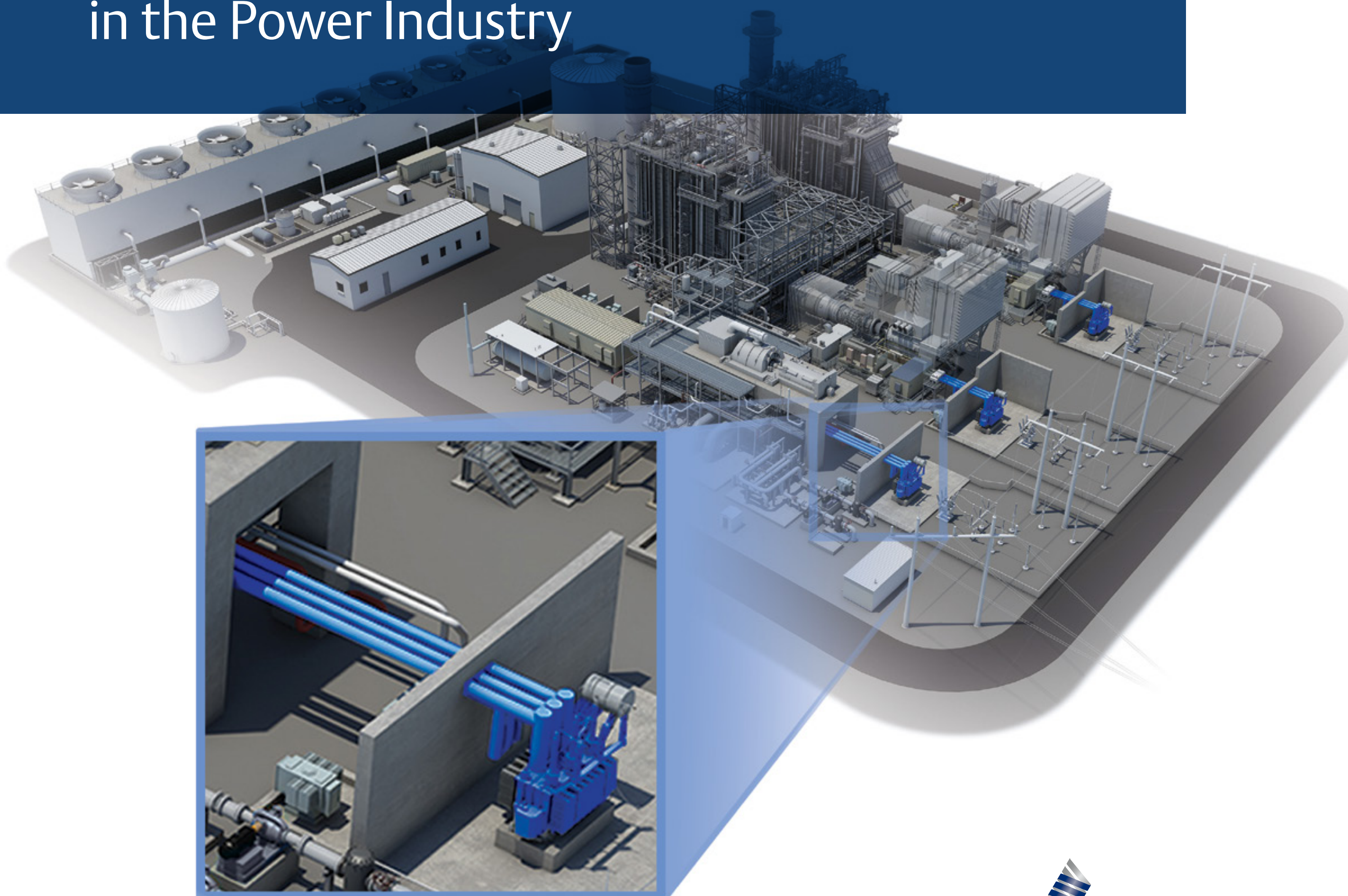
White Paper

3 Steps to Monitor Critical Electrical Assets

Continuous Condition-based Monitoring in the Power Industry



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3 Steps to Monitor Critical Electrical Power Assets

Electric utilities strive to improve reliability in the face of challenges such as fewer operators, aging assets and increased cycling. A critical asset failure can result in the forced outage of power generation, transmission or distribution leading to lost production, environmental issues, litigation arising from injuries or fatalities, and repairing and/or replacing the damaged asset, all of which can amount to millions of dollars of associated costs.

