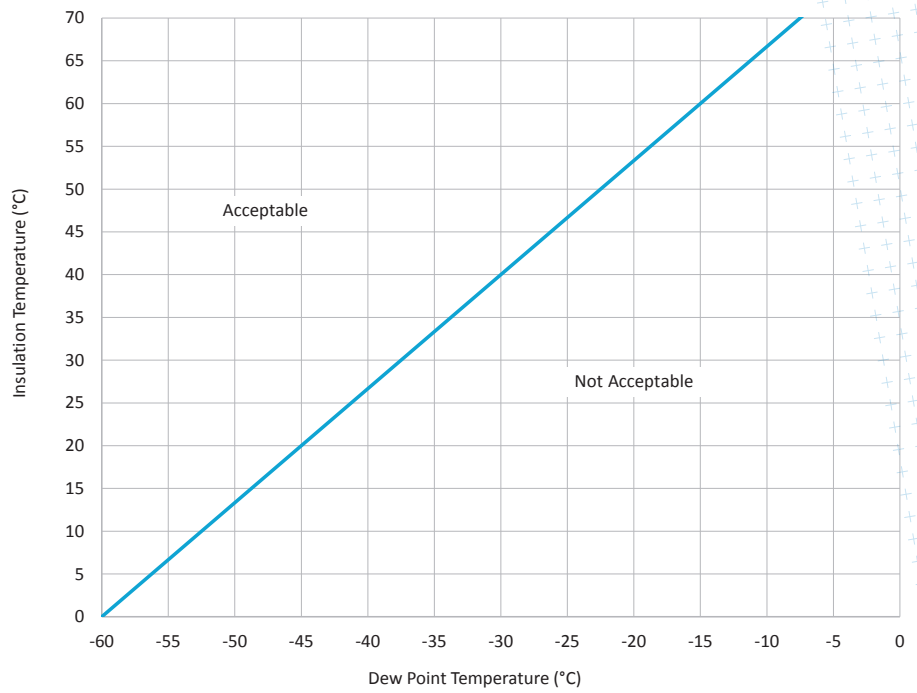


Figure 5. Transformer dry-out with on-line dryer

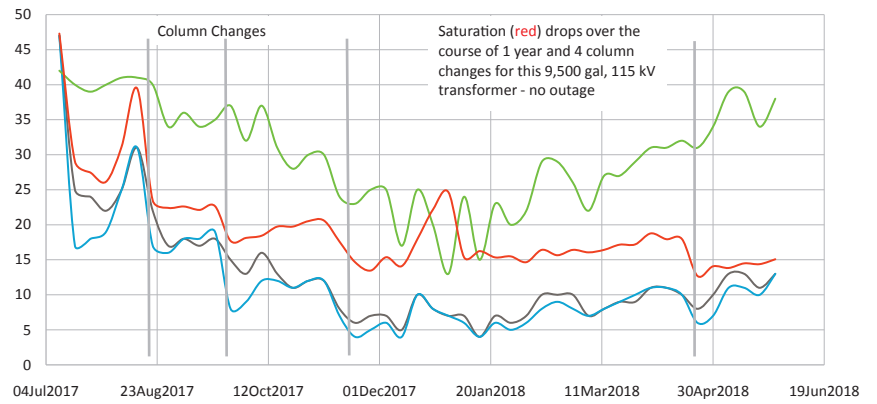
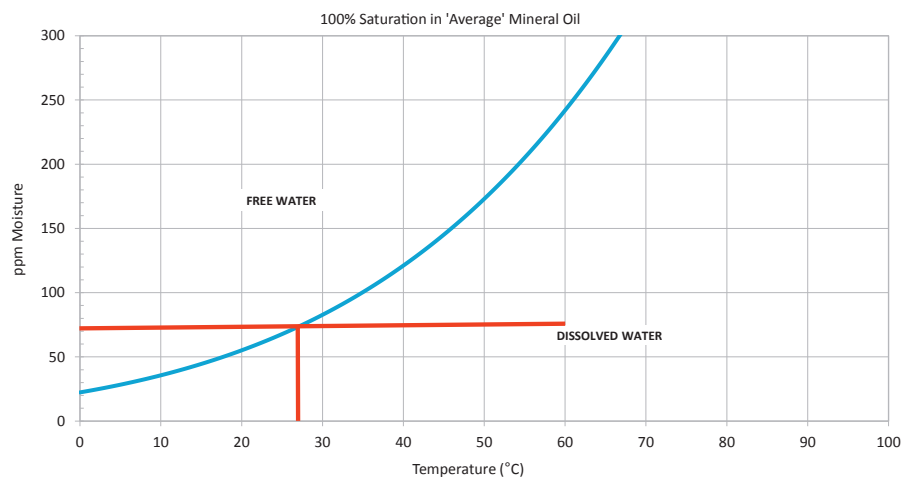


Figure 6. Mineral oil saturation curve



insulation dries, the moisture in the oil is first lowered, and then remains under 10 ppm. Profiles like this are common, although the time frame varies by the severity of the moisture levels and the size of the transformer. By transmitting data, the condition of the filters is monitored and aid in the efficiency and time frame for the dry-out.

How does moisture affect reliability and aging?

There are three or more potential modes of attack that moisture poses for a transformer – two are acute, and one more chronic. First the acute concerns:

1. Free water. Normally from a leak, this condition has an effect on the dielectric integrity of the oil, i.e. there is a possibility of dielectric failure. A variation of this issue arises for transformers with a higher % Saturation with varying loads, especially in the winter. For example, a transformer with 30% saturation at 60°C would become oversaturated if the temperature suddenly dropped to 27°C, Figure 6. The oil in the

radiators can oversaturate and cause the formation of water droplets, potentially leading to failure.

2. Another acute failure concern is when a transformer has a **very high moisture content at elevated temperatures**. At 4.5% moisture in the paper insulation and 90°C, reports indicate the moisture can vaporize at the hot spot and cause localized dielectric failure [6].

3. A third concern is accelerated aging. It has been known for many decades that the aging rate of paper insulation is proportional to its moisture content. In other words, the paper aging rate is doubled when the moisture in the paper is doubled. Conversely, the paper aging rate is cut in half when the moisture in the paper is cut in half. Further, if the paper aging rate is cut in half with half the moisture, then the remaining life of the paper is doubled. So, the moisture content has a profound effect on the life of the paper insulation, and thus on the life of the transformer.

