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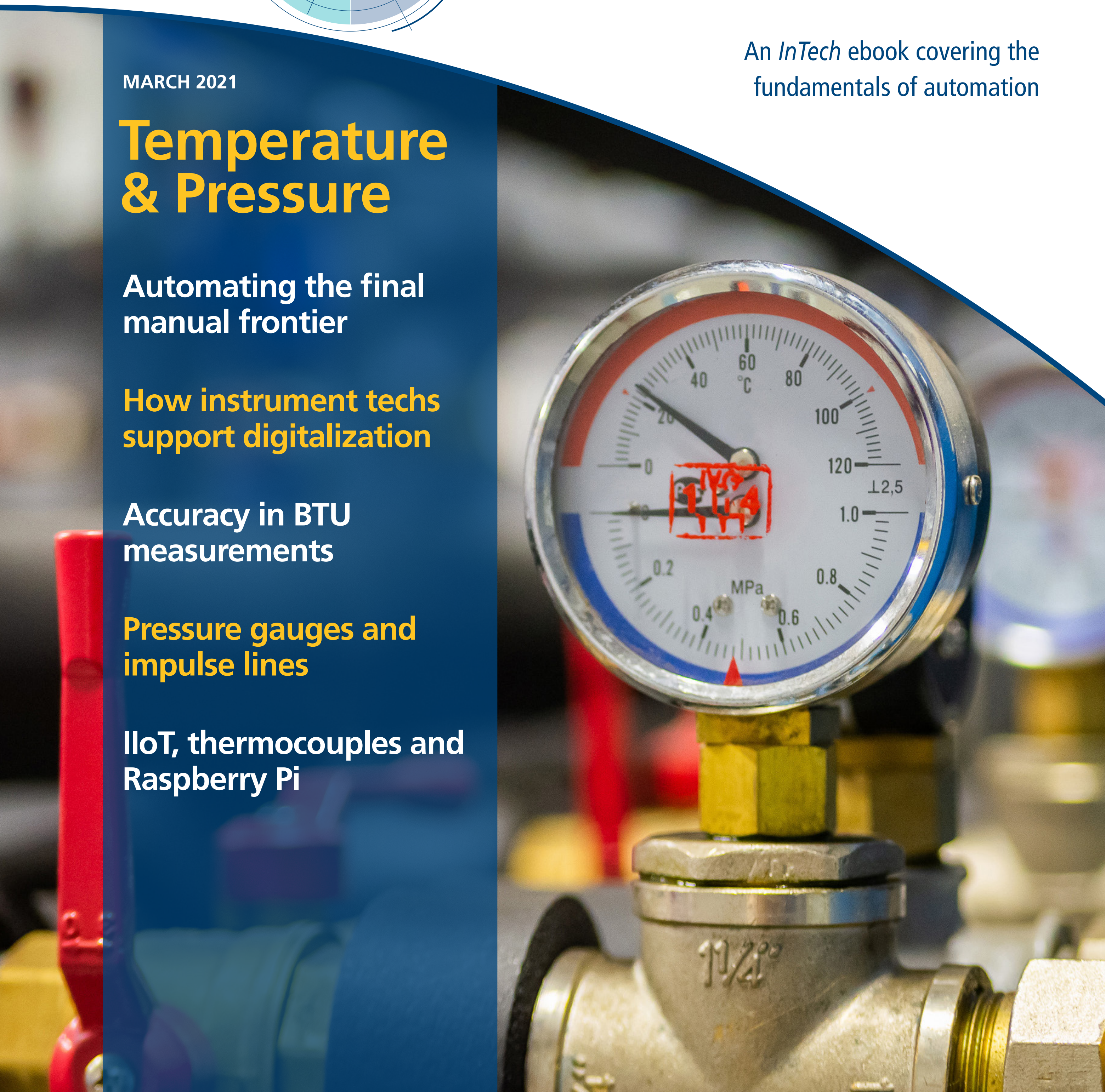
# Temperature & Pressure



## Automating the final manual frontier

## How instrument techs support digitalization

## Accuracy in BTU measurements

## Pressure gauges and impulse lines

## IIoT, thermocouples and Raspberry Pi

## *Introduction*

Temperature, pressure, and measurements from process control instrumentation are increasingly being recognized as key components for industrial asset health management specifically and for digital transformation overall. Determining why production unexpectedly stops mid-operation, or preemptively avoiding such stoppages, requires diagnostic data that can only come from the machines themselves. Gathering that data has been a mainstay of industrial operations for a long time. Viewing, analyzing, and applying the lessons of that data either to maintenance or real-time operations is the ongoing challenge.

Experienced personnel who understand measurement instrumentation—its potential as well as the limits—can help temper expectations and ensure digital transformation efforts are a success. Find out more in this edition of *InTech Focus* focused on temperature and pressure measurement.

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# Automating the Final Manual Frontier: Plant Asset Management

The last area where plants tend to give up manual monitoring and take up automation is asset health management. Here's why operations and maintenance teams must take this critical step.

By Ben Myers, Endress+Hauser

In the aftermath of a failed military campaign or attempt to stop an enemy attack, critics may blame intelligence services, saying they did not "connect the dots" and understand the true picture of an incident. This suggests information existed, and may have been collected, but did not get to the right people. The effort was too fragmented to be effective.

A process manufacturing plant trying to determine why production suddenly and unexpectedly ground to a halt may go through a similar discussion. The process shut down in mid-operation because of an equipment failure that should have been anticipated and fixed before a complete breakdown, but nobody could connect the dots and recognize the indications of the developing problem. Device diagnostic data was available but remained lost in log files of the control system where technicians could not access it.

Solving situations like this requires a field device management system, one that can recognize which assets need attention, and then provide information on how to fix a developing problem before the situation escalates into a full failure, possibly causing serious and costly damage. This type of system can collect and analyze large amounts of data from a population of smart field devices, including process analyzers and instruments, along with other control devices such as valve actuators and positioners. The system can connect the dots automatically to ensure effective operation without interruptions, supplemented by more effective use of maintenance resources.

Figure 1. An individual technician can evaluate instruments one by one, but this manual approach cannot keep up with a large population of field devices.

## Manual versus automated monitoring

Well-trained and experienced technicians equipped with appropriate field communicators (figure 1) can do a lot to diagnose the condition of a flowmeter or a pressure transmitter. This involves connecting to the individual instrument and scrolling through perhaps dozens of variables and configuration settings. If the person happens to catch a developing problem by recognizing something drifting out of its normal range or by viewing an alert message, it might prompt timely remedial action.

Unfortunately, such technicians are rare at many end user process industry companies, so the likelihood of one being in the right place at the right time is very low. The critical information is available from the instrument, but no one is there to see it, and the failure results.

Imagine posing questions to the production manager of a typical petrochemical plant unit. "Why do you have all this automated, computer-driven control system equipment working with all those electronic field devices? Wouldn't it be better to operate the plant manually?"

The question would be considered nonsensical. Responses would undoubtedly include points like the huge number of people who would be required to perform repetitive and tedious manual tasks, contrasted with the efficiency and effectiveness of a well-designed distributed control system (DCS). A follow-up question might be harder to answer: "So then why is so much of your asset health monitoring still manual? Shouldn't it be automated as well?"

## Capabilities of asset health monitoring solutions

Today's sophisticated field devices can provide enormous amounts of data. Estimates suggest that the basic primary variable represents barely 3 percent of the data originating from an instrument or analyzer. So, what does the other 97 percent represent (figure 2)? Naturally, it varies based on the type of instrument—a differential pressure transmitter will produce different information than a Coriolis flowmeter or smart valve actuator. But in general, it includes:

- Diagnostics – Discrete and continuous indicators for internal problem states and random failures of the sensor and electronic components. These can be indicated in various ways, including alerts and alarms. Device calibration history also resides here.
- Monitoring – Continuous asset and process indicators, such as process noise, which can indicate changes outside of an instrument's primary function.
- Soft sensing – Secondary, tertiary, and even additional variables. These can work individually or in conjunction with other instruments to approximate process measurements not directly measurable.

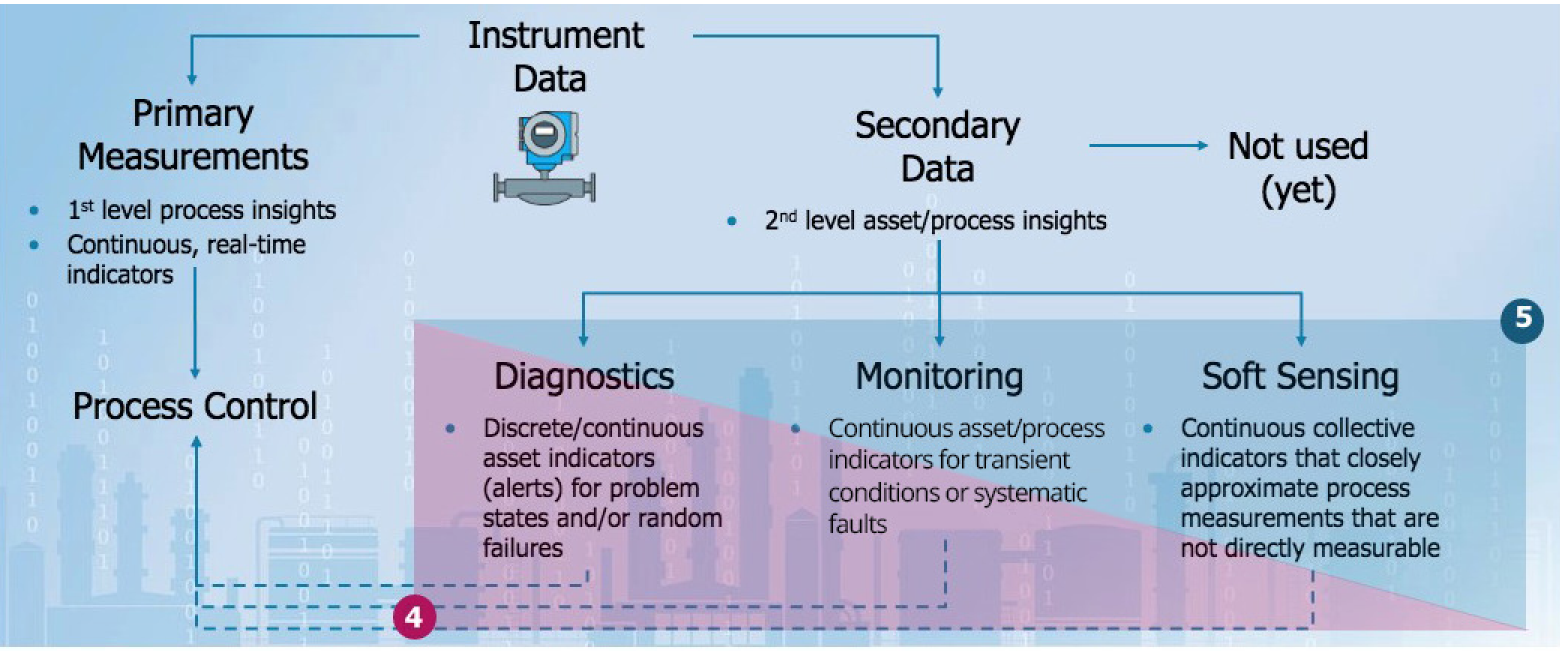



Figure 2. The primary measurement captured by a smart field instrument represents about 3 percent of the data it generates. The remaining 97 percent can be put to work for asset health management and other uses.

