API RECOMMENDED PRACTICE 550
FOURTH EDITION, FEBRUARY 1980

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Manual on Installation of Refinery Instruments and Control Systems

Part I — Process Instrumentation and Control
Section 2 — Level

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American Petroleum Institute
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Manual on Installation of Refinery Instruments and Control Systems

Part I — Process Instrumentation and Control
Section 2 — Level

Refining Department

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OFFICIAL PUBLICATION

REG U S PATENT OFFICE

FOREWORD

This recommended practice is based on the accumulated knowledge and experience of engineers in the petroleum industry. Its purpose is to aid in the installation of the more generally used measuring, control, and analytical instruments; transmission systems; and related accessories to achieve safe, continuous, accurate, and efficient operation with minimum maintenance. Although the information contained has been prepared primarily for use in petroleum refineries, much of it is applicable without change in chemical plants, gasoline plants, and similar installations

Successful instrumentation depends upon a workable arrangement which incorporates the simplest systems and devices that will satisfy specific requirements. Sufficient schedules, drawings, sketches, and other data should be provided to enable the constructor to install the equipment in the desired manner. Various industry codes and standards as well as laws and rules of regulating bodies should be followed where applicable.

For maximum plant personnel safety, transmission systems are used to eliminate the piping of hydrocarbons, acids, and other hazardous or noxious materials to instruments in control rooms. Proper installation is essential to use fully the capabilities that are built into the instrument or transmission system.

When installing an instrument, the various components must be accessible for efficient maintenance, and certain of these elements must be readable for good operation. Orifices, control valves, transmitters, thermocouples, level gages, and local controllers as well as analyzer sample points generally should be readily accessible from grade, permanent platforms, or fixed ladders. In this manual, special consideration is given to the location, accessibility, and readability of the elements.

Users of this manual are reminded that in the rapidly advancing field of instrumentation no publication of this type can be complete nor can any written document be substituted for qualified engineering analysis.

Certain systems are not covered in this section because of their highly specialized nature and limited use. When any of these systems gains wide-spread usage and installation reaches a fair degree of standardization, this section will be revised to incorporate such additional information.

Acknowledgment is made to all the engineers and operating and maintenance personnel who, through years of study, observation, invention, and sometimes trial and error, have contributed to the technology of instrumentation.

Suggested revisions are invited and should be submitted to the director, Refining Department, American Petroleum Institute, 2101 L Street, N.W., Washington, D.C. 20037.

PREFACE

This section is one of a series which make up RP 550, *Manual on Installation of Refinery Instruments and Control Systems*. RP 550 is composed of four parts:

Part I — Process Instrumentation and Control
Part II — Process Stream Analyzers
Part III — Fired Heaters and Inert Gas Generators
Part IV — Steam Generators

Part I analyzes the installation of the more commonly used measuring and control instruments, as well as protective devices and related accessories; Part II presents a detailed discussion of process stream analyzers; Part III covers installation requirements for instruments for fired heaters and inert gas generators; and Part IV covers installation requirements for instruments for steam generators. These discussions are supported by detailed information and illustrations to facilitate application of the recommendations.

The format of RP 550, Part I has been changed to facilitate continuity of presentation, convenience of reference, and flexibility of revision. Each section is now being published individually as follows:

Section 1 — Flow
Section 2 — Level
Section 3 — Temperature
Section 4 — Pressure
Section 5 — Automatic Controllers
Section 6 — Control Valves and Positioners
Section 7 — Transmission Systems
Section 8 — Seals, Purges, and Winterizing
Section 9 — Air Supply Systems
Section 10 — Hydraulic Systems
Section 11 — Electrical Power Supply
Section 12 — Control Centers
Section 13 — Alarms and Protective Devices
Section 14 — Process Computer Systems

When preparing these documents, it was necessary to decide on a logical method of presentation—should each point be explained as fully as possible, or should extensive cross-referencing be done between sections?

The publications contain a combination of these methods of presentation. Each section has been made as complete as possible, with cross-referencing done only where very extensive repetition would have been required.

Users of this recommended practice are cautioned to obtain a complete set of sections in order to accomplish efficiently any cross-referencing that is required for a better understanding of the subject matter.

CONTENTS

SECTION 2 — LEVEL

PAGE

2.1 Scope ... 1

2.2 General ... 1
- 2.2.1 Accessibility ... 1
- 2.2.2 Visibility ... 1
- 2.2.3 Connections to Vessels ... 1
- 2.2.4 Multiple Instrument Mounting ... 1
- 2.2.5 Block Valves ... 2
- 2.2.6 Strain Relief ... 2
- 2.2.7 Vibration ... 2
- 2.2.8 Drains and Vents ... 2

2.3 Locally Mounted Indicating Gages ... 3
- 2.3.1 Tubular Gage Glasses ... 3
- 2.3.2 Armored-Type Gage Glasses ... 3
- 2.3.3 Magnetic-Type Gages ... 4
- 2.3.4 Hydrostatic Head Pressure Gages ... 5
- 2.3.5 Differential Pressure Level Indicators ... 5

2.4 Level Transmitters ... 5
- 2.4.1 Displacement Transmitters ... 6
- 2.4.2 Differential Pressure Transmitters ... 8
- 2.4.3 Hydrostatic Head Transmitters ... 9
- 2.4.4 Nuclear-Type Level Transmitters ... 9
- 2.4.5 Ultrasonic-Type Level Transmitters ... 9
- 2.4.6 Capacitance-Type Level Transmitters ... 12

2.5 Locally Mounted Controllers ... 13
- 2.5.1 Displacement Controllers ... 13
- 2.5.2 Caged Ball-Float Controllers ... 13
- 2.5.3 Internal Ball-Float Controllers ... 13
- 2.5.4 Differential Pressure Controllers ... 13

2.6 Remote or Panel-Mounted Receivers ... 13
- 2.6.1 Installation ... 13
- 2.6.2 Range ... 14
- 2.6.3 Signal Transmission ... 14

2.7 Level Switches ... 14
- 2.7.1 Installation of Float Switches ... 14
- 2.7.2 Installation of Other Switches ... 14

2.8 Tank Gaging ... 14
- 2.8.1 Float and Cable (Automatic) Tank Gages ... 14
- 2.8.2 Other Tank Gaging Methods ... 15

2.9 Accessories ... 15
- 2.9.1 Seals and Purges ... 15
- 2.9.2 Gage Glass Illuminators ... 15
- 2.9.3 Weather Protection ... 16

LIST OF ILLUSTRATIONS

Figures

2-1 — Tubular Gage Glass Connections to Vessels 2
2-2 — Gage Assemblies 4
2-3 — Gage Glass Mounting Arrangements for Horizontal Vessels and for Interface Measurement 5
2-4 — Typical Magnetic Gage 5
2-5 — Hydrostatic Head Pressure Gage Arrangements 6
2-6 — External Gage Displacement Instrument With Parallel Gage Glass 7
2-7 — External Gage Displacement Controller With Parallel Gage or Standpipe 7
2-8 — Standpipe With External Gage Displacement Instrument and Multiple Sight Gages 8
2-9 — Typical Stilling Well 8
2-10 — Typical Installations of Differential Pressure Level Instruments 10
2-11 — Flange-Type Differential Level Transmitter 11
2-12 — Hydrostatic Head Level Transmitters 11
2-13 — Typical Arrangement of Nuclear Level Transmitter 11
2-14 — Top Mounted Ultrasonic-Type Level Transmitter 12
2-15 — Capacitance-Type Level Transmitter 12
2-16 — Arrangement of High- and Low-Level Alarm Switches With Parallel Gage Glass 14

Part I — Process Instrumentation and Control

SECTION 2 — LEVEL

2.1 Scope

This section discusses recommended practices for the installation of the more commonly used instruments and devices for indicating, recording, and controlling liquid and solid levels and liquid-liquid interface levels normally encountered in petroleum refinery processes.

