

Cut the Cost and Raise the Reliability of Your Instrumentation

Review your maintenance, engineering, purchasing, and construction practices. Often, big improvements are possible.

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In today's highly competitive global economy, most companies in the chemical process industries (CPI) are striving to reduce manufacturing costs and increase production from existing assets. This article discusses how better approaches for plant instrumentation can help you to achieve and sustain these goals.

Results at several companies prove that the following savings can be realized:

- instrument maintenance costs reduced by greater than 50%;
- production losses due to instrumentation cut by over 45%/y;
- instrument engineering time decreased by more than 75%;
- instrument prices pared by 20–35%; and
- instrument construction cost and time lowered by at least 30%.

Reducing maintenance costs

It is well-known throughout the CPI that approximately 90% of instrument maintenance usually comes from three primary direct or indirect causes. Sub-optimal installation practices typically account for about 60% of your instrument maintenance technicians' work orders. Around 20% stem from the selection of a sub-optimal technology to do the required measurement, while approximately 10% are due to a poor choice of materials of construction.

Examples of problems due to poor installation practices. Most of the time, an instrument maintenance technician's trip to the field does not result in the change-out of a failed instrument. Normally, about 60% of the time, the technician will find no problem with the actual instrument that is reading incorrectly. Instead, the technician fixes the problem by draining or refilling the tubing lines leading to the instrument, removing corrosion on terminals in wet junction boxes, unplugging blocked sensor lines, turning the heat tracing on or off, rezeroing the device, etc.

All of these situations can be avoided with pressure and differential pressure (DP) transmitters simply by close-coupling them to the block valve(s) at the process tap. By eliminating the tubing runs, you eliminate the error induced by condensate head forming in the lines to the transmitter, while saving on heat tracing, tubing supports, and transmitter stands. On DP flow transmitters, you not only should close-couple the transmitter, but should make sure that it is not mounted above or below the process tap. A DP flow transmitter and the orifice taps *must* be installed in the horizontal plane. Condensate formed in tubing lines to DP flow meters mounted across an orifice plate won't always drain back into the line even though the transmitter is above the tap, due to the small, 1/4-in. diameter opening of the orifice taps and the surface tension of the liquid.

Measurement and Control

The argument that mounting the transmitter at the tap creates an unacceptable maintenance or safety situation is often heard. Scaffolding would have to be built to get to the instrument, it is against company safety rules to work in the pipe rack, etc. In reality, a walk through of most plants usually shows that 70+% of the orifice plates are located within 6 ft of the ground. Plus, the smart transmitters now available fail much less frequently than the block valves located at the process taps. So, while the argument may have been valid in the days of pneumatic transmitters, it does not apply in today's world.

Likewise, the common practice of mounting DP flow transmitters at some distance from the orifice taps (Figure 1) needs to be completely eliminated and replaced with close-coupling (Figure 2).

Another typical maintenance problem with vortex and coriolis flow meters comes from line vibration. For best results, these meters need to be installed so that vibration is minimized.

And, even though everyone knows better, junction boxes still are being installed with top mounted entries and no drain holes; wiring is run to instrumentation without a drip loop, so that rain or wash water tracks directly to the entry point of the device; and smart instruments are being mounted in insulated boxes despite ambient temperature specifications of -40 to 130°C .

Examples of problems caused by poor selection of measurement technology. Most boiler feed drums use DP transmitters to measure level. It must be remembered that such devices do not monitor level directly, but actually measure pressure in the form of weight. During startup, when the water in the drum begins to heat up, its density changes drastically — therefore swinging the level measurement, which swings the water flow, etc. So, instead of DP transmitters, use magneto-strictive or radar technology in situations where density can vary.

Many level measurements are made using a DP transmitter with a piece of



■ Figure 1. This installation causes errors and increased maintenance.

tubing run to the top of the vessel. For this reading to be accurate, all condensate must be drained from this top tubing, and this is a maintenance problem. Using a fill fluid in the tubing is not necessarily the answer — unless you are sure that the density of the fill fluid matches that of the liquid in the vessel and does not change with ambient temperature, and that the fluid will not get contaminated with process vapor condensate. Radar or magneto-strictive technology solves the problem with much less maintenance.

Bubbler level measurements require that gas always flows through the standpipe that goes into the vessel. Even if this can be ensured, which it can't, there often is a plugging problem at the end of the bubbler pipe due to drying of the process liquid by the air or nitrogen flow. Again, radar or magneto-strictive technology is a better choice.