An effective plant asset management solution is designed to collect the extra data and unlock its potential. When implemented properly, it will improve plant availability and effectiveness while reducing production interruption risk, maintenance time, and effort. Critical benefits include:

- Data analysis helps direct preventive maintenance efforts to save time, especially for devices with high maintenance requirements.
- Much faster troubleshooting, eliminating the need for checking individual instruments.
- More effective use of technicians' time, because they can check the status of instruments before performing repairs.
- Data collected and displayed on dashboards for real-time performance and captured in histories for later analysis.

## Understanding the mechanics

An asset health monitoring system works in parallel with the larger DCS. It gathers the diagnostic, monitoring, and soft sensing data from all the smart field instruments and other smart devices using a digital communications protocol—for example HART or Profibus PA.

It is false to assume a complete DCS upgrade is required to integrate a new asset health monitoring system. Many legacy DCSs are already able to interface directly with smart devices, but when the legacy system does not provide the required communication capability, data collection can be done outside of the DCS (figure 3). In either case, health monitoring does not depend on the DCS to carry out its primary functions.

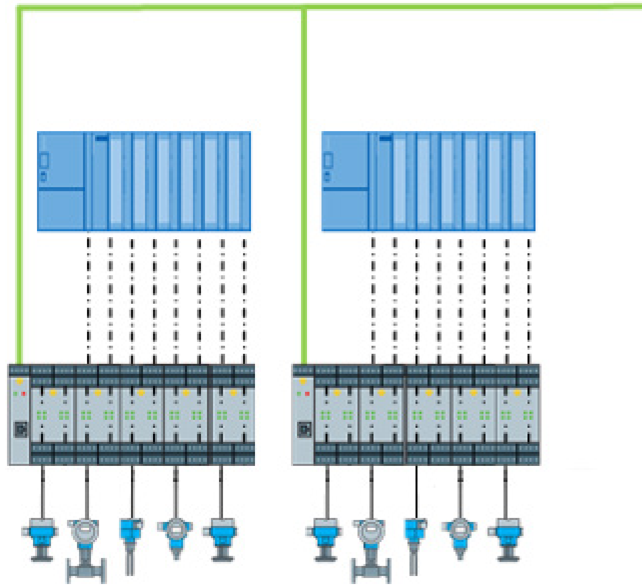


Figure 3. In legacy environments without the required smart device digital communication capabilities, a parallel connection can carry data without interfering with normal DCS functions.

Naturally, providing the means to gather data is only the first step. The asset health monitoring system must deliver a basic suite of functions:

- digital communications to field devices
- continuous monitoring and logging of smart device health status
- presentation of status data suitable for different types of users
- analysis of the installed base to determine the most critical devices
- self-checking and performance verification built into devices to extend calibration intervals.

How a system implements these functions is where the various options emerge and allow a plant to customize its solution. One approach is to host it entirely on site using the plant's servers for all processing and data storage functions. If required, it is a simple matter to pull device health status through the DCS using a client/server architecture, to provide the functions just mentioned. Such systems are modular and highly scalable to adjust to a given site's needs, and they support incremental adoption if desired.

Since the basic functions tend to be similar regardless of the plant type or size, it is possible to pre-engineer much of the functionality to minimize required end user integration time and cost. This includes standard desktop workstations and mobile clients. More advanced functions of on-site systems can include:

- centralized database support for multiple networks
- live web overview of field device status
- diagnostic events stored in a database with easy access
- field device notification history analysis used to optimize maintenance activities
- parallel access from central station via computer or tablet
- use of NAMUR NE107 standard categorization (figure 4) of diagnostics and graphics
- continuous monitoring and logging of instrumentation health status with easy access
- cause and remedy instruction accessibility for maintenance technicians.

| Status Signal | Color | Symbol |
|---|---|---|
| **Normal;** valid output signal | | |
| **Maintenance required;** still valid output signal | | |
| **Out of specification;** signal out of specified range | | |
| **Function check;** temporary non-valid output signal | | |
| **Failure;** non-valid output signal | | |

Figure 4. NAMUR NE107 has standardized the presentation of device condition information, so operators do not have to interpret cryptic messages to determine what is wrong.

## Sophisticated technologies extend capabilities

The capabilities mentioned so far should be part-and-parcel of any asset health management system. These are the most basic asset health monitoring tools, but even these will put a plant miles ahead of sporadic manual checks. Still, there are many new capabilities that have emerged from Industrial Internet of Things (IIoT) and digital transformation developments to drive advances much farther, taking advantage of new networking and communication options.


Figure 5. Cloud-based systems can offload platform hosting, but also support asset health monitoring as a service, such as Endress+Hauser's Netilion Health.

One of the first differences is where the system resides. There is now no necessity for a plant to maintain this kind of system on its own servers. Cloud-based systems (figure 5) are now a reality. They host a variety of sophisticated applications, including asset health monitoring.

Growing numbers of plants are embracing this cloud-based approach to transfer IT-related maintenance and support to a third party. The plant can concentrate on production and process optimization rather than IT services. When the system moves to the cloud, the whole implementation can be a solution as a service, including initial setup.

## Using today's networking technologies

The HART Protocol has served as the primary tool for sending device diagnostic data for decades, and it remains the leading protocol today. While it has gone through many improvements, its speed and bandwidth remain limited, particularly where a HART solution is retrofitted onto legacy hardwired I/O. WirelessHART, whether using a native wireless instrument or retrofitting a conventional HART instrument, offers some improvements, but newer networking protocols, such as Profibus PA, have expanded the range of options and offer better performance.

Networking protocols used in larger IIoT implementations can improve communication and offer a wider range of options for installations. Modbus and Bluetooth edge device protocols help interface with new instrumentation technologies. Many of these edge devices are set up for global systems for mobile communications (GSM) and long-term evolution (LTE) wireless networks, providing additional flexibility for delivering data to the cloud.

Equally exciting is the potential for intelligent field devices that are natively cloud ready. These include their own SIM card (figure 6), so they can send process variables and diagnostic data directly to the IIoT hub. The Endress+Hauser Micropilot FWR30 radar level transmitter, for example, can provide worldwide transmission of measured data and events via email and SMS using an integrated GSM/GPRS modem and battery-powered transmitter. The ultimate result will be an IIoT ecosystem where all data, both process and diagnostic, will be part of one fully integrated system. Plant production, maintenance, and even corporate management will be able to access appropriate areas to gather and analyze real-time data to improve the process, reliability, and profitability.

Figure 6. Endress+Hauser Micropilot FWR30 radar level transmitter with integrated SIM card.

## Connecting the dots

As important as these new technologies are, it is also important to keep the needs of a given plant in mind and concentrate on the overall benefits that asset health management and other tools can bring:

- reduction of unexpected failures and process interruptions
- live view of asset status with easy access, saving time required for routine maintenance
- reduction of complexity for technicians, providing greater productivity with less training and fewer tools
- less time spent on manual rounds and calibration.

The dots are out there, and the tools to complete the picture for more effective and more profitable operation are ready for any plant to adopt now.

*All figures courtesy of Endress+Hauser.*


### ABOUT THE AUTHOR

**Ben Myers** is the product marketing manager for solutions and service at Endress+Hauser. Prior to his current role, he spent four years as a process automation engineer on Endress+Hauser's Solution Engineering Team. While in that role, he was heavily involved with the field engineering and execution efforts of various solutions projects. Myers has a bachelor's degree in manufacturing engineering technology from Purdue University and an MBA from Anderson University.


# Three Ways Instrumentation Engineers Strengthen Digital Transformation Projects

Get the most from what exists currently and take advantage of new methods.

By Nicholas Meyer, Yokogawa

Digital transformation projects compel teams to spend time and effort in the development of data strategies, data requirements, and key metrics. The investment can be extensive. As a critical part of digital transformation, the delivery of accurate and analyzable data from instrumentation in the field will help deliver success. It cannot be an afterthought.

Teams today are discovering short- and long-term successes when they invite input from experienced personnel who understand measurement instrumentation—the potential as well as the limits—in streamlining the setup, distributing the data across the organization without data overload, and helping temper expectations to avoid dead ends. Ultimately, the instrumentation experts can help meet digital transformation goals in capabilities, schedule, and budget.

First, however, the instrumentation expert must understand the goals of the organization’s digital transformation. Is the first objective to create an area of industrial autonomy in, for example, tank inventory management? Is one of the goals to improve supply chain management through streamlined sharing of data? Without question, one of the goals is to remain within budget.

