



RP 30-2

INSTRUMENTATION AND CONTROL

SELECTION AND USE OF

MEASUREMENT INSTRUMENTATION

September 1993

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BP GROUP RECOMMENDED PRACTICES AND SPECIFICATIONS FOR ENGINEERING											
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SCOPE AND PURPOSE This Recommended Practice provides guidance on the design and application of Measurement Instrumentation used in production and process plant, storage facilities, pipelines and other installations handling flammable gasses and liquids. Its purpose is to provide design engineers and plant management with:- (a) guidance on the need and applicability of Measurement Instrumentation. (b) a basis for designing, evaluating and selecting types of Measurement Instrumentation for various duties. (c) guidance on health and safety aspects associated with the design, installation and operation of Measurement Instrumentation.											
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FOREWORD

Introduction to BP Group Recommended Practices and Specifications for Engineering

The Introductory volume contains a series of documents that provide an introduction to the BP Group Recommended Practices and Specifications for Engineering (RPSEs). In particular, the 'General Foreword' sets out the philosophy of the RPSEs. Other documents in the Introductory volume provide general guidance on using the RPSEs and background information to Engineering Standards in BP. There are also recommendations for specific definitions and requirements.

General

This is a revision of Part 2 of BP Recommended Practice CP 18, previously issued in separate sections from April 1986 onwards. With its supplementary 'yellow page's' it has been rationalised into a single document BP Group RP 30-2 composed of twelve sections:-

Section 1	Introduction
Section 2	Temperature Measurement
Section 3	Pressure Measurement
Section 4	Liquid Level Measurement
Section 5	Flow Measurement
Section 6	Storage Tank Measurement
Section 7	On Line Analysis
Section 8	Automatic Samplers for Offline Analysis
Section 9	Weighing Systems
Section 10	Environmental Monitoring
Section 11	HVAC Instrumentation
Section 12	Drilling Instrumentation

These Sections reflect the applicable previous sections generally retaining previous content but in some cases additional sections and sub-sections have been added (see Cross Reference List, page vii).

This document specifies all BP's general requirements for Measurement Instrumentation that are within its stated scope and is for use with a supplementary specification to adapt it for each specific application.

Value of this Recommended Practice

This Recommended Practice gives the basis for the Selection and Use of Measurement Instrumentation and the design of associated systems. It has been developed from cross-Business experience gained during capital project developments, operations and maintenance; and from equipment developments and evaluations carried out under BP's Business and Corporate R&D programme.



The document covers the rapidly developing field of digital technology, and gives guidance on measurement instrumentation strategy, equipment selection and project development which is not available from industry, national or international codes.

Where such codes exist for established elements of the technology, the document guides the user as to their correct application.

It is intended to review and update this document at regular intervals, because it is essential to maintain BP's commercial advantage from the effective deployment of the rapidly developing technology covered by this Practice.

Application

Text in italics is Commentary. Commentary provides background information which supports the requirements of the Recommended Practice, and may discuss alternative options. It also gives guidance on the implementation of any 'Specification' or 'Approval' actions; specific actions are indicated by an asterisk (*) preceding a paragraph number.

This document may refer to certain local, national or international regulations but the responsibility to ensure compliance with legislation and any other statutory requirements lies with the user. The user should adapt or supplement this document to ensure compliance for the specific application.

Principal Changes from Previous Edition

Principal changes to Sections Issued from March 1991:-

- (a) The Practice has been revised to the new format to rationalise the sections and to integrate the commentary into the main text.
- (b) The sections have been updated to include references to new standards and reflect changes in operating practices.
- (c) Section numbering has been amended to suit the applicable part.

The cross-referenced table at the end of this foreword shows relationships between new documents and the old CP18.

Feedback and Further Information

Users of BP RPSEs are invited to submit any comments and detail experiences in their application, to assist in their continuous improvement.

For feedback and further information, please contact Standards Group, BP International or the Custodian. See Quarterly Status List for contacts.



LIST OF SECTIONS CROSS REFERENCED TO CP 18

RP 30-1 TO RP 30-5

No equivalent in RP 3~X

CP 18 PARTS AND SECTIONS

Part 1 (Foreword and Introduction)

RP 30-1 INSTRUMENTATION AND CONTROL DESIGN AND PRACTICE

Part 2 Systems, Design and Practice

Section 1	Introduction	E Section 1	Introduction
Section 2	Control Engineering Principles	E Section 2	Control Engineering Principles
Section 3	Selection of Instrumentation Equipment	E Section 3	Selection of Instrumentation Equipment
Section 5	Earthing and Bonding	E Section 5	Earthing and Bonding
Section 6	Instrument Power Supplies	E Section 6	Instrument Power Supplies
Section 7	Instrument Air Systems	E Section 7	Instrument Air Systems
Section 8	Hydraulic Power Systems	E Section 8	Hydraulic Power Systems
Section 9	Control Panels	E Section 9	Control Panels
Section 10	Control Buildings	E Section 10	Control Buildings
Section 11	Instrument Database Systems	Section 11	Digital Systems (to RP 30-4 , Sect 2)
		+ Section 12	Advanced Control System (to RP 30-4 , Sect. 5)
		+ Section 13	Telecommunications (to RP 30-4 , Sect. 3)

RP 30-2 INSTRUMENTATION AND CONTROL SELECTION AND USE OF MEASUREMENT INSTRUMENTATION

Part 3 Measurement

Section 1	Introduction	E Section 1	Introduction
Section 2	Temperature Measurement	E Section 2	Temperature Measurement
Section 3	Pressure Measurement	E Section 3	Pressure Measurement
Section 4	Liquid Level Measurement	E Section 4	Liquid Level Measurement
Section 5	Flow Measurement	E Section 5	Flow Measurement
Section 6	Storage Tank Measurement	E Section 6	Storage Tank Measurement
Section 7	On Line Analytical Measurement	E Section 7	Measurement
Section 8	Automatic Samplers for Offline Analysis	E Section 8	Automatic Samplers for Offline Analysis
Section 9	Weighbridges and Weighscales	E + Section 9	Weighing Systems
Section 10	Environmental Monitoring		
Section 11	Instrumentation for HVAC systems		
Section 12	Drilling Instrumentation		

RP 30-3 INSTRUMENTATION AND CONTROL SELECTION AND USE OF CONTROL AND SHUTOFF VALVES

Part 4 Valves and Actuators

Section 1	Introduction	E Section 1	Introduction
Section 2	Regulating Control Valves	E Section 2	Regulating Control Valves
Section 3	Power Actuated Isolating Valves	E Section 3	Power Actuated Isolating Valves

RP 30-4 INSTRUMENTATION AND CONTROL SELECTION AND USE OF CONTROL AND DATA ACQUISITION SYSTEMS

Section I	Introduction
Section 2	Digital Systems (new commentary added)
Section 3	Telecommunications
Section 4	Subsea Control Systems
Section 5	+ Advanced Control Systems

RP 30-5 INSTRUMENTATION AND CONTROL SELECTION AND USE OF EQUIPMENT FOR INSTRUMENT PROTECTION SYSTEMS

Part 5 Protective Systems

Section I	Introduction	E Section I	Introduction
Section 2	Protective Instrument Systems	E Section 2	Protective Instrument Systems
Section 3	Alarm systems	E Section 3	Alarm Systems
Section 4	Fire and Gas Detection and Control Systems	E Section 4	Fire and Gas Detection and Control Systems
Section 5	Pipeline Leak Detection	E + Section 5	Pipeline Leak Detection
E-	equivalent (not identical)		
+/-	yet to be published		



1. INTRODUCTION

1.1 Scope

- 1.1.1 This Practice specifies BP requirements for the Selection and use of measurement Instrumentation. It contains sections that have general application to the provision of instrumentation and instrumentation systems including general principles, documentation and requirements for common systems.
- 1.1.2 BP requirements for instrumentation for the measurement of temperature, pressure, liquid level, flow, chemical composition and quality; in both onshore and offshore application are covered.
- 1.1.3 Other Instrumentation and Control Practices related to BP Group RP 30-2 specify BP General requirements for design and practice and requirements for specific equipment, i.e. Valves and Actuators, Control and Data Acquisition systems and Protective systems.

1.2 Application

- 1.2.1 Reference shall be made to BP Group [RP 30-1](#) to ensure that all relevant BP requirements for instrumentation are complied with.
- 1.2.2 To apply this Part, it shall be necessary to make reference to other BP RPSEs, national codes and standards as indicated in the relevant text.
- 1.2.3 Reference is made in the text to British Standards. These standards are generally being harmonised with other European standards and will be allocated ISO/EN reference numbers. In certain countries, national Standards may apply. BP shall approve use of other standards.

1.3 Units

- 1.3.1 This Practice employs SI metric units.
- 1.3.2 Nominal pipe sizes (NPS) are ANSI or API designations which have not yet been metricated. However, metric DN numbers are given in brackets.

bar - Except when referring to a pressure differential, the unit is stated as gauge pressure, bar (ga) or absolute pressure, bar (abs). Gauge pressure is measured from standard atmospheric pressure of 1.01325 bar.



1.4 Quantity Assurance

Verification of the vendor's quality system is normally part of the pre-qualification procedure, and is therefore not specified in the core text of this Recommended Practice. If this is not the case, clauses should be inserted to require the vendor to operate and be prepared to demonstrate the effectiveness of their quality system to the purchaser. The quality system should ensure that the technical and QA requirements specified in the enquiry and purchase documents are applied to all materials, equipment and services provided by sub-contractors and to any free issue materials.

Further suggestions may be found in the BP Group RPSEs Introductory volume.

2. TEMPERATURE MEASUREMENT

This Section specifies BP general requirements for temperature measurement.

2.1 Selection of Primary Elements

2.1.1 Measurement Precision

The type of element and its installation shall ensure that the overall discrimination and accuracy of measurement is consistent with application requirements.

To achieve accurate measurement, the sensitive length of the element shall match the thermowell provided; and shall ensure an adequate immersion depth into the line or vessel.

Good thermal contact between the sensitive part of the element and the thermowell is a requirement. Any filling medium used to achieve this requirement shall be restricted to the sensitive area, and shall not result in a thermal shunt to atmosphere.

2.1.2 Local Use

The preferred ranges for local indicators are as follows:-

40 °C	to	+80 °C	(-40 °F	to	+176 °F)
0 °C	to	+120 °C	(+32 °F	to	+248 °F)
0 °C	to	+200 °C	(+32 °F	to	+392 °F)
0 °C	to	+400 °C	(+32 °F	to	+752 °F)

These are preferred ranges only. The chosen manufacturer may not have the exact ranges, in which case the nearest standard ranges should be used. The number of ranges used should be kept to a minimum.



Bimetallic dial thermometers should be used for local indication; except for applications requiring the indication remote from the sensor, and for those requiring an accuracy of $\pm 1\%$ of span or better.

For local indications not requiring great accuracies ($\pm 1\%$ of span or less), bimetallic indicators are used; they are robust and cheap and can be used over the range of most process measurements $[-50^{\circ}\text{C}$ (-58°F) to $+500^{\circ}\text{C}$ ($+932^{\circ}\text{F}$)]. However, they can only be used for local mounting.

Where applications require indication remote from the sensor or where accuracy of $\pm 1\%$ of span or better is required, liquid filled dial thermometers should be used.

Where accuracies of $\pm 1\%$ of span or better are required, filled system indicators are used and can be supplied with a variety of fillings. These indicators are available with rigid stems, as for bimetallic indicators, or where the sensing point is inaccessible, the dial can be installed some distance away.

Where filled systems are used, the preferred filling liquid is mercury. These are available in the approximate range of bimetallic systems $[-40^{\circ}\text{C}$ (-40°F) to $+600^{\circ}\text{C}$ ($+1112^{\circ}\text{C}$)] and have a small bulb volume when compared with other forms of filling.

For the range -40°C (-40°F) to -120°C (-184°F), liquid filled systems should also be used, but the liquid filling will be different.

For the range -120°C (-184°F) to -200°C (-328°F), gas filled systems should be used, but the bulb volume is greater than that of liquid filled systems.

Vapour filled systems are not recommended for use as they suffer from the 'cross ambient' effect and are affected by any level difference between the sensor and indicator.

For liquid filled systems there is a slight effect due to ambient temperature changes, causing expansion or contraction in capillaries. Therefore, the capillary length is limited. This effect is less with mercury than with other liquids and is also found to a lesser extent with gas filled systems.

Where capillaries are used to connect the sensing element to the receiver, they should be compensated for longer lengths and for higher accuracy. As the reading can be affected by lengths of capillary, it is recommended that the capillary length should be limited to 35-40 metres (115-130 ft). Usually, capillaries are supplied with a minimum length of 3 metres (10 ft). Capillaries should be of a minimum length necessary, but modified by the spares holding requirement and hence chosen as a series of standard lengths.

Unprotected glass thermometers shall be used only for test measurements. Glass thermometers protected by a metal case may be used on low pressure water or lube oil applications provided they are fitted into thermowells.

On low pressure water or lube oil applications, particularly on rotating equipment, glass thermometers protected by a metal case can be more accurate although prone to breakage. This type of thermometer is not recommended for general plant use.

2.1.3 Remote Use

Thermocouples or resistance thermometers should be used for remote temperature measurement.

Resistance thermometers are preferred for measurements between -200 °C and +750°C provided this falls within the range recommended by the manufacturer, and the application does not suffer from vibration. Thermocouples should be used where resistance thermometers are not suitable.

For remote monitoring and control, RTD's should normally be used; they are accurate, do not suffer from cold junction problems and costs are similar to thermocouples.

* 2.1.4 Use Within Control, Alarm and Protective Systems

Thermocouples or resistance thermometers should be used for control, alarm and protective applications. Bimetallic and filled systems are a non-preferred option, and may only be used with BP approval.

Filled systems have an inherent failure mode such that when failed they indicate low temperature (i.e. the unsafe conditions for many applications). Bimetallic and filled systems are difficult to check locally, are susceptible to mechanical damage and failures are not self revealing.

Because of the above, the use of bimetallic and filled systems on control, alarm and shutdown service is not recommended. However, for some applications such as for local control on non-critical service or on pneumatic systems, (e.g. tank heating and electrical tracing) their use may be considered. Also, such systems are often supplied as part of a packaged plant. In this case, where such criteria as contractual guarantees are involved, the use of these systems should be individually assessed.

2.2 Bimetallic Thermometers

2.2.1 Bimetallic thermometers should be supplied with a means of adjusting the head orientation.

Adjustable head thermometers may be marginally dearer than fixed head type, but overall, the cost difference weighed against the operational advantages seems little. In certain cases the Project may agree to the use of fixed head thermometers (e.g. at ground level).

2.2.2 The element diameter shall be the manufacturer's standard with the thermowell bore supplied to suit, but subject to a maximum bore of 13 mm diameter.



2.3 Filled Systems

- 2.3.1 Within the range -40°C (-40°F) to +600°C (+1112°F), the filling material should be mercury. Where plant comprises equipment manufactured from aluminium, alternative fillings to mercury shall be used.

Should the element rupture, mercury could come in contact with aluminium plant equipment with serious consequences. Mercury and aluminium form an amalgam which severely degrades material strength. Ref to specialist metallurgist for advice.

- 2.3.2 The bulb and capillary material should be AISI Type 316 stainless steel. The capillary should be armoured and sheathed overall in PVC or polyethylene.

Capillaries should be sheathed in PVC as a standard. However, if plant atmosphere or spilt product could degrade PVC, polyethylene should be used.

- 2.3.3 Clause 2.2.2 above applies.

2.4 Thermocouples

- 2.4.1 Thermocouple characteristics should comply with [BS 4937](#) to tolerances specified in [BS 1041](#) : Part 4.

- 2.4.2 For the operating conditions shown, the following thermocouple types shall be used:-

Below 0°C (32°F) copper/copper-nickel
(Type T - see [BS 4937](#) : Part 5)

0°C-1100°C (32°F-2012°F) nickel-chromium/nickel-aluminium
(Type K - see [BS 4937](#) : Part 4)

Above 1100°C (2012°F) platinum -13% rhodium/platinum
(Type R - see [BS 4937](#) : Part 2)

- 2.4.3 Thermocouples should be mineral insulated to dimensions in accordance with [BS 2765](#), and with the hot junction insulated from the sheath.

It is preferred that the tip is insulated from earth as this makes both installation and earthing system cheaper and easier.

- 2.4.4 The element diameter should be 6 mm nominal.

The overall element length should be chosen to give a minimum spares holding.

2.4.5 Thermocouples should be terminated in a two wire block with clamp terminals and spring loaded head to ensure good tip contact with the well. Clamp terminals should be identified by polarity. Wire terminations (flying leads) should be colour coded to [BS 1843](#) or the ends sleeved and identified by polarity.

2.4.6 Thermocouples shall be provided with weatherproof terminal head assemblies to a degree of protection of IP 55 as specified in [BS 5345](#): Part 1, Appendix A. A union in the head conduit should be provided to allow head orientation.

2.4.7 For differential temperature measurement using thermocouples, two thermocouples connected in opposition into one measuring instrument should be used.

For differential temperature measurements, thermocouples connected back-to-back with a single converter are preferred with 'burn out' arrangements as required. However, as thermocouples are non-linear devices, should the difference of temperature be so great that non-linearity affects the required accuracy, individual converters or resistance thermometers may be necessary.

2.5 Resistance Thermometers

2.5.1 Resistance thermometers should comply with [IEC 751 \(BS 1904\)](#) and have a resistance of 100 ohms at 0°C (32°F) and a fundamental interval of 38.5 ohms.

The tolerance values of resistance thermometers are usually Class A or Class B as defined in [IEC 751 \(BS 1904\)](#). However, in some cases higher accuracy may be required. In these cases, it may be possible to purchase high accuracy class A RTD's to 1/3 DIN Standard or to have the resistance thermometer individually calibrated or a special thermometer manufactured which has a higher resistance at 0°C (32°F) or a higher fundamental interval, or both.

2.5.2 The thermometer dimensions should comply with [BS 2765](#) with an element diameter of 6 mm nominal.

The overall element length should be chosen to give a minimum spares holding.

2.5.3 Simplex resistance thermometers should be of the four wire type suitable for both voltage and current configuration. Resistance thermometers may be used in a three wire duplex configuration, provided the error criteria of 2.6.2 are met.

This allows for any configuration of receiver equipment to be used.

2.5.4 Resistance thermometers should be terminated in a four or six wire block with clamp terminals and a spring loaded head to ensure good tip contact with the well.

2.5.5 Resistance thermometers shall be provided with weatherproof terminal head assemblies to a degree of protection to IP 55 as specified in [BS 5345](#): Part 1, Appendix A. A union in the head conduit should be provided to allow head orientation.

2.5.6 Resistance thermometer circuit design should ensure that unrevealed faults will not impair plant control or safety.

Wiring or component faults within the primary measuring circuit may cause a transmitter or trip amplifier to 'fail to danger' (e.g. if the reference arm goes open circuit). Any requirement for fault alarming or secondary protective action should be assessed.

2.5.7 For differential temperature measurements using resistance thermometers, a four wire system should be used. Where such a system will not give the required accuracy, a six or eight wire system should be used.

Where small differential temperatures are to be measured or the non-linearity of thermocouple measurements is significant, a differential resistance system should be used. A four wire configuration (i.e. no compensation) is preferred. The signal cables should be of approximately equal lengths or ballasting resistors used.

2.6 Cables

2.6.1 Cables shall conform to the requirements of BP Group [RP 30-1](#) Section 3.

2.6.2 Resistance thermometers should be connected to measuring instruments by a four wire system. Three wire systems may be used where it can be demonstrated that errors due to cable length or ambient temperature variations are within the measurement accuracy requirements.

2.6.3 Compensating leads for thermocouple measurements should be:-

For Type T thermocouples	copper/copper-nickel (copper/constantan)
For Type K thermocouples	copper/copper-nickel (copper/constantan)
For Type R thermocouples	Specially characterised copper/copper-nickel (copper/constantan)

Compensating cables have approximately the same e.m.f. characteristics as the thermocouple wire, but they do introduce small additional errors. Where the small error can be accepted, they are used, being cheaper than extension cables. Where this error is not acceptable, extension cables (cables which have the same composition as the thermocouple wires) should be used. Also note, wherever

practical and economic Thermocouple head transmitters should be used, as those do not require compensating cable.

- 2.6.4 The temperature at the junction between the thermocouple and compensating leads should not exceed 60°C (140°F).

For junctions above 60°C (140°F) use extension cable to the first junction box, unless the increased errors can be accepted (see 2.6.3).

2.7 Thermowells

- 2.7.1 Temperature sensing elements shall be installed in thermowells accordance with Figs 2-1), 2-2) and 2-3) of this section; selection and materials of construction being in accordance with BP Group [RP 42-1](#).

BP standard thermowells should be used for all general purpose applications. However, in some cases where the speed of response or the type of line connection (e.g. welded-in connections) the standard thermowell may not be suitable. In these cases, special wells or no wells at all may be necessary (just a supporting probe).

For detecting elements, where it is specified that the sensing element outside diameter does not exceed a specified value, the element should fit snugly into the well bore. It is not intended that heat conducting filling materials are used as packing.

- * 2.7.2 Where special thermowells are required, for example for:-

- (a) fast response,
- (b) corrosive service,
- (c) erosive service,
- (d) reactor bed temperatures,
- (e) for installation in lines less than 4 in diameter,
- (f) within analyser installations.

The design of the well shall be subject to approval by BP.

It may be necessary to coat thermowells in high corrosive or erosive processes. Advice from manufacturers on various coatings should be obtained.

Where resistance thermometers and thermocouples are installed in tanks or reactors, fabricated wells may be used as they need usually to withstand only the pressure and temperature and not be subject to appreciable flowing fluid forces. These thermowells are also usually very much longer than the standard wells and have a larger bore as they may house multiple elements.

On small diameter pipework, very short thermowells may be required. In such a case the outer diameter of the well may also be required to be thinner in order to avoid large lags or measurement errors.

- 2.7.3 Elements shall be removable during normal plant operations, except under the following circumstances:-



- (a) Where bearing or motor/generator winding temperatures are being measured via embedded mineral insulated sensors.
- (b) On air conditioning systems, where removal and subsequent re-insertion of the sensor can be achieved without undue problems.
- (c) Where skin temperatures of heater or boiler tubes are measured by direct contact sensors.

In the listed cases ((a), (b) and (c)) thermowells are commonly not used. There is however a requirement to seal the process from the environment. The common method is via a compression fitting. On certain applications (e.g. reactor bed temperature), it may be necessary to pass the sensor through a special isolating shear valve in such a way that in the event of a failure of the compression fitting, isolation of the process can be achieved. In such cases care must be taken to ensure that the temperature sensor does not drop into the process. This may require the use of a special probe with a reduced diameter tip.

When sensors are installed without a thermowell and the process fluid is potentially hazardous, then the circuit should be intrinsically safe. It may be necessary to install a ball valve between the head and the pipeline, capable of shearing the element and sealing the connection.

- 2.7.4 Applications where a fast response is required, (i.e. the measurement application cannot tolerate the thermal lag inherent in thermowells), shall be approved by BP.

Where no thermowell is fitted, an effective secondary seal shall be provided to prevent process fluid under pressure from entering transmission cables.

- 2.7.5 Test thermowells shall be fitted with plugs which shall be secured to the thermowell by a chain or wire of corrosion resistant material.

- * 2.7.6 Thermowells shall be assessed for resonance effects by a method approved by BP, where:-

- (a) Special designs of thermowell are used.
- (b) BP standard wells are used and the following velocity criterion is exceeded:-

Thermowell length (mm) 225, 300, 450

Gas or liquid velocity (m/s) 18, 11, 5

- (c) Excessive mechanical vibration or 'organ pipe' effect is expected.



Thermowells are subject to vibration transmitted from adjacent machinery or vortex shedding from high fluid flow rates.

It is not considered necessary to check wells, special or otherwise in tanks or reactors. The checking procedure for special wells should be agreed.

BP standard wells should be checked for resonance due to vortex shedding. Advice can be obtained from the Custodian of this document.

Thermowells should be assessed for resonant effects where expected oscillations either physically from rotating machinery transmitted through the pipework, or fluid, or from standing waves (organ pipe effect) in the fluid are expected to be near the resonant frequency of the thermowell.

- * 2.7.7 Heater skin sensing thermocouples should be in accordance with BP Group [RP 22-1](#) except for increased accuracy, fast response or low thermal mass installations. In these cases, the design of the installation shall be subject to approval by BP.

For skin temperature measurements on heaters and boilers, the type of temperature detector should be considered very carefully. The 'hockey stick' type is suitable only for low temperatures where accuracy is not critical and the problem of 'hot spots' on the tubes is not significant. For critical service (e.g. high-pressure boilers), specially designed pad type thermocouple installations of low thermal mass should be used. These give good accuracy, fast response and do not cause 'hot spots'.

The preferred spans for transmitters and switches are 50°C, 100°C, 200°C, 400°C, 1000°C and 1200°C. (122°F, 212°F, 392°F, 752°F, 1832°F and 2192°F).

2.8 Temperature Transmitters and Switches

- 2.8.1 Millivolt and resistance input transmitters and switches should be mounted in an environmentally controlled building. Field mounted devices may be used where their overall accuracy (including ambient temperature effects) is demonstrated as meeting application requirements), and the device is designed for the environment on the plant.

For individual loops, the conversion from the resistance or e.m.f. value to a standard signal is usually done in the control room or auxiliary instrument room as installation is easier. However, some systems either have the converters in the head of the field device or have field mounted transmitters similar in type to DP cells. This type of system can be used, provided the conversion accuracy is adequate and the cost of installation is less than that with a remote mounted converter.

- 2.8.2 All transmitters and switches shall have input and output isolation and linearising facilities.
- 2.8.3 Thermocouple devices should be supplied with upscale or downscale 'burn out' protection which shall be capable of elimination or reversal. Sensor failure should be alarmed wherever possible. The device



should respond to both a sensor failure and a measurement circuit wiring fault.

For services which are for operator monitoring only and do not affect plant operation (e.g. indications, recordings or alarms), the 'burn out' protection should drive the measured variable reading to a condition showing plant fault. For services which can affect plant operation (e.g. control loops and trip functions), it is desirable the plant should not be tripped, nor any control malfunction be caused by 'burn out' of a thermocouple. Two from three voting system may be required to achieve this. To alert the operator, an alarm on thermocouple 'burn out' should be included for each system for important functions which may trip controls to manual. On control shutdown applications, each application should be individually reviewed. Failure detection of a resistance thermometer is more clearly defined.

A fully independent alarm will result from the use of separate sensors and transmitters. Where functions are not so important, group alarms may be used.

2.8.4 For alarms, the 'burn-out' action should initiate the alarm condition.

* 2.8.5 For shut-down and control duties, each application should be individually assessed to ensure that sensor, transmitter or wiring failure modes inherently drive the plant to the safe condition, or the burn-out protection initiates action to protect the plant (e.g. switch controller to manual). The methods adopted shall be subject to approval by BP.

2.8.6 Diagnostic features within 'smart' transmitters may be used to achieve the same functionality.

2.9 Read-Out and Display

2.9.1 Temperatures shall be displayed in engineering units and clearly identified by reference to point tag number.

2.9.2 Multipoint temperature selection shall be by interlocking pushbutton switches, or by a multiplexed system with discretely coded selection.

Low signal level switching shall be carried out by a method which does not affect the signal accuracy (e.g. low contact resistance).

2.9.3 Alarm functions for critical measurements, and for all control applications, should be derived from an independent sensor. Duplex elements may be used but the subsequent measurement and alarm circuits, and associated systems must be independent.

Duplex elements are preferred as they are cheaper to install. They also give closer conformity of readings than with separate installations.

Where duplex thermocouple elements are used for intrinsically safe measurements, the insulation should be checked, to ensure that it meets the intrinsically safe requirements for the area in which it is installed.



2.10 Installation

- 2.10.1 Temperature systems shall be installed in accordance with BP Group [RP 30-1](#).

3. PRESSURE MEASUREMENT

This Section specifies BP general requirements for pressure measurement.

3.1 Selection of Primary Pressure Measuring Elements

- 3.1.1 Pressure elements should be specified such that the steady normal operating pressure is below 75% of the maximum range.

- 3.1.2 Pressure elements for use on applications subject to fluctuating pressures should be specified to operate below 60% of the maximum range. Manufacturers should be informed when a sensor will be subject to regular cyclic operation, and required to guarantee an acceptable fatigue life.

For most applications, standard ranges of pressure measuring devices can be used, as the required accuracy of measurement can be met by them. Also, the use of ranges starting from zero are easier to calibrate and check.

- 3.1.3 When the application demands a greater discrimination in the measured value, narrow span transmitters with elevated zero may be used.

In some cases (e.g. the measurement of extra high steam pressures) a full range instrument will not give the required accuracy of pressure measurement. In these cases, it may be necessary to reduce the span of the instrument around the working value to obtain the necessary accuracy.

- 3.1.4 Pressure elements with static head correction should have a pressure range which ensures that the sum of the static head and the operating pressure still satisfies the 75% conditions of above.

- * 3.1.5 Where the maximum range is less than the process design pressure, equipment with adequate over pressure protection shall be specified. The method of over-range protection shall be subject to approval by BP.

- 3.1.6 For the measurement of slurries, viscous or highly corrosive fluids for which a Bourdon tube or bellows element is unsuitable, a Shaffer diaphragm or liquid filled diaphragm sealed element shall be used. Refillable seals are preferred.



- 3.1.7 Seal materials should be carefully chosen to meet the application. Consideration should be given to temperature and pressure ratings, resistance to corrosion and the toxicity of the liquid fill.
- 3.1.8 For optimum reliability, transmitters should employ a proven principle of operation, with the minimum of moving parts; but consistent with the accuracy and stability required for the application.
- 3.1.9 'Smart' transmitters should be used where a wide range, high stability or high degree of accuracy is a requirement. They are also preferred for applications where unit standardisation (i.e. reduced spare parts inventory) or in-built diagnostic capabilities show a benefit in maintenance operations.

3.2 Indicators and Gauges

- 3.2.1 Pressure gauges shall be supplied in accordance with BP Group [GS 130-4](#).
- 3.2.2 Gauges for the measurement of differential pressure should be of the bellows, piston or diaphragm type. Dual element gauges should only be used when the differential pressure exceeds 10% of the available static pressure.
- 3.2.3 Draft gauges may employ a quadrant illuminated edgewise indicator of suitable size.
- 3.2.4 Water gauge U-tube manometers may be used for test purposes only.

3.3 Transmitters and Switches

- 3.3.1 Bourdon tubes, bellows or diaphragms used in indicators, switches or transmitters should be in accordance with BP Group [GS 130-4](#).
- 3.3.2 Where space is limited low mass transmitters that are close coupled to the process may be used. This method is preferred for offshore applications.
- 3.3.3 All transmitted signals should be linearised locally to the sensing elements, where this facility exists.
- * 3.3.4 Use of mercury bottles for switch contacts is not recommended and shall only be permitted with the approval of BP.



3.4 Installation

3.4.1 Reference shall be made to BP Group [RP 30-1](#) Section 4 for general requirements for installation of instruments.

Where pulsation damping is used, such as on the discharge of positive displacement pumps, devices which are field adjustable should not be used. Proprietary items of an acceptable type include dampers which can be supplied with a number of fixed orifices. Field adjustable orifices should not be used as they could be abused in service.

Where pulsation dampers are used, specific attention should be given to the process fluid. Mechanical dampers should not be used where they can be blocked by contaminations in the process fluid.

Pulsation dampers may be fitted in the clean side of a chemical seal, but due consideration should be given to the problem of damage to liquid filled systems, and leakage of the filling fluid.

On critical applications, such as trips, consideration should be given to the following:-

- (a) Devices such as piezoelectric or strain gauge transmitters which can be electrically damped, and are less susceptible to mechanical damage due to pulsations.*
- (b) Processing of digital inputs using a short delay timer to eliminate spurious transient inputs.*

Calibration Equipment

Suitable calibration equipment should be included in the project specification.

4. LIQUID LEVEL MEASUREMENT

This Section specifies BP general requirements for liquid level measurement on plant and equipment. Refer to Section 6 for storage tank measurement.

4.1 Selection of Level Measuring Devices

* 4.1.1 General Requirements

The selection of level measuring devices and their installation shall provide reliable reproducible measurement with emphasis on simplicity of installation, maintenance and testing.

Local level gauges shall cover the full working range of the vessel and the level instrumentation mounted on it.



The level transmitter range shall cover the operating levels of associated level switches.

Selection of equipment for liquid - liquid interface measurement applications shall take account of the differential density of the two fluids, and the possibility of emulsion layers forming under normal or abnormal process conditions. The contractor shall submit the proposed method of measurement to BP for approval.

The top instrument connection should be at least 25 mm (1 in) above the maximum interface level and the lower connection at least 25 mm (1 in) below the minimum interface level.

Level measurement for boiler plant drums (including waste heat boilers and fired heaters) shall conform to the relevant statutory requirements. Final selection of types of instruments to be provided shall be subject to approval by BP.

All externally mounted level instruments require a lagged condensing device to ensure that the water in the measuring instrument is as near as possible the same temperature as that in the drum.

For high pressure [56 bar (ga) (812 psig) and above], differential pressure transmitters with trip amplifiers provide more reliable alarm and shutdown initiation devices.

The Hydrostep is also recommended by the UK National Generating Companies and has their approval.

In extra high pressure boilers [98 bar (ga) (1421 psig) and above], where water surging can occur, at least two sets of level measurements and switches, measuring on each side of the drum should be used. The trip initiation should come from both sides of the drum on a two from three basis. Additional transmitters may be required for control.

All continuous level measurement instruments shall be provided with a means of in-situ calibration and testing. Particular attention should be given to the problems associated with the calibration of direct mounted level instruments.

* 4.1.2 Local Observation

Local indication of level should be provided by:-

- (a) Local gauges for vessels and small tanks. Gauges glasses overlapping connections to provide continuous measurement over the working range of the vessel may be used on larger vessels.

Gauge glasses do not provide easy indication when the fluid is dirty. If a local visual measurement is required, purging a lighter liquid between the vessel isolating and level gauge isolating valves or the use of magnetic type gauges should be considered.



- (b) Float type instruments for large tanks where fiscal-quality measurement is unnecessary.

Where the fluid is viscous, a displacer instead of a float should be considered; alternatively, a close coupled differential pressure instrument should be the next consideration.

- (c) Static head pressure measurement, but subject to approval by BP.

Measurement of the back-pressure of a constant flow purge into the vessel may be applied for corrosive or viscous fluid applications.

* 4.1.3 Continuous Measurement

A differential pressure instrument should be used. For most ranges provided the overall precision of measurement meets application requirements.

The flange mounted version at the differential pressure transmitter provides a close coupled installation and is preferred for hazardous fluids.

Differential pressure instruments require to be fitted with zero suppression (for atmospheric vessels) or zero elevation (for pressurised vessels).

Displacer type instruments (10 ft). Preferred for applications where local control is required over small ranges.

The upper range of 3000 mm (10 ft) is chosen from the bulk and weight considerations in excess of 140 kg (308 lbs) and not economic reasons.

Nucleonic level instrumentation may be used for applications where reliable measurement by other means is impractical (e.g. severe fouling service). The preferred use is as a back-up measurement to another method. Equipment must meet applicable statutory regulations governing the handling and use of radioactive sources. Each and every application shall be the subject of a technical justification by the contractor, and subject to approval by BP.

Other types of measurement (e.g. ultrasonic, capacitance) may be used, but subject to a technical assessment by the contractor and approval by BP.

These techniques should be considered for difficult applications on both solids and liquids at atmospheric pressure.

Intrinsically safe versions of capacitance instruments are available for Zone 1. Sonic instruments are available for use in Zone 0 areas.



The application of ultrasonic would be severely restricted due to the diameter of the chamber which is required to accommodate the beam angle (typically 7 degrees).

Capacitance

This technique is suitable for both solids and liquids and may be used in applications where a small, lightweight probe may be mounted vertically through a top connection.

The use of an external chamber for process type measurements is more feasible than for the ultrasonic technique above.

Nucleonic Type Level Transmitters

Typically used where no other form of level measurement is possible.

Due to the dangers of radiation source strength containment, handling and installation must meet all national safety requirements.

The source, its container and its location relative to that of the detector, should be chosen so that the control zone (inside which personnel cannot enter unprotected) is minimised. Ideally, this zone should be restricted to the shielding provided by the vessel and its lagging.

There are two basic types: (a) Gamma Ray Absorption, and the more recent (b) Neutron Backscatter Gauge:-

(a) Gamma Ray Absorption

Due to the weight of the source in its protected case, a special mounting bracket may need to be designed for vessel mounting. The possibility of fire at the vessel should be considered since the lead casing has a relatively low melting point [328°C (622.4 °F)].

(b) Neutron Backscatter Gauge

Whereas it may be necessary to locate the source within the process vessel to obtain the necessary detection of sufficient gamma rays by a detector mounted outside the vessel, a neutron backscatter level gauge with both source and detector are located on the outside.

*** 4.1.4**

Point Level Detection

Ball float operated instruments should be used for point level detection.

On low level applications and where sludge could be a problem, a displacer should be considered rather than a float operated device. Although the effect of increased weight caused by sedimentation affects both float and displacer, the effect on buoyancy is less severe.

For dual point level detection, adjustable displacers mounted on a single support wire may be used on small vessels in non-process applications (e.g. sumps).



A dual displacer mounted on a support wire allows higher differential levels to be controlled than a single level switch and is especially useful where access is restricted.

Other types of measurement, e.g. capacitance, ultrasonic and nucleonic, may be used subject to approval by BP.

The engineer is advised to seek guidance from specialist manufacturers, as choice is very application dependant.

4.2 Local Level Gauges

4.2.1 Magnetic float follower gauges are preferred for high pressure, high temperature and toxic or hazardous duties, as defined in BP Group [RP 42-1](#). Materials of construction and design shall comply with BP Group [GS 142-6](#).

Magnetic level gauge construction involves fewer joints giving greater mechanical strength in a single length than the standard reflex or transparent sections.

* 4.2.2 Where the service permits the use of gauge glasses, they should conform to [BS 3463](#) and the following requirements:-

(a) The use of glass tube gauges is not permitted unless approved by BP for the specific application.

Glass tube gauges should be considered only for atmospheric vessels and clean, non-hazardous liquids at ambient temperatures due to frailty and susceptibility to damage. The gauge length should be restricted to 750 mm (2 ft 6 in).

(b) Each gauge shall be stamped with the maximum working pressure and temperature.

(c) All gauges other than those on vacuum service shall be fitted with safety shut-off ball checks.

(d) Through vision and reflex gauges should be fitted with toughened glass.

(e) Expansion and contraction of gauges used on hot or cold liquids shall be compensated for.

(f) Materials selection, connections and valves shall comply with BP Group [RP 42-1](#).

Through vision gauges should be for:-

(i) Determining the interface between two immiscible liquids.



Liquid and liquid interfaces cannot be observed in reflex gauges.

- (ii) All applications on viscous fluids.

On viscous services the fluid tends to clog the grooves forming the reflective surface in reflex gauges.

- (iii) Determining the colour or turbidity of a fluid.

Where the process media is corrosive to glass (e.g. caustic soda, hydrofluoric acid, high pressure steam/condensate services), the glass should be protected by an internal membrane which itself is impervious to the process media. Use of this method is a non-preferred option (see 4.2.1) and shall be subject to BP approval.

4.2.3 Reflex gauge glasses are preferred for all other liquid and vapour interface detection.

4.2.4 Gauges on services below ambient temperatures shall be of the non-frosting type.

4.2.5 To accommodate the dynamic state within gauges used on vaporising services, they should be manufactured with larger chambers (i.e. to accommodate the boil-off/condensation occurring within the body and pipework).

4.2.6 All gauges shall be supplied with a shut-off valve on the top and bottom mountings; and a full bore drain valve. Shut-off valves shall be of a quick acting, offset type and should have bolted bonnets.

A vent valve shall be provided on toxic services, on corrosive liquid and on liquid interface duties to allow piping to a safe point of disposal. In other applications, the vent should be capped.

Offset pattern valve bodies allow access to the gauge glass through the vent or drain connection for cleaning the gauge.

Where as all gauges require a drain valve, a vent valve is only used to allow hazardous materials to be vented under controlled conditions into the drainage and flare system.

4.2.7 Alarms or controls activated from auxiliary contacts on gauges are not permitted.



4.3 Displacer Type Instruments

- * 4.3.1 Displacers should be mounted in external chambers. Chambers with bottom entry lower connections and side entry upper connections shall be provided on dirty fluids. On clean fluids, a side lower may be used.

Alternatives to the preferred arrangement are, but not in any special order:-

- (a) Top upper and side lower.
- (b) Top upper and bottom lower.
- (c) Side upper and bottom lower.

The upper top connection should be avoided on condensing service as liquid droplets falling on the displacer could give erratic level measurements.

Use of a side lower entry on dirty fluids shall be subject to approval by BP. The contractor shall state the proposed method of minimising the effect of fouling.

- 4.3.2 Internal displacers may be used on vessels where an external arrangement is not feasible (e.g. sumps). Facilities shall be provided to permit testing and routine maintenance. Where the displacer is subjected to turbulence, the effect of this turbulence shall be minimised by shielding, guidance or equivalent means.

- 4.3.3 Displacer type instruments shall be glandless.

4.4 Float Type Instruments

- 4.4.1 Float type switches should be mounted in external chambers. Internal floats may be used within the restrictions detailed in 4.3.2.

The flanged float chamber construction which allows the float to be serviced is preferred. The welded chamber construction is cheaper, but its use should be restricted to ancillary systems where the fluid is maintained in a clean state.

- 4.4.2 Float operated level switches shall be glandless.

- 4.4.3 On applications where the float is not designed to withstand the test pressure of the chamber, the instrument shall be fitted with a permanently affixed label to this effect.

- 4.4.4 Integral stops shall be provided to limit the angle of float travel and shall be located as near to the float as practical.



- 4.4.5 Float type switches may be direct flange mounted. The float arm and float shall be sized to pass through the nozzle through which they are installed.

4.5 Differential Pressure Level Instruments

- 4.5.1 A secondary method of checking the reference level shall be provided on non-condensing services, e.g. a gauge glass.
- 4.5.2 When materials are liable to separate, solidify or deposit in impulse lines, the lines should be purged or trace heated, as appropriate. Alternatively direct mounting diaphragms may be used. Adequate mechanical protection for capillaries shall be provided. The effect of blockages or capillary failure on the integrity of process control and safety systems shall be assessed.
- 4.5.3 A dry or gas-purged reference leg should be used for applications where it is impractical to maintain a filled reference leg, (e.g. in vacuum systems).
- 4.5.4 Where a continuous purge is employed, it shall be controlled by a constant-differential relay. Tubing after the relay should be run in a continuous length to avoid leaks.

4.6 Local Controllers

- 4.6.1 Controller pilot action shall be reversible without requiring additional parts. Instruments should have an adjustable proportional band covering the range 10% to 100%. Where the effect of process load changes requires the additional use of integral control, integral action adjustment should cover the range 0.5 to 50 minutes per repeat.

4.7 Installation

- 4.7.1 Displacers and float switches mounted in chambers, and local gauges, should be connected directly to the vessel in accordance with Fig 4-1) of this section. Where the number of vessel tappings is uneconomic, standpipes in accordance with Fig 4-2) of this section should be used.

Level instruments directly connected to a vessel are preferred. However, where the vessel integrity is affected, or where the installation becomes congested, standpipes may be provided.

- 4.7.2 Vessel tappings to instruments and standpipes shall be located so as to ensure that each tapping remains in the appropriate fluid at all times. Where two interfaces are present in a vessel (e.g. water/oil and oil/vapour) two appropriately located standpipes shall be provided.

- * 4.7.3 The lower connection to the vessel should not be from the bottom of the vessel, or form a 'U' trap between the vessel connection and the instrument. Deviation from this requirement will only be permitted where no practical alternative is possible; and subject to approval by BP.
- 4.7.4 Full bore valves shall be provided at connections of standpipes to vessels on services where blockage is likely (e.g. wax formation, solids deposition). These valves should be locked open during normal operation.
- 4.7.5 Each instrument connection to the vessel or standpipe shall be provided with full bore isolation valves which conform to piping specification.

5. FLOW MEASUREMENT

This Section specifies BP general requirements for flow measurement.

5.1 Classification of Flow Measurement Equipment

5.1.1 General Requirements

Flow measurement equipment will be classified by BP, depending on the purpose of its application and the required accuracy of measurement.

Although 'fitness for purpose' will be the primary criterion, the general purpose classifications are as follows :-

Class 1 - Fiscal or commercial custody transfer use.

Class 2 - Plant mass balances, internal accounting purposes.

Class 3 - Plant control and operator aids.

Class 1 is the most stringent application, with ancillary equipment required to prove the accuracy and repeatability of the system. (Note that liquid and gas metering systems in this category must meet any regulations which apply in the country of installation).

The guidelines for Class 1 systems should be applied wherever possible. However, where Production from a BP operated Facility is routed to shore via a Third Party Operator's platform or gathering station, this Operator may require that equipment selected for BP's class 1 metering system be modified or enhanced such that equability is maintained with his own Class 1 system. In particular this Operator may specify that a piece of equipment from a particular manufacturer be used.



In such cases the specific requirements should be specified in the 'Oil and Gas Transport Agreement' or similar contract document. Otherwise the requirements should be discussed and agreed at minuted meetings between the two parties at an early stage during preparation of the Metering System Specification.

Class 2 systems are simpler, without dedicated proving equipment and a lower standard of accuracy and repeatability than Class 1.

Class 3 is only as accurate as the control system or operator need requires.

The categories for flow measurement applications defined in this paragraph are for general guidance. However there may be applications where a higher, or lower, standard of measurement accuracy is required than the general classification implies. For example, even in fiscal or custody transfer applications, the volumes involved may not justify the high expense of a Class 1 system, and provided that the agreement of the other interested parties and the fiscal authorities can be obtained, a reduced standard of measurement may sometimes be accepted. Conversely, for some plant mass balance or accounting measurements, a higher than Class 2 measurement may be required. In general, high value, high importance and high usage applications require high accuracy metering equipment while applications of low value and importance require less accurate equipment. However, the overriding factor in deciding the classification should be 'fitness for purpose'.

Class 1 and Class 2 systems are often supplied as factory assembled units. It is essential that all pipework and fabrication is in accordance with the line specification.

5.1.2 Unless otherwise approved by BP, piping fittings and valves used in the manufacture of a metering system shall comply with BP Group [RP 42-1](#) and BP Group [GS 142-6](#).

5.2 **Class 1 - Flow Measurement (Liquid)**

5.2.1 General Requirements

The international standards for fiscal and custody transfer measurement are well recognised by most legislative authorities and by other interested parties. However additional constraints are sometimes imposed. In the United Kingdom, the Department of Energy has drafted Design Guidelines for both liquid and gas measurement systems. For HM Customs and Excise approval of liquid systems the requirements of Notice 179 M must be observed.

Class 1 liquid flow measurement should be by turbine meters or displacement meters. Other metering devices, e.g. vortex shedders, magnetic flowmeters (for conducting liquids), or Coriolis effect meters (for mass) may be proposed by the vendor if supported by a written technical case, and subject to approval by BP.



To meet Class 1 measurement standards, the metering system shall be located to ensure the liquid is received free of entrained vapour, and maintained vapour free throughout the measurement system.

Generally the choice between turbine or displacement meters is governed by the liquid viscosity. Because of their lower cost, turbine meters are preferred wherever their use is practicable. They are suitable for low to medium viscosities - up to say 20 cSt, depending on the required linearity over the flow turn-down. Displacement meters should be used for higher viscosity liquids, and for low flowrates where small turbine meter characteristics are unsuitable. Turbine meters should be specified for LPG service provided it is possible to use a positive displacement prover at the pipeline operating temperature.

* 5.2.2 Metering Systems

The design and construction of Class 1 liquid metering systems shall comply with the [API Manual of Petroleum Measurement Standards](#), Chapters 4 and 5, Section 2 and 3.

An Institute of Petroleum - [Petroleum Measurement Manual](#) Part XV, Guide to Liquid Metering System Design is available for background information. The BP [Measurement Guidelines](#) Chapter 13, Section 1, Part 1, Volume 2, Dynamic Measurement of Crude Oil, gives comprehensive information on Class 1 metering systems for crude oil.

Turbine meters and displacement meters shall be installed with facilities to permit on-line proving without disrupting normal process operation. Permanent dedicated proving equipment is normally required. However, temporary or transportable facilities may be used subject to approval by BP.

Note: Small volume provers may be proposed by the vendor if supported by full design and performance data. Use shall be subject to approval by BP.

For continuous flow pipelines or ships loading systems in which the meters must be regularly proved on a frequent routine basis, a dedicated meter prover is normally required. However for applications in which it is necessary only to prove the meters at longer intervals, it may be acceptable to use a transportable or temporary proving device.