A wide variety of level instrumentation currently is available Selection and proper installation depends upon a number of variables such as: (a) type of vessel, fluid or material involved (that is, solids, granules, or liquids, or a liquid/liquid or liquid/foam interface); (b) process conditions (that is, pressure, temperature, specific gravity, boiling point, viscosity, and pour point); (c) what the instrument is to accomplish (monitor, on-off or modulating control or alarm); and (d) whether the signal is to be electronic or pneumatic.

Seven types of instruments are covered.

1. Locally mounted indicating gages (see 2.3) including tubular gage glasses, armored-type gage glasses, magnetic-type gages, hydrostatic head pressure gages, and differential pressure level indicators
2. Level transmitters (see 2.4) including displacement, differential-pressure, hydrostatic-head, nuclear, ultrasonic, and capacitance types.
3. Locally mounted controllers (see 2.5), including displacement, ball-float, and differential-pressure types.
4. Remote or panel-mounted receivers (see 2.6).
5. Level switches (see 2.7).
6. Tank gaging (see 2.8).
7. Accessories (see 2.9) including seals and purges, gage glass illuminators, and weather protection.

2.2 General

Certain general procedures, practices, and precautions apply to practically all instruments discussed in this section. Where applicable, the material discussed in 2.2.1 through 2.2.8 should be considered a part of the text of each of the subsequent discussions.

2.2.1 ACCESSIBILITY

All locally mounted liquid level instruments, including gage glasses, should be readily accessible from grade, platform, fixed walkway, or fixed ladder. For maintenance purposes, rolling platforms frequently are used when free access is available in the area below the instruments.

For general service, externally mounted level devices are preferred, since they permit access for calibration and maintenance. Internally mounted devices, therefore, usually are limited to those services where external devices cannot be used or in those services where a shutdown for maintenance is acceptable.

2.2.2 VISIBILITY

2.2.2.1 In all applications where a liquid level is regulated by a control valve, some indication of the level—gage glass, receiver pressure gages, or other indicator—should be clearly visible from the control valve location to permit manual control when necessary. Such level indication at the valve is not necessary if the control system cannot be operated manually from the control valve station.

2.2.2.2 Level indicating instruments should be located on vessels so they are visible from operating aisles.

2.2.3 CONNECTIONS TO VESSELS

2.2.3.1 Level instrument connections must be made directly to vessels and not to process flow lines or nozzles (continuous or intermittent) unless fluid velocity in the line is less than 2 feet (0.6 meters) per second.

2.2.3.2 Connections and interconnecting piping should be installed in such a manner that no pockets or traps can occur. Where pockets are unavoidable, drain valves should be provided at the lowest points.

2.2.4 MULTIPLE INSTRUMENT MOUNTING

2.2.4.1 When two or more instruments, including gage glasses, are required for any application (such as gage glass and controller or gage glass and alarm switch), they may be mounted in such a way that the number of openings in the vessel are kept to a minimum. Suggested methods are the use of tees (see 2.4.1.3) or a common standpipe (see 2.3.2.3 and 2.4.1.3).

2.2.4.2 Block valves generally are used between a vessel nozzle and a standpipe. However, some companies permit a standpipe to be installed without block valves at vessel nozzles.

2.2.5 BLOCK VALVES

2.2.5.1 Material

The materials of construction, the rating, and the type of connections for block valves must conform to the specifications for the equipment to which the valves are connected. This applies to all block valves whether installed directly on the equipment or on a standpipe that is connected to the equipment.

2.2.5.2 Location and Size

Block valves may be located at the vessel connection or on a standpipe. When valves are connected to standpipes, connections are to be a minimum of a ¾-inch (20-millimeter) size. Where the vessel connection is a flanged nozzle and the block valve is mounted directly on the nozzle, the minimum is a 1-inch (25-millimeter) size. Where the vessel connection is a coupling and the block valve is mounted to a nipple, the minimum connection size is ¾ inch (20 millimeters). Exceptions are noted in 2.2.5.3. Fittings or piping between the vessel and block valves should be minimized.

2.2.5.3 Exceptions

a. SPECIAL APPLICATIONS

In the event a vessel nozzle is flanged and the instrument (such as a differential-pressure type) to be connected has small-sized screwed connections, the block valve may be a minimum of ¾ inch (20 millimeters) and can be connected to the vessel nozzle with a reducing flange and nipple.

b. DUAL BLOCK VALVES

For parallel instruments connected by tees mounted directly on nozzles, dual block valves are permitted by some companies. This arrangement is a space-saver and in many cases is more economical than others.

c. FLANGE-MOUNTED, EXTENDED, DIAPHRAGM-TYPE LEVEL TRANSMITTERS

This type of instrument can be installed flush with the wall of the vessel; in this application, block valves are impractical (see 2.4.2.1,e). Transmitters can be installed with a flange-size block valve between the vessel nozzle and the transmitter.

2.2.6 STRAIN RELIEF

Connections between vessels and heavy gages, controllers, or transmitters should be relieved of strain by properly supporting such instruments (and seal pots where used) and by installing offsets or expansion loops where necessary to compensate for thermal expansion differences.

2.2.7 VIBRATION

Some level instruments are susceptible to damage or malfunctioning if mounted in locations where they are subject to vibration. To minimize vibration effects, such instruments should be mounted on a rigid support adjacent to, but not connected to, the source of vibration. Such an arrangement requires that the tubing or conduit connections between the source of vibration and the instrument be installed with flexibility. Additionally, shockproof mounts may be considered. Level instruments that must be mounted in locations subject to vibration should be carefully selected since some instruments are less susceptible to vibration effects.

2.2.8 DRAINS AND VENTS

Drain valves of a ½-inch or ¾-inch (12-millimeter or 20-millimeter) size should be installed on the bottom connection to level instruments and gage glasses (see 2.3.1.2, 2.3.2.2, 2.3.2.3, 2.3.4.2, and 2.4.1.3). In hazardous services, drains should be piped away from the instruments to a safe area of disposal. Vent valves are not generally necessary but can be installed when desired. Plugged vent connections should be provided on all installations where vent valves are not provided.

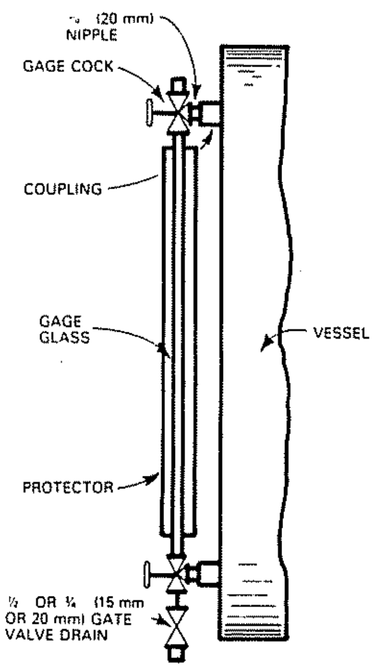


Figure 2-1—Tubular Gage Glass Connections to Vessels

2.3 Locally Mounted Indicating Gages

Locally mounted indicating devices include tubular gage glasses, armored-type gage glasses, magnetic-type gages, hydrostatic head pressure gages, and differential pressure level indicators.

2.3.1 TUBULAR GAGE GLASSES

2.3.1.1 Application

Most companies do not permit the use of tubular gage glasses on process units. Usage of this type gage should be limited to services where the temperature is below 200 F (94 C); the pressure is below 15 pounds per square inch gage (100 kilopascals); and the material is nontoxic and nonhazardous.

2.3.1.2 Connections

Tubular gage glass connections to a vessel may be made by means of gage cocks provided the requirements of 2.2.5 are met. (See Figure 2-1.)

2.3.1.3 Maximum Lengths

Tubular gage glasses should never exceed 30 inches (750 millimeters) in length. If a range greater than 30 inches (750 millimeters) is to be observed, use overlapping gage glasses.

