Manual on Installation of Refinery Instruments and Control Systems

Part I — Process Instrumentation and Control
Section 4 — Pressure

API RECOMMENDED PRACTICE 550
FOURTH EDITION, FEBRUARY 1980

Up to date as at June 1984

American Petroleum Institute
2101 L Street, Northwest
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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, 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 of the 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 to accomplish efficiently any cross-referencing that is required for a better understanding of the subject matter.

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Part I — Process Instrumentation and Control

SECTION 4 — PRESSURE

4.1 Scope

This section discusses recommended practices for the installation of the more commonly used instruments and devices for indicating, recording, and controlling pressure and differential pressure normally encountered in petroleum refinery processes. The types of instruments covered are process indicating pressure gages (see 4.3) and pressure transmitters, switches, and locally mounted controllers and recorders (see 4.4).

4.2 General

Certain general procedures, practices, and precautions apply to all instruments discussed. Where applicable, the material discussed in 4.2.1 through 4.2.9 should be considered a part of the text of the subsequent discussions.

4.2.1 APPLICATION PRACTICE

Hydrocarbons or other process fluids that may be hazardous or otherwise undesirable in the control room in the event of leakage should not be piped to any instruments located in a central control room. It is industry practice to transmit the pressures of such fluids either electrically or pneumatically to receiving instruments. It is also the practice to transmit the pressure of fluids for local installations where long piping or capillary systems would otherwise be required. Examples include instances where solids present in the process fluid could cause plugging or where differences in elevation could result in liquid head problems. Insulation and heating of long leads to prevent freezing also can be eliminated by transmission systems.

4.2.2 ACCESSIBILITY

All locally mounted pressure instruments should be readily accessible from grade, platform, fixed walkway, or fixed ladder. Some users employ a rolling platform where free access is available to the space below the instruments.

4.2.3 VISIBILITY

In applications where pressure can be manually controlled at a control valve station, some means of pressure indication should be clearly visible from the valve location to permit manual control where necessary. Such pressure indication is not necessary if the control system cannot be manually operated from the control valve station.

4.2.4 VIBRATION

Most pressure instruments are susceptible to damage, abnormal wear, or malfunction if mounted in locations where they are subject to vibration. If any part of the pressure system or equipment is subject to vibration, the instrument should be mounted on a vibration-free remote support. Coiled tubing, armored hose, or a capillary system should be provided between the pressure source and the instrument

4.2.5 PULSATION

Pressure instruments that measure pulsating pressures of reciprocating pumps and reciprocating compressors should be equipped with pulsation dampeners to prevent premature failure of the movements or the pressure elements. Needle valves, floating pins, or porous metal devices often are used for this purpose (see Figure 4-1). Indicating pressure gages with liquid-filled cases also should be considered for pulsating service applications.

4.2.6 PURGING AND SEALING

4.2.6.1 When viscous liquids or corrosive process fluid pressures are measured, or if there is a possibility of plugging where solids exist, an instrument may be sealed, purged, or protected by a diaphragm seal or protector (see Figure 4-1). The diaphragm seal unit should have a flushing

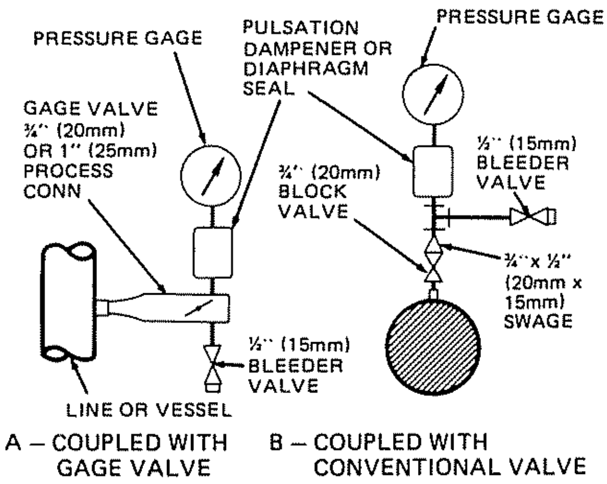


Figure 4-1 — Piping for Pressure Gages in Pulsating, Corrosive, Slurry, or Freezing Fluid Service

