ENGINEERING STANDARD

FOR

LEVEL INSTRUMENTS

FIRST EDITION

FEBRUARY 2013

FOREWORD

The Iranian Petroleum Standards (IPS) reflect the views of the Iranian Ministry of Petroleum and are intended for use in the oil and gas production facilities, oil refineries, chemical and petrochemical plants, gas handling and processing installations and other such facilities.

IPS are based on internationally acceptable standards and include selections from the items stipulated in the referenced standards. They are also supplemented by additional requirements and/or modifications based on the experience acquired by the Iranian Petroleum Industry and the local market availability. The options which are not specified in the text of the standards are itemized in data sheet/s, so that, the user can select his appropriate preferences therein.

The IPS standards are therefore expected to be sufficiently flexible so that the users can adapt these standards to their requirements. However, they may not cover every requirement of each project. For such cases, an addendum to IPS Standard shall be prepared by the user which elaborates the particular requirements of the user. This addendum together with the relevant IPS shall form the job specification for the specific project or work.

The IPS is reviewed and up-dated approximately every five years. Each standards are subject to amendment or withdrawal, if required, thus the latest edition of IPS shall be applicable

The users of IPS are therefore requested to send their views and comments, including any addendum prepared for particular cases to the following address. These comments and recommendations will be reviewed by the relevant technical committee and in case of approval will be incorporated in the next revision of the standard.

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GENERAL DEFINITIONS

Throughout this Standard the following definitions shall apply.

COMPANY :

Refers to one of the related and/or affiliated companies of the Iranian Ministry of Petroleum such as National Iranian Oil Company, National Iranian Gas Company, National Petrochemical Company and National Iranian Oil Refinery And Distribution Company.

PURCHASER :

Means the “Company" where this standard is a part of direct purchaser order by the “Company”, and the “Contractor” where this Standard is a part of contract document.

VENDOR AND SUPPLIER:

Refers to firm or person who will supply and/or fabricate the equipment or material.

CONTRACTOR:

Refers to the persons, firm or company whose tender has been accepted by the company.

EXECUTOR :

Executor is the party which carries out all or part of construction and/or commissioning for the project.

INSPECTOR :

The Inspector referred to in this Standard is a person/persons or a body appointed in writing by the company for the inspection of fabrication and installation work.

SHALL:

Is used where a provision is mandatory.

SHOULD:

Is used where a provision is advisory only.

WILL:

Is normally used in connection with the action by the “Company” rather than by a contractor, supplier or vendor.

MAY:

Is used where a provision is completely discretionary.

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APPENDICES:

1. SCOPE

This Standard discusses recommended practices for design and engineering aspects of more commonly used instruments and devices for indicating, recording and controlling liquid and solid levels and liquid-liquid interface levels normally encountered in oil, gas, and petrochemical industries.

Note 1:

This standard specification is reviewed and updated by the relevant technical committee on Jan. 1999. The approved modifications by T.C. were sent to IPS users as amendment No. 1 by circular No. 45 on Jan. 1999. These modifications are included in the present issue of IPS.

Note 2:

This is a revised version of this standard, which is issued as revision (1)-2013. Revision (0)-1994 of the said standard specification is withdrawn.

2. REFERENCES

Throughout this Standard the following dated and undated standards/codes are referred to. These referenced documents shall, to the extent specified herein, form a part of this standard. For dated references, the edition cited applies. The applicability of changes in dated references that occur after the cited date shall be mutually agreed upon by the Company and the Vendor. For undated references, the latest edition of the referenced documents (including any supplements and amendments) applies.

API (AMERICAN PETROLEUM INSTITUTE)

RP 551	"Process Measurement Instrumentation Section 3 and Section 6"
MPMS Chapter 3	"Tank Gauging, Section 1A- Standard Practice for the Manual Gauging of Petroleum and Petroleum Products"
RP 2350	"Overfill Protection for Storage Tanks in Petroleum Facilities"

ISA (THE INTERNATIONAL SOCIETY OF AUTOMATION)

TR 20.00.01	"Specification Forms for Process Measurement and Control Instruments – (Part 1: General Considerations)"

IPS (IRANIAN PETROLEUM STANDARDS)

IPS-E-GN-100	"Engineering Standard for Units"
IPS-C-IN-140	"Construction and Installation Standard for Level Instruments"
IPS-M-IN-140	"Material and Quality Control Standard for Level Instruments"
IPS-M-IN-150	"Material and Quality Control Standard for Receiving Instruments"
IPS-E-IN-190	"Engineering Standard for Transmission Systems"
IPS-G-IN-210	"General Standard for Instrument Protection"
IPS-G-IN-260	"General Standard for Indicating Lights, Alarms and Protective Systems"
IPS-G-IN-300	"Tank Gauging Devices for Petroleum and Petroleum Products"

3. UNITS

This standard is based on international system of units (SI), as per IPS-E-GN-100 except otherwise specified.

4. GENERAL

4.1 Proper selection and application of level instruments depends on the following variables:

a) Type of vessel, fluid or material involved (that is, solids, granules, or liquids, liquid or liquid/foam interface).

b) Process conditions (that is, pressure, temperature, specific gravity, boiling point, viscosity, and pour point).

c) Nature of accomplishment (monitor, on-off or modulating control or alarm);

d) Electronic or pneumatic signal.

4.2 Types of Instruments Are Covered:

a) Locally mounted indicating gauges, including tubular gauge glasses, armored-type gauge glasses, magnetic-type gauges, hydrostatic head pressure gauges, and differential-pressure level indicators.

b) Level transmitters, including displacement, differential-pressure, hydrostatic-head, nuclear, ultrasonic, capacitance and radar types.

c) Locally mounted controllers, including displacement, ball-float, and differential-pressure types.

d) Remote or panel-mounted receivers.

e) Level switches.

f) Tank level gauges.

g) Accessories, including seals and purges, gauge glass illuminators, and weather protection.

4.3 Where only local indication of liquid level other than by means of level gauge glasses is required and instrument air supply or instrument electricity supply is not available, level indicators with magnetic coupling should be considered, (see 5.3).

4.4 For remote transmission or local control, displacer level instruments or differential-pressure level instruments should be applied, unless otherwise specified.

4.5 The differential pressure type level instruments should be considered for the following applications:

- High pressures services;
- Where the liquid is very viscous and/or highly corrosive;
- Where flashing and/or vibration may occur;
- Applications where a solid contaminant might settle in the displacer chamber;
- Cryogenic services;

Note:

The user may specify capacitance type level instruments in particular for viscous and/or highly corrosive liquids, where a solid contaminant might settle in the instrument impulse lines and for cryogenic services.

4.6 For special applications, other principles of measurement may be considered, such as ultrasonic instruments or instruments based on conductivity, radioactivity, radar/laser or bubbler type, such applications require written approval of the user.

4.7 Special provisions such as purging or heating should be considered to ensure proper operation of level instruments for highly viscous liquids, or for liquids containing water or solids, especially if the latter tend to form sediments.

4.8 For instruments on high-pressure/temperature service, the difference in density between liquid and vapor during normal operation is usually much smaller than during plant commissioning. To obtain in such cases satisfactory indication of the actual level under all operating conditions, consideration should be given to correcting the level transmitter output by a computing device using the output of the pressure transmitter or other suitable means.

4.9 For all applications the difference between liquid density and gas/vapor density should be taken into account when specifying displacer instruments or calculating the range for differential-pressure instruments.

4.10 For liquid-interface services, special attention shall be paid to the diameter of the displacer or float to achieve a satisfactory sensitivity, especially when the difference in densities is small. For measuring level interfaces, with density differences of 100 kg/m^3 or less, capacitance type instruments should be considered.

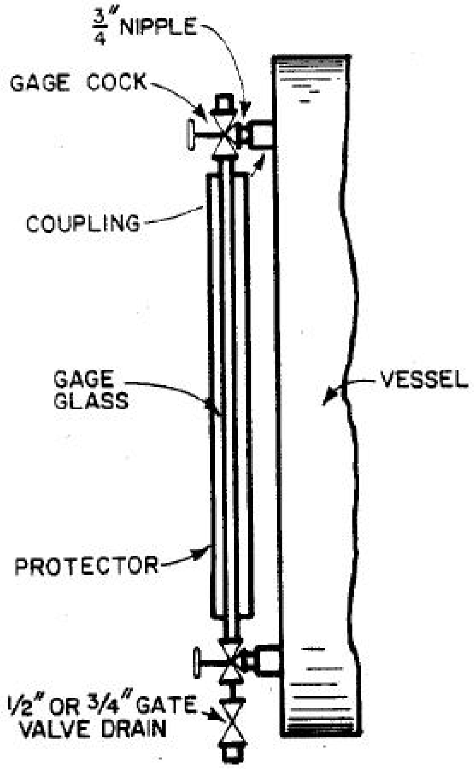
4.11 The use of an "air-fin torque tube extension" is required for high temperatures. The purpose is to maintain the instrument case temperature at a reasonable level to prevent failure of transmitter mechanism. For temperatures over 200 degrees celcius an air-fin extension torque tube is required.

5. LOCALLY MOUNTED INDICATING GAUGES

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

5.1 Tubular Gauge Glasses

Tubular gauge glasses are not recommended for process unites.



TUBULAR GAUGE GLASS CONNECTIONS TO VESSELS

Fig. 1

5.2 Armored-Type Gauge Glasses

- The most commonly used types of armored gauge glasses are the transparent (through-vision) and reflex gauges.

Magnetic-type gauges are available for special application or high-pressure services (see 5.3).

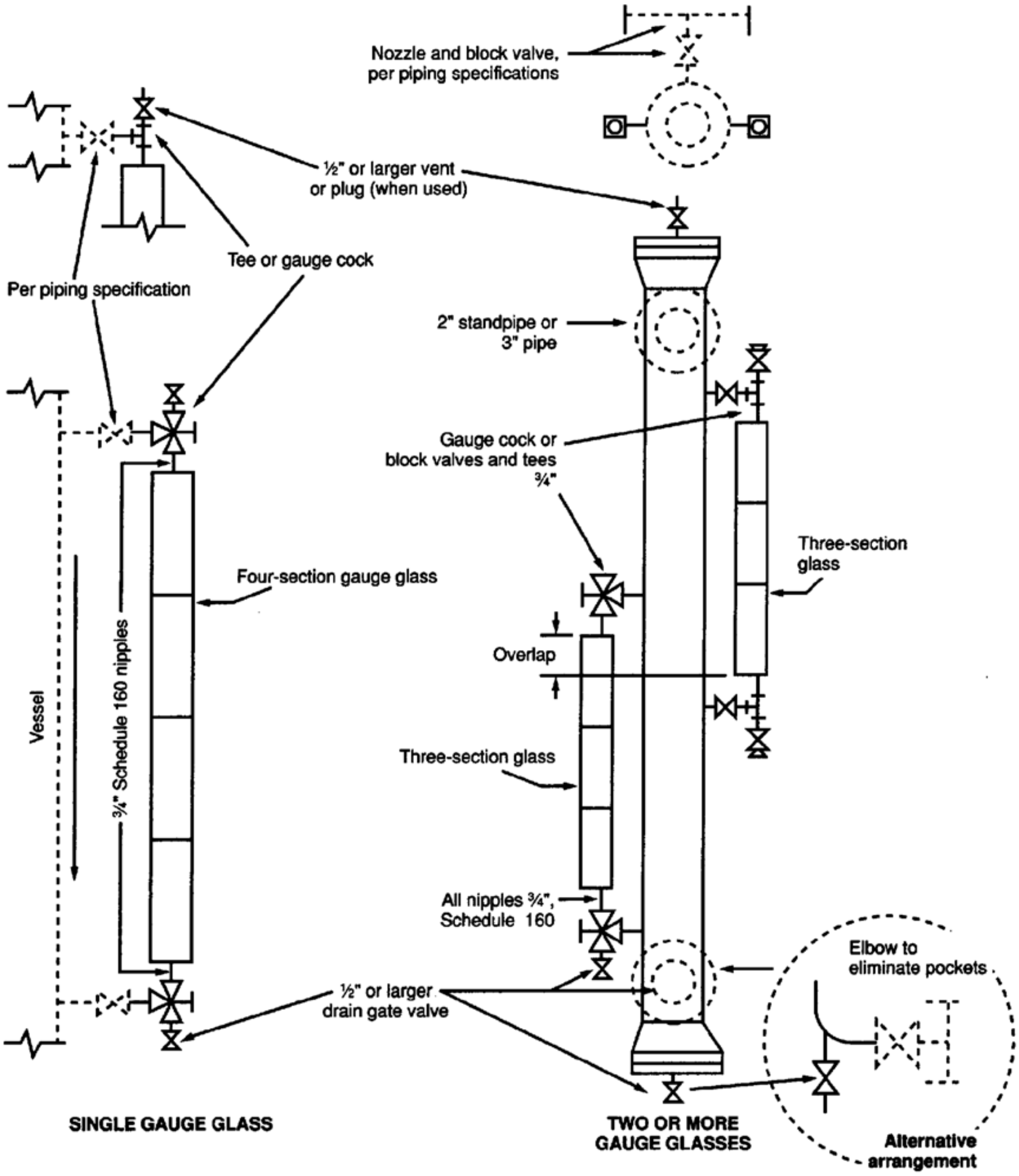
- Transparent Gauges: should be used in installations involving acid, caustic, or dirty (or dark-colored) liquids, in high-pressure steam applications, for liquid-liquid interface service, and in any application where it is necessary to illuminate the glass from the rear.