What can be said for the economic effects of moisture on a transformer and the costs for restoration to reliability?

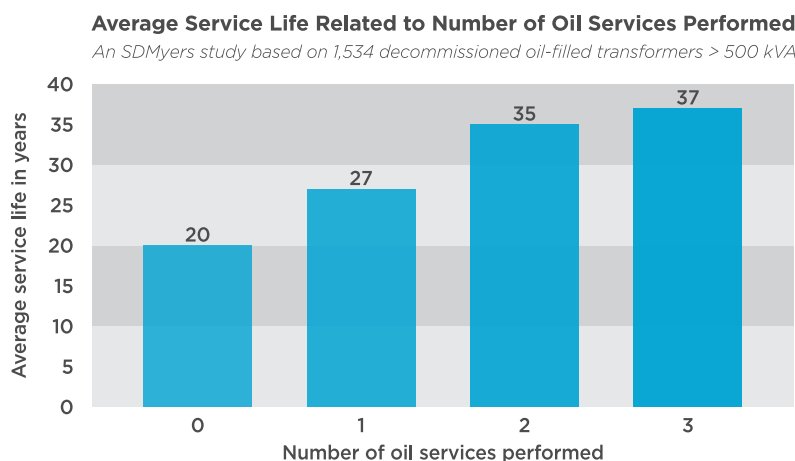
The most economical way to keep moisture and its effects at bay is by prevention. Regular fluid testing and visual inspections for leaks are the key. Although less common these days, units with desiccant dryers must also stay well maintained. Moreover, elevated moisture levels, being more problematic in larger transformers, have a component of service cost versus outage cost to consider. A 50 MVA transformer could be dried in just two weeks with a field vacuum dry-out. This same unit may take over a year to dry with an on-line dryer, but there is no service interruption. The cost of a field vacuum dry-out is estimated at double the cost of service with or purchase of an on-line dryer.

Additional consideration needs to be given to oil qualities. Whether a vacuum dry-out or an on-line dryer, there are oil conditions that should be corrected with either method of dehydration. Hot Oil Cleaning of the oil and paper insulation help maintain reliability and restore life. A study of 1,500 transformers with issues of moisture, elevated acid number, or with the need for replenishment of oxidation inhibitor showed that units that received the needed service had on average almost six additional years of life per service performed, Figure 7.

Conclusion

Moisture in transformers has become much more understood over the past ten years. Moisture mitigation solutions in addition to the traditional vacuum processes allow for economical field restoration to a more reliable condition. The effects of allowing elevated moisture levels in transformers range from acute to chronic. Moisture levels can be field-corrected, along with their cause – often the result of aging gaskets. By correcting the source of the moisture and then removing the moisture from the paper insulation, the reliability and remaining life of the transformer can be significantly improved.

Figure 7. Average service life related to number of oil services performed.
A study based on 1,534 decommissioned oil-filled transformers >500 kVA [7]



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- [6] A. Stannett, *The Problems of Water in Transformers*, 1965
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Ultrasound for Reliable Electrical Assets

by **Allan Rienstra**
+ + + + + + + + +

Ultrasound testing is a powerful solution for assessing the condition of our assets. The technology hears defects in the ultrasonic range and transfers these inaudible faults to low frequency sounds we can hear. Ultrasound signals from failing assets are measured, trended, and analyzed so we can execute an action plan that minimizes the impact.



Allan Rienstra Some say I am passionate about ultrasound. They are not wrong, but not right either. I am passionate about helping people get the most from their investment in technologies that create safe workplaces, reduce unplanned downtime, and eliminate waste. Ultrasound just so happens to be that technology. There is so much we can do to create accident free, proactive, environmentally sustainable conditions in manufacturing. All we need to do is care and hear more. If you care like I do, join me and together let's make Earth Great Again!

Reliable plants need FIT assets

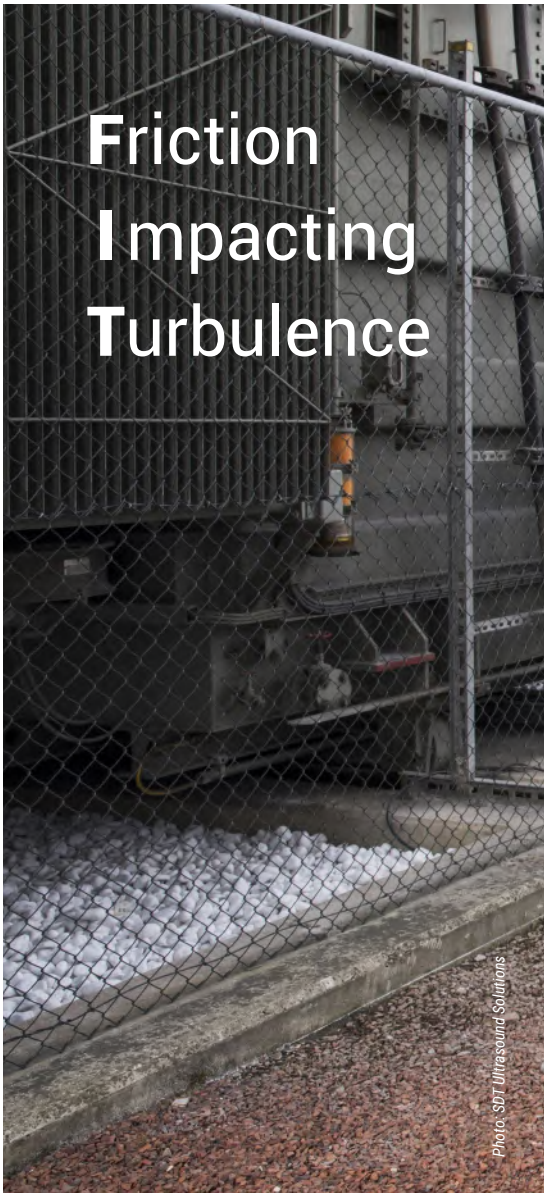
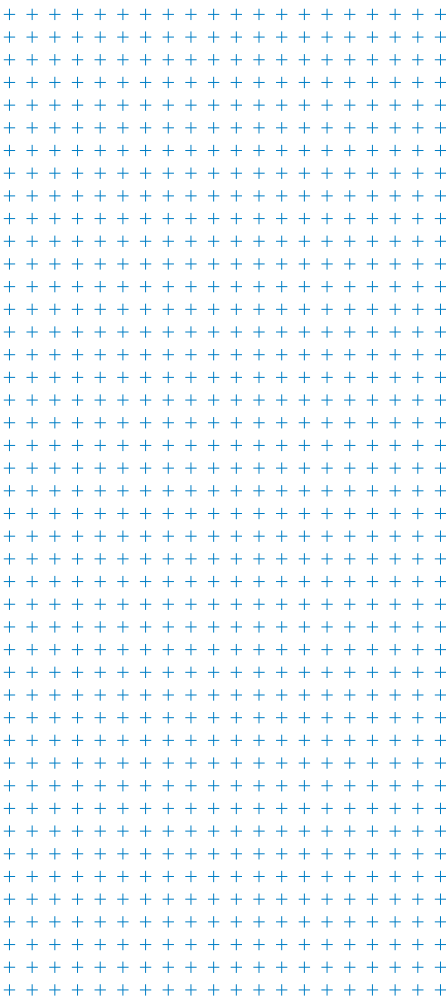
Most defects that threaten uptime produce Friction, Impacting, and Turbulence (FIT). These conditions exist silently in the ultrasound region. Find one – or any combination – of these and you now have data to monitor the asset condition at an advanced level.

