EMERSON
Process Management

Level User Guide for the Instrument and Project Engineer in the Refining Industry

ROSEMOUNT

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1 The refining industry

1. The refining industry

1.1 Level measurement and detection in the refining industry

The refining industry is currently undergoing many changes. The existing refineries are being modernized to stay competitive. These “Brownfield” projects are being designed to upgrade refineries to improve their energy efficiency, maximize throughput and improve product quality. Improvement of energy efficiency, and reduction of operating and maintenance costs are important considerations. Refinery safety and meeting stricter environmental regulations are also key challenges in such upgrade projects. New “Greenfield” refinery projects also face similar complex challenges but in addition must minimize capital expenditures.

The operating refineries are continuously trying to reduce manpower but the equipment and operating requirements are becoming increasingly complex. To take advantage of cheaper high sulfur or heavy crude(s), refinery automation must be upgraded to deliver on-spec products.

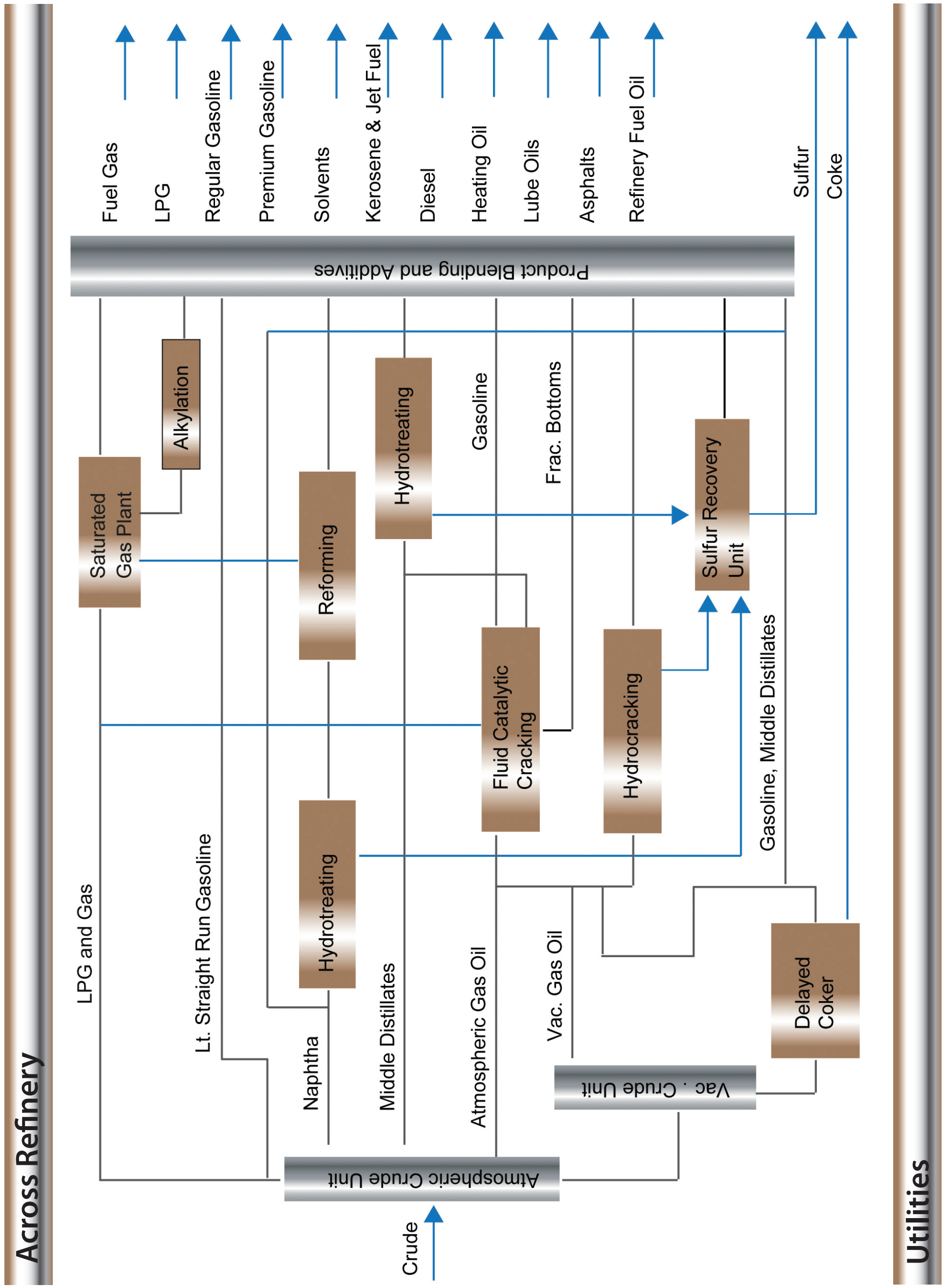
For reliable refinery operation, level measurement and level control is necessary in all refinery units. An average 100,000 barrels per day refinery may have more than 1000 level measurement points. Traditionally, displacers and floats have been used in about 80% of the level applications. Accuracy of these types of level instruments is affected by varying density and temperature which is caused by varying process conditions resulting from different crude types. Such density and temperature variations are present throughout the refinery. Such changes can cause inaccurate level measurements and affect control, which can negatively impact refinery production rates and quality.

When considering the upgrade of level instrumentation, refiners are changing from floats, bubblers, capacitance and displacer technologies to lower maintenance and higher accuracy devices. Thus, using technologies that are immune to density changes hold additional value to the refiner and are a key step towards improving measurement accuracy and performance.

Finally, refinery safety is of utmost importance. Just as there must be guards against overfilling vessels, the basic level measurement must be reliable, robust and accurate.

To accomplish this, instrumentation upgrades are planned with an eye towards higher performance, lower maintenance and higher reliability. No one level technology will work in all applications. Decisions must be made with respect to the required performance, the characteristics of the application, the installation constraints, and the capabilities of the level product. This refinery handbook has been developed to provide the information necessary to understand the available level equipment, where to apply them, and the best practices for their implementation in a refinery.

1.2 Refinery diagram



1.3 Overview of refinery units

Atmospheric Crude Unit: is the first major unit in the refinery used to process the petroleum crude by distillation into various fractions according to their boiling point ranges, so that each of the following refinery units will have feedstocks that meet their particular specifications. Typical boiling point cuts from the atmospheric crude unit include gas, naphtha, gasoline, kerosene, diesel, heavy gas oil and residue which is fed to the Vacuum Crude Unit for further distillation and separation under vacuum.

Fluid Catalytic Cracking Unit (FCC): FCC is the most important conversion process in the refinery. It uses thermal catalytic cracking to convert heavy hydrocarbon molecules to more valuable products such as gasoline, diesel, olefinic gases and other products.

Hydrotreating: Purpose of hydrotreating operation is to remove contaminants and impurities in various refinery streams by using hydrogen to bind with sulfur and nitrogen in the presence of a catalyst. Hydrotreating helps in meeting low sulfur specification in diesel fuel, providing low sulfur feed to the FCC unit and reducing environmental emissions.

Hydrocracking breaks or "cracks" heavier hydrocarbons into gasoline blending stocks using heat, catalyst and hydrogen under very high pressure. First stage of hydrocracking removes nitrogen and sulfur contaminants in a manner similar to hydrotreating. In the next stage, it produces high quality diesel fuels, jet fuels and naphtha feed for the reformer.

Reformer Unit: using heat, catalyst and moderate pressure, converts crude and coker naphtha into high octane gasoline blendstock called reformate. This process re-arranges paraffinic and cyclic hydrocarbon molecules into products that are higher in aromatic content. This unit is also a net hydrogen producer which is used elsewhere in the refinery.

Alkylation Unit: Alkylation process uses acid catalysts such as HF (hydrofluoric acid) or sulfuric acid to combine smaller hydrocarbon molecules like propylene and isobutane into larger ones collectively called alkylate. Product of alkylation unit is a high octane fuel which is the best quality gasoline blendstock.

Delayed Coker Unit: processes very heavy vacuum residue, which is heated to over 900° F and put into the coke drums, where it undergoes thermal cracking as the oil decomposes under extreme heat. Products include butane and lighter material, naphtha for Reforming, turbine and diesel fuel, gas oil for Cat Cracking, and fuel grade petroleum coke.

Sulfur Recovery Unit is a desulfurizing process used to recover elemental sulfur from gaseous hydrogen sulfide. Claus process is most commonly used to recover sulfur from various refinery gases that contain high concentration (more than 25%) of H_2S.

Gas Plant: main function of the refinery gas processing unit is to recover valuable C3, C4, C5 and C6 components from various gas streams generated by refinery processing units such as crude unit, delayed coker, FCC, reformer and hydrocracker. This recovery is done by using fractionators and absorbers. Recovered light hydrocarbon gases C1 and C2 are used as refinery fuel in various direct fired heaters.

Blending and Storage: Products made in various refining units are blended in various ratios to meet final product specifications of gasoline, diesel or other products that are shipped out of the refinery via pipelines or barges.

2 Available technologies

2. Available technologies

2.1 Guided wave radar

- continuous level measurement

2.1.1 Basic principle

Guided wave radar (GWR) is also called time domain reflectometry (TDR) or micro-impulse radar (MIR). In a Guided Wave Radar installation, the GWR is mounted on the top of the tank or chamber, and the probe usually extends to the full depth of the vessel. A low energy pulse of microwaves, travelling at the speed of light, is sent down the probe. At the point of the liquid level (air / water interface) on the probe, a significant proportion of the microwave energy is reflected back up the probe to the transmitter. The transmitter measures the time delay between the transmitted and received echo signal and the on-board microprocessor calculates the distance to the liquid surface using the formula:

Distance = (Speed of light x time delay) / 2

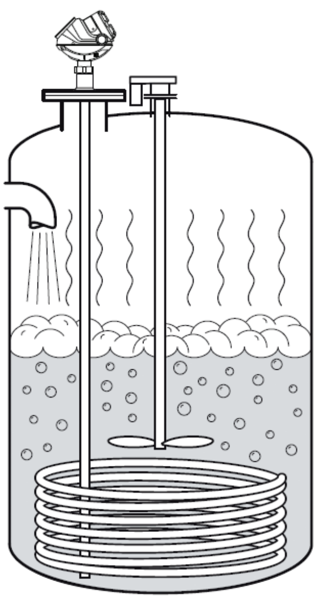


Figure 2.1.1 Guided wave radar can handle disturbing objects and tough process conditions.

Once the transmitter is programmed with the bottom reference of the application – usually the bottom of the tank or chamber – the liquid depth is calculated by the microprocessor.

Because a proportion of the pulse will continue down the probe through low dielectric fluids, a second echo can be detected from an interface between two liquids at a lower level.

This characteristic makes guided wave radar a good technique for measuring liquid/liquid interfaces such as oil and water and measuring through some foams.

Guided wave radar can be used in vessels with tight geometry, in chambers, and in tanks of all sizes. It also works well in low dielectric, turbulent applications. Because it is not dependent on reflecting off a “flat” surface, it works well with many powders and grains as well as liquids with slanted surfaces caused by vortices.

2.1.2 Advantages

Guided wave radar (GWR) provides an accurate and reliable measurement for both level and interface, and can be used in a wide variety of applications. It is a top-down, direct measurement as it measures the distance to the surface. GWR can be used with liquids, sludges, slurries, and some solids. A key advantage of radar is that no compensation is necessary for changes in density, dielectric, or conductivity of the fluid. Changes in pressure, temperature, and vapor space conditions have no impact on the accuracy of radar measurements. In addition, radar devices have no moving parts so maintenance is minimal. GWR is easy to install and can easily replace other technologies, such as displacer and capacitance.

2.1.3 Limitations

While guided wave radar works in many conditions, some precautions need to be taken with respect to probe choice. Several probe styles are available and the application, length, and mounting restrictions influence their choice. Unless a coax-style probe is used, probes should not be in direct contact with a metallic object, as that will impact the signal. If the application tends to be sticky or coat, then only single lead probes should be used.

2.2 Non-contacting radar

- continuous level measurement

2.2.1 Basic principle

Non-contacting radar sends a signal through the vapor space that bounces off the surface and returns to the gauge. Because it is non-contacting, its susceptibility to corrosion is limited and it is an ideal choice for viscous, sticky, and abrasive fluids. Non-contacting radar can frequently be used in vessels with agitators. It can be completely isolated from the process and used with isolation valves. Most vendors offer non-contacting versions that can be used in applications from 1 to 30 or 40 meters.

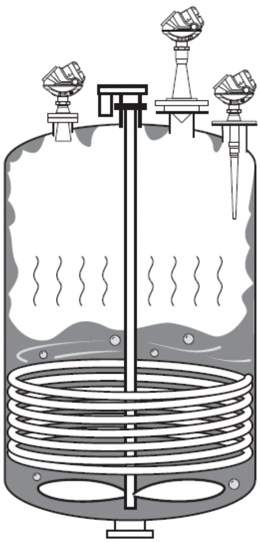


Figure 2.2.1 Non-contacting radars with different antennas to fit different applications.

The frequency ranges of the non-contacting radar can impact its performance more than the techniques used. A lower frequency reduces sensitivity to vapor, foam, and contamination of the antenna, whereas a higher frequency keeps the radar beam narrow in order to minimize influence from nozzles, walls, and disturbing objects. Beam width is inversely proportional to antenna size. The beam width of a given frequency will decrease as the antenna size increases.

2.2.2 Advantages

Non-contacting radar provides a top-down, direct measurement as it measures the distance to the surface. It can be used with liquids, sludges, slurries, and some solids. A key advantage of radar is that no compensation is necessary for changes in density, dielectric, or conductivity of the fluid. Changes in pressure, temperature, and vapor space conditions have no impact on the accuracy of radar measurements. In addition, radar devices have no moving parts so maintenance is minimal. The non-contacting radar devices can be isolated from the process by using barriers, such as PTFE, windows or valves. Since it is not in contact with the measured media, it is also good for corrosive applications.

2.2.3 Limitations

For non-contacting radar, a good installation is the key to success, it needs a clear view of the surface with a smooth, unobstructed, unrestricted mounting nozzle.

The measured surface needs to be relatively flat, not slanted. Non-contacting radar gauges can handle agitation, but their success will depend on a combination of the fluid properties and the amount of turbulence. Dielectric properties of the medium and the surface conditions will impact the measurement. With low dielectric process fluids, much of the radiated energy is lost to the fluid, leaving very little energy to be reflected back to the gauge.

If the surface is turbulent, whether from agitation, product blending, or splashing, more of the signal is lost. So a combination of low dielectric fluid and turbulence can limit the return signal to a non-contacting radar gauge. To get around this, bypass pipes or stilling wells can be used to isolate the surface from the turbulence.

2.3 Ultrasonic
- continuous level measurement

2.3.1 Basic principle

An ultrasonic level transmitter is mounted on the top of the tank and transmits an ultrasonic pulse down into the tank. This pulse, travelling at the speed of sound, is reflected back to the transmitter from the liquid surface. The transmitter measures the time delay between the transmitted and received echo signal and the on-board microprocessor calculates the distance to the liquid surface using the formula:-

Distance = (Speed of sound x time delay) / 2

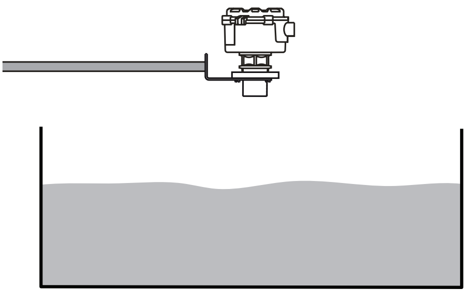


Figure 2.3.1 Illustration showing an ultrasonic transmitter

Once the transmitter is programmed with the bottom reference of the application – usually the bottom of the tank – the liquid depth is calculated by the microprocessor.

2.3.2 Advantages

Ultrasonic transmitters are easy to install on empty tanks or on tanks containing liquid. Set-up is simple and those devices with on-board programming capability can be configured in minutes.

As there is no contact with the media and no moving parts, the devices are virtually maintenance free. Wetted materials are usually an inert fluorocarbon, and resistant to corrosion from condensing vapors.

Because the device is non-contacting, the level measurement is unaffected by changes in liquid density, dielectric, or viscosity, and performs well on aqueous liquids and many chemicals.
Changes in process temperature will change the speed of the ultrasonic pulse through the space above the liquid, but built-in temperature compensation automatically corrects this. Changes in process pressure do not affect the measurement.

2.3.3 Limitations

Ultrasonic transmitters rely on the pulse being unaffected during its flight time. Liquids which form heavy vapors, steam or vapor layers should be avoided (use a Radar transmitter in these instances). As the pulse needs air to travel through, vacuum applications are not possible.

Materials of construction generally limit the process temperature to around 158°F (70°C) and pressure to 43 psi (3 bar).

The condition of the liquid surface is also important. Some turbulence can be tolerated but foaming will often damp out the return echo.

In-tank obstructions such as pipes, strengthening bars and agitators will cause false echoes, but most transmitters have sophisticated software algorithms to allow masking or ignoring of these echoes.

Ultrasonic transmitters can be used on silos containing dry products such as pellets, grains or powders, but these are more difficult to commission as factors such as surface angle of repose, dusting and long ranges must be taken into account. A Guided Wave Radar transmitter is better suited to dry product applications.

2.4 Pressure transmitters

- continuous level measurement

2.4.1 Basic principle

Pressure transmitters are the most commonly used technology for liquid level measurement. They are straightforward, easy to use and install, and work in a variety of applications and a wide range of conditions.

If a level measurement is being made on an open/vented vessel, a single gauge (GP) or differential pressure (DP) is required. If the tank is closed or pressurized, a DP transmitter must be used to compensate for the vessel pressure.

In addition to basic level measurements, DP transmitters can be set up to provide density and interface level measurements.

<u>Open vessel level measurement</u>

In an open-vessel configuration, the head pressure of the liquid is measured to infer a level measurement. Any column of liquid exerts a force at the base of the column because of its own weight. This force, called hydrostatic pressure or head pressure, can be measured in pressure units. Hydrostatic pressure is determined by the following equation:

Hydrostatic Pressure = Height x Specific Gravity

If the liquid level (height) changes, hydrostatic pressure changes proportionally. Therefore, a simple way to measure level is to install a pressure gauge on the holding vessel at the lowest level to be measured. The level of the liquid above the measurement point can then be inferred from hydrostatic pressure by rearranging the formula above to solve for height.

<u>Closed tank level measurement</u>

If a vessel is pressurized, a single GP transmitter is not adequate, as changes in the overall pressure of the vessel can affect the level of the process. To solve this issue, a DP transmitter should be used in closed tank applications to compensate for the vessel pressure.

When a DP transmitter is used, changes in the overall vessel pressure affect the high and low pressure taps of the transmitter equally, so the effects of the pressure are cancelled out.

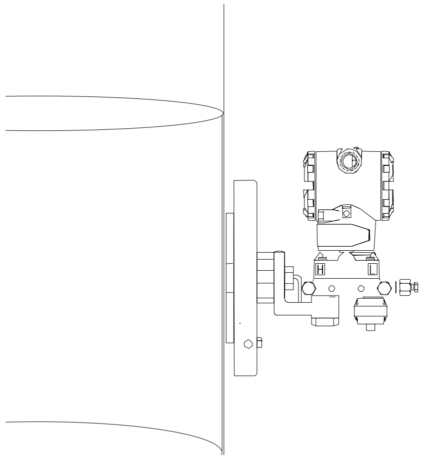


Figure 2.4.1 Illustration showing a DP transmitter

The high pressure DP transmitter connected near the bottom of the vessel measures hydrostatic pressure plus vapor space pressure. The low-pressure DP transmitter connected near the top of the vessel reads only the pressure in the vapor space. The difference in pressure between the two transmitters (differential pressure) is used to determine level.

Level = Differential Pressure / Specific Gravity

2.4.2 Advantages

In general, pressure transmitters are economical, easy to use and well understood. In addition, pressure transmitters can handle almost any tank and liquid, including slurries, and function in a wide pressure and temperature range.

2.4.3 Limitations

Level measurement accuracy with pressure transmitters can be affected by changes in fluid density. Special precautions are therefore required with thick, corrosive, or otherwise hostile fluids. In addition, some fluids (e.g., paper stock) tend to solidify as their concentration increases. Pressure transmitters do not work well with such solidified states.

2.5 Capacitance
- continuous and point level measurement

2.5.1 Basic principle

A capacitor is formed when a level sensing electrode is installed in a vessel. The metal rod of the electrode acts as one plate of the capacitor and the tank wall (or reference electrode in a non-metallic vessel) acts as the other plate. As level rises, the air or gas normally surrounding the electrode is displaced by material having a different dielectric constant. A change in the value of the capacitor takes place because the dielectric between the plates has changed. RF (radio frequency) capacitance instruments detect this change and convert it into a relay actuation or a proportional output signal.

The capacitance relationship is illustrated with the following equation:

$$C = 0.225\ K\ (A / D)$$

where:

C = Capacitance in picoFarads
K = Dielectric constant of material
A = Area of plates in square inches
D = Distance between the plates in inches

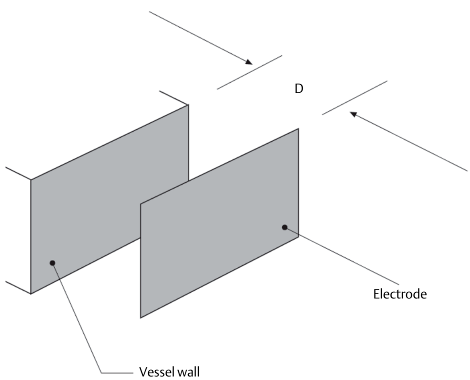


Figure 2.5.1 Capacitance principle

The dielectric constant is a numerical value on a scale of 1 to 100 which relates to the ability of the dielectric (material between the plates) to store an electrostatic charge. The dielectric constant of a material is determined in an actual test cell.
In actual practice, capacitance change is produced in different ways depending on the material being measured and the level electrode selection. However, the basic principle always applies. If a higher dielectric material replaces a lower one, the total capacitance output of the system will increase.

If the electrode is made larger (effectively increasing the surface area) the capacitance output increases; if the distance between measuring electrode and reference decreases, then the capacitance output decreases.

2.5.2 Advantages

A capacitor tolerates a variety of process conditions, such as variable density, high temperatures (1000 F), high pressures (5000 psi), viscous/sticky products, slurries, foams, pastes. It can be used to measure point or continuous level in both solids and liquids, and it is also good for interface measurements. In addition, a capacitor is inexpensive and rugged.

2.5.3 Limitations

For a capacitor, a change in dielectric creates errors in the reading, as well as coating on the probe by product. Options are available to compensate for the build up of product on capacitance probes. With non metallic tanks or tanks without vertical walls, the addition of a reference probe is required. Calibration of a capacitor can be difficult, especially since one cannot “bench calibrate”, and changing vapor space can affect the output. Capacitors are also upset by heavy foams.

2.6 Displacers
- continuous measurement

2.6.1 Basic Principle

A displacer transmitter is fitted to the top of a tank or more usually in a chamber which is valved to the tank, and comprises a displacer element which is suspended from a hanger - either a torque tube or a spring - connected to the transmitter/switch head. The displacer element is designed to be heavier than the liquid in which it is being used so that, even when fully immersed in the liquid, it still exerts a downward force on the hanger.

As the liquid in the vessel rises to cover the element, a buoyancy force is created which is equal to the weight of the liquid displaced by the element (Archimedes principle). This is seen by the transmitter as an effective reduction of the hanging weight of the element, and, as the displacer element hanging weight is proportional to the liquid level around it, the microprocessor in the transmitter head can give a readout of liquid level.

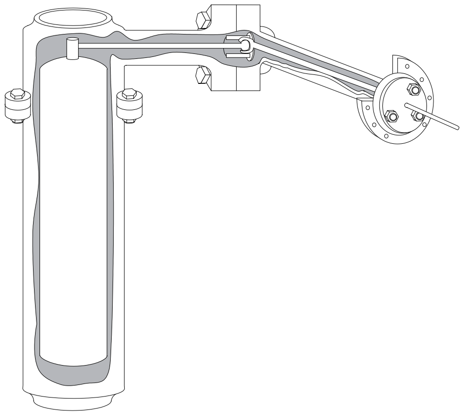


Figure 2.6.1 Illustration showing a displacer

2.6.2 Advantages

Displacer transmitters and switches have a huge installed base and, provided they are regularly maintained and their calibration checked, give years of reliable service. Able to operate at extremes of pressure and temperature, and commonly used to give interface level measurement even where emulsive layers exist between two liquids, these instruments allow level measurements to be made in many difficult applications.

2.6.2 Limitations

The accuracy of the level measurement is dependant upon correct calibration of the instrument at operating conditions; should these change then the level reading will be incorrect.

Torque tube displacer transmitters in particular require regular maintenance and calibration checks, and can suffer from damage during surge conditions. Operating ranges greater than 5m are impractical, mainly due to handling issues.

2.7 Nuclear

- continuous and point level measurement

2.7.1 Basic principle

Nuclear devices comprise a shielded radioisotope source attached to one side of a vessel or pipe and a detector placed on the opposite side. Gamma rays are emitted from the source and are focused to travel through the tank wall, the medium in the tank and the far tank wall through to the detector. Nuclear level switches use radioisotope sources sized to provide measurable radiation at the detector when no product material is present between source and detector.

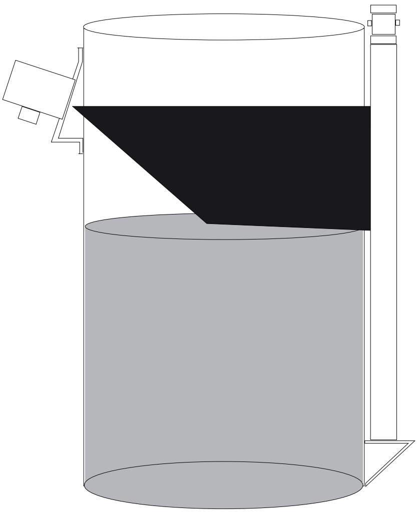


Figure 2.7.1 Illustration showing a nuclear device

Nuclear level transmitters use the same radioisotope sources, but respond to the total absorption of gamma rays as they pass from the source to detector. The amount of radiation reaching the detector is inversely proportional to the amount of material in the vessel.

Although the word “nuclear” sometimes causes concern, the industry has sustained an excellent safety record over the course of the last 30 years or more.

2.7.2 Advantages

The biggest advantage with nuclear technology, is that it is non-invasive i.e., there is no need for any instrument process connections on the tank. In addition, the nuclear level devices are non-contacting and unaffected by high temperatures, high pressures, corrosive materials, abrasive materials, viscous materials, agitation, clogging/plugging.
It can be used for both point and continuous level measurements in both liquids and solids, as well as interface.

2.7.3 Limitations

Large density changes, especially the density of Hydrogen in a material, can create errors. Layers of coating on vessel walls can also affect the measurement results. In order to use the nuclear technology, licensing and leak checks are required, as well as a high degree of health and safety checks and care over source handling and disposal. Nuclear has a relatively high cost.

2.8 Magnetostrictive

- continuous level measurement

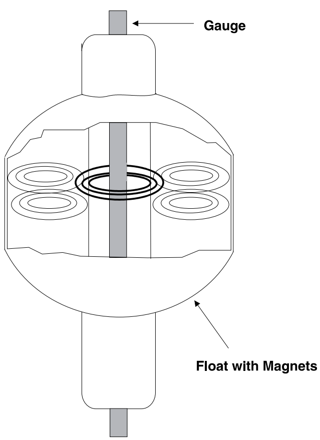


Figure 2.8.1 Illustration showing the magnetostrictive magnetic fields

2.8.1 Basic principle

The magnostrictive devices measure the intersection of two magnetic fields, one in a float, the other in a guide. Electronics send a low current pulse along the guide and when the magnetic field generated by the pulse reaches the field generated by the float, torsional “twist” is initiated. This then creates a sonic wave, which is detected and timed.

2.8.2 Advantages

The magnostrictive devices are precise (<1/32” or 1 mm) and in addition to level, interface and numerous temperatures can also be measured on the same assembly.

2.8.3 Limitations

The magnetostrictive technology is intrusive and can therefore clog or stick, and it is also corrosion sensitive.

2.9 Vibrating fork switches

- point level detection

2.9.1 Basic principle

A tuning fork switch comprises a two prong fork which is driven to oscillation at its natural frequency, usually by a piezo-crystal assembly. The switch is mounted on the side or top of a tank using a flange or threaded process connection such that the forks protrude into the tank.

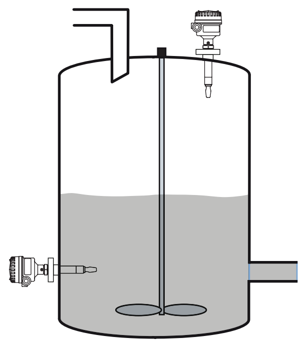


Figure 2.9.1 Illustration showing vibrating fork switches mounted on top and on the side of the tank

When in air, the forks vibrate at their natural frequency which is monitored by a detector circuit. When liquid covers the forks the frequency of oscillation drops and is detected by the switch electronics, which in turn changes the output state of the switch to operate an alarm, pump or valve. The frequency of operation of the switch is chosen to avoid interference from normal plant vibration which may cause false switching.

The design is glandless, and material of construction is usually stainless steel, allowing use in high pressure and temperature applications, with options of coated wetside or exotic materials for corrosive applications.

2.9.2 Advantages

The vibrating fork switches are virtually unaffected by flow, bubbles, turbulence, foam, vibration, solids content, coating, properties of the liquid, and product variations. There is also no need for calibration and it requires minimum installation procedures. No moving parts or crevices means virtually no maintenance.

Sophisticated self checking and diagnostics ensure high reliability in both high and low level applications, with some models even trending performance and signalling a trend to failure before a failure actually occurs.

2.9.3 Limitations

Vibrating fork switches are not suitable for very viscous media. Build up between the forks, causing the forks to be connected, will disturb the level detection.

2.10 Float and displacer switches

- point level detection

2.10.1 Basic principle

A float switch is usually mounted on the side of a tank or in an external chamber, and relies upon the liquid lifting the float as it arrives at the switching level. The float carries a permanent magnet as part of the float assembly which interacts with a second permanent magnet in the switch housing. The assembly is glandless as the magnets interact through the wall of the switch body.

These simple electro-mechanical devices are relatively trouble free and give reliable switching in high or low level applications.

There are many variations on this theme and models to meet almost any application, process connection or switching duty are available.

Where switching points are required a long distance below the mounting point of the switch, a displacer type switch can be used. Operating in a similar manner to a displacer transmitter, the displacer element is positioned on a cable and suspended from a spring below the mounting point at the required

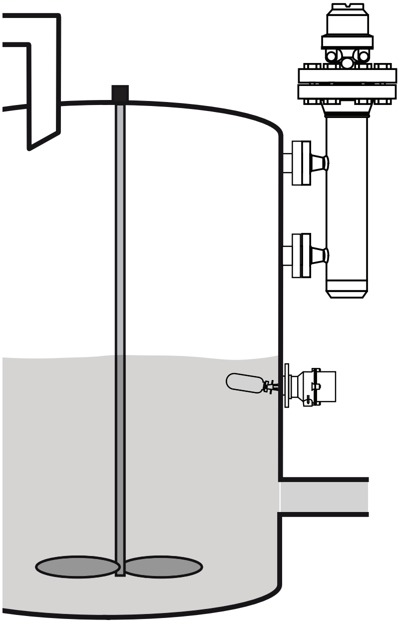


Figure 2.10.1 Illustration showing level float switches installed in a chamber and on the side of the tank

switching level. The displacer element has a fixed hanging weight which is supported by the spring. As liquid covers the element, the effective weight seen by the spring is reduced and an operating permanent magnet is lifted which interacts with a second permanent magnet in the switch housing. Displacer designs are also used in very high pressures or where low Specific Gravity liquids are present.

2.10.2 Advantages

Being very simple with only a few components, float and displacer switches are very reliable and easy to maintain. High pressures and temperatures are not a problem, and a variety of wetted materials allow use in almost any liquid.

2.10.3 Limitations

Float and displacer switches are simple passive devices and have no self checking features, so regular checking and maintenance is advisable. The float or displacer is a moving part so it can be subject to fouling in thicker or viscous liquids.

2.11 Technology overview

Process Conditions	Pressure	Capacitance	Ultrasonic	GW radar	NC radar	Nuclear	Displacer	Magnetostrictive	Floats	Vibrating fork
Aeration	2	1	2	1	2	2	1	2	1	1
Agitation	1	2	3	2	2	1	1	2	2	1
Ambient temperature changes	2	1	2	1	1	1	2	1	1	1
Corrosion	2	1	1	2	1	1	2	2	2	2
Density changes	2	1	1	1	1	2	2	2	2	1
Dielectric changes*	1	3	1	1	1	1	1	1	1	1
Dust	1	1	3	1	2	1	3	1	3	3
Foam	1	2	3	2	2	1	1	1	1	2
High process temperature limits	1	1	3	1	2	1	1	3	1	1
High vessel pressure limits	1	1	3	1	2	1	1	3	1	1
Internal obstructions	1	2	3	2	2	2	1	1	2	1
Low process temperatures	1	1	1	1	2	1	2	1	1	1
Low vessel pressures (vacuum)	2	1	3	1	1	1	1	1	1	1
Noise (EMI, motors)	1	1	2	2	1	1	1	1	1	1
Product coating	3	3	2	2	1	2	3	3	2	2
Slurries	2	1	1	2	1	1	3	2	2	2
Solids	3	2	2	1	1	1	3	3	3	3
Vapors	1	2	2	1	1	1	1	1	1	1
Viscous, sticky product	2	2	1	2	1	1	3	3	2	2

Table 2.11.1: Rating of each technology based on its capability of handling each challenge.

1 = Good: This condition has little or no impact on performance of this technology.

2 = Moderate: This technology can handle this condition, but performance could be affected or special installation is needed.

3 = Poor: This technology does not handle this condition well.

**A changing dielectric value will impact interface measurement accuracy.*

3 Rosemount level products

Topic **Page**

3. Rosemount level products

3.1 Continuous level measurement

3.1.1 Guided wave radar

Rosemount guided wave radar transmitters
- Highly accurate and reliable direct level measurement
- MultiVariable™ output includes the choice of level, interface level, distance, upper product thickness, volume and signal strength

5300 series superior performance
- Handles even the most challenging applications reliably including process vessels, control and safety
- Direct switch technology provides stronger signals and allows single lead probes to be used in more applications and over longer distances
- Enhanced configuration and diagnostic information through RadarMaster and EDDL-based user interface
- Probe end projection function provides reliable measurements during times of low signal strength

Rosemount 5300

Rosemount 3300

3300 series versatile and easy to use
- Handles most liquid storage and monitoring applications
- First 2-wire level and interface transmitter with field proven reliability

3.1.2 Non-contacting radar

Rosemount 5400 series 2-wire superior performance
- Market leading signal software logic to handle dynamic tank environments
- Circular Polarization allows mounting close to tank walls and filters out more extra echoes
- High and low frequencies available for maximum application coverage
- Enhanced EDDL-based user interface provides visualization of configuration and diagnostic information
- Dual Port design puts more power on the surface than any other 2-wire radar

Rosemount 5400

Rosemount 5600

5600 series 4-wire for niche applications
- Power of 4-wire gives maximum sensitivity and performance for solids, challenging reactors, rapid level changes and excessive process conditions
- Maximum sensitivity and performance for the toughest applications, including solids
- Market leading signal processing capacity to handle challenging tank environments

3.1.3 Ultrasonic

Rosemount 3100 series ultrasonic level transmitters
- Reliable liquid level measurement up to 36ft (11m)
- Top down non-contacting measurement minimizes maintenance costs
- Local operator interface or remote programming for fast and efficient commissioning
- Two on-board relays for control and/or alarm duties
- Inert wetted materials for corrosive liquids and vapors
- Sophisticated echo detection and processing algorithms enable reliable liquid level measurement

Rosemount 3100

3.1.4 Differential pressure

Rosemount integrated level transmitters
- Available for 3051S, 3051C and 2051 level transmitter configurations
- Advanced diagnostics with process alerts
- Wireless configurations provide new data access
- Single model for easy ordering

Rosemount 3051S Direct Mount Level

Rosemount 3051S with 1199 seal system

Rosemount 1199 seal systems
- Multiple direct mount and capillary options to match vessel mounting requirements
- Available for all transmitter configurations

9700 Hydrostatic level transmitters

- Submersible or external level transmitters for use in vented and open tanks
- Rugged stainless steel or aluminum bronze construction
- Tough flush mounted ceramic sensor for long life
- Simple, low cost installation

3.2 Point level detection

3.2.1 Vibrating fork switches

Rosemount vibrating fork level switches

- Level detection and control for the process industries
- Short fork design for minimal tank intrusion or pipe mounting
- Compact and lightweight design for side or top mounting
- Can be used with a Rosemount 702 wireless transmitter
- Rapid wet to dry time for highly responsive switching

Standard model
- Choice of switch outputs includes intrinsically safe and relay
- DIBt/WHG Overfill protection certification
- Flanged, threaded and extended length options

Rosemount 2120 - standard model

Rosemount 2130 - high temperature model

Extreme temperature model
- -94 to 500°F (-70 to 260°C) extended operating temperature range
- Built-in diagnostics continuously check electronic and mechanical health
- Ideal for critical alarm duties

3.2.2 Electro-mechanical float and displacer switches

- Robust and reliable switching in most liquids
- Unique 3 magnet switching system
- Operates in extremes of pressure and temperature
- Wide range of flanges, floats and switching outputs available
- Vertical mount switches for in-tank or external chamber mounting
- Wide range of materials of construction available
- Comprehensive standard range or custom design chambers to suit existing process connections

3.2.3 How to choose between a float and a vibrating fork switch?

	Floats	Vibrating forks
Mounting arrangements	Top, side, chamber	Top, side, chamber
Size	Large, heavy	Compact
Pressure range	Vac to 2900 psi/200bar	Vac to 1450 psi/100 bar
Temperature range	H: -22 to 752 F/-30 to 400°C V: -58 to 572 F/-50 to 300°C	-94 to 500°F -70 to 260°C
Output options	SPCO, DPCO dry contacts. Available with gold plated contacts, hermetically sealed switches. Dry contact allows wireless	Direct load, DPDT, PNP for PLC, Intrinsically Safe Namur
External self test, diagnostics	Yes – Mechanical test device available for horizontal only	Yes, magnetic test point tests switching function
Switching point	Subject to installation, configuration etc.	13 mm/0.5” in H20 (density dependent)
Approvals (Exproof)	Yes	Yes
SIL 2 suitable	No	Yes
Materials of construction	SST, Alloy 400 & others upon request	SST, Alloy C-276 & SST coated ECTFE/PFA copolymer/PFA
Application sensitivity	Variable density min. SG <0.4 , media buildup	SG <0.6, heavy coating, Viscosity > 10000 cP

Table 3.2.1: Specification overview of floats and vibrating forks

3.3 9901 - chambers for process level instrumentation

3.3.1 Introduction

The Rosemount 9901 is a self-contained chamber for externally mounting the Rosemount range of process level instruments to a vessel (figure 3.3.1).

Externally mounting an instrument in a chamber means that it can be isolated for routine maintenance whilst keeping the plant operational. It is also useful for in-tank restrictions that do not allow mounting of the instrument in the vessel.

Figure 3.3.1

This approach offers many advantages when solving application challenges:

In tank constraints:

- agitator
- heat exchanger
- internal structures

Isolation of instrument:

- live maintenance
- safety
- hazardous liquids
- high pressure
- high temperature

Turbulent vessel conditions:

- chamber acts as a stilling well

3.3.2 Chamber

The chamber, also known as a cage or bridle, houses the liquid being measured and the instrument's sensing element.

There are two process connections on the body of the chamber which allow mounting to the vessel.

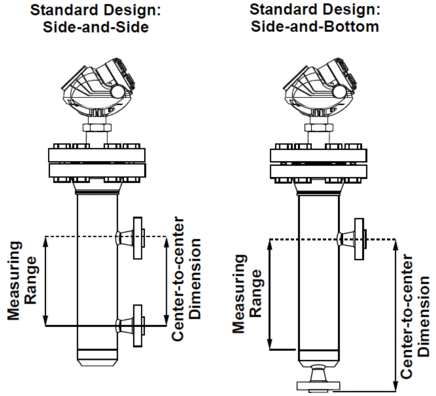


Figure 3.3.2: Showing the most common configurations

The instrument is mounted on top of the chamber through the flanged or threaded instrument connection. A threaded version is available for the vertical float level switch.

Standard materials are carbon steel and stainless steel, with other materials available upon request.

3.3.3 Chamber design

The Rosemount 9901 chamber is designed to the ASME B31.3 standard, and is Pressure Equipment Directive (PED) compliant.

Weld neck flanges and full penetration welds in accordance with EN ISO 15614-1:2004 and ASME Boiler and Pressure Vessel Code Section IX are used through out. All welders are qualified to EN 287-1:2004 and ASME Boiler and Pressure Vessel Code Section IX.

All construction materials have full traceability in accordance with the EN 10204 type 3.1 certificate.

Every 9901 is hydro-tested as standard. A full range of non destructive testing (NDT) is also available.

4 Best practice

NOTE:
Please note that all best practices in this user guide are recommendations based on prior experience in the field. However, all applications differ and if uncertain, please consult your local Emerson representative for guidance.

4. Best practice

4.1 Radar in chamber installations

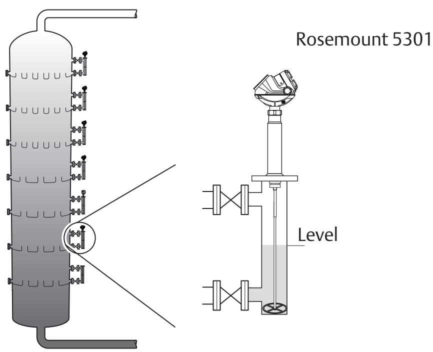
For guidelines for choosing and installing radar in chambers, see technical note on page 93.

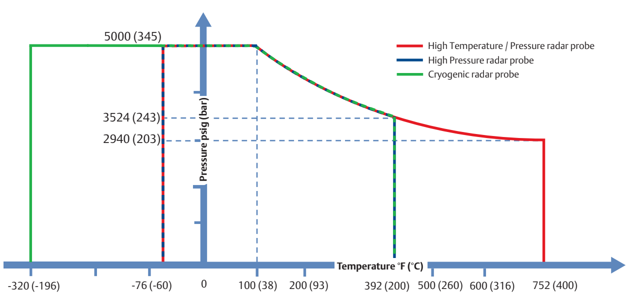
4.1.1 High temperature / low pressure OR high pressure / low temperature - level measurement

Application characteristics
- Boiling fluid results in a low signal return for the radar, especially hydrocarbon products, e.g. Oils and Diesel in crude oil distillation towers
- The product may be very viscous and cause heavy build-up in the chamber and on the probe

A: High temperature at low to moderate pressure - HTHP seal is recommended

Typical applications
- Distillation Towers (Lower Portions)
- Asphalt / Bitumen
- Naphta
- Coker feed





B: High pressure at low to moderate temperature - HP seal is recommended

Typical applications
- Compressors and associated knock-out drums and scrubbers
- Reflux/Reboilers
- Debutanizer
- Depropanizer

Best practice for both category A and B

- A Rosemount 5301 with a single probe, option code "4A" or "5A" is recommended. A centering disk should be included, if needed
- Flexible probes may be used in chamber installations. If this is done, the short weight option (W2) and a centering disk should be used. This helps to minimize the lower threshold zone.
- Temperature considerations:
  - For high temperature applications, the HTHP seal should be used. It has a maximum temperature of 750 °F (400 °C)
  - For high pressure, but moderate temperature applications, the HP seal should be used
  - Use metallic centering disks, option code 'Sx'
- In applications with very low signal strength, it is recommended to activate the transmitter firmware function Probe End Projection (PEP). For more information, refer to Rosemount 5300 Series Reference Manual (Document No. 00809-0100-4530)
- Insulate the chamber to reduce the amount of condensation

NOTE

In some processes, e.g. vacuum residue towers, the fluid may be too viscous for practical use in a chamber. For these cases, a DP with flushing connections is recommended.

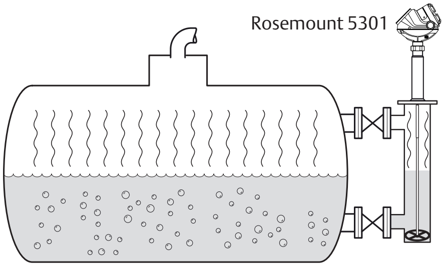
If the temperature is lower than 300 °F (150 °C) and the pressure is less than 580 psi (40 bar), the standard tank seal may be used instead of the HP option. For example, this may apply to the upper portion of a distillation tower.

Graph showing the temperature and pressure ratings for the HTHP, HP and Cryogenic seals.

4.1.2 High temperature and high pressure - level measurement

Typical applications

- Boiler and feedwater systems



Application characteristics

- Boiling water with saturated steam vapors
- Heavy water condensation
- Water and saturated steam have certain properties, see Table 5.1.1
  - The returned signal from the surface becomes weaker as water temperature increases.
  - If not taken into account, the saturated steam alters the propagation velocity of the radar signal and generates an error in the level reading proportional to the measured distance. Increased pressure and temperature will affect the error in measured distance.

Best practice

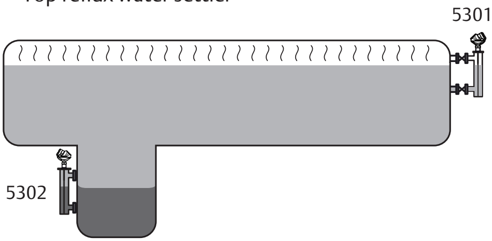
- It is recommended that the Rosemount 5301 uses a single lead probe, option-code "4A", and a centering disk if needed.
- Temperature considerations:
  - Use the high-temperature high-pressure (HTHP) tank seal, option code 'H', with maximum P/T 2940 psig at 752 °F (203 bar at 400 °C)
  - Use metallic centering disks, option-code 'Sx'
- Insulate the chamber to reduce condensation
- When commissioning the transmitter, the specific properties of water and saturated steam must be taken into account.
- For applications with a pressure of more than 600 psi/ 40 bar, we recommend that the dynamic vapor compensation functionality is used. This will reduce the error rate to less than 2%.

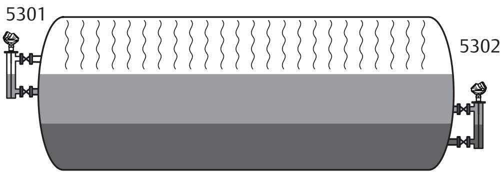
For further information about dynamic vapor compensation, see technical note on page 102.

