Offshore Pipelines
This book is dedicated to the families of the authors for their understanding and encouragement that were as responsible as the experience and knowledge that have been inscribed herein.
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Preface

Producing oil and gas from offshore and deepwater by means of pipelines has gained a tremendous momentum in the energy industry in the past ten years. At the time of this writing, the pipeline technology has been successfully used in areas with water depths of greater than 6000 feet. It is not uncommon that the costs of pipeline construction and management are higher than that of drilling and production components. Optimizing pipeline development process has become a vitally important topic for achieving cost-effective management in offshore and deepwater pipeline operations.

As the submarine pipeline is a relatively new industry, there is lack of a set of systematic rules that can be employed to optimize pipeline development projects. Pipeline operating companies are looking more and more to engineering innovation to provide them with cost-effective approaches for developing their pipeline systems. Because of the huge investment in offshore, especially in deepwater development, any experience gained from any pipeline project is very valuable to the whole industry. Sharing with other engineers and management personnel the authors’ experiences gained from years of working on multiple pipeline projects was the motivation of writing this book.

This book is written primarily for new and experienced engineers and management personnel who work on oil and gas pipelines in offshore and deepwater. It is not the authors’ intention to duplicate general information that can be found from other books. This book gathers the authors’ experiences gained through years of designing, installing, testing, and operating submarine pipelines. The mission of the book is to provide engineers and management personnel a guideline to achieve cost-effective management in their offshore and deepwater pipeline development and operations. This book can also be used as a reference for college students of undergraduate and graduate levels in Ocean Engineering, Mechanical Engineering, and Petroleum Engineering.

This book was intended to cover the full scope of pipeline development from pipeline designing, installing, and testing to operating. Following the sequence of pipeline development, this book presents its contents in three parts. Part I presents design practices that are currently used in development of submarine oil and gas pipelines and risers. Contents of this part include selection of pipe size, coating, and insulation. Part II provides guidelines for pipeline installations. It focuses on controlling bending stresses and pipe stability during laying pipelines. Part III deals with problems that occur during pipeline operations. Topics include pipeline testing and commissioning, flow assurance engineering, and pigging operations. Appendices A, B, and C present fundamentals of multiphase flow in pipeline and some details of mathematical models used in pipeline design and analysis.

Since the substance of this book is virtually boundless, knowing what to omit was the greatest difficulty with its editing. The authors believe that it requires many books to
describe the foundation of knowledge in pipeline technology. To counter any deficiency that might arise from the limitations of space, we provide a reference list of books and papers at the end of each chapter so that readers should experience little difficulty in pursuing each topic beyond the presented scope.

As regards presentation, this book focuses on presenting principles, criteria, and data necessary to perform engineering analyses. Derivation of mathematical models is beyond the scope of this book. Also, the number of example calculations is limited due to the fact that most engineering analyses are carried out with computer packages in today's industry. This format of presentation was also intended to attract non-technical readers such as pipeline management personnel.

This book is based on numerous documents including reports and papers accumulated through many years of work in the University of Louisiana at Lafayette, ChevronTexaco, and INTEC Engineering. The authors are grateful to these companies for permission to publish the materials. Special thanks go to the ChevronTexaco and American Petroleum Institute (API) for providing ChevronTexaco Professorship and API Professorship in Petroleum Engineering throughout editing of this book. Last but not least, our thanks are due to friends and colleagues too numerous to mention, who encouraged, assessed, and made possible our editing this book. Among them are Dr. Holden Zhang, a professor from the University of Tulsa, who reviewed the chapter on multiphase flow in pipeline; Dr. Jeff Creek of ChevronTexaco, who reviewed the chapter on flow assurance; Mr. Roger Bergman of ChevronTexaco, who reviewed the chapter on pipeline testing and pre-commissioning; and Mr. Daniel Stone of Elsevier S&T Books whose professional attitude helped assure the quality of this book. On the basis of their collective experience, we expect this book to be of value to engineers and management personnel in the pipeline industry.

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June 2004
## List of Symbols

- $A$: pipeline (steel) cross-sectional area
- $A_c$: total external area
- $A_{e}$: exposed anode surface area
- $A_f$: pipeline cross-sectional area open for fluid flow
- $A_g$: pipeline cross-sectional area occupied by gas
- $A_l$: pipeline cross-sectional area occupied by liquid
- $A_s$: cross-sectional area of stress
- $a$: outside radius (for thick cylinder)
- $a_T$: trench slope ratio, height/lateral distance
- $b$: inside radius (for thick cylinders)
- $b_i$: width of pipe/soil contact
- $b_{wo}$: spacing between wave orthogonals
- $b_{wo}$: spacing between wave orthogonals in deepwater
- $C$: water wave velocity
- $C_a$: average soil cohesion
- $C_b$: soil cohesion at base of pipe
- $C_D$: hydrodynamic drag coefficient
- $C_e$: constants depending on the ends condition
- $C_l$: hydrodynamic inertia coefficient
- $C_o$: deepwater wave velocity
- $C_p$: specific heat of fluid at constant pressure
- $C_1$: wave velocity at depth of the first bottom contour
- $C_2$: wave velocity at depth of the second bottom contour
- $c$: wave velocity in pipe
- $c_a$: anode current capacity
- $c_1$: empirical constant in the wave spectrum equation
- $c_2$: empirical constant in the wave spectrum equation
- $D$: pipeline outside diameter
- $D_g$: hydraulic diameter of gas phase
- $D_i$: inner diameter
- $D_j$: hydraulic diameter of liquid phase
- $D_{\text{max}}$: maximum diameter through cross section
- $D_{\text{min}}$: minimum diameter through cross section
- $C_L$: hydrodynamic lift coefficient
- $D_r$: relative density for sand (0.05-0.5 typical)
- $d$: water depth
List of Symbols

d_m \quad \text{depth of embedment}
d_p \quad \text{distance between drain points}
E \quad \text{steel modulus of elasticity}
E_A \quad \text{change in potential at drain point}
E_B \quad \text{change in potential at the midpoint between the two drain points}
E_d^o \quad \text{design protective potential}
E_c^o \quad \text{design closed circuit potential of the anode}
E_w \quad \text{weld joint factor (typical value 1.0)}
E_x \quad \text{change in potential at point x}
F \quad \text{force}
F_b \quad \text{buoyant force}
F_D \quad \text{hydrodynamic drag force}
F_f \quad \text{lateral sliding friction force} = \mu(W_s - F_L)
F_b^u \quad \text{ultimate break-out force for embedded pipe}
F_L \quad \text{hydrodynamic lift force}
F_R \quad \text{embedment-dependent soil resistance}
F_t \quad \text{temperature derating factor (from Table 6.2)}
F_h \quad \text{hoop stress design factor}
F_s \quad \text{longitudinal stress design factor}
f \quad \text{longitudinal soil friction resistance}
f_b \quad \text{coating breakdown factor}
f_c \quad \text{the concentration of the dispersed phase at which the emulsion viscosity } \mu_e \text{ is 100 times of the viscosity of the continuous phase } \mu_c
f_d \quad \text{the volume fraction of the dispersed phase (less than 0.1)}
f_g \quad \text{friction factor of gas wall}
f_i \quad \text{friction factor at liquid-gas interface}
f_l \quad \text{friction factor of liquid wall}
f_n \quad \text{natural frequency}
f_p \quad \text{secondary pipe imperfection parameter}
f_v \quad \text{vortex-shedding frequency}
f_W \quad \text{wave frequency}
f_w \quad \text{water cut or phase fraction}
G \quad \text{thermal-gradient outside the insulation}
g \quad \text{gravitational acceleration}
g_p \quad \text{primary pipe imperfection parameter for collapse pressure}
H \quad \text{wave height}
H_{IS} \quad \text{liquid holdup inside slug body}
H_{IF} \quad \text{liquid holdup inside the liquid film}
H_{IC} \quad \text{liquid holdup inside the gas core or gas packet}
H_l \quad \text{liquid holdup}
H_{max} \quad \text{maximum wave height}
H_o \quad \text{deepwater wave height}
H\text{\_T} \quad \text{significant wave height, approximately } H_{max}/1.9
h_l \quad \text{trench height}
h_l \quad \text{height (depth) of water column}
I \quad = \pi/64(D^4 - D_i^4), \text{ pipeline inertia}
List of Symbols

$I_A$  total current pick up
$I_a$  anode current output
$I_{af}$ individual anode current output
$I_c$  current demand
$I_{cf}$ current demands required for re-polarization at the end of design life
$I_{cm}$ total final current demand for the pipeline
$I_{ci}$ current demands required for initial polarization
$i_c$  current density
$K$  curvature
$K_c$  Keulegan number
$K_s$  stability parameter
$K_y$  yield curvature
$k$  wave number
$k_n$  thermal conductivity of insulation layer
$k_p$  polarization slope
$L$  length of pipe
$L_c$  critical span length
$L_f$  fatigue life
$L_o$  deepwater wave length
$L_s$  span length
$L_w$  wave length
$M$  moment
$M_a$  added mass
$M_b$  bending moment
$M_c$  mass of content
$M_e$  effective mass
$M_p$  mass of pipe, coating, and insulation materials
$M_t$  total net anode mass
$M_y$  yield moment
$MAOP$ maximum allowable operating pressure
$MBR$ minimum bend radius
$m$  empirical constant in the wave spectrum equation
$m_a$ net mass per anode
$N_f$ number of cycles per year
$N$  wave parameter
$N_o$ number of observed waves
$N_l$ lateral stability coefficient
$N_{f3}$ number of cycles to failure
$n$  empirical constant in the wave spectrum equation
$n_a$ number of anodes
$P$  net internal pressure
$P_c$  collapse pressure
$P_d$  design internal pressure
$P_e$  external pressure
$P_{el}$ elastic collapse pressure of pipe
List of Symbols

\[
\begin{align*}
P_b & \quad \text{hydrostatic pressure} \\
P_i & \quad \text{internal pressure} \\
P_o & \quad \text{external pressure} \\
P_p & \quad \text{buckle propagation pressure} \\
P_y & \quad \text{plastic collapse pressure of pipe} \\
p & \quad \text{internal pressure} \\
Q & \quad \text{volumetric flowrate} \\
Q_g & \quad \text{gas volumetric flowrate} \\
Q_o & \quad \text{oil volumetric flowrate} \\
Q_w & \quad \text{water volumetric flowrate} \\
g & \quad \text{rate of heat transfer, W} \\
R & \quad \text{pipe radius} \\
R_a & \quad \text{anode resistance} \\
R_c & \quad \text{wave/current ratio (} = \frac{U_c}{U_m}\text{)} \\
R_D & \quad \text{damage ratio} \\
Re & \quad \text{Reynold's number} \\
Re_e & \quad \text{effective Reynold's number} \\
R_L & \quad \text{ultimate lateral resistance} \\
R_l & \quad \text{linear resistance of the pipeline} \\
R_n & \quad \text{inner-radius of insulation layer} \\
R_r & \quad \text{ultimate lateral resistance} \\
r & \quad \text{pipe radius} \\
S & \quad \text{Strouhal number} \\
S_y & \quad \text{specified minimum yield strength} \\
S_u & \quad \text{undrained shear strength of clay} \\
SMYS & \quad \text{specified minimum yield strength} \\
s & \quad \text{thickness of insulation layer} \\
s_c & \quad \text{sheltering coefficient or pipe perimeter} \\
T & \quad \text{wave period} \\
T_a & \quad \text{axial tension} \\
T_f & \quad \text{fluid temperature inside the pipe} \\
T_i & \quad \text{current duration} \\
T_j & \quad \text{temperature of fluid at the fluid entry point} \\
T_Y & \quad \text{Yield tension} \\
T_z & \quad \text{average zero crossing period of wave} \\
T_0 & \quad \text{temperature of outer medium at the fluid entry point} \\
T_1 & \quad \text{initial temperature} \\
T_2 & \quad \text{final temperature} \\
t & \quad \text{wall thickness} \\
t_a & \quad \text{wall thickness allowance for corrosion} \\
t_d & \quad \text{design life} \\
t_f & \quad \text{fluid flow time} \\
t_{\text{NOM}} & \quad \text{nominal wall thickness} \\
U & \quad \text{fluid superficial velocity} \\
U_c & \quad \text{steady current velocity} \\
U_m & \quad \text{maximum water particle velocity (water plus current)}
\end{align*}
\]
List of Symbols

\[ U_r \] reduced velocity
\[ U_g \] gas superficial velocity
\[ U_l \] liquid superficial velocity
\[ U_w \] particle velocity due to wave only
\[ u \] fluid velocity
\[ u_C \] gas core velocity
\[ u_F \] liquid film velocity
\[ u_f \] anode utilization factor
\[ u_g \] average gas velocity
\[ u_l \] average liquid velocity
\[ u_S \] slug velocity that equals to the mixture velocity
\[ u_T \] slug translational velocity
\[ u_w \] velocity of the solitary wave
\[ V \] pipe volume
\[ v \] the average flow velocity of fluid in the pipe
\[ W \] weight of soil
\[ W_p \] weight of pipe and its contents
\[ W_s \] pipeline submerged weight
\[ x \] distance along pipe axis
\[ Z \] length from free end to point of no movement (soil friction cases only)
\[ z \] pipeline penetration in soil

**Creeks**

\[ \alpha \] current ratio \( (= \frac{U_C}{U_w}) \)
\[ \alpha_g \] gas void fraction
\[ \alpha_t \] thermal expansion coefficient \( = 6.5 \times 10^{-6} \text{°C}^{-1} \)
\[ \alpha_1, \alpha_1 \] angles of wave crest with bottom contours 1 and 2
\[ \beta \] frequency parameter \( (= \frac{D}{Tn_k}) \)
\[ \zeta \] safety factor
\[ \delta \] seabed slope angle perpendicular to pipe axis
\[ \delta_i \] average thickness of the liquid film in annular flow
\[ \delta_o \] initial out-of-roundness due to fabrication tolerances
\[ \delta_s \] logarithmic decrement of structural damping \( (0.125) \)
\[ \varepsilon \] strain
\[ \varepsilon_B \] bending strain at buckling failure due to pure bending
\[ \varepsilon_b \] bending strain
\[ \varepsilon_e \] the electrochemical efficiency
\[ \varepsilon_h \] hoop strain
\[ \varepsilon_L \] longitudinal strain
\[ \varepsilon_t \] thermal strain
\[ \eta \] usage factor
\[ \sigma \] surface tension
\[ \sigma_a \] axial stress
\[ \sigma_h \] hoop stress
\[ \sigma_L \] longitudinal stress
List of Symbols

\( \sigma_r \)  
 radial stress  

\( \sigma_{\text{range}} \)  
 cyclic stress range (bending)  

\( \sigma' \)  
 von Mises stress  

\( \mu \)  
 coefficient of longitudinal soil friction  

\( \mu_l \)  
 liquid viscosity  

\( \mu_m \)  
 mixture viscosity  

\( \mu_g \)  
 gas viscosity  

\( \mu_o \)  
 oil viscosity  

\( \mu_w \)  
 water viscosity  

\( \nu \)  
 Poisson’s ratio (typical value 0.3 for steel in the elastic range)  

\( \nu_g \)  
 gas kinematic viscosity  

\( \nu_l \)  
 liquid kinematic viscosity  

\( \nu_k \)  
 kinematic viscosity of external fluid (seawater at 60°F = \(1.2 \times 10^{-5}\) ft²/sec)  

\( \kappa \)  
 mean roughness  

\( \pi \)  
 constant of 3.14159  

\( \theta \)  
 angle between the thermal gradient and pipe orientation, degree  

\( \theta_p \)  
 pipeline inclination angle, degree  

\( \rho \)  
 density  

\( \rho_e \)  
 environmental resistivity  

\( \rho_f \)  
 density of fluid in pipe  

\( \rho_g \)  
 gas density, respectively  

\( \rho_l \)  
 liquid density  

\( \rho_m \)  
 gas-liquid mixture density  

\( \rho_p \)  
 density of pipe  

\( \gamma' \)  
 submerged weight of soil  

\( \Delta \varepsilon \)  
 cyclic strain range  

\( \Delta L \)  
 movement of pipe longitudinally at free end  

\( \Delta R \)  
 radial dilation of pipe  

\( T \)  
 shear stress  

\( \tau_g \)  
 shear stress in gas  

\( \tau_l \)  
 shear stress in liquid  

\( \tau_i \)  
 shear stress at gas-liquid interface  

\( \tau_t \)  
 tangential shear stress  

\( \Theta \)  
 temperature difference, \( T_2 - T_1 \) (°F)  

\( \Theta_l \)  
 pipe wall fraction wetted by liquid
Unit Conversion Factors

Length

1 in. = 25.4 mm
1 ft = 0.3048 m
1 mile = 1.609 km
1 nautical mile = 1.852 km
1 fathom = 6 ft = 1.8288 m

Area

1 in² = 6.4516 cm²
1 ft² = 0.0929 m²

Volume

1 in³ = 16.387 cm³
1 ft³ = 0.028317 m³

Liquid Volume

1 oz = 29.574 ml
1 gal (US) = 0.134 ft³ = 3.785 l
1 gal (Imp) = 4.546 l
1 barrel = 42 gal (US) = 158.991 = 5.6146 ft³

Mass

1 lbm = 0.4536 kg
1 slug = 1 lbf·sec²/ft
1 slug = 32.174 lbm = 14.59 kg

Force

1 lbf = 4.448 N
1 lbf = 32.174 poundals
1 N = 1 kg·m/sec² = 0.225 lbf
1 ton (short) = 907.2 kg
1 ton (long) = 1016.0 kg
1 lbf/ft = 14.59 N/m
**Unit Conversion Factors**

1 lb/ft = 1.488 kg/m  
1 lb/ft² = 47.880 N/m²  
1 kN = 224.8 lbf

**Density**

1 lbf/in³ = 27.68 g/cm³  
1 lbf/ft³ (pcs) = 16.02 kg/m³

**Pressure or Stress**

1 psi = 0.006895 Mpa = 6.895 kPa = 6895 Pa  
1 psi = 68947 dynes/cm²  
1 psi = 0.0703 kg/cm²  
1 psi = 0.0680 atm  
1 psi = 0.0685 bar  
1 psf = 47.88 Pa  
1 psf = 4.882 kg/m²

**Flow Rate**

1 gal/min = .0631 l/s  
1 ft³/sec = 101.94 m³/hr  
1 ft³/sec = 0.472 l/s  
1 bbl/hr = 0.159 m³/hr  
1 MBPD = 158.99 m³/day

**Viscosities**

**Kinematic (ν)**

1 ft²/sec = 929 cm²/s (stokes)  
1 ft²/sec = 92903 cs (centistokes)

**Absolute (μ = ρν)**

1 lbm/sec*ft = 14.88 Poise (g/s*cm)  
1 lbm/sec*ft = 1488 cp (centipoises)  
1 lbf*sec/ft² = 47880 cp  
1 cp = 0.001 Pa*s

**Energy**

1 cal = 4.184 J  
1 Btu = 778.2 ft*lbf  
1 ft*lbf = 1.3556 J  
1 ft*lbf = 0.324 cal  
1 ft³*lbf/in² = 46.66 cal  
1 Btu = 1055 J = 252 cal  
1 Btu = 0.2931 W*hr  
1 Btu = 0.000393 hp*hr
### Power

- \( 1 \text{ Btu/hr} = 0.2931 \text{ W} \)
- \( 1 \text{ Btu/hr} = 0.00039846 \text{ hp (metric)} \)
- \( 1 \text{ hp (Imp)} = 745.7 \text{ W} = 1.0139 \text{ hp (metric)} \)
- \( 1 \text{ ft lb/min} = 0.0226 \text{ W} \)
- \( 1 \text{ ft lb/sec} = 0.324 \text{ cal/s} \)

### Specific Energy (or latent heat)

- \( 1 \text{ Btu/lbm} = 2.326 \text{ J/g} \)
- \( 1 \text{ Btu/lbm} = 0.556 \text{ cal/g} \)

### Specific Energy per Degree (specific heat)

- \( 1 \text{ Btu/lbm}^\circ F = 4.186 \text{ J/g}^\circ C \)
- \( 1 \text{ Btu/lbm}^\circ F = 4.186 \text{ J/kg}^\circ K \)
- \( 1 \text{ Btu/lbm}^\circ F = 1.0007 \text{ cal/g}^\circ C \)
- \( 1 \text{ Btu/slug}^\circ F = 130.1 \text{ J/kg}^\circ K \)

### Heat Flux

- \( 1 \text{ Btu/hr}^{*}\text{ft}^2 = 0.0003155 \text{ W/cm}^2 \)
- \( 1 \text{ Btu/hr}^{*}\text{ft}^2 = 0.0007535 \text{ cal/s}^\circ \text{cm}^2 \)
- \( 1 \text{ Btu/hr}^{*}\text{ft}^2 = 0.2712 \text{ cal/hr}^*\text{cm}^2 \)

### Heat Transfer Coefficient

- \( 1 \text{ Btu/hr}^{*}\text{ft}^{2*}\circ F = 0.0005678 \text{ W/cm}^2^*\circ C \)
- \( 1 \text{ Btu/hr}^{*}\text{ft}^{2*}\circ F = 0.0001356 \text{ cal/s}^\circ \text{cm}^2^*\circ C \)
- \( 1 \text{ Btu/hr}^{*}\text{ft}^{2*}\circ F = 4882 \text{ cal/hr}^*\text{m}^{2*}\circ C \)

### Thermal Conductivity

- \( 1 \text{ Btu/hr}^{*}\text{ft}^{*}\circ F = 0.0173 \text{ W/cm}^*\circ C \)
- \( 1 \text{ Btu/hr}^{*}\text{t}^{*}\circ F = 1.731 \text{ W/m}^*\circ C \)
- \( 1 \text{ Btu/hr}^{*}\text{ft}^{*}\circ F = 0.004134 \text{ cal/s}^*\text{cm}^*\circ C \)

### Speed

- \( 1 \text{ knot} = 0.514 \text{ m/s} = 1.688 \text{ ft/s} \)
- \( 1 \text{ mi/hr (mph)} = 1.61 \text{ km/hr} \)

### Temperature

- \( ^\circ R = (9/5)^*K \)
- \( ^\circ F = [(9/5)^*^\circ C] + 32^\circ F \)
- \( ^\circ C = (^\circ F - 32^\circ F)\times(5/9) \)
- \( ^\circ C = K - 273.15 \)
**Unit Conversion Factors**

°F = °R – 459.67

°F = Degree Rankine

K = Degree Kelvin
CHAPTER 1

Introduction

1.1 Overview

The first pipeline was built in the United States in 1859 to transport crude oil (Wolbert, 1952). Through the one-and-a-half century of pipeline operating practice, the petroleum industry has proven that pipelines are by far the most economical means of large scale overland transportation for crude oil, natural gas, and their products, clearly superior to rail and truck transportation over competing routes, given large quantities to be moved on a regular basis. Transporting petroleum fluids with pipelines is a continuous and reliable operation. Pipelines have demonstrated an ability to adapt to a wide variety of environments including remote areas and hostile environments. Because of their superior flexibility to the alternatives, with very minor exceptions, largely due to local peculiarities, most refineries are served by one or more pipelines.