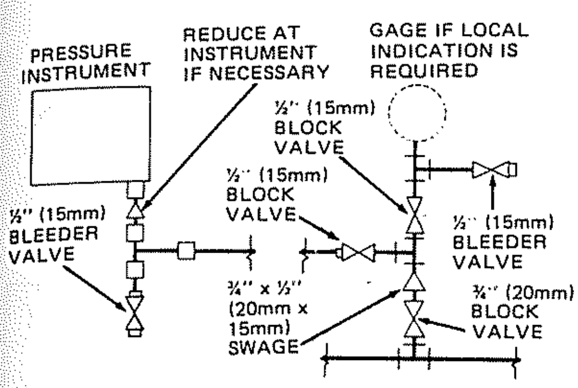


Figure 4-2 — Piping Manifold for Pressure Instruments From a Common Process Connection

connection and wetted parts of a suitable material to resist corrosion.

4.2.6.2 Diaphragm seals with or without capillary leads are becoming more widely accepted because of the availability of suitable filling fluids. Nonflammability, low vapor pressure, and low coefficient of expansion are characteristics of the fluids used. To minimize heat tracing, some prefer diaphragm-sealed pressure gages on all fluids that freeze at ambient temperatures. Manufacturers can supply instruments complete with the seal and capillary assembled. Care should be taken to isolate the capillary from any variable heat source such as heat tracing or process piping. Required accuracy should be investigated for filled system units. Errors increase as the range decreases.

For pressure instruments in fluidized solids service, a purge commonly is used. The purge medium is introduced through a restriction orifice, needle valve, drilled gate valve, or rotameter. The purge medium must not introduce a hazard during normal, abnormal, or startup operations; contaminate the process; or affect product quality. Anytime the user elects to purge an instrument, the consequences of a purge failure should be evaluated carefully. For further information on seals, purge quantities, and purge point location and methods, see API RP 550, Part I, Section 8 — Seals, Purges, and Winterizing.

4.2.7 PIPING

4.2.7.1 Size and Design

Process connections to the instruments should be furnished and installed in accordance with the piping and material specifications. When pipe is selected, ½-inch (15-millimeter) Schedule 80 pipe and fittings should be used. When tubing is selected, ½-inch (12-millimeter) or ⅜-inch (10-millimeter) OD tubing with a 0.035-inch (0.89-millimeter) minimum wall thickness is generally acceptable. Stainless steel or alloy tubing sometimes is used where carbon steel would otherwise be acceptable to reduce or eliminate corrosion as well as to eliminate the expense of cleaning and painting carbon steel

For instruments that have connections smaller than a ½-inch (15-millimeter) pipe size, the line size should be reduced at the instrument. The first block valve at the process connection should be a process piping specification valve, normally a ¾-inch (20-millimeter) size and a minimum ½-inch (15-millimeter) size (see Figure 4-2). Some companies prefer to use extended body gate valves for small piping requirements in accordance with API Standard 606. Some users permit valves of the same rating but less rigid specification for secondary valving in the manifold. To avoid damage to the connected instrument, the instrument should be disconnected during hydrostatic testing.

4.2.7.2 Cleaning

All pipe should be deburred after cutting and blown clean of cuttings and other foreign material. This subject is usually covered by the process piping specification.

4.2.7.3 Short Connections

Usually the most satisfactory as well as the most economical installation of a pressure device is achieved by coupling it as close to the process connection as practicable, consistent with required accessibility and visibility (see Figure 4-3). This practice requires less material and heat tracing, eliminates vapor traps and liquid head problems, and reduces the possibility of leaks and plugging.