Why is ultrasound useful?

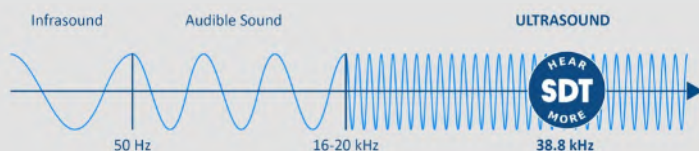
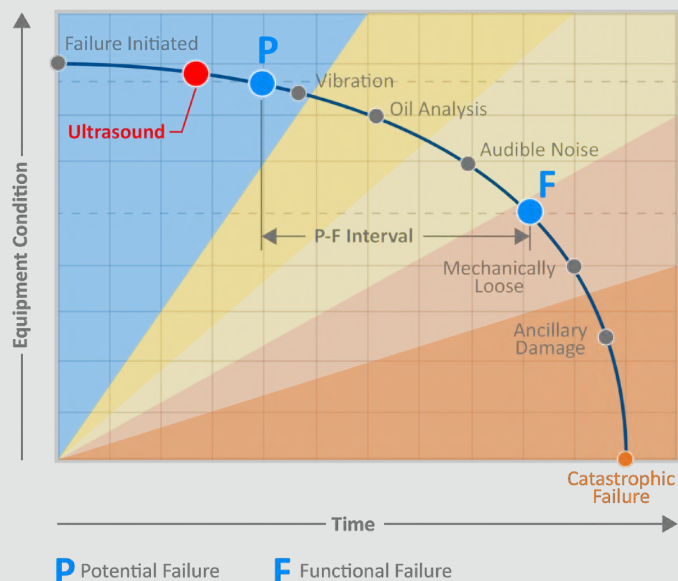
Ultrasound Owns the Apex of the P-F Curve. Newly formed defects present themselves ultrasonically first, and only become audible once they have advanced closer to the moment of failure. Ultrasound testing is considered one of the earliest indicators that an asset will soon need attention.

Ultrasound instruments are particularly effective in high noise situations. Inspections can be carried out any time of day, regardless of background noise.

Ultrasound is introverted. It prefers to remain isolated to its source. This unique characteristic makes ultrasound extremely effective for distinguishing specific anomalies occurring in close proximity to each other; like finding that one needle in a haystack full of needles.



Ultrasound Is The First Line of Defense



Versatility

Ultrasound's versatility is unlike any other condition monitoring technology. SDT identified eight application pillars and within each pillar there are virtually hundreds of ways to increase safety, eliminate unplanned downtime, and reduce energy waste. Ultrasound is the first line of defense for industries seeking higher profits and a sustainable future.

ULTRASOUND IS INTROVERTED. IT PREFERS TO REMAIN ISOLATED TO ITS SOURCE. THIS UNIQUE CHARACTERISTIC MAKES ULTRASOUND EXTREMELY EFFECTIVE FOR DISTINGUISHING SPECIFIC ANOMALIES OCCURRING IN CLOSE PROXIMITY TO EACH OTHER; LIKE FINDING THAT ONE NEEDLE IN A HAYSTACK FULL OF NEEDLES.





Ultrasound for reliable electrical assets

The term "Electrical Asset" casts a large net over an important class of systems. Whether it be substations, transmission and distribution lines, transformers, or motor circuit control cabinets, electrical assets play a key role in practically everything we do. Like most things, we take them for granted until they fail to deliver their value. Then we scream.

Energy's journey begins at the point of creation, can include storage, then transmission, distribution, and finally consumption. That journey is full of risk and the most significant risk contributor is partial discharge. Partial discharge happens when insulation material is compromised. One thing we know for certain is that once partial discharge begins, it will only get worse.

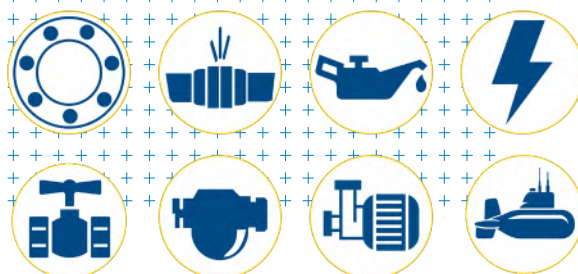
Partial discharge is more common than we would like to believe, even in new installations. Detecting these defects represents a serious challenge. Particularly at an early stage. There is no one perfect inspection technique, or technology, which can, on its own, detect and localize every defect, in every instance on every part of the electrical system.

Selecting the most appropriate method requires that the inspector understand the nature of the defect and the signs and signals available to be detected. The next logical step is to have the right technology available to pinpoint their location. Ultrasound is one technology that is mandatory for all electrical maintenance personnel. To not only reduce the risk of arc flash explosion but also enhance the overall reliability of system components.

When speaking about risk, health and safety should always take center stage. Safety aside, we must consider the risks from unreliable assets and loss of electrical equipment. They are both linked to downtime, costly legal exercises, and ultimately lost profit. Ultrasound is a solution that provides a reduced risk of all three in one go.