Man’s inexorable demand for petroleum products intensified the search for oil in the offshore regions of the world as early as 1897, when the offshore oil exploration and production started from the Summerland, California (Leffler et al., 2003). The first offshore pipeline was born in the Summerland, an idyllic-sounding spot just southeast of Santa Barbara. Since then the offshore pipeline has become the unique means of efficiently transporting offshore fluids, i.e., oil, gas, and water.

Offshore pipelines can be classified as follows (Figure 1.1):

- Flowlines transporting oil and/or gas from satellite subsea wells to subsea manifolds;
- Flowlines transporting oil and/or gas from subsea manifolds to production facility platforms;
- Infield flowlines transporting oil and/or gas between production facility platforms;
- Export pipelines transporting oil and/or gas from production facility platforms to shore; and
- Flowlines transporting water or chemicals from production facility platforms, through subsea injection manifolds, to injection wellheads.

The further downstream from the subsea wellhead, as more streams commingle, the larger the diameter of the pipelines. Of course, the pipelines are sized to handle the expected pressure and fluid flow. To ensure desired flow rate of product, pipeline size varies significantly from project to project. To contain the pressures, wall thicknesses of the pipelines range from 3/8 inch to 1 1/2 inch.
1.2 Pipeline Design

Design of offshore pipelines is usually carried out in three stages: conceptual engineering, preliminary engineering, and detail engineering. During the conceptual engineering stage, issues of technical feasibility and constraints on the system design and construction are addressed. Potential difficulties are revealed and non-viable options are eliminated. Required information for the forthcoming design and construction are identified. The outcome of the conceptual engineering allows for scheduling of development and a rough estimate of associated cost. The preliminary engineering defines system concept (pipeline size and grade), prepares authority applications, and provides design details sufficient to order pipeline. In the detail engineering phase, the design is completed in sufficient detail to define the technical input for all procurement and construction tendering. The materials covered in this book fit mostly into the preliminary engineering.

A complete pipeline design includes pipeline sizing (diameter and wall thickness) and material grade selection based on analyses of stress, hydrodynamic stability, span, thermal insulation, corrosion and stability coating, and riser specification. The following data establish design basis:
Reservoir performance
Fluid and water compositions
Fluid PVT properties
Sand concentration
Sand particle distribution
Geotechnical survey data
Meteorological and oceanographic data

Table 1.1 shows sizes of some pipelines. This table also gives order of magnitude of typical diameter/wall thickness ratios (D/t). Smaller diameter pipes are often flowlines with high design pressure leading to D/t between 15 and 20. For deepwater, transmission lines with D/t of 25 to 30 are more common. Depending upon types, some pipelines are bundled and others are thermal- or concrete-coated steel pipes to reduce heat loss and increase stability.

Although sophisticated engineering tools involving finite element simulations (Bai, 2001) are available to engineers for pipeline design, for procedure transparency, this book describes a simple and practical approach. Details are discussed in Part I of this book.

### 1.3 Pipeline Installation

Once design is finalized, pipeline is ordered for pipe construction and coating and/or insulation fabrication. Upon shipping to the site, pipeline can be installed. There are several methods for pipeline installation including S-lay, J-lay, reel barge, and tow-in methods. As depicted in Figure 1.2, the S-lay requires a laying barge to have on its
deck several welding stations where the crew welds together 40- to 80-foot lengths of insulated pipe in a dry environment away from wind and rain. As the barge moves forward, the pipe is eased off the stern, curving downward through the water as it leaves until it reaches the touchdown point. After touchdown, as more pipe is played out, it assumes the normal S-shape. To reduce bending stress in the pipe, a stinger is used to support the pipe as it leaves the barge. To avoid buckling of the pipe, a tensioning roller and controlled forward thrust must be used to provide appropriate tensile load to the pipeline. This method is used for pipeline installations in a range of water depths from shallow to deep. The J-lay method is shown in Figure 1.3. It avoids some of the difficulties of S-laying such as tensile load and forward thrust. J-lay barges drop the pipe down almost vertically until it reaches touchdown. After that, the pipe assumes the normal J-shape. J-lay barges have a tall tower on the stern to weld and slip pre-welded pipe sections of lengths up to 240 feet. With the simpler pipeline shape, J-lay can be used in deeper water than S-lay.

Small-diameter pipelines can be installed with reel barges where the pipe is welded, coated, and wound onshore to reduce costs. Horizontal reels lay pipe with an S-lay configuration. Vertical reels most commonly do J-lay, but can also S-lay.

There are four variations of the tow-in method: surface tow, mid-depth tow, off-bottom tow, and bottom tow. For the surface tow approach as shown in Figure 1.4, buoyancy modules are added to the pipeline so that it floats at the surface. Once the pipeline is towed on site by the two towboats, the buoyancy modules are removed or flooded, and the pipeline settles to the sea floor. Figure 1.5 illustrates the mid-depth tow. It requires fewer buoyancy modules. The pipeline settles to the bottom on its own when the forward progression ceases. Depicted in Figure 1.6 is the off-bottom tow. It involves both buoyancy modules and added weight in the form of chains. Once on location, the buoyancy is removed, and the pipeline settles to the sea floor. Figure 1.7 shows the bottom tow. The
**Introduction**

**Figure 1.3** J-lay barge method for deepwater pipelines.

**Figure 1.4** Surface tow for pipeline installation.
pipeline is allowed to sink to the bottom and then towed along the sea floor. It is primarily used for soft and flat sea floor in shallow water.

Several concerns require attention during pipeline installation. These include pipeline external corrosion protection, pipeline installation protection, and installation bending stress/strain control. Details are discussed in Part II of this book.
1.4 Pipeline Operations

Pipeline operation starts with pipeline testing and commissioning. Operations to be carried out include flooding, cleaning, gauging, hydrostatic pressure testing, leak testing, and commissioning procedures. Daily operations include flow assurance and pigging operations to maintain the pipeline under good conditions.

Flow assurance is defined as an operation that generates a reliable flow of fluids from the reservoir to the sales point. The operation deals with formation and depositions of gas hydrates, paraffin, asphaltenes, and scales that can reduce flow efficiency of oil and gas pipelines. Because of technical challenges involved, this operation requires the combined efforts of a multidisciplinary team consisting of scientists, engineers, and field personnel.

Technical challenges in the flow assurance operation include prevention and control of depositions of gas hydrates, paraffin (wax), asphaltenes, and scales in the oil and gas production systems. Usually one or two of these problems dominate in a given oil/gas field.

Natural gas hydrate is formed when methane molecules—the primary component of natural gas—are trapped in a microscopic cage of water molecules under certain pressure and temperature conditions (Katz and Lee, 1990). As a rough rule of thumb, methane hydrate will form in a natural gas system if free water is available at a temperature as high as 40°F and a pressure as low as 170 psig. Decreasing temperature and increasing pressure are favorable for hydrate formation (Guo et al., 1992). Hydrate forming conditions are predictable with computer programs. Natural gas hydrate can form within gas pipelines as a solid or semi-solid mass that can slow or completely block gas flow. Clearing hydrate-plugged pipelines is an expensive and time-consuming task that can take as long as several weeks. There are five methods for preventing hydrate formation (Makogon, 1997):
• Remove free water from the system,
• Keep the system operating temperature above the hydrate formation threshold,
• Maintain the system operating pressure below the hydrate formation threshold,
• Inject hydrate inhibitors, such as methanol and glycol, to effectively decrease the hydrate formation temperature, or delay hydrate crystal growth, and
• Add anti-agglomerates to prevent the aggregation of hydrate crystals.

The choice of which methods to use depends upon system characteristics, technology availability, and cost considerations.

Paraffin or wax (n-alkane) has a straight chain linear structure composed entirely of carbon and hydrogen (Becker, 1997). The long-chain paraffin (>C20H42) components cause deposition or congealing oil in crude oil systems. Paraffin can deposit from the fractures in the formation rock to the pipelines that deliver oil to the refineries. The deposits can vary in consistency from rock hard for the highest chain length paraffin to very soft, mayonnaise-like congealing oil deposits. Paraffin components account for a significant portion of a majority of crude oils heavier than 20° API. One of the primary methods of controlling paraffin deposits is to use solvent. Complete success in paraffin removal has been elusive, depending on the type of deposit being dissolved, its location in the system, the temperature, and type of application. A number of factors can affect the removal of paraffin from a production system using solvent. Some of the most important factors are: types of solvents used, type of paraffin, quantity of paraffin, temperature, and contact time. Even the best paraffin solvent applied to long-chain paraffin at low temperature for too short a time will fail to give a clean system. A poor solvent applied to short-chain paraffin at high temperature in large quantities will clean the system every time. Different solvents have different abilities to dissolve paraffin. Two general classes of solvents used in the oilfield to dissolve paraffin are aliphatic and aromatic. Common aliphatic solvents used in the oilfield are diesel, kerosene, and condensate. Aromatic solvents used are xylene and toluene. Solvents are frequently chosen based on price per gallon or price per barrel rather than effectiveness.

Other techniques used for paraffin removal include mechanical scratching and hot fluid treatments. Magnetic treatment of crude oils has also been reported to reduce paraffin deposition in wells.

Asphaltenes identified in oil production systems are generally high molecular weight organic fractions of crude oils that are soluble in toluene, but are insoluble in alkanes (Becker, 1997). Asphaltenene precipitation from crude oils can cause serious problems in the reservoir, wellbore, and in the production facilities. Asphaltenenes remain in solution under reservoir temperature and pressure conditions. They destabilize and start to precipitate when pressure and temperature changes occur during primary oil production. The precipitated asphaltene particles then grow in size and may start to deposit onto the production string and/or flowlines, causing operational problems. Several factors, including the oil composition, pressure and temperature, and the properties of asphaltene, influence asphaltene precipitation from reservoir oil. A variety of models for predicting the onset of asphaltene precipitation from live crude oil are available in the literature. These models have been proposed based on different microscopic theories. Each model has its limitations due to the inherent assumptions built-in. A common practice for remediating or mitigating well impairment caused by asphaltene deposition consists of periodic
treatments with a solvent (i.e., washing the tubing and squeezing into the near-wellbore formation). However, an economical limitation exists because of the transient effect of such cleanup operations. In addition, solvents in use in the field, such as xylene or naphtha, did not completely dissolve the asphalt deposits or completely extract asphaltenes fixed on clay minerals.

Scale deposits of many different chemical compositions are formed as a result of crystallization and precipitation of minerals from the produced water (Becker, 1998). The most common scale is formed from calcium carbonate (commonly known as calcite). These deposits become solids, which cause problems in pipelines and equipment when they are attached to the walls. This reduces the diameter of the pipes and the cross-sectional area available for flow. Scale is one of the most common and costly problems in the petroleum industry. This is because it interferes with the production of oil and gas, resulting in an additional cost for treatment, protection, and removal. Scale also results in a loss of profit that makes marginal wells uneconomical. Scale deposition can be minimized using scale inhibition chemicals. Antiscale magnetic treatment methods have been studied for the past few decades as a new alternative. Acid washing treatments are also used for removal of scale deposits in wells.

Deepwater exploration and development have become key activities for the majority of oil and gas exploration and production companies. Development activities in the deepwater face significant challenges in flow assurance due mainly to high pressure and low temperature of seawater (Hatton et al., 2002). Of particular concern are the effects of produced fluid hydrocarbon solids (i.e., asphaltene, wax, and hydrate) and their potential to disrupt production due to deposition in the production system (Zhang et al., 2002).

It has been noted that the deposition of inorganic solids arising from the aqueous phase (i.e., scale) also poses a serious threat to flow assurance. Gas hydrate plugging problems can occur in deepwater drilling, gas production, and gas transportation through pipelines. The potential for hydrocarbon solid formation and deposition adversely affecting flow assurance in deepwater production systems is a key risk factor in assessing deepwater developments. To reduce this risk, a systematic approach to defining and understanding the thermodynamic and hydrodynamic factors impacting flow assurance is required.

Flow assurance engineering has been known as an operation that does not directly make money, but costs a great deal in pipeline operations, if not managed correctly. Details about this issue are discussed in Part III of this book.

References

Hatton, G.J.; Anselmi, A.; Curti, G. Deepwater Natural Gas Pipeline Hydrate Blockage Caused by a Seawater Leak Test, Proceedings of the Offshore Technology Conference, Houston, Texas, USA (May 6–9, 2002).


Wolbert, G.; American Pipelines 5 (1952).

Design of marine pipelines is usually carried out in three stages: conceptual engineering, preliminary engineering, and detail engineering. During the conceptual engineering stage, issues of technical feasibility and constraints on the system design and construction are addressed. Potential difficulties are revealed and non-viable options are eliminated. Required information for the forthcoming design and construction are identified. The outcome of the conceptual engineering allows for scheduling of development and a rough estimate of associated cost. The preliminary engineering defines system concept (pipeline size and grade), prepares authority applications, and provides design details sufficient to order pipeline. In the detail engineering phase, the design is completed in sufficient detail to define the technical input for all procurement and construction tendering. The materials covered in Part I fit mostly into the preliminary engineering.

Although sophisticated engineering tools involving finite element simulations (Bai, 2001) are available to engineers for pipeline design, for procedure transparency, this book describes a simple and practical approach. This part of the book includes the following chapters:

Chapter 2: General Design Information
Chapter 3: Diameter and Wall Thickness
Chapter 4: Hydrodynamic Stability of Pipelines
Chapter 5: Pipeline Span
Chapter 6: Operating Stresses
Chapter 7: Pipeline Riser Design
Chapter 8: Pipeline External Corrosion Protection
Chapter 9: Pipeline Insulation
Chapter 10: Introduction to Flexible Pipelines
CHAPTER 2

General Design Information

2.1 Introduction

Before designing an offshore pipeline, the design engineers need to understand the environments in which the pipeline will be installed and operated. What is the water depth? What are the water currents? How big are the waves? All those parameters will affect the mechanical design of the pipeline system. The fluids inside the pipeline will also influence the pipeline design. Is it single-phase or multiphase? Are the fluids corrosive? How much sand will be in the fluids? What are the operating pressures and temperatures? All these will influence the pipeline metallurgy selection. A list of the data that will affect the pipeline design follows:

- Reservoir performance
- Fluid and water compositions
- Fluid PVT properties
- Sand concentration
- Sand particle distribution
- Geotechnical survey data
- Meteorological and oceanographic data

In this chapter, all the parameters that would affect the pipeline design will be covered. The design engineers should try to collect all these data and have a good understanding of their impacts before they start to perform the pipeline design.

2.2 Design Data

There are numerous parameters that can affect the pipeline design and operations. The following sections will cover the most critical ones.

2.2.1 Reservoir Performance

How the reservoir would perform over the whole field life can have profound impacts on the pipeline design and operations. Pipeline cannot simply be sized to deliver the maximum production. How the pipeline will be operated at different stages of the field life must be taken into account. The oil, water, and gas flowrates will be different at
different stages of field life. Different gas and liquid flowrates will then result in different
flow behaviors inside the pipeline. Thus, to properly design the pipeline and formulate the
operation strategies, how the reservoir will perform over the whole field life needs to be
well understood.

2.2.1.1 Reservoir Pressure & Temperature

Both reservoir pressure and temperature will affect the pipeline design and operations. Reservoir pressure is directly related to the wellhead pressure, which will affect the pipeline
operating pressure. Very high reservoir pressure can require special metallurgy for the
piping and can drive up the material cost dramatically. On the other hand, if reservoir
pressure is too low, gas-lift or other artificial lift mechanisms may be required. Gas-lift gas
can affect the pipeline design and operations. Gas-lift gas can make Joule-Thomson
cooling effects even worse and cause metallurgy concerns. Joule-Thomson effect (tem-
perature drop) is associated with gas flowing through production chokes where large
pressure drop can occur. Gas-lift gas can also make the fluid flow inside the pipeline
stable or unstable.

Reservoir temperature can also affect pipeline metallurgy and operations. Very high
reservoir temperature may require use of special materials and drive up pipeline cost.
Extreme high or low temperature can also eliminate some design flexibility; for example,
some flexible pipeline may not be applicable due to high or low fluid temperature.
Whether or not flexible pipeline can be used, the specific flexible pipeline manufacturers
need to be consulted. If the reservoir temperature is too low and the pipeline fluid
temperature is lower than the wax appearance temperature and the gas hydrate tempera-
ture, extra thermal insulation design, such as wet insulation or pipe-in-pipe, will be
required.

2.2.1.2 Reservoir Formations

Reservoir formation can be classified as either consolidated or unconsolidated. Marine-
deposited sands, like in sandstone formations, are often cemented with calcareous or
siliceous minerals and may be strongly consolidated (Bradley et al., 1992). Miocene and
younger sands are often unconsolidated or only partially consolidated with soft clay or silt.

With unconsolidated formations, individual grains tend to move easily, especially under
high pressure drop, which is often associated with high production flowrates. Thus, if the
formation is unconsolidated, even with sound sand control technology, sand would more
likely be produced into the pipeline system, accelerating pipeline erosion. What kind of
reservoir formations and likelihood that sand will be produced into the pipeline are
important pieces of information for pipeline design engineers.

2.2.1.3 Production Profiles

Production profile is one of the most important data for pipeline sizing. Production
profiles define how the oil, water, and gas flowrates will change with time for the whole
field life. The production profiles are normally generated by reservoir engineers by
performing reservoir simulations. Figure 2.1 shows typical black-oil production profiles
for oil, water, and gas. Normally, the oil flowrate will reach a maximum in a short period
of time and stay at the maximum flowrate for a few years before starting to decline. The water may not be produced for the early stage of production. Once water is breaking through, the water flowrate tends to increase rapidly and stay at the maximum flowrate for some time before starting to decline. If successful pressure maintenance programs are utilized, water production may not decline much for the whole field life. The gas flowrate is normally associated with the oil production and is determined by the gas-oil ratio unless there is an active gas cap in the formation. If a gas cap exists, gas production will be much higher than the solution gas rate.

Pipeline engineers need to understand the impacts of the gas and liquid production on the pipeline design and pipeline operations. The pipeline needs to be sized such that it will transport close to the maximum production and is also easy to operate for the whole field life, especially for the late stage of the field life when flowrates are much lower than the maximum. If the pipeline is oversized for the late field life, the fluid flow inside the pipeline may become unstable and cause terrain slugs inside the pipeline. Unstable flow may impact pipeline mechanical integrity by causing pipeline vibration and excessive corrosion. Unstable (slug) flow will be discussed in more detail in the appendix.

Pipeline design engineers need to know that there are three different production profiles: the P10, P50, and P90. While the P50 production profile should be used for pipeline design, the effect of P10 and P90 production profiles on pipeline design and operations must be considered.

2.2.2 Fluid & Water Compositions

Fluid and water compositions will affect both pipeline design and operations. Whether or not the pipeline metallurgy must satisfy sour service requirements depends upon the fluid and water compositions. If produced fluids contain CO₂ and/or H₂S, pipeline corrosion will be most likely and corrosion mitigation strategies will be developed. Either CRA (Corrosion Resistance Alloy) or chemical inhibition will be required. Corrosion allowance must be included in the wall thickness design.

If seawater injection will be used for reservoir pressure maintenance, after injection water breakthrough, sometimes H₂S will also be produced (Seto and Beliveau; 2000,
Evans, 2001; Khatib and Salanitro, 1997; Smith and Thurlow, 1978). This is also called reservoir souring. Water injection may not always result in reservoir souring. Some fields have water injection for years and no H$_2$S ever appears. But there are also many examples showing reservoir souring due to water injection. If seawater injection is planned, reservoir souring studies should be performed to assess the amount of H$_2$S that may be produced, and the pipeline material must be chosen accordingly.

Compositions of produced water can also have significant impacts on pipeline design and operations. The cations, like calcium, magnesium, and barium, can react with the anions, like sulfate, carbonate, and bicarbonate, to form scales which can block pipeline flow (Oddo and Tomson, 1976; Cowan and Weintritt, 1976). Scales are formed when incompatible waters are mixed together.

It is well known that saltwater is also corrosive. The more salt in water, the more corrosive it is. Seawater contains high salt concentrations and seawater is very corrosive. The dissolved gases in water, such as oxygen, hydrogen sulfide, carbon dioxide, would significantly increase the water’s corrosivity. Accurate analysis of water compositions is thus very critical for proper pipeline design and operations.

2.2.3 Fluid PVT Properties

Fluid PVT (Pressure-Volume-Temperature) properties will greatly affect pipeline sizing. The pipeline must be sized to transport the designed flowrate with a specified pressure drop. The pressure drop is normally determined by the pipeline outlet pressure, which is often the first stage separator pressure and pipeline inlet pressure which can be the reservoir pressure minus the pressure drop inside the wellbore.

On the other hand, pressure drop associated with multiphase flow is a strong function of the fluid properties such as fluid density, fluid viscosity, gas-liquid ratio, water-oil ratio, water-oil emulsions, fluid interfacial tension, etc. Thus, a very important step in sizing the pipeline is to accurately characterize the fluids. With the characterized fluids, the above-mentioned properties can be calculated using commercial PVT software.

Normally, during drilling or pre-drilling, reservoir fluids are captured with elevated pressure downhole. If water aquifer is encountered during drilling, water samples are obtained. The sampled fluids are sent to a PVT lab to measure properties that are not limited to:

- Reservoir fluid compositions
- Gas-oil ratio by single stage flash or multiple stage flash
- API gravity (oil gravity at 14.7 psia and 60°F)
- Formation volume factor
- Bubble point pressure at reservoir temperature
- Density at bubble point pressure and reservoir temperature
- Water, oil compressibilities
- Reservoir fluid viscosity at reservoir temperature
- Interfacial tension

Measured reservoir fluid compositions are characterized by matching the above-mentioned measured parameters. It is very important to characterize the fluid compositions at both reservoir conditions and at pipeline outlet conditions. Thus, the characterized
2.2.4 Solid Production

Sand production affects the pipeline design and operations mainly in three areas. One is that sands in the pipeline increase pipeline erosion. Another is that fluid velocity would have to be high enough to carry the sands out of the flowline. Otherwise the sands can deposit inside the pipeline and block the flow. Finally, sand deposition inside the pipeline can prevent inhibition chemicals, like corrosion chemicals, from touching the pipe wall, thus reducing the effectiveness of chemicals.