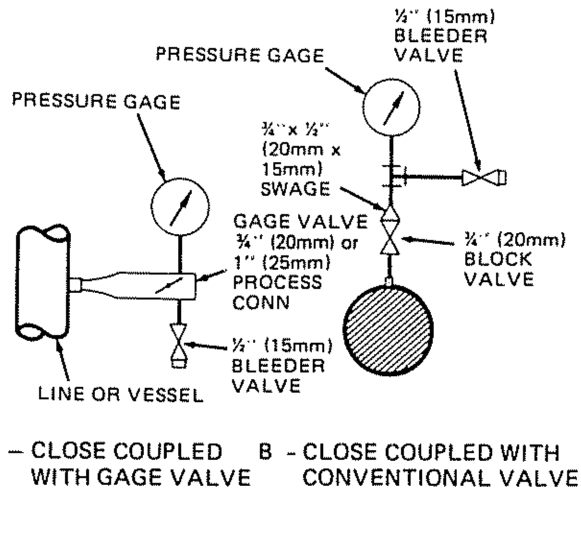


Figure 4-3 — Gages Supported by Piping

4.2.7.4 Long Connections

Where the process block valve is not readily accessible from the instrument location, an additional block valve should be installed at the instrument.

When several pressure-measuring devices are manifolded from one process pressure tap, good practice requires a separate block and bleed valve for each pressure instrument (see Figure 4-2).

4.2.7.5 Piping Flexibility

Instrument pressure piping should be installed and supported so that the forces developed from the expansion of hot piping or vessels cannot result in piping failure or strain on the instrument. High-pressure armored hose or coiled tubing can be used where a high degree of piping flexibility is required.

4.2.8 ENCLOSURES

Enclosures should be provided to protect locally mounted instruments from ambient conditions if the manufacturer's standard case is not adequate. The enclosures must not restrict bleed air from pneumatic instruments nor heat dissipation from electronic devices. Area classification may require special enclosures to meet the National Electrical Code (NFPA No. 70[1]) and other appropriate national or local code requirements.

4.2.9 ELEMENT AND SOCKET (WETTED) MATERIALS

Materials should be selected to withstand corrosion from the process fluid and environmental conditions. Direct pressure elements, such as bourdon tubes and bellows, are thin and afford minimum corrosion allowance. Type 316 stainless steel is the most commonly used material in corrosive service for elements, sockets, and other wetted parts. Bronze is commonly used for air, sweet water, and inert gases. Monel is a superior material for caustic and salt solutions where chloride stress corrosion might adversely affect stainless steel. Other materials are available for special situations, but a more usual choice in severely corrosive conditions is the use of a diaphragm seal of suitable material. (See 4.2.6.)

4.3 Process Indicating Pressure Gages

4.3.1 CONNECTIONS

Indicating bourdon tube pressure gages for flush mounting on local field instrument panels should be back connected. Surface-mounted local gages and field mounting gages should be bottom connected. The recommended connection size for mechanical strength is ½ inch (15 millimeters).

[1] National Fire Protection Association, 470 Atlantic Avenue, Boston, Mass 02210

