UTILIZING ADVANCED MEASUREMENT DIAGNOSTICS TO IMPROVE POWERPLANT/POWERPLANT AVAILABILITY

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Abstract

Many past improvements in plant safety and availability have been accomplished by upgrading instrumentation, leading to improved measurement performance and/or device reliability. Unfortunately, many users are finding that while upgrading an older field device to state-of-the-art can deliver significant improvements, the newest devices are so close to perfection that further upgrades will yield diminishing returns. The next round of improvements will be largely driven by the desire to increase overall plant availability. The advanced diagnostics present in today’s smart transmitters, when combined with open digital protocols and Asset Management software, allow the user to remotely diagnose field devices and go beyond alarming transmitters failures to actually predict impending failures in the complete measurement system. This will significantly reduce unscheduled outages and improve overall plant availability.

Traditional Approaches When Modernizing Field Devices

When modernizing field devices, engineers have been driven by the desire to improve the measurement performance and/or device reliability and traditionally used a combination of three approaches:

1. **Use more robust transmitters:** Using robust transmitters that fail less frequently will directly improve the measurement performance and device reliability. For example, a plant with 400 transmitters each with an MTBF of 100 years can expect about 4 transmitter failures each year. Upgrading to higher quality transmitters with an MTBF of 400 years will reduce this to 1 failure each year.

2. **Improve measurement accuracy and repeatability:** Accurate and repeatable measurements minimize undetected failures and false trips. Consider the example of a control application such as fuel-air cross limiting were the user needs to maintain the ratio between fuel and air flowrates. Most users operate with an excess air “safety buffer” since the environmental and safety consequences of excess fuel greatly outweigh the purely economic consequences of excess air. Although many factors contribute to make a system non-ideal, it should be apparent that a system with a 5% flow measurement uncertainty will require a minimum 5% safety buffer. Improving the flow measurement from 5% to 1% improves consistency and provides the user with the opportunity, at no increased
environmental or safety risk, to improve process efficiency and reduce excess air and therefore reduce fuel cost.

3. **Employ “best practices” in installation and maintenance:** Many measurement failures can be attributed to poor installations or maintenance practices. For example, using very long impulse lines in a differential pressure flowmeter installation will increase the likelihood of impulse lines plugging and freezing. Using shorter impulse lines or converting to direct mount will improve both measurement performance and reliability and should actually cost less.

Most users have continuously improved their measurements using the approaches outlined above. Unfortunately, many users are finding that while upgrading an older field device to state-of-the-art can deliver significant improvements, further upgrades will show little or no returns. In the example above, while the improvement from 5% to 1% flow measurement uncertainty may have significant benefits, it should be clear that future improvements, even to perfection, will return no more then one-third of the benefits of the previous upgrade. Similar comments apply to improvements in installation “best practices” and transmitter robustness.

**The Next Round of Improvements – Increase Overall Plant Availability**

Diagnostics present in today’s smart transmitters allow the user to remotely diagnose field devices and increase plant availability. These diagnostics are of limited usefulness unless the user can economically and conveniently access diagnostics alerts and information. Open Digital Protocols and Asset Management Software enable a user to access this information in an economic and convenient way. For an example, how useful is an “Sensor failure detection” if the user must climb a ladder to read that message on the transmitters local display? This diagnostic information is much more useful if it could be easily accessed at a PC online in the maintenance shop or at the local console of the control system.

**Open digital protocols** such as HART or FOUNDATION Fieldbus allow a field device to transmit additional information on the same pair of wires that carry the process variable and allow access to diagnostic alerts and information online without any additional wiring. While proprietary digital protocols have existed for years, these continue to be abandoned by users and suppliers in favor of open protocols (Figure 1).
Figure 1 – Global Pressure Transmitter Shipments (by protocol) – (thousands)

Once the diagnostics have been generated in the field device, and communicated via the digital protocol, the user needs some way of communicating that information in an organized fashion. Open standards means that users no longer require multiple maintenance terminals, and can consolidate all diagnostic information into a single asset management system, as shown in Figure 2. This not only minimizes capital, installation and training costs, but also simplifies maintenance and streamlines regulatory compliance.

Figure 2 – Asset Management System
Smart Transmitter Diagnostics

Today’s smart transmitters provide significant improvements in plant availability in areas of Device Diagnostics, Predictive Maintenance, and Onscale Failures.

**Device Diagnostics:** Most all transmitter failures are “repair by replacement”. Reducing time to repair is really the time it takes to isolate the problem. Device diagnostics enables the user to quickly isolate the source of any problem. The screen capture below shows (Figure 3) shows a failed pressure transmitter electronics board “ROM Checksum Error”.

![Figure 3 – Device Diagnostics](image)

This is an example of basic transmitter diagnostics “what component in the transmitter has failed”. Although the specific diagnostics “ROM Checksum Error” is usually of less interest then the recommended action, which is “Replace Electronics”, this detailed diagnostic message can trace failure to a specific component and assist the manufacture in preventing repeat failures of the same type.