- Reflex Gauges: should be used on all other clean services, provided the product does not dissolve the paint or other coating on the inside of the gauge, thereby leaving a bare metal back-wall which in turn reduces the effectiveness of the prisms.

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

- Multiple-section gauge 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 Fig. 2A.

For greater visibility and safety, gauge glasses should be limited in length to four sections 1.5 meters between connections. In services at 200°C or higher, length to be limited to three sections, In noncritical level applications and where temperatures are less than 200°C, longer gauge 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.

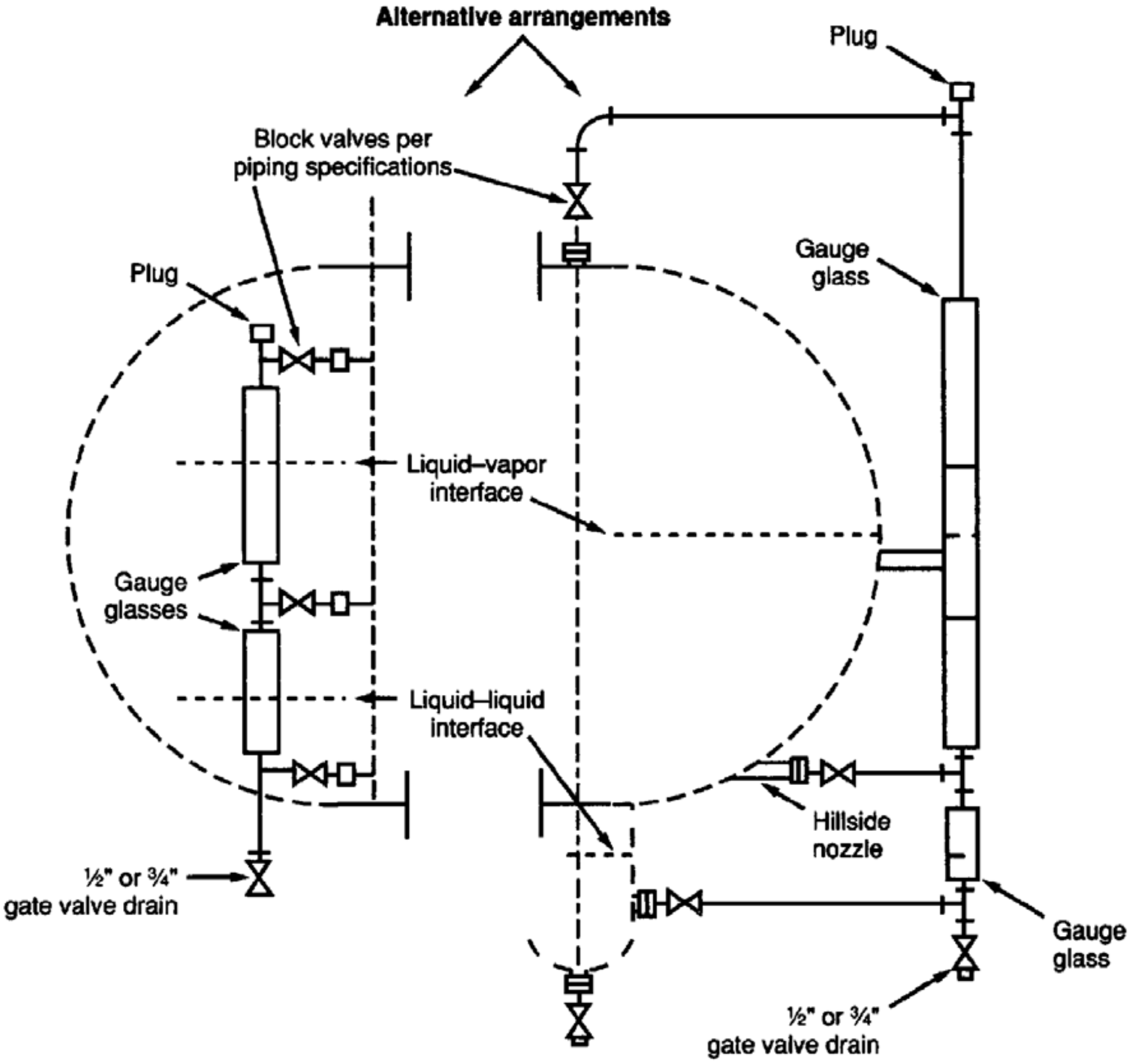


GAUGE ASSEMBLIES

Fig. 2

- Large ranges of level preferably are observed by the use of overlapping gauge glasses. The mounting of over lapping gauge glasses on a stand pipe is shown in Fig. 2B (minimum visible length is 50 mm). Gauge cocks ¾" in size generally are used on multiple gauges. It has been found that the maintenance required on the ball checks of automatic gauge cocks is so great that the most users prefer to use individual block valves and pipe tees. Both types of installations are shown in Fig. 2(B).

- Interface observation requires the use of transparent gauge glasses. Fig. 3, shows two commonly used and recommended methods of mounting multiple gauges on horizontal vessels where both Liquid-Liquid and Liquid- Vapor interfaces are to be observed. Connections to the vessels must be arranged so that there is always one in each phase of each interface being measured.



GAUGE GLASS MOUNTING ARRANGEMENT FOR HORIZONTAL VESSELS AND FOR INTERFACE MEASUREMENT

Fig. 3

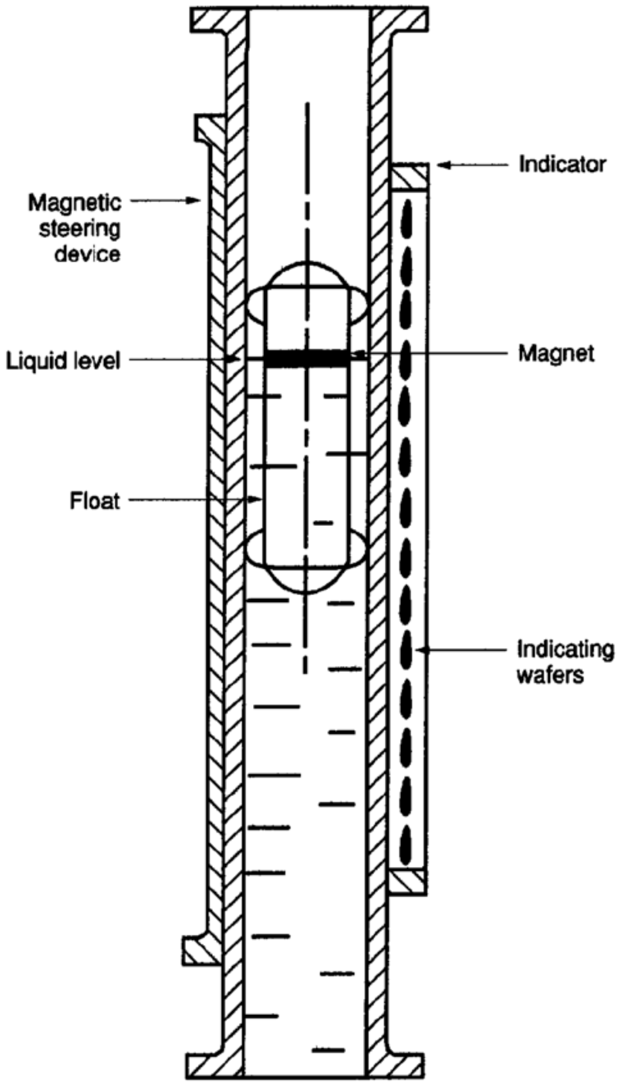
Protection of Gauge Glasses: Gauge glasses can be attacked (etched) by both vapor and liquids**,** for example, steam at a pressure of 250 pounds per square inch, (1675 kilopascals), hydrofluoric acid, amines, caustics. In these cases, a thin protective film is recommended on the inside of the glass. Sunlight discolors some plastics, so this should be considered when the film is selected. Such shields cannot be used in reflex gauges because they render prisms ineffective.

5.3 Magnetic-Type Gauges

- Magnetic-type gauges are used in gauging 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 non-magnetic 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.

- 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 degrees presenting the opposite face and color to the observer, (see Fig. 4).



TYPICAL MAGNETIC GAUGE

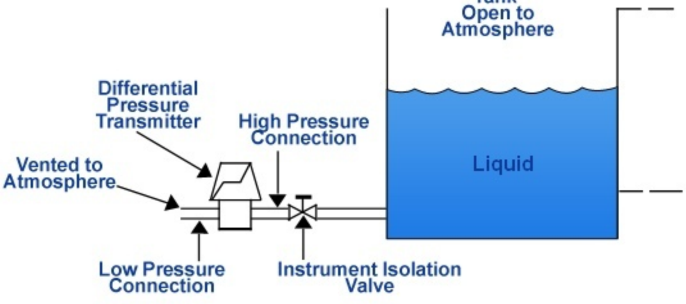
Fig. 4

Precautions: Magnetic gauges must not be used in areas where forces or matter will affect the magnetic fields. This includes areas that contain items such as steel support straps, heater wires, and steam-tracing tubing.

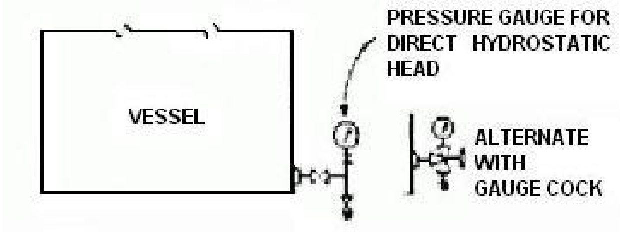
5.4 Hydrostatic Head Pressure Gauges

- Level indication by this means is limited to tanks or vessels not under pressure. The height of a liquid above a pressure gauge can be determined from the pressure gauge 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.

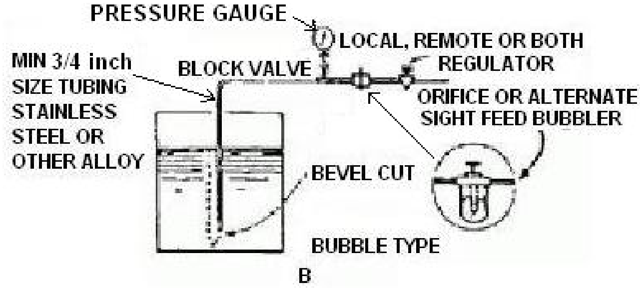
- Pressure gauge arrangements are illustrated in Fig. 5, view A in the Fig. shows the direct hydrostatic head type, and view B shows an air-bubbler system with either remote or local indication.



C) PRESSURE TRANSMITTER



A) PRESSURE GAUGE



B) BUBBLE TYPE

HYDROSTATIC HEAD PRESSURE GAUGE ARRANGEMENTS

Fig. 5

5.5 Differential Pressure Level Indicators

- Differential pressure level instruments generally are used as transmitters and seldom as level indicators alone. A transmitter with an indicator on the output signal may serve to indicate level.

- Certain high-displacement type (bellows type) differential pressure instruments are furnished with integral indicators and can be used to indicate level see 6.2.

6. LEVEL TRANSMITTERS

- Transmitters include pneumatic and electrical (conventional or smart) output systems that use a wide variety of measurement principles, including displacement, differential pressure, hydrostatic head, nuclear, ultrasonic, and capacitance.

- The transmission of the signal is accomplished as described in IPS-E-IN-190.

6.1 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 to cover the full range of the level measurement independent of controller settings, and the other for local level control.