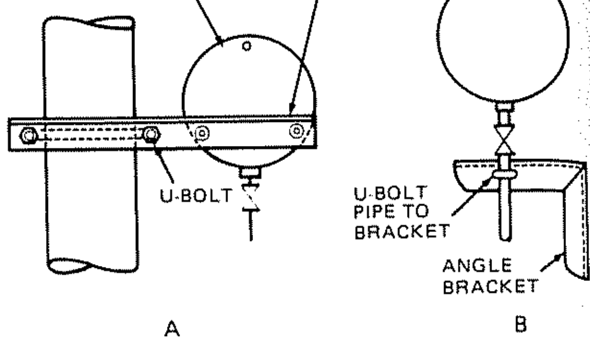


Figure 4-4 — Field-Mounted Gage Supports

4.3.2 SUPPORTS

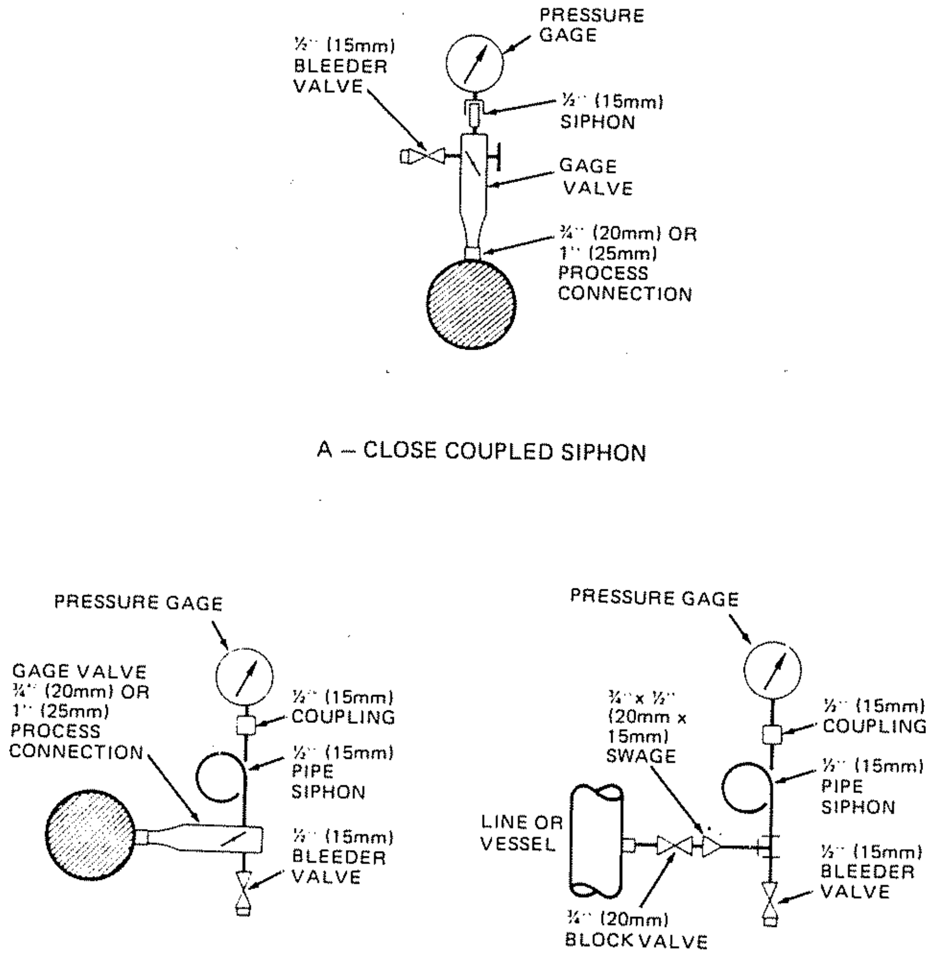
A gage may be supported by its piping if it is close-coupled to the process connection (see Figure 4-3). Where vibration is anticipated, good practice requires independent support (see 4.2.4, 4.2.7.5, and Figure 4-4).

4.3.3 SAFETY DEVICES

Every process pressure gage should be provided with a device, such as a disc insert or blowout back, designed to relieve excess case pressure. Such a device can prevent bursting of the glass or the case in the event of pressure element failure. Some users also require a solid front gage design for gages in high-pressure service. Gages are available with safety glass or plastic windows as an additional safeguard. Gage supports should be designed so that the blowout disc is not covered. Field gages should not be painted and insulation over heat tracing should not cover or restrict the disc or blowout back. Excess pressure cutouts, with or without velocity checks, are available for limiting overrange.