Instrumentation experts both inside and outside the organization can assist in at least three ways:

1. Help the digital transformation team understand the instrumentation potential they already have in their facilities.

2. Identify returns on the investments that innovative instrumentation technologies can bring.

3. Integrate benefits that come from choosing high-quality devices.

## One:
## Find sound value in previous investments

Instrumentation can play a major role in forming the solid data foundation that all digital transformation projects require. The information that is widely used throughout a digitally transformed enterprise originates in instrumentation. In addition to process monitoring and control, the measurements are used by digital twins for optimization of process units, advanced analytics using artificial intelligence and machine learning (AI/ML) for value chain optimization, and cloud-based predictive asset management applications.

According to one expert, “If an organization is not willing to take the steps necessary to establish a solid data foundation before applying advanced analytical methods, the likelihood that those methods will provide the correct answer is greatly diminished.”

A digital transformation project in an existing facility can benefit from many intelligent field devices already in place. Although sometimes well hidden, existing instrumentation capabilities can help the project avoid unnecessary waste in schedule and budget.

The instrumentation expert will help discover the device capabilities, will know which devices bring extra value, and will know where to add devices. Once the team is fully aware of the available devices and their capabilities, the instrumentation expert can share how they can help meet current project goals.

For example, consider communication protocols. A transmitter currently in the facility might be able to communicate additional information on a protocol that was not previously used in the facility but that will move the project toward the digital transformation goal. For example, in addition to a process variable, the transmitter could also source information that is used for asset management and process diagnostics.

Consider the evaluation of wireless devices rather than making them a requirement. Many digital transformation teams can expect gains from wireless, but they should weigh the costs of the devices, the maintenance tools, and training versus the savings of bringing in remote data. Often, the wireless convenience will pay for itself, but there might be a simpler path already available. Existing wired devices might do just as well and save project resources and future operating costs.

Instrumentation experts in the facility will be familiar with existing transmitters that have a wealth of stranded data and offer options for multiple measurements. For instance, a transmitter currently used for differential pressure might also be capable of static pressure or temperature measurements. And since not all traditional technology needs to be replaced, the facility will save on training costs. Instead, teams can focus education on the new processes, methods, and technology that digital transformation will naturally bring.

## Two:
## Maximize returns on investments

As investments in instrumentation are planned, many opportunities will arise for innovative technology and methods to bring transformational growth. One of the keys to success lies in realistically determining what instrumentation can do to help attain digital transformation goals. Seeing realistically includes both working within instrumentation limits as well as pushing them.

Digital transformation projects require thorough assessments of all data sources early on. Applying advanced methods such as analytics, AI/ML, and digital twins is prone to failure if the information feeding them is inaccurate and unreliable.

Setting realistic expectations for instruments includes both working within limits as well as pushing them.

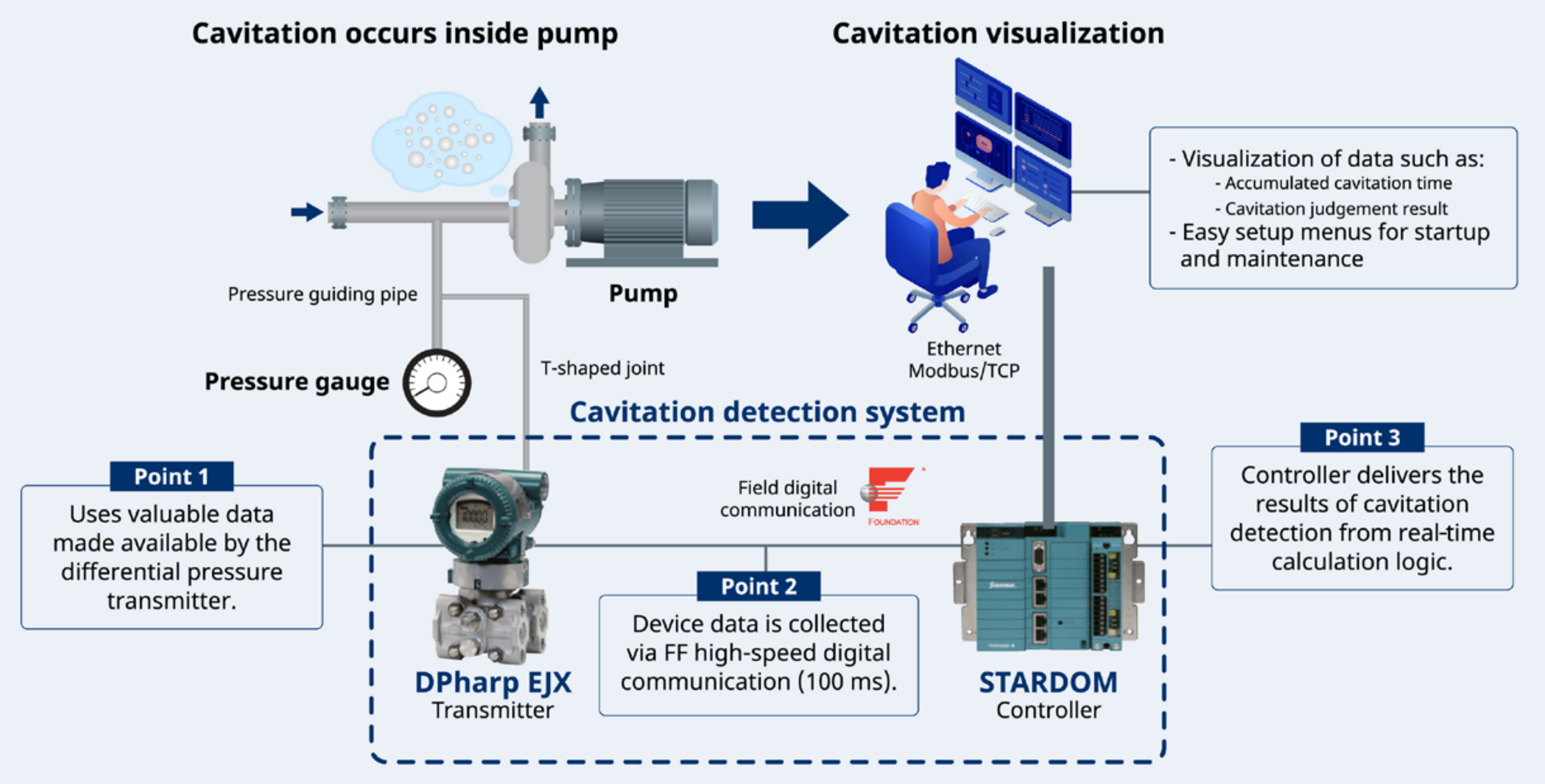
With instrumentation knowledge on the team, the digital transformation effort can deliver data needed to develop process improvements. Not only can instrument experts direct the team to sources of data and innovative ways to gather it, but they will also have the background to understand that not all data is what the team might expect.

For example, many pressure measurements are dampened to "smooth out" process control, or temperature transmitters might be set to filter out transients and avoid spikes. To receive the data that will help drive analytical models or machine learning, it might be necessary to remove some filters or to set a method that enables access to the raw data.

Discover returns in plant operations management and maintenance by asking the instrumentation expert to identify smart devices that help improve human productivity through plant asset management, including asset monitoring and health analysis. Embedding the potential for predictive maintenance in devices saves maintenance teams hours of troubleshooting and repair, thus avoiding time wasted in both reactive and preventive maintenance. Not only can the data be used for predictive maintenance, but it can also be fed into analytical models that drive recommendations to improve plant operations.

Another significant return relates to changing how data is gathered. For instance, general pressure and temperature data might have been received periodically as technicians and operators performed manual rounds. If a digital transformation goal includes moving toward industrial autonomy to improve human productivity, the digital transformation team might consider adding a wireless sensor or transmitter to relieve personnel from the data-gathering task—allowing them to concentrate on tasks where people have the greatest impact.

Gathering large quantities of meaningful data might help meet goals, but the returns will be realized only if the organization has tools to maintain, analyze, interpret, and act on the results. Plan to gather what is required—and no more—and be prepared to use the data to find patterns. An instrumentation expert can assist by determining, for example, if a transmitter has the power to gather data fast enough to meet the analytical model's demands. But make sure the data is required before the team pursues that path because it could also require additional infrastructure costs. By the way, the instrumentation expert will know that too.




Pump cavitation diagram

The team might then push to have that data sampled at a greater frequency, but just because a wireless pressure or temperature device can update every second, does not mean that it should. While temperature measurements are practically never required at high sampling rates, fast pressure measurements might be required by an edge device to prevent pump cavitation. Refer to pump cavitation diagram on previous page.

Before moving ahead with what might seem like an improvement—to get more data—think about how much data is needed to generate an impactful result and how much the extra data will cost in terms of battery life. Find the fine balance between the cost of maintenance, the expense of added sensor replacement, and the savings of personnel time and process improvements. The instrumentation expert will be familiar with that information and can compare solutions.

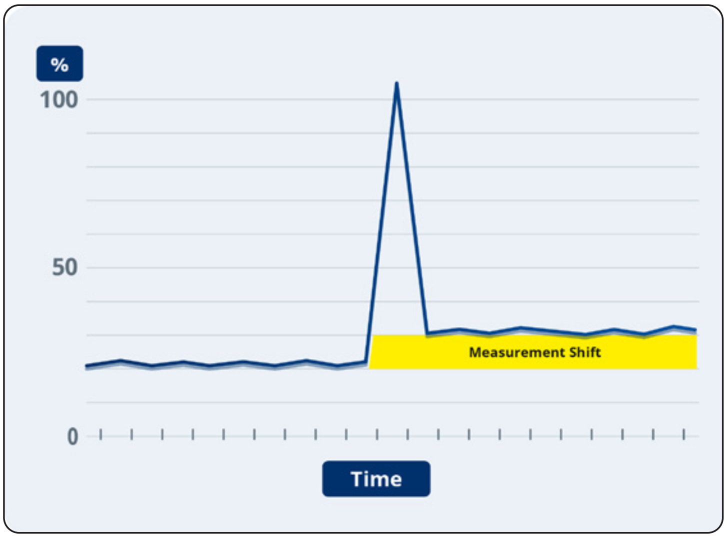
## Three:
## Improve long-term digital transformation by emphasizing quality

In a digitally transformed enterprise, a "single version of the truth" is essential. The data validation process is critical. Every member of the digital transformation team—and every person in the organization for that matter—understands the adage "garbage in, garbage out." Since the foundation of success for digital transformation is good data, the adage applies well here.