The proving device used will depend upon the application. It has been industry practice to use bi-directional positive displacement provers for the larger permanent metering system installations, although there is now increasing confidence in the use of small compact provers, especially for proving light product meters. These should therefore be considered, and subject to evidence of satisfactory performance in a similar application, may be selected. When considering prover performance criteria, reference should be made to the performance recommendations of [ISO/DIS 7278/2](#) and to the latest edition of [IP PPM: Part X: \(Provers\)](#).



For the measurement of the volumetric flow of low viscosity liquids (typically 20 cSt and less), turbine meters should be used.

Proprietary turbine meters designed for higher viscosities may be used provided that evidence of proven performance is submitted to BP for approval.

For other high viscosity applications, displacement meters should be used.

Separate provers for white and black oils should be used. A common prover shall only be used if adequate flushing facilities are provided.

The use of master meters or prover tanks for proving product meters shall be subject to approval by BP. When used for proving or rail car loading meter proving, they shall conform with the requirements of [IP Petroleum Measurement Manual](#), Part X, Section 2.

For road or rail gantry loading meters, or other applications where it may be impracticable or uneconomic to use displacement provers, the use of master meters or proving tanks may be acceptable. Master meters must have a certificate of calibration traceable to National Standards obtained using a liquid or similar properties to the metered liquid, especially its viscosity at the meter operating temperatures.

The recommended operational practices for proving gantry meters are given in the [IP. Petroleum Measurement Manual](#) Part X, Section 2.

Where continuous operation is required, all of the components of a metering run and the proving system shall be accessible for maintenance without process shutdown.

For continuous pipeline metering duty or any other application where loss of a meter would prejudice normal process operation, a standby operational meter run must be provided.

Positive isolation shall be provided at any point in the metering or proving system or in associated pipework which can constitute a bypass route through which flow can prejudice the integrity of measurement. Isolating valves shall be capable of demonstrable leak free closure.

Twin seal block and bleed valves must be specified for any position where leakage can constitute a bypass route around either the meter or the prover. Connection from the bleed port must be made to a drain with the facility to check that the seals are leak tight in the closed position. Automatic leak detection, for remotely operated metering systems should be by differential pressure switch.



For stability and to minimise measurement uncertainties, the temperature difference and distance between a meter under test and the prover loop shall be kept to a minimum.

The system pressure loss across each metering run and the prover shall be calculated for normal and maximum rate of flow to ensure that the metering system is compatible with the hydraulic dynamics of the total process system.

The minimum back pressure at the meters shall be sufficient to prevent cavitation of high vapour pressure liquids.

To prevent cavitation (vapour break-out) at the meter, the minimum back pressure, (P_b), shall be twice the pressure drop across the meter (D_p) at maximum flowrate, plus 1.25 times the liquid vapour pressure (V_p) at the maximum operating temperature: i.e.

$$P_b = 2D_p + 1.25 V_p$$

When specified by BP, automatic samplers shall be in accordance with BP Group RP 30-2 Section 8.

For crude oil metering systems, or other applications where a representative sample is required from which to determine water content or other liquid properties, an automatic sampling system will be required. This will normally be a flow cell device, installed in a pumped fast loop system. Details of preferred devices and their installation are given in BP Group RP 30-2 Section 8. For automatic pipeline sampling, reference should be made to the international standard [ISO/DIS 3171](#) and to [IP PPM](#): Part VI: Section 2.

A specification for Crude Oil Sampling Equipment is published by BP. For more information contact the custodian of this document.

For details of a typical Class 1 metering system, see Fig. 5-1.

5.2.3 Metering Run

The number and size of metering runs shall be subject to approval by BP and shall suit the required maximum rate of flow and turn-down. When continuous operation is required, spare capacity shall be provided to permit the removal of one metering run for maintenance.

The number and size of parallel connected meter runs will depend upon the turn-down of the flow to be metered and upon the linear measuring range of the meters with the liquid viscosity at its pipeline operating temperature. Additionally, a standby meter run may be required.

Each meter shall be protected by an appropriate upstream filter.



A strainer or filter upstream of each meter is essential to protect the meter against pipeline debris or particular matter. The pressure drop across the strainer should be monitored to detect impending blockage.

A flow trimming valve (butterfly type) shall be provided to balance the flow between runs.

Meter run flow trimming valves are required to balance the flows between parallel meter runs, to ensure that meters are operated over the most linear section of their calibration curve, and to adjust the meter flowrate during the proving operation.

Turbine meters shall be installed within the requisite lengths of upstream and downstream straight pipe. A flow straightener may be used as an alternative to the full upstream straight length.

Automatic flow limiting devices shall be installed where process conditions may cause excessive flow rates which may damage meters.

Facilities to measure liquid pressure and temperature shall be provided at a point close to the meter.

Temperature measurement shall be by resistance thermometer to [IEC 751 \(BS 1904\)](#), Grade I specification (tolerance $\pm 0.19^{\circ}\text{C}$ over the range $0-100^{\circ}\text{C}$). Facilities for checking the calibration of the resistance thermometer by means of a certified mercury-in-glass thermometer shall be provided.

For details of a typical liquid metering run, together with the type of components to be used See Fig. 5-2.

5.2.4 Turbine and Displacement Meters

The design and materials for each turbine or displacement meter shall be subject to approval by BP for each application.

Each turbine or displacement meter of NPS 4 (DN 100) and above shall be provided with its own characteristics curve of calibration (meter K factor versus flowrate) and meet the following requirements:-

Repeatability. $\pm 0.02\%$

Linearity. Within $\pm 0.15\%$ over the defined flow turn-down and viscosity range.

These requirements may be relaxed for meters of NPS 3 (DN 75) or less to:-



Repeatability. $\pm 0.05\%$

Linearity. $\pm 0.25\%$

Turbine and displacement meters shall be fitted with dual pulse transmitters to allow the integrity of pulse transmission to be checked in accordance with [IP Petroleum Measurement Manual](#) (IP 252), Part XIII, Section 1.

Prior to installation in the system, the meter performance requirements stated above shall be demonstrated at an independent flow testing station to the satisfaction of BP. A hydrocarbon oil of similar viscosity to the specified process fluid shall be used for the test.

Generally a linear range of at least 6:1 at the operating liquid viscosity is required, and must be demonstrated by the manufacturer before the meter is accepted for site installation. Subsequently, the performance curve under actual operating conditions must be established as soon as possible after meter system start up.

5.2.5 Meter Provers

Prover loops should be of the bi-directional type, and internally lined with a coating material appropriate for the liquid(s) to be metered. Other types, such as small volume piston provers, may be used subject to approval by BP.

When considering the design and performance of provers, reference should be made to the recommendations of [ISO/DIS 7278/2](#) and the [IP PPM: Part X: Section 3](#).

Two detector switches shall be fitted at each end of the prover to provide two independent calibrated volumes, (i.e. S1/S3 and S2/S4).

The calibrated volumes between the two detector pairs must be sufficiently different to allow positive identification of the pair in use i.e. say 0.5% volume difference.

The number of meter pulses generated over the swept volume between detectors shall be at least 10 000 pulses (equivalent to 20 000 pulses for a round trip on bi-directional provers). Alternatively, pulse interpolation techniques may be used subject to approval by BP of the vendors full design information.

Use of a pulse interpolation technique to generate the equivalent of 10 000 pulses from a low pulse frequency meter is only acceptable provided that the intra-rotational non-linearity of the raw pulse generation is within $\pm 10\%$ and if the other criterion of [ISO/DIS 7278/3](#) are observed. Pulse interpolation will be essential with small volume provers.

The velocity of the displacer sphere at minimum flowrate shall be sufficient to prevent judder with non-lubricating liquids.



Connections shall be provided for routine re-calibration of the prover loop.

A block and bleed valve with a valved and flanged stub on either side is normally provided downstream of the prover to allow diversion of the prover flow through an in-series connected master proving system for routine re-calibration.

Suitable space to accommodate the master proving system, with electrical power and drainage facilities, should be provided close at hand to keep connecting piping to a minimum length.

The repeatability of the prover shall lie within a range of $\pm 0.02\%$ during calibration and subsequent re-calibrations.

When the prover is used to prove a high performance pulse generating meter, over its normal operating range of flow rates, the individual calculated 'K' factor for five successive proving runs shall lie within a range of $\pm 0.02\%$ of the average 'K' factor of the five runs.

The flanged joints within the calibrated volume shall have metal to metal contact together with dowel pins in each flange. Other methods for positive location may be used subject to approval by BP.

The prover valve shall be fully seated and sealed before the displacer meets the first detector. The prover valve shall incorporate facilities to demonstrate that it is sealed. An automatic arrangement is preferred.

Normally the valve seal detection system should operate continuously throughout a proving run. However, with some small volume provers without an external valve, a non-dynamic leak detection test, carried out before and after a proving run, may be acceptable by agreement with other interested parties.

The prover shall be designed such that there will be no hydraulic shock when the displacer is launched or received.

Provers with dynamic launch facilities, with a reduced run-up length before the first detector, may be acceptable subject to evidence of satisfactory performance.

The equipment supplied with the prover shall include a sphere sizing ring. Handling equipment shall be provided for spheres larger than 150 mm (6 in). Nets or baskets shall be provided for the storage of spheres not in use.

* 5.2.6 Mass Measurement - Inferential Method

The measurement of liquid mass flow for Class 1 applications shall be by the inferential method, using volume meters (turbine or displacement) and density meters as specified in this document. An



alternative, direct method which may be used for mass flow measurement is given in the section entitled Mass Measurement - Direct Method.

The inferential method should be used for mass flow measurement. In this, volume (V) and density (p) are measured separately and the mass flow (M) obtained from their product. $M = V \times p$.

Density measurement and proving systems used in fiscal/commercial custody transfer inferential mass metering systems, shall be in accordance with IP Petroleum Measurement Manual, Part VII, Section 2.

Two on-line density transducers of a design approved by BP shall be provided. The density transducers shall be installed in a pumped fast bypass loop sampling system. The sampling loop shall include a low flow alarm and flow indicator. A stand-by sample pump shall be provided.

Vibrating element (tube type) density transducers are preferred for liquid density measurement.

In fiscal mass measurement systems, two densitometers shall be installed in parallel in a fully duplicated system included a standby pump. In normal use, one densitometer is designated to be the working instrument while the other is operated in a standby mode. The two signals will be compared continuously, and an alarm generated if the difference exceeds a preset limit.

Care must be taken to ensure that the sample entry to the densitometer fast loop system is positioned at a point in the pipeline where the flow is homogeneous, so that a representative sample passes through the instruments. Entry to the fast loop should be through a scoop type probe, facing upstream. Preferably the probe entry diameter will be at least 25 mm (1 in) with an internal chamber on the bore of the scoop entry.

The density transducer system shall include either pyknometer or transfer standard proving facilities.

The density measurement system shall be designed so that the temperature differences between the meter run, transducers and pyknometers are minimised. If necessary the system shall be lagged. The fast sample loop shall be free from cavitation and shall incorporate solvent flushing facilities where necessary, e.g. where wax deposition can occur.

For the accurate determination of mass flow, it is essential that both the liquid volume measurement and that of its density are at the same temperature, or that proper correction is made for any difference. Hence, accurate temperature measurement is required at a point as close to the densitometers as is practicable.



For detail of requirements for a typical liquid metering run, see Fig 5-2.

A resistance thermometer to [IEC 751 \(BS 1904\)](#), Grade I specification (tolerance $\pm 0.19^{\circ}\text{C}$ over the range $0-100^{\circ}\text{C}$) shall be provided to monitor the temperature at each densitometer. Means to check the resistance thermometer calibration using a certified mercury-in-glass thermometer shall be provided.

* 5.2.7 Mass Measurement - Direct Method.

For Class 1 liquid mass measurement of light products such as LPG, direct mass flowmeters of the Coriolis type may be proposed by the vendor if supported by a written technical case for approval by BP. This type of meter shall not be used for the measurement of two phase (liquid/gas) fluids.

For suitable mass flow measurement applications, consideration may be given to 'direct' or 'true' mass flowmeters. Proprietary true mass flowmeters operating on the 'Coriolis' principle are gaining acceptance and may be suitable for LPG or other products normally traded by weight. However, there can be some risk of failure due to stress corrosion with some such devices and with hazardous liquids. Precautions must therefore be taken to limit the consequences of failure by isolating the meter and containing any escaped fluid.

Coriolis type flowmeters shall be installed strictly in accordance with the manufacturers instructions. Their physical orientation shall be such as to minimise the effects of vapours which may be present in the metered fluids. Associated pipework shall be designed to ensure that the meters are not subjected to induced stress.

Where Coriolis type meters are to be used for hazardous or toxic liquid measurement, adequate safety precautions shall be taken to limit possible hazard due to tube rupture. This may be by totally enclosing the tubes within a pressure vessel of adequate rating for the service, and/or by automatic isolation of the meter by upstream and downstream valves; with a bursting disc or other form of protection provided on the casing, as appropriate.

To prevent corrosion, construction materials, of Coriolis type meters shall be compatible with the specified process fluid, and with test and calibration fluids. The vendor shall provide material certificates.

When ordering 'Coriolis' type meters the manufacturer must be formally notified of the process conditions, particularly the process fluid constituents and the operating temperature and pressure.

Meters shall be adequately sized so as not to:-



- (a) Form an unacceptable restriction within the process.
- (b) Cause cavitation or flashing at any construction within the meter or upstream piping system when operating at maximum design volumetric flowrate.

Special attention shall be given to the method proposed for proving the calibration of direct mass flowmeters on a routine basis. Gravitational proving systems e.g. weigh tanks, are unlikely to be suitable for most on-line process applications and an inferential proving technique should be used, i.e. using a volumetric prover and a transfer standard densitometer. The method of proving shall be subject to approval by BP.

Accuracies of $\pm 0.5\%$ are claimed for these meters but independent evidence of performance on a similar application should be obtained before approval for use is given. The accuracy of these devices can be prejudiced by gas entrainment and therefore, they should not be used for two phase flow applications. Unfortunately, as yet there is no direct equivalent to the volumetric prover which can be used to check the calibration of direct mass flow meters under custody transfer process conditions. Gravity systems such as weigh tanks can only be used in the batch mode and are not suitable for uninterrupted pipeline flow meter proving service. For this duty there are three alternative methods available, listed below in order of BP preferences :-

- (a) *An inferential proving system comprising a volumetric prover and a transfer standard densitometer.*
- (b) *Master meter proving, using either a transfer standard, direct mass flowmeter or an inferential system with transfer standard volume meter and densitometer.*
- (c) *Off line, or centralised proving with the meter to be checked removed to a testing site after replacement by a standby meter.*

N.B. Angular momentum true mass flowmeter provide a suitable means of low mass flow measurement of clean liquids, e.g. for metering fuel on aircraft.

5.3 Class 1 - Flow Measurement - (Gas)

* 5.3.1 General Requirements

Class 1 gas measurement systems which require the approval of fiscal authorities (for example in the UK and Norway), shall use orifice plates as the primary measuring element. For other custody transfer gas measurement applications either orifice plates or gas turbine meters may be used, subject to approval by BP.

Other gas metering devices for example multi-path ultrasonic meters or vortex shedders may be proposed by the vendor who shall submit a



written technical case (including references to proven use on similar applications); which shall be subject to approval by BP.

It is unlikely that Class 1 measurement standards will be achieved if the gas flow contains condensed liquids.

5.3.2 Orifice Plate Metering Systems - Requirements.

Class 1 orifice plate systems shall be designed and constructed in accordance with [ISO 5167](#) or [BS 1042](#) Part 1. Section 1.1. Calculations for measurement uncertainty shall be based on [ISO 5168](#) ([BS 5844](#)).

ISO 5167 and BS 1042: Part 1: Section 1.1 are the international standards for differential pressure measurement devices and are applied in Europe for fiscal and commercial gas metering by orifice plate. The American AGA 3 standard is not acceptable for UK fiscal measurement purpose, since its use may result in a higher measurement uncertainty arising from the reduced straight length requirements. Guidelines on the design of Class 1 gas metering systems are being published in [IP PPM](#): Part XV: Section 2.

The discharge coefficient of a pressure difference flow element is almost directly derived from its mechanical dimensions, and thus once the coefficient is established, no further proof of calibration is required provided that no physical change occurs.

Orifice plates are preferred for fiscal and commercial gas flow measurement, and are accepted for this duty by the legislative authorities and by major commercial organisations. Acceptance is conditional upon the system design being such that overall measurement uncertainty is reduced below $\pm 1\%$ of reading, as calculated using the methods of [ISO 5167](#) and [ISO 5168](#). In practical terms this requirement imposes a number of design constraints. These are detailed in the main text and commented upon below.

The number and the size of the metering runs provided in an orifice plate system shall be such that the overall measurement uncertainty is not greater than $\pm 1\%$ of reading over the operating flow range.

Concentric square edged orifice plates are the preferred primary element. The number and size of meter runs must be chosen so that the turn-down of the flow through each orifice plate run does not exceed 5:1 and the turn-down for a single differential pressure transducer does not exceed 2.3:1. Thus two transducers, one high range and one low range are required on a orifice plate to cover 5:1 rangeability.

It is unlikely that the specified overall flow measurement uncertainty of $\pm 1\%$ will be achieved if these flow turn-downs are exceeded.

Other systems constraints affecting the flow measurement uncertainty are :-

- (a) Accuracy of differential pressure transmitter (see 5.3.5 'Secondary Metering Instrumentation')

and



- (b) Accuracy of density measurement (see 5.3.5 'Secondary Metering Instrumentation')

The variation of expandability 'E' , and the discharge coefficient 'C', over the flow range must not exceed 0.25%.

The overall measurement uncertainty of the complete orifice plate system may be estimated using the procedures of ISO 5167 and ISO 5168. Refer to ISO 5168 when dealing with secondary transducer errors. Not that at low flow rates the uncertainties of 'E', 'C' and D_p increase and their values should thereafter also be calculated at the minimum expected flow rate.

When continuous operation is required spare capacity shall be provided to allow the shut-down of one metering run for maintenance without prejudice to the measurement uncertainty specified above.

Note that the addition of a standby operational meter run may be mandatory for fiscal or custody transfer systems which are subject to legislative authority or third party approval.

Where specified by BP, automatic gas sampling systems shall be provided and installed in accordance with BP Group RP 30-2 Section 8.

For details of a typical gas metering system, see Fig. 5-3.

Class 1 gas metering equipment should be installed in a metering house affording an environment suitable for stable operation; and suitable for the high precision calibration equipment used at regular intervals.

5.3.3 Orifice Plates - Primary Metering Elements

Each metering run shall be in accordance with the full straight length requirements of ISO 5167 or BS 1042: Part 1: Section 1.1. The orifice plate shall be mounted in an orifice fitting welded directly to the upstream meter tube. Fittings which allow the plate to be readily removed for inspection or exchange should be used. The complete metering run assembly shall be purchased from one manufacturer. To allow convenient in-site inspection of the plate, the downstream meter tube should be flanged at 0 and 7.5 pipe diameters.

ISO 5167 and BS 1042: Part 1: Section 1.1 provides full information on upstream straight length requirements.

The meter run configuration of Fig 5-7 may be preceded by any combination of fittings and only requires an upstream straight length of 43 pipe diameters. Other meter run arrangements are possible, but are unlikely to allow shorter upstream straight lengths.



It is essential that the complete assembly is obtained from a specialist supplier. This is to ensure that the meter tube and orifice plate dimensions are within tolerance, that the tube and plate are correctly aligned and that the surface finishes are acceptable. The provision of a flanged spool downstream of the plate allows visual in-situ inspection of the upstream meter tube and plate.

If a metering run incorporates a flow straightener, 'Zanker' type units are preference.

'Zanker' type flow straighteners offer the lowest head loss.

Connections to the differential pressure transducers shall be from flange taps for NPS 2(DN 50) and above, and corner taps for pipes below NPS 2.

Flange taps are preferred to corner taps or D and D/2 taps, especially if flow pulsations are present.

For details of a typical gas metering run, See Figure 5-4.

Twin seal isolation valves of the double block and bleed type are essential to ensure positive stream isolation.

5.3.4

Orifice Plate Systems - Design Constraints

In addition to [ISO 5167](#) or [BS 1042](#) : Part 1: Section 1.1, the system shall satisfy the following constraints:-

- (a) Maximum d/D ratio 0.6.

For d/D ratios above 0.6 the uncertainty of the discharge coefficient value will be unacceptable.

- (b) Maximum Reynolds number 3.3×10^7 .

The discharge coefficient for high values of Reynolds Number (Re) is extrapolated from empirical data, and above a Re value of 3.3×10^7 , the associated uncertainty is unacceptable.

- (c) Maximum differential pressure 500 mbar.

- (d) The thickness of the plate shall be such as to ensure that maximum elastic deformation at 500 mbar is less than 1 per cent.

The orifice plate should have sufficient strength and thickness to limit elastic deformation caused by the differential pressure across it. This is because the resulting change in discharge coefficient will cause a flow measurement error. In design, the flow error due to elastic deformation must not exceed 0.1%, and the plate flatness should not be distorted more than 1% slope at the maximum differential pressure. Reference Fig 5-8.



- (e) Differential pressure tapping distance from the orifice plate shall be within the tolerance of [ISO 5167](#) or [BS 1042](#): Part 1: Section 1.1. at maximum designed differential pressure.

Unacceptable lateral movement of the orifice plate relative to the differential pressure taps can occur either when the plate is supported by elastomer seals or if the plate carrier is of poor design.

In order to achieve the specified measurement accuracy, the following design constraints shall apply:-

- (a) The flow turn-down ratio of a single metering run shall not exceed 5:1.
- (b) A single high stability, high turndown digital output transducer is preferred (see Secondary Metering Instrumentation below).
- (c) The flow-turn down ratio for a single fixed range analogue output differential pressure transmitter shall not exceed 2.4:1. Separate high and low range transmitters shall be provided when a greater turn-down is required. Alternatively, variable range transmitters of the 'smart' type may be used, subject to approval by BP.

When pulsations in the gas flow exist, their amplitude in the pipeline shall be attenuated to limit the uncertainty due to this effect to 0.1%.

Note: There may be difficulty in achieving this standard downstream of reciprocating gas compressors.

Reciprocating compressors can cause pressure pulsations producing a square root averaging error which results in over registration of flow. The error can be calculated from

$$E = 1.56 \frac{(Dpa)^2 \%}{(DPd)}$$

Where E = percentage 'over registration in flow'.

Dpa = Peak to peak amplitude of the fluctuations in differential pressure at the flange taps (mbar).

Dpd = Mean differential pressure across the orifice plate (mbar).

5.3.5

Orifice Plate Systems - Secondary Metering Instrumentation

Differential pressure transmitters shall have an accuracy of better than $\pm 0.25\%$ of span and 0.6% of reading at maximum turndown. A



calibration stability of better than $\pm 0.25\%$ of span over 6 months is required. The vendor shall provide temperature static pressure coefficients for use in the calculation of measurement uncertainty.

Differential pressure transmitters for each metering run shall be mounted in a thermostatically controlled enclosure. A five valve manifold shall be provided with each differential pressure transmitter. For typical gas flow measurement impulse line arrangements see BP Group [RP 30-1](#) Section 4, Fig. 5-5.

Changes in ambient temperature can cause significant errors in differential pressure (Dp) transmitter calibration. To reduce this effect and for environmental protection, Dp cells are best installed in a temperature controlled enclosure.

The gas density of each metering run shall be measured by an on-line density transducer installed in accordance with [IP Petroleum Measurement Manual](#), Part VII, Section 2. The accuracy of density measurement shall be better than $\pm 0.3\%$ of reading. The preferred method for obtaining a sample for the transducer is the 'pressure recovery' technique as described in the IP Petroleum Measurement Manual. The density transducer shall include temperature measuring element to [IEC 751 \(BS 1904\)](#), Grade I.

After corrections have been made for the temperature and velocity of sound effects, the uncertainty of the measured line density shall not be greater than $\pm 0.3\%$.

The use of density calculated from an on-line chromatographic analysis of the gas shall be subject to approval by BP.

Where liquid entrainment may seriously impair densitometer performance, the PTZ calculated method may be employed, subject to BP approval.

On-line density transducers are superior in accuracy when compared with PTZ methods for calculating the pipeline gas density. Vibrating spool type densitometers are preferred for gas density measurement. They should be installed according to the principles of Chapter 8 in Part VII Section 2 of IP Petroleum Measurement Manual.

The frequency output of a vibrating spool transducer is a function of gas density, temperature and the velocity of sound in the pipeline gas. Errors of up to $\pm 1\%$ can occur if the transducer calibration is not corrected for temperature and velocity of sound effects.

Relative density transducers shall be provided when it is required to calculate standard volumetric rate of flow.



The use of an on-line relative density transducer is preferred to the PTZ method of calculating relative density. This is because the accurate determination of the compressibility factor z is difficult for complex gas mixtures.

Each metering run shall be provided with a resistance thermometer element to [IEC 751 \(BS 1904\)](#), Grade I specification (tolerance $\pm 0.19^{\circ}\text{C}$ over the range $0 - 100^{\circ}\text{C}$) and located in the pipe beyond the straight length requirements of [ISO 5167](#) or [BS 1042](#): Part 1: Section 1.1. Facilities for checking the calibration of the resistance thermometer by means of a certified mercury in glass thermometer shall be provided.

The resistance thermometer is required to give temperature measurement for the following purposes:-

- (a) *To correct meter tube and orifice plate dimensions for line temperature.*
- (b) *To correct the temperature coefficient of density transducers.*
- (c) *To provide the temperature term in PTZ calculations for density. Correction for the temperature difference between the density transducer and meter run is an additional option, but is seldom exercised except where required by national fiscal regulations, e.g. NPD.*

When security of measurement is essential, BP will specify a requirement for transducers to be provided in duplicate or triplicate.

The provision of a dedicated standby meter run, complete with all instrumentation, is normally preferred to additional secondary instrumentation on each working run, and will usually satisfy the requirement of legislative authorities or third parties. However, where an exceptionally high level of system integrity is required, consideration should be given to providing duplication or even triplication of secondary transducers.

For typical gas metering system requirements, see Figs 5-3 and 5-4 of this section.

5.3.6 Turbine Meters - Gas

Turbine meters may be proposed by the vendor for suitable Class 1 gas measurement applications, e.g. for the custody transfer metering of ethylene gas. The turbine meters should be installed in accordance with the recommendations of [AGA Report No. 7](#) and the meters themselves should comply with [BS 4161](#): Part 6: 1979. Alternatively the standards applicable in the country of installation shall apply.

NB Turbine meters are unsuitable for applications where pulsations in flow can exceed $\pm 10\%$ peak to peak of the nominal flow rate.

Turbine meters may be proposed for suitable Class 1 gas measurement applications but their use shall be conditional upon approval by BP and the agreement of other parties, including the fiscal authority.



The calibration of gas turbine meters used for Class 1 service must be proved periodically against a certified measurement standard. Alternative methods for proving are available and may be acceptable. The method shall be subject to approval by BP and other interested parties.

Although gas turbine meters are capable of a lower measurement uncertainty than orifice plates, they need to have their calibration periodically proved in service. Alternative proving methods are available. These are given in the main text and commented upon below.



5.3.7 Methods of Proving - Gas

Centralised Proving: For calibration at a separate proving installation the turbine meters shall be installed so that the complete metering section, i.e. the meter together with its requisite upstream and downstream flow conditioning sections, may be removed in its entirety for installation at the proving site.

In this procedure the complete metering section is removed from the measurement site and taken to a central proving station where it is re-installed and its calibration checked against a transfer standard device. At least one standby meter run must be provided at the measurement site to allow uninterrupted operation while a meter is removed for calibration.

Transfer Standard Meter Proving: For this method, provision shall be made, downstream of the meter to be tested, for the installation of a transfer standard master meter together with its flow straightening sections. The installation shall be such that the calibration of neither meter is affected by swirl or pulsations generated by the other.

Transfer Standard Meter Proving: When a transfer standard (master) turbine meter is to be as the calibration device the procedures described in AGA Report No. 6 Part III 1975 should be observed. Care must be taken to ensure that pulsating flow swirl conditions are not transmitted from one meter to the other. Master meters themselves require regular calibration.

Sonic Nozzles or Critical Flow Orifice Provers: These devices may be considered for applications where high system pressure drops are tolerable while proving is taking place. With sonic nozzles, the discharge pressure after recovery will be less than 85% of the inlet pressure, while with critical flow orifices, the exit pressure will be less than 50% of the inlet pressure.

If it is necessary to prove the calibration of a fixed flowrate device at more than one flowrate, a multiple nozzle or orifice proving system, suitably valved, shall be supplied.

Sonic Nozzles or Critical Flow Orifice Provers: Both of these devices are capable of calibration at operating conditions to an accuracy of $\pm 0.25\%$ of actual flow rate. Their major disadvantages are that both impose a high pressure drop on the metering system and that they operate only at a single fixed flow rate. Therefore, where calibration of the operating meter is required at more than one point on its working range, a number of parallel connected devices will be necessary.

Bell Provers: Calibration against a bell prover may be possible for small turbine meters operating at low pressures.

Although suitable only for low pressure use, bell provers can be one of the most accurate and repeatable standards. Meters tested against a bell prover are usually operated near the bell pressure (a few inches, water gauge). However, testing at a



higher pressure is possible by expanding the gas from the meter, through a throttling valve, to the bell pressure before entering the bell.

Alternative Prover Types: Other types of gas proving systems, e.g. compact gas provers, may be proposed but their use shall be subject to approval by BP and dependent on evidence submitted by the vendor of successful performance on a similar gas measurement application.

Some types of compact prover, operating on low differential pressure, may be suitable for proving gas turbine meters. Proposals for their use must be supported by evidence of successful operation in a similar application.

5.3.8 Turbine Meter System Design

Proving: The metering system shall be designed so that the chosen method of checking the calibration of each meter may be carried out without affecting the operation of the others. Proving devices shall be installed downstream of the meter under test in such a position that calibration of one is unaffected by the presence of the other. Where necessary, appropriate block and bleed valving shall be installed to divert the gas flow through the proving device.

Metering Runs: The number and size of metering runs shall be subject to approval by BP and shall suit the required maximum flowrate and turndown. When continuous operation is required, spare capacity shall be provided to permit the removal of one metering section for maintenance or, if necessary, for proving.

Flow Conditioning: A uniform flow profile, without jetting or swirl, must be presented at the turbine meter inlet. To achieve this a flow straightening section conforming with the requirements of [ISO 5167](#) or [BS 1042](#) Part 1: Section 1.1 should be installed upstream of the meter. A length of five nominal pipe diameters is required downstream of the meter. Both upstream and downstream pipes shall be of the same nominal size as the meter.

The turbine rotor speed will be influenced if the gas at the meter inlet has significant swirl. Similarly a non-uniform velocity profile will usually result in a higher turbine rotor speed than a uniform velocity profile. Precautions must be taken therefore to reduce swirl to an insignificant level and to make the velocity profile essentially uniform. Observation of the upstream straight length requirements of [ISO 5167](#) Section 6.2 on the use of an approved flow straightener, particularly the Zanker types, should remove both swirl and velocity profile dissymetry.

Alignment: Concentric alignment of the bore of the meter with the bore of the upstream and downstream pipe sections shall be maintained and there shall be no protrusion of welds or gasket material into the bore at the meter connections.



The meter and the meter piping system shall be designed so as to minimise strain due to pipeline stress.

Wet Gas: In applications where there is a possibility of liquid accumulation, the pipework should be inclined to prevent accumulation in the meter.

In installations where liquid could be encountered, the meter and its associated pipework should be sloped or installed in the vertical position to provide continual draining of the meter. Where a significant quantity of liquid may be expected, the installation of a separator upstream of the meter is recommended. The distortion to the flow profile caused by the separator must be corrected in the upstream pipework.

Filtration: In applications where there is a possibility of foreign particles being carried with the gas flow, an appropriated sized strainer or filter shall be installed upstream of the meter. The differential pressure across the filter shall be monitored to give alarm in the event of impending blockage.

Strainers should be sized so that at maximum flow rate there is a minimum pressure drop, and installed so that there is no distortion to the flow profile (see requirements under 'Wet Gas' above).

Overspeeding: Turbine meters shall be operated within the vendor's specified flow range. If necessary a flow restriction shall be provided downstream of the meter, sized to limit the flow to within the maximum rating of the meter. Shock loading when opening up a meter run shall be prevented by installing a small bypass line around the upstream meter isolating valve.

Turbine Meters can generally withstand a gradual but limited overspeeding without damage other than accelerated wear of the internal parts, but continued overrunning should be avoided by correct meter sizing. As with all meters, turbines should be pressurised and brought into service slowly. Shock loading, by opening valves quickly will usually result in rotor damage. The installation of a small bypass line around the upstream meter isolating valve can be used to safely pressurise the meter to its normal operating pressure.

Flow Control: Flow balancing in multiple meter run systems shall be by downstream throttling valves in each meter run. These shall be located at least 10 diameters downstream and shall not reflect any flow disturbances back to the meter. They shall not affect the correct measurement of meter temperature.

Temperature Measurement: A thermowell shall be provided downstream of the turbine meter within the five diameter downstream straight pipe section. Temperature measurement shall be by resistance thermometer to [IEC 751 \(BS 1904\)](#) Grade 1 specification (tolerance



$\pm 0.19^{\circ}\text{C}$ over the range $0\text{--}100^{\circ}\text{C}$). Facilities for checking the calibration of the resistance thermometer by means of a certified mercury in glass thermometer shall be provided.

Locate the thermowell within 5 diameters of the turbine meter outlet and upstream of any outlet valve or flow restriction. The thermowell should be installed to ensure that the gas temperature measurement is not influenced by heat transfer from the piping and well attachment.

Density Measurement: In mass flow measurement applications densitometers shall be provided so as to measure the density of the gas at conditions as close as possible to the rotor pressure and temperature conditions without disturbing the meter flow profile or creating an unmetered flow bypass.

Information on continuous gas density measurement may be found in [IP Petroleum Measurement Manual](#) Part VII Section 2. The densitometer installation shall comply with the recommendations of this document.

Vibrating element density meters are preferred. Measurement should be made so as to determine density at the pressure tap location of the turbine meter.

5.3.9

Meter Requirements

Meter Size: The meter size and flow rating shall be in accordance with the preferred standards of [BS 4161](#): Part 6: 1979.

[BS 4161](#): Part 6 1979 lists preferred maximum/minimum flowrate for standard turbine meter sizes. These preferred flowrates are related to preferred ISO inlet/outlet connection sizes in the following table.

<i>Q max (actual cubic meters/hour)</i>	<i>Meter Connection Size (mm)</i>
40	50
65	50
100	50
160	80
250	80
400	100
650	150
1000	150
1600	200
<i>Q max (actual cubic meters/hour)</i>	<i>Meter Connection Size (mm)</i>
2500	250
4000	300
6500	400
10000	500
16000	600



25000
40000

750
1000

Materials: To prevent corrosion, the materials of construction of turbine meters shall be compatible with the specified process fluids, and with test and calibration fluids. Exterior surfaces of the meter shall be protected as necessary against corrosion; and be suitable for installation in hazardous atmospheres.

The meter body, connections and all fluid containing parts shall be designed to suit the specified pressure and temperature.

The meter body should be tested at 1.5 times the maximum operating pressure for up to 180 seconds, depending on size. It shall be subjected to a leakage test at up to 1.25 times the maximum operating pressure, as required by [BS 4161: Part 6 1979](#).

Accuracy and Repeatability: Each turbine meter shall be provided with its own characteristic curve of calibration (meter K factor versus flow rate); and shall meet the following performance requirements on a fluid of similar characteristics to those of the gas to be metered.

Accuracy

Within $\pm 1\%$ of the volume over 10:1 flow turn-down.

Repeatability

Within $\pm 0.1\%$ at 95% confidence level on successive calibration runs in short term tests.

Linearity

Within $\pm 1\%$ over 10:1 flow turn-down at specified pressure.

The figures for accuracy and repeatability given are requirements for turbine meters to be used in Class 1 applications. They shall be demonstrated by the manufacturers at conditions as close as possible to those at which the meter is to operate in the field.

Signal Output: Turbine meters shall be provided with pulse transmitters. Dual transmitters shall be provided to allow the integrity of pulse transmission to be checked.

Pressure Tap: A pressure test point shall be provided on the meter body to measure the static pressure at the turbine rotor.

Direction of Flow: The direction of flow, or identification of the inlet of the meter shall be clearly and permanently marked.



Spin Time: The meter manufacturer shall provide test data on free rotation spin times so that periodic checks may be made on the condition of the meter bearings and of internal dirt or damage to the rotating parts.

Spin time tests give an indication of the relative level of mechanical friction between the bearing surfaces of the meter. A spin time which has extended beyond the reference time provided by the manufacturer provides a warning of deteriorating meter performance, especially at low flow rates. The rotor should be turned at least 5% of the rated speed corresponding to maximum flow rate and the time taken for it to come to rest. Repeat the test at least 3 times and take the average, for comparison with the manufacturers figures.

5.4 Class 1 - Data Handling (Liquid and Gas)

5.4.1 Flow Computers (Electronic Data Handling and Transmission)

The specification describes a preferred arrangement of microprocessor flow computing modules, i.e. individual meter run instruments feeding data to a totalising data base bank instrument. Most reputable flow computer manufacturers supply instruments suitable for this arrangement and which fulfil the detailed requirements of this section concerning the fidelity and integrity of the handled data.

The flow calculations to be performed for liquid metering systems are explained fully in the BP Measurement Guidelines Part 1, Vol. 2 and the API. Manual of Petroleum Measurement Standards in Chapter 12, Section 2.

In [ISO 5167](#) ([BS 1042](#) Section 1.1) the calculations for gas flow in differential pressure measurement systems are to be found. In both liquid and in gas measurement flow computers the calculations must be carried out with sufficient resolution such that the lowest significant digit is compatible with the required accuracy of measurement of the total transferred volume or mass.

For example, if the total volume transferred is 1,000 meters cubed per meter run, and the required measurement accuracy is 0.1%, then the lowest significant digit in the run flow computer calculation should be 0.1 meters cubed to allow for appropriate rounding. For typical flow computer requirements for liquid and gas respectively see Figure No's 5-5 and 5-6.

Each metering run (stream) shall be provided with a dedicated microprocessor based flow computer.

The summation of the total flow through the meter bank shall be performed in a microprocessor based data base bank instrument. This shall be connected to each stream flow computer by a serial data link system data bus.

For liquid systems, a dedicated instrument should be provided for the control of proving sequences and the automatic calculation of meter 'K' factors. Alternatively, the calculation may be carried out by the stream

instrument. Communication with the stream and bank instrument shall be via the system data bus. As an alternative, a combined data base bank and prover instrument may be used, subject to approval by BP.

Calculations shall follow the principles of the [API Manual of Petroleum Measurement Standards](#), Chapter 12, Section 2; [IP Petroleum Measurement Manual](#), Part X for liquids, and [ISO 5167](#) or [BS 1042](#): Part 1: Section 1.1 for gas.

For liquids, volume correction factors shall be calculated in accordance with [ASTM D 1250-IP 200](#). Oil compressibility factors shall be calculated in accordance with [API Manual of Petroleum Measurement Standards](#), Chapter 11.2.1M.

A pulse security system at least to Level B of the [IP PPM](#): Part XIII: Section 1 (IP 252) for turbine and displacement meter signals shall be provided (Also see [ISO 6551 \(BS 6439\)](#)).

The integrity of all input signals shall be monitored. An alarm shall be given in the event of a signal failure, and the last good value used for calculation purposes. Provision shall be provided to manually enter values for density, pressure, temperature and other parameters as specified.

Each microprocessor instrument shall continuously monitor its operation and alarm on malfunction.

All calculation coefficients shall be keypad entered under keyswitch or security code.

All data should be stored in triplicate memories. Battery back up shall be provided for volatile memories. (BP Group [RP 30-1](#), Section 2 for constraints in the use of batteries offshore).

Access shall be provided to all parameters (variables and constants) to facilitate manual verification of calculations provided by the microprocessors.

The microprocessor data base instrument shall be capable of communicating with computer systems by means of a serial data link that shall be subject to approval by BP. Exceptionally, in local, stand alone systems, this facility may not be required.

The typical relationship between the instrumentation and the data displayed is shown in Figs. 5-3 and 5-5.



5.4.2 Mechanical Flow Totalisers

Meters with integral mechanical flow totalisers and temperature compensators may be used for small rates of flow. In all cases, the use of mechanical flow totalisers and temperature compensators shall be subject to approval by BP.

5.5 Class 1 - Inspection and Documentation

5.5.1 General Requirements

Inspection of the fiscal/custody transfer metering system during design, construction, testing and commissioning, shall be carried out by BP or an independent inspection authority appointed by BP. Detailed testing and inspection requirements for each application shall be subject to specification or approval by BP.

All test equipment, with the exception of temperature measurement equipment, shall have an uncertainty of calibration one order of magnitude lower than the instrument being calibrated. Temperature measurement equipment may have an uncertainty no greater than $\pm 0.1^{\circ}\text{C}$.

All calibration equipment shall have a calibration certificate less than 12 months old traceable to National Standards. In the UK, a British Calibration Service (BCS) certificate shall be supplied.

The documentation requirements for a particular metering application will be specified by BP. As a minimum requirement the vendor shall provide a dossier describing the design and operation of the metering system, flow calculations, uncertainty calculations and copies of all calibration, electrical safety, pipework, fittings and material certificates.

5.6 Class 2 Flow Measurement Equipment (Liquid and Gas)

* 5.6.1 Primary Elements

The preferred primary device for plant mass balance/internal accounting measurements will be the square edged concentric orifice plate with flange taps. These shall be specified in accordance with [ISO 5167](#) or [BS 1042](#): Part 1: Section 1.1. and BP Group [GS 130-5](#). The maximum d/D ratio shall be 0.7.

For both liquid and gas, orifice plate flowmeters provide an acceptable method of metering for most mass balances and other intermediate standard plant measurements, for both liquid and gas.

They have the advantages of relatively low cost and versatility - i.e. ranges may be changed quickly at negligible cost, but the disadvantages are that they create a permanent obstruction in the pipeline and have reduced accuracy if the fluid physical properties vary appreciably. Where these disadvantages are unacceptable, the use of an alternative measurement device should be considered.

For Class 2 intermediate standard accuracy orifice plate metering in the order of $\pm 2\%$, the relaxed constraints on d/D ratios and other parameters are given in section 5.3.

The preferred differential pressure for orifice sizing is 250 mbar; other ranges should be selected from the following :-

- (a) 50 mbar
- (b) 100 mbar
- (c) 500 mbar

Wherever possible, standard ranges of the vendor should be selected. For flow turn-downs greater than 3:1, the use of multiple or 'smart' differential pressure transmitters should be considered.

The material for orifice plates shall be compatible with the fluid handled. The preferred material is Type 316 austenitic stainless steel. All other materials including those to satisfy the requirements for sour service, as detailed in [NACE Standard MR-01-75](#) and BP Group [GS 136-1](#), shall be subject to approval by BP.

Orifice plates should be mounted between orifice flanges in accordance with Fig 5-8 or integral orifice assembly in accordance with Fig 5-2. Where it is necessary to change orifice plates without disrupting plant operations, a carrier or retractable plate design may be used.



Flange taps are the preferred tapping arrangement for orifice plates in line sizes NPS 2 (DN 50) and above. Other tapings may be used subject to approval by BP. Corner taps are preferred for line sizes below NPS 2 (DN 50).

The use of flange taps on ring type joint flanges shall be subject to approval by BP. For these, alternative tapping arrangements or measurement techniques should be considered, for example; orifice carrier or fitting, line taps or venturi section. Selection depends on the measurement accuracy required and operating conditions and shall be subject to approval by BP. For preferred flange taps arrangements for liquid service, see BP Group [RP 30-1](#) Section 4, Figure 5-4.

For viscous liquids, conical-entrance or quarter-circle orifice plates may be proposed by the vendor and shall be subject to approval by BP. These units shall be in accordance with [BS 1042](#): Part 1: Section 1.2 (Note - the maximum d/D ratio for conical-entrance is 0.3, for quarter-circle 0.6).

For liquids with entrained solids, eccentric orifice plates may be used, subject to approval by BP.

Where there is a likelihood of condensation occurring in the pipes, a drain hole may be provided through the orifice plate at the bottom, to avoid accumulation of liquid. An appropriate correction shall be made in the plate discharge coefficient calculation. (Refer also to the following section 5.6.2 'Metering Runs').

An accumulation of condensate at the base of an orifice plate can affect the discharge coefficient. Wherever possible a metering system for wet gases should be installed in a vertical plane. Where the meter must be installed horizontally, a drain hole may be provided through the bottom of the plate. Drain holes should only be used when the pipe exceeds NPS 4 (DN 100) and the diameter of the drain hole should not exceed 0.1 of the orifice bore. An additional uncertainty of 0.3% should be added arithmetically to the uncertainty of the discharge coefficient when a drain hole is provided. An allowance for the additional orifice area (d) must be made thus:-

$$d = dm [(1 + 0.55 (dh/dm)^2)]$$

where dm = orifice diameter
 dh = drain hole diameter
(Reference Fig 5-8.)

Where the process conditions require a minimum permanent pressure loss, venturi type meters may be proposed. Venturi tubes shall comply with [ISO 5167](#) or [BS 1042](#) : Part 1: Section 1.1.



Where no appreciable pressure loss can be tolerated, Pitot and similar propriety tubes may be used, provided the fluid is clean. These shall be of the retractable type where the line cannot be readily isolated.

Coriolis effect flow meter may be used where a mass readout is required or acceptable, and where the calculated volume flowrate meets the accuracy requirements for the application. Refer to 5.2 for other requirements.

Variable area meters may be used for small rates of flow (e.g. utilities to plant). Refer to 5.7 for constraints.

For steam applications, flow nozzles may be used.

Other in-line flowmeters such as turbine, displacement, vortex, ultrasonic (time of flight), insertion types, (e.g. turbines or vortex) may be proposed by the vendor and shall be subject to approval by BP. The vendor shall provide written evidence that the proposed flowmeter has been proved on similar service.

For applications where an alternative type of meter must be considered, the vendor's recommendations for installation must be observed, particularly regarding upstream straight length requirements and the need for filtration. The following notes give guidance for choice of alternative types of meters:-

- (a) *Turbine or Displacement meters. The choice between these two meters, both capable of high accuracy, will usually be made on the basis of cost or, for some applications on size and weight. Use turbines meters wherever possible, but observe the performance limitations governed by the fluid viscosity (see 5.2.1). Without special precautions, displacement meters may be unsuitable where failure causing line blockage can cause hazard, e.g. fuel lines to burners.*
- (b) *Vortex shedding meters, although not widely used within BP, have become recognised elsewhere as an established device for Class 2 type flow measurement, in the range NPS 1 (DN 25) up to and including NPS 6 (DN 150). They are best used where the flow is always turbulent since their accuracy falls off at Reynolds Numbers below 20 000. In suitable applications an accuracy $\pm 1\%$ over a 10:1 turn-down is obtainable. And should be considered where cost effective versus orifice installations.*
- (c) *Ultrasonic Meters are of two main types, 'Doppler' and 'Time of Flight'. A third type, the cross correlation meter is also available but should only be considered for special applications for which other types of meter are unsuitable, e.g. for two phase flow. 'Time of Flight' meters designed specifically for flare gas flow measurement are available (see 5.6.1.16).*

'Doppler' meters are generally not sufficiently accurate for Class 2 measurement, but may be suitable for Class 3 metering.

'Ultrasonic Time of Flight' meters, especially multi-chorded diagonal beam devices, in sizes above NPS 4 (DN 100) can be of Class 2 accuracy or



better. They are however, generally expensive, and should only be considered where a non-intrusive meter with no head loss is essential. This type of meter has a comparative high turn-down ratio and thus may have economic advantage over other types where a wide flow range must be measured. They should not be used where fouling at the transducers can occur, e.g. by waxing.

- (d) Insertion flowmeters may be preferred for applications where a permanent line obstruction is undesirable or when the cost of installing a permanent flowmeter in an existing pipeline is uneconomic. For best performance the measuring head of an insertion meter should be positioned at a distance $0.75 R$ from the centre of the pipe (R = pipe radius). At this point the flow velocity is approximately equal to the mean pipe velocity, provided that the flow profile is fully developed.

Insertion meters should not be mounted close to bends or downstream of other pipe fittings likely to disturb the flow profile. If this cannot be avoided then an Anubar Pitot principle insertion meter may be the best choice. A large bladed trash resistant insertion turbine is the preferred choice for pacing automatic samplers installed on ships discharge lines. (See Section 8 of this Recommended Practice).

Ultrasonic 'Time of Flight' meters are preferred for flare gas flow measurement.

Flare Gas Flowmetering. Ultrasonic meters of the 'Time of Flight' type have superior performance to thermal flowmeters for this application. Although primarily velocity measuring devices, a subsidiary measurement is made of molecular weight and thus computation can be made of mass flow rate. These meters, however, are very much more expensive and their use must be justified by the importance of the application. Fitness for purpose is the guiding criterion.

Magnetic flowmeters may be proposed by the vendor for appropriate applications with conducting liquids, and shall be subject to approval by BP.

