ENGINEERING STANDARD

FOR

ONSHORE TRANSPORTATION PIPELINES

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0. INTRODUCTION

This Engineering Standard is based on the experiences acquired by various organizations and companies within the Oil Industry in Iran for more than 80 years of involvement with design, construction, operation and maintenance of petroleum production and processing units and transportation facilities on the one hand and on the engineering standards and recommended codes of practices published by major International Petroleum Corporations such as Shell group and British Petroleum Company as well as applicable national and international codes and standards on the other hand and reflects the requirements of the National Iranian Oil Company, National Iranian Gas Company and National Petrochemical Company and their affiliated companies and subsidiaries in oil, gas and petrochemical industries in Iran on onshore transportation pipeline engineering.

1. SCOPE

This Standard provides a baseline for minimum technical requirements and recommended engineering practices for design of off-plot onshore pipelines used for transportation of hydrocarbons in Iranian Oil, Gas and Petrochemical Industries. Facilities to which this Standard applies are indicated in Scope of ANSI/ASME B 31.4 and B 31.8. 1992 editions.

2. REFERENCES

Throughout this Standard the following standards and codes are referred to. The editions of these standards and codes that are in effect at the time of publication of this Standard shall, to the extent specified herein, form a part of this Standard. The applicability of changes in standards and codes that occur after the date of this Standard shall be mutually agreed upon by the Company and the Vendor/Consultant/Contractor (Executor).

ANSI/ASME (AMERICAN NATIONAL STANDARD INSTITUTE / AMERICAN SOCIETY OF MECHANICAL ENGINEERS)

B 31.4	"Liquid Transportation for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia and Alchohols", 1992 Edition
B 31.8	"Gas Transmission and Distribution Piping Systems", 1992 Edition

API (AMERICAN PETROLEUM INSTITUTE)

6 D	"Specification for Pipeline Valves"
Spec. 5L	"Specification for Line Pipe"
RP 1102	"Steel Pipelines Crossing Rail Roads and Highways"

IP (INSTITUTE OF PETROLEUM)

Model code of safe practice part 15	"Area Classification Code for Petroleum Installations"

IPS (IRANIAN PETROLEUM STANDARDS)

IPS-C-CE-112	"Earthworks"
IPS-C-PI-270	"Welding of Transportation Pipelines"
IPS-C-PI-370	"Transportation Pipelines-Pressure Testing"
IPS-E-PI-240	"Plant Piping Systems"
IPS-G-PI-280	"Pipe Supports"
IPS-M-PI-110	"Valves"
IPS-M-PI-130	"Pig Launching and Receiving Traps"
IPS-M-PI-150	"Flanges and Fittings"
IPS-M-PI-190	"Line Pipe"
IPS-D-PI-110	"Pipeline Surveys"
IPS-D-PI-143	"Pipeline Right-of-Way"
IPS-E-TP-270	"Coatings"
IPS-E-TP-820	"Electrochemical Protection (Cathodic & Anodic)"
IPS-D-TP-712	"Combined Marker and Test Point and Bond Box Details"

NACE (NATIONAL ASSOCIATION OF CORROSION ENGINEERS)

RP 0175	"Control of Internal Corrosion in Steel Pipelines and Piping Systems"

3. DEFINITIONS

3.1 General Terms

3.1.1 Engineer

Refers to person or party representing the Company for supervision of design, engineering services, and execution of project as required and specified by the Company.

3.1.2 Manufacturer

The party that manufactures or produces line pipe and piping components according to the requirements of relevant IPS Standards.

3.1.3 Consultant

Is the party which carries out all or part of a pipeline design and engineering.

3.2 Specific Terms

3.2.1 Design factor

Ratio of the hoop stress developed in the pipeline by the design pressure and the Specified Minimum Yield Stress (SMYS) of the pipeline material.

3.2.2 Flammable fluid

A fluid having a flash point lower than 100°C.

3.2.3 Flowline

A pipeline (including valves and fittings) for transporting untreated hydrocarbons and other reservoir fluids between the stone trap outlet flange and the first flange on the incoming manifold at the production unit or the wellhead separator surface safety valve.

3.2.4 Gas gathering line

A pipeline (including valves, traps and fittings) between the block valve on the wellhead separator (or wellhead separator cluster) gas outlet line and the block valve on the NGL plant or production unit gas inlet line.

3.2.5 Gas transmission line (gas trunk line)

A pipeline (including valves, traps and fittings) between the block valve on the NGL plant or gas refinery or gas compressor station gas outlet line and the block valve at gas distribution terminal or consumers premises inlet line but excluding the piping, valves, fittings, etc. between the booster stations main inlet and outlet block valves.

3.2.6 Incidental pressure

Pressure which occurs in a pipeline with limited frequency and within a limited period of time, such as surge pressures and thermal expansions, if not occurring most of the time.

3.2.7 Main oil line (oil trunk line)

A pipeline (including valves and fittings) between the main block valve on the production unit oil outlet line and the main block valve on crude oil terminal inlet line but excluding the piping, valves, fittings, etc. between the booster stations main inlet and outlet block valves.

3.2.8 Maximum allowable incidental pressure (MAIP)

The maximum pressure that is allowed by ANSI/ASME B 31.4 and B 31.8 to occur in a pipeline with a limited frequency and during limited period of time.

3.2.9 Maximum allowable operating pressure (MAOP)

The maximum pressure at which a pipeline is allowed to be operated under steady state process conditions, in accordance with ANSI/ASME B 31.4 and 8.

3.2.10 NGL line

A pipeline (including valves and fittings) between the block valve at the NGL plant liquid outlet line and the block valve at the NGL distribution terminal or LPG plant or consumers premises inlet line.

3.2.11 Specified minimum yield stress (SMYS)

The level of stress which produces 0.5 percent total strain (API definition). This is specified by the Company and shall be guaranteed by the Manufacturers /Suppliers/Vendors.

3.2.12 Stable fluid

A fluid which has an NFPA reactivity grade number of zero. (Refer to IPS-E-SF-100).

3.2.13 Toxic fluid

Includes all fluids in the slightly toxic, toxic and highly toxic categories.

4. ABBREVIATIONS

DN	Nominal Diameter
ERW	Electric Resistance Welding
ESD	Emergency Shut Down
GRP	Glass Reinforced Plastics
GRE	Glass Reinforced Epoxy
HFI	High Frequency Induction
LPG	Liquefied Petroleum Gas
MAIP	Maximum Allowable Incidental Pressure
MAOP	Maximum Allowable Operating Pressure
NGL	Natural Gas Liquid
NPS	Nominal Pipe Size
PN	Nominal Pressure Rating (class) Designation
Re	Reynold No.
RF	Raised Face
ROW	Right-of-Way
RTJ	Ring Type Joint
SAW	Submerged Arc Welding
SI	International System of Units
SMYS	Specified Minimum Yield Stress

5. UNITS

This Standard is based on International System of Units (SI), unless otherwise specified.

6. FLUID CATEGORIES

Based on the hazard potential of a fluid transported in the pipeline, it should be categorized in one of the following four groups.