- Ranges for displacer instruments shall be selected from the following series:

356	813	1219	1524	1829	2134	2438	2743	3048	mm
14	32	48	60	72	84	96	108	120	in

- For instruments mounted on (standard) external displacer chambers, the hanger extension length may be:

- 185 mm for rating ANSI class 150/300
- 215 mm for rating ANSI class 600
- 230 mm for rating ANSI class 900
- 255 mm for rating ANSI class 1500

- 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.

- Displacement transmitters sometimes are used for vacuum service or service with volatile liquids.

- Internal displacers should be avoided particularly on vessels that cannot be isolated without shutting down part of the plant.

- Where the signal is transmitted to a remote controller or panel-mounted instrument, the transmission should be accomplished as outlined in IPS-E-IN-190.

6.2 Differential Pressure Transmitters

See IPS-G-IN-210.

- Differential pressure transmitters have faster response characteristics than external cage displacement transmitters and require less range for stable control.

- Applications of displacement transmitters include remote control and remote indicating or recording of liquid level. This type of transmitter (usually the blind type) generally has an adjustable range and can have a high span elevation/ suppression capability. A receiver-type indicator on the output signal may be provided for local indication.

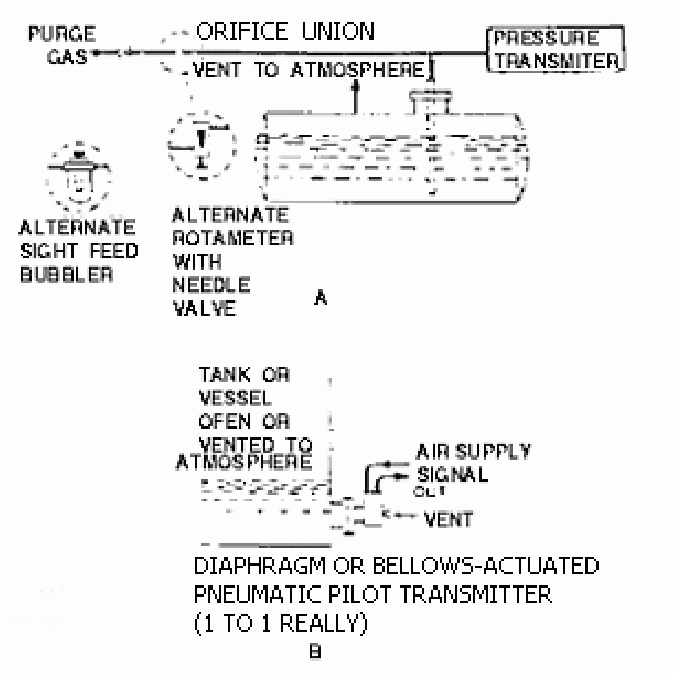
- Constant head may be maintained on the external or reference leg of the transmitter, because displacement of the measuring element with measurement changes is minimal even with condensable, no seal pot is required.

- A flange-connected, direct-tank mounted transmitter is used advantageously for measurement of slurries or viscous fluids. If required, the sensing diaphragm can be mounted flush with the inside of the vessel.

6.3 Hydrostatic-head Transmitters

- Hydrostatic head may be transmitted either by means of bubbler tube and pressure transmitter as shown in Fig. 6(A) or by means of diaphragm actuated air pilot transmitter mounted directly on the vessel as shown in Fig. 6(B).

- It should be pointed out that some makes of the diaphragm actuated pneumatic pilot are non-linear in the lower 20 percent of their range.



HYDROSTATIC HEAD LEVEL TRANSMITTERS

Fig. 6

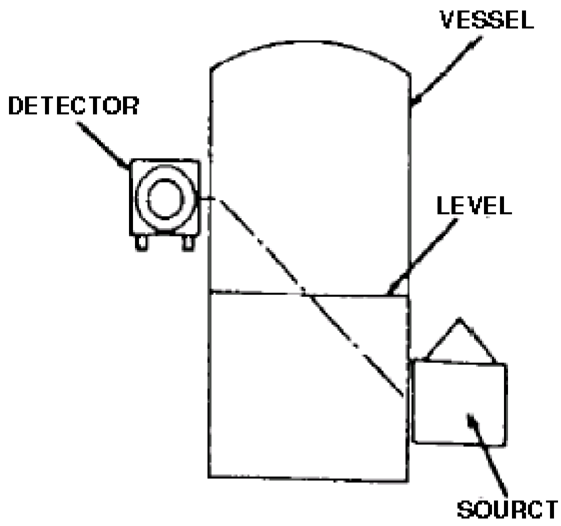
6.4 Nuclear Type Level Transmitters

- Nuclear-type level instruments are used where other types of internal or external instruments cannot be used, such as cocking or vacuum towers.

- Nuclear level instruments measure with beta or gamma rays that are sensed by radiation detectors. A radioactive source is placed so that the vessel contents are between the source and the detector. When the vessel is empty the count rate is high and as the level rises, the count rate decreases.

- The strength of the radiation sensed by the detector depends on the density or thickness of the material in the vessel, the distance between the source and the detector, and the thickness of the vessel wall and insulation. The range is limited by the size of the source (factory selected for application). Multiple sources are used sometimes to measure wide ranges see Fig. 7.

- Additional information shall be obtained from the manufacturers.



TYPICAL ARRANGEMENT OF NUCLEAR LEVEL TRANSMITTER

Fig. 7

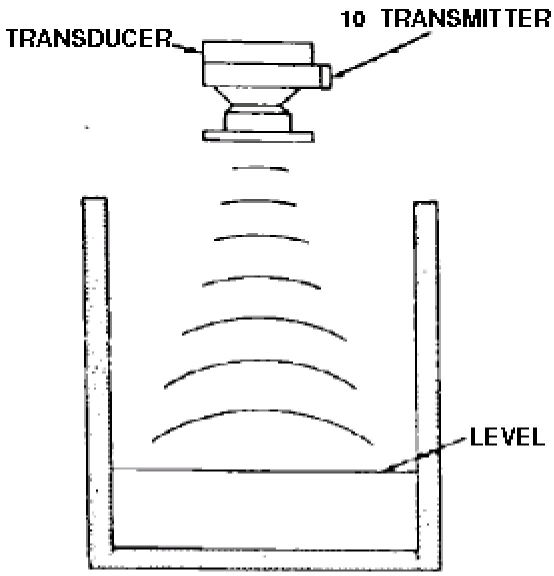
6.5 Ultrasonic-type Level Transmitters

- Ultrasonic-transmitters work on the principle of measurement of the time required for sound waves to travel through space. They are suitable for difficult level measurement applications of liquids and solids. (See Fig. 8).

- 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.

- Other types of radiation such as radar, RF, laser may be considered.



TOP MOUNTED ULTRASONIC-TYPE LEVEL TRANSMITTER

Fig. 8

6.6 Capacitance-type Level Transmitters

- Capacitance level transmitters measure the changing electrical capacitance that occurs in the device as the level in the vessel being measured varies. (See Fig. 9).

- 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.

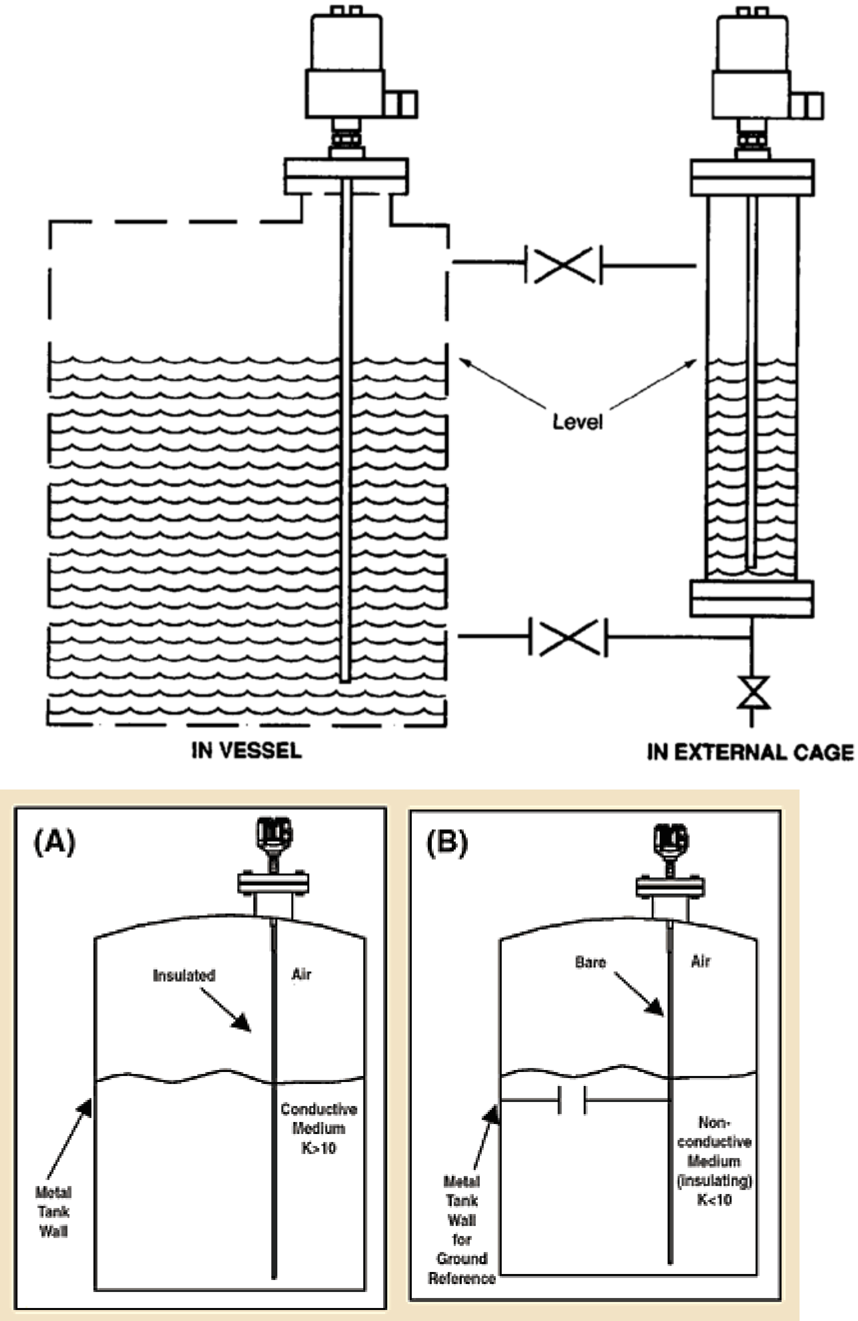
- The capacitance level transmitter consists of a vertical probe that is inserted into the vessel in which the level is being measured.

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 (liquid or granular) being measured is an insulator, a plain bare 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.

- With a capacitance/radio-frequency sensing element in an external cage, the difference in density due to temperature that results in a lower liquid level in the chamber is, to a large degree, offset by the higher dielectric constant of the denser liquid; hence, the indicated level will be close to the vessel's liquid level.



CAPACITANCE-TYPE LEVEL TRANSMITTER

Fig. 9

7. LOCALLY MOUNTED CONTROLLERS

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

- "Dual Pilot" displacement instruments provide local control as well as transmission when operated from a single displacer.

- Direct operated type level controls (ball float and mechanically linked valve) shall not be used.

- Internal ball-float controllers sometimes are used for asphaltic or waxy fluids, for coking service, or where the liquid contains particles or materials that tend to settle down 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.

- In severe services (the float will be subjected to turbulence within the vessel), it is recommended that the controller be supplemented by another type of instrument (for example, differential pressure or other special type).

- Differential pressure controllers 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.

8. 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. (See IPS-M-IN-150).

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

- For signal transmission, see IPS-G-IN-190.

9. LEVEL SWITCHES

- Basic instruments for intiating high-level or low-level alarm signals are, with the possible exception of the float size, the same as those discussed in 6 and 7.

- 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 non pressurized tanks, and differential pressure actuated switches on pressurized vessels), sometimes are used. For a detailed discussion of alarms and protective devices, see IPS-G-IN- 260.