The most challenging tasks of assessing the sand impacts on pipeline design are determining the particle sizes and determining the concentration of the sands that would be transported by the pipeline. Both particle size distribution and concentration depend upon such parameters as formation rock types and sand control technologies used in well completion. If the formation is unconsolidated, more sands can potentially be produced. Sand grain sizes can be determined by obtaining representative formation samples and performing sieve analysis (Bradley et al., 1992). Once grain sizes are determined, the proper sand control method can be designed to block sand from flowing into wellbore and surface pipeline.

Even the best sand control technologies can potentially fail and allow sands to be introduced into the production system, including the pipeline. Thus, sand detection becomes very important for pipeline operations. No matter whether an intrusive technique, like impedance sensors, or a non-intrusive technique, like ultrasonic sensors, is used for sand detection, an accurate interpretation method must be developed.

2.2.5 Seafloor Bathymetry/Geotechnical Survey Data

Geotechnical survey data provide important information on seafloor conditions that can affect both pipeline mechanical design and operations. Seafloor bathymetry would affect pipeline routing, alignment, and spanning. Pipeline should be routed away from any seafloor obstructions and hazards. Spanning analysis should be conducted, based upon geotechnical survey data, to identify any locations where spans will be longer than allowable span lengths.

A pipeline bathymetry is preferred if pipeline flow is going upward. In other words, it is preferable that the water depth at the pipeline outlet be shallower than that at the inlet. This is because the multiphase slug flow is much less severe with an upward-inclined pipeline than with a downward-inclined pipeline. Pipeline A, shown in Figure 2.2, will tend to have more severe slugging problems than Pipeline B. More discussions on slug flow can be found in Appendix A.

Pipeline will be laid on the bottom of the seabed. The mechanical conditions of the seabed will affect the stability of the pipeline. It is possible that the pipeline may sink below the seabed and be buried into the subsea soil. Depending upon how deep the pipeline will sink, surrounding soil may have significant impact on the heat transfer process of the
pipeline. Understanding the soil mechanical properties will help the design of subsea pipelines.

Soil mechanical properties depend largely upon the soil components and their fractions. There are coarse-grained components, like boulder, cobble, gravel, and sand. The fine grained components consist mainly of silt, clay, and organic matter (Lambe and Whitman, 1969). Boulders and cobbles are very stable components. Foundations with boulders and cobbles present good stability. Silt is unstable and, with increased water moisture, becomes a “quasi-liquid” offering little resistance to erosion and piping. Clay is difficult to compact when it is wet, but compacted clay is resistant to erosion. Organic matters tend to increase the compressibility of the soil and reduce the soil stability.

Silt and clay are the major components of seabed soil down to a few feet in depth. Thus, when pipeline is laid on the seabed, it will normally sink into the soil. How much the pipeline will sink depends largely upon the mechanical properties of the soil. The following parameters are normally obtained when performing geo-technical analysis.

\textit{Water moisture content} is defined as the ratio of the mass of the free water in the soil to the mass of soil solid material. Water moisture content is normally expressed as a percentage. Some soils can hold so much water that their water moisture content can be more than 100%.

\textit{Absolute porosity} is defined as the ratio, expressed as a percentage, of void volume of soil to the soil bulk volume.

\textit{Absolute permeability} is defined as a measure of the soil’s ability to transmit fluid. To determine the permeability of the soil, a sample is put into a pressure device and water is conducted through the soil. The rate of water flow under a given pressure drop is proportional to the soil permeability.

\textit{Liquid limit} is determined by measuring the water moisture content and the number of blows required to close a specific groove which was cut through a standard brass cup filled with soil. Liquid limit indicates how much water the soil can hold without getting into the “liquid” state.

\textit{Plastic limit} is defined as the water moisture content at which a thread of soil with 3.2-mm diameter begins to crumble. Plastic limit is the minimum water content required for the soil to present “plastic” properties.
Plasticity index is defined as the difference between liquid limit and plastic limit. Liquidity index, LI, is defined as the ratio of the difference between the natural water moisture content and the plastic limit to the plasticity index. Activity number is defined as the ratio of plasticity index to the weight percentage of soil particles finer than 2 macros. Activity number indicates how much water will be attracted into soil.

Other mechanical and thermal property data are also important to pipeline design. These well-known data can be obtained through standard tests and will not be repeated here.

2.2.6 Oceanographic Data

Ocean currents and waves greatly affect the stability of offshore pipelines. To design a pipeline required to be mechanically stable for the whole field life, pipeline engineers must understand the importance of oceanographic data. Pipeline installation and towing can also be affected by the ocean conditions.

Oceanographic data include 1-year, 5-year, 10-year, and 100-year extreme wave cases and associated currents: wave heights, wave directions, current speeds, and tide data. Near-bottom conditions (waves, winds, tide, currents, etc.) should be clearly defined.

2.2.7 Other Data

Quite a few other data will affect pipeline design and operations. Water temperature profiles (minimum and maximum) affect the pipeline operations through heat transfer. To be conservative, the minimum temperature profile should be used for pipeline design.

Splash zone should be clearly defined. Splash zone is the pipe or riser section that will be splashed by the surface wave. Because of seawater splashes, the affected pipe or riser section tends to have more severe corrosion problems. Extra coatings are required.

References

CHAPTER 3

Diameter and Wall Thickness

3.1 Introduction

Design of pipeline involves selection of pipeline diameter, thickness, and material to be used. Pipeline diameter should be selected on the basis of flow capacity required to transport production fluids at an expected rate provided by the oil or gas wells. This task demands a comprehensive flow assurance analysis assuming the worst operating condition during the whole life of the pipeline. Due to the complex nature of multiphase flow as described in Appendix A, a calibrated computer model in flow assurance analysis is required. In the last decade, multiphase flow simulators have gained significant popularity. Both steady-state and transient simulators have been used for pipeline design and for pipeline operation simulations. Flow assurance analysis is described in Chapter 15.

This chapter covers wall thickness design for subsea steel pipelines and risers as governed by US Codes ASME/ANSI B32.8. Other codes such as Z187 (Canada), DnV (Norway), and IP6 (UK) have essentially the same requirements, but should be checked by the readers.

Except for large diameter pipes (over 30 in.), material grade is usually taken as X-60 or X-65 (414 or 448 MPa) for high-pressure pipelines or on deepwater. Higher grades can be selected in special cases. Lower grades such as X-42, X-52, or X-56 can be selected in shallow water or for low-pressure, large diameter pipelines to reduce material cost, or in cases where high ductility is required for improved impact resistance. Pipe types are:

- Seamless
- Submerged arc welded (SAW or DSAW)
- Electric resistance welded (ERW)
- Spiral weld

Except in specific cases, only seamless or SAW pipe is to be used, with seamless being the preference for diameters of 12 in. or less. If ERW pipe is used, special inspection provisions such as full body ultrasonic testing are required. Spiral weld pipe is very unusual for oil/gas pipelines and should be used only for low-pressure water or outfall lines.
3.2 Design Procedure

Determination of pipeline wall thickness is based on the design internal pressure or the external hydrostatic pressure. Maximum longitudinal stresses and combined stresses are sometimes limited by applicable codes and must be checked for installation and operation. However, these criteria (addressed in Chapter 6) are not normally used for wall thickness determination. Increasing wall thickness can sometimes ensure hydrodynamic stability in lieu of other stabilization methods (such as weight coating). This is not normally an economic except in deepwater where the presence of concrete may interfere with the preferred installation method. Bai (2001) presents a Design Through Analysis (DTA) method for pipeline sizing. In this book we recommend the following procedure for designing pipeline wall thickness:

**Step 1:** Calculate the minimum wall thickness required for the design internal pressure.

**Step 2:** Calculate the minimum wall thickness required to withstand external pressure.

**Step 3:** Add wall thickness allowance for corrosion if applicable to the maximum of the above.

**Step 4:** Select next highest nominal wall thickness. Note: In certain cases, it may be desirable to order a non-standard wall. This can be done for large orders.

**Step 5:** Check selected wall thickness for hydrotest condition.

**Step 6:** Check for handling practice, i.e., pipeline handling is difficult for D/t larger than 50; welding of wall thickness less than 0.3 in. (7.6 mm) requires special provisions.

3.3 Design Codes

3.3.1 Pipeline Design for Internal Pressure

Three pipeline codes typically used for design are ASME B31.4 (ASME, 1989), ASME B31.8 (ASME, 1990), and DnV 1981 (DnV, 1981). ASME B31.4 is for all oil lines in North America. ASME B31.8 is for all gas lines and two-phase flow pipelines in North America. DnV 1981 is for oil, gas, and two-phase flow pipelines in the North Sea. All these codes can be used in other areas when no other code is available.

The nominal pipeline wall thickness (\(t_{NOM}\)) can be calculated as follows:

\[
t_{NOM} = \frac{P_d D}{2E_w \eta \sigma_f} + t_a
\]

where \(P_d\) is the design internal pressure defined as the difference between the internal pressure (\(P_i\)) and external pressure (\(P_e\)), \(D\) is nominal outside diameter, \(t_a\) is thickness allowance for corrosion, and \(\sigma_f\) is the specified minimum yield strength.

Most codes allow credit for external pressure. This credit should be used whenever possible, although care should be exercised for oil export lines to account for head of fluid and for lines which traverse from deep to shallow water.

ASME B31.4 and DnV 1981 define \(P_i\) as the Maximum Allowable Operating Pressure (MAOP) under normal conditions, indicating that surge pressure up to 110% MAOP is
acceptable. In some cases, \( P_i \) is defined as Wellhead Shut-In Pressure (WSIP) or specified by the operators.

In Equation (3.1), the weld efficiency factor \( (E_w) \) is 1.0 for seamless, ERW, and DSAW pipes. The temperature de-rating factor \( (F_t) \) is equal to 1.0 for temperatures under 250°F. The usage factor \( (\eta) \) is defined in Tables 3.1 and 3.2 for oil and gas lines, respectively.

The under-thickness due to manufacturing tolerance is taken into account in the design factor. There is no need to add any allowance for fabrication to the wall thickness calculated with Equation (3.1).

### 3.3.2 Pipeline Design for External Pressure

Different practices can be found in the industry using different external pressure criteria. As a rule of thumb, or unless qualified thereafter, it is recommended to use propagation criterion for pipeline diameters under 16 inches and collapse criterion for pipeline diameters above or equal to 16 inches.

**Table 3.1** Design and Hydrostatic Pressure Definitions and Usage Factors for Oil Lines

<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>Normal Operations</td>
<td></td>
<td></td>
</tr>
<tr>
<td>( P_d^{(1)} )</td>
<td>( P_i - P_e [401.2.2] )</td>
<td>( P_i - P_e [4.2.2.2] )</td>
</tr>
<tr>
<td>( \eta ) for pipelines</td>
<td>0.72 [402.3.1(a)]</td>
<td>0.72 [4.2.2.1]</td>
</tr>
<tr>
<td>( \eta ) for riser sections</td>
<td>no specific value use 0.50</td>
<td>0.50 [4.2.2.1]</td>
</tr>
<tr>
<td>( P_b )</td>
<td>1.25 ( P_i^{(2)} [437.4.1(a)] )</td>
<td>1.25 ( P_d [8.8.4.3] )</td>
</tr>
</tbody>
</table>

Notes:
1. Credit can be taken for external pressure for gathering lines or flowlines when the MAOP (\( P_i \)) is applied at the wellhead or at the seabed. For export lines, when \( P_i \) is applied on a platform deck, the head fluid shall be added to \( P_i \) for the pipeline section on the seabed.
2. If hoop stress exceeds 90% of yield stress based on nominal wall thickness, special care shall be taken to prevent overstrain of the pipe.

**Table 3.2** Design and Hydrostatic Pressure Definitions and Usage Factors for Gas Lines

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal Operations</td>
<td></td>
<td></td>
</tr>
<tr>
<td>( P_d^{(1)} )</td>
<td>( P_i - P_e [A842.221] )</td>
<td>( P_i - P_e [4.2.2.2] )</td>
</tr>
<tr>
<td>( \eta ) for pipeline</td>
<td>0.72 [A842.221]</td>
<td>0.72 [4.2.2.1]</td>
</tr>
<tr>
<td>( \eta ) for riser sections(^{(2)})</td>
<td>0.5 [A842.221]</td>
<td>0.5 [4.2.2.1]</td>
</tr>
<tr>
<td>( P_b )</td>
<td>1.25 ( P_i^{(3)} [A847.2] )</td>
<td>1.25 ( P_d [8.8.4.3] )</td>
</tr>
</tbody>
</table>

Notes:
1. Credit can be taken for external pressure for gathering lines or flowlines when the MAOP (\( P_i \)) is applied at the wellhead or at the seabed. For export lines, when \( P_i \) is applied on a platform deck, the head fluid shall be added to \( P_i \) for the pipeline section on the seabed (particularly for two-phase flow).
2. Including pre-fabricated or retrofit sections and pipeline section in a J-tube.
3. ASME B31.8 imposes \( P_b = 1.4 \ P_i \) for offshore risers but allows onshore testing of prefabricated portions.
The propagation criterion is more conservative and should be used where optimization of the wall thickness is not required or for pipeline installation methods not compatible with the use of buckle arrestors such as reel and tow methods. It is generally economical to design for propagation pressure for diameters less than 16 inches. For greater diameters, the wall thickness penalty is too high. When a pipeline is designed based on the collapse criterion, buckle arrestors are recommended. The external pressure criterion should be based on nominal wall thickness, as the safety factors included below account for wall variations.

3.3.2.1 Propagation Criterion

Although a large number of empirical relationships have been published, the recommended formula is the latest given by AGA.PRC (AGA, 1990):

\[
P_p = 33S_y t_{NOM} \left( \frac{D}{C_{16}/C_{17}} \right)^{2.46}
\]

(3.2)

The nominal wall thickness should be determined such that:

\[
P_p > 1.3P_e
\]

(3.3)

The safety factor of 1.3 is recommended to account for uncertainty in the envelope of data points used to derive Equation (3.2). It can be rewritten as:

\[
t_{NOM} \geq D \left( \frac{1.3P_e}{33S_y} \right)^{\frac{1}{2.46}}
\]

(3.4)

For the reel barge method, the preferred pipeline grade is below X-60. However, X-65 steel can be used if the ductility is kept high by selecting the proper steel chemistry and micro alloying. For deepwater pipelines, D/t ratios of less than 30 are recommended. It has been noted that bending loads have no demonstrated influence on the propagation pressure.

3.3.2.2 Collapse Criterion

The mode of collapse is a function of D/t ratio, pipeline imperfections, and load conditions. The theoretical background is not given in this book. An empirical general formulation that applies to all situations is provided. It corresponds to the transition mode of collapse under external pressure (\(P_e\)), axial tension (\(T_a\)), and bending strain (\(\varepsilon_b\)) as detailed in literature (Murphey and Langner, 1985; AGA, 1990).

The nominal wall thickness should be determined such that:

\[
\frac{1.3P_e}{P_C} + \frac{\varepsilon_b}{\varepsilon_B} \leq g_p
\]

(3.5)

where 1.3 is the recommended safety factor on collapse, \(\varepsilon_B\) is the bending strain of buckling failure due to pure bending, and \(g_p\) is an imperfection parameter defined below.
The safety factor on collapse is calculated for D/t ratios along with the loads \( P_e, \varepsilon_b, T_a \) and initial pipeline out-of-roundness \( \delta_o \). The equations are:

\[
P_C = \frac{P_dP_y'}{\sqrt{p_{el}^2 + p_y'^2}} \tag{3.6}
\]

\[
p_y' = P_y \left[ \sqrt{1 - 0.75 \left( \frac{T_a}{T_y} \right)^2} - \frac{T_a}{2T_y} \right] \tag{3.7}
\]

\[
P_{el} = \frac{2E}{1 - \nu^2} \left( \frac{t}{D} \right)^3 \tag{3.8}
\]

\[
P_y = 2S_y \left( \frac{t}{D} \right) \tag{3.9}
\]

\[
T_y = AS_y \tag{3.10}
\]

where \( g_p \) is based on pipeline imperfections such as initial out-of-roundness \( \delta_o \), eccentricity (usually neglected), and residual stress (usually neglected). Hence,

\[
g_p = \sqrt{ \frac{1 + p^2}{p^2 - f_p^2} } \tag{3.11}
\]

with

\[
p = \frac{p_y'}{P_{el}} \tag{3.12}
\]

\[
f_p = \sqrt{1 + \left( \frac{\delta_o}{t} \right)^2} - \frac{\delta_o D}{t} \tag{3.13}
\]

\[
\varepsilon_B = \frac{t}{2D} \tag{3.14}
\]

\[
\delta_o = \frac{D_{\text{max}} - D_{\text{min}}}{D_{\text{max}} + D_{\text{min}}} \tag{3.15}
\]

When a pipeline is designed using the collapse criterion, a good knowledge of the loading conditions is required \( (T_a \text{ and } \varepsilon_b) \). An upper conservative limit is necessary and must often be estimated.

Under high bending loads, care should be taken in estimating \( \varepsilon_b \) using an appropriate moment-curvature relationship. A Ramberg Osgood relationship can be used as

\[
K^* = M^* + AM^{*B} \tag{3.16}
\]

where \( K^* = K/K_y \) and \( M^* = M/M_y \) with \( K_y = 2S_y/ED \) is the yield curvature and \( M_y = 2IS_y/D \) is the yield moment. The coefficients \( A \) and \( B \) are calculated from the two data points on stress-strain curve generated during a tensile test.
3.3.3 Corrosion Allowance

To account for corrosion when water is present in a fluid along with contaminants such as oxygen, hydrogen sulfide (H₂S), and carbon dioxide (CO₂), extra wall thickness is added. A review of standards, rules, and codes of practices (Hill and Warwick, 1986) shows that wall allowance is only one of several methods available to prevent corrosion, and it is often the least recommended.

For H₂S and CO₂ contaminants, corrosion is often localized (pitting) and the rate of corrosion allowance ineffective. Corrosion allowance is made to account for damage during fabrication, transportation, and storage. A value of 1/16 in. may be appropriate. A thorough assessment of the internal corrosion mechanism and rate is necessary before any corrosion allowance is taken.

3.3.4 Check for Hydrotest Condition

The minimum hydrotest pressure for oil and gas lines is given in Tables 3.1 and 3.2, respectively, and is equal to 1.25 times the design pressure for pipelines. Codes do not require that the pipeline be designed for hydrotest conditions, but sometimes give a tensile hoop stress limit 90% SMYS, which is always satisfied if credit has not been taken for external pressure. For cases where the wall thickness is based on \( P_d = P_i - P_e \), codes recommend not to overstrain the pipe. Some of the codes are ASME B31.4 (Clause 437.4.1), ASME B31.8 (no limit on hoop stress during hydrotest), and DnV (Clause 8.8.4.3).

For design purposes, condition \( \sigma_h \leq \sigma_y \) should be confirmed, and increasing wall thickness or reducing test pressure should be considered in other cases. For pipelines connected to riser sections requiring \( P_h = 1.4P_i \), it is recommended to consider testing the riser separately (for prefabricated sections) or to determine the hydrotest pressure based on the actual internal pressure experienced by the pipeline section. It is important to note that most pressure testing of subsea pipelines is done with water, but on occasion, nitrogen or air has been used. For low D/t ratios (less than 20), the actual hoop stress in a pipeline tested from the surface is overestimated when using the thin wall equations provided in this chapter. Credit for this effect is allowed by DnV Clause 4.2.2.2, but is not normally taken into account.

References

CHAPTER 4

Hydrodynamic Stability of Pipelines

4.1 Introduction

This chapter addresses stability analysis of marine pipelines on the seabed under hydrodynamic loads (wave and current) and provides guidelines for pipeline stabilization using concrete coating. It does not address alternative methods such as pre- or post-trenching techniques, mattress covers, etc. Stability is checked for the installation case with the pipe empty using the 1-year return period condition and for lifetime (pipe with concrete) using the 100-year storm.

4.2 Analysis Procedure

There are several basic approaches to determining the required submerged weight for a marine pipeline. One of them is use of AGA Program “LSTAB.” It should be used in cases where the pipe is partially embedded or pre-trenched as the lift, drag, and inertia coefficients are adjusted for exposure. Regardless of the computer program selected, hydrodynamic stability analysis involves the following steps:

Step 1: Collect or define environmental criteria for the 1-year and 100-year conditions, including:

- Water depth
- Wave spectrum
- Current characteristics
- Soil properties
- Seabed condition

Step 2: Determine hydrodynamic coefficients: drag ($C_D$), lift ($C_L$), and inertia ($C_I$). These may be adjusted for Reynolds Number, Keulegan Number, ratio of wave to steady current, and embedment.

Step 3: Calculate hydrodynamic forces, typically, drag ($F_D$), lift ($F_L$), and inertial force ($F_I$).

Step 4: Perform static force balance at time step increments and assess stability and calculate concrete coating thickness for worst combination of lift, drag, and inertial force.


Hydrodynamics stability is determined using Morison’s Equation which relates hydraulic lift, drag, and inertial forces to local water particle velocity and acceleration. The coefficients used, however, vary significantly from one situation to another. For example, the lift and drag coefficients of 0.6 and 1.2, which are representative of a steady current, are not appropriate for oscillating flow in a wave field. In addition, these coefficients are reduced if the pipe is not fully exposed because of trenching or embedment. The literature is extensive in this area of research and is summarized in the next section.

To determine wave particle velocity, the equations used depend on wave height, water depth, and wave period. Figure 4.1 indicates the domain of applicability of the various theories. For most situations, linear theory is adequate as bottom velocities and accelerations do not vary significantly between theories. However, as the wave height to water depth ratio increases, Stokes 5th order theory becomes appropriate.

For shallow water or very high wave heights, a cnoidal or solitary theory should be used to predict particle velocity and accelerations (Sarpkaya and Isaacson, 1981). For breaking waves, or large diameter pipe, which may affect the flow regime, other analysis methods may be appropriate. In general, pipelines should be trenched within the breaking wave (surf) zone.

Experimental and theoretical research (Sarpkaya and Isaacson, 1981; Ayers, 1989) has shown that traditional static analysis methods have been conservative in most cases, understanding hydrodynamic forces but ignoring the effect of pipe embedment. In the 1980s, two research groups developed theoretical and experimental models to assess pipe stability. Findings of these groups (AGA in USA and PIPESTAB in Europe) resulted in the development of program LSTAB which accounts for the effects of embedment.

**Figure 4.1** Domain of applicability of the various theories.
4.3 Methodology

4.3.1 Definitions of Environmental Criteria

Environmental criteria during operation and pipeline installation can be estimated based on prior projects in the same area for feasibility studies or preliminary design purposes. For final design, measurements of steady current in the water column should be conducted to enable prediction by extrapolation extreme values for long return periods (1-year to 100-year).