Electromagnetic Flowmeters. Where their cost can be justified electromagnetic meters may be considered for use with electrically conducting liquids, e.g. water based. The installation must be such that the meter-tube will always run full and there is no entrainment of gas or vapour. The temperature limitations which apply to the non-metallic liner must be considered. Special attention must be given to the electrical installations, particularly the earthing arrangement. A continuous electrical contact to the same earth potential is required for the liquid, the piping and the meter. The vendor's recommendations must be observed.

All flow devices shall have positive means of identifying the direction of flow.

5.6.2 Metering Runs

For Class 2 orifice plate metering, the full straight pipeline run indicated in [ISO 5167](#) or [BS 1042](#) : Part 1: Section 1.1 shall apply. Any variation on this shall be supported by calculations showing the revised accuracy of the system for the reduced pipe lengths proposed, and shall be subject to approval by BP.

Orifice metering runs shall not be less than NPS 2 (DN 50) (the minimum line size for flange taps covered by [ISO 5167](#) or [BS 1042](#) : Part 1: Section 1.1). With corner taps the minimum line size shall be in NSP 1 (DN 25). The orifice bore shall be not less than 6 mm (1/4 in), unless otherwise approved by BP.

For very low rates of flow, small bore special purpose meter runs, or differential pressure transmitters with integral orifice may be proposed by the vendor and shall be subject to approval by BP.

Except for wet gas or steam flows (see also previous section 5.6.1 'Primary Elements'), the preferred arrangement for all metering runs is horizontal. This is mandatory where eccentric orifices are used. Vertical runs should be used with downward flow for steam and condensables, and with upward flow for liquids nearing their boiling point.

For a flow measurement service where uninterrupted flow must be maintained in the event of meter failure (e.g. fuel gas measurement) a standby parallel meter should be provided if it can be justified by the cost of measurement loss. Alternatively, a retractable orifice plate fitting or a meter bypass may be installed.

For alternative types of flowmeter, the vendors installation recommendations shall be observed.

* 5.6.3 Mass Measurement

Class 2 liquid mass flow measurement: This should be by the inferential method described in 5.2 using a volume meter and an on-line densitometer. The transducers shall be installed in accordance with [IP Petroleum Measurement Manual](#), Part VII, Section 2. However, where the liquid density is constant to within the required accuracy of measurement, the density of a sample may be taken and used in the simple computation $\text{mass} = \text{volume} \times \text{density}$ (at standard conditions). Where economic, Coriolis type direct mass meters may be proposed by the vendor subject to the constraints in 5.2. Use shall be subject to approval by BP.



In inferential mass measurement systems vibrating element type density meters are preferred for:-

- (a) *Gas, the vibrating spool type installed either directly in the pipe or in a pocket downstream of the flowmetering device.*

and

- (b) *Liquid, the vibrating tube type installed either in a bypass loop or, with small pipes, with the flow routed directly through.*

In such installations adequate provision shall be made to bypass the densitometer in the event of failure.

The use of PTZ compensation depends on accurate measurement of gas composition. It may be applicable if gas composition changes very little over time.

The use of Coriolis effect direct mass flowmeters can sometimes be justified on the grounds of required accuracy versus economic constraint. No on-line proving system will be required for Class 2 measurement.

Class 2 gas mass flow measurement: This should be by on-line densitometer as for Class 1 (see 5.3). Alternatively, it may be possible to use PTZ compensation, provided that the gas composition is suitable; and preferred if the gas is wet. Calculation for natural gas may be made to [AGA Report No. 8](#), or other suitable equations of state.

Systems employing PTZ compensation shall be subject to approval by BP.

*** 5.7**

Class 3 - Flow Measurement Equipment (Liquid and Gas)

Requirements shall be as detailed for Class 2 measurements except as detailed below:-

Half straight run lengths detailed in [ISO 5167](#) or [BS 1042](#) : part 1 : Section 1.1 may be used. The use of shorter lengths shall be subject to approval by BP.

Where an orifice plate or venturi is unsuitable for a service, alternative flow devices as listed in 5.6 may be proposed by the vendor. In addition to these, Ultrasonic, variable area, target or thermal type flow devices may also be proposed. The vendor shall provide written evidence that the proposed flow device has been proven in similar service, and shall be subject to approval by BP.



In addition to the types discussed under Class 2 measurement, the following alternative flowmeter types may be considered for Class 3 service:-

- (a) *'Doppler' clamp-on type ultrasonic meters are simple and cheap to install. However, they will only function on fluids with some particle or gas/air entrainment and thus are unsuitable for clean fluids.*
- (b) *Variable area flowmeters (Rotameters) may be considered for Class 3 duty in applications where the fluid density and viscosity are relatively constant. Metal tube types with magnetic followers are preferred.*

Glass tube meters shall only be used on non-hazardous service and should generally be confined to use in analyser sampling systems and to meter purge gas or water flow rates, or non-dangerous fluids. Maximum working pressure and temperature ratings must be scrupulously observed.

- (c) *'Target' flowmeters are essentially differential pressure devices suitable generally for low turn-down flows of particularly viscous or dirty fluids, with suspended solids.*
- (d) *'Thermal' type mass flowmeters have been used primarily for flare gas flow measurement. Their accuracy is affected by changes in the heat transfer properties of the fluid, i.e. its composition and its density. Ultrasonic 'Time of Flight' meters are superseding thermal meters for this application (see 5.6.1).*

Mechanically protected glass tube variable area meters may be used on suitable non-hazardous, low flow service and temperatures up to 130°C (266°F). Their use shall be limited to meters up to NPS 1/2 (DN 15) in size.

For hazardous service, glass tube meters shall not be used; metal tube meters shall be provided.

Hazardous service is defined in BP Group [RP 42-1](#).

The use of glass tubed variable area flowmeters must be restricted to non-hazardous low temperature, low pressure service.

Failure of the tube (e.g. mechanical damage) could release significant stored energy on gas systems. Therefore, integrity of any secondary safety shield also requires assessment.



6. STORAGE TANK MEASUREMENT

This section specifies BP general requirements for the design, selection and installation of storage tank measurement equipment for liquid level and temperature.

6.1 Categorisation of Tank Measurement Equipment

6.1.1 General Requirements

Equipment for gauging the contents of storage tanks will be categorised by BP depending upon the purpose of its application and the required accuracy of measurement. Although fitness for purpose will be the primary criterion in specifying equipment standards, two general performance categorisations for tank gauging equipment have been established, as follows:-

Category 1

- (a) Fiscal or commercial custody transfer measurements.
- (b) Inventory/stock reporting and accounting.

Category 2

- (a) General tank content monitoring and control.

The categories defined for tank gauging equipment in this paragraph are for general guidance and apply for most applications. However, the main criterion to be satisfied when selecting equipment should always be fitness for purpose. Thus there may be a few applications where, for example, the relatively high price of a comprehensive Category 1 gauging system may not be justified by the low volume or cost of the product involved; or conversely, where the high volume/cost of the product in a nominally Category 2 application might justify a more accurate or comprehensive system. Provided that all the parties who have a commercial interest in the measurements agree, including where applicable, the fiscal authority, then the most appropriate equipment should be selected for such cases.

6.1.2 Category 1 Equipment

Category 1 is the most stringent application requiring the highest standards of accuracy and reliability. Gauging equipment in this category must meet the regulatory standards which apply in the country of installation.

The calibration of Category 1 gauges used for fiscal or custody transfer tank measurements will need to be regularly checked against manual tank dip measurements.



Generally, only equipment from a limited range of equipment types will be capable of satisfying Category 1 accuracy and reliability standards (See 6.2).

The requirements for periodic calibration checking will normally be specified by the fiscal authority or by the commercially interested parties in a transaction.

Procedures for manually dipping tanks are contained in Chapters 1 and 2 of the BP Measurement Standards.

6.1.3 Category 2 Equipment

Category 2 gauges are suitable for general tank content monitoring and level control and may normally be of a lower accuracy standard. Although reliability is still a prerequisite for Category 2 equipment, the requirement for accuracy is reduced to a level compatible with the practical needs of the application. Calibration checks will not generally be required on a routine basis but will be carried out on suspicion of malfunction or high error.

6.1.4 Environment

All tank gauging equipment, regardless of category, shall be suitable for the environment in which it is to be installed and maintained. In selecting the equipment, account shall be taken of the factors listed in BP Group [RP 30-1](#).

6.2 Category 1 Tank Gauging Equipment

* 6.2.1 General Requirements

Electrically powered servo-operated tank gauges with a surface sensor are normally preferred by BP for Category 1 applications. However, this preference does not preclude the vendor from proposing an alternative type of tank level measurement device if supported by a written technical case; and subject to approval by BP. Thus, alternative gauge types designed to detect tank levels using one of the following principles of operation may also be acceptable for Category 1 use, where independent evidence can be provided of satisfactory operation in an application similar to that of their intended use:-

- (a) microwave, radar,
- (b) laser,
- (c) ultrasonic,
- (d) capacitance, or
- (e) hydrostatic head (for mass).



Category 1 tank gauging systems shall be designed and installed in accordance with the recommendations of the Institute of Petroleum Measurement Manual ([IP PMM](#)) Part V, Automatic Tank Gauging (January 1982), and Part XIII Section 2, Electrical and/or Electronic Data Transmission for Automatic Tank Gauge Systems (December 1979).

Caution should be exercised when considering the use of alternative gauge types for Category 1 applications. Although manufacturers claim high accuracy for some of the newer, non-intrusive gauge types now available on the market, these claims have not yet been fully substantiated in the BP trials so far carried out.

Trials on radar and hydrostatic head type gauges, in particular, are continuing with encouraging results.

Non-intrusive gauges are, in general, simpler to install than in-tank servo or float type gauges. The accuracy of radar type gauges may be prejudiced, however, by reflections from tank or stilling well walls if the manufacturer's recommendations concerning minimum spacing dimensions are not observed.

It must also be emphasised that hydrostatic head gauges are essentially tank mass measurement devices and that derived figures for tank level and volume measurements are based on calculations using a sample density measured at one area at the tank wall only. Thus, because of temperature/density stratification, they are unlikely to meet fiscal/custody transfer accuracy requirements. However, hydrostatic head gauges may have advantage for the measurement of products, which are the subject of commercial transactions on the basis of mass, e.g. LPG or chemicals.

6.2.2 Ancillary Equipment

In addition to the level measurement device itself, tank gauging systems for Category 1 measurement shall include the following ancillary equipment:-

- (a) Tank content temperature sensing equipment (see 6.2.4).
- (b) A data transmission system for level and temperature readings connecting with remote, microprocessor based data handling and readout equipment (see 6.2.5).
- (c) Local indication of tank level, and if specified, temperature.

6.2.3 Performance

The accuracy and repeatability of Category 1 tank gauging systems shall conform with the requirements of [BP Measurement Standards Part 1](#) Vol. 1. (Static Methods) and with the standards of any other interested parties, e.g. the fiscal authorities.



The [IP PMM](#) Part V, specifies an accuracy of +2.5 mm to -2.5 mm for automatic tank gauges, when compared with reference manual tank readings.

Methods for checking the performance of automatic tank gauging equipment are explained in detail in Chapter 3 of [BP Measurement Guidelines](#), Part 1, Volume 1: Static Methods. For Category 1 applications: gauge readings should agree with manual dips within ± 2.5 mm.

The dynamic performance of Category 1 level gauges shall be adequate to follow, without loss of accuracy, the most severe rate of level changes (filling and emptying) which will be experienced in the application.

The dynamic response (raise/lower mechanism speed) of electrically powered servo-gauges will normally be adequate to follow level changes in tanks of typical diameter/height ratio. The response speed need only be confirmed for tanks of small diameter which are subject to extreme level change.

Most alternative electronic gauge types, e.g. radar, laser, ultrasonic etc. will respond without significant delay.

Category 1 gauge systems shall be of the highest reliability and shall be simple to install, operate and maintain.

6.2.4 Temperature Measurement

Temperature measurement in Category 1 systems shall be by averaging resistance thermometers, generally as recommended in the [IP PMM](#) Part V, Chapter 5 and in [API 2543 \(ASTM D1086-64\)](#) Appendix 1. The temperature measurement accuracy shall be within $\pm 0.3^{\circ}\text{C}$.

Temperature gradients are always present in liquid storage tanks. However, the gradients are less with low viscosity oils than with high viscosity or heated oils. With low viscosity oils the maximum vertical temperature gradient will be over the bottom 1.0 m of product, reducing to perhaps 0.1°C over the higher levels in the tank. Horizontal gradients may be in the order of 0.2°C . For such applications, single point temperature measurement may be adequate. Thermometers for spot measurement should be positioned at 2.0 m from the tank bottom, with the element at least 1.0 m in from the tank shell.

For fixed roof tanks multi-element resistance thermometer assemblies should be used. Alternatively for both fixed and floating roof tanks, three point (top, middle and bottom) resistance thermometer systems may be used. The material of the sheath shall be immune to corrosion or other damage caused by contact with the tank liquid.

Generally a PTFE sheath is adequate, but if H_2S is likely to be present a stainless steel sheath shall be used.



Resistance thermometer elements shall comply with [IEC 751 \(BS 1904\)](#) Class A, for platinum elements. Copper wound elements shall have a resistance of 100 ohm at 25degC in accordance with oil industry practice.

Whereas platinum resistance thermometers have a resistance of 100 ohms at 0°C to accord with [IEC 715](#), copper elements are wound in accordance with American practice, to have a resistance of 100 ohms at 25°C (77°F). The resistance/temperature characteristics of copper and platinum are also different. For these reasons care must be taken to ensure that the resistance to temperature convertor is appropriately calibrated to suit the type of resistance thermometer element.

Note that some manufacturers will, on request, ballast a copper wound thermometer to adjust its resistance to 100 ohms at 0°C and will also electronically characterise its temperature/resistance curve to match that of a platinum resistance element. This practice is not recommended for Category 1 gauging system because of the additional measurement uncertainty which is introduced.

When a multi-element temperature measurement system is used, the longest totally immersed element shall be selected automatically by the level sensing equipment. The facility for override of the element selector switch shall be available in the remote location.

With high viscosity oils, including most crude oils, convection currents within the tank are lower and consequently temperature gradients in both vertical and horizontal directions are high, in the order of 3°C, or higher in the case of heated tanks. Therefore, multi-point temperature measurement is essential. Multi-element platinum or copper resistance thermometers are preferred, with the longest immersed element selected to provide an average temperature measurement over the depth of liquid in the tank. The temperature of sludge deposits or water bottoms should not be included in the measurement and the bottom of the element should be positioned above the maximum level of these. In heated tanks the lowest temperature measurement point should be 0.75 m above the steam coils.

The requirements of BP Group [RP 58-1](#), shall be observed for heated and unheated tanks.

A local temperature indicator, either operating directly from a separate in-tank spot temperature sensor or from the remote temperature indication transmission system shall be provided. Separate spot temperature sensors shall be positioned at least 1.0 m in from the tank shell.

6.2.5 Data Transmission and Remote Indication

Except where specified by BP, Category 1 tank gauging systems shall be used in association with dedicated readout equipment sited at a remote location. The readout equipment should be microprocessor



based with VDU screen displays of information and with data logging/printout facilities. The capability for a high resolution data link to other computer based remote data acquisition systems shall be provided; for example, refinery information systems (RIS), or management information systems. Detailed overall system requirements will be specified by BP for each particular case.

Dedicated microprocessor based readout and data processing equipment is available for most proprietary tank gauging and temperature measurement systems. Generally, for reasons of signal compatibility, it is not advisable to construct hybrid systems using components from different manufacturers. However, the data processing equipment itself must be capable of communication, at the requisite level of data resolution, with other plant computers, e.g. supervisory control and data system (SCADA), those used for refinery information systems (RIS) or for management information systems. Thus the tank gauge system and the data to be produced by it, should be specified to satisfy not only the local information needs of the tank farm operators, but also with consideration for the wider requirements of an integrated plant or business activity, including, for example, other process plant operations and/or commercial, accounting or administrative departments.

In special cases, usually involving a small number of tanks and where it is economically advantageous, individual indication/readout facilities for each tank may be proposed, subject to approval by BP.

For Category 1 tank gauging, the data transmission system between the on-tank sensors and the remote readout equipment shall comply with the recommendations of the [IP PMM Part XIII Section 2](#). The security of the data transmission shall be at least to Level 2.

Data transmission systems shall be protected from and shall be immune to interference or hazard from lightening strikes or other electrical transients and surges.

6.2.6 Local Indication

Where the requirement for local indication of tank level or temperature is specified, the indicators shall be located so as to be clearly visible from appropriate local control points, (e.g. filling or draining valves, or steam heater control valves).

The signals for local level indicators, (as for thermometers, see 6.2.4.), may be taken from the data transmission circuits supplied for the remote indication system - provided that the additional loading does not prejudice the fidelity of the remote readout (see 6.4.4 for the exception applicable to LNG/LPG measurement).

6.3 Category 2 Tank Gauging Equipment

* 6.3.1 General Requirements



Because the requirements for level measurement quality, in terms of accuracy and repeatability, are normally lower for general tank content monitoring and control than for fiscal or custody transfer purposes, a wider and more economic range of gauge types may be acceptable for Category 2 Systems. However, reliability of measurement remains equally important, as does simplicity of installation, operation and maintenance.

In addition to the types of tank gauge listed in 6.2.1, the following gauges may also be suitable for Category 2 application - subject to approval by BP:-

(a) Float type gauges (non-servo) with gauge board. Note: The accuracy of level measurement of this gauge type is generally not better than ± 25 mm.

(b) Hydrostatic tank gauges.

This gauge type fundamentally measures head and not level. Therefore, it may not be acceptable for critical application such as overfill or low level alarm systems.

(c) Nucleonic beam gauges, (suitable for difficult application e.g. bitumen storage).

6.4 Tank Gauging of LNG and LPG

6.4.1 Tank gauges fitted on high pressure tanks containing LNG or LPG shall conform with the recommendations of the [IP PMM Part V](#).

6.4.2 For volatile fluids such as LPG or LNG, where measurement is required of the total volumetric or mass contents, accurate measurement shall be made of the temperature and pressure of the vapour phase in addition to that of the liquid. The value of these variables shall be recorded separately for later calculation of the total fluid contents.

6.4.3 Liquid temperature measurement shall be by means of a multi-element platinum resistance thermometer to [IEC 751 \(BS 1904\)](#) Class A mounted within a thermowell pipe.

6.4.4 In addition to the primary gauge fitted for the accurate measurement of tank level, a secondary gauge shall be installed for alarm purposes. Independent transmission/wiring for the level signal to the remote control point shall be provided.



- * 6.4.5 The use of hydrostatic tank gauges for pressure storage tanks shall be subject to approval by BP.

6.5 Gauging of Refrigerated LNG and LPG

- 6.5.1 Level gauging and temperature measuring equipment for refrigerated storage tanks shall comply with the recommendations of IP PPM Part XII, Static Measurement of Refrigerated Hydrocarbon Liquids, Section 3, Instruments for Primary Measurement. Refer also to [ISO/DIS 8310](#).

- 6.5.2 Electrical powered servo-operated gauges shall be installed for Category 1 applications. Tapes shall be of a material with a low coefficient of thermal expansion.

- 6.5.3 Multipoint temperature measurement shall be made, both over the depth of liquid in the tank, and in the vapour space above the liquid. Temperature measurement shall be by 3 or 4 wire platinum resistance thermometer to [IEC 751 \(BS 1904\)](#) Grade 1, (100 ohm). Alternatively copper/copper-nickel thermocouples to [BS 4937](#) Part 5 may be proposed, subject to approval by BP.

Refer to [ISO/DIS 8310](#). Refrigerated Light Hydrocarbon Fluids - Measurement of temperature in tanks containing liquefied gases, for details of recommended resistance thermometers and thermocouples.

- 6.5.4 Pressure measurement of the vapour space in the tank shall be made.

- 6.5.5 Density measurement; if specified, shall be by non-intrusive nucleonic densitometer (gamma-ray type). Alternative methods of density measurement may be proposed, e.g. vibrating element, ultrasonic or capacitive, subject to approval by BP.

Gamma Ray type density meters have a longer history of satisfactory use in low temperature storage than other densitometer types. However, vibrating element types may be suitable provided a suitable method of calibration is used, taking account of the low operating temperature.

Early warning of the potential hazard from 'rollover'; a phenomenon in which the tank contents suddenly invert after low density product becomes trapped beneath incoming heavier fluid, may be obtained from signals given by an in-tank scanning system which measures continuously, density and temperature throughout the vertical liquid depth.

- 6.5.6 Calculations to obtain the contents of refrigerated tanks shall be carried out using the procedures detailed in the [IP PPM](#) Part XII, Static Measurement of Refrigerated Hydrocarbon Liquids, Section 1.

- * 6.5.7 The use of hydrostatic tank gauges for refrigerated storage tanks shall be subject to approval by BP.



6.6 Alarms and Trips

As a general principle, all alarm and trip circuits used to monitor critical functions shall derive their signals from independent, separately wired, high reliability transducers, installed specifically for safety/tank protection purposes.

Non-critical alarm functions may be initiated from measurements generated primarily for tank level/temperature inventory monitoring purposes

6.6.1 General Requirements

Measurement signals produced by level and temperature gauges on storage tanks shall be used to operate alarm and trip circuits in accordance with the requirements of BP Group [RP 58-1](#).

Protection is required against the following circumstances:-

- (a) Tank overfill:-
 - (i) by high level alarm
- (b) Floating roof or mixer damage:-
 - (i) by low level alarm
 - (ii) by mixer motor trip
- (c) Tank overheat or water bottoms boil over:-
 - (i) by low level alarm
 - (ii) by high temperature alarm
 - (iii) by steam valve control
- (d) Other events, e.g. excess rate of level change, alarm or control; as specified by BP.

6.6.2 Level Alarms

Alarms shall be generated whenever preset high and low level points are reached. They may be initiated by any of the following methods:-

- (a) Where tank levels are scanned; by automatic checking of level readings against alarm set points.
- (b) By electric switch in the gauge head.
- (c) By externally mounted float type level switch.



- (d) Alternative methods, e.g. by position switch on floating roofs, may only be used subject to approval by BP.

6.6.3 Level Trips

All trip and control functions to be operated when level set points are exceeded shall be initiated by level sensors independent of any alarm switch or transmission system associated with normal level indication or monitoring duties.

6.6.4 Temperature Alarms

Alarms shall be generated whenever preset high or low temperature set-points are reached. They may be initiated by any of the following methods:-

- (a) Where tank temperatures are scanned; by automatic checking of temperature readings against alarm set points.
- (b) By individual electronic thermal trip units connected to the temperature transmission circuits, subject to approval by BP.
- (c) By filled system temperature switch with armoured capillary with the sensing element enclosed within a thermowell, subject to approval by BP.

6.6.5 Temperature Trips

All temperature trip functions shall operate from temperature sensors independent of alarm switches or transmission systems associated with normal temperature indication. On heated tanks the temperature sensor shall be mounted 750 mm above the steam coils and the trip linked with the steam shut off valve.

6.7 Installation of Automatic Tank Gauging Equipment

6.7.1 General Requirements

The installation of automatic tank gauging and temperature measuring equipment shall be in accordance with the recommendations of the [IP PMM Part V \(Chapter 3\) Automatic Tank Gauging \(1982\)](#). In particular the following practice shall be observed.

6.7.2 For Category 1 Gauge Systems (Low Vapour Pressure Liquid Storage).

Category 1 electrically powered servo-operated tank gauges used on vertical cylindrical tanks shall be mounted on top of a support pipe



which may also be used as a still pipe for the surface sensor. The support pipe shall be NPS 12 (DN 300), with the centre line approximately 500 mm in from the tank shell and shall only be fixed to, and supported by, the tank bottom in such a way that the imposed load is distributed so that it does not exceed the equivalent of 3.0 m of liquid product. A flexible seal shall be fitted to allow relative movement and to prevent vapour escaping between the support pipe and tank roof.

In order to achieve the best possible accuracy, Category 1 tank gauges must be mounted so that any distortions of the lower tank shell, which occur inevitably due to the varying weight/pressure of the liquid contents, do not adversely affect the level measurement. The only practicable way to ensure stability of the gauge mounting is to install it at the top of a support/stilling pipe affixed with evenly distributed weight over a solid area of the tank bottom.

The internal diameter and uniformity of support pipes for radar type gauges shall conform with the manufacturers recommendation.

Alternative gauge types operating on a principle unsuited to support pipe mounting shall be mounted according to the manufacturer's instructions, particularly with regard to the distance from the tank wall and the still pipe diameter. In any case, the mounting shall be such that the gauge accuracy is unaffected by any distortion of the tank shell. The mounting method shall be subject to approval by BP.

A separate still pipe shall be provided for manual dipping/sampling.

For the same reason manual dip still pipe/reference plates used when the automatic gauge is being calibrated, should also be fixed in relation to the tank bottom and not the lower tank wall.

Still pipes, or support pipes where they are used as still pipes, shall be perforated with holes/slots in accordance with [IP PPM](#) Part V, Figure 6-8.

The performance of radar type gauges can be adversely affected if the diameter of the support pipe differs from that recommended or if the holes or slots in the pipe are spaced such that the edges are coincident with the nodes of the microwave transmissions. Advice should be sought from the gauge manufacturer on support pipe diameter and on recommended hole/slot spacing.

The automatic tank gauge head, with a float inspection chamber, shall be mounted in proximity to the manual dip/sampling hatch and be accessible from the gauger's platform. Wherever possible this should be situated on the shaded side of the tank and remote from disturbances from inlet/outlet pipes and the effects of mixers.



The size of sample and dip hatches shall be as specified in BP Group [RP 46-1](#) and BP Group [RP 58-1](#) respectively, dependant on the type of tank.

To facilitate maintenance both power and signal cables shall be capable of isolation from the gauge by provision of a flameproof switch mounted adjacent to the gauge head. Consideration shall also be given to the provision of extra cores to allow communication with the control room via an intrinsically safe portable telephone.

6.7.3 For Category 2 Gauge Systems

Electrically powered servo-operated gauges and mechanically operated gauges for Category 2 applications, shall be mounted using one of the methods described in Figures 6-1 - 6-3 of the [IP PPM](#) Part V. Tank shell mounted gauge heads shall be fixed at a height of 2.0 m above tank base level.

The mounting arrangements for other Category 2 type gauges shall be in accordance with the manufacturers recommendations.

The installation arrangements for still pipes for manual dips and sampling, where provided, shall be as for Category 1 applications.

6.7.4 Temperature Measurement Equipment

For Category 1 applications multiple element resistance thermometers shall be installed within a thermowell pipe situated on the shaded side of the tank and at a minimum distance of 500 mm from the tank wall. The installation shall be as Figures 6-6 and 6-8 of [IP PPM](#) Part V.

Category 1 three point resistance thermometers shall be installed through roof manholes and as Figure 6-6 of [IP PMM](#) Part V. The top and bottom elements shall be located within the liquid, 0.9 m from the surface, and the tank bottom respectively.

Spot thermometers shall be mounted at a height of 2.0 m from the tank bottom with the element 1.0 m in from the tank shell.

6.7.5 For High Pressure Tanks (Horizontal)

The installation of gauges and thermometers on high pressure tanks shall comply with the requirements of BP Group [RP 46-1](#) and BP Group [GS 118-1](#), and in general, with the recommendations of the [IP PMM](#) Part V (Section 3.11 and Figures 6-4(e) - 6-4(d)).



For Category 1 applications, electrically powered servo-gauges shall be mounted on the inspection hatch, with the surface sensor within a still pipe (Figure 6-4(e) [IP PMM Part V](#)).

The inspection chamber shall be capable of isolation from the tank contents by a double block valve with bleed. The inspection chamber shall be fitted with a vent valve.

Category 2 gauges may be mounted on a tank support.

6.7.6

For Refrigerated Tanks

The installation of gauges and thermometers on refrigerated tanks shall comply with the requirements of [IP PMM Part XII Section 3](#).

The design shall ensure that the still pipe is vertical when the tank is at its normal working temperature. Account shall be taken of any relative movement of the tank top mounting point to the tank base/inner shell; and the effect of such movement on still pipe mounting and location points.

For Category 1 applications, electrical power servo-gauges shall be rigidly mounted in relation to the tank wall or other datum, with the surface detecting element within a still pipe.

On refrigerated spherical tanks the gauge shall be mounted on the pipe tower, with the gauge reference point on an imaginary vertical axis projecting through the south pole of the tank.

The installation shall be such the surface sensor can be removed from the tank for inspection without leakage of vapour or product.

Materials used for installations in tanks (e.g. cables) must be specified for cryogenic service.

6.8

Capacitance Gauges

*

6.8.1

Capacitance gauges may be used for the measurement of LPG and LNG in storage vessels, but subject to BP approval for each particular application.

6.8.2

Capacitance gauges shall conform with the recommendations of International Standard [ISO/DIS 8309](#), in particular for following:-

Coaxial type capacitance sensors shall be constructed such that the relative positions of inner and outer tubes are rigidly fixed.



Coaxial sensors used for custody transfer tank gauges shall be divided into sections of such length that the overall uncertainty (combined error) does not exceed ± 5 mm.

Reference sensors shall always be submerged in the liquid in order to sense changes in dielectric constant. The reference sensor may either be a dedicated item or a section of the submerged section of the main sensor. It shall be installed in such a way that it cannot be fouled by accumulations of foreign deposits or such that it may be simply cleaned and maintained.

Main sensors shall be installed vertically from the tank bottom, and secured along a supporting column of sufficient strength to ensure that wave motion and other forces do not affect the accuracy of measurement.

7. ON-LINE ANALYTICAL MEASUREMENT

This Section specifies BP general requirements for on-line analytical measurement.

7.1 General Requirements

- * 7.1.1 As a general principle, the minimum number of on-line quality analysers necessary for the efficient and safe operation of plant shall be provided. Analysers should not be specified solely as a replacement for laboratory testing unless this can be shown to be economically viable. The type, application and installation of such instruments shall be subject to approval by BP.

Quantity, type and duty of analysers will normally be furnished by BP to the contractor. However, there are instances where this does not apply, e.g. analysers required solely to meet local and national regulations.

This Section of BP Group RP 30-2 does not cover samples for laboratory use. Refer to BP Group RP 30-2 Section 10 for environmental monitors for fire or atmospheric gas detection.

Analysers should be robust and properly designed for field use. The approach of using laboratory type equipment, even if installed in air purged boxes, should be avoided.

7.1.2 Analysers shall be single stream.

Single stream analysers are preferred because:-

- (a) *There are no cross contamination problems.*
- (b) *They have simpler and more reliable sample systems.*
- (c) *There is no sample change which may affect analyser calibration and operation.*



If single stream analysers cannot be justified, then the application is in doubt.

7.1.3

To ensure accurate, reliable and safe measurement of the stream property with adequate accuracy, reliability and safety, analysers shall be provided with all necessary sample systems, services, weather protection and ancillary equipment.

Analysers, their associated sample systems, and ancillary equipment should satisfy all the following criteria:-

- (a) Where applicable, be certified for use in the relevant hazardous area as detailed in BP Group [RP 30-1](#) Section 3.
- (b) Provide continuous output signals in accordance with BP Group [RP 30-1](#) Section 2 preferably without the use of ancillary equipment.

All signal manipulation should be integral with the analyser, e.g. peak pickers on chromatographs.

- (c) Provide the minimum of sample conditioning consistent with the requirements of the analyser.
- (d) Incorporate all necessary features to protect against abnormal sample and services conditions.
- (e) Be designed for continuous operation within the limits of specification. Routine maintenance shall not be more frequent than every seven days.

Routine maintenance is defined as calibration.

- (f) Permit routine maintenance without opening safety enclosures.

Zeroing, filter changes, sample flow, temperature and pressure adjustments. The frequency can be between once per week and once per few months.

This does not include visual examination (which should be on a daily basis), planned maintenance and preventative maintenance.

- (g) Be suitable for the environmental conditions in which they operate.

7.1.4

In the absence of more rigorous requirements which may be specified by local or national authorities, analysers shall be installed in accordance with the latest editions of the following:-



- (a) [IP Model code](#) of safe practice in the petroleum industry. Parts 1 and 8.
- (b) [BS 5345](#).
- (c) [BS 6739](#).
- (d) [API RP 550](#) - Part II.
- (e) BP Group [RP 12](#).

Further guidance is contained in [EEMUA Publication No 138](#).

7.1.5 When measuring elements are mounted in the main process line, they shall be removable without interrupting the process or creating a hazardous condition.

7.1.6 For critical applications, such as safety systems, or where specified by BP, a reliability assessment shall be made. Redundant voting systems shall be used if the reliability of a system using a single analyser is shown to be inadequate.

- * 7.1.7 The analysis time lag shall be as short as practicable. In all control applications, including alarm and protective systems, the analysis time lag shall be subject to approval by BP.

In closed loop control, it should be remembered that 'process lag' needs to be added to the 'analysis time lag' to give an 'overall time lag' for use in control calculations.

7.1.8 To reduce site work and to permit operational testing of the entire assembly before despatch to site, prefabricated installations containing one or more analysers shall be provided.

- * 7.1.9 The following shall be submitted for approval by BP:-
 - (a) The specifications and proposals for design and safety.
 - (b) Detailed sampling system design and installation, including material schedules.

Pre-fabrication may include analysers, sampling equipment, services and their weather protection, piped and wired to a common frame or analyser house. Note, it may be more cost effective to do all installation work on site, when simple 'one off' or direct insertion analysers (in-line) are used.

7.1.10 The analyser or systems vendor shall ensure that the application of winterisation does not adversely affect the operation of the analyser system components.



Cooling water can be overheated if steam tracing is incorrectly applied. Overheating of samples can cause vaporisation which will upset analysis.

- 7.1.11 Analyser tag numbers shall be to [ISA-S5.1](#), or existing plant standard.
- 7.1.12 Routine maintenance should be possible without disturbing the operation or location of the analyser.

7.2 Measurement, Status and Alarm Presentation

- 7.2.1 Recorders, indicators and controllers (and transducers which are not an integral part of the analyser) shall be of the type used for the main process instrumentation, provided that analyser performance is not impaired.
- 7.2.2 Recorders, indicators, controllers, quality alarms, stream indicators of direct concern to the plant operator shall be integrated into the appropriate process control panel or display configuration.
- 7.2.3 Quality alarms may be derived from the transmitted quality signal via control or central data gathering equipment, except when the alarm condition indicates a safety hazard of any description, in which case the alarm should be initiated directly from the analyser.
- 7.2.4 Control units where applicable, test displays, service alarms and similar equipment, should be grouped together in a separate lockable panel located in a safe area. The panel shall be readily accessible for maintenance.
- 7.2.5 Service alarms may be grouped together with one common output to the main alarm display. Under these circumstances 're-flash facility' is mandatory.
- 7.2.6 To assist with maintenance, analysers which require field adjustment shall have local indicators. A local display facility (test recorder, indicator or meter connection) shall be provided where the panel display is not visible from the control unit.
- 7.2.7 Analysers on closed loop control shall operate through a cascade loop. The range of set-point adjustment on the slave controller shall be restricted within adjustable pre-set high and low limits. Alarms shall be actuated if these limits are exceeded.
- 7.2.8 Analysers on closed loop control shall provide status indication to the control system. This shall take the form of an 'out-of-service' contact generated whenever the analyser or sample system is not functioning in a manner consistent with correct analysis of the process.



Typical fault detections generating 'out of service' are, sample flow failure, power failure, calibration sample selected, analyser in maintenance mode (manual switch), analyser self diagnostic giving 'fatal fault', analyser purge failure etc.

- 7.2.9 Cyclic analysers on closed loop control initiating digital systems shall provide a 'ready-to-read' contact for synchronising output updates to control actions.
- 7.2.10 Where analysers supply signals to local annunciators and the analyser is on control duty, failure or maintenance of the annunciator shall not compromise the control function.
- * 7.2.11 When analysers are to be interfaced with process computers, the method of interfacing shall be subject to approval by BP.

7.3 Sampling Systems

7.3.1 Basis For Design

The sampling system shall include all equipment necessary to provide the analyser with a continuous sample representative of the process stream in respect of the property to be measured and within conditions specified for the analyser.

To ensure a representative sample, items such as probe, filters, winterisation, materials, etc., need to be assessed with respect to the property being measured, e.g. chemical effects, adsorption, absorption, hold-up, process mixing at sample point, etc.

For multi-phase flows, isokinetic sampling, probe orientation and probe tip design can be important, e.g. refer to [ISO 3171](#) for water in crude oil sampling.

- 7.3.2 Precautions shall be taken to prevent damage to the analyser or sample system because of either abnormal plant or sample system conditions (e.g. temperature, reverse flow, or cross contamination of process stream or overpressure due to failure of pressure control facilities).

Precautions may include items such as non-return valves, flow limiters, break tanks and relief valves.

Over temperature can be a problem for sample system components as well as the analyser. Over temperature protection should be provided by use of temperature shut-off valves sited as close as possible to the source of over temperature e.g. immediately downstream of coolers or the process take-off point.

- 7.3.3 Pressure relief facilities shall be provided (relief valve or bursting disc) immediately downstream of pressure reduction stations. If discharging to closed vent systems or vent systems common to other analysers,



lockable isolation valves downstream of the relief facility should be provided to facilitate maintenance. For design and installation of relief facilities refer to BP Group [RP 44-1](#).

- * 7.3.4 Flammable vapour discharges from analysers shall be connected to a vent line and disposed to atmosphere at a safe height. Analyser vent systems shall be independent of any process vent, with due regard to the influence of the discharge on the surrounding area classification. Refer to Fig. 7-3 for details of a typical system. The location of the vent discharge shall be subject to approval by BP.

For correct operation, analysers should discharge to defined and steady back pressures.

- 7.3.5 A point shall be provided on each sample stream for taking a sample to check the analyser. This point shall be close to and upstream of the analyser, easily accessible, outside the analyser house, and arranged such that drawing the sample does not impair analyser operation. This check sample point is additional to the routine laboratory sample point provided elsewhere.

Sample points on the analyser system should be upstream of the analyser because:-

- (a) *The analyser may modify the sample, e.g. consume or convert the components monitored.*
- (b) *Higher pressures are available to assist sample removal. Many analysers discharge to atmospheric pressure and cannot tolerate back pressure.*

A separate laboratory sample point is mandatory. As it is directly on the process and independent of the analyser system, it serves to check that unwanted reactions are not taking place within the analyser sample systems.

- * 7.3.6 Facilities shall be provided for introducing test samples into the analysers unless otherwise specified by BP. Gaseous test samples, or volatile, toxic or otherwise dangerous liquid samples shall be stored outside the housing. Introduction of a test sample shall not cause a hazard. The provision for introducing a test sample shall include sample containers and any necessary relief valves, pressure gauges, pressurisation facilities and sample container heating facilities.

Note: Sample storage conditions and containment must conform to local or national regulations that apply.

Some analysers incorporate self calibration and hence may not require test samples to be introduced.

Aqueous or very viscous non-volatile samples may have to be stored in a warm environment to avoid freezing and to maintain fluidity.



- 7.3.7 If test samples are stored in vessels permanently piped into the sample system then they shall be isolated from the process sample by double block and bleed facilities.

Automatic validation systems require permanently connected calibration vessels.

In many instances it is desirable to be able to fill these vessels direct from the sample system. The filling line must also have double block and bleed arrangements. Facilities for monitoring vessel level and pressure and extraction of samples for laboratory tests shall be provided.

7.4 Sample Offtake

- 7.4.1 The optimum location of the sample offtake shall be selected to ensure that:-

- (a) The analysis is truly representative of the process being monitored or controlled.
- (b) The analysis satisfies the intent of quality commitments in commercial or fiscal agreements.
- (c) The response time of the overall analyser system satisfies the dynamics of the associated control or safety system.
- (d) Safe maintenance access is provided to sample probes, vaporisers, pressure reducing valves, and other process line mounted sample conditioning equipment.

Horizontal off-takes ensure that once the sample enters the probe there is no tendency for separation to occur by gravity.

Probes in vertical lines aid representative sampling by minimising liquid carry over (e.g. in gas streams), and minimising profile effects (e.g. stratification of fluids due to density differences, gravitational separation of immiscible fluids).

In some systems (e.g. moisture analysis, specific gravity analysis or catalyst regeneration stream analysis), where free liquids or solids are not wanted in the sample, configurations to eliminate these components are necessary. These may include special probes, probe orientations and locations not covered by this Section.

Solutions are too many and varied to be covered here. The final selection will rely on experience of the equipment vendor, checking on known existing applications, referring to any internal reports on evaluations of such equipment and engineering judgement.

- 7.4.2 Samples should be drawn from a point in the process where stream conditions are such that the minimum of sample conditioning is necessary.



- 7.4.3 To minimise vapour, water or dirt entrainment, samples should be taken from the side of the line; preferably with the offtake horizontal. Gaseous samples may be taken from the top of the line.
- 7.4.4 For general service on single phase fluids in process lines sized NPS 2 or greater, the sample offtake shall be by a probe in accordance with Fig 7-5.
- To minimise measurement lag, the contained volume of the probe shall be as small as practicable. When a liquid sample is to be vaporised, double extra strong pipe and reduced bore valves should be used in its construction.
- Materials selection, rating, flange type, fittings, valves, instrument connection, branch connection details, fabrication, welding, post weld heat treatment, testing and inspection shall be in accordance with BP Group [RP 42-1](#) and BP Group [GS 142-6](#). Double valving shall be provided only when required by BP Group [RP 42-1](#).
- Probe orientation and service tag number shall be stamped on the flange.
- 7.4.5 Proprietary probes should be used for specialist applications (e.g. flue gas sampling).
- * 7.4.6 Where multiphase fluids are expected, the contractor shall design the offtake to ensure that a representative sample is presented to the analyser. The design for each application (with supporting documentation) shall be approved by BP.
- * 7.4.7 For process lines below NPS 2, and for applications where a probe is impractical, a welded connection (NPS 3/4 (DN 20) or NPS 1 (DN 25) minimum with isolation valve(s)) in accordance with BP Group [RP 42-1](#) shall be provided. The design for each application shall be approved by BP.
- 7.4.8 For fast loop service, size of the sample offtake (including probe size and bore) may be increased to meet the desired loop flow requirements for the analyser system; and to ensure that pressure drop in the inlet system will not result in flashing of volatile fluids.
- 7.5 Sample Handling and Conditioning**
- 7.5.1 Liquid and gas samples, having sufficient pressure available, should be returned to process. Other methods of disposal shall ensure safety,



freedom from pollution and minimising sample loss, down-grading and reprocessing (see Fig 7-6. of this section).

In certain circumstances samples are vented or put to drain, e.g.

- (a) *Oxygen probe:- Flue gas samples plus condensed steam from ejectors. Contaminated condensate must not be returned to condensate lines.*
- (b) *Vaporised samples for chromatographs. Normally the flows are small, typically 1 litre/min, and provided only one or two analysers share a suitably located vent line, no safety hazard exists.*

7.5.2 Fast circulating loops shall not be terminated in vents or drains.

7.5.3 Fast circulating loops shall not be taken across control or isolating valves, or any primary device used for flow measurement. Devices shall not be introduced into main flow lines specifically to create a differential pressure for sampling.

Precedents have been set on introduction of differential pressure devices into process lines, e.g. density analyser sample loops. However, this practice should be avoided. Factors that may be taken into account include economics, compactness of installation, process tolerance and 'property measured' sensitivity. Typically for gas density, introduction of a differential pressure device can make the pressure at which the density is measured uncertain, affecting accuracy of analysis.

7.5.4 Fast circulating loops should be taken from a point downstream of a process pump and returned to pump suction. Where a sample pump is necessary, it shall be located so as to ensure adequate net positive suction head.

7.5.5 Sample off-take from a fast circulating loop shall be through a by-pass filter unless this can affect the measured property.

This clause refers to the filter element through which the sample is delivered to the analyser.

Filters provided to protect equipment in the fast loop (e.g. pumps, flowmeters, regulators) need separate consideration. The filter mesh size provided to protect these items would normally be inadequate for the analyser.

7.5.6 High pressure gas which is not being analysed at line pressure shall have a pressure reducer located immediately adjacent to the process line sample probe or offtake from the fast loop, as applicable.

Individual isolation of components or indicators is only necessary when their removal is required without interrupting analysis.

7.5.7 Liquefied gas samples shall be either:-



- (a) For a by-pass sample system, be completely vaporised adjacent to the process line sample probe.

or

- (b) For a liquid fast loop system, be completely vaporised at the off-take from the fast loop to the analyser.

7.5.8 Gas and vapour phase samples shall thereafter be maintained above their water and hydrocarbon dew points throughout the sample system.

7.5.9 Liquid phase sampling systems shall be heat traced and lagged as necessary to ensure that the desired sample conditions and at least the minimum flow-rates are maintained under all weather conditions.

7.5.10 Flue gas and other vapour samples containing a large proportion of steam or other component which needs to be condensed and removed before analysis shall be subject to specific design measures.

Lines shall not be heated or lagged (except as necessary to prevent freezing or for personnel protection) and shall be continuously sloped downwards from the process connections to condensate removal points.

7.6 Lines, Fittings and Accessories

- * 7.6.1 Lines from the process connection to and including the main sample filter or main pressure reducing valve, and all piping and components within a fast loop shall meet the process piping specification. In limited instances departure can be made from this requirement subject to approval by BP.

Other lines shall be of AISI Type 316 stainless steel tube with compression fittings, unless otherwise specified by BP. (Reference shall be made to BP Group [RP 42-1](#) and BP Group [GS 142-13](#) for the limitations of use of tube and compression fittings). Synthetic materials are preferred for sample lines on flue gas service.

An exclusion is allowed in BP Group [RP 42-1](#) piping codes to allow for special cases in analyser sample systems. It is not always possible to obtain sample system components such as by-pass filters, pumps, flowmeters etc., with flanged connections especially if unusual materials are involved.

The break-point between pipe-line specification and screwed or compression fittings can be made after a double isolation. The tapping or probe into the process line, the pipe, and the double isolation valve shall be to process specification. The connection to the non-process specification section shall be via flanged fittings.



This departure shall require justification by the project engineer. It shall be ensured that high integrity instrument pipe or compression fittings are used subject to full quality control procedures to ensure compatibility with process and line specification.

- 7.6.2 Pressure relief facilities (relief valve or bursting disc) shall be provided immediately downstream of pressure reducing stations. If the relief device discharges to a closed vent system, or it discharges into a vent system common to other analysers, a lockable isolation valve should be provided to facilitate safe maintenance.

The design and installation of the relief facility and isolation valve shall comply with BP Group [RP 44-1](#).

Any provision of isolating valves downstream of a relief device must be audited for safety. As a minimum, use of the isolation valve must be covered in plant operating procedures.

- 7.6.3 Each sample isolating valve and the ends of each sample line shall be clearly labelled with the stream identity and analyser tag number.
- 7.6.4 Sample isolating valves, accessible from grade or platform, shall be provided near to the analyser and outside any housing. The valves shall isolate the analyser and any local sample system.
- 7.6.5 Sample systems shall have drains and vents as necessary to permit safe depressurising for maintenance operations, at points where any accumulation of liquid or gas is likely to occur. Systems should be arranged for depressurising as a whole or as modules to minimise unnecessary valves and fittings. Isolation and depressuring points shall be identified on design and maintenance drawings and manuals.
- * 7.6.6 The sample flow-rate through each loop, by-pass and analyser shall be indicated locally. Sample pressure (and temperature where appropriate) at the analyser inlet shall also be indicated. Indicators within analyser sampling systems should be provided in accordance with this Recommended Practice. Any specified minimum diameter or scale length may be relaxed subject to approval by BP.
- 7.6.7 Ancillary parts such as flowmeters, gauges and valves, shall be grouped near to the analyser, external to the analyser house where possible. Components of a heated system shall be grouped within heated enclosures wherever practicable.
- * 7.6.8 All sample lines containing toxic and flammable fluid shall be fitted with an excess flow preventer before entry to a housing. This is to keep gas emissions to a safe level in the event of a pipe or tubing



failure within the housing. The type shall be subject to approval by BP.

Excess flow preventers of the ball and cone type are preferred. Restriction orifices should be avoided if any possibility of blockage exists, e.g. dirty fluids.

- 7.6.9 Heat sources for vaporising and tracing shall be independent of the process tracing.

Process tracing may only be energised during winter months whereas sample systems may require the heat source all year round.

- 7.6.10 Permanent facilities should be provided for flushing sample lines and analysers when the sample viscosity is greater than 500 cSt at 50°C (122°F). Double block and bleed isolation shall be provided between the sample and flushing medium.

Gas sample lines prone to particulate matter blockages may be provided with gas back flushing or blast clearing facilities.

- 7.6.11 Sample lines and associated components shall be installed so that there are no hot or cold spots.

- 7.6.12 When using solenoids for actuation of sample system valves (e.g. stream selection, shut-off) located in a sample handling cabinet, pneumatic pilot operated systems shall be used..

There is a preference to avoid electrical equipment in sample handling cabinets with internal sources of release of flammable materials unless adequate ventilation can be shown to exist. If ventilation cannot be shown to cope with a possible source of release within the cabinet, then only electrical equipment designated suitable for Zone 0 is acceptable.