10. TANK LEVEL GAUGING

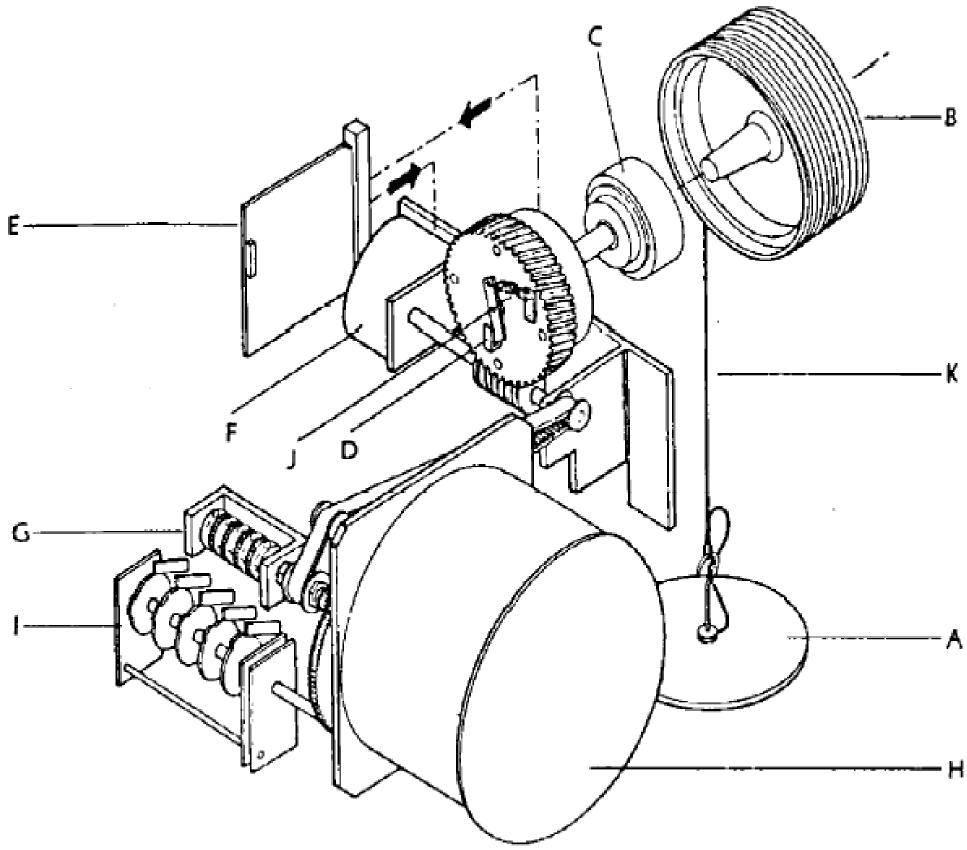
10.1 Traditional Methods of Tank Level Gauging

a) Float and cable tank level gauges are the most common means of indirect tank level indication. These gauges are used primarily on large storage tanks. see Fig. 14. Gauge boards (targets) are sometimes used for read out on small tanks or other noncritical applications, also it is called "Ground Reading Tank Level Indicator". See Fig. 13.

b) The reliability and continuing accuracy of a tank gauge 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 gauge, however carefully installed, can correct.

c) Where maximum accuracy is required, a tank level gauging system should provide compensation for the variation of float immersion due to liquid specific gravity. High accuracy also may require powered floats or displacer to reduce immersion and hysteresis errors (servo or spring-operated automatic tank gauging).

d) Through use of a low-voltage servomotor or spring/measuring error induced by friction, are eliminated, while improving sensitivity and repeatability. See Fig. 10, which illustrates the typical parts of servomotor type of level gauging.



TYPICAL SERVO LEVEL GAUGE

Fig. 10

A: **Displacer**
K: **Flexible Wire**
B: **Measuring Drum**
C: **Magnetic Coupling**
D: **Detection Plate**
J: **Balance Spring**
E: **Integration Circuit**
F: **Servomotor**
G: **Digital Counter**
H: **Transmitter (analog or digital)**
I: **Limit/Level/Alarm Switches**

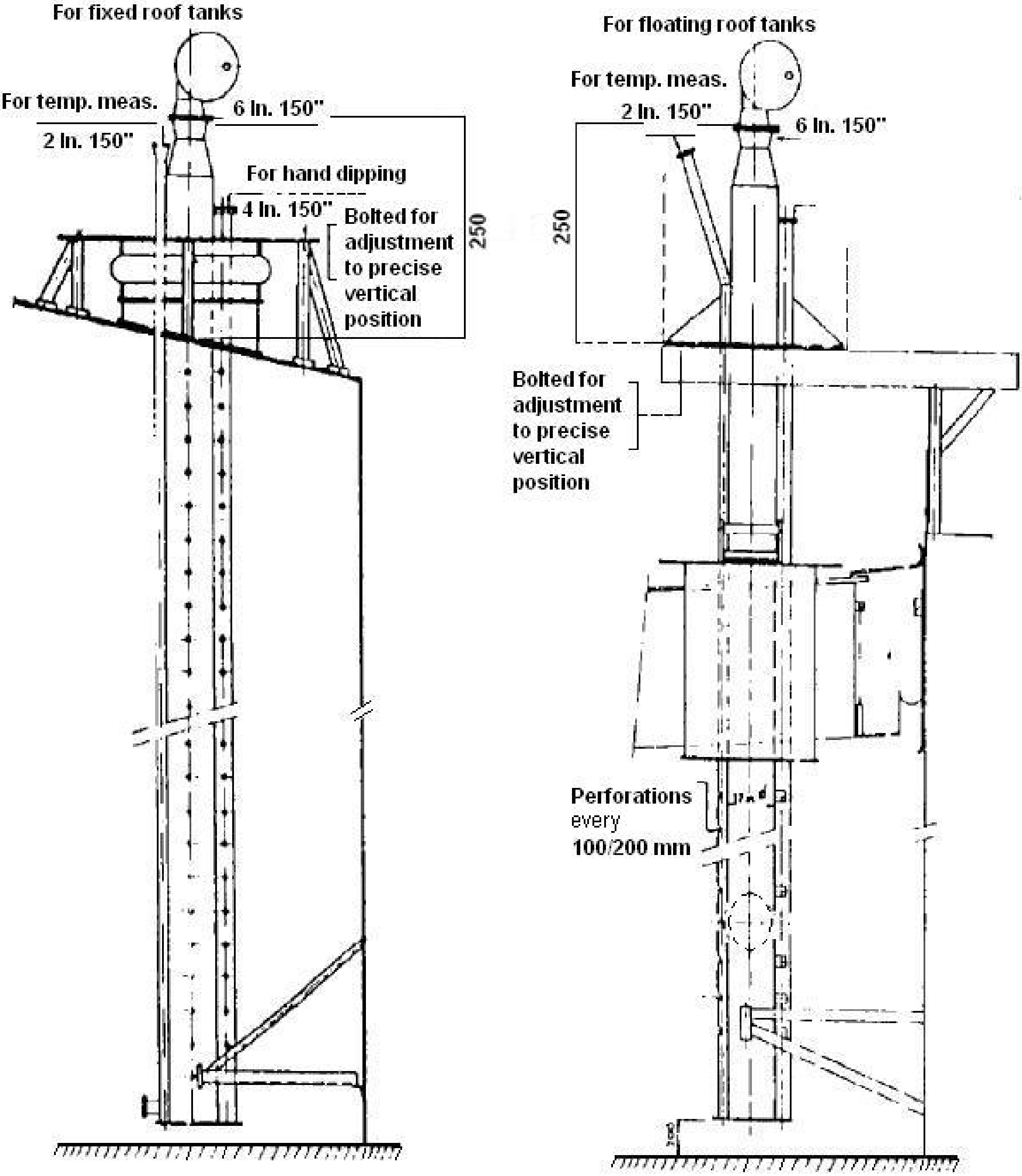
e) Where turbulence caused by high emptying and filling rates or by mechanical agitators can affect the float or sensing element, it is usually necessary to enclose the measuring element in a stilling well. These wells shall be installed in a perfectly vertical position. See Fig. 11 where high-viscosity materials are encountered, it may be desirable to provide heating for stilling well Liquefied Petroleum Gas (LPG) or other boiling surface services usually require a stilling well.

- Tank level gauges often are tied into a multiple tank remote read out. There are a number of-different proprietary or systems. These transmission systems usually are designed to minimize wire costs, and they usually include temperature transmission.

- Supervisory computers and micro processor-based read-out systems monitor tank fields. To provide an adequate scan cycle, a computerized tank level gauging system requires a rapid response from the tank gauge transmitter.

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

    a) Separate float-type level switches mounted outside the tank.



TYPICAL ARRANGEMENT OF STILLING WELLS FOR TANK GAUGES

Fig. 11

b) Position detector sensing the floating roof.

c) Electrical switches mounted in the gauge head.

d) Continuous monitoring 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 gauge float or the gauging system fails.

- Some of the practices mentioned are outlined in MPMS Ch. 3 They cover installing and using automatic tank gauges and should be referred to for additional information.

- For more details regarding Automatic Tank Gauging see IPS-G-IN-300.

10.2 Hydrostatic Tank Gauging (HTG)

- Hydrostatic Tank Gauging (HTG) is a relatively new method for measuring the mass, volume, or level of the product in a tank by sensing the hydrostatic pressure-rather than the level.

- A typical HTG on an atmospheric tank consists of two precision pressure transmitters and a resistance temperature sensor (RTD).

A third pressure transmitter (P_3) is used for pressurized tanks. One pressure transmitter (P_1) is mounted on the tank shell just above the bottom. The second pressure transmitter (P_2) is mounted above the P_1. P_1 measures the total hydrostatic pressure of the product. The difference between P_1 and P_2 pressure permits calculation of the fluid density at storage temperature. The temperature sensor permits calculation of standard density.

- Multiplying the bottom hydrostatic pressure by the tank area gives the product mass. Dividing the mass by the standard density gives the standard volume. Dividing the mass by the product density and the tank area gives the tank level see Fig. 12.

- The previous mentioned calculations are achieved by the microprocessor circuits in the HIU (hydrostatic interface unit) were the final breakthrough. The HIU is a field-mounted device that contains logic to calculate the product mass, density at product temperature, standard density, product volume, and standard product volume and level. It also has microprocessor memory for a set of tank capacity tables for each tank. Essentially perfect calculation accuracy is provided so that the total system accuracy is determined by the accuracy of the pressure transmitters. The HIU includes hardware and diagnostic routines and extensive alarm capabilities.

10.2.1 Corrections:

Some corrections may be considered as follows:

- The height of the P_1 transmitter and the distance between P_1 and P_2 transmitters.

- Tank shell diameter and height expansion due to temperature.

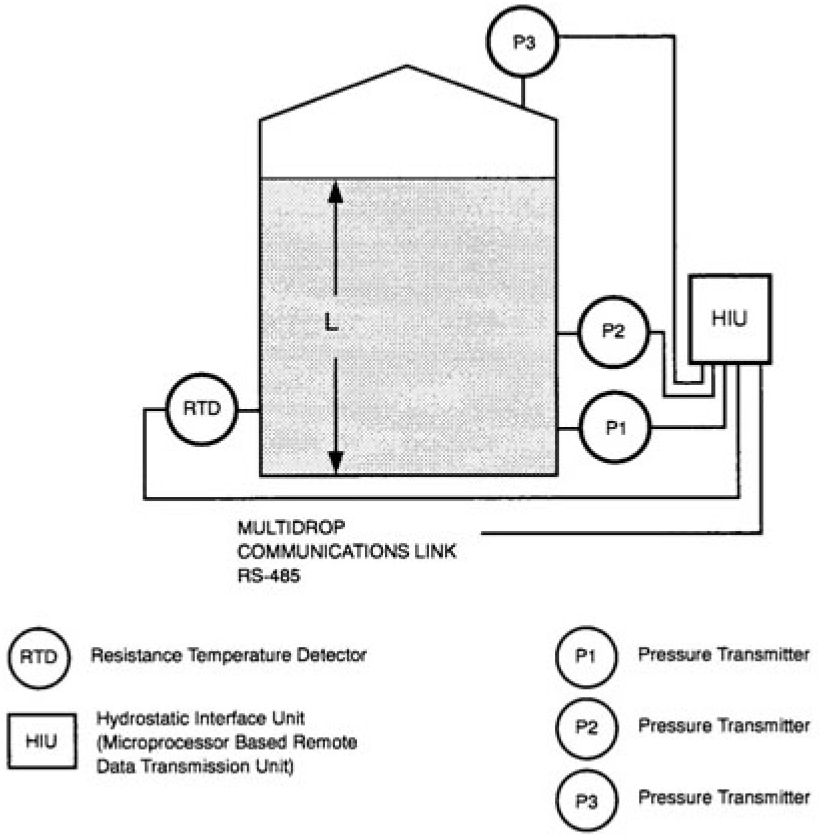
- Tank shell diameter expansion from product hydrostatic pressure.