2.3.1.4 Protection

The tubular gage glass should be protected by sheet metal, plastic, or safety glass protectors and should be mounted on the side of the vessel away from the most likely source of damage. However, the gage must be visible to the operator.

2.3.2 ARMORED-TYPE GAGE GLASSES

2.3.2.1 Application

a. The most commonly used types of armored gage glasses are the transparent (through-vision) and reflex gages. Magnetic-type gages are available for special applications or high-pressure service (refer to 2.3.3).

1. *Transparent Gages:* These gages should be used in installations involving acid, caustic, or dirty (or dark-colored) liquids; in high-pressure steam applications; for liquid-liquid interface service; and in any application where it is necessary to illuminate the glass from the rear.
2. *Reflex Gages:* These gages preferably should be used on all other clean service applications including C_4 and heavier hydrocarbons. They also may be used on C_3 and lighter hydrocarbons provided the product does not dissolve the paint or other coating on the inside of the gage, thereby leaving a bare metal backwall which in turn reduces the effectiveness of the prisms.

b. In service applications involving liquids that may boil, large-chamber reflex or transparent gage glasses often are used. These are designed to give an accurate level indication of liquids that boil or tend to surge in the gage glass.

2.3.2.2 Gage Assemblies

Multiple-section gage glasses are made up of more than one standard-length section and can be connected to the vessel by one of the alternatives recommended in Figure 2-2(A). For the greatest accuracy and safety, gage glasses should be limited in length to four sections or 5 feet (1.5 meters) between connections. In services at 400 F (200 C) or higher, some companies limit length to three sections. In noncritical level applications and where temperatures are less than 400 F (200 C), longer gage glasses often are used. Whenever four or more section glasses are used, additional support may be required. Expansion and contraction, which result from temperature changes, should be considered to determine the need for installing offsets or expansion loops.

2.3.2.3 Multiple-Gage Mounting

Large ranges of level preferably are observed by the use of overlapping gage glasses. The mounting of overlapping gage glasses on a standpipe is shown in Figure 2-2(B). Gage cocks ¾ inch (20 millimeters) in size generally are used on multiple gages. Many refiners have found that the maintenance required on the ball checks of automatic gage cocks is so great that they prefer to use individual block valves and pipe tees. Both types of installations are shown in Figure 2-2(B).

Interface observation requires the use of transparent gage glasses. Figure 2-3 shows two commonly used and recommended methods of mounting multiple gages on horizontal vessels where both liquid-liquid and liquid-vapor interfaces are to be observed. Connections to the vessel must be arranged so that there is always one in each phase of each interface being measured.

2.3.2.4 Protection Against Etching

On transparent gage glasses to be installed where the liquid or vapor will attack glass (for example, on steam service of 250 pounds per square inch gage (1675 kilopascals) or higher or in applications involving hydrofluoric acid, amines, or caustic solutions), a thin sheet of mica, polytetrafluoroethylene,[1] monoclorofluoroethylene polymer,[2] or other material that will withstand attack is sometimes inserted between the gage glass and the gage gasket to prevent etching of the glass. Sunlight discolors some plastics; therefore, care should be used in selecting the material

[1] For example, Teflon®.
[2] For example, Kel F®.

for the shield. Such shields cannot be used in reflex gages as they render the prisms ineffective.

2.3.2.5 Gage Glass Assembly

Improper torquing of nuts on the gage glass assembly bolts can result in glass failure. The manufacturer's recommended torquing procedures must be followed.

2.3.3 MAGNETIC-TYPE GAGES

Magnetic-type gages are used in gaging liquids (a) where glass failure is likely to occur due to fluids being handled and (b) where the release of toxic gases, flammable liquids, and so forth is to be avoided.

Typical construction consists of a float inside a sealed nonmagnetic chamber, and an indicator mounted outside of the chamber, actuated or coupled magnetically to indicate level. Mounting to vessel usually is accomplished by means of flanged connections and valves similar to flanged-type external displacement units.

2.3.3.1 Operation

An external magnetic guide controls the orientation of the float which contains the actuating magnet. The actuating magnet has a greater magnetic force than the edges of the magnetized wafers of the indicating scale. As the actuating magnet passes the wafers, they are rotated 180 de-