TABLE 1 - FLUID CATEGORIES

CATEGORY	DESCRIPTION	EXAMPLE
A	Non-flammable, stable and non-toxic fluids which are in liquid form at ambient temperature and 50 kPa (0.5 bar) above atmospheric pressure, i.e. having vapor pressure lower than 150 kPa (1.5 bar) (abs) at ambient temperature.	Water, slurries
B	Flammable, or unstable or toxic fluids which are in liquid form at ambient temperature and 50 kPa (0.5 bar) above atmospheric pressure, i.e. having vapor pressure lower than 150 kPa (1.5 bar) (abs) at ambient temperature.	Stabilized crude, gas oil
C	Non-flammable, stable, non-toxic fluids which are in gaseous form or a mixture of gas and liquid at ambient temperature and 50 kPa (0.5 bar) above atmospheric pressure, i.e. having vapor pressure higher than 150 kPa (1.5 bar (abs) at ambient temperature.	Nitrogen, carbon dioxide
D	Flammable, or unstable or toxic fluids which are in gaseous form or a mixture of gas and liquid at ambient temperature and 50 kPa (0.5 bar) above atmospheric pressure, i.e. having vapor pressure higher than 150 kPa (1.5 bar) (abs) at ambient temperature.	Natural gas, LPG, ammonia

Note:

For definition of flammable, stable and toxic fluids see 3.2 of this Standard.

7. DESIGN

7.1 General Considerations

The relevant sections of ANSI/ASME and API codes and standards referred to and supplemented by this Standard shall be used for design of the pipeline in which the operating conditions and requirements, ease of inspection and maintenance, environmental conditions, safety requirements, geographic location, climatic, geotechnic and seismic conditions as well as future changes and expansions should be taken into account over the pipeline entire projected life cycle including its final abandonment.

7.2 Operational Requirements

In designing the pipeline and its associated piping systems, due account shall be given to the operation, inspection and maintenance requirements for the predicted life cycle and the planned conditions and criteria as set by and/or agreed in advance with the personnel responsible for the operation and maintenance of the pipeline. Due regard should also be given to manning levels, pipeline condition monitoring and maintenance system, remote operations, communications, means of access to the right-of-way, by-pass requirements for components needing regular maintenance without interruption of the pipeline operation, etc.

7.3 Economic Considerations (Optimization)

When there are alternatives for designing and constructing a pipeline, an economic analysis shall be carried out to determine the optimum design specifications to meet the specified operating requirements with the highest technical integrity in the best possible way at the lowest possible cost. The analysis should consider the following parameters as well as other factors which could have significant cost implications on the one hand and safety risks and environmental impacts on the other:

a) Different pipe diameters, operating pressures, flow velocities, materials, etc.

b) Distances between booster stations, with due consideration to other facilities required for operation and maintenance of booster stations.

c) Alternative routes with their problems, peculiarities, impacts and risks with due consideration to the interaction between the pipeline and the environment during each stage of the pipeline life cycle.

d) Various construction methods particularly at different crossings, difficult terrains, marshy areas, etc.

For fluid Category B and C in location classes 3 and 4 and for category D in all location classes, risk assessment should be carried out to confirm that the selected design factors (refer to 7.5.2.2) and proximity distances (refer to 9.3) are adequate. Consideration shall be given to the potential causes of failure such as internal corrosion and Hydrogen Induced Cracking (HIC), internal erosion, external corrosion and bicarbonate and sulphide stress corrosion cracking, mechanical impacts and external interferences, fatigue, hydrodynamic forces, geotechnical forces, material defects, thermal expansion forces, etc. and their frequencies and the factors critical to public safety. The environment protection should be analyzed for the life span of the pipeline. While the risk of failures should be reduced to as low as reasonably practicable the economic risk aspects including cost of repairs, liabilities to the public and environment as well as loss of revenue should be evaluated for various alternatives and for each phase of the pipeline operating life all of which should be compatible with the overall objectives of the Company.

7.4 Hydraulic Design

7.4.1 General considerations

Flow rate and/or pressure drop calculations may be made for the pipelines in various services using the formulas and methods set out and/or referred to in this Sub-section. Although the equations and methods for calculating the pressure drops quoted or referred to in this Sub-section have proved to be generally consistent with the actual experienced results during operation, nevertheless, more accurate methods of calculation should be considered for particular cases and where the fluid characteristics are fully known.

For a given pipe size, fluid characteristics and flow rate, a hydraulic analysis should be carried out to establish the possible range of operational parameters which should provide the pressure and temperature profiles along the pipeline for steady state and transient conditions by taking full account of the possible changes in flow rates and operational modes over the life span of the pipeline.

The analysis should provide data to address the following:

- Surge pressure during sudden shut-down of the liquid lines.

- Turn-down limitation and inhibition or insulation requirements to avoid wax or hydrates or other impurities to deposit.

- Effect of flow rates on the efficiency of the corrosion inhibitors.

- Liquid catching and slug control requirement specially at the downstream end of two-phase lines or at the low pressure points.

- Effect of higher velocity ranges on impingement, cavitation and erosion on pipe wall, fittings and valves.

- Cleaning requirements for water and other corrosive substances which may deposit in the line. (refer to NACE RP 0175).

7.4.2 Velocity limitations

For liquid lines the normal average flow velocities should be selected between 1 to 2 m/s. Operations above 4 m/s should be avoided and lines containing a separate water phase (even in small quantity such as 1% water cut) should not operate at velocities below 1 m/s (to prevent water dropout which may create corrosive situations).

For gas lines the normal average flow velocities should be selected between 5 to 10 m/s. In special cases, continuous operations up to 20 m/s. Velocities lower than 5 m/s may have to be used for fluids containing solid particles where maximum velocity will be dictated by the occurrence of erosion.

Note:

The maximum velocity that can be attained by a compressible fluid is the critical or sonic velocity. In no case should the operating velocity exceed one half of the critical velocity.

For ideal gases critical velocity, $V_c = \sqrt{\frac{KRT}{M}}$ **m/s**

Where:

$K = \frac{Cp}{Cv}$ **= Ratio of specific heats at constant pressure and constant volume,**

R = Universal gas constant in J/kg Mol °K

T = Flowing temperature in kelvin

M = mass in kg/Mol

Where a mixture of gas and liquid is being transported, the erosional velocity may be determined by $Ve = \frac{1.22\ C}{\sqrt{\rho_m}}$ **m/s**

Where:

ρ_m = **Density of the gas/liquid. mixture in kg/m³ at operating pressure and temperature.(see Note 1 in Appendix C)**

C = Emperical constant = 125 for non-continuous operation and 100 for continuous operation.

If sand or other erosive solids are expected to be present, the fluid velocity should be reduced and/or special materials selected to avoid or reduce erosion.

However in two-phase lines (specially for long lines with elevation changes) the velocity shall be selected to have a suitable flow regime with minimum pressure drop across the lines.

7.4.3 Pressure drop calculations

7.4.3.1 Pressure drop in crude oil pipelines

a) For sizes up to DN 750 (NPS 30) and fully turbulent flow, the Service Pipeline Co. formula may be used (see Appendix A).

b) For sizes above DN 750 (NPS 30) the Shell/MIT (Massachusetts Institute of Technology) formula may be used for both laminar and turbulent flow (see Appendix B).

Notes:

1) As for diameter sizes of DN 750 (NPS 30) and below, the MIT equation also gives acceptable results, it may be used for laminar flow in all pipe sizes.

2) The above formulas have given accurate results for the crude oils presently produced from most of the fields in south of Iran (with API No ranging between 30 and 34). However, for crude oil properties which are substantially different, these formulas may not be accurate enough and therefore basic hydraulic principles shall be applied to determine the friction factor.

3) Flow lines should be sized primarily on the basis of flow velocity which should be kept at least below fluid erosional velocity (see Note in 7.4.2).

The pressure drop in the flow line as well as other design parameters shall be such that gas separation from the oil can not occur in the pipeline.

For estimating the pressure drop, the use of a simplified Darcy equation is recommended (see Appendix C). However, for appropriate hydraulic design of flowlines, B.T Yocum computer program shall be used with due consideration to flow regime and well characteristics.

7.4.3.2 Pressure drop in refinery products pipelines

a) Gas oil and fuel oil

Service pipeline formula (Appendix A) may be used.

b) Kerosene, aviation turbine kerosene, motor spirit, jet petroleum naphta and condensate

The T.R Aude or Hazen-William's formulas may be used. (See Appendix D).