If field data is inaccurate or misapplied, the analysis results will be suboptimal, the aim of future direction will not be true, and the work initiated by the analysis will be misdirected and wasted. A habitually incorrect measurement can magnify and multiply errors throughout the organization. The way to obtain data quality appropriate to the need is to assess its accuracy, reliability, and consistency. Understanding and striving for quality data will greatly improve everything downstream in the digital transformation process/project.

Be cautious of simply adding wireless capabilities to devices that will consistently and reliably deliver *poor data*.

Device accuracy requirements must be fully understood. Be aware that communicating the data in the desired way, whether via wired or wireless, is relatively simple compared to obtaining accurate measurements. Be cautious of simply adding wireless capabilities to devices that will consistently and reliably deliver *poor data*. The instrumentation expert can help make sure of sensor accuracy for the process conditions and that it is manufactured by a trusted partner who will stand by the device for the long term—digital transformation is a long-term journey.




After a process spike occurs, some devices continue operating while delivering inaccurate data. The requirement for maintenance might go unnoticed due to seemingly continued correct operation.

Instrument installation best practices are very important to obtaining high-quality measurements. Sometimes digital transformation requirements and best practices conflict with measurement best practices. For example, mounting a pressure or temperature sensor directly on process equipment can eliminate errors associated with impulse piping or sensor wiring, but wireless best practices favor a remote mount to achieve a better signal. Which is more important to meet the goals? Can the process afford to compromise a certain level of accuracy? Will the choice cause the facility to incur additional maintenance costs?

To assess reliability, evaluate instrument devices for how well the sensors can recover from extreme conditions in the process. If a process spike occurs, some devices cannot recover and might be damaged or impaired. Unfortunately, these devices require maintenance to restore proper functionality, and incorrect measurements might go unnoticed (see the figure). Ideally, analytical models will detect irregularities. But if they cannot, the instrumentation team needs to know so they can give the situation proper attention. The instrumentation expert can direct the digital transformation team to devices that can recover to deliver accurate, consistent, and repeatable data.

Also, assess whether devices can deliver data at the right time. For example, achieving the digital transformation goal might require that a certain set of data must be collected within a small window of time. If each device does not deliver in the appropriate window, the analysis will be incorrect. Deterministic networks—wired or wireless—are important in this case. Instrumentation experts can assist with evaluating the best protocol standard for the team's digital transformation requirements.

## Predictions for success

Navigating digital transformation in an organization is a long-term initiative with potentially significant results. Get the most from what exists currently, take advantage of new methods, and consider quality by inviting instrumentation expertise into the digital transformation team. The planning and execution are worth doing well to lay the groundwork for the organization's future in the use of smart manufacturing and digital technology to accelerate business strategy.

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Attaining Proficiency in Industrial Pressure Measurements | Webinar

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**ABOUT THE AUTHOR**

**Nicholas Meyer** is the chemical industry marketing manager for Yokogawa Corporation of America. He graduated from the University of Minnesota with a degree in chemical engineering. His experience with field instrumentation spans two decades including pioneering the shift from traditional to digital enterprises. Meyer holds multiple patents from wireless technology, cybersecurity, and digital work practices.

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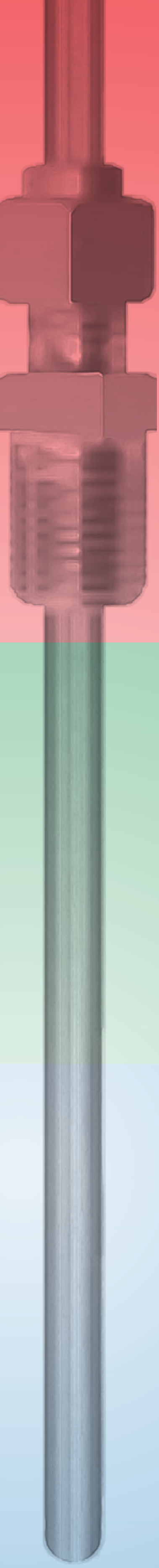


# The Importance of Temperature Accuracy in BTU Measurement

## Control the temperature of the fluids and air servicing a building.

By Denis Richard and Jesse Cameron, Intempco

The costs of ignoring temperature accuracy in energy measurement (British Thermal Unit) can be worse than expected. Inaccuracy occurs when poor techniques and equipment are used in the system, which can result in wasting thousands of dollars every year. This waste can be avoided by paying attention to the details. For instance, the temperature sensors used in the thermal energy system must be a matched pair, or uncertainties could instantly increase depending on the sensor's performance. No matter how big or small the BTU measurement system is, it is important to comprehend that temperature sensors are a critical part of the system and should be procured, installed, and maintained correctly.

Maintaining proper measurement and control of the temperature of the fluids and air servicing the building is often thought of as a simple task. Still, it requires effort and diligence. Another major issue that is overlooked when caring for thermal BTU metering is the comfort of the people inside the building. It is important to maintain proper control, so the individuals can perform at optimal efficiencies. In this article, we will discuss:

- fundamentals of BTU measurements
- roles of relative temperature
- techniques used to effectively measure temperature and reduce uncertainties
- suitable temperature sensors.

## Fundamentals of BTU measurements

BTU is a thermal energy unit used primarily in residential and commercial buildings to measure the energy used for heating, cooling, operations, and other applications involving the transfer of fluid for energy purposes. Systems typically contain a central heating or cooling unit and distributes energy throughout the facility. A BTU is defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. To give perspective on the unit, a gallon of gasoline contains about 125,000 BTU. It is an energy unit, like calories.

The governing equation for BTU is $Q=mCp\Delta T$. $Q$ is the amount of energy, $m$ is the mass, $Cp$ is the specific heat of the fluid, and $\Delta T$ is the temperature difference between the two temperature sensors.

BTU metering applications use mass flow rate, $\dot{m}$, as many systems have circulating fluids instead of static reservoirs to circulate the energy. Thus, the equation becomes $\dot{Q}=\dot{m}Cp\Delta T$. This is the rate of heat transfer, which is multiplied by the time to get the total amount of energy that passed through the system.

The instrumentation that is used in the system normally contains one set of matched-pair temperature sensors, one flowmeter, and one BTU meter with data logging and communication capabilities.

Resistance temperature detectors (RTDs) are the most common type of temperature sensor used in BTU metering. The measurement of the RTD resistance is made by passing a small current across the RTD and measuring the voltage drop across the RTD as its resistance varies with temperature. The change in voltage is then converted to a change in temperature electronically.

One temperature sensor is inserted into the inlet pipe, and one is inserted into the outlet pipe to capture the difference between the fluid temperatures after it travels through the system.

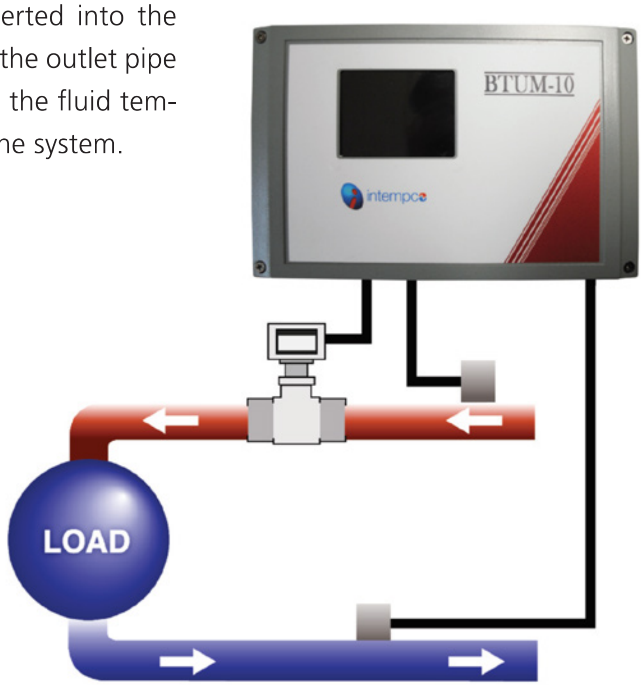



Figure 1. A BTU metering system includes two temperature sensors, a flowmeter, and a BTU meter.

## Roles of relative temperature

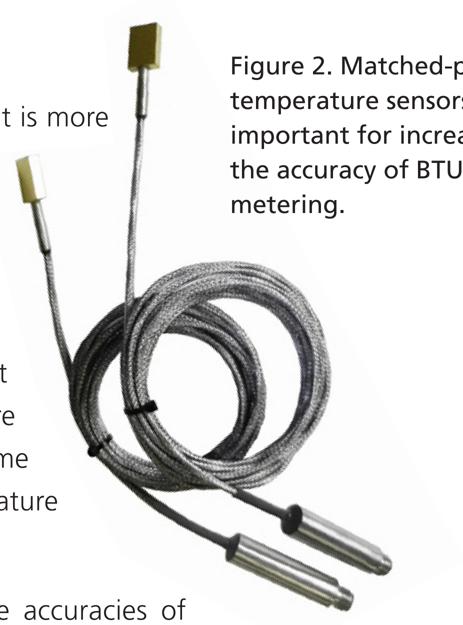


Figure 2. Matched-pair temperature sensors are important for increasing the accuracy of BTU metering.

The relative temperature between the input and output is more important to quantify BTUs than the absolute temperature at those locations. The equation for BTU is dependent on the difference between the two sensors, which is not relevant to their absolute temperature. For example, having the inlet temperature sensor at 140°F and the outlet temperature at 104°F does not add more energy into the system than if the values were much lower at 86°F and 50°F. They will input the same amount of energy, because they both have a temperature difference of 36°F.