Ultrasound helps reduce the risk of arc flash exposure by detecting defects which, when left unattended, will lead to an arc flash event. I am not suggesting for one moment that we should not use PPE and other preventative measures. But I am yet to meet an arc flash suit which can detect an arc flash at its inception. So, the question is this: *If an Arc Flash Suit is the last line of defense, then what is the first?*

Some reliability minds seem obsessed with machines that rotate, while failure modes of non-rotating asset components seldom receive the routine surveillance they need. Pumps and motors receive all the attention while the balance of the system is run-to-failure. Ultrasound testing can change this lackadaisical attitude; especially considering its versatility, ease of use, and applicability to so many non-rotating applications.





What are common failure modes?

Figures produced by the IEEE suggest that electrical defects originating in switchgear were associated with insulation failure 90% of the time. Asset age had very little influence over the cause of failure. This points to the fact that the lion's share of failures are not due to aging and in fact, are mostly associated to poor workmanship, contributing to problems related to the insulation, ingress of water, cracked insulators, and poor installation.

Partial discharge is the symptom, insulation failure is the defect, and the severity is observed as either tracking, arcing, or corona.

How can ultrasound help?

Why ultrasound? Before answering that question, it is helpful to look more closely at types of electrical discharges. What are they; what causes them, and how they behave?

We generally speak of partial discharge and arcing. But they are broken down into further subsets. Partial Discharge (PD) is an atomic reaction which, due to the

movement of electrons, ionizes air molecules and produce locations of high stress. This ionization phenomenon splits the oxygen molecule to form ozone and nitrous oxide which in their normal states are generally harmless. But when mixed with moisture, they become corrosive.

If you have ever walked into a substation and noticed the smell of ozone, then you have witnessed partial discharge firsthand. Ozone odor is quite often the first indicator of the presence of PD.

IF YOU HAVE EVER WALKED INTO A SUBSTATION AND NOTICED THE SMELL OF OZONE, THEN YOU HAVE WITNESSED PARTIAL DISCHARGE FIRSTHAND. OZONE ODOR IS QUITE OFTEN THE FIRST INDICATOR OF THE PRESENCE OF PD.



PARTIAL DISCHARGE IS DESTRUCTIVE



Corona

Corona is a type of PD. Corona is unique in that the discharge is into air molecules with no insulation present between the conductors. Corona is most commonly found on transmission lines, and sometimes it can be heard in the audible range of frequencies. This is dependent primarily on system voltage.

Corona is influenced by humidity levels; however, it generates a lower discharge in higher humidity areas. This is contrary to what was normally believed. Water in the air captures some of the free electrons which would otherwise initiate the discharge.

Tracking

Tracking is another form of PD. It is the flow of electricity over an interface of different insulation materials and most commonly involves a solid type of insulation. Tracking can present itself on the

surface of an insulator contaminated with hydroscopic dust. Increased moisture or humidity can reduce the insulator's resistance on the surface and enhance the tracking type discharge. By implication then, one distinction between corona and tracking is to check whether there is a positive or negative correlation with absolute moisture content in the air. In any case, an ultrasound inspector must be focused on finding the symptoms of the condition first.

Another fact is that partial discharge – both corona and tracking – do not generate any noticeable change in temperature in electrical systems below 240 kV. One thing we do know with certainty though, is that they are often precursors to fires, explosions, and catastrophic failure of electrical plant systems. Partial discharge only begins to appear acoustically at around 4.4 kV, so any low voltage inspections for PD are a waste of time. Arcing however occurs at even very low voltages.

Arcing

Arcing, and in some instances partial arcing, is the flow of electricity through the air from one conductor to another object which conducts electricity. It is characterized by a rapid expansion of gas, causes fires and explosions, is extremely violent, generates extreme temperatures, and consequently the catastrophic destruction of all equipment connected.

Detection methods

To understand which technology or inspection technique is the best to use on a particular piece of electrical equipment, or in search of a particular defect, we need to know the signs and signals generated and made available for detection by an inspector with the correct tool and appropriate training.

Partial discharge generates ozone, which produces an unmistakable odor. Visual evidence is sometimes available, but it is not a reliable method. PD generates sound throughout the frequency spectrum. However, it presents a particularly clear and unmistakable signal in the ultrasonic range.

Arcing is obvious and visible on external equipment. It also generates ultrasound throughout the spectrum. It also generates electromagnetic radiation, and of course, massive amounts of heat. Both ultrasound and infrared are successful detection methods, however ultrasound wins the initial detection due to its ability to hear through narrow air gaps such as those found on Motor Circuit Control (MCC) panels and doors. Safety for our inspectors must always be our number one priority.

One example of a partial discharge defect saw a cable termination where two phases were crossed too closely together. The ultrasound signal clearly revealed the PD activity while infrared showed nothing. By combining ultrasound with IR, this defect was detected before it had opportunity to advance to a state of flashover.



Electromagnetic Radiation Equipment works well, even if it has its disadvantages. TEV or transient earth voltage detects partial discharge in medium and high voltage equipment which induces a voltage on the inner surface of switch gear cabinets and panels. These transient earth voltages can be measured for amplitude, are comparable, and can be trended. However, TEV detectors have minimal diagnosis capabilities and there are many components nearby which give off transient earth voltages that often lead to misdiagnosis.

Radio frequency devices are great at picking up defects because all defects generate electromagnetic noise. But so are many other components found inside a substation. Electromagnetic noise coming from light ballasts, CPUs, and a several other electronic components interfere with the effectiveness of RF detection. RF devices detect fast transients which can be useful in a substation or on overhead lines. They are a simple indicating tool and can stand in well when other technologies fall short. Always remember that RF technology provides no diagnostic capabilities.



Our eyes are only sensitive to a very narrow band of light. UV Cameras detect ultraviolet light present at the point of discharge. Although a fantastic technology, UV cameras require line of sight and therefore, like Infrared cameras, their usability is too limited to be standalone effective.

Finally, online condition assessment technology, the subject of which is too broad for this paper, is the electrical measurement and analysis of radio frequency cable insulation aging signals which are emitted from the cable whilst in its normal service. It is the most diagnostic and comprehensive tool, however it is not portable and requires a specialist operator.