Note:

Hazen-William's formula also gives very accurate result for water pipelines.

7.4.3.3 Pressure drop in NGL pipelines

Pressure drop calculations may be made by using one of the appropriate methods given for liquid transmission. Due consideration should be given to the thermal expansion and contraction of the liquid due to temperature variations. Also pressure loss should not create vaporization and hence or otherwise two-phase flow in the pipeline.

7.4.3.4 Pressure drop in natural gas pipelines

For line sizes up to DN 300 (NPS 12) and operating pressures below 450 kPa, Weymouth formula may be used (see Appendix E).

For line sizes up to DN 300 (NPS 12) and operating pressures above 450 kPa, the Panhandle revised (or B) equation may be used (see Appendix F). For pipelines with diameters greater than DN 300 (NPS 12) the IGT/AGA formula may be used (see Appendix G).

Notes:

1) Gas gathering lines between wellhead separators and production units or NGL plants may contain liquids and the effect of two-phase flow should be taken into account in pressure drop calculations. Also the effect of liquid accumulation at low sections of the pipelines with provision of liquid knock-out traps, if necessary and where permitted, should be considered in the design.

2) If periodical cleaning of the pipeline from liquids and other deposits is considered necessary by running pigs during operation, due regard should be given to the additional pressure requirements for pigging.

3) Increased system availability by having the possibility of line packing should be considered by excluding sections of decreasing design pressure in the pipeline.

7.5 Mechanical Design

7.5.1 General considerations

7.5.1.1 Application of codes (category B fluids)

Pipelines carrying Category B fluids should be designed and constructed in accordance with ANSI/ASME B 31.4 and the additional requirements of this Standard.

7.5.1.2 Application of codes (category C and D fluids)

Pipelines carrying category C or D fluids should be designed and constructed in accordance with ANSI/ASME B 31.8 and the additional requirements of this Standard.

Notes:

1) Although LPG and anhydrous ammonia are covered by ANSI/ASME B 31.4 but according to this Standard they fall under category D and therefore pipelines carrying these products should be designed to ANSI/ASME B 31.8.

2) Flow lines should also meet the requirements of Standard Production Facilities Manual Section 4 except for what is specified in this Standard specially for inhabited areas 50% of SMYS should be used.

7.5.1.3 Welding

Welding of carbon steel pipeline shall comply with IPS-C-PI-270.

7.5.1.4 Pigging requirements

All pipelines shall be designed to have the capability of passing suitable types of pigs through them as and when required.

Permanent pigging facilities should be considered for those pipelines which require frequent pigging and/or have operational constraints. The distance between pigging stations should be determined on the basis of anticipated pig wear and amount of collected solids which can be pushed through as well as time required for traveling of pig between launcher and receiver. Bends should have a sufficient radius to allow passage of those types of pigs which are anticipated to pass through them The minimum radius of bend shall be 7D.

Permanent pig signalers should only be considered when frequent pigging operations are anticipated. Flush mounted ancillary equipment, barred tees and sphere tees with suitable drainage facilities should be considered where appropriate. Pig launcher and receiver systems for pipelines shall be designed in accordance with IPS-M-PI-130.

Valves to be used in the pipeline which will be pigged shall be full bore through-conduit gate valve or full bore ball valves.

Reduced bore wedge gate or ball valves may be used in piping which is not to be pigged.

Check valves should not normally be installed in pipelines which will be pigged unless they have special design to make them capable of passing pigs.

7.5.1.5 Hydrostatic testing

The pipeline and associated piping system to be hydrostatically tested in accordance with IPS-C-PI-370.

7.5.1.6 Block valves

Block valves should be provided at each end of all pipelines, at all connections and branches of the pipeline and where necessary for safety and maintenance reasons to isolate long pipelines into sections as to limit the release of line content in case of leaks or line raptures.

The appropriate method of operating block valves (i.e. locally, or automatically) shall be determined from the likely effects of a leak or line rupture and its acceptable released volume based on the total time in which a leak can be detected, located and isolated.

Automatic valves can be activated by detection of low pressure, increased flow, rate of loss of pressure or a combination of these, or a signal from a leak detection system. Automatic valves shall be fail-safe. The closure time of the valves shall not cause unacceptably high surge pressures.

The emergency shutdown valves should be automatically actuated when an emergency shutdown condition occurs at the plant or facility.

7.5.1.7 Thermal relief valves

Thermal relief valves should be considered for each section of liquid filled pipeline (including pig traps) that could be isolated by or between valves.

7.5.1.8 Vents and drains

Vent and drain connections should be provided where necessary for satisfactory testing, commissioning and operation.

7.5.1.9 Valves and flanges

The rating of valves should be adequate for MAIP and test pressures of the pipeline subject to ANSI/ASME B 31.4 and B 31.8 pressure and temperature limitations.

The number of flanges in the pipeline and piping systems should be kept to a minimum and should be installed only to facilitate maintenance and inspection and where construction conditions or process requirements dictate. Tie-in welds are preferred.

7.5.1.10 Double block and bleed system

Double block and bleed system should be used in the situations where isolation of the main stream from the ancillary equipment is needed for safe operation and maintenance without depressurizing the pipeline.

7.5.1.11 Emergency depressurization facilities

Emergency depressurization facilities shall be considered at one end of all pipelines and for category C and D fluids, at each sectionalising valve location. The material specified for the blowdown system should be suitable for low temperatures encountered during blowdown of category C and D fluids. The capacity of the blowdown system should be such that the pipeline can be depressurized as rapidly as practicable. Due regards should be given to the control of excessive movements and vibration of the system due to forces created by sudden blowdown.

7.5.1.12 Overpressure protection system

Any type of pressure control system shall not be considered as an overpressure protection system. An overpressure protection system (consisting of mechanical safety/relief valves) shall be fitted between the pipeline and the upstream facilities which can generate pressures in excess of MAIP of the pipeline. MAOP shall not be exceeded at any point along the pipeline during normal continuous operations and MAIP shall not be exceeded at any point along the pipeline during upset conditions of limited frequency and duration.

The pipeline system shall be designed such that surge pressure cannot exceed MAIP at any point along the pipeline and will not trigger the over-pressure protection system if fitted for protection from upstream facilities.

The occurrence of pressure surges should be determined for fluids with high density and low compressibility (such as liquid fluids) by transient pressure analysis, using a specialized simulation computer program. The location of the highest pressure points along the pipeline should be recognized specially in hilly terrain.

Unacceptably high surge pressures shall be prevented by one or a combination of the following methods:

- Valve closure speed reduction.
- Special fast-response pressure relief systems close to the point of surge initiation.
- Strict adherence to well formulated operating procedures (especially when other methods are insufficient).

7.5.1.13 Pipeline stability

Sections of the pipelines in swamps, floodable areas, high water table areas, river crossings, etc. shall be stable under the combined action of hydrostatic and hydrodynamic forces. The negative buoyancy should be sufficient to prevent unacceptable lateral and vertical movements and displacement of the pipeline. One or a combination of the following methods can be employed to achieve on-bottom stability:

- Increasing the pipe wall thickness.
- Applying concrete weight coating.
- Installing spaced anchor points, set-on weights or bolt-on weights.
- Burying the pipeline.

The pipeline should be stable while empty or filled with water (for test) or with fluid for which it is designed. When calculating the negative buoyancy the density of water-logged backfill mud should be taken into account.

Special consideration shall be given to possible differential settlements in weak soils which may cause damage to the pipeline.

7.5.2 Pipeline wall thickness

7.5.2.1 Minimum wall thickness

The nominal pipe wall thickness shall be calculated according to ANSI B 31.4 for category B service and ANSI B 31.8 for categories C and D services.