To address these issues, asset maintenance is transitioning from traditional reactive and time-based maintenance to a proactive strategy through implementing continuous condition-based monitoring. Modern sensing technology makes it possible to continuously monitor the health of electrical power critical assets and inform plant personnel when, or even before, problems arise.

This white paper describes the three steps for deploying condition-based monitoring on critical electrical power assets which will lead to a proactive – and eventually, predictive – maintenance strategy:

1. Prioritize which assets should be monitored.
2. Apply continuous condition-based monitoring.
3. Analyze data and evaluate asset health.

Step 1: Prioritize your assets

Outages are expensive

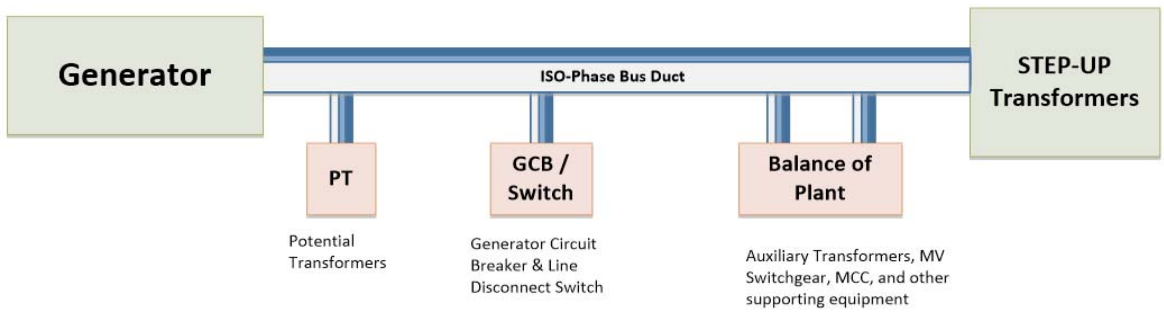
The following table shows a simple view of the associated average potential revenue lost if a 500MW generator was down due to a forced outage.

Estimates based on Electric Power Annual 2015, issued November 2016 by the U.S. Energy Information Administration	
Average price per kW (60% industrial / 40% commercial customers)	$ 0.030
Average price per MWh	$ 30
Generator output (MW)	500
Generator output per hour ($ per MWh)	$ 15,000
Average price for 12 hours of operation	$ 180,000
Average potential revenue lost over 7-day period	**$ 1,260,000**

Asset ranking

Independent of the type of power plant, a typical electrical power delivery system includes assets such as generators, generator circuit breakers (GCBs), line disconnect switches, step-up and step-down transformers, segregated and non-segregated bus ducts, potential transformer cabinets, medium voltage switchgear, motors, and other equipment needed to support the transmission and distribution of power.

Figure 1. Asset Diagram



Unfortunately, how critical an asset is, is often subjective and stakeholders will have different opinions. Taking a more objective approach by prioritizing and ranking the plant assets can help. The process should include all necessary stakeholders covering the needs of the entire plant, such as maintenance, operations, purchasing, safety, environmental, and customer impact.

If this is the first assessment of critical assets, start from a system level rather than an equipment level to ensure you are not overwhelming the stakeholders during the decision-making process. Questions should cover each area of interest and calculations should be made to rank the effect of a system failure on the power plant. The systems with the greatest impact will be the highest priority. Once systems have been identified and ranked, the next step is to rank the individual assets within the system using the same approach.

Take the highest priority equipment and employ a Failure Mode, Effects, and Criticality Assessment (FMECA) to help identify where and how the equipment might fail. The FMECA is an in-depth evaluation and takes significant time to complete, so it should not be used on every asset; many companies look at the top 10 percent of their most critical assets. The results of the assessment provide the failure probability against the severity of the consequence, giving a clear picture of which maintenance techniques are warranted.

Diagnosing and detecting all potential failure modes (such as generator vibration or transformer oil deterioration) in the mix of equipment is beyond the scope of this white paper. Instead, we will concentrate on how to monitor three of the main sources of failures for the majority of electrical power critical assets.

Step 2: Apply continuous condition-based monitoring

Common electrical asset failure modes

Electrical assets are subject to overheating due to excessive loads, normal wear and tear, and challenging environmental conditions. Left unattended, these conditions can lead to failures and costly damage to the asset and surrounding equipment, power production loss, and in extreme cases, severe injury or death. Common failure modes include thermal breakdown, insulation breakdown, and air dielectric breakdown.

- Thermal breakdown
  Circuit breaker, bus bar and cable connections tend to loosen and/or corrode over time, resulting in thermal failure of the connection and nearby cable insulation.
- Insulation breakdown
  As insulators age, weak spots and defects evolve, and under certain load conditions, a dielectric breakdown will initiate across the defect, causing a partial arc between conductors at different potentials. This effect is known as a Partial Discharge (PD) and left unmonitored, this condition can cause electrical assets to have flashovers (see Figure 2).