4.1.3 High temperature - interface measurement

Typical applications

- Separators, such as cold HP, hot LP in the hydrotreater
- Coalescers
- Gasoline/water interface
- Top reflux water settler





Application characteristics

- There may be a fairly large emulsion between the products, which may make the interface indistinct
- Vapors may generate build-up

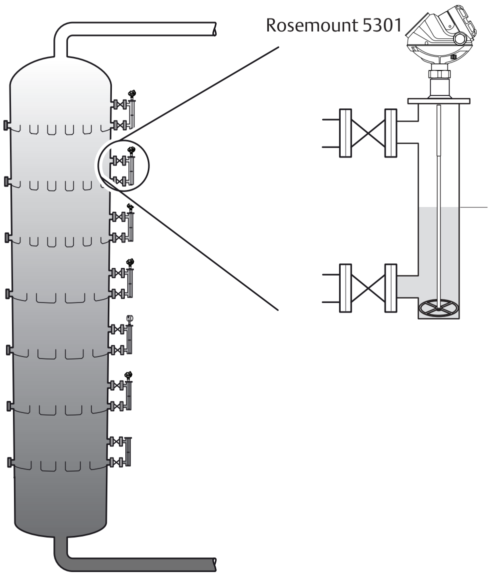
Best practice

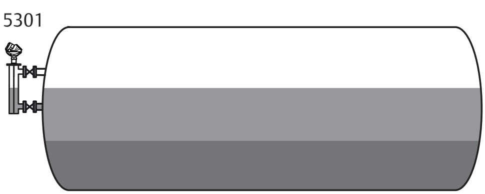
- Use the Rosemount 5301 with a separate flushing ring or flange and the integrated venting option. Alternatively, if there is an air gap, use the 5302
- Refer to the 5300 Product Data Sheet (Document No. 00813-0100-4530) to ensure that the conditions for interface measurement are fulfilled, especially with respect to the emulsion layer
- For chambers, it is recommended that the single lead probe, option-code "4A" or "5A" is used along with a centering disk, if needed
- Temperature and pressure considerations:
  - Use the high-temperature high-pressure (HTHP) tank seal, option code 'H', maximum P/T 2940 psig at 752 °F (203 bar at 400 °C).
  - Use metallic centering disks, option-code 'Sx'
- Because of the emulsion layer, Interface Threshold may need manual adjustment

4.1.4 Standard temperature and standard pressure - level measurement

Typical applications

- Distillation Towers (Upper portions)
- Separators
- Knock-out drums
- Accumulators/Feed tanks





Best practice

- It is recommended that the Rosemount 5301 with a single lead probe, option-code "4A" or "5A" is used along with a centering disk, if needed
- Use the standard tank seal, option code 'S', with pressure and temperature range 15 psig (-1bar) to 580 psig (40 bar) @ 302 °F (150 °C)
- Besides the metallic centering disk, PTFE may also be used, option code 'Px'

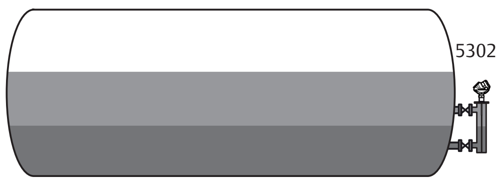
4.1.5 Standard temperature and standard pressure - interface measurement

Typical applications

- Accumulators
- Settling Tanks
- Skimmers
- Separators

Best practice

- Use the Rosemount 5301 with a separate flushing ring or flange and integrated venting option. Alternatively, if there is an air gap, use the 5302
- For chambers, it is recommended that the single lead probe, option code "4A" or "5A" is used along with a centering disk, if needed
- Use the standard tank seal, option code 'S', with pressure and temperature range 15 psig (-1bar) to 580 psig (40 bar) @ 302 °F (150 °C)
- Besides the metallic centering disk, PTFE may also be used, option code 'Px'



4.2 Radar in stilling well installations

For guidelines for choosing and installing radar in stilling wells, see technical note on page 93.

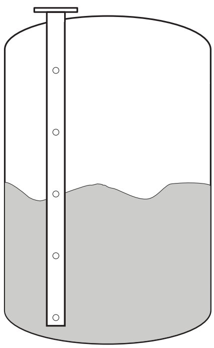
4.2.1 Liquified gases or low dielectric fluids in large vessels

Typical applications

- Small containers of LNG, LPG
- Large Vessels (such as spheres) containing butane, isobutane
- Large upright tanks containing raw crude.
- Propylene
- Flare knockout with stilling well access

Application characteristics

- Liquified gases have a very low dielectric constant and a very small signal return
- Boiling fluid of liquified gases reduces the signal return additionally
- Some level and interface applications



Best practice

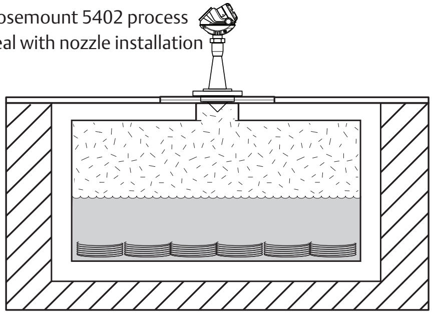
- Crude may be stored in vessels with stilling wells or where a floating roof is used in combination with stilling well.
- Some flare knock-outs may be accessed only via stilling well. Use 5400 or 5300. If 5300 is used, stilling well diameter should be at least 3". See technical note in appendix 4, pg A48 for details
- For non-inventory measurements, the Rosemount 5402 with cone- or process-seal antenna can be used
- A 2-4 in. (50-100 mm) stilling well is required to calm the surface
- A full-port ball-valve may be used for process isolation with a 5402
- If a stilling well is used for a level and interface application with GWR, multiple holes or slots should be drilled to ensure good fluid flow-thru for representative measurement.

4.3 In-tank installations

4.3.1 Solids

Typical applications

- Coke bins
- Spent catalyst hopper
- Sulfur pits



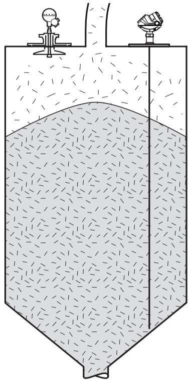
Application characteristics

- The surface of solid materials is rarely flat or horizontal, and the angle of repose, or surface inclination, will change as the vessel fills and empties
- The dielectric value of most solids is fairly low. For radar, this is a key indicator of the amount of signal that will be reflected back to the transmitter
- There is often a lot of dust during the fill cycle
- Heavier materials can create a pull force that can break cables. This can be an issue in vessels taller than 50 ft (15 m). Consider using non-contacting radar in these cases.

Best practice

- Sulfur pits: use Rosemount 5402 with process-seal antenna. Purge, insulate, heat-trace the nozzle or similar to reduce the amount of build-up. A 5600 with parabolic antenna may also be used. The antenna should be inside the vessel.

- Spent catalyst hoppers under 60 ft (18 m): use Rosemount 5303 with long-stud and standard 6A-probe. Over 60 ft (18 m): use Rosemount 5601 parabolic with dust-cover
- Coke bins: use Rosemount 5600

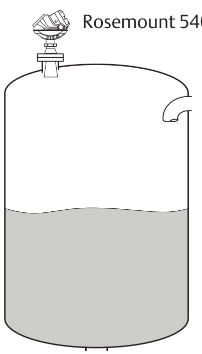


Rosemount 5600 and 5303

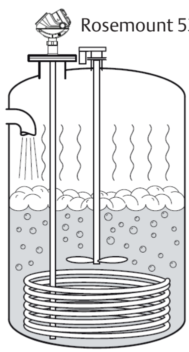
4.3.2 Storage tanks

Typical applications

- Chemical storage - acids, caustics, fuels
- Crude oil buffer storage
- Waste water



Rosemount 5402

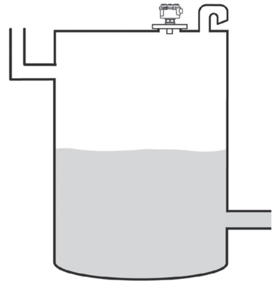


Rosemount 5300

Best practice

- Crude buffer storage: use Rosemount 5402 with cone antenna
- Consider material compatibility
- Use GWR in shorter applications such as cooling tower basins or where space is limited
- Use 3100 for simple aqueous liquids and non-volatile chemicals outside of explosion proof area

Rosemount 3100

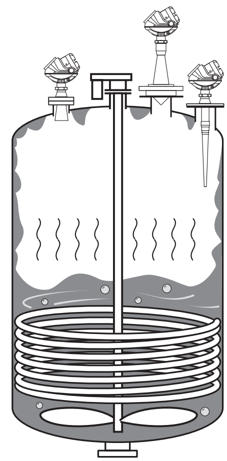


4.3.3 Tanks with agitators

Typical applications

- Mixing tanks - acids, catalysts
- Blending tanks
- Reactors
- Slurries

Rosemount 5400 Series



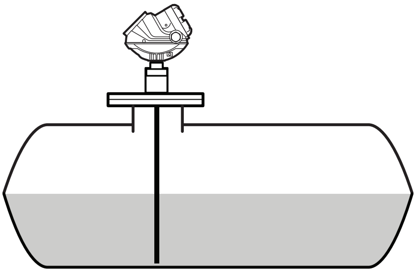
Application characteristics

- May be corrosive, vapors, turbulence, foam

Best practice

- Typically 5400 is used

4.3.4 Small pots, reservoirs and knockouts



Applications characteristics

- Small tank containing oil
- The tank may be too small to fit a chamber - direct connection is more likely

Best practice

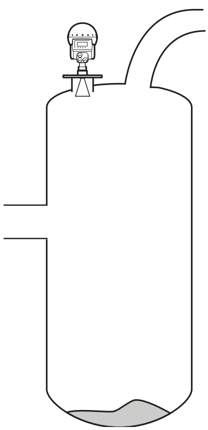
- Rosemount 5301 standard single is recommended

4.3.5 Tanks with very rapid level changes

Typical applications

- Blowdown drum

Rosemount 5600 Series



Application characteristics

- Tank may fill up very rapidly, due to upset in the process

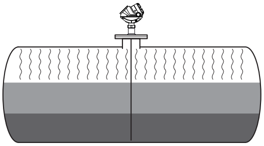
Best practice

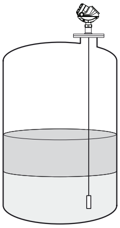
- Use Rosemount 5600

4.3.6 Level and interface

Typical applications

- Oil skim tanks (oil on water)
- Sumps (oil or amines over water)
- Spent Catalyst (oil over catalyst fines)
- Separators
- Accumulators
- Acid settlers





Application characteristics

- Low dielectric hydrocarbon on top of high dielectric material (water or metal particles)

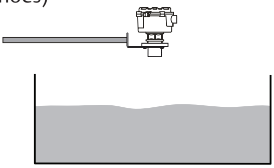
Best practice

- Use 5302 with single lead flexible probe
- Mount device away from tank wall or nearby obstacles
- Level and interface measurements may be accomplished effectively in stilling wells if there are adequate holes or slots along the length of the pipe. Stilling well diameter should be 3" (80 mm) or larger.

4.4 Open sump and well installations

Best practice

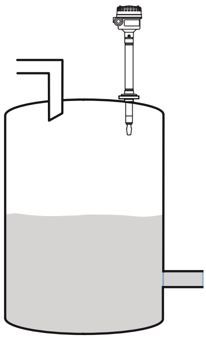
- Use a Rosemount 3100 for most applications. If vapors are present, use a 5401 low frequency radar.
- Mount out of direct sunlight or use a sun-shield if necessary
- Do not mount too close to well wall – refer to manual for optimum mounting position
- Do not mount directly over an inlet (stream of liquid in gives false echoes)
- Can be used with 3490 Universal Control Unit to give local pump control functions and readout.



4.5 Switch installations

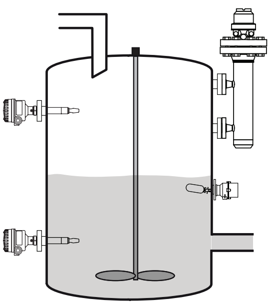
4.5.1 Typical applications

- Overfill protection



Spillage caused by overfilling can be hazardous to people and the environment, resulting in lost product and potentially high clean up costs. The Rosemount 2120 is available with DIBt/WHG overfill protection approval.

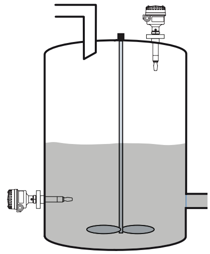
- High and low level alarm



Maximum and minimum level detection in tanks containing many different types of liquids are ideal applications for vibrating forks and float switches. Rosemount vibrating forks are robust and operate continuously across the temperature range of –94 to 500 °F (–70 to 260 °C) and operating pressures of up to 1450 psig (100 barg), making them perfect for use as a high or low level alarm. It is common practice to fit an independent high level alarm switch as a backup device to an installed level device in case of primary device failure.

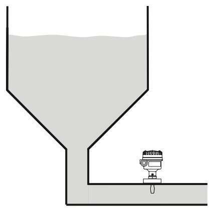
Float switches can be either mounted directly into the tank or externally in a chamber. Able to work up to very high pressures and temperatures, float switches remain a popular technology for alarm duties.

- Pump control



Batch processing tanks often contain stirrers and agitators to ensure mixing and product 'fluidity'. The standard user selectable time delay, ranging from 0.3 to 30 seconds, virtually eliminates the risk of false switching due to splashing caused by stirrers and agitators.

- Pump protection or empty pipe detection



Short forks mean minimum intrusion on the wet-side and allow simple low cost installation at any angle into pipes or vessels. With the fork projecting only 2-in. (50 mm) (dependant on connection type), the 2120 and 2130 can be installed in small diameter pipes. By selecting the option of direct load switching electronics, the 2120 and 2130 are ideal for reliable pump control and can be used to protect against pumps running dry.

4.5.2 Best practice vibrating forks

The 2120 can be used in hazardous (IS or Exd) areas with process temperatures up to 302 °F (150 °C). The 2130 can also be used in hazardous (IS or Exd) areas, but supports higher process temperatures up to 500 °F (260 °C).

The 2120 and 2130 can be mounted in any position in a tank or pipe. There is a wide range of threaded or flanged connections.

<u>Application considerations</u>

- Ensure the liquid viscosity is within the recommended viscosity range.
- Check that the liquid density is higher than 37.5 lb/ft^3 (600 kg/m^3), or above 31.2 lb/ft^3 (500 kg/m^3) when ordered with the low density range option.
- Ensure there is no risk of bridging the forks. Examples of products that can create bridging of forks are dense slurries and bitumen.
- Check the solids content in the liquid. As a guideline, the maximum solid particle diameter

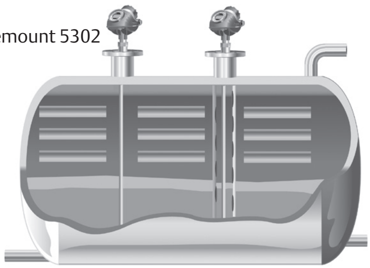
in the liquid is 0.2-in. (5 mm). Extra consideration is needed when dealing with particles bigger than 0.2 in. (5 mm). Consult the factory.
- In almost all cases, the 2120 and 2130 is insensitive to foams (do not see the foam).

4.5.3 Best practice float switches

Float switches operate in virtually any liquid and have a very wide temperature and pressure capability. They may be mounted on the side or the top of a tank, or in an external chamber to allow live maintenance or if internal obstructions or excessive agitation are present.

- Use in most liquids provided chemically compatible
- Mount on side of tank for clean liquids, top of tank for viscous liquids
- Ensure float meets process conditions
- Check space inside the tank for the float, no mechanical obstructions
- When mounting a switch on a nozzle, ensure that the nozzle internal diameter is sufficient to allow the float to pass through, and that the nozzle is not too long or the float may become trapped.

4.6 Desalter installations



Application characteristics

- The crude oil is viscous and dirty with solids and water content
- The interface may be indistinct, because of a large emulsion layer between the two products

Best practice

- Use the Rosemount 5302 with multivariable output for measurement of both level and interface
- If a stilling well is used, it is recommended that the diameter be at least 4 inches (100 mm). A flexible probe (5A) with centering may be used. Drill as many holes as possible, since these effectively set the resolution for the interface measurement.
- If a stilling well is not being used, a rigid single lead probe is recommended. The probe should not contact the electrical grid or other objects.
- Use the standard tank seal, option code 'S', with pressure and temperature range -15 psig (-1 bar) to 580 psig (40 bar) @ 302 ºF (150 ºC)
- Ensure that the electronics housing does not get warmer than the specified temperature limit; if needed, use the high-pressure (HP) tank seal, option code 'P', to move the transmitter housing further away from the process
- Because of the emulsion layer, it is likely that the Interface threshold will need manual adjustment

For more information on desalter installations, see white paper on page 119.

4.7 Measurement challenges

4.7.1 Interface measurement

There are some basic conditions which must be met in interface measurements:

- The lower dielectric fluid must be on top
- The two liquids must have a dielectric difference of at least 6
- The upper layer dielectric must be known (in-field determination is possible)

Rosemount 3300 and 5300 series:
- For the interface to be detectable, the upper fluid layer thickness must be at least 4" (10 cm) for 3300 rigid probes, and 8" (20 cm) for 3300 flexible probes. For the 5300 with rigid and flexible probes it has to be 5" (12.5 cm)
- The maximum thickness of the upper layer depends on the dielectric, probe type and transmitter
- Target applications: low upper layer dielectric (< 3), high lower layer dielectric (>20)

4.7.2 Low dielectic measurements

Guided Wave Radar is the preferred technology for level measurement of low dielectric materials. With the direct switch technology, the Rosemount 5300 offers additional signal strength to enable measurement of very low dielectric materials.

When installed in bypass chambers, the 5300 with a single lead probe can be used for these measurements. The single lead is the preferred choice for dirty or sticky applications that tend to coat probes. The chamber helps to concentrate the signal to create a stronger reflection. In the event that the fluid is also turbulent or boiling, the 5300 offers a probe end projection (PEP) function which can serve as backup to the standard measurement.

For very clean applications, such as liquified gases, the 5300 with a coaxial probe can be used directly in the vessel.

4.7.3 Measuring ammonia with radar

Application characteristics

- Anhydrous ammonia has heavy vapors that attenuate the signal

Best practice

- Use 5301 with any of the probe-types
- Ensure the wetted materials are compatible with the process. For example, many users consider Viton® and Buna-N® O-rings to be incompatible with this process. The High Pressure tank seal, option code 'P', can be used if a solution without O-rings is preferred.
- For further information, see technical note on page 100.

4.7.4 Accurate and reliable level measurement using Rosemount 5400 series shooting at a metal plate

In some radar level measurement applications, for example floating roof tanks, it may be beneficial, or even the only solution, to use a reflector plate. In these applications the reflector (or transmitter head!) moves along with the surface and thereby corresponds to the level. The Rosemount 5400 Series is often ideal for these applications with reflectors if a few simple guidelines in this document are applied.

Transmitter selection

Antenna beam angle is the key in these applications. Use the 5402 with 4” Cone Antenna since it has the most narrow beam. If a 5402 is not possible, then use the 5401 with an 8” Cone. Maximum measuring range for both of these is 115 ft. / 35 m in this application. Multiple mounting arrangements are possible, typically bracket-mounting is preferred but often flanged connection works as well. Visit http://www.rosemount.com/5400 for detailed installation drawings.

Reflector

The reflector, or target, will simulate a surface. For the Rosemount 5400 Series a flat metal plate of arbitrary thickness is recommended. The shape shall be either circular or square.

The dimensions can be derived from the Fresnel zone and are presented in tables 5.6.1 and 5.6.2. Of course larger reflectors can be used, there is no (theoretical) upper limit. Note: The reflector will be smaller than the antenna footprint. Avoid disturbing objects with large horizontal metal surfaces inside the antenna beam.

Max measuring distance	Plate diameter (circular)	Plate dimensions (square)
5 m	Ø=0.3 m	W=0.3 m
10 m	Ø=0.4 m	W=0.4 m
15 m	Ø=0.5 m	W=0.5 m
20 m	Ø=0.6 m	W=0.6 m
30 m	Ø=0.7 m	W=0.7 m
35 m	Ø=0.8 m	W=0.8 m

Table 4.7.1: Minimum reflector dimensions for Rosemount 5402 with 4" cone antenna (preferred choice)

Max measuring distance	Plate diameter (circular)	Plate dimensions (square)
5 m	Ø=1.0 m	W=1.0 m
10 m	Ø=1.6 m	W=1.5 m
15 m	Ø=1.7 m	W=1.7 m
20 m	Ø=2.0 m	W=2.0 m
30 m	Ø=2.4 m	W=2.4 m
35 m	Ø=2.6 m	W=2.6 m

Table 4.7.2: Minimum reflector dimensions for Rosemount 5401 with 8" cone antenna (use only if 5402 is not possible)

Reflectors are not available from the factory; they have to be supplied by the local sales office or the customer. Reflector shape can be rectangular or elliptical but then the shortest dimension must fulfill W or Ø respectively in the tables above.

<u>Installation</u>
Follow the mechanical mounting recommendations in figure 5.6.1. In this configuration the antenna is not pressure retaining, but temperature limits still apply. Also take into account the effects of vibration. A string/wire/rope can be used to align the reflector.

Often the reflector has an offset relative to the ‘true’ surface. The outputted level reading can then be adjusted in the transmitter firmware by changing the parameter Distance Offset (G):

RRM - Tank - Geometry - Activate Advanced viewing mode - Distance Offset (G)

Also ensure that the reflector is moving along with the level and does not get stuck or tilted.

<u>Reflector build-up</u>
The reflection from the target plate is typically so strong that normal outdoor environments (eg. rain) are not a problem. In some installations however, large amounts of attenuating build-up occurs; for example snow. Sometimes the solution is as easy as drilling drainage holes in the reflector plate, but there are also more advanced reflector designs; consult the factory if this is needed.

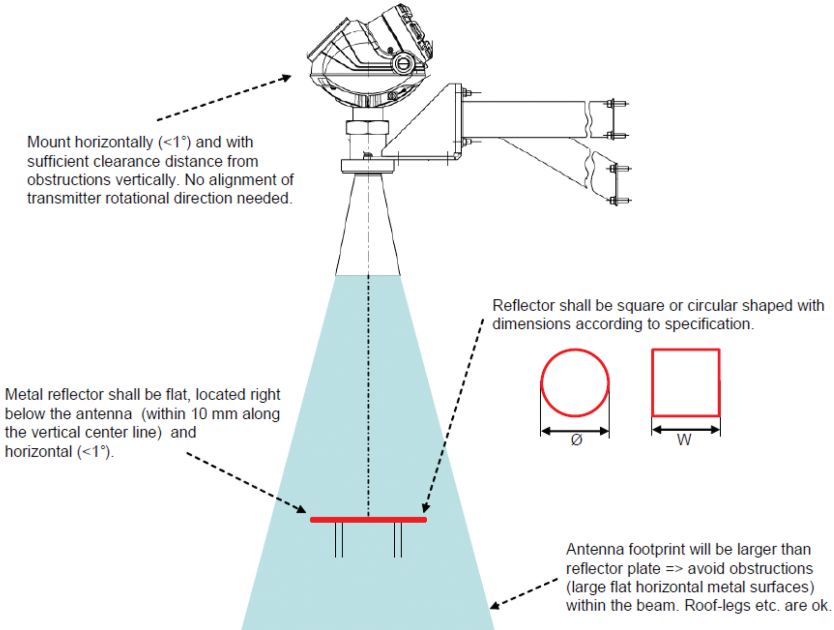


Figure 4.7.1: Mechanical mounting recommendations for Rosemount 5400 Series with reflector plate.

4.8 Application limitations for radar

Generally, GWR is not suitable for extremely viscous products where fluid flow is minimal. If GWR is used in a chamber with very viscous fluids, the chamber should be heat traced and insulated to ensure fluidity. A vacuum residue unit is an example of this type of application. Applications where heavy coating is likely, such as asphalt, are more suitable for non-contacting radar.

Very small vessels (less than 18 in. (450 mm)) may result in measurements that are more within the transition zones than the active measurement region. Accuracy and linearity may be reduced.

Coke drums are tall vessels that operate at high temperatures with low dielectric, turbulent fluid and foam. The end result of the process is solid coke. They are unsuitable for any GWR and an extremely difficult application for non-contacting radar. Nuclear point level is the traditional technology used for these applications.

Applications with foam are difficult to predict. Results may vary depending upon the dielectric properties, the density and the thickness of the foam. Consider a test installation or consult a level specialist for assistance.

There are also some level applications where radar is not suitable, such as:

- Applications with process temperature above 752°F (400°C)

- Interface applications where the upper layer has a higher dielectric constant than the lower layer

- Interface applications where the layers have similar dielectrics. For GWR to work on an interface application, a dielectric difference of 6 is required to reflect the signal

- Interface applications with heavy, thick emulsion layers. GWR requires a distinct dielectric difference to detect the interface

For these applications, differential pressure or displacer gauges might be the preferred choice.

5 Installation considerations

Topic **Page**

5. Installation considerations

5.1 Radar in chamber installations

For guidelines for choosing and installing radar in chambers, see technical note on page 93.

Chambers - also known as bridles, side-pipes, bypass-pipes, and cages - are typically used because:

- External mounting with valves allows for servicing of the level device, even in pressurized tanks that are in continuous operation for many years
- They allow for radar measurement in tanks or regions with side-connections only, such as towers
- They provide a calmer surface in case of turbulence, boiling, or other conditions that upset the product

However, chambers also have some disadvantages:

- Inlet pipes may clog and generate a discrepancy between the level inside the chamber and the actual level in the tank
- The effective measuring range is limited to the region between the upper and lower inlet pipes

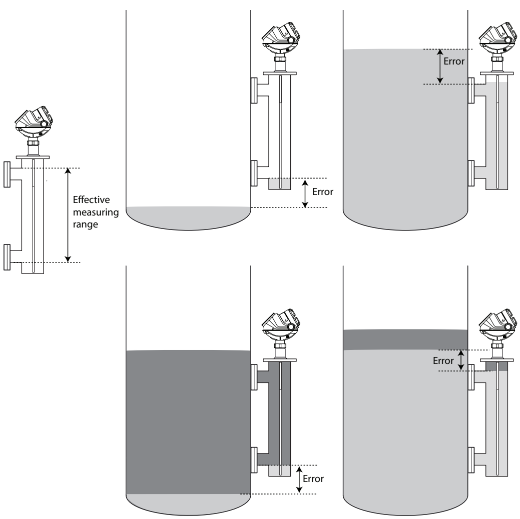


Figure 5.1.1 Effective measuring range and possible error sources

Generally, Guided Wave Radar (GWR) is favored in these applications since non-contacting radar may be disturbed by the inlet-pipes. The Rosemount 5300 Series can be used in chambers to measure either level or interface level.

5.1.1 Chamber fabrication and probe selection

Dimensioning the chamber correctly and selecting the appropriate probe is key to success in these applications. Either follow the recommendations below and have the chamber manufactured accordingly, or purchase the Rosemount 5300 Series transmitter bundled with the Rosemount 9901 chamber where Emerson has already incorporated these best practices.

The recommended chamber diameter is 3" (75 mm) or 4" (100 mm). Chambers with a diameter less than 3" (75 mm) may cause problems with build-up and it may also be difficult to center the probe. Chambers larger than 6" (150 mm) can be used, but provide no advantages for the radar measurement. With the Rosemount 5300 Series it is recommended that single probes in 3" (75 mm) and 4" (100 mm) cages be used. Other probe types are more susceptible to build-up and should not be used in this application. (1) The probe must not touch the chamber wall and should extend the full height of the chamber, but does not need to touch the bottom of the chamber. Probe type selection depends on the probe length:

- Probe length is less than 3 ft (1 m): Use Single Rigid Probe and no centering disk is needed.(2)

- Probe length is between 3 ft (1 m) and 10 ft (3 m): Use either Rigid Single or Flexible Single Probe with the weight and centering disk. The Rigid Single is easier to clean and has smaller transition zones, while the Flexible Single requires less head-space during installation and is less likely to be damaged.

- Probe length is more than 10 ft (3 m): Use Flexible Single Probe with weight and centering disk

(1) *The single probe creates a virtual coaxial probe with the chamber as the outer tube. The extra gain provided by the twin and coaxial probes is not necessary; the electronics in the 5300 Series is very sensitive and is not a limiting factor.*

(2) *The transition zones, and the height of the weight, limit the usage of single flexible probes shorter than 3 ft (1 m).*

5.1.2 Replacing displacers in existing chambers

Displacers have moving parts that require frequent cleaning and replacement. They are affected by mechanical vibration and turbulence, the mechanical parts can give false readings, and maintenance costs can be expensive.

Guided Wave Radar technology has no moving parts, which means a reduction in maintenance costs as well as improved measurement. GWR is not density dependent and provides reliable measurement even with mechanical vibration or high turbulence. Since existing chambers can often be used, replacement is simplified.

There are many displacer flanges and styles, so it is important to correctly match the 3300/5300 flange choice and probe length to the chamber. Both standard ANSI and DIN are used, as well as proprietary chamber flanges with a non-standard diameter and gasket surface.

For further information about replacing displacers with GWR, refer to technical note on page 88.

When not to replace a displacer with GWR

- Displacers have an advantage over GWR's on interface applications where there is a heavy, thick emulsion layer. This is because GWR's require a distinct dielectric difference to detect the interface. GWR's have been proven to work with some emulsion layers but success is difficult to predict. Since displacers rely on a buoyancy effect and not a change in dielectric they will therefore track the mid point of an emulsion layer.

- A displacer is not reliant on dielectric so it can be used on interface applications where the liquid layers have similar dielectrics. For a GWR to work on an interface application, a dielectric difference of 6 is required to reflect the signal.

- When the low dielectric fluid is on the bottom layer, GWR's require that they see the low dielectric first.

5.2 Radar in stilling well installations

For guidelines for choosing and installing radar in stilling wells, see technical note on page 93.

Stilling wells or pipes are used in many applications and many different types of tanks and vessels. The reasons for having the pipes differ, but are typically beneficial from an application standpoint, since pipes will offer a calmer, cleaner surface and eliminate issues with disturbing obstacles.

Both Guided Wave and non-contacting Radar perform well in pipes:

- Use the 5300 Series in shorter pipes (less than 10 ft [3 m]) or if interface measurement is required
- Use the 5400 Series in longer pipes (over 10 ft [3 m]) or if there is a risk for build-up on a GWR probe
- The 5300 Series cannot be isolated; use the Rosemount 5402 with a full-port ball valve for applications that cannot be taken out of operation for service

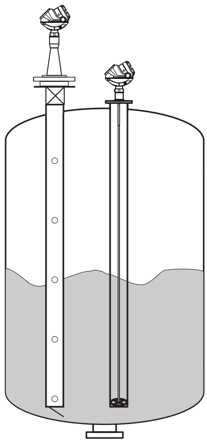


Figure 5.2.1: 5400 and 5300 installed in stilling wells

With the 5400 Series, ensure that the cone antenna or process seal antenna is used in the pipes, and that the size of the holes or slots is limited in size.

Holes should be drilled on one side of the pipe. The gap between the cone-antenna and the pipe should not be larger than 0.2" (5 mm). If needed, buy an oversized cone and cut on site. With non-contacting radar in pipe installations with low dielectric fluids, install a deflection plate with an approximate angle of

45° at the bottom of the pipe. Failure to follow these requirements may affect the reliability of the level measurement.

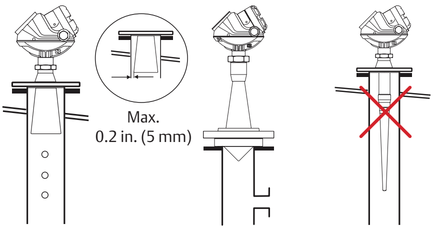


Figure 5.2.2: 5400 in stilling wells and slot size

For the 5300 Series the installation considerations are virtually identical with chambers, as covered in the previous section of this document. For more details, refer to the Technical Note "Guidelines for Choosing and Installing Radar in Stilling Wells and bypass chambers" (page 91).

5.3 Radar in tank installations

5.3.1 Recommended mounting position

When finding an appropriate mounting position for the transmitter, the conditions of the tank must be carefully considered.

For the Rosemount 5300 Series:
- Do not mount close to inlet pipes and ensure that the probe does not come in contact with the nozzle (X)
- If there is a chance that the probe may come in contact with the tank wall, nozzle or other tank obstructions, the coaxial probe is the only recommended choice. Minimum clearance is given in Table 6.3.1 on page 44
- Generally, the Rosemount 5400 Series is recommended in tanks with agitators. If the probe sways due to turbulent conditions, the probe should be anchored to the tank bottom (Y). Refer to the 5300 series reference manual for anchoring options. Also note that violent fluid movements that cause high sideway forces may break rigid probes.

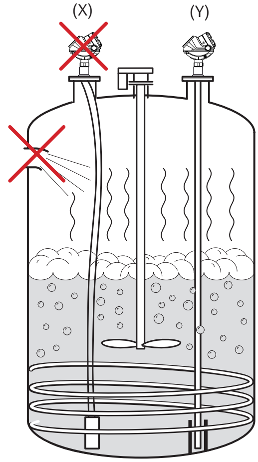


Figure 5.3.1: 5300 in tank with agitator

	Coaxial	Rigid / flexible twin lead	Rigid / flexible single lead
Min clearance to tank wall or obstruction	0 in. (0 cm)	4 in. (10 cm)	4 in. (10 cm) in the case of smooth metallic wall. 20 in. (50 cm) in the case of disturbing objects, rugged metallic or concrete/ plastic walls.

Table 5.3.1: Minimum clearance of probes

The Rosemount 5400 Series should be installed in locations with a clear and unobstructed view of the level surface (A) for optimum performance:
- Filling inlets creating turbulence (B), and stationary metallic objects with horizontal surfaces (C) should be kept at a distance, outside the signal beam. See the 5400 product data sheet for more information (Document No. 00813-0100-4026)
- Agitators with large horizontal blades may reduce the performance of the transmitter, so install the transmitter in a location where this effect is minimized. Vertical or slanted blades are often invisible to radar, but create turbulence (D)
- Do not install the transmitter in the center of the tank (E)

- Because of circular polarization, there is no clearance distance requirement from the tank wall if it is flat and free from obstructions, such as heating coils and ladders (F). Usually, the optimal location is 1/3 of the radius from the tank wall

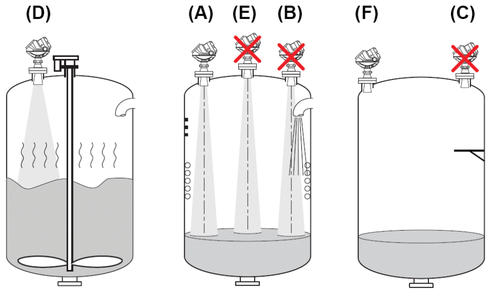


Figure 5.3.2: Proper and improper locations for the 5400 series transmitter

5.3.2 Nozzle considerations

Depending on the selection of transmitter model and probe/antenna, special considerations may have to be taken because of the nozzle.

Rosemount 5300 Series

The coaxial probe signal is unaffected by the nozzle. The single and twin probes have some nozzle restrictions, e.g. avoid using nozzles with reducers, and nozzles that are too tall or too narrow.

	Single (rigid/flex)	Coaxial	Twin (rigid/flex)
Recommended nozzle diameter	4-6 in. (100-150 mm)	> probe diameter	4-6 in. (100-150 mm)
Minimum nozzle diameter(1)	2 in. (50 mm)	> probe diameter	2 in. (50 mm)
Maximum nozzle diameter	4 in. + nozzle diameter	N/A	4 in. + nozzle diamater (2)

Table 5.3.2: Nozzle considerations

(1) An upper null zone setup may be required to mask the nozzle, which may reduce the measuring range.
(2) When using single flexible probes in tall nozzles, it is recommended to use the long stud (LS)

Rosemount 5400 Series

5402 with cone antenna
The antenna can be used in nozzles equal to or larger than 2" (50 mm). It can be recessed in smooth nozzles up to 6 ft (2 m). If the inside of the nozzle contains disturbing objects, use the extended cone (I).

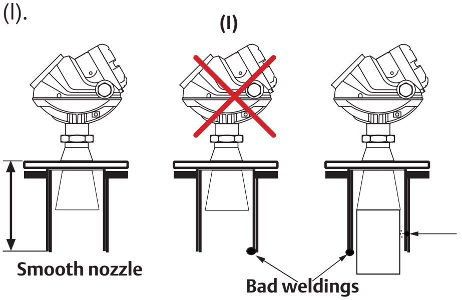


Figure 5.3.3: 5402 with cone antenna

5402 with process seal antenna
The antenna can be used in 2, 3, and 4". (50, 75, and 100 mm) nozzles up to 6 ft (2 m) tall (J), but disturbing objects inside the nozzle (K) may impact the measurement, and should be avoided. The flange on the tank should have a flat or raised face, but other tank flanges may be possible. Consult your local Emerson Process Management representative for assistance.

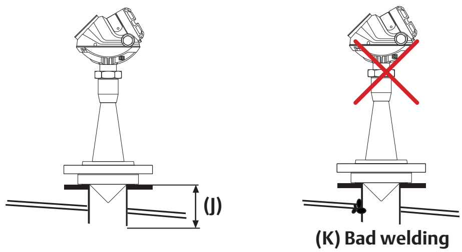


Figure 5.3.4: 5402 with process seal antenna

5401 with cone antenna
This antenna can be used in tanks with nozzles equal to or larger than 4" (100 mm) and can extend 0.4" (10 mm) or more below the nozzle (L). If required, use the extended cone solution.

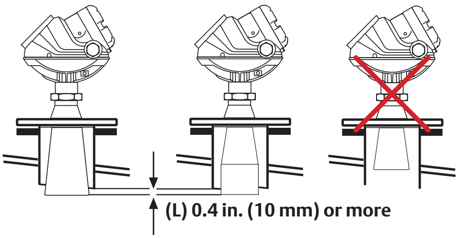


Figure 5.3.5: 5401 with cone antenna

5.3.3 Process isolation for service

It is recommended that the Rosemount 5400 Series uses a full-port ball valve in applications that cannot be taken out of operation for service. The 5402 is required, and the preferred choice is the process seal antenna, since it does not require a spool piece. The cone antenna can also be used, but a spool piece will be needed. Ensure there is no edge between the ball valve and the nozzle/pipe. The inside should be smooth.

The 5300 Series cannot be used with valves because of the protrusion of the probe into the tank. If process isolation is needed with the 5300 Series, a chamber is recommended.

5.3.4 Probe and antenna selection

In addition to mounting position, nozzle considerations, and process isolation, there are other factors that need to be taken into consideration when selecting the probe or antenna:

- Single probes and cone-antennas are recommended in most applications. Always use the largest possible antenna
- In case of turbulent surface conditions or foam, consider using the coaxial probe with GWR. When using non-contacting radar, consider using a stilling well
- The coaxial and twin lead probes have longer measuring ranges than the single probes, but are more sensitive to build-up and coating

Always ensure that the wetted materials are compatible with the process and that the probe/antenna will withstand the application's temperature and pressure range.

5.4 Ultrasonic installations

Ultrasonic transmitters will give trouble free and reliable service provided care is take during installation. The following points should be considered:-

- The 3100 is used on open, atmospheric or low pressure (max 45psig / 3 bar) applications.
- Do not mount directly above an inlet or outlet, or above any internal tank structures which can cause false reflections. Avoid positioning above any areas of the tank where foams may gather and stagnate.
- The optimum position for the transmitter is generally 1/3 of the tank radius in from the side wall. If mounting closer to the tank wall, ensure that the tank wall is smooth and free of protrusions, weld beads or scum lines.
- The 3100 is designed to be mounted in a non-metallic flange. Plastic flanges are available as accessories. If there is no option but to use a metallic flange, ensure the transmitter is only screwed into the flange to “hand tight”.
- It is always preferable to mount the transmitter so that the front face protrudes at least 0.25" (6mm) into the tank. If mounting on a nozzle or stand-off, the internal diameter should be 6"(150mm) minimum and the maximum nozzle length should be no more than 14" (350mm).
- If the instrument is exposed to direct sunlight such that it may heat up to 122°F (50°C) or greater, the use of a sunshade is recommended.
- The 3100 can be used to measure flow in open channels. In such applications, there are specific guidelines which must be followed to achieve accuracy of readings – refer to the instrument installation manual for full details.

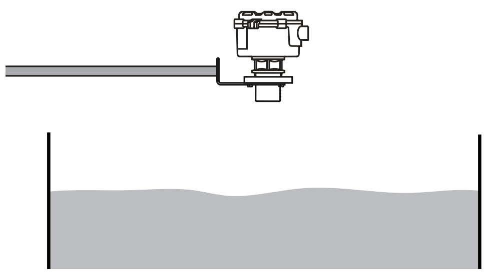


Figure 5.4.1: Ultrasonic transmitter on an open reservoir

5.5 Switch installations

Before installing the Rosemount 2120/2130 level switch, consider specific installation recommendations and mounting requirements.

- Install in any orientation in a tank containing liquid
- Always install in the normally "on" state
- For high level the recommendation is Dry = on
- For low level the recommendation is Wet = on
- Always ensure the system is tested by using the local magnetic test point during commissioning
- Ensure sufficient room for mounting and electrical connection
- Ensure that the forks do not come into contact with the tank wall or any internal fittings or obstructions
- Avoid installing the 2120 or 2130 where it will be exposed to liquid entering the tank at the fill point
- Avoid heavy splashing on the forks
- Raising the time delay reduces accidental switching caused by splashing
- Avoid product buildup
- Ensure no risk of bridging the forks
- Ensure there is sufficient distance between build-up on the tank wall and the fork
- Ensure installation does not create tank crevices around the forks where liquid may collect (important for high viscosity and high density liquids)

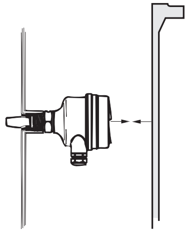


Figure 5.5.1: Ensure adequate space outside tank

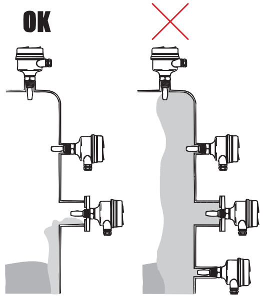


Figure 5.5.2: Example of ok and not ok build-up on tank wall

- Extra consideration is needed if the plant vibration is close to the 1300 Hz operating frequency of the 2120 or 2130
- Avoid long fork length vibration by supporting the fork

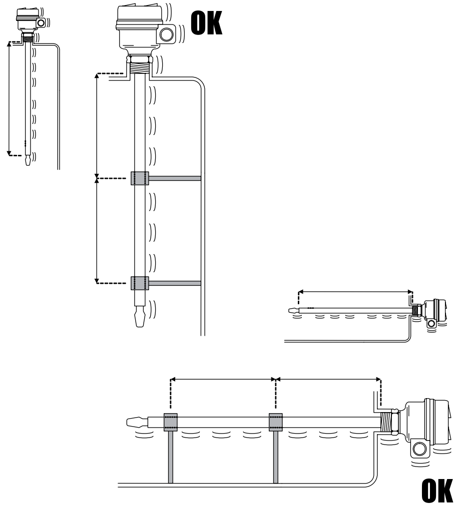


Figure 5.5.3: Support fork if high dynamic loads

6 Documentation

Topic **Page**

6.1.1 Application notes - Guided wave radar

In this section, we show some examples of what we have done with Guided Wave Radar transmitters in the refining industry.

Some of the examples are of specific product models; however, all the applications done with the 3300 can also be carried out with the 5300 if higher sensitivity and performance is needed.

Refinery Increased Throughput and Reduced Safety Risks with Direct Switch Technology

RESULTS

- Decreased risk of production interruptions
- Reduced safety and environmental risks
- Lowered operating costs

The Rosemount 5301 HTHP reduced operating costs by eliminating trips to the field to verify fuel oil supply.

APPLICATION

Fuel oil buffer tank level monitoring

Application Characteristics: High temperature and high viscosity hydrocarbon

CUSTOMER

Leading refinery in southeast Asia

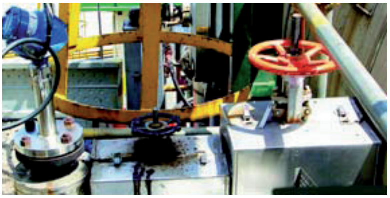
CHALLENGE

This refinery was having problems maintaining sufficient fuel oil storage in its buffer tank. This buffer tank is used to store fuel oil from various refinery sources and supplies fuel to refinery process heaters.

Accurate supply management of fuel oil needs a reliable level tank measurement. A remote seal DP level transmitter was originally installed on this buffer tank. However, the deposition of solids and coke on the diaphragm seals at high temperatures of 600 °F (315 °C) and the high fuel oil viscosity created inaccurate measurements.

A DP transmitter was replaced with a non-Emerson, non-contacting radar level transmitter. Heavy hydrocarbon vapors caused condensation on the antenna seal. Therefore, the previously installed transmitter could not provide an accurate and continuous level measurement due to attenuation of the signal.

The unreliable level measurement created negative business impacts on this customer. There was a high risk of frequent heater interruptions, risking plant availability and throughput. There was a high risk, and in some cases tank overfills, which caused safety and environmental incidents. Due to the unreliability of the previous level measurement, operating costs were higher as a result of frequent trips to the field by operators to verify available fuel oil supply.



Rosemount Guided Wave Radar site installation

REFINING

SOLUTION

This customer's problem was solved by installing the Rosemount 5301 High Pressure, High Temperature Guided Wave Radar Level Transmitter in a 3-in side chamber. This level transmitter was not affected by the buffer tank conditions, such as: vapor condensation, high viscosity, or coke formation in the process fluid at high temperatures. Due to the Direct Switch Technology within the 5301, the transmitter minimized signal loss and ensured a high signal to noise ratio for a reliable and robust level measurement. Since the 5301 is not affected by changing densities or viscosity, the accuracy of the measurement was greatly improved.

The Rosemount 5301 Guided Wave Radar allowed this refinery to decrease the risk of production interruptions of process heaters with an accurate level measurement of the available fuel oil supply. Safety and environmental risks were also minimized due to the reduced risk of spillage. Trips to the field to verify the available fuel oil supply were virtually eliminated, thereby reducing operating costs.

RESOURCES

Rosemount Level

http://www.emersonprocess.com/rosemount/products/level/index.html

Rosemount 5300 Product Data Sheet

http://www.emersonprocess.com/rosemount/products/level/m5300.html

Rosemount 5301 Guided Wave Radar with an HTHP Probe

Guided Wave Radar Improves Reliability of Desalter Interface Measurement While Reducing Maintenance Costs

RESULTS

- Improved efficiency of desalter
- Reduced maintenance costs
- Significantly decreased process downtime

APPLICATION

Crude Desalter Interface Level Control

Application Characteristics: Crude oil on water with 6 inch (150 mm) emulsion layer in a vessel with a 10 KV electrostatic grid. Crude oil density varies with supply.

With the use of Guided Wave Radar, maintenance and associated downtime was eliminated.

CUSTOMER

A North American refinery

CHALLENGE

Raw crude coming into a refinery contains varying degrees of salt contaminants. If the salt contaminants are not removed, they can cause significant corrosion of downstream process equipment as the oil is heated to high temperatures in the refining processes. These contaminants are removed in a desalter where the crude and water are separated.

This refinery receives their crude oil from a variety of sources. Every time the oil supply source changes, they have to make adjustments to the interface level instrumentation in the desalter to accommodate for the varying salt content and crude gravity.When operators do not have confidence in the interface reading they will operate the desalter at a lower interface level to prevent tripping the unit. This reduces the efficiency of the desalter, increases downtime, and decreases throughput.

To remove the salts, emulsifying chemicals and water are mixed with the oil to wash the salts out of the oil. This emulsified oil water mixture then needs to be separated quickly and efficiently. A desalter separates crude oil from water using an electro-static grid operating at about 10KV. The grid causes the dispersed water droplets and salts to coalesce and drop to the bottom of the vessel. This electro-static field operates at maximum efficiency when the water and oil interface is maintained at a level just below the electrostatic grid. A reliable interface measurement just below the composite electrodes allows the desalter to run at optimal efficiency without the risk of water getting into the grid.

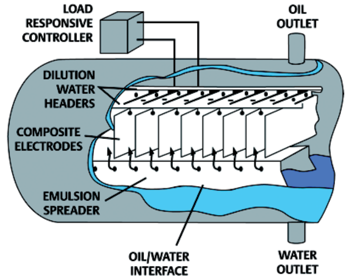


Diagram showing internal parts of a desalter. The water level must be kept below the electrodes.