Wave criteria (height and period) can be developed by hindcasting techniques based on existing wind and wave data in the area and further offshore. Wave hindcasting methods may involve refraction and shoaling analyses as well, to take into account local bathymetry irregularities.

4.3.1.1 Design Waves

An important design step is the estimation of an extreme design wave on the basis of recorded or hindcast wave data. This generally involves selecting and fitting a suitable probability distribution to wave height data and extrapolating to a suitable design wave with a predetermined return period. The actual selection of a design wave is a matter of engineering judgment and will vary according to the risk chosen for the design. The selection of a design wave is to be carried out in the following stages:

1. Oceanographic data is collected over a long time (at least five years, depending upon the design return period) at the site of interest. Alternatively, a hindcasting technique may be used to provide data over a much larger time period.
2. A plotting formula is used to reduce the data to a set of points describing the probability distribution of wave heights. Two such formulas are the Gumbel or external function and the Weibull function.
3. These points are plotted on extreme value probability paper corresponding to the desired probability distribution function.
4. A straight line is fitted through the points to present a trend.
5. The line is extrapolated to locate a design value corresponding to a chosen return period or chosen encounter probability.

The significant wave height is often used as the main parameter to define a seastate. Statistically, significant wave height is the average of the one-third highest waves and is denoted as $H_s$ or $H_{1/3}$. Empirically, $H_s$ is significant wave height in a seastate and is the value most often assigned by visual observations. Some other reference is sometimes used such as $H_{3\%}$ in the USSR.

The maximum expected wave height ($H_{\text{max}}$) can be derived from the significant wave height by:

$$H_{\text{max}} = H_s \sqrt{\frac{1}{2} \ln N_o} \quad (4.1)$$

where $N_o$ is the number of observed waves. Typically for 1000 waves, $H_{\text{max}} = 1.68 H_s$. In addition to wave height, a characteristic wave period must also be given to define a seastate.
The average zero crossing period, $T_z$, is commonly used. This period is defined as the average time between consecutive up or down crossing of the mean sea level. Finally, irregular seas must also be described by a given wave spectrum. A large number of empirical formulations for wave spectra have been proposed for different conditions such as a fully arisen sea, a short fetch sea, combined seas, etc. Most empirical spectra have the following basis form:

$$S_n(f_w) = \frac{c_1}{f_w^{m}} \exp \left( -\frac{c_2}{f_w^{n}} \right)$$

(4.2)

where $f_w$ is wave frequency in Hz, $S_n(f_w)$ is wave spectral density in ft$^2$/Hz, $c_1$ and $c_2$ are dimensional constants related to significant wave height and period, and $m$ and $n$ are integer coefficients. There are several common one-dimensional frequency spectra used to describe ocean waves including Bretschneider, Pierson-Moskowitz, and JONSWAP.

### 4.3.1.2 Wave Refraction

The use of wave fraction techniques allows accurate transformation of deep water wave data (however it was obtained) into shallower water and allows an estimation of when the maximum wave height/breaking criteria takes over. A complete wave refraction/shoaling analysis can be done in two ways. The first way is by manual means, as shown below, and provides a good, quick method suitable for preliminary studies. The second method involves the same principle, but is done by computer on a detailed grid.

The manual wave refraction method described here is the “Forward Ray” method, where the hand-constructed rays travel from deep to shallow water. A better method is the “Reverse Ray” technique which uses basically the same equations, but can provide a better answer, consisting of refraction coefficients for all wave directions at one site, faster than the forward technique. The forward technique can illustrate areas of wave height concentration along a coastline.

When waves approach a bottom slope obliquely, they travel slower in the shallower water depth, causing the line of the wave crest to bend toward alignment with the bottom contours. The process is known as wave refraction. The change of direction of wave orthogonals (lines perpendicular to the wave crests) from deep to shallower water may be approximated by Snell’s Law:

$$\frac{C_2}{C_1} = \frac{\sin \alpha_1}{\sin \alpha_2}$$

(4.3)

where $\alpha_1$ is the angle a wave crest makes with the bottom contour over which it is passing, $\alpha_2$ is the angle a wave crest makes with the next bottom contour over which it is passing, $C_1$ is wave velocity at depth of first bottom contour, and $C_2$ is wave velocity at depth of second bottom contour.

The assumptions made in a refraction analysis include:

1. Wave energy between wave orthogonals remains constant.
2. Wave direction is perpendicular to the wave crests in the direction of the orthogonals.
3. Speed of a wave of a given period at a particular location depends only on the water depth at the location.
4. Bottom topography changes are gradual.
5. Effects of currents, winds, wave reflections, and underwater topographic variations are negligible.
6. Waves are constant period Airy waves.

Under the above assumptions, the following wave height relationship can be derived:

\[ H = H_0 \sqrt{\frac{b_{wo}C_o}{2b_wCN}} \]  

where \( H \) is wave height at water depth \( d \) in feet, \( H_0 \) is deepwater wave height in feet, \( b_{wo} \) is deepwater spacing between orthogonals in feet, \( C_o \) is deepwater wave velocity in ft/sec, \( b_w \) is spacing between orthogonals at water depth \( d \) in feet, \( C \) is wave velocity at water depth \( d \) in ft/sec, and \( N \) is expressed as

\[ N = \frac{1}{2} \left[ 1 + \frac{4\pi d}{L \sinh \left( \frac{4\pi d}{L} \right)} \right] \]  

where \( L \) is wave length at water depth \( d \) in feet. The analysis procedure used to determine maximum or limiting wave heights at a given location is:

1. Define and draw bottom contours over sea of interest.
2. Calculate wave velocities at selected bottom contours moving into deep water.
3. Select an angle of wave attack at the desired location.
4. Calculate and construct wave crest angles moving into deep water.
5. In deep water, define an orthogonal spacing, \( b_{wo} \).
6. Perform a second wave crest angle analysis shoreward on the new wave track.
7. At the desired location, measure orthogonal spacing, \( b_w \).
8. Calculate wave height at desired location.
9. Define new angles of wave attack at the desired location and repeat Steps 4 through 9.

The analysis can be performed by hand as outlined above, or by using refraction templates. Refraction diagrams can provide information on the change in waves approaching a shore. Analysis validity is limited by depth data accuracy and the preciseness of the model.

### 4.3.1.3 Wave Shoaling

When a wave moves into shallower water, its wave height and wave length change. This process is described as shoaling. The effect of shoaling may be estimated from any particular wave theory under the following assumptions:

1. Motion is two-dimensional.
2. Wave period remains constant.
3. Average rate of energy transfer is constant in direction of wave propagation.
4. Wave theory applies at all water depths considered.

These assumptions are often valid until the wave breaks.

Using Airy wave theory, the following comparative relationships can be approximated (Sarpkaya and Isaacson, 1981):

$$\frac{L_w}{L_o} = 2\pi \sqrt{\frac{d}{gT^2}} = \sqrt{2\pi \frac{d}{L_o}}$$  \hspace{1cm} (4.6)

and

$$\frac{H}{H_o} = \frac{1}{\sqrt{16\pi^2 \frac{d}{gT^2}}} = \frac{1}{\sqrt{8\pi \frac{d}{L_o}}}$$ \hspace{1cm} (4.7)

where

- $d$ = water depth (ft)
- $T$ = wave period (sec)
- $g$ = gravitational acceleration, 32 ft/sec$^2$
- $L_w$ = wave length (ft)
- $H$ = wave height (ft)
- $L_o$ = deep water wave length (t)
- $H_o$ = deep water wave height (ft)

For the above Airy wave theory case, graphical aids may be developed. Selection of different wave theories will result in similar but different relationships.

Note that environmental data such as wind, waves, and currents can have specific interrelationships. A common assumption of taking the combined maximum effect of each may not always produce the worst design conditions, and, in some cases, joint statistics of current and wave should be considered.

4.3.1.4 Soil Friction Factor

Friction factor ($\mu$) is defined as the ratio between the force required to move a section of pipe and the vertical contact force applied by the pipe on the seabed. This simplified model (Coulomb) is used to assess stability. The friction factor depends on the type of soil, the pipe roughness, seabed slope, and depth of burial. For practical purposes, only the type of soil is considered and the pipe roughness ignored.

For stability analysis, a lower bound estimate for soil friction is conservatively assumed, whereas for pulling or towing analysis, an upper bound estimate would be appropriate. The following lateral friction factors are given as guidelines for stability analysis in the absence of site specific data:

- Loose sand: $\mu = \tan \phi$ (generally $\phi = 30^\circ$)
- Compact sand: $\mu = \tan \phi$ (generally $\phi = 35^\circ$)
Soft clay: \( \mu = 0.7 \)
Stiff clay: \( \mu = 0.4 \)
Rock and gravel: \( \mu = 0.7 \)

These coefficients represent the “best” estimate for generalized soil types and do not include safety factors.

Small scale tests (Lyons, 1973) and offshore tests (Lambrakos, 1985) have shown that the starting friction factor in sand is about 30% less than the maximum value which occurs after a very small displacement of the pipe builds a wedge of soil; past this point, the friction factor levels off. The value given above accounts for the build-up of this wedge of soil which has been shown to take place. The Coulomb model underestimates the actual lateral soil resistance if settlement is anticipated.

4.3.2 Hydrodynamic Coefficient Selection

Hydrodynamic coefficients have been the subject of numerous theoretical and experimental investigations and are often subject to argumentation. The purpose of this section is to provide a method for selection of \( C_D \), \( C_L \), and \( C_I \) for one of the following three situations:

- Steady current only
- Waves only
- Steady current and waves

4.3.2.1 Steady Current Only

The \( C_d \) and \( C_L \) depend on pipe roughness and Reynolds number. Figure 4.2 provides graphs of lift and draft coefficients for these parametric considerations (Jones, 1976).

Pipe roughness is defined as the ratio between the mean roughness height and the pipe diameter, i.e., \( R_r = \kappa / D \). For FBE-coated pipe (smooth), \( R_r \) should be taken as 0. For other coatings when \( \kappa \) is not known, an approximate value must be estimated knowing that the hydrodynamic drag increases as \( R_r \) increases, while the lift coefficient decreases. The following \( \kappa \) values are given as guidelines:

- FBE, yellow jacket: \( \kappa = 0 \) (fine)
- Concrete coating or abrasion coating: \( \kappa = 0.1 \) in. (medium)
- Marine growth (barnacles): \( \kappa = 1.6 \) in. (rough) (Teng and Nath, 1989)
- Marine growth (anemones): \( \kappa = 2.7 \) in. (rough) (Teng and Nath, 1989)

Reynolds number is defined as ratio between inertial force and viscous force, i.e., \( Re = U_c D / \nu_k \). The seawater kinematic viscosity (\( \nu_k \)) increases as the seawater temperature decreases. In deep water or cold water, the following value should be used:

\[
\nu_k = 1.7E-5 \text{ ft}^2\text{s}^{-1}(1.57E-6 \text{ m}^2/\text{s}) \text{ at } 40^\circ \text{F}(5^\circ \text{C})
\]

In warm waters or for hot pipes, the following value should be used:

\[
\nu_k = 1.0E-5 \text{ ft}^2\text{s}^{-1}(0.92E-6 \text{ m}^2/\text{s})
\]
Hydrodynamic coefficients increase as $Re$ decreases (for the range of Reynolds number normally encountered), which justifies the use of a conservative high $v_k$-value.

### 4.3.2.2 Waves Acting Alone

The hydrodynamic coefficients ($C_D$, $C_L$, $C_I$) depend on pipe roughness and Keulegan number $K_c = U_w T / D$. For a pipe resting on the seabed, five references are applicable as shown in Figure 4.2. (Det norske Varitas, 1981; Bryndum et al., 1983; Bryndum, 1983; Zdravkovich, 1977; and Verley and Lambrakos, 1987.) The references show that $C_D$ presents a peak for $K_c$ values between 10 and 20, $C_L$ decreases with increasing $K_c$ values, and $C_I$ increases with increasing $K_c$ values. Figure 4.3 is recommended for $K_c$ values less than 20 (Sarpkaya, 1979). The frequency parameter ($\beta$) is defined as $\beta = Du / T$. Figure 4.4 is for $K_c$ values greater than 20 but less than 160 (Bryndum et al., 1983). Figure 4.5 is for $K_c$ values greater than 160 (Jones, 1976).

### 4.3.2.3 Waves and Currents Acting Simultaneously

In addition to the variables previously mentioned, the steady current ratio $R_c = U_c / U_m$ must be taken into account for the selection of $C_D$, $C_L$, and $C_I$. Another current ratio is sometimes used (Bryndum et al., 1983) and noted $\alpha = U_c / U_w$. Note that $K_c$ is based on particle velocity $U_w$ and not maximum velocity $U_m$.

Refer to the selection flowchart, Figure 4.6, to identify the relevant reference. Only three papers apply to pipelines resting on the bottom. They are OMAE paper (1988) (Bryndum...
Experimental tests (Bryndum et al., 1983) have shown that the presence of a steady current leads, in all cases, to a reduction of the hydrodynamic coefficients. For $15 < K_c < 70$, Figure 4.7 should be used (Bryndum et al., 1983). This requires the use of $\alpha (= U_c / U_w)$ for small values. For $K_c$ values less than 15, Figure 4.8 should be used (Bryndum, 1983). Figures 4.2 and 4.6 show other references, which apply unusual situations such as pipelines away from a plane boundary. These may be used for piles or pipeline spans, but

**Figure 4.3(a)** Hydrodynamic coefficient $C_D$ for wave acting alone in the low $K_c$ region.
care should be taken when deviating from this guideline. Note that the election of coefficients depends on the value $U_w$. This velocity can be calculated using a computer program or manual calculation.

### 4.3.3 Hydrodynamic Force Calculation

The third step of the stability analysis involves the determination of the hydrodynamic drag force ($F_D$), lift force ($F_L$), and inertia force ($F_I$), represented by the Morison Equations:

FIGURE 4.3 (contd.) (b) Hydrodynamic coefficient $C_L$ for wave acting alone in the low $K_c$ region. (c) Hydrodynamic coefficient $C_I$ for wave acting alone in the low $K_c$ region.
Figure 4.4 (a) Hydrodynamic coefficient $C_D$ for wave acting alone in the high $K_c$ region. (b) Hydrodynamic coefficient $C_L$ for wave acting alone in the high $K_c$ region. (c) Hydrodynamic coefficient $C_I$ for wave acting alone in the high $K_c$ region.
Figure 4.5 (a) Recommended effective drag coefficient $C_D$ for design of pipeline resting on bottom subject to current acting alone. (b) Recommended effective lift coefficient $C_L$ for design of pipeline resting on bottom subject to current acting alone.

\[ F_D = \frac{1}{2} C_D \rho D U_m |U_m| \]  
\[ F_L = \frac{1}{2} C_L \rho D U_m^2 \]  
\[ F_I = C_I \rho \left( \frac{\pi D^2}{4} \right) U_w \]
4.3.4 Hydrodynamic Stability Assessment

The last step of the analysis consists of assessing stability and computing concrete coating thickness requirement, using the AGA program LSTAB. Seabed slope and safety factor should be considered.

A pipeline is stable on a slope ($\delta$) if its submerged weight ($W_s$) satisfies the following relationship:

$$
\mu (W_s \cos \delta - F_L) \geq \zeta [(F_D + F_D)_{\text{max}} + W_s \sin \delta].
$$

Figure 4.6 Hydrodynamic coefficient selection flowchart for waves and currents acting simultaneously.

4.3.4 Hydrodynamic Stability Assessment

The last step of the analysis consists of assessing stability and computing concrete coating thickness requirement, using the AGA program LSTAB. Seabed slope and safety factor should be considered.

A pipeline is stable on a slope ($\delta$) if its submerged weight ($W_s$) satisfies the following relationship:

$$
\mu (W_s \cos \delta - F_L) \geq \zeta [(F_D + F_D)_{\text{max}} + W_s \sin \delta].
$$

where $\zeta$ is a safety factor. This formulation assumes a Coulomb friction model and is not applicable if the pipe is embedded. A preliminary conservative approach, however, is to consider no embedment.

The safety factor is designed to account for uncertainties in actual soil factor, actual environmental data (wave, current), actual particle velocity and acceleration, and actual hydrodynamic coefficients. The safety factor can be imposed by the pipe operator, the governing code, or it can be selected by the engineer, depending on the design conditions. Recommended safety factors are $\zeta = 1.05$ for installation and $\zeta = 1.1$ for operation. The latter is also recommended by DnV RP E305 Clause 3.2.2 (DnV, 1988), DnV 1981 Clause 4.2.5.9 (DnV, 1981), and Canadian CAN/CSA.Z187.
Safety factors depend on how conservative a design has been conducted and should cover any uncertainty while, at the same time, avoid compounding conservatism. For example, nominal dimensions are normally used to calculate pipeline submerged-weight; however, for large diameter pipes, manufacturing tolerances and sometimes seawater density should be taken into account.

Figure 4.7 (a) Hydrodynamic coefficient $C_D$ for waves and currents acting simultaneously. (b) Hydrodynamic coefficient $C_I$ for waves and currents acting simultaneously.
4.4 Partially Buried Pipelines

This section indicates “rules of thumb” to determine stability of partially buried lines. It involves the determination of the break-out force on a partially buried pipeline under oscillatory loading, and the selection of modified hydrodynamic coefficients. Tests were for sand and clay conditions where embedment due to cyclic pipe motions may occur. For partially buried or settled pipelines, program LSTAB should be used. Different considerations apply to partially buried pipelines in sand and in clay.

Recent Norwegian compilation of existing test data (SINTEF, 1988) gives a simplified model for pipelines partially buried in sand. For a burial depth of such that

$0 < z = 0.35D$,

the ultimate break-out force $F_b$ is given by

$$F_b = F_f + F_R$$

where $F_R$ is the penetration dependent soil resistance given by

$$F_R = 0.72W_s(0.87D_r^2 - 1.96D_r + 1.1)$$

where $D_r$ is relative density of sand. For dense sand, $D_r = 0.46$. For loose sand, $D_r = 0.05$. 

\[\text{Figure 4.7 (contd.) (c) Hydrodynamic coefficient } C_L \text{ for waves and currents acting simultaneously.}\]
Figure 4.8  (a) Hydrodynamic coefficient $C_D$ for waves and current acting simultaneously. 
(b) Hydrodynamic coefficient $C_I$ for waves and current acting simultaneously.
(c) Hydrodynamic coefficient $C_L$ for waves and current acting simultaneously.
For pipelines partially buried in clay, the ultimate lateral resistance \((R_L)\) depends on the pipe embedment \((z)\), cohesion at the base of the pipe \((C_b)\), and surface of contact \((b_s)\) between the pipe and the seabed. The following equations should be used to determine \(z\)-value (Wantland, 1979):

\[
4C_b + \gamma'z = 2.5 \left( \frac{W_s \cos \delta - F_L}{b_i} \right)
\]

(4.14)

where

\[
b_i = 2z \sqrt{\frac{D}{z}} - 1 \quad \text{for} \quad z < \frac{D}{2}
\]

(4.15)
\[ b_s = D \quad \text{for} \quad z \geq \frac{D}{2} \quad (4.16) \]

and

\[ R_L = N_s C_a D \quad (4.17) \]

where \( C_a \) is the average cohesion over two pipe diameters and \( N_s \) is given by Figure 4.9 (Wantland, 1979). Pipeline stability must be based on

\[ R_L > \zeta (F_{D_a} + F_I + W_s \sin \delta)_{\text{max}} \quad (4.18) \]

where \( \delta \) is the seabed slope and \( \zeta \) is the safety factor = 1.1.

The effects of embedment or pre-trenching reduce hydrodynamic coefficients. Refer to Figure 4.10 for the reduction factor associated with embedment \( d_m \). Figure 4.11 is
Figure 4.10 (a) Hydrodynamic coefficient $C_D$ reduction factor for partially buried pipelines. (b) Hydrodynamic coefficient $C_M$ reduction factor for partially buried pipelines. (c) Hydrodynamic coefficient $C_L$ reduction factor for partially buried pipelines.
Figure 4.10 (contd.) (d) Hydrodynamic coefficient $C_V$ reduction factor for partially buried pipelines. (e) Hydrodynamic coefficient $C_D$ reduction factor for partially buried pipelines. (f) Hydrodynamic coefficient $C_M$ reduction factor for partially buried pipelines.
\( \alpha = \frac{U_c}{U_w} \)

\( K_c = 30 \)

**Figure 4.10 (contd.)** (g) Hydrodynamic coefficient \( C_L \) reduction factor for partially buried pipelines.

\( C_D/C_{D_0} \) for pipelines in open trench. (b) Hydrodynamic coefficient \( C_M \) reduction factor for pipelines in open trench.
for the reduction factor related to pre-trenching, where $H_T$ is trench height and $a_T$ is trench slope ratio.

**References**


Ismail, N.M.: Wave Forces on Partially Buried Submarine Pipelines, OTC paper 5295.


CHAPTER 5

Pipeline Span

5.1 Introduction

Pipeline spanning can occur when the contact between the pipeline and seabed is lost over an appreciable distance on a rough seabed. An evaluation of an allowable free-span length is required in pipeline design. Should actual span lengths exceed the allowable length, correction is then necessary to reduce the span to avoid pipeline damage. The flow of wave and current around a pipeline span can result in the generation of sheet vortices in the wake. These vortices are shed alternately from top to bottom of the pipeline resulting in an oscillatory force exerted on the span. This chapter provides information about the determination of the allowable pipeline span length, based on the avoidance of vortex shedding induced oscillations. Both in-line and cross-flow vortex shedding induced oscillations will be discussed and evaluated. There is also a brief discussion and equations are presented for calculating the fatigue life of a pipeline based on the stresses incurred due to vortex shedding induced oscillations in a free span. This chapter will provide information based only on vortex shedding induced oscillations due to currents, which in most deepwater pipelines is the limiting factor for the allowable span length. It does not address vortex shedding induced oscillations due to wave motions or wave and current combined motions.

5.2 Problem Description

5.2.1 Free Span

Free span can result in failure of pipelines due to excessive yielding and fatigue. It may also cause interference with human activities such as fishing. Free span can occur due to unsupported weight of the pipeline section and dynamic loads from waves and currents. When a fluid flows across a pipeline, the flow separates, vortices are shed, and a periodic wake is formed. Each time a vortex is shed it alters the local pressure distribution, and the pipeline experiences a time-varying force at the frequency of vortex shedding. Under resonant conditions, sustained oscillations can be excited and the pipeline will oscillate at a frequency. This oscillation will fatigue the pipeline and can eventually lead to catastrophic failure. These oscillations are normally in-line with the flow direction but can be transverse (cross-flow), depending on current velocity and span length.
5.2.2 In-Line Oscillations

In-line oscillations are excited at flow velocities lower than the critical velocities for cross-flow motion. However, the amplitude of the in-line motion is only 10% of those associated with cross-flow motion. Several parameters are used in determining the potential for vibration. These include the reduced velocity, $U_r$, and the stability parameter, $K_s$. These are defined in later sections.