ADVANCED
ULTRASOUND
DETECTORS ALLOW
INSPECTORS TO RECORD
THE SOUND, MEASURE
THE AMPLITUDE, AND
ANALYZE THE SIGNAL
FOR DIAGNOSIS.
CONDITION INDICATORS
ARE A RECENT
INNOVATION AND
THEY ARE USEFUL
TOOLS THAT PROVIDE
ADVANCED INSIGHT
ABOUT SYSTEM
CONDITION BY
PROVIDING INSIGHT
THAT SINGLE DECIBEL
INSTRUMENTS SIMPLY
CANNOT.

Why ultrasound is so effective

We use the term ultrasound to refer to any sound signal above the range of human hearing. It is generally accepted to be any signal above 20 kHz in the frequency range.

Ultrasound signals can travel through solids, liquids, and gases. That applies nicely to cable termination boxes, transformer oil, and air.

Ultrasound tends to be directional in nature which means their source is easily pinpointed, unlike audible sounds which tends to disperse more freely and widely. Ultrasound is a low energy signal which means it attenuates a short distance from its origin. This further enhances our ability to locate its source without threat of interference from alternate, nearby sources of ultrasound be them defects or otherwise.

With the right ultrasound detector, some basic training and a little experience, inspectors can quickly locate a defect in a high noise environment. The difference between corona discharge, tracking and arcing is obvious, which means the inspector knows exactly which defect is present and how to plan a corrective maintenance strategy.

Advanced ultrasound detectors allow inspectors to record the sound, measure the amplitude, and analyze the signal for diagnosis. Condition indicators are a recent innovation offered only by SDT. These useful tools provide advanced insight about system condition by providing insight that single decibel instruments simply cannot. These detectors allow inspectors to more confidently categorize the defect and present a strategy for repair. Many things are now possible with the right ultrasound detector.

Panels and cabinets

So here we have an easy to use, handheld technology to detect partial discharge and arcing at their inception.

The moment the defect appears it generates ultrasound. For example, in switch gear panels, the presence of an electrical defect floods

the insides of the cabinet with ultrasound. Small in wavelength, ultrasound passes through the tiniest of air gaps making it easy to identify which panels need closer attention, and which to simply leave alone.

Sometimes, rarely even, panels are airtight. Don't be tempted to open them. An ultrasound contact sensor placed on the outer surface of the panel can still detect the presence of electrical defects directly through the metal. The signal is only slightly reduced and is effectively detected.

By listening to, and capturing the ultrasound signal, well-trained inspectors can often categorize the defect on-the-spot. This point emphasizes the need for inspectors to seek training from their ultrasound manufacturer and maintain a mentor relationship with the trainer afterwards.

No single technology solves everything

There is no perfect single technology and ultrasound is no exception. Ultrasound is limited to the ability of the sensor to access the source of the defect through one of the three earlier mentioned media (gas, liquid, or solid). In some installations, no matter which technique or technology you use, you may still come up empty-handed. Reliability leaders should be well-versed in all technology options and be free to choose the one that suits their inspection best. Don't be chided into believing one reigns superior over all others.

Although, without bias or risk of offering advice that could lead to failure, ultrasound is clearly the most versatile, easy-to-use, cost effective technology to begin.

To recap, partial discharge is more common than we like to believe. There are ready technologies available that help to not only reduce the risk of arc flash exposure but also simultaneously enhance the overall

reliability of the electrical system. Ultrasound presents the best win-win scenario for safety and reliability. There are a few technologies available, and some are better than others especially in applications that are suited for a specific purpose.

Comparatively however, ultrasound appears the most practical, simple, comprehensive, and cost-effective. Consider ultrasound as your first line of defense technology to build out your overall electrical condition monitoring and analysis strategy.



Managing the Reliability of an Industrial or Commercial Electrical Power System / E 03

by **Chuck Baker**

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Cast

Brian	Regional Vice President (head person for this plant)
Andy	Reliability Manager of Electrical Power System (recently hired by Brian, the Plant RVP)
Kevin	Director of Reliability
Tina	Maintenance Manager (who reports to Brian also)
Tim	Electrical Engineer (who reports to Andy)



Chuck Baker is the President of PowerPro 360, a company offering power system reliability assessment and reliability maintenance programs for Industrial and commercial organizations. Chuck entered the world of Substation and Power System Maintenance 36 years ago and has spent a majority of that career on the operations side of power and distribution system maintenance and the development of power system maintenance programs.



Hello and thanks for continuing to follow us through our experiences in the design and implementation of a Reliability Centered Maintenance (RCM) program into Smith Industries. I am Brian, the Regional Vice President / Plant Manager for the largest Smith Industries plant.

If you recall, in our first article [1] I had just hired Andy. He started out by reviewing the historic and current electrical system maintenance program. In the first meeting with the team, he presented areas of concern with our current power system and I was very pleased with both the presentation and how it was received by the team.

In the second article [2], Andy began to work with the team to introduce key components to the RCM program he was going to be implementing. The good news to me was the positive reaction from Kevin and Tina. If you recall, Tina was our Maintenance Manager and prior to Andy's arrival was responsible for the maintenance of the power distribution system. She knew she did not have the expertise to take the Power System

into the world of Reliability Centered Maintenance and welcomed him on board.

Kevin, on the other hand, was a little more difficult of a challenge. Kevin, Director of Reliability, is a top Mechanical Engineer and is very experienced. From the time he came on board, he has significantly improved the RCM program for everything but the power system. I had been working with him for a couple of months before I brought Andy onboard and had laid the groundwork for the final piece of the puzzle, bringing our power system into the world of RCM.

I knew I was in trouble the first month I had arrived. I am not going to exaggerate, and I do think the world of Kevin, but when we walked into the

distribution North Mill Sub in the North plant and I asked him about how RCM had been touching our power system, his response told me everything I needed to know. His key statements were:

1. With a chuckle, he pointed out that in that vault there was not a single moving part.
2. He continued pointing at the silicone filled transformer saying that it was 25 years old and has never been a problem. "Not a priority for us" was his final comment.
3. Not knowing my past RCM experience, he pointed out to me that a failed motor bearing was reality and was where the reliability attention needed to be spent.

It is quite common that plant managers in the commercial and industrial market are excellent with most of the plant, just not the power system. The power system is an anomaly in the logic of a program. It is unique, not seen, has no sound and 98% of the employees never see it or hear about it.