- API temperature/gravity conversion constants.

- Geographic variation of the earth’s gravity.

10.2.2 Advantages of HTG;

HTG offers the following advantages: bottom-up measurement, no moving parts, external tank mounting, density read out, mass read out, ease of maintenance and low installation costs. HTG uses a fundamentally different method of product measurement. Eliminates errors caused by bottom movement, encrustation, and tank calibration (strapping) affect. HTG, however, avoids many of the level measurement errors caused by top-down measurement, and measuring devices.



TANK HYDROSTATIC GAGING AND INVENTORY MANAGEMENT SYSTEM

Fig. 12

10.3 Radar Tank Gauging

Radar Tank gauging is designed for refineries, tank terminals and the petrochemical industry. It is the accurate system for custody transfer, process control, inventory control or for filling a tank without risk of overflow .The system includes products for level and temperature measurement. Radar gauge measurement is independent of the process conditions inside the tank. Temperature, pressure and gas vapors have minimal affect on “radar beams”.

10.3.1 Level transmitter

The Radar Level gauge is possible to use with a wide range of antennas for different applications. Radar tank gauges are "downward-looking" measuring system installed on the tank roof. They measure the distance from the reference point (process connection) to the product surface.

Currently there are two measurement techniques in common use for level measurement. They are frequency modulated continuous wave (FMCW) radar and PULSE radar.

Due to the nature of the microwave, radar tank gauges need to be equipped with functions to suppress interference echoes (e.g. from edges and weld seams) in the tank so they are not interpreted as level measurement. Radar technology is suitable for measuring a wide range of petroleum products.

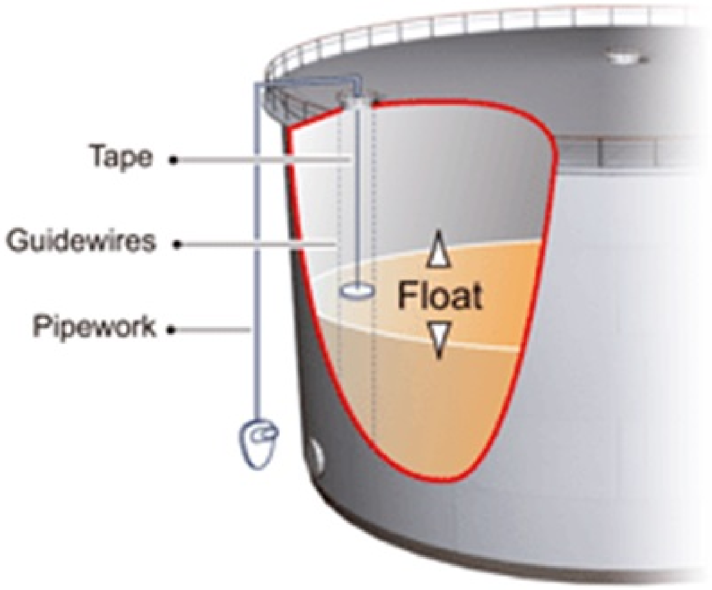
10.3.2 Temperature sensor

For temperature compensation considering for tank volume calculation, a number of spot elements are placed at different heights to provide a tank temperature profile and an average temperature. Only fully immersed elements are used to determine product temperature.

A multi spot or average temperature sensor may be integrated with a water level sensor.

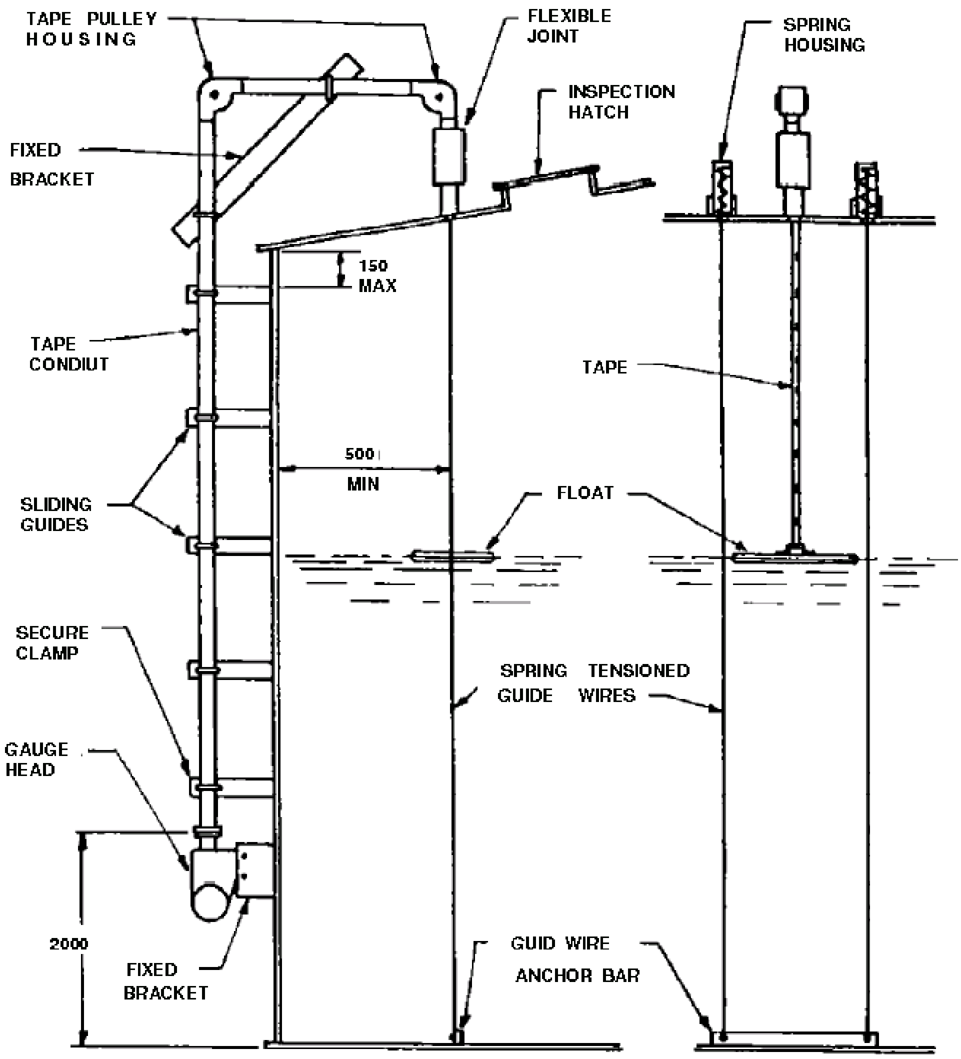
11. ACCESSORIES

Regarding seals and purges, gauge glass illuminators, and weather protection, see IPS-C-IN-140.



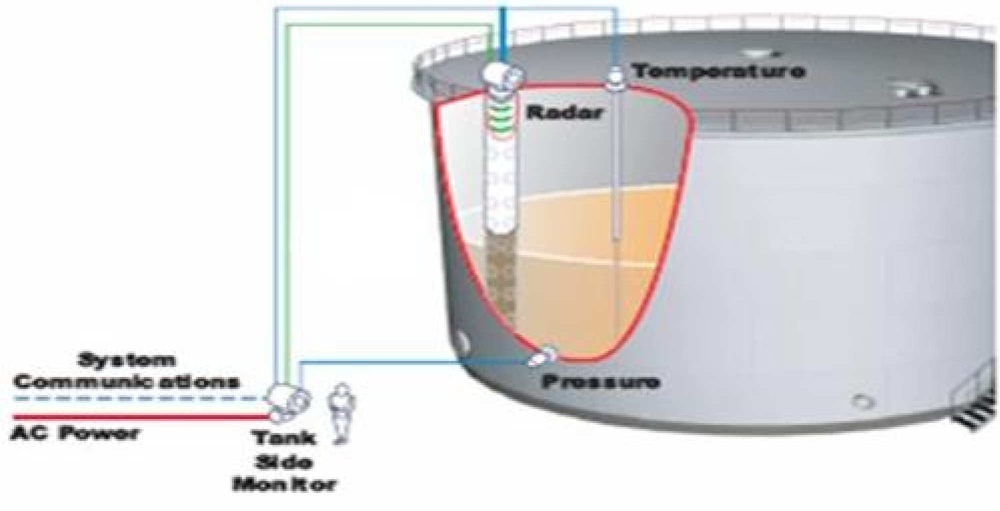
GROUND READING TANK LEVEL INDICATOR

Fig. 13



TRADITIONAL AUTOMATIC TANK GAGING

Fig. 14



RADAR TYPE TANK GAUGING

Fig. 15

APPENDICES

APPENDIX A

DATA SHEETS WITH THEIR FILLING INSTRUCTIONS

	GAUGE GLASSES AND COCKS				SHEET ---------- OF ----------		
	No.	BY	DATE	REVISION	SPEC. No.		REV
					CONTRACT		DATE
					REQ.	P.O.	
					BY	CHK'D	APPR.

1. Gauge Column ☐ Cocks ☐
   Assembled with Nipples ☐ Unassembled ☐

GAUGE GLASSES

2. Type: Reflex ☐ Transparent ☐ Tubular ☐
   Large Chamber ☐ Weld Pad ☐
3. Conn.: Size and Type______________________
   Top & Bot. ☐ Side ☐ Back ☐
   Vent__________Drain ______________
4. Material ____________________________
5. Rating __________
6. Options: Illuminator ☐
   Illuminator Housing Material ______________
   Power Voltage / Consumption ______________
   Cable Entry / Connection ______________
   Enclosure Protection ______________
   Area Classification ______________
   Internal Tube ☐ External Jkt ☐
   Non-Frost ☐ Ext. Length ______________
   Calb. Scale ☐
   Protective Coating ☐ Mica Shield ☐
   Other ______________________________
7. Manufacturer ______________________

GAUGE COCKS

8. Type: Offset ☐ Straight ☐
9. Conn.: Vessel _____ Gauge ____Vent/Drain____________
10. Material: Body ________Trim ______________________
11. Rating: _________
12. Construction: ______________________________
13. Type of Conn.: Vessel ______________________
    Gauge ______________________
14. Bonnet ______________________________
15. Options: Ball Checks ☐ Renewable Seats ☐
    Other ______________________________
16. Manufacturer & Model______________________________

Item	Rev.	Tag No.	Visible Length	Sections required Number/ Length	Conn. Length	Gauge Model No.	Operating		Fluid	Vessel Tag Number	Notes
							Press.	Temp.			

Notes:

IPS-FORM E-IN-140.1

GAUGE GLASSES AND COCKS

Instructions for IPS Form E-IN-140.1

1. Check what is to be supplied, and whether assembled or unassembled.

2. Select one type only per sheet.

3. Specify size, style and location of process connections. If side or back connections are used, vent and drain connections are available.

4. Material of gauge glass chamber and connections.

5. Specify rating. It is assumed that a higher rating is also acceptable. For example ANSI Class 300.

6. This section is used only if the option applies to all items listed on the sheet. Where options apply to certain items only, use the notes column instead.

7. Use for Manufacturer and Series or Type; detailed number may be listed in the tabulation.

8. Select style of cock, if used.

9. Show connection sizes only.

10. Write in body and trim materials.

11. See line 5 above.

12. Specify action and type of handle; plain closing or quick closing, handwheel or lever handle. This may be covered by the Model No. given on Line 16.

13. Specify type of connection on each side; plain union, spherical union, solid shank. Give flange size, rating and type, if applicable.

14. Bonnet may be screwed, union type, or bolted.

15. Options checked here apply to all items. See line 6 above. Include special packing.

16. Fill in if required, or as a final record after selection is made.

"Conn. Length" in tabulation refers to distance between center lines of vessel connections.

	LEVEL INSTRUMENTS (DISPLACER or FLOAT)				SHEET ---------- OF ----------	
					SPEC. NO.	REV
	No.	BY	DATE	REVISION		
					CONTRACT	DATE
					REQ. P.O.	
					BY CHK'D	APPR.