The first and second modes of in-line instability are associated with symmetrical vortex shedding and have a peak response at reduced velocities ($U_r$) of 1.9 and 2.6, respectively. To prevent this in-line response at either mode of vortex shedding excitation, it is suggested that the stability parameter ($K_s$) be larger than 1.8 (Wootton, 1991). DnV also states that resonant in-line vortex shedding induced oscillation may occur when $1.0 < U_r < 2.2$, the shedding will be symmetrical; and for $U_r > 2.2$, the shedding will be alternate.

5.2.3 Cross-Flow Oscillations

Excitation in the cross-flow direction is potentially more dangerous than that in in-line since amplitudes of response are much greater than those associated with in-line motion. However, these oscillations occur at much larger velocities than in-line oscillations and are not normally governing. The limiting value for cross-flow oscillation based on DnV is $K_s < 16$ (DnV, 1981; Wootton, 1991).

5.2.4 Galloping

Galloping is a form of oscillation that occurs for certain structural shapes and flow directions. Circular sections such as pipelines do not gallop because there can be no steady force on a circular cylinder other than drag. Therefore, galloping is not of concern to the pipeline engineer when evaluating the allowable span length. For non-circular shapes, it has been found to occur only in steady flows, but it may also occur in wave flows with long wavelengths. The motion is normal to the direction of flow and amplitude increases with increasing flow speed. Galloping generally occurs only when the reduced velocity is greater than the values for dynamic response to vortex shedding in steady flow.

5.3 Design Considerations

5.3.1 Dynamic Stresses

The presence of bottom currents can cause significant dynamic stresses, if fluid structure interaction (vortex shedding) in these free-span areas causes the pipeline to oscillate. These oscillations can result in fatigue of the pipeline welds, which can reduce pipeline life. The frequency of vortex shedding is a function of the pipe diameter, current velocity, and Strouhal Number. If the vortex shedding frequency (also referred to as the Strouhal frequency) is synchronized with one of the natural frequencies of the pipeline span, then
resonance occurs and the pipe span vibrates. Pipeline failure due to vortex excited motions can be prevented if the vortex-shedding frequency is sufficiently far from the natural frequency of the pipe span such that dynamic oscillations of the pipe are minimized.

5.3.2 Vortex-Shedding Frequency

The vortex-shedding frequency is the frequency at which pairs of vortices are shed from the pipeline and is calculated based on the following:

\[ f_s = \frac{SU_c}{D} \]  

(5.1)

where

- \( f_s \) = vortex-shedding frequency
- \( S \) = Strouhal Number
- \( U_c \) = design current velocity
- \( D \) = pipe outside diameter

Strouhal Number is the dimensionless frequency of the vortex shedding and is a function of the Reynolds Number. Reynolds Number \( Re \) is a dimensionless parameter representing the ratio of inertial force to viscous force:

\[ Re = \frac{U_c D}{\nu_k} \]  

(5.2)

where \( \nu \) is kinematic viscosity of fluid (1.2 \times 10^{-5} \text{ ft}^2/\text{sec} for water at 60°F).

5.3.3 Pipeline Natural Frequency

The natural frequency of the pipeline span depends on pipe stiffness, end conditions of the pipe span, length of the span, and effective mass of the pipe. The natural frequency for vibration of the pipe span is given by the following formulas:

\[ f_n = \frac{C_e}{2\pi} \sqrt{\frac{EI}{M_e L_s^4}} \]  

(5.3)

where

- \( f_n \) = pipe span natural frequency
- \( L_s \) = span length
- \( M_e \) = effective mass
- \( C_e \) = end condition constant

The end condition constant is a function of the type of model that is selected in determining the support conditions of the pipeline span. The following values are used based on these end conditions:
Ce = (1.00 \pi)^2 = 9.87 \text{ (pinned-pinned)}
Ce = (1.25 \pi)^2 = 15.5 \text{ (clamped-pinned)}
Ce = (1.50 \pi)^2 = 22.2 \text{ (clamped-clamped)}

The effective mass is the sum of total unit mass of the pipe, the unit mass of the pipe contents, and the unit mass of the displaced water (added mass).

\[ M_e = M_p + M_c + M_a \]  

(5.4)

where

\( M_p \) = unit mass of pipe including coatings (slugs/ft or kg/m)
\( M_c \) = unit mass of contents (slugs/ft or kg/m)
\( M_a \) = added unit mass (slugs /ft or kg/m)

The added mass is the mass of water displaced by the pipeline and is calculated based on the following:

\[ M_a = \frac{\pi D^2 \rho}{4} \]  

(5.5)

where \( \rho \) is mass density of fluid around the pipe (seawater = 2 slugs/ft\(^3\) or 1025 kg/m\(^3\)).

5.3.4 Reduced Velocity

The reduced velocity, \( U_r \), is the velocity at which vortex shedding induced oscillations may occur. The equation for reduced velocity is:

\[ U_r = \frac{U_c}{f_nD} \]  

(5.6)

Figure 5.1 presents the reduced velocity for cross-flow oscillations based on the Reynolds Number (DnV, 1981). Figure 5.2 presents the reduced velocity for in-line oscillations based on the stability parameter \( K_i \) defined in the next subsection.

5.3.5 Stability Parameter

A significance for defining vortex-induced motion is the stability parameter, \( K_i \), defined as:

\[ K_i = \frac{2M_a \delta_i}{\rho D^2} \]  

(5.7)

where \( \delta_i \) is logarithmic decrement of structural damping (= 0.125).
5.3.6 Critical Span Length

The critical span length or the unsupported pipeline length at which oscillations of the pipeline occur for a specific current is based on the relationship between the natural frequency of the pipe free span and the reduced velocity. The critical span length for cross-flow motion is expressed as:

**Figure 5.1** Reduced velocity for cross-flow oscillations based on the Reynolds Number.

**Figure 5.2** Reduced velocity for in-line oscillations based on the stability parameter.
The critical span length for in-line motion is expressed as:

\[ L_c = \sqrt{\frac{C_e U_D}{2\pi U_c} \sqrt{\frac{EI}{M_c}}} \]  

(5.8)

The critical span length for in-line motion is expressed as:

\[ L_c = \sqrt{\frac{C_{efu}}{2\pi} \sqrt{\frac{EI}{M_c}}} \]  

(5.9)

### 5.4 Design Criteria

#### 5.4.1 General Considerations

For preliminary design purposes, it is customary to design a pipeline such that at no location along the pipeline route does the unsupported pipeline span length exceed the critical span length for which in-line motion occurs due to vortex shedding, at any time during the design life of the pipeline. However, in deep water, where traditional deployment of span supports is not possible, this conservative design procedure can be quite costly. Thus, the selection of the allowable span length can become a risk assessment type solution.

#### 5.4.2 Current Velocity Selection

The calculated reduced velocity, stability parameter, Reynolds Number, and critical span length should all be based on a current velocity that is perpendicular to the pipeline. This design current should be based on the 100-year near bottom current unless otherwise directed.

#### 5.4.3 End Condition Selection

The selection of the proper end conditions for the pipe free span has a significant impact on the allowable span length selected. The typical rule of thumb for selecting the proper model for the end conditions are as follows:

- **Pinned-Pinned**: Used for spans where each end is allowed to rotate about the pipe axis.
- **Pinned-Fixed**: Used for the majority of spans, any span that does not fit the other two categories.
- **Fixed-Fixed**: Should be used only for those spans that are fixed in place by some sort of anchor at both ends of the span.

The end condition selected can influence the calculated critical span length by as much as 50 percent, thus making the selection of the proper end conditions a critical step in selecting the proper allowable span length.
5.4.4 Design Parameters

As previously discussed, two types of motions are created by vortex shedding. The first of these is in-line motion. The amplitude of in-line motion can vary between 10 and 20 percent of the pipe diameter and occurs at low critical velocities. For most pipeline cases a prudent and conservative design should be based on the avoidance of in-line motion for the design bottom current. The second type of motion, cross-flow, occurs at higher critical velocities and with a larger amplitude, in the order of 1 to 2 times the pipe diameter. The allowable pipeline span length should always be designed such that cross-flow motion will never occur. The design engineer should only design the pipeline such that in-line motion is allowed to occur after evaluating the possible economic impacts that a smaller allowable span length would create. Even after such a decision has been made, the designer should undertake a fatigue life analysis check.

5.4.5 Design Steps

The following steps are based on the use of Figures 5.1 and 5.2 to assist in determining the allowable pipeline free span length.

Step 1: Determine the design current (100-year near bottom perpendicular to the pipeline).
Step 2: Calculate the effective unit mass of the pipeline with Equation 5.4.
Step 3: Calculate Reynolds Number with Equation 5.2.
Step 4: Calculate stability parameter with Equation 5.7.
Step 5: Using the stability parameter enter Figure 5.2 to determine the reduced velocity for in-line motion.
Step 6: Using the Reynolds Number enter Figure 5.1 to determine the reduced velocity for cross-flow motion.
Step 7: Based on the terrain and conditions involved, determine the type of free span end conditions and calculate the end condition constant.
Step 8: Calculate the critical span length for both in-line and cross-flow motion with Eqs. 5.8 and 5.9.
Step 9: For the majority of projects, the allowable span length is the critical span length calculated for in-line motion. However, when economic factors warrant, the critical span length calculated for cross-flow motion can be selected.
Step 10: When in-line motion is permitted, the fatigue life of the free span should be calculated and evaluated for the pipeline.

5.4.6 Example Calculation

This example calculates the allowable span length to the cross-flow oscillation based on the following information:

Outside diameter of pipe \((D)\) = 0.2757 m
Inside diameter of pipe \((D_i)\) = 0.2509 m
Density of fluid in pipe \((\rho_f)\) = 107 kg/m\(^3\)
Density of pipe ($\rho_p$) = 1024 kg/m$^3$
Mass of pipe and coatings ($M_p$) = 74 kg/m
Kinematic viscosity of external fluid ($\nu_k$) = $1.565 \times 10^{-6}$ m$^2$/sec
Current velocity ($U_c$) = 0.35 m/s
Constant for clamped-pinned ends ($C_e$) = 15.4

**Step 1: Effective Mass**

$$M_p = 74 \text{ kg/m}$$

$$M_c = \frac{(3.14)(0.2509)^2}{4}(107) = 5.29 \text{ kg/m}$$

$$M_u = \frac{(3.14)(0.2757)^2}{4}(1024) = 61.13 \text{ kg/m}$$

$$M_e = 74 + 5.29 + 61.13 = 140.5 \text{ kg/m}$$

**Step 2: Stability Parameter**

$$K_s = \frac{(2)(140.5)(0.125)}{(1024)(0.2757)} = 0.451$$

**Step 3: Reynolds Number**

$$R_e = \frac{(0.35)(0.2757)}{(1.56 \times 10^{-6})} = 6.1658 \times 10^4$$

**Step 4: Reduced Velocities**

$$U_r = 1.6 \text{ from Figure 5.2 for in-line motion}$$

$$U_r = 5.0 \text{ from Figure 5.1 for cross-flow motion}$$

**Step 5: Critical Span Length for Cross-Flow Motion**

$$L_c = \sqrt{\frac{(15.4)(5)(0.2757)}{(2\pi)(0.35)}} \sqrt{\frac{(2.07 \times 10^{11})\left[\frac{\pi}{64}\left((0.2757)^2 - (0.2509)^2\right)\right]}{(140.5)\left(0.35\right)}}$$

$$L_c = 59.1 \text{ m}$$

**Step 6: Critical Span Length for In-Line Motion**

$$L_c = \sqrt{\frac{(2.45)(1.6)(0.2757)}{(0.35)}} \sqrt{131247}$$

$$L_c = 33.5 \text{ m}$$
5.5 Fatigue Analysis Guideline

The fatigue life equation presented in this section is based on the Palmgren-Miner Fatigue Model, which uses an S-N model based on the AWS-X modified curve of the form:

\[ N = \frac{6.48 \times 10^{-8}}{\Delta \varepsilon^4} \]  

(5.10)

where \( N \) is number of cycles to failure and \( \Delta \varepsilon \) is the strain range in each cycle. This extremely simplified fatigue life equation is expanded as follows:

\[
L_f = \left[ \frac{5.133 \times 10^{-18} (L_s^8)}{(D_s^4 f_n)} \right] \times \left[ \frac{1}{\sum_i (f/f_n)(A/D)^i T_i} \right] 
\]  

(5.11)

where

- \( L_f \) = fatigue life (years)
- \( L_s \) = span length
- \( D_s \) = outside diameter of steel
- \( f_n \) = pipe frequency (Hz)
- \( f/f_n \) = frequency ratio (Figure 5.3)
- \( A/D \) = amplitude ratio (Figure 5.4)
- \( T_i \) = current duration (hrs/day).

![Figure 5.3 Chart for determination of frequency ratio based on \((V/D_o f_n)\).](image)
The following steps should be followed when checking the fatigue life of free span length:

**Step 1:** Calculate the pipe natural frequency (Equation 5.3)

**Step 2:** Determine the near bottom current velocity occurrence distribution in histogram form using current duration blocks

**Step 3:** For each current segment determine the frequency ratio based on \((U_c/D_f)\) and Figure 5.3

**Step 4:** For each current segment determine the amplitude ratio based on the stability parameter and Figure 5.4

**Step 5:** Calculate the fatigue life (Equation 5.11)

For cases where it can be illustrated that the fatigue life for in-line motion is much greater than the pipeline lifetime, cross-flow motion will become the limiting factor on critical span length. The fatigue life for cross-flow motion should be similarly checked to assume a factor of 10 for the amplitude ratio. This will normally show that cross-flow motion is prohibitive.

### References


CHAPTER 6

Operating Stresses

6.1 Introduction

This chapter addresses the calculation of operation stresses and end movements (expansion) for trenched and non-trenched, single well pipelines. Operating stresses are those which result from a combination of internal pressure and thermal stresses that occur during operation. Equations of operating stresses and expansion are provided. Only single well pipe internal pressure is addressed. In the case of relatively thin-wall pipe \((D/t > 20)\), the equations presented can be used with \(P\) representing the difference between the internal and external pressure. This is not the case with thick-wall cylinders \((D/t < 20)\).

6.2 Operating Forces

When in operation, pressure and thermal forces exist, which act to expand the pipeline both rapidly and longitudinally. These are due to internal pressure and temperature difference between the pipe and surrounding fluid. The magnitude of these stresses is dependent upon forces opposing the above conditions, and boundary conditions, namely, soil friction acting longitudinally, end constraints, and end cap effect.

6.2.1 Internal Pressure Stresses

A pipeline is a pressure vessel in the form of a cylinder, and, for this reason, some of the most detailed information available is obtained in the literature for pressure vessel design. Pipes with \(D/t\) greater than 20 are referred to as thin-wall pipes, and that with \(D/t\) less than 20 are called thick-wall pipes.

6.2.1.1 Thin-Wall Pipe

If a thin-wall pipe is subjected to internal pressure, \(P\), the action of radial force distributed around the circumference will produce a circumferential (or hoop) stress given by:

\[
\sigma_b = \frac{PD}{2t}
\]  

(6.1)
where

\[ \sigma_h = \text{hoop stress} \]
\[ D = \text{internal diameter} \]
\[ t = \text{wall thickness} \]
\[ P = \text{net internal pressure} \]

The mitigating effect of external pressure can be considered, and for deepwater pipelines, this can be a factor in reducing required wall thickness. For pipeline design, \( D \) is taken as the nominal outside diameter to account for mill tolerance. This will be slightly conservative in most cases, but the hoop stress must be calculated in this manner to meet the ANSI/ASME B31.8, B31.4 design practices.

The longitudinal stress, \( \sigma_L \), is calculated by dividing the total pressure force against the end of the pipe (end cap effect) by the cross-section area of the pipe.

\[ \sigma_L = \frac{PD}{4t} \]  
(6.2)

These stresses in thin-wall pipes are illustrated in Figure 6.1. Strains can be calculated based on stresses and elastic modulus by \( \varepsilon_h = \sigma_h / E \) and \( \varepsilon_L = \sigma_L / E \).

### 6.2.1.2 Thick-Wall Pipe

For \( D/t \) less than 20, the convention is to use the thick-wall equations for hoop and radial stresses that are slightly more complicated. The thin-wall equations for hoop stress can be used, but it results in slightly high estimates of stresses.

---

**FIGURE 6.1** Operating stresses in thin-wall pipes.
The principal difference between the thin- and thick-wall formulations is that for thick-wall conditions, the variation in stress between inner and outer surface becomes significant. The cross section for a thick cylinder and its representative stresses are depicted in Figure 6.2.

For the case of internal pressure only, the following equations apply:

\[
\sigma_r = \frac{b^2 P}{a^2 - b^2} \left(1 - \frac{a^2}{r^2}\right) \quad (6.3)
\]

\[
\sigma_h = \frac{b^2 P}{a^2 - b^2} \left(1 + \frac{a^2}{r^2}\right) \quad (6.4)
\]

where \(r\) varies from \(b\) to \(a\), which are the inside and outside radii, respectively. Both \(\sigma_h\) and \(\sigma_r\) have maximum at \(r = b\).

The longitudinal stress, \(\sigma_L\), is given by:

\[
\sigma_L = \frac{b^2 P}{a^2 - b^2} \quad (6.5)
\]

For the calculation of burst pressure, the maximum shear stress theory correlates well with data. This is given by one-half the algebraic difference between the maximum and
minimum principal stresses at any point. Since the longitudinal stress is neither the maximum nor the minimum value, it is ignored resulting in:

$$\tau = \frac{\sigma_h - \sigma_r}{2} \quad (6.6)$$

which, when Eqs. (6.3) and (6.4) are used, becomes:

$$\tau = \frac{a^2 b^2 P}{r^2 (a^2 - b^2)} \quad (6.7)$$

For the case of internal pressure only, the shear stress is a maximum on the inner surface. Therefore,

$$\tau_{\text{max}} = \frac{a^2 P}{a^2 - b^2} \quad (6.8)$$

### 6.2.2 Thermal Expansion Stresses

Temperature gradient exists between the maximum operating temperature and the minimum installation temperature. Operating temperature along the pipeline can be predicted using the heat transfer model presented in Appendix B. The longitudinal strain is proportional to the magnitude of the temperature difference. In an unrestrained unaxial condition, the longitudinal thermal stress is zero, but the thermal strain, $\varepsilon_t$, is given by:

$$\varepsilon_t = \alpha_t \Theta \quad (6.9)$$

where $\alpha_t$ is the coefficient of thermal expansion ($6.5 \times 10^{-6}$ in./in.-°F for steel), and $\Theta$ is the value of temperature change $T_2 - T_1$.

In the restrained condition, the longitudinal strain is zero, but the compressive stress generated by the restrained expansion is given by:

$$\sigma = -E\alpha_t \Theta \quad (6.10)$$

The negative sign reflects the fact that the stresses for a positive temperature increase under restrained conditions is compressive. Similarly, the stresses are tensile for a restrained pipe if a temperature decrease exists.

When a two-dimensional element is heated but subjected to a restraint in the $y$-direction, the strain in the $x$-direction is increased due to the Poisson ratio $\nu$. This is illustrated in Figure 6.3. If the element is heated and restrained in both the $x$- and $y$-directions, the principal stresses become:

$$\sigma_1 = \sigma_2 = -\frac{E\alpha_t \Theta}{1 - \nu} \quad (6.11)$$
For a heated cube having restraints in all directions, the stresses are given by:

\[ \sigma_1 = \sigma_2 = \sigma_3 = -\frac{E\alpha_t \Theta}{1 - 2\nu} \]  

(6.12)

6.2.3 Combined Pressure and Temperature

Pressure and temperature-induced stresses in single wall pipe depend on restraining conditions such as unrestrained, partially restrained by longitudinal soil friction, and fully restrained by end anchor. Different equation sets apply to thin-wall and thick-wall pipes. In all cases, positive stresses are tensile stresses and negative stresses are compressive stresses.

6.2.3.1 Equations for Thin-Wall Pipe

For thin-wall (D/t > 20) unrestrained pipe with ends capped, the equations for hoop stress, strain, end movement, and radial dilation are given as follows (Roark and Young, 1989):

Hoop Stress: \( \sigma_h = \frac{PD}{2t} \)  

(6.13)

Longitudinal Stress: \( \sigma_L = \frac{PD}{4t} \)  

(6.14)
Hoop Strain: \( \varepsilon_b = \alpha_r \Theta + \frac{PD}{2tE} \left( 1 - \frac{\nu}{2} \right) \) (6.15)

Longitudinal Strain: \( \varepsilon_L = \alpha_r \Theta + \frac{PD}{2tE} \left( 1 - \frac{\nu}{2} \right) \) (6.16)

End Movement: \( \Delta L = \frac{LE_L}{2} \) (6.17)

Radial Movement: \( \Delta R = a\varepsilon_b \) (6.18)

where \( P \) may represent the difference between internal and external pressures.