4.3.4 SIPHONS

Siphons or "pigtail" condensate seals should be provided for steam or other hot condensable vapors when the gage is mounted above the process connection, allowing condensate drainage to the process. Siphons protect the gage from thermal damage and errors due to temperature. Close-coupled siphons are available from most gage manufacturers. (See Figure 4-5.)



A – CLOSE COUPLED SIPHON

COUPLED WITH GAGE VALVE

COUPLED WITH CONVENTIONAL VALVE

B – PIGTAIL SIPHON

Figure 4-5 — Gages With Siphon Required in Hot Condensable Vapor Service

4.3.5 CASE MATERIAL AND SIZE

Pressure gage cases are made of stainless steel, aluminum, or plastic Plastic case gages should not be used in locations where temperature will deform the plastic Cases of 3½-inch (90-millimeter) and 4½-inch (115-millimeter) sizes are generally acceptable in process fluid service

4.4 Pressure Transmitters, Switches, and Locally Mounted Controllers and Recorders

4.4.1 MEASUREMENT TERMINOLOGY

When installing a pressure transmitting, controlling, or recording device, it is important to understand the terminology associated with pressure measurement Figure 4-6 contains illustrations of the use of range and span terminology In pressure applications, it is common practice to use suppressed ranges to achieve greater accuracy When selecting a pressure instrument, consult the manufacturer's literature to ensure that the device is capable of covering the desired measurement range The user also should ensure that the device selected will withstand pressure extremes encountered during process upsets, startup, and shutdown

4.4.2 CONNECTIONS

As discussed in 4.2.7.1, the process connection is generally ¾ inch (20 millimeters), with the first block valve conforming to process piping specifications The most

TYPICAL RANGES	NAME	RANGE	LOWER RANGE-VALUE	UPPER RANGE-VALUE	SPAN	SUPPLEMENTARY DATA
0 +100	–	0 to 100	0	+100	100	–
20 +100	SUPPRESSED ZERO RANGE	20 to 100	20	+100	80	SUPPRESSION RATIO = 0.25
−25 0 +100	ELEVATED ZERO RANGE	−25 to +100	−25	+100	125	–
−100 0	ELEVATED ZERO RANGE	−100 to 0	−100	0	100	–
−100 −20	ELEVATED ZERO RANGE	−100 to −20	−100	−20	80	–

Source: ISA Standard S51.1, *Process Instrumentation Terminology*, p. 26, 1976. Reprinted by permission of Instrument Society of America.

DEFINITION OF PRESSURES

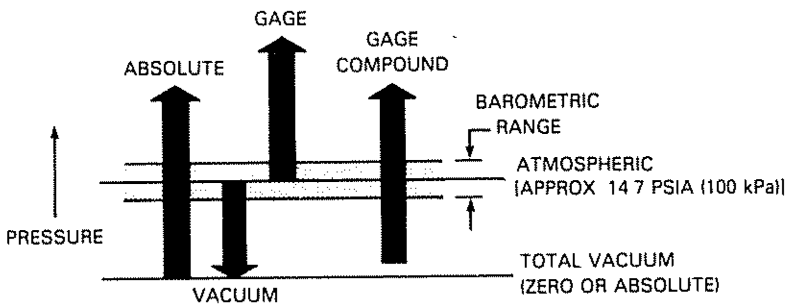


Figure 4-6 — Illustrations of the Use of Range and Span Terminology for Gage Pressure Instruments

common instrument connection size is ½ inch (15 millimeters).

For gas service, the process tap generally is located on the top of horizontal lines so that any liquids in the instrument piping will "self drain" back into the line. For liquid and steam service, the process tap generally is located on the side of the line so that any bubbles or noncondensable vapor in the instrument piping will "self vent" back into the line. Taps on the bottom of the line are not recommended because of the possible presence of sediment or scale. See Figure 4-7 for an illustration of tap location in horizontal lines. The pressure tap also may be located in vertical lines.