Again, he is excellent with most of the plant, just not the power system. And I will tell you, this is more common in the commercial and industrial market than we may think. The power system is an anomaly in the logic of a program. It is unique, not seen, has no sound and 98% of the employees never see it or hear about it.

With interest in our aging power maintenance program I continued learning with a plant walk through with Tina, the Maintenance Manager for the plant.

That was interesting as well. When we went past the North Mill Sub, I asked her if we could poke our heads in there. She said sure, and led us in. Now, this is the moment when everything I had suspected was verified. Tina is also an excellent Mechanical Engineer; in fact, she is a PE. When we were touring the plant, I was impressed with not just her technical expertise, but her understanding of our product flow, areas classified as JIT production zones and her reviewing the major changes she has made over the last couple of years. She has worked very

well with Kevin on improving our safety and production rates – with every area except the Electric Distribution System.

As we entered the substation, she began to recite her maintenance SOP mentioning high current testing of the low voltage breakers every three years, full dielectric fluid analysis on all liquid filled equipment every year, cleaning/ torqueing and servicing the dry type transformers, etc. She updated me on some decisions for load management and protection that she and Tim (our Electrical Engineer) had made



over the past couple of years. I was comfortable that Tina was good at her job, but her lack of expertise on RCM management on the electrical side has forced her to use standard maintenance protocol.

As I headed back to the front offices, I felt great that when I brought a power system reliability centered maintenance manager on board, the current system could absorb that, it would take a little pressure off of them and they would be able to see the value.

When we are successful, the foundation of that success is the education, understanding and clarity of the program with the participants having the time and resources to do it.

The other problem I was thinking through, was how to use the changes created with the new position, to address some shortcomings in the balance of our Plant RCM program. Again, it is good, but it is lacking in certain areas. Being the new guy, I knew this was the best way to address it.

Let me share some of the general components and considerations that have to be made when starting an RCM program for your power system. The reason I wanted to talk to you in May was so that you understood what was behind the scenes before Andy walks you through implementation.

Here are some points you will need to consider:

1. As the “project leader”, you are going to need to understand the fundamental outline of the program. You may not have the expertise, but you need to know enough to pick the right person to lead. Do some online learning, read, research, attend seminars... you get the idea, know the fundamentals.
2. Be realistic with what will be required. This starts with outlining the knowledge your power reliability team will need. This includes understanding the base power system, but more importantly, the fundamental steps to a reliability program. Many organizations do not have this expertise in house. Your choices are simply to hire or train.
3. When you have selected the reliability leader, begin to look at the impact on your organization. The first issue to look at is true resources within your core team. Operations, Engineering, and Maintenance will all be a part of the eventual reliability program. Who in each key group will be a lead, and how much time do they really have available? Many positions are filled with experienced and talented people, but many times they are reactionary, which is required for their normal day to day responsibilities, but not good with this challenge. You need to pick staff that can support and participate in the program and that have time to contribute to your team. Be realistic.
4. When you have qualified your core team and confirmed their abilities and how their responsibilities can be organized to include the time requirements of this new program, educate them. There are many great programs that can take a team and walk them through the fundamentals of a reliability program. The key is to spend enough time to get everybody up to speed, speaking the same language with key terms, and to let them contribute in the actual building of the program. If you do not take these steps, the individuals will drift back to their normal habits which they are comfortable with and have been at for many years.
5. Now that you have your team; you must plan. This sounds obvious but let us make sure we have detailed the “procedures” that everyone on the team truly understands. Your team will have different learning styles and different levels of expertise on the program, your job is to keep everybody together. In June, Andy and implementation of the key steps to a solid program will be back. But before you start your plan you need to have these fundamentals in place.
6. Make sure your Reliability Leader has detailed the procedures of the plan, has the data collection and management system laid out and

The key to having your reliability program succeed is giving everyone the appropriate understanding, having a clear procedure, making sure everyone understands their role and has the time and resources to accomplish it. If you do not take these steps, the individuals will drift back to their normal habits which they are comfortable with and have been at for many years.



COMMUNICATION



EXCHANGE



DISCUSSION



INFORMATION



TECHNOLOGY



ADVICE



TEAMWORK

has identified the required labor for each phase. As you walk through the first phase of data gathering, you will face both issues. Is the data gathering in a format that regardless of who is performing the tasks, the right information will be collected, in a common format and the data will be stored in the proper program?

7. After you have outlined the requirements of implementation of the tasks, be realistic on required labor again. You went through this with your reliability team, now you must look at the secondary and tertiary levels of impact. What are the tasks, who will be doing them and will the people who received the assignments have the time and understanding to do it?
8. When you write up instructions for the tasks, be consistent and clear on the key steps, sequence, timing and data management. It needs to be simple, clear and easy to understand and implement. One of the components of the program will be an outline of the expected timing. Be sure and be realistic on this, if the person assigned does not have the time, it will not get done. Like so many new programs, it is better to go slow with solid retention and understanding versus fast – which will always fade out.
9. You have trained and educated your Reliability Team, now spend some time providing this same understanding to those front-line workers who will be implementing the fundamentals. Share with them their value. When they are gathering nameplate information,

The bottom line that you must understand is that you are going to attempt to change a culture, not a procedure.

make sure they understand the importance of that; the fact that it is a key component to the master plan, an understanding that the program is only as good as the quality of their work. Let them know that you are relying on them.

10. And lastly, a critical component that is difficult but necessary; inform the masses. Take time to think out the most fundamental steps of the program, and the expected benefit. Define common terms that will be used going forward. One of the more common programs says to tell them seven times before they really understand and accept. This is true for your core team, your extended team, and the employees. Educate them on the fact that this will be a new way of life; what they can expect to see; who the champions of the program are and how it may affect them along the way. This creates an environment that will be more successful than what happens if you do not.

The bottom line that you must understand is that you are going to attempt to change a culture, not a procedure. Your expertise has been gained over many years, remember that theirs has not. This is new to them.

So many of these programs fizzle out and employees return to the way they have always done it. That is human nature and will always be the temptation. Through giving everyone the appropriate understanding, having a clear procedure, making sure everyone understands their role and has the time and resources to accomplish it; your reliability program can succeed.