For pipe partially restrained by soil friction, the equations for hoop stress, strain, end movement, and radial dilation are given below (from Harvey (1985) except otherwise noted):

Hoop Stress: \( \sigma_b = \frac{PD}{2t} \) (6.19)

Longitudinal Stress: \( \sigma_L = \frac{PD}{4t} - \frac{fx}{2\pi at} \) for \( x < Z \) (end-cap pressure effect included) \( \sigma_L = \frac{vPD}{2t} - E\alpha_r \Theta \) for \( x \geq Z \) (6.21)

Hoop Strain: \( \varepsilon_b = \alpha_r \Theta + \frac{PD}{2tE} \left( 1 - \frac{\nu}{2} \right) + \frac{vfx}{2\pi atE} \) for \( x < Z \) (6.22) or
\[ \varepsilon_b = \alpha_r \Theta + \frac{PD}{2tE} \left( 1 - \frac{\nu^2}{2} \right) + \nu \alpha_r \Theta \] (by Roark and Young, 1989) (6.23)

Longitudinal Strain: \( \varepsilon_L = \alpha_r \Theta + \frac{PD}{2tE} \left( 1 - \frac{\nu}{2} \right) - \frac{fx}{EA_i} \) for \( x < Z \) (6.24)

Longitudinal Strain at Free-End: \( \varepsilon_o = \alpha_r \Theta + \frac{PD}{2tE} \left( \frac{1}{2} - \nu \right) \) for \( x < Z \) (6.25)

End Movement: \( \Delta L = \bar{\varepsilon}Z \) (6.26)

\[ Z = \frac{\pi Dt}{f} \left( E\alpha_r \Theta - \frac{vPD}{2t} \right) + \frac{\pi Pa^2}{f} \]

If \( Z \geq \frac{L}{2} \), then \( Z = \frac{L}{2} \) and \( \bar{\varepsilon} = \frac{1}{2}(\varepsilon_o - \varepsilon_z) \)

If \( Z \leq \frac{L}{2} \), then \( \bar{\varepsilon} = \frac{\varepsilon_o}{2} \)

Radial Movement: \( \Delta R = a\varepsilon_b \). (6.27)
For pipe fully restrained by end anchors, the equations for hoop stress, strain, end movement, and radial dilation are summarized as below (from Harvey (1985) except otherwise noted):

**Hoop Stress**: \[ \sigma_h = \frac{PD}{2t} \]  
(6.28)

Longitudinal Stress: \[ \sigma_L = \frac{V PD}{2t} - E \alpha_r \Theta \]  
(6.29)

Hoop Strain: \[ \varepsilon_h = \alpha_r \Theta + \frac{\sigma_h - V \sigma_L}{E} \]  
(6.30)

Longitudinal Strain: \[ \varepsilon_L = 0 \]  
(6.31)

End Movement: \[ \Delta L = 0 \]  
(6.32)

Radial Movement: \[ \Delta R = a \varepsilon_h \]  
(6.33)

Force on Anchor: \[ F = 2 \pi d t \left( E \alpha \Theta - \frac{V PD}{2t} \right) + \pi Pb^2 \]  
(6.34)

### 6.2.3.2 Equations for Thick-Wall Pipe

For thick-wall (D/t < 20) unrestrained pipe with ends capped, the equations for hoop stress, strain, end movement, and radial dilation are given as follows (Harvey, 1985):

Hoop Stress: \[ \sigma_h = \frac{Pb^2(a^2 + r^2)}{r^2(a^2 - b^2)} \]  
(6.35)

Longitudinal Stress: \[ \sigma_L = \frac{Pb^2}{a^2 - b^2} \]  
(6.36)

Radial Stress: \[ \sigma_b = \frac{Pb^2(a^2 - r^2)}{r^2(a^2 - b^2)} \]  
(6.37)

Radial Movement at \( a \): \[ \Delta R_a = \frac{Pab^2(2 - \nu)}{E(a^2 - b^2)} + \alpha_r \Theta a \]  
(6.38)

Radial Movement at \( b \): \[ \Delta R_b = \frac{Pb[a^2(1 + \nu) + b^2(1 - 2\nu)]}{E(a^2 - b^2)} + \alpha_r \Theta b \]  
(6.39)

Longitudinal Strain: \[ \varepsilon_L = \frac{1}{E} \left[ \sigma_L - \nu(\sigma_{ha} + \sigma_{ra}) \right] + \alpha_r \Theta \]  
(6.40)

End Movement: \[ \Delta L = \frac{L}{2} \left[ \frac{Pb^2(1 - 2\nu)}{E(a^2 - b^2)} + \alpha_r \Theta \right] \]  
(6.41)
For partially restrained pipe by soil friction, the equations for hoop stress, strain, end movement, and radial dilation are given as follows (Roark and Young, 1989):

**Hoop Stress:**
$$
\sigma_h = \frac{Pb^2 (a^2 + r^2)}{r^2(a^2 - b^2)}
$$

(6.42)

**Longitudinal Stress:**
$$
\sigma_L = \frac{1}{a^2 - b^2} \left( \frac{Pb^2}{a^2} - \frac{r^2}{r^2} \right) \text{ for } x < Z
$$

$$
\sigma_L = \frac{\nu Pb^2}{a^2 - b^2} - E\alpha_i \Theta \text{ for } x \geq Z
$$

(6.43)

(6.44)

**Radial Stress:**
$$
\sigma_r = \frac{Pb^2}{a^2 - b^2} \left( 1 - \frac{a^2}{r^2} \right)
$$

(6.45)

**Radial Movement at a:**
$$
\Delta R_a = \frac{a}{E} \left[ \sigma_{ha} - \nu (\sigma_{rad} + \sigma_{La}) \right] + \alpha_i \Theta a
$$

(6.46)

**Radial Movement at b:**
$$
\Delta R_b = \frac{b}{E} \left[ \sigma_{hb} - \nu (\sigma_{rb} + \sigma_{Lb}) \right] + \alpha_i \Theta b
$$

(6.47)

**Longitudinal Strain:**
$$
\varepsilon_L = \alpha_i \Theta + \frac{1}{E} \left[ \sigma_L - \nu \left( \frac{\sigma_{rb}}{2} + \sigma_{ha} \right) \right] \text{ for } x < Z
$$

$$
\varepsilon_L = 0 \text{ for } x \geq Z
$$

(6.48)

$$
Z = \frac{\pi (a^2 - b^2)}{2f} \left[ E\alpha_i \Theta + \frac{Pb^2 (1 - 2\nu)}{a^2 - b^2} \right]
$$

(6.49)

**Longitudinal Strain at Free-End:**
$$
\varepsilon_0 = \alpha_i \Theta + \frac{P}{E} \left[ \frac{\nu}{2} + \frac{b^2}{a^2 - b^2} (1 - 2\nu) \right]
$$

(6.50)

**End Movement:**
$$
\Delta L = \varepsilon Z \text{ for } Z < \frac{L}{2}, \varepsilon = \frac{\varepsilon_0}{2}
$$

$$
\Delta L = \frac{\varepsilon L Z}{2} \text{ for } Z \geq \frac{L}{2}
$$

(6.51)

(6.52)

$$
\varepsilon_L = \frac{1}{2} \left( \varepsilon_L \text{ at } x = 0 + \varepsilon_L \text{ at } x = \frac{L}{2} \right)
$$

For pipe fully restrained by end anchors, the equations for hoop stress, strain, end movement, and radial dilation are summarized as follows (from Harvey (1985) except otherwise noted):

**Hoop Stress:**
$$
\sigma_h = \frac{Pb^2 (a^2 + r^2)}{r^2(a^2 - b^2)}
$$

(6.53)

**Longitudinal Stress:**
$$
\sigma_L = \frac{2\nu Pb^2}{a^2 - b^2} - E\alpha_i \Theta
$$

(6.54)
Maximum Radial Stress: \( \sigma_{rb} = -P \) \hspace{1cm} (6.55)

Radial Movement at \( a \): \( \Delta R_a = \frac{a}{E} [\sigma_{ha} - \nu(\sigma_{ra} + \sigma_{La})] + \alpha_i \Theta a \) \hspace{1cm} (6.56)

Radial Movement at \( b \): \( \Delta R_b = \frac{b}{E} [\sigma_{hb} - \nu(\sigma_{rb} + \sigma_{Lb})] + \alpha_i \Theta b \) \hspace{1cm} (6.57)

Longitudinal Strain: \( \varepsilon_L = 0 \) \hspace{1cm} (6.58)

End Movement: \( \Delta L = 0 \) \hspace{1cm} (6.59)

Force on Anchor: \( F = A_i (E \alpha_i \Theta - \nu \sigma_{ha}) + \pi P b^2 \) \hspace{1cm} (6.60)

When calculating Von Mises equivalent stresses, the highest value is obtained in areas where the longitudinal stress is compressive since

\[
2\sigma_V^2 = (\sigma_h - \sigma_L)^2 + (\sigma_L - \sigma_r)^2 + (\sigma_r - \sigma_h)^2
\]

In thin-wall applications, \( \sigma_r \) can be assumed zero and the Von Mises equivalent stress is simplified to:

\[
\sigma_V = \sqrt{\sigma_h^2 + \sigma_L^2 + \sigma_h \sigma_L}
\]

### 6.2.3.3 Soil Friction

Soil friction force is the result of pipe-soil interaction building up a negative (compressive) strain in the pipeline. Friction force per unit length is equal to the product of the friction coefficient and the normal soil force acting around the pipe. Since actual distribution of normal force is hard to determine for the purpose of friction force calculation, a simplified model can be used. The soil force for a completely backfilled line is estimated by the following equation:

\[
f = \mu (W + W_p - F_b)
\]

where

\( W \) = weight of soil overburden (lbs/ft)

\( W_p \) = dry weight of pipe and contents (lbs/ft)

\( F_b \) = buoyant force (lbs/ft)

\( \mu \) = coefficient of friction for soil

\( f \) = friction force (lbs/ft)

For an untrenched pipe, the soil force is given by:

\[
f = \mu (W_p - F_b)
\]

When soil cover ranges from one to three times the pipe diameter, the soil force can be taken as the weight of the soil over the pipe. For increased depth of cover, the soil
force may not increase proportionately due to soil arching. The actual soil force must consider the type and composition of the overburden and is beyond the scope of this section.

### 6.2.3.4 End Constraint

End constraint is a reaction at structures such as a rigid flange, anchor, or a rigid tie-in. The restraint prevents pipe expansion. The restraining force generated is calculated by summing the internal pressure and thermal expansion forces. Soil friction is not a factor in this case as there is no longitudinal movement.

### 6.3 Stress-Analysis-Based Design

The pipeline design against the operating stresses involves stress analyses using the equations presented in the last section.

#### 6.3.1 Analysis Procedure

A general method of calculating the operating stresses is given below:

1. Determine the wall thickness of the pipe using the method described in Chapter 3, Pipeline Wall Thickness.
2. If \( D/t < 20 \), then use thick-wall pipe equations for subsequent calculations, otherwise use thin-wall equations.
3. Choose the appropriate pipe scenario case (fully restrained, unrestrained, or partially restrained).
4. Calculate the distance to no movement to determine whether the pipeline half-length is longer or shorter than its distance. If the half-length is shorter, the strain at the midpoint is non-zero.
5. Calculate the hoop stress using the pressure difference between the internal fluid and external hydrostatic pressure.
6. Calculate the longitudinal stress using the appropriate equation selected from Step 3.
7. If no end restraint is present, calculate the resulting longitudinal strain.
8. Calculate the end and radial movement experienced by the pipe.
9. Check the results of the stress calculation with the ASME codes described below.

#### 6.3.2 Code Requirements

This section outlines standards to follow when designing for maximum allowable operating stresses and end movements.

##### 6.3.2.1 Hoop Stress

According to ASME Codes, the following requirement should hold for hoop stress:

\[
\sigma_h < F_1 F_2 S_y
\]  
(6.65)
where

\( \sigma_h = \) hoop stress
\( F_1 = \) hoop stress design factor from Table 6.1
\( S_y = \) specified minimum yield strength (SMYS), psi
\( F_t = \) temperature de-rating factor from Table 6.2.

### 6.3.2.2 Longitudinal Stress

ASME Codes specify the following requirements for longitudinal stress:

\[
|\sigma_L| < F_2 S_y
\]

where

\( \sigma_L = \) maximum longitudinal stress, psi
\( F_2 = \) longitudinal stress design factor from Table 6.1.

### 6.3.2.3 Combined Stress

The combined stress shall meet the following requirement:

\[
\sqrt{\sigma_h^2 + \sigma_L^2 - \sigma_h \sigma_L + 3\tau_t^2} \leq F_3 S_y
\]

### Table 6.1 Design Factors for Offshore Pipelines

<table>
<thead>
<tr>
<th>Content Type</th>
<th>F1 (Hoop Stress)</th>
<th>F2 (Longitudinal Stress)</th>
<th>F3 (Combined Stress)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas(^{(1)})</td>
<td>0.72</td>
<td>0.8</td>
<td>0.9</td>
</tr>
<tr>
<td>Oil(^{(2)})</td>
<td>0.72</td>
<td>0.675/0.54/0.8(^{(3)})</td>
<td>-</td>
</tr>
</tbody>
</table>

Notes:
3. ASME (1989), 402.3.2(d) represents 0.75 \( \times \) 0.90 for standard loads in restrained pipelines. This is reduced to 0.75 \( \times \) 0.72 for unstrained pipelines as may be the case in a span area where pipeline is not in contact with the seabed. These stress limits refer to tensile only. Design factor is increased to 0.8 when considering occasional loads in addition to sustained loads.

### Table 6.2 Temperature De-rating Factor for Steel Pipe

<table>
<thead>
<tr>
<th>Temperature (°F)</th>
<th>Temperature De-rating Factor, ( F_t )</th>
</tr>
</thead>
<tbody>
<tr>
<td>250 or less</td>
<td>1.000</td>
</tr>
<tr>
<td>300</td>
<td>0.967</td>
</tr>
<tr>
<td>350</td>
<td>0.933</td>
</tr>
<tr>
<td>400</td>
<td>0.900</td>
</tr>
<tr>
<td>450</td>
<td>0.867</td>
</tr>
</tbody>
</table>
where

\[ F_3 = \text{combined stress design factor from Table 6.1.} \]
\[ \tau_t = \text{tangential shear stress, psi.} \]

In most cases, no torsion is present and \( \tau_t = 0 \). Note that the most compressive (-) value of \( \sigma_L \) must be used for conservatism.

### 6.3.3 Example Calculation

For the following pipeline, calculate the operating stress and end movement.

**Pipeline type** = Gas  
**Pipe outside diameter,** \( D \) = 8.625 in.  
**Wall thickness,** \( t \) = 0.375 in.  
**Steel modulus,** \( E \) = \( 3 \times 10^7 \) lbs/in.\(^2\)  
**Soil friction force,** \( f \) = 2.755 lb/in.  
**Pipe length,** \( L \) = 20,381 ft  
**Poisson ratio,** \( \nu \) = 0.3  
**Yield stress,** \( S \) = 65.0 Ksi  
**Restraint condition** = partially restrained  
**Temperature differential,** \( \Theta \) = 50°F  
**Thermal expansion coefficient,** \( \alpha_t \) = \( 6.5 \times 10^{-6} \) in./in./°F  
**Internal pressure,** \( P \) = 1440 psig

1. Calculate \( D/t \).

\[
\frac{8.625}{0.375} = 23
\]

2. Due to \( D/t = 23 \), thin-wall pipe equations are adequate.
3. The applicable pipe case is for a thin, single wall, partially restrained by soil friction.
4. Calculate the distance to no movement using a corresponding equation.

\[
Z = \frac{\pi D t}{f} \left( E \alpha_t \Theta - \frac{\nu P D}{2t} \right) + \frac{\pi P a^2}{f}
\]

\[
Z = (3.688)(9750 - 4968) + 30,538 \text{ ft}
\]

\[
Z = 4014 \text{ ft}
\]

Pipe half-length 20,381 ft is greater than \( Z = 4014 \) ft.

5. Calculate longitudinal and hoop stress and strain.
   a) Hoop stress and strain:

\[
\sigma_h = \frac{P D}{2t} = 16,560 \text{ psi}
\]
For \( x \geq Z \):

\[ \varepsilon_h = \alpha_r \Theta + \left(1 - \nu^2\right) \frac{PD}{2Et} + n\alpha_r \Theta = 0.000925 \]

b) Longitudinal stress and strain:

\( x \geq Z \):

\[ \sigma_L = \nu \frac{PD}{2t} - E\alpha_r \Theta = -4782 \text{ psi} \]

\[ \varepsilon_L = 0 \]

\( x = 0 \):

\[ \sigma_L = \frac{PD}{4t} = 8280 \text{ psi} \]

\[ \varepsilon_o = 0.000435 \]

c) End movement (pipe half-length > \( Z \))

\[ \Delta L = \bar{e}Z \]

\[ \Delta L = 0.5\varepsilon_o Z \]

\[ \Delta L = 0.87 \text{ ft} \]

6. Compare the calculated stresses with code for gas lines.

\[ \sigma_h = 16,650 \leq 0.72 \times 65,000 \text{ psi} \]

\[ \sigma_L = 8280 \leq 0.80 \times 65,000 \text{ psi} \]

\[ \sigma_V = \sqrt{(16,560)^2 + (-4782)^2 - (16,650)(-4782)} \text{ psi} \]

\[ = 19,398 \leq 0.9 \times 65,000 \text{ psi} \]

References


CHAPTER 7

Pipeline Riser Design

7.1 Introduction

Riser is defined as the vertical or near-vertical segment of pipe connecting the facilities above water to the subsea pipeline. The riser portion extends (as a minimum) from the first above-water valve or isolation flange to a point five pipe diameters beyond the bottom elbow, based on codes. The design engineer must select the exact limits on a case-by-case basis. This may often extend the riser beyond the five diameters limit or above the isolation flange. Many operators prefer a length of 200 feet from the elbow to protect against dropped objects (i.e., heavier wall pipe). The riser design usually considers adjoining pipework segments, clamps, supports, guides, and expansion absorbing devices. These are illustrated schematically in Figure 7.1.

This chapter addresses the engineering analysis and design of conventional steel risers and riser clamps. It is written on the basis of related codes and rules in riser design. This chapter provides guideline for pre-installed and post-installed conventional steel risers, but does not address J-tube or flexible pipe risers. Risers are assumed to be of API 5L line pipe and are operated at a temperature less than 250°F. For other cases, refer to specific code allowables.

7.2 Design Procedure

For a conventional steel riser, the design procedure includes the following steps:

Step 1: Establish the design basis.

- Maximum wave height and period for return periods of 1 and 100 years
- Annual significant wave height occurrence in 5-foot height intervals
- Associated wave periods for annual significant wave height distribution
- Steady current profile
- Seismicity (if applicable)
- Splash zone limits
- Befouling thickness profile
- Minimum pipeline installation temperature
- Maximum allowable operating pressure (MAOP)
- Maximum allowable pipeline operating temperature (This should reflect the effects of temperature drop along pipeline in the direction of flow.)
Pipe-to-soil longitudinal friction  
Soil elastic modulus

**Step 2:** Obtain platform design data.

- Jacket design drawings  
- Batter of the jacket on the riser face  
- Movements of the platform during storm (100-year)  
- Intended riser locations: cellar deck plan

**Step 3:** Determine the minimum wall thickness for riser based on design pressure, pipe size, material grade, and corrosion allowance. This is defined by code formula and allowable hoop stress.

**Step 4:** Select a base riser configuration and perform static stress analyses for selected load cases. The detailed procedure is illustrated in the next section.

**Step 5:** Perform vortex shedding and fatigue analyses using cumulative damage methods to verify life of riser.

**Figure 7.1 Typical Riser Schematic.**
**Step 6:** Modify clamp locations, riser design, or wall thickness as necessary to meet codes and re-analyses for all cases.

**Step 7:** Design riser clamps based on jacket design and the forces calculated from static stress analysis.

**Step 8:** Design riser anchor at top clamp, if needed. This is generally only required in water depths greater than 100 feet where the riser cannot be free-standing.

A flowchart for the riser design procedure is shown in Figure 7.2. The core of the riser design is static stress analysis.

### 7.3 Load Cases

Risers are subjected to various types of loads including functional loads, environmental loads, installation loads. Based on ANSI B31.8 and B31.4, Tables 7.1 and 7.2 illustrate the required load cases for stress analysis for gas and oil riser systems, respectively.
<table>
<thead>
<tr>
<th>Loads</th>
<th>Riser Design Load Combinations</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Operation (Case 1)</td>
</tr>
<tr>
<td></td>
<td>MAOP</td>
</tr>
<tr>
<td></td>
<td>Weights</td>
</tr>
<tr>
<td>Functional Loads</td>
<td>Internal Pressure</td>
</tr>
<tr>
<td></td>
<td>Operating Temperatures</td>
</tr>
<tr>
<td></td>
<td>Weights</td>
</tr>
<tr>
<td></td>
<td>Pipeline Expansion</td>
</tr>
<tr>
<td></td>
<td>External Pressure</td>
</tr>
<tr>
<td>Environmental Loads</td>
<td>Wind</td>
</tr>
<tr>
<td></td>
<td>100-Year Wind</td>
</tr>
<tr>
<td></td>
<td>1-Year Wave</td>
</tr>
<tr>
<td></td>
<td>1-Year Current</td>
</tr>
<tr>
<td></td>
<td>Platform Motion</td>
</tr>
<tr>
<td>Installation Loads</td>
<td>Cold Springing</td>
</tr>
<tr>
<td></td>
<td>Residual Stresses</td>
</tr>
</tbody>
</table>
### TABLE 7.2 Static Design Load Cases for Oil Risers (ANSI B31.4)

<table>
<thead>
<tr>
<th>Loads</th>
<th>Riser Design Load Combinations</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Operation Case 1</td>
</tr>
<tr>
<td>Functional Loads</td>
<td></td>
</tr>
<tr>
<td>Internal Pressure</td>
<td>MAOP</td>
</tr>
<tr>
<td>Operating Temperatures</td>
<td>Design Temperature Weights</td>
</tr>
<tr>
<td>Weights</td>
<td></td>
</tr>
<tr>
<td>Pipeline Expansion</td>
<td>Pipeline Expansion</td>
</tr>
<tr>
<td>External Pressure</td>
<td></td>
</tr>
<tr>
<td>Environmental Loads</td>
<td></td>
</tr>
<tr>
<td>Wind</td>
<td>100-Year Wind</td>
</tr>
<tr>
<td>Wave</td>
<td>100-Year Wave</td>
</tr>
<tr>
<td>Current</td>
<td>100-Year Current</td>
</tr>
<tr>
<td>Platform Motion</td>
<td>Platform Motion</td>
</tr>
<tr>
<td>安装荷载</td>
<td></td>
</tr>
<tr>
<td>Cold Springing</td>
<td></td>
</tr>
<tr>
<td>Residual Stresses</td>
<td></td>
</tr>
</tbody>
</table>
7.3.1 Functional Loads

Functional loads acting on the riser can be classified as internal pressure, load due to operational expansion of pipeline, and deadweight of riser.

Two internal pressure conditions must be considered in riser design: the maximum allowable operating pressure and the test pressure. The maximum allowable operating pressure (MAOP) is the maximum pressure at which a gas system may be operated in accordance with the provisions of the design code. The MAOP should include the effects of shut-in to a live well if appropriate. Surge pressure is not normally considered as a part of MAOP. The test pressure is the maximum internal fluid pressure permitted by the design code for a pressure test based on the material and location involved. Gas risers are hydrostatically tested to 1.4 times MAOP (ANSI B31.8 par 847.2). Oil risers are tested to 1.25 times MAOP (ANSI B31.4 par 437.4.1). Some operators refer a test pressure of 1.5 times MAOP and this should be established as part of the design basis, if applicable. Note: riser test pressures are higher than pipeline hydrotest pressures for gas risers. This means that the “riser” must be tested in the yard separately from the pipe unless the pipe has been designed to withstand the elevated riser test pressure. The US MMS allows one weld to be made joining the riser with the pipeline after the hydrotest provided it is fully radiographed.

The temperature difference between the operating pipeline and its initial installation temperature will cause pipeline expansion. Internal pressure also causes expansion although to a lesser extent than temperature.

The loadings, due to the self-weight contents, are dependent on the design conditions. For installation, the pipeline is assumed to be empty. Analysis for operational conditions should consider the line to be filled with product. Hydrotesting is characterized by the pipe being filled with seawater at 64 lb/ft³.