4.4.3 SUPPORTS

In general, instruments should be supported independent of the process connection. Some transmitters, however, are small enough and light enough to consider a direct mounting. In all cases, access for service must be considered.

Where independent support is necessary, pipe stands at grade and on platform structures commonly are used. Instruments that are to be accessible from a platform should be supported from the platform structural steel and not from the platform or handrails. Care should be taken to avoid imposing stresses on the instrument from piping or conduit (see API RP 550, Part I, Section 7—Transmission Systems).

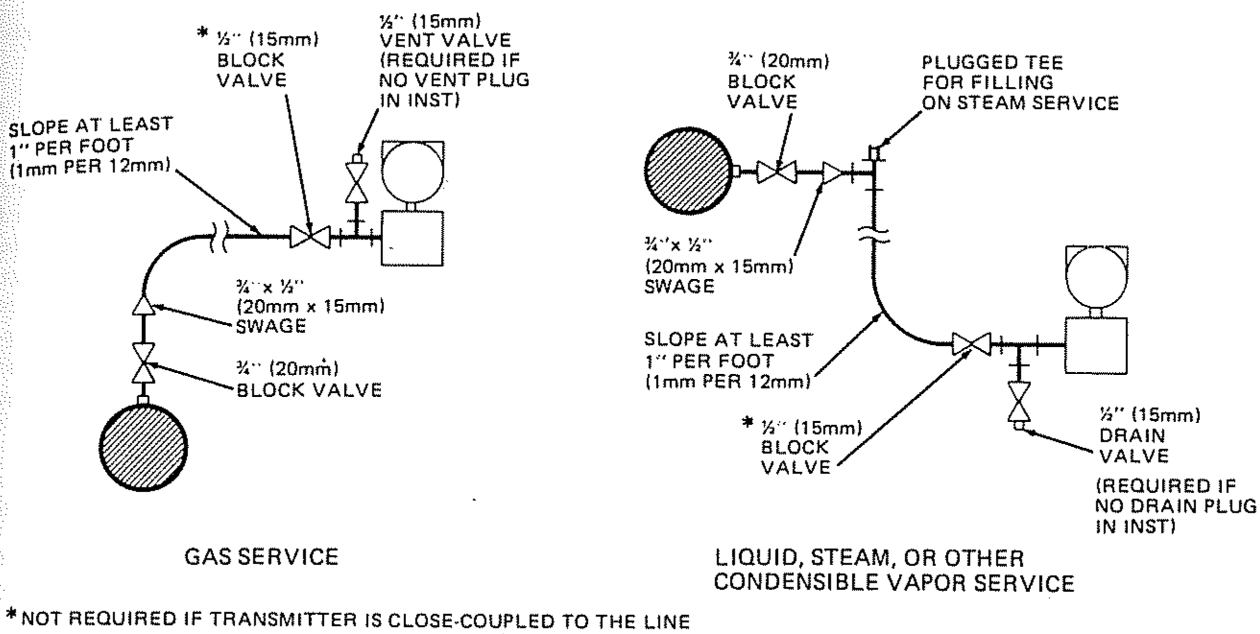


Figure 4-7 — Typical Installation of Pressure Transmitter for Gas, Liquid, and Steam Service

