EXISTING IN A CRYOGENIC WORLD

Dan Cychosz and Douglas Carlson, Emerson Automation Solutions, USA, show that even in extremely low temperatures, differential pressure-based instrumentation can deliver versatility, accuracy and value.

Natural gas continues to gain popularity as a versatile fuel due to its relatively low cost, ease-of-transport and clean burning properties. However, if production sites and consumers are widely separated and cannot be linked with a pipeline, an alternate form of transport is needed. Liquefaction, i.e. cooling the gas until it converts into its liquid phase, allows transport across great distances on ships specifically created for this purpose. LNG has many benefits, but its low temperature can present challenges when it comes to instrumentation, such as material embrittlement or slowed response time. This article will look at two common instrumentation applications, flow and level, and how these challenges can be overcome in LNG applications.

Why DP flow?

Flow measurement and control is critical during the liquefaction process. The technology selected for process flow measurement points should provide the most effective operation balanced with a low lifetime cost of ownership. This considers purchase price, maintenance costs, flow meter life and the cost of any downtime due to a failed measurement. In non-custody transfer applications, differential pressure (DP) flow is often the measurement

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method of choice due to its simplicity, robustness and low lifetime costs. However, due to the challenges posed by the unique properties of LNG, the following best practices should be considered in these applications.

There are a wide variety of flow technologies on the market, but those with moving parts are typically unsuitable for LNG service. Although a liquid, LNG does not provide lubrication to prevent wear on moving parts, leading to increased maintenance requirements and higher lifetime cost. Since DP flow meters contain no moving parts, they are well-suited to LNG service without any need for special construction. Flow meters with moving parts may still be used for LNG service, but they require special construction in order to function reliably in this environment, which tends to lead to a much higher initial cost.

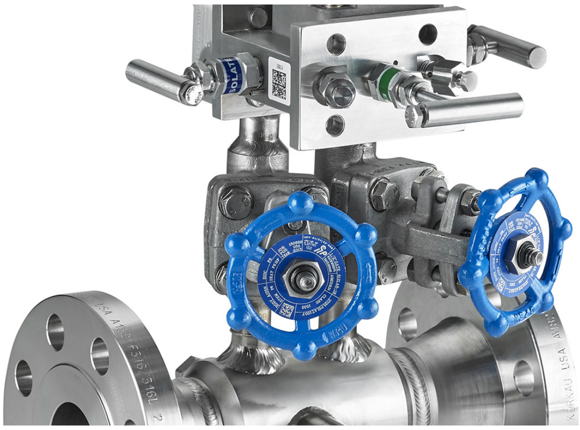

Figure 1. Welded impulse lines make it possible to move the transmitter and its seals away from the coldest temperatures. Locating the transmitter above the primary element also helps protect the internal diaphragms.

Figure 2. A conditioning orifice with multiple holes reduces the need for long straight pipe runs upstream and downstream.

Material selection

The low temperatures of LNG service tend to eliminate carbon steel as a piping material, but most flow meters are available in stainless steel, which can handle cryogenic temperatures. However, a stainless steel main body is not the only consideration. Care needs to be taken to ensure gaskets, o-rings and bolting material are also compatible with these low temperatures since incorrect materials can become brittle at low temperatures and lead to leakage. DP flow meters equipped with welded impulse lines (Figure 1) reduce the potential for sealing material embrittlement by moving gaskets away from the frost line. The frost line marks the distance up the impulse lines that freezing temperatures extend, often seen as frost on the outside of the tubing.

Installation considerations

For DP flow meters in conventional liquid applications, the typical mounting position places the transmitter and impulse lines below the pipe to prevent air and gas entrapment. LNG applications reverse this, positioning the transmitter above the primary element (Figure 1) so there is an insulating gas barrier preventing contact of the cold liquid directly with the transmitter diaphragm. Direct contact of cold liquid with the transmitter diaphragm will not cause the instrument to fail, but it will slow its response to changes in flow. The distance above the line depends on local temperature conditions. Shorter impulse lines can be used when the temperature is expected to stay above freezing, but longer impulse lines must be used in colder climates.

In conjunction with the mounting position, impulse tubing should be small diameter, typically 0.25 in. (6 mm) to help maintain the gas barrier. Insulation of the flow meter's primary element should not cover the impulse piping beyond the pipe flanges. Exposing the impulse lines to the surrounding environment also helps maintain the gas barrier. This may seem counterintuitive to many installers, so special attention must be given to this point during construction.

Appropriate straight pipe run length must be included for most flow metering technologies to ensure expected accuracy. Newer technologies such as multi-bore conditioning orifice designs (Figure 2) allow effective flow measurement with much shorter lengths of required upstream and downstream straight runs needed by single-bore office plates. This allows retrofit of existing and underperforming measurement points, or optimisation for new plants to reduce a flow meter's footprint and associated piping material costs.

A fully-integrated DP flow meter can accommodate all the best practices just discussed. Additionally, this approach reduces the likelihood of installation errors and saves time onsite since no local fabrication is needed. Project cost savings are captured from streamline procurement, reduced installation labour, and reduced or eliminated rework. Other process flow measurements, such as coolant or gas flows, can also be measured reliably with an integrated DP flow meter. These support a standard solution across the plant, thereby eliminating the need for multiple spares and reducing complexity.