7.3.2 Environmental Loads

Environmental loads are loads caused by wind, waves, current, and other external forces. Wind, waves, and current loads can also induce platform movements. The hydrodynamic loads acting on the riser are divided into two categories: 1) drag, lift, and inertia forces, and 2) flow induced vortex shedding on riser. Figure 7.3 shows a profile of wave- and current-induced loading. The platform movement is referred to as the relative displacement between the platform members where the riser clamps are connected. The relative displacement between clamps will increase the bending stress in the riser, which may be critical in some cases. Most platforms will have a stiff axis and a soft axis. The most conservative direction of movement should be selected taking into account wave loading and pipeline expansion. This will normally be in the direction of the pipeline or wave approach.

7.3.3 Installation Loads

Installation loads are determined by the installation procedure and tie-in methods. A typical installation load is the permanent bending loads caused by cold springing. The designer may need to consult with installation contractor in special situations.
7.4 Wall Thickness

The nominal wall thickness after corrosion withstands the internal pressure. The hoop stress, $\sigma_h$, is determined by:

$$\sigma_h = \frac{PD}{2t}$$  \hspace{1cm} (7.1)

where

$P = MAOP$

$D = \text{outside diameter}$

$t = \text{nominal wall thickness}$.

For oil and gas risers, the hoop stress must not exceed 0.6 SMYS and 0.5 SMYS, respectively. In deep water, the effect of hydrostatic pressure must be checked using the design procedure presented in Chapter 3. An allowance for corrosion of 1/8 inch may also be required.

7.5 Allowable Stress Criteria

Tables 7.3 and 7.4 list the allowable stress criteria, based on ANSI/ASME B31.8 and B31.4, for offshore gas and oil risers, respectively. Three types of stresses should be checked in riser design: hoop, longitudinal, and von Mises. A typical riser model is shown in Figure 7.4.

Hoop stress can be calculated by Equation (7.1). Longitudinal stress should be calculated considering end-cap effect. The maximum Von Mises stress in a riser is calculated using
\[ 2\sigma_v^2 = (\sigma_r - \sigma_h)^2 + (\sigma_h - \sigma_a)^2 + (\sigma_a - \sigma_r)^2 \]  

(7.2)

where

- \( \sigma_h \) = hoop stress (+ value)
- \( \sigma_r \) = radial stress = \( P \) (internal pressure)
- \( \sigma_V \) = von Mises stress

and the axial stress is given by

\[ \sigma_a = \frac{D_i M_b}{2I} + \frac{T_a}{A_i} \]  

(7.3)

where

- \( D_i \) = riser inside diameter
- \( M_b \) = bending moment
- \( I \) = moment of inertia
- \( T_a \) = axial force
- \( A_i \) = steel cross-sectional area

Note that the maximum von Mises stress normally occurs at the inside wall of the compressive side of bending moment. Therefore, the negative value of bending moment and “without end-capped” tensile stress should be used in axial stress calculations.
Dynamic and Fatigue Analysis

Computer programs are required to perform dynamic and fatigue analyses. Such analyses often indicate that the spacing between clamps will not permit a vortex-induced riser resonance to occur. Also the cyclic stresses in the riser are sufficiently low to allow a life substantially greater than that required. A minimum safety factor of five is necessary owing to the uncertainty of the data.

With computer programs, the maximum allowable span length for a riser in a given current field can be determined. It is recommended that the pinned-fixed condition be used unless rotational anchors are specified within the clamp design. Ordinarily, the content’s density should be used in the analysis. The wall thickness should be the actual wall less the corrosion allowance. If riser dynamic amplification during wave or seismic loading is possible, the dynamic solution should also be determined.

Figure 7.4 Typical riser model for pipelines.
Fatigue life is determined based on cumulative damage due to cyclic loads. Provided that a proper clamp spacing has been selected, vortex-induced oscillation is not a factor and the primary aspect is wave loading. Note that any increase in diameter and mass due to biofouling should be considered in developing the wave loads. The bending stresses in each section of the riser are determined for a range of wave heights. This would, for example, be for wave heights of 0–5, 5–10, 10–15, 15–20, 20–30, 30–40, and 40–50 feet. For practical reasons, wave height refers to the significant wave height. This is slightly conservative as the significant wave actually represents the average of the highest one third in the wave population. From annual wave statistics such as the Summary of Synoptic Marine Observation (SSMO) for the region of interest, the number of cycles of each wave height group in a one-year period can be developed. For each wave height group, the cyclic stress range can be determined. Normally, this is a quasi-static solution, but a full dynamic solution may be needed if dynamic amplification is present at the wave frequency.

Stresses are determined based on the highest wave in each group to generate a load profile and a peak bending stress. The stress range, $S_{range}$, is twice the peak amplitude. This is a quasi-static solution which excludes the effect of dynamic amplification. This is normally justified because the clamp spacing is small enough to prevent any significant resonance at wave frequencies. In certain cases, such as catenary risers, a full dynamic analysis may be required.

To define the number of cycles to failure, the AWS-X1 curve is used. This has been shown to be valid for butt-welded line pipe in a seawater environment regardless of material grade. This curve is illustrated in Figure 7.5.

For each wave group, the damage ratio is determined by:

$$ R_D = \frac{N_f}{N_3} $$

\[\text{(7.4)}\]

\[\text{Figure 7.5 AWS-X1 S-N curve for butt-welded pipe.}\]
where

\[ N_f = \text{number of cycles per year} \]
\[ N_3 = \text{number of cycles to failure}. \]

The annual damage ratio is the sum of all individual ratios and is the inverse of the calculation life of the riser. An example fatigue life calculation is shown in Table 7.5.

### 7.7 Corrosion Control Consideration

Risers are installed in corrosive environments. Corrosion control is normally considered using extra wall thickness, coatings, and cathodic protection.

Since the risers are the most prone to damage either by corrosion, vessel impact, or fatigue, extra wall thickness beyond that required by code is a good practice. A typical corrosion allowance is \( \frac{1}{8} \) inch.

Risers are subject to more aggressive wave loading in the splash zone. This region is generally given a \( \frac{1}{2} \)-inch coating of bonded neoprene. Alternatively, a monel sheathing welded to the pipe has been used in areas where biofouling is a factor. Concrete-coated risers are generally a poor idea, although they have been used offshore Mexico. The disadvantage is corrosion monitoring. Above the splash zone, the operator-preferred coating is usually used.

Common practice is to isolate the riser electrically from the platform to prevent the platform anodes from being consumed by the pipeline. Anodes placed on the pipeline protect the riser. Isolation is achieved by the use of neoprene (typically \( \frac{1}{4} \) to \( \frac{1}{2} \) in.) vulcanized to the inside of the riser clamps and an electrical isolation joint above the water line between the riser and deck piping. Two styles of isolation joints are used. The first is an insulating kit for a flange which consists of a non-metallic gasket and sleeves/washers for the bolts to insulate the two flange halves. The second type, which is generally preferred, is an integral rubber/steel union (Monobloc), which is welded in line. The clamps must also be insulated, which requires neoprene or non-conducting spacers. If the riser must be electrically connected to the jacket for some reason, extra anodes are needed at the base of the riser. This approach can be used in shallow water where diver surveys are routine.
7.8 Riser Bends

The elbow at the base of the riser is normally designed for inspection pigging. For typical inspection pigs of diameters larger than 4 inches, a minimum bend radius (MBR) is required. The MBR depends on diameter and wall thickness, but is generally 3 to 5 times the pipe diameter. This means that an 18-inch pipe designed with a 3D radius will have a radius to centerline of 54 inches.

The angle of the bend must be such that the riser follows the platform batter in the plane of the riser and pipeline. For example, if the platform batter is 1:12, or 85.24°, and the pipe approaches normal to the jacket face, the riser bend will subtend an arc of 85.24°. If the pipe approaches parallel to the face, the bend will be 90°. Typically, this aspect of geometry must be checked carefully, particularly when the jacket has different batters for different faces. Above the waterline (typically 10 to 15 feet) the platform supports change from battered to vertical. The riser will have a transition piece at this location to mirror the platform batter.

7.9 Riser Clamps

For shallow water risers (less than 100 feet), the riser is encircled, i.e., guided, but not suspended. In deeper water, a suspension clamp at a location above the water line is normally used. The exact depth limits are dependent on diameter and client practice. The suspension clamps restrain the riser laterally. A slight (1/8 to 1/4 inch) gap should be used with the encirclement clamps to allow the riser to slide vertically and hang off the suspension clamp.

The spacing of the encirclement clamps is determined depending upon environmental loads and generally results in the closest spacing in the splash zone. In deep water, the spacing between clamps near bottom may be 50 to 60 feet to correspond with available bracing. To accommodate pipeline expansion, the bottom clamp should not be installed too close to the seabed.

With X-braced jackets, the riser can sometimes be located at a position that optimizes the availability of clamp supports. Occasionally, clamps are attached to jacket legs. This provides convenient clamp supports, but may expose the risers to somewhat greater risk of boat damage, particularly on corner columns.

7.9.1 Design Overview

Before riser clamps can be designed, the function they perform and loads to be resisted must be thoroughly understood. The items listed below are desirable features for riser clamps:

- The number of different types of clamps should be kept to a minimum.
- Bolted connections should be avoided wherever possible. Necessary bolted connections must be designed to minimize the risk of bolts becoming loose such as by double nuts.
- Standardization of components—bolts, hinges, plate thicknesses, etc., is desirable, i.e., hinged clamps.
• Excessive use of gusset plates (stiffeners) should be avoided.
• Reduction of diving time during riser installation is desirable.
• Clamps should be internally lined with neoprene or coated.

7.9.1.1 Basic Clamp Types

The two types of commonly used clamps are anchor and guide. These are depicted in Figures 7.6 and 7.7. The guide clamp allows vertical movement and has an internal radius of 1/8-inch to 1/4-inch greater than the pipe radius. In cases where no anchor clamp is to be used, the guide is designed to squeeze the riser. After make-up, a gap of 1/2–inch should remain between the flange faces to ensure a tight fit.

7.9.1.2 Adjustable Clamp Designs

Adjustable clamps are those in which the position of the riser end of the clamp may be altered even after the connection to the jacket. Figure 7.8 shows the adjustable clamp concept most widely used in the industry. The device consists of a tubular stub piece fitted with a riser clamp that is bolted on one side and hinged on the other side. The connection to the bracing can be as shown in the figure or by directly welding the clamp to the bracing, if the jacket is being fabricated.

A vertical stub piece has been included to ease welding procedure and inspection. The basic components of these units are the clamp shells and the stub pieces. The wall thickness of the stub piece is based on the maximum loading, taking into account the shear force, axial force, and bending moments. Larger moments will be induced by having an adjustable stub piece. In addition, the vertical stub piece and bracing clamp have to cater for the additional moment due to the vertical offset of the bracing clamp, which sometimes results in larger stiffeners or higher grade material for the bracing clamp. This clamp type can be pre-installed on the platform during fabrication by welding the clamp stub piece onto the jacket. The adjustable clamp requires bolting for closure around the riser. The clamp also gives more flexibility during installation due to the adjustable stub piece.

Figure 7.9 shows an adjustable clamp used for connection to diagonals in the North Sea. The dual plates must be designed with consideration that moments around two axes must be taken into account. In addition, local stress concentrations and high shear forces on the welds may be experienced by the lack of stiffeners in this section.

The adjustable clamp design shown in Figure 7.10 consists of a double clamp of both jacket bracing and the adjustable stub piece and a single clamp to the riser. In the clamp position shown, the adjustable stub piece is arranged normal to the riser and the bracing clamp. This figure also displays the directional and rotational degrees of freedom for the clamp, minor misalignment of the riser and pipeline can be adjusted for. The clamp assembly can be attached to a vertical member (jacket leg) or a diagonal member.

The dual clamp part for connection to the jacket member and to the adjustable stub piece is for the friction grip type. In other words, any loads transferred from the riser will be restrained by frictional forces. The riser clamp is closed with a pinned connection on one side and bolts on the other side. The bolted connection is made such that the riser can move and rotate freely within the clamp.
Figure 7.6 Typical riser anchor clamp.
RADIUS = PIPE
RADIUS + 1/4 In.

NEOPRENE LINING

**Figure 7.7** Typical riser guide clamp.

**Figure 7.8** Adjustable clamp concept most widely used in the industry.
Item (c) of Figure 7.10 shows an alternative arrangement, for easy connection, whereby the dual clamp sections can be rotated for connection to each other. Two flanges are welded to the connecting sides of the sections. One plate is fitted with two slotted holes,
and the other contains two threaded studs for bolting the two flange plates together. This will allow some adjustments to be made during installation within the tolerance of the two slotted holes. The connection, however, between the flange plates and the clamp is weak in twisting and bending, in addition to being difficult to weld and inspect.

The clamps themselves are of a standard design except that the pinned connection contains three pins which are used to connect the clamp shells together, thus increasing the number of parts of the clamp. The use of the adjustable stub piece increases the independence of accurate measurements during riser installation. The clamp assembly also allows the design of the adjustable stub piece clamp ("C2" in Figure 7.10) for "failure." In the splash zone area, the bolt loads for this clamp are designed such that if accidents with a vessel occur, the adjustable stub piece will deflect, minimizing the damage on the riser.

### 7.9.1.3 Stub Piece Connection Clamp Design

Figure 7.11 shows an alternative design which facilitates future riser installation. The stub piece with a flange welded to the jacket bracing has been used extensively in the Middle East. This is not required for design of the inner stub piece, as that piece is more dependent upon the size of the jacket bracing. However, the number of bolts in the flange is important to know the approximate size of the future riser. The outer part of the clamp is shown with a plated and tubular design. The smaller riser sizes were based on plated structures, as the use of a tubular stub piece was not feasible due to the short distance between the centerline of the riser and the flange face.

Figure 7.12 shows a vertical stub clamped to the riser clamp for use with future adjustable clamps. This stub piece has the advantage of not protruding from the jacket since it is oriented along the vertical axes. It is important to know the riser size in order to determine the number of bolts in the stub piece.

![Figure 7.11 An alternative clamp design.](image)
7.9.1.4 Load-Bearing Clamp Designs

The load-bearing clamp is generally located above sea level, giving the option of welding the clamp directly on the jacket bracing or using a friction grip clamp. The strength of the clamp stub piece is dependent upon the riser fixity to the clamp. With a completely fixed riser connection to the clamp, the riser forces and moments are transferred to the clamp, resulting in a requirement for a structurally strong clamp such as a plated box-type structure between the riser clamp and jacket bracing. For seating of the riser, the top part of the riser clamp is fitted with a flange. For easy installation, the clamp may be hinged and secured on one or two sides with bolts, depending on riser size and resulting forces and moments. As the installation generally takes place above water, no diving is required.

Figures 7.13 and 7.14 show two typical load-bearing clamps which follow the concept of rigid-type clamps apart from the flange located on the top of the riser clamp. Normally, the riser sits on top of the clamp, either using a flange welded to a sleeve which, in turn, is welded to the riser (Figure 7.13) or an anchor flange welded to the riser as part of the riser. The flange may also be used as a support for a temporary clamp to support the weight of the riser (Figure 7.15).

The required strength of the clamp is dependent upon the type of support, whether the two flange faces are bolted (fully fixed) or are resting on top of each other. With a bolted flange connection, all forces and moments experienced by the riser at this elevation will be transferred into the clamp. The reasoning for a bolted flange connection is often due to lack of deck piping data or imposed restrictions on the translations and rotations of the deck piping. With a bolted connection, all riser movements and rotations can be stopped at the load-bearing clamp. If, however, the flange connection is not bolted, only translational and vertical forces will be transferred to the clamp, resulting in a “lighter” clamp layout. Figure 7.14 shows the load-bearing clamp to consist of a tubular stub piece, while Figure 7.13 depicts the load-bearing clamp to be of a box-type construction consisting of plates welded together.

For the connection of the clamp to the riser and jacket bracing, dependent upon the riser size, bolts on both sides of the clamp are recommended to secure the riser clamp and ensure a friction grip at the bracing. Generally, with the clamp installed above water, the clamp stub piece can be welded directly onto a member of the jacket using a sleeve, if
required. Dependent upon forces and moments, however, the requirement for welding the load-bearing clamp to the jacket member of bolts have been increased with respect to standard clamps, the bolting of the clamps will take place above water, avoiding time-consuming diver operations.

The temporary weight clamps shown in Figures 7.15 and 7.16 are installed on the riser to transfer its weight to the load-bearing clamp during installation and hydrostatic testing of the pipeline and risers. After successful testing, hook-up to the deck piping can take place, and riser weight can be transferred to a clamp located at a higher elevation or can be taken by the deck piping support and the stiffness of the deck piping as in shallow water riser installations.

**Figure 7.13** Typical load-bearing clamp following the concept of rigid type clamps.
The temporary weight clamp shown in Figure 7.15 is designed for shallow water installation or for smaller riser pipe sizes in deeper water. The clamp concept shown in Figure 7.16 is designed to be installed temporarily on a splash zone coated joint having a uniform load distribution to the load-bearing clamp. Both temporary clamps are designed to hold the riser in place by frictional force achieved through connection together with the two clamp shells with a gap between the two bolt flanges. The number of bolts is based on the weight of the riser filled with water (including the weight of the test head). In addition, if the clamp is to be attached to a splash zone coated joint, the number of bolts is increased in order to minimize the compressive stress in the coating (Figure 7.16).

7.9.2 Design Analyses

The design of clamp assemblies, including riser and platform member clamps, bolts, lining, pins, and stubs, should consider the load combinations listed in Tables 7.1 and
Figure 7.15 Temporary weight clamp.
Figure 7.16 Another temporary weight clamp.
7.2, as well as fabrication and maintenance. Clamp assemblies are to be elastically designed in accordance with AISC specification and API RP2A. Governing stress criteria are listed in Table 7.6.

<table>
<thead>
<tr>
<th>Stress Type</th>
<th>Allowable Stress Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>AISC Specification</td>
</tr>
<tr>
<td>Compression</td>
<td>0.6</td>
</tr>
<tr>
<td>Tension</td>
<td>0.6</td>
</tr>
<tr>
<td>Shear</td>
<td>0.4</td>
</tr>
<tr>
<td>Bending</td>
<td>0.66</td>
</tr>
</tbody>
</table>
CHAPTER 8

Pipeline External Corrosion Protection

8.1 Introduction

Offshore steel pipelines are normally designed for a life ranging from 10 years to 40 years. To enable the pipeline to last for the design life, the pipeline needs to be protected from corrosion both internally and externally. Internal corrosion is related to fluid that is carried by the pipeline, and this topic is not covered here. This chapter describes the method by which the external corrosion of offshore pipelines may be minimized.

A strong adhesive external coating over the whole length of the pipeline will tend to prevent corrosion. However, there is always the possibility of coating damage during handling of the coated pipe either during shipping or during installation. Cathodic protection is provided by sacrificial anodes to prevent the damaged areas from corroding.

8.2 External Pipe Coatings

This first external pipe coating layer is used to protect the pipe against corrosion. A single-layer coating is used when the installed pipeline is always in a static, laterally stable condition lying on soils such as clay or sand. Additional layers of coating are used for additional protection, for weight to help the pipeline remain laterally stable on the seabed, or for providing insulation. A multi-layer coating is generally used in cases where the external environment tends to easily wear out the external coating (e.g., pipeline lying on top of rocky soil, calcareous material, etc.). Insulation is provided to maintain a higher temperature of the flowing internal fluid compared to the ambient. Depending on the external environment and on the location or use of the pipeline, a single-layer coating or a multi-layer coating is required.

The properties that are considered desirable for deepwater pipeline coatings are:

- Resistance to seawater absorption
- Resistance to chemicals in seawater
- Resistance to cathodic disbondment
- Adhesion to the pipe surface
- Flexibility
Impact and abrasion resistance
Resistance to weathering
Compatibility with cathodic protection

A single-layer coating may not be able to provide all of these properties under all operating conditions of pipeline. In such cases multi-layered coatings are used.

As the coating must adhere to steel pipe, the surface finish process of line pipe manufacturing must be carefully examined. This is required because in some instances unacceptable surface finish of the line pipe can lead to loss of adhesion of the coating. The next step is to apply the coating in the coating plant following the manufacturer’s recommended method of application.

8.2.1 Single-Layer Coating

The most common choice for single-layer coating for deepwater pipelines is Fusion Bonded Epoxy (FBE). Properties and coating requirements are shown in Table 8.1.

For deepwater pipelines where there is no other requirement on the external coating, FBE is most frequently used. Most deepwater oil and gas transmission lines use FBE as they are extremely cost effective. This coating can be used in conjunction with concrete weight coating. The other coatings that can be used with concrete coating are coal tar enamel and coal tar epoxy and they are used with lower product temperatures. Both of these coatings are bituminous coatings reinforced with fiberglass. However, most bituminous coatings are not desirable due to environmental laws and decreasing efficiency (sagging, cracking, permeation, and chemical deterioration).

The FBE field joint coating is carried out using the same coating material as mill-applied coating. Further advantages include:

- Easy to repair
- Easy for coating application
- High adhesion to steel
- Good for pipeline operating temperatures

In the US and UK, FBE coating is preferred for offshore pipelines.

8.2.2 Multi-Layer Coatings

Table 8.2 lists the most common choices that are available for multi-layer coating for deepwater pipelines.

<table>
<thead>
<tr>
<th>Coating Type</th>
<th>Max. Temperature (°C)</th>
<th>Average Coating Thickness (mils)</th>
<th>Some Manufacturers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fusion Bonded Epoxy</td>
<td>90</td>
<td>14 to 18</td>
<td>Dupont, 3M, Lilly, BASE, Jotun</td>
</tr>
</tbody>
</table>
Dual-Layer FBE. Dual-layer FBE coatings are used when additional protection is required for the outer layer such as high temperature, abrasion resistance, etc. For deep-water trunklines the high temperature of the internal fluid dissipates rapidly reaching ambient within a few miles. Therefore, the need for such coatings is limited for SCRs at the touchdown area where abrasion is high and an additional coating with high abrasion resistance is used. The Duval system consists of an FBE base coat (20 mils) bonded to a polypropylene coating (20 mils). The polypropylene layer provides mechanical protection.

Three-Layer. Three-layer PP coating consists of an epoxy or FBE, a thermoplastic adhesive coating and a polypropylene top coat. The polyethylene (PE) and polypropylene (PP) coatings are extruded coatings. These coatings are used for additional protection against corrosion and are commonly used for dynamic systems like steel catenary risers and where the temperature of the internal fluid is high. These pipe coatings are frequently used in pipelines that are installed by the reeling method. The field joint coating for the three-layer systems is more difficult to apply and takes a longer time. However, in Europe, PE and PP coatings are preferred because of their high dielectric strength, water tightness, thickness, and very low CP current requirement.