Sample handling systems invariably involve high pressure and unrestricted sources of release in the event of failure. It is almost impossible to demonstrate adequate ventilation exists therefore, the use of electric solenoid operated air pilot valves located in a separate approved enclosure driving pneumatic valves in the sample handling enclosure, is the preferred system.

7.7 Services

7.7.1 General Requirements

Where common utilities are shared between analysers, they shall be capable of being isolated at each single analyser without influencing the performance of associated analysers.

7.7.2 Cooling Water



Clean coolant shall be supplied which satisfies in all respects the conditions required by the analyser and sampling system over the full range of ambient and operating conditions. If sea water is proposed as coolant, its suitability shall be confirmed by the analyser and sampling systems vendors.

Sea water and process water should only be used as a last resort because of corrosion and blockage problems.

Facilities shall be provided to prevent any dangerous situation arising in the event of coolant or cooling equipment failure. Isolation and drainage points shall be fitted to coolant systems. Pressure relief shall be provided on sample coolers.

Where water cooling is used, the water side of the cooler must be protected against overpressure resulting from a blockage and subsequent boiling. It is advisable to ensure that liquid sample streams are below 100°C (212°F) before water cooling is used. Air or steam should be used for pre-cooling.

Local indicators of pressure, temperature and flow shall be provided as necessary for monitoring satisfactory operation of the cooling system.

- * A closed circuit coolant system with a pump circulating clean water or anti-freeze mixture is preferred. Coolant heat exchange may be by any convenient means. Systems requiring refrigeration shall be subject to approval by BP.

Preferred systems involve straight heat exchange with a convenient medium, e.g. sea water or process water.

Addition of a refrigeration unit increases complexity, maintenance, space and power supply requirements.

If potable water is used as coolant, the distribution system shall comply with local regulations. These may require the use of a break tank or other device to protect the supply from possible contamination.

In some cases the analyser provides the break tank and uses potable water for top-up only.

7.7.3 Instrument Air

Instrument air distribution systems shall comply with BP Group [RP 30-1](#) Section 7.

7.7.4 Industrial Water



Water for duties other than cooling shall meet the requirements stated in 7.7.2 above with the exception of those for closed circuit cooling systems.

7.7.5 Electrical Power

The power supply availability will be specified by BP and the distribution systems shall conform to BP Group [RP 12-5](#).

7.7.6 Gas Cylinder Supplies

The supplies of carrier gas from cylinders shall have a minimum capacity of 21 days at the design rate of usage. To ensure continuity of supply, at least 2 cylinders with individual regulators and isolating valves shall be connected to a manifold. The stand-by cylinder regulator will be set to a slightly lower pressure than the manifold normal working pressure to ensure automatic operation in the event of main supply failure. Connection between cylinder and manifold shall be flexible AISI Type 316 stainless steel hose and between analyser and manifold AISI Type 316 stainless steel tubing, unless unsuitable for service.

Gas cylinder regulators must be correct for the duty and marked accordingly. If it is possible to cross connect regulators, precautions to prevent this occurrence must be taken, e.g. physical separation.

Carrier gases are generally flammable and must not be piped in non-ferrous materials

Gas cylinders and any manifolds shall be firmly secured in racks external to enclosed premises or analyser shelters. The racks shall be well ventilated, shaded against direct sunlight and be accessible for conveyance and replacement of cylinders. For details of a typical gas bottle rack, refer to Fig. 7-1.

7.8 Housings

* 7.8.1 The type, design and ventilation method of housings (see Figs. 7-3 and 7-4) shall be subject to approval by BP and shall depend on the following:-

- (a) The hazardous area classification of the equipment.
- (b) The hazardous area classification outside the house.
- (c) The importance of the application to plant safety and operability.
- (d) The type of equipment installed.



- (e) The degree of weather protection necessary to facilitate maintenance and routine calibration.
- (f) Local and national regulations and requirements.

Reference is made in [EEMUA Publication No. 138](#) for definitions and design data of housings.

Ventilation systems shall be in accordance with BP Group [RP 14 -2](#).

The type of housing should be addressed early in any project development since economic factors may influence the degree of centralisation of analysers within one or more housings on a plant. Housings can be considered under two main categories:-

- (1) Naturally ventilated
- (2) Forced ventilated

Many factors must be considered when determining the type of housing and its specification to suit any analyser system. The more important issues are addressed below.

The ultimate choice of housing has to be addressed against the requirements of individual applications. Local climatic conditions, the sensitivity of the analyser, the importance of the analyser to operations, local preferences and established site procedures will influence that choice.

The housings shall be suitable for hazardous area classifications as defined in Part 2 of BP Group [RP 12](#).

For naturally ventilated housings, the area classification is generally accepted as being the same as that outside.

For forced ventilated housings, the area classification may be the same as that outside or may be of a lower classification. In the event of ventilation failure the area classification may change and influence the certification requirements of equipment within the housing.

All electrical equipment which is intended to remain in operation during a ventilation failure should have a type of protection suitable for Zone 1. In the event of ventilation failure or the detection of gas, uncertified equipment should be immediately isolated. In the event of ventilation failure and the coincident detection of gas, Zone 2 equipment should be isolated. Depending on the external area classification and the characteristics of the internal sources of release, a time delay may be incorporated in the safety measures. Consideration should be given to a degree of redundancy in the ventilation supply system and its power supply. This is particularly important if installed analysers contribute to the safety or profitability of the plant.

Forced ventilated housings should be provided with the following safeguards:-

- (a) All lines entering the housing and containing flammable materials fitted with flow limiters, see 7.5.7.



- (b) Gas detection.
- (c) Ventilation failure detection.

Naturally ventilated housings may be expected to give protection only from direct rain, snow or sun. They will give no significant protection from extremes of ambient temperature or humidity, dust, or other atmospheric effects.

Some improvement in environmental protection may be afforded by fan assistance, including a degree of heating and cooling. The level of natural ventilation would, on fan failure, have to be the minimum consistent with the required internal area classification.

Natural ventilation, with or without fan assistance, has the advantages of lower cost and simplicity.

Forced ventilated housings are capable of providing any desired environment for equipment and personnel. Installed equipment is protected from the environment, is subjected to more constant conditions (e.g. temperature variation) and may be expected to be more accurate and reliable. Working conditions are consistent with good maintenance and calibration operations, particularly in harsh environments. Designs (and appropriate operating procedures) which create an electrically safe area within the house may further assist such activities.

7.8.2 Where only simple weather protection is required, the analyser(s) should be located in a naturally ventilated position and be protected by an existing structure, open cabinet or shelter.

7.8.3 Where closed cabinets are required, they shall be used with forced ventilation, purging, heating or cooling as necessary.

A typical use for a closed cabinet is to improve area classification by purging.

7.8.4 Housings for use in hot climates shall, where necessary, be designed to reduce heat gain.

* 7.8.5 Analysers handling materials above the occupational exposure limits as defined in the HSE publication [EH 40](#) or other relevant national standards, require special attention. Housing design shall be subject to approval by BP.

Handling of materials above the occupational exposure limits presents special problems for housed analysers.

In some cases it may not be economical or practical to segregate the analysers handling toxic materials. The following offers solutions to this problem:-

- (a) Sample systems can be modified to dilute samples to below occupational exposure limit before entry into the housing.
- (b) Housings can be designed to have purge rates sufficient to dilute any leak. In this case, maximum leaks must be limited by flow limiters external to the analyser housing.



7.8.6 Housings shall be constructed of fire resistant materials in accordance with the requirements of BP Group [RP 4-4](#). Doors shall have non-opening windows, glazed with wire glass at least 6 mm (1/4 in thick).

Perspex or laminated plastics are acceptable for windows, provided they are demonstrated to be adequate for the job.

7.8.7 Where doors are required for personnel entry, two lockable outward opening doors shall be provided at both ends of the housing. These doors shall be fitted with crash bars and capable of being opened from the inside in the locked condition.

7.8.8 Where specified by BP or when required by the local and national authority, provision shall be made for the monitoring of releases of toxic or hydrocarbon materials.

7.8.9 Houses and shelters shall:-

- (a) Have a minimum unobstructed headroom of 2 metres (6.5 ft).
- (b) Be suitable for prevailing ambient conditions.
- (c) Be fitted with electric lighting.
- (d) Have access which conforms with BP Group [RP 4-4](#).

7.8.10 Analysers shall be rigidly mounted and vibration free. Where installations are affected by structural movement (e.g. thermal effects on plant piping systems), the piping and cable connections used shall be flexible.

7.8.11 Ancillary equipment located outside the house shall be provided with simple weather protection only.

Example:- Bottle racks need only a sun shield to prevent direct exposure to the sun. However, under certain climatic and/or process conditions, ancillaries may require special precautions in the way of lagged enclosures, general winterising, protection from water spraying, etc.

7.8.12 Housings shall not be sited in the proximity of a likely discharge of a flammable or dangerous material.

7.9 **Inspection and Test**

* 7.9.1 BP shall be given the opportunity to witness calibration tests of the analysers at the analyser vendor's works. Where an approved joint BP/analyser vendor inspection procedure exists, this shall be used; otherwise [IP 340](#) shall be used.



Prior to submission to BP for witness test, the analyser vendor shall provide evidence of satisfactory operation on test samples for a period of several hours. The test samples must cover the full specified range of operation of the analyser. The test is required to demonstrate that stability, repeatability and accuracy are within manufacturer's specifications.

At the time of placing an order, it should be established whether or not the manufacturer is capable of demonstrating the equipment at his works; safety requirements may prohibit this. If tests cannot be performed at the works, it is desirable that alternative test sites be arranged, rather than waiting for validation after site installation.

- * 7.9.2 The complete analyser system, including control room mounted equipment such as recorders, transducers, peak pickers and programmers, shall be tested in operation on test samples, at the systems vendor's factory and witnessed by BP specialist engineers. Analyser calibration will not usually be necessary at this stage. Acceptable standards for system performance shall be agreed between BP, contractor and systems vendor prior to testing.
- 7.9.3 Any communication links between component parts of the analyser system, and between the analyser system and the main plant control system shall be demonstrated. This may be at an independent inspection, or may be incorporated within the programmes identified in 7.9.1 and 7.9.2 above.
- 7.9.4 Detailed test, electrical and safety certificates and other relevant documentation (including operating instructions) shall be available at all stages of BP inspection and test.

It is essential that documentation is available on inspection before the equipment leaves the manufacturer's works. If not available, the equipment should be failed. All too often, equipment arrives on site without documentation, which is then difficult to obtain.
- 7.9.5 Suitable samples for analyser and system testing shall be provided by the vendor; with relevant quality analysis from a recognised test laboratory.

8. AUTOMATIC SAMPLERS FOR OFFLINE ANALYSIS

This section specifies BP general requirements for the design, selection and installation of automatic samplers for offline analysis.

It applies to both onshore and offshore installations and is primarily for sampling crude oil for the subsequent off-line measurement of water content. Other laboratory



measurements on crude oil are possible providing the relevant precautions are observed. Similarly other liquids may be sampled using the principles outlined.

This Section does not cover automatic sampling of gases or multiphase fluids. BP will specify its requirements for such applications.

Water content determination is the main reason for sampling crudes, but other laboratory tests to determine salt content, composition by gas chromatograph, hydrocarbon density, vapour pressure, sulphur content, and distillation are also frequently required from automatic sampler derived samples. Although this Recommended Practice is primarily concerned with the automatic sampling of crude oil, it is also applicable to most non-cryogenic hydrocarbon liquids. The principles can be applied to other sampling problems, but not, for example, sampling for solids entrained in gas.

8.1 Application of this Section

8.1.1 The requirements of this Recommended Practice are primarily to aid BP or an appointed contractor to prepare a job specification based upon BP Group [GS 130-1](#) (see 8.2.1). The vendor shall then design/manufacture/supply the sampling system to the required specification. However, responsibility for certain parts of the sampling system could equally apply to either the contractor or vendor depending upon the particular circumstances.

The contractor shall be responsible for:-

- (a) All main line fittings/branches and installing jets, scoop tube and flowmeter (if required).
- (b) Piping between the external loop pump and the main line.
- (c) External loop piping between the sampler package and the main line.
- (d) All power and signal cables external to the package.
- (e) Sampler controller, if this forms part of another vendor's package.
- (f) Installation and testing.

The remainder of the equipment should form part of the vendor supplied package(s).

The vendor or contractor could be responsible for the design of the sampler loop piping, jet mix piping and final connections to the pipeline. The sample controller could be supplied as part of the package or form part of the metering system package (i.e. the data base could also double as a sample controller). The metering system vendor could be responsible for the complete sampler package as supplied from the



sub vendor. This will depend on factors such as the size of the complete package and location of the sampler package.

8.2 General Requirements

8.2.1 Sampling systems shall comply with BP Group [GS 130-1](#). BP Group [GS 130-1](#) and this section are based upon:-

- (a) [ISO 3171](#) Petroleum products - automatic pipeline sampling.
- (b) [API Manual of petroleum measurement standards](#) Chapter 8 sampling, Section 2. Automatic sampling of petroleum and petroleum products.
- (c) [IP Petroleum measurement manual](#), Part VI sampling, Section 2. Guide to automatic sampling of liquids from pipelines.

BP Group [GS 130-1](#) is based on a specification for crude oil sampling equipment that can be presented to vendors. It is based on BP experience and American, British and International Standards, so the system is compatible to all requirements and locations.

* 8.2.2 A typical sampling system (see fig. 8-1), will comprise but not be limited to the following main items of equipment:-

- (a) means of mixing the line content,
- (b) scoop type sample probe,
- (c) pumped external loop,
- (d) external loop sampler,
- (e) main pipeline flow measurement,
- (f) sampler controller,
- (g) sample receivers, and
- (h) ventilated enclosure.

The above major items of equipment shall be obtained from manufacturers' approved by BP.

The total sampling system shall be supplied as a package(s) from a vendor approved by BP.

The sampling equipment described in BP Group [GS 130-1](#) relates particularly to a system suitable for installation on a pipeline in which can flow a non - homogeneous crude oil/water mix. In these circumstances, some form of additional pipeline mixing will be required in order to ensure that a representative sample is always available at the entry to the sample probe.

BP Group [RP 30-2](#), Section 8 describes the BP preferred method for mixing when the pipeline flowrate is varying. In this additional fluid energy is injected into the pipeline in the form of jets to lift and disperse any separated water across the pipe in



a uniform way. However, in some circumstances, an alternative method of mixing can be acceptable; for example, using static mixing devices. (See 8.4(g)).

- * 8.2.3 The use of in-line samplers shall be subject to approval by BP.
- 8.2.4 All items of equipment, including the sample receivers shall be located within a ventilated weatherproof enclosure. Good means of access and lighting shall be provided for operations and maintenance purposes; and to ensure the safe handling of sample receivers. (Note that this is regular daily or weekly task).

For most pipeline applications the sampling equipment will require protection from the environment by housing in a weatherproof enclosure. However there may be situations, (e.g. offshore), where the sampling position is within a module or other housing which already provides adequate protection. In such cases the need for additional protection is left to the discretion of the design engineer. Note that it is essential to prevent the ingress of extraneous water, whether from rain or any other source, (e.g. hosing), into receivers containing samples destined for water determination tests. Therefore, in most applications, some protection for the receivers at least will be required. Where an enclosure is required, the preferred material of construction should be specified. Generally, GRP is the preferred material, but stainless steel may be a requirement in some situations, (e.g. offshore). If GRP is used, it must be amine free marine grade, satisfying [BS 476](#) Parts 7 & 8, since GRP materials, when combined with water and oxygen, can cause 'season cracking' of brass fittings.

Heating of the enclosure, where required (see 8.9.1.3), shall be provided by space heaters.

Lighting and space heating is only required within enclosures. Generally, heating within enclosures will be required where the system is to be installed in an exposed situation, or where low ambient temperatures prevail. Protection against problems caused by high viscosities or waxing can be provided by trace heating.

- * 8.2.5 A sampling probe shall be positioned where the contents of the line are always homogeneous as determined either by profile testing or the method described in Appendix E of the [Petroleum Measurement Manual](#), Part VI, Section 2. The sampling location shall be subject to approval by BP.

Some form of mixing will be necessary to ensure that the contents of the line are always homogeneous. Jet mixing is preferred, but only if necessary. Other forms of mixing may be adequate (even natural mixing by upstream pumps or pipe configuration), but this must be confirmed by calculation or profile testing. IP Part VI Section 2 Automatic Sampling, recommends that calculations as para 4.2.5.2 and Appendix B (derived from [ISO 3171](#)), are used after a potential sampling point has been selected. Other methods are described in Appendix D, namely:-

[ISO 3171](#) Annex A (IP Appendix B method)
Karabelas
Segev



No details of these methods are given in the IP document, other than that all 3 methods are coordinated in a program called 'SAMPLE' available from the Cranfield Institute of Technology (Fluid Dynamics Division).

The sample probe should be specified 'for live line insertion' for applications where the line is normally in continuous service (e.g. offshore metering stations). For batch type applications, probes may be directly flange mounted, provided the main process line may be routinely depressured for probe withdrawal, cleaning and inspection.

8.3 Design Requirements

8.3.1 General Requirements

Piping shall specified and installed in accordance with BP Group [RP 42-1](#) and BP Group [GS 142-6](#).

It is essential that all pipework and fabrication is in accordance with the line specification

Instrumentation installation shall be in accordance with BP Group [RP 30-1](#) Section 4.

Electrical equipment (including lighting) and installation shall be in accordance with BP Group [RP 12](#).

For lighting see 8.2.4.

Ventilation design of the package shall ensure no build up of:-

- (i) Hydrocarbon gases which could increase the electrical area classification within the enclosure.
- (ii) Toxic gas which may be a hazard to personnel.

8.4 Mixing

Mixing facilities shall be provided in the mainline upstream of the sample probe unless it can be shown by either calculations or practical testing that the required standard of homogeneity is assured by the pipeline configuration under all circumstances (see 8.2.5) of flow rate, line liquid properties and water content.

For representative sampling it is essential that any water present in the crude oil is finely dispersed and uniformly distributed across the pipeline at the plane of the sample probe entry. Where complete homogeneity of the pipeline contents at all conditions of operation cannot be assured then a form of pipeline mixing is required. Of the various methods available, the BP preference is for jet mixing. For this, a proportion of the main line flow is withdrawn and then reinjected under pressure



back through nozzles into the bottom sector of the pipeline, upstream of the sampling point. Any separated water is thus lifted and distributed across the pipe.

The advantages of jet mixing over other forms of static or powered mixing are as follows:-

- (a) It is an efficient system creating good distribution at low pipeline flowrates with negligible pressure drop in the main pipe.
- (b) It is flexible. The jet pump may be turned off at high flow rates provided that adequate water distribution is produced by natural line turbulence without the need for a mixer. Positive confirmation that good mixing is being achieved will be required before this option can be used.
- (c) Only two flanged pipe stubs on the main pipeline are required for installation. These may be hot - tapped onto existing pipelines without the need for depressurising or draining.
- (d) The nozzle assembly may be inserted or withdrawn from the pipeline through a seal housing, allowing the line to be pigged, or for inspection of the nozzles.
- (e) No moving parts are within the pipeline. The jet pump/motor unit can be mounted close to the pipeline in a position accessible for maintenance.
- (f) Fixed type static mixers may be considered in special circumstances subject to BP approval. These consist of a fixed series of baffles mounted in a flanged pipe unit installed in the pipeline. Liquid pumped through the unit follows the path dictated by the baffles. The mixing is achieved by splitting, rearrangement and reunification of the process stream. The elements may be corrugated plates, intermeshing and intersecting bars, or helical shaped vanes.
- (g) Static mixers operate in the turbulent or transitional flow regime. The process stream flow provides all the energy for mixing. The energy is absorbed in the form of a pressure drop across the mixer, which is proportional to the square of the liquid velocity. The pressure drop at maximum flowrate must be determined. A working flow turndown ratio of a maximum of 4 to 1 must be considered and the static mixer must be designed to give satisfactory mixing at the minimum flowrate. Flow velocities generally need to be above 0.75 m/s for effective mixing, but manufacturers data should be referred to for the minimum flow velocity at which a particular mixer type is still effective.

8.5 External Loop Equipment

* 8.5.1 Sample Probe

The sample probe shall be of the scoop-entry type, suitable for insertion to the centre of the pipeline with the scoop facing the direction of flow. The probe should be located in a vertical downward flowing section of pipe. Location in a horizontal pipe shall be subject to approval by BP.

The sampling probe should be designed to create minimum disturbance to the main pipeline flow. Field tests and experience have shown that the scoop entry type probe (Pitot tube type probe entry with an internal chamfered edge) is the most suitable. The probes shall be designed to resist stresses resulting from stream velocity conditions. (i.e. vortex shedding).

Because the force of gravity tends to promote stratification in horizontal lines whereas vertical lines tend to promote more uniform distribution, the preferred location for the probe is in a downflowing section of vertical pipe. The pumping rate should be significantly higher than the water droplet settling rate, so that the settling rate will be less than 5% of the crude oil flowrate. The droplet settling rate can be estimated from [ISO 3171 Petroleum Liquids - Automatic Sampling, Annexe A 3](#), equation 8 or fig 8-11.

The improved distribution afforded by a vertical section of pipeline may be obtained by inserting a vertical loop into a horizontal line. (Ref: [IP PMM Part VI 4.2.2.3](#))

If sampling from a vertical pipe section is not possible then the flow in a horizontal pipe may be sampled provided that precautions are taken to ensure that the pipe contents are thoroughly mixed, (see 8.4 of this supplement). Theoretical procedures to assess the probability of an acceptable degree of mixing may be found in [ISO 3171](#) or [IP PMM](#), Part VI Section 2.

If the probe is specified for live line insertion and withdrawal, sufficient clearance shall be provided for the operation; including the use of any special tools required. A means of removing sludge from the reception chamber is also necessary.

Fixed or retractable probes can be used. Retractable probes must be used where live line entry will be necessary, where retraction is required to allow for pigging or cleaning and maintenance of the probe, (or any other circumstances which might require removal of the probe while the pipeline is pressurised). Where hydraulic or mechanical winding mechanisms are not used, safety precautions should be taken, such as chains fitted to the probe to prevent the probe being ejected under pressure when being withdrawn. Sufficient space must be allowed for fitting a suitable insertion and withdrawal device and for withdrawal of the probe.

The minimum sample probe scoop entry size depends on the pipeline size as follows:-

For line sizes less than but including NPS 30 (DN 750) - NPS 1 (DN 25)

For line sizes greater than NPS 30 (DN 750) - NPS 1 1/2 (DN 40)



Sampler probes are inserted into the main pipeline through a flanged stub and an isolation valve. In crude oil lines, deposits of sludge and scale can accumulate in the stub and valve bore. This can consolidate, making it difficult to withdraw the probe after a prolonged period of use. It may also prevent complete closure of the isolation valve once the probe has been extracted.

The following procedures may help alleviate the problem:-

- (a) *Apply fire main water pressure through a check valve to the purge connection on the sample probe seal housing to clear the deposits. The recommended sample probe assemblies include a NPS 1 1/2 (DN 40) connection on the seal housing for this purpose.*
- (b) *Use ball type isolation valves on the pipeline stubs. These may close easier than gate valves in the presence of sludge, although the possibility of damage to the seals from scale must be considered.*
- (c) *If live line insertion and withdrawal is unnecessary, fixed probes can be used. (Refer to [IP PMM](#) Part VI Section 6.4).*

The sample probe assembly shall be flanged to suit the branch connection and line specification.

Refer to BP Group GS 130-1 for flange details.

For a vertical pipeline the scoop shall be on the pipe axis.

The direction of the probe entry into a vertical pipeline is horizontal and the scoop entry point must face upstream and be positioned close to the pipe axis.

For a horizontal pipeline the sample probe shall be inserted from the lower half of pipe such that the scoop entry is at the pipe axis or within 0.1 nominal pipe diameter semi-circle below the horizontal centre line (see fig 8-2).

For horizontal pipelines, the direction of insertion of the probe will depend upon the accessibility of the pipeline. It should preferably be horizontal but in any case, not from above the horizontal centre line.

8.5.2

External Loop Pump

The external loop pump shall be of the centrifugal type complying with BP Group [GS 134-4](#).

The purpose of the external loop is to provide a continuous sample stream at a convenient point where it may be sampled and collected with a minimum dead volume. It also facilitates isokinetic sample extraction at the probe entry point, a preferred condition for representative sampling. In order to reduce any associated time lag, and any possibilities of water settling, the loop length must be as short as possible and the loop velocity as fast as practicable. To achieve this, nearly all fast loops are pumped. This provides added advantages in that the bypass flow is thoroughly mixed and that loop velocities can be predetermined and controlled.



Note that the diameter and schedule of the fast loop pump suction should be the same as that of the scoop probe.

8.5.3 Automatic Sampler

The automatic sampler shall be of the external loop and bottom sample exit type. It shall be capable of flow proportional operation over the full range of pipeline flow rates.

Flow cell type samplers, installed in an external loop are preferred over other types of sampling devices for the following reasons:-

- (a) Blockage of sampler upstream entry ports is less likely with flow cell samplers than with in - line types, which are susceptible to line trash.*
- (b) The sampling mechanism of flow cell devices is installed external to the main pipeline and thus can be easily isolated and made accessible for maintenance.*
- (c) Small bore low flow rate pipework between flow cell samplers and the associated receivers can be significantly shorter than with in - line samplers, thus reducing the likelihood of water dropout or blockage due to waxing.*

8.5.4 External Loop Strainer

The external loop strainer shall be an in-line co-axial type, and positioned to permit element removal/cleaning. The mesh size shall be as large as possible to avoid coalescing water droplets in the sample; but consistent with protecting the pump.

In applications where there is no upstream filtration in the main pipeline, a strainer is required in the sample loop to prevent the sample extraction mechanism or other loop components becoming fouled by entrained trash. An in - line coaxial type strainer is mandatory to prevent water hold up in the strainer body. In applications where continuous sampler operation is imperative and where there may be particular problems with trash or debris in the main pipeline, consideration should be given to fitting a duplicate parallel strainer as standby.

It is generally recommended that the strainers are cleaned between batches or every 24 hours, but this may be extended based on operational experience. A differential pressure (DP) indicator is required across the strainer to give warning of strainer blockage. Its range should be chosen for full scale at full flowrate with the strainer mesh in and 25% blockage across the strainer. The pressure rating should be 1.5 times the full line pressure. On some applications (i.e. unmanned) it may be necessary to include a DP switch with remote alarm facility to the control room.

Local pressure should be indicated by a bourden tube type gauge. It should have a dual scale, in bars and in the required pressure units. (Refer to BP Group [GS 130-1](#)).

8.5.5 External Loop Flow



The flow through the external loop shall be measured by a local variable area flow indicator or equivalent. Refer to BP Group RP 30-2 Section 5.

The flow shall be adjusted by a local manually adjustable flow regulating hand valve.

The external loop flow indicator need only have an accuracy of $\pm 10\%$ over the full range of loop process conditions. Variable area flowmeters (rotometers) are specified for this function. Metal tube types with magnetic followers are preferred. These are considered suitable for class 3 applications (plant control and operator aids, as classified in Flow Measurement Section 5 of this Recommended Practice) where density and viscosity are relatively constant. The option for remote alarm indication for no - flow in the loop should be considered. Flow control in the loop will be by a manually adjustable flow regulator (e.g. Fisher model 184) or a rising plug or needle valve.

In fiscal metering applications the external fast sampling loop may also provide a convenient situation for other ancillary measurement components, for example, densitometers or in-line water monitors, where these are required. Such components should be connected in series with the sampling device in such a way that the siting and operation of one does not interfere with the others.

8.6 Control Equipment

- 8.6.1 The sampler controller transmits operating signals to the sampler at the required interval. This signal may be generated either from a dedicated sampler controller, or from the flow totalizer of a meter station.

Most sampler system manufacturers supply sampler microprocessor controllers which can either be panel mounted in the control room or locally mounted in a suitable enclosure. Total system flowrate signal input to the controller will be either a 4 - 20 MA signal from the flow computer (if used with a custody transfer metering system) or the frequency output signal direct from the line flowmeter.

- 8.6.2 The sampler controller should operate in the flow proportional mode. Means should also be provided for the controller to operate in the time proportional mode. Clear indication of the mode in which the sampler controller is operating shall be displayed to the operator.

- 8.6.3 When functioning in the flow proportional mode, the sampler controller shall be capable of operating the sampler over the full range of expected flow rates and batch sizes in order to produce the required representative sample volume, with a contingency of $\pm 20\%$.

Time proportional as well as flow proportional modes are required in the event of flow meter failure. BP Group [GS 130-1](#) gives the preferred detailed specification for the sampler controller.



8.6.4 A dedicated sampler controller may be sited local to the sampler or in a control or equipment room. When a dedicated sampler controller operates in conjunction with a metering station the sampler controller shall be mounted on the metering station control panel. Sampler control and monitoring functions shall be incorporated in any remote display and operation of the meter station (e.g. at the CCR).

8.6.5 The sampler controller shall have provision for setting the batch transfer quantity, or the time over which the sample is to be collected.

To enable the sampler controller to take flow or time proportional samples over the total batch, facilities must exist to key in the total batch quantity or the total time over which the sample is to be taken. Generally, for the water content and density tests normally carried out on stabilised crude oil sample from continuous pipeline transfers or tanker batch loadings or discharges, a total sample volume of about 10 litres is required. Typically, a sampling batch will be made up of 10 000 grabs of 1 ml taken flow proportionately over the duration of the transfer.

8.6.6 An information alarm shall be generated on sampling completion, both on a time or batch basis, and displayed to the operator.

If very low flowrates for long periods are expected, then a sampler start/stop trigger at an adjustable preset flowrate, together with a manual override switch should be provided. This will normally be set below the point where the flow meter signal becomes unreliable.

The sampler control system should include means to stop or transfer the flow of sample once a predetermined volume has been deposited into the receiver. Options available include a 'can weighing' system with automatic can change when the contents reach a preset weight.

8.6.7 Means shall be provided to operate the sampler during maintenance and testing procedures, and for generating an internally adjustable flow signal.

8.7 Main Line Flow Measurement

8.7.1 When a totalised flow signal from an associated custody transfer metering system is available it should be used to provide the flow proportioning input to the controller.

8.7.2 If such a flowrate signal is not available, a separate flow meter shall be provided, capable of live line insertion and be of a trash resistant design. An accuracy of better than $\pm 10\%$ over the full working flow rate range is required.

Crude oil pipeline transfers, especially from marine tankers, are likely to carry entrained quantities of fibrous materials which can quickly foul conventional insertion type flowmeters. This will cause errors in flow measurement and eventually lead to loss of flow measurement and consequently, sampling failure.



To overcome this problem, a large 6 inch blade 'trash shredding' insertion turbine meter has been developed.

8.8 Sample Receivers

8.8.1 Sample receivers shall comply with BP Group [GS 130-1](#).

It is important to specify the correct sample receiver for specific applications. The type of sample receiving system will depend on the vapour pressure of the crude oil to be sampled and upon the laboratory test procedures to which the samples will be subjected. For most applications, these can be split into two groups:-

(1) *Receivers for Stabilised Crudes. (Low Vapour Pressure):-*

- (a) *These receivers are suitable generally for the water content and density tests normally carried out on stabilised crude oil sampled from continuous transfer pipeline or from tanker cargo loadings and discharges, where the loss of light ends will not materially effect the subsequent analysis, e.g. samples for water content determination. The total sample quantity is about 10 litres.*
- (b) *Sufficient ullage space should be allowed for thermal expansion and mixing within the receiver. This should be between 5% and 10% of the sample volume. It is essential that the sample is collected and maintained in a representative state right through to analysis without contamination or degradation of its composition. For this reason, mixing, either in the receiver or external to the receiver is applied. Advice on this point may be found in the [BP Measurement Guidelines](#) Part 1. Vol. 1.*
- (c) *Normally, for stabilised crude, the sample is maintained at 0.5 bar above its vapour pressure.*
- (d) *Either reusable or disposable receivers can be used. If reusable receivers are used, care should be taken to ensure that they are cleaned and dried properly prior to use. It is generally advisable to follow the manufacturers recommended procedures for cleaning and pressure testing. If disposable receivers are used, no attempt should be made to recycle the receivers after use.*

(2) *Receivers for High Vapour Pressure Crudes and Condensates:-*

- (a) *In shared pipe line allocation systems, samples of high vapour pressure crude oil are required for analytical tests to determine hydrocarbon composition and distillation range. For these tests the required quantity is typically between 1 litre and 3 litres allowing sufficient ullage of between 5% and 10% for mixing.*
- (b) *For high vapour oil samples, to prevent contamination, inert gas, either helium or argon, is used for back pressure. Double chamber piston receivers are preferred over single chamber designs, since with single chamber receivers the interconnection to a duplicate receiver for mixing may be by an initially empty pipe. Any initial*



vaporisation of sample within this pipe upon sample transfer must not significantly affect the accuracy of any subsequent sample analysis

8.9 Installation Requirements

The design of the installation should follow good engineering practice and should comply with appropriate engineering standards, specifications and codes of practice. The design should also enable the equipment to be operated safely and provide easy access for inspection, testing and maintenance and removal of sample receivers. Correct installation of the sampling equipment is essential to ensure that a representative sample is obtained in the sample receiver. Where applicable, installation work should follow the guidelines laid down in [BS 6739](#) 'Recommended Practice for Instrument Installation'.

To prevent the build up of static electrical charge, sample system piping installations shall be properly bonded to earth.

8.9.1 Piping

Vent and drain points shall be provided for venting the system during commissioning, and for the safe depressurising/draining the loop for maintenance purposes.

Receiver vents shall be piped to a safe location outside of the enclosure.

The sampling loop should be installed with suitable valves and connections to enable the equipment to be flushed through automatically or manually with solvent or the liquid being sampled. Disposal of the flushings and solvent should be properly provided for. It is essential that all the solvent is removed from the circulating lines to avoid contamination of the next sample. The receiver should be isolated and cleaned separately. The pipework installation should provide easy access for cleaning and maintenance and must not necessitate the shutting down of the main pipeline.

The external loop pipe work shall be as short as possible with no low points before the sampler where water could collect.

The pipe run from the sampler to the receiver shall have a downward gradient of at least 1:10 with a maximum length of 1.0 m.

Entrained water or heavy particles have a natural tendency to coalesce and collect at low points or in pockets or enlarged sections in the sampler pipework and components. If this happens, accumulations of water can be carried through into the receiver causing misrepresentation in subsequent samples. To prevent this, the system should be free from pockets or enlarged sections in which water can be trapped. Pipework should be kept as short as possible. Another important aspect of installation is that all internal parts and pipework must be kept clean and free from any debris that could cause interference with flow through the narrow passages in the component parts.



If the specified sample is likely to wax or reach its pour point, or any free water liable to freeze, under the plant ambient conditions specified, process pipe work and fittings shall be lagged and traced, and the enclosure heated.

To prevent waxing or solidification of high pour point crude oils or products and to reduce high viscosity oils to a free flowing state (e.g. 100 cSt max) the external loop, process pipework and fittings should be heat traced and insulated. Care should be taken not to overheat the sample liquid, although the temperature should be high enough to keep the product in the liquid phase to ensure correct operation of the automatic sampler system. Thermostatic temperature control may be necessary if self-limiting heat tracing is not used. Steam or hot oil tracing may be used if these services are available.

8.9.2 Sampling Equipment

The sampler shall be installed in a horizontal section of the external loop. The sample port connection to the receivers shall be vertically downwards.

8.10 Requirement for Proving Sampler System in Service

8.10.1 After installation, and as part of the commissioning procedure the accuracy of the sample system shall be proved.

Once the system has been installed, some means of assessing the performance is required in terms of the system ability to measure water with known accuracy, uncertainty and repeatability. Validation tests must be performed both during commissioning and periodically thereafter. Since the only way of doing this is by comparing a known oil/water mix in the pipeline with that obtained by the sampler, the random and systematic errors, uncertainties and repeatability of the instrumentation, sub-sampling and subsequent laboratory analysis have to be taken into account.

Sample Volume: a test should also be carried out to determine the accuracy and repeatability of the grab volume taken by the sampler. (Test procedures detailed in [ISO 3171](#) and [IP PMM Pt VI](#)).

The volume of sample 'grabs' can be affected by some sampler faults and therefore should be verified before each water injection test by measuring the size of a sample delivered by 1000 grabs at both the maximum and minimum grab frequencies.

The volume obtained should be within $\pm 2\%$ of the calculated sample volume, e.g. after 1000 grabs, each of nominally 1cc, the collected volume should be 1 litre ± 20 cc.

To facilitate initial validation, and also ongoing verification of sampler representativity, and on-line testing, water injection points shall be installed on the main line at one or more points upstream of the probe. Reference should be made to:-

- (1) [ISO 3171](#)



(2) **IP Measurement Manual** Part VI Section 2, 3rd Edition.

Water Injection: the water injection point should be located as far upstream as practicable to enable full mixing to be carried out. It should be located at the bottom or side of the main pipeline and the velocity of injection should not exceed 130% of the crude pipeline velocity. This is to ensure that no additional mixing is introduced by injection of the water.

In order to inject a known volume of water over the duration of the test, connection valves, strainer, pressure gauges, piping, pump and a flow meter are required.

Total volume and flowrate of the water and pipeline oil should be measured to an accuracy of better than $\pm 2\%$ during the test.

The water injection flowrate should preferably be between 1% and 5% of the crude oil flowrate during the test. If for operational reasons the water injection flowrate has to be less than 1%, then the injected water volume measurement and the accuracy of the laboratory analysis have a greater affect on the overall accuracy and uncertainty assessment of the sampling system.

8.10.2

Further commentary on operation and tests.

Tests are carried out under steady pipeline conditions which are easiest to achieve during tank to tank transfer. If possible, tests should be carried out in worst-case conditions (i.e. lowest density and lowest viscosity from the normal range of oils used, with considerations of any surfactants or demulsifiers present which might affect separation). If worst case conditions are not easy to define, more than one test should be carried out.

In order to obtain a reference, the tests are carried out by obtaining 'before' 'test' and 'after' samples (i.e. pipeline product with the normal amount of water present before and after the test sample). Differences between the before and after water content must not exceed 0.1%.

It may be necessary to speed up the sampler (within the manufacturers limits) and use test receivers of small capacity so that the volume collected is large enough for good homogenisation prior to laboratory analysis.

Once stable conditions have been obtained and the sampler system has been purged, operate the sampler for at least one hour to obtain the 'before' sample.

Remove the 'before' sample and install the 'test' sample receiver. Start the water injection and run for at least one hour making sure that the time in which the sampler is running, overlaps the time period over which the water is injected. (Before and after water injection).

Operate the sampler for sufficient time to ensure that all the injected water has passed the sampling point. Note that at low flowrates, the injection water may move at a lower velocity than the crude oil and that sampling into the test receiver should therefore be continued for some time after the end of the expected passing of the injected water. The objective is to collect a sample of the whole of the measured volume of water comprising the specified test. This will be a defined percentage of the measured volume of oil passing during the duration of the test sampling. The period before and after the arrival of the water should not be excessively extended.



After completion of the test sample, remove the receiver containing the test sample and install an empty receiver. Run for a further hour to obtain the 'after' baseline water content sample. After analysis, the difference between the before and after water contents should not differ more than 0.1%. This is to ensure that the water content in the test crude volume has remained constant within 0.1% for the duration of the test, and that the laboratory test procedure has been carried out correctly.

8.10.3

Calculations

All measurements are carried out on a volume basis. The difference between the % water content established by test and the actual % water content is derived from the formula:-

$$\%W \text{ dev} = (\%W \text{ test} - \%W \text{ base}) - \%W \text{ inj}$$

Where: %W dev = Difference between sample derived (test) % water and actual injected % water allowing for the average water already present in the pipeline crude.

%W test = % water in the test sample receiver

%W base = Ave of % water contained in 'before' (%W bef) and 'after' (%W aft) samples but adjusted to the 'test' conditions by:-

$$\%W \text{ base} = (\%W \text{ bef} + \%W \text{ aft})/2 \times (V2 - V1)/V2$$

i.e.: % water of original oil/water mix is converted to % of increased volume (original oil/water + injected water)

Where: V2 = Total volume of oil and water past the sample point during the 'test' sampling

V1 = Total volume of injected water

%W inj = % water injected into the oil



The ratio:- $\frac{\%W \text{ dev}}{\%W \text{ inj} + \%W \text{ base}}$

Is used to give a measure of the samplers performance as follows:-

Rating	Ratio	Remarks
A	±0.05	Acceptable to fiscal standard.
B	±0.10	Questionable. Not normally suitable for fiscal application.
C	±0.15	Not acceptable for fiscal standard and probably not adequate for internal company accounting procedures
D	Greater than ±0.15	Not acceptable.

A check on system performance can be made by examination of operational records. Trend analysis should be carried out on the periodical validation results.

9. WEIGHBRIDGES AND WEIGHSCALES

9.1 Introduction

9.1.1 General

This Section of BP Group RP 30-2 covers oil industry weighing systems. Its requirements are based on good perceived industry practice and on the information given in the documents covering this subject published by national or international standards organisations. Existing weighing installations at BP sites may have been designed to satisfy local requirements and thus may not confirm with some of the recommended practices set down in this document.

Weighbridges are used widely by BP to measure the weight (mass) of products or crude oil transferred by road or rail tankers from terminals, refineries or chemical plant. Weighscales or platforms are used to measure the smaller mass of products entered into drums or cylinders.

Weighbridges and platforms are simply special purpose weighing machines adapted to accommodate a particular type of load - in the examples considered in this document; for weighbridges: road vehicles or rail trucks with gross weights up to 50 tonnes, for platforms: drums or cylinders up to say 200 kg in weight.

The principles of operation of modern electronic weighing machines are simple. The object to be weighed, in weighbridges supported by a rigid steel or concrete



framework of sufficient size to accommodate the wheelbase of the largest envisaged vehicular load, is measured by an array of electrical loadcells. These are connected in such a way that the resulting signal output is directly proportional to the gross distributed load. The tare weight of the supporting structure is then subtracted from the total load in order to arrive at the weight of the loaded vehicle. Further deduction of the weight of the empty vehicle yields the net weight of the vehicle tank contents.

Weighscale platforms are smaller and have a lower weight capacity than bridges. They have many applications but within BP are most commonly used to measure the net weight of LPG cylinders or lubricant drums after the filling operation. The scale platform is normally supported on four shear beam loadcells and may be surface or flush mounted at a suitable position in vessel filling line.

Unlike other methods of fiscal or custody transfer measurement weighbridges and platforms have no oil industry Standard or Code of Practice governing the equipment, its installation or its calibration and use. The quality of the installations and the standards of measurement performance can therefore vary.

9.1.2 Purpose

The purpose of this section is to provide a common basis for all BP weighing installations which are intended for use for fiscal measurements or for the custody transfer of hydrocarbon products. The referenced standards are intended to at least match the requirements of fiscal or legislative authorities in the United Kingdom, in Europe, the USA or in other countries in which BP operates.

The operation of most weighbridges and weighscopes used by BP depends upon the intervention of a human operator. Hence, by definition, these weighing systems fall into the classification of non-automatic weighing instruments and as such their design, manufacture, installation, testing and use are covered by particular national and international recommendations.

This Section draws attention to the requirements of these documents and also makes additional recommendations consistent with good oil industry engineering practice.

9.1.3 Scope

This section sets out the basic requirements for the design, installation, test calibration and the subsequent operation of road and rail weighbridges and of weighscopes and platforms used for drum and cylinder weighing. It does not cover weighing devices used for in-motion weighing.



The recommendations apply to all static weighing systems intended for use where the weight measurement has fiscal or commercial implications e.g., for custody transfer and point of sale operations. They are based largely on regulations published by the UK National Weights and Measures Laboratory of the Department of Trade and Industry and on the Council of the European Communities Directive on non-automatic weighing instruments published in June 1990. It is not the intention of this to duplicate unnecessarily the regulations laid down in the statutory documents and the user is advised to refer to the applicable national or international regulations especially on matters of detail concerning scale intervals, testing and approval procedures.

While it is recognised that many existing weighing installations may not entirely conform with these recommendations or that local legislative requirements may differ from those listed herein, it is nevertheless advised that the regulations concerning the safety of the equipment are mandatory and shall be applied retrospectively to all installations.

9.2 Essential Requirements

9.2.1 Codes of Practice

The practices recommended in this document are based on perceived good industry engineering and safety practices and wherever possible, upon applicable national and international standards. Regulations imposed by regional fiscal authorities or other measurement standards agreed between the partners of commercial transactions may complement these recommendations.

The recommendations are based on the national and international Standards and Directives as referenced in appendix B.

Non-automatic weighing instruments used in the oil industry are classified as Class III machines and the requirements regarding verification intervals and accuracy given in the above Standards and Directives relating to this classification shall apply.

9.2.2 Safety

As a minimum requirement, all weighing system installations shall comply with the local national safety regulations.

9.3 Recommended Practices

9.3.1 General

Weighbridge platforms may be pit or above ground mounted. Pit mounted weighbridges are preferred for rail car tank load measurement



or for non-volatile liquid road vehicle loading sites. Above ground platforms are preferred for loading applications involving light hydrocarbon products and may be preferred for sites where the cost of pit excavation may be uneconomic.

Weighbridge structures are of two main types; those designed for above ground installations and those designed for pits. Generally, above ground weighbridges are built with a light, low profile, relatively flexible frame to minimise the raised height. Because of their mechanical flexibility, above ground weighbridges require a higher number of supporting loadcells than pit mounted systems. These, having a rigid, deeper profile frame, require fewer support points. Applications for which above ground installations are most appropriate include those where inflammable vapours may collect, wet or flood prone sites, or those where the costs of pit excavation may be prohibitive. Pit mounted platforms may be preferred for rail car tank load measurement or for non-volatile liquid road vehicle loading sites, for example, bitumen plants.

9.3.2 Location

Weighbridges shall be sited such that the operator in his normal control position has an unobstructed view of the weighbridge platform and its immediate surrounds.

Pit mounted weighbridges shall not be located at sites where there is a high water table or a particularly risk from flooding - or in other low lying situations where accumulations of light hydrocarbon vapours may collect.

9.3.3 Foundations/Civil Works

Weighbridge foundations shall be adequate to withstand all predictable platform loads and movements.

The civil works (foundations etc.) for a weighbridge shall be designed to take account of the fact that the entire working load (platform and fully laden vehicle) will be transmitted through a number of localised points. This number will depend upon the platform length - typically 4 or 6 (or more) points.

Pit mounted weighbridges shall be provided with adequate drainage to prevent flooding from storm or other drainage water.

Open sided pits shall be installed to allow purging where there is the possibility of an accumulation of hydrocarbon vapours.

Rail weighbridges shall be separated from the main track by lead in/lead off isolation rails and shall be adequately isolated from the effects of rail expansion.

An adequate level transition area shall be provided at either end of above ground platforms to allow parking for roller weights used in the verification procedures.

The gradient of approach ramps leading up to above ground platforms should not exceed 1 in 10.

Weighbridge platforms shall be provided with a non-slip surface impervious to hydrocarbon liquid spillage.

9.3.4 Mechanical Design

The dimensions and mechanical stiffness of a weighbridge or weighscale platform shall be suitable for the maximum load likely to be placed upon it. The mechanical carrying strength of weighbridges shall comply with BS 5400, i.e. 3 tonnes/metre of length evenly distributed, plus one 12 tonne load concentrated transversely at any point on the weighbridge length.

The materials of frame and platform construction shall be chosen with regard for the local environment and working conditions.

The materials of construction are chosen with regard to the conditions of use and the local environment wherein the weighbridge is installed. For example; a pressurised concrete structure may be preferred to steelwork in salt laden marine, or similarly corrosive atmospheres, or at sites which are prone to flooding.

For weighbridges, the design of the platform structure shall be such that individual load carrying components (e.g.. loadcells) shall not be overloaded during the time that vehicles are moving on or off the platform.

The mechanical arrangement of weighbridge and weighscale systems shall ensure that the load is applied vertically through the design axis of each load cell.

In pit mounted weighbridge platforms, lateral movement shall be constrained by bump stops. In above ground platforms end to end movement shall be constrained by the ramps; lateral movement shall be constrained by the load cell mountings.

Weighbridge and weighscale installations and any associated equipment not mounted within a control room or other protected area shall be hose proof.

9.3.5 Loadcells



There are three primary designs for loadcells used to support and measure the weight of applied loads - compression cells in which short steel supporting column are directly compressed by the load, and those in which the load deflects a supporting beam to create either shear or bending stresses, depending upon the beam design.

The principles of operation are simple. The downward force created by the loaded vessel on the platform distorts the resistive strain gauge elements which are bonded to the column or beam causing a weight proportional resistance change. The strain gauge elements are wired into an electrical resistance bridge arrangement supplied from a stable low level AC or DC excitation voltage source. The resistance change unbalances the bridge circuit causing a millivolt level output signal proportional to the applied load. This signal is transmitted to a local or remotely mounted weight indicator or to a data processing system where it may be converted into digital form for weight indication, recording and data processing or control purposes.