Special attention shall be paid to the requirements given in the above mentioned standards for the least wall thickness of the pipe when the ratio of pipe nominal diameter to wall thickness exceeds 96.

7.5.2.2 Design factors (for hoop stress limitation)

The recommended design factors for the calculation of the nominal wall thickness (excluding any corrosion allowance) are given in the following table, derived from ANSI/ASME B 31.8 Table 841.114 B but expanded.

TABLE 2 - DESIGN FACTORS FOR ONSHORE STEEL PIPELINES

FLUID CATEGORY	B	C AND D			
APPLICABLE ANSI/ASME CODE	B 31.4 (Note 1)	B 31.8			
Location classes	1, 2, 3 and 4	1	2	3	4
Pipelines	0.72	0.72	0.60	0.50	0.40
Crossings (Note 2)					
Private roads	0.72	0.72	0.60	0.50	0.40
Unimproved public roads	0.60	0.60	0.60	0.50	0.40
Roads, highways, streets and railways	0.60	0.60	0.60	0.50	0.40
Rivers, dunes and beaches	0.60	0.60	0.60	0.50	0.40
Parallel encroachments (Note 3)					
Private roads	0.72	0.72	0.60	0.50	0.40
Unimproved public roads	0.72	0.60	0.60	0.50	0.40
Roads, highways, streets and railways	0.72	0.60	0.60	0.50	0.40
Fabricated assemblies (Note 4)	0.60	0.60	0.60	0.50	0.40
Pipelines on bridges	0.60	0.60	0.60	0.50	0.40
Near concentration of people	0.72	0.50 (Note 5)	0.50 (Note 5)	0.50	0.40
Pipelines, within plant fences, block valve stations and pig trap stations (Note 6)	0.60	0.60	0.60	0.50	0.40

Notes:

1) ANSI/ASME B 31.4 does not use design factors other than 0.72, which is considered inappropriate at critical locations (e.g. crossings, within plant fences), and for fabricated assemblies. In these situations, design factors in line with ANSI/ASME B 31.8 location Class 1 are recommended.

2) ANSI/ASME B 31.8 differentiates crossings with casings and without casings. Because of the poor experience of cased crossings (i.e. annular corrosion), the same design factor is recommended, whether a casing is used or not. Design factors for crossings of rivers, dunes and beaches, not included in ANSI/ASME B 31.8, are provided.

3) Parallel encroachments are defined as those sections of a pipeline running parallel to existing roads or railways, at a distance less than 50 meters.

4) Fabricated assemblies include pig traps, valve stations, headers, finger type slugcatchers, etc.

5) Concentrations of people are defined in ANSI/ASME B 31.8 Article 840.3.

6) This category, not specifically covered in ANSI/ASME B 31.8, is added for increased safety.

7.5.2.3 Strain based design for hot products pipelines

For hot products pipelines (above 80°C) strain based approach may be used. In this case a maximum permanent deformation strain of 2% is acceptable.

7.5.2.4 Derating factors

Derating factors for carbon steel materials operating at above 120°C should be used in accordance with Table 841.116 A of ANSI/ASME B 31.8. For duplex stainless steel derating is required at lower temperatures (above 50°C).

8. MATERIALS

8.1 General

Depending mainly on the type of the fluid to be transported, specially its corrosivity, flow regime, temperature and pressure, the selection of pipeline material type can become a fundamental issue which should be decided at the conceptual design stage of a pipeline project. The most frequently used pipeline materials are metallic, specially carbon steel. Since the protection of internal corrosion and erosion of the pipe wall, which are governed by a variety of process conditions such as corrosivity of the fluid (particularly due to presence of water combined with hydrogen sulphide, carbon dioxide or oxygen), temperature, pressure and velocity of the fluid as well as deposition of solids, etc., can not be easily achieved in the same manner as for the protection of external corrosion, the selection of pipeline material should be made after careful consideration of all conditions to ensure that pipeline can remain fit-for-purpose throughout its life time.

When sour service conditions are foreseen (as specified in NACE MR 0175) the linepipe material and other materials shall be specified to resist sour services, regardless of whether or not the fluid is to be dehydrated and inhibitors are to be used.

Carbon steel linepipe material may be used in "light" sour corrosive conditions (typically where rate of corrosion is less than 0.5 mm/year without inhibition) but with sufficient corrosion allowance, inhibitor injection, appropriate inspection and controlled operation. Corrosion allowances in excess of 3 mm shall not be considered without detailed analysis by corrosion specialists.

If conditions which may cause erosion can not be avoided, special materials with improved designs to reduce or eliminate erosion should be used.

When selecting higher grades of steel linepipe (× 60 and higher), special attention shall be given to weldability and welding procedure (specially requirement for preheating to 300°C the unfinished welds before re-welding, and required yield to tensile ratio. Use of grades higher than × 70 is not recommended at present.

When low temperatures are expected (e.g. at downstream of gas pressure reducing stations), attention shall be given to the fracture toughness properties of pipe material (for possibility of long running fractures). See IPS-M-PI-190.

8.2 Material Procurement

All materials should comply with relevant codes, standards, specifications and technical requirements set and/or approved by the Company and should be procured from company approved Vendors/ Manufacturers/ Suppliers.

Depending on criticality of pipeline, type of material, past performance and quality control system of manufacturer, the Company shall specify the level and extent of inspection that the Company intends to perform (if any).

For each pipe size, sufficient spare materials for possible route deviations, transportation and construction damages, testing and set-up of contingency stock should be estimated and ordered with the actual quantities required for the project.

8.3 Line pipe Materials

Carbon steel line pipe shall be in accordance with API Spec. 5L supplemented by IPS-M-PI-190.

Line pipe materials other than carbon steel shall comply with ANSI/ASME B 31.4 and B 31.8 and this supplement as well as other specific relevant supplements and codes specified by the Company.

8.4 Valves

Valves should comply with IPS-M-PI-110. The valve inlet and outlet passages should be specified to match the pipe internal diameter.

Check valves should preferably be swing type to API-6D. Other types may be considered subject to prior approval of the Company.

8.5 Connections, Fittings, etc.

Threaded connections (pipe to pipe, fittings, etc.) and slip-on flanges shall not be used in any part of the pipeline system. "Pup" pieces should not be less than 0.15 m or 2½ pipe diameter whichever is greater.

Flanges should preferably be of welding neck type and the neck should match the internal diameter of the line pipe for welding.

For flanges in flow lines and all flanges above class 900, Ring Type Joint (RTJ) flanges to API shall be used. All other flanges shall be Raised Face (RF) and in accordance with the IPS-M-PI-150:

Note:

Gaskets should be raised face spiral wound for raised face flanges.

Branch or instrument connections smaller than DN 50 (NPS 2) should not be used on pipeline for mechanical strength reasons. For pipelines smaller than DN 50 (NPS 2), the branch connections shall be of the same diameter as the pipeline.

Weldolets larger than DN 80 (NPS 3) should not be used.

9. PIPELINE ROUTE SELECTION

9.1 General

In selecting the route, full account shall be taken of the associated risks (particularly safety and environmental risks based on location classes, fluid categories, expected frequency of failure, etc.), the accessibility for maintenance and inspection, as well as economic factors (length of line, difficult terrains and crossings, etc.).

Site checks of alternative routes should be made and available maps and geotechnical/geological information should be studied before selecting a suitable route for detailed survey.

9.2 Route and Soil Surveys

Detailed survey data should be made available before finalising the pipeline route and carrying out detailed design. These data shall comply with those indicated in IPS-D-PI-110. Additional plan and profile drawings at enlarged scales should be provided for difficult sections such as crossings at rivers, roads, railways, etc. Full topographic surveys may be required for certain areas.