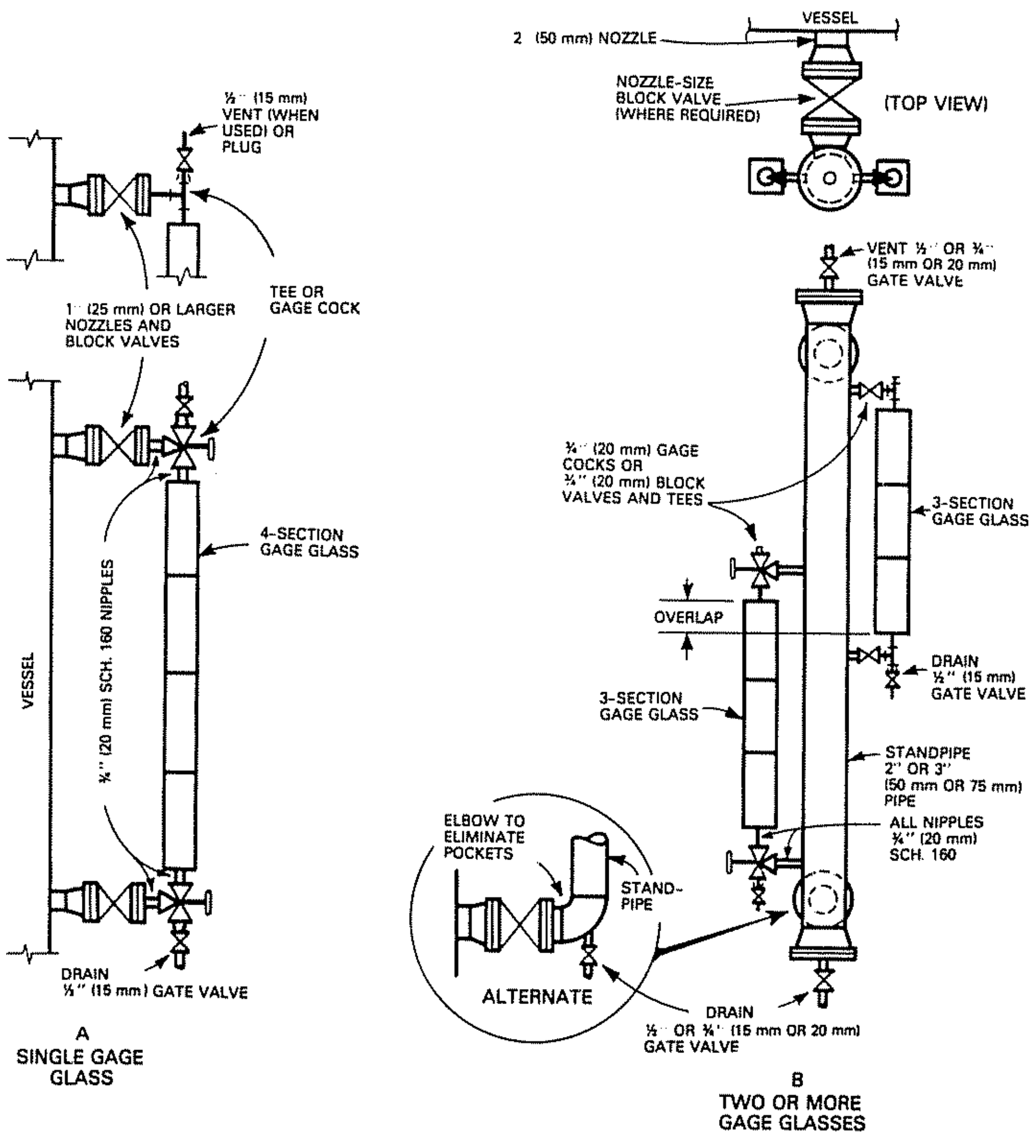


Figure 2-2—Gage Assemblies

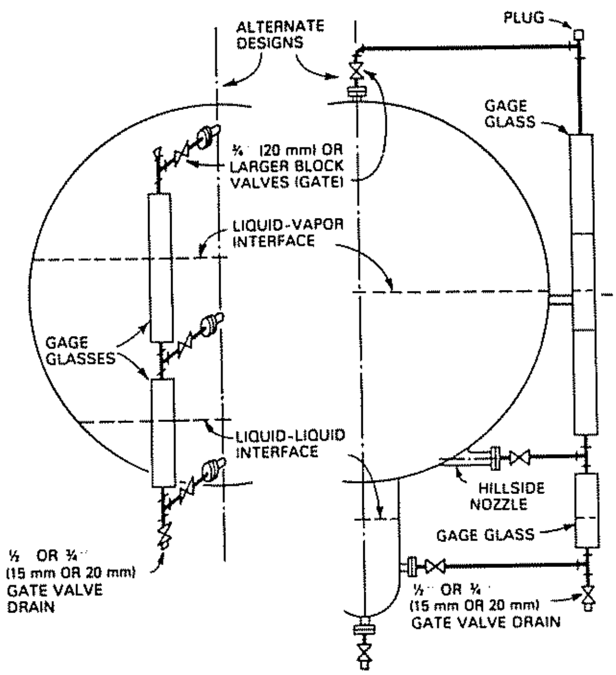


Figure 2-3—Gage Glass Mounting Arrangements for Horizontal Vessels and for Interface Measurement

grees presenting the opposite face and color to the observer. (See Figure 2-4.)

2.3.3.2 Precautions

Magnetic gages must be operated in areas free of forces or matter that will affect the magnetic fields. This would include items such as steel support straps, heater wires, and steam tracing tubing.

2.3.4 HYDROSTATIC HEAD PRESSURE GAGES

2.3.4.1 Applications and Limitations

Level indication by this means is limited to tanks or vessels not under pressure. The height of a liquid above a pressure gage can be determined from the pressure gage reading (hydrostatic head) provided the density of the liquid is known. However, where specific gravity changes are large, this type of level indicator is highly inaccurate if read under one condition of calibration.

2.3.4.2 Installation

Gages used for reading head pressure are standard pressure instruments of relatively low range and should be installed in accordance with the recommendations outlined in API RP 550, Part I, Section 4 — Pressure. Pressure gage arrangements are illustrated in Figure 2-5. View A in the figure shows the direct hydrostatic-head type, and View B shows an air-bubbler system with either remote or loca[l] indication.

2.3.4.3 Precaution

Great care must be taken to prevent dirt, scale, or sedi[-] ment from entering the lead lines or tubing, as hydrostati[c] head pressure gages ordinarily have small process connec[-] tions and are plugged easily.

2.3.5 DIFFERENTIAL PRESSURE LEVEL INDICATORS

2.3.5.1 Differential pressure level instruments generall[y] are used as transmitters and seldom as level indicator[s] alone. A transmitter with an indicator on the output signa[l] may serve to indicate level.

2.3.5.2 Certain high-displacement-type differential pres[-] sure instruments (see 2.4.2) are furnished with integra[l] indicators and can be used to indicate level.

2.4 Level Transmitters

Transmitters include pneumatic and electrical outpu[t] systems that use a wide variety of measurement principles including displacement, differential pressure, hydrostati[c] head, nuclear, ultrasonic, and capacitance.

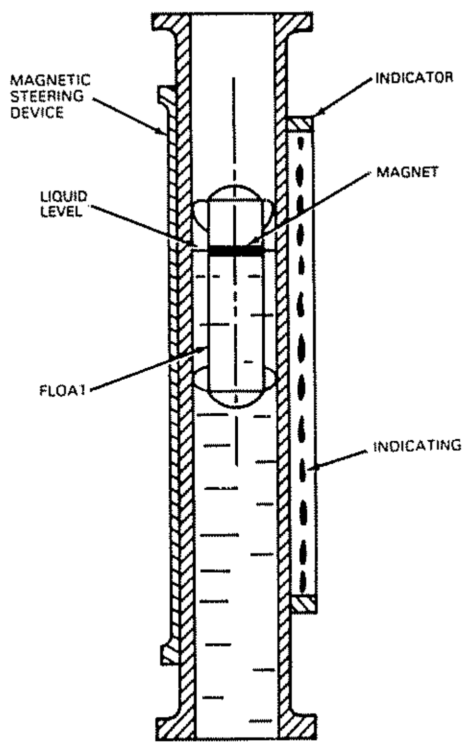


Figure 2-4—Typical Magnetic Gage

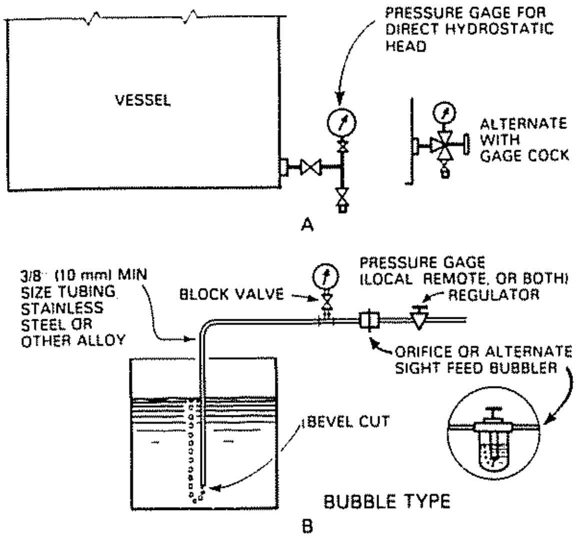


Figure 2-5—Hydrostatic Head Pressure Gage Arrangements

In all cases, the sensing device is installed in accordance with the practices outlined in the following paragraphs, and the transmission of the signal is accomplished as described in API RP 550, Part I, Section 7—Transmission Systems.

Transmitters or transducers for electronic instruments should not be located too close to hot lines, vessels, or other equipment. Locations where ambient temperatures exceed the manufacturer's specified limit should be avoided since they are likely to result in calibration difficulties and rapid deterioration of electronic components. Susceptibility of mechanical or electronic components to vibration should be ascertained and, where necessary, adjustments should be made in the mounting.

Because of the speed of response of electronic differential transmitters, caution should be exercised where level surges may be encountered. Such transmitters should be provided with damping.

2.4.1 DISPLACEMENT TRANSMITTERS

Displacement transmitters may be either blind or of the local indicating type. For blind transmitters, a receiver-type indicator on the output signal may be provided for local indication. Some pneumatic units are equipped with dual pilots, one with a fixed band for level transmission and the other for local level control.

2.4.1.1 Applications

Because the displacer itself has relatively little motion, it should be used with caution. For example, highly viscous material can cling to the displacer and affect its calibration. When a displacement transmitter is used in such service, a liquid purge or heat tracing should be considered.

Caution also should be used in the application of displacement transmitters to services where hydraulic resonance[3] may occur or where boiling liquid may cause violent agitation of the liquid surface. In these cases a differential-pressure type instrument can be used to advantage since (a) its output can be damped and (b) a seal liquid can be used to avoid boiling in the external legs.

Displacement transmitters sometimes are used for vacuum service or service with volatile liquids. If a differential-pressure type level instrument is used, a suitable seal liquid or purge should be used in both legs.

Displacement transmitters in temperature services below 0 F (−18 C) or above approximately 400 F (200 C) should be provided with a means to isolate the transmitter mechanism from the process temperature to prevent malfunction.

2.4.1.2 Mounting of External Cage Displacement Transmitters on Vessels

For external cage displacement transmitter installations, connections to vessels should be made by means of nozzles, block valves, and pipe fittings selected for the service.

Transmitter and controller installations should be provided with gage glasses in parallel as shown in Figures 2-6, 2-7, and 2-8. However, it may be advantageous to have a separate set of taps on the vessel for independent indication of level.