Whatever basic cell design is employed, it is preferred that the load is mechanically decoupled from direct connection with the cell in order to avoid as far as possible errors which might arise from extraneous forces which are other than directly vertical. Thus loads are more accurately weighted when coupled to the cell by some form of free motion device or if it is practicable, suspended from the cell by a rod and ball arrangement than when directly applied at the top.

Compression Cells. Loadcells of this type comprise a number of short steel supporting columns of square cross section, (typically four), to each face of which is firmly bonded a resistive strain gauge element. In operation, the columns are mechanically compressed by the load and the resulting distortion of the dimensional of the strain gauge elements causes resistance changes which are proportional to the applied weight. To increase sensitivity, the strain gauges are arranged such that two of the elements are in compression and two in tension.

Shear Force Cells . An alternative mechanical loadcell design, in which the applied load causes shear forces to distort the supporting beam, may be used for weighing lighter loads. Capable of weighing loads up to 10 tonnes per cell, shear force (or shear beam) loadcells may be used in the oil industry for smaller road vehicle weighbridges, or for weighscale platforms employed to check the weight of the contents of lubricant drums, LPG cylinders or similar containers. The design of shear beam cells is arranged such that the resistive elements, and the associated resistance bridge circuits, respond primarily to shear forces and are largely immune to deflections caused by bending stresses. Shear beam cells are also claimed to be more tolerant of side loads and to misapplied loads than are compression cells. However, cells of this design which are capable of very high loadings can be impracticably large and thus they are recommended only for light to medium load applications.

Bending Beam Cells. In this design the beam to which the strain gauge elements are bonded simply deflects under the influence of the bending moment caused by the applied load. Bending beam cells have a low profile but again have a limited load carrying capability compared with compression cells.

According to [OIML R 76-1](#), the maximum capacity of a load cell shall satisfy the condition:-

$$E_{\max} \leq Q_{\max} R/N$$



where:-

$E_{\max}$ = maximum capacity of load cell

N = number of load cells

R = reduction ratio *

Q= correction factor (considering the effect of eccentric loading etc.)

* reduction ratio $R = \frac{\text{Force acting on the load measuring device}}{\text{Force acting on the load receptor}}$

The weighing system loadcell ratings shall be chosen to allow sufficient overload capacity. Normally the total load (platform and fully loaded vessel), shall not exceed 70% of the rated loadcell capacity.

Loadcells used for weighbridges may be either of the compression or shear beam type. Loadcells for weigh scales shall be of the shear beam design.

Loadcells shall be hermetically sealed and capable of operation while totally immersed in water or in the range of hydrocarbon products predicted to be present at the weighing location.

9.3.6 Electrical Design

All electrical equipment associated with the weighing system, including the ticket printer or read out device, shall be suitable for and approved for use in the hazardous area classification and the environmental conditions in which it will operate. Loadcell connecting cables shall be hermetically sealed into the cell body.

Electrical connections and earth bondings between the moving platform and stationary surround shall be made in a manner which does not affect the accuracy of the weighing operation.

Load cell signal circuits shall be designed to be immune to interference from RF interference or electrostatic radiation.

To prevent the possibility of insulation breakdown between the loadcell strain gauges and their mechanical supports due to lightning strikes, high voltage surge suppression devices shall be installed in the load cell bridge circuits.

9.3.7 Signal Processing



Load cell circuits require certain additional facilities to condition the signal from the basic unbalanced basic strain gauge bridge. For example; the unloaded or 'tare' weight of the platform the unloaded vessel or vehicle must be electronically 'backed off' to effectively rebalance the bridge circuit at a new zero in order to arrive at the net contents of the vessel after loading. This may be done automatically or by operator intervention.

An automatic zero tracking circuit will also normally be included in the system to compensate for any long term zero drift of the load cells. Ambient temperature compensation, normally over the range -10°C to +40°C is usually also provided.

The equipment shall be fitted with a zeroing facility. The operation of this device shall allow accurate zeroing and shall not cause incorrect measurement results.

Depending on the application the equipment shall be fitted with a suitable tare weight correction device. This may be adjustable or where the empty weight of the vessel to be filled is constant, may be a preset device. In any case the operation of the tare device shall result in correct zeroing and shall ensure correct net weighing.

Faults in the weighing system leading to errors of measurement shall be detected automatically and shall cause an audible or visual alarm that shall continue until corrective action is taken or the error disappears.

The accuracy of the measurement displayed by the equipment or its readout shall not be prejudiced by the effect of any fault.

9.3.8 Data Acquisition System

A comprehensive range of sophisticated data processing and control options are now available. The precise form of the data indication, the format and content of the ticket printout and the extent of the automatic control facilities should be chosen to suit the overall site philosophy for system control and management information.

The form of data acquisition/readout/recording system may be selected to suit the management information and control philosophy of the site.

The system shall have no characteristics likely to facilitate fraudulent use. The possibilities for unintentional misuse shall be minimised. All components which must not be adjusted by the system operator shall be secured against unauthorised adjustment.

As a minimum, the data recorded by a weighbridge system printout device shall include the following:-

Site identification

Vehicle/Load/product identification



Date/time of loading
Unladen weight
Loaded weight
Net load weight

The data acquisition, read out and ticket printing equipment shall be of adequate capacity to deal with the maximum anticipated frequency of weighing system utilisation.

Printed results shall be correct, suitably identified as in the listings above and shall be unambiguous. The printing shall be clear, legible, non-erasable and durable.

9.3.9 Control

Options for automatic control of the vehicle or vessel loading operation are available because of the capability of present day weigh system data processing equipment to interface with higher level microprocessor based computing systems. These options may be exploited provided that such interfacing does not cause errors in net measurement and that adequate precautions are taken to prevent mal-operation of the vessel filling process.

Available options include:-

- Controlled filling flow profile
- Vehicle identification
- Automatic tare adjustment
- Vehicle/vessel positioning
- Net weight totalisation
- Comprehensive data collection facilities and transaction listings
- Comprehensive data print-out
- System security and integrity checks
- RS 232 interface with Management Information Systems

9.4 Calibration and Accuracy

9.4.1 Indication

The indication of the weighing results and other weight values shall be accurate, clear, unambiguous and not misleading and the indicating device shall permit easy reading of the indication under normal conditions of use.

The number of scale intervals (n) and the resolution (d) of indication of a Class III weighing instrument shall be:-



For weighbridges suitable for loads between 25 kg and 100 tonnes:-

the resolution shall be: $50\text{g} \leq d \leq 10\text{ kg}$.

the number of scale intervals shall be: $500 \leq n \leq 10,000$.

For weigh scales suitable for loads between 5 kg and 200 kg:-

the resolution shall be $10\text{ g} \leq d \leq 20\text{ g}$

the number of scale intervals shall be: $500 \leq n \leq 10,000$

the verification scale interval (e), that is; the metrologically significant value of the scale interval for the verification of the instrument, shall, for Class III machines suitable for the loads specified above, be equal to (d).

Indication shall be impossible above the maximum weight capacity of the system increased by 9e.

9.4.2 Accuracy

According to Schedule 2 of the [UK Statutory Instrument 1988 No. 876](#) and of Annex A of [OIML R 76-1](#), on initial verification the limits of error of non-automatic weighing machines shall not exceed $\pm 1.0 e$ where e is the verification interval and, for the load range specified in 9.4.1 above, is equal to the resolution of indication of the instrument.

The maximum permissible error in service shall be no greater than twice the maximum permissible error on initial verification.

Class III weighing systems shall preferably meet the metrological requirements prescribed above over an ambient temperature range of between -10°C and $+40^{\circ}\text{C}$. The Minimum permissible range over which the accuracy criteria shall be met is 30°C .

9.4.3 Testing (Initial Verification)

Weighting systems shall be tested in accordance with relevant national standard.

Weighting systems installed in the United Kingdom shall be tested after installation, but before use (initial verification), and passed as 'fit for trade' by an inspector representing the local Trading Standards Department, following the procedure prescribed in Part IV of [Statutory Instrument 1988 No. 876](#). After satisfactory testing the equipment shall be stamped with the recognised mark.

Testing for Approval for non-automatic weighing instruments installed in EC countries shall follow the procedure prescribed in Annex A of [OIML R76-1](#).

Both the UK and the OIML documents described the required test procedure in great detail and the reader is advised to refer to these documents for full information on the range of approval tests. However, in essence the procedures involve progressively loading and unloading the platform of the weighing system with standard weights or standard masses at least 10 points, including the minimum and maximum rated loads for the system, and checking that the weight indication satisfies the accuracy criteria defined in 9.4.2 above. Checks are made with the loads placed both centrally and eccentrically and tests are made to ensure that system repeatability, hysteresis, zero stability and creep, (long term drift under load), are within the prescribed limits. The facilities provided to set the weigh system zero and to make correction for tare weights are also tested.

The discrimination of the system shall be checked by placing a small additional load on the platform of equivalent weight to the minimum scale interval and confirming that the readout device indicates the load increase. With systems having digital indicators, the additional weight necessary to change the initial indication shall not exceed 1.4 times the scale interval.

Small weighing systems not permanently installed, such as weigh scales, may also be tilt tested, i.e. with the platform tilted transversely and longitudinally from its true level position by 2 parts in 1000.

The standard weights or masses used for the verification of a weighing system shall not have an error greater than 1/3 of the maximum permissible error of the system at the applied load. Where appropriate, ballast may be used to substitute for weights during the verification procedure.

9.4.4 Subsequent Verification/In Service Inspection

Subsequent verification or in service inspections by the local inspectors shall be carried out at prescribed intervals, typically annually for subsequent verification and 3 monthly for in service checks.

More frequent checks at weekly intervals may be required for cylinder filling plant weigh scales. Only an abbreviated series of tests will normally be required.

The error limits allowable on in service inspection are twice those permitted on initial verification.

9.5 Weighing System Approval

9.5.1 National

All weighing systems installed at BP sites and used for fiscal or custody transfer measurement purposes shall be subject to the approval of the legislative authority in the country of use. In the United Kingdom this will be the National Weights and Measures Laboratory of the DTI. Before use the equipment shall be tested and stamped by the local Trading Standards Department. Similar arrangements will apply in other countries.

Note that in EEC countries, from January 1st 1993, new non-automatic weighing installations are subject to the European Council directive referred to in 9.5.2 below.

The Council of the European Communities has published a [Council Directive \(90/384\)](#), on the harmonisation of the laws of the Member States relating to non-automatic weighing instruments. The Articles of this Directive apply to all new non-automatic weighing instruments to be installed after 1st January, 1993 have been prepared by the OIML. These will be adopted by EEC countries in place of national regulations on 31st December 1992.

Weighing instruments confirming with the requirements of the Directive shall bear the EC marking described in Annex IV of the Directive.

Note that the EC Directive is based largely upon the OIML International Recommendations [OIML R76-1](#) for non-automatic weighing instruments. International subscribers to this document include representatives from most countries in which BP operates. Additional to EEC countries, these include the USA, Indonesia, Australia and many Eastern European and ex-Soviet states. Thus these documents are likely to have world wide status in future years.



9.6 Operation

9.6.1 General

The weighing system manufacturers operating instructions shall be observed.

Loads (vehicles) shall, wherever possible, be centrally situated and shall be stationary on the platform before the weighing operation.

Any connections between the weigh platform and its stationary surround shall not affect the accuracy of weighing. Filling hoses shall be removed and stowed before final weights are taken.

Note: Flexible earth bonding cables may be left in place provided no measurement error results from the connection.

Correct compensation shall be made for the tare weight of the vessel or vehicle before final net weights are taken.

9.7 Maintenance

9.7.1 General

The weighing system manufacturers recommendations for routine maintenance procedures shall be rigorously observed.

Daily inspection shall be made to ensure that the free movement of the weigh platform is not obstructed or restricted in any way likely to cause a measurement error by an accumulation of debris or other material.

A half yearly inspection shall be made of the load cell cabling at the point of entry into the cell housing to ensure that the hermetic sealing is still good.

10. ENVIRONMENTAL MONITORING

10.1 Introduction

10.1.1 To control and minimise the quantity of hydrocarbons and other pollutants escaping from oil, chemical and other process plant is an objective essential for the long term protection and preservation of the Earth's environment. Recognition of this obligation has motivated many governmental and international authorities to draft legislation which prescribes maximum acceptable limits for most of the more damaging pollutants. To comply with these regulations, dedicated



monitoring equipment is frequently required to measure the concentration of the chemical components of concern so that, if necessary, their level may be controlled and reduced to below the defined limits.

- 10.1.2 BP's Corporate HSE Policy includes as a priority issue an intent to strive for progressive improvement in the company's environmental performance by reducing emissions, wastes and the use of energy. This BP section of BP Group RP 30-2 describes the methods and procedures available for monitoring environmental emissions.

10.2 Scope

- 10.2.1 The primary purpose is to advise the reader of the available methods of measuring the most commonly prescribed components, to recommend preferred monitoring equipment and installation practices and to suggest basic calibration, operating and maintenance procedures. Advice is given on methods of monitoring the four basic areas affected by pollution - in stacks, in the atmosphere, ground and water.
- 10.2.2 Wherever possible the reader is informed of typical concentration limits set on the major environmental contaminants in legislation applying in most of the international areas in which BP operates. Where the information has been available we have listed, in Appendix C, applicable international or national legislative standards.
- 10.2.3 The Recommended Practice deals only with continuous monitoring methods. It does not cover methods of determining pollutant levels by intermittent sampling followed by analytical tests carried out in a laboratory.
- 10.2.4 Tables are used wherever possible in this document for clarity and to minimise unnecessary text.

10.3 Area Categories

- 10.3.1 Stacks/Vents. Monitoring at source of the concentration of noxious components in stack and flue gases and of the gases exhausting from vent pipes.
- 10.3.2 Atmospheric/Fugitive. This category embraces monitoring of the air quality in the atmosphere, both within a process area and in the general vicinity of a plant or terminal. It also includes monitoring of the concentrations of a gas at local points adjacent to a likely source of emission or leak, e.g. from stacks or relief and vent valves.



- 10.3.3 Water. This category includes all effluent monitoring and the measurement of water quality in seas, rivers or estuaries into which process or drainage liquids from a process site or terminal may be discharged.
- 10.3.4 Ground. Within this category falls monitoring of escapes and leaks into the surrounding soil of fluids from storage tanks, pipe runs or from process plant components. It includes measurement of sump contents, of bore holes and of the fill material around sub-surface tanks. Methods of pipeline leak detection involving flow-in/flow-out measurement or pipeline parameter modelling are not included.
- 10.3.5 Noise. Although it does not fall within an area category, the monitoring of environmental noise can be required to ensure that sound pressure levels do not exceed those limits set by national or local authorities.

10.4 Regulations and Legislative Standards

- 10.4.1 Even a rudimentary search discloses a list of international legislation and regulations covering environmental contaminants which is of unmanageable length. In this document therefore, only those regulations relating to the control of major environmental pollutants that apply in the countries of the world wherein BP has process operations have been included. The lists may not be exhaustive and include only those documents having relevance to possible chemical discharges or emissions from BP processing sites or terminals.
- 10.4.2 The lists, which are presented in Appendix C, are tabulated on a 'per country' basis, and show the regulations applying in the major Area Categories defined in 10.3, together with the chemical pollutants which must be measured and controlled. of petroleum and petroleum products.

10.5 Emission and Discharge Limits for Chemical Pollutants

- 10.5.1 Appendix C, lists the maximum levels of contamination specified for the major chemical pollutants commonly to be found in emissions/discharges from oil or chemical processing plants or terminals. Although the acceptable limits may vary slightly from country to country they are, in general, of the same order of magnitude. Therefore the measurement range of the analytical instruments or sensing devices used to detect the presence of the chemicals is likely to be the same, wherever their area of use. The tables show, in summary, the maximum permitted levels of the common chemical pollutants and, based on these, suggest preferred measurement ranges for the monitoring devices to be used for their detection.



10.6

Methods of Measurement

All the pollutants tabulated in Appendices C and D can be determined by manual or automatic grab sampling and laboratory analysis in accordance with standards indicated in Appendix B. This Recommended Practice deals with those analyses that have been successfully applied with automatic fixed on-line analysers. However, for some applications, dependent upon technical or economic considerations, it may be acceptable to monitor an emission or discharge in an intermittent mode. This may sometimes be done by a local on-line intermittent monitor or, quite frequently, on samples, using a laboratory technique. However, it is not the purpose of this Recommended Practice to cover the procedures for sampling and analysis employed for determination of pollutant levels in the laboratory.

This Section summarises in tabular form the pollutants generally achieved by continuous automatic on-line analysis in each of the area categories indicated in section 3 and describes in brief, the possible methods available for measuring these pollutants bearing in mind the practicability of the method for continuous measurement over the preferred concentration range. It also identifies the technique recommended by BP Engineering for each service.

10.6.1

Stack/Vent Emission Monitoring

Stack or Vent pipe monitors may have their sensing heads mounted either within the stack to directly measure the components of interest in the passing gas or mounted externally to monitor samples of the gas withdrawn from a position in the stack from which a representative sample can be assured.

The measurements most commonly carried out by fixed on-line analyser systems for stack emission monitoring installations tabulated below. The limits stated in this table are much higher than those expected for ambient monitoring which are normally associated with the levels hazardous to health. In this case the limits are based on mass flow rates considered acceptable by the authorities which by subsequent dilution in the atmosphere will not exceed levels hazardous to health and the environment in general.

Component	Limits (mg/m ³)	Analyser Range (mg/m ³)
Sulphur Dioxide	100 - 1700	0 - 3000
Nitrogen Oxides (NOX)	500	0 - 1000



Carbon Monoxide	100 - 200	0 - 300
Hydrogen Sulphide	10	0 -15
Dust/Smoke	50	0 - 100% obscuration

(a) Sulphur Dioxide (SO₂)

There are two primary methods for SO₂ measurement, both of which are suitable for stack gas emission monitoring.

These are:-

- the photometric technique using Non-Dispersive Infra Red (NDIR)
- conductometry after reaction with an appropriate reagent

Of these the preferred technique is NDIR since instruments based on the conductometric method require a continuous supply of reagent and can be temperature dependent. In the NDIR method electronic comparison is made between the absorption of a characteristic wavelength of infra red radiation after passage through the sample gas and through a reference gas mixture.

(b) Nitrogen Oxides (NO, NO₂, NO_x)

Three alternative methods are available.

These are:-

- Non-dispersive Infra Red Photometry
- Ultra violet Photometry (absorption method similar to NDIR)
- Chemiluminescence, in which measurement by photomultiplier is made of the intensity of chemiluminescence emitted during the oxidation of NO molecules with ozone (O₃) in a reaction chamber. For total nitrogen oxides (NO_x) and nitrogen dioxide (NO₂) determination, the sample gas is first passed through a thermocatalytic converter which reduces the NO₂ to NO before the analysis is performed.

(c) Carbon Monoxide (CO).

Almost without exception the non-dispersive Infra Red technique is used for carbon Monoxide measurement.

(d) Hydrogen Sulphide (H_2).

The techniques available for hydrogen sulphide measurement are limited. The only satisfactory continuous measurement method has been found to be one based on colorimetry in which the colour of a paper tape impregnated with a reagent (usually lead acetate), is compared before and after its exposure to a controlled quantity of the sample gas for a defined period of time.

(e) Particulate Emissions.

Two measurements may be required to determine particulate emissions:-

Total Dust and Gas Opacity (Smoke Density).

Total Dust. Alternative techniques are available:-

- Photometric via optical transmission (for general use).
- By Beta ray absorption (for low particulate levels).
- By scatter light effect (for very low particulate levels).

Gas Opacity - Smoke Density. - Photometric via optical transmission.

To describe these principles:-

Photometric . A beam of light is passed across the cross-section of the pipe or stack carrying the particulate laden gas. An attenuation in light intensity results from absorption and scattering, and the ratio of received to transmitted light is exponentially related to the dust or smoke concentration. Usually the light source and the detector are located together, the light being reflected back across the stack by a mirror system.

Comparison is made with an unattenuated reference light beam to compensate for source light variance and detector sensitivity drift.

Beta ray absorption . A particle laden sample gas stream is extracted from the stack through a probe at isokinetic velocity. It is sucked through a filter tape upon which it is deposited before the tape passes between a beta emitting isotope and a suitable detector. Measurements of the beta absorption through the tape are taken before and after dust filtration to arrive at the rate of dust deposition.

Scatter Light Measurement. Similar to conventional photometers in general principle, scatter light photometers detect the intensity of the portion of a light beam which has been caused to deviate (scatter) from its parallel aligned axis by the effect of particulates in the sample gas. Again comparison is made with a reference beam to correct for light source and detector variabilities.

10.6.2 Atmospheric/Fugitive Emission Monitoring

Measurement of pollutant gases in the atmosphere in or around process sites or terminals may be made either at specific positions (point monitoring) or of the space between two points (long or open path monitoring). The former technique is most suitable for fugitive emission monitoring when sensors or sampling probes for multipoint systems may be mounted local to likely escape points, while open path monitoring will be best suited for across site measurements or at plant boundaries. Long or open path systems can be either double-ended, with the radiation source and detector at the opposite ends of the monitored space, or single-ended with the source and detector mounted together and a reflecting mirror at the path extremity.

The measurements commonly carried out by fixed on-line analysers systems for ambient air monitoring installations are tabulated below with descriptions of the analytical techniques available for sample system type analysers, open path optical analysers and point detection gas sensors. The analytical ranges are generally much higher than the 8 hourly time weighted average limits shown below as these must allow for short term exposure level measurement capability where applicable.

Component	Limits (mg/m ³)	Analyser Range (mg/m ³)
Hydrocarbons (Flammable range)	-	0 - 100% LEL
Hydrocarbons (ppm range)	-	150 - 2000
Hydrogen sulphide	14	0 - 30
Nitrogen oxides	30	0 - 50
Carbon monoxide	55	55
Sulphur dioxide	5	0 -20
Methyly Iodide	28	0 - 100
Benzene	15	0 - 30

10.6.2.1 Analysers with Sample Systems

(a) Hydrocarbons.

There are two analytical methods suited for the measurement of total hydrocarbons.

These are:-



- by catalytic combustion
- by flame ionisation detection (FID).

In the catalytic combustion method sample gas is passed over a heated catalyst (usually of ceramic material), causing a temperature rise due to catalytic oxidation of the combustible gas components. The temperature rise is measured and is proportional to the total organic compounds in the sample gas. A suitable pre-filter is necessary to remove CO from the sample to avoid measurement errors from this source.

Point sensors of the 'Pellistor' type fall into the catalytic combustion category but are generally capable of measurement at low percentage hydrocarbon levels and thus are more suitable for flammable gas detection than for emission monitoring.

Organic carbon compounds easily ionise in a hydrogen flame. In FID analysers the sample gas is burnt in a steady hydrogen gas flame to produce an ion cloud which, when subjected to a sufficiently high electric potential by electrodes placed near the flame, causes an electric current to flow which is proportional to the mass flow rate of organic bound carbon atoms.

(b) H₂S, NO_x, CO, SO₂.

Many of the analytical techniques described in 6.1 above are suitable for use at the higher sensitivity levels required for atmospheric gas monitoring of these gases, in particular, the non-dispersive infra red or ultra violet photometric methods, applied either in short or long path instruments.

Nitrous oxides are invariably measured by chemiluminescence techniques in ambient monitoring situations.

For H₂S the colorimetric technique can be applied with sample system based monitors but alternatives are available if response time and or cost is important. The favoured techniques for H₂S are electrochemical cells or the 'Sulphistor' (a hybrid technique based on a combination of semiconductor and catalytic principles) with the electrochemical cell finding application for CO and SO₂.

(c) Methyl Iodide.

Methyl Iodide is measured using Beta absorption. The analyser uses a Nickel 63 Radioactive source emitting beta particles at a constant rate. The methyl iodide absorbs the electron energy and the measurement is made by detection of an attenuation in current across the measuring cell.

(d) Benzene.

Benzene and other aromatics are usually measured by Ultra Violet Photo Ionisation. The sample is passed through a Photo Ionisation Detector (PID) with suitably selected energising potential to improve selectivity. Sample can be fed via chromatograph type columns to separate interfering components.

10.6.2.2 Open or Long Path Methods

(a) Visible Light/U-V Open Path

Spectrophotometer. In this technique a wide bandwidth beam of energy in the visible/near u-v region is transmitted over the monitored path to a spectrophotometer receiver. In this instrument the absorption at different wavelengths of the transmitted beam is compared with the reference absorption spectra of the pollutants of interest. The average concentration of a range of pollutant gases in the monitored path may be determined in this way, although there can be difficulties in discriminating between gases with overlapping absorption spectra.

This method has good sensitivity for aromatics such as benzene, toluene and xylene, but can be less sensitive for other hydrocarbons.

(b) Laser Based Systems (LIDAR, DIAL).

Environmental monitoring systems based on laser beam transmission over long path lengths are bulky and as yet, too expensive for most routine applications. They can however, provide a useful tool for measurement in special investigations, for example when a scan is required to determine the area and concentration of a gas plume emanating from a particular emission source.

(c) LIDAR

(Light Detection and Ranging) is the optical equivalent of radar and, by using pulsed transmissions of high intensity laser beams in the infra-red, visible or ultra-violet regions of the spectrum, can locate, identify and quantify concentrations of a wide range of pollutant gases down to ppb levels.



(d) DIAL (Differential Absorption Lidar)

The technique is extended by scanning the beam in both planes to allow a two or three dimensional map of the gas concentration to be built up over distances of several kilometres. By analysing the radiation back-scattered from the pollutant gas cloud as a function of time after the pulse transmission, the distance from which the scattering is reflected as well as its intensity can be calculated, thus yielding total information on the spatial extent and concentration variations of the cloud. Tuning the beam to the specific wavelengths absorbed by the target emission gases allows identification of the gases within the cloud.

10.6.2.3 Point Monitoring

The following techniques are suitable for local point monitoring of most common hydrocarbon gases:-

(a) Catalytic Combustion Sensors (Pellistors).

These devices are described in 6.2 above

They are not discriminative and measure only the total concentration of combustible components. They may also suffer a decline in sensitivity due to poisoning when exposed to some elements - in particular lead, sulphur and silicon compounds. They have the advantages of being small and cheap and are commonly used in multipoint monitoring systems in which they are connected back to a central control point, either by direct wiring or via a digital communications loop encircling a plant or process area.

(b) Semiconductor Sensors.

An alternative simple, low cost detection system may be based on semiconductor sensing elements.

In these, measurement is made of the change in electrical conductance between two electrodes caused by chemisorption of the contaminant gas into the surface of a heated metal (usually tin) oxide element.

Semiconductor sensors are more gas specific than Pellistors and less susceptible to poisoning. Again, they may be used either as single point monitors or in multipoint systems connected back to a central surveillance position.

(c) Diffusion Monitoring.



Although not a continuous on-line method of monitoring, this technique, developed by RCS at Sunbury, is sometimes used to obtain a retrospective time-weighted average measurement of the gas concentration present at the monitoring over the period that the device has been in place. It comprises a sampling tube containing a sorbent material into which the gas of interest is absorbed. After the tube has been in place for an appropriate time the tube is removed to the laboratory where the absorbed vapour can be analysed in a suitable detecting instrument. Because of the time-weighting effect the system is limited in its application and is not suitable for detecting sudden rises in gas concentration, neither will it identify gradual increases over a background concentration level. The device is passive in principle but may be used in more active mode by aspirating the sample gas through the sorbent by means of a pump.

(d) Electrochemical Sensors.

Simple in principle, these sensors are essentially small fuel cells comprising an anode, cathode and electrolyte from which, in accordance with Faradays Law, a small electric current is produced proportional to the concentration of a specific gas diffusing into the electrolyte through a membrane. Gas diffused to the sensing electrode reacts at its surface, either by oxidation (e.g.. CO, H₂S, SO₂, H₂, HCN, HCl), or reduction (NO₂ and Cl₂). The electrode material decides to which gas the cell will react. Cells are available for most common pollutant gases and have good sensitivity, are small in size and have an operating life of two to three years. To reduce cross sensitivity effects the cells may be manufactured with built-in chemical filters to absorb or block contaminating gases which are not of specific interest.

10.6.3 Water/Effluent Monitoring

Water/Effluent measurements most commonly carried out by fixed on-line analyser systems are tabulated below.

Pollutant	Limits (mg/l)	Range Range
Ammonia - NH ₃	10 - 30	50
BOD - (Biochemical Oxygen Demand)	Demand)	1000 O ₂
Heavy Metals (Total)	10	20
Hydrocarbons (Oil in Water)	15	30
Phenol	1	5

Sulphide	1	5
TSS - (Total Suspended Solids)	50	200
TOC - (Total Organic Carbon)		

(a) Ammonia

Normally measured using pH which is correlated to ammonia content

(b) BOD - Biological Oxygen Demand

The laboratory method involves a five day analysis. The on-line analyser is designed to operate on a 3 minute cycle which can be correlated to the BOD₅ method. The analysis principle is based on oxygen consumption by micro-organisms contained in a bio-reactor chamber. The effluent sample is circulated through the reactor with an oxygen saturated fresh water diluent. Oxygen difference between inlet and outlet of the reactor is held constant by regulation of the diluent. The amount of diluent required gives a measure of the BOD.

(c) Heavy Metals

Metals in water are measured using X-Ray Fluorescence. The sample is exposed to low intensity radiation from an isotope X-ray source. The resulting fluorescent X-rays of the metals are analysed by means of a crystal spectrometer and concentrations are determined based on their characteristic X-rays.

(d) Hydrocarbons (Oil in Water)

The preferred measurement technique is based on Near Infra Red scatter. The sample is prepared by removal of particulates and gas bubbles before being passed through the IR cell. The amount of reflected IR is a measure of the oil content.

This technique only measures free oil. The laboratory techniques are usually based on solvent extraction with the oil measured by passing the solvent/oil mixture through an IR cell - the degree of IR absorption is related to the oil content. This technique was once favoured for on-line analysis because it has the advantage of measuring both free and dissolved oil without many of the problems of susceptibility of the measurement to oil type, particulates and gas bubbles but its transfer to on-line analysis has not been very successful and with the advent of the Montreal Protocol on release of CFC's to the atmosphere has severely restricted choice of solvent possibly to the point where its efficiency in removing all the oil from the sample is too low for practical purposes.

(e) Phenol/Sulphide

The method used IDS based on the colorimetric analysis principles. The sample is reacted with a suitable reagent and the resulting colour change is measured optically and correlated to the component concentration.

(f) Total Suspended Solids

Normally based on turbidity measurements which measure light absorption in the visible range. The degree of absorption is correlated to the total solids content.

(g) Total Organic Carbon

The analysis is based on oxidation of the organic carbon to carbon dioxide. The CO₂ concentration is measured using a standard Near Infra Red analyser.

10.6.4 Ground Monitoring

Even small leakages from storage tanks or buried pipelines can contaminate the local environment with devastating consequences. It is therefore essential to:-

- (a) minimise the possibility of leaks by preventive methods, e.g. double containment.
- (b) monitor the local groundwater in order to detect leakages before the escape seeps to contaminate more sensitive ground areas.

There are five common methods for detecting leakages from tanks and pipes:-

- inventory reconciliation.
- tank content monitoring by precise automatic gauging.
- groundwater monitoring.
- interstitial monitoring of double containment systems.
- vapour monitoring.

Of these, only the last three are of concern to this Recommended Practice.

10.6.4.1 Groundwater Monitoring



This method uses observation wells positioned at strategic points around the tank site to monitor the groundwater for traces of the stored products. The well depth must of course, descend to below the area water table. Detection is achieved either by installing sensors in the well, by extracting a continuous sample flow from the well into a local analyser or by laboratory testing of bailed samples. The precise analytical technique will depend on the stored products and may be selected from those described in Section 6.3 covering Water/Effluent Monitors.

This method has the disadvantage that it is retrospective - the leak is only detected after the contamination has spread to the observation well.

10.6.4.2 Interstitial Monitoring

This is probably the most effective environmental protection system and the most immediate of the monitoring methods. It is, unfortunately, also the most expensive with double-walled tanks costing up to twice that of single wall vessels.

Sensors may be placed in the annular space between the two walls to detect either the presence of leaked low vapour pressure liquid or the vapours from more volatile liquids. Alternatively, vapour may be drawn from the interstice for analysis in an externally mounted instrument. By using an appropriate sampling system a common vapour analyser may be shared between a number of tanks.

Checking the integrity of externally mounted analysers is relatively simple. To verify sensors situated in the annulus is more difficult and either an automatic system must be employed or the sensor must be removed, tested and replaced.

As with groundwater monitoring, the analytical technique used to detect and measure the leaked fluid will depend on the composition of the stored product.

10.6.4.3 Vapour Monitoring

A fast and effective way of detecting leakage from tanks or pipes is to monitor increases of hydrocarbon vapour levels in the ground by placing sensing devices or probes in observation wells placed strategically around the tank site. Hydrocarbon vapours travel significantly faster through soil backfill than does the leaking liquid and thus vapour monitoring can rapidly detect a leak before major contamination occurs.



Vapour monitoring systems can be either passive or active. In passive systems the individual sensors are permanently placed in the observation well and thus may gradually degrade or become saturated due to constant exposure to background vapour levels. With active systems the vapours are aspirated continuously from the backfill by a pumping system into an externally mounted analyser/sensor. Again, a common analyser can be used to monitor a number of points and, by injecting uncontaminated air into the sampling system, the sensing device can be routinely checked for degradation before further tests of the wells are made.

10.6.4.4 Noise Monitoring

The requirements for environmental noise monitoring are well described in the series of International Standards (ISO 1996 & 3744/6), tabulated in Appendix A, while IEC documents IEC 651 and IEC 804 specify the performance of the sound level meters to be used to determine whether the noise limits prescribed by the national or local authority are being observed.

In principle, sound level measurement is simply a matter of placing microphones connected to recording instruments at pre-determined points in the area of interest monitoring the A-weighted sound pressure levels, sound rating levels and long-term average sound level over a prescribed time period. Comparison is then made with the limits specified for the locality after account is taken of factors such as atmospheric/meteorological conditions etc.

10.7 Preferred Equipment Types

Tabulated in this Section are the measurement techniques recommended by BP as being the most suitable for monitoring the specified chemical components in the preferred measurement range.

In some countries the choice of equipment is limited by the authorities themselves and it may well have to be authority approved. In other countries such as the UK the equipment choice is left to the user on the Best Available Techniques Not Entailing Excessive Cost (BATNEEC).

The selection of a monitoring technique for a particular component and it's integration into an overall multi- component monitoring system can have a significant effect on the accuracy of the results obtained. Factors to be considered when selecting a monitoring technique include:-

*Accuracy and precision
Reliability
Ease of operation and maintenance
Sample conditioning requirements
Cost*



All of the above factors are important, although it should be stressed that demonstrated accuracy and precision are crucial considerations since without these the data will be worthless.

The list drawn up below is preliminary based on measurements currently proven in site applications and known authority approvals (e.g. German) and will be extended as experience progresses.

(a) Stack Monitoring

Pollutant	Technique
CO/SOX	IR
NOX	Chemiluminescence or IR
H ₂ S	Colorimetric (Paper Tape)
Dust/Smoke	Photometric

(b) Ambient Monitoring

Pollutant	Technique
H ₂ S	Suphisor
Flammables	IR or Catalytic
Hydrocarbons (ppm)	FID
Aromatics	PID
Methyl Iodide	Beta Absorption

(c) Effluent Monitoring

Pollutant	Technique
BOD	BOD-M3
Metals	X-ray Fluorescence
Oil in Water	IR Scatter
Phenol/Sulphide	Colorimetric
Total Organic Carbon	Oxidation to CO ₂

10.8 Methods of Installation

The preferred method of installation for each of the commercial monitors tabulated above will be advised by their manufacturers. There are, however some general installation rules reflecting good engineering practice which must be observed at all BP sites. These are given below.

If the analysers are installed to meet the regulatory requirements the installation should be dedicated to the particular measurements. Many



authorities will not entertain adaptation of existing systems installed for other purposes such as plant control to provide measurements for emission/ pollution reporting.

The installation should have automatic calibration facility and any data handling facility for averaging and reporting should be specific to the system.

Each system should be stand alone.

General design and installation principles are adequately covered in BP Group RP 30-2 section 7 'On-line Analysers'.

Where mass flow of the pollutant is required the installation should include a means of determining flow of the polluted stream.

10.9

Sampling Systems

The accuracy with which the concentration of a chemical pollutant in any environment can be measured depends only partially on the intrinsic performance capability of the monitor itself. It also depends, usually to a much larger extent, upon the representativity of the sample presented to the instrument for analytical treatment. If this is in doubt, then the credibility of the measurement system itself is similarly prejudiced.

Therefore great care must be taken to ensure that the sample, be it gas or liquid, entering the analytical area of the monitor is entirely representative of the fluid at the point at which measurement is required and that it is delivered to the analyser at the appropriate temperature and pressure, free from contaminants which will interfere with the analysis.

The following general guidelines will advise the reader on the most critical aspects of good sampling practice. Advice, more specific to particular types of environmental monitor will be supplied by the manufacturers.

For stack emission analysers all data required by the authorities is on a dry basis normally referred to an excess oxygen measurement. For this reason it is preferable to use sample system type installations where sample conditioning can be used to get dry analyses for NOX, SOX, CO etc. The only exception is for smoke/dust monitors as achieving representative sample via an extractive system is virtually impossible.



If cross duct in-situ analysers are considered then it will be necessary to have a measurement of water content to enable dry gas analysis to be achieved. Water can be measured with IR (cross duct) or alternatively by measurement of oxygen in-situ with Zirconia to give a wet analysis and extractively with paramagnetic types to get a dry analysis and computing water levels from difference.

For Emission monitoring reporting mass flows may be required as well as or instead of concentration data. In this case dry gas flow rate is required. It may simply be adequate enough to infer flow rates from fuel consumption and combustion air flow data but if actual stack flow rate measurements are required then it must be appreciated that this is a wet gas flow rate and suitable methods of assessing water contents must be addressed. This is case where in-situ analysis could be an advantage as a wet measurement of both component and flow will give the answer i.e. wet concentration x wet flow rate = dry concentration x dry flow rate.

For extractive stack analysers it is important that sample temperature is kept well above dew points until the water can be removed in a controlled way. This is especially important where soluble gases are to measured such as SO₂. Some manufacturers will recommend heated probes and traced sample lines using steam as the heating medium. Flue gas dew point temperatures can be very high and it is doubtful that steam tracing is totally effective. Careful investigation of dew points and tracing efficiency is needed at all climatic conditions likely to be encountered before opting for steam heating methods. Alternatives are electric tracing or possibly hot oil/gas heat exchange if a suitable source exists close to the sample point.

The enforcement of stricter controls on flue gas compositions is making this sampling problem easier and the use of sintered filter probes with blast back purging is now well proven for all but the dirtiest of conditions.

Where sulphur compounds are present avoidance of cold spots in the sample systems is essential to prevent blockages by deposits of free sulphur.

Removal of water vapour and the way in which it is done is important. Two methods are available - condensation or membrane filtration.

Membrane filtration will allow drying without the problem of solubility and removal of some of the SO₂ with the water.



When condensing water from flue gas samples it should be done at a constant and controlled temperature low enough to ensure minimal water vapour interference in the IR measurements of CO and SO₂. For SO₂ the dry gas will have a lower content because of the solubility of SO₂ in water. To overcome this the SO₂ calibration gas must be bubbled through water at the same temperature as the flue gas sample condenser thereby ensuring the calibration compensates for the water soluble portion.

For water sampling care must be taken to ensure particulates and gas bubbles do not interfere with the analysis.

Ambient monitoring presents formidable problems in selecting points or lines of sight (for open path devices) that are representative of the pollution measurement you are trying to make. Site surveys and/or simulation techniques may be necessary to place monitors

For ground monitoring detection of volatiles is best accomplished by pumped sample systems drawing samples from pre - defined locations either through holes in the sample tubing or via diffusion of the contaminant through the tube walls. Intermittent withdrawing of sample coupled with time measurement for pollutant to arrive at the analyser will give indication of location of contamination.

Ground monitoring can be simplified if plant design can ensure leakages are gathered and concentrated in specified places i.e. for tanks use of membranes suitably sloped to a gathering point of for surface water drainage systems directed to sumps.

11. INSTRUMENTATION FOR HVAC SYSTEMS

11.1 General Requirements

This section specifies BP general requirements for instrumentation and control equipment provided as part of a HVAC System for BP operational sites. It shall only be used in conjunction with the relevant BP Specifications which specify detailed requirements for the HVAC System itself.

Instrumentation and control equipment is, for BP projects, supplied usually in accordance with BP Group [BP 30-1](#). This recommended practice is based on the requirements for process plant and is unnecessarily severe for HVAC systems. If BP Group RP 30-1 is used for HVAC systems extra cost would be incurred. This recommended practice specifies the requirements for HVAC systems and should be used in place of BP Group RP 30-1 for items shown. Where items are not included in this recommended practice BP Group [BP 30-1](#) should be used.



BP Operational sites usually consist of a number of widely spaced units each of which will be supplied with its own HVAC unit. Their units are usually small and can be supplied as packaged units. All controls and monitoring should be on the packaged unit with a certain number of signals to and from the Packaged unit. Packaged units may be interconnected and interface with the site management system. This recommend practice does not cover complex buildings requiring a building management system. If a building management system is required it shall be separately specified.

11.2 General

11.2.1 This recommended practice gives BP's general requirements, however local or national statutory regulations in the country of operation take precedence over the contents of this practice.

11.2.2 Any point not specifically referred to in this document should be referenced to BP Group [RP 30-1](#).

11.2.3 Reference in this recommended practice to other codes and standards are to be the latest published issue, unless otherwise stated.

11.2.4 A total HVAC system shall consist of either a single or a number of interconnected stand alone packages. The instrumentation on each package shall conform to this specification.

11.2.5 The minimum number of signals shall be made available for remote monitoring of HVAC units.

Remote indications controls and alarms shall be defined at the design stage.

Electrical isolated signals shall be provided to and from HVAC units to allow remote indication and control of the units.

11.2.6 Where equipment in a HVAC system forms part of another system which may be common to more than one plant item the equipment should be designed to the system requirements.

Where items of equipment on the HVAC system forms part of other systems such as fire and gas and emergency shutdown the specification of associated items shall be by the relevant system supplier and shall conform to the design requirements and be installed in accordance with their requirements. Termination boxes or cabinets suitable for the hazardous area classification and segregation requirements shall be provided to interface with remote equipment.

11.2.7 All controls supplied shall fully conform to BP Group [RP 14-2](#) heating, ventilating and air conditioning.



This document specifies control requirements for HVAC systems and designs should fully conform to this practice.

- 11.2.8 If any instruments covered by this specification are located in hazardous areas, then their electrical certification must conform to that area.

11.3 Pressure Instrumentation

- 11.3.1 Indicating pressure sensors shall be of the diaphragm or capsule type, protected against over pressure.

- 11.3.2 The sensing element of electronic transmitters shall be either strain gauge or linear variable transformer type.

- 11.3.3 Pressure instruments shall conform to the following parameters :-

Uncertainty-	$\pm 2.0\%$ span
Response Time-	≤ 200 MS
Hysteresis-	$\pm 0.4\%$ span
Repeatability-	$\pm 0.25\%$ span

- 11.3.4 Pressure sensors shall be provided with facilities to allow their isolation from the sensing point.

Pressure sensors need only be capable of isolation by means of a cock. It is not considered necessary to provide vent or drains as HVAC systems pressure instruments are usually confined to air, water and lube oil and maintenance, calibration and testing can be carried out by removal of the instrument.

The same may apply to fuel oil and gas, so long as the pressure is low.

11.4 Flow Instrumentation

- 11.4.1 Flow meters for HVAC systems should be as specified in this section. Other principles of measurement may be used where practicable and economic.

Because of the low pressure drops usually encountered in HVAC systems the petrochemical standard flow measurement principle of the orifice plate is not normally used. However in some cases such as seawater cooling water flow measurement, where a permanent pressure drop may be an advantage this type of measurement could be used. Other flow meters such as coriolis, variable area or thermal meters may be considered for specific applications.

- 11.4.2 Water and steam flow meters should be of the vortex shedding or electromagnetic principle and should conform to the following:-



Uncertainty better than $\pm 1\%$ of actual value for flows of more than 5% of FSD.

Response time less than 5 seconds

Repeatability better than 0.5% of the flow rate for flows of greater than 5% FSD.

11.4.3 For sea water cooling water flows orifice metering systems may be used.

With sea water cooling water flows the pressure drop which can be accepted is usually much higher than in other processes and the permanent orifice pressure drop may be acceptable. For some applications the added pressure drop caused by an orifice metering system may be advantageous as it causes a flow restriction for limiting water flow without additional pumping control equipment. Also for this application the additional straight pipe length required for the measurement may not be restrictive. Orifice meters should be installed to standards shown in section of this Recommended Practice.

Other flow meters may be used if standard to a packaged unit and if agreed with BP.

Where small flows such as individual cooling water flows are metered variable area meters or sight glasses may be used. This equipment is usually supplied as standard by packaged unit manufacturers.

Also in some cases new forms of flow meters such as thermal meters or insertion meters developed for this service may be used and where proposed by the package unit manufacturers should be considered.

11.4.4 Air flows shall be metered by either insertion meters or in line primary elements. Insertion meters are preferred.

In line flow elements may consist of fabricated venturi's or duct inlet/outlet devices.

In many cases it is possible to infer a reasonable flow from duct inlet or outlet differential pressure measurements. This method of measurement may be used where the measurement point is acceptable for this type of system, where a cheaper less accurate measurement is acceptable and where the measurement will not be contaminated by natural elements such as frost. Where more accurate measurements are required fabricated duct venturi's should be used.

Insertion meters shall be either pitot tubes, insertion turbine flow meters or insertion thermal flow meters.

Insertion meters should be mounted in straight lengths of ductwork in areas of no swirl, in accordance with the manufacturers



recommendation and shall be inserted at a depth which will give an average velocity measurement.

Pitot tube air flow meters shall have an uncertainty of less than $\pm 2.0\%$ of the full scale reading and shall conform to the standard shown in the relevant Appendix.

Insertion meters other than pitot tubes shall conform to the following.

Uncertainty better than $\pm 2\%$ of the measured rate over the range of application.

Repeatability better than 0.1% over the range of application.

11.4.5 Differential pressure elements should be used for flow alarms or the alarm signal derived from the measurement sensor.

11.4.6 Paddle switches shall not be used for flow alarms or controls.

11.5 Temperature Instrumentation

11.5.1 Local temperature indicators shall be of the bi-metal multi angle type.

11.5.2 Other temperature measurements should conform to the following table:-

Fluid	Range (°C) Uncertainty (°C)	Type
Air	-10 to +30 ± 0.25	Higher accuracy resistance thermometer or Graded Thermistor
Flue Gas	+30 to +850 ± 5.0	Lower accuracy resistance thermometer or thermocouple
Chilled Water	-10 to +30 ± 0.25	Higher Accuracy resistance thermometer or graded thermistor
Water	+10 to +100 ± 1.0	Lower resistance thermometer or graded thermistor

11.5.3 Resistance thermometers should conform to the following.

Be of two, three or four wire to suit the application.

Be 100/1000 ohms at 0°C and have fundamental interval of 38.5 ohms.

Conform to the relevant standard as shown in the Appendices.

- 11.5.4 Thermocouples shall be selected to give the necessary readout when used with remote equipment and conform to the guidance given in Section 2 of this Recommended Practice.

Usually this thermocouple will be type K with suitable compensation or extension cable. The selection of extension or compensating cable should be considered on the required uncertainty of the reading and the cost of relevant cables.

- 11.5.5 Thermowells of the package manufacturers standard shall be used for all temperature measurements.

11.6 Humidity Instrumentation

- 11.6.1 Humidity sensors should be of the capacitance type and conform to the following having :-

Operating range	10 - 90% RH.
Uncertainty	better than $\pm 5\%$ of measured variable.
Response time	better than 30 seconds.
Hysteresis	better than 3% of the measured variable.
Drift	not exceeding 5% of the measured range per year.

11.7 Enthalpy Instrumentation

- 11.7.1 Enthalpy sensors shall conform to the requirements of sections 5 and 6 of this recommended practice.

- 11.7.2 Combined humidity and temperature sensors may be used for enthalpy measurement.

Enthalpy measurements are normally computed from relative humidity and temperature measurements. Those measurements may be made separately or they can be obtained from a single transducer. It may be cost advantageous to use a single transducer.

11.8 Analysers

- 11.8.1 Analysers when required by the plant specification shall be supplied in accordance with this section.



11.8.2 Exhaust gas analysers used for monitoring flue gas condition shall conform to the following and the requirements of the appendices

Uncertainty better than $\pm 2\%$ of the measured range.

Sensor life Greater than one year.

Response to a 90% range change Less than 20 seconds.

Long term drift Less than 10% per year without recalibration.

11.8.3 Boiler water analysers where supplied shall conform to the following:-

For PH measurements the equipment supplied shall have :-

Uncertainty better than $\pm 1\%$ of Span.

Minimum sensitivity 0.01 PH.

Response time change. less than 10 seconds for a 90% signal

Repeatability better than 0.02 PH.