Remote seals and filled capillaries sometimes are used in level measurements for corrosive or plugging liquids. These systems always give level reading variations when the temperature of the fill fluid in the capillaries changes. The problem is so well known that this system often is referred to as a "cloud tracker!" If radar will not work in these applications, great care has to be taken to insulate the capillaries from ambient and process-induced temperature excursions, and to eliminate the error caused by the differences in the densities of the process liquids and the capillary fill fluids. When a capillary is used in plugging applications, a flush ring should be mounted between the capillary and the block valve; that way, plugging can be elimi-



■ Figure 2. Recommended mounting for a DP sensor.

nated without disassembling the system. When used in vacuum systems, the transmitter must be mounted at or below the vessel's bottom tap, and the capillary/remote-seal connection must be welded. These systems can be very accurate and reliable, but they often require a level of sophistication and experience not commonly found in the average instrument technician or instrument engineer.

A common temperature-measurement error with resistance temperature detectors (RTDs) occurs when using 2- or 3-wire units. Any change in resistance caused by corrosion of the lead wires or at the terminals gives a temperature error. The solution is always to use 4-wire RTDs, because they function as a wheatstone bridge and eliminate changes in resistance of the lead wiring.

Examples of problems due to wrong materials of construction. All transmitter failures due to corrosion or hydrogen permeation of diaphragms or sensing elements fall into this category. They occur relatively infrequently, say, once or twice a year, so the reason for the failure usually isn't probed. Instead, it is common practice to replace the failed transmitter with another of the same material, guaranteeing another failure in the same time frame. Whenever a transmitter fails, it needs to be analyzed by the supplier and the reason for failure documented and rectified. Solving this problem often requires help from a metallurgist.

Procedure to use in existing facilities. The above discussions apply clearly and obviously to new installations. What should be done with all of the existing instruments that are presently installed wrong or that use the wrong technology? The answer is simple — only upgrade the ones that

result in adding value greater than the cost of upgrading. As a rule of thumb, if a maintenance technician is making more than three repair calls on an instrument per year, consider changing the installation or the technology. If a corrosion problem has to be addressed more than once a year, change the materials of construction. If the process control system needs a higher degree of accuracy or repeatability for effective control, change the installation or the technology. Typically, around 20% of your existing instruments will fall into one of these three categories. Under no circumstances, assuming the plant is presently capable of producing product, is it worth a wholesale change-out of most of the existing equipment.

Reducing engineering costs

Minimize and justify the instrumentation. Traditionally, 10–15% of the total cost of new capital projects goes for instrumentation. In actuality, this results in somewhere between 25% and 40% excessive or low-value-added instrumentation. It has been proven on numerous occasions that requiring the project team to justify the value of every instrument on the basic process and instrumentation diagrams (P&IDs) will significantly reduce the amount of instrumentation purchased and installed. If the right technology has been selected, with the right materials of construction, and the device is installed correctly, the need for almost all redundant instrumentation is eliminated. In research-type situations, where the best location for instruments can be uncertain, add taps and block valves. Instruments can be moved later on, based on operational and research experience. This type of mindset on new projects, coupled with an effective review process, can reduce capital cost to the 2.5–4% range, while still ensuring that business, safety, and environmental objectives are met. Remember, every instrument bubble on the P&ID costs you an average of \$4,000 for the equipment and installation!

In an existing plant, a careful review

of which instruments are really important and which alarms are truly needed usually results in disconnecting about 35% of the devices. In fact, in plants that have been in operation for several years and have a distributed control system (DCS), we've found that, on average, almost a quarter of the instruments brought to the DCS are never used in the control or alarm code!

Disconnecting unnecessary instruments saves maintenance and often simplifies the operator's life, especially during startups and shutdowns.

Develop and use standards for typical instrumentation. Your plant should have standard documents or software that define very clearly for contractors and maintenance technicians the application, which technology to use, the materials of construction, acceptable suppliers, and proper installation. These data need to exist for all of the measurements you normally deal with and, for best results, should be standardized across your entire company. Table 1 provides an example.

Remote seals. Your company should standardize on one size of remote seal (≈ 3 in. dia. diaphragm) for all applications. It may be necessary to have these seals made from different materials of construction (stainless, Monel, Hastelloy, etc.), but the size should be the same. Connecting these seals to different-sized process taps is accomplished by installing flush rings that fit various flange or block-valve sizes and bolt patterns on the flush ring's backside and the standard remote seal on the front side. Besides reducing engineering time and cost, there are two main reasons to do this: to drastically decrease the number of spare remote seals you have to keep in inventory, and to greatly enhance accuracy thanks

to the larger seal diaphragm. Flush rings to do these transitions are commercially available in a variety of materials. Figure 3 illustrates a typical flush ring.