2.4.1.3 Connections to Vessels

In most process applications, level transmitters and controllers should have 1½-inch (40-millimeter) or 2-inch (50-millimeter) flanged connections. When screwed or socket-weld connections are permitted, the nozzles and piping may be 1½ inches (40 millimeters) in size with unions placed as shown in Figure 2-6. Drain gate valves ½ inch (12 millimeters) or ¾ inch (20 millimeters) in size always should be provided; and, if a vent or vents are required or desired, they should be gate valves ½ inch (12 millimeters) or ¾ inch (20 millimeters) in size and installed as indicated in Figure 2-6.

2.4.1.4 Installation of External Cage Displacement Unit and Standpipe

For long level ranges or where it is desirable to minimize vessel connections, a standpipe and overlapping gage glasses can be used as shown in Figures 2-7 and 2-8. The standpipe, usually of 2-inch (50-millimeter) or 3-inch (75-millimeter) pipe, serves as a mechanical support for the

[3] F. G. Shinskey, *Process Control Systems*, "Hydraulic Resonance," McGraw-Hill Book Co., New York, pp. 71-74, 1967.

instruments and as a surge chamber to prevent turbulence or foam from interfering with the operation of the transmitter. On horizontal vessels when standpipes are used with long-level range or when multiple instruments of considerable weight are used, it is often necessary to provide additional support. Also, the arrangement in Figure 2-8 permits direct calibration of a transmitter or controller with the vessel either in or out of service. This can be done by manipulating the block, drain, and vent valves in such a way as to run the level of the fluid up and down in the gage glass and transmitter in parallel. In cases where levels of considerable range are to be transmitted, it may be preferable to use a differential pressure transmitter (see 2.4.2).

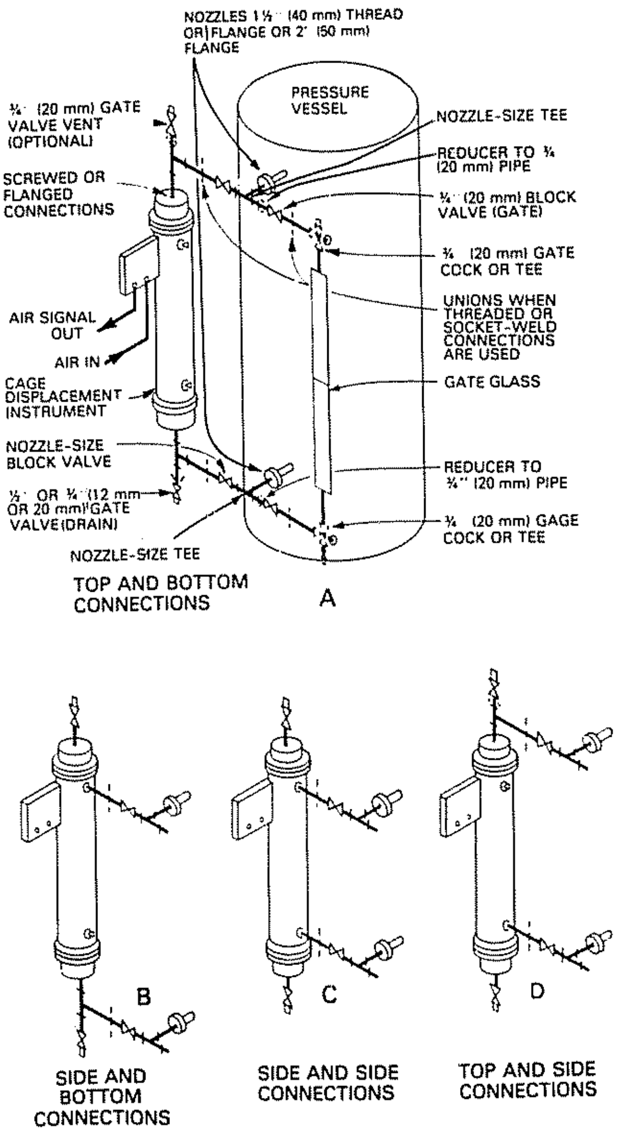
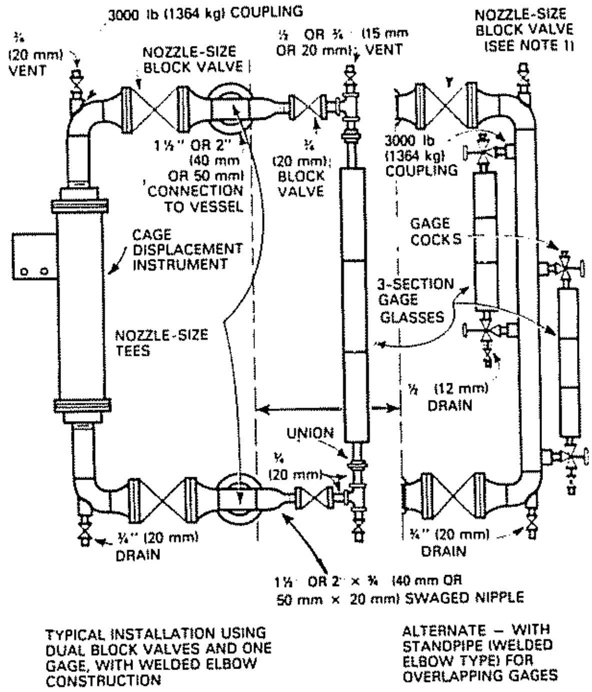


Figure 2-6—External Cage Displacement Instrument With Parallel Gage Glass



NOTES:
1. Some companies omit the block valve at the nozzle in this type of assembly. If the block valve is omitted a gage cock alone should not be used.
2. Controller may be piped with side and bottom, side and side, or top and side connections as shown in Figure 2—6.
3. Nozzle spacing on the vessel is critical on close-coupled installations, especially where side and side connections are used because of differential expansion of vessel and controller. Double or reverse elbow connections are sometimes used on the upper side connection to minimize trouble from this source.

Figure 2-7—External Cage Displacement Controller With Parallel Gage or Standpipe

2.4.1.5 Purging

In some installations (for example on crude-oil unit steam strippers where condensing steam can drip into hot oil in the displacer cage), it is sometimes necessary to purge the top of the displacer cage with gas. Purging installations are described in API RP 550, Part I, Section 8—Seals, Purges, and Winterizing.

2.4.1.6 Internal Displacers

Occasionally, the displacer may be mounted inside the vessel rather than in an outside cage. For example, when it is desirable to avoid steam tracing, the vessel nozzle and the head casting of the instrument must be provided with mating flanges of the type and specification required by the service. Generally, it is preferable to use steam-traced external displacers where possible. Internal displacers should be avoided particularly on vessels that cannot be isolated without shutting down part of the plant.

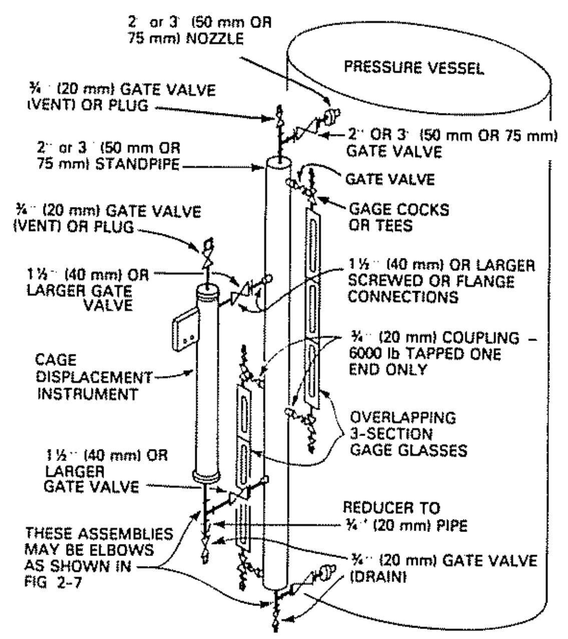
Ample clearance must be provided for removal of the displacer and rod. When a side mounting is required, provision should be made for access to the displacer—for example, a manhole.