Long term drift less than 0.25% of span per and shall conform to the month requirements of standards shown in the Appendices.

For dissolved oxygen analysers the equipment supplied shall be of the electro chemical cell type and shall have :-

A range of 0 to 15 mg/litre

An uncertainty of better than $\pm 5\%$ on 200 PPB range.

A minimum sensitivity of 1% of full scale.

A response for changes of 0.1 mg/litre.

A response time of better than 60 seconds for a 90% range change.

A repeatability of better than 2% of full scale.

A long term drift of better than 1PPB in 30 days.

For total dissolved solids analysers the equipment supplied shall be of the conductivity type and shall have :-

An operating range of 0 to 1000 micro s/ cm

An uncertainty better than $\pm 2\%$ of reading over the operating range.

A minimum sensitivity of 0.1 ohms micro secs/cm and shall conform to the requirements of the standards shown in the Appendices.



- 11.8.4 The characteristics of other analysis equipment shall be agreed with BP.

The above analysers are the types most commonly used on HVAC systems. All or only some of them may be used for a specific plant. The numbers used will depend on the design of the plant.

In some cases other analysers may be required for control or monitoring. If this is the case their characteristics shall be specified on a project basis, at the design stage.

11.9 Alarm Instrumentation

- 11.9.1 All packaged units shall be supplied with an integral alarm system located on the unit.

- 11.9.2 The alarm system should be of the modular type in accordance with BP [Group RP 30-5](#) unless otherwise agreed with BP or as shown in 11.9.6 below.

This system will give the maximum amount of information and will allow faults to be identified from groups of alarms also full warnings to the operator will be given.

- 11.9.3 The systems in 9.2 above shall be supplied with a first up feature if required by the plant.

Where more than one alarm can be indicated at a plant fault or shutdown a first up feature will allow the cause to be identified.

- 11.9.4 Common or group repeat facilities shall be provided.

- 11.9.5 Unless agreed with BP repeat reflash facilities shall be provided.

Reflash facilities should be used where it is possible for more than one alarm in a repeated group can be actuated to allow remote operators to be warned of all faults. In some cases (See 11.9.6 below) this requirement may be relaxed.

- 11.9.6 Where a simple alarm system is required and only indication of fault is necessary the alarm system may consist of a number of lights and repeat facilities. Any such systems shall only be used with company agreement.

This type of system should only be used where there are a small number of alarms on a unit, where it is expected that not more than one alarm will be actuated at any one time an plant operators can early distinguish the initial cause of alarm.



11.10 Self acting Control Systems

- 11.10.1 Self acting Control Systems may be used where reliability and fast response are required.

Self acting control loops are used where fixed and low gain applications are relevant and where some simplification in control is acceptable.

The usual applications on HVAC systems are for gas and liquid fuel pressure controls and for temperature controls on steam heaters.

Their use is limited by the restricted control loop settings and droop characteristics on high load variation.

For other forms of control a conventional control loop should be used.

- 11.10.2 Self acting controls may also be used where utilities such as power or air is not available for plant operation.

11.11 Controls

- 11.11.1. All controls should be carried out at the local installation (packaged unit).

- 11.11.2 Controls shall be pneumatic in hazardous locations and/or electronic in other locations.

Controls shall be designed to suit the complexity of the plant. Where simple indications and controls are acceptable and where an instrument air supply is available the controls may be pneumatic otherwise the controls shall be electronic or electric. Where computations are required electronic equipment shall be used. The cost of the system should also be considered at the design stage.

- 11.11.3 Signals within the packaged unit shall be the unit manufacturers standard.

While the standard plant signal for electronic equipment is 4-20 mADC for the petrochemical industry, HVAC units may use other signals such as 0-10V d.c. These signals are acceptable provided that they are standard on a packaged unit. Every effort however should be made to make them consistent over the HVAC system for a site.

- 11.11.4 Calculations and computations shall be carried out by modularised electronic equipment installed at a local panel.

In some cases calculations and computations are necessary for the control and management of a unit. With present day multifunction controls these calculations and



the necessary controls should be carried out by stand alone multi-variable controllers. This will increase the accuracy and reliability of the control.

- 11.11.5 Multi-variable controllers may be used for packaged unit controls.

Where measurement manipulation is necessary (such as Enthalpy computation). The control equipment used for this may have redundant functions. These functions may be used for other controls on the unit before separate equipment is purchased.

- 11.11.6 Indications on units shall be visible from walkways or grouped at the edge of the unit.

- 11.11.7 Local Controls shall be part of packaged units and mounted on the unit.

Controls such as pump and/or fan start/stop auto start of standby equipment and integral shutdown systems which are part of the normal operation of the unit shall be supplied by the unit manufacturers to their standard provided they are considered workable and safe. These functions shall be mounted on the skid in a suitably protected environment such as a control panel.

- 11.11.8 Facilities shall be provided for the connection of external controls and indications to a remote location.

Usually it is necessary for indications and alarms to be transmitted to a remote location for plant monitoring and for controls to be sent to the unit from a remote location.

Facilities to allow these to operate should be provided by the manufacturer on the package. Interfaces shall be provided to allow these signals to be connected to the package in the form of junction boxes or segregated panel terminals.

11.12 Plant Interfaces

- 11.12.1 Interfaces between the HVAC packaged units and the main plant monitoring system shall be fully isolated.

- 11.12.2 Interfaces at the packaged units should be either separate junction boxes or blocks of designated terminals at the local panel. Signal segregation shall be as the plant specification.

- 11.12.3 Interfaces shall conform to the following:-

Analogue signals 4-20 mA d.c.

Alarm signals - contact closure which should be normally closed and open on alarm condition.



Digital indication signals - contact closure, open or closed on indication. The required operation shall depend on the plant specification.

Shutdown signals - fail safe contact operation shall be maintained for safety and interlock circuits.

Pulsed signals where digital output from flow meters is required (e.g. turbine and positive displacement meters)

11.12.4 Serial interfaces shall only be used with BP Agreement.

Usually HVAC packaged units have a small number of signals transmitted to supervisory equipment and it is not economic to use a serial interface. However should a reasonable number of signals be transmitted a serial interface may be advantageous. However even if such a communication system is used great care must be taken to maintain the integrity of safety signals such as fire and gas.

11.12.5 Interfaces for other system equipment supplied in the HVAC (such as ESD and fire and gas) should conform to the relevant system standard.

11.13 Electrical

11.13.1 Installation

In the UK installation of HVAC controls/circuits shall comply with the current edition of the IEE Regulations unless otherwise stated. Elsewhere relevant equipment nationally recognised standards shall apply.

11.14 Cables

11.14.1 All instrument cables on skids shall be as per the manufacturers standard supply.

11.14.2 Cables interconnecting skids or interfacing to other plant or equipment shall conform to site or project practice.



12. DRILLING INSTRUMENTATION

12.1 Introduction

12.1.1 Background

Drilling packages have their own very specific requirements for instrumentation which are not adequately addressed in the current BP Recommended Practices. This has caused considerable problems on projects and disputes with Vendors and Clients. The aim of this section is to fill this gap.

There are no external standards available that cover this requirement comprehensively.

There are some relevant documents that do cover specific aspects of drilling instrumentation.

Reference should be made to the following documents:-

- *The BP Drilling document 'Well Control Manual' Although this is primarily an operational document not a design document, there are sections detailing instrumentation requirements for specific drilling applications.*
- *API RP 16E : Recommended Practice for Design of Control Systems for Drilling Well Control Equipment.*
- *The BPX 'Drilling Policy' document.*
- *The Aberdeen based 'HP/HT manual'.*
- *The BPX 'Drilling Facilities Manual'*

Compliance with the Certifying Authority rules and regulations should also be ensured e.g. the rule-book of one of:-

- *The Lloyds Register of Shipping*
- *The American Bureau of Shipping*
- *Den Norske Veritas (probably the strictest)*

12.1.2 Scope and Objective

This section of BP Group RP 30-2 has been developed to cover specific instrumentation and interface requirements for 'Drilling Packages' for offshore platforms.

12.2 General Requirements

12.2.1 This document shall apply to all BP operated platforms where drilling packages are located.



It is the intention that this document shall cover all new installations. Where appropriate, this document shall also apply to existing drilling packages and to deployment of new drilling packages onto existing installations. In particular, section 12.4.2 should apply to all new and existing packages.

- 12.2.2 Instrumentation shall be as simple as possible and the minimum consistent with meeting the requirements for reliable and safe operation of the drilling equipment.

The intended purpose of this section is not to restrict functionality of the drilling packages, but to detail general principles and in particular to detail areas where interfaces with permanent platform systems may be required.

12.3 **General Comments**

Many of the drilling packages that we are concerned with here are also used on Mobile Drilling Rigs. It is important to note that the regulations governing their use on these rigs may be significantly different to those in force on production platforms. Therefore, it is important to ensure that particular platform requirements are met when such drilling packages are brought on board.

12.4 **Package Design**

12.4.1 Safety Aspects

All permanently installed drilling packages shall be included within any Formal Safety Assessment that is prepared for the overall platform.

All temporarily installed drilling packages shall be considered as potential modifications to the overall Safety Assessment. Where appropriate, any amendment to the Assessment should be notified to the relevant Regulatory Authorities.

Some drilling packages, although nominally temporary additions to the platform equipment, are in reality virtually permanent equipment. For this reason it is normally unreasonable to treat them as temporary equipment. Other packages may be truly temporary installations, brought on board for the duration of a particular drilling activity only.

It is reasonable that such truly temporary packages should not be included within the platform FSA. However, such packages should otherwise be fully suitable for the environment in which they are to work.

12.4.2 Electrical Certification for Hazardous Areas.

All equipment shall be certified appropriately for the hazardous area it will be operated in. This shall be true for both drilling packages designated 'temporary' and 'permanent'.

Equipment designated for use within Europe (both EEC and Non-EEC) should be certified to CENELEC standards by a national test-house (e.g. BASEEFA or SIRA in



the UK). However, as much of the drilling equipment normally used originates within the US, some components may only be certified to U/L, CSA or FM standard. Such certified equipment shall only be acceptable when the test method used is the same as a referred to European Standard and with the proviso that the indicated gas groups and temperature classes are appropriate to the proposed service. (North American gas groups etc. are not directly equivalent to European ones.) Such certified equipment shall also be confirmed as acceptable to the installation certifying authority.

Instrument control panels for drilling packages can be made a 'Safe Area' by use of a certified pressurised system, even though the panel itself may be within an overall hazardous area. However, this method can give considerable operational and maintenance problems and should be avoided wherever possible. It should also be recognised that use of the Ex'p' technique will mean that electrical power will be lost on loss of pressurisation for whatever reason and for a given time after start of the re-pressurisation process.

12.5 Interfaces

12.5.1 Temporary and Permanent Drilling Package Interfaces

The interfaces between each proposed or potential drilling package and the main platform systems should be identified and catered for during the design phase.

It is recognised that some assumptions will have to be made where interfaces are with as yet unknown items.

The requirements and correct definition of interfaces to any or all of the following platform systems shall be clearly identified at an early stage in the conceptual design.

(a) The Fire and Gas system.

Common alarms for 'fire', 'gas' or 'extinguishant released' within individual drilling packages may be required as interface signals to the main platform F&G system. Other F&G logic for individual packages should normally be self contained within the packages themselves. The common alarms should have inhibit/override facility at the main F&G panel to allow detector testing.

Similarly, some common platform F&G alarms may be required to be annunciated within some drilling packages.

All permanent and temporary drilling packages should comply with any specific national regulations in force in the country of use. (For example the Norwegian Petroleum Directorate requires that any Manual Alarm Callpoints should initiate the platform Public Address System - this then means that an



interface signal is required if any of the MAC's are located within the drilling packages.)

An interface signal may be required to all drilling packages to isolate all socket outlets or small power points in case of gas detection anywhere on the platform.

(b) The ESD system.

Initiated ESD actions to drilling packages are normally very few and may be limited to Red shutdown only (i.e. total loss of power to all systems). Lower level shutdowns are not normally required on the basis that in many cases it would be considered more dangerous to shut in a well at a critical stage of drilling than it would be to continue drilling activity during a platform shutdown. Thus interfaces to the drilling packages will normally be limited to the Red shutdown/power trip plus any alarm only signals required to provide indication of platform hazards/shutdowns.

Operational procedures will probably also require that wherever possible, advance notice of the activation of a Red shutdown should be given to allow the drilling facilities to be made as safe as possible.

(c) The Distributed Control System

Most drilling packages will not normally have any interface with the platform DCS system. Control of the individual packages will be self contained.

Consideration may, however, be given to providing for common alarms back from the individual drilling packages for particular reasons - for example if the Cuttings Cleaning system or Drilling Drains system has implications for Environmental control.

(d) Electrical Power Supply.

Power may be provided to drilling packages either from the platform power supply or generated within the drilling area itself (e.g. diesel cement unit). Some of the instrumentation may be provided via an Uninterruptable Power Supply system. The only requirement would be that all power would be isolated on Red Shutdown.

(e) PA System Interface



Drilling Packages may have their own self-contained PA system but may require a link into the main platform system (Ref. also the comment under 12.5.1 a)).

12.5.2 Platform Facilities for Temporary Drilling Packages/Cabins

Most platforms where drilling is possible will, at some stage, have temporary drilling or well service packages on board. It is recommended that provision for these should be made during the design phase to save on later operational costs. Provision of the following should be considered for each Drilling Package envisaged:-

- (a) General power supply - normally 380-440 volts, 3 phase, 16 amp.
- (b) Power supply for lighting
- (c) Air Supply - normally Rig Air (120 psi)
- (d) At least one common F&G alarm point as detailed above
- (e) Telephone Point
- (f) HVAC
- (g) Other Instrumentation - Where it is likely that additional instrumentation will be required by temporary drilling packages, space and provision shall be provided such that this can easily be added.

In the past, problems have arisen when there has been no provision made for additional third party sensors - for example often a third party mud logging unit will use additional sensors for determining depth/volume of fluid tanks. These issues must be addressed early in the design phase.

Typically up to 3 temporary drilling cabins may be on board at some stage (but see section 12.6.4 for exception). It is recommended that provision for the above facilities or utilities should be made during the design - perhaps located at common points around the pipedeck and/or BOP deck. (Actual requirement would be platform specific.)

12.5.3 Drag Chain

It is recommended that additional spare cabling is provided within the drag chain to provide for the instrumentation required on the drillfloor for temporary packages. Both spare coaxial cable and ordinary specification instrument cable will be required in the drag chain.



Temporary drilling cabins are never sited on the drillfloor itself. Therefore any additional temporary monitoring signals required should be routed via the drag chain. Failure to provide spare cabling in the drag chain will lead to significant operational expenditure at the time of temporary cabin deployment as long length cable runs and lash-up gap bridging will need to be achieved.

12.6 Other Aspects

12.6.1 Consistency with the rest of the Platform

Packages shall be selected such that the internal Instrumentation is as far as practicable consistent with that used on the remainder of the platform.

This is particularly important for areas where there are safety implications. For example, a mixture of imperial and metric instrument fittings should be avoided or at least rigorously controlled.

12.6.2 General Instrument Philosophy

The design shall attempt to ensure that drilling packages specified to have the same overall instrument philosophy as for the remainder of the platform.

This requirement should cover such aspect as: acceptability of PLC control systems; philosophy for stop/start/Emergency stop of motor and pump controls; philosophy on providing dual redundant or hot standby equipment etc.

Consideration should be given to providing a manual override of critical control functions in cases where failure would lead to an undesirable situation e.g. a manual override might be provided to pull back the drill string from the hole bottom in the case of control system failure.

12.6.3 Human Factors Engineering

Human Factors issues should be addressed during the design phase as these will have an important impact on the overall drilling safety.

The safety impact of automating certain drilling operations should be considered during the design process. For example both Chemical Handling and Drilling Fluid Property Control should be considered as candidates for automation.

Consideration should be given to making up full scale plywood models of drilling instrumentation - particularly of the Drilling Console. This will enable operational problems to be avoided and will aid the design process by optimising the siting of equipment. The use of models is preferred to the use of CAD in this instance.



Once Drilling manning levels have been determined, Task Analysis should be carried out on individual drilling operator functions. Although this is basically an operational concern not a design issue, there are implications for the designer in that he should be aware of the implications of the particular design selected.

12.6.4 Minimum Facilities Platforms

With the advent of minimum facilities platforms in the North Sea, we may see platforms designed with 'flat tops'. In these cases the drilling packages all become very much more temporary. This is already common practice in the Gulf of Mexico, where some workover packages are on and off the 'flat top' in a matter of days.

In these specific cases, the number of temporary cabins may be greater than the three mentioned in section 12.5.2. There is also likely to be a need for considerable temporary cabling, including connections between the 'flat top' and the workover vessel, all requiring trunking.

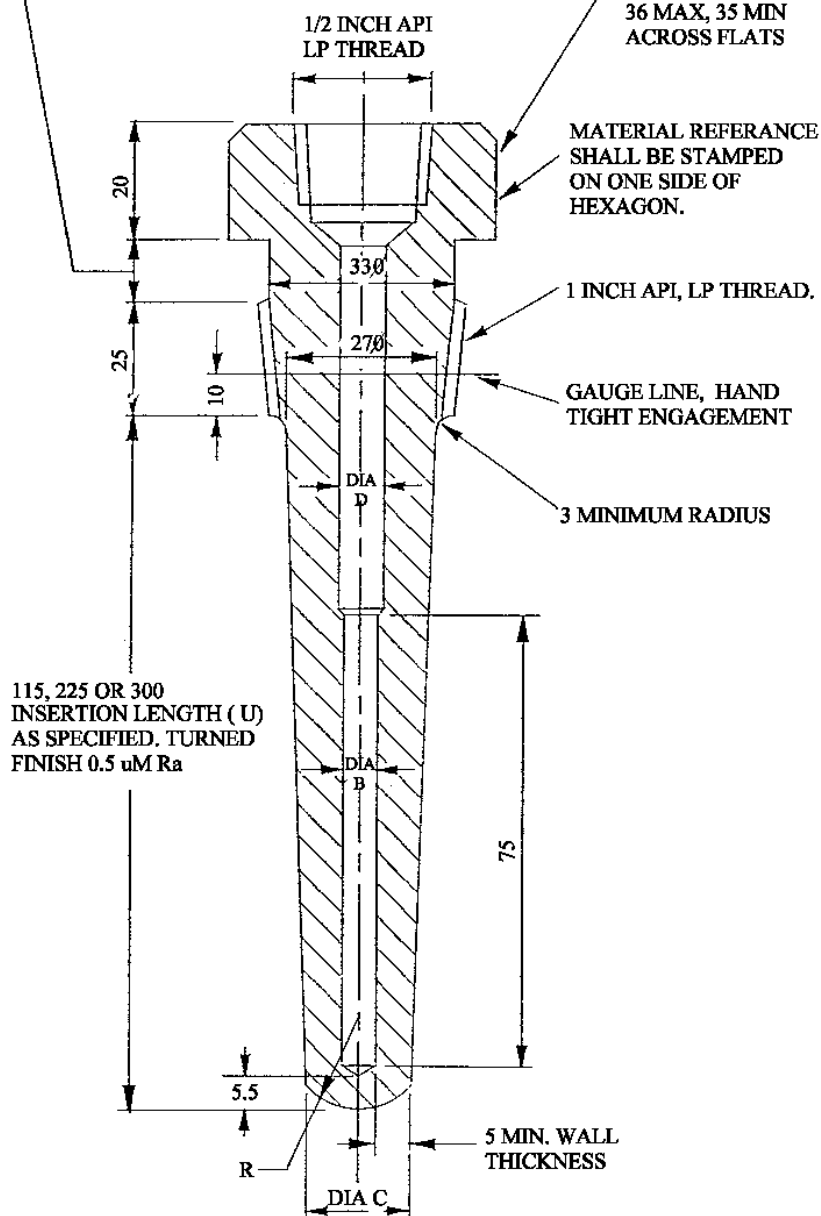
Assuming the minimum facilities platform is unmanned and continues production, there is likely to be a requirement for at least the following:-

- The capability to initiate an ESD of the platform production from the workover vessel/jack-up.
- F&G on the workover vessel/jack-up to initiate a platform shutdown.
- An alarm on the platform to be annunciated on the workover vessel/jack-up.



LENGTH (T) STANDARD 25.
INCREASE TO 60 OR 85 AS
SPECIFIED FOR LAGGING
EXTENSION

HEXAGON 36 MAX, 35
MIN ACROSS FLATS.
ALTERNATIVELY DIA 40
ROUND BAR HAVING
TWO SPANNER FLATS
36 MAX, 35 MIN
ACROSS FLATS



NOTE:
UNLESS OTHERWISE SPECIFIED, ALL DIMENSIONS ARE IN MILLIMETRES.

FIGURE 2-1
SCREWED THERMOWELL



APPLICATION:

FOR USE WITHIN THE LIMITS OF TEMPERATURE AND PRESSURE SPECIFIED BY [ANSI B16.5](#) FOR CLASS 150 FLANGES, ANY USE OF THE THERMOWELL OUTSIDE THESE LIMITS SHALL BE SUBJECT TO APPROVAL BY BP.

CONSTRUCTION:

POCKETS SHALL BE MACHINED FROM THE SOLID.

MATERIALS OF CONSTRUCTION:

BAR: [BS 1502 316S31](#), [BS1502 316S33](#) OR [BS1506](#) GRADE 845
FORGINGS: [BS 1503 316S31](#), [BS1503 316S33](#) OR ASTM [A 182 F316](#)

SPECIAL MATERIALS:

THE USE OF MATERIALS OTHER THAN THOSE SPECIFIED ON THIS DRAWING SHALL BE SUBJECT TO APPROVAL BY BP.

BORE:

BORING SHALL BE CARRIED OUT ON A GUN-DRILLING MACHINE TO ENSURE STRAIGHTNESS AND GOOD FINISH.

FOR THERMOCOUPLES & RESISTANCE ELEMENTS:

DIMENSIONS SHALL BE IN ACCORDANCE WITH THOSE LISTED IN THE FOLLOWING TABLE FOR ELEMENT DIA. G.

FOR FILLED SYSTEMS , EG. MERCURY IN STEEL, THE BORE SHALL SUIT VENDOR'S EQUIPMENT. TYPICAL DIMENSIONS ARE SHOWN IN THE FOLLOWING TABLE FOR INTERMEDIATE SIZES, DIMENSIONS SHALL BE DETAILED.

ELEMENT DIA.	6	TYPICAL, MAX. 13
DIA. B	6.2 $\pm$ 0.1	13.2 $\pm$ 0.1
DIA. C	18	25
DIA. D	8	15
RAD. R	12 $\pm$ 2	17 $\pm$ 2

ALL OTHER DIMENSIONS $\pm$ 0.5

HEAT TREATMENT:

FORGING SHALL BE SOLUTION ANNEALED AT 1050°C FOR 1HOUR PER 25MM OF SECTION (MINIMUM PERIOD 1 HOUR), FOLLOWED BY WATER QUENCH.
NO HEAT TREATMENT REQUIRED AFTER MACHINING.

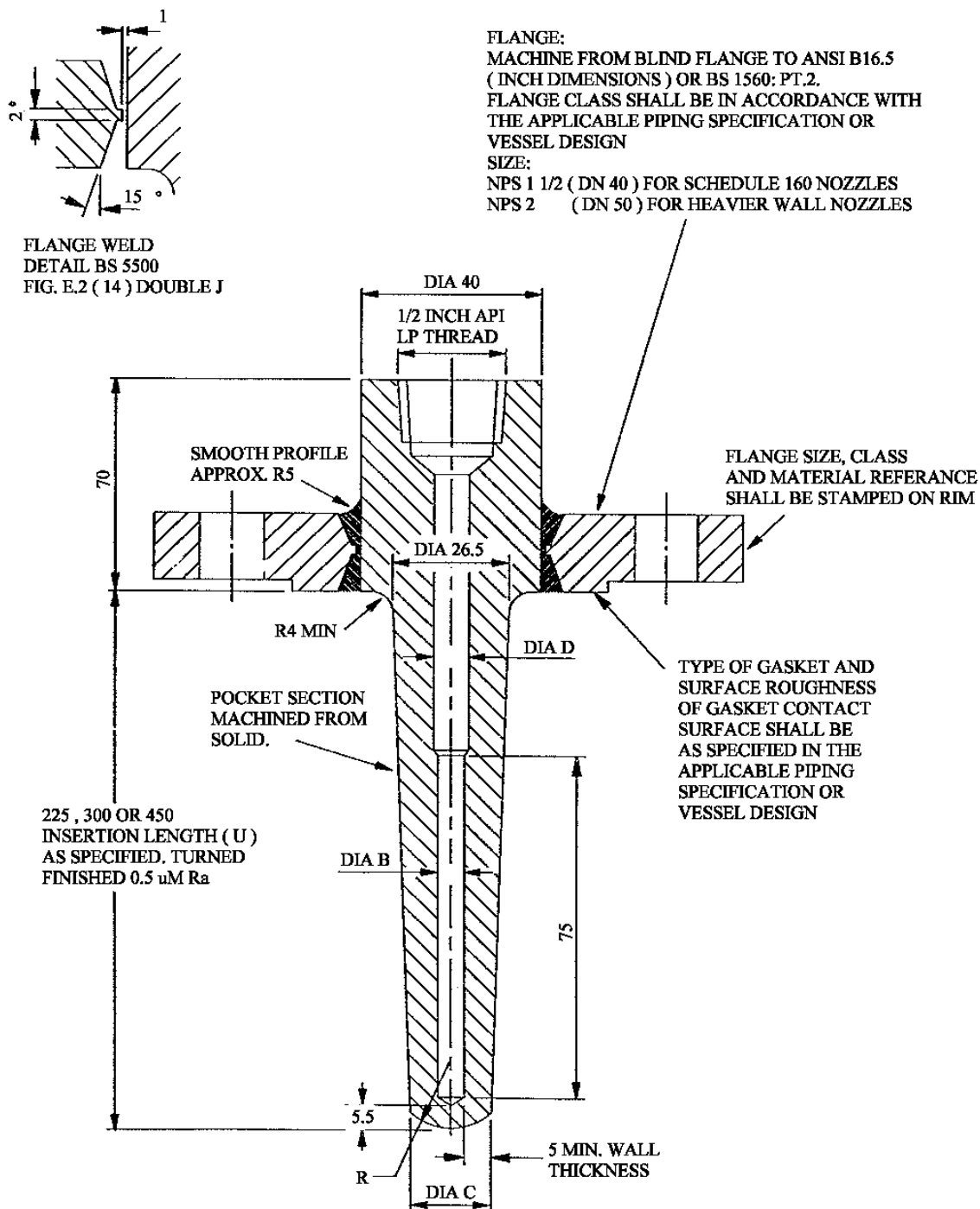
TEST PRESSURE:

FINISHED THERMOWELL SHALL BE SUBJECTED TO AN EXTERNAL TEST PRESSURE OF 30 BAR (GA) (435PSIG) AT AMBIENT TEMPERATURE.. IF THE THERMOWELL IS APPROVED BY BP FOR USE OUTSIDE THE LIMITS SPECIFIED BY ANSI 16.5 FOR CLASS 150, THE THERMOWELL SHALL BE TESTED AT 1.5 TIMES THE APPLICABLE NON-SHOCK WORKING PRESSURE AT AMBIENT TEMPERATURE.

FIGURE 2-1 NOTES

SCREWED THERMOWELL





NOTE:
UNLESS OTHERWISE SPECIFIED ALL DIMENSIONS ARE IN MILLIMETRES.

FIGURE 2-2
FLANGED THERMOWELL WELDED CONSTRUCTION

APPLICATION:	FOR USE WITH RAISED FACE FLANGES TO ANSI B16.5 (INCH DIMENSIONS) OR BS1560 :PT.2, UP TO AND INCLUDING CLASS 3000																
MAXIMUM AND AND MINIMUM WORKING PRESSURE AND TEMPERATURE:	AS SPECIFIED BY ANSI B16.5 FOR THE CLASS OF FLANGE AND THE MATERIALS SPECIFIED ON THIS DRAWING.																
MATERIALS OF CONSTRUCTION:	BAR:	BS 1502 316S31 , BS1502 316S33 OR BS 1506 GRADE 845															
	FORGINGS:	BS 1503 316S31 , BS1503 316S33 OR ASTM A182 F316															
	PLATE:	BS 1501 PT.3 316S16 OR ASTM A240 316 .															
	NOTE THAT THE MATERIAL OF POCKET AND FLANGE SHALL HAVE THE SAME COMPOSITION																
SPECIAL MATERIALS:	THE USE OF MATERIALS OTHER THAN THOSE SPECIFIED ON THIS DRAWING SHALL BE SUBJECT TO APPROVAL BY BP.																
WELDING:	1. FULL PENETRATION WELD ONLY. 2. T.I.G. WELD SHALL BE EMPLOYED USING A HIGH FREQUENCY STARTING UNIT AND CRATER ELIMATING DEVICE.. 3. WELD MATERIALS SHALL BE OF SAME COMPOSITION AS FLANGE AND POCKET. 4. BACKFACE OF WELD TO BE INERT GAS PURGED. 5. FINISHED WELD TO BE DYE PENETRANT TESTED.																
BORE:	BORING SHALL BE CARRIED OUT ON A GUN-DRILLING MACHINE TO ENSURE STRAIGHTNESS AND GOOD FINISH. FOR THERMOCOUPLES & RESISTANCE ELEMENTS, DIMENSIONS SHALL BE IN ACCORDANCE WITH THOSE LISTED IN THE FOLLOWING TABLE FOR ELEMENT DIA. G. FOR FILLED SYSTEMS , EG. MERCURY IN STEEL, THE BORE SHALL SUIT VENDOR'S EQUIPMENT. TYPICAL DIMENSIONS ARE SHOWN IN THE FOLLOWING TABLE. FOR INTERMEDIATE SIZES, DIMENSIONS SHALL BE DETAILED. <table border="1"> <thead> <tr> <th>ELEMENT DIA.</th><th>6</th><th>TYPICAL, MAX. 13</th></tr> </thead> <tbody> <tr> <td>DIA. B</td><td>6.2 $\pm$ 0.1</td><td>13.2 $\pm$ 0.1</td></tr> <tr> <td>DIA. C</td><td>18</td><td>25</td></tr> <tr> <td>DIA. D</td><td>8</td><td>15</td></tr> <tr> <td>RAD. R</td><td>12 $\pm$ 2</td><td>17 $\pm$ 2</td></tr> </tbody> </table> ALL OTHER DIMENSIONS $\pm$0.5		ELEMENT DIA.	6	TYPICAL, MAX. 13	DIA. B	6.2 $\pm$ 0.1	13.2 $\pm$ 0.1	DIA. C	18	25	DIA. D	8	15	RAD. R	12 $\pm$ 2	17 $\pm$ 2
ELEMENT DIA.	6	TYPICAL, MAX. 13															
DIA. B	6.2 $\pm$ 0.1	13.2 $\pm$ 0.1															
DIA. C	18	25															
DIA. D	8	15															
RAD. R	12 $\pm$ 2	17 $\pm$ 2															
HEAT TREATMENT:	AFTER WELDING, THE COMPLETE ASSEMBLY SHALL BE SOLUTION ANNEALED AT 1050°C FOR 1 HOUR PER 25MM OF SECTION (MINIMUM PERIOD 1 HOUR) FOLLOWED BY WATER QUENCH.																
TEST PRESSURE:	FINISHED THERMOWELL SHALL BE SUBJECTED TO AN EXTERNAL TEST PRESSURE OF 1.5 TIMES THE MAXIMUM NON-SHOCK WORKING PRESSURE RATING FOR THE MATERIAL AND CLASS OF FLANGE AT AMBIENT TEMPERATURE.																

FIGURE 2-2 NOTES

FLANGED THERMOWELL WELDED CONSTRUCTION



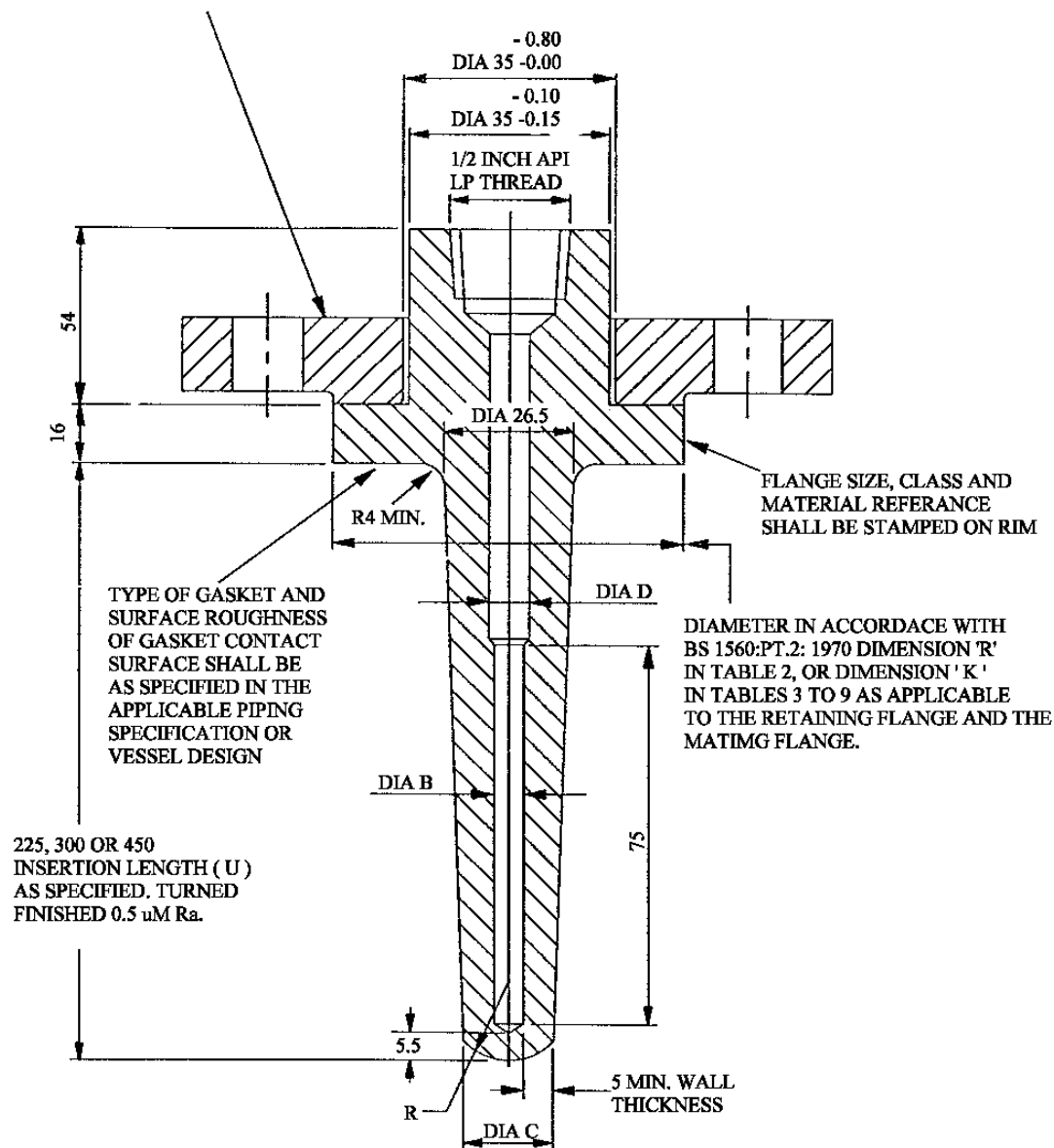
RETAINING FLANGE:

MACHINE FROM BLIND FLANGE TO ANSI B16.5 (INCH DIMENSIONS) OR BS 1650: PT.2. FLANGE CLASS AND DIAMETER OF FACING (RAISED FACE OR JOINT RING) SHALL BE IN ACCORDANCE WITH THE APPLICABLE PIPING SPECIFICATION OR VESSEL DESIGN.

SIZE :

NPS 1 1/2 (DN 40) FOR SCHEDULE 160 NOZZLES.

NPS 2 (DN 50) FOR HEAVIER WALL NOZZLES.



NOTE: UNLESS OTHERWISE SPECIFIED ALL DIMENSIONS ARE IN MILLIMETRES.

FIGURE 2-3

FLANGED THERMOWELL WITH RETAINING FLANGE

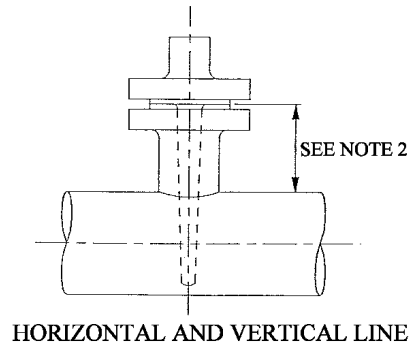


APPLICATION:	FOR USE WITH RAISED FACE OR SOLID METAL RING-JOINT FLANGES TO ANSI B16.5 (INCH DIMENSIONS) OR BS1560 :PT.2, UP TO AND INCLUDING CLASS 2500																
MAXIMUM WORKING PRESSURE AND TEMPERATURE:	AS SPECIFIED BY ANSI B16.5 FOR THE MATERIAL AND CLASS OF THE RETAINING FLANGE.																
MINIMUM WORKING TEMPERATURE:	MINUS 200°C																
CONSTRUCTION:POCKET:	FORGED AS A SINGLE PIECE																
	RETAINING FLANGE	IN ACCORDANCE WITH ANSI B16.5 OR BS1560 : PT.2.															
MATERIALS OF CONSTRUCTION:POCKET:	BS 1503 316S31 , BS 1503 316S33 , OR ASTM A182 F316																
CONSTRUCTION:RETAINING FLANGE:	IN ACCORDANCE WITH THE APPLICABLE PIPING SPECIFICATION OR VESSEL DESIGN.																
SPECIAL MATERIALS:	THE USE OF MATERIALS OTHER THAN THOSE SPECIFIED ON THIS DRAWING SHALL BE SUBJECT TO APPROVAL BY BP.																
BORE:	BORING SHALL BE CARRIED OUT ON A GUN-DRILLING MACHINE TO ENSURE STRAIGHTNESS AND GOOD FINISH.																
	FOR THERMOCOUPLES & RESISTANCE ELEMENTS, DIMENSIONS SHALL BE IN ACCORDANCE WITH THOSE LISTED IN THE FOLLOWING TABLE FOR ELEMENT DIA. 6.																
	FOR FILLED SYSTEMS , EG. MERCURY IN STEEL, THE BORE SHALL SUIT VENDOR'S EQUIPMENT. TYPICAL DIMENSIONS ARE SHOWN IN THE FOLLOWING TABLE.																
	FOR INTERMEDIATE SIZES, DIMENSIONS SHALL BE DETAILED.																
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DIA. D	8	15															
RAD. R	12 $\pm$ 2	17 $\pm$ 2															
	ALL OTHER DIMENSIONS $\pm$ 0.5																
HEAT TREATMENT:	FORGING SHALL BE SOLUTION ANNEALED AT 1050°C FOR 1HOUR PER 25MM OF SECTION (MINIMUM PERIOD 1 HOUR), FOLLOWED BY WATER QUENCH. NO HEAT TREATMENT REQUIRED AFTER MACHINING.																
TEST PRESSURE:	FINISHED THERMOWELL SHALL BE SUBJECTED TO AN EXTERNAL TEST PRESSURE OF 1.5 TIMES THE MAXIMUM NON-SHOCK WORKING PRESSURE RATING FOR THE MATERIAL AND CLASS OF FLANGE AT AMBIENT TEMPERATURE.																

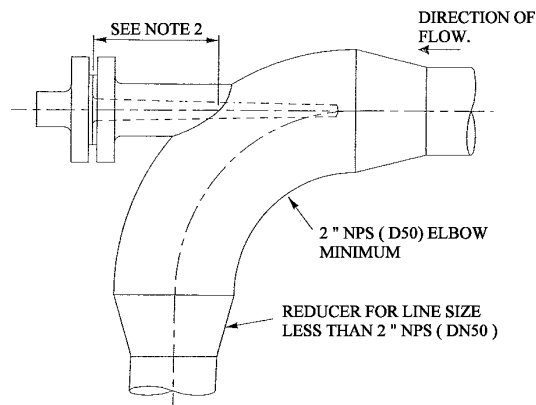
FIGURE 2-3 NOTES

FLANGED THERMOWELL WITH RETAINING FLANGE

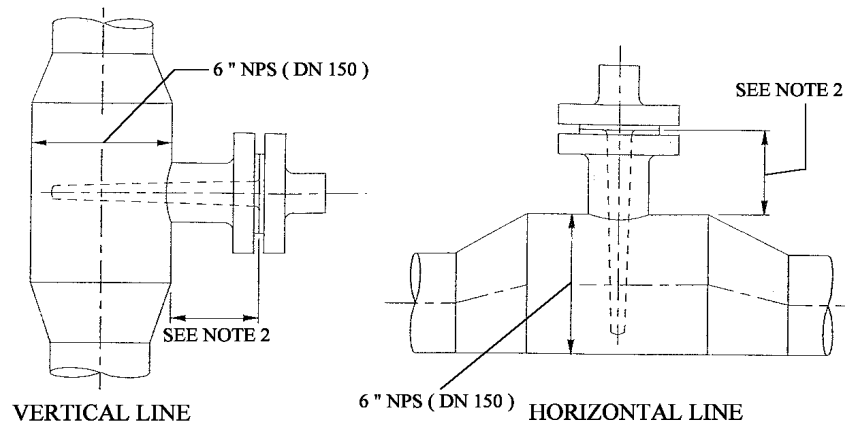




DETAIL A: INSTALLATION FOR LINE SIZE 6" NPS (DN 150) AND ABOVE



DETAIL B: PREFERRED INSTALLATION LINE SIZE LESS THAN 6" NPS (DN 150)



DETAIL C: NON-PREFERRED INSTALLATIONS . LINE SIZE LESS THAN 6" NPS (DN 150)

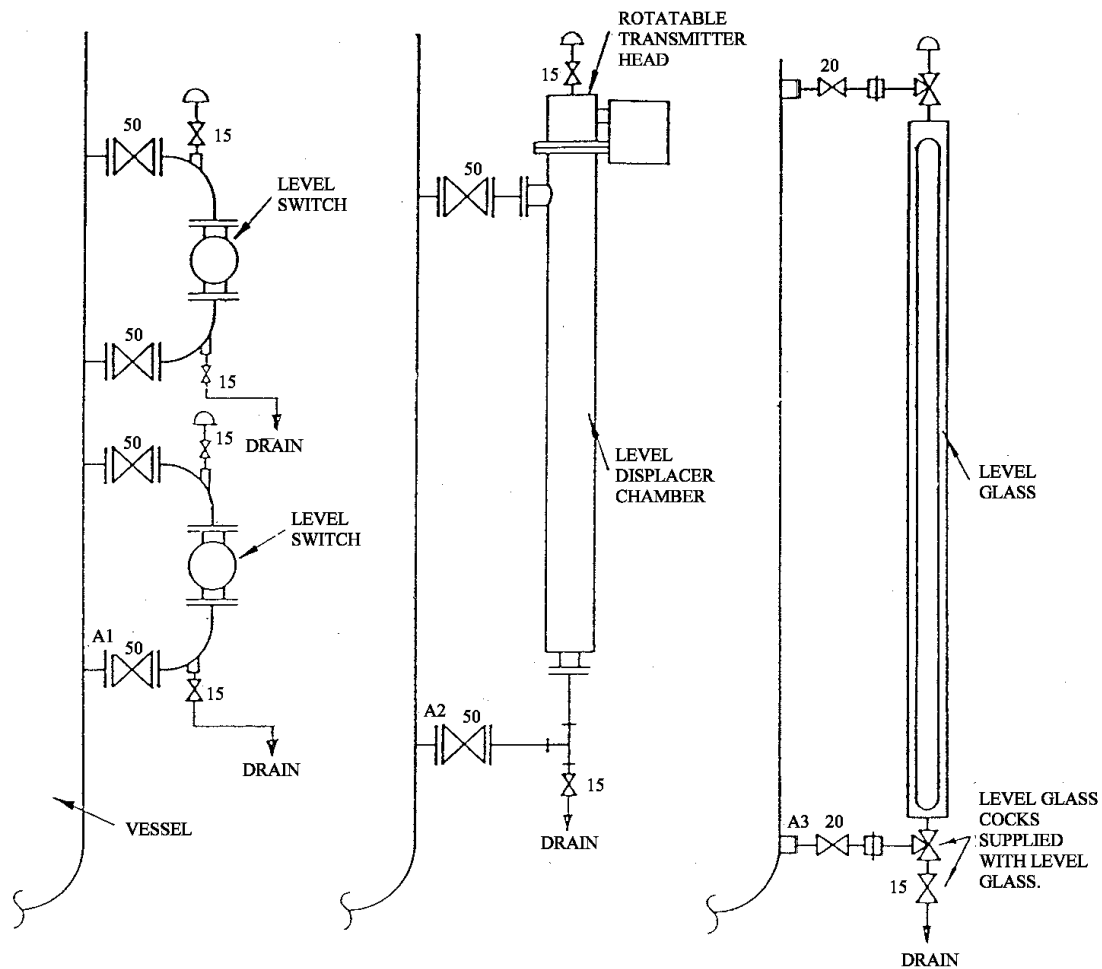
NOTES:

1. NOZZLE CONNECTIONS AND FITTINGS TO CONFORM WITH LINE SPEC. FOR UNSUPPORTED BRANCHES. (SEE BP GS142-6).
2. BRANCH LENGTH 125MM MINIMUM OR AS NECESSARY OR FLANGE TO CLEAR LAGGING.
3. THERMOWELL LENGTH 225MM (MINIMUM), 300MM OR 450MM TO SUIT LINE SIZE, APPLICATION AND NOZZLE EXTENSION FOR LAGGING.
4. SEE FIGURES 2.2/2.3 FOR FLANGED THERMOWELL DETAILS.

FIGURE 2-4

THERMOWELL INSTALLATION

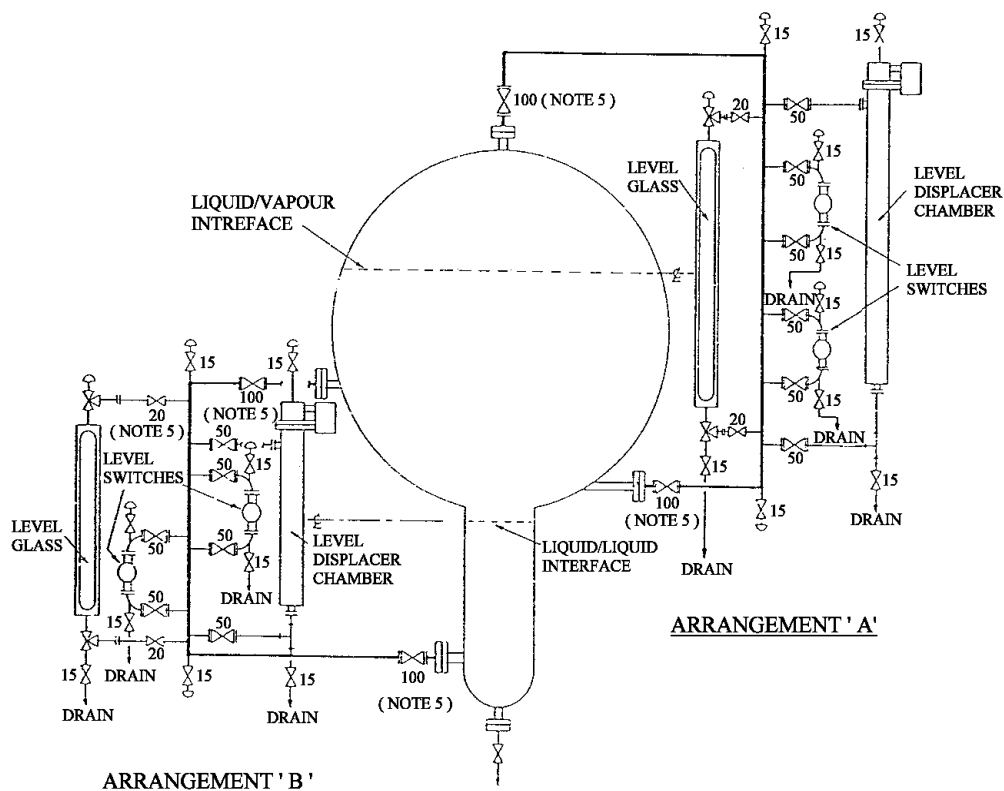




NOTES:

THIS DRAWING TO BE READ IN CONJUNCTION WITH NOTES DETAILED ON FIGURE 4.2.