In addition to detecting failures, today’s smart transmitters allow the user to easily diagnose application, configuration and installation errors. For example, the screen below (Figure 4) allows the user to see the current configuration of a pressure transmitter and easily determine the units configuration properties (range values, units, sensor limits) as well as additional information to determine if the transmitter is installed within the specified temperature limits.
Figure 4 – Diagnosing Configuration Error

The screen below (Figure 5) is an example of diagnosing application errors allowing the user to simulate a flow signal and test both the electronics and the configuration of the vortex meter. While older vortex meters allowed a fixed flow simulation to be done via board jumpers, today’s smart devices allow user selected simulation to be done easily, either as shown from the Asset Management software or from a connected handheld configurator. Successful flow simulation in a vortex meter quickly determines any transmitter or configuration problems, and helps isolate an application error.

Figure 5 – Diagnosing Application Errors
**Onscale Failures:** Most transmitter failures are easy to detect the output of the transmitter either fails offscale high or offscale low. More difficult failures to detect are when the output of the transmitter is within normal range, and the measurement is failed *onscale*. Onscale failures tend to be associated not with the transmitter itself but with the rest of the measurement system. Many of these diagnostics overlap with those used to enable predictive maintenance.

**Predictive Maintenance:** There are three different methods of maintenance that a plant can operate under:

1. Reactive: “Fix it when it breaks”
2. Preventive: Regularly scheduled maintenance to prevent failures
3. Predictive: Maximize uptime and “fix it just before it breaks”

Most often plants operate with a combination of reactive and preventive maintenance. Consider an example of a boiler that has tripped do to a drop off of the primary airflow signal. The technician goes out to the unit and seeing a differential pressure of zero he/she changes out the transmitter. Fixing the transmitter when the problem occurred is *reactive* maintenance. The technician wants to prevent this from becoming a problem again and decides to add the transmitter to a six-month *preventative* maintenance schedule. Thinking that the problem was fixed the boiler is started up and after a short period of time trips again do to a zero primary airflow signal. Now looking at the situation closer the technician was able to find that the impulse lines from the transmitter to the orifice plate had become plugged. Seeing this, the lines were cleaned out and the unit was brought back on line. What is needed in this situation is *predictive* maintenance, which is the ability to diagnose that the lines are plugging and correct the situation before it fails and trips the boiler. This approach minimizes both maintenance labor and the risk of an unscheduled outage.

Many users have used data from the DCS to predict measurement system failures. Although this approach is good to predict the overall health of the boiler a diagnostic located in the transmitter itself has a much better chance of detecting a problem with the measurement system before it causes a failure. For example, detecting and predicting plugged or frozen impulse lines. Figure 6 shows the undamped signals in the impulse lines measured by the differential pressure transmitter in a typical orifice meter installation.
An open (unplugged) impulse line has high frequency noise due to fluid turbulence, comparable amplitude of noise for both the high and low side lines. If both lines are open, the physical offset between the high and low impulse lines creates a phase shift. As a result, the SUM has half the amplitude of either signal. If either line plugs, its signal will become flat – with minimal cancellation, the SUM will have twice the amplitude of the “OK” SUM. If both lines are plugged, both will become flat, and as a result the SUM will be flat.

To perform this diagnostic, the transmitter must calculate “Variability Index”. The transmitter must “learn” the process and characterize an “OK” condition for a varying flow rate. Once the process is “learned”, and the diagnostic is online, an Index trending high will alert one line plugging, and an Index trending low will alert both lines plugging. A screen capture from Asset Management software is shown in Figure 7.

Figure 6 – Impulse Line Signals

![Impulse Line Signals](image)

Figure 7 – Asset Management Screen Capture for Plugged Impulse Line Diagnostic

![Asset Management Screen Capture](image)
It should be clear that this diagnostic is only practical with a very fast pressure sensor. Since the diagnostic is performed in the transmitter itself, update rate to the DCS is not important, but a fast sensor, 50msec or less, is vital. Many pressure transmitters available today exceed this maximum response time by a factor of two to five times.

Another example of predictive diagnostics in today’s transmitters is detecting RTD drift with a redundant sensor. Located inside a dual input temperature transmitter connected to a dual element RTD, this diagnostic measures the difference between the two RTD’s. If the RTD’s have been “sensor matched” by the supplier, the difference should be less than 0.25 °C. If the difference exceeds some user defined limit 1 °C, the transmitter the alert is detected in the Asset Management software as shown below (Figure 8). Note that the transmitter can continue to operate with either RTD providing no interruption in the measurement.

**Figure 8 – RTD Failure or Drift Diagnostic (Dual Element RTD)**

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**Conclusion**

Advanced diagnostics in today’s smart field devices will significantly reduce unscheduled outages and improve overall plant availability. This paper has only presented diagnostics that exist today in field devices. The future of advanced diagnostic is bright and is being looked at as the “Next Frontier” in process control field devices. To ensure that the maximum benefit of advanced diagnostic capabilities in field devices is received users need to:

- Ensure that open protocols such as HART or FOUNDATION Fieldbus are being used.
- Gain experience with Asset Management software
- Ask their suppliers, what diagnostics are available now and what are planned for the future?