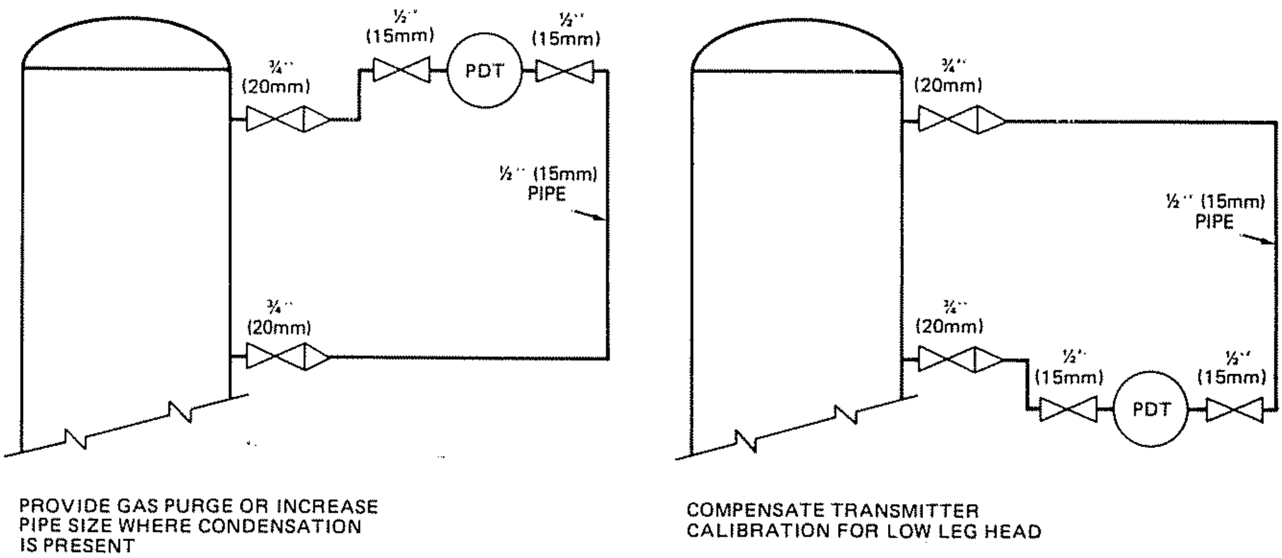


Figure 4-8 — Schematic for Measurement of Differential Pressure Across Reactor or Section of Tower

4.4.4 INSTALLATION CONSIDERATIONS

The installation of a pressure instrument requires the careful weighing of a variety of factors. It is of the utmost importance to know the physical characteristics and the operating conditions of the process fluid. The following are some guidelines. (See Figure 4-7.)

1. Make impulse piping as short as possible.
2. Instruments in liquid or condensable vapor service such as steam should be self-venting, (that is, mounted below the process connection with all lines sloping toward the instrument to avoid trapping gas in the instrument).
3. Gas service instruments should be self-draining (that is, mounted above the process connection with all lines sloping toward the process connection to avoid trapping liquids in the instrument).
4. The installation must protect the instrument from both ambient and process temperatures. If the process temperature itself is outside of the instrument's limits, the following measures can be used to ensure that the temperature at the instrument is within the manufacturer's specifications.
   a. Provide a sufficient length of uninsulated piping to lower (or raise) the temperature of the process fluid at the instrument.
   b. Purge the instrument. When purging, use piping of sufficient diameter to minimize friction effects. (See API RP 550, Part I, Section 8—Seals, Purges, and Winterizing.)
   c. Use a diaphragm seal and capillary to transmit pressure to the instrument.

4.4.5 LOCAL INDICATION

Where local indication is desired, and nonindicating transmitters (electronic and pneumatic), switches, and locally mounted pressure controls are used, they should be supplemented with direct-connected process pressure gages (see Figure 4-2) or output indicators, or both. Any pressure transmitter whose range does not include atmospheric pressure should be supplemented with a process pressure gage, even if the transmitter is equipped with an output indicator.

4.4.6 DIFFERENTIAL PRESSURE INSTRUMENTS

Differential pressure can be measured with an instrument of the same type used for flow measurement or an instrument specifically designed for differential pressure. If purging is necessary on low-differential services, special care should be taken to ensure that the purge rate does not cause erroneous readings (see API RP 550, Part I, Section 8—Seals, Purges, and Winterizing). See Figure 4-8 for an example. Low gage pressure can be measured with differential pressure instruments by leaving the low-pressure connection open to the atmosphere.