2.4.1.7 Internal Displacer Guides

In many internal displacer installations, guides are required. A stilling well for side-mounted displacers (see Figure 2-9) usually is provided for this purpose, although rod or ring guides sometimes are used. Ring guides are particularly suitable for emulsion service.

2.4.1.8 Signal Transmission

Where the signal is transmitted to a remote controller or panel-mounted instrument, the transmission should be accomplished as outlined in API RP 550, Part I, Section 7—Transmission Systems. When the displacement instrument mounted in any of the foregoing ways is of the electrical type, as for alarms or protective devices, it should be



NOTE: Instrument may be piped with side and bottom or side and side connections as shown in Figure 2—6.

Figure 2-8—Standpipe With External Cage Displacement Instrument and Multiple Sight Gages

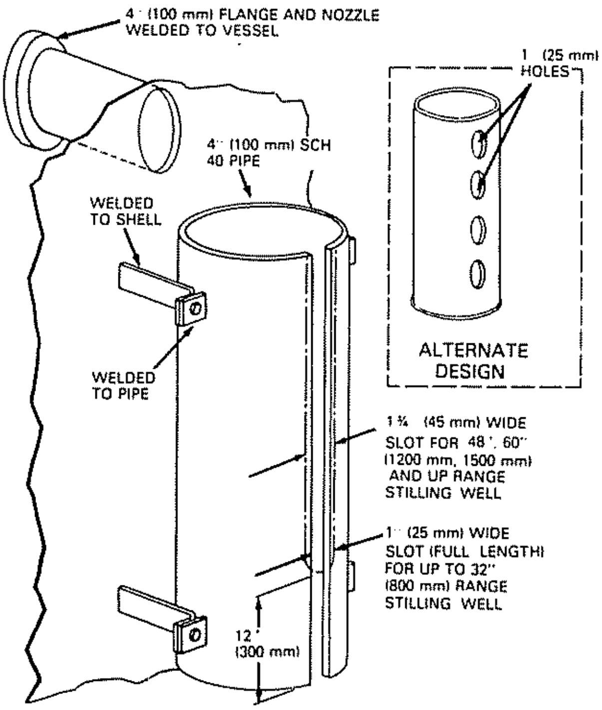


Figure 2-9—Typical Stilling Well

piped as described in this section. The electrical wiring should conform to the electrical code applicable (see also API RP 550, Part I, Section 13 — Alarms and Protective Devices).

2.4.2 DIFFERENTIAL PRESSURE TRANSMITTERS

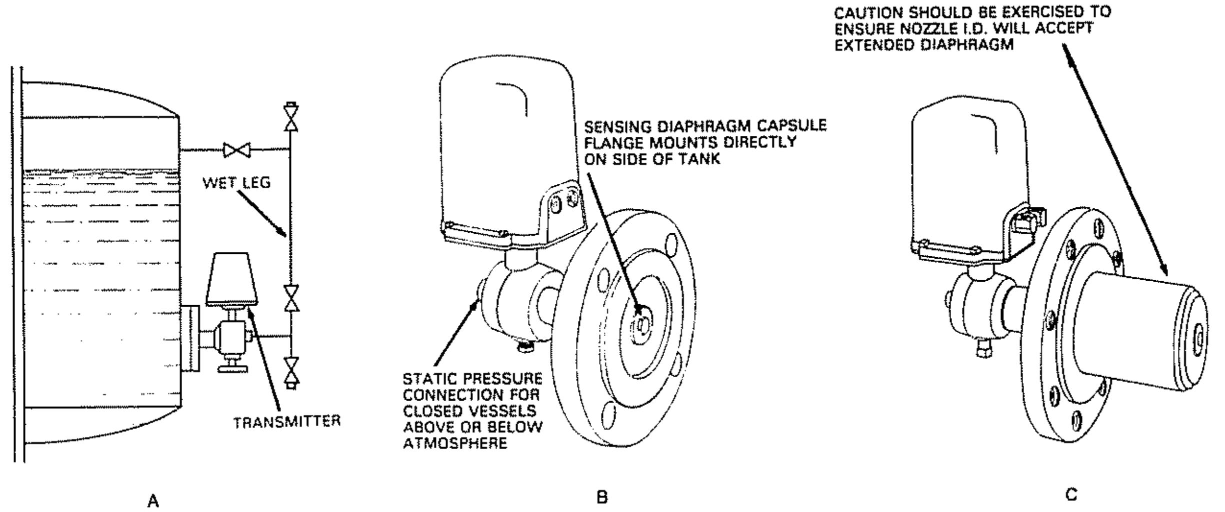
There are two general types of differential pressure transmitters; low displacement (diaphragm type) and high displacement (bellows type). When using external seals the bellows type requires the use of seal pots to maintain a constant external head and to ensure highest accuracy. (See RP 550, Part I, Section 8 — Seals, Purges, and Winterizing.)

Differential pressure transmitters have faster response characteristics than external cage displacement transmitters and require less range for stable control.[4] The different requirements are described further in 2.4.2.1 and 2.4.2.2.

2.4.2.1 Low-Displacement-Type Transmitters

a. Applications of low-displacement transmitters include remote control and remote indicating or recording of liquid level. This type of transmitter (usually the blind type)

[4] Shinskey, *Process Control Systems*, pp 71-74.



A—Typical Tank and Transmitter Installation
B—Liquid Level Transmitter
C—Liquid Level Transmitter with Extended Diaphragm

NOTE: Compensation to balance out initial hydrostatic head in wet leg is available

Figure 2-11—Flange-Type Differential Level Transmitter

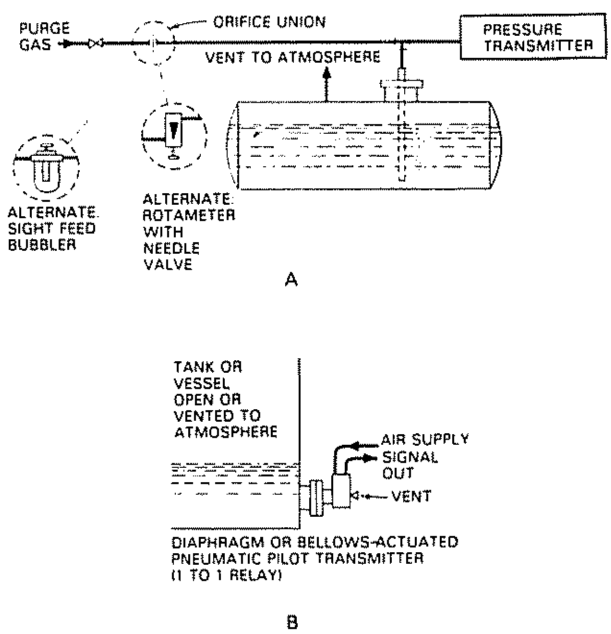


Figure 2-12—Hydrostatic Head Level Transmitters

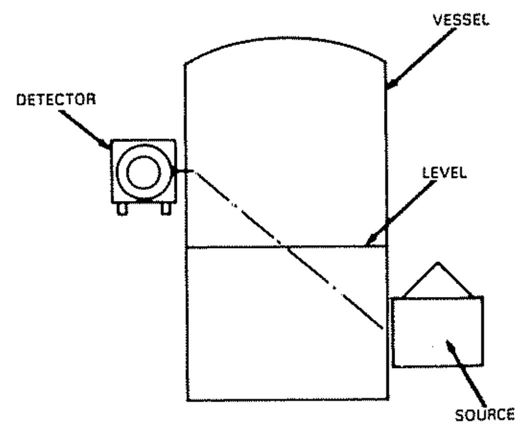


Figure 2-13—Typical Arrangement of Nuclear Level Transmitter

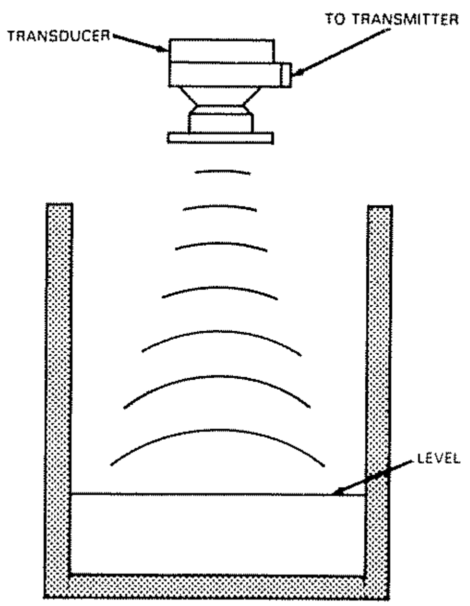


Figure 2-14—Top Mounted Ultrasonic-Type Level Transmitter

2.4.5.1 Operation

A sound transmitter (transducer) converts an electrical pulse to sound waves which reflect off the level surface being measured. The reflected signal is detected by either the same or another transducer.