Figure 2. Switchgear Accident Due to PD

- Air dielectric breakdown
  Often caused by high humidity, moisture causes corrosion on conductors and can be absorbed in the insulators, leading to elevated heating, partial discharge, surface tracking and the potential for shorts and flashover.

Determine asset monitoring technique

Today's methods for electrical asset monitoring is often achieved through periodic manual inspections during an outage, although there are some tests that can be performed while power is online. Such manual inspections look for obvious problems such as physical damage, frayed connectors, degraded insulation, moisture, and evidence of overheated components. Electrical measurements can also be conducted while power is off. Applying voltage with calibrated ac and dc HiPot test sets checks insulation resistance in the panel enclosure, bus bars, circuit breakers and other components—and checks contact resistance to confirm bus bar joints are connected properly.

Manual inspections for thermal breakdown can be accomplished with infrared (IR) equipment and can be conducted while power is on. This technique requires multi-tempered glass windows to be installed in the asset, a relatively expensive IR camera, and a trained technician. Significant limitations of this type of inspection include:

- Personnel cannot perform monitoring procedures behind bus insulators or in assets that cannot be reached (elevated ISO-phase bus ducts) because line-of-sight is required with IR technology
- IR technology is a measure of emissivity, or how much infrared energy is emitted, as opposed to actual point of contact temperature
- Manually monitoring all necessary assets is a timely and expensive activity and can be dangerous to the technician doing the monitoring
- Data may be translated or entered incorrectly by the technician

Figure 3. Traditional manual inspection doesn't allow for continuous monitoring.

The most commonly used partial discharge detection instruments directly measure the current and voltage spikes with high-frequency current transformers or high-voltage capacitive couplers as outlined in the International Electrotechnical Commission's IEC 60270 standard: "*Partial Discharge Measurements*."

This method has several strengths, including the ability to analyze pulse shapes and to assemble a graph of the discharge events relative to the phase of the power line waveform. Significant limitations of these systems:

- Expensive equipment does not lend itself to be permanently installed in all required assets
- Testing is periodic even though it can be performed 'online', a phrase used to signify power is being generated
- Trained technicians are required to conduct the tests and analyze the data

Most companies are currently not monitoring humidity, instead they install heaters in their assets with the hope the heater element does not fail.

Regardless of the type of manual inspection, trained technicians and specialized test equipment are often required, leading to the need for an outside service provider. Since the testing is periodic, any electrical problems occurring after the inspection can go undetected until the next inspection. During that time, small problems can become large ones, potentially leading to a complete failure of the asset and a power outage.

To mitigate these issues, the industry is moving toward continuous condition-based monitoring, giving asset owners the ability to collect data generated during normal operating conditions, thereby providing awareness to problems in real time.

Selecting sensor types

Using the asset priority list, FMECA data, along with evaluating the equipment's specifications such as system voltage, current, environment conditions, or accessibility, will provide a baseline of information to determine the type of continuous condition-based monitoring sensors to install.

Monitoring and trending data continuously, and in real-time, provides new insights into the health of the assets. With this data, and in conjunction with other asset parameters, asset owners can plan proactive maintenance, instead of running to failure or another unexpected condition.

Temperature monitoring

Temperature monitoring is a primary method for detecting corrosion, wear, loose connections, and other problems associated with the asset's conductors (e.g. bus bar, cables). One challenge is implementing continuous temperature monitoring of critical connection points in air insulated assets . The sensors must maintain the impulse-withstand voltage, also known as basic impulse level (BIL). Consequently, conductors at different potentials must have a minimal distance between each other to prevent breakdown to ensure the impulse rating. Another key challenge is how to power the sensors to avoid regular maintenance requirements.

Figure 4. SAW Sensors

Specific to the BIL concern, the IEEE Standards Association's C37.20.3:"*Standard for Metal-Enclosed Interrupter Switchgear*, Section 5.2" states switchgear rated with a maximum voltage of 15 kilovolts must have an impulse voltage of 95 kilovolts, relating to a distance (in air) of approximately 160 millimeters. This requirement eliminates the most common types of direct contact temperature monitoring systems such as thermocouples and RTDs, leaving only non-invasive systems such as fiber optics, continuous IR sensing and wireless direct contact sensors.