High-quality resistance temperature detectors have accuracies of DIN Class A ± 0.15 + 0.002*|T|°C. This can result in the worst case to uncertainties of 0.27°F at 32°F and 0.63°F at 212°F, but this uncertainty is increased when they are not a matched pair. The relative difference between them can go as high as two times these values.

When temperature sensors are calibrated by manufacturers, they generally use a fluid bath, as it is the most stable medium, and create a two- or three-point resistance versus temperature (RvsT) calibration curve. This curve may change slightly between calibrations, as each RTD does contain its own manufacturing uncertainties. Once the curves are created, it is possible to match the RTDs that have the most similar curves. This is a time-consuming process and will increase the costs of the matched-pair sensors compared to buying the sensors without a matched pair. This purchase cost increase could represent substantial money over time.

## Techniques to effectively measure temperature and reduce uncertainties

There are techniques that can save costs when implemented. First, place the temperature sensors to the extremities of the inlet and the outlet of the system. It is best to go as close as possible, but insure space is left for servicing. The placement should be reachable from floor level when possible and as far away from any sources of electrical noise as possible.

Account for the additional resistance from the lead wires of the supplied temperature sensors. This is typically corrected from within the BTU meter and should always be verified on the specific unit. If the BTU metering unit comes already calibrated with dedicated temperature sensors, the wires cannot be cut or modified, or this would cause a significant reduction in the accuracy of the BTU metering. To prevent any tampering with lead wires, many manufacturers will prevent any access to the PCB port terminals. The use of shield cable is also required to avoid errors from interference.

Lead wires are also affected by the surrounding atmosphere and improper power usage, which will increase the drift of the sensor. This causes additional errors in the readings.

Ideally, temperature sensors will be inserted into the conduit used to circulate the water, steam, or other fluid. The best performance occurs when the tip is directly in the path of the fluid. This ensures that the temperature reading is coming directly from the fluid flow. If this is not possible in certain circumstances, then surface-mount temperature sensors should be used.

Circumstances that would lead to the need for surface-mount sensors could include a pressurized system, where shutdown is not an option, or higher costs to design for insertion.

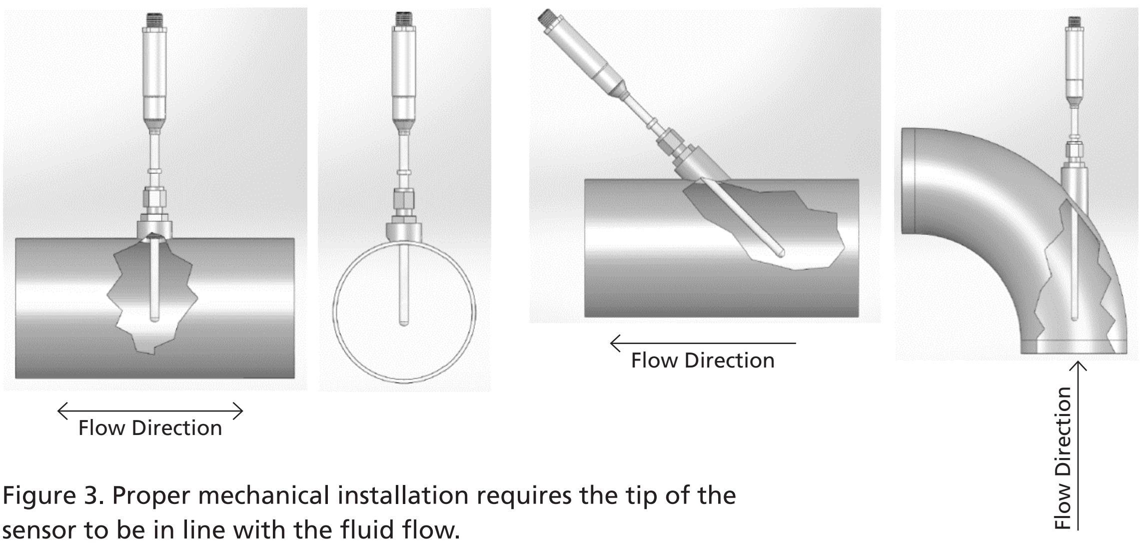



Figure 3. Proper mechanical installation requires the tip of the sensor to be in line with the fluid flow.

When using surface-mount temperature sensors, using thermal paste to ensure a good transfer between the conduit and the sensor is recommended. It is also good to add some insulation over the temperature sensor to minimize the heat exchange with the environment. Modern BTU meters can account for the heat transfer losses through the piping and would include some form of offset constant.

Besides the temperature probe positioning, there are many other factors that can reduce the accuracy of the readings. Generic sources of error from RTDs include:

- **Interchangeability**: Interchangeability refers to the "closeness of agreement" between an actual RTD RvsT relationship and a predefined RvsT relationship.
- **Insulation resistance**: Current leaks into or out of the circuit from the body of the sensor or between the element leads.
- **Stability**: Ability to maintain RvsT over time as a result of thermal exposure.
- **Repeatability**: Ability to maintain RvsT under the same conditions after experiencing thermal cycling throughout a specified temperature range.

- **Hysteresis**: Ability to maintain RvsT relationship when approaching temperatures from different directions and magnitude.
- **Stem/body conduction**: Error that results from the RTD sheath/body conducting heat into or out of the process. Proper mechanical installation is critical to minimize stem or body conduction errors.
- **Calibration/interpolation**: Errors that occur due to calibration uncertainty at the calibration points or between calibration points due to propagation of uncertainty or curve fit errors.
- **Lead wire**: Discussed previously.
- **Self-heating**: Since the RTD is a resistive device, it acts as a small heater. Self-heating errors can be higher on a 1000 ohm RTD. Proper electronics with lower measuring currents must be used on 1000 RTDs.
- **Time response**: Errors are produced only during temperature transients, because the RTD cannot respond to change fast enough.

Figure 4. Surface-mount temperature sensors are required in certain circumstances when in-line temperature sensors are not an option.

When uncertainties are not maintained, costs can quickly creep up. See below for the costs with simply 1.0°F of uncertainty at room temperature using water flowing at 100 gallons per minute. Assuming the system runs 24/7 for 365 days a year, then the total BTUs wasted would be 437,824,800 and would result in a cost of $15,393 at an energy consumption rate of 12¢/kWh.

$$\dot{Q} = \dot{m} C_p \Delta T$$

$$\dot{Q} = rate\ of\ heat\ transfer\ \left(\frac{BTU}{min}\right) = ?$$

$$\dot{m} = mass\ flow\ rate\ (lbm/min) = 833$$

$$C_p = specific\ heat\ of\ fluid\ \left(\frac{\frac{BTU}{lb}}{°\mathrm{F}}\right) = 1.00$$

$$\Delta T = temperature\ difference\ (°\mathrm{F}) = 1.0$$

$$\dot{Q} = 833 * 1.00 * 1.0 = 833 \frac{BTU}{min}$$

$$Q = \dot{Q} t$$

$$833 \frac{BTU}{min} * 525600 \frac{min}{yr}$$

$$= 437{,}824{,}800\ BTU$$

$$= 128{,}282 kWhr$$

## Suitable temperature sensors

RTDs are the most suitable temperature sensors to use for BTU metering because of their excellent stability and repeatability over their full calibration curve.

There are some RTD errors that can be resolved by incorporating advanced sensor technologies, such as a microprocessor-based transmitter for an RTD. These transmitter technologies are capable of reducing RTD uncertainties, such as interchangeability, lead wire errors, self-heating, and thermal EMF. During their calibration procedure, they can be electronically replicated, creating a matched pair. When two temperature sensors with integrated transmitters are calibrated together, they essentially make an exactly matched calibration curve with each other.

Advanced circuitry, like the one found in Intempco's MIST series, utilizes a three-wire configuration with matched current sources to deliver a constant current excitation to the RTD. The matched current sources are also used to generate the reference voltage that is used for the digital conversion of the RTD signal. That type of architecture improves the accuracy because of a radiometric reference voltage and also eliminates the error due to the RTD wires, making it the best solution for high-accuracy application like BTU measurement.

Other features, such as a digital display, reprogrammability, and rescalability, can be extremely advantageous for the system. Digital displays allow technicians and inspectors to visually determine the temperatures at a point in the system. This is helpful when troubleshooting. Having the ability to reprogram the temperature sensor can also eliminate the need for a complete replacement if a system parameter has changed. For example, suppose the output was originally

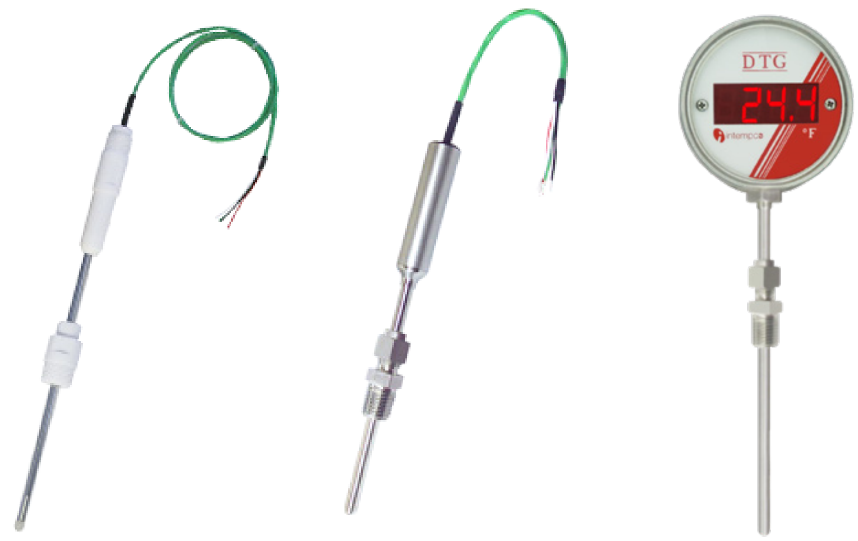



Figure 5. Microprocessor-based transmitter technology is enabling higher accuracy readings for RTDs. Intempco's MIST probes are on the left, and Intempco's DTG series is on the right.