	1	Tag Number				
	2	Service				
	3	Line No./Vessel No.				
BODY/CAGE	4	Body Or Cage Mtl				
		Rating				
	5	Conn Size & Location Upper				
		Type				
	6	Conn Size & Location Lower				
		Type				
	7	Case Mounting				
		Type				
	8	Rotatable Head				
	9					
	10	Orientation				
	11	Cooling Extension				
	12					
DISPLACER OR FLOAT	13	Dimensions				
	14	Insertion Depth				
	15	Displacer Extension				
	16	Disp. or Float Material				
	17	Displacer Spring Tube Mtl				
	18					
	19					
XMTR/CONT	20	Function				
	21	Output				
	22	Control Modes				
	23	Differential				
	24	Output Action. Level Rise				
	25	Mounting				
	26	Mounting				
	27	Elec. Power or Air Supply				
	28	Calibration Span				
SERVICE	29	Upper Liquid				
	30	Lower Liquid				
	31	Sp. gr.: Upper / Lower				
	32	Press. Max. / Normal				
	33	Temp. Max. / Normal				
	34					
	35					
OPTIONS	36	Airset / Supply Gauge				
	37	Gauge Glass Connections				
	38	Gauge Glass Model No.				
	39	Contacts: No. / Form				
	40	Contact Rating				
	41	Action of Contacts				
	42					
	43					
	44					
	45					
	46	Manufacturer				
	47	Model Number				
	48					
Notes:						

IPS-FORM E-IN-140.2

LEVEL INSTRUMENTS

(DISPLACER OR FLOAT)

Instructions for IPS Form E-IN-140.2

1. Tag No. or other identification.

2. Process service.

3. Line number or vessel number on which cage or body is installed.

4. Material of chamber and/or mounting flange.

5. For float specify top or side of vessel connection. For displacer in a chamber specify upper, then lower connection; such as side-side, side-bottom, top-bottom, etc. Give flange size and rating or NPT size.

6. Same as 5.

7. Refers to position of case when viewing the front of the case relative to the chamber; the case is either to the left, right, or top.

8. On displacer instruments specify if case is to be rotatable with respect to the chamber. This only applies if there is one or more side connections.

10. Orientation of control with respect to displacer cage.

11. Cooling Extension.

13. Specify float diameter or displacer length. The displacer length is also the range.

14. Insertion depth applied to ball floats. It is the mounting flange to the center of the ball.

15. The displacer extension is measured from the face of the mounting flange to the top of the displacer. This dimension is required only for top of vessel mounted instruments.

16. Includes rod.

17. Refer to MFR's standard materials or special materials.

18.

19.

20. Transmitter, controller, switch, etc.

21. Air pressure or electrical signal output of transmitter or controller.

22. P: Proportional

Pn: Narrow band proportional

Pi: Proportional plus Integral (Reset).

23. Differential if controller on/off must specify differential adj. or fixed State adjustable range or fixed amount.

24. INCREASE (Direct action) or DECREASE (Reverse Action).

25. Remote or integral.

26. Electrical classification of housing NEMA number.

27. Air pressure or voltage. If electronic, state whether ac or dc.

28. Calibration span to be written.

29. Used only for interface application.

30. Used for all services.

31. Specific gravities at operating temperature.

32. Operating and max. pressure or vacuum.

33. For cryogenic service, give minimum temperature.

34.

35.

36. Airset assumed mounted to case.

37. Connections on chamber, give size.

38. Specify gauge glass, if required.

39. Contact form: SPST, SPDT, etc.

40. Give volts, Amps.

41. Describe contact action with level.

42.

43.

44.

45.

46. Manufacturer.

47. Model number.

	DIFFERENTIAL PRESSURE INSTRUMENTS				SHEET ---------- OF ---------		
					SPEC. NO.		**REV**
	No.	BY	DATE	REVISION			
					CONTRACT		DATE
					REQ.	P.O.	
					BY	CHK'D	APPR.

	1	**Tag Number**	**Service**
GENERAL	2	Function	Record ☐ Indicate ☐ Control ☐ Blind ☐ Trans ☐ Integ ☐ Other ———
	3	Case	MFR STD ☐ Nom Size ——— Color: MFR STD ☐ Other ———
	4	Mounting	Flush ☐ Surface ☐ Yoke ☐ Other ———
	5	Enclosure Class	General Purpose ☐ Weather Proof ☐ Explosion Proof ☐ Class ———
			For use in Intrinsically Safe System ☐ Other ———
	6	Power Supply	117V 60 Hz ☐ Other ac ——— dc ☐ ——— Volts ———
	7	Chart	12 in. Circ. ☐ Other ——— Range ——— No. ———
	8	Chart Drive	24 hr Other ——— Elec. ☐ Spring ☐ Other ———
	9	Scale	Type ——— Range: 1 ——— 2 ——— 3 ———
XMTR	10	Transmitter	4–20 mA ☐ 10-50 mA ☐ 21-103 kpa (3-15 psig) ☐ Other ———
		Output	For Receiver, See Spec Sheet ———
CONTROLLER	11	Control Modes	P = Prop (Gain), I = Integral (Auto Reset), D = Derivative (Rate)
			Sub: s = Slow, f = Fast If ☐ Df ☐ P ☐ PI ☐ PD ☐ PID ☐ Is ☐ Ds ☐
			Other ———
	12	Action	On Meas. Increase Output: Increase ☐ Decrease ☐ ———
	13	Auto Man Switch	None ☐ MFR STD ☐ Other ———
	14	Set Point Adj.	Manual ☐ External ☐ Remote ☐ Other ———
	15	Manual Reg.	None ☐ MFR STD ☐ Other ———
	16	Output	4-20 mA ☐ 10-50 mA ☐ 21-103 kpa (3-15 psig) ☐ Other ———
UNIT	17	Service	Flow ☐ Level ☐ Diff. Pressure ☐ Other ———
	78	Element Type	Diaphragm ☐ Bellows ☐ Mercury ☐ Other ———
	19	Material	Body ——— Element ———
	20	Rating	Over range ——— Body Rating ——— Psig
	21	Diff. Range	Fixed ☐ Adj. Range ——— Set At ———
	22		Elevation ——— Suppression ———
	23	Process Data	Fluid ——— Max Temp. ——— Max Press. ———
	24	Process Conn.	½ in. NPT ☐ Other ———
	25	Alarm Switches	Quantity ——— From ——— Rating ———
	26	Function	Meas. Var. ☐ Deviation ☐ Contacts To ——— on Inc. Meas.
	27	Options	Pressure Element ☐ Range ——— Material ———
			Temp. Element ☐ Range ——— Type ———
			———
			Filt Reg. ☐ Sup. Gauge ☐ Output Gauge ☐ ——— Charts
			Valve Manifold ———
			Cond. Pots ☐ Adj. Damp ☐ Integral Sq. Rt. Ext. ☐
			Integral ———
			Other ———
	28	MFR & Model No.	———
Notes:			

	DIFFERENTIAL PRESSURE INSTRUMENTS				SHEET------------ OF----------		
	No.	BY	DATE	REVISION	SPEC. NO.		REV
					CONTRACT		DATE
					REQ.	P.O.	
					BY	CHK'D	APPR.

Rev.	Tag	Adj. Range	Set Range	Scale or Chart	Scale Factor	Service	Notes

Notes:

DIFFERENTIAL PRESSURE INSTRUMENTS

Instructions for IPS Forms E-IN-140 3a & 3b

1. To be used for a single item. Use secondary sheet for multiple listing.

2. Check as many as apply.

3. Nominal size refers to approximate front of case dimensions; Width × height.

4. Yoke refers to a bracket designed for mounting the instrument on a pipe stand.

5. Enclosure class refers to composite instrument. If electrical contacts are in the case they must meet this classification inherently or by reasons of the enclosure. Use NEMA identification system or ISA identification RP 8.1.

6. Specify electrical power to the entire instrument from an external source.

7. Specify chart size, range and number if applicable.

8. "24 hr" is the time for one rotation of the chart. Other speeds should be listed in hours or days. If a spring wound clock is used fill in number of hours or days it runs between windings.

9. The scale type may be SEGMENTAL, ECCENTRIC, or DIAL (CIRCULAR). Space is provided for multiple ranges on the same scale.

10. Specify transmitter output if applicable.

11. See explanation of terminology given on specification sheet. For further definition refer to American National Standard C85-1-1963 "Terminology for Automatic Control". Specific ranges of control modes can be listed after "OTHER", if required.

12. For multiple items specify on second sheet.

13. If standard auto-manual switching is not known or not adequate, specify number of positions.

14. Remote set point adjustment assumes full adjustment range. Specify limits if required.

15. Specify if applicable.

16. Specify if applicable.

17. Specify measure variable.

18. Specify type of element or write in "MFR. STD".

19. Materials refer to wetted parts only.

20. Over-range protection refers to maximum differential pressure. The instrument can withstand without a shift in calibration.

21. Adjustable range means that the range can be changed without replacing any parts.

22. Elevation

23. Give process data affecting meter selection. Flow elements such as orifice plates are specified on separate forms.

24. Refers to connections piped to process equipment or pipe line. Special flanged connections and extended diaphragms for level applications should be described after "OTHER".

25. Form may be SPST, DPDT, or others. Rating refers to electrical rating of switch or contacts in Amps.

26. Specify if alarm is actuated by measured variable or by deviation from controller set point. Give contact action if single throw form.

27. Specify required accessories. If temperature element is used, the second line is provided to specify well, length of capillary tubing and other details of the thermal system.

28. After selection is made fill in manufacturer and specific model number.

SECONDARY SHEET- for listing multiple instruments. List all instruments of the same type specified on the primary sheet, with variations as shown. "Notes" refers to notes listed by number at the bottom of the sheet.

	LEVEL INSTRUMENTS CAPACITANCE				**SHEET----------- OF---------**	
	No.	BY	DATE	REVISION	SPEC. NO.	REV
					CONTRACT	DATE
					REQ. P.O.	
					BY / CHK'D / APPR.	

GENERAL	1	Tag Number			
	2	Service			
	3	Line No.	Vessel No.		
	4	Application			
	5	Function			
	6	Fail-Safe			
	7				
PROCESS CONDITIONS	8	Upper Fluid			
	9	Upper Fluid Dielectrical Connection			
	10	Lower Fluid			
	11	Lower Fluid Dielectrical Connection			
	12	Max. Pressure	Oper. Pressure		
	13	Max. Temperature	Oper. Temperature		
	14	Moisture			
	15	Vibration			
	16	Material Build – Up			
	17				
PROBE	18	Model No.			
	19	Orientation			
	20	Style			
	21	Material			
	22	Sheath			
	23	Insertion Length			
	24	Inactive Length			
	25	Gland Size	Gland Material		
	26	Conduit Size & Connection			
	27				
AMLIFIER	28	Location			
	29	Enclosure			
	30	Power Supply			
	31	Conduit Size & Connection			
	32				
SWITCH	33	Type			
	34	Quantity	Form		
	35	Rating			
	36	Load Type			
	37	Contacts Open on Level			
	38				
TRANSMITTER	39	Output			
	40	Power Supply			
	41	Enclosure			
	42	Range			
	43				
OPTIONS	44	Compensation Cable			
	45	Local Indicator			
	46				
PURCHASE	48	Manufacturer			
	49	Model			
	50	Purchase Order Number			
	51	Price	Item Number		
	52	Serial Number			

Notes:

LEVEL INSTRUMENTS, CAPACITANCE TYPE

Specification Sheet Instructions for IPS Form E-IN-140.4 Prefix number designates line number on corresponding Specification Sheet.

1. Enter the capacitance level instrument tag number from the P&ID.

2. Enter a narrative description of the process service in which the capacitance level instrument is installed. Example; P-101 Stripper Bottoms

3. Enter the process line number from the P&ID (if applicable). Enter the vessel number on which the capacitance level instrument is attached.

4. Denote the type of application that the capacitance level instrument will be used in, such as solids level, interface detection or liquid level, etc.

5. Enter the capacitance level instrument's function. The instrument's function can either be Control or Indication which is determined from the control function shown on the P&ID.

6. Specify the direction the capacitance level instrument's output should move if the instrument should fail, such as high, low or none.

7. **Blank:** Modify the data sheet to display the "Area Classification" instead of Blank in Line 7: then enter the Area Classification where the instrument is located in the field. Consult with the project electrical engineer for area classification. Example: Class 1, Div. 2, Group C&D (Group B if Hydrogen is present).

8. Applicable only for interface level measurements. If applicable, enter the type of fluid in the pipe or vessel to which the capacitance level instrument is attached, such as gasoline, water, hydrocarbon condensate, etc.

9. (Check the data sheet for the correct heading, earlier version my have "Upper Fluid Dielectrical Connection". If this is the case, then have the SPI Administrator make the change in the data sheet to reflect Upper Fluid Dielectric Constant.) Applicable only for interface level measurements. Fluid dielectric constant should be provided by the Process Engineer in the SPI process data module.