The profile drawings should also indicate areas in which major excavation or elevated pipeline supports may be required. The radius of curvature of the pipeline foundation along the route should not be less than 500 times the pipeline diameter (bends should be used when lower values are necessary). Additional data to be furnished as follows:

a) Geotechnical and other environmental data (such as landslides, faults, earthquakes, floods, currents at river crossings, climatic data, vegetation, fauna, etc.).

b) Soil investigation for type and consolidation of ground for assessing the degree of excavation difficulties.

c) Soil investigation for foundation design (burial and/or support design), subsidence areas (e.g. underground erosion and cavitation by acidic water or mining activities).

d) Water table levels at mid spring and winter along the route of the pipeline where it is to be buried.

e) Soil resistivity along the pipeline route for coating selection and cathodic protection design. Areas where soil properties may change due to causes such as sulphate reducing bacteria, which increases current required for cathodic protection systems, should be identified.

9.3 Proximity to Occupied Buildings

For minimum distance of pipeline from occupied buildings, reference shall be made to the safety regulations enforced by related Company.

9.4 Proximity to Other Facilities

- For categories B, C and D, the separation requirements of the pipeline to other facilities within plant fences should be in accordance with IPS-E-PI-240.

- For separation requirement at crossings see Section 11 of this Standard.

- Refer to the Institute of Petroleum Model Code of Safe Practice Part 15 for area classifications around the pipeline.

9.5 Right-of-Way

Every pipeline shall have a permanent right-of-way with sufficient width to enable the line to be constructed (including future additional lines) and to allow access for pipeline inspection and maintenance.

Land acquisition drawings shall be prepared and necessary coordination with related authorities shall be made.

9.5.1 Right-of-way width

For every pipeline project, the width of the right-of-way should be decided based on the following criteria:

- Pipeline being buried or above ground.
- Diameter of the pipeline.
- Method of construction.
- Zig-zag configuration of above ground pipeline.
- Pipeline being in flat areas or in mountainous or hilly areas, etc.
- Future pipelines along the same route (particularly in hilly and moutainous areas where blasting and/or excavation for widening the existing right-of-way may create problem).
- Type of fluid and pressure of the pipeline and the consequential risks of pipeline failure.

For buried pipeline widths of right-of-way shall conform to standard drawing (IPS-D-PI-143).

The following figures can be considered as minimum widths of right-of-way and may be increased where necessary to suit the particular requirements of a specific project or may be reduced, subject to prior approval of the Company, if certain restrictions do not permit widening of the right-of-way to the required ideal widths:

a) For above ground pipelines in flat areas:

For DN 150 (NPS 6) and below	25 m
For DN 200 (NPS 8) up to and including DN 650 (NPS 26)	40 m
For above DN 650 (NPS 26) and based on 1 to 3 lines per track	60 m

b) For above ground pipelines in hilly and mountainous areas:

For DN 400 (NPS 16) and below	21 m
For above DN 400 (NPS 16)	24 m

c) For buried pipelines the following table should be used for one line per track:

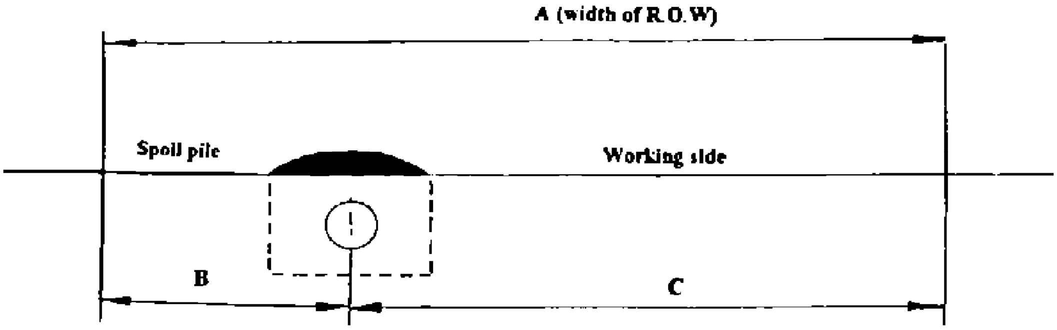


TABLE 3 - RIGHT-OF-WAY WIDTH

PIPELINE DIAMETER (mm)		WIDTHS OF R.O.W IN SOFT SOIL (m)			WIDTHS OF R.O.W IN ROCKY GROUND (m)		
		A	B	C	A	B	C
Up to DN 300	(NPS 12)	16	4	12	11	3	8
DN 350 - DN 400	(NPS 14 - 16)	18	5	13	11	3	8
DN 450 - DN 550	(NPS 18 - 22)	20	5	15	12	3	9
DN 600 - DN 900	(NPS 24 - 36)	23	5	18	15	3.5	11.5
DN 950 - DN 1050	(NPS 36 - 42)	25	7	18	17	4	13
Above DN 1050	(NPS 42)	28	8	20	19	5	14

Notes:

1) For additional lines the width should be increased by one dimension B for each new line. (when two lines are not of the same diameter, the larger diameter should be assumed for both lines).

2) When several pipelines have to be installed in the same trench, the minimum separation between 2 adjacent pipelines shall be 0.3 m.

3) The crossing of existing pipelines, cables, power lines, roads, railways and waterways should be at an angle between 90 and 60 degrees.

4) When installing a pipeline along power lines, the horizontal distance from any of the power cables and posts should be at least 4 m for power lines up to 63 kV and 10 m for power lines above 63 kV.

9.5.2 Other considerations

The longitudinal slope of right-of-way should not exceed 22%. However, for short distances (less than 1 km), the longitudinal slope of the right-of-way may be up to 30% in which case the service roads with maximum longitudinal slope of 22% should be considered for access to these sections. In high longitudinal slope and depending on depth of trench coverage and type of soil and seasonal inundation where pipeline may lose its full restraint, it should be ensured that the equivalent stresses in the pipe wall are within acceptable limits or else remedial provisions are considered to reduce or eliminate longitudinal forces due to effective component of the dead weight of the pipeline and its content.

The design of right-of-way should comply with line bending specification and also civil construction standard specification IPS-C-CE-112 (Earthworks).

10. PIPELINE PROTECTION AND MARKING

10.1 Burial Philosophy

Pipelines are normally buried to protect them from mechanical damage, unusual environmental and climatical conditions, fires, tampering, etc. and to assure that they are fully restrained. As a general rule, pipelines of DN 400 (NPS 16) and larger should normally be buried unless the terrain would make burial impracticable or the length is too short to justify burial advantages. Pipelines of DN 300 (NPS 12) and smaller and short life pipelines of all sizes (such as flowlines) may be laid above ground unless there are good reasons for burial; e.g. process requirements or where protection from diurnal temperature variation is necessary or where the line passes through populated areas, etc.

10.2 Trench Dimensions

The recommended minimum covers are given in Table 4, based on ANSI/ASME B 31.8 Article 841.142 but with some modifications for increased safety margins.

TABLE 4 - RECOMMENDED MINIMUM COVER FOR BURIED PIPELINES

LOCAL	MINIMUM COVER (m) IN NORMAL GROUND	MINIMUM COVER (m) IN ROCK REQUIRING BLASTING
Class 1	0.9	0.6
Class 2	1.0	0.8
Class 3 & 4	1.2	1.0
Public road and railway crossings	2	2

Notes:

1) The cover refers to the undisturbed ground level to the top of the pipe.

2) A minimum vertical clearance of 0.3 m should be kept between the pipeline and other buried structures (see also 11.3.4 for crossing other pipelines).

Additional depth may be required in certain locations such as agricultural areas where depth of ploughing and of drain systems shall be taken into account. A cover of 1.2 m would be adequate in most cases. The width of trench should be not less than 400 mm wider than the pipeline outside diameter in all ground conditions including rock.