0–5 Vdc, but after upgrading your BTU meter, now it only accepts 0–10 Vdc, then the ability to change output voltages without losing any accuracy is integrated into the sensor. The same principles apply to the temperature range. If at any time the temperature range changes in the system, then the scale can be adjusted in the sensor without the loss of accuracy.

## Crucial aspect

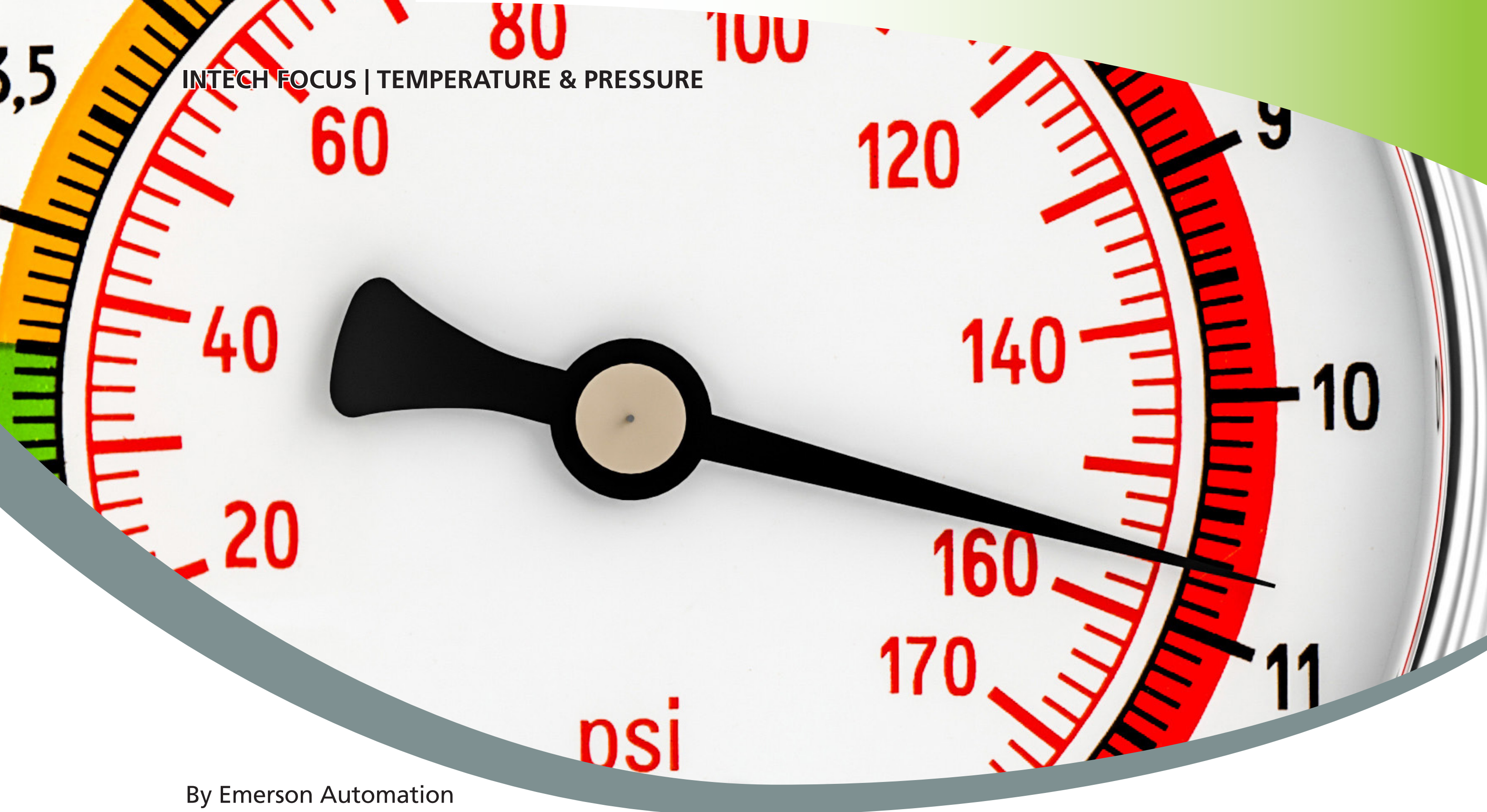
Thus, increasing the accuracy of the temperature measurement is a crucial aspect of proper BTU metering. When temperature sensors are matched, they will perform much better than individual temperature sensors. It is important to reduce the errors by choosing high-quality RTDs that can be adjusted by having an integrated transmitter built into it or by the BTU meter itself. These upgrades could save tremendous costs over long periods of time.


### ABOUT THE AUTHORS

**Denis Richard** has been the senior electrical engineer with Intempco for more than 20 years. He works closely with clients to design custom PCB boards for instrumentation designs. He is responsible for managing all electronic assembly and design for all product lines. Richard also leads R&D projects and the development of new products.



**Jesse Cameron** has a degree in sustainable design engineering and has been a product engineer at Intempco for the past three years. He assists with product documentation and marketing materials. Cameron also has experience developing products involving vast amounts of thermodynamic principles.




By Emerson Automation Solutions

# Troubleshooting Pressure Gauges and Impulse Lines

Remove operational obstacles from legacy pressure instruments.

Automation professionals are confronted every day with obstacles caused by outdated instrumentation technologies and practices. When first installed, these solutions were likely state-of-the-art and improved existing installations, but many have now been superseded by even better solutions and may be creating problems ranging from operational annoyances to outright hazards. The causes and effects of the problems are different, but all can be mitigated or eliminated entirely by using advanced instrumentation, with each instrument consisting of a sensor in contact with the process, connected to an electronic transmitter.

When it comes to measuring pressure, problems can crop up with mechanical pressure gauges, electronic pressure transmitters, and the connections that carry the pressure to the instruments.

## Impulse lines and process connection issues

Taking a differential pressure (DP), gauge, or absolute pressure reading from a process involves creating process connections so the pressure can reach the sensor. (We will discuss mechanical gauges later. Here we will concentrate on electronic pressure transmitters.) Frequently this is done via impulse lines that carry the pressure to the transmitter (figure 1). In some cases, these can be short and very direct, or they may need to be long so the transmitter can be mounted some distance from the process equipment.

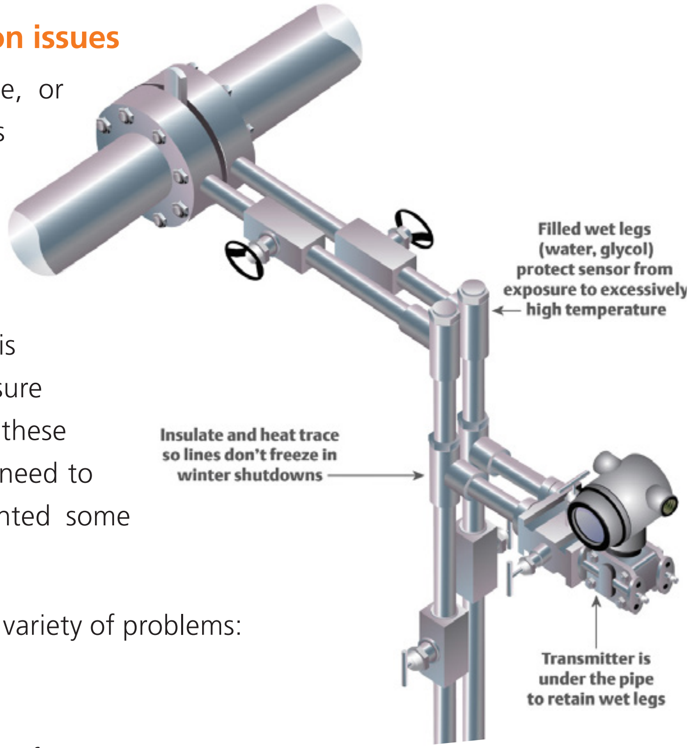



Figure 1. Impulse lines may be simple or complex, but they share a similar set of problems.

Conventional impulse lines can create a variety of problems:

- They are part of the process containment.
- If they leak, product is lost, with potential safety, economic, and environmental implications.
- If process equipment calls for exotic materials, the impulse lines need it too.
- They can fill with gas or liquid that compromise their ability to transmit pressure accurately.
- They can freeze in cold weather.

Impulse lines are typically custom efforts and often built in the plant's maintenance shop, reflecting the skill of local contractors or pipe fitters. A better choice is to use a preassembled instrument, such as the kind available with a DP flow meter like Emerson's Rosemount™ 3051SFP Integral Orifice Flow Meter (figure 2), a complete unit built in a factory and fully tested. All fasteners are tightened to the optimal torque level, and the finished assembly can be leak tested. These meters are ready to install right out of the box and even include a calibration report.

Figure 2. A fully assembled flow meter avoids the problems associated with custom impulse line setups.

## Avoiding impulse line problems

Whatever the situation, impulse lines must not impede pressure delivery, so the transmitter can read the sensor value indicating the actual process condition. As an extreme example, if there is an isolation valve on the impulse line and the valve is closed, nothing can reach the transmitter, and its reading will not reflect the process conditions. Such a situation is not always easy to detect because some pressurized fluid may be trapped in the line and reflected by the transmitter. Similarly, inaccurate readings can result when the line is partially plugged, frozen, or there is some other internal obstruction.