10. Applicable for all level measurements. Enter the type of fluid in the pipe or vessel to which the capacitance level instrument is attached, such as gasoline, water, hydrocarbon condensate, etc.

11. (Check the data sheet for the correct heading, earlier version my have "Lower Fluid Dielectrical Connection". If this is the case, then have the SPI Administrator make the change in the data sheet to reflect Lower Fluid Dielectric Constant.) Applicable for all level measurements. Enter the type of fluid in the pipe or vessel to which the capacitance level instrument is attached, such as gasoline, water, hydrocarbon condensate, etc.

12. The maximum and operating pressures at which the fluid in the pipe or vessel operates. Operating pressures are provided by the Process Engineer in the SPI process data module or can be found on the P&ID under the Vessel Information as Design Pressure.

13. The maximum and operating temperatures at which the fluid in the pipe or vessel operates. Operating temperatures are provided by the Process Engineer in the SPI process data module or on the P&ID under the Vessel Information as Design Temperature.

14. Applicable only for solids level measurement. Denote the percentage of moisture in the content of the solids that the capacitance level instrument will be measuring.

15. Denote whether or not the capacitance level instrument will experience any vibration in this application.

16. Denote whether or not if there is a potential for material to accumulate on the capacitance level instrument sensor.

17. **Blank.**

18. Specify the model number of the capacitance level instrument probe from the manufacturer's catalog or as provided in the vendor's quotation.

19. Specify the orientation of the capacitance level instrument probe when installed on the vessel or pipe, such as horizontal or vertical.

20. Specify the style of the capacitance level instrument probe, such as general purpose, heavy duty, concentric shield, etc.

21. Enter the capacitance level instrument probe material. Normally this material should be compatible with the plant environment. Consult the manufacturer's catalog for available materials including compatibility to the process maximum pressure and temperature.

22. If a sheath is required, specify the sheath thickness as well as the sheath material. Normally this material should be compatible with the plant environment. Consult the manufacturer's catalog for available materials including compatibility to the process maximum pressure and temperature.

23. Specify the expected total immersion of the capacitance level instrument probe in the process fluid.

24. Specify the inactive extension of the capacitance level instrument probe above the process fluid.

25. Specify the capacitance level instrument's sealing gland size and material of construction.

26. Enter the electrical connection size and type. Electrical connections are normally 1/2" NPT for electrical conduit entry. Consult manufacturer's catalog for available connection sizes and compliance with the design installation details.

27. Modify the data sheet to display the "Process Connection" instead of Blank in Line 27: then enter the size, type and connection rating for the Process Connection. I applicable, include the process connection flange material. Example: 2", 150#RF, SS.

28. Denote if the capacitance level instrument's electronics are integral to the probe or remotely mounted.

29. Enter the NEMA rating of the capacitance level instrument's amplifier housing.

30. Denote the voltage level that the capacitance level instrument amplifier uses, such as 24 VDC loop or external power, 120 VAC, 60 Hz, 1-phase.

31. Enter the electrical connection size and type. Electrical connections are normally 1/2" NPT for electrical conduit entry. Consult manufacturer's catalog for available connection sizes and compliance with the design installation details.

32. Blank.

33. Denote the type of switch contact, such as mercury, snap, etc.

34. Denote the number of switch contacts within the switch housing and denote the contact form, such as SPST, SPDT, etc.

35. Denote the switch contact rating in voltage and amperes.

36. Denote the contact load type, such as inductive or non-inductive.

37. Denote the action of the switch contacts, i.e. on rising liquid level the contacts open or close. Denote the cause of the actuation, such as low liquid level, high liquid level, etc.

38. Blank.

39. Denote the type of signal output the capacitance level instrument's transmitter will provide such as 4 – 20 mA.

40. Denote the voltage level that the capacitance level instrument transmitter uses, such as 24 VDC loop or external power, 120 VAC, 60 Hz, 1-phase.

41. Enter the NEMA rating of the capacitance level instrument's transmitter housing.

42. Enter the vessel fluid range that the capacitance level instrument transmitter will need to measure. This range is selected to cover the level points as noted on the P&ID by the Process Engineer. Consult with the project Process Engineer for vessel fluid range if not denoted on the P&ID.

43. Blank.

44. If required, specify the length of special compensation cable to be furnished with the capacitance level instrument's probe.

45. Denote whether or not a local indicator is to be included in the capacitance level instrument's transmitter housing. Specify a display calibration range which is typically the transmitter calibrated range.

46. Blank.

47. Blank.

48. Enter the name of the capacitance level instrument manufacturer.

49. Specify the model number of the capacitance level instrument from the manufacturer's catalog or as provided in the vendor's quotation.

50. Enter the purchase order number for the capacitance level instrument.

51. Do not fill in the price field. Prices will be shown on the purchase order. Enter the purchase order item number for the capacitance level instrument.

52. Do not fill in the serial number. This can be filled in later by Plant Maintenance if required.

Notes:

Include any explanatory notes for the manufacturer here.

As a minimum specify the following:

1. Any special tagging requirements.
2. Denote the P&ID number on which the capacitance level instrument is located.
3. Denote the electrical area classification where the capacitance level instrument is located in the field.
4. Denote the ambient temperature range from the process site conditions document.
5. Enter the vessel trim number along with the vessel material of construction.
6. Denote the required flange finish if the capacitance level instrument's connections are to be flanged.
7. Denote whether the displacer level instrument has any special type of material requirements, such as PMI, NACE, etc.

LEVEL SWITCHS (FLOAT AND DISPLACEMENT TYPE) SPECIFICATION SHEET	INSTRUMENT SPECIFICATIONS				SHEET----------- OF---------		
	No.	BY	DATE	REVISION	SPEC. NO.		REV
					CONTRACT		DATE
					REQ.	P.O.	
					BY	CHK'D	APPR.

GENERAL	1	Tag Number					
	2	TYPE					
	3						
	4	Service					
BODY	5	Material					
	6	Top Conn. Location					
	7	Bottom Conn. Location					
	8	Conn. Size & Rating					
	9	Gauge Glass Conn					
	10	Type Glass					
	11	Type of Gauge Cock					
	12	Try Cocks					
	13	Whistle					
FLOAT OR DISPLACER	14	Dimensions					
	15	Length Rod / Arm					
	16	Material					
SWITCH	17	Type					
	18	Quantity / Form					
	19	Enclosure					
	20	Conduit Conn: Size & Type					
	21	Rating: Volts / CY or D.C.					
	22	Amps / Watts / HP-KW					
	23	Load Type					
	24	Diff: Fixed / Adjust					
	25	Adjustment: Int / Ext.					
	26	Contacts / Open Close / On Level / Incr. Decr.					
	27						
SERVICE CONDITIONS	28	Upper Fluid					
	29	LOWER FLUID					
	30	SP. GR. Upper / Lower					
	31	Minimum SP. GR. Diff.					
	32	Press: Oper. / Max.					
	33	Temp: Oper. / Max.					
	34	Manufacturers Model No.					
		Notes:					

IPS-FORM E-IN-140.5

	INSTRUMENT SPECIFICATION ULTRASONIC LEVEL INSTRUMENT				SHEET–––––––––– OF–––––––––		
	No.	BY	DATE	REVISION	SPEC. NO.		REV
					CONTRACT		DATE
					REQ.	P.O.	
					BY	CHK'D	APPR.

GENERAL	1	Tag No.			
	2	Service			
	3	Line No.	P&ID No.		
	4	Tank/Vessel No.	Tank Roof		
	5	Area Classification			
	6	Enclosure Class			
	7	Electrical Power Supply			
PROCESS CONDITIONS	8	Fluid			
	9	Solids Buildup Expected?			
	10	Pressure Oper.	Max.		
	11	Temperature Oper.	Max.		
	12	Density			
	13	Level Min.	Max.		
	14	Specific Gravity			
	15	Dielectric Constant			
	16	Tank Wall Material	Lining Material		
DEVICE	17	Sensor Type			
	18	Sensor Installation			
	19	Sensor Matl			
	20	Seal Matl			
	21	Wetted Part			
	22	Electronics Lopcation			
	23	Distance to Electronics			
	24	Measuring Range			
	25	Rating Press	Temp		
	26	Process Conn. Size	Rating		
TRANSMITTER	27	Tag Number			
	28	Calibration Range			
	29	Output Signal	Protocol		
	30	Display			
	31	Method of Calibration			
	32	Power Supply			
	33	Accuracy	Repeatability		
	34	Electrical Connection			
SWITCH SW1	35	Type	No of Contact		
	36	Contact Action	Actuation		
	37	Contact Form	Rating		
	38	Load Type @ Rating	Deadband		
	39	Setpoint	Setpoint Range		
SWITCH SW2	40	Type	No of Contact		
	41	Contact Action	Actuation		
	42	Contact Form	Rating		
	43	Load Type @ Rating	Deadband		
	44	Setpoint	Setpoint Range		
PURCHASE	45	Vendor			
	46	Manufacturer			
	47	Model			
	48	Purchase Order Number			

Note:

ULTRASONIC LEVEL INSTRUMENT

Following are instructions for completion of the SPI Instrument Specification for Ultrasonic Level Instrumentation. Required reference documents are P&ID's, Piping Line Class Specifications and Ultrasonic Level Instrument Manufacturer's catalog.

1. Enter the ultrasonic level instrument tag number from the P&ID.

2. Enter a narrative description of the process service in which the ultrasonic level instrument is installed. Example; P-101 Stripper Bottoms

3. Enter the process line number from the P&ID (if applicable). Insert the P&ID number on which the ultrasonic level instrument is located.

4. Enter the vessel number on which the ultrasonic level instrument is attached. If the ultrasonic level instrument is installed on a tank, denote the type of roof, such as conical, flat, etc.

5. Enter the electrical area classification where the ultrasonic level instrument is located in the field. Consult with the project Electrical Engineer for Area Classification. Generally, Class 1, Division 2, Groups C & D. (Group B if Hydrogen is present.)

6. Enter the NEMA rating of the ultrasonic level instrument transmitter housing.

7. Denote the ultrasonic level instrument transmitter voltage level, such as 24 VDC loop or external power, 120 VAC, etc.

8. Enter the type of fluid in the vessel to which the ultrasonic level instrument is attached, such as gasoline, water, hydrocarbon condensate, etc.

9. Denote whether or not if there is a potential for solids to build up on the ultrasonic level instrument sensor.

10. The maximum and operating pressures at which the fluid in the pipe or vessel operates. Operating pressures are provided by the Process Engineer in the SPI process data module or can be found on the Piping Line List.

11. The maximum and operating temperatures at which the fluid in the pipe or vessel operates. Operating temperatures are provided by the Process Engineer in the SPI process data module or the Piping Line List.

12. Fluid density should be provided by the Process Engineer in the SPI process data module.

13. The minimum and maximum operating fluid liquid levels at which the ultrasonic level instrument will be required to measure. Minimum and maximum operating fluid levels are provided by the Process Engineer.

14. Fluid specific gravity should be provided by the Process Engineer in the SPI process data module.

15. Fluid dielectric constant should be provided by the Process Engineer in the SPI process data module.

16. Enter the material of the tank wall on which the ultrasonic level instrument is attached. If the tank has a liner, enter the material of the tank liner.

17. Denote the type of sensor used, such as non-contact ultrasonic.

18. Denote where the sensor is to be installed. Typically this will be the tank roof.

19. Enter the ultrasonic level instrument sensor material. Normally this material should be compatible with the plant environment. Consult the manufacturer's catalog for available materials including compatibility to the process maximum pressure and temperature.

20. Enter the ultrasonic level instrument seal material. Normally this material should be compatible with the plant environment. Consult the manufacturer's catalog for available materials including compatibility to the process maximum pressure and temperature.

21. Enter the ultrasonic level instrument wetted parts material. Normally this material should be compatible with the plant environment. Consult the manufacturer’s catalog for available materials including compatibility to the process maximum pressure and temperature.

22. Denote whether the ultrasonic level instrument transmitter housing will be integral to the sensor or remote mounted from the sensor.

23. If the ultrasonic level instrument transmitter will be remote mounted from the sensor, denote the distance from the ultrasonic level instrument sensor to the transmitter.

24. Enter the total possible measuring range of the ultrasonic level instrument sensor. Consult the manufacturer’s catalog for ultrasonic level instrument capabilities.