Analytical instrumentation. Most CPI firms understand that to avoid variations in temperature that lead to errors and false readings and, frequently, cause malfunctions, on-line process analyzers must be protected from the weather and kept at a stable environmental temperature. For example, a process gas chromatograph that typically would warrant replacement in 12–15 years simply because of advances in technology instead will last only 3–4 years, on average, if in a poorly sheltered installation. Additional maintenance and the resulting downtimes during these 3–4 years will increase total cost to as much as ten times that expected for the entire 12–15-year life of a properly sheltered unit.

Thus, equipment generally is located inside an enclosure, or analyzer house, designed to control environmental conditions. The application engineering of the shelters and sample systems, along with the installation of on-line process analyzers, traditionally has been customized. Therefore, each installation required complete re-engineering. This practice is extremely costly and is not justified.

There are only two parts of an analyzer installation that are application sensitive. One is the sensor technology that is located within the analyzer itself. The instrument manufacturer always provides this. The other is the sample-conditioning equipment, which prepares the sample for delivery to the analyzer's sample system, and this is located outside the shelter. Standard-

Table 1. Example of standardization.

Application	Technology	Material	Supplier	Installation drawings and procedures
Boiler drum level 30–1,250 psig	Magneto-strictive	316 SS	XYZ Co.	ID3406-2

ization of the sample-conditioning equipment (valves, filters, regulators, etc.), along with standard designs for the spacing of sample-system components, can enable nearly all of the interconnecting tubing, fittings, and other components to be prefabricated. A great deal of this is not only possible but also practical. It can minimize fabrication and assembly, and also make the quality of each analyzer package more predictable and consistent. And adoption of this design philosophy also leads to somewhat simplified maintenance of the devices.

This same design approach for the mounting of sample-system equipment also can be used for mounting the analyzers inside the shelter. The house walls themselves, along with the brackets and other components, can be standardized, so that the installation of any analyzer of any type, model, or manufacturer would be exactly the same. More often than not, a variety of analyzer types are installed in a house. The amount of wall space required to mount every type of analyzer required should be predetermined and used to quickly select the most-efficient house size and layout. Air conditioning and heating equipment also should be selected and standardized according to the house size, the area electrical classification, the environmental conditions, and the number and type of analyzers to be installed. Lighting fixtures, electrical switches, and power drops for the house should be similarly standardized. Entrance ways should be standardized with a shatterproof safety window and an internal horizontal safety bar for opening the door.

Utility-gas supplies, instrument-air headers, as well as vents and drains installed inside the house all should be standardized, leaving the materials of construction (stainless steel, Monel, copper, Teflon, etc.) as the only options to be selected.

Adopting a standardized analyzer house (see Figure 4) and sample-system package typically leads to savings in equipment and labor of about \$15,000 per analyzer vs. customized

engineering.

In addition, the availability of analyzers properly installed usually exceeds 99.8% on closed-loop control, and more than 50 can be maintained per technician. These results actually have been attained at several large petrochemical sites, and certainly far surpass the industry average.

Other opportunities. Consider other possibilities for standardizing, including:

- pressure gauges (three types for all applications — standard gauge for nonhazardous, nonpulsating services; standard gauge with an internal seal for hazardous, nonpulsating services; and silicon-filled standard gauge with internal seal for high pulsation services);
- diverter valves and actuator packages;
- wire, cable, and conduit;
- junction boxes as well as terminal connectors;
- company-wide computerized maintenance management system (CMMS) failure codes for maintenance-history tracking; and
- process-control strategy and instrumentation templates for common equipment (cooling towers, distillation columns, reactors, etc.).

Do not expect your engineering/procurement/construction contractors to have these data. After all, they often were the ones who chose the wrong technology and specified the wrong installation practices that exist today in your facilities.

Reducing purchase prices

Develop and use supplier agreements. The common practice of allowing every plant to buy from whomever it chooses is costing you a significant amount of money. This practice results in variability of performance, more spare parts, increased training, and higher purchase prices. Instead, letting your technical experts define two or more technically acceptable suppliers and then having purchasing negotiate leveraged contracts often can reduce the prices you are paying for commodity-type instruments by 20–35%. Con-



Figure 3. A typical flush ring. Photo courtesy of TBV, Inc.

centrate first on establishing national or global contracts with a minimum number of suppliers of the equipment you spend the most money on. Typically, such equipment includes:

- control valves, block valves, diverter valves;
- pressure and DP transmitters;
- flow devices;
- level devices;
- tubing, fittings, and small valves; and
- analytical devices.