As I mentioned, in June Andy will roll up his sleeves and take the first tangible steps in the implementation of his power system reliability plan. The reason for this communication was to share that when we are successful, the foundation of that success is the education, understanding and clarity of the program with the participants having the time and resources to do it. Most will never know what I did before and behind the scenes, but that is what comes with being the leader and the ultimate implementer: good luck and turn the team to Reliability.

References

- [1] Chuck Baker, "Managing the Reliability of an Industrial or Commercial Electrical Power System," in *Transformer Technology*, Issue 4, pp. 52-57, 2019
- [2] Chuck Baker, "Managing the Reliability of an Industrial or Commercial Electrical Power System: Episode #2," in *Transformer Technology*, Issue 5, pp. 48-53, 2020

What to Look for in a Transformer DGA Monitor

by **Dominique Legrand**

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When choosing a transformer monitoring system for DGA (Dissolved Gas Analysis), there are now plenty of brands and systems on offer and it is becoming harder to understand the differences and make a selection. More often, the underlying technology and the resulting technical specifications are used to differentiate. But times have changed and over the years, a new wave of asset managers has resulted in the products evolving. Now, some previously less regarded factors should also be considered. We will explore the main ones here.



Dominique Legrand is a Senior Product Manager with GE's Asset Monitoring and Diagnostics business, part of GE Renewable Energy. He is part of the leadership team of the business based in Northern Ireland, UK where he is responsible for supporting the strategy and driving the development. He has held a number of product manager roles including single gas DGA monitors and bushing monitors and is currently expanding the M&D portfolio outside of transformers to circuit breaker monitoring. Dominique holds a bachelor's degree in Industrial Engineering from the University of New South Wales in Australia.



Technology

Different underlying technologies are used for DGA monitors, including Gas Chromatography (GC), Non Dispersive InfraRed (NDIR), Photo Acoustic Spectroscopy (PAS), etc. While the fundamental differences are rather well known, so are the issues with gas consumables management, recalibration requirements, measurement discontinuities and Lower Detection Limits (LDL). Judging from product brochures, it seems that most specifications end up looking very similar, even if that is not always verified by customer testing protocols. Large customers are increasingly conducting their own tests to validate the product's theoretical values, using their own testing method in their own environment. While this is a time-consuming exercise, it certainly highlights the differences.

Accuracy and LDL are always well prized attributes, but others like repeatability and response time are often overlooked. The latter indicates, following a gas increase, the percentage of the gas value that is measured by the monitor at the first measurement – 90% is good, but if it is only 65%, then it will take a second measurement to reach the same level and show the true gas level increase. If the machine is set to measure DGA every eight hours (three measurements per day), it may take another day before the alarm threshold is reached and you get alerted to the true magnitude of the problem.

Many systems automatically increase the measurement frequency when an alarm is raised to show more rapidly the rate of change. Some technologies will have limits as to the minimum time between measurements; others will degrade accuracy if the frequency is increased. If, for example, the acetylene level is rising fast, this is particularly frustrating, when you would like another confirmatory result (or two) before you decide to shut down the transformer. Some products offer one hour minimum, some newer product offer as low as 30 minutes.



There are many factors to consider when selecting a transformer DGA monitor: the monitor with its features and performance; the underlying technology used as well as the long-term reliability; the software environment available and the reputation of the manufacturer to continually enhance the product over time.

Data/Communication

More and more DGA systems are connected to large databases to collect data, so that the trends can be interpreted and patterns recognised. This is where Artificial Intelligence (AI) and data scientists are now trying to help transformer experts predict what is going to happen to a transformer. Therefore, having a range of reliable communication options is key to facilitate connections. Most systems offer Modbus and DNP3, but the future belongs to IEC 61850. This protocol should be supported, even if it is not needed right now. It should

be up to date (latest edition) and preferably certified by an outside body to make sure that your new system will not have any issues integrating with others.

Collecting data into a historian is one thing, but transforming this data into actionable intelligence is the real worth of a DGA monitor. Otherwise, it becomes another un-mined data lake. Fortunately, there are a lot of standards and graphical tools that can be used to analyse the data and provide a diagnostic of the transformer. Having easy access to quality software tools connected to your

DGA monitor is therefore essential. With more monitors being deployed, even with these tools, it becomes harder to spend the time analysing the results one by one, without some fleet management functionalities. Otherwise, one quickly relies solely on alarms and loses some of the benefits of continuous monitoring.

Some software and/or systems can perform an automated analysis of the data and provide a 1-to-5 Risk Index (RI) to deliver a quick transformer assessment and an indication of the severity of the problem. This is particularly useful for non-DGA

It is now all about adding “defensive layers”: having multiple password levels that can be changed, offering secure data transmission using https, being able to upload SSL certificates, providing firewall and white listing functionalities, etc. are some of the features to look out for when evaluating the cybersecurity credentials.



experts, who may not instantly appreciate the difference between a huge acetylene vs methane increase. The risk indexes provide the added advantage of being able to categorise and rank your transformer fleet, so that you can concentrate your resources on the transformers with worst RI or with a recently changed RI.

Finally, living in a modern world, the ability to send an email or SMS text message when an alarm is raised is a nice feature that should not be overlooked; and so is having a local display where you can appraise the situation when at the substation,

without having to connect your laptop. Nice colour graphic web pages are what we all expect nowadays from products.

Cybersecurity

Making it harder for the unscrupulous to gain access and disrupt the power infrastructure is becoming a mandatory requirement for all connected products. It is now all about adding “defensive layers”: having multiple password levels that can be changed, offering secure data transmission using https, being able to upload SSL certificates, providing

firewall and white listing functionalities, etc. These are some of the features to look out for when evaluating the cybersecurity credentials. The firmware should also allow remote uploading of any security patches whenever a weakness is discovered, all this without having to go to site.

In America, there is a recent trend at some utilities for prohibiting contractors' laptops inside their substation. This makes it difficult to either install or repair a unit if it does not have a built-in LCD display or internet web browser interface that can be accessed through a utility's standard laptop / internet browser. This trend is likely to accelerate.

Evolution

Transformers are designed to last a long time. Monitors should also be a long-term investment with the ability to be supported, upgraded and kept relevant.

New functionalities and improvements will happen over the life of the product and are most likely to be firmware related, rather than hardware based – whether it is to meet a new standard, update the communication protocol, deliver new data analysis or simply improve the basic performance of the system. A DGA monitor will soon be like a PC or a phone and need to have remote upgrade capability to be kept up to date.