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This application is a challenging interface measurement. The oil and water layers both have changing properties. The properties of the oil, especially the API gravity, change with different crude supplies. The water density will change with the amount of contaminants. In addition, the presence of the emulsion, or rag layer, creates an indistinct interface between the fluids.

Displacer/Float technology was previously used to measure the interface level, however, every time the oil density changed the displacer had to be re-spanned, which increased maintenance time and costs. If the torque tube required recalibration, the desalter had to be taken out of service.

SOLUTION

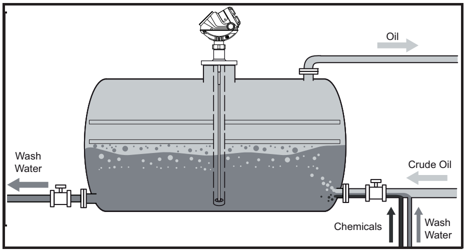
Rosemount Guided Wave Radar for level and interface with a flexible probe was installed in a 6" stilling well with slots. The still pipe minimizes the effect of the emulsion layer and protects the probe from interference from the electrical grid.

The instrumentation team for this company had been using Rosemount Guided Wave Radar level transmitters on a variety of applications within the refinery. They were pleased with the advantages that it provides. Of particular interest was its immunity to density changes caused by the varying levels of salt in the supply crude.

To verify that the interface level was correct, operators were able to manually check for the presence of oil or water by using a series of taps on the side of the vessel. The interface reading from the Rosemount Guided Wave Radar corresponded between the correct oil and water taps. In addition, the control shows a stable trend line and they are able to control within 3 to 4% of the set point.

The unit has been running for over a year without incident. Efficient operation of the desalting unit can minimize corrosion and fouling in downstream process units. Additionally, controlling the percentage of water in oil can reduce the potential of over pressuring the distillation columns.

With reliable interface level control, the desalter was able to operate more efficiently with reduced water and salt carryover to the crude unit, and also prevented oil from going out with the water into the sewer system. The need for maintenance and adjustment of the previous level devices and the associated downtime was eliminated.



The GWR is installed in a slotted stilling well in the desalter. The interface measurement is below the electrostatic grids.

RESOURCES

Rosemount Guided Wave Radar Products

http://www.emersonprocess.com/rosemount/products/level/index.html

Guided Wave Radar Transmitter Improves Oil/Water Interface Detection Reliability

RESULTS

- Reduced maintenance
- Measured interface accurately
- Easy retrofit of existing displacer technology

APPLICATION

Oil and water separator interface measurement

Application Characteristics: Low dielectric (dielectric < 3) oil on top of high dielectric water; frequent density changes

CUSTOMER

A major refinery in the U. S.

CHALLENGE

The refinery had several oil/water separators which used displacer based transmitters for interface detection. The goal was to allow the oil and water to separate and then send the water to the wastewater facility and the oil back to the refinery stream. The oil in the separator came from various sources which caused varying oil density.

The displacer based transmitters were adversely affected by the changing process density, resulting in an inaccurate interface measurement. This resulted in oil occasionally being sent to the wastewater facility. An alternative technology which was not affected by varying densities and offered reduced maintenance was sought.

Cost was a key factor in the choice for a more reliable solution. Ideally the refinery wanted to re-use the existing displacer cages and to find a technology that avoided the need for density compensation.

SOLUTION

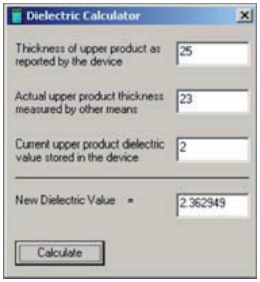
Emerson offered the Rosemount 3300 Series Guided Wave Radar Transmitter as the solution. This measured the interface with no affect from the changing oil density, thus providing an accurate and reliable measurement. The refinery was also able to re-use the existing cages resulting in a simple and low cost retrofit.

The Rosemount 3300 was chosen as a best fit for this application in part because configuration was simple. This configuration involved setting the

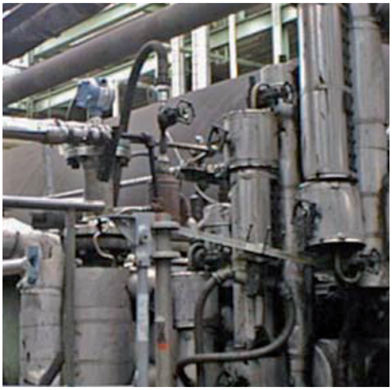
REFINING

measurement mode, the probe length, the range values and the dielectric of the oil. To determine the fluid dielectric, the water was temporarily removed and the chamber was flooded with oil. While in this condition, the peak created by the end of the probe (a known distance) and the dielectric calculator in Radar Configuration tools were used to determine the dielectric.

When first installed, the Rosemount 3300 was mounted next to the displacer so both devices detected the same interface. Through trial and error, the refinery found the Rosemount 3300 to be more accurate for tracking the interface. They since switched to the 3300 for control of their separator.



The dielectric calculator in the Radar Configuration Tools



When first installed, the 3300 was mounted next to the displacer so both devices detected the same interface.

RESOURCES

Rosemount 3300

http://www.emersonprocess.com/rosemount/products/level/m3300.html

Rosemount Technical Note - Replacing Displacers with Guided Wave Radar

Document Number: 00840-2200-4811

Guided Wave Radar Upgrades the Measurements at Petro-Canada™ in Wildcat Hills

RESULTS

- Maintenance virtually eliminated
- Continuous online measurements
- Minimized start-up time with easy to use software tools and diagnostic capabilities

The Rosemount 3300 Guided Wave Radar was chosen for its diagnostic capabilities and easy-to-use software tools.

APPLICATION

Gas Condensate skim tanks

Application Characteristics: Low dielectric, some coating

CUSTOMER

Petro-Canada Gas Plant, Wildcat Hills, Alberta

CHALLENGE

Two gas condensate storage tanks at the Petro-Canada Wildcat Hills Gas Plant had tape style level transmitters that were failing and needed to be replaced. Tape style measurement requires a great deal of cleaning and adjustment to get a valid measurement. The site wanted to stay with a top down, two-wire measurement.

SOLUTION

The plant considered Guided Wave Radar (GWR) to be a suitable replacement for the tape-style transmitters. It is a top-down, 2-wire technology that can tolerate light coating on the probes. It provides a direct level measurement that is independent of fluid changes. The Rosemount 3300 Guided Wave Radar was chosen for its diagnostic capabilities and easy-to-use software tools.

By switching to GWR, maintenance has been eliminated. GWR can tolerate buildup in the probes, and recalibration is not required. The devices are now continuously online and reliable.

The 3300 includes both installation and operational diagnostic capabilities. Dynamic Gain Optimization allows automatic adjustment of gain to maximize signal-to-noise to compensate for changes in the process. Intelligent Signal Processing works such that in the event of a lost signal, the 3301 can evaluate the last location of the level peak and the location of the end of the probe to determine if a tank is full or empty. Depending on the results, it will drive the mA signal to a high or low saturation value. This prevents over-spills. Other units simply go into alarm mode under similar

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www.emersonprocess.com/rosemount

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Guided Wave Radar Successfully Measures Level and Oil/Water Interface in a Pump Sump Pit

RESULTS

- Convenient installation and configuration
- Accurate and reliable level and interface information
- Eliminates level upsets and oil overflows

APPLICATION

Level and interface control in a pump sump pit

Application Characteristics: Low dielectric oil on top of high dielectric water

CUSTOMER

Preem Refinery, Gothenburg, Sweden

CHALLENGE

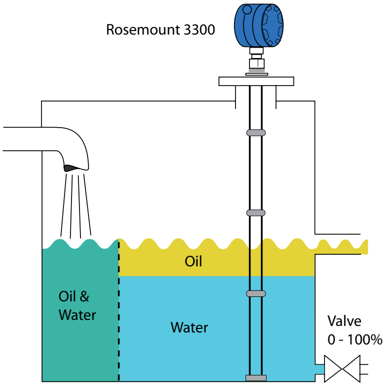
The level in the pump sump pit is measured for control purposes. The oily water separates in the sump pit, forming a top and an interface level. It is important to measure the overall level in order to prevent overfill of the sump. Knowing the interface level prevents the accidental removal of oil in the water outlet. It is of primary importance that the level measurement provides consistent and reliable information to avoid level upsets and subsequent overflow.

SOLUTION

Preem Refinery in Gothenburg installed the Rosemount 3300 Guided Wave Radar transmitter for this application. The 3300 is the first two-wire guided wave radar transmitter that simultaneously measures both level and interface.

The transmitter not only gives a correct reading of the upper surface, it also measures the thickness of the oil layer. This gives the opportunity to reliably separate the oil from the water. The probe used in this application is a rigid twin lead probe which is suitable for a viscous media like oil.

According to the customer, the installation of the transmitter was very convenient and the transmitter was configured with the user-friendly Radar Configuration Tool. Since the exact upper product dielectric constant was not known, the dielectric calculator (included in the software) was used. This feature enables the customer to calculate the upper product dielectric



For more information:
www.rosemount.com

REFINING

constant in a convenient and reliable manner which results in correct interface readings.

Preem Refinery is very pleased with the performance of the 3300. Since the installation in March 2002, it has provided accurate and reliable level and interface information for level control in the sump. The previous level upsets and oil overflows have been eliminated.

RESOURCES

Rosemount 3300

http://www.emersonprocess.com/rosemount/products/level/m3300.html

The Rosemount 3300 reliably measures level and interface in pump sump pits.

BP Achieves Worry-Free Interface Measurement with Rosemount Radar Technology

RESULTS

- Increased product quality through accurate, reliable interface measurement
- Reduced maintenance due to elimination of drifting problems
- Simple and fast setup
- Improved process efficiency

APPLICATION

Absorber-Stripper Separator Interface Level Control - Diesel Oil and Water Interface

Application Characteristics: Clean oil and water fluids; oil SG varies from 0.7 to 0.8; oil has dielectric of about 2, water has a high dielectric.

CUSTOMER

BP Refinery, Toledo, OH

BACKGROUND

This vessel is used to separate water from the oil. The oil is then fed back to the absorber for further processing and the water is routed to the treatment facility (see Figure 1). A properly functioning interface level transmitter helps to improve the efficiency of this process and decreases the potential for product hazing. Hazing occurs when the oil is contaminated with water.

- Measurement Range: 4 feet (1.2 meters)
- Pressure: 250 psig (17 bar)
- Temperature: 80-120 °F (27 - 49 °C)

CHALLENGE

This BP Refinery needed a more reliable interface measurement. They used a competitive probe for several years. While it provided a good interface measurement, it tended to drift and needed constant readjustments. Based on past experience with other technologies, BP wanted to stay with a device that had no moving parts.

Complicating the matter were changes in oil density. A change in specific gravity of 0.7 to 0.8 was very common. This ruled out mass-based measurement technologies.

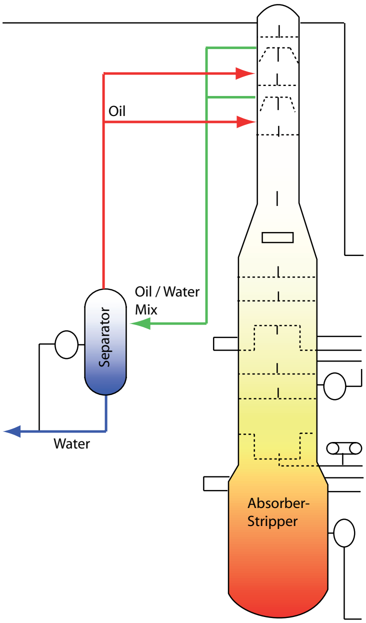


Figure 1: A diagram of the Absorber-Stripper with the separator and oil/water feedlines highlighted.

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SOLUTION

A Rosemount 3302 Interface Level Transmitter with a coaxial probe was installed in the separator in the spring of 2003. Like the previous probe, it has no moving parts and is unaffected by changing densities. The easy-to-use, yet comprehensive, software made the setup procedure very simple and fast, even for an interface measurement.

BP has been using the 3302 successfully since its installation and has not experienced any problems with drift.

RESOURCES

Rosemount 3300

http://www.emersonprocess.com/rosemount/products/level/m3300.html

Guided Wave Radar Saves $57,000 Annually for Gas Plant By Improving Measurement of Skim Tank

RESULTS

- Reduced frequency of changing filters from three times per week to once per week for annual cost savings of $57,000
- Reduced amount of water to separator, resulting in longer life expectancy and improved efficiency
- More consistent measurements

APPLICATION

Oil and water skim tank

Application Characteristics: 3,000 barrel salt-water disposal tank; 10-15,000 barrels of oil/water mixture flow through daily; changes in density.

CUSTOMER

Gas Plant, USA

CHALLENGE

A Gas Plant has a 3,000-barrel saltwater disposal tank. They run between 10 and 15,000 barrels of water per day through this tank. The incoming water is a mixture of oil and water and is put into the tank to separate. Knowing the location of the interface is important to the operation because they filter the water and re-inject it back into the ground. If oil comes through with the water, it plugs the filters and they have to be replaced.

This gas plant had been using a pressure transmitter on the tank in combination with a radar gauge to determine both the level in the tank and the interface level. Some very involved calculations have to take place to arrive at the interface level. In the equations, you have to assume a constant density so that the calculations will work. The problem is that the density is never constant and the results have never been accurate.

With this method, some filters were changed daily because of oil in the water. The operators were not able to skim the tank efficiently for fear of getting oil in the filters.

Rosemount 3300 installed on salt water disposal tank.

Some filters were replaced daily due to inaccurate level and interface measurement.

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Under normal conditions, it costs around $28,600 per year to change the filters on a weekly basis. When the oil goes through, the filters must be changed immediately. Of course, this is unplanned and takes people away from other tasks that they would be doing. This happened often with the old equipment. It was estimated that the filters were changed an average of three times per week at a cost of $85,800 per year.

SOLUTION

The solution implemented was a Rosemount 3302 Guided Wave Radar transmitter and a Rosemount 333 Tri-loop. The 3302 provided both overall level and interface level measurements using a standard 4-20 mA analog signal and a HART digital output. The tri-loop took the extra process variable on the HART signal and provided a second analog signal to the control system. The customer is able to skim the oil off the tank with a much higher degree of confidence than ever before. As a result of the Rosemount 3302 radar gauge, the gas plant is getting the expected life out of the filters and the process is more efficient.

With the Rosemount 3302, the customer is back to changing the filters once per week. This is saving the gas plant around $57,000 per year and had a payback of three weeks. The interface also helps with the oil side of the tank by reducing the amount of water that is sent to the separator. After going through the separator, the oil is sold to a pipeline which takes it to a local refinery. Reducing the amount of water the separator has to handle will prolong its life and make that process more efficient.

RESOURCES

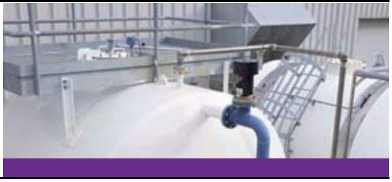
Rosemount 3300 Series Guided Wave Radar Level and Interface Transmitters

http://www.emersonprocess.com/rosemount/products/level/m3300.html

Guided Wave Radar Successfully Measures Level of Anhydrous Ammonia

RESULTS

- Accurate and reliable measurement despite heavy vapors
- Reduced maintenance problems
- Accurate level readings independent of density changes



APPLICATION

100% Liquid Anhydrous Ammonia

Application Characteristics: Clean fluid, heavy vapors, variable density

CUSTOMER

The Kerteh Terminals® in Malaysia

CHALLENGE

The Kerteh Terminals in Malaysia previously used a displacer to measure the level of anhydrous ammonia. Displacer technology is commonly used for low temperature applications. These applications can reach as low as -33° C.

When using the displacer technology, the customer faced many problems with the difficult measurement. First, the readings were inconsistent and did not match the actual level. Second, the density of ammonia often changes as it moves between vapor and liquid phases and can also change with moderate pressure or level changes. Lastly, the customer had to do frequent repairs and replace parts regularly on the existing displacer technology.

Because of the small span, heavy vapors, and changing density, differential pressure level and non-contact radar technologies are not good choices for the anhydrous ammonia application.

SOLUTION

The customer installed the Rosemount 3300 and found that it met their expectations. With its low frequency, the Rosemount 3300 is unaffected by heavy vapors that commonly attenuate higher frequency signals. The coaxial probe provides a strong signal that further enhances the level signal in this highly condensing environment. In addition, the Rosemount 3300 has no moving parts, making it virtually maintenance free.

With the Rosemount 3300, the customer has an accurate, reliable, and low maintenance level measurement.

Rosemount 3300 with a coaxial probe is suitable for heavy vapor applications.

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OIL & GAS

RESOURCES

Rosemount 3300

http://www.emersonprocess.com/rosemount/products/level/m3300.html

Rosemount Technical Note - Measuring Ammonia with Radar

Document Number: 00840-0100-4811

Gas Plant Cuts Maintenance Costs On Natural Gas Liquid Tanks with Guided Wave Radar Level

RESULTS

- Eliminated time consuming trips to the remote parts of the plant
- Annual maintenance savings of $17,188 per tank
- Provided accurate level reading

APPLICATION

Natural Gas Liquid Storage Tanks
Application Characteristics: Clean fluid, low dielectric (1.7)

CUSTOMER

BP Amoco, Painter Complex, WY

CHALLENGE

The BP Painter Complex gas plant removes liquids from natural gas. To accomplish this, they chill the gas coming into the plant allowing the liquids to condense and drop out of the gas. The Natural Gas Liquid (NGL) accumulates in large bullet tanks and is shipped to another facility for further refining. A continuous level measurement is needed because the operators need to know the overall amount of NGL at the plant for production reporting and product shrinkage.

Historically, level was measured using a dry leg installation with DP transmitters. The difficulty with this installation method was that with any significant temperature change or plant upsets, water would condense out of the gas and fill the dry leg. The instrumentation group would then have to send someone to the tanks to drain the leg and verify that the measurement was correct. With up to three trips per tank per week all winter, the cost for the maintenance on the dry legs on each bullet tank averaged $17,188 per year.

The 3300s were installed in February 2003 and have been working very well. No maintenance on the equipment has been required, nor do they expect any.

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OIL & GAS

SOLUTION

To solve this issue, the Rosemount 3300 Guided Waver Radar transmitter was proposed to make the level measurement and eliminate the dry leg. To use the 3300, BP had to modify the bridles on the tanks so they could mount the unit in the top. The 3300 was then able to be installed directly into the NGL-filled bridles. The 3300s were installed in February 2003 and have been working very well. No maintenance on the equipment has been required, nor do they expect any.

If adjustments are needed, the techs are happy with the supplied Radar Configuration Tools (RCT) software. They can communicate with the instrument from anywhere on the 4-20mA loop so they don't have to go out into the cold to find out what is wrong. Because it is so easy to use, they can make adjustments and run advanced diagnostics without having to wait for a service person or specialist to come on site to help them.

The tanks are now running in an automatic mode and operators do not have to physically check the tanks any more. Payback for each tank was about six weeks. Operators are now relying on the level measurement and the tanks are used to their design capacity. Confidence in the measurement is at an all-time high. Process variability is down and efficiency is up.

RESOURCES

Rosemount 3300 Series Guided Wave Radar Level and Interface Transmitters

http://www.emersonprocess.com/rosemount/products/level/m3300.html

Payback for each tank was about six weeks. The plant will have annual maintenance savings of $17,188 per tank.

Guided Wave Radar Successful in Liquid Propane Accumulator Level Application

RESULTS

- $350,000 savings in upgrade costs
- Provided a reliable measurement for a problematic application
- Accurate level measurement was detected immediately

"Emerson worked with us, presented a solution, and now our control system is working for the first time."

Gerald East
Instrument/Electrical Reliability

APPLICATION

Distribute liquid propane, which is used as a refrigerant, to several coolers.

Application Characteristics: Propane accumulator; turbulence, low dielectric, variable density, temperature variations;

CUSTOMER

Chevron Phillips® Chemical Company, Borger, Texas

CHALLENGE

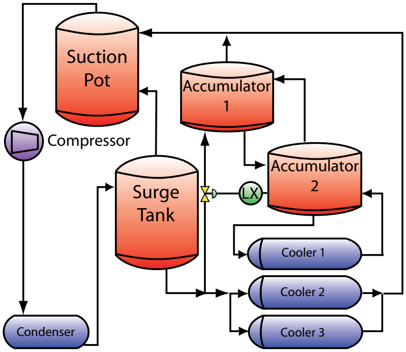
Chevron Phillips Chemical Company is a specialty chemical processing facility that creates over 400 different chemicals that are used by various industries. The Commercial Products Unit (C.P.U.) of the facility has some measurement applications that require special application engineering. One of the difficult level measurements is a propane accumulator used in their refrigeration system.

The intent of the design was to distribute liquid propane, which is used as a refrigerant, to several coolers. To control the distribution and ensure its availability, the propane was collected in accumulators. Once a sufficient level was obtained in the accumulator, the propane could be diverted to other coolers.

Unfortunately, because of the turbulence, low dielectric, variable density, and temperature variations of the propane, it was difficult to obtain a reliable measurement on the secondary accumulator. Since the level appeared to be insufficient, the valves were never able to send propane to the other coolers.

SOLUTION

Emerson Process Management presented Rosemount 3301 Guided Wave Radar (GWR) technology as a possible solution. The radar was a possible solution because it works well in applications where density and temperature changes are common. With GWR, a radar signal is



CHEMICAL

sent down a probe within a concentrated area. The range of measurement is more contained and the signal to noise ratio was much higher, allowing it to work better in low dielectric, turbulent environments.

Chevron Phillips agreed to try a field test version of the Rosemount 3301 with a coaxial probe. Using existing process connections, a bridle was constructed to allow the installation of the Rosemount 3301, replacing a sight glass and differential pressure transmitter. A coaxial probe was used because of its ability to maximize the signal-to-noise ratio for this dielectric fluid. The overall range of the measurement was approximately 5 feet (1.5 m).

The propane level was detected immediately. The Rosemount 3300 has made accurate measurements for several months and Chevron Phillips considers the problem solved.

Since the Rosemount 3300 was able to make this measurement, the accumulator was found to be functioning correctly. Plans for an upgrade to the accumulator was cancelled. The upgrade cost was estimated to be $350,000.

Gerald East, Instrument/Electrical Reliability, said his confidence in Rosemount products has reached a new level because of the Rosemount 3301. “When Rosemount beta products come in, they are just expected to work whereas with new technologies from other companies, expectations are not nearly as high.” Mr. East has never been able to rely on any type of level measurement in this particular application and tried to work with other vendors to find a solution but was never presented with any. “We looked at all of our choices and tried to work with a vendor who could present us with a reliable solution. They either never came through or their representative would say one thing and their literature would say another. Emerson worked with us, presented a solution, and now our control system is working for the first time.” Referring to their trend charts, Mr. East can clearly see the changes in his tank and is confident that what he sees on his screen is what is really happening in the tank.

Phil Moran, C.P.U. Operations Director, said the transmitter has worked perfectly in an application that has been nothing but problems. “We have never had a reliable measurement out of that tank. This is the first time that system has worked effectively and we have other applications that we’d like to try that unit on too when it becomes available.”

RESOURCES

Rosemount 3300
http://www.emersonprocess.com/rosemount/products/level/m3300.html

6.1.2 Application notes - Non-contacting radar

Refinery Improves Safety and Reduces Maintenance Cost in Blowdown Drum

RESULTS

- Accurate on-line monitoring
- Eliminated expensive maintenance associated with mechanical tank gauges
- Level measurement unaffected by density
- Rapid level changes detected and tracked

APPLICATION

Blowdown drum level measurement

Application Characteristics: Mixtures of fluids lead to changing density and changing dielectric; rapid level changes and turbulence during fill process

CUSTOMER

Refinery

CHALLENGE

If there is a malfunction in the refinery process, gases and liquids are evacuated to the blowdown drum through safety valves and piping. In this case, the tank is filled uncontrolled through a Ø 42 in. (1.1 m) pipe connected horizontally to the tank. Gases and liquids transported to the tank are typically light and heavy hydrocarbons, occasionally containing considerable amounts of water.

A safety study made by the third party inspection authority, SAQ, and the refinery determined the highest allowed level in the tank. The study was based on an API Standard and resulted in a maximum filling height of 9.8 ft (3 m) in normal operation. This is to ensure that there is enough space left for emergency situations. The liquids are analyzed at the 4.6 ft (1.4 m) level to decide where to pump them. At 6.5 ft (2 m), the liquids are pumped to other storage tanks. When the level gets down to 3.3 ft (1 m), the pump stops. The gases in the tank are transported through a Ø 20 in. (0.5 m) pipe from the top of the tank to the flare.

Critical Factors

It is important to have reliable level measurement as part of this alarm system. If the blowdown drum is overfilled, the liquids will flow into the gas outlet pipe which can cause the safety valves in the inlet pipe to malfunction. If the level is too low, it can result in pump failure.

The blowdown drum is 28 ft (8.5 m) high but the required measuring range is approximately 9.8 ft (3 m). The tank can be filled to a maximum of 9.8 ft (3 m).

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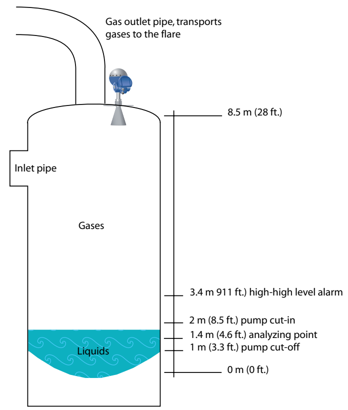
Large density differences and solid contents make level measurement difficult. Before installing the Rosemount 5600 Radar Level Transmitter, the refinery had a mechanical tank gauge in a stand-pipe (bridle) outside the tank.

SOLUTION

The change to the 5600 improved the reliability and accuracy, and avoided expensive maintenance. Another advantage is that radar measurement is not affected by density. Before the 5600 was installed, the error span could be more than 20 in. (500 mm) because of density differences between the product in the bridle and the tank.

A Rosemount 5600 was installed on the existing 2-in. (50 mm) nozzle on the tank roof. A 6-in. (150 mm) cone antenna located under the tank roof was used, and special arrangements were made to fit the nozzle.

The 5600 transmitter provides a reliable level measurement independent of fluid properties. The 4-20 analog signal representing the level is sent to the control system and is used as part of the pump control scheme to ensure that the pump does not run dry. The signal is also used to alert the operator to run the analysis of the liquid. Limit values are set in the DCS system for low level alarm, pump cut-off, analysis of product, pump cut-in and high level alarm.



The blowdown drum at the refinery serves as an accumulator for the refinery process. The Rosemount 5600 measures level and communicates the measurement to the DCS.

RESOURCES

Rosemount 5600

http://www.emersonprocess.com/rosemount/products/level/m5600.html

Dependable Level Measurement in a Liquid Propylene Tank

RESULTS

- Reduced maintenance with better stability and reduced fouling
- Removable electronics and process seal reduced downtime
- Reduced number of false readings, even while coated

APPLICATION

Liquid propylene tank

Application Characteristics: Pressurized propylene tanks; interruption-free measurement

CUSTOMER

Plastics Factory

CHALLENGE

In this application, it is vital that the level measurement works without interruption since the pressurized tanks are only taken out of service every three to five years. Earlier contacting technologies proved unreliable and required maintenance as they would often foul and cause erroneous readings which could lead to costly overfill situations. In addition, it is critical for the production group to know what available propylene stock is on-site for production mixing.

SOLUTION

Rosemount 5600 Radar Level Transmitters were installed in these production propylene tanks which delivered the tank level values with 4-20 mA signals. These inputs are transmitted to the control room where the measurements are then converted to volume. When the tanks are filled, the measured volume is compared to the weight of the rail tankers, double checking the values and ensuring performance.

The decision to use the Rosemount 5600 has improved reliability and accuracy, and enabled removal of the electronics without taking the vessel out of service. Another advantage to using the 5600 in these situations was that it was easier to install over previous technologies. By using these instruments, no modifications to the vessels were required, thus lowering maintenance costs through saved time and infrastructure customization.

The Rosemount 5600 Radar Level transmitter is mounted on the flange on the tank roof.

ROSEMOUNT

For more information:
www.rosemount.com

EMERSON
Process Management

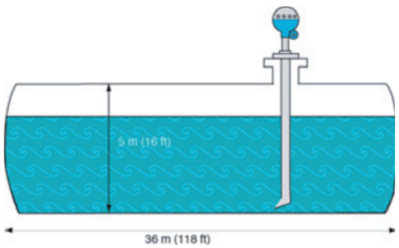
CHEMICAL

The decision to use the Rosemount 5600 has improved reliability and accuracy, and enabled removal of the electronics without taking the vessel out of service.

Installation and Configuration

The 5600 level transmitter is directly mounted on the existing tank nozzle with a stainless steel pipe and flange which is commonly in place. This transmitter allows for wide installation flexibility. In this application, a two inch stilling well was mounted inside a six inch nozzle. The 5600 was supplied with a six inch flange and a two inch antenna.

Once the transmitter was mounted, initial setup was conducted using a HART® modem and a laptop computer in the control room. No additional tuning was required after the initial setup. This made the measurement point very easy to install, and also saved maintenance time and costs.



Plastic factory liquid propylene stored in a bullet-shaped tank.

RESOURCES

Rosemount 5600

http://www.emersonprocess.com/rosemount/products/level/m5600.html

Robust Level Measurement Provided for Lube Oil Blending Tank

RESULTS

- Reliable level measurement despite turbulence
- No affects from vapor space changes
- Maintenance-free operation

APPLICATION

Blending Tank

Application Characteristics: Low dielectric, turbulent fluid with vapors, internal obstructions

CUSTOMER

A major oil company in South-East Asia

CHALLENGE

This oil company uses Base Oil for blending into lubricants. The blending process is comprised of mixing in chemical additives, heating, and agitating the mixture.

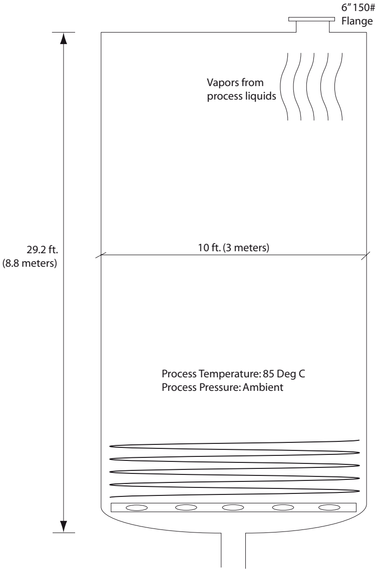
A pulsed air system causes the agitation required for the blending process. This also causes the tank to shake and vibrate vigorously. Running steam through serpentine type coils heats up the process to 85° C (185° F). With the combination of agitation and heating fluctuations, the surface of the fluid becomes very turbulent.

The previous ultrasonic level transmitter failed due to heavy turbulence caused by the agitation. The heated process environment caused vapors to form. The resulting condensation also contributed to the failure of the ultrasonic. The customer needed a reliable device that would overcome those problems and provide an uninterrupted level reading.

SOLUTION

A Rosemount 5401 low frequency radar transmitter with a 6-in. cone antenna was installed on this blending tank. With radar, the level measurement accuracy is unaffected by changes in the vapor space.

The Rosemount 5401 was a great fit for this application with vapors and turbulent surface conditions. The low frequency signal of the Rosemount 5401 is better able to handle condensing vapors than a high frequency device. The transmitter also uses dual port microwave technology that results in a two times better signal-to-noise ratio than other radar transmitters. This is especially important in low dielectric, turbulent applications where the return signal can be very weak.



Blending oil tank with pneumatic agitation and steam coils

ROSEMOUNT

For more information:
www.rosemount.com

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Process Management

OIL & GAS

In addition, the cone antenna design of the 5400 is more resistant to the build-up of any condensation. Combining the low frequency microwave signal with the dual port technology and a condensation resistant antenna delivers a reliable level measurement for this application with heavy condensing vapors and turbulence. The end result is a maintenance free reliable level measurement.

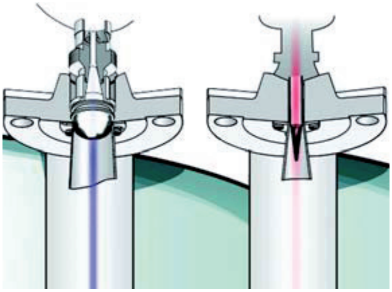
To ensure continuous reliable operation on the tank, radar devices must be configured for the specific tank to be able to handle false echoes and influences from tank obstructions, the bottom, and the roof. The false echo handling software includes several parameters including:

- amplitude threshold curves
- inactive zones
- bottom echo handling
- false echo registration

The false echo registration enables weak surface echoes to pass strong false echoes. It is important that the echo handling of the radar is configured for the specific application to ensure a reliable and continuous measurement. For many radar devices start-up can be time consuming, especially with difficult applications.

The 5400 series reduces the start-up time considerably because it has a built-in function block called “Measure and Learn.” When activated by the user, this function block automatically selects the best false echo suppression tools and settings by using a series of logic decisions. The built-in logics of the Measure and Learn functionality are a result of 30 years of radar experience.

The customer finds the Rosemount 5401 to be an ideal, reliable solution for this application.



The cone antenna design of the 5400 (left) is more resistant to condensation build-up. Combining the low frequency microwave signal with dual port technology and the condensation resistance delivers a reliable measurement.

RESOURCES

Rosemount 5400

http://www.emersonprocess.com/rosemount/products/level/m5400.html

Using Non-contacting Radar on Underground Flare Knockout Tank Reduces Costs

RESULTS

- Saved $10,000 per year in operation and maintenance costs
- Enables automatic control of level, reduced flare emissions, and full use of tank capacity
- Trending software enables correlation of level measurement to process events

Since the operator confidence in the level measurement was much higher, the tanks were able to be automated and utilized to their capacity.

APPLICATION

Flare Knockout Tank

Application Characteristics: Mixture of oil/hydrocarbons and dirty water that tends to leave deposits on surfaces

CUSTOMER

Petro-Canada

CHALLENGE

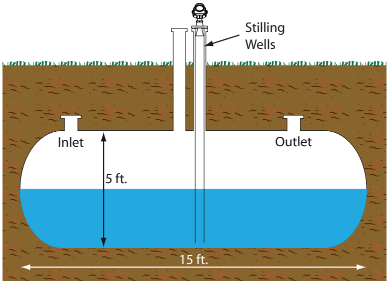
A Flare Knockout Tank is typically an 8' x 24' (2.4 m x 7.2 m) horizontal bullet vessel used for liquid removal and short term storage upstream of a hydrocarbon processing plant flare system. Fluid in knockout vessels is mostly water along with some hydrocarbon which is subjected to further processing in the plant.

In cold climates, flare knockout tanks are often buried at least 8 feet (2.4 m) underground to prevent freezing. The simplest way to access the tank is with a stilling well that begins above ground and reaches down to the bottom of the vessel. These particular tanks have stilling wells with only 1.5 or 2” diameters.

Because of accessibility, only top down level technologies can be used. Mechanical float technologies have been used, but the coating tendencies of the oily water mix required regular cleaning. Guided wave radar was another option, but would require long rigid probes which could be damaged during shipping and installation. Even a slightly bent probe can create a false level where it touches the surface of the pipe. High level switches have also been attempted, but they too were unsuccessful. Due to maintenance and unreliability of the level devices, Petro-Canada had not been able to automate these tanks. In order to prevent overfill and maintain plant safety, trucks were sent to empty them sooner than was necessary.

SOLUTION

Given the constraints, radar is a good solution for this application. By using non-contacting designs, maintenance issues are eliminated. With narrow diameter stilling wells, it is necessary to use a radar device with a suitable antenna.



The flare knockout tanks are buried underground for insulation from the Canadian winters.

ROSEMOUNT

For more information:
www.rosemount.com

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Process Management

OIL & GAS

The Rosemount 5400 Series Radar Transmitter was the right fit for this application. Often for these applications, a best practice is to install a new small-diameter well that fits inside the existing well to ensure its integrity. When installing non-contacting radar in stilling wells, it is important that the antenna size matches the stilling well's inside diameter as closely as possible, preferably with a 1 mm or smaller gap between the antenna and the pipe wall. For this application, a Rosemount 5402 was installed on the existing flanged 3" (80 mm) diameter outer stilling well with a flanged 1.5" (40 mm) diameter inner stilling well, and the antenna was trimmed to fit the 1.5" well.

After installation, the device must be configured for the application. In the case of the Rosemount 5400, this process is very simple. The transmitter is shipped with Radar Master, an easy-to-use PC configuration tool. The wizard embedded in the software guides the user through the setup process. One of the elements of setting up a radar unit for use in stilling wells is the need to compensate for the change in propagation speed of the signal which naturally occurs in pipes. Radar Master automatically initiates this calculation when the user inputs the pipe's inside diameter. This function helps to optimize the performance of the device for this type of application.

When compared to competitive devices, the customer noted that the Rosemount 5400 was much easier to set up and the software was more intuitive. He also liked the trending tools that came as part of the package. Not only did it provide redundancy to the DCS trends, but it allowed the operators to focus more closely on the level readings corresponding to process events.

Since the operator confidence in the level measurement was much higher, the tanks were able to be automated and utilized to their capacity. This resulted in fewer trips to empty the tank and reduced trucking costs. By using the Rosemount 5400 in this application, Petro-Canada estimates they save about $10,000 per year in operational and maintenance costs. Being able to make this measurement reliably, eliminating the maintenance nuisances, and improving their operations made the Rosemount 5400 a good fit for this application.

The Rosemount 5400 was mounted on a stilling well shell. The antenna was trimmed to fit the smaller pipe inside

A view of the level trend from the DCS.

RESOURCES

Rosemount 5400

http://www.emersonprocess.com/rosemount/products/level/m5400.html

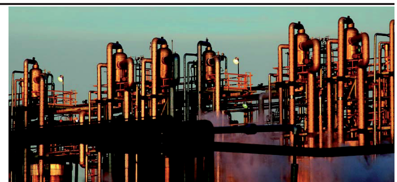
Rosemount Technical Note - Guidelines for Choosing and Installing Radar in Stilling Wells and Bypass Pipes

Document Number: 00840-0200-4024

Increase Molten Sulfur Throughput with Non-Contacting Radar Technology

PROPOSED RESULTS

- Reduce environmental risks
- Increase throughput by utilizing more sulfer storage capacity
- Reduce routine cleaning



APPLICATION

Level of molten sulfur in Sulfur Recovery Units (SRU)

Application Characteristics: Extremely harsh environment; high temperatures around 300 F° (149 C°) or more, splashing, and heavy vapors.

CHALLENGE

Due to environmental risks, refineries are faced with more stringent sulfur emission restrictions, and therefore need to maximize the efficiency of their sulfur recovery units (SRU). The purpose of an SRU is to recover sulfur present in acid gas streams before they are released into the atmosphere. The SRU removes the sulfur from acid gas streams by reacting with oxygen to convert the H_2S into elemental sulfur and water. The reliability of the removal process is important for meeting environmental regulations. Additionally, SRU performance is critical to the hydroprocessing throughput. Limited capacity of the SRU can act as a bottleneck, resulting in a loss of hydroprocessing throughput. Inaccurate level measurements and frequent maintenance of level devices prevent plant managers from maximizing the efficiency of their SRU.

SRU level measurements are challenging because temperatures reach around 300 F° (149 C°) , and sulfur fumes condense and coat on cold spots in the tank. Sulfur can build up fast and require labor intensive clean-up. Therefore, routine maintenance is a key component in successful SRU level measurements. Plant managers seek to increase the time between maintenance to reduce downtime.

Bubbler technology, an alternative level measurement, requires frequent maintenance. Plant managers want a level measurement device that can withstand the harsh conditions of the SRU and minimize routine cleaning. It is important to obtain a reliable measurement, allowing for greater utilization of the storage unit, creating higher throughput for processing acid gas.

The 5400 and 5600 provide reliable level measurements and monitor the health of the signal strength through advanced diagnostics.

Figure 1: The Rosemount 5400 series with process seal antenna

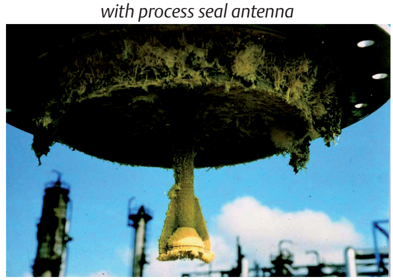


Figure 2: A Rosemount parabolic antenna coated in sulfur.

ROSEMOUNT®

For more information:
www.rosemount.com

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VALUE PROPOSAL

SOLUTION

Rosemount non-contacting radar products have proven to be successful in sulfur pits, tanks, and pipes. These units have been installed by a variety of leading refineries to strengthen the reliability of their molten sulfur level measurement. Emerson offers two models of non-contacting radar instrumentation, the Rosemount 5400 series and 5600 series. Both have been successful in molten sulfur applications. The Rosemount 5402 (high frequency option) with a 4-in. (DN 100) process seal is a good solution to this application. An advantage to the process seal connection is that it can be installed in a 4-in. (DN 100) nozzle rather than down in the pit. However, splashing sulfur will build up on cold spots, so it is recommended to have the nozzle or manway and radar antenna well insulated or heat traced. A gas/air purge or flushing connection works well as a backup, but heat tracing or insulation is essential.

Through correct installation and heat tracing, Rosemount Radar units can operate with routine maintenance of 6 to 12 month intervals or longer.

The Rosemount 5600 Series, 4-wire Radar transmitter, with a parabolic antenna is a strong solution for this application. Since a parabolic antenna is installed inside the pit or tank, the need for insulation/heat tracing is minimized, and it can tolerate a higher degree of coating. Figure 2 is an example of a Rosemount parabolic antenna coated with sulfur.

Correctly installed Rosemount radar units reduce the need for maintenance, increasing the intervals up to 6 - 12 months or longer. The advanced diagnostic capabilities of Rosemount radar units allow them to track signal strength as a process variable. This capability provides superior field intelligence to monitor the buildup and help predict maintenance . Figures 3 and 4 are plots of an installed Rosemount 5402 Non-contacting Radar Transmitter in a molten sulfur collection pipe at a leading refinery. Figure 3 shows the radar signal after 2 days of running with a non-insulated nozzle. The surface pulse signal is hardly distinguishable amidst the noise. Figure 4 shows the radar signal after being cleaned and with the nozzle insulated. The surface pulse is strong and easy to identify. This is an example of how the signal strength can be tracked to indicate that the unit needs to be cleaned. Now it is possible to run at 6 month intervals without cleaning.

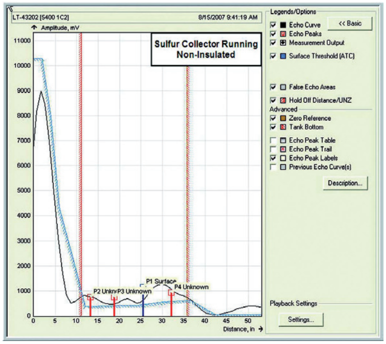

Figure 3: Radar signal in non-insulated nozzle.

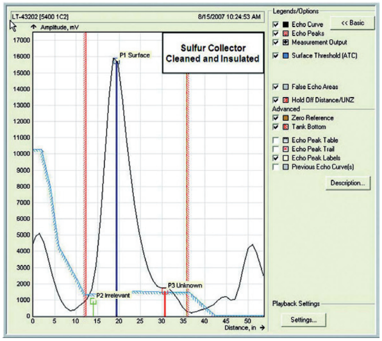

Figure 4: Radar signal after cleaning and insulation of nozzle.

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VALUE PROPOSAL

The Rosemount 5400 series and the Rosemount 5600 series provide a reliable and constant level measurement that allows for higher utilization of the storage vessel. Plant managers are more confident in the measurement output and therefore reduce the buffer zone and increase the operating limits. This increases the storage capacity of the vessel. Since sulfur is a highly regulated by-product, an increase in storage capacity can result in an increase in throughput and a reduction in environmental hazards. Additionally, heat traced nozzles and monitoring of the signal strength can help minimize and plan for routine cleaning. Correct installation of Rosemount radar transmitters can effectively save money through coordinated maintenance and grow profit through increased plant throughput.

RESOURCES

Rosemount 5400 Level

http://www.emersonprocess.com/rosemount/products/level/m5400.html

Rosemount 5600 Level

http://www.emersonprocess.com/rosemount/products/level/m5600.html

6.1.3 Application notes - Ultrasonic

Stormwater levels controlled and flooding eliminated for Australian water authority


1

RESULTS

- Flooding prevented in storm conditions
- Creek no longer runs dry
- Maintenance of water levels in all conditions

"The 3100s' were easy to install and program and are providing stable signals"

Site engineer

APPLICATION

Water levels in stormwater creeks

CUSTOMER

An Australian Water Authority

CHALLENGE

A water authority in Australia needs to control and maintain the water level in a stormwater creek, which normally drains to the sea.

The creek runs through a housing estate. During storm conditions, the level in the creek can rise dramatically causing local flooding in the estate and during dry conditions the creek runs dry, leading to unpleasant smells. The surface of the water in the creek gets very turbulent, particularly under storm conditions when waves of up to 1 metre can travel up or down the creek.

SOLUTION

The authority installed two creek water channels with penstock control gates and two large pumps which are used to maintain the water level in all conditions.

Four Rosemount 3100s' have been installed, two either side of each penstock gate to monitor the level across the penstock and control the gate. (Note: The gates are not installed in the figures (right), but the guide runners are clearly shown). To eliminate excessive turbulence at the measurement points, the 3100s' have been installed on 5" diameter stilling tubes.

Rosemount Ultrasonic level transmitters are perfectly suited to this type of installation provided some simple rules as given in the installation manual are followed. Typically, the stilling tubes must be 100mm (4") or larger, be smooth and free from any weld defects which could cause false targets and ideally be cut at 45 degrees at the end which should remain submerged under all conditions.

In this application the 3100s' provide a stable level signal to the penstock control equipment, and were chosen because of their programming simplicity, ease of installation and competitive cost.


2

Figure 1 Two 3100 transmitters mounted on 5" diameter 316 stainless steel stilling tubes.

Figure 2. 3100 transmitter located on the upstream side of the two channels and pen-stocks. (Penstock gates not installed at time of photo).

ROSEMOUNT

For more information:
www.rosemount.com

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6.1.4 Application notes - Switches

Prevent Overspills on Floating Roof Tanks with Alarm Switch Utilizing Wireless Technology

PROPOSED RESULTS

- Reduce environmental and safety risks from tank overfilling
- Minimize capital and installation costs
- Decrease risk of shutdown

The Mobrey DS20D provides a cost effective high level alarm measurement and the Rosemount 702 minimizes the capital costs associated with installation and labor.

APPLICATION

Level detection and alarm on a floating roof tank

CUSTOMER

Customers with floating roof tanks

CHALLENGE

Customers with floating roof tanks have difficulties finding a method to detect tank overfills. Floating roof tanks are considered a safety requirement as well as a pollution prevention measure for many industrial facilities.

Floating roof tanks do not have a fixed point of reference to mount a liquid level detection switch because the roof sits directly on the liquid. If the roof rises to a high level, it is necessary to signal an alarm and shut any feed line valves or pumps to the tank.

The absence of a secondary measurement for overfill protection could lead to overfills. Many brownfield facilities measure level on these tanks, but do not have a secondary high level alarm. Greenfield facilities find it difficult to incorporate high level protection in their designs.

Not having high level detection on floating roof tanks increases environmental and safety risks. Adding a secondary measurement adds to high capital costs with extra wiring, labor, and other installation costs. Lastly, the lack of a high level alarm measurement increases the risk of facility shutdowns from tank overfills.