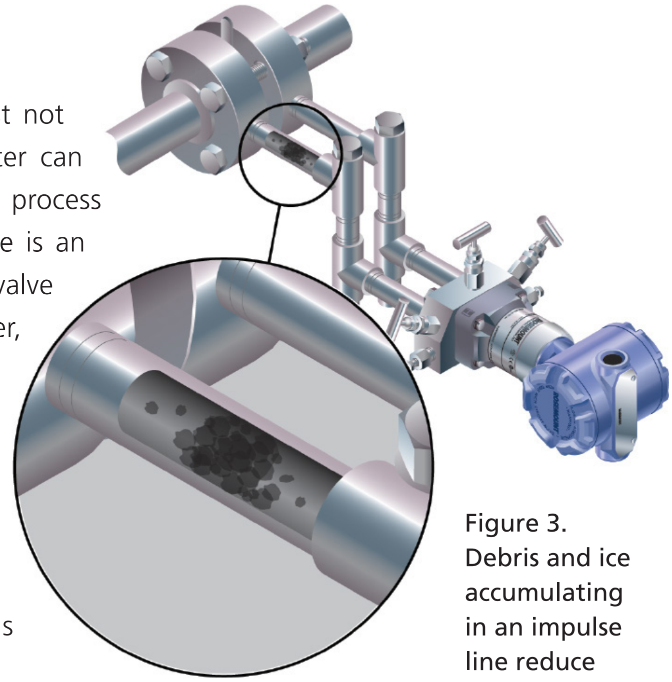


Figure 3. Debris and ice accumulating in an impulse line reduce the amount of process data reaching the transmitter from the sensor.

Today's advanced transmitters are able to perform a plugged impulse line diagnostic (figure 3) and detect such situations because they listen to the process noise through the connection. If the noise level decreases or changes character and there is no attributable cause, there is likely an obstruction forming in the lines. Once the change crosses a designated threshold, the transmitter can warn operators and maintenance engineers.

Process intelligence capabilities can also be built into pressure transmitters, allowing them to listen to process noise continuously (figure 4). Once a baseline of normal noise is retained in the

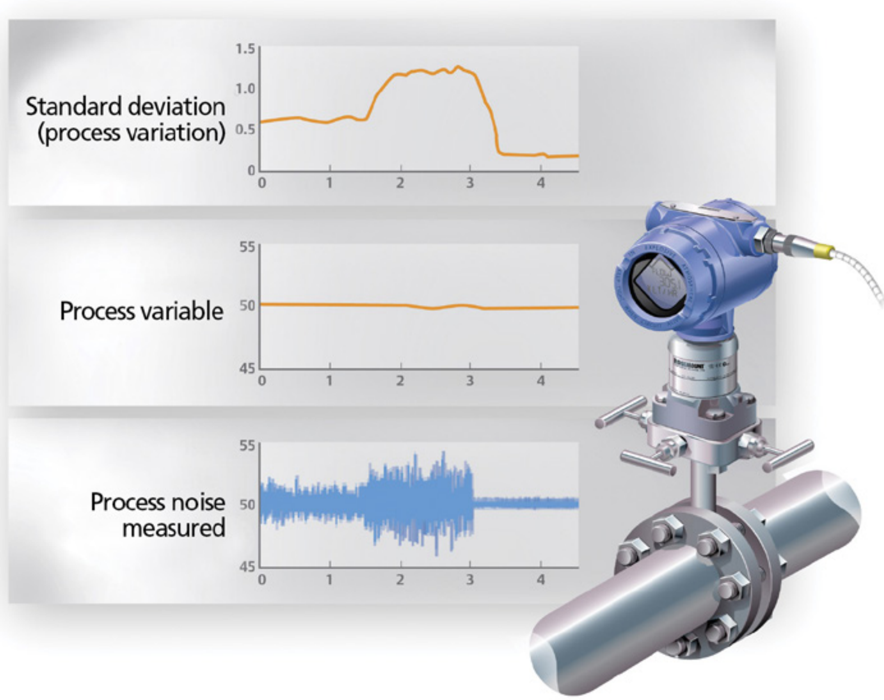



Figure 4. Process noise can be quantified and analyzed by the transmitter. It can alert operators to changes that may indicate developing problems.

transmitter's memory, it can perform statistical analysis on what it hears, listening for patterns deviating from normal. Reasons for such changes can include:

- pump cavitation
- distillation column flooding
- regulator and valve setting changes
- furnace flame instability.

Characterizing and analyzing such noise provides a tool to help operators or engineers identify a likely source. Operators and maintenance engineers can be informed early, so they can correct the situation immediately if necessary or monitor it until a scheduled shutdown.

Process alerts can also indicate upsets and other conditions capable of creating spikes or dips in normal readings. Such alerts can be logged in individual transmitters and accessed during troubleshooting. A status log can look back at the last 10 events, with time stamps to capture extreme readings for later analysis.

## Mechanical pressure gauge challenges

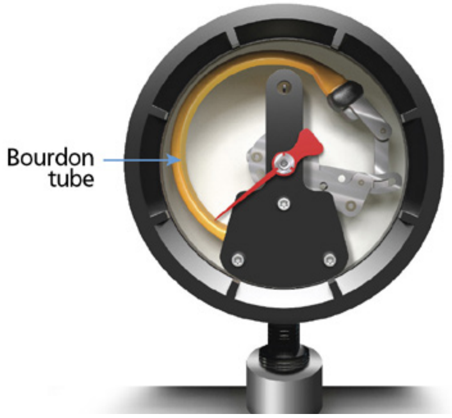



**Figure 5. Mechanical gauges remain popular due to their low cost but still have many drawbacks.**

Long before there were pressure transmitters, there were mechanical pressure gauges. The concept of a curved Bourdon tube dates back to the mid-19th century, and there are devices available today little removed from that time. Gauges operate using a delicate mechanism with springs and gears, making them vulnerable to shock and damage (figure 5). Most operators have seen typical failures, including broken glass, bent indicator needles, or needles pointing straight down from broken gearing. In many environments, pressure transmitters are considered disposable due to their low cost and frequent failures.

So, what is the use case for gauges? They are installed where a reading may be useful for occasional checking, troubleshooting, or maintenance. Any critical output likely already has an instrument installed and connected to the host system. Gauges also serve a critical safety function by verifying the local process pressure when servicing equipment. A gauge must be read by an operator, and given the few manual rounds performed these days, it may not be checked regularly. Functionally, it has to provide a visual, local indication of the pressure. If it could also send the reading to a central location, such as the host system or maintenance shop, it could probably be useful there also.

## A modern alternative

Electronic gauges, including Emerson's Rosemount Wireless Pressure Gauge and Smart Pressure Gauge (figure 6), combine the benefits of an electronic transmitter with the usefulness of a traditional mechanical design. These gauges use a solid-state sensor rather than a Bourdon tube, and process the signal electronically rather than mechanically. The needle is driven by a tiny motor, so there is only one moving part, making the mechanism far more resistant to shocks, vibration, and other extreme operating conditions.


Figure 6. The Rosemount Wireless Pressure Gauge and Smart Pressure Gauge are identical except for the wireless capability.

Eliminating the Bourdon tube removes a critical failure point. An electronic gauge has multiple barriers of process isolation versus a single process isolation with a Bourdon tube. The overpressure tolerance of this electronic solution is also much higher. The added layers of isolation and overpressure capabilities mean there is far less potential for process fluid escape with an electronic gauge.

Using sophisticated electronics, these new gauges are also able to monitor their own status. There is no way to verify a mechanical gauge is working properly short of removing it from the process and testing, but a glance at an electronic gauge can show its operational status via an LED indicator.

For some applications, the most critical drawback of a traditional gauge is its inability to send information to an automation system. This issue is addressed by the Rosemount Wireless Pressure Gauge because it includes the *Wireless*HART® communication protocol, which can send the pressure reading and status indications to the host system. This is an optional function and can be used whenever necessary. This communication capability can be deployed in a sophisticated networking environment as the Industrial Internet of Things moves into more manufacturing applications. Even if the wireless capability is not needed today, it may be soon, and the Rosemount Wireless Pressure Gauge future proofs any installation.

### For More Information

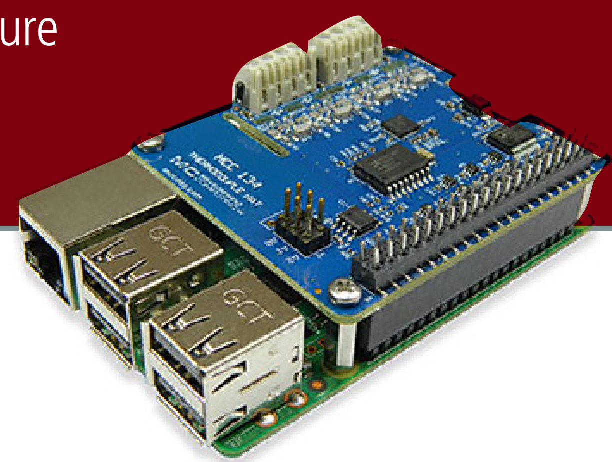
This article is adapted from Emerson Automation Solutions' August 2020 whitepaper, "Solve 6 Leading Pressure and Temperature Measurement Issues Using Advanced Instrumentation."


For additional information on Emerson's pressure measurement products, visit Emerson.com/PressureMeasurement.

# Thermocouples and Raspberry Pi for IIoT Machine Monitoring

## DAQ devices can accurately measure thermocouples in a Raspberry Pi environment. Here's how.

By Steve Radecky, Measurement Computing Corp.




Leading-edge Internet of Things (IoT) technology and advanced analytics are increasingly being used for process optimization and improved efficiency of industrial machinery because they enable predictive maintenance. The data being analyzed for this form of asset management often includes temperature measurements. And the compute power to perform those analyses is increasingly being provided by IoT devices based on Raspberry Pi.

Raspberry Pi is a series of small single-board computers developed in the U.K. by the Raspberry Pi Foundation in association with Broadcom. The Raspberry Pi project originally focused on teaching basic computer science in schools and in developing countries, but the growing base of Raspberry Pi means the computer boards are increasingly finding their way into industrial automation applications—particularly as IIoT devices. The use of open-source C/C++ and Python lets users develop applications on Linux.

Although thermocouples are a popular way to measure temperature, designing and building data acquisition (DAQ) devices that accurately measure thermocouples in a Raspberry Pi environment is challenging. This article explains the difficulties in making accurate thermocouple measurements, how the MCC 134 DAQ HAT accomplishes it, and how MCC 134 is being used in IIoT devices for machine health monitoring.