FIGURE 4-1
LEVEL INSTRUMENTS DIRECT TO VESSEL



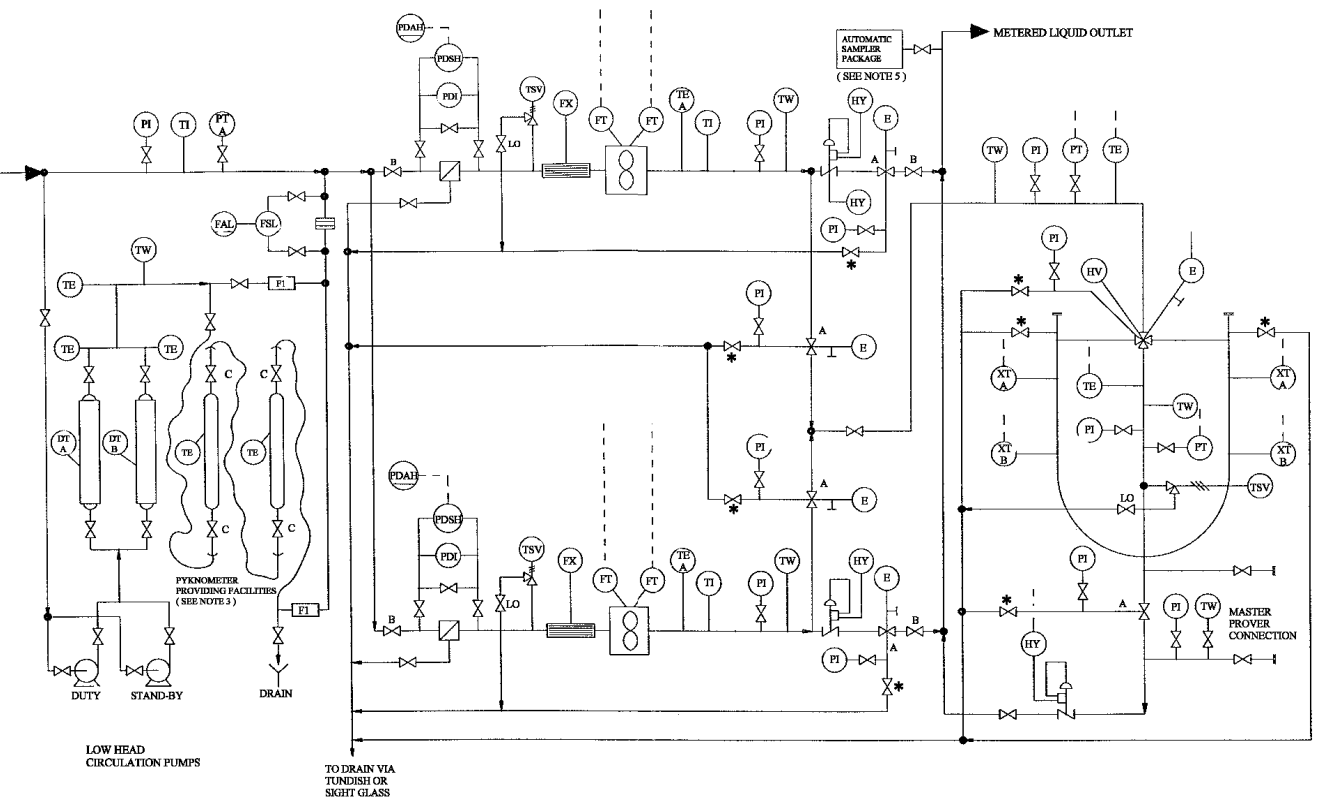
NOTES:

1. GAUGE GLASS(ES) SHALL COVER THE FULL WORKING RANGE OF VESSEL AND OTHER LEVEL INSTRUMENTATION.
2. LEVEL TRANSMITTER INSTRUMENT RANGE SHALL COVER THE OPERATING LEVELS OF ASSOCIATED LEVEL SWITCHES.
3. TWO STANDPIPE ARRANGEMENTS SHALL BE PROVIDED FOR VESSELS ON THREE PHASE SERVICE.
4. THE LOWER CONNECTION TO VESSEL SHALL NOT BE FROM THE BOTTOM OF THE VESSEL OR FORM A "U" TRAP BETWEEN VESSEL CONNECTION AND INSTRUMENT DEVIATION FROM THIS WILL ONLY BE PERMITTED WHERE NO PRACTICAL ALTERNATIVE IS AVAILABLE AND EACH APPLICATION SHALL BE AGREED WITH BP.
5. FULL BORE BLOCK VALVES SHALL BE PROVIDED AT CONNECTION OF STANDPIPES TO VESSELS ON SERVICES WHERE BLOCKAGE IS POSSIBLE SUCH AS WAX FORMATION OR SOLID DEPOSITION. THESE VALVES SHALL BE LOCKED OPEN DURING NORMAL OPERATION.
6. EACH INSTRUMENT CONNECTION TO THE VESSEL OR STANDPIPE SHALL BE PROVIDED WITH FULL BORE ISOLATING BLOCK VALVES WHICH CONFORM TO VESSEL SPECIFICATION.
7. THE DRAIN VALVE AT THE BOTTOM OF DISPLACERS SHALL BE FULL BORE AND MOUNTED IN VERTICAL LINE WITH THE DISPLACER.
8. A UNION COUPLING SHALL BE PROVIDED IN ALL DRAIN LINES IMMEDIATELY BELOW THE DRAIN VALVE WHERE NO ALTERNATIVE BREAK POINT IS AVAILABLE (EG. FLANGE).
9. Baffles SHALL BE PROVIDED TO SHIELD CONNECTIONS WHERE THERE IS THE POSSIBILITY OF IMPINGEMENT OF LIQUIDS OR GASES ON INSTRUMENTS.
10. DISPLACER CHAMBERS CONNECTED TO VESSELS EMPLOYING STEAM AS A STRIPPING MEDIUM SHALL BE PROVIDED WITH A GAS PURGE INTO THE VAPOUR CONNECTION.
11. DISPLACER CHAMBERS CONNECTED TO VESSELS CONTAINING SLURRIES AND HIGHLY VISCOUS LIQUIDS SHALL BE PROVIDED WITH A LIQUID PURGE INTO THE LIQUID CONNECTION.
12. GAUGE GLASSES SHALL BE LOCATED SO THAT THE LEVELS ARE VISIBLE FROM GRADE OR PERMANENT PLATFORM EXCEPT WHERE OTHERWISE AGREED WITH BP (EG. VERY LONG GAUGE GLASSES).
13. ALL PIPING AND FITTINGS SHALL COMPLY WITH VESSEL SPECIFICATION.

FIGURE 4-2

LEVEL INSTRUMENTS ON STANDPIPE

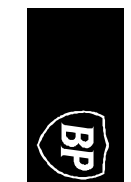




LEGEND
 * INDICATES LOCKABLE VALVES
 A DOUBLE BLOCK & BLEED
 B ISOLATION VALVES
 C PLUG VALVE

FIGURE 5-1

TYPICAL CLASS 1 LIQUID METERING SYSTEM



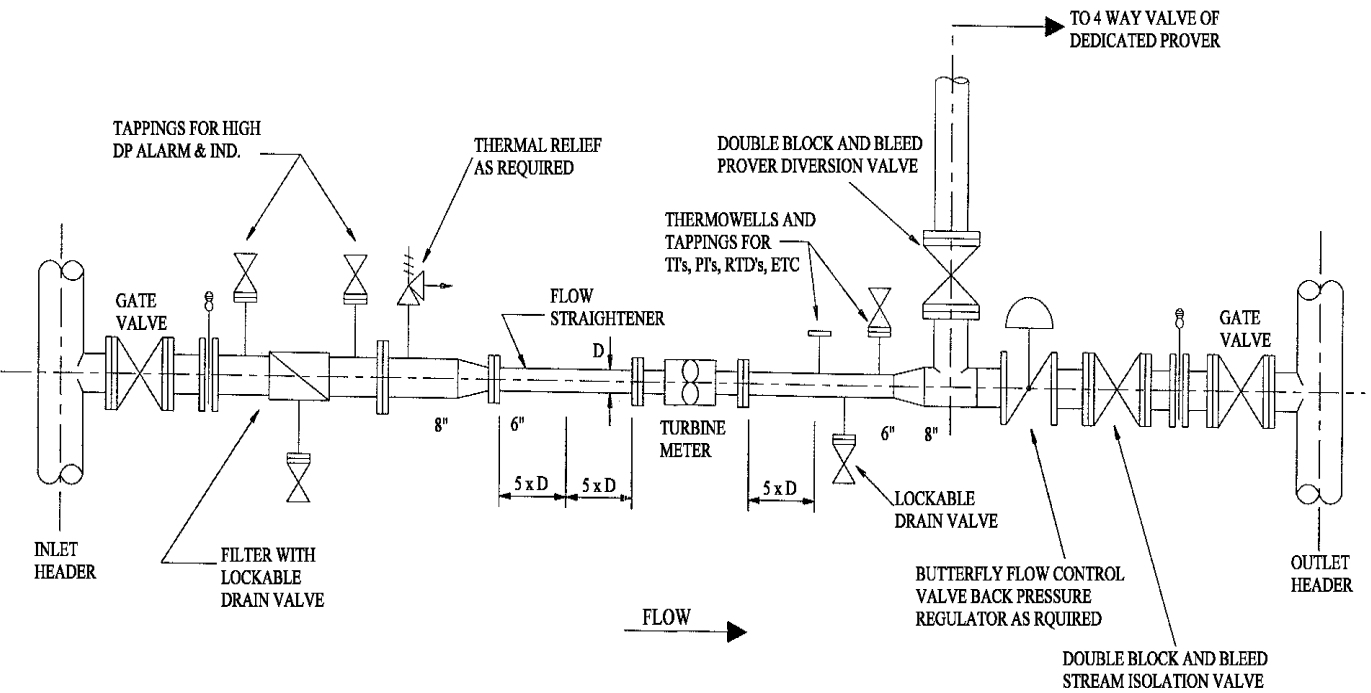
NOTES:

1. DENSITY LOOP TYPICAL FOR A MASS MEASUREMENT SYSTEM
2. VENT & DRAIN VALVES, P I ETC ON PYKNOMETER HOSES NOT SHOWN FOR SIMPLICITY.
3. PYKNOMETERS MAY BE REPLACED BY A SUITABLE TRANSFER STANDARD.
4. IF A WELL MIXED HOMOGENEOUS SAMPLE FOR DENSITY TRANSDUCERS CANNOT BE GUARANTEED, RELOCATE SAMPLE LOOP TO DOWNSTREAM HEADER.
5. THE AUTOMATIC SAMPLE PROBE MAY BE INSTALLED EITHER UPSTREAM OR DOWNSTREAM OF THE METERING SYSTEM AT A LOCATION WHERE FLOW IS WELL MIXED.

FIGURE 5-1 NOTES

TYPICAL CLASS 1 LIQUID METERING SYSTEM

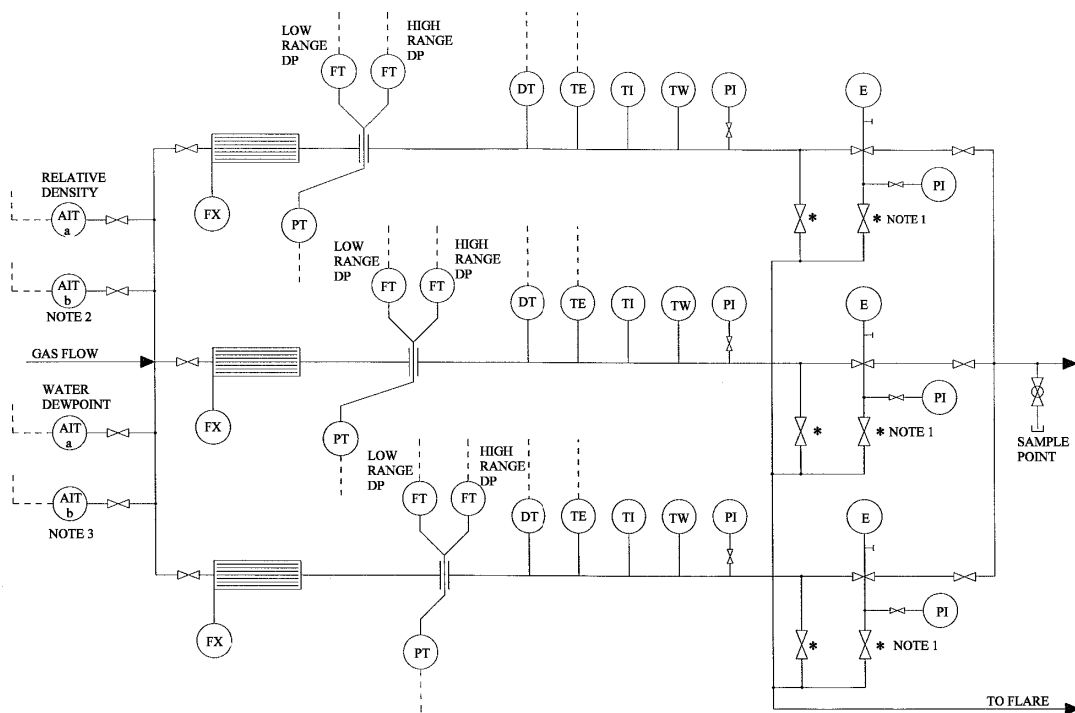




NOTE:
1. FOR SOME APPLICATIONS SITE OPERATOR MAY REQUIRE DOUBLE BLOCK AND BLEED ISOLATION UPSTREAM AND DOWNSTREAM OF METER RUN.

FIGURE 5-2

TYPICAL LIQUID METERING RUN

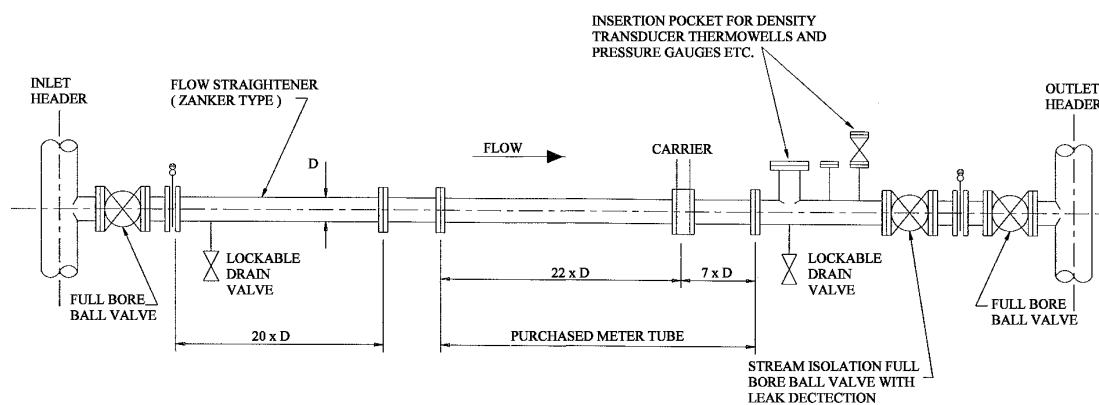


NOTES:

1. LOCKABLE VALVES.
2. OPTIONAL, DUPLICATE AS REQUIRED.
3. OPTIONAL, DUPLICATE, TRIPLICATE AS REQUIRED.

FIGURE 5-3
TYPICAL CLASS 1 GAS METERING SYSTEM





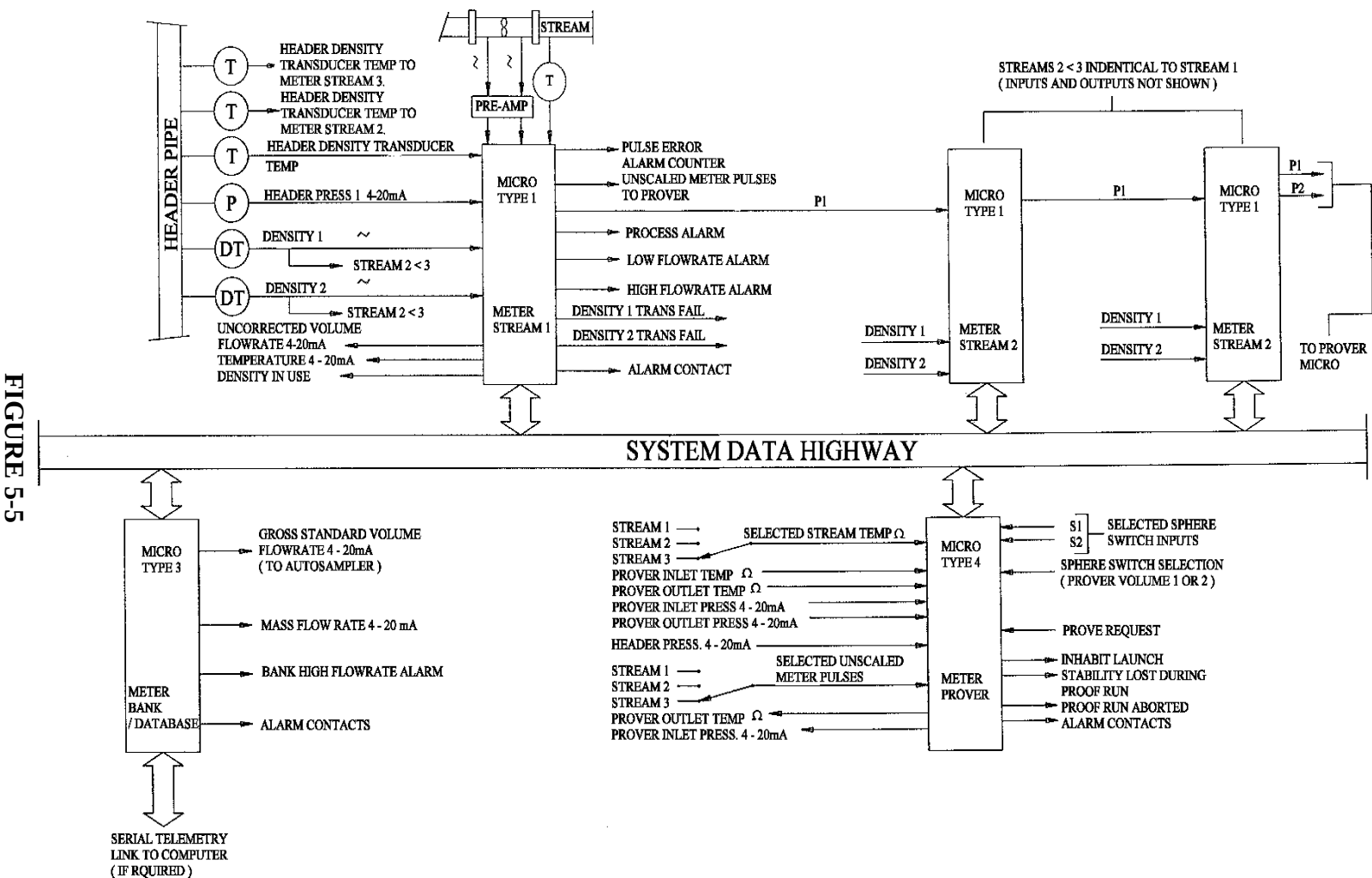
NOTES:

1. ORIFICE CARRIER MAY BE FLANGED.
2. METER TUBES AND CARRIER TO [ISO 5167](#) TOLERANCES.
3. FILTERS MAY BE REQUIRED UPSTREAM OF EACH METER RUN FOR SOME APPLICATIONS.
4. FOR SOME APPLICATIONS SITE OPERATOR MAY REQUIRE DOUBLE BLOCK AND BLEED ISOLATION UPSTREAM AND DOWNSTREAM OF METER RUN.

FIGURE 5-4
TYPICAL GAS METERING



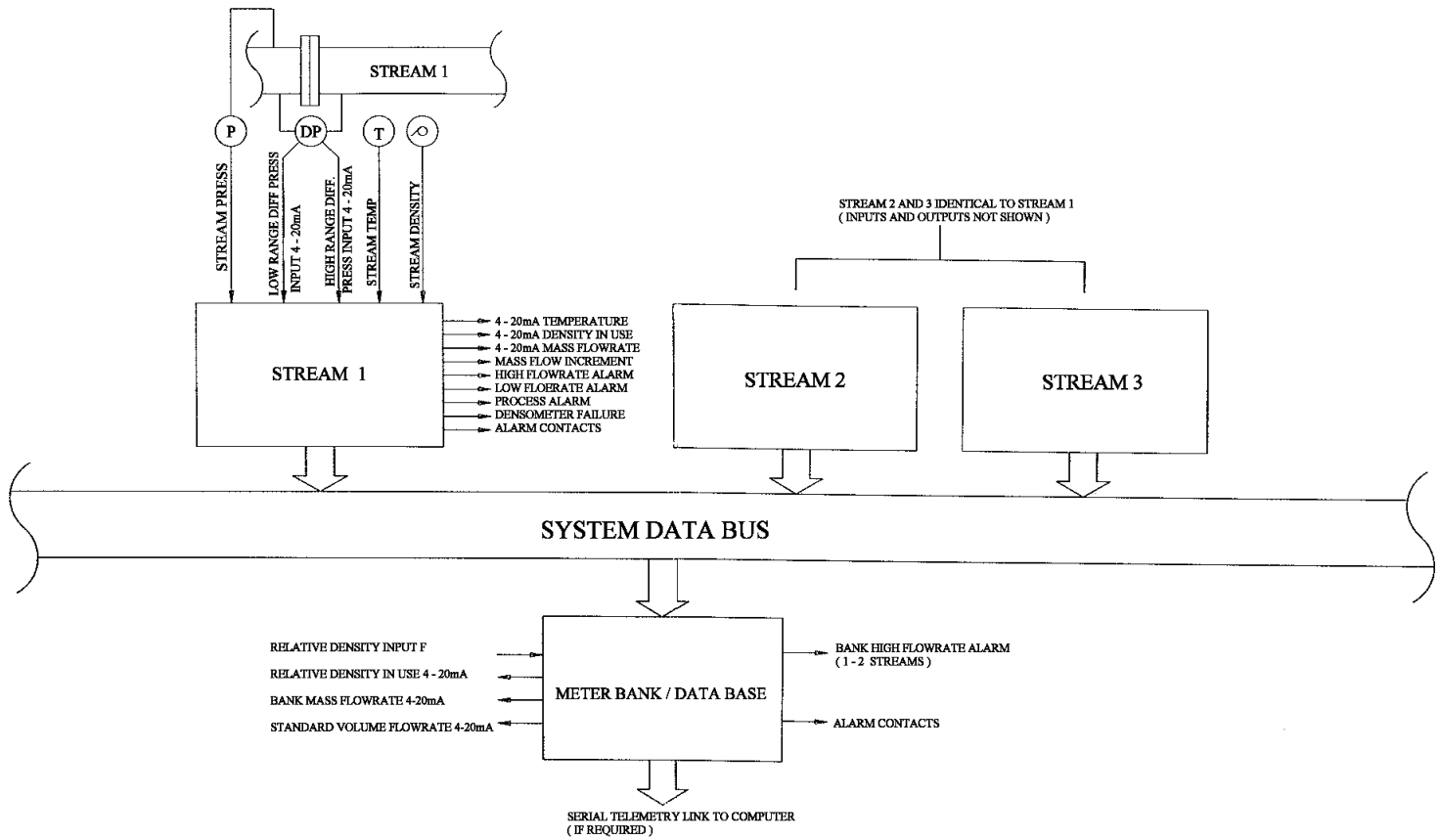
TYPICAL LIQUID MICROPROCESSOR BASED FLOW COMPUTER SYSTEM





TYPICAL GAS MICROPROCESSOR BASED FLOW COMPUTER SYSTEM

FIGURE 5-6



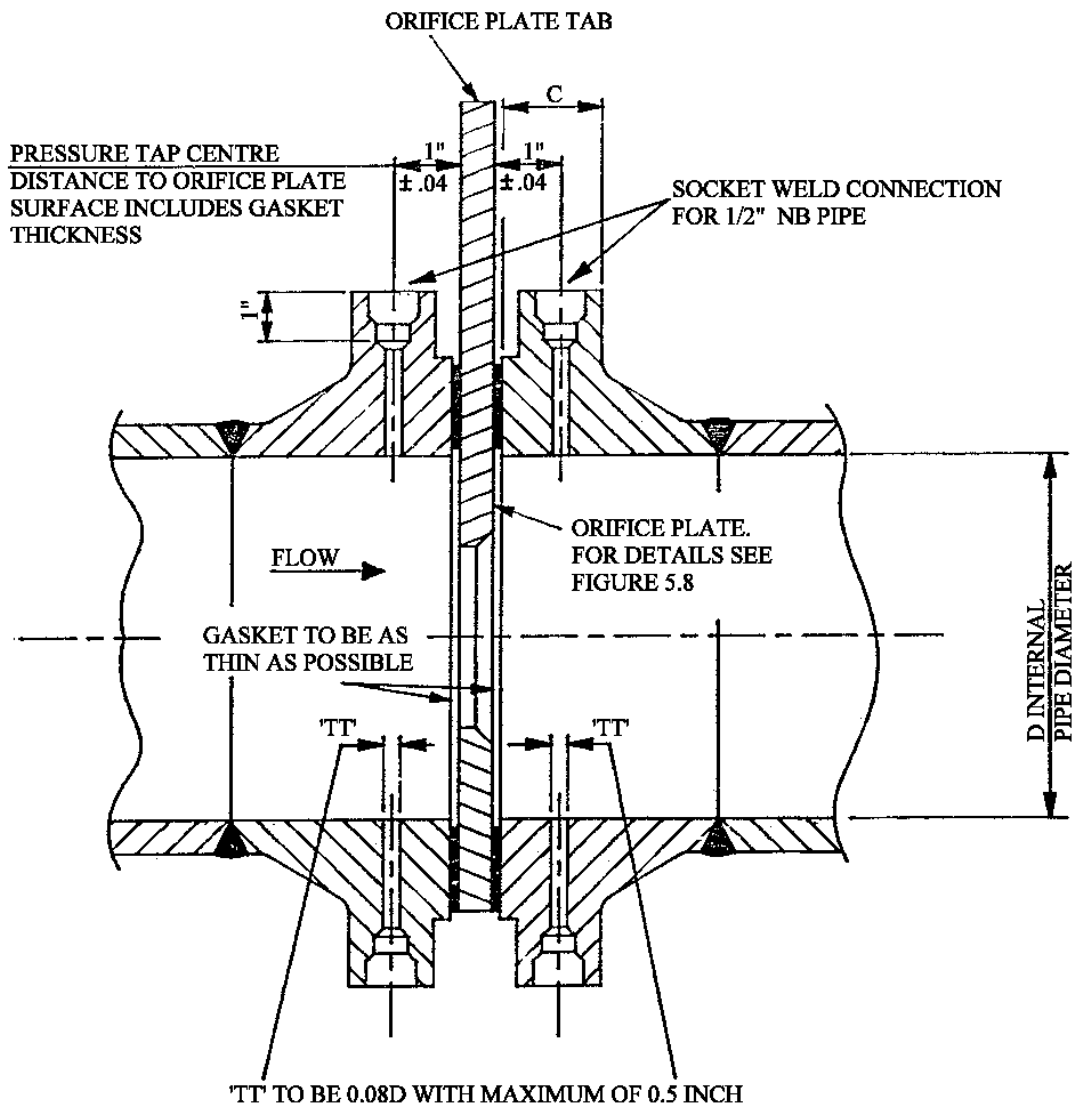


FIGURE 5-7

DETAIL OF BP STANDARDS ORIFICE FLANGES



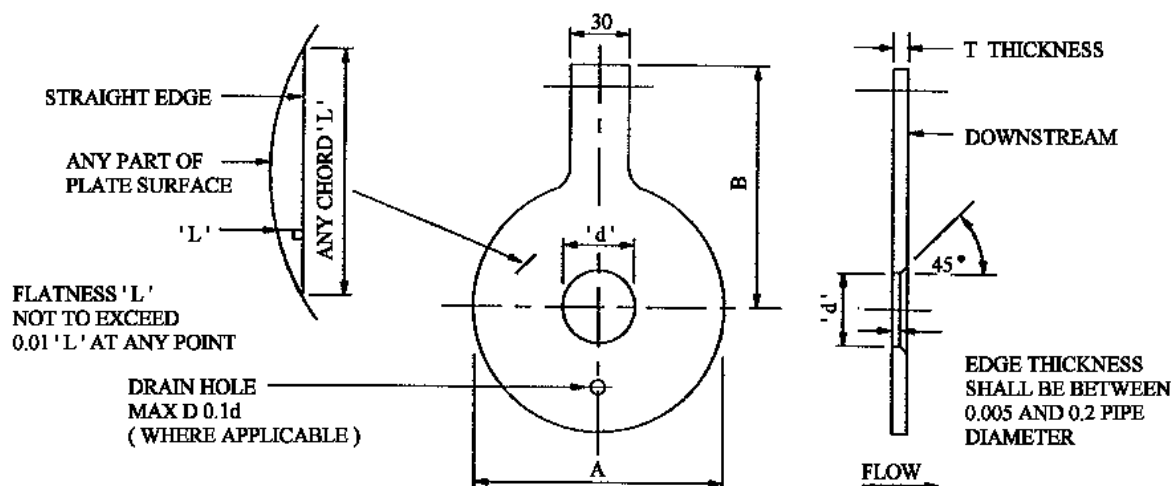
NOTES:

1. FOR USE ON 2NPS MINIMUM AND GENERAL SERVICES FROM CLASS 300 TO CLASS 900. FOR SERVICES BELOW CLASS 300 USE CLASS 300 FLANGES.
2. FOR RING TYPE JOINTS, SERVICES BELOW 2NPS AND HYDROGEN CLASS 900 SERVICE, REFER TO BP STD. DRAWING S1967. ANY OTHER DESIGN AND NOT REQUIREMENTS FOR SPECIAL SERVICES TO BE SPECIFIED BY BP.
3. FLANGE CONNECTIONS TO BE THREADED, SEAL, BUTT OR SOCKET WELDED AS SPECIFIED BY THE PURCHASER.
4. ORIFICE FLANGES SHALL COMPLY WITH LINE SPECIFICATION.
5. FLANGES SHALL BE IN ACCORDANCE WITH ANSI B16.36.
6. ALL FLANGES SHALL BE OF WELD NECK TYPE.
7. INNER SURFACES AT WELDS SHALL BE GROUND TO REMOVE ALL BURRS AND TO CONFORM TO [ISO 5167](#) SECTION 6.5 1.2
8. SPREADER BOLTS SHALL BE PROVIDED IN FLANGES.
9. FLANGE AND PIPE SHALL BE CONCENTRIC ORIFICE AND PIPE SHALL BE CONCENTRIC TO ISO 5167 SECTION 6.5.3.
10. INSIDE BORE OF PIPE ONE DIAMETER UP STREAM AND ONE DIAMETER DOWNSTREAM SHALL BE RECORDED. FOR FISCAL MEASUREMENT, RECORD AS SPECIFIED IN [ISO 5167](#) SECTION 6.1.5 AND 6.5.1.5.
11. UNUSED TAPPINGS SHALL BE PLUGGED AND WELDED.
12. THE INTERNAL DIAMETER OF GASKETS SHALL BE BETWEEN PIPE INTERNAL DIAMETER AND 1.03 X PIPE INTERNAL DIAMETER.
13. SURFACE FINISH TO COMPLY WITH BP [GS 142.12](#).
14. ALL OTHER TOLERANCES SHALL BE IN ACCORDANCE WITH ISO 5167.
15. FOR USE WITH CLASS 2 OR 3 METERING APPLICATIONS ONLY.

FIGURE 5-7 NOTES

DETAIL OF BP STANDARDS ORIFICE FLANGES





SIZE OF PIPE ¹		ANSI B16.3						
NPS (INCHES)	DN	T	CLASS 150		CLASS 300		CLASS 600	
			A	B	A	B	A	B
1	25	2.5	64	100	70	115	70	115
1 ½	40	2.5	82	115	90	130	92	130
2	50	2.5	100	130	105	135	108	135
2 ½	65	3	120	140	125	145	125	145
3	80	3	132	145	145	155	145	155
4	100	3	170	165	175	180	190	190
6	150	3	220	190	245	210	264	230
8	200	4	275	220	305	240	318	250
10	250	4	335	255	360	275	395	305
12	300	6	405	290	420	310	454	330
14	350	6	445	320	480	345	490	350
16	400	8	510	350	535	375	560	395
18	450	8	545	370	595	400	610	420
20	500	8	600	400	650	440	680	460
24	600	10	715	450	770	510	785	520

FIGURE 5-8
STANDARD ORIFICE PLATES

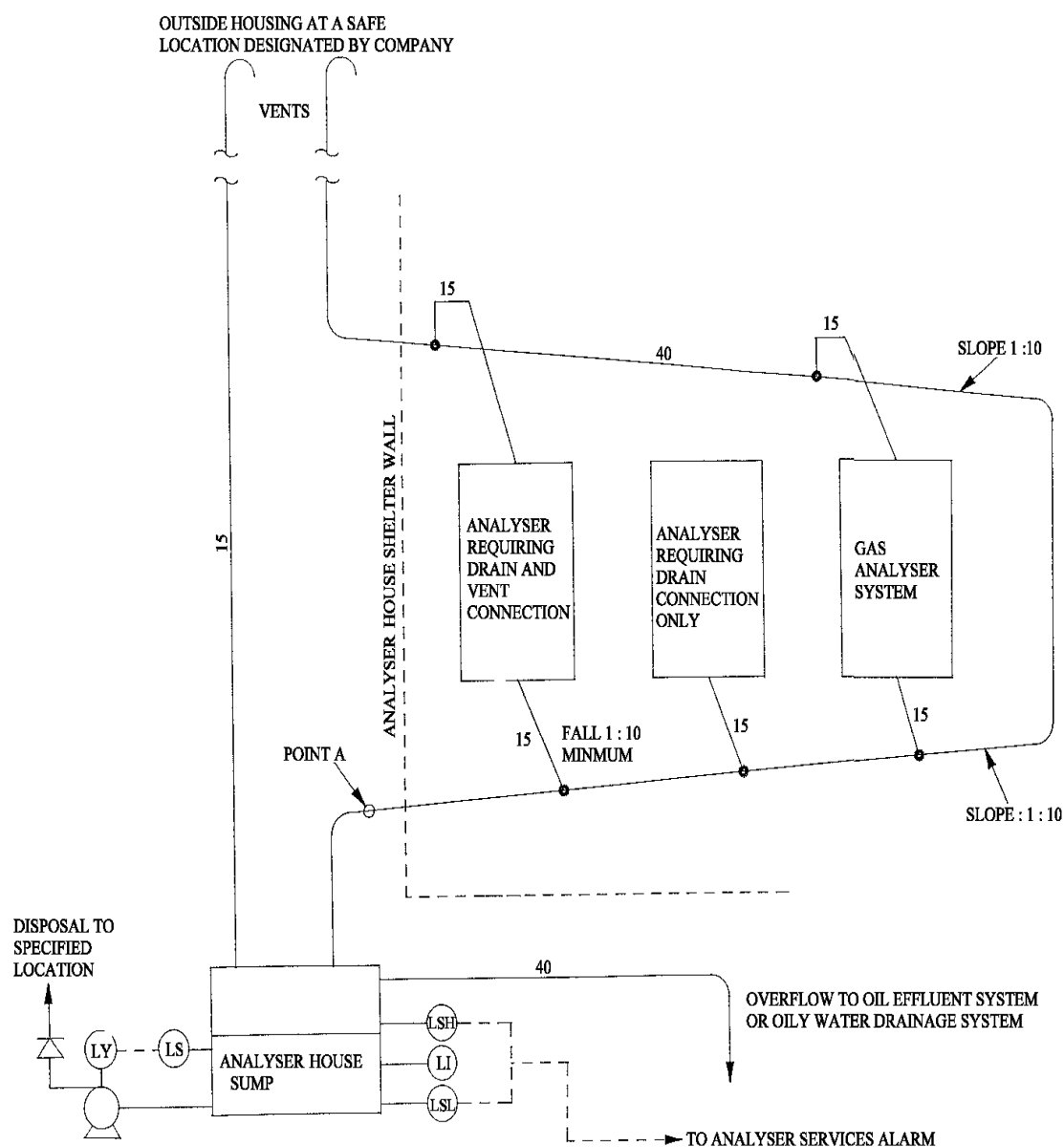
NOTES:

1. FOR DETAILS OF ORIFICE PLATE FLANGES SEE FIGURE 5.7.
2. THESE SIZES SHOULD BE AVOIDED WHENEVER POSSIBLE.
3. ORIFICE DIAMETER 'd' SHALL BE MACHINED OR GROUND TO WITHIN $\pm 0.025 \times$ THE SPECIFIED DIAMETER AND SHALL BE TRULY AT RIGHT ANGLES TO FACE OF PLATE. THE CIRCULARITY SHALL COMPLY WITH ISO 5167 SECTION 7.1.7.3.
4. DIMENSION 'd' SHALL BE DETERMINED BY CONDITIONS OF MEASUREMENT.
5. THE UPSTREAM EDGE OF THE ORIFICE MUST BE SHARP AND FREE FROM BURRS OR RIMS.
6. NO BURRS OR RIDGE MUST ENCROACH INTO THE BORE FROM THE DOWNSTREAM EDGE.
7. UPSTREAM FACE OF TAB SHALL BE STAMPED WITH ORIFICE DIAMETER, LINE SIZE, PLATE MATERIAL AND THE INSTRUMENT TAG NUMBER.
8. MATERIALS SHALL BE AS SPECIFIED IN ORDER.
9. UNLESS OTHERWISE SPECIFIED ON THIS DRAWING, ALL DETAIL SHALL BE IN ACCORDANCE WITH [ISO 5167](#).
10. SURFACE FINISH SHALL COMPLY WITH BP [GS 142-12](#).
11. PLATES TO BE INSPECTED TO ISO 5167 REQUIREMENTS SECTION 7.
12. THICKNESS 'T' TO BE 0.050.
13. USE OF DRAIN HOLE NOT ALLOWED FOR FISCAL MEASUREMENT. SHOULD BE USED ONLY FOR WET GAS SERVICE ON PLATES > 4NPS.
14. DRAIN HOLE CENTRE TO BE ON PCD OF D 0.15d.
15. ORIFICE PLATE TO BE CENTRED BETWEEN FLANGES IN ACCORDANCE WITH ISO 5167 SECTION 6.5.3.
16. OUTSIDE DIAMETER OF PLATE TO BE MACHINED, PROVIDING A UNIFORMLY CIRCULAR DISC TO A TOLERANCE OF + 0.02 INCHES. ALL OTHER TOLERANCES SHALL BE IN ACCORDANCE WITH [ISO 5167](#).
17. FOR SERVICES BELOW CLASS 300, USE CLASS 300 ORIFICE PLATE AND FLANGES.

FIGURE 5-8 NOTES

STANDARD ORIFICE PLATES





NOTES:

1. ALL PIPES TO BE CARBON STEEL
2. ALL PIPE SIZES ARE IN MILLIMETRES.
3. IF THERE IS NO ANALYSER HOUSE SUMP THE USED SAMPLE IS TO BE PIPED FROM POINT 'A' TO THE OIL EFFLUENT SYSTEM OR THE OILY WATER DRAINAGE SYSTEM.
4. FLAME TRAPS MAY BE REQUIRED IN VENT LINES.
5. DRAIN AND VENT CONNECTIONS TO BE PLUGGED WHEN AN ANALYSER IS REMOVED.
6. DRAIN AND VENT LINE TO BE AT ATMOSPHERIC PRESSURE.
7. ANALYSERS REQUIRING GAS VENTING SYSTEM (FIG.7.6) MAY BE CONNECTED.
8. PUM TOP STARTS WHEN LEVEL IS 200mm FROM AND STOPS 200mm ABOVE PUMP SUCTION OFFTAKE.
9. GAS OIL FLUSHING AND/OR HEAT TRACING TO BE PROVIDED AS NECESSARY WHEN HIGH VISCOSITY SAMPLE INVOLVED.

FIGURE 7-1

PRINCIPLE OF SAMPLE RECOVERY AND VENT SYSTEM FOR LIQUIDSTREAM ANALYSERS



NOTES:

1. ALL DIMENSIONS IN MILLIMETRES.
2. FULLY WELDED CONSTRUCTION.
3. ALL WELDS FINISHED FLUSH.
4. STRUCTURE TO COMPLY WITH BP [RP 4-2](#).
5. FABRICATION TO COMPLY WITH BP [GS 118-3](#).
6. PAINTING TO COMPLY WITH BP [GS 106-2](#).

NO OF BOTTLES	A
1	300
2	575
3	850
4	1125
5	1400
6	1675
7	1950
8	2225
9	2500
10	2775

FIGURE 7-2 NOTES
TYPICAL GAS BOTTLE RACK



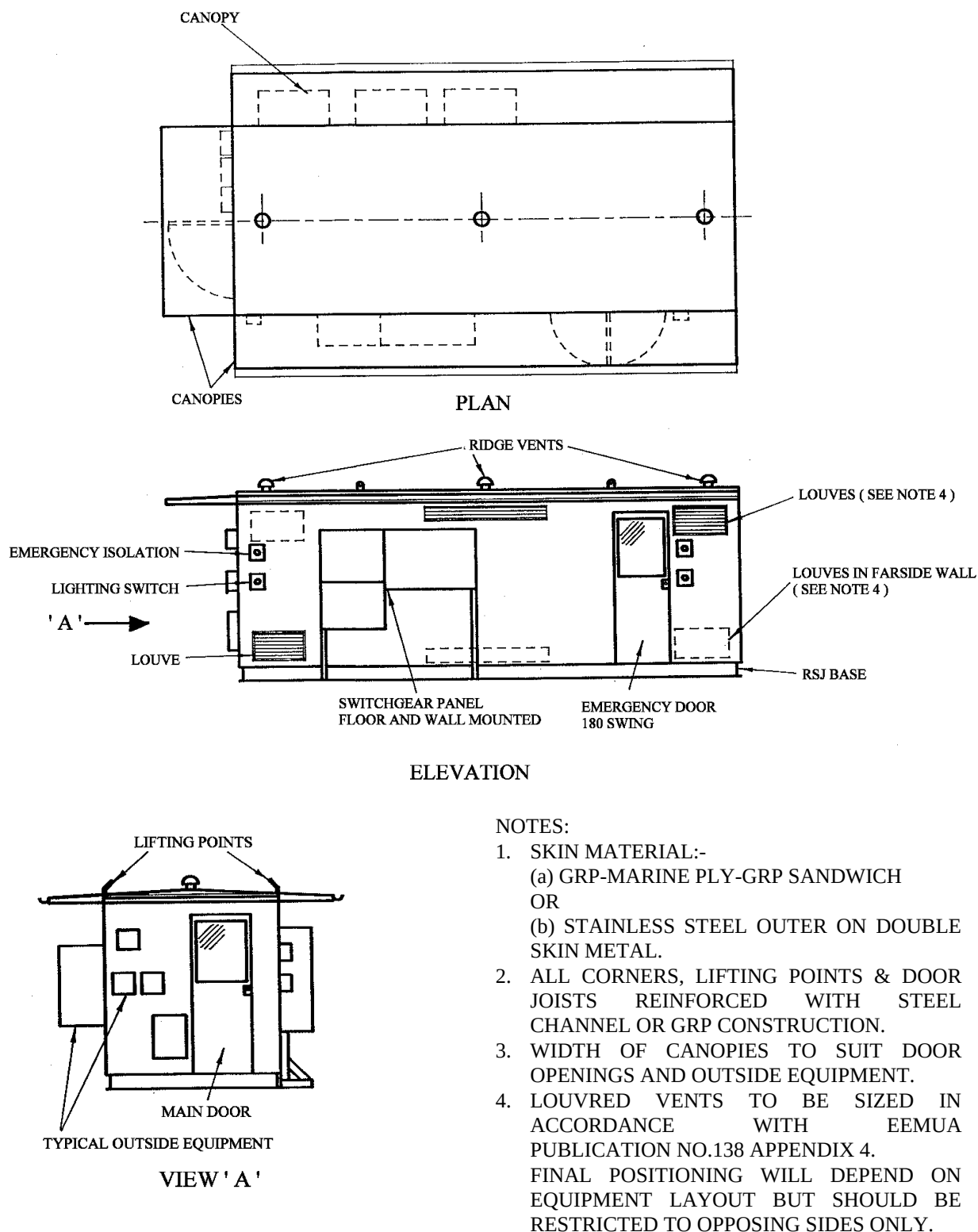
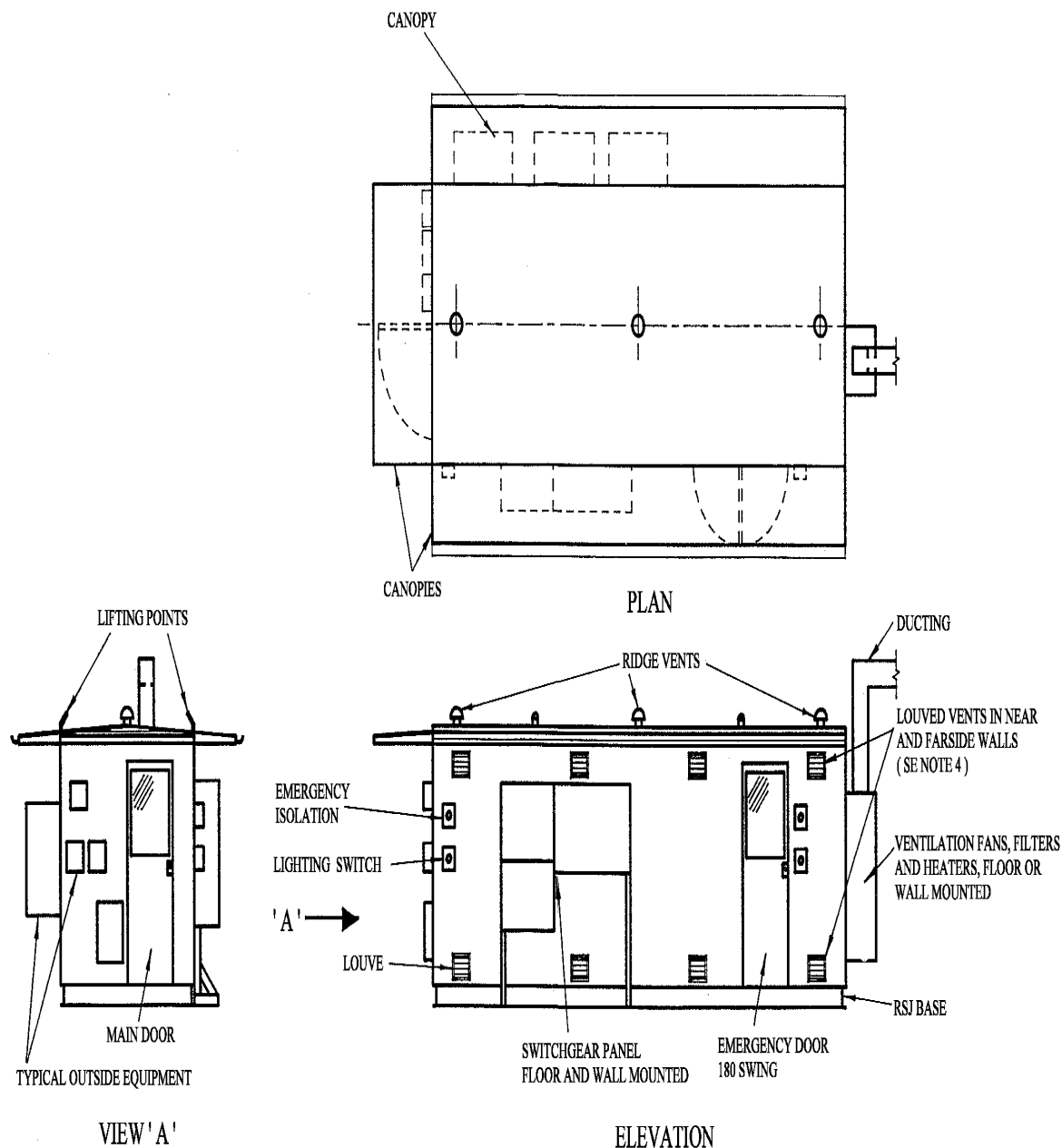


FIGURE 7-3

TYPICAL NATURALLY VENTED ANALYSER HOUSE

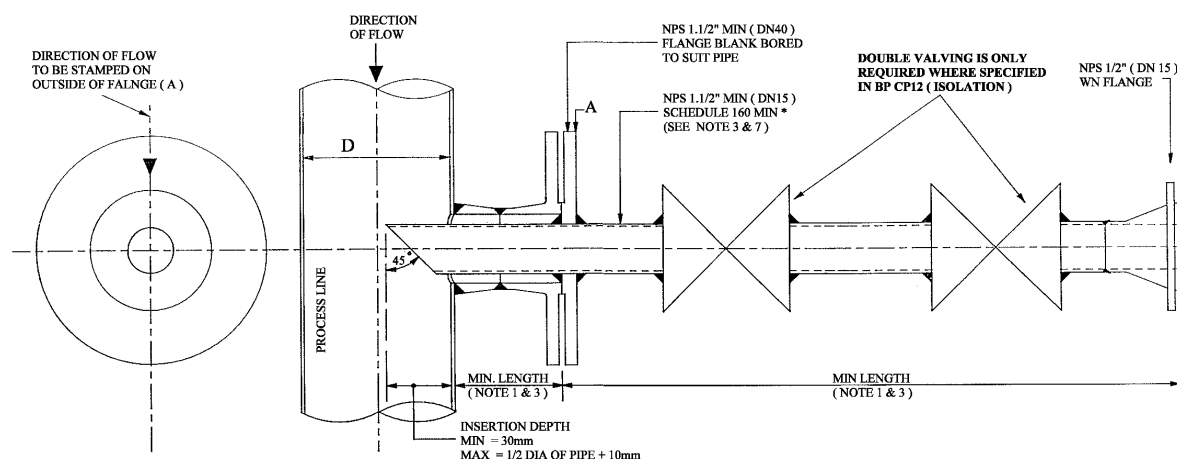


NOTES:

1. SKIN MATERIAL:-
 (a) GRP-MARINE PLY-GRP SANDWICH
 OR
 (b) STAINLESS STEEL OUTER ON DOUBLE SKIN METAL.
2. ALL CORNERS, LIFTING POINTS & DOOR JOISTS REINFORCED WITH STEEL CHANNEL OR GRP CONSTRUCTION.
3. WIDTH OF CANOPIES TO SUIT DOOR OPENINGS AND OUTSIDE EQUIPMENT.
4. LOUVRED VENTS ARE TO BE POSITIONED TO ENSURE EVEN DISTRIBUTION OF AIR FLOW. THE HOUSE PRESSURE IS TO BE CONTROLLED BY SOME OF THE VENTS BEING WEIGHTED. THE NUMBER AND DISTRIBUTION OF VENTS MUST ENSURE AT LEAST 50% ARE OPERATIONAL UNDER ALL WIND CONDITIONS.