SOLUTION

The Mobrey DS20D Vertical Switch with Rosemount 702 Discrete Input Wireless Transmitter, part of Emerson's Smart Wireless Solutions, solves the problems associated with tank overfills and high level alarm detection.

The hermetically sealed Mobrey DS20D has moving parts and contacts completely enclosed, making it reliable and suitable for use in corrosive atmospheres and low temperature environments.The Mobrey DS20D also has a built-in backup alarm switch mechanism in case of mechanical problems.

A Mobrey DS20D Level Switch with a Rosemount 702 Discrete Input Wireless Transmitter mounted on a chamber.

ROSEMOUNT®

For more information:
www.rosemount.com

EMERSON™
Process Management

VALUE PROPOSAL

In combination with the Rosemount 702 Discrete Input Wireless Transmitter, the Mobrey DS20D can send measurements using WirelessHART™ with greater than 99% data reliability. Also, the 702 utilizes a SmartPower™ module and provides a battery life of 10 years with one minute updates.

The Mobrey DS20D and Rosemount 702 offer innovative technology and easy implementation to make a positive business impact to your facility. These technologies can reduce safety and environmental risks associated with tank overfilling. The Mobrey DS20D provides a cost effective high level alarm measurement, and the Rosemount 702 minimizes the capital costs associated with installation and labor. Lastly, your facility will decrease the risk of facility shutdown from tank overfills by having a backup high level alarm.

RESOURCES

Mobrey DS20D and Rosemount Level Switches

http://www.emersonprocess.com/rosemount/products/level/index.html

Emerson's Smart Wireless

http://www.EmersonSmartWireless.com

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00860-0100-4030, Rev AA

Refinery Improves Operation of Critical Turbine Pumps with Vibrating Fork Technology

RESULTS

- Reduced the risk of damage to turbine pumps
- Decreased the risk of unit downtime
- Reduced safety risk

The monitoring of lube oil reservoir level greatly reduced the risk of emergency repairs and possible replacement of expensive turbine pumps.

APPLICATION

Low level monitoring of lube oil reservoir for turbine driven pumps

CUSTOMER

Refinery located in North America

CHALLENGE

This refinery was having problems with its turbine driven pumps. At times during operation, the pump bearings were running hot and damage was being caused to the primary and secondary pump seals.

The problem was caused by a low supply of available oil in the lube oil system reservoir. There was no level switch or other level monitoring of this oil reservoir that could alert the operators when the lube oil level became too low.

This resulted in several negative business impacts to this refinery. First, it increased the risk of capital damage to their expensive turbine pumps. Secondly, it increased the risk of unit downtime due to possible failure of the pumps. Lastly, personnel safety risks were higher due to frequent field inspections of the lube oil level in the reservoir.

SOLUTION

The customer solved this problem by installing a Rosemount 2120 Level Switch in the lube oil reservoir of the turbine pumps. The Rosemount 2120 activates an alarm if the oil level in the reservoir becomes too low and needs replenishment. There is a heartbeat LED mounted on the top of the device, which provided this customer with an easy way to check the status and health of the Rosemount 2120 without pulling the device out of the process.

Rosemount 2120 Vibrating Fork Liquid Level Switch

ROSEMOUNT

For more information:
www.rosemount.com

EMERSON
Process Management

REFINING

Installation of this lube oil level detection switch had several positive business impacts for this operation. It substantially decreased the risk of damage to their expensive turbine pumps, which could cause emergency repairs or replacement, resulting in unit downtime. Personnel safety risks were also reduced by decreasing their exposure to the process.

Typical turbine driven pumps with a dedicated lube oil system

RESOURCES

Rosemount 2120

http://www.emersonprocess.com/rosemount/products/level/m2120.html

6.2 Documentation - Technical notes

In this section, we have included technical notes in their full versions. These technical notes may have been referred to earlier in the handbook.

The technical notes are: **Page**

Replacing Displacers with Guided Wave Radar

KEY POINTS

- Mounting flanges vary by displacer supplier
- Probe must extend the length of the displacer chamber
- Single rigid probes are the preferred probe style for chamber installations
- Guided Wave Radar measurements are reliable even with vibrations, high turbulence, or density changes

Guided Wave Radar is immune to density changes and provides a low maintenance alternative to displacers.

INTRODUCTION

Rosemount Guided Wave vs. Displacers

Displacers are used for level, interface, and density applications, where the buoyancy of the displacer in the fluids is the primary measurement principle. Density of the fluid is a key factor in determining the sizing of the displacer and stability of the application, and any deviation from the initial density will impact the measurement accuracy.

Displacers have moving parts that require frequent cleaning and replacement. They are affected by mechanical vibration and turbulence, the mechanical parts can give false readings, and maintenance costs can be expensive.

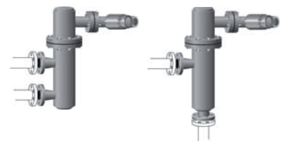
Guided Wave Radar (GWR) technology has no moving parts, which means a reduction in maintenance costs as well as improved measurement. GWR is not density dependent and provides reliable measurement even with mechanical vibration of high turbulence. Since existing chambers can often be used, replacement is simplified.

There are many displacer flanges and styles, so it is important to correctly match the 3300/5300 flange choice and probe length to the chamber. Both standard ANSI and DIN, are used, as well as proprietary chamber flanges with a non-standard diameter and gasket surface.

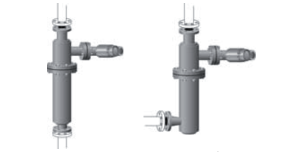
STEPS TO DETERMINING REPLACEMENT WITH THE 3300 OR THE 5300 SERIES

1. *Determine which measurement is needed: level, interface, or density?* GWR is an easy, direct replacement for level measurements. For interface measurements, the upper fluid must have a lower dielectric value than the lower fluid. See interface guidelines below for more details. For interfaces with thick emulsion layers, GWR can be unpredictable. Consider Emerson's high performance displacer transmitters instead. If density is the desired measurement, then GWR is not a solution; consider a differential pressure transmitter instead.
2. *Check Displacer chamber mounting style with the diagrams shown in Figure 1*

Figure 1: Displacer Chamber Mounting Styles



Can be retrofitted with Guided Wave Radar



Cannot be retrofitted directly with Guided Wave Radar.
Contact factory for assistance.

TECHNICAL NOTE

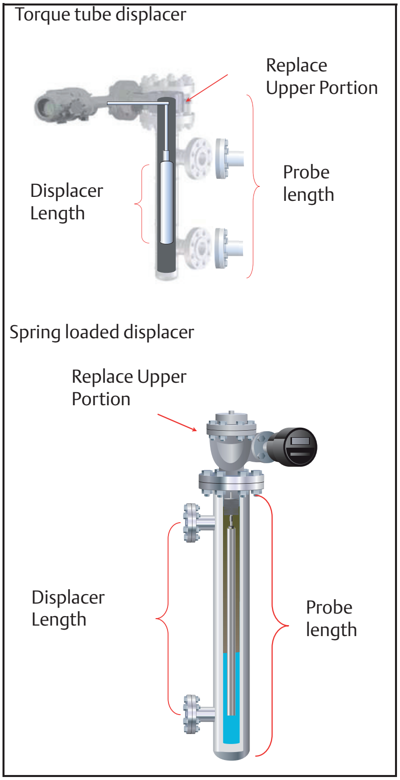
3. *Determine manufacturer and type of displacer chamber flange (proprietary, ANSI or DIN)*. The Outside Diameter (OD) of the chamber flange on top of the chamber can help determine if a proprietary flange is used:
   Major torque tube chambers
   249B and 259B OD: 9.0 in. (229 mm)
   249C OD: 5.8 in. (148 mm)
   249K: 10 in. (254 mm)
   249N: 10 in. (254 mm)
   Masoneilan OD: 7.5 in. (190 mm)
   All others: per ANSI or DIN specifications
4. *Determine from Figure 2 if it is a torque tube or spring loaded displacer chamber.*
5. *Determine probe length*. The probe length is measured from the flange face to the bottom of the chamber (internally) as shown in Figure 2 or listed in Table 1. While the probe needs to extend the full height of the chamber, it should not touch the bottom of the chamber. There should be a small gap (about 1/2 to 1 in. [12 – 25 mm]) between the end of the probe and the bottom of the chamber.

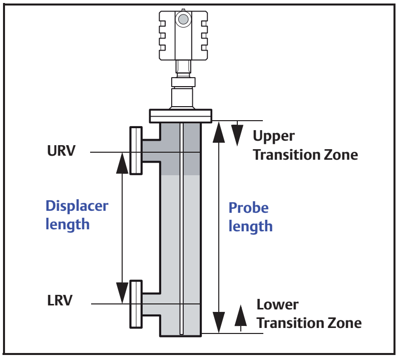
TABLE 1. Chamber Manufacturers with Probe Length Corrections

Chamber Manufacturer	Probe Length*
Major torque-tube manufacturer (249B, 249C, 2449K, 249N, 259B)	Displacer +9 in. (229 mm)
Masoneilan (Torque tube operated), proprietary flange	Displacer +8 in. (203 mm)
Other - torque tube**	Displacer+8 in. (203 mm)
Magnetrol (spring operated)***	Displacer+ between 7.8 in.(195mm) to 15in (383mm)
Others - spring operated**	Displacer +19.7 in. (500mm)

**If flushing ring is used, add 1 in. (25 mm)*
***For other manufacturers, there are small variations. This is an approximate value, actual length should be verified.*
**** Lengths vary depending on model, SG and rating, and should be verified.*

Figure 2: Probe Length is longer than displacer length





TECHNICAL NOTE

INTERFACE APPLICATION

Rosemount 3301/5301 Interface with a Submerged Probe

Many displacers are located on the vessel where they will only measure interface. In these applications, the upper part of the probe will be submerged in the upper fluid and only the interface of the two fluids is measured. The same interface guidelines about dielectric properties of the fluid apply for both submerged probe interface applications and where level and interface measurements are desired.

Submerged probe interface applications

Interface Application Guidelines

- Lower dielectric fluid must be on the top
- The two liquids must have a dielectric difference of at least 6
- The upper layer dielectric must be known (in-field determination is possible)
- The upper fluid layer thickness must be at least 4 in. (10 cm) for 3300 rigid probes and 5.1 in. (13 cm) for 5300
- Target applications; low upper layer dielectric (<3), high lower layer dielectric (>20)
- Dielectrics of oil and gasoline range from 1.8 to 4. Water and water-based acids have high dielectrics (>50)

Rosemount 3300 and 5300 Series

- Rosemount 3301/5301 can be used for level or interface measurements. Only interface is measured in the submerged probe mode. Flushing option should be used to eliminate air pocket
- Rosemount 3302 or 5302 can be used to measure both level and interface. These products are recommended if there is a large air pocket at the top of the chamber

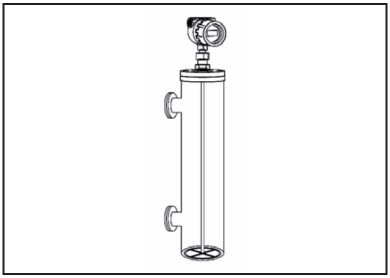
Probe Styles - single probes are available in standard and high pressure/high temperature versions

RECOMMENDED PROBE STYLES

Single rigid probes are recommended mostly for chamber installations. Exception is for high pressure (over 580psi / 40 bar) liquefied gases where the coaxial probe is preferred. Single lead probes are the easiest to clean and are the best choice for dirty or viscous fluids. Since the chamber walls help to amplify the signal, single probes can be used for interface measurement and measurements on low dielectric materials. Centering disks are recommended.

Chamberless Displacers

Displacers can be mounted directly in the vessel, usually suspended down a stilling well. In these cases, sizing is based on the overall height. Rigid probes are recommended, but if a flexible probe must be used, make sure to center the cable to prevent it from touching the sides of the well. If a flexible cable is used, a 4 in. (10 cm) stilling well is the recommended minimum size.



Rigid single probe style with centering disk

TECHNICAL NOTE

Flushing Connections and Vents

It is often desirable to vent the chamber near the top. This will ensure there is no trapped air or gas for submerged probe applications. Venting is also needed if the level in the chamber will be manipulated in order to verify the output of the 3300/5300 or to drain the chamber. The following options will accomplish this task:

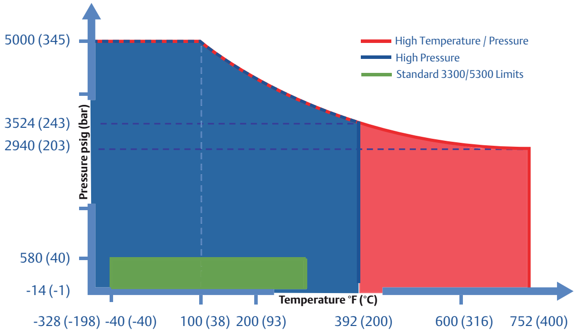
- A separate flushing ring may be inserted between the 3300/5300 flange and the chambers that use ANSI or DIN flanges
- Proprietary flanges are available with an integrated vent option. They are used with 1 $^{1}/_{2}$ NPT threaded probes.

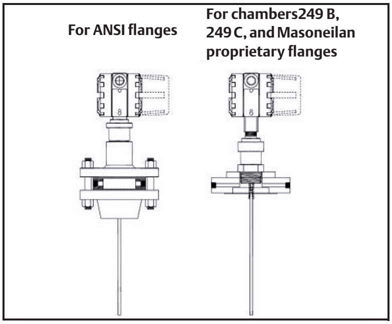
Pressure and Temperature

The standard Guided Wave Radar products may be used in applications up to 302 °F (150 °C) and 580 psi (40 bar). For higher pressures and temperatures, the high pressure/high temperature or high pressure probe is available. See Figure 3 for details.

The 5300 has a higher sensitivity and is recommended for all liquefied gas applications above 580 psi (40 bar) that need the High Pressure or High Temperature / Pressure probe, with the exception of fully submerged interface applications.

Figure 3: Pressure and temperature limits for standard, high pressure, high temperature/high pressure probes.





3300/5300 flushing ring/vent options

TECHNICAL NOTE

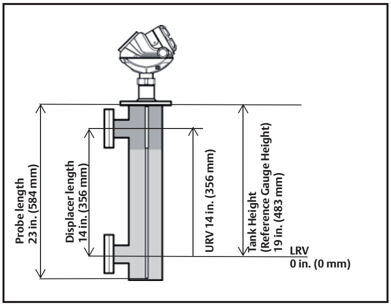
SETTING RANGE VALUES - THREE OPTIONS

Chambers are mounted on the tank to correspond with the desired measurement and area of control. This is often a small portion of the overall height.

With displacers, the output span corresponds to the displacer length. The lower (LRV) and upper range values (URV) represent the bottom and top of the displacer. In the side-to-side chambers, this corresponds to center-of-the-pipe connections to the vessel.

Option 1 - Setting LRV to 0 In.(0 mm) at the Lower Tap

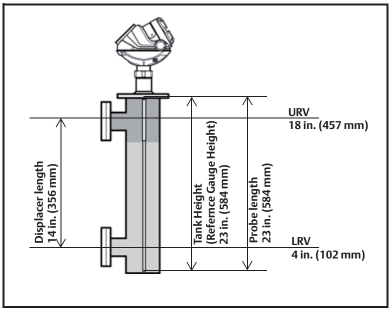
Set the Tank Height to the distance to the zero level point. In this example, it is the lower side-pipe which is located 19 in. (483 mm) below the reference point. Output range values will equal the pipe connection heights relative to the zero level point. LRV should be set at 0 in. (0 mm) and the URV should be set at 14 in. (356 mm). The probe should be set to the correct probe length.



Setting range values, Option 1

Option 2 - Matching Displacer Output

The tank height (reference gauge height) and the probe length should be set to the same value. The LRV is the distance from the bottom of the probe to the lower tap. The URV is the LRV plus the distance to the upper tap. In this example, Tank Height (Reference Gauge Height) equals the probe length of 23 in. (584 mm), the LRV is 4 in. (102 mm), and the URV is 18 in. (457 mm).

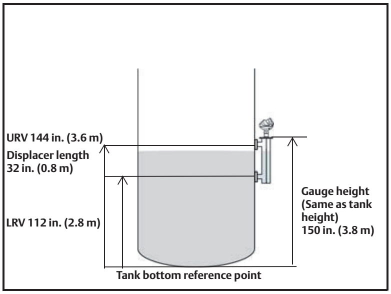


Setting range values, Option 2

Option 3 - Matching Actual Tank Level

For the level measurement to correspond to the actual level, the correct gauge height needs to be entered The LRV is the distance from the bottom of the tank, or the common reference line, to the lower tank connection tap. For the URV, simply add the tank connection distance. The actual probe length needs to be entered.

Example: Replacing a 32 in. (813 mm) displacer with a 41 in. (1041 mm) probe. The gauge height is the distance from the top flange to the tank bottom reference point. The probe length will be the actual probe length. The LRV setting will correspond to height of the lower tank connection relative to the tank bottom.



Setting range values, Option 3

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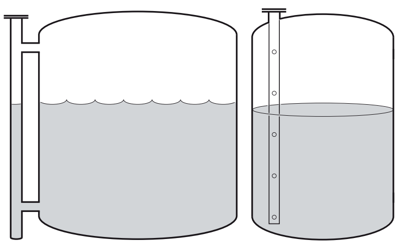
Rosemount Radar Transmitters

Guidelines for Choosing and Installing Radar in Stilling Wells and Bypass Chambers

INTRODUCTION

This document provides a guideline for choosing and installing Rosemount radar devices in stilling wells and bypass chambers.

Stilling wells and bypass chambers are used in many applications and many different types of tanks and vessels. The two installation methods will jointly be referred to as pipes. Radar transmitters can be used in these installations, but function differently in pipes than in normal vessel installations. This guide is intended to assist with radar device selection and installation for optimal performance.



Example of a bypass chamber mount (left) and a stilling well mount (right).

ADVANTAGES OF USING BYPASS CHAMBERS AND STILLING WELLS

Stilling wells and bypass chambers are used in many applications and many different types of tanks/vessels. The reasons for having the pipes in the vessels differ depending on the application but are typically beneficial from an application standpoint. Reasons for using pipes include:

Pipes offer a calmer, cleaner surface

A pipe can increase the reliability and robustness of the level measurement, especially for non-contacting radar.

It should be noted that the coaxial probe of a Guided Wave Radar (GWR) is essentially a probe within a small stilling well. It should be considered as an alternative to stilling wells for clean fluid applications.

Pipes eliminate issues with disturbing obstacles.

Pipes completely isolate the transmitter from disturbances such as other pipes, agitation, fluid flow, foam and other objects. The pipes can be located anywhere in the vessel that allows access. For GWR, the microwave signals are guided by the probe, making it resistant to disturbing objects.

Pipes may be more accessible to the area of interest

Bypass chambers may be located on a small portion of a tank or column and allow access to the measurement instrument. This may be especially important for interface measurements near the bottom of a taller vessel or for measurements in a distillation column.

Pipes allow instrumentation to be isolated from vessel

Bypass chambers often include valves to allow instrumentation calibration verification or removal for service.

Bypass chambers and stilling wells are not without limitations. Generally, pipes should be used with cleaner fluids that are less likely to leave deposits and that are not viscous or adhesive. Apart from the additional cost of installation, there are some sizing and selection criteria for the radar gauges that must be considered. This document outlines those considerations.

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Rosemount Radar Transmitters

WHICH RADAR TO USE: GUIDED WAVE RADAR OR NON-CONTACTING?

Although non-contacting radar works well in pipe applications, contacting or GWR may be a simpler choice. Non-contacting radar must meet certain installation requirements for optimum results. The GWR has simpler installation requirements and provides better performance than non-contacting radar. GWR can maintain its accuracy and sensitivity independently of the pipe.

GWR is the preferred technology for shorter installations where rigid probes may be used. This makes it a suitable replacement for caged displacers, which are often less than 10 ft. (3 m). (See Rosemount technical note 00840-2200-4811, Replacing Displacers with GWR, for more details.) The probes are available in a variety of materials to handle corrosive fluids.

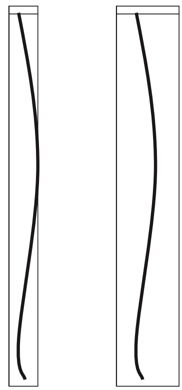
For taller applications or those with limited head space for installing rigid probes, non-contacting radar may be advantageous. Non-contacting radar is also the preferred technology for applications with heavy deposition or very sticky and viscous fluids.

INSTALLATION GUIDELINES FOR GUIDED WAVE RADAR

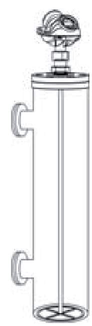
Using GWR in pipes: rigid or flexible?

In most cases, rigid probes are preferred for pipe installations. When used in a metal, small diameter pipes, single rigid probes offer a stronger return signal than when used in open applications. This makes them suitable for low dielectric and interface applications. Flexible probes may be used in longer pipes, but care must be taken to assure that the probe is suspended in a true vertical position and does not touch the pipe wall.

If flexible probes are to be used, the pipes should be 4” (100 mm) or larger to allow room for some flexing. Also, as fluid moves into the pipe, it may push the probe towards the pipe wall. If the probe touches the wall, false reflections may create false level measurements. Rigid probes are less susceptible to these issues. Flexible probes simply need more room. Very narrow pipes allow little room for movement or flexing of the probe.



Narrow pipes allow little room for movement or flexing of the probe.



A centering disk helps to keep the probe away from the chamber walls. It is recommended for single rigid probes. Its applicability with long flexible probes is more limited.

Pipe requirements

There are multiple styles and materials of probes available for the Rosemount GWR products. Table 1 shows the various options and where each may be used with regard to pipe size and length. GWR may be used in pipes made of metal, plastic and other non-metallic materials. All pipes will provide isolation from the process materials and conditions. Metallic pipes help to increase signal strength and shield the probe from EMI disturbances. If EMI is present and a non-metallic pipe must be used, then the Rosemount 5300 should be used.

TABLE 1. Probe Styles and Installation Considerations

Probe Style	Maximum recommended length of pipe	Centering disk?	Recommended pipe diameter	Minimum Dielectric(1) 3300	Minimum Dielectric(1) 5300	SST	PTFE Coated	Alloy C-276	Alloy 400
Single Rigid(2)	3 m (9.9 ft)	yes	8 cm (3")	1.7	1.25	yes	yes	yes	yes
Single Flexible	10 m (33 ft)	yes	15 cm (6")	2.0	1.4	yes	yes	no	no
Twin Rigid	3 m (9.9 f t)	no	8 cm (3")	1.9	1.4	yes	no	no	no
Twin Flexible	10 m (33 ft)	yes	15 cm (6")	1.6	1.4	yes	no	no	no
Coaxial(2)(3)	6 m (19.8 ft)	no	>3.7 cm (1.5")	1.4 (STD) 2.0 (HTHP)	1.2 (STD) 1.4 (HP), 2.0 (HTHP)	yes	no	yes	yes

(1) When installed in metal pipe

(2) Single and coaxial probes are available with process seals for high pressure and high temperature conditions. SST or Alloy C-276

(3) Coaxial probes are not recommended for submerged probe applications

TABLE 2. 3300: Transition Zones Vary with Probe Type when Installed in Metallic Pipes

Probe Style	Upper Transition Zone High Dielectric	Upper Transition Zone Low Dielectric	Lower Transition Zone High Dielectric	Lower Transition Zone Low Dielectric
Single Rigid(1)	10 cm (4")	10 cm (4")	5 cm (2")	10 cm (4")
Single Flexible(1)	15 cm (5.9")	20 cm (8")	19 cm (7.5")(2)	26 cm (10.2")(2)
Twin Rigid	10 cm (4")	10 cm (4")	5 cm (2")	7 cm (2.8")
Twin Flexible	15 cm (5.9")	20 cm (8")	14 cm (5.5")(2)	24 cm (9.4")(2)
Coaxial(3)	10 cm (4")	10 cm (4")	3 cm (1.2")	5 cm (2")

(1) Single probes are the preferred choice

(2) Includes weight

(3) Coaxial should only be used for very clean or low DC applications

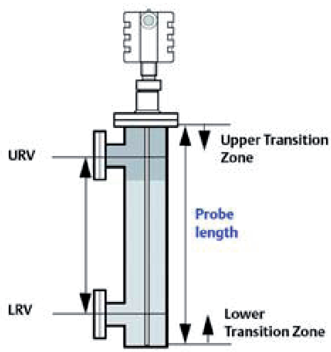
TABLE 3. 5300: Transition Zones Vary with Probe Type when Installed in Metallic Pipes

Probe Style	Upper Transition Zone High Dielectric	Upper Transition Zone Low Dielectric	Lower Transition Zone High Dielectric	Lower Transition Zone Low Dielectric
Single Rigid(1)	11 cm (4.3")	16 cm (6.3")	5 cm (2")	7 cm (2.8")
Single Flexible(1)	11 cm (4.3")	18 cm (7.1")	14 cm (5.5")(2)	19 cm (7.5")(2)
Twin Rigid	11 cm (4.3")	14 cm (5.5")	3 cm (1.2")	10 cm (4")
Twin Flexible	12 cm (4.7")	14 cm (5.5")	5 cm (2")(2)	14 cm (5.5")(2)
Coaxial(3)	11 cm (4.3")	11 cm (4.3")	10 cm (4")	14 cm (5.5")

(1) Single probes are the preferred choice

(2) Includes weight

(3) Coaxial should only be used for very clean or low DC applications



When sizing a probe for use in a bypass chamber, it is important to allow for some extra length for the upper and lower transition zones of the probe. Level measurements are compromised in these areas.

Rosemount Radar Transmitters

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INSTALLATION GUIDELINES FOR NON-CONTACTING RADAR

Using non-contacting radar in stilling wells and bypass chambers

When radar transmitters are used in metallic pipes, the microwave signal is guided and contained within the pipe. This restriction of the signal results in a stronger signal on the surface which can be an advantage for low dielectric and/or turbulent applications. Non-contacting radar can be advantageous over longer distances especially when the use of GWR is not convenient.

The impact of frequency

When radar is used inside the pipe, more than one microwave mode is generated and each mode has a unique propagation speed. The number of microwave modes that are generated varies with the frequency of the radar signal and the pipe diameter. Emerson Process Management recommends using a 2-in. or 3-in. pipe to minimize the number of microwave modes. The use of higher frequency radar transmitters should be restricted to smaller diameters. Conversely, lower frequency units perform better than higher frequency units on larger diameter pipes. Non-contacting radar transmitters should not be used on pipes larger than 8-in.

Low frequency radar handles dirty pipes, heavy vapors, and condensation better than high frequency units. High frequency may have slightly better performance, but should be used on clean applications. High frequency has better tolerance for installations that may not meet all mechanical requirements.

5401 is not recommended for chambers as its wider pulse frequency makes it sensitive for disturbances generated by the inlets and compromise level measurements nearby those areas.

Choosing the right antenna

The 5400 and 5600 Series transmitters offer a wide range of antennas, including Rod antennas, Cone antennas, and Process Seal antennas. Of these, the Cone antenna is the only suitable antenna for level measurement in pipes. All units are available with SST, Alloy C-276, and Alloy 400 antennas.

With any radar unit, the antenna should match the pipe size as closely as possible. The antennas are sized to fit within schedule 80 or lower pipes.

Ideally, the maximum gap between the antenna and the pipe wall should be as small as possible see “A” in Figure 1 below. For the 5600, gaps of up to 10 mm are acceptable.

For the 5400, gaps of up to 5 mm are acceptable. Larger gaps may result in inaccuracies.

FIGURE 1. Pipe installation dimensions

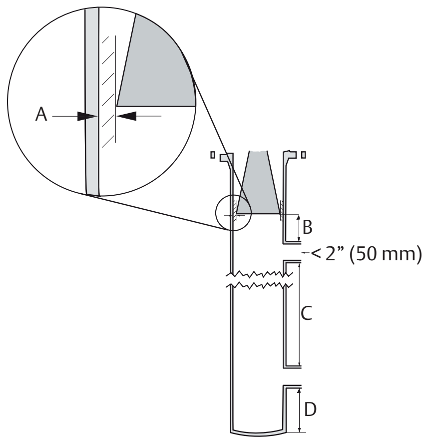

TABLE 4. Installation Guidelines for Non-contacting Radar

		5401	5402	5600
A: Maximum gap between antenna and pipe(1)		5 mm (0.2”)	5 mm (0.2”)	10 mm (0.4”)(2)
B: Min distance between antenna and inlet pipe		NR(3)	50 mm (2”)	100 mm (4 “)
C: Minimum distance between inlets		NR	500 mm	500 mm
D: Minimum distance between lower inlet and bottom of pipe		NR	150 mm	150 mm
Minimum dielectric constant		1.6	1.6	1.4
Availability per pipe size				
	2” pipe	NA(3)	Yes(4)	NA
	3” pipe	Yes	Yes	Yes
	4” pipe	Yes	Yes	Yes
	6” pipe	Yes	NR	Yes
	8” pipe	Yes	NR	NR
Can be used with full port valve		yes	yes	yes

(1) *In difficult measurement conditions (dirty pipes, steam, echoes from inlet pipes, welds, or valves), accuracy and range will be improved with a tighter fit between pipe and antenna.*

(2) *In bypass chambers, the gap should be as small as possible.*

(3) *NA = Not Available and NR= Not Recommended*

(4) *Fits schedule 40 or lower pipes*

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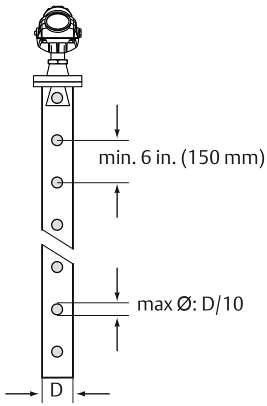
Rosemount Radar Transmitters

Stilling well requirements

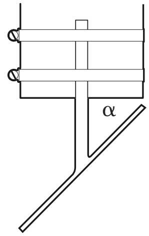


Pipes should be an all-metal material. Non-metallic pipes or sections are not recommended for non-contacting radar. Plastic, plexiglas, or other non-metal materials do not shield the radar from outside disturbances and offer minimal, if any, application benefit. Other requirements include:

- Pipe should have a constant inside diameter
- Pipe must be smooth on the inside (smooth pipe joints are acceptable, but may reduce accuracy)
- Avoid deposits, rust, gaps and slots
- One hole above the product surface
- Minimum hole diameter is 0.25 in. (6 mm)
- Hole diameter (Ø) should not exceed 10% of the pipe diameter (D)
- Minimum distance between holes is 6 in. (150 mm)(1)
- Holes should be drilled on one side and de-burred
- Ball valve or other full port valves must be completely open

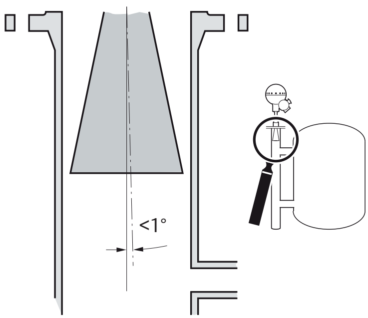
Failure to follow these requirements may affect the reliability of the level measurement.

In flat bottom tanks (<20° incline), where the fluid has a low dielectric and a measurement close to the bottom of the tank is desired, a deflection plate should be used. This will suppress the bottom echo and allow measurements closer to the actual tank bottom. This is not necessary for dish-or cone-bottomed tanks where the slope is more than 20°.



Bypass chamber requirements

The guidelines for stilling wells also apply to bypass chambers, with a few additions. Most importantly, the inlet pipes must not protrude into the measuring pipe and the edge should be as smooth as possible. In addition, the distances between the antenna and the chamber wall and inlet pipes should meet those shown in Table 4. If the inlet pipe tolerances are too restrictive, an alternative solution may be to mount a smaller pipe within the bypass chamber, or consider using GWR.



When the transmitter is mounted in a pipe, the inclination should be within 1° of vertical. Even small deviations can cause large measurement errors. Also, the cone should be mounted in the center of the pipe to achieve a uniform gap around the antenna.

(1) The minimum distance between holes is not always the optimal distance. Consult factory or product documentation for best installation practices.

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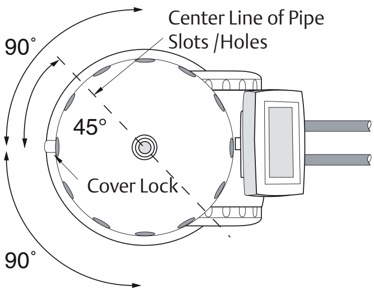
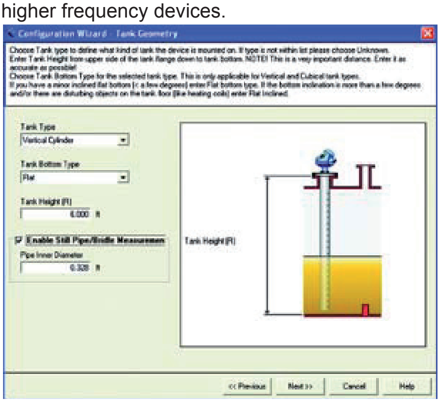


The 5600 electronics head should be oriented so that the cover lock is 45° from any disturbances such as pipe inlets or stilling well holes. It is also good if the installation allows for a ±90° rotation from this point to allow alternative orientations. This is not necessary for the 5400 thanks to circular polarization.

Transmitter configuration

The transmitter software contains a special pipe measurement mode which is turned on by entering the internal diameter of the pipe. This can be done using Rosemount Radar Master, the 275/375, AMS™ or any other DD-compatible host-system. When this mode is turned on, the transmitter will be optimized for pipe measurements. For example, the dynamic gain curve will be adapted for pipes and the lower propagation velocity of the radar signal in the pipe will be compensated. Entering the pipe diameter into the transmitter is therefore crucial and must not be omitted. Compensation is more important on higher frequency devices.



Transmitter Configuration Wizard

PERFORMANCE AND MEASURING RANGE

The following figures reflect the anticipated performance for different radar devices when used in a pipe installation and following the guidelines contained in this document. The values in the table assume that all the installation requirements stated above have been fulfilled and that the pipe is made per our recommendations.

The maximum measuring range is independent of the dielectric constant of the product. However, the dielectric constant has to be greater than 1.4 for the 5600 and 1.6 for the 5400. For the GWR the minimum dielectric and maximum range varies with probe type (see Table 1 on page 3). For lower dielectric constants, contact the factory.

KEY

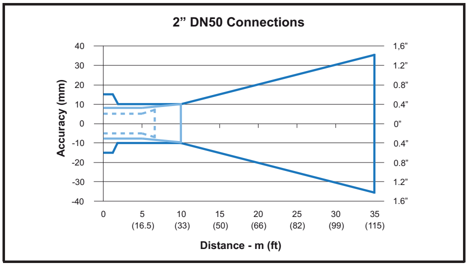
GWR With Coaxial Probe or Rigid Twin Leads*

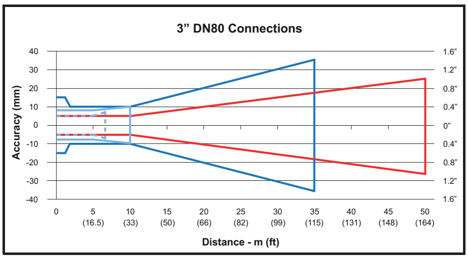
GWR With Rigid or Flexible Single Lead*

5400

5600

***Standard probes, reference conditions**





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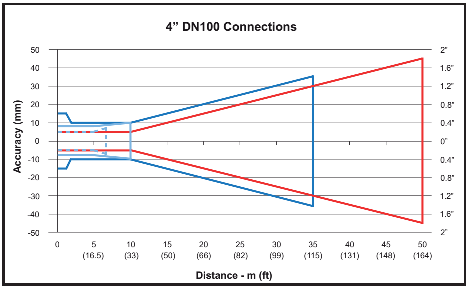

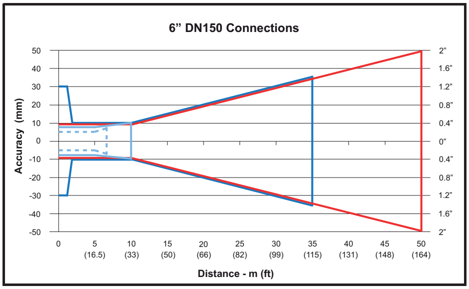

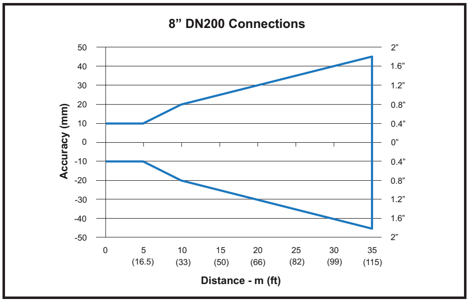

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Measuring Ammonia with Radar

KEY POINTS

- Any of the radar products can be used with aqueous ammonia
- For anhydrous ammonia, the Rosemount 5301, 3301 and 5601 are the preferred choices
- Measurement range will decrease with higher storage pressure

APPLICATION

Radar is a suitable method for measuring liquid ammonia. Since all Rosemount radar products have transmitter heads that can be serviced without breaching the tank atmosphere, radar is perfect for applications where tank openings must be minimized.

Emerson Process management offers four different radar solutions: the Rosemount 5301 high performance Guided Wave Radar, the Rosemount 3301 guided wave-radar, the Rosemount 5601 non-contacting radar with 10 GHz frequency and the Rosemount 5400 non-contacting radar with 6 and 26 GHz frequencies.

This technical note offers guidelines for choosing the most suitable Rosemount radar depending on the liquid ammonia application.

Aqueous ammonia (NH_4OH)

Liquid aqueous ammonia (ammonium hydroxide or ammonium hydrate) is a suitable application for both Guided Wave Radar and non-contacting radar. Any Rosemount radar is suitable for these application.

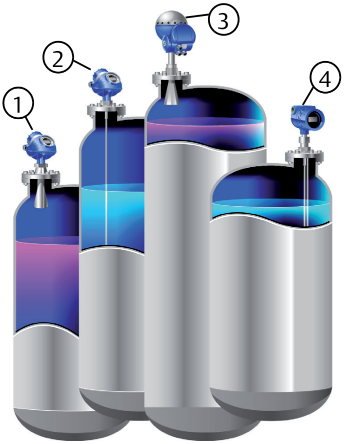
However, these tanks sometimes require isolation valves. It is not possible to use Guided Wave Radar with valves unless a bypass pipe is used. If a valve is required, it must be a full port valve so the inside of the nozzle is smooth. The Rosemount 5402 with a process seal antenna is preferred with valves because its higher frequency allows better signal propagation down the nozzle.

Other liquid ammonia solutions such as ammonia chloride will work with radar technology similarly to liquid aqueous ammonia.

Anhydrous Ammonia (NH_3)

Liquid anhydrous ammonia is difficult to measure because it produces heavy vapors that attenuate radar signals. As the storage pressure increases, the density of vapors will increase. With heavier vapors, signal attenuation is increased. Lower frequency radar signals are less attenuated than higher frequencies. Since Guided Wave Radar operates with a low frequency pulse, it will have minimal signal attenuation in heavy vapors. Therefore, Guided Wave Radar works better than non-contacting radar in high-pressure applications.

The low frequency of the Guided Wave Radar products ensures reliable level measurements in vessels with vapors such as anhydrous ammonia.



1. Rosemount 5400 Non-Contacting Radar 6 GHz and 24 GHz
2. Rosemount 5301 High Performance Guided Wave Radar
3. Rosemount 5601 Non-Contacting Radar 10 GHz
4. Rosemount 3301 Guided Wave Radar

For more information:
www.rosemount.com

TECHNICAL NOTE

During operation, product boiling may affect the radar reflection. If Guided Wave Radar or a 5601 in a still pipe is used, the effect will be minimized.

There are two main types of anhydrous ammonia applications:

1. Larger chilled tanks, 33-75 feet (10-23 m) high, with temperatures approximately -40 °F (40 °C) and with pressure up to 29 psig (2 bar). In these applications, the 3301, 5301 or the 5601 can be used (see measuring range graph).
2. Smaller pressurized tanks, 3 - 33 feet (1-10 M) high, with pressure to 145 psig (10 bar). Here, Guided Wave Radar has an advantage as compared to non-contacting.

The 5400 radar transmitter is not recommended in anhydrous ammonia applications.

If there is a nozzle with full port valves, the 5601 may be used. Since valves give uncontrolled microwave performance, a test installation is required.

Probe/antenna selection

For the 3301, the coaxial probe (up to 19.7 feet/6 m) is preferred but the flexible twin lead probe will work as well. Any of the probe types may be used with the 5300.

The preferred mounting location for the 5601 is on a still pipe. A 4-in. pipe with a 4-in. cone antenna is recommended. Eight-inch pipes should be avoided. If the gauge is to be mounted on a nozzle, a larger cone antenna (6- or 8-in.) is recommended.

In aqueous ammonia vessels with taller nozzles, the 5402 with a PTFE seal may be used. This helps to reduce signal attenuation in taller vessels.

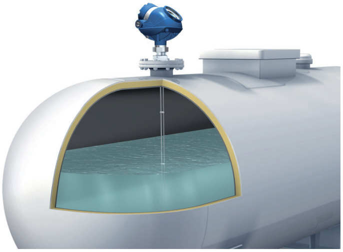
Measuring range

For aqueous ammonia, the measuring range is not limited by signal attenuation from the vapors. (See the appropriate Product Data Sheet.)

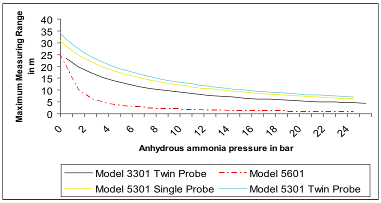
The graphs give guidelines for the maximum possible measuring range in anhydrous ammonia depending on the maximum pressure. If a still pipe is used for the 5601, the maximum measuring range can be improved.

Material compatibility

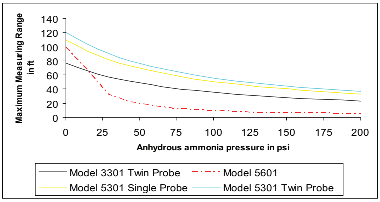
Material compatibility is ultimately the user's decision. Compatibility may vary with material concentration, temperature and if in a liquid or gas form. In the case of the radar products, the process seal of the standard units is a combination of PTFE and o-rings. The optional high pressure probe of the Guided Wave Radar products contains a ceramic process seal and no o-rings. It should be considered if unsure of o-ring compatibility.



Guided wave radar is a suitable method in anhydrous ammonia applications. Since it operates with a low frequency pulse, the signal attenuation will be minimal in heavy vapors



Measuring range in bar versus meters



Measuring range in psi versus feet

Technical Note
00840-0100-4530, Rev AB
April 2009

Rosemount 5300 Series

Using Guided Wave Radar for Level in High Pressure Steam Applications

INTRODUCTION

This document describes the advantages of using a Rosemount 5300 Series Guided Wave Radar (GWR) with Dynamic Vapor Compensation (DVC) in high pressure saturated steam applications, such as boiler drums, high pressure feed water heaters and steam separators.

GWR is used for direct level measurement and is completely independent of density. With no moving parts, it offers the advantages of lower maintenance and greater reliability. The Rosemount 5300 Series Superior Performance GWR also provides a Dynamic Vapor Compensation function.

BACKGROUND

A good level measurement in a boiler application will:

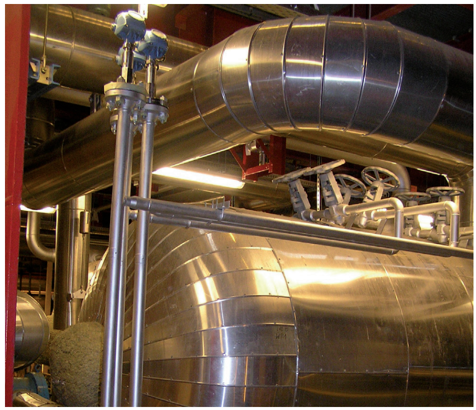
- Prevent wet steam carryover to turbine
- Optimize heat exchanger performance
- Continuously control condensate level
- Control condenser vacuum
- Ensure pump safety
- Optimize drum level control

The cylindrical vessel where the water-steam interface occurs is called the boiler drum. The boiler drum level is a critical variable in the safe operation of a boiler. A low drum level risks uncovering the water tubes and exposing them to heat stress and damage.

High drum level risks water carryover into the steam header and exposing steam turbines to corrosion and damage. An accurate level measurement helps to optimize the level control of the boiler.

Steam separators and HP feed water heaters have similar level control needs as boilers.

In all of these applications, as the pressure and temperature increases, the accuracy of the level measurement can be impacted by changes in fluid properties. The two fluid properties of most concern are the density and the dielectric.

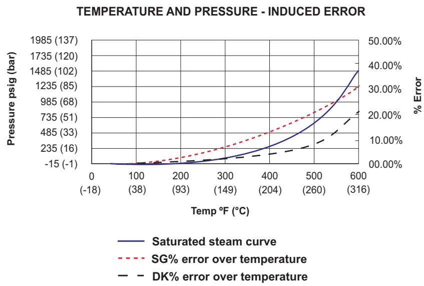


ADVANTAGES OF GWR OVER OTHER TECHNIQUES

Both the liquid and steam phases of the system will have density changes as the system reaches operating temperatures and pressures. Any density-based level measurement device will need to be compensated to discern the actual level from the density-associated errors. Algorithms have been developed to make this compensation as seamless as possible in the control systems, but require input of operating pressure as well as level.

Since GWR measurement devices are completely independent of density, these associated errors are not present, thus eliminating the need for this compensation.

While these applications are generally considered to be composed of clean water and steam, with the higher pressures and higher pH, there is often a layer of magnetite coating the metallic surfaces and this can cause some mechanical linkages to freeze and stick. With no moving parts, GWR offers additional advantages of lower maintenance and greater reliability.

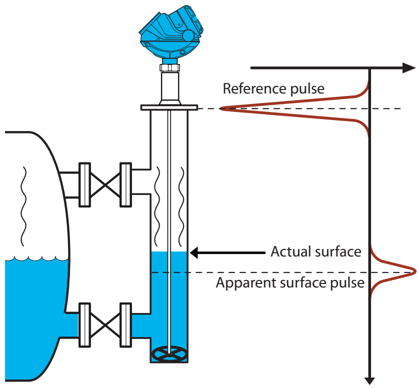


Both the density (SG) and dielectric (DK) properties of water and steam change with pressure and temperature. If not compensated, significant errors can result.

CHANGING DIELECTRICS

For radar level measurements, the actual quantity being measured is the propagation time through the empty space between the radar transmitter and the liquid surface. In order for the accuracy to remain high, it is important that the propagation speed of the radar signal is very close to the perfectly constant velocity of light in vacuum. With most fluids, there is a negligible change in dielectric of the vapor. Water, however, is a notable exception.

Water vapor under high pressure and varying temperature will have different dielectric constants and these changes can influence the radar level transmitter measurements. An increase in the dielectric constant slows propagation down, causing the signal for the liquid level to appear beyond the actual level point. In some important cases, this deviation is not negligible and must be taken into account, in order to get high accuracy. High tank pressures in combination with certain gases are examples of these cases.



The figure illustrates how the surface appears to be beyond the actual level point because of the vapor present. No vapor compensation is used in this case.

Even though the dielectric of water decreases with temperature increase, the level can be measured as long as the water dielectric remains sufficiently high so there is a reflection back from the surface.

However, as the temperature increases, the dielectric difference between the liquid and the steam becomes smaller and at a certain point it will be too small for a reliable measurement with radar transmitters.