Wireless passive sensor systems provide real-time continuous monitoring via direct connection to critical measurement points. These systems are easy to install, require no maintenance or yearly calibration, and have a life expectancy comparable to the assets themselves. These sensors employ surface acoustic wave (SAW) technology (see Figure 4).

Compared to other non-invasive sensors, passive SAW temperature sensors have no physical connection to a control device, do not require batteries, and do not require line-of-sight for measurements.

PD monitoring

The most commonly used PD detection instruments (phase resolved) directly measure the current and voltage spikes of the asset. This method has several strengths, including the ability to analyze pulse shapes and to assemble a graph of the discharge events relative to the phase of the power line waveform. These systems are very expensive and require trained technicians to analyze the data. They do not lend themselves to permanent, continuous monitoring installations to cover the complete power delivery system.

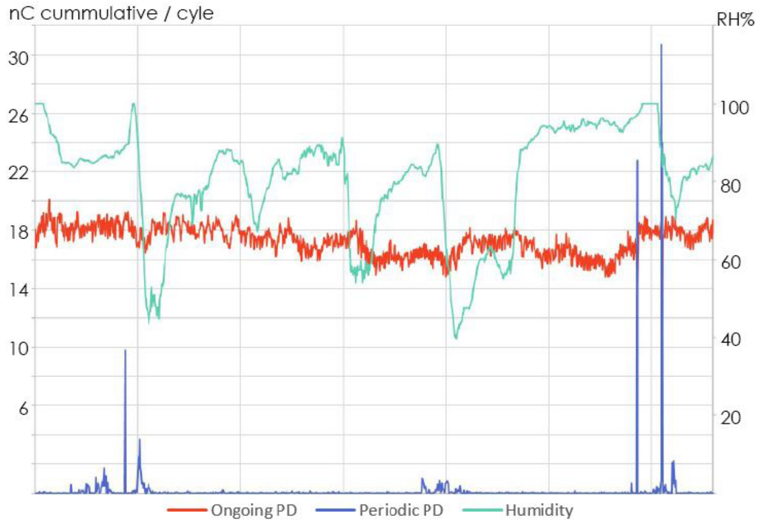
Figure 5. PD Monitoring System

Many companies are currently evaluating partial discharge detection methods outlined in accordance to IEC 62478, a prospective standard for acoustic and electromagnetic PD measurements. These methods use non-conventional instruments to make indirect analytical measurements and obtain a relative signature of PD pulses that can be used for system trending.

With PD pulse currents having short rise times (<1ns) and exciting electromagnetic waves, a common technique is to monitor these waves in the Ultra High Frequency (UHF) range between 300 MHz to 3GHz using a broadband antenna. Traditional UHF methods are susceptible to noise from cell phones, radios and other transmitters. However, newer instruments use selective, banded and filtered UHF monitoring to detect partial discharges while rejecting noise sources. UHF provides the safest, most non-intrusive continuous PD monitoring system.

Effective UHF partial discharge detection for continuous monitoring requires distillation of an overwhelming amount of complex data down to a concise piece of information, all without the intervention of a highly-trained operator. To provide an autonomous approach for PD monitoring, advanced system algorithms must be implemented to present data (see Figure 6) that can be easily processed for a health assessment and long-term system trending.

Figure 6. Continuous PD Monitoring Graph



Humidity monitoring

Humidity contamination and moisture within electrical assets will result in long term insulation damage and metallic corrosion. Assets that are continually exposed to high humidity will absorb moisture, while voltage stresses will cause the hydrophobic conductor surfaces to break down, eventually leading to system failure or flashovers. When selecting a sensor, it should be designed for the harsh environments of electrical assets and have no required maintenance or calibration schedule.

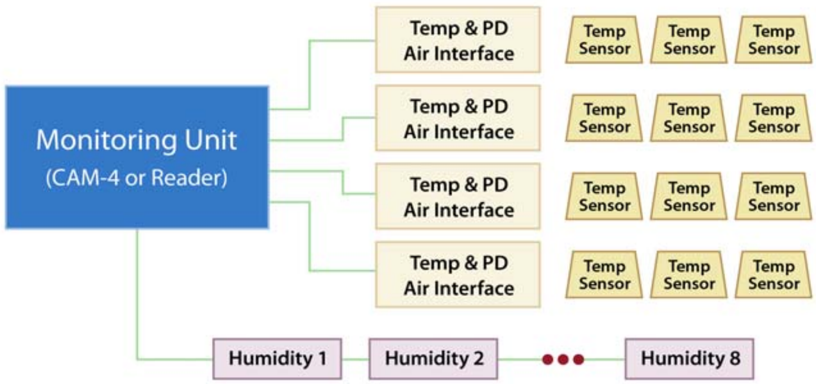
Typical monitoring system architecture

Although manual inspections can be used to monitor less critical assets, continuous condition-based monitoring is the preferred alternative for assets which must be kept online at all times.