FIGURE 7-4

TYPICAL FORCED VENTILATED ANALYSER HOUSE



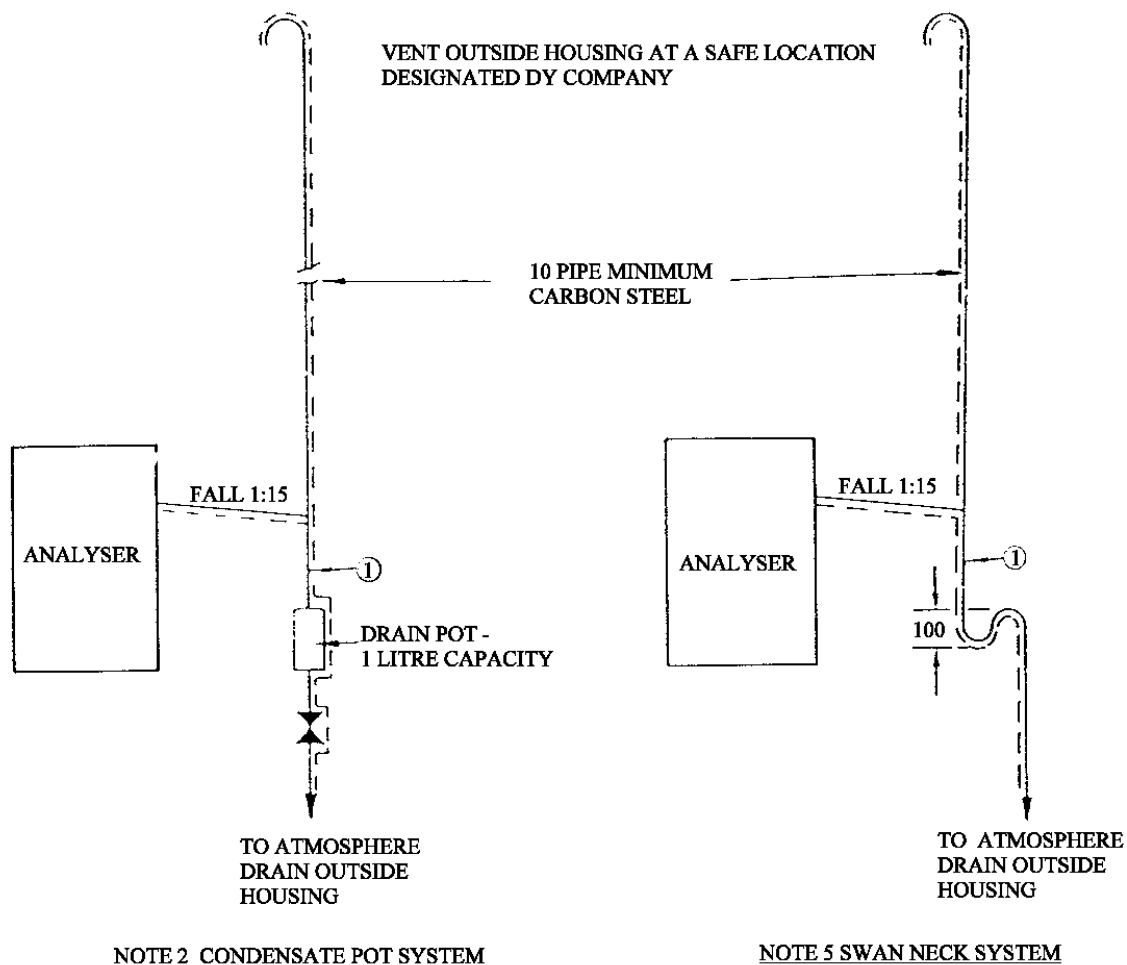
NOTES:

1. ALL MATERIAL, FLANGE TYPE, PIPE FITTINGS, VALVES, CLASS RATING, BRANCH CONNECTION DETAILS, INSTRUMENT CONNECTION, WELDING DETAILS AND HEAT TREATMENT SHALL COMPLY WITH LINE SPECIFICATION TO BP [RP 42-1](#) AND BP [GS 142-6](#),
 2. THE PROBE SHALL NOT BE INSTALLED IN THE BOTTOM OF PROCESS LINES TO AVOID DIRT/WATER ENTRAINMENT IN SAMPLE.
 3. THE CONTAINED VOLUME OF THE PROBE SHALL BE MINIMISED BY LIMITING THE DIMENSIONS AS GIVEN ABOVE.
- *WHEN THE LIQUID SAMPLE IS TO BE VAPOURISED, DOUBLE EXTRA STRONG PIPE AND REDUCED BORE VALVES SHALL BE USED.
4. THE FLANGE NUMBER AND TIP CHAMFER SHALL BE STAMPED WITH THE PROBE TAG ORIENTATION.
 5. SAMPLING ARRANGEMENTS FOR LINES BELOW 2" NPS (DN 50) SHALL BE SPECIFIED BY BP.
 6. THIS PROBE IS ONLY RECOMMENDED FOR SINGLE PHASE PROCESS SAMPLING. WHERE MULTIPHASE CONDITIONS CAN BE EXPECTED REFER TO BP.
 7. FOR FAST LOOP SERVICE, THE PROBE SIZE, AND IF NECESSARY BRANCH CONNECTION, MAY BE INCREASED TO MEET LOOP FLOW REQUIREMENTS.
 8. ALL PROBES TO BE HYDROSTATIC TESTED ON A TEST RIG.

FIGURE 7-5

TYPICAL INSTRUMENTATION SAMPLING OF SIZE NPS 2 AND ABOVE





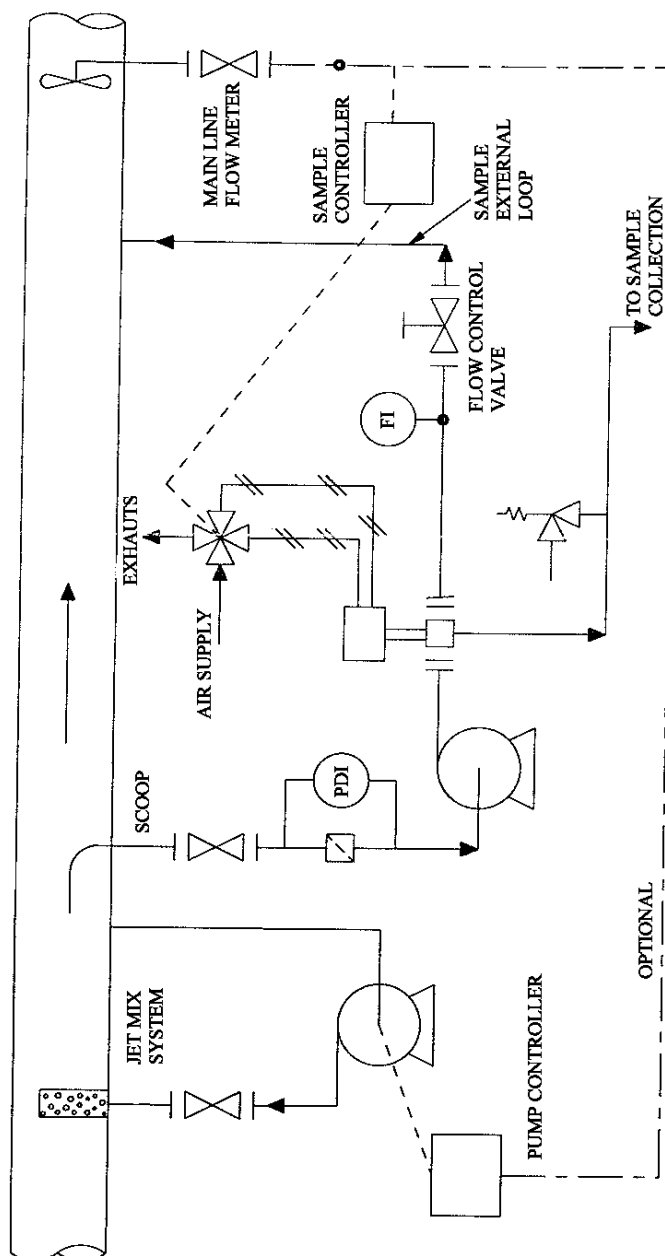
NOTES:

1. LINES WINTERISED BELOW THIS POINT. TRACING AND LAGGING ABOVE THIS POINT WHEN NECESSARY TO MAINTAIN GASEOUS COMPONENT ABOVE DEW POINT.
2. FOR USE ON SERVICES WHERE SAMPLE IS NORMALLY WHOLLY IN THE VAPOUR PHASE OR CAN BE EASILY MAINTAINED IN VAPOUR PHASE BY HEAT TRACING (EG. LPG) DRAIN POT PREVENTS ATMOSPHERIC WATER CONDENSATION ENTERING ANALYSER DURING SHUT-DOWN PERIOD.
3. FOR USE WHERE SAMPLE EFFLUENT IS TWO-PHASE (EG. GAS AND STEAM/WATER). SWAN-NECK ALLOWS CONDENSATE TO DRAIN. CONDENSATE QUANTITY AND HEAT TRACING MUST BE SO AS TO ALWAYS MAINTAIN WATER SEAL.
4. MANUFACTURERS SPECIFIED LIMITS FOR BACK-PRESSURE. WINDACE EFFECTS AND SEGREGATION OF VENTS MUST BE OBSERVED.

FIGURE 7-6

PRINCIPLE OF GAS VENTING SYSTEMS FOR ANALYSER INSTALLATIONS





MAIN COMPONENTS:-

JET MIX SYSTEM:

SAMPLER EXTERNAL:
LOOP:

PUMP WITH OPTIONAL STOP/START CONTROLLED FROM MAIN LINE FLOW.

SCOOP TUBE - EITHER 1" OR 1½ " DEPENDING ON LINE SIZE.

(LIVE LINE INSERTION POSSIBLE. COARSE STRAINER WITH D.P. MEASUREMENT.

CELL SAMPLER (OPERATION MAY BE HYDRAULIC)

SAMPLER CONTROLLER, CONTROL MAY BE FROM METER STATION FLOW COMPUTER.

SAMPLE COLLECTION SYSTEM WITH USER OPTIONS (eg. CAN WEIGH & CAN
CHANGEOVER)

MAIN LINE FLOW:

TRASH RESISTANT FLOWMETER (LIVE LINE INSERTION POSSIBLE) OR FROM
METERING SYSTEM.

FIGURE 8-1

RECOMMENDED SAMPLING SYSTEM SCHEMATIC

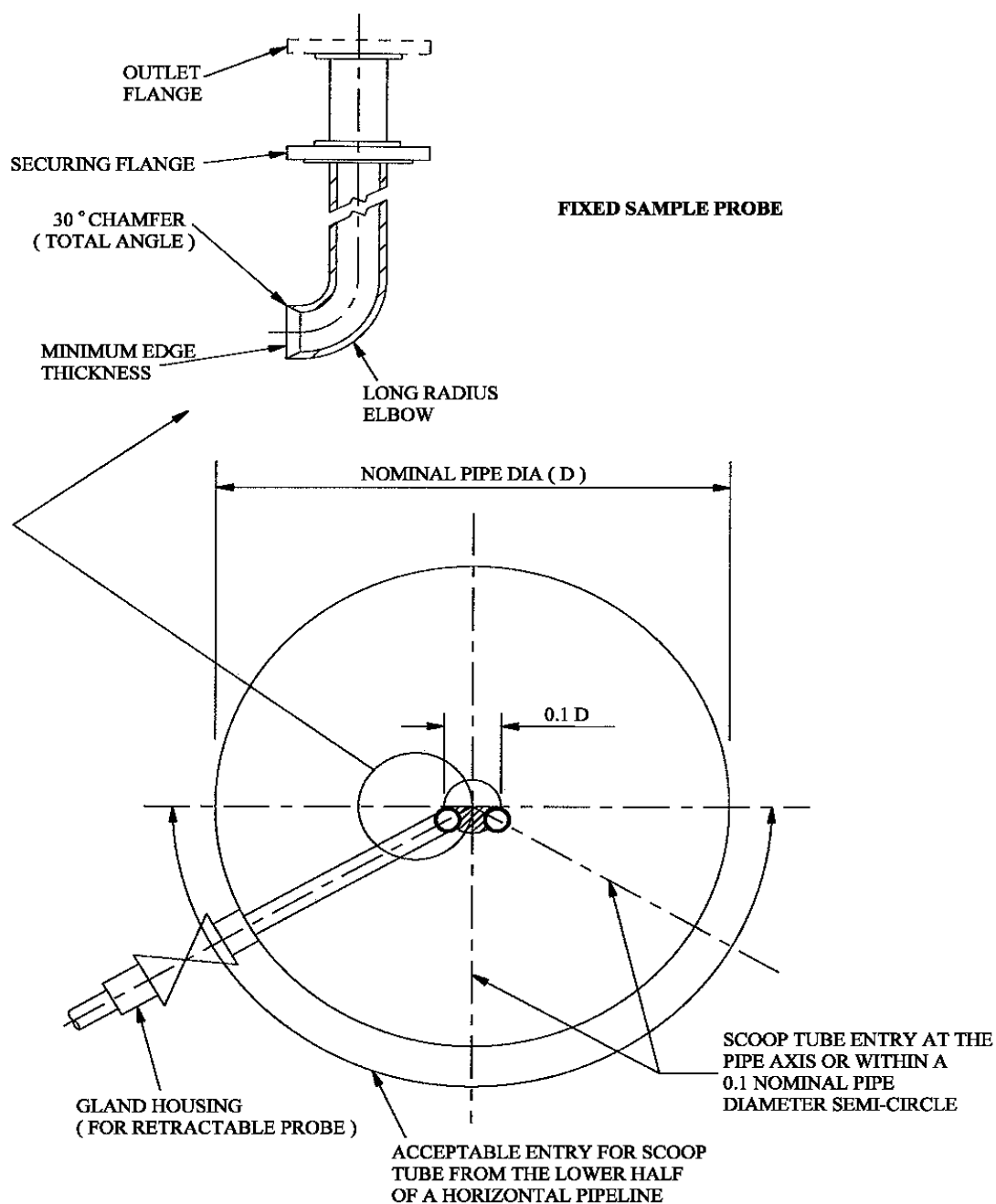


FIGURE 8-2

SCOOP TUBE ENTRY (HORIZONTAL LINE)

DEFINITIONS AND ABBREVIATIONS

Definitions

Standardised definitions may be found in the BP Group RPSEs Introductory Volume.

analysing time:	(a) for continuous analysers, the time taken to reach 95% of a step change, i.e. 3 time constants.
	(b) for cyclic analysers the time taken to complete each cycle.
analysis time lag:	the sum of the 'sample system lag' and the 'analysing time', i.e. the time between withdrawal of sample from the process and the analysis result.
bypass filter:	a filter in which only the analyser offtake passes through the filter medium. The fast loop passes through the filter housing, acting to scour the filter element giving a self cleaning effect.
closed cabinet:	a housing usually enclosing a single analyser with access by personnel remaining external to the housing.
contract:	the agreement or order between the purchaser and the vendor (however made) for the execution of the works including the conditions, specification and drawings (if any) annexed thereto and such schedules as are referred to therein.
Coriolis effect flowmeter:	a type of mass flowmeter, commonly referred to as a Coriolis effect flowmeter, in which is measured the degree of a twist of a tube due to reactionary forces created by mechanical acceleration of the mass flow within it.
cost of ownership:	the life cost of a system including initial supply contract value, installation cost, ongoing support costs (e.g. spares, maintenance and service charges).



Ex:	electrical apparatus protected to meet hazard classification in accordance with BS 5349.
external loop:	a pumped flow loop taking suction from the returning to the main oil line.
external loop sampler:	an automatic sampler located within the external loop. (Sometimes referred to as cell sampler).
fast loop:	a sample circulating system from the process to the process, with sample usually removed via a bypass filter within the loop.
house:	building that accommodates any number of analysers and allows complete entry of personnel.
housings:	a general term covering buildings, houses, cabinets and shelters.
homogeneity:	the degree of mixing of the non-miscible pipeline liquids. For crude oil and water the mixture is accepted as homogeneous if the ratio of the water concentration between the top and bottom of a horizontal pipeline is better than 0.9 over the specified range of main pipeline flow rates and water contents. For a vertical pipeline, the ratio is measured across a diameter inline with the last bend.
inline sampler:	an automatic sampler located within the main oil line.
jet mixing:	a technique using an external energy source to create homogeneous line conditions where a centrifugal pump taken suction from the main line and discharges back into the main line through jets specially designed and aligned to disperse and distribute the water.
lockable panel:	a closed structure for supporting equipment, e.g. cubicles, cabinets within a housing.
measuring element:	transducer or sensor which converts the measured property into a usable signal (usually



	electrical), e.g. moisture sensors, density transducers.
	Measuring elements can be mounted in-line or out-of-line via a sample system.
meter 'K' factor:	the calibrating constant of a pulse producing flowmeter, generally expressed in pulses per cubic metre.
on-line quality analyser:	applies to any analyser used for monitoring process variables on a continuous and unattended basis in the field. Both in-line and out-of-line (using a sample system) analysers are covered. Laboratory analysers are not in this category, nor are environmental monitors, i.e. fire and gas detectors.
open cabinet:	see definition for shelter.
overall time lag:	the sum of 'analysis time lag' and 'process lag'.
panel:	any structure for supporting equipment. May be free standing or fixed to a housing wall.
probe:	a device for inserting into the line for the purpose of extracting a sample for use with an out-of-line analyser.
process lag:	the sum of transmission, control element and process delays, i.e. the time between analyser output signal change and the resulting change in the process at the sampling point.
profile testing:	an experimental programme to examine the variation in the concentration of the property of interest (usually water content in oil) across the diameter of the pipeline.
pykonmeter:	a vessel of known weight and internal volume used in laboratories for determining liquid density.



sample:	the sample, ex fast loops or direct from process, after appropriate conditioning, e.g. filter, heating or cooling, etc.
sample system lag:	the time between withdrawal of sample from the process and its delivery to the analyser.
sampler controller:	the device that generates a signal to operate the sampler. This may be either on a time basis (time proportional) or after a set quantity of liquid has passed a particular point in the main oil line (flow proportional).
sample probe:	the suction probe at the inlet to the external loop.
shelter:	a housing with at least one side open offering only rudimentary protection from the elements. This can allow complete entry of personnel or not, depending on size and application.
smart transmitter:	a transmitter where the calibrated range may be changed on-line by remote electronic means.
static mixing:	a technique using the energy in the pipeline liquid to create homogeneous line conditions. A system of plates or bafflex divides and disperses the water. This method causes a permanent pressure drop within the main oil line.
systems vendor:	supplier of assembled systems comprising of own and/or other equipment manufacturer's products. In some cases the analyser vendor and the systems vendor is the same.
works:	all equipment to be provided and work to be carried out by the vendor under the contract.
Zanker:	a preferred design of flow straightener with the flow directed through a 'honeycomb' of square section tubes via entry holes of graded diameter. (See ISO 5167).



Abbreviations

AGA	American Gas Association
AISI	Iron and Steel Institute
ANSI	American National Standards Institute
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BASEEFA	British Approvals Service for Electrical Equipment in Flammable Atmospheres
BS	British Standard
CAD	Computer Aided Design
CAE	Computer Aided Engineering
CCR	Central Control Room
CSA	Canadian Standards Association
CST	Centistokes
d.c.	Direct Current
DCS	Distributed Control System
DN	Nominal Diameter
DIN	German Standard Reference
DIS	Draft International Standard (6x ISO)
Dp	Differential Pressure
EDP	Electronic Data Processing
EC	European Community
EEMUA	Engineering Equipment and materials Users Association
EIC	Energy Industries Council
e.m.f.	Electro motive force
EMI	Electro-Magnetic Interference
EN	European Standards issued by CEN (European Committee for Standardisation) and CENELEC (European Committee for Electrotechnical Standardisation)
ESD	Emergency Shutdown
FAT	Factory Acceptance Tests
FCI	Fluid Controls Institute
FEED	Front End Engineering Design
FGCP	Fire and Gas Control Panel
F&G	Fire and Gas
FM	Factory Mutual Research Corporation
FPS	Fixed Program System
FSA	Formal Safety Assessment
FVS	Full Variability System
GRP	Glass Reinforced Plastic
HAZOP	Hazard and Operability Study
HP/HT	High Pressure /High Temperature
HSE	Health and Safety Executive
HVAC	Heating, Ventilation and Air Conditioning
IEC	International Electrotechnical Commission



IEE	Institution of Electrical Engineers
IEEE	Institute of Electrical and Electronic Engineers (USA)
I/O	Input/Output
IP	Institute of Petroleum
IR	Infra-Red
IS	Intrinsically Safe
ISA	Instrument Society of America
ISO	International Organisation for Standardisation
ITT	Instructions to Tender
LED	Light Emitting Diode
LEL	Lower Explosive Limit
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LVS	Limited Variability System
MAC	Manual Alarm Call Points
MICC	Mineral-Insulated Copper-Sheathed Cable
MIL	(American) Military Standard/Specification
MTBF	Mean Time Between Failures
MTTR	Mean Time to Repair
NACE	National Association of Corrosion Engineers
NAS	National Aerospace Standard
NFPA	National Fire Protection Association
NPD	Norwegian Petroleum Directorate
NPS	Nominal Pipe Size
OEL	Occupational Exposure Limit
PA	Public Address
PAU	Pre-Assembled Units
PC	Personal computer
PLC	Programmable Logic Controller
PPM	Parts per million
psig	Pound per square inch gauge
PTFE	Polytetrafluorethylene
PVC	Polyvinyl Chloride
QA	Quality Assurance
RTD	Resistance Temperature Detector
SCADA	Supervisory Control and Data Acquisition
SI	Système International d'Unités
SIREP	International Instrument Users Association
SOLAS	Safety of Life at Sea
SOR	Statement of Requirements
UK	United Kingdom
U/L	Underwriters Laboratories
UV	Ultra Violet
VDU	Visual Display Unit
VESDA	Very Early Smoke Detection Apparatus



LIST OF REFERENCED DOCUMENTS

A reference invokes the latest published issue or amendment unless stated otherwise.

Referenced standards may be replaced by equivalent standards that are internationally or otherwise recognised provided that it can be shown to the satisfaction of the purchaser's professional engineer that they meet or exceed the requirements of the referenced standards.

ISO/DIS 3171	Petroleum liquids - Automatic pipeline sampling.
ISO/DIS 5309	Capacitance gauges.
ISO 5167 (Technically equivalent to BS 1042: Pt 1: Section 1.1)	Measurement of fluid flow by means of orifice plate nozzles and venturi tubes inserted in circular cross-section conduits running full.
ISO 5168 (Identical to BS 5844)	Measurement of fluid flow - Estimation of uncertainty of a flow-rate measurement.
ISO 6551 (Identical to BS 6439)	Petroleum liquids and gases - Fidelity and security of dynamic measurement - Cabled transmission of electric and/or electronic pulsed data.
ISO/DIS 7278/2 Proving BS 84/51854	Liquid hydrocarbons - Dynamic measurement-systems for volumetric meters Part 2: Pipe provers.
ISO/DIS 7278/3 Proving BS 84/51854	Liquid hydrocarbons - Dynamic measurement-systems for volumetric meters Part 3: Pulse interpolation techniques.
ISO/DIS 8310 (Draft Std for reference only)	Refrigerated light hydrocarbon fluids - Measurement of temperature in tanks containing liquefied gases.
IEC 751 (Identical to BS 1904)	Industrial platinum resistance thermometer sensors.
	AGA Transmission Measurement Committee Report



AGA 3	Orifice Plate Meters.
AGA 6	Gas Meter Provers
AGA 7	Measurement of fuel gas by turbine meters.
AGA 8	Mass Measurement
ANSI B16.5	Pipe flanges and flanged fittings, steel nickel alloy and other special alloys.
	API Manual of Petroleum Measurement Standards
Chapter 4	Proving systems
Chapter 5	Metering
Section 2	Measurement of liquid hydrocarbons by displacement meter systems.
Section 3	Turbine meters.
Chapter 8	Sampling
Section 2	Automatic sampling of petroleum and petroleum products.
Chapter 11.2.1M	Compressibility factors for hydrocarbons: 638-1074 kilograms per cubic meter range.
Chapter 12	Calculation of petroleum quantities measured by turbine
Section 2	displacement meters.
API RP 550	Manual on Installation of Refinery Instruments and Control Systems.
Part 2	Process stream analysers.
API 2543	American standard method of measuring the temperature
(ASTM D1086)	of petroleum and petroleum products.
HM Custom and Excise	Hydrocarbon oils



Notice 179M	Flow meters at bonded oil installations
ASTM D 1250-IP 200	Petroleum Measurement Tables
ISA-S5.1	Instrumentation symbols and identification.
BS 476	Fire tests on building materials and structures Part 7: Method for classification of the surface spread of flame of products Part 8: Test methods and criteria for the fire resistance of elements of building construction.
BS 1041	Temperature Measurement Part 4: Thermocouples.
BS 1780	Specification for Bourdon tube pressure and vacuum gauges.
BS 1843	Colour code for twin compensating cables for thermocouples.
BS 2765	Specification for dimension of temperature detecting elements and corresponding pockets.
BS 3463	Specification for observation and gauge glasses for pressure vessels.
BS 4161	Gas meters. Part 6: Specification for rotary displacement and turbine meters for gas pressure up to 100 bar.
BS 4937	International thermocouple reference tables.
BS 5345	Recommended practice for selection, installation and maintenance of electrical apparatus for use in potentially explosive atmospheres (other than mining applications or explosive processing and manufacturer).
BS 6739	Recommended practice for instrumentation in process control systems: installation design and practice.
IP Petroleum Measurement manual (IP PPM)	
Part V	Automatic tank gauging (Jan. 1982)



Part VI Section 2	Sampling Guide to automatic sampling of liquids from pipelines.
Part VII Section 2	Density Continuous density measurement.
Part X Section 2	Meter proving. Recommended UK Operational practice for proving gantry meters.
Part XII Section 1 Section 3	Static measurement of refrigerated hydrocarbon liquids. Calculation procedures. Instruments for primary measurement.
Part XIII Section 1 Section 2	Fidelity and security of measurement data transmission systems. Electrical and/or electronic pulsed data cabled transmission for fluid metering systems, IP 252. Electrical and/or electronic data transmission for automatic tank gauge systems (Dec 1979).
Part XV Section 2	Metering systems Guide to the design of gas metering systems
IP Model Code of Safe Practice in the Petroleum Industry	
Part 1 Part 8	Electrical Drilling and production in marine areas.
IP 340	Recommended Practice for Calibrating and Checking Process Analysers - A General Guide to the Principles and Methods used.
HSE EH 40	Guidance Note. Environmental Hygiene Series. Occupational Exposure Limits.
NACE Standard MR0175-90	Material Requirements - Sulfide Stress Cracking Resistant Metallic Material For Oilfield Equipment.
EEMUA Publication No. 138	On-Line Analysers.



BP Measurement Guidelines

Part 1 Volume 2

BP Measurement Standards

Part 1 Volume 1

BP Group [RP 22-1](#)

Dynamic Measurement of Crude Oil

Static Methods.

BP Group [RP 46-1](#)

Fired Heaters
(replaces BP CP 7)

Unfired Pressure Vessels
(replaces BP CP 8)

BP Group [RP 42-1](#)

Piping Systems
(replaces BP CP 12)

BP Group [RP 44-1](#)

Overpressure Protection Systems.
(replaces BP CP 14)

BP Group [RP 12 Series](#)

Electrical Systems and Installations.
(replaces BP CP 17)

BP Group [RP 4-4](#)

Buildings
(replaces BP CP 19)

BP Group [RP 58-1](#)

Non-refrigerated Petroleum and Petrochemical
Storage.
(replaces BP CP 21)

BP Group [RP 30-6](#)

Protective Instrumentation
(replaces BP CP 48)

BP Group [GS 136-1](#)

Materials for Sour Service to NACE Standard
MR-01-75 (1980 Revision).
(replaces BP Std 153)

BP Group [GS 130-4](#)

Pressure Gauges.
(replaces BP Std 177)

BP Group [GS 118-1](#)

Unfired Pressure Vessels, Ferritic Steels.
(replaces BP Std 111 Pt A-J)

BP Group [GS 134-4](#)

Centrifugal Pumps to API 610.

BP Group [GS 130-1](#)

Automatic Pipeline Sampling.
(replaces BP Std 232)



BP Group [GS 130-5](#) Flow Elements for Plant Control and Maintenance

BP Group [GS 142-13](#) Compression Fittings
(replaces BP Std 261)

BP Group [GS 142-6](#) Piping Specifications
(replaces BP Std 170)

Weighbridges and Weighscales - retrenched aliment

Council of European Communities - Directive on Non-Automatic Weighing Instruments.
20th June 1990.

Organisation Internationale De Métrologie Légale. (OIML). Document R76-1. Non Automatic Weighing Instruments. Part 1 & 2.

OIML International Recommendations; Automatic Rail Weighbridges.

[HM Statutory Instrument 1988 No. 876](#). The Weighing Equipment (Non-Automatic Weighing Machines) Regulations and its later amendments.

The National Weights and Measures Laboratory (NWML), (UK). Design Assessment Guidelines for Non-Automatic Industrial Weighing Equipment 0341.

US Scale Code of the National Bureau of Standards (NBS).

UK Weights and Measures Regulations 1963. Regulations 119, 120, 121. In-motion weighing of loaded or unloaded rail vehicles. (Modified by NWML letter of dispensation).

[British Standard BS 5400](#). Steel, Concrete and Composite Bridges.

[British Standard BS 5781](#). Measurement and Calibration Systems.



LEGISLATION AND STANDARDS RELATING TO ENVIRONMENTAL MONITORING WHICH MAY AFFECT ANY BP PROCESS PLANT OR TERMINAL WORLDWIDE

The following lists the known legislation and standards on a per country basis that are considered to have impact on environmental monitoring systems. This Recommended Practice deals with requirements for fixed automatic analyser systems and it will be noted that the majority of the standards listed below are for manual sampling and laboratory type measurements. However it is thought necessary that these standards are included because they will either directly or indirectly influence choice of fixed measuring technique and the ability to correlate calibrations to the satisfaction of the authorities.

International Standards

ISO 1996	Description and measurement of environmental noise. Guide to application to noise limits.
ISO 4219:1979	Air quality - Determination of gaseous sulphur compounds in ambient air - Sampling equipment.
ISO 4220:1983	Ambient air - Determination of a gaseous acid air pollution index - Titrimetric method with indicator or potentiometric end-point detection.
ISO 4221:1980	Air quality - Determination of mass concentration of sulphur dioxide in ambient air - dioxide in ambient air - Thorin spectrophotometric method.
ISO/TR 4227:1989	Planning of ambient air quality monitoring.
ISO 6767:1990	Ambient air - Determination of the mass concentration of sulphur dioxide - Tetrachloromercurate/pararosaniline method.
ISO 6768	Ambient air - Determination of the mass concentration of nitrogen dioxide - Modified Griess-Saltzman method.
ISO 7934	Stationary source emissions - Determination of the mass concentration of sulphur dioxide - Hydrogen peroxide/barium perchlorate/Thorin method.
ISO 7996:1985	Ambient air - Determination of the mass concentration of nitrogen oxides - Chemiluminescence method.



ISO 8186	Ambient air - Determination of the mass concentration of carbon monoxide - Gas chromatographic method.
ISO 5813:1983	Water quality - Determination of dissolved oxygen - Iodometric method.
ISO 5814:1990	Water quality - Determination of dissolved oxygen - Electrochemical probe method.
ISO 5815:1989	Water quality - Determination of Biochemical Oxygen Demand after 5 days (BOD 5) - Dilution and seeding method.
ISO 6060:1989	Water quality - Determination of the Chemical Oxygen Demand.
ISO 7393	All parts - Determination of free chlorine and total chlorine.
ISO 7890	All parts - Determination of nitrate.
ISO 8192:1986	Water quality - Test for inhibition of oxygen consumption by activated sludge.
ISO 9280:1990	Water quality - Determination of sulphate - Gravimetric method using barium chloride
ISO 9297:1989	Water quality - Determination of chloride - Silver nitrate titration with chromate indicator (Mohr's method).
ISO 9390:1990	Water quality - Determination of borate - Spectrometric method using azomethine-H.
ISO 9509:1989	Water quality - Method for assessing the inhibition of nitrification of activated sludge micro-organisms by chemicals and waste waters.
ISO 9562:1989	Water quality - Determination of absorbable organic halogens (AOX).
ISO 10048:1991	Water quality - Determination of nitrogen - Catalytic digestion after reduction with Devarda's alloy.

European Legislation

DI 80-779	Council directive on air quality limit values and guide values for sulphur dioxide and suspended particulates.
OENORM M 9450	Emission limits for contaminations in air; general requirements.
OENORM M 9485	Emission limits for vapours of organic compounds, particularly solvents.

European Standards

prEN 689	Workplace atmospheres; guidance for the assessment of exposure to chemical agents for comparison with limit values and measurement strategy.
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USA Legislation

Toxic Characteristic Rule 1990.

Refinery Primary Sludge Listing 1990.

Satellite Accumulation Rule.

Resource Conservation and Recovery Act.

Clean Air Act.

Clean water act.

Code of Federal Regulations

National Emissions Standards for Hazardous Air Pollution.

USA Standards

EPA Standards

API 420	Management of water discharges, the chemistry and chemicals of coagulation and flocculation.
API 421	Management of water discharges, design and operation of oil-water separators.



API 4471	Treatment system for the reduction of aromatic hydrocarbons and ether concentrations in groundwater.
API 4484, 4494/95/96	Monitoring near refineries for airbourne chemicals.
ASTM D3371	Standard test for nitriles in aqueous solution by gas-liquid chromatography.
ASTM D1605	Standard practices for sampling atmospheres for analysis of gases and vapours.
ASTM D3608	Standard test method for nitrogen oxides (combined) content in the atmosphere by the Griess - Saltzman reaction.
ASTM D3685	Standard test method for particulates independently or for particulates and collected residue simultaneously in stack gases.
ASTM D3824	Standard test methods for continuous measurement of oxides of nitrogen in the ambient or workplace atmosphere by the chemiluminescent method.
ASTM G91	Monitoring atmospheric SO ₂ using the sulphation plate technique.
CHI 73	Atmospheric monitoring for chlorine

UK Legislation

1990 Environmental Protection Act (EPA).

EPA Guidance Notes IPR1/1	Boilers and Furnaces > 50 MW
EPA Guidance Notes PG1/3	Boilers and Furnaces 20 - 50 MW
COSHH Regulations	

UK Standards

HSE EH 40	Guidance Note on Occupational Exposure Limits
BS 7445	Description and measurement of environmental noise. Guide to application to noise limits.
BS 6068	Standards for determination of water quality. - Corresponds to relevant ISO standards.



BS 6069	Characterisation of air quality. - Corresponds to ISO standards 4226, 4225, 8518, 9486, 9487, 8762, 7924.
BS 3405	Measurement of particulate emission including grit and dust.
BS 7750	Specification for environmental management systems.
BS 1747 Parts 1-3,6-10	Measurement of air pollution - smoke, nitrogen oxides, gaseous sulphur compounds. Corresponds to ISO standards 4219, 4221, 6768, 7996, 6767.
BS 7527	Classification of environmental conditions. - Corresponds to relevant IEC standards.
BS 5295	Environmental cleanliness in enclosed spaces.
BS 2690	Methods of testing water used in industry.

German Legislation

Code of Federal regulations - Protection of Environment.

BImSchV 2	2nd ordinance for the implementation of the Federal Immission Control Act (ordinance for the limitation of emission of highly volatile halogenated hydrocarbons - 2 BImSchV).
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German Standards

DIN ISO 4219	Air quality; Determination of gaseous sulphur compounds in ambient air; Sampling equipment.
DIN ISO 4220	Ambient air; Determination of a gaseous air pollution index; Titrimetric method with indicator or potentiometric end-point detection.
DIN ISO 4221	Air quality; Determination of mass concentration of sulphur dioxide in ambient air; Thorin spectrophotometric method.
DIN ISO 7996	Ambient air; Determination of the mass concentration of nitrogen oxides; Chemiluminescence method.
DIN ISO 7168	Air quality; Presentation of ambient air quality data in alphanumerical form.



[DIN 38402/04/14](#)

German standard methods for the examination/ analysis of water, waste water and sludge.

Norwegian Legislation

[Act of 13/3/1981, No. 6](#)

Concerning protection against pollution and concerning waste, (Pollution control act), with amendments in pursuance of the Act of 15 April 1983, No. 21.

[Act of 22/3/1985 No. 11](#)

Pertaining to petroleum activities - Chapter 5 - liability of pollution damage.

[Act of 21/12/1990](#)

Relating to carbon dioxide tax. Latest amendments 20 July 1991.

Provisional regulations

Concerning littering and pollution caused by petroleum activities on the Norwegian continental shelf, given by Royal decree of 26 October 1979 pursuant to act No. 12 of 21 June 1963 concerning exploration for and exploitation of subsea natural resources.

Australian Standards

[SAA AS 3580.13.2](#)

Methods for sampling and analysis of ambient air - determination of fluorides, particulates, hydrogen sulphide, ozone, sulphur dioxide and acid gases.

[SAA AS 2618](#)

Ambient air - Determination of gaseous and particulate fluorides.

Japanese standards

[JIS B 7951](#)

Continuous analyser for carbon monoxide in ambient air.

[JIS B 7952](#)

Continuous analysers for sulphur dioxide in ambient air.

[JIS B 7953](#)

Continuous analysers for oxides of nitrogen in ambient air.

[JIS B 7954](#)

Automatic monitors for suspended particulate matter in ambient air.

[JIS B 7955](#)

Continuous analysers for Chlorine in ambient air.



JIS B 7956	Continuous analysers for hydrocarbons in ambient air.
JIS B 7957	Continuous analysers for oxidants in ambient air.
JIS B 7958	Continuous analysers for Fluorine compounds in ambient air.
JIS K 0093	Method for determination of Polychlorinated Biphenyl in industrial waste water.
JIS K 0094	Sampling methods for industrial water and industrial waste water.
JIS K 0100	Testing method for corrosivity of industrial water.
JIS K 0101	Testing method for industrial water.
JIS K 0102	Testing methods for industrial waste water,'
JIS K 0125	Testing methods for determination of low molecular weight halogenated hydrocarbons in industrial water and waste water.
JIS K 0806	Automatic chemical oxygen demand meter.
JIS K 0807	UV photometer for monitoring of water pollution.
JIS K 3602	Apparatus for the estimation of Biochemical Oxygen Demand with microbial sensor.
JIS Z 8813	General rules of measuring methods for airbourne dust concentration in environmental atmosphere.
JIS Z 8814	Low volume air samplers and methods for measuring mass concentration of airbourne dust by the low volume air samplers.

**LIST OF COMMON POLLUTANTS APPLICABLE TO THE PETROLEUM AND
PETROCHEMICAL INDUSTRIES WHICH MAY BE REQUIRED TO BE
MEASURED UNDER ENVIRONMENTAL LEGISLATION FOR ATMOSPHERIC
AND STACK EMISSION MONITORING**

The following is a list of pollutants which could be included in pollution control authorisation constraints for atmospheric and stack emission monitoring in the petroleum industries. This list has been drawn from legislative references worldwide but in particular those of Germany and represents typical component monitoring requirements. Where possible from information available the typical concentration levels upon which consents will be based are given. The concentrations and mass flow information given in the table are for waste gas analysis and the exposure limits are for ambient analysis. This list is by no means exhaustive.

Pollutant	Maximum Concentrations when Emissive Mass Flow of Component in Waste Gas is Exceeded and 8 Hour Average Ambient Exposure Limits
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concentration mass flow Exposure Limits

	(mg/3m ³)	(g/h)	(ppm)	(mg/m ³)
Acrylonitrile	5	25	2	4
Amines - Organic compounds of N ₂ from NH ₃ Ammonia - NH ₃	2 @ 1/2 hr		25	17
	1 @ 24 hr			
	0.5 @ 1yr			
Arsine - AsH ₃	1	10	0.05	0.2
Arsenic (dust)	1	5		0.1
Benzene	5	25	5	15
Bromine	5	50	0.1	0.7
Butadiene - unsaturated aromatic hydrocarbon	5	25	10	22
Carbon dioxide			5000	9000
Carbon disulphide			10	30
Carbon monoxide	170		50	55
Chlorine	5	50	0.5	1.5
Chlorine plus compounds	30	300		
Cyanides	5	25		5



**Maximum Concentrations when Emissive
Mass Flow of Component in Waste Gas is
Exceeded and 8 Hour Average Ambient
Exposure Limits**

concentration mass flow Exposure Limits

	(mg/m ³)	(g/h)	(ppm)	(mg/m ³)
Cyanogen Chloride	1	10	0.3	0.6
Dibenzanthracen	0.1	5		
1,2-Dibromomethane	5	25	0.5	4
3,3-Dichlorobenzidine	1	5		
Dimethyle Sulphate	1	5	0.1	0.5
Dust	50	500		5-10
Epichlorohydrin	5	25	2	8
Ethyleneimine	1	5	0.5	1
Ethylene oxide	5	25	5	10
Fluorides (dust)	5	25		
Fluorides (gas)	5	50		2.5
Fluorine plus compounds	5	50	1	1.5
Formaldehyde			2	2.5
Hydrazine	5	25	0.1	0.1
Hydrocarbons (flammable hazard)		0-100% LEL		
Hydrocarbons/VOC's (leak and waste gas)	150-2000			
Hydrochloric acid (indicated as C1)	30	3000		
Hydrocyanic acid	5	50		
Hydrogen bromide	5	50	3	10
Hydrogen chloride			5	7
Hydrogen phosphide	1	10		
Hydrogen sulphide	5	50	10	14
Hydrogen Sulphide - Sulphur producing plant	10			

Pollutant**Maximum Concentrations when Emissive Mass Flow of Component in Waste Gas is Exceeded and 8 Hour Average Ambient Exposure Limits**

concentration mass flow Exposure Limits

	(mg/m ³)	(g/h)	(ppm)	(mg/m ³)	
Ketones-acetone			1000	2400	
Lead plus compounds	5	25		0.1	
Methane		Asphixiant			
Methanol				200	260
Methylbromide - Halogenated Hydrocarbon				200	890
Methyl iodide				5	28
Nitric acid				2	5
Nitrogen oxides - NOX (Fuel Oil Combustion)	250 -	450			
Nitrogen oxides - NOX (Fuel Oil Combustion)	200				
Nitrogen oxides	0.5		5000		
Nitrogen dioxide	0.2 @ 1/2hr		5000	3	5
	0.1 @ 24hr		5000		
Nitrogen monoxide	1 @ 1/2hr		5000	25	30
	0.5 @ 24hr		5000		
Ozone - oxidant	0.15 @ 1/2hr			0.1	0.2
	0.05 @ 1yr				
Particulates (Fuel Oil Combustion)	80				
Particulates (Fuel Gas Combustion)	5				
Palladium plus compounds	5		25		
Phenol				5	19
Phosgene - Carbonyl Chloride COCl ₂	1		10	0.1	0.4
Platinum plus compounds	5	25			5
Propane - Hydrocarbon C ₃ H ₈		Asphyxiant			
Propylene Oxide				20	50



Pollutant**Maximum Concentrations when Emissive Mass Flow of Component in Waste Gas is Exceeded and 8 Hour Average Ambient Exposure Limits**

concentration mass flow Exposure Limits

	(mg/m ³)	(g/h)	(ppm)	(mg/m ³)
Selenium plus compounds	1	5		0.1
Smoke		Opacity		
Styrene - Hydrocarbon			100	420
Sulphur oxides - SOX (Fuel Oil Combustion)	1700			
Sulphur oxides - SOX (Fuel Gas Combustion)	100			
Sulphur oxides - SOX (Associated Gas Combustion)	1700			
Sulphur dioxide	1 @ 1/2hr	2	5	
	0.3 @ 24hr			
	0.1 @ 1yr			
Suspended Particles	0.15 - 0.3			
Tellurium plus compounds	1	5		0.1
Thallium plus compounds	0.2	1		0.1
Vanadium plus compounds	5	25		
Vinyl chloride	5	25	7	
VOC	500			



**LIST OF COMMON POLLUTANTS APPLICABLE TO THE PETROLEUM AND
PETROCHEMICAL INDUSTRIES WHICH MAY BE REQUIRED TO BE
MEASURED UNDER ENVIRONMENT LEGISLATION FOR WATER EFFLUENT
AND GROUND CONTAMINATION MONITORING**

The following is lists of pollutants which could be included in pollution control consents for water effluent and ground contamination monitoring in the petroleum industries. This list has been drawn from legislative references and internal questionnaires worldwide and represents typical component monitoring requirements. Where possible from information available the typical concentration levels upon which consents will be based are given. These lists are by no means exhaustive.

WATER EFFLUENT

Pollutant

Maximum Levels

concentration mass flow

	(mg/l)	(kg/day)
Acrylonitrile	0.35	0.4
Ammonia - NH ₃	10 - 30	50
Benzene	0.5	
BOD - (Biochemical Oxygen Demand)	250BOD ₅	
Carbon Tetrachloride - CCl ₄	0.5	0.1
Chlorine (Residual)	>1	
Chlorobenzene	100	
Chloroethanes	0.09 - 1.2	0.01 - 0.15
Chloroform	6	
Chloropropanes	1.2	0.015 - 0.15
COD - (Chemical Oxygen Demand)	100 COD	
Cresol (o.m.n)	200	
Cyanide (Amenable)	0.03	0.1
Dichlorobenzenes	0.07 - 7.5	
Ethylbenzene	0.6	0.07
Formaldehyde		
Hexachlorobenzene	0.13	



Pollutant**Maximum Levels**

concentration mass flow range

	(mg/l)	(kg/day)
Hydrocarbon (Oil in Water)	15	150
Metal - Arsenic	5	
Metal - Barium	100	
Metal - Cadmium		
Metal - Chromium	1 - 5	3
Metal - Copper	0.1 - 3	0.2
Metal - Lead		
Metal - Mercury	0.2	
Metal - Nickel	1	
Metal - Vanadium		
Metal - Zinc	1 - 3	3
Metals (Total)	10	
Methylene Chloride	0.26	0.03
Methyl Chloride	0.44	0.04
Methyl Ethyl Ketone	200	
Nitrobenzene	2 - 10	1
Nitrogen		50
Nitrophenols	0.35 - 6.5	0.04 - 0.7
pH	6 to 9 Standard	Units
Phenol	1	20
Pentachlorophenol	100	
Pyridine	5	
Sulphide	1	15
TSS - (Total Suspended Solids)	50	200
TOC - (Total Organic Carbon)		
Toluene	0.11	0.15
Vinyl Chloride	0.2	0.3



GROUND CONTAMINANT

Pollutant

Maximum Levels

concentration

	(ppm)	(mg/l)
Acetone	160	
Acetonitrile (in ground water)		0.1
Acetonitrile (in debris)	incinerate	
Acrylonitrile (in ground water)		0.01
Acronitrile (in soil)	84	
Chloride		
Cyanide		0.03
Formaldehyde (in debris)	incinerate	
Hydrocarbons		
Hydrogen Cyanide	110	
Lead Alkyls - (TEL, MEL)		
Metal - Arsenic		
Metal - Barium		
Metal - Cadmium		
Metal - Chromium		0.01
Metal - Iron		
Metal - Lead		
Metal - Manganese		
Metal - Mercury		
Metal - Selenium		
Metal - Silver		
Metal - Sodium		
Phenolics		
Sulphate		
TOC - (Total Organic Carbon)		