Beyond this point, at approximately 2030 psi (140 bar)[1], guided wave radar transmitters are no longer a suitable choice for level measurements. In the very high pressure systems, there is no level measurement, since there is no distinct liquid/steam interface.

(1) This is the process pressure, design pressure can be higher.

Technical Note
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Rosemount 5300 Series

VAPOR COMPENSATION FUNCTIONALITY

In the Rosemount 5300 Series Superior Performance GWR, there are two functions to compensate for the vapor dielectric; one static and one dynamic. The default vapor dielectric value is set to 1, which corresponds to the dielectric of vacuum.

TABLE 1. Table showing the error in distance with changing temperature and pressure, without vapor compensation.

Temp. °F/°C	Pressure psia/bar	DK of liquid	DK of vapor	Error in distance %
100/38	1/0.1	73.95	1.001	0.0
200/93	12/1	57.26	1.005	0.2
300/149	67/5	44.26	1.022	1.1
400/204	247/17	34.00	1.069	3.4
500/260	681/47	25.58	1.180	8.6
600/316	1543/106	18.04	1.461	20.9
687/364	2900/200	~13	2.5	58

As can be seen in the table above, at 247 psia (17 bar) there is an error in distance of 3.4% and at 1543 psia (106 bar) there is an error of 20.9% when there is no compensation for the vapor dielectric. The error in distance increases with the pressure and at some point this deviation is not negligible and must be taken into account, in order to get high accuracy.

Standard Function: Static Vapor Compensation

For the static compensation function, the dielectric of the vapor at expected operating pressure and temperature is manually entered as part of the configuration of the transmitter. This allows the unit to compensate for the dielectric at operating conditions.

The static compensation works well under stable conditions and in these applications, the standard high temperature/high pressure probe is used.

Optional Function: Dynamic Vapor Compensation

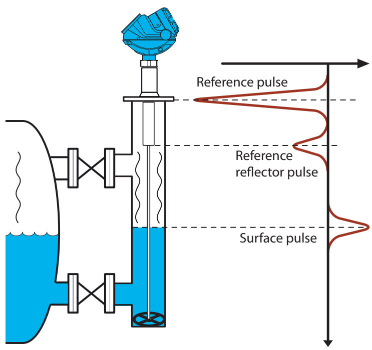
Dynamic Vapor Compensation becomes more important for the higher pressure applications that may have more variations in the operating conditions or where the users want to be able to verify the unit under near ambient conditions, such as during start-up and shut down, without having to modify the vapor dielectric settings.

Vapor Compensation does not have an effect on the accuracy until the pressure is higher than 145 psi (10 bar). When to recommend Dynamic Vapor Compensation depends on what accuracy the application requires, but around 600 psi (40 bar) and higher it makes a significant difference in accuracy.

In these cases, Dynamic Vapor Compensation will reduce the error to less than 2% under varying conditions.

Dynamic Vapor Compensation works by using a target at a fixed distance. With this target, the vapor dielectric will be measured continuously.

The transmitter knows where the reference reflector pulse should have been if there were no vapor present. However, since there is vapor in the tank, the reference reflector pulse will appear beyond the actual reflector point. The distance between the actual reflector point and the apparent reflector point will be used to calculate the vapor dielectric.



The figure illustrates how the surface appears at the correct surface level point when using Dynamic Vapor Compensation.

The calculated dielectric is then dynamically used to compensate for vapor dielectric changes and eliminates the need to do any compensation in the control system.

When the distance between the mounting flange and the surface is less than 17.3 in. (440 mm) for short probes(<78.7 in. (2000 mm)) and 28 in. (710 mm) for long probes (>78.7 in. (2000 mm)), the function switches from dynamic to static vapor compensation using the last known vapor dielectric constant.

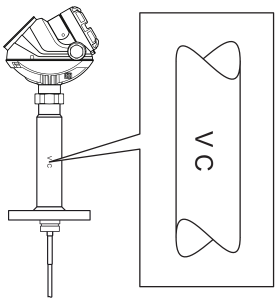
Rosemount 5300 Series

COMPETITIVE ADVANTAGES

For the Rosemount 5300 with Dynamic Vapor Compensation, the single rigid probe is used. This offers a great advantage compared to solutions with a coaxial probe, since the single probe is more tolerant of coating and also reduces maintenance.

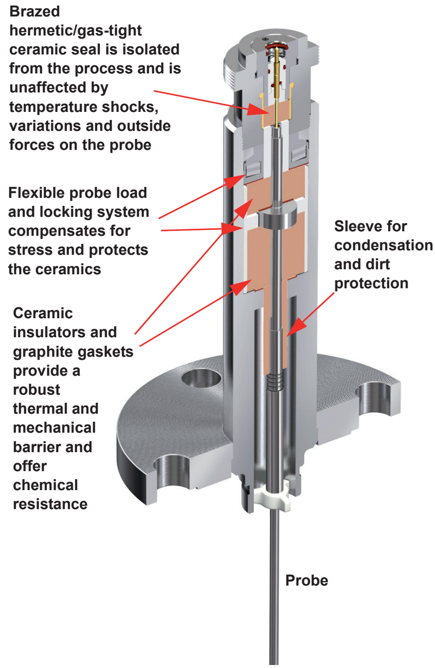
Rosemount GWR extreme temperature and pressure probes are designed to prevent leakage and perform reliably when exposed to extreme process conditions for extended periods of time. Materials are selected to avoid stress fractures commonly induced by changes in temperature and pressure conditions.

The robustness of the probes and the materials, means high safety for these extreme temperature and pressure applications.



Probe with reference reflector marked “VC” for recognition

The GWR Probe Design Provides Multiple Layers of Protection



DVC INSTALLATION REQUIREMENTS

The GWR should be mounted in a 2, 3, or 4 - in. (50, 75, and 100 mm) inner diameter bypass chamber with flanges appropriately sized for the pressure and temperature of the application. Materials used for the chamber should meet ASME boiler code requirement and the chamber should be isolated directly from the boiler or HP heater by valves.

A rigid single lead HTHP probe with reference reflector for vapor compensation should be used. A centering disk will keep the probe centered in the chamber. The single lead probe can tolerate any magnetite layer that may occur. Probes up to 13.1 ft. (4 m) length are supported for Dynamic Vapor Compensation.

Dynamic Vapor Compensation requires a minimum distance from the flange to the surface level to measure the change in the vapor dielectric constant. If the level rises within this area, the unit switches over to static compensation, using the last known vapor dielectric constant.

This minimum distance (X in the picture) is 17.3 in. (440 mm) for probe length < 6.6 ft (2 m), and 28 in. (710 mm) for probe length > 6.6 ft (2 m) (see diagram below), to dynamically compensate up to level 100%.

The minimum measuring range for this functionality is 12 in. (300 mm).

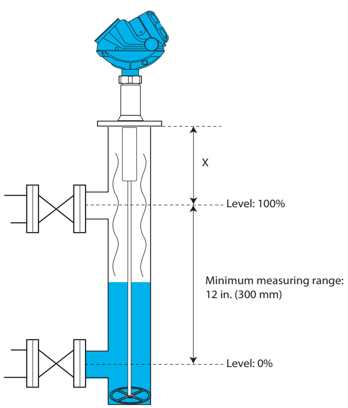
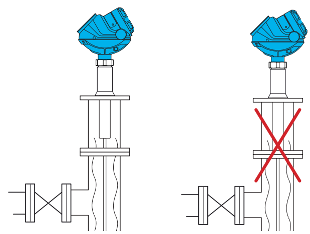


TABLE 2. Minimum distance X.

Probe Length	Reflector	Minimum Distance X
< 78.7 in. (2000 mm)	9 in. (230 mm)	17.3 in. (440 mm)
> 78.7 in. (2000 mm)	20 in. (500 mm)	28 in. (710 mm)

If a 5300 Series transmitter is ordered from Rosemount together with a 9901 Chamber, these space requirements are met. If an existing chamber is used, which does not meet these space requirements, a spool piece can be added. For an installation with a spool piece, it is important to make sure that the reference reflector and the spool piece do not have the same length. The spool piece needs to be at least 2 in. (50 mm) longer or shorter.



If a spool piece is used, it is important that the reference reflector and the spool piece do not have the same length.

When a transmitter is ordered with the optional Dynamic Vapor Compensation, the function is activated from factory and the special probe is supplied. However, a calibration procedure with an empty chamber is needed on-site during the commissioning phase. The installation wizard in Rosemount Radar Master will prompt for this and guide the user through the necessary steps.

Note that Probe End Projection and Signal Quality Metrics are disabled when Dynamic Vapor Compensation is enabled.

Technical Note
00840-0700-4016, Rev AA
February 2009

Rosemount 1199

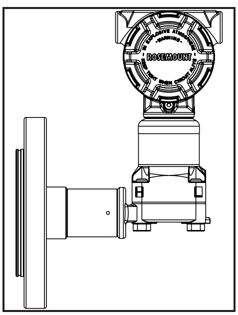
1199 Direct Mount Connection Guidelines

INTRODUCTION

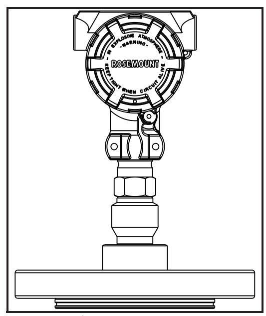
In this document, you will find direct mount guidelines for the Rosemount 1199 Diaphragm Seal System. Direct mount remote seal systems provide a compact way of directly connecting a pressure transmitter to vessel fittings. This note discusses direct mount configurations, direct mount operating limits, and installation guidelines.

DIRECT MOUNT CONFIGURATIONS

Direct mount configurations can be ordered as an integrated level transmitter (i.e: 3051S2L) or as an 1199 seal system. The 1199 direct mount connections are available to attach to Coplanar™ and In-line sensor modules and almost every seal type. There are three direct mount extension lengths for Coplanar configurations and two extension lengths for In-line configurations with longer extension lengths used to separate the transmitter from higher process temperatures. The different configurations and associated model codes are listed below.



Coplanar Connections



In-line Connections

Coplanar Connections				
Direct Mount Extension "X"	Welded Repairable		All-Welded Vacuum	
	1 Seal	2 Seals	1 Seal	2 Seals
0 in (0 mm)	93	94	97	96
2 in (50 mm)	B3	B4	B7	B6
4 in (100 mm)	D3	D4	D7	D6

In-line Connections	
Direct Mount Extension "X"	Option Codes
1 in (25 mm)	95
5.72 (145 mm)	D5

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Process Management

Technical Note
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February 2009

Rosemount 1199

DIRECT MOUNT OPERATING LIMITS

Temperature: A direct mount seal system protects the transmitter from process temperatures while maintaining the seal system fill fluid within its operating temperature limits. Pressure transmitter ambient limits are based on its electronics (typically -40° to 185°F/85°C) and process temperature limits are based on the module configuration (typically -40° to 250°F/121°C for Coplanar flanges or in-line connections).

The seal system fill fluid is selected to operate within the process and ambient temperature limits for an application. For direct mount systems, heat transferred from the process keeps the fill fluid & direct mount connection warm. This enables the fill fluid to continue to respond properly even at cold ambient conditions. An example is the Thermal Optimizer In-line code D5 designed for high process temperature applications. The Thermal Optimizer separates the In-line sensor module from the high process temperature while insulating the high temperature fill fluid to enable it to operate properly even at the coldest ambient conditions. In capillary seal systems, the process heat is dissipated and most of the fill fluid is exposed to the ambient temperature. At cold ambient temperatures, high temperature fluids like DC704 or DC705 become too viscous to provide acceptable time response.

The tables below highlight temperature limits for the variety of 1199 fill fluids in direct mount or capillary seal system configurations.

Coplanar Transmitter Seal System Fill Fluid Limits

Fill Fluid	Direct Mount			
	Minimum Temperature	Maximum Temperature		
		LT/0 ext.	2-in./ 50 mm ext.	4-in./ 100 mm ext.
DC200	-45 °C/ -49 °F	205 °C/ 401 °F		
DC704	-40 °C/F		240 °C/ 464 °F	260 °C/ 500 °F
DC705	-40 °C/F		240 °C/ 464 °F	260 °C/ 500 °F
Inert (Halocarbon)	-45 °C/ -49 °F	160 °C/ 320 °F		
Glycerine and Water	-15 °C/ 5 °F	95 °C/ 203 °F		
Propylene Glycol and Water	-15 °C/ 5 °F	95 °C/ 203 °F		
Neobee M-20	-15 °C/ 5 °F	205 °C/ 401 °F	225 °C/ 437 °F	
Syltherm XLT	-75 °C/ -102 °F	145 °C/ 293 °F		

In-line Transmitter Seal System Fill Fluid Limits

Fill Fluid	Minimum Temperature	Maximum Temperature	
		1-in. (25 mm)	5.72-in. (145 mm)
DC200	-45 °C/-49 °F	205 °C/401 °F	
DC704	-40 °C/F		315 °C/599 °F
DC705	-40 °C/F		350 °C/662 °F
Inert (Halocarbon)	-45 °C/-49 °F	160 °C/320 °F	
Glycerine and Water	-15 °C/5 °F	95 °C/203 °F	
Propylene Glycol and Water	-15 °C/5 °F	95 °C/203 °F	
Neobee M-20	-15 °C/5 °F	205 °C/401 °F	225 °C/437 °F
Syltherm XLT	-75 °C/-102 °F	145 °C/293 °F	

Capillary Seal System Fill Fluid Limits

Fill Fluid	Minimum Temperature	Maximum Temperature
DC200	-45 °C/-49 °F	205 °C/401 °F
DC704	0 °C/32 °F	315 °C/599 °F
DC705	20 °C/68 °F	350 °C/662 °F
Inert (Halocarbon)	-45 °C/-49 °F	160 °C/320 °F
Glycerine and Water	-15 °C/5 °F	95 °C/203 °F
Propylene Glycol and Water	-15 °C/5 °F	95 °C/203 °F
Neobee M-20	-15 °C/5 °F	225 °C/437 °F
Syltherm XLT	-75 °C/-102 °F	145 °C/293 °F

Pressure: The operating pressure limits for a direct mount seal system depend on the process connection and/or sensor URL for the maximum limit and the sensor static pressure limit and remote seal construction for the minimum limit. For example, the maximum limit for a FFW seal with an ANSI class 150 SST flange would be 285 psig(19.6 bar). The maximum limit for a gage Coplanar range 4 the URL would be 300 psig(20.7 bar). The maximum limit would be the lower of these values for a given seal system. For minimum pressure, the sensor limit depends on module and sensor type as shown below.

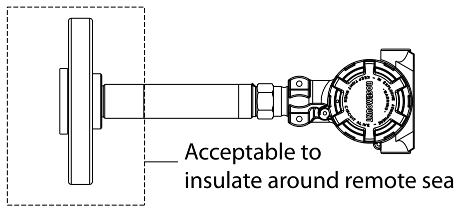
Module Type	Sensor Type	Lower Pressure Limit
Coplanar	Differential	LRL or 0.5 psia (34.5 mbar abs)
	Gage	LRL or 0.5 psia (34.5 mbar abs)
	Absolute	0 psia (0 bar)
In-line	Gage	-14.7 psig (-1.01 bar)
	Absolute	0 psia (0 bar)

The remote seal construction also needs to be evaluated for lower limits on vacuum applications. Standard Welded-Repairable remote seal construction on Coplanar modules uses PTFE o-rings, so it can be used for vacuum pressures down to 6 psia (0.41 bar). Below 6 psia (0.41 bar), All-Welded Vacuum construction should be used as it also includes welded isolator caps to eliminate any potential for air to be sucked into the seal system under deep vacuum conditions.

If the minimum process pressure is below the sensor pressure limit, then the pressure transmitter needs to be mounted below the bottom process connection using a short length of capillary. The vertical column of fill fluid creates a head pressure on the sensor module to protect the sensor's fill fluid within its operating limit.

INSTALLATION GUIDELINES

Direct mount remote seal systems need to be installed properly to ensure they operate within the operating limits stated above. In particular, the use and location of insulation will determine if a direct mount remote seal system will operate to its limits. The general recommendation is to wrap insulation around vessel process connections and seal only, not the direct mount transmitter/flange. The direct mount systems are designed to balance the heat dissipation from the remote seal and process connection, so if the entire unit is wrapped in insulation, the transmitter electronics could be overheated. For the example shown to the right, it is acceptable to insulate around the remote seal and process pipe, but not the direct mount extension.



TECHNICAL NOTE

Specify the Right Solution for Vacuum Applications

KEY POINTS

- Specify a high temperature fill fluid (DC704)
- Specify All-Welded Vacuum Construction for vacuums below 6 psia (300 mmHgA)
- Mount transmitter at or below the lower tap (3 feet or 1 meter is rule of thumb)
- Use Instrument Toolkit® software to validate system in your application

OVERVIEW

When a vessel is under a vacuum pressure, it is important to specify the correct transmitter remote seal system to measure level accurately and reliably. Failure to do so will result in output drift or complete system failure. The combination of high process temperature and vacuum process pressure conditions creates additional requirements when specifying the transmitter remote seal system.

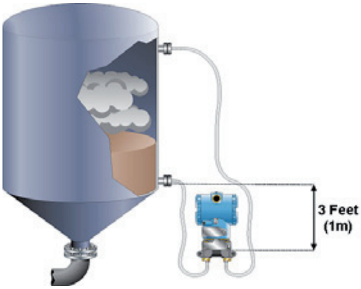
APPLICATION

There are three primary transmitter-seal system components necessary to successfully specify vacuum application solutions:

- Mounting Position
- Fill Fluid Selection
- Seal System Construction

Mounting Position

Mounting the pressure transmitter at or below the bottom vessel tap is an important factor to ensure a stable measurement with vacuum applications. The static pressure limit for a differential pressure transmitter is 0.5 psia (25 mmHgA), which ensures the transmitter sensor module fill fluid typically (DC200) remains within the liquid phase of the vapor pressure curve.



If the vessel static limit is below 0.5 psia, mounting the transmitter below the bottom tap provides a capillary fill fluid head pressure on the module. A general rule of thumb is to always mount the transmitter approximately 3 feet (1 meter) below the bottom tap of the vessel. The actual head pressure can be calculated by multiplying the vertical distance between the bottom tap and transmitter by the specific gravity of the fill fluid. Finally, validate the system in your application using Instrument Toolkit Software to ensure the system will perform under your operating conditions.

ROSEMOUNT

For more information:
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EMERSON Process Management

TECHNICAL NOTE

Fill Fluid Selection

When the process is under vacuum conditions, the fill fluid will vaporize under a lower temperature than when it is under normal atmospheric or greater pressure. Emerson Process Management offers over 16 different types of fill fluids for filled systems. Each fill fluid has a specific Vapor-Pressure curve. The Vapor-Pressure curve indicates the pressure and temperature relationship where the fluid is in a liquid or a vapor state. Proper seal operation requires the fill fluid to remain in a liquid state. For vacuum applications, specify fluids with a premium combination of vapor-pressure curve and high temperature limits like DC704 or DC705.

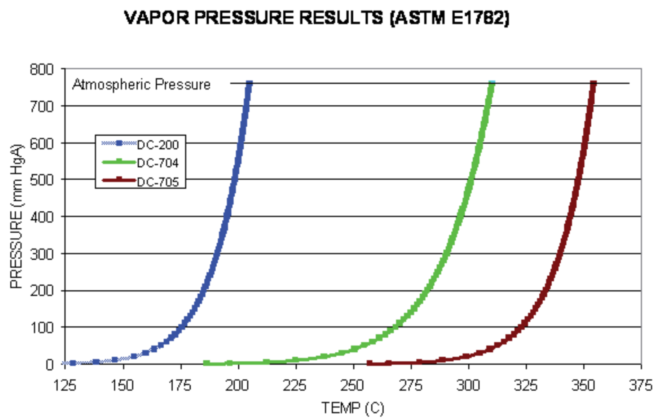


TABLE 1. Temperature Limits(1)

Fill Fluid	Maximum Temperature at Minimum Pressure	Maximum Temperature at ATM Pressure
D.C.® 200 Silicone	257°F (125°C) @ 25 mmHgA	–49°F (–45°C) to 400°F (205°C)
D.C. 704 Silicone(2)	See vapor pressure curve	32°F (0°C) to 600°F (315°C)
D.C. 705 Silicone(2)	See vapor pressure curve	68°F (20°C) to 662°F (350°C)

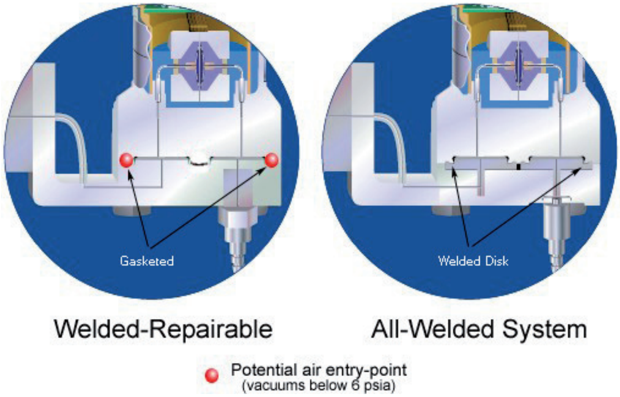
(1) *Vapor pressure curve and operating limit details for published fill fluids can be found in the Rosemount 1199 Fill Fluid Specifications Technical Note, document 00840-2100-4016.*

(2) *Upper temperature limit is for capillary seal systems mounted away from the transmitter.*

TECHNICAL NOTE

Seal System Construction

Emerson offers Rosemount 1199 seals with welded-repairable and All-Welded vacuum system construction methods. In vacuum applications, specify the All-Welded vacuum construction. Threaded or gasket connections allow the potential for vacuum pressure to draw air into the capillary system causing drift or complete system failure. No air in the system eliminates the need to re-zero and thus improves plant availability by preventing unscheduled downtime and instrument repair or replacement.



The all welded vacuum construction was designed specifically for high temperature and vacuum applications. In this construction, the sensor module gaskets are removed and a disk is welded over the sensor isolators. This eliminates the possibility of air being drawn into the seal system in deep vacuum conditions. This premium design is strongly suggested for vacuum pressures below 6 psia (310 mmHga).

Remote seal system construction model codes can be found in the Rosemount 1199 Diaphragm Seal System Product Data Sheet (00813-0100-4016, Tables 4, 5, and 50). Furthermore, Rosemount has improved the manufacturing processes for remote seals used for high temperature/high vacuum applications.

TECHNICAL NOTE

Fill Fluid Preparation

The fill fluids used in remote seal systems were developed for other applications, then adapted for use in seal systems. For example, DC704 was developed to be a heat transfer fluid in diffusion pumps for high vacuum chambers common in semiconductor manufacturing. When applied into a remote seal system, Rosemount has implemented the further preparation to purify the fluid and remove residual entrapped air or water to ensure a stable measurement performance under extreme vacuum conditions.

System Components Preconditioned

To ensure long term reliability, manufacturing process improvements were implemented to prepare the seal system for high temperature and vacuum conditions. System components are preconditioned at high temperatures and vacuum pressures to prepare them for the end use.

Stringent Manufacturing Processes

The equipment and procedures used to build remote seal systems for high temperature/high vacuum applications are continuously improved to deliver products for ever increasing application demands. Tight quality control measures like 100% helium leak checking of system welds ensures the reliability of every seal system. The process includes monitoring to detect any station leaks and to confirm the fill quality of the finished seal system.

Summary

Implementing the right combination of seal system construction, fill fluid, and mounting position can ensure long term stable measurement performance for high temperature and vacuum applications. If you have questions on a vacuum installation, contact your local Emerson Process Management representative for application assistance.

6.3 Documentation - White papers

In this section, we have included white papers in their full versions. These white papers may have been referred to earlier in the handbook.

The white papers are: **Page**

Dielectric Constant Changes In Hydrocarbons – Affects On Radar Measurement Accuracy In Interface Applications

Summary

This document covers some of the physics and theories behind dielectric constants, and, in particular, changes in dielectric constants due to temperature changes.

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Dielectric Constant

Dielectric Constant (DC): An index of the ability of a substance to attenuate the transmissions of an electrostatic force from one charged body to another, as in a condenser. This means that the lower the value, the greater the attenuation. A vacuum has a DC of 1.0, while metals, being conductors, have an infinite DC. Low dielectric materials are good electrical insulators and most hydrocarbons have low dielectric constants.

Difference in Dielectric Constant

Although the molecular structure has a great deal to do with the ability of a material to transmit electrical potential energy, polarization dictates the extent of this ability. For example, a common six carbon chain hydrocarbon is Hexane with a DC of 1.88, while another six carbon hydrocarbon compound, Benzene, has a DC of 2.28. Molecularly, both are six carbon compounds, but because of the symmetry of the molecules and an imbalance in ions and charges, the polarization of each is different. The simple addition of a nitrogen or oxygen group to the molecule can significantly change the polarity characteristics of the compound. For example, Hexanol, a six carbon molecule with an –OH group, has a DC of 9.

Phase changes can have significant impact on dielectric properties. While liquid water has a dielectric of 40 or more, depending on the purity level, water vapour have very low dielectric constants. Steam has a DC of 1.008 at 100 °C, while ice (solid water) has a DC of 3.2 at 12 °C

Temperature Effects on Dielectric Constant

Temperature affects the DC of a material because the density of the material changes can cause more or less molecules to be within a known volume. As the temperature increases, the DC decreases as the molecules spread out more and minimize the ability of the material to transmit electrical potential energy. However, the typical changes in dielectric constants observed in Hydrocarbons range from 0.0013 to 0.05% per degree Celsius. The following table illustrates the percentage of change in relation to the DC change:

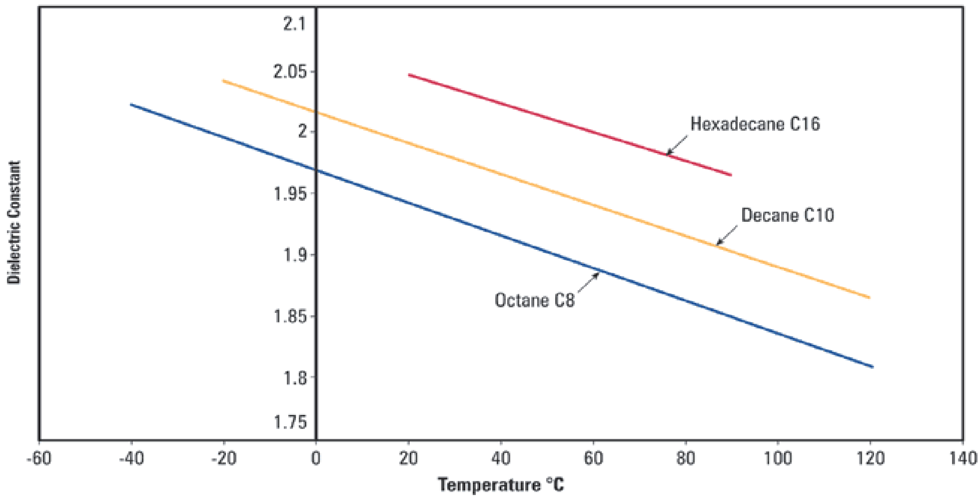
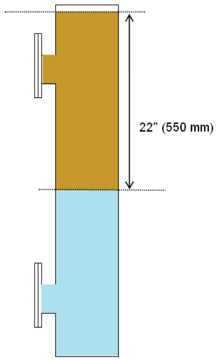


Figure 1. Dielectric Constant vs. Temperature for Three Hydrocarbons

With these three hydrocarbons (C8, C10, and C16) we can observe the change of the DC as the change of temperature. Because this change is very minimal, illustrated below is a calculation of what this change of DC represents in error on an interface measurement. In this example, the same magnitude of a dielectric change is compared to the same magnitude of change in density.

White paper: Dielectric Constant Changes In Hydrocarbons
July 2008 – Page 3



Example of top fluid changes:

Density (SG) change from 0.7 to 0.9

Dielectric ε_r change from 1.8 to 2.0

Δ SG of 0.2:
error = 4.4" (110 mm)

Δ ε_r of 0.2:
error = 1.5" (38 mm)

The error shown is if a change of DC of around 0.2, but our typical change in DC with hydrocarbons is much less than this, as observed in Figure 1.

The dielectric change results in an electrical distance change of 1.5 inches over the physical distance of 22.0 inches. This is calculated by the error:

Error = √DC1 * (physical distance) - √DC2 * (physical distance)

Compared to a density change over this same distance, the error is substantially smaller.

One additional factor is the interface measurements are only influenced by the dielectric change of the upper fluid, since only the distance to the interface surface is measured by the radar device. If a density-based measurement device is used, then both fluids must be measured and density changes that occur in one or both fluids and will affect the overall measurement.

White paper: Improve Reliability of Desalter Interface Measurmement while Reducing Maintenance with the use of Guided Wave Radar
June, 2009 – Page 1

Improve Reliability of Desalter Interface Measurement While Reducing Maintenance with the use of Guided Wave Radar

Introduction

This document provides information on improving reliability of desalter interface measurement and reducing maintenance with the use of Guided Wave Radar (GWR) transmitters.

Potential Results

By using GWR, the potential results include

- More efficient operation of desalter minimizes corrosion of refinery equipment and reduces risk of over-pressuring crude distillation column
- Eliminate need to re-span measurement output when density changes
- Reliable interface measurement prevents oil from entering waste water stream
- Reliable interface measurement can improve quality of the oil for downstream usage
- Reliable interface measurement allows automation and increases throughput

Application Background

Raw crude oil contains a lot of salt contaminants and water. If the salts are not removed, then they can cause significant corrosion of downstream refinery equipment due to high operating temperatures. To remove the salts, emulsifying chemicals and additional water are mixed with the oil to wash the salts out of the oil. This emulsified oil water mixture then needs to be separated quickly and efficiently. An electrostatic grid causes the dispersed water droplets and salts to coalesce and drop. This electro-static field operates at maximum efficiency when the water and oil interface is maintained at a level just below the electrostatic grid.

In refineries, a desalter is used to separate crude oil from water using an electro-static grid operating at about 10KV. A reliable interface measurement is needed to allow it to run at optimal efficiency without the risk of water getting into the grid.

When operators do not have confidence in the interface level measurement they will operate these units at a low interface level to prevent tripping the unit. This lessens the efficiency of the unit and reduces throughput.

Key Characteristics: Crude oil on water with 6 to 12 inch (150 to 300 mm) emulsion layer in a vessel with a 10 to 22 kV electrostatic grid.
Crude oil API gravity varies with source of supply. Normally desalters are operated between 165-190 PSIG (11 to 13 Bar) with a max of 215 PSIG (15 Bar). The operating temperature is typically 265-275 F (129- 135C) with a max of 300 F (150 C).

Traditional technologies used for measurement: Displacers, capacitance, or magnetostrictive, all with frequent manual verification.

White paper: Improve Reliability of Desalter Interface Measurement while Reducing Maintenance with the use of Guided Wave Radar
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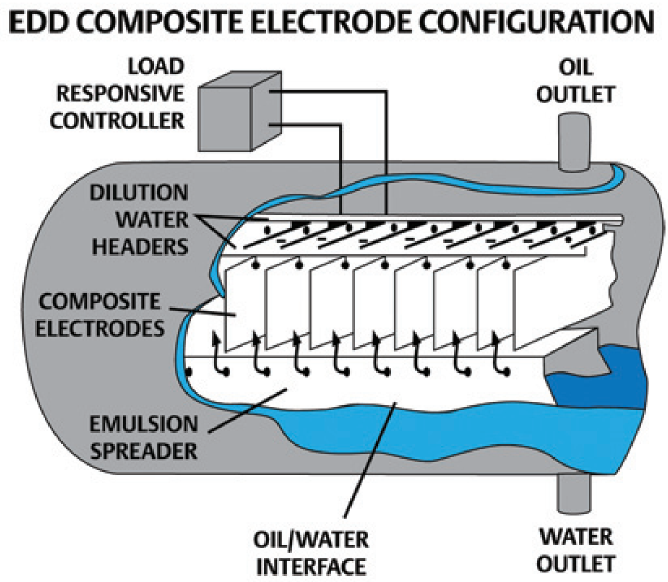

Fig 1: Schematic drawing indicating the key components in a desalter application

It is very important to know the actual interface level to avoid tripping the electrical grid. If the water and salt layer contact the grid, the excessive high current would trip it.

Challenge

This application is a challenging interface measurement. The oil and water layers both have varying properties. The properties of the oil, especially the density, change with different crude supplies and as the fluid is heated. The water density will change with the amount of contaminants and the heat. The crude can contain sticky components that tend to build up on surfaces, coat probes, or cause mechanical parts to stick. The presence of the emulsion, or rag layer, creates an indistinct interface between the fluids which can be difficult to read.

Displacers, magnetostrictive, or capacitance technologies have traditionally been used to measure the interface level. Changes in oil density require that displacers be re-spanned which results in extra maintenance time. If the torque tube requires recalibration, the unit has to be taken out of service. Capacitance probes are susceptible to errors due to coating. This results in instability and unpredicatble measurements.

Because of the various challenges of the technologies and the critical need to know the interface, desalters have been built with bleed taps so that the interface location can be manually verified.

White paper: Improve Reliability of Desalter Interface Measurmement while Reducing Maintenance with the use of Guided Wave Radar
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If displacers are used, they are often installed in a stilling well. Capacitance probes are often installed directly in the vessel in a location where they will not contact the grid.

Fig 2. Bleed taps in the area near the desired interface level allow manual verification of the interface.

SOLUTION

Guided Wave Radar offers several advantages for this application. It is immune to density changes, can handle coating and has no moving parts to maintain. It can measure both level and interface and is easy to set up and configure. The presence of the electrostatic grid has no impact on the instrument operation provided the unit is grounded and installed to local codes.

In one desalter that had previously used a displacer, a Rosemount Guided Wave Radar with a flexible single lead was installed in the 6” stilling well with slots. In another unit, a rigid twin probe was used within the stilling well. Both worked, but to reduce long term maintenance, the single lead probe is recommended.

In another application, a Rosemount Guided Wave Radar with a rigid single lead probe was used to replace a capacitance probe. The use of a rigid probe help to minimize movement of the probe. This one also worked well.

To verify that the interface levels from each of these radar transmitters was correct, the operators were able to manually check for the presence of oil or water by using a series of taps on the side of vessel. In each case, the interface reading from the transmitter corresponded to the area between the correct oil and water taps. In addition,

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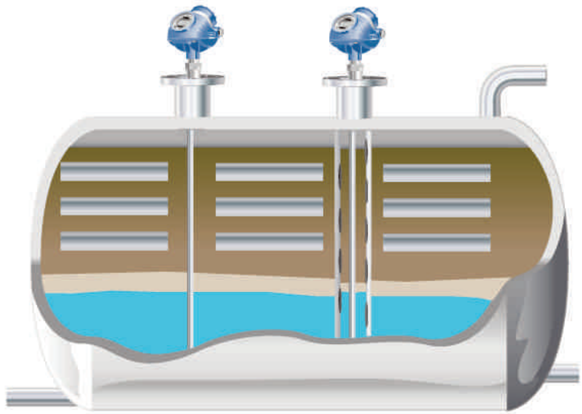
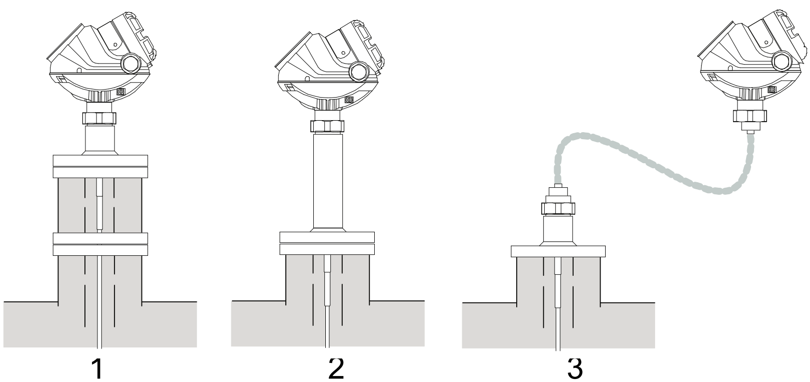
Fig 3. The Guided Wave Radar can be installed inside a slotted stilling well within the vessel. It can also be installed directly into the desalter as long as the probe does not contact the grid or any other metallic obstacles. The electronic grid of the desalter does not disturb the signal.



Heat rising from the vessel may exceed the ambient temp limit of the electronics when mounted close to the vessel. This may cause the ambient temperature limits of the electronics head to be exceeded. To prevent this, there are a number of options: Elevate the electronics head with a spool piece; use an HP (high pressure and higher temperature) probe, or use a remote extension for the electronics.

Fig 4. Heat rising from the vessel can exceed the ambient temperature limit. This can be avoided by either: 1) The addition of a spool piece, 2) Using an High Pressure probe, or 3) Using a remote connection.



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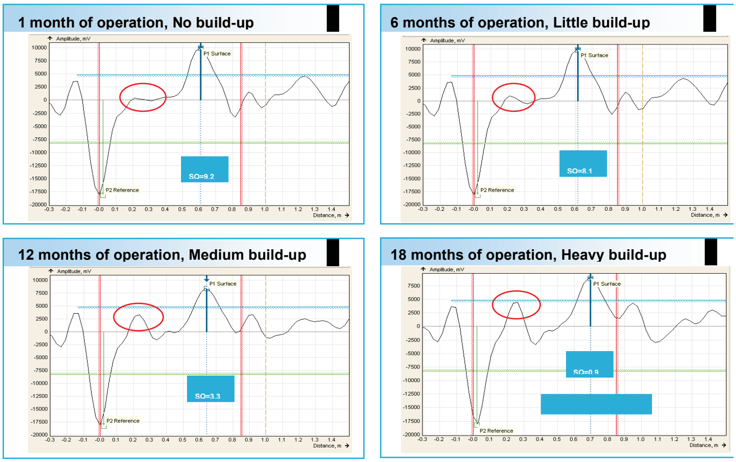
Probe coating potential

Crude oil can contain sticky components that tend to build up on surfaces, coat probes, or cause mechanical parts to stick. Some key advantages of Guided Wave Radar technology is that it is more tolerant of material buildup on the probe surface and has no moving parts. The use of a single lead probe helps to eliminate any bridging that could create a false target if coaxial or twin lead probes were used. An additional feature of the Rosemount 5300 is its Signal Quality diagnostics. With this feature, the strength of the signal in relation to any buildup can be monitored over time to ensure the signal is not degrading and remains reliable.

Fig 5.
Signal Quality Metrics can be use to assure signal strength remains reliable.

NOTE: These plots are for illustration only.



Emulsion Layers

One of the challenges of this measurement is the presence of a wide emulsion layer between the oil and the water. In applications using a stilling well, the pipe may create a settling effect and cause the emulsion to be reduced. In applications where the probe is installed without a stilling well, the probe may see the entire emulsion layer. This emulsion can cause the interface layer to be less distinct than normal. Since the interface peak tends to be smaller than normal, some manual setting of the transmitter thresholds may be required. By comparing the manual tap samples and the interface measurement, it can be verified that the Guided Wave Radar transmitter will read the top of the emulsion layer. Repeatable measurement of the emulsion layer can provide good interface control of the desalter. In some cases, it may be possible to see the bottom of the emulsion layer however this needs to be determined on a case by case basis as the results depend on the crude oil properties.

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Results

Efficient operation of the desalting unit can minimize the effects of corrosion and fouling in downstream process units. Additionally, controlling the percentage of water in oil can reduce the potential of over-pressuring of the crude distillation column.

With reliable interface level control, a desalter is able to operate more efficiently with reduced water and salt carryover to the crude unit. Effective separation of the oil improves its quality and reduces oil contamination to downstream water treatment plant. The need for maintenance and associated downtime is eliminated.

Improving Differential Pressure Diaphragm Seal System Performance and Installed Cost

Tuned-Systems™; Deliver the Best Practice Diaphragm Seal Installation to Compensate Errors Caused by Temperature Variations.

Tuned-Systems™ are the best practice for differential pressure diaphragm seal system configurations. Tuned-Systems contrast significantly to traditional symmetrical configurations; achieving the lowest temperature-induced errors, best time response, and lowest installed cost when measuring level in closed vessels. Differential pressure seal systems have traditionally been specified with identical capillary lengths and seal configurations on both the high and low pressure process connection. Specifying symmetrical systems was once believed to achieve best total system performance. Actually, the asymmetry of Tuned-Systems compensates for temperature-induced errors. The following discussion will explore how a diaphragm seal system works and prove the theory behind Tuned-Systems.

What are *Tuned-Systems*?

Tuned-Systems are an asymmetric configuration of a differential pressure diaphragm seal system. The simplest form of a Tuned-System directly mounts the diaphragm seal to the high pressure process connection. Elimination of the excess high pressure capillary immediately improves response time, and performance, while reducing installed cost. Total system error is compensated by leveraging diaphragm induced temperature errors against head effect temperature errors. Further performance improvements are achieved by adjusting configuration variables as detailed below. Installed cost is reduced by eliminating the excess high pressure capillary. Because the transmitter is direct-mounted to the vessel, neither mounting stand nor mounting bracket are required for further reduce installed cost.

How Do Seal Systems Work?

Diaphragm seal systems respond to changes in both process pressure as the level changes, and in static pressure over the liquid. These variations in pressure are transmitted through an oil- filled capillary to a differential pressure transmitter-sensor. The capillaries and seals are filled with an incompressible oil compatible with the process temperature, pressure, and media composition. The transmitter is commonly mounted at grade, or in close proximity to the high-pressure process connection. For applications under vacuum, the transmitter is mounted below the high-pressure connection

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to reduce vacuum effects on the transmitter fill fluid. The minimum capillary length is dictated by the distance between the mounting position of the transmitter and the low-pressure connection. All cavities within the assembly are oil-filled including the diaphragm, capillary, and transmitter body. Although manufacturing techniques help ensure a high-quality fill, temperature-induced errors are inherent to diaphragm seal systems.

Diaphragm Seal System Elements

Because the transport mechanism of a diaphragm seal system is the fill fluid, it is important to understand the fill fluid physical characteristics. The fill fluid oil is an incompressible fluid and a change in pressure within the process is directly translated to the transmitter-sensor. Proper fill fluid and assembly preparation are critical to achieve a high quality filled system. Proper preparation requires removing all gases from both the fill fluid and the un-filled transmitter-seal assembly. A successful fill process prevents ambient air from entering the assembly. Air or other gases in the system are compressible fluids and cause erratic transmitter output shifts.

Each fill fluid has it own unique physical characteristics and play the largest role in total system performance. The physical characteristics include: viscosity, coefficient of thermal expansion, and specific gravity.

Fill fluid viscosity is a measure of velocity flow rate and dictates the response time of the diaphragm seal system. A temperature increase causes the fill fluid to become less viscous and yields a faster response time, while a decrease in temperature slows the response time. Capillary inside diameter and length also impact system response time. A small inside diameter restricts the fill fluid flow causing slower response time. Capillary length relates to the time for a change in pressure to reach the transmitter-sensor.

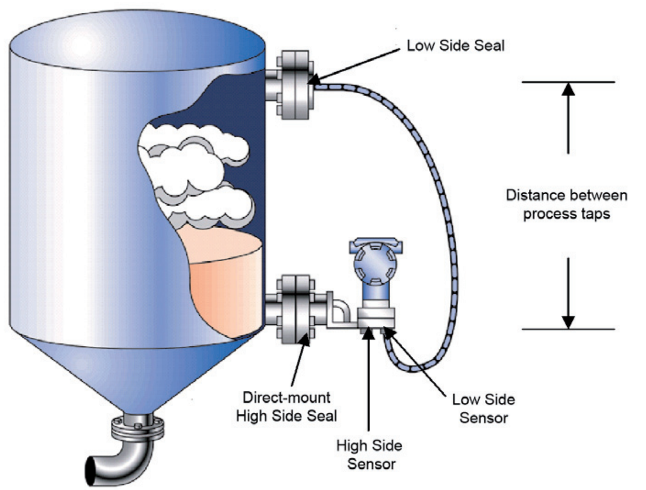

Figure 1. *Tuned-System used to measure level in a closed vessel.*

Seal Temperature Effect Error:

The fill fluid coefficient of thermal expansion is the rate a fill fluid volume expands or contracts in response to temperature changes. A larger coefficient of thermal expansion factor equates to higher response rate to the change. The fill fluid volume expands to an increase in temperature and contracts to a decrease in temperature. The larger fill fluid volume within the seal system, the greater the total volume expansion or contraction. System volume is highly dependent on capillary inside diameter, capillary length, and seal cavity volume.

Because a diaphragm seal assembly is a closed system, the expanding fill fluid volume presses against the seal diaphragm. The seal diaphragm restricts the expansion causing a back-pressure on the fill fluid. The diaphragm back-pressure is highly dependent on diaphragm stiffness, or spring rate. Diaphragm spring rate is a function of the diaphragm pattern, thickness, material modulus of elasticity, and diameter. A more flexible diaphragm with a high spring rate minimizes the back-pressure exerted on the transmitter-sensor. The variations in back-pressure exerted on the transmitter-sensor are commonly referred to as *Seal Temperature Effect*.

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Head Temperature Effect Error:

The fill fluid specific gravity is the ratio of the fill fluid density compared to the density of water. As temperature changes, the specific gravity of the fill fluid changes; an increase in temperature lowers the specific gravity while a decrease in temperature increases the specific gravity. The seal elevation exerts pressure on the differential pressure transmitter-sensor and is referred to as Head Pressure. The fill fluid specific gravity, combined with seal elevation, are the primary variables required to determine the head pressure (Head Pressure = Specific Gravity x Height). The initial head pressure can be calculated and is zeroed out of the differential pressure system during calibration and commissioning. However, variations in temperature cause changes in fill fluid specific gravity and subsequent variations in head pressure from original commissioning. These variations in head pressure are commonly referred to as *Head Temperature Effect Error*.

Harnessing System Elements:

Traditional systems apply equivalent seals and capillary lengths to either side of the differential pressure transmitter-sensor, this creates identical (or nearly identical) pressure changes due to seal temperature effect error. Because the pressure changes are equal and are on opposite sides of the transmitter-sensor, the net seal temperature effect error is cancelled. Therefore, the net error is completely a function of the head temperature effect error. The symmetric design was considered to deliver the best total system performance. However, traditional symmetric configurations ignore the largest source of error; head temperature effect error does not realize the opportunity to reduce total system error. Tuned-Systems harness the physical characteristics of the fill fluid, and the mechanical design features of the diaphragm seal system to deliver best total system performance.

Both head and seal temperature effect errors occur simultaneously within the system in response to temperature changes. The differential transmitter-sensor cannot differentiate the error type. Therefore, the Total System Error is the sum of the seal temperature effect plus the head temperature error, and represents the error transmitted to the differential pressure transmitter-sensor. It can be concluded that differential pressure diaphragm seals must be viewed as a system to effectively compensate for total system errors induced by temperature changes.

Consider a Tuned-System that eliminates excess high-pressure capillary, and experiences an increase in temperature from original zero. The head temperature error causes a net positive error and is identical in magnitude to a symmetrical system installation, under the same temperature variation conditions. However, the Tuned-System seal temperature effect errors yield a net negative error. The fill fluid volume on the high-pressure side of the system has less volume compared to the low- pressure side of the system. Therefore, the volumetric displacement, and resulting diaphragm back-pressure, is dominated by the low pressure side, thus proving total system error for Tuned-Systems is less than traditional systems. The detailed mathematical proof is outlined below.