When pipelines are coated and/or insulated, the outside diameter of coated or insulated pipe should be assumed as outside diameter for minimum coverage.

10.3 Thermal Expansion and Other Forces

Buried pipelines operating at very high temperatures may be prone to upheaval buckling caused by high compressive loads due to expansion. In such cases, the depth of burial cover should be increased to prevent the upheaval buckling. In general, the recommended cover depth should be enough to make the pipeline fully restrained and to contain thermal expansion and contraction of the pipeline as well as other forces due to internal pressure and pipeline weight in slopes.

Pipeline anchors should be installed at end points of buried pipelines and at other locations where the pipeline rises above ground level for connections to facilities, etc.

Pipeline anchors should be designed for the particular application to withstand forces due to MAIP and temperature variations and to suit the ground conditions specially where subject to seasonal inundation or in dry water courses in high slopes where pipeline dead weight creates longitudinal stresses.

10.4 Non-Buried Pipelines

Any non-buried pipeline sections shall be justified on an individual basis and hence shall be installed in such a way that stay clear of the ground all the time to avoid external corrosion. Pipe supports should be designed in accordance with IPS-G-PI-280.

The height of supports should be chosen to suit local conditions but should be sufficient to keep the bottom of pipeline at least 300 mm above the highest recorded flood level.

Non-buried pipelines should normally be laid in a zig-zag configuration to cater for the effect of thermal expansion and contraction. The zig-zag configuration may be in accordance with Fig. 1. However, for specific cases, the correct configuration should be determined by appropriate design.

Where zig-zag configuration is not or can not be employed, alternative means, such as fully restraining the pipeline from movements (e.g. by adequate anchoring at appropriate intervals), should be provided to contain thermal expansion and contraction as well as other prevailing forces.

Pipeline anchors should be considered for non-buried pipelines at all tie-in connections to other facilities and at other positions where restraint may be necessary.

Hillside anchors shall be designed, as and where required and shall be installed on steep hills to restrain pipeline movement and to keep the combined stresses in the pipeline wall within the acceptable limits. The effect of the weight of the pipeline and its contents on the longitudinal stress in the pipeline wall should be considered in calculating the combined stresses.

10.5 Corrosion Protection

As a general rule, in normally dry climates, no external anti-corrosion coating is required for above-ground pipelines which are supported clear of the ground. However, where the climatic conditions or the ground are such that external corrosion may occur, either a corrosion allowance on the pipewall thickness may be required or, alternatively, a suitable anti-corrosion coating should be considered.

Where sections of above-ground pipelines are to be buried (e.g. road, railway or river crossings), the buried sections shall be suitably coated, cathodically protected and electrically isolated from the rest of the pipeline in accordance with IPS-E-TP-820.

Those sections of pipeline which pass above waterways and rivers should be externally coated for protection against corrosion caused by condensation of water vapor on the pipeline exterior.

Where above-ground pipelines pass through culverts or below bridges (which are normally for pipelines crossing the main roads and/or for surface water passages), these sections of the lines shall be suitably coated for protection against splashing water and blown sand and dirt.

All metallic buried pipelines including duplex material pipelines, shall be coated externally by a suitable anti-corrosion coating, supplemented by cathodic protection and electrically isolated from the plants and facilities to which they are connected.

The design of cathodic protection systems shall be carried out in accordance with IPS-E-TP-820.

Protective coatings shall be selected to suit the soil and other environmental conditions and shall comply with IPS-E-TP-270.

10.6 Pipeline Markers

The location of buried pipelines shall be clearly identified by markers. In areas where the risk of interference or disturbance by mechanical excavators or boat anchors (at river crossings) is high, additional warning signs should be installed to lower the risk. Pipeline markers should be installed at the following locations along buried pipelines:

a) At one kilometer interval.
b) At all major changes in direction of the pipeline.
c) At both sides of every road, railway and under-water crossings.
d) At changes in wall thickness.
e) At branches.
f) At buried valves and fittings such as check valves, vents, drains, slug-catchers, etc.

Fabrication and installation details should be as per Standard Drawing No. IPS-D-TP-712.

11. CROSSINGS

11.1 River Crossings

11.1.1 Where pipeline has to cross a major river, careful studies shall be carried out as to determine the most suitable way of crossing which will ensure maximum reliability during the pipeline operating life with minimum maintenance problems. The selection of the most suitable location and type of crossing should be based on the survey results and information on geotechnical and hydroclimatological conditions and other prevailing environmental issues. The migration of the river course should also receive particular attention.

11.1.2 Elevated pipe supports should be high enough to carry the line at least 300 mm clear of highest flood level (oldest available return conditions). This clearance should be increased if there is likelihood of large floating objects being carried by flood water and where the river is navigable. Elevated pipe supports should be designed to suit the particular circumstances and be strong to withstand the forces imposed on them by flood water and the objects which are carried by the flood and may be caught by the supports. In wide rivers and where there are possibility of torrential flood, pipe bridges are preferred to single pipe supports. If pipeline is to be cathodically protected, means of isolating the pipeline from the supports should be considered.

11.1.3 The sections of pipelines laid under the river bed should be coated and wrapped in accordance with IPS-E-TP-270 and cathodically protected in accordance with IPS-E-TP-820.

11.1.4 The sections of pipeline laid in trenches in the river bed should be weight coated to give the necessary negative buoyancy to the pipeline to fully restrain the pipeline in position at all times, during construction, operation and while shut down for maintenance or inspection. The weight coating should normally be designed to maintain pipeline stability in mud of specific gravity 1.2. In any case, the nature of the river bed should be taken into account in determination of required weight..

Depth of cover and the curvature of the pipeline during laying and henceforth as well as method of laying the pipeline should be selected for the particular application to avoid damage to the pipeline specially when it is being installed.

11.1.5 Isolating block valves fitted with automatic line-break-operators should be installed in fenced areas on either side of the major river crossings. If valves are installed in valve pits, the top of the pits should be above maximum recorded high water level and if there is possibilities of water ingressing into the pits, facilities should be considered for emptying the water.

The automatic line-break-operators should be designed to close the valve in the event of pipeline failure and subsequent rapid rate of change of pressure in the pipeline but should not be affected by normal operational pressure fluctuations. The design should ensure that changes of the water course and/or collapse of the river side walls will not endanger the integrity of the valve support.

11.2 Road and Railway Crossings

Pipelines crossing roads and railways should preferably be through culverts or concrete box and bridges (new or existing). The use of casing pipe should be discouraged (due to external corrosion problems and electrical contact between casing pipe and carrier pipe). (See API RP 1102 for recommendations in this respect.) Suitable protection should be provided on both sides of the road to prevent damage to the pipeline by vehicles leaving the road. For minimum recommended coverage at crossings see Table 4 Clause 10.2 of this Standard.

If the right-of-way is intended for more than one pipeline, culverts or bridge should be wide enough to accommodate future pipeline(s). In this case the horizontal space between two adjacent pipelines should not be less than 400 mm. For angle of crossing refer to Note 3 of Table 3 Clause 9.5.1 of this Standard.

11.3 Crossing Other Pipelines

11.3.1 Where above-ground pipelines cross each other a minimum clearance of 300 mm should be maintained between adjacent lines.

11.3.2 Where a buried pipeline is to cross an existing above-ground pipeline an increased depth of cover should be specified for the whole width of the right-of-way.

11.3.3 Where an above-ground pipeline is to cross an existing buried pipeline means should be provided to allow continued use of the buried pipeline right-of-way.

11.3.4 Where a buried pipeline is to cross an existing buried pipeline the new line should pass under the existing line with at least 900 mm clearance between the two lines.