Since the speed of sound through the medium above the level surface can be determined, round trip time from signal transmission to reception can be measured and is proportional to level.

2.4.5.2 Installation

Units should be installed in areas without strong electrical fields (motors, relays, electric generators, and so forth).

2.4.5.3 Precautions

Application parameters must be reviewed carefully to ensure correct use of ultrasonic devices. Factors such as process pressure and temperature variations, relative humidity, and varying concentrations of gases and vapors will affect sound velocity. Compensation for these variables is available.

2.4.6 CAPACITANCE-TYPE LEVEL TRANSMITTERS

Capacitance transmitters measure the changing electrical capacitance that occurs in the device as the level in the vessel being measured varies. See Figure 2-15.

2.4.6.1 Operation

A capacitor consists of two conductive plates separated by an insulator. Its capacitance is a function of the area of the plates, the spacing between them, and the dielectric constant of the insulator.

The capacitance level transmitter consists of a vertical probe that is inserted into the vessel in which the level is being measured. The probe may either be plain or sheathed with an insulating material and serves as one of the plates of the capacitor.

If the vessel is an electrical conductor and the material being measured is an insulator, a plain probe normally is used. In this case, the vessel serves as the other plate. Since the material being measured has a different dielectric constant than the air, vapor, or gas being displaced, the electrical capacitance between the probe and tank varies with level.

If the material being measured is an electrical conductor, an insulated probe is used—the sheath serving as the dielectric and the material measured replacing the tank as the other plate. In this case, the size of the capacitor plate and therefore its capacity varies with level.

2.4.6.2 Installation

The probe must be vertical and must not contact vessel wall or internals. Applications with nonconductive container walls and nonconductive medium may require a counter-electrode made from any kind of conductive material installed outside on the vessel wall.

In applications requiring an insulated probe, use care during installation to prevent accidental punctures of the insulating sheath.

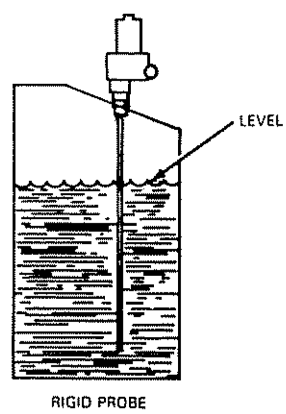


Figure 2-15—Capacitance-Type Level Transmitter

2.5 Locally Mounted Controllers

Locally mounted controllers used on all pressure vessels include the displacement, caged ball-float, internal ball-float, and differential-pressure types.

2.5.1 DISPLACEMENT CONTROLLERS

Recommended practices for the installation of displacement controllers are the same as for equivalent types of transmitters outlined in 2.4.1 "Dual pilot" displacement instruments provide local control as well as transmission when operated from a single displacer

2.5.2 CAGED BALL-FLOAT CONTROLLERS

2.5.2.1 Pneumatic and Electric Types

Pneumatic and electric controllers most generally are used in clean services for the direct operation of valves or electrical switches for alarms or pump motor controls. Where they are installed directly on vessels, connections should be made as described in 2.4.1 for the installation of displacement transmitters.

2.5.2.2 Mechanical Types

Mechanical controllers most generally are used in water service and consist of a mechanically actuated valve connected by a shaft or lever linkage to either an external caged float or an internal float. Installation of the float mechanism is the same as that for a pneumatic or electric ball-float instrument. Care must be taken to ensure that the action of the float is not restricted and that it is protected from turbulence. Furthermore, the valve and the piping must be installed and supported so that there is no strain on the valve or packing gland and no interference with linkages or levers that might prevent full travel of the float and valve.

2.5.3 INTERNAL BALL-FLOAT CONTROLLERS

2.5.3.1 Application

This type of instrument sometimes is used for asphaltic or waxy fluids, for coking service, or where the liquid contains particles or materials that tend to settle out and that would eventually block the float action in an external cage-type instrument. On severe coking applications, it may be desirable to use a steam or flushing-oil purge to keep the shaft free and the packing in suitable condition. In such applications, it is preferable to use dip-tube, purge-type, or differential-pressure-type level transmitters and controllers where possible.

2.5.3.2 Installation

Where the float will be subjected to turbulence within the vessel, shielding, guiding, or other provision should be made to eliminate the effects of turbulence on the float Pneumatic piping or electrical wiring to such instruments should be in accordance with the recommended practices for transmission as outlined in API RP 550, Part I, Section 7—Transmission Systems.

2.5.3.3 Supplemental Indicator

In severe services, as noted in 2.5.3.2, it is recommended that the controller be supplemented by another type of instrument (for example, differential pressure or other special type).

2.5.4 DIFFERENTIAL PRESSURE CONTROLLERS

2.5.4.1 Application

This type instrument may be in the form of a controller integrally mounted on a high-displacement-type differential pressure unit. However, the most common use of differential pressure instruments in level control is to use a differential pressure transmitter with a separately mounted receiver controller.

2.5.4.2 Installation

The installation is basically the same as for transmitters (see 2.4.2.1 and 2.4.2.2).

2.6 Remote or Panel-Mounted Receivers

Receiver level instruments actuated by transmitted signals are often desired on control panels or other remote locations. These receivers may be either electronic or pneumatic. Remote receiver level instruments are normally indicating controllers or indicators only, although recorders are sometimes used for special applications.

2.6.1 INSTALLATION

Recommended practices for the installation of remote or panel-mounted receivers may be found in API RP 550, Part I, Section 5—Automatic Controllers, Section 7—Transmission Systems, and Section 12—Control Centers. Design of the installation should be such that a high level causes the pointer or pen to move upscale or toward the outside of round charts. (Instruments that read in the reverse of normal are likely to cause confusion and be misread, particularly during upset conditions when it is most important that they be read easily, quickly, and correctly; therefore, they should not be used.)

2.6.2 RANGE

The recommended scale or chart range for level instruments is 0 to 100 linear, representing a percentage of maximum.

2.6.3 SIGNAL TRANSMISSION

Installation practices are discussed in API RP 550, Part I, Section 7—Transmission Systems and Section 13—Alarms and Protective Devices.

2.7 Level Switches

Basic instruments for initiating high-level or low-level alarm signals are, with the possible exception of the float size, the same as those discussed in 2.4 and 2.5. Other types (for example, pressure switches at the receiver in pneumatic transmission systems, current or voltage switches in electronic transmission systems, hydrostatic-head-pressure-actuated switches on nonpressurized tanks, and differential-pressure-actuated switches on pressurized vessels) sometimes are used. For a detailed discussion of alarms and protective devices, see API RP 550, Part I, Section 13—Alarms and Protective Devices.

2.7.1 INSTALLATION OF FLOAT SWITCHES

The installation of float switches is the same as for the transmitters covered in 2.4.1. A typical installation of high-level and low-level alarm switches with a parallel gage glass is shown in Figure 2-16. Level switches used as protective devices should have separate connections to the vessel, independent of other instruments.