Minimizing Total System Errors:

To take the theory of Tuned-Systems a step further, total system errors can be compensated, and in some cases eliminated. Minimizing total system errors requires creating seal temperature effect errors that are equal, and opposite in magnitude to head temperature effect errors. In addition to reducing high-pressure capillary fill fluid volume, the following can be varied for additional performance improvements; decrease high-pressure diaphragm stiffness, increase low-pressure fill fluid volume, increase fill fluid expansion coefficient, and/or increase low-pressure diaphragm stiffness. Due to the number of variables, achieving a fully compensated differential pressure seal system requires an automated software tool, such as Rosemount Instrument Toolkit. Instrument Toolkit has the capability to quickly and easily calculate numerous potential compensated seal systems for any given application condition.

Conclusion:

Temperature-induced errors are inherent to differential pressure diaphragm seal systems. The errors are caused primarily by the fill fluid physical characteristics responding to a change in temperature. Total system error is also a function of the distance between vessel process connections and the mechanical design of the diaphragm seal system. Total system error is uncompensated in traditional symmetrical system configurations.

The asymmetry of Tuned-Systems compensates total system error by reducing the high pressure side capillary volume. Further performance improvements can be achieved by varying diaphragm spring rate, system fill volumes, and fill fluid type. The reduced volume and configuration variations compensate for changes in fill fluid specific gravity, thereby providing improved performance in differential pressure diaphragm seal applications.

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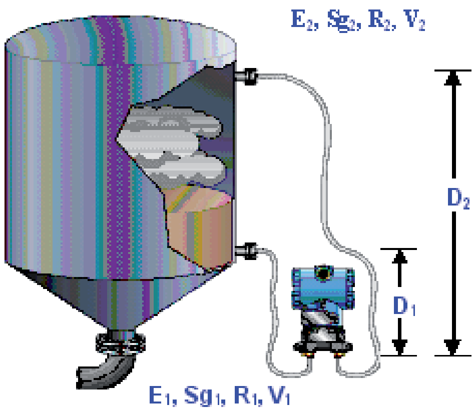
Mathematic Proof:



Head Pressure Error on Transmitter Sensor:

High-side Sensor Head Pressure (H_1): $H_1 = (D_1 \times Sg \times E \times \Delta T)$

Low-side Sensor Head Pressure (H_2): $H_2 = (D_2 \times Sg \times E \times \Delta T)$
Head Pressure = $H_1 - H_2$

Head Pressure = $(D_1 \times Sg \times E \times \Delta T) - (D_2 \times Sg \times E \times \Delta T)$

$= (D_1 - D_2)(Sg \times E \times \Delta T)$

$D_2 > D_1$ therefore, $D_1 - D_2 = -D$

Head Pressure = $-D \times Sg \times E \times \Delta T$

Seal Pressure Error or Transmitter Sensor:

High-Pressure Seal:

Volumetric Displacement = $V_1 \times E \times \Delta T$

Pressure Change = $\dfrac{V_1 \times E \times \Delta T}{R_1}$

Low-Pressure Seal:

Volumetric Displacement = $V_2 \times E \times \Delta T$

$$\text{Pressure Change} = \frac{V_2 \times E \times \Delta T}{R_2}$$

Total Seal Pressure Error:

$$\text{Seal Pressure Error} = \frac{V_1 \times E \times \Delta T}{R_1} - \frac{V_2 \times E \times \Delta T}{R_2}$$

$$= \left\{\frac{V_1}{R_1} - \frac{V_2}{R_2}\right\} E\Delta T$$

Assumed Variables:

D_1 = Distance between high-pressure connection and transmitter
D_2 = Distance between low-pressure connection and transmitter
V_1 = Fill fluid volume within high-pressure capillary-seal assembly
V_2 = Fill fluid volume within low-pressure capillary-seal assembly
ΔT = Relative change in temperature from original zero
Sg = Fill Fluid Specific Gravity; Assume Sg1 = Sg2
E = Fill Fluid Coefficient of Thermal Expansion; Assume E1 = E2
R_1 = Spring rate of seal diaphragm on high-pressure connection.
R_2 = Spring rate of seal diaphragm on low-pressure connection.

Note: Spring rate is the fill fluid volume change divided by corresponding change in diaphragm back-pressure. Therefore, a diaphragm with a larger R-value is more flexible.

Total System Error (TSE):

Total System Error (TSE):
Total system seal error is eliminated when head pressure error equals seal temperature error. Therefore, Tuned-Systems performance improvement is proven by solving theTotal System Error equation below.

$$\text{TSE} = -D \times Sg \times E \times \Delta T - \left\{\frac{V_1}{R_1} - \frac{V2}{R_2}\right\} E\Delta T$$

Factor out like variables and qualitatively compare results of the traditional system scenario versus Tuned-System scenarios:

$$\text{TSE} = \left\{- DSg - \left\{\frac{V_1}{R_1} - \frac{V2}{R_2}\right\}\right\} E\Delta T$$

Symmetrical System Case:

If,

$V_1 = V_2$ and $R_1 = R_2$ then, $TSE = - DSgE\Delta T$

All of the total system error is caused by head pressure error acting on the transmitter-sensor.

Tuned-Systems Case:

If,

$V_1 < V_2$	or $V_1 < V_2$	or	$V_1 = V_2$
$R_1 = R_2$	$R_1 > R_2$		$R_1 > R_2$

Then, Tuned-Systems are proven. All scenarios have improved total system error. Instrument Toolkit provides further proof and quantitatively solves equation.

In summary, apply the following basic rules to prove additional compensation of diaphragm seal systems:

- Apply an asymmetrical system configuration
- Reduce the high pressure side fill fluid volume
- Minimize the high pressure diaphragm stiffness (increase spring rate)
- Increase the low pressure side fill fluid volume
- Increase the low pressure diaphragm stiffness (decrease spring rate)
- Use Rosemount Instrument Toolkit to optimize total system performance

7 Focus Areas

7. Focus areas

7.1 Safety Integrity Level (SIL)

The international standard IEC 61508 defines SIL using requirements grouped into two broad categories: hardware safety integrity and systematic safety integrity. A device or system must meet the requirements for both categories to achieve a given SIL.

The SIL requirements for hardware safety integrity are based on a probabilistic analysis of the device. To achieve a given SIL, the device must have less than the specified Probability of Dangerous Failure (PDF) and have greater than the specified Safe Failure Fraction (SFF). These failure probabilities are calculated by performing a Failure Modes, Effects, and Diagnostic Analysis (FMEDA). The actual targets required vary depending on the likelihood of a demand, the complexity of the device(s), and types of redundancy used.

The SIL requirements for systematic safety integrity define a set of techniques and measures required to prevent systematic failures (bugs) from being designed into the device or system. These requirements can either be met by establishing a rigorous development process, or by establishing that the device has sufficient operating history to argue that it has been proven in use.

Electric and electronic devices can be certified for use in functional safety applications according to IEC 61508, providing application developers the evidence required to demonstrate that the application including the device is also compliant.

IEC 61511 is an application specific adaptation of IEC 61508 for the Process Industry sector. IEC 61508 addresses the requirements for manufacturers of safety components used on SIS and IEC 61511 outline the requirements for end-users and integrators only.

7.1.1 Selecting a safe sensor

Within IEC 61511, there are two options for selecting sensors.

The first option is a safety certified device that is designed per IEC 61508. This means that the manufacturer proves that the device or transmitter is safe and the user proves the actual interface to the process is safe.

The second option is to select a sensor based on “Prior-Use”. That means that the end user proves the entire system is safe.

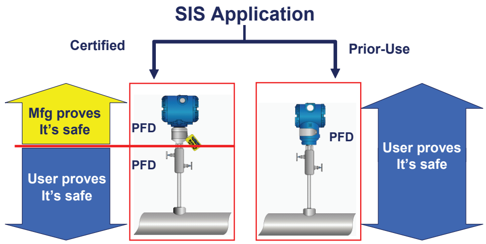


Figure 7.1.1: Responsibility of proof for SIS sensors

These are two options with the same result.

Note: No radar on the market is "Certified", all are "Prior-Use"!

7.1.2 FMEDA

One step in selecting a sensor technology is to look at the safety and reliability of the sensor. This is typically in the form of a Failure Modes, Effects, and Diagnostic Analysis or FMEDA. This evaluation can be done for non-certified and certified products.

This is an exercise where typically an independent 3rd party, such as Exida, will look at the schematics and hardware of the product and identify what all the failure modes are. It will give the safe detected, safe undetected, dangerous detected, and dangerous undetected failures. It will also provide the Safe Failure Fraction (SFF). The SFF tells if the product meets one of the requirements for certification – the SFF must be 90% or higher to achieve certification.

The FMEDA will also provide Probability of Failure on Demand (PFD) data and how the PFD changes over time. When a sensor is new, it has a certain PFD. Over time, the probability of failure on demand is going to increase and can be reduced by proof-tests.

Important is that the proof test interval of a sensor is greater than or equal to your plant turnaround interval. This way, there is no process interruption and there is a reduced risk to your personnel.

7.1.3 Hardware Fault Tolerance

The Hardware Fault Tolerance (HFT) is the ability of a system to respond to an unexpected hardware or software failure. There are many levels of fault tolerance, the lowest being the ability to continue operation in the event of a power failure.

7.1.4 Certified sensors

For a certified sensor, there are really two systems. The 1st system is the actual device or transmitter. For this system or top half, the burden is on the manufacturer to prove that it is safe. The second system, or bottom half, is the actual interface to the process. The 2nd half or bottom portion is the user's responsibility. The user must prove it's safe.

Both of these systems will have a probability of failure on demand or PFD – there will be a PFD for the transmitter and a PFD for the interface and these will be added together. Probability of Failure on Demand is the probability that the loop/device will be in a failure mode when there is a demand on the system.

7.1.4 Prior-use

For a prior-use transmitter, the user proves that the entire system is safe. The user must have data to support that both the transmitter and interface are safe to use in that application.

In addition, there are two ways to claim SIL suitable prior-use; either with a SFF from the hardware assessment (according to IEC 61508), or with a SFF from the hardware assessment (according to IEC 61508) combined with plant specific proven-in-use data (per IEC 61511).

This means, as an example; a sensor with a SFF >90% will be SIL2 suitable (if the system has a Hardware Fault Tolerance (HTF) of 0) and a sensor with a SFF in the range of 60 to <90% will be SIL1 suitable in that same system. However, users can reduce the HTF by one according to IEC 61511 in their validation together with proven-in-use data. See table below.

Note: Scope in IEC 61511-1 part 1 states: "...does not apply to manufacturers wishing to claim that devices are suitable for use in safety instrumented systems ..."

Proven-in-use data should be plant specific data and manufacturers, or assessors for manufacturers, can not qualify and claim proven-in-use as per IEC 61511.

SFF	HFT=0	HFT=1 (0*)	HFT=2 (1*)
<60%	N/A	SIL1	SIL2
60%...<90%	SIL1	SIL2	SIL3
90%...<99%	SIL2	SIL3	(SIL4)
≥99%	SIL3	(SIL4)	(SIL4)

*Table 7.1.1 Prior-use Safety Integrity Levels based on SFF for type B safety related subsystems. *Users can reduce the Hardware Fault Tolerance (HTF) by one with proven-in-use according to IEC 61511 in their validation. Only users, not manufacturers can do this.*

7.1.5 Rosemount 5300 series guided wave radar SIL2 suitable

The 5300 series has been evaluated by third party Exida per hardware assessment IEC 61508. The hardware assessment consists of a FMEDA (Failure Mode, Effects and Diagnostic Analysis) report.

Rosemount 5300 series is considered to be a type B subsystem with hardware fault tolerance of 0. With Safe Failure Fraction (SFF) > 90% it has shown prior-use SIL2 suitable. This option provides the safety instrumentation engineer with the required failure data as per IEC 61508 /IEC 61511 and with proof test recommendations.

- SFF: 90.7%
- PFDAVG (Tproof (1 year)): 6.13E-04
- MTBF: 64 years
- Proof test interval: 5 years (based on sensor average probability of failure on demand should be better or equal to 3.5E-03 for SIL2)
- Valid for 4...20 mA output (HART)

For more information regarding safety, go to: www.emersonprocess.com/rosemount/safety

7.2 NACE compliance of the radar products

7.2.1 Scope

This specification identifies the metallic materials of construction used in the Rosemount 3300, 5300, and 5400 radar products that comply with NACE standard guidelines for corrosion resistance in sour oilfield and refining applications. ISO 15156/MR0175 applies to petroleum production, drilling, gathering and flow line equipment, and field processing facilities to be used in hydrogen sulfide, H2S, bearing hydrocarbon service. MR0103 provides material requirements exclusive to sour petroleum refining environments. Sour environments are commonly defined as containing more than 50 ppm dissolved H2S in water and/or 0.05 psia partial pressure H2S in the vapor phase.

Specification compliance guidelines in this document are intended to include wetted material as recommended by both NACE standards. Metallurgical requirements for alloys used within our devices are virtually identical for the two standards. However, application limits enforced by our customers are distinctly different for upstream (ISO 15156/MR0175) and downstream (MR0103) sour conditions and can limit material acceptance. Though both environments are considered sour from the presence of H2S, each has discrete corrosion mechanisms created by differences in pH and chloride content levels. As such, final selection of the appropriate material for a given application is the responsibility of the end-user.

7.2.2 Background

For over 25 years, MR0175 has provided recommendations for proper use of various metals and alloys to avoid problems with sulfide stress corrosion (SSC). NACE has added to it recommendations practical limits to avoid stress corrosion cracking (SCC). NACE international and others developed ISO 15156 to replace MR0175 to provide more comprehensive material requirements and recommendations for use in environments containing H2S in oil and gas production systems.

In April 2003, NACE International released MR0103 to provide a separate set of material requirements exclusive to sour refining environments. Alloy K-500 use is not restricted under MR0103 provided less than 35 HRC. MR0103 was revised in 2005 and 2007.

Technical Corrigendum 2 for ISO 15156/MR0175, released in 2005, removed certain material restrictions that were imposed by previous revisions. Specifically relating to instrumentation and control devices, the corrigendum removed the 60°C temperature limit for exposed austenitic stainless steels though it is still regarded as a 'best practice' to use SCC resistant materials such as Alloy C-276 for brackish conditions above 60°C commonly associated with sour reserves. The corrigendum included Alloy 400/405 as acceptable provided hardness less than 35 HRC and expanded application criteria for Alloy C-276. Alloy K-500 use is restricted under ISO 15156/MR0175.

7.2.3 Applicability

Corrosion of metallic materials is influenced by a number of factors. Some of the interacting influences identified include the material condition (chemistry, hardness, heat treatment, etc), pH, chloride content, H2S concentration and total pressure, stress, temperature and time. Consult individual standards for more details.

ISO 15156/MR0175 and MR0103 are not code documents and make no provision for certification to the materials and procedures described therein. Instead, it is ultimately the end users responsibility to determine the appropriate application of, and conformance to the standard.

The NACE standard applies to all components of equipment exposed to sour refinery environments as defined where failure by SSC would:

(1) compromise the integrity of the pressure-containment system,
(2) prevent the basic function of the equipment, and/or
(3) prevent the equipment from being restored to an operating condition while continuing to contain pressure.

7.2.4 Sour environment exposure

In service, only the transmitter's wetted parts, those in direct contact with the process fluid, are exposed to the sour environment at sufficient pressure to require application of the standard. Unless the transmitter is mounted in a protective enclosure, the transmitter's non-wetted parts (bolting, electronic housing and covers) are exposed to atmospheric conditions.

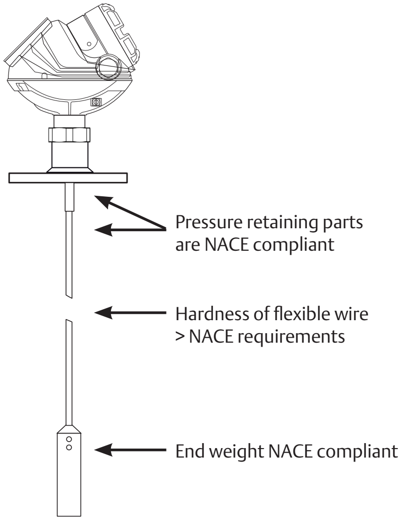
7.2.5 Non-wetted parts

The bolting, electronic housing and covers are not normally in direct contact with the sour process and are therefore considered outside the scope of the standard.

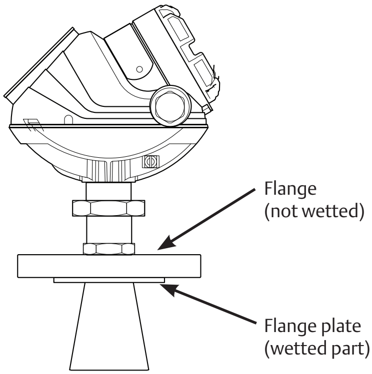
7.2.6 Wetted parts

On the GWR products, the coaxial probes and single rigid probes (types 3A, 3B and 4A) in SST, Alloy C-276, and Alloy 400 meet ISO 15156/NACE MR0175 and NACE MR0103 standards for all wetted parts.

The SST flexible probe (type 5A) meets the ISO 15156/NACE MR0175 and NACE MR0103 standards for pressure-retaining parts only. Due to the manufacturing methods of such wires, the flexible wire itself exceeds the allowable hardness limit stated by the NACE standards. This leaves the product at risk of losing basic function. PTFE covered probes may be an alternative for some users, but since the base material is still the higher hardness SST, it is not considered NACE compliant.



On the non-contacting 5400 products, antennas are available in SST, Alloy C-276, Alloy 400 and PTFE. This includes antenna types 2H – 8H (Alloy C-276), 2M- 8M (Alloy 400), 2N- 8N (316 SST), and 1R-4R (PTFE rod antenna) and 2P-4P (PTFE process seal). On the cone-style antennas, this involves the use of a welded flange plate and cone antenna assembly for the wetted parts.



The product antenna and probe options are compliant with ISO 15156/NACE MR0175 and MR0103.

Rosemount 3300 and 5300 series guided wave radar			
Probe type	Coaxial (3A, 3B)	Single rigid (4A)	Flexible (5A)
SST	Yes	Yes	Pressure retaining parts only
Alloy 400	Yes	Yes	Pressure retaining parts only
Alloy C-276	Yes	Yes	Pressure retaining parts only
PTFE covered SST	Yes	Yes	Pressure retaining parts only

Rosemount 5400 series non-contacting radar			
Antenna type	Cone style	Rod style	Process seal
SST	Yes - antenna codes 2N-8N	N/A	N/A
Alloy 400	Yes - antenna codes 2M-8M	N/A	N/A
Alloy C-276	Yes - antenna codes 2H-8H	N/A	N/A
PTFE	N/A	Yes - antenna codes 1R-4R	Yes - antenna codes 2P-4P

7.2.7 Typical refinery equipment susceptible to sulfide stress cracking (not all-inclusive)

Reference: NACE paper 04649, 2004

Crude units - atmospheric and vacuum	Atm tower overhead system	Coolers
		Accumulators
	Vacuum tower overhead system	Coolers
		Accumulators
	Light ends recovery section	Debutanizers
		Waste gas scrubbers
		Sour water collection system
Catalytic cracking units	Main fractionator overhead system	Overhead line
		Coolers/condensers
		Accumulators
		Coalescers
		Absorbers
	Wet gas system	Compressor suction drum
		Accumulators
		Coolers
	Light ends recovery section	Deethanizers
		Debutanizers
		Accumulators
Hydro-processing units	Feed system	Feed surge drums
	Reactor effluent section	High pressure/low pressure separators
		Trim coolers
	Fractionation section	Stripper towers
		Reflux drums
	Gas treating section	Amine absorbers
		Off gas absorbers
		Flash tower
	Recycle gas system	Knockout pots
		Condensers
Coker units	Coker fractionator overhead system	Overhead line
		Coolers/condensers
		Accumulators
		Coalescers
		Absorbers
	Coker light ends recovery section	Deethanizers
		Debutanizers
		Accumulators
Other	Sour water recovery units	Sour water stripper
		Column overhead system
	Amine regenerator systems	Amine regenerator system
		Accumulator drum
		Quench tower
	Gas recovery plants	Debutanizers
		Waste gas scrubbers
		Sour water collection system
	Sulfur recovery units	Acid gas knock out drums
		Condensers
		Blow down drums

Appendices

Topic	Page

Appendix 1 - Dielectric constants

COMPOUND	DK	°F	°C	STATE
2-AMINO-2-METHYL-1-PROPANOL (AMP)	18-20	122-86	50-30	L
ACTIVATED COKE PELLETS	14	RT	RT	S
AMINOOCTANE	3.9	54	12	L
AMINOOCTANE	4.1	36	2	L
AMINOPENTANE	4.5	72	22	L
AMINOTOLUENE	4.6	68	20	L
AMLMERCAPTAN	4.7	68.0	20.0	L
AMMONIA	1.0072	32.0	0.0	GA
AMMONIA	14.9	77	25	L
AMMONIA	15.5	68.0	20.0	L
AMMONIA	18.9	40.0	4.4	L
AMMONIA	22.0	-30.0	-34.4	L
AMMONIA	22.7	-58	-50	L
AMMONIA	25.0	-104.0	-75.6	L
AMMONIA	25.0	-74.0	-58.9	L
AMMONIA. AQUEOUS (25%)	31.6	68	20	L
ASPHALT	2.7	75.2	24.0	L
ASPHALT	3.7	400.0	204.4	L
ASPHALT	2.6	75.0	23.9	S
AVIATION GASOLINE	1.9	77.0	25.0	L
BAYOL	2.1	75.2	24.0	L
BAYOL-16	2.2	75.2	24.0	L
BAYOL-D	2.1	75.2	24.0	L
BAYOL-F	2.1	75.2	24.0	L
BENZALDEHYDE	17.0	68.0	20.0	L
BENZALDEHYDE	19.0	32.0	0.0	L
BENZALDEHYDE	10.9	59	15	L
BENZENE	1.0028	700.0	371.1	GA
BENZENE	2.1	275.0	135.0	L
BENZENE	2.3	68.0	20.0	L
BENZENE. (BROMOMETHYL)	6.7	68.0	20.0	L
BENZENE. (DICHLOROMETHYL)	6.9	68.0	20.0	L
BENZENE. (TRIFLUOROMETHYL)	9.2	77.0	25.0	L
BENZENE. HEAVY	3.2	68	20	L
BENZENE. PURE	1.9	68	20	L

COMPOUND	DK	° F	° C	STATE
BENZENEDIOL	13.6	248.0	120.0	L
BENZENEPHOSPHONIC ACID DICHLORIDE	26.0	68.0	20.0	L
BENZENEPHOSPHONIC ACID DIFLUORIDE	27.9	68.0	20.0	L
BENZENESULFONYL CHLORIDE	28.9	122.0	50.0	L
BENZENESULFONYL CHLORIDE. (TRIFLUOROMETHYLSULFONYL)	4.7	77.0	25.0	L
BENZENETHIOL	4.3	86.0	30.0	L
BENZENETHIOL. (TRIFLUOROMETHYLSULFONYL)	28.5	77.0	25.0	L
BENZIL	5.9	158	70	L
BENZIL	13.0	203.0	95.0	L
BENZINE (LIGROIN)	7.6	75.0	23.9	L
BENZOLE	2.3	50	10	L
BENZOLE. HEAVY	3.2	68	20	L
BENZOLE+ MALONATE. WITHOUT EMULSION	3.5	68	20	L
BENZONITRILE	22.0	160.0	71.1	L
BENZONITRILE	25.9-26	68.0	20.0	L
BENZOPHENONE	11.4	112.0	44.4	L
BENZOPHENONE	12.6	80.6	27.0	L
BENZOTRICHLORIDE	7.4	68.0	20.0	L
BENZOTRICHLORIDE	19.0	68.0	20.0	L
BENZOYL (P-CHLOROPHENYL) THIODIIMINE	7.9	19.4	-7.0	L
BENZOYL (P-FLUOROPHENYL) THIODIIMINE	7.3	152.6	67.0	L
BENZOYL (P-METHYLPHENYL) THIODIIMINE	13.1	154.4	68.0	L
BENZOYL (P-TRIFLUORO-METHYLSULFONYL) PHENYTHIODIIMINE	15.9	158.0	70.0	L
BENZOYL ACETATE	11.5	70	21	L
BENZOYL ACETONE	3.8	68.0	20.0	L
BENZOYL ACETONE	29.0	68.0	20.0	L
BENZOYL BROMIDE	21.3	68.0	20.0	L
BENZOYL CHLORIDE	19.0	75.0	23.9	L
BENZOYL CHLORIDE	20.0	68	20	L
BENZOYL CHLORIDE	23.0	68.0	20.0	L
BENZOYL FLUORIDE	22.7	68.0	20.0	L
BENZOYLIMIDOSULFUROUS DICHLORIDE	31.6	104.0	40.0	L
BENZYL ACETATE	5.0	70.0	21.1	L
BENZYL ACETATE	5.3	86.0	30.0	L

COMPOUND	DK	° F	° C	STATE
BENZYL ALCOHOL	6.6	270	132	L
BENZYL ALCOHOL	9.5	158	70	L
BENZYL ALCOHOL	11.9	86.0	30.0	L
BENZYL ALCOHOL	13.0	68.0	20.0	L
BENZYL BENZOATE	4.8	68.0	20.0	L
BENZYL BENZOATE	5.3	86.0	30.0	L
BENZYL BUTANOATE	4.6	82.4	28.0	L
BENZYL CHLORIDE	7.0	55	13	L
BENZYL CHLORIDE	6.4-6.9	68.0	20.0	L
BENZYL CYANIDE	6.0	155.0	68.3	L
BENZYL CYANIDE	18.3	68.0	20.0	L
BENZYL ETHYL ETHER	3.9	77.0	25.0	L
BENZYL ETHYLAMINE	4.3	68.0	20.0	L
BENZYL FORMATE	6.3	86.0	30.0	L
BENZYL IODIDE	4.6	68	20	L
BENZYL NITRITE	7.8	77.0	25.0	L
BENZYL PHENYL ETHER	3.7	104.0	40.0	L
BENZYL PHENYLACETATE	4.5	86.0	30.0	L
BENZYL PROPANOATE	5.1	86.0	30.0	L
BENZYL SALICYLATE	4.1	68	20	L
BENZYL SALICYLATE	4.1	82.4	28.0	L
BENZYLAMINE (AMINO TOLUENE)	4.3	120.0	48.9	L
BENZYLAMINE (AMINO TOLUENE)	4.6	68.0	20.0	L
BENZYLAMINE (AMINO TOLUENE)	5.5	32.0	0.0	L
BENZYLETHYLAMINE	4.3	68.0	20.0	L
BENZYLMETHYLAMINE	4.4	66.2	19.0	L
BENZYLTHIOL	4.7	77.0	25.0	L
BIOPROPANOL	25.0	68	20	L
BIS(3-METHYLBUTYL)AMINE	2.5	64.4	18.0	L
BITUMEN	2.3	140	60	L
BITUMEN	2.8	68	20	L
BITUMEN FROTH	4.1	75.0	23.9	L
BUTADIENE	2.1	17.6	-8.0	L
BUTANAL	13.0	77.0	25.0	L
BUTANE	1.4	30.2	-1.0	L

COMPOUND	DK	° F	° C	STATE
BUTANE	1.8	71.6	22.0	L
BUTANE	2.9	68	20	L
BUTANEDIOL	22.4	77.0	25.0	L
BUTANEDIOL	30.0	80.0	26.7	L
BUTANEDIOL DINITRATE	18.0-18.9	68.0	20.0	L
BUTANEDIOL-(1.3)-DINITRATE	18.9	68	20	L
BUTANEDIOL-(1.4)	30.2	86	30	L
BUTANEDIOL-(2.3)-DINITRATE	28.8	68	20	L
BUTANEDIOLDIACETATE	5.1	77	25	L
BUTANOL (BUTYL ALCOHOL)	15.4	104	40	L
BUTANOL (BUTYL ALCOHOL)	23.8	-13	-25	L
BUTANOL (BUTYL ALCOHOL)	17.3-17.8	68.0	20.0	L
BUTANONE	18.5-18.6	68.0	20.0	L
BUTANONE (-2)	17.6	104	40	L
BUTANONE (-2)-OXIME	3.4	68	20	L
BUTANONE OXIME	3.4	68.0	20.0	L
BUTANONEOXIM	3.4	68	20	L
BUTENE	2.0	73.4	23.0	L
BUTOXYACETYLENE	6.6	77.0	25.0	L
BUTOXYACETYLENE	6.6	68	20	L
BUTOXYETHANOL	9.4	77.0	25.0	L
BUTOXYETHYL ISOCYANATE	9.4	68.0	20.0	L
BUTYL ACETATE	3.4	140.0	60.0	L
BUTYL ACETATE	5.1	68.0	20.0	L
BUTYL ACRYLATE	5.3	82.4	28.0	L
BUTYL ACRYLATE	4.2	68	20	L
BUTYL ALCOHOL (BUTANOL)	7.0	140	60	L
BUTYL ALCOHOL (BUTANOL)	11.2	86	30	L
BUTYL ALCOHOL (BUTANOL)	19.5	50	10	L
BUTYL ALCOHOL (BUTANOL)	20.0	75.0	23.9	L
BUTYL ALCOHOL (BUTANOL)	23.8	-13	-25	L
BUTYL ALCOHOL (N-)	7.8	66.0	18.9	L
BUTYL BENZENE	2.3	86	30	L
BUTYL BENZOATE	5.5	86.0	30.0	L
CARBON BISULFIDE. PURE	2.6	68	20	L

COMPOUND	DK	° F	° C	STATE
CARBON DISULPHIDE	2.2	180.0	82.2	L
CARBON DISULPHIDE	2.2	350.0	176.7	L
CARBON DISULPHIDE	2.6	68.0	20.0	L
CARBON DISULPHIDE	3.0	-166.0	-110.0	L
CHLORO-2-METHYL BUTANE	9.3	61	16	L
CHLORO-2-METHYL BUTANE	12.3	-59	-50	L
CHLORO-2-METHYL PROPANE	6.5	59	15	L
CHLORO-2-METHYL PROPANE	9.2	86	30	L
CHLORO-2-METHYL PROPANE	11.7	14	-10	L
CHLORO-2-NITRO-BENZENE	37.7	122	50	S
CHLORO-3-BROMOBENZENE	4.6	68	20	L
CHLORO-3-METHYL BUTANE	6.1	66	19	S
CHLORO-3-NITRO-BENZENE	13.3	149	65	S
CHLORO-3-NITRO-BENZOTRIFLUORIDE	12.8	86	30	L
CHLORO-4-ETHYL-BENZENE	6.0	77	25	L
CHLORO-4-NITRO-BENZENE	8.1	248	120	S
CHLORO-5-NITRO-BENZOTRIFLUORIDE	9.8	86	30	L
CHLOROBENZENE	4.7	100.0	37.8	L
CHLOROBENZENE	5.9	68.0	20.0	L
CHLOROBENZENE	6.1	32	0	L
CHLOROBENZENE	7.2	-50.0	-45.6	L
CHLOROBUTADIENE	4.9	68.0	20.0	L
CHLOROBUTANE	6.8	108	42	L
CHLOROBUTANE	7.3	68.0	20.0	L
CHLOROBUTANE	9.1	-20.0	-28.9	L
CHLOROBUTANE	12.2	-130	-90	L
CHLOROETHANE	6.2	340.0	171.1	L
CHLOROETHANE	9.5	68.0	20.0	L
CHLOROHEXANE	6.1	68.0	20.0	L
CHLOROMETHANE	10.0	71.6	22.0	L
CHLOROMETHANE	12.6	-35.0	-37.2	L
CHLOROMETHYLBUTANE	6.1	66.2	19.0	L
CHLOROMETHYLBUTANE	12.3	-58.0	-50.0	L
CHLOROMETHYLPROPANE	6.5	45.0	7.2	L
CHLOROMETHYLPROPANE	7.0	68.0	20.0	L

COMPOUND	DK	°F	°C	STATE
CHLORONITROBENZENE	8.1	248.0	120.0	L
CHLORONITROPROPANE	31.9	-9.4	-23.0	L
CHLORONITROTOLUENE	28.1	82.4	28.0	L
CHLOROPROPYLENE	8.9	79	26	L
CHLOROPYRIDINE	27.3	77.0	25.0	L
CLEANER'S NAPHTHA	2.0	68	20	L
COKE	3.0	68	20	S
COKE	8.0	68	20	S
COKE	1.1 - 2.2			S
CRUDE TAR	4.0	68	20	L
CYCLOHEXADIONE	4.4	170.0	76.7	L
CYCLOHEXANDIONE	4.4	172	78	L
CYCLOHEXANE	2.0	68.0	20.0	L
CYCLOHEXANE	2.0	68	20	L
CYCLOHEXANECARBOXYLIC ACID (HEXAHYDROBENZOIC ACID)	2.6	88.0	31.0	L
CYCLOHEXANEDIONE	4.4	172.4	78.0	L
CYCLOHEXANEMETHANOL	8.1	176.0	80.0	L
CYCLOHEXANEMETHANOL	9.7	140.0	60.0	L
CYCLOHEXANETHIOL	5.4	77.0	25.0	L
CYCLOHEXANOL	12.5	113	45	L
CYCLOHEXANOL	14.1	95	35	L
CYCLOHEXANOL	14.8	77	25	L
CYCLOHEXANOL	15.0	68	20	L
CYCLOHEXANONE	18.3	68	20	L
CYCLOHEXANONE	19.0	-40.0	-40.0	L
CYCLOHEXANONE (KETOHEXAMETHYLENE)	18.2	68.0	20.0	L
DECANE	1.8	340.0	171.1	L
DECANE	2.0	68.0	20.0	L
DIBROMOBENZENE	2.6	23.0	-5.0	L
DIBROMOBENZENE	4.5	190.0	87.8	L
DIBROMOBENZENE	4.7	73	23	L
DIBROMOBENZENE	7.5	68	20	L
DIBROMOBENZENE	8.8	68.0	20.0	L
DIBROMOBENZENE (P-)	4.5	190.0	87.8	S
DIBROMOBUTANE	4.7	68.0	20.0	L

COMPOUND	DK	° F	° C	STATE
DIBROMOBUTANE	5.8	77	25	L
DIBROMODECANE	6.6	86.0	30.0	L
DIBROMODICHLOROMETHANE	2.5	77.0	25.0	L
DIBROMODIFLUOROMETHANE	2.9	32.0	0.0	L
DIBROMOETHANE	4.1	212	100	L
DIBROMOETHANE	4.1	265.0	129.4	L
DIBROMOETHANE	4.6	131	55	L
DIBROMOETHANE	4.7	104	40	L
DIBROMOETHANE	4.8	77	25	L
DIBROMOETHENE	7.1	77	25	L
DIBROMOETHENE	7.7	32	0	L
DIBROMOETHYLENE	2.9	68	20	L
DIBROMOETHYLENE	3.0	32	0	L
DIBROMOETHYLENE (CIS)	7.1	77.0	25.0	L
DIBROMOETHYLENE (CIS-1. 2)	7.7	32.0	0.0	L
DIBROMOETHYLENE (TRANS)	2.9	77.0	25.0	L
DIBROMOHEPTANE	3.8	77	25	L
DIBROMOHEPTANE	3.8	150.0	65.6	L
DIBROMOHEPTANE	5.08	24.0	-4.4	L
DIBROMOHEPTANE	5.1	76.0	24.4	L
DIBROMOHEXANE	4.7-5.0	77.0	25.0	L
DIBROMOMETHANE	6.7	104	40	L
DIBROMOMETHANE	7.0	68	20	L
DIBROMOMETHANE	7.8	50.0	10.0	L
DIBROMOMETHYLPROPANE	4.1	68.0	20.0	L
DIBROMONONANE	7.2	68.0	20.0	L
DIBROMOOCTANE	7.4	77.0	25.0	L
DIBROMOPENTANE	4.3	68.0	20.0	L
DIBROMOPROPANE	4.3	68.0	20.0	L
DIBUTOXYDIMETHYLSILANE	2.8	77.0	25.0	L
DICHLORO-1-CHLOROMETHYLBENZENE	6.3	77.0	25.0	L
DICHLORO-1-METHYL BENZENE	9.0	77	25	L
DICHLORO-1-NITROETHANE	16.3	86.0	30.0	L
DICHLORO-2-CHLOROETHYLBENZENE	5.2	75.2	24.0	L
DICHLORO-2-METHYL PROPANE	7.2	73	23	L

COMPOUND	DK	° F	° C	STATE
DICHLORO-2-VINYL BENZENE	2.6	77	25	L
DICHLORO-3.5BIS (TRIFLUOROMETHYL) BENZENE	3.1	86.0	30.0	L
DIESEL FUEL	2.1	68	20	L
DIETHANOLAMINE (DEA)	22-25	122-86	50-30	L
DIETHOXYETHANE	3.9	68.0	20.0	L
DIETHOXYMETHANE	2.5	68.0	20.0	L
DIETHYLAMINE	3.7	68	20	L
DIETHYL DISULFIDE	10.2	64.4	18.0	L
DIETHYL SILANE	2.5	68	20	L
DIISOPROPANOLAMINE (DIPA)	13.2-13.9	122-86	50-30	L
DIMETHYL SULFATE	55.0	77.0	25.0	L
DIMETHYL SULFIDE	6.3	68.0	20.0	L
DIMETHYL SULFONE	47.4	230.0	110.0	L
DIMETHYL SULFOXIDE	47.2	68.0	20.0	L
ETHANE	1.9	-288.4	-178.0	L
ETHYLBENZAMIDE	42.6	176.0	80.0	L
ETHYLBENZENE	2.4	68.0	20.0	L
ETHYLBENZENE	3.0	76.0	24.4	L
ETHYLBENZYLAMINE	4.3	68.0	20.0	L
ETHYLENE	1.5	26.6	-3.0	L
ETHYLENE OXIDE	12.4	68.0	20.0	L
ETHYLENE OXIDE	13.9	30	-1	GA
ETHYLENE SULFITE	39.6	77.0	25.0	L
GASOLINE	2.0	70.0	21.1	L
GASOLINE. FUEL	2.1	75.0	23.9	L
HEAVY OIL	3.0			L
HEAVY OIL. C	2.6			L
HELIUM	1.1	-358.0	-216.7	GA
HELIUM	1.1	-455.8	-271.0	GA
HELIUM -3	1.055	58.0	14.4	L
HELIUM. LIQUID	1.9-2.0			L
HEPTANE	1.9	68.0	20.0	L
HEPTANE	2.1	-130.0	-90.0	L
HEXANE	1.8	167	75	L
HEXANE	1.9	68.0	20.0	L

COMPOUND	DK	° F	° C	STATE
HEXANE	1.9	86	30	L
HEXANE	2.0	-130.0	-90.0	L
HEXANE	3.2	-200.0	-128.9	L
HEXANE (CIS-3-)	2.1	76.0	24.4	L
HEXANE (N-)	1.9	68.0	20.0	L
HEXANONE	14.6	68.0	20.0	L
HEXANONE-(2)	14.6	58	15	L
HEXENE	2.0	69.8	21.0	L
HEXENE (CIS-3-)	2.1	76.0	24.4	L
HEXENE (TRANS-3-)	2.0	76.0	24.4	L
HEXYLAMINE	4.1	68.0	20.0	L
HYDRAZINE	51.7	77.0	25.0	L
HYDRAZINE	52.9	68	20	L
HYDROFLUORIC ACID	83.6	32.0	0.0	L
HYDROGEN SULFIDE	5.9	50.0	10.0	L
HYDROGEN SULFIDE	9.3	-120.0	-84.4	L
HYDROGEN SULPHIDE	8.0	-78	-61	L
HYDROGEN SULPHIDE	9.0	-109	-79	L
HYDROGEN SULPHIDE	9.3	-122	-86	L
HYDROGEN SULPHIDE	5.9	50	10	GA
HYDROGEN SUPEROXIDE. 30%	11.0	68	20	L
ISOOCTANE	2.1-2.3			L
ISOPENTANE	1.8	68	20	L
ISOPENTANE	1.9	32	0	L
JET FUEL (JP1)	2.1	77.0	25.0	L
JET FUEL (JP3)	2.0	77.0	25.0	L
JET FUEL (MILITARY-JP4)	1.7	69.8	21.0	L
LIQUID PARAFFIN	2.0	68	20	L
LIQUIFIED AIR	1.5			L
LIQUIFIED HYDROGEN	1.2			L
LPG	1.6-1.9			L
METHYLAMINE	9.4	77	25	L
METHYLAMINE	11.3	32	0	L
METHYLAMINE	11.4	14	-10	L
METHANE	1.005 - 1.05	10	50	GA

COMPOUND	DK	° F	° C	STATE
METHANE (LIQ. NATURAL GAS)	1.7	-295.6	-182.0	L
METHYL MERCAPTAN	7.6	35.0	1.7	L
METHYL NAPHTHALIN	2.7	77	25	L
METHYL NITRATE	23.9	68.0	20.0	L
METHYL NITRATE	23.5	64	18	L
METHYLNAPHTHALENE	2.7	68.0	20.0	L
METHYLNAPHTHALENE	2.7	104.0	40.0	L
METHYLPENTADIENE-(1.3)	2.4	77	25	L
METHYLPENTADIENE-(1.3)	2.5	122	50	L
METHYLPENTADIENE-(1.3)	3.2	-103	-75	L
METHYLPENTANE	1.9	68.0	20.0	L
MINERAL OIL	2.1	80.0	26.7	L
NAPHTHA (REFINERY CUT)	2.0	75.0	23.9	L
NAPHTHALENE	2.3	185.0	85.0	L
NAPHTHALENE	2.5	194	90	L
NAPHTHALENE	2.5	75.0	23.9	S
NAPHTHALENE	2.5	68	20	S
NAPHTHENIC ACID	2.6	68	20	L
NAPHTHOL	5.0	212.0	100.0	L
NAPHTHOLINE	2.5	75.0	23.9	L
NAPHTHONITRILE	6.4	70.0	21.1	L
NAPHTHONITRILE	16.0	158.0	70.0	L
NAPHTHYL NITRILE	16.0	158	70	L
NAPHTHYL NITRILE	19.2	72	22	L
NAPHTHYL SALICYLATE	6.3	68.0	20.0	L
NAPHTHYLAMINE	5.2	140.0	60.0	L
NAPHTHYLENEYLACETAMIDE	24.3	320.0	160.0	L
NAPTHONITRILE	6.4	69.8	21.0	L
NAPTHYL ETHYL ETHER	3.2	68.0	20.0	L
NITRIC ACID	50.0	14.0	-10.0	L
NITRIC ACID 97% HNO3	33.6	68	20	L
NITRIC ACID 98% HNO3	19.0	68	20	L
NITROGEN	1.00058	68.0	20.0	GA
NITROGEN	1.5	-346.0	-210.0	L
NITROGEN	1.4	-352	-213	L

COMPOUND	DK	° F	° C	STATE
NITROGEN	1.5	-318	-195	L
NITROGEN (LIQUIFIED)	1.3	-310	-190	L
NITROGEN (LIQUIFIED)	1.5	336.0	168.9	L
N-METHYLDIETHANOLAMINE (MDEA)	19-22	122-86	50-30	L
OCTANE	1.061			GA
OCTANE	1.8	230.0	110.0	L
OCTANE	1.9	160.0	71.1	L
OCTANE	1.95	68.0	20.0	L
OCTANE	1.9	77	25	L
OCTANONE	7.4	212.0	100.0	L
OCTANONE	9.5	68.0	20.0	L
OCTANONE	12.5	-4.0	-20.0	L
OCTYLBENZENE	2.3	68.0	20.0	L
OCTYLENE	4.1	66.2	19.0	L
OIL	2.04 - 3	68	20	L
OIL / DEA 124	2.4	68	20	L
OIL / WATER MIXTURE	24.2	68	20	L
OIL B1	6.0	68	20	L
OIL B3	4.2	68	20	L
OIL D8	6.8	122	50	L
OIL. COMPOUND. DRY	2.4	68	20	
OIL. COMPOUND. WET	2.4	68	20	L
OIL. CONSERVE+C2733	2.4	68	20	L
OIL. FUEL (#2)	2.7	75.0	23.9	L
OIL. HB-40	2.3	77.0	25.0	L
OIL. HEATING	2.1	68	20	L
OIL. HEAVY	2.2	68	20	L
OIL. KEL-F GRADE #1	2.2	77.0	25.0	L
OIL. KEL-F GRADE #10	2.1	77.0	25.0	L
OIL. KEL-F GRADE #3	2.1	77.0	25.0	L
OIL. MOBIL	2.3	68	20	L
OIL. MOTOR	2.6	68	20	L
OIL. MOTOR 10W40 AND SAE30	2.2	75.0	23.9	L
OIL. NON-CONDUCTIVE	3.0	68	20	L
OIL. PARAFFIN	2.2-4.7	68.0	20.0	L

COMPOUND	DK	° F	° C	STATE
OIL. PETROLEUM	2.1	68.0	20.0	L
OIL. PYRANOL	5.3	68.0	20.0	L
OIL. SAE 90	2.2	50	10	L
OIL. SAE 90	2.2	140	60	L
OIL. TRANSFORMER	2.1	68	20	L
OIL. TRANSIL	2.2	78.8	26.0	L
OIL. TRANSIL 10C	2.1	78.8	26.0	L
OIL. TRANSMISSION	2.2	80.6	27.0	L
OIL. TURPENTINE	2.2	68.0	20.0	L
PENTANDIONE	23.0	68	20	L
PENTANE	1.8	68.0	20.0	L
PENTANE	2.0	-130.0	-90.0	L
PENTANEDIOL	17.3	73.4	23.0	L
PENTANEDIONE	26.5	86.0	30.0	L
PENTANOL	13.4	77.0	25.0	L
PHENYLETHYLENE (STYRENE)	2.3	167.0	75.0	L
PHENYLETHYLENE (STYRENE)	2.4	77.0	25.0	L
POLYPROPYLENE. LIQUID	2.2 - 2.4	68	20	L
PROPANE	1.6	32.0	0.0	L
PROPANE	1.7	68.0	20.0	L
PROPANEDIOL	27.5	86.0	30.0	L
PROPANEDIOL DINITRATE	19.0	68.0	20.0	L
PROPANEDITHIOL	7.2	68.0	20.0	L
PROPANENITRILE	29.7	68.0	20.0	L
PROPANETHIOL	5.9	59.0	15.0	L
PROPANETRIOL 1.2-DIACETATE	18.2	-20.2	-29.0	L
PROPANETRIOL 1.3-DIACETATE	9.8	59.0	15.0	L
PROPENE	1.3	197.0	91.7	L
PROPENE	1.7	150.0	65.6	L
PROPENE	1.8	112.0	44.4	L
PROPENE	1.9	68.0	20.0	L
PROPENE	2.1	-63.4	-53.0	L
PROPYLAMINE	2.9	72	22	L
PROPYLAMINE	5.1	73.4	23.0	L
PROPYLAMINE	5.3	68	20	L