Applying DP level

Plant operators have found a variety of ways to measure level within spherical LPG or standard LNG storage tanks, including DP. With an externally mounted diaphragm (Figure 3) in contact with the cold liquid in the tank, it is possible to get an accurate and prompt reading of the resulting static liquid pressure, but there also has to be the pressure reading from the headspace. The challenge encountered most often has been the long tap-to-tap distances between the top and bottom of the tank.

With the low temperatures involved, combined with long distances, condensation often builds up in the lines and freezes. A partial solution is to use a large oil-filled capillary system, but the readings must be compensated for the extra fill-fluid pressure, which can distort the headspace reading. A change in ambient temperature can also affect the fill-fluid density and cause level reading errors.

The most effective way to eliminate these problems is by adding electrical or steam heat tracing. When working properly these systems can stabilise the temperature factors, but they are maintenance intensive and costly to operate. For operators wanting to use DP level, there is a better way to bridge the distance.

The solution is to eliminate the need to measure pressure across such a long distance. The headspace pressure reading is still necessary, but it can be taken by a transmitter at the top of the tank and the reading can then be sent to the lower transmitter electronically (Figure 4). This eliminates distance and ambient temperature conditions as concerns because capillary and wet/dry leg systems are no longer needed.

The remote transmitter on top of the tank sends its reading to the lower transmitter, and the lower transmitter calculates the DP just as it would in a conventional DP application.

This electronic remote sensor technique works well in LNG applications since these tanks are typically below 800 psi (42 bar). Under these conditions, it can outperform legacy systems by delivering accuracy of ±0.20 in. water column (±0.5 mbar) with up to 500 ft (152 m) distance between taps. With an armoured cable between the two transmitters rather than a tube, it is much easier to link them regardless of the equipment around the tanks. When working with oil-filled systems, this becomes far more complex. Response time also improves because there is no reading lag caused by high viscosity in the oil-filled line.

This approach simplifies installation regardless of location. Traditionally, installing a DP level system on a storage tank required mounting the transmitter on a standoff pipe and then installing the flanges. With an electronic remote sensor, the two transmitters can be installed independently, and there is no need to disconnect an oil-filled capillary. If one of the transmitters has to be replaced, the other can be left in place, reducing calibration requirements.

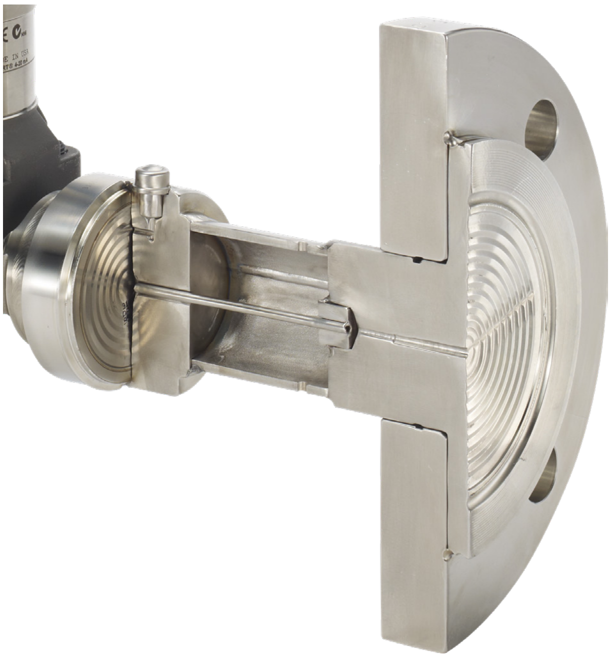

Figure 3. As this cut-away unit shows, the external diaphragm is exposed to the cold liquid but does not allow it to reach the internal diaphragm, so the reading response is not slowed.

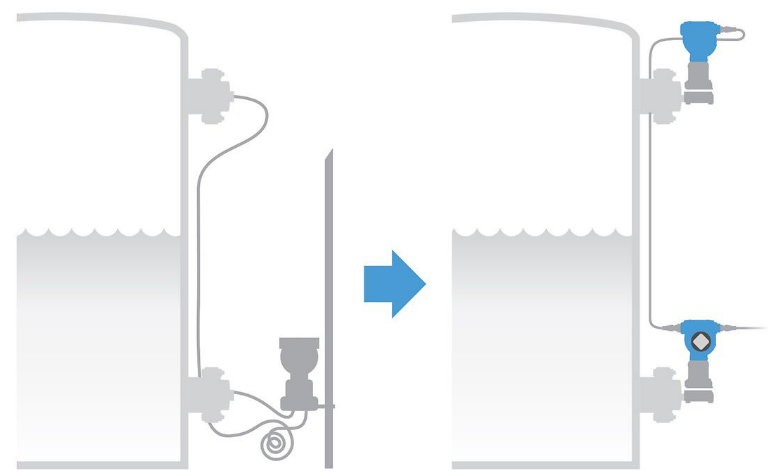

Figure 4. The tank headspace pressure reading can be captured by a second transmitter rather than sending it to the lower DP transmitter via a fluid-filled tube.

Using the electronic approach provides more process information since there are additional effective measuring points. The automation host system can extract the basic level reading, but also the ullage/vapour pressure and tank pressure. Traditional capillary systems require additional transmitters for these extra measurements. This gives operators more insight into rapidly changing processes over traditional systems.

Conclusion

The versatility of DP solutions for flow and level is proven every day in countless industries. The capabilities are pushed even further in more extreme applications such as the cryogenic conditions encountered in LNG applications. The accuracy and flexibility of these systems combined with their low lifecycle costs makes them ideal for flow and level applications – hot, cold and in between.