Reducing construction costs

Instrument installation. Purchasing prefabricated instrument-installation kits and having the general mechanical contractor install and mount the instrumentation on them can save substantial time and money on new construction. There are companies that manufacture these pre-assembled installation hookups from designs that have been optimized to generate the best accuracy and lowest maintenance, and at less cost than conventional tubing installation.

Banish bypasses. A common mindset in the CPI is to install bypasses around most control valves. Instead, the default should be to never bypass a control valve. All exceptions should have to be justified based on value, cost, and the probability that the bypass will work when needed and is capable of being safely and correctly controlled by the operator.

Reduce redundant instrumentation. Dual redundant instrumentation usually causes more problems than it solves. The thinking should be to install the right technology in the optimum way and, in most cases, to use a



■ Figure 4. Example of a standardized analyzer house.

single reading for control or alarms. (After all, the mean time before failure (MTBF) of most instruments is far greater than the MTBF of the mechanical equipment.) There, of course, are exceptions to this, but they need to be justified on a case-by-case basis. Simple reliability models of the process can be used to verify these decisions.

Wiring. It is not necessary to use individually shielded twisted pairs as the power or signal source connected to most instruments. A single shield on the multipair cable is adequate. This reduces the number of connections made at the junction boxes and termination panels by one-third without any loss of quality in all 4–20-ma signals.

Achieving and sustaining the results

Reducing instrument costs by 30–50% while increasing asset utilization usually will require you to do things differently. There probably are many people in your company who already know everything that we have discussed — and more. The fact that the technology already exists, yet mistakes still are being made, underscores this point. It takes people to make improvements — technical knowledge by itself does not capture the opportunity gaps that exist within a company. Indeed, technology determination is simple. It is dealing with the people part that is hard.

So, to truly achieve and sustain significant improvements requires changes in leadership messages, people's intentions, and the way work is done, in addition to knowledge of the most appropriate technology.

Leadership. Your management needs to clearly define what they want

instrument costs and reliability to look like in the next 3–5 years. This is most easily accomplished via clear “stretch” goals, such as:

- We will decrease the cost of instrument maintenance by 35% in 5 years.
- We will reduce the instrument-supplier base by 75%, and prices by 25% in 5 years.
- We will establish technical standards for selection, materials of construction, and installation of all major types of instrumentation in 2 years.
- We will cut production losses due to instrument problems (people errors or equipment problems) by 50%/year for the next 5 years.

It then must be made clear who is accountable for accomplishing each of the goals, and these people must be empowered and supported to succeed.

In addition, the leadership must change the culture of some of the people. Everyone must think like a business owner — if something does not add value, don't do it!

People. Are the people in your instrument group focused on achieving the best possible business result in addition to being best in safety and environmental performance? Do they understand what adds or destroys value?

You need to communicate examples of what does and does not add value.

You also must set clearly defined hurdles that must be exceeded before a project is approved.

You need to form multifunctional teams to optimize cooperative efforts across the various disciplines like purchasing, maintenance, engineering, operations, and construction.

It is crucial to create a mindset that people should work together to achieve the highest return for the business. The people need to be empowered and supported to do only value-adding work!

Work processes. Most things done in manufacturing are fairly routine. It is unusual when work that has never been done before becomes necessary. Work processes are simply a list of clearly defined steps that must be performed, with the input and output of each step

spelled out, along with who is accountable and who is a participant. These work processes then are optimized to eliminate wasteful variability and bureaucracy in the way the work is performed.

In instrumentation, there need to be work processes for maintenance, equipment justification and minimization, engineering, managing and transferring instrument technology, improving reliability, construction, purchasing, etc. A key role in many work processes is that of the “gatekeeper.” This person is responsible for approving work that adds value and purging work that does not meet a business-defined hurdle or obvious need in the plant. Although this role is crucial in the instrument business, it usually should be filled by a member of the production staff.

In manufacturing, there are five main work processes and about 20 subprocesses. You can't just concentrate on a few of these to optimize performance, because each affects all the others. This integration or linking of the work processes with each other applies to the subprocesses, as well as the main ones, and they all must address safety and environmental issues. We have found this to be the critical difference in optimizing the sustainable results!

By the way, technology developed at Stanford University's construction management department now exists to model and simulate these work processes for optimized performance based on the skill and experience level of the people in the key roles. **CEP**

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