11.3.5 Potential test points, current test points and bonding points (direct or resistance) should be installed on both lines at the crossing to enable the cathodic protection systems to be interconnected, if required.

11.3.6 For a minimum distance of 15 meters on either side of the pipeline crossing the new pipeline shall be double wrapped.

11.3.7 Where a pipeline crosses an existing pipeline owned by an outside Company, the design of the crossing and cathodic protection should satisfy the requirements of the outside Company.

11.4 Crossing Land Faults

When pipeline has to cross a passive fault, the necessity of provision of any protection system should be decided after geothechnical survey results are studied by Company geological department or Company appointed geologist and hence or otherwise their recommendations are given. Crossing an active fault shall be avoided if feasible. When, however, pipeline has to cross an active fault or a passive fault which is expected to become active, the following considerations should be given at the crossing for the protection of the pipeline

11.4.1 Design factors similar to those indicated for rivers, dunes and beaches should be used (see Table 2 of Clause 7.5.2.2 of this Standard).

11.4.2 Crossing angle should be selected for minimum bending and shear stresses in the pipeline wall due to movement of the fault banks.

11.4.3 There should be no horizontal bends, flanges, tees, valves or similar constraints such as concrete weights in at least 200 meters of the pipeline either sides of the fault center.

11.4.4 The trench dimensions and the backfill material around the pipeline at 200 meters either sides of the fault center should be selected in such a way that the pipeline is subjected to minimum restraint.

11.4.5 Line break valves with automatic shut-down operators shall be installed at 250 meters either side of the fault center. These valves should be secured against movements of the section of the pipeline which crosses the fault by means of adequately designed anchors.

11.5 Land Slides

Passing near the areas where there are evidence of land slide shall be avoided by using alternative routes or going around the suspected areas.

12. RECORDS

A comprehensive set of design documents shall be produced and retained for the life of the pipeline. These documents should include all the design criteria, calculations and assessments which led to the technical choices during conception and design of the pipeline. They shall also include pipeline operating and maintenance manual which should cover the range of key operating conditions that can be envisaged for the entire life span, major features, parameters, contingency plans, etc.

APPENDICES

APPENDIX A
SERVICE PIPELINE CO. FORMULA

For turbulent flow up to Re = 170,000

$$P = \frac{31.92 \times 10^{3} \times Q^{1.748} \times v^{0.2518} \times S}{D^{4.748}}$$

or

$$Q = \frac{2.6527 \times 10^{-3} \times D^{2.716} \times P^{0.572}}{v^{0.144} \times S^{0.572}}$$

Where:

P	= Pressure drop	bar/km
Q	= Flowrate	m^3/d
D	= Pipe inside diameter	mm
v	= Kinematic viscosity	cS
S	= Specific gravity	

APPENDIX B
SHELL / MIT FORMULA

Calculations are made in accordance with the method recommended by Wilson and Mc Adams and reported in "Contribution No. 19 from the Department of Chemical Engineering, Massachusetts Institute of Technology". Converted to metric form the formulas are as follows:

$$P = \frac{4.4191 \times 10^6 \times f \times SXQ^2}{D^5}$$

For viscous flow $$f = 0.16025 \left(\frac{v}{DV}\right)$$

For turbulent flow $$f = 0.0018 + 0.013685 \left(\frac{v}{DV}\right)^{0.355}$$

Where:

P	= Pressure drop	bar/km
Q	= Flowrate	m^3/d
D	= Pipe inside diameter	mm
v	= Kinematic viscosity	cS
S	= Specific gravity	
f	= Friction factor	
V	= Average velocity of fluid	m/s

APPENDIX C
SIMPLIFIED DARCY EQUATION

$$P = 6.254 \times 10^5 \times \frac{f_m \times W_T^{\ 2}}{d^5 \rho_m}$$

Where:

P	= Pressure drop	(Bar/km)
f_m	= Darcy or moody friction factor	(see Appendix H)
W_T	= Total liquid plus vapor flow rate	(kg/h)
d	= Inside diameter of pipe	(mm)
ρ_m	= Gas/liquid mixture density at operating pressure and temperature (kg/m^3)	

Notes:

1) ρ_m may be calculated from the following derived equation:

$$\rho_m = \frac{28829.6\ S_L \times P + 35.22\ R \times G \times P}{28.82\ P + 10.12\ R \times T \times Z}$$

Where:

S_L	**= Relative density of oil (water = 1)**
P	**= Operating pressure (kPa Absolute)**
R	**= Gas/oil ratio (m^3 of gas/m^3 of oil at metric standard conditions)**
G	**= Gas relative density =** $\left(\frac{MW}{28.9}\right)$ **at standard conditions**
MW	**= Molecular weight of the gas at 20°C and 760 mm mercury**
T	**= Operating temperature (°K)**
Z	**= Gas compressibility factor**

2) The above Darcy equation loses its accuracy when pressure drop is more than 10% (due to changes in density of gas). For pressure drops higher than 10%, calculations should be carried out for smaller segments of the pipeline and the values added together.

APPENDIX D
T.R. AUDE AND HAZEN-WILLIAM'S FORMULAS

1) T.R. Aude formula

$$Q = \frac{3.4657 \times 10^{-3} \times D^{2.66} \times P^{0.552} \times C}{S^{0.448} \times \mu^{0.104}}$$

or

$$P = \frac{28635\ Q^{1.812} \times \mu^{0.188} \times S^{0.812}}{C^{1.812} \times D^{4.819}}$$

2) Hazen-William's formula

$$Q = \frac{2.6 \times 10^{-3} \times D^{2.63} \times P^{0.54} \times C}{S^{0.54}}$$

or

$$P = \frac{61.07 \times 10^{3} \times Q^{1.852} \times S}{C^{1.852} \times D^{4.87}}$$

Where:

Q	= Rate of flow	(m^3/d)
D	= Inside diameter of pipe	(mm)
P	= Pressure drop	(bar/km)
C	= T.R. Aude's friction factor	
	= (pipe efficiency)	= 1.2 for new steel pipe
		= 1.0 for old steel pipe
S	= Specific gravity of liquid	
μ	= Absolute viscosity	(centipoise)

APPENDIX E
WEYMOUTH FORMULA

$$Q = 0.003749 \times \frac{To}{Po}\left(\frac{(P_1^2 - P_2^2)\, D^{5.333}}{S \times T \times L}\right)^{0.5}$$

Where:

Q	= Flowrate	m^3/d
S	= Specific gravity of gas	(Air=1)
L	= Length of line	km
To	= Temperature basis for defining gas	°K
T	= Mean flowing temperature	°K
P_1	= Inlet pressure	bar (abs)
P_2	= Final pressure	bar (abs)
Po	= Pressure basis for defining gas	bar (abs)
D	= Pipe inside diameter	mm

APPENDIX F
PANHANDLE REVISED OR B FORMULA

$$Q = 10.024 \times 10^{-3} \times \left(\frac{To}{Po}\right)^{1.02} \times D^{2.53} \times \left(\frac{P_1^{\,2} - P_2^{\,2}}{S^{0.961} \times T \times L \times Z}\right)^{0.51} \times E$$

Where:

Q	= Flowrate	m^3/d
S	= Specific gravity of gas	(Air=1)
L	= Length of line	km
To	= Temperature basis for defining gas	°K
T	= Mean flowing temperature	°K
P_1	= Inlet pressure	bar (abs)
P_2	= Final pressure	bar (abs)
Po	= Pressure basis for defining gas	bar (abs)
D	= Pipe inside diameter	mm
E	= Efficiency factor	(taken as 0.9)
Z	= Compressibility factor	