25. Enter ultrasonic level instrument pressure and temperature ratings as provided by the manufacturer.

26. Enter the size for the process connection on the ultrasonic level instrument. Enter the connection rating for the ultrasonic level instrument process connection.

27. Enter the ultrasonic level instrument transmitter tag number from the P&ID. Typically, this is the same tag number from Line 1.

28. Enter the vessel fluid range that the ultrasonic level instrument transmitter will need to measure. This range is selected to cover the level points as noted on the P&ID by the Process Engineer. Consult with the project Process Engineer for vessel fluid range if not denoted on the P&ID.

29. Denote the type of signal output the transmitter will provide such as 4 – 20 mA and the type of protocol used to communicate, such as HART or Foundation Fieldbus.

30. Denote whether or not a display is to be included in the ultrasonic level instrument transmitter housing. Specify a display calibration range which is typically the transmitter calibrated range.

31. Denote how the transmitter is to be calibrated by the vendor.

32. Denote the voltage level that the ultrasonic level instrument transmitter uses, such as 24 VDC loop or external power, 120 VAC, etc.

33. Enter the transmitter accuracy and repeatability as noted in the manufacturer’s catalog.

34. Enter the electrical connection size and type. Electrical connections are normally 1/2” NPT for electrical conduit entry. Consult manufacturer's catalog for available connection sizes and compliance with the design installation details.

35. Denote the type of switch contact, such as mercury, snap, etc. and denote the number of switch contacts within the switch housing.

36. Denote the action of the switch contacts, i.e. on rising liquid level the contacts open or close. Denote the cause of the actuation, such as low liquid level, high liquid level, etc.

37. Denote the switch contact form, such as SPST, SPDT, etc. Denote the switch contact rating in voltage and amperes.

38. Denote the switch contact load type, such as inductive or non-inductive, and denote if the switch deadband is adjustable or fixed.

39. Denote the setpoint at which the switch is to actuate and specify a setpoint range within which the setpoint maybe established or within which the setpoint is allowed to occur.

40. Denote the type of switch contact, such as mercury, snap, etc. and denote the number of switch contacts within the switch housing.

41. Denote the action of the switch contacts, i.e. on rising liquid level the contacts open or close. Denote the cause of the actuation, such as low liquid level, high liquid level, etc.

42. Denote the switch contact form, such as SPST, SPDT, etc. Denote the switch contact rating in voltage and amperes.

43. Denote the switch contact load type, such as inductive or non-inductive, and denote if the switch deadband is adjustable or fixed.

44. Denote the setpoint at which the switch is to actuate and specify a setpoint range within which the setpoint maybe established or within which the setpoint is allowed to occur.

45. Enter the name of the vendor who sold the ultrasonic level instrument.

46. Enter the name of the ultrasonic level instrument manufacturer.

47. Specify the model number of the ultrasonic level instrument from the manufacturer's catalog or as provided in the vendor's quotation.

48. Enter the purchase order number for the ultrasonic level instrument.

Notes:

Include any explanatory notes for the manufacturer here.

As a minimum specify the following:

1. Any special tagging requirements.
2. Denote the ambient temperature range from the process site conditions document.
3. Enter the vessel trim number along with the vessel material of construction.
4. Denote the required flange finish if the ultrasonic level instrument's connections are to be flanged.

	RADAR LEVEL				SHEET––––––––––– OF–––––––––
	No.	BY	DATE	REVISION	SPEC. NO. / REV
					CONTRACT / DATE
					REQ. P.O.
					BY / CHK'D / APPR.

GENERAL	1	Tag No.			
	2	Service			
	3	Application			
	4	Vessel Number	Line Number		
	5	Vessel Int. Diameter	Vessel Length		
	6	Line Size	Line Schedule		
	7	Vessel Material	Line material		
	8	Area Classification			
	9	Ambient Temperature			
	10	P&ID Number			
	11	Vessel Orientation	Type		
PROCESS CONDITIONS	12	Fluid Name			
	13	Specific Gravity			
	14	Viscosity			
	15	Temperature Oper.	Max.		
	16	Pressure Oper.	Max.		
	17	Max. Liquid Level (Tank Bot.=0)			
	18	Min. Liquid Level (Tank Bot.=0)			
RADAR GAUGE SYSTEM	19	Model			
	20	Measurement Principle			
	21	Signal Processing	Oper. Frequency		
	22	Measurement Range			
	23	Accuracy			
	24	Ingress Protection – IEC Certificate			
	25	Elect. Protection			
ANTENNA	26	Type			
	27	Function			
	28	Stem Length	Diameter		
	29	Process Connection			
	30	Mounting Position	Mounting Location		
	31	Mounting Type			
	32	Distance (Adapter Plate to Tank Bot)			
	33	Material			
ANTENNA UNIT	34	Function			
	35	Output			
	36	Mounting Location			
	37	Cable to Control Unit			
CONTROL UNIT	38	Function			
	39	Local Display	Programming Access		
	40	Output			
	41	Power Supply			
	42	Mounting Location			
OPTION	43	Special Painting			
	44	Installation Kit			
	45	Cable (Antenna Unit to Control Unit)			
PURCHASE	46	Vendor	Price		
	47	Manufacturer			
	48	Model			
	49	Purchase Order Number			
	50	Serial Number			

Note:

RADAR LEVEL

Following are instructions for completion of the SPI Instrument Specification for radar level instruments. Required reference documents are P&ID's, Piping Line Class Specifications and radar level instrument Manufacturer's catalog.

1. Enter the radar level instrument tag number from the P&ID.

2. Enter a narrative description of the process service in which the radar level instrument is installed. Example; P-101 Stripper Bottoms

3. Denote the type of application that the radar level instrument will be used in, such as solids level, liquid level, etc.

4. Enter the vessel number on which the radar level instrument is attached. Enter the process line number from the P&ID (if applicable).

5. Enter the interior diameter and length of the vessel on which the radar level instrument is attached.

6. If applicable, enter the process line size from the P&ID and the pipe schedule. Common examples are the use of stilling wells and stands pipes or level bridles used for mounting of radar gage.

7. Line material of the stilling well or stand pipe.

8. Enter the electrical area classification where the radar level instrument is located in the field. Consult with the project Electrical Engineer for Area Classification. Generally, Class 1, Division 2, Groups C & D. (Group B if Hydrogen is present.)

9. Denote the ambient temperature range from the process site conditions document.

10. Insert the P&ID number on which the radar level instrument is located.

11. Denote the orientation of the vessel, such as horizontal or vertical and denote the type of vessel on which the radar level instrument is mounted, such as ASME, conical roof, etc.

12. Enter the type of fluid in the pipe or vessel to which the radar level instrument is attached, such as gasoline, water, hydrocarbon condensate, etc.

13. Fluid specific gravity should be provided by the Process Engineer in the SPI process data module.

14. Fluid viscosity should be provided by the Process Engineer in the SPI process data module.

15. The maximum and operating temperatures at which the fluid in the pipe or vessel operates. Operating temperatures are provided by the Process Engineer in the SPI process data module or can be found on the P&ID under the Vessel Information as Operating and Design Temperature.

16. The maximum and operating pressures at which the fluid in the pipe or vessel operates. Operating pressures are provided by the Process Engineer in the SPI process data module or can be found on the P&ID under the Vessel Information as Operating and Design Pressure.

17. The maximum operating fluid liquid level in reference to the tank or vessel bottom at which the radar level instrument will be required to measure. The maximum operating fluid level is provided by the Process Engineer.

18. The minimum operating fluid liquid level in reference to the tank or vessel bottom at which the radar level instrument will be required to measure. The minimum operating fluid level is provided by the Process Engineer.

19. Specify the model number series of the radar level instrument from the manufacturer's catalog or as provided in the vendor's quotation.

20. Specify either Non-Contacting (Propagation) or Guided Wave Radar.

21. Denote the type of signal processing the radar level instrument is provided with as noted in the manufacturer's catalog. Enter the frequency at which the radar level instrument operates.

Example of Non-contacting radar gage: Pulsed, free propagating / 6 GHz. Example of Guided Wave Radar: Time Domain Reflectometry (TDR) / leave blank.

22. Enter the vessel fluid range that the radar level instrument transmitter will need to measure. This range is selected to cover the level points as noted on the P&ID by the Process Engineer. Consult with the project Process Engineer for vessel fluid range if not denoted on the P&ID.

23. Enter the radar level instrument's accuracy as noted in the manufacturer's catalog.

24. Enter the enclosure type such as NEMA 4X or IP66.

25. Enter if CENELEC or UL Certificates stamps are required for electrical protection.

26. Enter the type of antenna, such as cone, parabolic, for non contacting and Coaxial probe rigid or flexible for guided wave radar.

27. Enter the radar level instrument's function. The instrument's function can either be Continuous Level Surface, Continuous Interface Level, or Continuous Level Surface and Interface Level.

28. Specify the length of the radar level instrument's antenna along with the antenna's diameter. Consider the nozzle projection from the top of the vessel as well as the nozzle pipe schedule. In application where and external stand pipe is being use, you must also consider the inside length of the stand pipe.

29. Enter the size, type and connection rating for the process connection on the radar level instrument. If applicable, include the process connection flange material. For example: 2" 150# RF.

30. Denote the mounting position of the radar level instrument antenna in reference to the vessel or tank and denote the mounting location, such as xx feet from the center of the tank. In application where and external stand pipe is being use, enter Stand Pipe or if a stilling well is being used enter stilling well.

31. Enter the mounting type such flange adapter plate for gage NPT connections

32. Specify the distance from the bottom of the vessel or tank to the bottom of the radar level instrument's antenna.

33. Enter the radar level instrument antenna material, antenna sealing material and o-ring materials. Normally this material should be compatible with the plant environment. Consult the manufacturer's catalog for available materials including compatibility to the process maximum pressure and temperature.

34. Enter the radar level instrument's function. The instrument's function can either be Local Indication only, Indicating Transmitter or Transmitter only, which is determined from the control function shown on the P&ID.

35. Denote the type of signal output the antenna will provide.

36. Denote if the radar level instrument's electronics are integral to the antenna or remotely mounted

37. If the transmitter is to be remote mounted from the antenna, specify if the vendor is to provide cabling between the antenna and transmitter. Enter the type of cable that the vendor will supply.

38. Enter the radar level instrument's function. The instrument's function can either be Control or Indication which is determined from the control function shown on the P&ID. Control function would include tank gauging applications where multiple temperature and pressure compensation calculation would be performed in the Control Unit.

39. Denote whether or not a local indicator is to be included in the radar level instrument's transmitter housing. Specify a display calibration range which is typically the transmitter calibrated range. Denote whether or not special programming access is available with the transmitter housing.

40. Denote the type of signal output the transmitter will provide such as 4 – 20 mA and the type of protocol used to communicate, such as HART or Foundation Fieldbus.

41. Denote the voltage level that the radar level instrument uses, such as 24 VDC loop or external power, 120 VAC, 60 Hz, 1-phase.

42. Specify if the transmitter is integral to the antenna or is to be remote mounted.

43. Denote whether or not any special painting is required.

44. Denote whether or not an installation kit is required to be supplied with the radar level instrument.

45. See Line 37.

46. Enter the name of the vendor who sold the radar level instrument. Do not fill in the price field. Prices will be shown on the purchase order.

47. Enter the name of the radar level instrument manufacturer.

48. Specify the model number of the radar level instrument from the manufacturer's catalog or as provided in the vendor's quotation.

49. Enter the purchase order number for the radar level instrument.

50. Do not fill in the serial number. This can be filled in later by Plant Maintenance if required.

Notes:

Include any explanatory notes for the manufacturer here.

As a minimum specify the following:

1. Enter the Dielectric Constant of the fluid, if measuring interface enter both upper and lower fluid Dielectric Constants. This is applicable for Guided Wave Radar gages.

2. Any special tagging requirements.

3. Enter the vessel trim number.

4. Denote the transmitter enclosure material.

5. Denote the vessel nozzle projection and schedule on which the radar level transmitter is to be installed.

6. Denote the electrical connection size and type. Electrical connections are normally 1/2" NPT for electrical conduit entry. Consult manufacturer's catalog for available connection sizes and compliance with the design installation details.

7. Denote the required flange finish if the radar level instrument's connections are to be flanged.

8. Denote whether the displacer level instrument has any special type of material requirements, such as PMI, NACE, etc.

APPENDIX B
ADDITIONAL REFERENCES

1) SHELL

   DEP 32.31.00.32-Gen "Instruments for Measurement and Control"