Continuous condition-based monitoring systems are available with temperature, humidity and PD sensing capabilities. In addition to the wireless temperature and PD sensors outlined above, wired sensors are often installed on the asset enclosure to provide ambient temperature and humidity readings. Ambient temperature readings are important because the critical issue is temperature rise of hot spots above ambient, as opposed to absolute temperature.

A typical continuous condition-based monitoring system for an electrical asset includes a monitoring unit connecting temperature, humidity and partial discharge sensors as shown in Figure 7. Each Temperature and PD Air Interface uses banded UHF technology to sense PD directly. Each air interface device can also wirelessly link to three or more SAW temperature sensors.

Figure 7. Monitoring System Block Diagram



Up to four air interfaces can be wired to the monitoring unit via low loss coaxial cables. The monitoring unit can also accept up to eight conventional wired humidity and ambient temperature sensors, which are well suited for making measurements in long runs of bus ducts.

The monitoring unit can be a full-featured HMI with monitoring capabilities, or a unit which provides remote monitoring capabilities. The monitoring unit provides all the necessary wireless interrogation signals for the SAW sensors through the air interface device, internally implements the PD detection algorithms, and communicates directly with the humidity and ambient temperature sensors.

All data is accessible through industry standard Modbus® RTU (RS485), DNP3, or IEC-61850 communication protocols affording ease of integration into a power plant's existing SCADA, history, or DCS system. Figure 8 depicts the display of monitoring system data on an Ovation™ DCS.

Figure 8. Ovation Screen with System Data

Step 3: Analyze data and evaluate asset health

Once data is acquired and brought into a digital space where it can be analyzed, limits and alarms can be placed on data trends. This allows the delivery of actionable information to the maintenance and engineering team responsible for the assets. The following example shows how installing pervasive sensing and analyzing data can lead to actionable results.

Example 1

A large utility in the southeastern U.S.A. operates a multi-unit peaking combustion turbine power plant. The plant operators are tasked with quickly bringing generating capacity on-line, requiring cold-starts.

In the high humidity environments often found in this part of the U.S.A., this type of operation was causing corrosion of GCB switch contacts. Frequent manual inspection with corresponding forced downtime was required to prevent system failures. A continuous asset monitoring system was installed on the GCBs and bus ducts.

This system provides continuous real-time views of asset health. Data is wirelessly transmitted to the control room and integrated into the facilities' OSIsoft PI process historian.

The Critical Asset Monitoring (CAM™) system detected excessive temperatures on four of the six GCB bushings, and a scheduled maintenance inspection during a period of low demand confirmed bushing deterioration. The bushings were replaced and operation returned to normal, averting a failure which would have cost about $250,000 USD for repairs, and cause weeks of downtime.

Figure 9. Confirmed generator circuit breaker bushing deterioration detected using the IntelliSAW CAM system.

Example 2

A major utility in the western U.S.A. operates several hydroelectric power plants installed in various rivers. Many of these plants are small and simple, so the utility is transitioning to unmanned operation.

The utility implemented continuous condition-based monitoring to ensure its plants would operate and provide feedback when unmanned. Temperature, PD and humidity monitoring systems were installed in the bus ducts, as well as transformer connections and disconnect switches. All data is now transmitted wirelessly back to servers for data analysis, allowing the utility to operate these remote facilities with confidence.

Figure 10. Remote facility operation using wireless temperature, PD, and humidity monitoring system in the bus ducts and step up transformers.

Example 3

A utility based in the southern U.S.A. had a failure on a bus duct running from the generator to the step-up transformer that cost about $100,000 USD to repair and resulted in two weeks of lost production. To predict and prevent these types of failures in the future, the power plant installed a continuous monitoring system to monitor bus duct temperature, PD and humidity. The data collected by the system is sent to the plant's Ovation DCS where it is continuously monitored by operators.

Figure 11. Continuous monitoring system on an iso-phase bus duct measuring temperature and humidity.

Conclusion

Electric utilities need new and cost effective sensing technologies to replace inefficient manual data collection techniques. Today, many are implementing continuous condition-based monitoring systems for electrical assets.

These systems allow operators and engineers to collect and analyze data in real-time for predictive maintenance and other purposes. This helps power plants avoid unscheduled downtime by performing work during planned outages, reduces labor and overtime costs by avoiding system breakdowns, and recovers lost productivity by avoiding emergencies.

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