COMPOUND	DK	° F	° C	STATE
PROPYLBENZENE	2.4	68.0	20.0	L
PROPYLENE (LIQUID)	11.9			L
PROPYLENE GLYCOL (PG)	25-28	122-86	50-30	L
PROPYLENE. LIQUID	1.9	68	20	L
PYRAZINE	2.8	120.0	48.9	L
PYRIDINE	2.8	122.0	50.0	L
PYRIDINE	12.3	77	25	L
PYRIDINE	12.5	68.0	20.0	L
STEAM. WATER	1.008	212.0	100.0	GA
SULFATE. FINE	3.6	68	20	S
SULFINYL ANILINE. (TRIFLUOROMETHYLSAULFONYL)-N-	15.1	168.8	76.0	L
SULFINYLANILINE	7.0	77.0	25.0	L
SULFITE. SPENT LIQUOR	32.0	68	20	L
SULFUR	3.4	752.0	400.0	L
SULFUR	3.5	447.0	230.6	L
SULFUR	3.55	244.0	117.8	L
SULFUR	2.2	75.0	23.9	S
SULFUR	3.5	68	20	S
SULFUR	1.6 - 3.4	75.0	23.9	S
SULFUR CHLORIDE	3.0	77.0	25.0	L
SULFUR CHLORIDE	4.8	59	15	L
SULFUR DIOXIDE	14.0	68.0	20.0	L
SULFUR DIOXIDE	15.0	32	0	L
SULFUR DIOXIDE	17.6	-4.0	-20.0	L
SULFUR DIOXIDE	17.7	-6	-21	L
SULFUR. POWDER	1.6-3.6			S
SULFURIC ACID	21.9	68	20	L
SULFURIC ACID. 15%	31.0	68	20	L
SULFURIC ACID. 95%	8.3	68	20	L
SULFURIC ACID. 96%	7.8	68	20	L
SULFURIC ACID. 97%	8.6	68	20	L
SULFURIC ACID. 98%	7.2	68	20	L
SULFURIC ACID. CONC.	3.5	70	21	L
TAR PASTE BT 80/125 WITH BITUMEN	4.0	68	20	S
TAR PASTE T 40/60. VERY THIN	4.7	68	20	S

COMPOUND	DK	° F	° C	STATE
TAR PASTE TV 49/51. VERY THICK	4.3	158	70	S
TAR. CRUDE	4.0	68	20	L
TAR. CRUDE WITH 4.1% MOISTURE	5.5	68	20	L
TAR. OIL	3.8	86	30	L
TOLUENE	2.0	360.0	182.2	L
TOLUENE	2.2	260.0	126.7	L
TOLUENE	2.4	32.0	0.0	L
TOLUENE (C7H8)	2.3	68	20	L
TOLUENE DIISOCYANATE	5.1	68.0	20.0	L
TOLUENE. (TRIFLUOROMETHYLSULFONYL)	23.4	104.0	40.0	L
TRANSFORMER OIL	2.1	68	20	L
TRIETHANOLAMINE (TEA)	24-28	122-86	50-30	L
VASELIN OIL	1.6	68	20	L
VASELINE	2.2-2.9	77.0	25.0	S
WATER	10.1	687	364	L
WATER	20.4	248	120	L
WATER	34.5	390.0	198.9	L
WATER	80.4	68.0	20.0	L
WATER	88.0	32.0	0.0	L
WATER	48.0-55.0	212.0	100.0	L
WATER (STEAM)	1.00785	68.0	20.0	GA
WATER. DEMINERALISED	29.3	68	20	L
WATER. DISTILLED	34.0	77.0	25.0	L
WATER. HEAVY	78.3	77	25	L
WATER. HEAVY (DEUTERIUM OXIDE)	80.0	68.0	20.0	L
WAX	1.8	68	20	S
WAX	2.4-6.5			S
WAX:135 APM WAX	2.3			S
WAX:ACRAWAX	2.4			S
WAX:BEESWAX	2.7	75.0	23.9	S
WAX:BIWAX	2.5	75.0	23.9	S
WAX:CANDELILLA	2.25-2.5			S
WAX:CARNAUBA	2.9	75.0	23.9	S
WAX:CERESE	2.4	75.0	23.9	S
WAX:CERESE. BROWN G	2.3			S

COMPOUND	DK	° F	° C	STATE
WAX:CERESINE	2.25-2.5			S
WAX:HALOWAX 1001	4.1	75.0	23.9	S
WAX:HALOWAX 1013	4.8	75.0	23.9	S
WAX:HALOWAX 1014	4.4	75.0	23.9	S
WAX:HALOWAX 11-314	2.9	75.0	23.9	S
WAX:PARAFFIN	1.9	250.0	121.1	L
WAX:PARAFFIN	2.2	75.0	23.9	S
WAX:PARAWAX	2.3	75.0	23.9	S
WAX:PETROLEUM	2.1	300.0	148.9	L
WAX:PETROLEUM	3.0	200.0	93.3	L
XYLENE	2.4	77	25	L
XYLENE (C8H10) (P-)	2.2	56	13	L
XYLENE (M-)	2.3	86	30	L
XYLENE (M-)	2.4	68.0	20.0	L

Appendix 2 - Conversion matrixes

Appendix 2 - Conversion matrixes

A2.1 Temperature conversion

-459.4° to 0°			1° to 60°			61° to 290°			300° to 890°			900° to 3000°		
C	F C	F	C	F C	F	C	F C	F	C	F C	F	C	F C	F
-273	-459.4		-17.2	1	33.8	16.1	61	141.8	149	300	572	482	900	1652
-268	-450		-16.7	2	35.6	16.7	62	143.6	154	310	590	488	910	1670
-262	-440		-16.1	3	37.4	17.2	63	145.4	160	320	608	493	920	1688
-257	-430		-15.6	4	39.2	17.8	64	147.2	166	330	626	499	930	1706
-251	-420		-15.0	5	41.0	18.3	65	149.0	171	340	644	504	940	1724
-246	-410		-14.4	6	42.8	18.9	66	150.8	177	350	662	510	950	1742
-240	-400		-13.9	7	44.6	19.4	67	152.6	182	360	680	516	960	1760
-234	-390		-13.3	8	46.4	20.0	68	154.4	188	370	698	521	970	1778
-229	-380		-12.8	9	48.2	20.6	69	156.2	193	380	716	527	980	1796
-223	-370		-12.2	10	50.0	21.1	70	158.0	199	390	734	532	990	1814
-218	-360		-11.7	11	51.8	21.7	71	159.8	204	400	752	538	1000	1832
-212	-350		-11.1	12	53.6	22.2	72	161.6	210	410	770	549	1020	1868
-207	-340		-10.6	13	55.4	22.8	73	163.4	216	420	788	560	1040	1904
-201	-330		-10.0	14	57.2	23.3	74	165.2	221	430	806	571	1060	1940
-196	-320		-9.4	15	59.0	23.9	75	167.0	227	440	824	582	1080	1976
-190	-310		-8.9	16	60.8	24.4	76	168.8	232	450	842	593	1100	2012
-184	-300		-8.3	17	62.6	25.0	77	170.6	238	460	860	604	1120	2048
-179	-290		-7.8	18	64.4	25.6	78	172.4	243	470	878	616	1140	2084
-173	-280		-7.2	19	66.2	26.1	79	174.2	249	480	896	627	1160	2120
-169	-273	-459.4	-6.7	20	68.0	26.7	80	176.0	254	490	914	638	1180	2156
-168	-270	-454	-6.1	21	69.8	27.2	81	177.8	260	500	932	649	1200	2192
-162	-260	-436	-5.6	22	71.6	27.8	82	179.6	266	510	950	660	1220	2228
-157	-250	-418	-5.0	23	73.4	28.3	83	181.4	271	520	968	671	1240	2264
-151	-240	-400	-4.4	24	75.2	28.9	84	183.2	277	530	986	682	1260	2300
-146	-230	-382	-3.9	25	77.0	29.4	85	185.0	282	540	1004	693	1280	2336
-140	-220	-364	-3.3	26	78.8	30.0	86	186.8	288	550	1022	704	1300	2372
-134	-210	-346	-2.8	27	80.6	30.6	87	188.6	293	560	1040	732	1350	2462
-129	-200	-328	-2.2	28	82.4	31.1	88	190.4	299	570	1058	760	1400	2552
-123	-190	-310	-1.7	29	84.2	31.7	89	192.2	304	580	1076	788	1450	2642
-118	-180	-292	-1.1	30	86.0	32.2	90	194.0	310	590	1094	816	1500	2732
-112	-170	-274	-0.6	31	87.8	32.8	91	195.8	316	600	1112	843	1550	2822
-107	-160	-256	0.0	32	89.6	33.3	92	197.6	321	610	1130	871	1600	2912
-101	-150	-238	0.6	33	91.4	33.9	93	199.4	327	620	1148	899	1650	3002
-96	-140	-220	1.1	34	93.2	34.4	94	201.2	332	630	1166	927	1700	3092
-90	-130	-202	1.7	35	95.0	35.0	95	203.0	338	640	1184	954	1750	3182
-84	-120	-184	2.2	36	96.8	35.6	96	204.8	343	650	1202	982	1800	3272
-79	-110	-166	2.8	37	98.6	36.1	97	206.6	349	660	1220	1010	1850	3362
-73	-100	-148	3.3	38	100.4	36.7	98	208.4	354	670	1238	1038	1900	3452
-68	-90	-130	3.9	39	102.2	37.2	99	210.2	360	680	1256	1066	1950	3542
-62	-80	-112	4.4	40	104.0	37.8	100	212.0	366	690	1274	1093	2000	3632
-57	-70	-94	5.0	41	105.8	43	110	230	371	700	1292	1121	2050	3722
-51	-60	-76	5.6	42	107.6	49	120	248	377	710	1310	1149	2100	3812
-46	-50	-58	6.1	43	109.4	54	130	266	382	720	1328	1177	2150	3902
-40	-40	-40	6.7	44	111.2	60	140	284	388	730	1346	1204	2200	3992
-34	-30	-22	7.2	45	113.0	66	150	302	393	740	1364	1232	2250	4082
-29	-20	-4	7.8	46	114.8	71	160	320	399	750	1382	1260	2300	4172
-23	-10	14	8.3	47	116.6	77	170	338	404	760	1400	1288	2350	4262
-17.8	0	32	8.9	48	118.4	82	180	356	410	770	1418	1316	2400	4352
			9.4	49	120.2	88	190	374	416	780	1436	1343	2450	4442
			10.0	50	122.0	93	200	392	421	790	1454	1371	2500	4532
			10.6	51	123.8	99	210	410	427	800	1472	1399	2550	4622
			11.1	52	125.6	100	212	413.6	432	810	1490	1427	2600	4712
			11.7	53	127.4	104	220	428	438	820	1508	1454	2650	4802
			12.2	54	129.2	110	230	446	443	830	1526	1482	2700	4892
			12.8	55	131.0	116	240	464	449	840	1544	1510	2750	4982
			13.3	56	132.8	121	250	482	454	850	1562	1538	2800	5072
			13.9	57	134.6	127	260	500	460	860	1580	1566	2850	5162
			14.4	58	136.4	132	270	518	466	870	1598	1593	2900	5252
			15.0	59	138.2	138	280	536	471	880	1616	1621	2950	5342
			15.6	60	140.0	143	290	554	477	890	1634	1649	3000	5432

(1) Locate temperature in middle column. If in degrees Celsius, read Fahrenheit equivalent in right hand column; if in degrees Fahrenheit, read Celsius equivalent in left hand column.

A2.2 Pressure conversion

from/to	PSI	KPA	Inches(2) H_2O	mmH_2O	Inches(3) Hg	mm Hg	Bars	m Bars	Kg/cm^2	gm/cm^2
PSI	1	6.8948	27.7620	705.1500	2.0360	51.7149	0.0689	68.9470	0.0703	70.3070
KPA	0.1450	1	4.0266	102.2742	0.2953	7.5006	0.0100	10.0000	0.0102	10.197
inH_2O*	0.0361	0.2483	1	25.4210	0.0734	1.8650	0.0025	2.4864	0.0025	2.5355
mmH_2O	0.0014	0.0098	0.0394	1	0.0028	0.0734	0.0001	0.0979	0.00001	0.0982
inHg**	0.4912	3.3867	13.6195	345.936	1	25.4000	0.0339	33.8639	0.0345	34.532
mm Hg	0.0193	0.1331	0.5362	13.6195	0.0394	1	0.0013	1.3332	0.0014	1.3595
Bars	14.5040	100.000	402.180	10215.0	29.5300	750.060	1	1000	1.0197	1019.72
m Bars	0.0145	0.1000	0.4022	10.2150	0.0295	0.7501	0.001	1	0.0010	1.0197
Kg/cm^2	14.2233	97.9047	394.408	10018.0	28.9590	735.559	0.9000	980.700	1	1000
gm/cm^2	0.0142	0.0979	0.3944	10.0180	0.0290	0.7356	0.0009	0.9807	0.001	1

(1) EXAMPLE
1 mm Hg = 0.5362 inH_2O = 1.3332 mBars
97 mm Hg = 97(0.5362) = 52.0114 inH_2O
97 mm Hg = 97(1.332) = 129.3204 mBars
(2) at 60 °F
(3) at 32 °F

A2.3 Volume conversion

from\to	cm^3	liter	m^3	in^3	ft^3	yd^3	fl oz	fl pt	fl qt	gal	gal(Imp.)	bbl(oil)	bbl(liq)
cm^3	1	0.001	1×10^{-6}	0.06102	3.53×10^{-5}	1.31×10^{-4}	0.03381	0.00211	0.00106	2.64×10^{-4}	2.20×10^{-4}	6.29×10^{-6}	8.39×10^{-6}
liter	1000	1	0.001	61.02	0.03532	0.00131	33.81	2.113	1.057	0.2642	0.2200	0.00629	0.00839
m^3	1×10^{6}	1000	1	6.10×10^{4}	35.31	1.308	3.38×10^{4}	2113	1057	264.2	220.0	6.290	8.386
in^3	16.39	0.01639	1.64×10^{-5}	1	5.79×10^{-4}	2.14×10^{-5}	0.5541	0.03463	0.01732	0.00433	0.00360	1.03×10^{-4}	1.37×10^{-4}
ft^3	2.83×10^{4}	28.32	0.02832	1728	1	0.03704	957.5	59.84	29.92	7.481	6.229	0.1781	0.2375
yd^3	7.65×10^{5}	764.5	0.7646	4.67×10^{4}	27	1	2.59×10^{4}	1616	807.9	202.0	168.2	4.809	6.412
fl oz	29.57	0.02957	2.96×10^{-6}	1.805	0.00104	3.87×10^{-5}	1	0.06250	0.03125	0.00781	0.00651	1.86×10^{-4}	2.48×10^{-4}
fl pt	473.2	0.4732	4.73×10^{-4}	28.88	0.01671	6.19×10^{-4}	16	1	0.5000	0.1250	0.1041	0.00298	0.00397
fl qt	946.4	0.0463	9.46×10^{-4}	57.75	0.03342	0.00124	32	2	1	0.2500	0.2082	0.00595	0.00794
gal	3785	3.785	0.00379	231.0	0.1337	0.00495	128	8	4	1	0.8327	0.02381	0.03175
gal(Imp)	4546	4.546	0.00455	277.4	0.1605	0.00595	153.7	9.608	4.804	1.201	1	0.02859	0.03813
bbl(oil)	1.59×10^{5}	159.0	0.1590	9702	5.615	0.2079	5376	336	168	42	34.97	1	1.333

(1) 1 cord = 128 ft^3 = 3.625 m^3

A2.4 Flow rate conversion

from\to	lit/sec	gal/min	ft^3/sec	ft^3/min	bbl/hr	bbl/day
lit/sec	1	15.85	0.03532	2.119	22.66	543.8
gal/min	0.06309	1	0.00223	0.1337	1.429	34.30
ft^3/sec	28.32	448.8	1	60	641.1	1.54×10^{4}
ft^3/min	0.4719	7.481	0.01667	1	10.69	256.5
bbl/hr	0.04415	0.6997	0.00156	0.09359	1	24
bbl/day	0.00184	0.02917	6.50×10^{-5}	0.00390	0.04167	1

(1) bbl refers to bbl oil = 42 gallons

A2.5 Equivalents

Linear Measure		Measure of Volume	
1 micron	0.000001 meter	1 cu centimeter	0.061 cu in.
1 mm	0.03937 in.	1 cu inch	16.39 cu cm
1mm	0.00328 ft	1 cu decimeter	0.0353 cu ft
1 centimeter	0.3937 in.	1 cu foot	28.317 cu decimeters
1 inch	2.54 centimeters	1 cu yard	0.7646 cu meters
1 inch	25.4 mm	1 stere	0.2759 cord
1 decimeter	3.937 in.	1 cord	3.264 steres
1 decimeter	0.328 foot	1 liter	0.908 qt dry
1 foot	3.048 decimeters	1 liter	1.0567 qts liq
1 foot	30.48 cm	1 quart dry	1.101 liters
1 foot	304.8 mm	1 quart liquid	0.9463 liters
1 meter	39.37 in.	1 dekaliter	2.6417 gals
1 meter	1.0936 yds	1 dekaliter	1.135 pecks
1 yard	0.9144 meter	1 gallon	0.3785 dekaliter
1 dekameter	1.9884 rods	1 peck	0.881 dekaliter
1 rod	0.5029 dekameter	1 hectoliter	2.8375 bushels
1 kilometer	0.62137 mile	1 bushel	0.3524 hectoliter
1 mile	1.6093 kilometers		
Square Measure		**Weights**	
1 sq centimeter	0.1550 sq in.	1 gram	0.03527 ounce
1 sq centimeter	0.00108 sq ft	1 ounce	28.35 grams
1 sq inch	6.4516 sq centimeters	1 kilogram	2.2046 pounds
1 sq decimeter	0.1076 sq ft	1 pound	0.4536 kilogram
1 sq ft	929.03 sq cm	1 metric ton	0.98421 English ton
1 sq ft	9.2903 sq dec	1 English ton	1.016 metric ton
1 sq meter	1.196 sq yds	1 kg	2.205 pounds
1 sq yard	0.8361 sq meter	1 cu in. of water (60 °F)	0.073551 cu in. of mercury (32 °F)
1 acre	160 sq rods	1 cu in. of mercury (32 °F)	13.596 cu in. of water (60 °F)
1 sq rod	0.00625 acre	1 cu in. of mercury (32 °F)	0.4905 pounds
1 hectare	2.47 acres		
1 acre	0.4047 hectare		
1 sq kilometer	0.386 sq mile		
1 sq mile	2.59 sq kilometers		
Circumference of a circle	$2\pi r$		
Circumference of a circle	πd		
Area of a circle	πr^2		
Area of a circle	$\pi d^2/4$		
		Velocity	
		1 ft/sec	0.3048 m/sec
		1 m/sec	3.2808 ft/sec
		Density	
		1 lb/cu in	27.68 gram/cu cm
		1 gr/cu cm	0.03613 lb/cu in.
		1 lb/cu ft	16.0184 kg/cu m
		1 kg/cu m	0.06243 lb/cu ft
		1 lb/gal	120 kg/cu m

A2.6 English to metric system conversion

1 To Convert from:	2 To:	3 Multiply by:	To Convert Column 2 to Column 1 Multiply by:
acre-feet	cubic meters	1233	8.11×10^{-4}
cubic feet (cu ft) (US)	cubic centimeters	28,317	3.53×10^{-5}
cubic feet (cu ft) (US)	cubic meters	0.0283	35.33
cubic feet (cu ft) (US)	liters	28.32	0.035
cu ft/min	cu cm/sec	472	0.0021
cu ft/min	liters/sec	0.472	2.119
cu ft/sec	liters/min	1699	5.886×10^{-4}
cubic inches (US)	cubic meters	1.64×10^{-5}	61,024
cubic inches (US)	liters	0.0164	61.024
cubic inches (US)	milliliters (ml)	16.387	0.0610
feet (US)	meters	0.3048	3.281
feet (US)	millimeters (mm)	304.8	3.28×10^{-3}
feet/min	cm/sec	0.508	1.97
feet/min	kilometers/hr	1.829×10^{-2}	54.68
feet/min	meters/min	0.305	3.28
ft/sec^2	km/hr/sec	1.0973	0.911
gallons (US)	cu cm (ml)	3785	2.64×10^{-4}
gallons (US)	liters	3.785	0.264
gallons/min	liters/sec	0.063	15.87
US gal/min	cu meters/hr	0.227	4.4
US gal/sq ft/min	cu meters/hr/sq meters	2.45	0.408
grains (troy)	grams	0.0648	15.432
grains (troy)	milligrams (mg)	64.8	0.01543
grains/gal (US)	grams/liter	0.0171	58.417
grains/gal (US)	ppm	17.1	0.0584
inches (US)	centimeters (cm)	2.54	0.3937
inches (US)	millimeters (mm)	25.4	0.0394
miles (US)	kilometers (km)	1.609	0.6215
miles (US)	meters	1609	6.214×10^{-4}
miles/hr	cm/sec	44.7	0.0224
miles/hr	meters/min	26.82	0.0373
miles/min	kilometers/hr	96.6	1.03×10^{-2}
ounces (avoirdupois)	grams	28.35	0.0353
ounces (US fluid)	ml	29.6	0.0338
ounces (US fluid)	liters	0.0296	33.81
pounds (av)	grams	453.6	0.0022
pounds (av)/sq in	kgr/cm^2	0.071	14.223
pounds (av)	kilograms	0.4536	2.205
pounds (av)	grains	7000	14.2×10^{-5}
pounds/cu ft	grams/l	16.02	0.0624
pounds/ft	grams/cm	14.88	0.067
pounds/gal (US)	grams/ml	0.12	8.345
pounds/gal (US)	grams/liter	119.8	8.34×10^{-3}
quart (US liq)	ml	946.4	0.001057
quart (US liq)	liters	0.946	1.057
square feet (US)	sq cm	929	1.08×10^{-3}
square feet (US)	sq meters	0.0929	10.76
square inches (US)	sq cm	6.452	0.155

A2.7 Decimal equivalents

8ths	16ths	32nds	64ths	
1/8 = 0.125	1/16 = 0.0625	1/32 = 0.03125	1/64 = 0.015625	33/64 = 0.515625
1/4 = 0.250	3/16 = 0.1875	3/32 = 0.09375	3/64 = 0.046875	35/64 = 0.546875
3/8 = 0.375	5/16 = 0.3125	5/32 = 0.15625	5/64 = 0.078125	37/64 = 0.578125
1/2 = 0.500	7/16 = 0.4375	7/32 = 0.21875	7/64 = 0.109375	39/64 = 0.609375
5/8 = 0.625	9/16 = 0.5625	9/32 = 0.28125	9/64 = 0.140625	41/64 = 0.640625
3/4 = 0.750	11/16 = 0.6875	11/32 = 0.34375	11/64 = 0.171875	43/64 = 0.671875
7/8 = 0.875	13/16 = 0.8125	13/32 = 0.40625	13/64 = 0.203125	45/64 = 0.703125
	15/16 = 0.9375	15/32 = 0.46875	15/64 = 0.234375	47/64 = 0.734375
		17/32 = 0.53125	17/64 = 0.265625	49/64 = 0.765625
		19/32 = 0.59375	19/64 = 0.296875	51/64 = 0.796875
		21/32 = 0.65625	21/64 = 0.328125	53/64 = 0.828125
		23/32 = 0.71875	23/64 = 0.359375	55/64 = 0.859375
		25/32 = 0.78125	25/64 = 0.390625	57/64 = 0.890625
		27/32 = 0.84375	27/32 = 0.421875	59/64 = 0.921875
		29/32 = 0.90625	29/32 = 0.453125	61/64 = 0.953125
		31/32 = 0.96875	31/64 = 0.484375	63/64 = 0.984375

A2.8 Multiplication factors

Prefix	Symbol	Name	Multiplication Factor	
atto	a	one-quintillionth	0.000 000 000 000 000 001	10^{-18}
femto	f	one-quadrillionth	0.000 000 000 000 001	10^{-15}
pico	p	one-trillionth	0.000 000 000 001	10^{-12}
nano	n	one-billionth	0.000 000 001	10^{-9}
micro	m	one-millionth	0.000 001	10^{-6}
milli	m	one-thousandth	0.001	10^{-3}
centi	c	one-hundreth	0.01	10^{-2}
deci	d	one-tenth	0.1	10^{-1}
uni		one	1.0	10^{0}
deka	da	ten	10.0	10^{1}
hecto	h	one hundred	100.0	10^{2}
kilo	k	one thousand	1 000.0	10^{3}
mega	M	one million	1 000 000.0	10^{6}
giga	G	one billion	1 000 000 000.0	10^{9}
tera	T	one trillion	1 000 000 000 000.0	10^{12}

A2.9 Saturated steam table (Metric units)

Gage Pressure (bar)	Absolute Pressure (bar)	Temperature (°C)	Specific Volume (m3/kg)	Specific Enthalpy (kJ/kg)		
				Sat. Liquid	Evap.	Sat. Vapor
0,0	1,01325	100	1,673	419,11	2257	2676
0,1	1,1	102,32	1,5492	428,89	2250,61	2679,49
0,3	1,3	107,13	1,3252	449,24	2237,75	2686,99
0,6	1,6	113,32	1,0913	475,42	2220,98	2696,41
1,0	2	120,23	0,88554	504,75	2201,89	2706,65
1,3	2,3	124,71	0,77694	523,78	2189,32	2713,1
1,6	2,6	128,73	0,6927	540,93	2177,85	2718,77
2,0	3	133,54	0,60567	561,49	2163,92	2725,4
2,5	3,5	138,88	0,5241	584,33	2148,2	2732,53
3,0	4	143,63	0,46232	604,72	2133,94	2738,66
3,5	4,5	147,92	0,41384	623,21	2120,82	2744,03
4,0	5	151,85	0,37478	640,16	2108,62	2748,79
5,0	6	158,84	0,31556	670,47	2086,42	2756,89
6,0	7	164,96	0,27275	697,1	2066,44	2763,54
7,0	8	170,41	0,24032	720,97	2048,16	2769,13
8,0	9	175,36	0,21486	742,68	2031,21	2773,89
9,0	10	179,88	0,19435	762,63	2015,35	2777,99
11,5	12,5	189,81	0,15698	806,7	1979,34	2786,04
14,0	15	198,28	0,13171	844,68	1947,15	2791,82
16,5	17,5	205,72	0,11342	878,28	1917,69	2795,98
19,0	20	212,37	0,09958	908,6	1890,36	2798,96
21,5	22,5	218,4	0,0887	936,33	1864,7	2801,04
24,0	25	223,94	0,07994	961,98	1840,41	2802,39
26,5	27,5	229,06	0,07271	985,91	1817,25	2803,16
29,0	30	233,84	0,06666	1008,39	1795,04	2803,43
34,0	35	242,54	0,05705	1049,81	1752,97	2802,77
39,0	40	250,33	0,04977	1087,46	1713,37	2800,82
44,0	45	257,41	0,04405	1122,18	1675,68	2797,86
49,0	50	263,92	0,03944	1154,54	1639,53	2794,06
54,0	55	269,94	0,03564	1184,96	1604,58	2789,53
59,0	60	275,56	0,03244	1213,75	1570,61	2784,36
64,0	65	280,83	0,02972	1241,13	1537,52	2778,65
69,0	70	285,8	0,02737	1267,44	1504,94	2772,37
74,0	75	290,51	0,02533	1292,68	1472,95	2765,62
79,0	80	294,98	0,02352	1317,05	1441,35	2758,4
84,0	85	299,24	0,02191	1340,65	1410,07	2750,72
89,0	90	303,31	0,02048	1363,59	1378,99	2742,59
94,0	95	307,22	0,01919	1385,95	1348,04	2733,98
99,0	100	310,96	0,01802	1407,78	1317,1	2724,88
109,0	110	318,04	0,01598	1450,19	1255,36	2705,55
119,0	120	324,64	0,01426	1491,26	1193,52	2684,78
129,0	130	330,81	0,01278	1531,41	1130,97	2662,38
139,0	140	336,63	0,01149	1570,99	1067,03	2638,03
149,0	150	342,12	0,01035	1610,29	1000,99	2611,27
159,0	160	347,32	0,009319	1649,77	931,84	2581,61
169,0	170	352,26	0,00838	1690,02	858,31	2548,33

A2.10 Saturated steam table (English units)

Gage Pressure Lbs. \ Sq. Inch	Absolute Pressure Lbs./Sq. In.	Temperature °F	Cu. Ft./Lb. Sat. Vapor	TOTAL HEAT IN B.T.U. PER LB. Sat. Liquid	Evap.	Sat. Vapor
0.0	14.696	212	26.8	180.0	970.2	1150.2
1.3	16	216	24.8	184.35	967.4	1151.8
2.3	17	219	23.4	187.48	965.4	1152.9
3.3	18	222	22.2	190.48	963.5	1154.0
4.3	19	225	21.1	193.34	961.7	1155.0
5.3	20	228	20.1	196.09	959.9	1156.0
7.3	22	233	18.4	201.25	956.6	1157.8
10.3	25	240	16.3	208.33	951.9	1160.2
15.3	30	250	13.7	218.73	945.0	1163.7
20.3	35	259	11.9	227.82	938.9	1166.7
25.3	40	267	10.5	235.93	933.3	1169.2
30.3	45	274	9.40	243.28	928.2	1171.5
35.3	50	281	8.51	249.98	923.5	1173.5
40.3	55	287	7.78	256.19	919.1	1175.3
45.3	60	293	7.17	261.98	915.0	1177.0
50.3	65	298	6.65	267.39	911.1	1178.5
55.3	70	303	6.20	272.49	907.4	1179.9
60.3	75	307	5.81	277.32	903.9	1181.2
65.3	80	312	5.47	281.90	900.5	1182.4
70.3	85	316	5.16	286.90	897.3	1183.6
75.3	90	320	4.89	290.45	894.2	1184.6
80.3	95	324	4.65	294.47	891.2	1185.6
85.3	100	328	4.42	298.33	888.2	1186.6
90.3	105	331	4.22	302.03	885.4	1187.5
95.3	110	335	4.04	305.61	882.7	1188.3
100.3	115	338	3.88	309.04	880.0	1189.1
105.3	120	341	3.72	312.37	877.4	1189.8
110.3	125	344	3.60	315.60	874.9	1190.5
115.3	130	347	3.45	318.73	872.4	1191.2
120.3	135	350	3.33	321.77	870.0	1191.8
125.3	140	353	3.22	324.74	867.7	1192.4
130.3	145	356	3.20	327.63	865.3	1193.0
135.3	150	358	3.01	330.44	863.1	1193.5
140.3	155	361	2.92	333.18	860.8	1194.0
145.3	160	363	2.83	335.86	858.7	1194.5
150.3	165	366	2.75	338.47	856.5	1195.0
155.3	170	368	2.67	341.03	854.5	1195.4
160.3	175	370	2.60	343.54	852.3	1195.9
165.3	180	373	2.53	345.99	850.3	1196.3
170.3	185	375	2.46	348.42	848.2	1196.7
175.3	190	377	2.40	350.77	846.3	1197.0
180.3	195	380	2.34	353.07	844.3	1197.4
185.3	200	382	2.28	355.33	842.4	1197.8
210.3	225	392	2.039	366.10	833.2	1199.3
235.3	250	401	1.841	376.02	824.5	1200.5
260.3	275	409	1.678	385.24	816.3	1201.6
285.3	300	417	1.541	393.90	808.5	1202.4
335.3	350	432	1.324	409.81	793.7	1203.6
385.3	400	444	1.160	424.2	779.8	1204.1
435.3	450	456	1.030	437.4	766.7	1204.1
485.3	500	467	0.926	449.7	754.0	1203.7
585.3	600	486	0.767	472.3	729.8	1202.1
685.3	700	503	0.653	492.9	706.8	1199.7
785.3	800	518	0.565	511.8	684.9	1196.7
885.3	900	532	0.496	529.5	663.8	1193.3
985.3	1000	544	0.442	546.0	643.5	1189.6
1235.3	1250	572	0.341	583.6	595.6	1179.2
1485.3	1500	596	0.274	617.5	550.2	1167.6
1985.3	2000	635	0.187	679.0	460.0	1139.0
2485.3	2500	668	0.130	742.8	352.8	1095.6

A2.11 Maximum permissible ID and minimum wall in accordance with ASTM A106 pipe

Nominal Pipe Size	Outside Diam. Max.	Wall I.D.	Nominal Wall Thickness and Inside Diameters												
			Schedule 10	Schedule 20	Schedule 30	Standard Weight	Schedule 40	Schedule 60	Extra Strong	Schedule 80	Schedule 100	Schedule 120	Schedule 140	Schedule 160	Dbl. Ext. Strong
1/8	0.421	Wall				0.060	0.060		0.083	0.083					
		I.D.				0.302	0.302		0.254	0.254					
1/4	0.556	Wall				0.077	0.077		0.110	0.110					
		I.D.				0.402	0.402		0.335	0.335					
3/8	0.691	Wall				0.080	0.080		0.110	0.110					
		I.D.				0.531	0.531		0.470	0.470					
1/2	0.856	Wall				0.095	0.095		0.129	0.129				0.164	0.257
		I.D.				0.665	0.665		0.598	0.598				0.528	0.341
3/4	1.066	Wall				0.099	0.099		0.135	0.135				0.191	0.270
		I.D.				0.868	0.868		0.796	0.796				0.684	0.527
1	1.331	Wall				0.116	0.116		0.157	0.157				0.219	0.313
		I.D.				1.098	1.098		1.017	1.017				0.893	0.704
1 1/4	1.676	Wall				0.123	0.123		0.167	0.167				0.219	0.334
		I.D.				1.431	1.431		1.341	1.341				1.238	1.007
1 1/2	1.916	Wall				0.127	0.127		0.175	0.175				0.246	0.350
		I.D.				1.662	1.662		1.566	1.566				1.424	1.216
2	2.406	Wall				0.135	0.135		0.191	0.191				0.300	0.382
		I.D.				2.137	2.137		2.025	2.025				1.806	1.643
2 1/2	2.906	Wall				0.178	0.178		0.242	0.242				0.328	0.483
		I.D.				2.551	2.551		2.423	2.423				2.250	1.940
3	3.531	Wall				0.189	0.189		0.263	0.263				0.383	0.525
		I.D.				3.153	3.153		3.006	3.006				2.765	2.481
3 1/2	4.031	Wall				0.198	0.198		0.278	0.278					0.557
		I.D.				3.636	0.3636		3.475	0.3475					2.918
4	4.531	Wall				0.207	0.207		0.295	0.295		0.383		0.465	0.590
		I.D.				4.117	4.117		3.942	3.942		3.765		3.602	3.352
5	5.626	Wall				0.226	0.226		0.328	0.328		0.438		0.547	0.656
		I.D.				5.174	5.174		4.969	4.969		4.751		4.532	4.313
6	6.688	Wall				0.245	0.245		0.378	0.378		0.492		0.628	0.756
		I.D.				6.198	6.198		5.932	5.932		5.704		5.431	5.176
8		Wall		0.219	0.242	0.282	0.282	0.355	0.438	0.438	0.519	0.628	0.711	0.793	0.766
		I.D.		8.250	8.203	8.124	8.124	7.977	7.813	7.813	7.650	7.431	7.267	7.102	7.156
10	10.844	Wall		0.219	0.269	0.319	0.319	0.438	0.438	0.519	0.628	0.738	0.875	0.984	
		I.D.		10.406	10.307	10.205	10.205	9.969	9.969	9.806	9.587	9.369	9.094	8.875	
12	12.844	Wall		0.219	0.289	0.328	0.355	0.492	0.438	0.601	0.738	0.875	0.984	1.148	
		I.D.		12.406	12.266	12.188	12.133	11.860	11.969	11.642	11.369	11.094	10.875	10.548	
14	14.094	Wall	0.219	0.273	0.328	0.328	0.383	0.519	0.438	0.656	0.820	0.956	1.094	1.230	
		I.D.	13.656	13.548	13.438	13.438	13.327	13.056	13.219	12.781	12.454	12.181	11.906	11.633	
16	16.094	Wall	0.219	0.273	0.328	0.328	0.438	0.574	0.438	0.738	0.902	1.066	1.258	1.394	
		I.D.	15.656	15.548	15.438	15.438	15.219	14.946	15.219	14.619	14.290	13.962	13.577	13.306	
18	18.094	Wall	0.219	0.273	0.383	0.328	0.492	0.656	0.438	0.820	1.012	1.203	1.367	1.558	
		I.D.	17.656	17.548	17.327	17.438	17.110	16.781	17.219	16.454	16.071	15.688	15.360	14.977	
20	20.125	Wall	0.219	0.328	0.438	0.328	0.519	0.711	0.438	0.902	1.121	1.313	1.531	1.722	
		I.D.	19.688	19.469	19.250	19.469	19.087	18.704	19.250	18.321	17.883	17.500	17.063	16.681	
24	24.125	Wall	0.219	0.328	0.492	0.328	0.601	0.847	0.438	1.066	1.340	1.586	1.804	2.050	
		I.D.	23.688	23.469	23.142	23.469	22.923	22.431	23.250	21.994	21.446	20.954	20.517	20.025	
30	30.125	Wall	0.273	0.438	0.547	0.328			0.438						
		I.D.	29.579	29.250	29.031	29.469			29.250						

(1) O.D.—MAX. I.D.—MAX. WALL—MIN.

A2.12 Dimensions of welded and seamless pipe carbon and alloy steel

Nominal Pipe Size	Outside Diameter	Wall Thickness Inside Diameter	Nominal Wall Thickness And Inside Diameter			
			Schedule 5S*	Schedule 10S*	Schedule 40S	Schedule 80S
1/8	0.405	Wall	–	0.049	0.068	0.095
		I.D.	–	0.307	0.269	0.215
1/4	0.540	Wall	–	0.065	0.088	0.119
		I.D.	–	0.410	0.364	0.302
3/8	0.675	Wall	–	0.065	0.091	0.126
		I.D.	–	0.545	0.493	0.423
1/2	0.840	Wall	0.065	0.083	0.109	0.147
		I.D.	0.710	0.674	0.622	0.546
3/4	1.050	Wall	0.065	0.083	0.113	0.154
		I.D.	0.920	0.884	0.824	0.742
1	1.315	Wall	0.065	0.109	0.133	0.179
		I.D.	1.185	1.097	1.049	0.957
1 1/4	1.660	Wall	0.065	0.109	0.140	0.191
		I.D.	1.530	1.442	1.380	1.278
1 1/2	1.900	Wall	0.065	0.109	0.145	0.200
		I.D.	1.770	1.682	1.610	1.500
2	2.375	Wall	0.065	0.109	0.154	0.218
		I.D.	2.245	2.157	2.067	1.939
2 1/2	2.875	Wall	0.083	0.120	0.203	0.276
		I.D.	2.709	2.635	2.469	2.323
3	3.500	Wall	0.083	0.120	0.216	0.300
		I.D.	3.334	3.260	3.068	2.900
3 1/2	4.000	Wall	0.083	0.120	0.226	0.318
		I.D.	3.834	3.760	3.548	3.364
4	4.500	Wall	0.083	0.120	0.237	0.337
		I.D.	4.334	4.260	4.026	3.826
5	5.563	Wall	0.109	0.134	0.258	0.375
		I.D.	5.345	5.295	5.047	4.813
6	6.625	Wall	0.109	0.134	0.280	0.432
		I.D.	6.407	6.357	6.065	5.761
8	8.625	Wall	0.109	0.148	0.322	0.500
		I.D.	8.407	8.329	7.981	7.625
10	10.750	Wall	0.134	0.165	0.365	0.500**
		I.D.	10.482	10.420	10.020	9.750**
12	12.750	Wall	0.156	0.180	0.375**	0.500**
		I.D.	12.438	12.390	12.000**	11.750**
14†	14.000	Wall	0.156	0.188	–	–
		I.D.	13.688	13.624	–	–
16†	16.000	Wall	0.165	0.188	–	–
		I.D.	15.670	15.624	–	–
18†	18.000	Wall	0.165	0.188	–	–
		I.D.	17.670	17.624	–	–
20†	20.000	Wall	0.188	0.218	–	–
		I.D.	19.624	19.564	–	–
24†	24.000	Wall	0.218	0.250	–	–
		I.D.	23.564	23.500	–	–
30†	30.000	Wall	0.250	0.312	–	–
		I.D.	29.500	29.376	–	–

NOTE

All dimensions given for inches. The wall thicknesses shown represent nominal or average wall dimensions which are subject to 12.5% mill tolerance.
†Sizes 14" through 30" show dimensions commonly used in the industry.
*Schedule 5S and 10S wall thicknesses do not permit threading in accordance with ASA B2.1.
**Schedule 40S and schedule 80S in these sizes do not agree with schedule 40 and schedule 80 of ASA B36.10 and that they are identical to standard weight and extra strong respectively of ASA B36.10.

Appendix 3 - Glossary

A

Absorbent
The material that can selectively remove a target constituent from another compound by dissolving it. Absorbtion: An operation in which the significant or desired transfer of materials is from the vapor phase to the liquid phase. Absorption usually designates an operation in which liquid is supplied as a separate stream independent of the vapor being treated.

Acid Gas
Gas stream containing hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2).

Acid Heat Test
A test indicative of unsaturated components in petroleum distillates. The test measures the amount of reaction of unsaturated hydrocarbons with sulfuric acid (H_2SO_4).

Adsorbents
Special materials like activated charcoal, alumina or silica gel , used in an adsorption process, that selectively cause some compounds, but not others, to attach themselves mechanically as liquids.

Adsorption
A separation process in which gas molecules condense or liquid molecules crystallize onto a solid that has a porous surface. The pore size dictates the selectivity of the solid for a particular solute.

Afterburning
This occurs in the regenerator dilute phase. It is the combustion of carbon monoxide (CO) with oxygen (O_2) in the flue gases.

Alkylate
The product of an alkylation process.
Alkylate Bottoms: A thick, dark-brown oil containing high-molecular-weight polymerization products of alkylation reactions.

Alkylation
A polymerization process uniting olefins and isoparaffins, particularly, the reacting of butylene and isobutane, with sulfuric acid or hydrofluoric acid as a catalyst, to produce a high-octane, low-sensitivity blending agent for gasoline.

Aluminum Chloride Treating
A process that improves the quality of steam-cracked naphthas by use of aluminum chloride ($AlCl_3$) as a catalyst. The process improves the color and odor of the naphtha by polymerization of undesirable olefins into resins. Aluminum chloride treating is also used when production of resins is desirable.

Amines
Chemical solvent for the removal of H_2S and CO_2 from natural gas streams. Common amines include: monoethanolamine (MEA) and diethanolamine (DEA).

Aniline Point
Temperature at which a hydrocarbon sample becomes miscible in an equal volume of aniline. Higher aniline points indicate a less aromatic sample. The aniline point is used in some FCC feed characterization methods.

API Gravity
An arbitrary scale used for characterizing the gravity of a petroleum product. The degrees API (written °API) aer related to specific gravity scale by the formula:
$°API = (141.5/(sp.gr.@15\ °C/\ 15\ °C))-131.5$

Aromatics
Cyclic hydrocarbons in which five, six, or seven carbon atoms are linked in a ring structure with alternating double and single bonds. Common aromatics in refinery streams are benzene, toluene, xylene, and naphthalene.

Asphalt
1.A heavy, semi-solid petroleum product that gradually softens when heated and is used for surface cementing. Typically, brown or black in color, it is composed of high carbon-to-hydrogen hydrocarbons plus some oxygen. It occurs naturally in crude oil or can be distilled or extracted. 2.The end product used for area surfacing consisting of refinery asphalt mixed with aggregate.

Asphaltenes
Polyaromatic materials in heavy residues characterized by not being soluble in aromatic-free low-boiling point solvents. They are soluble in carbon disulfide.

Associated Natural Gas
Natural gas that is dissolved in crude in the reservoir and is co-produced with the crude oil.

ASTM Distillation
A standardized laboratory batch process for distillation of naphthas and middle distillates carried out at atmospheric pressure without fractionation.

B

Barrel
A standard of measurement in the oil industry: equivalent 42 US gallons, 35 Imperial gallons, or 159 liters.

Barrels Per Calendar Day (bpcd)
Maximum number of barrels of input that can be processed during a 24 hour period, after making allowances for the following: types and grades of inputs to be processed, types and grades of products to be manufactured, environmental constraints associated with refinery operations, and scheduled downtime such as mechanical problems, repairs, and slowdowns.

Barrels Per Stream Day (bpsd)
Number of barrels of input that a unit can process when running at full capacity under optimal feedstock and product slate conditions.

Benzene
(C_6H_6) A chemical consisting a six-carbon ring connected by with double and single bonds. Benzene has excellent octane characteristics but it is carcinogenic and therefore it's content in gasoline is limited severely by regulation. Benzene is used in a large number of chemical processes including styrene and detergents.

BFOE
Barrels fuel oil equivalent based on net heating value (LHV) of 6,050,000 Btu per BFOE.

Bitumen
That component of petroleum, asphalt, and tar products that will dissolve completely in carbon disulfide (CS_2). This dissolving ability permits a complete separation from foreign products not soluble in carbon disulfide.

Black oil
Residual fuel or more generally the very heavy residue in the refinery.

Blending
One of the final operations in refining, in which two or more components are mixed to obtain a specified range of properties in the finished product.

Blocked Operation
Operation of a unit, e.g., a pipe still, under periodic change of feed or internal conditions that will yield a required range of raw products. Blocked operation is needed to meet critical specifications of various finished products. No mixed stocks are charged; therefore, the efficiency of operation is often increased because each charge stock is processed at its optimum operating conditions.

Blown Asphalt
A special grade of asphalt made by oxidizing flasher bottoms by blowing heated air through it.

Boiling point
The temperature at which a liquid will boil. (See end point and initial boiling point.)

Boiling range
The lowest temperature between which a hydrocarbon will begin to boil and completely vaporized.

Bottoms
In general, the higher boiling residue that is removed from the bottom of a fractionating column.

Bright Stock
Heavy lube oils from which wax paraffins and asphaltic compounds have been removed. Bright stock is the feed to a lube oil blending plant.

British thermal unit
A standard measure of energy: the quantity of heat required to raise the temperature of 1 pound of water 1 F.

BS&W
The bottom sediment and water that settle out of petroleum stored in a tank.

Bubble cap tray
The trays in a fractionator consisting of a plate with hole & bubble caps. The latter cause the vapor coming from the bottom to come in intimate contact with the liquid sitting on the tray.

Bunker fuel
Fuel oil or diesel used as ship fuel. Originally coal stored in the ship's bunker.

Butadiene (CH_2=$CHCH$=CH_2)
A colorless gas resulting from cracking process. Traces result from cat cracking; made on-purpose by catalytic dehydrogenation of butane or butylene and in ethylene plants using butane, naphtha or gas oil as feeds. Butadiene is principally used to make polymers like synthetic rubber & ABS plastic.

Butane (C4H10)
Commercial butane is typically a mixture of normal butane and isobutene. predominantly normal To keep them liquid and economically stored, butane must be maintained under pressure or low temperatures.

Butylene (C4H8)
Hydrocarbons with of several different isomers in the olefin series, used a raw materials for making gasoline blending components in an alkylation plant or solvents and other chemicals.

C

Catalyst
A substance present in a chemical reaction that will promote , or even cause , the reaction, but not take part in it by chemically changing itself. Sometimes used to lower the temperature or pressure at which the reaction takes place or speed it up.

Catalytic cracking
A central process in refining in which heavy gas oil range feeds are subjected to heat in the presence of a catalyst and large molecule s crack into smaller molecules in the gasoline and surrounding ranges.

Catalytic reforming
The process in refining in which in naphthas are changed chemically to increase their octane numbers. Paraffins are converted to iso-paraffins and naphthenes are converted to aromatics. The catalyst is platinum and sometimes palladium.

Carbon Burning Rate
This is the rate, in pounds per hour, at which carbon is burned off the catalyst in the regenerator. Catalyst: A substance that assists or deters a chemical reaction but is not itself chemically changed as a result.

Catalyst Activity
A catalyst sample is reacted, under standard cracking conditions with a standard feedstock. The yield of gasoline obtained is a measure of the activity of the catalyst, i.e., its tendency to convert feedstock to gasoline.

Catalyst Circulation Rate
The weight, in tons per minute, of regenerated catalyst transferred from the regenerator to the reactor.

Catalyst Density
The weight in pounds of a cubic foot of fluidized catalyst.

Catalyst Hold-up
Weight of catalyst in tons held above the grid in either the reactor or regenerator.