Standards compliance (Electrical Safety, Environmental Resistance, EMC interference) is also an issue. Safety standards change and test certificates obtained 10 years ago may no longer guarantee that the machine would pass the current version of the compliance tests. To maintain appropriate compliance, one should insist on fairly recent test (or re-test) reports as well as reports from an independent third-party testing house.

It is important to select a supplier for the long run, that has capabilities in terms of R&D, that believes in “Kaizen” continuous quality improvement and that will constantly invest in improving the product, so that it remains state of the art.



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Making sure that the monitors do not cause more maintenance issues than the transformers themselves has long been a customer request.

Reliability

With some utilities having hundreds (and even thousands) of DGA monitors deployed, making sure that the monitors do not cause more maintenance issues than the transformers themselves has long been a customer request. As new technology was rolled out, it performed, but often proved not to be very robust in the long term. Failures and need for repairs accumulated, and this, I believe, has led to a slower adoption rate of DGA monitoring in some countries. But time has moved on and vendors have worked hard to improve both their quality and reliability. Manufacturer's warranty periods are getting longer, although it is important to ensure that they are backed-up by field experience and/or long-term reliability testing.

It is a bit like buying a stock market fund: you need to look at the fund manager's reputation, how long he has been managing that fund and what his long-term track record shows. Newer funds might show a better short-term return but, with only a very short history, they have an unknown ability to weather stock market storms. The same type of analysis should be applied when evaluating DGA vendors, also taking into account their ability to provide rapid local service and support in your country.

Conclusion

There are many factors to consider when selecting a DGA transformer monitor: the monitor with its features and performance; the underlying technology used as well as the long-term reliability; the software environment available and the reputation of the manufacturer to continually enhance the product over time.

With "asset optimisation" being the current buzz word in the industry, it boils down to the ability for the monitor to reliably and consistently deliver data that can easily be processed into actionable intelligence. This is how users will make best use of their monitor to reduce risk, extend asset life and save both time and money.



MONITORING,
DIAGNOSTICS &
DIGITALIZATION

With "asset optimisation" being the current buzz word in the industry, it boils down to the ability for the monitor to reliably and consistently deliver data that can easily be processed into actionable intelligence. This is how users will make best use of their monitor to reduce risk, extend asset life and save both time and money.



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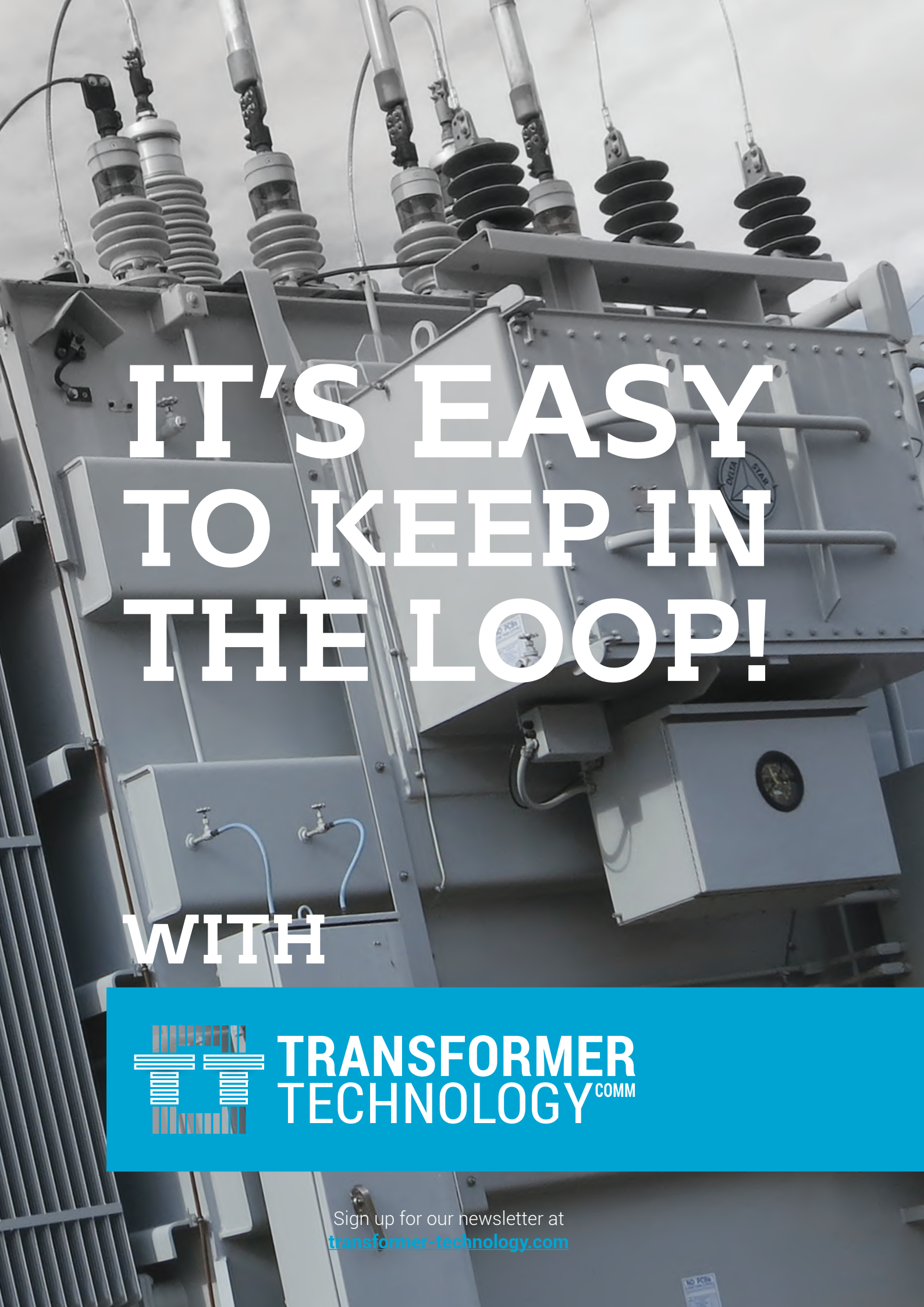


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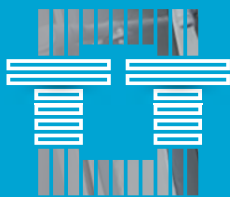
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