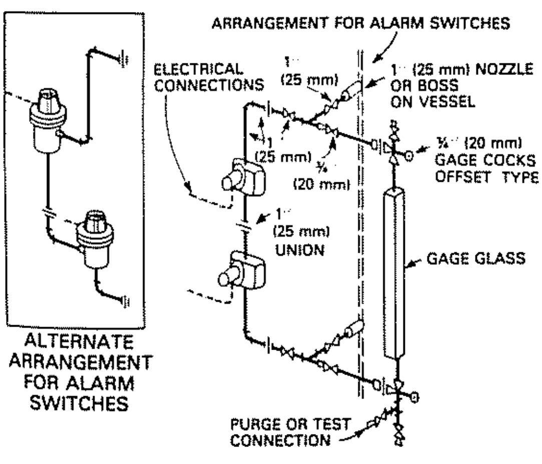


Figure 2-16—Arrangement of High- and Low-Level Alarm Switches With Parallel Gage Glass

2.7.2 INSTALLATION OF OTHER SWITCHES

Pressure switches in pneumatic transmission circuits normally are installed with block valves and often with a plugged test tee. A sensitive pressure-actuated switch or differential-pressure-actuated switch mounted directly on a tank or vessel to signal high- or low-hydrostatic head should be located at a point not subject to blocking by sediment.

2.8 Tank Gaging

2.8.1 FLOAT-AND-CABLE (AUTOMATIC) TANK GAGES

2.8.1.1 General

Float-and-cable tank gages are the most common means of indirect tank level indication. These gages are used primarily on large storage tanks where high accuracy—typically ± ⅛ inch (± 3 millimeters) —is required. Gage boards (targets) are sometimes used for readout on small tanks or other noncritical applications.

These gages are sometimes installed by the tank manufacturer and always should be installed in strict accordance with the gage manufacturer's recommendations and, where appropriate, governmental weights and measures regulations.

2.8.1.2 Reliability

The reliability and continuing accuracy of a tank gage installation is dependent directly upon the condition of the tank on which it is installed. Old and incorrectly erected tanks—particularly those with unstable bottoms, shells, or roofs—will introduce appreciable amounts of error and variation that no gage, however carefully installed, can correct. Generally, the following practices and precautions apply to all types of tank gage installations.

2.8.1.3 Location

The entry point of automatic tank gages should be located in close proximity to a manway, yet sufficiently distant from mechanical agitation and the suction and filling lines to minimize the disturbing effects of eddies, currents, or turbulence arising from these sources.

The entry point of the automatic gage tape should be located where it will eliminate most effectively errors caused by roof movement.

2.8.1.4 Reading Devices

Ground-level or tank-top reading devices should be at a convenient height from the ground or the gaging platform to ensure easy and correct readings.

2.8.1.5 Stilling Wells

Where turbulence caused by high emptying and filling rates or by mechanical agitators can affect the float or sensing element, it is usually necessary to enclose the measuring element in a stilling well. Where high-viscosity materials are encountered, it may be desirable to provide heating for the stilling well. Liquefied petroleum gas (LPG) or other boiling surface services usually require a stilling well.

2.8.1.6 Mounting

All gages must be mounted securely to the tank shell with a sufficient number of brackets properly attached and adequately spaced to hold the gage rigidly in place and in proper alignment at all points. The top horizontal tape conduit (extension arm) must be braced by support members from the top angle only.

2.8.1.7 Floating-Roof Tank Installations

The tape can be attached to a float in a gage well in the floating roof. If tape is exposed, wind drift can cause errors. There are errors involved in connecting the tape to the floating roof, and this method is not recommended.

2.8.1.8 Float Guide Wires

Float guide wires should be installed plumb, properly centered, free of kinks or twists, and pulled taut under proper spring tension.

2.8.1.9 Accuracy

Where maximum accuracy is required, a tank gaging system should provide compensation for the variation of float immersion due to liquid specific gravity. High accuracy also may require powered floats to reduce immersion and hysteresis errors.

2.8.1.10 Remote-Reading Gaging Systems

Tank gages often are tied into a multiple tank remote readout. There are a number of different proprietary systems available from various makers. These transmission systems usually are designed to minimize wire costs, and they usually include temperature transmission.

2.8.1.11 Tank Monitoring Computers

Process computers and microprocessor-based readout systems monitor tank fields. To provide an adequate scan cycle, a computerized tank gaging system requires a rapid response from the tank gage transmitter.

2.8.1.12 Level Alarms

High- or low-level alarms can be provided in four ways:

1. Separate float-type level switches mounted outside the tank.
2. Position detectors sensing the floating roof.
3. Electrical switches mounted in the gage head.
4. Continuous scanning of tank levels with automatic comparison with an alarm setting.

The first three ways require extra wiring from the tank to the control center. The first and second way will provide an alarm even if the tank gage float or the gaging system fails.

2.8.1.13 Piping

Connecting pipe between the tank and the gage head should be 1½ inches (40 millimeters) minimum. Pipe and sheaves should be of galvanized iron or steel, stainless steel, aluminum, or another corrosion-resistant material.

2.8.1.14 Seals

A gastight liquid seal should be installed in the connecting piping on tanks that are gas blanketed. A seal also should be used on tanks in which vapors could enter the gage piping and condense.

2.8.1.15 Corrosion Protection

When measuring corrosive liquids, it may be necessary to protect the gage head or the transmitter from internal corrosion. This can be done by internal plastic coatings, oil filling, electrical heating, or by providing a seal leg in the connecting pipe.

2.8.2 OTHER TANK GAGING METHODS

A number of tank gages are now available which do not use floats and cables. These gages may not provide the high accuracy normally required.

Some of the practices mentioned are outlined in API Standard 2545, *Method of Gaging Petroleum and Petroleum Products*.[5] It covers installing and using automatic tank gages and should be referred to for additional information.

2.9 Accessories

2.9.1 SEALS AND PURGES

Occasionally it is necessary to use seal pots or purges in connection with liquid level instruments. The application of seals and purges is discussed in API RP 550, Part I, Section 8—Seals, Purges, and Winterizing.

2.9.2 GAGE GLASS ILLUMINATORS

Where it is necessary to back-illuminate transparent gage glasses, it is recommended that light fittings made for the

[5] In the process of being revised for publication as API *Manual of Petroleum Measurement Standards*, Chapter 3—Tank Gaging.

purpose and suitable for the service conditions be purchased and installed in accordance with applicable codes and the manufacturer's recommendations. Generally, it is preferable to use back illumination on all transparent glasses.

2.9.3 WEATHER PROTECTION

2.9.3.1 General

All locally mounted instruments and lead lines handling water or process fluids that may freeze, form hydrates, or become excessively viscous in cold weather should be heated and insulated or sealed with a suitable nonfreezing fluid. Also, transmitters and locally mounted instruments should be suitably protected to prevent improper instrument performance or excessive maintenance caused by the effects of weather. Frost shields should be used on transparent and reflex gage glasses if the operating temperatures are below 32 F (0 C). Heated gage glasses and jacketed gage cocks are available from some manufacturers, but generally external heating is recommended.

2.9.3.2 Steam Tracing

Steam tracing commonly is used for protection of both instruments and lead lines. A correctly installed steam-tracing system must have an individual shutoff valve and a trap on each individual tracer. Where the process fluid in the lines or instruments being steam traced has a boiling point lower than the steam temperature, care must be taken to separate or insulate the steam tracer to prevent the possibility of causing the fluid to boil (see API RP 550, Part I, Section 8—Seals, Purges, and Winterizing).

2.9.3.3 Other Methods of Heating

In some climates steam condensate is satisfactorily used for tracing. Electrical tracing sometimes is used to heat gage glasses, instrument cases, and lead lines.

2.9.3.4 Winterizing

For complete coverage of steam-tracing practices, seals and purges, and winterizing in general, refer to API RP 550, Part I, Section 8—Seals, Purges, and Winterizing.