Catalyst Inventory
Weight of catalyst in tons contained in the entire unit. This includes catalyst in the reactor, stripper, regenerator, spent and regenerated U-bends, riser, standpipe, cyclones, and lines.

Catalyst Replacement Rate
The weight in tons per day of catalyst which must be added to the unit to maintain catalyst activity.

Catalyst Selectivity
A measure of the catalyst's ability to alter product distribution and consists of (1) Coke Producing Factor (CPF) and (2) Gas Producing Factor (GPF).

Catalyst/Oil Ratio (C/O)
The weight of circulating catalyst fed to the reactor of a fluid-bed catalytic cracking unit, divided by the weight of the hydrocarbons charged during the same internal.

Catalytic Cycle Stock
The portion of a catalytic cracker effluent that is not converted to naphtha and lighter products. This material, generally at temperatures of 340 ° F or more, may be partly recycled, in which case the remainder is blended to products or further processed.

Caustic soda
The name that used for sodium hydroxide (NaOH) used in refineries to treat acidic hydrocarbon stream to neutralize them. The term is derived from the corrosive effect on skin.

Cavern
Underground storage either leached out of a natural salt dome or mined out of a rock formation.

Cetene Number
A number designating the percentage of pure cetane in a blend of cetane and alphamethyl-naphthalene that matches the ignition quality of a diesel fuel sample. This number, specified for middle distillate fuels, is synonymous with the octane number of gasolines.

Centipoise
A measure of viscosity related to centistokes by adjusting for density.

Centistoke
A measure of viscosity.

CFR
Combined feed ratio. Ratio of total feed (including, recycle) to fresh feed.

Characterization Factor
An index of feedstock quality, also useful for correlating data based on physical properties such as average boiling point and specific gravity.

Clay Treating
A process conducted at high temperatures and pressures, usually applied to thermally cracked naphthas to improve stability and color. Stability is increased by the adsorption and polymerization of reactive diolefins in the cracked naphtha. Clay treating is now used extensively for treating jet fuel to remove surface active agents that adversely affect the wastewater separator.

Coke
1. A product of the coking process in the form of solid, densely packed carbon atoms. Various forms of coke include green coke , a run of the mill coke from most cokers; sponge coke, the same as green coke and notable by its fine, sponge-like-stucture; calcinable coke, a high grade of coke that is suitable for making industrial product; needle coke, avery high grade of coke characterized by crystalline structure. 2. Deposits of carbon that settle on catalysts in cat crackers, cat reformers, hydrocrackers, and hydrotreaters and degrade their effectiveness.

Coke Producing Factor (CPF)
the ratio of the weight yields of coke produced by the test catalyst and a reference catalyst, at the same conversion level.

Coke Yield
The carbon yield plus the hydrogen associated with the carbon. The latter is calculated by flue gas oxygen disappearance.

Coker
A refinery process in which heavy feed such as flasher bottoms cycle oil from a cat cracker or thermal crack gas oil cooked at high temperatures. Cracking creates light oils; coke form in the reactors and needs to be removed after they fill up.

Conradson Carbon (Concarbon)
Residue left behind following pyrolisis of an oil sample under specified testing conditions. This measurement is used to estimate the fraction of FCC feed that cannot be vaporized.

Compression ratio
The ratio of volumes in a cylinder when the piston is at the bottom of the stroke and the top of the stroke, giving a measure of how much the air or air /fuel mixture is compressed in the compression stroke.

Condensate
1. The relatively small amount of liquid hydrocarbon, typically C4's through naphtha or oil gas, that gets produce in the oil patch with an unassociated gas. 2. The liquid formed when a vapor cools.

Conversion
A measure of quantity of feed converted into lighter products. Conversion is calculated by subtracting the percent yield of material heavier than gasoline from 100. Standard conversion is based on a 430 'F TBP cut point gasoline.

Cracked gas
The c4 stream coming from a cat cracker, coker or thermal cracker, containing olefins in addition to the saturated paraffins .

Cracked gas plants
The set of column & treaters in refinery that handle separation and treating of the cracked, olefinic gases.

Cracking
The breaking down of higher molecular-weight hydrocarbons to lighter components by application of heat. Cracking in the presence of a catalyst improves product yield and quality over those obtained in simple thermal cracking.

Cracking Severity
The conversion obtained in a catalytic cracking operation is dependent on the unit operating conditions and also on reactor. The effect of the unit operating conditions alone on conversion is referred to as absolute cracking.

Crude Assay Distillation
See fifteen/five (15/5) distillation.

Cut
The portion of a crude that boils within certain temperature limits. Usually the limits are specified on a cruded assay true boiling point basis.

Cut Point
The temperature limit of a cut, usually on a true boiling point basis. ASTM distillation cut points are not uncommon.

Cutter Stock
Diluent added to residue to meet residual fuel specifications of viscosity and perhaps sulfur content. Typically cracked gas oil.

Cycle Gas Oil
This designation is given to all liquid products from the cracking process boiling above gasoline.

Cyclic compound
(See ring compound).

D

Deasphalting
A process in which the asphaltic constituents of a heavy residual oil are separated by mixing with liquid propane. Everything will dissolve in the propane but the asphaltics which can then be easily removed.

Debutanizer
A tower in which butane is removed by distillation from a hydrocarbon stream.

De-coking
The process of removing coke from catalyst in a cat cracker, cat reformer, hydrocracker, or hydrotreater. Usually heated air will oxidize the coke to carbon monoxide or carbon dioxide.

Delayed coker
A process unit in which residue is cooked until it cracks to coke & light products.

Deisobutanizer
A distillation column in which isobutane is removed from a petroleum fraction.

Dense Bed
The catalyst bed in the reactor or regenerator vessels.

Diene
Same as a di-olefin.

Diesel
1. An internal combustion engine in which ignition occurs by injecting fuel in a cylinder where air has been compressed and is at a very high temperature, causing self- ignition.
2. Distillate fuel used in a diesel engine.

Diesel Index (DI)
A measure of the ignition quality of a diesel fuel. The diesel index is defined as:

gravity (° API) x aniline point (° F)/100

The higher the diesel index, the higher the ignition quality of the fuel. By means of correlations unique to each crude and manufacturing process, this index can be used to predict cetane number if no standardized test for the latter is available.

Di-olefin (CnH2n-2)
A paraffin type molecule except that it is missing hydrogen atoms that cause it to have two double bonds somewhere along it chains.

Dilute Phase
The space above the catalyst bed in the reactor or regenerator vessels.

Distillate
A product of distillation, or the fluid condensed from the vapor driven off during distillation. Gasoline, naphtha, kerosene, and light lubricating oils are examples of distillates.

Distillation
A physical separation process in which different hydrocarbon fractions are separated by means of heating, vaporization, fractionation, condensation, and cooling.

Distillation range
(See boiling range).

Distribution
A device in a vessel that disperses either liquid or vapor to promote better circulation.

Doctor Test
A method of determining the presence of mercaptan sulfur in petroleum products. This test is used for products in which a "sweet" odor is desirable for commercial reasons, especially naphthas; ASTM D-484.

Dry Gas
All methane (C1) to propane (C3) material, whether associated with a crude or produced as a byproduct of refinery processing. By convention, hydrogen is often included in dry-gas yields.

E

Effective cut points
Cut points that can be considered a clean cut, ignoring any tail ends.

End Point (EP)
Upper temperature limit of a distillation.

Endothermic Reaction
A reaction in which must be added to maintain reactants and products at a constant temperature.

Ethane (C2H6)
A colorless gas, a minor constituent of natural gas and a component in refinery gas that ,along with methane, is typically used as refinery fuel. An important feedstock for making ethylene.

Ethylene (C2H4)
A colorless gas created by cracking processes. In refineries it is typically burned with the methane and ethane. In chemical plants it is made in ethylene plants and is a basic building block for a wide range of products including polyethylene and ethyl alcohol.

Exothermic Reaction
A reaction in which heat is evolved. Alkylation, polymerization, and hydrogenation reactions are exothermic.

Extract
The target constituent in a solvent extraction process.(See solvent extraction).

F

Fixed bed
A place in a vessel for catalyst through or by which feed can be passed for reaction; as opposed to a fluid bed, where the catalyst moves with the feed.

FBT
The final boiling point of a cut, in degrees Fahrenheit, usually on an ASTM distillation basis.

Fifteen/Five (15/5) Distillation
A laboratory batch distillation performed in a theoretical plate three-to-one reflux ratio. A good fractionation results in accurate boiling temperatures. For this reason, the distillation is referred to as the true-boiling-point (TBP) distillation.

Fixed Carbon
The organic portion of the residual coke obtained when hydrocarbon products are evaporated to dryness in the absence of air.

Flash Point
The temperature to which a product must be heated under prescribed conditions to release sufficient vapor to form a mixture with air that can be readily ignited. Flash point is generally used as an indication of the fire and explosion potential of a product; ASTM D-56, D-92, D-93, E-134, D-1320.

Flash Chamber
A wide vessel in a vacuum flasher, thermal cracking plant, or similar operation into which hot stream under pressure is introduced, causing the lighter fractions of that stream to vaporize and leave by the top.

Flue Gas
Gas from various furnaces going up the flue (stack).

Fluid Bed
See fixed bed.

Fluid cat cracking
The most popular design of cat cracking in which a powdery catalyst that flows like a fluid is mixed with the feed and the reaction takes place as the feed/catalyst is in motion.

Fractionation
A countercurrent operation in which a vapor mixture is repeatedly brought in contact with liquids having nearly the same composition as the respective vapors, Liquids are at their boiling points; hence part of the vapor is condensed and part of the liquid is vaporized during each contact. In a series of contact treatments, the vapor finally becomes rich in low-boiling components, and the liquid becomes rich in high-boiling components.

Fractionator
A closed cylindrical tower arranged with trays through which distilled gas/liquid is caused to bubble. The trays retain a portion of the condensed liquid and thus separate the heavier fractions of the gas/liquid from the lighter fractions of gas/liquid. Also called stabilizer column, fractionating tower, or bubble tower.

Freeze point
The temperature at which crystal first appear as a liquid is cooled, which is especially important in aviation fuels, diesel and furnace oil.

Free Carbon
The organic matter in tars that is insoluble in carbon disulfide (CS2).

Fresh Catalyst
Catalyst as received from the supplier.

Fresh Feed
Stocks charged to a cracking unit.

Fresh feed rate
The feed going into a reaction without counting the amount of recycling of any reaction products.

Fuel oil
Usually residual fuel but sometimes distillate fuel.

Fuel Oil Equivalent (FOE)
The heating value of a standard barrel of fuel oil, equal to 6.05 x 106 Btu. On a yield chart, dry gas and refinery fuel gas are usually expressed in FOE barrels.

Furnace oil
A distillate fuel made of cracked or straight run light gas oils, primary for domestic heating because of its ease of handling & storing.

FVT
The final vapor temperature of a cut, in degrees Fahrenheit. Boiling ranges expressed in this manner are usually on a crude assay, true-boiling-point basis.

G

Gain
The volumetric expansion resulting from the creation of lighter, less dense molecule from heavier, compact molecules even given the same weight, before and after.

Gas Cap
An accumulation of natural gas in at the top of a crude oil reservoir. The gas cap often provides the pressure to rapidly evacuate the crude oil from the reservoir.

Gas Oil
That material boiling within the general range of 300° to 750°. This range usually includes kerosene, diesel fuel, heating oils, and light fuel oils. Actual initial and final cut points are determined by specifications of the desired products.

Gasoline
A light petroleum product in the range of approximately 80-400 F for use in spark ignited internal combustion engines.

Gas Producing Factor (GPF)
The volume yield of gas produced by the test catalyst and a reference catalyst at the same conversion level.

Gilsonite
A trade name for uintaite, a black, lustrous asphalt.

Gum
A complex sticky substance that forms by oxidation of gasolines, especially those stored over a long period of time. Gum fouls car engines especially the fuel injection ports.

H

Heat exchanger
An apparatus of transferring heat from one liquid or vapor stream to another. A typical heat exchanger will have a cylindrical vessel through which one stream can flow and a set of pipes or tubes in series in the cylinder through which the other can flow . Heat transfers through the tubes by conduction.

Heating oil
Any distillate or residual fuel.

Heart Cut Recycle
The unconverted portion of catalytically cracked material that is recycled to the catalytic cracker. This recycle is usually in the boiling range of the feed and, by definition, contains no bottoms. Recycle allows less severe operation and suppresses the cracking of desirable products.

Heavy Gas Oil
A distillate product composed of material having a cut point of 650-800 ° F. The heavy gas oil is then sent to the catalytic cracker as feed.

HF alkylation
Alkylation using hydrofluoric acid as a catalyst.

Hydrocarbon
Any organic compound comprised of hydrogen and carbon, including crude oil , natural gas and coal.

Hydrocrackate
The gasoline range product from a hydrocracker.

Hydrocracking
The breaking of hydrocarbon chains into smaller compounds in the presence of hydrogen and a catalyst. The end result is high quality gasoline and isobutane which is then used in the alkylation plant.

Hydrodesulfurization
A sub process of hydrotreating. Used primarily to remove sulfur from the crude feedstock and finished products utilizing a selected catalyst in a hydrogen environment.

Hydrogeneration
Filling in with hydrogen the "free" places around the double bonds in an unsaturated hydrocarbon molecule.

Hydrophilic
An adjective meaning having an affinity for water. For example, bourbon has an affinity for water because it mixes easily with it. Olive oil is not hydrophilic because it does not.(It is hydrophobic). A single molecule can have both a hydrophilic and hydrophobic sites, such as soap.

Hydrophobic
(See hydrophilic).

Hydrotreating
A process used to saturate olefins and improve hydrocarbon streams by removing unwanted materials such as nitrogen, sulfur, and metals utilizing a selected catalyst in a hydrogen environment.

I

IBP
Initial boiling point of a cut, usually on an ASTM distillation basis.

Isobutane
A branched-chain butane compound (C4H10).

Isomerizate
The product of an isomerization process.

Isomerization
The rearrangement of straight-chain hydrocarbon molecules to form branched-chain products. Pentanes and hexanes, which are difficult to reform, are isomerized by the use of aluminum chloride or precious-metal catalysts to form gasoline-blending components of high octane value. Normal butane may be isomerized to provide a portion of the isobutane feed needed for alkylation processes.

Isomers
Two compounds composed of the identical atoms, but with different configurations, giving different physical properties.

Iso-octane (C8H18)
The liquid used with normal heptane to measure the octane number of gasolines.

IVT
Initial vapor temperature of a cut, in degrees Fahrenheit, usually based on a crude assay distillation.

J

Jug
A salt dome storage cavern for hydrocarbon or chemical.

K

Kerosene
A middle-distillate product composed of material of 300° to 550° FWT. The exact cut is determined by various specifications of the finished kerosene.

L

Lamp Sulfur
The total amount of sulfur present per unit of liquid product. The analysis is make by burning a sample so that the sulfur content is converted to sulfur dioxide, which can be measured quantitatively. Lamp sulfur is a critical specification of ail motor, tractor, and burner fuels; ASTM D-1266, D-2784.

Lead Susceptibility
The variation of the octane number of a gasoline as a function of the tetraethyl lead content.

Lean oil
(See absorption process).

LHSV
Liquid hour space velocity; volume of feed per hour per volume of catalyst.

Light Ends
Hydrocarbon fractions in the butane and lighter boiling range.

Light Gas Oil
A distillate product composed of material having a cut point of 450-650 ° F.

Liquified Petroleum Gas (LPG)
Liquified light-end gases used for home heating and cooking. This gas is usually 95 percent propane, and the remainder consists of equal parts of ethane and butane.

Long residue
Straight run residue from a distilling unit.

Lubricating Oils
A fluid used to reduce friction when introduced between solid surfaces. The major constituents of lubricating oils are from distillate or residual fractions of the crude. The manufacture and compounding of lubricating oils are highly specialized and confined to a few major refineries. some refineries produce lube base stocks (bright oils), which are transferred to a refinery specializing in lube oil finishing and compounding.

M

Mercaptans
A group of sulfur-containing compounds found in some crude oils having a skunk-like odor. Mercaptans are manufactured and injected into natural gas and LPG as an odorant for safety purposes.

Methane (CH4)
A light odorless, flammable gas that is the principal component of natural gas.

Methanol (CH3OH)
Methyl alcohol, also known as wood alcohol. Methanol can be made by the destructive distillation of wood or through a process starting with the methane or a heavier hydrocarbon, decomposing it to a synthesis gas, and recombining it to methanol.

Middle Distillates
Atmospheric pipe-still cuts boiling in the range of 300° to 700° FVT. The exact cut is determined by the specifications of the products.

Mid-Percent Point
The vapor temperature at which one-half of the material of a cut has been vaporized. Mid-percent point is often used in place of temperature to characterize a cut.

Monomer
A reactive species fed to a polymerization unit which reacts in a repetitive manner to form long polymer chains. Typical monomers are ethylene, propylene, styrene, and vinyl chloride.

Motor octane number
One of two standard of measures of gasoline knock, this one stimulating more severe operating conditions.

MTBE
Methyl tertiary butyl ether is an alternative high octane blending agent to TEL (tetraethyl lead).

N

Naphtha
A pipe-still cut in the range of 160° to 420° F, Pentanes (C5) are the lower boiling naphthas, at approximately 160° F. Naphthas are subdivided according to the actual pipe-still cuts into light, intermediate, heavy and very heavy virgin naphthas. The quantity of the individual cut varies with the crude. A typical pipe-still operation would yield:
C5-160° F - Light virgin naphtha
160° F-280° F - Intermediate virgin naphtha
280° F-330° F - Heavy virgin naphtha
330° F-420° F - Very heavy virgin naphtha

Naphthas, the major constituents of gasoline, generally must be further processed to make suitable quality gasoline.

Naphthenes
Hydrocarbons with saturated ring structures with general formula CnH2n.

Naphthenic acids
Organic acids occurring in petroleum that contain a naphthene ring and one or more carboxylic acid groups. Naphthenic acids are used in the manufacture of paint driers and industrial soap.

Natural Gas
Naturally occurring gas consisting predominantly of methane, sometimes in conjunction with crude (associated gas), sometimes alone(unassociated gas).

Natural Gasoline
A gasoline range product separated at a location near the point of production from natural gas streams and used as a gasoline blending component.

Neutralization Number
The quantity of acid or base that is require to neutralize all basic or acidic components present in a sample of specified quantity. This is a measure of the amount of oxidation of a product in storage or in service; ASTM D-664, D-974.

Non-Associated gas
Natural gas that exists in a reservoir alone and is produced without any crude oil.

O

Octane number
An index measured by finding a blend of iso-octane and normal heptane that knocks under the identical conditions as the gasoline being evaluated. It is a measure of the resistance to ignition of the fuel without the aid of a spark plug. The higher the octane number, the more resistance to pre-or self ignition. (See MON and RON.)

Olefins
A class of hydrocarbons similar to paraffins, but that has two hydrogen atoms missing and a double bond replacing it. The general formula is C_nH_{2n} for mono-olefins and $C_nH_{2n-2}$for di-olefins, those having 2 sets of double bonds.

Olefin Space Velocity
Volume of olefin charged per hour to an alkylation reactor, divided by the volume of aci in the reactor.

Organic compound
Any compound that includes carbon (exceps carbon dioxide and some carbonates).Generally, organic compounds can be classified as either aliphatics (straight chain compounds), cyclics (compound with ring structure), and combination of aliphatics and cyclic.

P

Paraffins
Straight chain hydrocarbons with the general formula C_nH_{2n+2}.

Paraffinic Raffinates
Straight chain, saturated hydrocarbon fraction remaining after distillation or extraction.

Performance Rating
A method of expressing the quality of a high-octane gasoline relative to isooctane. This rating is used for fuels of higher quality than isooctane.

Penetration
A measure of the hardness and consistency of asphalt in terms of the depth that a special pointed device will penetrate the product in a set time & temperature.

Petroleum coke
(See coke).

Petroleum Fraction
A major product that may be separated from petroleum, i.e., gasoline, kerosene, gas oil; an elementary compound with a constant boiling range. Heavier fractions have higher boiling ranges than lighter fractions.

Pitch
Residue coming from the bottom of a flasher.

Platformer
Archaic name for reformer.

Polymerization
The combination of two or more unsaturated molecules to form a molecule of higher molecular weight. Propylenes and butylenes are the primary feed material for refinery polymerization processes, which use solid or liquid phosphoric acid catalysts.

Pour Point
The lowest temperature at which a petroleum oil will flow or pour when it is chilled, and poured without disturbance at a standard rate. Pour point is a critical specification of middle distillate products used in cold climates; ASTM D-99.

Precursor
Compounds that are suitable or susceptible to specific conversion to another compound. For example, methyl cyclopentane is a good precursor for making toluene in a cat reformer.

Propane (C_3H_8)
A hydrocarbon gas that is a principal constituent of the heating fuel, LPG. Propane is used extensively for domestic heating and as a feed to ethylene plants.

Propylene
A hydrocarbon compound containing three carbon atoms, seven hydrogen atoms, and a double bond making it unsaturated and highly reactive.

Pyrolysis Gasoline (Pygas)
The gasoline created in an ethylene plant using gas oil or naphtha feedstocks. Sometimes called pygas, it has a high content of aromatics and olefins and some di-olefins.

Pyrolisis
Heating a feedstock to high temperature to promote cracking , as in an ethylene plant.

Q

Quench
Hitting a very hot stream coming out of a reactor, with a cooler stream to stop immediately the reaction underway.

R

Raffinate
The residue recovered from an extraction process. An example is the SO2 extraction of raw kerosene. The SO2 raffinate is relatively free of aromatics and other impurities that have poor burning characteristics.

Reactor
The vessel in which the chemical reaction takes place.

Reboiler
A heat exchanger used towards the bottom of a fractionator to re-heat or even vaporize a liquid and introduce it several trays higher to get more heat into the column to improve separation.

Reflux
A heat exchanger, which takes vapor from the upper parts of a fractionator, cools it to liquefy it and reintroduces it lower column. The purpose is to assure sufficient downward liquid flow meeting the rising vapor to improve separation.

Reformate
A high octane, primary product of reforming naphtha.

Reforming
See cat reforming or steam methane-reformer.

Regenerator
The vessel in the catalytic process where a spent catalyst is brought back up to strength before being recycled back to the process. An example is the cat cracker regenerator where coke is burned off the catalyst.

Regenerated Catalyst
Catalyst after the carbon has been burnt off. Specifically, it refers to catalyst after it has passed through the regenerator.

Relative Activity
The relative ability of a catalyst to accelerate the cracking of gas oils to lighter hydrocarbons. Activity ratio of a catalyst refers to its activity as measured by any one of the standard unit test methods under standard conditions.

Reid vapor pressure (RVP)
The pressure necessary to keep a liquid from continually vaporizing as measure in an apparatus design by Reid himself. Use as a standard measure for gasoline specification.

Refractive Index
A measure of the change is direction of a beam of light passing through the interface between two substances. Used in the n-d-M method to estimate the carbon distribution in oils. The n-d-M procedure uses the refractive index (n), the density (d), and the molecular weight (M) to estimate Ca (carbon atoms in aromatic rings), Cn (carbon atoms in naphthenic rings), and Cp (carbon atoms in paraffinic chains). Cp includes the carbon atoms in paraffinic side chains linked to either aromatic or naphthenic ring structures.

Research Octane number (RON)
One of two standards measures of gasoline knock, this one simulating less severe operating conditions like cruising.

Residence time
The amount of time a hydrocarbon spends in a vessel where a reaction is taking place.

Residuals
Heavy material that has a cut point of 800° F and higher.

Residual fuel (Resid)
Heavy fuel oil made from long, short or cracked residue plus whatever cutter stock is necessary to meet market specification.

Ring compound
Hydrocarbon molecules in which the carbon atoms form at least 1 closed such naphthenes and aromatics. Also called cyclics.

Riser
A pipe used to carry the catalyst to a higher level under the lifting force of an aerating medium such as air, steam, or oil vapors. The unit has two risers: spent catalyst and reactor.

Residue
The bottoms from a crude oil distilling unit, vacuum flasher, thermal cracker, or visbreaker. See long residue and short residue.

S

Salt dome
A naturally occurring column of salt lying several hundred to thousand of feet below the surface. Many salt domes are suitable for leaching out and using as a hydrocarbon storage.

Sats gas plant
The sets of columns and treaters in a refinery that handle separation and treatment of the saturated gases.

Service Factor
A quantity that relates the actual onstream time of a process unit to the total time available for use. Service factors include both expected and unexpected unit shutdowns.

Severity
The degree of intensity of the operating conditions of a process unit. Severity may be indicated by clear research octane number of the product, percent yield of the product, or operating conditions alone.

Short residue
Flasher bottoms or residue from the vacuum flasher.

Sieve trays
A variation of the trays used in fractionating columns, consisting of perforated plates to allow vapor passage.

Slurry Oil
A cycle gas oil containing catalyst in suspension.

Smoke Point
A test measuring the burning quality of jet fuels, kerosene, and illuminating oils. It is defined as the height of the flame in millimeters beyond which smoking takes place; ASTM D-1322.

Solvent Extraction
A process which separates certain petroleum compounds from a hydrocarbon mixture, by the use of solvents. Typical solvents include: liquid SO2, Furfural, Sulfolane, Phenol, and Propane.

Sour or Sweet Crude
A general classification of crudes according to sulfur content. Various definitions are available:

Sour Crude: A crude that contains sulfur in amounts greater than 0.5 to 1.0 percent or that contains 0.05 ft3 or more of hydrogen sulfide (H2S) per 100 gal. The exception is West Texas crude, which is always considered sweet regardless of content. Although of high sulfur content, this crude does not contain highly active sulfur compounds.

Sweet Crude: A sweet crude contains little or no dissolved hydrogen sulfide and relatively small amounts of mercaptans and other sulfur compounds.

Space Velocity
The volume (or weight) of gas or liquid passing through a given catalyst or reaction space per unit time, divided by the volume (or weight) of catalyst through which the fluid passes. High space velocities correspond to short reaction times. See LHSV or WHSV.

Spent Catalyst
Catalyst after use in the cracking reaction. Specifically it refers to catalyst leaving the reactor stripper.

Sponge oil
The liquid used in an absorption plant to soak up the constituent to be extracted.(See absorption or solvent extraction).

Stabilization
A fractionation operation conducted for the purpose of removing high-vapor-pressure components.

Stabilizer
A fractionator use to remove most of the light ends from straight run gasoline or natural gasoline to make them less volatile.

Standpipe
A vertical pipe in which fluidized catalyst builds up a static head sufficient to keep the catalyst circulating. The unit is provided with one long standpipe for the regenerated catalyst flowing out of the regenerator and a short one for spent catalyst flowing out of the stripper.

Steam Cracking
The same as cat cracking, but specifically referring to the steam injected with the catalyst and feed to give the mixture lift up the riser.

Steam methane reformer
A primary source of hydrogen in a refinery, this operating units converts methane and steam to hydrogen, with by product carbon monoxide and carbon dioxide.

Straight-Run Gasoline
An uncracked gasoline fraction distilled from crude. Straight-run gasolines contain primarily paraffinic hydrocarbons and have lower octane values than cracked gasolines from the same feedstocks.

Sulfolane: (CH2)4SO2
A chemical used as a solvent in extraction and extractive distillation process.

Surface area
The total area that a solid catalyst expose to the feeds in a reaction. Surface area is enhanced in some catalyst like zeolytes by extensive microscopic pores.

Stripping
An operation in which the significant or desired transfer of material is from the liquid to the vapor phase.

Stripping Steam Rate
The pounds of stripping steam per 1000 pounds of catalyst.

Superficial Gas Velocity
This is a measure of the rate of speed at which gas passes through a vessel. It is obtained by dividing the gas flow, in cubic feet per second, by the cross-sectional area of the vessel in square feet.

Sweet crude
Crude typically containing 0.5% (by weight) or less sulfur.

Sweetening
The removal of sulfur compounds or their conversion to innocuous substances in a petroleum product by any of several processes (doctor treating, caustic and water washing, etc.).

Synthesis gas
The product of a reforming operation in which a hydrocarbon usually methane, and water are chemically rearranged to produce carbon monoxide, carbon dioxide and hydrogen. The composition of the product stream can be varied to fit the needs for hydrogen and carbon monoxide ratios at refineries or chemical plants.

Synthetic Crude
Wide-boiling-range product of catalytic cracking.

T

Tail Gas
Light gases (C1 to C3 and H2) produced as byproducts of refinery processing.

Tar
Complex, large molecules of predominantly carbon with some hydrogen & miscellaneous other elements that generally deteriorate the quality of processes and apparatus.

Tetraethyl Lead (TEL)
An antiknock additive for gasoline.

Thermal Cracking
The breaking of hydrocarbon molecules into smaller compounds. Coking and visbreaking are severe forms of thermal cracking.

Toluene (C6H5CH3)
One of the aromatic compounds used as a chemical feedstock, most notoriously for the manufacture of TNT trinitrotoluene.

Topped crude
Crude that has been run through a distilling unit to remove the gas oil and lighter streams. The so-called simple refineries that do this sell the long residue as residual fuel.

Topping
Removal by distillation of the light products from crud oil, leaving in the still all the heavier constituents.

Total Feed
This is the sum of all feedstocks charged to a cracking unit. It may consist of 100 percent fresh feed or may contain stocks previously cracked by not converted wholly to gasoline, gas, and coke.

Treat Gas
Light gas, usually high in hydrogen, which is required for refinery hydrotreating processes such as hydrodesulfurization. The treat gas for hydrodesulfurization is usually the tail gas from catalytic reforming.

U

Unsaturated
A class of hydrocarbons similar to paraffins and naphthenes but that has double bonds or triple bonds replacing the missing hydrogen.

V

Vacuum distillation
Distillation under reduced pressure in order to keep the temperature low and prevent cracking. Most often used to distill lubricant feedstock.

Valve tray
Fractionator tray that have perforations covered by discs which operate as valve and allow the passage of varying methods amounts of vapor to flow upward.

Vapor Lock Index
A measure of the tendency of a gasoline to generate excessive vapors in the fuel line, thus causing displacement of liquid fuel and subsequent interruption of normal engine operation. The vapor lock index generally is related to RVP and to percentages distilled at 158° F.

Vapor pressure
(See Reid vapor pressure).

Virgin Stocks
Petroleum oils that have not been cracked or otherwise subjected to any treatment that would produce appreciable chemical change.

Visbreaking
Mild thermal cracking aimed at producing sufficient middle distillates to reduce the viscosity of the heavy feed.

Viscosity
The property of liquids under flow conditions that causes them to resist instantaneous change of shape or instantaneous rearrangement of their parts due to internal friction. Viscosity is generally measured as the number of seconds, at a definite temperature, required for a standard quantity of oil to flow through a standard apparatus. Common viscosity scales in use are Saybolt Universal, Saybolt Furol, and Kinematic (Stokes).

Volatile
A hydrocarbon is volatile if it has a sufficient amount of butanes and lighter material to noticeable give off vapors at atmospheric conditions.

Volatiles
Oil patch nomenclature for butane and propane, sometimes ethane.

Volatility Factor
An empirical quantity that indicates good gasoline performance with respect to volatility. It involves actual automobile operating conditions and climatic factors. The volatility factor is generally defined as a function of RVP, and of percentages distilled at 158° F and 212° F. This factor is used to predict the vapor-lock tendency of a gasoline.

W

Wet Gas
Natural gas that has not had the C4 and natural gasoline removed. Also the equivalent of refinery gas stream.

White oil
Same as light oil. See black oil the opposite.

WHSV
Weight hour space velocity is defined as the weight of feed per hour per weight of catalyst.

Wick Char Test
A test used to indicate the burning quality of a kerosene or illuminating oil. Wick char is defined as the weight of deposits remaining on the wick after a specified quantity of sample is burned.

X

Xylene
Special name given to dimethylbenzene.

Y

Yield
Either the amount of the desired products or all the products resulting from a process involving chemical change of the feed.

Z

Zeolytes
Compounds used extensively as catalysts, made of silica or aluminum, as well as sodium or calcium and other compounds. Zeolytes comes in a variety of forms – porous and sand-like or gelatinous and provide the platform for numerous catalysts. The solid zeolytes have extensive pores that give them very large surface areas. The precise control during the fabrication of the pore sizes enables selected access to different size molecules during reaction.

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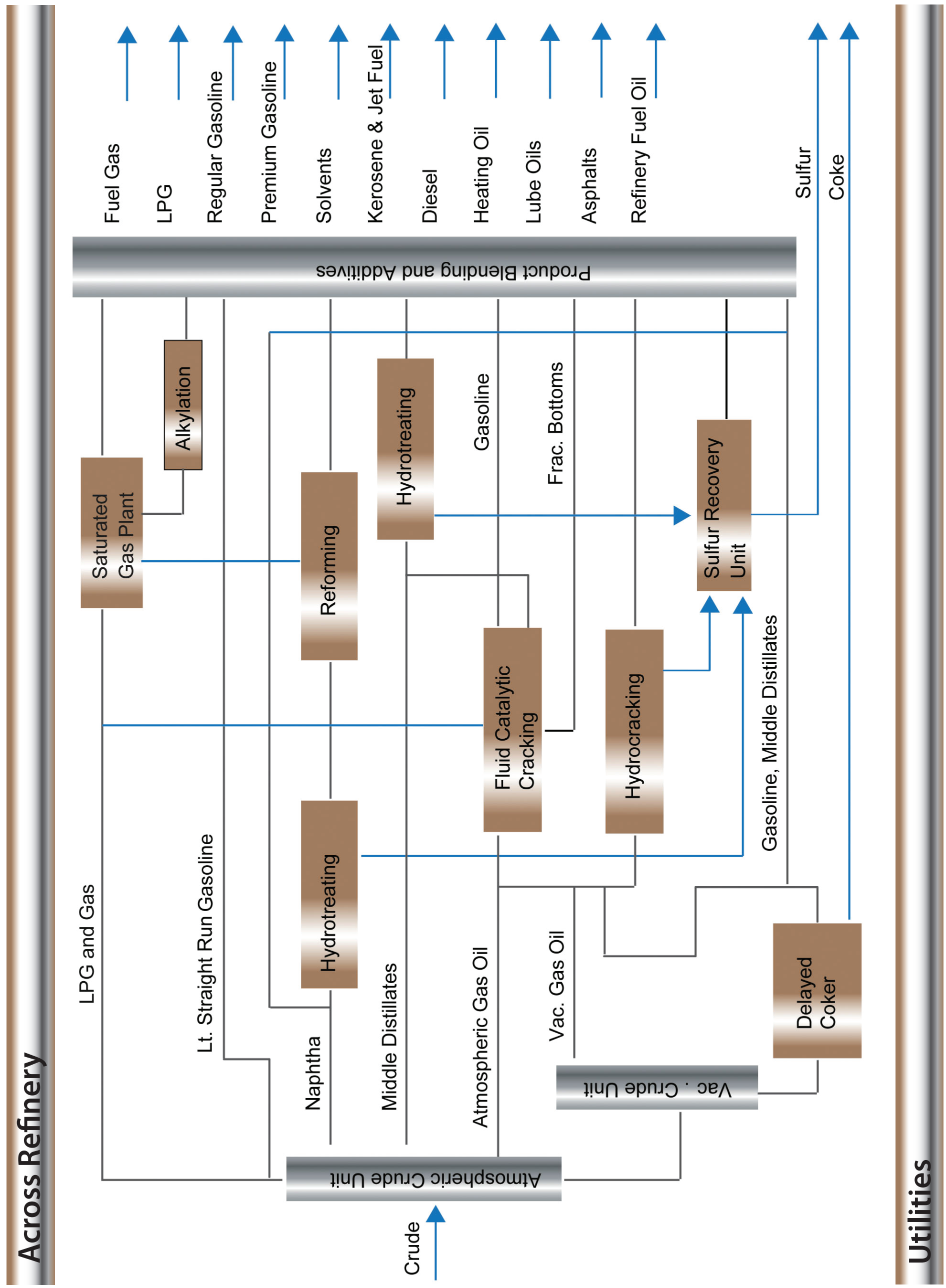
Internal information

Appendix 5 - Rosemount level device selector

Rosemount level device selector



		Continuous products					Point products							
Unit	Process	5300	5400	5600	3100	DP	2100	Float switch	9901	Process Medium	Measure-ment	Temp/pressure seal type	Installation type	Best practice in section:
Across Refinery	Accumulators	1				1				HC liquid	Level	Standard	Varies	4.1.4/4.3.2 /pg108
Across Refinery	Accumulators	1								HC liquid/water	Interface	Standard	Varies	4.1.5/4.3.6
Across Refinery	Accumulators/feedtanks	1					1		1	Condensed gases, oils	Level	Standard	Chamber	4.1.4
Across Refinery	Blowdown drums			1				1	1	Varies, mostly HC	Level	Standard	In tank	4.3.5
Across Refinery	Chemical storage	2	1			1	1			Acids, caustics, polymers, fuels	Level	Standard	In tank	4.3.2/ pg108
Across Refinery	Compressor knock-out pots	1							1	HC liquid	Level	High pressure / low temp	Chamber	4.1.1b
Across Refinery	Compressor scrubbers					1				HC liquid	Level	High pressure/ low temp	Direct mount with DP	pg108
Across Refinery	Compressor scrubbers	1							1	HC liquid	Level	High pressure / low temp	Chamber	4.1.1b
Across Refinery	Compressor seal pots	1				1	1			Oil	Level	Standard	In tank	4.3.4/ pg108
Across Refinery	Compressor - various	1					1	2	1	HC liquid	Level	High pressure / low temp	Chamber	4.1.1b
Across Refinery	Knock out drums	1	2				2	1		HC liquid	Level	Standard	Varies	4.1.4/4.3.2
Across Refinery	Knock out pots	1						1		Oil	Level	Standard	In tank	4.3.4
Across Refinery	Lube oil tanks/reservoirs	1				1	1	2		Lube oil	Level	Standard	In tank	4.3.4/ pg108
Across Refinery	Seal pots for compressors	1					1			Oil	Level	Standard	In tank	4.3.4
Across Refinery	Separators/knockout drums	1					1		1	Gas/oil, oil water	Interface	Standard	Chamber	4.1.5
Across Refinery	Water boot separators	1					1	2	1	Oil/water	Interface	Standard	Chamber	4.1.5
Alkylation Units	Isobutane		1							Isobutane	Level	Standard	Stilling well	4.2.1
Alkylation Units	Mixing tanks		2	1						Acids, catalysts	Level	Standard	In tank	4.3.3
Alkylation Units	Propylene feedstock		1	2						Propylene	Level	Standard	Stilling well	4.2.1
Alkylation Units*	Settling tanks*	1					1		1	Oil/acid	Interface	Standard	In tank or chamber	4.1.5/4.3.6
Blending and Additives	Asphault/Bitumen		1	2						Heavy HC	Level	Standard	In tank	4.3.2
Blending and Additives	Blending tanks	2	1			1	1			HC liquid	Level	Standard	In tank	4.3.3/ pg108

The coding system for the products is: 1 = Good choice 2 = Suitable choice

*In aklylation units using HF acid, special attention must be given to materials of construction.

Appendix 5 -Rosemount level device selector

Unit	Process	Continuous products 5300	5400	5600	3100	DP	Point products 2100	Float switch	9901	Process Medium	Measure-ment	Temp/pressure seal type	Installation type	Best practice in section:
Blending and Additives	Lube oil		1			1	1			Lube oil	Level	Standard	In tank	4.3.3/ pg108
Crude Unit	Crude oil buffer storage		1	1			1	2		Oil	Level	Standard	Stilling well	4.3.2
Crude Unit	Crude oil buffer storage					1				Oil	Level	Standard	Direct mount with DP	pg108
Crude Unit	Desalters	1								Oil/water	Interface	Standard	Stilling well	4.6
Crude Unit	Desalters	1								Oil/water	Interface	Standard	In tank	4.6
Crude Unit	Distillation towers	1						1	1	Oil	Level	High temp / low pressure	Chamber	4.1.1A
Crude Unit	Distillation towers	1					2	1	1	Oil	Level	Standard	Chamber	4.1.4
Crude unit	Distillation towers					1				Oil	Level	Standard or high temp	Direct mount with DP	pg108
Crude Unit, Vacuum	Asphault/bitumen	1								Heavy HC	Level	High temp / low pressure	Chamber	4.1.1A
Crude Unit, Vacuum	Bottoms					1				Heavy HC	Level	High temp / low pressure	Direct mount with DP	pg108
Crude Unit, Vacuum	Slurries			1						Water w/ coke, steam vapors	Level	Standard	In tank	4.3.3
Delayed Coker	Coke bins			1						Coke	Level	Standard	In tank	4.3.1
Delayed Coker	Coke drums									Heavy HC	Level	Hot	No Rosemount offering; Nuclear is commonly used	
Delayed Coker	Coker feed tank			1						HC liquid	Level	High temp / low pressure	Chamber	4.1.1A
Delayed Coker	Defoaming fluid tank	1	2			1	1	2		Chemical	Level	Standard	In tank	4.3.2/ pg108
Delayed Coker	Heavy oil/water interface**	1							1	Oil/water	Interface	Standard	Chamber	4.1.5
Delayed Coker	Spent catalyst hopper			1						Catalyst	Level	Standard	In tank	4.3.1
FCC	Absorbers	1							1	Rich sponge oil and water	Interface	Standard	Chamber	4.1.5
FCC	Deethanizer column	1							1	HC liquid	Level	Standard	Chamber	4.1.4
FCC	Depropanizer	1							1	HC liquid	Level	High temp / low pressure	Chamber	4.1.1A
FCC	Flare knock out drum		1			1	1	2		HC liquid	Level	Standard	In tank	4.3.4 / pg108
FCC	Flare knock out drum	1		2			2	1		HC liquid	Level	High temp / low pressure	Stilling well	4.2.1

The coding system for the products is: 1 = Good choice 2 = Suitable choice

** In some interface applications with heavy emulsions, DP level may be a better solution.

Appendix 5 -Rosemount level device selector

		Continuous products					Point products							
Unit	Process	5300	5400	5600	3100	DP	2100	Float switch	9901	Process Medium	Measure-ment	Temp/pressure seal type	Installation type	Best practice in section:
FCC	Fractionator	1							1	HC	Level	High temp / low pressure	Chamber	4.1.1A
FCC	Fractionator drums	1							1	DCO/water	Interface	Standard	Chamber	4.1.5
FCC	Fuel gas KO drum	1					2	1	1	HC liquid	Level	High temp / low pressure	Chamber	4.1.1A
FCC	Gasoline water interface	1							1	Gasoline / water	Interface	High temp / low pressure	Chamber	4.1.3
FCC	Jet cut tower	1							1	HC liquid	Level	High temp / low pressure	Chamber	4.1.1A
FCC	Rerun tower	1							1	Gasoline	Level	High temp / low pressure	Chamber	4.1.1A
FCC	Spent catalyst	1								Oil/metallic particles	Level and interface	Standard	In tank	4.3.6
FCC	Top reflux water settler	1							1	HC liquid/sour water	Interface	High temp / low pressure	Chamber	4.1.3
FCC	Ultrafiner	1							1	HC liquid	Level	High temp / low pressure	Chamber	4.1.1A
Feed Hydrotreaters	Catalyst hoppers	1								Dry metallic particles	Level	Standard	In tank	4.3.1
Feed Hydrotreaters	Coalescers (water boot separator)	1							1	Oil/water	Interface	High pressure / low temp	Chamber	4.1.3
Gas Plant	Absorber deethanizer tower	1							1	HC liquid	Level	High pressure / low temp	Chamber	4.1.1b
Gas Plant	Cat poly deprop OH accumulator	1							1	HC liquid	Level	High pressure / low temp	Chamber	4.1.1b
Gas Plant	De-ethanizer tower bottoms	1							1	HC liquid	Level	High pressure / low temp	Chamber	4.1.1b
Gas Plant	Depropanizer OH accumulator	1							1	Propane, propylene	Level	High pressure / low temp	Chamber	4.1.1b
Gas Plant	Depropanizer reboiler	1							1	HC liquid	Level	High pressure / low temp	Chamber	4.1.1b
Gas Plant	Depropanizer reboiler	1							1	Water	Level	High pressure / low temp	Chamber	4.1.1b
Gas plant	Gas discharge scrubber	1					1	2	1	Gas/water	Interface	Standard	Chamber	4.1.5
Gas Plant	Isobutane sphere		1							Isobutane	Level	Standard	Stilling well	4.2.1
Gas Plant	NGL, Propane, other liquified gases	1								Low DK liquified gases	Level	Standard	In tank or chamber	4.2.1/4.1.4
Hydrotreater	Ammonia	1								Ammonia	Level	Standard	In tank	4.3.2/4.7.3

The coding system for the products is: 1 = Good choice 2 = Suitable choice

Appendix 5 -Rosemount level device selector

		Continuous products					Point products							
Unit	**Process**	**5300**	**5400**	**5600**	**3100**	**DP**	**2100**	**Float switch**	**9901**	**Process Medium**	**Measure-ment**	**Temp/pressure seal type**	**Installation type**	**Best practice in section:**
Hydrotreater	Cold HP separator	1					2	1	1	Oil/water	Interface	High pressure / low temp	Chamber	4.1.3
Hydrotreater	Debutanizer	1							1	HC liquids	Level	High pressure / low temp	Chamber	4.1.1b
Hydrotreater	Depropanizer	1							1	HC liquids	Level	High pressure / low temp	Chamber	4.1.1b
Hydrotreater	Hot LP separator	1					2	1	1	Oil/water	Interface	High temp/high pressure	Chamber	4.1.3
Hydrotreater	Sulfur pits		1	1						Molten sulphur	Level	High temp / low pressure	In tank	4.3.1
Hydrotreater - Amine Unit	Amine sumps	1								Amine/ water	Interface	Standard	In tank	4.3.6
Hydrotreater - Amine Unit	Rich amine	1							1	Amine/water	Interface	Standard	Chamber	4.1.5
Hydrotreater - Amine Unit	Spent amine	1							1	Spent amine/ water	Interface	Standard	Chamber	4.1.5
Hydrotreaters, Sulfur Recovery unit	Oil skim tank	1								Oil/water	Level and interface	Standard	In tank	4.3.6
Naptha Hydrotreater	Naptha vacuum level	1							1	Naptha	Level	High temp / low pressure	Chamber	4.1.1A
Naptha Hydrotreater	Wild naptha interface	1							1	Naptha/water	Interface	High temp / low pressure	Chamber	4.1.3
Tank Farm	Floating roof applications		1					1		Tank roof	Level, alarm	Standard	Above tanks	4.7.4
Tank Farm	Fixed roof applications						1			HC liquid	Level, alarm	Standard	In tanks	4.5.2
Utilities	Boiler & feedwater system					1				Water	Level	High temp/high pressure	Direct mount with DP	pg108
Utilities	Boiler & feedwater system	1						1	1	Water	Level	High temp/high pressure	Chamber	4.1.2
Utilities	Condensate return tanks	1				1	1			Water	Level	High temp/high pressure	In tank or chamber	4.1.2/ pg108
Utilities	Cooling towers	1	2				1	2		Water	Level	Standard	In tank	4.3.2
Utilities	Flue gas scrubbers	2	1				1	2		Water	Level	Standard	In tank	4.3.2
Utilities	Reserve & service tanks		1			1	1			Water	Level	Standard	In tank	4.3.2/ pg108
Utilities	Sumps	1	2		2					HC or water	Level and interface	Standard	In tank	4.3.6
Utilities	Waste water	2	1		2					Water	Level	Standard	In tank	4.3.2

The coding system for the products is: 1 = Good choice 2 = Suitable choice

Notes

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Recommended retail price $24.99

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