## How thermocouples work

A thermocouple is a sensor used to measure temperature. It works by converting thermal gradients into electrical potential difference—a phenomenon known as the Seebeck effect. A thermocouple is made of two wires with dissimilar metals joined together at one end, creating a junction. Because two dissimilar metal wires create different electric potentials over a temperature gradient, a voltage that can be measured is induced in the circuit.

Different thermocouple types have different combinations of metal in the wires and are used to measure different temperature ranges. For example, J type thermocouples are made with iron and constantan (copper-nickel alloy) and are suited for measurements in the –210°C to 1200°C range, while T type thermocouples are made with copper and constantan and are suited for measurements in the –270°C to 400°C range.

The thermal gradient mentioned above is referred to as the temperature difference between the two junctions: the measurement, or hot junction, at the point of interest and the reference, or cold junction, at the measurement device connector block (figure 1). Note that the hot junction refers to the measurement junction and not its temperature; this junction might be hotter or colder than the reference or cold junction temperature.

Thermocouples produce a voltage relative to the temperature gradient—the difference between the hot and cold junction. The only way to determine the absolute temperature of the hot junction is to know the absolute temperature of the cold junction.

While older systems relied on ice baths to implement a known cold junction reference, modern thermocouple measurement devices use a sensor or multiple sensors to measure the terminal block (cold junction) where thermocouples connect to the measurement device.

## Sources of thermocouple errors

Thermocouple measurement error comes from many sources, including noise, linearity, and offset error; the thermocouple itself; and measurement of the reference or cold junction temperature. In modern 24-bit measurement devices, high-accuracy ADCs are used, and design practices are implemented to minimize noise, linearity, and offset errors.

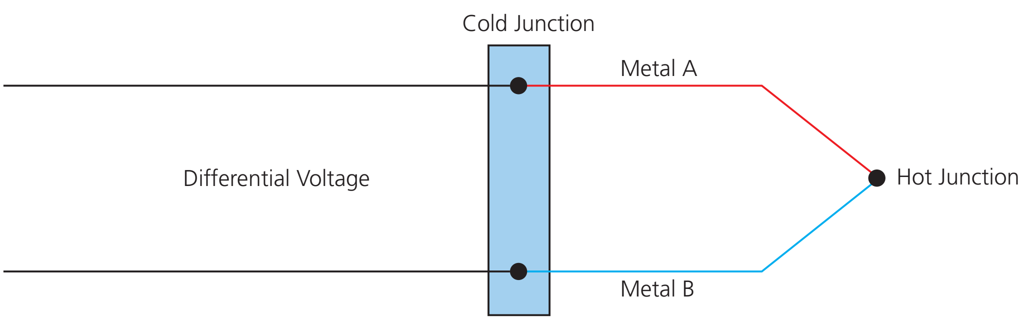



Figure 1. MCC hot junction graphic

Thermocouple error cannot be avoided, but it can be minimized. This error is due to the imperfections in alloys used, because they vary slightly from batch to batch. Certain thermocouples inherently have less error. Standard type K and J thermocouples have up to ±2.2°C error, while type T thermocouples have up to a ±1°C error. More expensive thermocouples (special limits of error [SLE]) are made with higher-grade wire and can be used to reduce errors by a factor of two.

Accurately measuring the cold junction, where the thermocouples connect to the device, can be a challenge. In more expensive instruments like the DT MEASURpoint products, an isothermal metal plate is employed to keep the cold junction consistent and easy to measure with good accuracy.

In lower-cost devices, isothermal metal blocks are cost prohibitive, and without an isothermal block it is not possible to measure the temperature at the exact point of contact between the thermocouple and the copper connector. This fact makes the cold junction temperature measurement vulnerable to temporary error driven by quickly changing temperatures or power conditions near the cold junction.

## Design challenges

To better understand the design challenges of the MCC 134, we can compare it to the design of MCC's popular E-TC—a high-accuracy, Ethernet-connected thermocouple measurement device. The cold junction temperature of the E-TC is measured by Analog Devices' ADT7310 IC temperature sensor.

The IC sensor design works well in the MCC E-TC because the measurement environment is controlled and consistent. The outer plastic case controls the airflow, and the electronic components and processors operate at a constant load. In the controlled environment of the E-TC, the IC sensor does an excellent job of measuring the cold junction temperature accurately.

However, when the MCC 134 was first designed with an IC sensor to measure the cold junction temperature, the accuracy was insufficient. Because the IC sensor could not be placed close enough to the connector block, large and uncontrolled temperature gradients caused by the Raspberry Pi and the external environment led to poor measurement repeatability.

So the MCC 134 was redesigned with an improved scheme that has far better accuracy and repeatability while keeping the cost low. Instead of using an IC sensor and one terminal block, MCC redesigned the board with two terminal blocks and three thermistors—one placed on either side and in between the terminal blocks, as shown in figure 2.

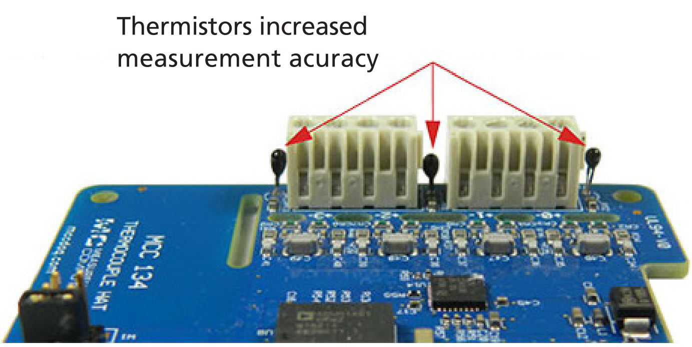



Figure 2. Thermistors

Although this added complexity to the design, the thermistors more accurately tracked the temperature changes of the cold junction, even during changes in processor load and environmental temperature. This design yields excellent results that are far less susceptible to the uncontrolled Raspberry Pi environment.

The MCC 134 should achieve results within the maximum thermocouple accuracy specifications when operating within the documented environmental conditions. Because certain factors still affect accuracy, users can improve measurement results by reducing quick changes in temperature gradients across the MCC 134 and following other best practices.

## MCC 134 in Action: Thinaer Health Usage Monitoring System

The Thinaer Health Usage Monitoring System (HUMS) collects data from machining centers, CNC machinery, milling machines, and engines and uses this data to provide an "always-on" solution for monitoring, utilization reports, and predictive maintenance. Thinaer's IoT platform integrates machine data with human feedback and uses a mix of MCC and Thinaer hardware and software to capture real-time machine data like temperature, location, vibration, voltage, pressure, and electrical current.

The MCC DAQ HATs fit easily within the existing system enclosure.

Thinaer systems use Raspberry Pi nodes that communicate with smart sensors via Bluetooth Low Energy. These smart sensors, however, do not have the high-accuracy temperature or high-speed vibration data needed for better analysis.

The solution for Thinaer was to use the MCC 134 thermocouple measurement HAT (see box) to measure temperature (as well as the MCC 172 IEPE measurement HAT to measure vibration) and to collect the data needed to create accurate measurements, analyses, and strategy.

The stackable DAQ HATs also allow Thinaer to scale without having to change its platform or do any internal hardware development or assembly. The system was programmed using provided C and Python libraries for continuous, multi-HAT acquisition of data.

The Thinaer solution collects data from systems like CNC machines and helps users reduce machine failures by quickly detecting operational anomalies.

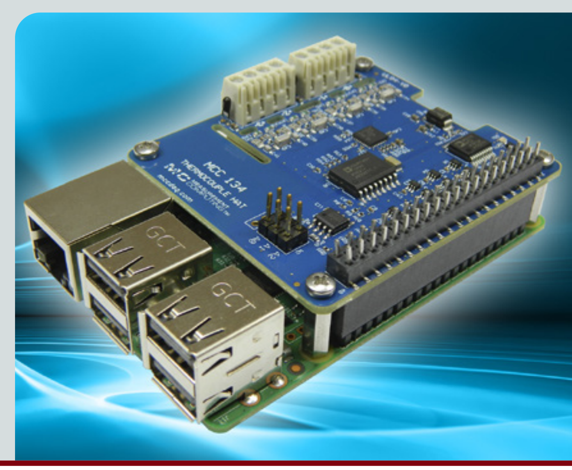
Using MCC technology saved Thinaer both time and labor. The MCC DAQ HATs easily fit into the existing system enclosure and the off-the-shelf design saved Thinaer from having to develop a custom, in-house solution.

## Accurately measuring

Thermocouples provide a low-cost and flexible way to measure temperature, but measuring thermocouples accurately is difficult. Through innovative design and extensive testing, MCC overcame the challenge of measuring thermocouples accurately in the uncontrolled Raspberry Pi environment. The MCC 134 DAQ HAT provides the ability to use standard thermocouples with the fast growing, low-cost computing platform.

### Raspberry Pi Thermocouple Measurement HAT

The MCC 134 thermocouple measurement HAT for Raspberry Pi brings high-quality, temperature measurement capability to the popular low-cost computer. The device has four thermocouple (TC) inputs capable of measuring the most popular TC types, including J, K, R, S, T, N, E, and B. Each channel type is selectable on a per-channel basis. The MCC 134 has 24-bit resolution and professional-grade accuracy. Open thermocouple detection lets users monitor for broken or disconnected thermocouples.




Up to eight MCC HATs can be stacked onto one Raspberry Pi. With the already available MCC 118, eight channel voltage measurement HAT, and the MCC 152 voltage output and digital I/O HAT, users can configure multifunction, Pi-based solutions with analog input, output, and digital I/O.

### ABOUT THE AUTHOR

**Steve Radecky** is Marketing Engineer for Measurement Computing. Measurement Computing (www.mccdaq.com) designs and manufactures data acquisition devices that are easy to use, easy to integrate, and easy to support. Included software options are extensive and provided for both programmers and nonprogrammers. Please contact Measurement Computing Corporation if you have any questions or if you would like any further information: (508) 946-5100 or info@mccdaq.com.