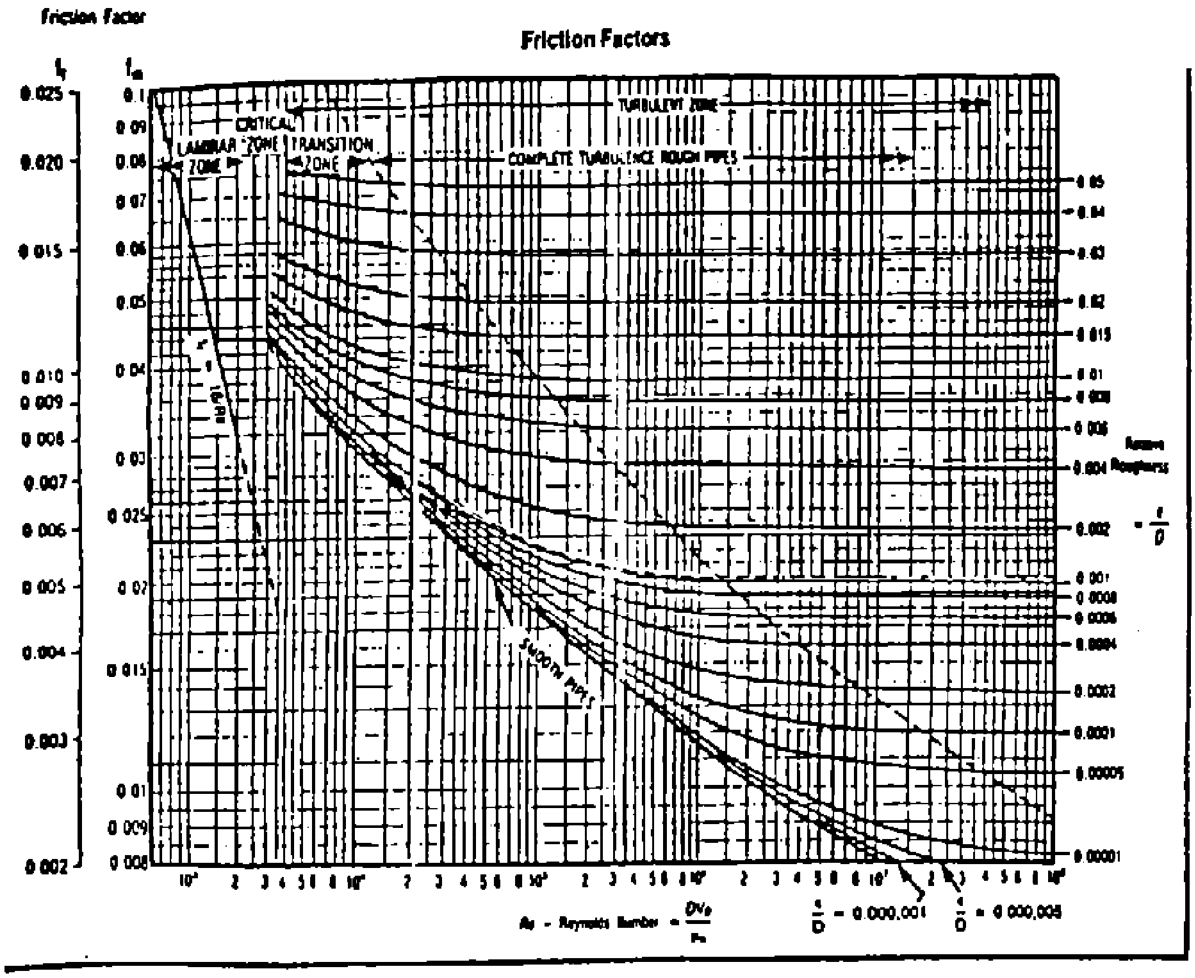
APPENDIX G
IGT/AGA FORMULA

$$Q = 2.298 \times 10^{-3} \times \frac{To}{Po} \left(\frac{P_1^{\,2} - P_2^{\,2} - \left(\frac{0.06834\ (h_2 - h_1)\ P^2}{TXZ} \right)}{S \times T \times Z \times L} \right)^{0.5} D^{2.5} \times \text{Log} \frac{3.7D}{Ke}$$

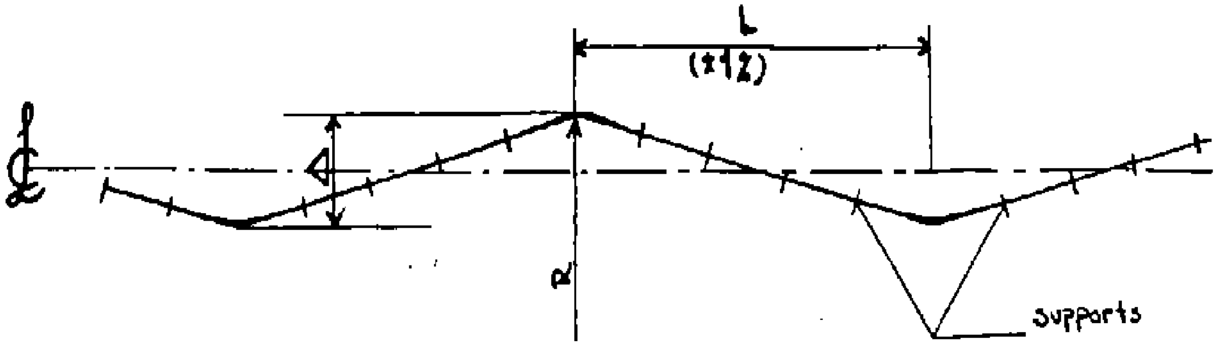
Where:

Q	= Flowrate	m^3/d
S	= Specific gravity	(Air = 1)
To	= Temperature basis for defining gas	°K
T	= Mean flowing temperature	°K
P_1	= Inlet pressure	bar (abs)
P_2	= Final pressure	bar (abs)
Po	= Pressure basis for defining gas	bar (abs)
P	= Average pressure	bar (abs)
L	= Length of line	km
D	= Pipe inside diameter	mm
Z	= Average compressibility factor at P and T	
Ke	= Effective roughness of pipe wall	mm
h_1	= Initial elevation of line	m
h_2	= Final elevation of line	m

APPENDIX H
MOODY FRICTION FACTOR CHART



D	= Pipe diameter	mm
V	= Fluid velocity	m/s
ρ	= Fluid density	
μ	= Fluid viscosity	cP
ε	= Absolute pipe roughness	mm
f_m	= Moody friction factor	
f_F	= Fanning friction factor	
f_D	= Darcy's friction factor = f_m = $4f_F$	



PLAN VIEW OF ZIG-ZAG CONFIGURATION FOR ABOVE-GROUND PIPELINE
Fig. 1

TABLE 5 - ZIG-ZAG CONFIGURATION DIMENSIONS

PIPE SIZE DN (NPS)		PIPE MATERIAL GRADE PER API 5L	STRAIGHT LENGTH L (m)	OFFSET Δ (m) (MINIMUM)	BEND RADIUS R (m) (MINIMUM)
Up to DN 300	(NPS 12)	GR B	60	4	25 × Dia.
DN 400	(NPS 16)	GR B/ × 42	116	9.1	17
		× 52/ × 60	100	6.5	17
DN 500	(NPS 20)	GR B/ × 42	116	9.1	22
		× 52/ × 60	100	6.5	22
DN 550	(NPS 22)	GR B/ × 42	116	9.5	23
		× 52/ × 60	100	6.5	23
DN 600	(NPS 24)	GR B/ × 42	116	9.5	25
		× 52/ × 60	100	6.5	25
DN 650	(NPS 26)	GR B/ × 42	116	7.1	28
		× 52/ × 60	100	6.5	28
DN 750	(NPS 30)	GR B/ × 42	116	7.1	31
		× 52/ × 60	100	6.5	31