Concrete Weight Coating. Concrete weight coating is used when stability of the pipeline on the seabed is an issue. The two common densities of concrete that are used are 140 lbs/cu. ft and 190 lbs/cu. ft. Higher density is obtained by adding iron ore to the concrete mix. Recently, higher density iron ore has been used to obtain concrete density ranging from 275 to 300 lbs/cu. ft for the Ormen Lange pipeline in the North Sea.

### 8.2.3 Standards Organizations with Specifications Related to Pipe Coatings

The main organizations in the US are:

- American Society of Testing Methods (ASTM)
- Steel Structures Painting Council (SSPC)
- National Association of Corrosion Engineers (NACE)
- National Bureau of Standards (NBS)
- International Organization for Standardization (ISO)

In Europe, the more common ones are:

- Det Norske Veritas (DnV)
- Deutsches Institut fur Nurmung (DIN)
- British Standards (BS)
- International Organization for Standardization (ISO)
8.3 Cathodic Protection

Cathodic protection is a method by which corrosion of the parent metal is prevented. The two main methods of cathodic protection are galvanic anodes and impressed current systems. For offshore pipelines, the galvanic anode system is generally used.

Corrosion is an electrochemical reaction that involves the loss of metal. This is due to the fact that the steel pipeline surface consists of randomly distributed cathodic and anodic areas, and seawater is the electrolyte that completes the galvanic cell. This causes electrons to flow from one point to the other, resulting in corrosion. By connecting a metal of higher potential to the steel pipeline, it is possible to create an electrochemical cell in which the metal with lower potential becomes a cathode and is protected.

Pipeline coatings are the first barriers of defense against corrosion. However, after coating the pipe the process of transportation and installation of the pipelines results in some damage to the coating. Cathodic protection uses another metal that will lose electrons in preference to steel. The main metals used as sacrificial anodes are alloys of aluminum and zinc. By attaching anodes of these metals to the steel pipeline, the steel area where the coating is damaged is protected from corrosion.

Zinc anodes are not normally used in deepwater pipelines because they are less efficient and therefore require a larger mass for protecting the pipeline. However, zinc anodes can be cast onto the pipe joint and therefore no cables need to be used for electrical connection to the steel. Zinc has been used in projects where the pipeline needed to be towed along the seabed and cast-on zinc anodes were less liable to be knocked off in the process of installation. Zinc anodes do not perform well for hot buried pipelines and are subject to intergranular attack at temperatures above 50°C. There is also a tendency for zinc anodes to passivate at temperatures above 70°C.

Aluminum anodes, on the other hand, perform much better. They are better suited for hot buried pipelines. Generally, for deepwater pipelines, aluminum alloy anodes that are attached to the pipeline are bracelet anodes. These anodes are normally attached to the pipe joint at the coating yard for S-lay and J-lay installation methods. Electrical contact to the pipeline is made by thermite welding or brazing the cable from the anode.

In the case of installation of pipeline by the reeling method, the anodes are installed on the lay vessel during unreeling and straightening. In this case, bracelet anodes are attached to the pipe by bolting and attaching the cable by thermit/cadweld to the pipeline.

The design of cathodic protection systems must consider the potential detrimental effects of the CP system such as hydrogen embrittlement of steel and local stresses that may lead to hydrogen induced stress cracking (HISC).

8.3.1 Cathodic Protection Design

In order to conduct a CP design for a deepwater pipeline, the parameters that need to be known are:

- Service/design life (years)
- Coating breakdown (%)
- Current density for protection (mA/sq.m) buried or unburied
- Seawater resistivity (ohm-cm)
Soil resistivity (ohm-cm)
- Pipeline protective potential (normally, $-900 \text{ mV w.r.t Ag/AgCl}$)
- Anode output (amp-hr/kg)
- Anode potential (mV w.r.t. Ag/AgCl)
- Anode utilization factor (%)
- Seawater temperature
- Pipeline temperature
- Depth of pipeline sinkage/burial

The design life of the pipeline is based on whether it is trunkline or an infield line. The life of a trunkline can be as long as 40 years while that of an infield line is normally 20 years. The coating breakdown factor depends on the type of coating. There is very little historical data available on coating breakdown. DnV (RP-F103) and NACE (RP-01-76) have recommended values based on the type of pipeline coating. Three values of coating breakdown are typically given—initial, mean, and final.

The current density, resistivity, and temperature depends on the geographical location where the pipeline is located. In deepwater pipelines, the approximate seawater temperature range is from 1.7°C to 7.5°C. DnV and NACE give values for current densities and resistivities for offshore geographical locations. For bare steel buried in sediments, a design current density of $0.020 \text{A/m}^2$ is recommended by DnV.

The type of anode used determines its electrochemical properties. The Galvalum III® anode, for example, has an anode output of approximately 2250 amp-hr/kg in seawater temperature less than 25°C and its potential is approximately $-1050 \text{ mV}$. Manufacturers of anodes provide these properties for design.

The anode utilization factor depends on the shape and application of the anode. Bracelet anodes are typically assumed to be 80% utilized at the end of their life, while stand-off anodes are 90% utilized. For pipeline temperatures above 25°C, the design current densities increase. For each degree above 25°C the current density is increased by $0.001 \text{A/m}^2$.

8.3.1.1 CP Design Methodology

The design methodology summarized here follows that given in DnV RP B401.

Designs must satisfy two requirements:

- The total net anode mass must be sufficient to meet the total current demand over the design life.
- The final exposed anode surface area must be sufficient to meet current demand at the end of design life (the final exposed anode surface area is calculated from anode initial dimensions, net mass, and the utilization factor).

First, one computes the current demand, $(I_c)$, for initial, mean, and final stages of the design life. The current demand to protect each pipeline is calculated by multiplying the total external area $(A_e)$ with the relevant design current density $(i_c)$ and coating breakdown factor $(f_b)$:

$$I_c = A_e f_b i_c \quad (8.1)$$
The current demands for initial polarization, $I_{ci}$, and for re-polarization at the end of the design life, $I_{cf}$, are normally to be calculated together with the mean current demand $I_{cm}$ required to maintain cathodic protection throughout the design period. It is not necessary to calculate the current demand required for initial polarization, $I_{ci}$, because, initially, the pipeline corrosion coatings greatly reduce the current demand and time required for initial polarization.

The coating breakdown factors for various coatings, initial, mean, and final, are given in DnV and NACE publications. For example, in the Gulf of Mexico, for FBE coating with a design life of 20 years, the initial, mean, and final coating breakdown factors normally used are 1%, 3%, and 5%, respectively. The total net anode mass $M_t$ required to maintain cathodic protection of a pipeline throughout the design life $t_d$ (years) is given by:

$$M_t = \frac{8760 I_{cm} t_d}{u_f \varepsilon_e}$$

where

$I_{cm}$ = mean current demand

$\varepsilon_e$ = the electrochemical efficiency (A-h/kg)

$u_f$ = the anode utilization factor.

The required current output (initial/final) and current capacity for a specific number of anodes determines the required anode dimensions and net weight. The following requirements must be met by the cathodic system design:

$$n_a c_a \geq 8760 I_{cm} t_d$$

$$n_a I_a \text{ (initial/final)} \geq I_c \text{ (initial/final)}$$

where

$n_a$ = number of anodes

$c_a$ = anode current capacity (A-h)

$I_a$ = anode current output (A).

The anode current capacity ($c_a$) is given by:

$$c_a = m_a \varepsilon_e u_f$$

where, $m_a$ is the net mass per anode. The anode current output ($I_a$) is calculated from Ohm's law:

$$I_a = \frac{E^0_c - E^0_a}{R_a}$$

where

$E^0_c$ = design closed circuit potential of the anode

$E^0_a$ = design protective potential

$R_a$ = anode resistance
The design protective potential \( (E_0^c) \) for carbon steel is \(-0.80 \text{ V (rel. Ag/AgCl/seawater)} \) when in aerated seawater and \(-0.90 \text{ V (rel. Ag/AgCl/seawater)} \) when in anaerobic environments including typical marine sediments. Recommended practice states that the \( E_0^c = -0.8 \text{ V} \) should be used for all design calculations because the initial and final design current densities are referred to this protective potential.

The closed circuit anode potential \( (E_0^a) \) for an Al-based anode is taken to be \(-1.1 \text{ V} \) for the pipeline at ambient temperature and \(-1.085 \text{ V} \) for the pipeline at elevated temperatures. The anode resistance \( (R_a) \) formula for a bracelet anode is given by:

\[
R_a = \frac{0.315 \cdot \rho}{\sqrt{A_e}} \tag{8.5}
\]

where

\( \rho_e \) = environmental resistivity

\( A_e \) = exposed anode surface area.

The required number of anodes, \( n \), can be obtained by:

\[
na = \frac{I_{cft}}{I_{af}} \tag{8.6}
\]

where,

\( I_{cft} \) = total final current demand for the pipeline

\( I_{af} \) = individual anode current output.

Some iterations may be required to meet the requirements of both the total net anode mass, \( M_t \), and the total final anode current output \( (naI_{af}) \).

Generally, maximum spacing of the anodes recommended is 300 m. However, methods to calculate attenuation of protective potential with distance can be used to determine the mass and spacing of anodes.

Attenuation computations are specifically useful for determining anodes for cathodic protection of Steel Catenary Risers (SCR). In SCRs, rather than placing anodes on the suspended dynamic portion, several anodes may be placed on static pipeline sections past the touchdown point.

This method is also useful for short (up to 3 miles) bottom-towed pipelines with sleds at each end. Instead of placing discrete bracelet anodes along the pipeline, all total mass of anodes required for the pipeline can be placed on the end sleds. Placing them on the end sleds prevent the accidental impact and loss of bracelet anodes from the pipeline being towed along the seabed.

Attenuation calculations show that if current is drained from two points on a pipeline, the change in potential of the pipe may be calculated using the following equations:

\[
E_x = E_B \cosh \left[ \left( 2\pi r R_l/k_p z_d \right)^{1/2} (x - d_p/2) \right] \tag{8.7}
\]

\[
E_A = E_B \cosh \left[ -\left( 2\pi r R_l/k_p z_d \right)^{1/2} d_p/2 \right] \tag{8.8}
\]
\[ I_A = \left( \frac{2E_B}{R_l} \right) \left[ \frac{(2\pi r R_l/k_p z_a)^{1/2}}{\sinh(d_p/2(2\pi R_l/k_p z_a)^{1/2})} \right] \]  

(8.9)

where

\( E_x \) = change in potential at point \( x \)
\( E_A \) = change in potential at drain point
\( r \) = pipe radius
\( E_B \) = change in potential at the midpoint between the two drain points
\( R_l \) = linear resistance of the pipeline
\( I_A \) = total current pick up
\( d_p \) = distance between drain points
\( x \) = distance from drain point
\( k_p \) = polarization slope
\( z_a \) = actual bare area per linear length of pipeline

Additional constraints are:

- The current, \( I_A \), must be equal to the current that can be delivered by the lumped anode array.
- \( E_A \) must equal the anode potential less the IR drop, using the anode array resistance.
- The anode weight must exceed the weight necessary to protect the section of the pipeline for the specified design life.

Using the above equations and constraints, a greater spacing of the required mass/array of anodes may be computed.

References

DNV-RP-F103 “Cathodic Protection of Submarine Pipelines by Galvanic Anodes.”
NACE RP 0176 “Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production.”
CHAPTER 9

Pipeline Insulation

9.1 Introduction

Oilfield pipelines are insulated mainly to conserve heat. The need to keep the product in the pipeline at a temperature higher than the ambient could exist for the following reasons including:

- Preventing formation of gas hydrates
- Preventing formation of wax or asphaltenes
- Enhancing product flow properties
- Increasing cool-down time after shutting down
- Meeting other operational/process equipment requirements

In liquefied gas pipelines, such as LNG, insulation is required to maintain the cold temperature of the gas to keep it in a liquid state. This chapter describes commonly used insulation materials, insulation finish on pipes, and general requirements for insulation of offshore and deepwater pipeline.

9.2 Insulation Materials

Polypropylene, polyethylene, and polyurethane are three base materials widely used in the industry for pipeline insulation. Their thermal conductivities are given in Table 9.1 (Carter et al., 2003).

Depending on applications, these base materials are used in different forms resulting in different overall conductivities. A 3-layer polypropylene applied to pipe surface has a conductivity of 0.13 BTU/hr-ft-°F, while a 4-layer polypropylene has a conductivity of 0.10 BTU/hr-ft-°F. Solid polypropylene has higher conductivity than polypropylene foam. Polymer syntactic polyurethane has a conductivity of 0.07 BTU/hr-ft-°F, while glass syntactic polyurethane has a conductivity of 0.09 BTU/hr-ft-°F. These materials have lower conductivities in dry conditions such as that in pipe-in-pipe applications.

Because of its low thermal conductivity, more and more polyurethane foams are used in deepwater applications. Physical properties of polyurethane foams include density, compressive strength, thermal conductivity, closed cell content, leachable halides, flammability, tensile strength, tensile modulus, and water absorption. The values of these properties vary
depending on density of the foam. Table 9.2 summarizes the properties of CAPE MODERN high-density polyurethane foams.

### 9.3 Pipe-in-Pipe Insulation

Under certain conditions, pipe-in-pipe systems may be considered over conventional single-pipe systems. Pipe-in-pipe insulation may be required to produce fluids from high-pressure/high-temperature (above 150°C) reservoirs in deepwater (Carmichael et al., 1999). The annulus between pipes can be filled with different types of insulation materials such as foam, granular, gel, and inert gas or vacuum.

A pipeline bundled system, a special configuration of pipe-in-pipe insulation, can be used to group individual flowlines together to form a bundle (McKelvie, 2000). Heat-up lines can be included in the bundle if necessary. The complete bundle may be transported to site and installed with a considerable cost saving relative to other methods. The extra steel required for the carrier pipe and spacers can be sometimes justified by a combination of the following cost advantages (Bai, 2001):

- A carrier pipe can contain multiple lines including flowline, control lines, hydraulic hoses, power cables, glycol lines, etc.
- Insulation of the bundle with foam, gel, or inert gas is usually cheaper than individual flowline insulation.

### 9.4 General Requirements

The requirements for pipeline insulation vary from field to field. Flow assurance analyses need to be performed to determine the minimum insulation requirements for a given field. These analyses include:

- Flash analysis of the production fluid to determine the hydrate forming temperatures in the range of operating pressure.
- Global thermal hydraulics analysis to determine the required overall heat transfer coefficient at each location in the pipeline.
- Local heat transfer analysis to determine the type and thickness of insulation to be used at the location.

### Table 9.1 Thermal Conductivities of Materials Used in Pipeline Insulation

<table>
<thead>
<tr>
<th>Material Name</th>
<th>Thermal Conductivity</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(BTU/hr-ft-°F)</td>
</tr>
<tr>
<td>Polypropylene</td>
<td>0.13</td>
</tr>
<tr>
<td>Polyethylene</td>
<td>0.20</td>
</tr>
<tr>
<td>Polyurethane</td>
<td>0.07</td>
</tr>
<tr>
<td>Foam Property</td>
<td>Nominal Density kg/m³</td>
</tr>
<tr>
<td>---------------</td>
<td>-----------------------</td>
</tr>
<tr>
<td>160</td>
<td>2035</td>
</tr>
<tr>
<td>224</td>
<td>4,563</td>
</tr>
<tr>
<td>320</td>
<td>8,144</td>
</tr>
<tr>
<td>500</td>
<td>22,998</td>
</tr>
<tr>
<td>Compressive Strength at 20°C, MPa</td>
<td>1.999</td>
</tr>
<tr>
<td>3.819</td>
<td>15.829</td>
</tr>
<tr>
<td>7.540</td>
<td>17.107</td>
</tr>
<tr>
<td>0.0292</td>
<td>0.0407</td>
</tr>
<tr>
<td>Compressive Strength at −196°C, MPa</td>
<td>0.0253</td>
</tr>
<tr>
<td>0.0316</td>
<td>0.0346</td>
</tr>
<tr>
<td>0.0345</td>
<td>0.0364</td>
</tr>
<tr>
<td>0.0345</td>
<td>0.0364</td>
</tr>
<tr>
<td>Thermal Conductivity at 20°C, W/mK</td>
<td>0.0253</td>
</tr>
<tr>
<td>0.0316</td>
<td>0.0346</td>
</tr>
<tr>
<td>0.0345</td>
<td>0.0364</td>
</tr>
<tr>
<td>0.0345</td>
<td>0.0364</td>
</tr>
<tr>
<td>Thermal Conductivity at −160°C, W/mK</td>
<td>2.412</td>
</tr>
<tr>
<td>3.517</td>
<td>6.649</td>
</tr>
<tr>
<td>4.854</td>
<td>8.305</td>
</tr>
<tr>
<td>11.8</td>
<td>29.5</td>
</tr>
<tr>
<td>Closed Cell Content, %</td>
<td>95</td>
</tr>
<tr>
<td>95</td>
<td>96</td>
</tr>
<tr>
<td>95</td>
<td>96</td>
</tr>
<tr>
<td>Leachable Halides, ppm</td>
<td>&lt; 20</td>
</tr>
<tr>
<td>&lt; 20</td>
<td>&lt; 20</td>
</tr>
<tr>
<td>&lt; 20</td>
<td>&lt; 20</td>
</tr>
<tr>
<td>Burn time, S.E</td>
<td>10</td>
</tr>
<tr>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Tensile Strength at 22°C, MPa</td>
<td>2.412</td>
</tr>
<tr>
<td>3.517</td>
<td>6.649</td>
</tr>
<tr>
<td>4.854</td>
<td>8.305</td>
</tr>
<tr>
<td>11.8</td>
<td>29.5</td>
</tr>
<tr>
<td>Tensile Modulus, MPa</td>
<td>11.8</td>
</tr>
<tr>
<td>19.4</td>
<td>24.0</td>
</tr>
<tr>
<td>24.0</td>
<td>29.5</td>
</tr>
<tr>
<td>Water Absorption, % Vol.</td>
<td>0.17</td>
</tr>
<tr>
<td>0.15</td>
<td>0.12</td>
</tr>
<tr>
<td>0.15</td>
<td>0.12</td>
</tr>
</tbody>
</table>
• Local transient heat transfer analysis at special locations along the pipeline to develop cool down curves and times to the critical minimum allowable temperature at each location.

A number of computer packages are available in the industry for performing these analyses efficiently.

In steady state flow conditions in an insulated pipeline, the heat flow, $Q$, through the pipe wall is given by

$$Q_r = U_o A_r \Delta T$$

where

$Q_r =$ Heat transfer rate  
$U_o =$ Overall heat transfer coefficient (OHTC) at the reference radius  
$A_r =$ Area of the pipeline at the reference radius  
$\Delta T =$ Difference in temperature between the pipeline product and the ambient temperature outside

The OHTC, $U_o$, for a system is the sum of the thermal resistances and is given by (Holman, 1981):

$$U_o = \frac{1}{A_r \left( \frac{1}{A_i h_i} + \sum_{m=1}^{n} \frac{\ln (r_{m+1}/r_m)}{2 \pi L k_m} + \frac{1}{A_o h_o} \right)}$$  \hspace{1cm} (9.1)$$

where

$h_i =$ film coefficient of pipeline inner surface  
$h_o =$ film coefficient of pipeline outer surface  
$A_i =$ area of pipeline inner surface  
$A_o =$ area of pipeline outer surface  
$r_m =$ radius  
$k_m =$ thermal conductivity

Similar equations exist for transient heat flow giving instantaneous rate for heat flow. Typically required insulation performances in terms of overall heat transfer coefficient ($U$-value) of steel pipelines of different configurations are summarized in Table 9.3.

9.4.1 Dry Insulations

Pipeline insulation comes in two main types—dry insulation and wet insulation. The dry insulations require an outer barrier to prevent water ingress (pipe-in-pipe). The most common types of this are:

• Closed cell polyurethane foam (CCPUF)
• Open cell polyurethane foam (OCPUF)
• Poly-isocyanurate foam (PIF)
For deepwater pipelines, the outer barrier is a steel line pipe called the casing pipe. These pipelines are called Pipe-in-Pipe (PIP) systems. Most deepwater insulated pipelines that are insulated fall into this category.

The manufacture of PIP systems consists of placing the carrier pipe concentrically in the casing pipe using spacers and foaming the annulus. Large coating companies in the US such as Bayou Companies and Bredero-Shaw produce these PIP systems in an assembly line and are therefore able to produce large quantities in a short time for offshore deepwater use.

For installation by reel method or bottom tow, the insulation can be placed on the carrier pipe and then pulled into the casing pipe by using low friction spacers or rollers attached to the carrier pipe. This is performed manually and therefore uses preformed insulation panels.

In the bottom tow method for deepwater pipelines, the casing is pressurized with dry nitrogen to enable the reduction in the casing wall thickness. In such cases, the insulation needs to be open-cell PUF, fiberglass, or syntactic foam. The open cell allows the pressurized nitrogen to permeate the cells and prevent any collapse of the cells. Closed cells would collapse under the pressure. Syntactic foam is designed to withstand high pressures.

In a pressurized gas/nitrogen environment, the k-value of the insulation increases due to convection. If the pipeline is lying on a slope, the “chimney effect” causes convection currents to dissipate the heat and lower increases the effective k-value. To prevent this, an HDPE layer or pipe is placed concentrically around the carrier pipe and the annulus is foamed. Holes are placed in the bottom position of the HDPE layer to allow the nitrogen to permeate into the open cells. Tests on such a configuration of insulated PIP have shown it to work well even in a pressurized nitrogen environment. Fiberglass insulation can be used instead of open-cell foam for similar configuration. Table 9.4 shows properties of some dry insulations.

<table>
<thead>
<tr>
<th>Insulation Type</th>
<th>U-Value (BTU/hr-ft²-°F)</th>
<th>W/m²·K</th>
<th>Field Proven</th>
<th>Potential</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solid Polypropylene</td>
<td>0.50</td>
<td>2.84</td>
<td>5000</td>
<td>13,000</td>
</tr>
<tr>
<td>Polypropylene Foam</td>
<td>0.28</td>
<td>1.59</td>
<td>2100</td>
<td>6300</td>
</tr>
<tr>
<td>Syntactic Polyurethane</td>
<td>0.32</td>
<td>1.81</td>
<td>3600</td>
<td>11,000</td>
</tr>
<tr>
<td>Syntactic Polyurethane Foam</td>
<td>0.30</td>
<td>1.70</td>
<td>6200</td>
<td>11,000</td>
</tr>
<tr>
<td>Pipe-in-Pipe Syntactic Polyurethane Foam</td>
<td>0.17</td>
<td>0.96</td>
<td>9500</td>
<td>13,000</td>
</tr>
<tr>
<td>Composite</td>
<td>0.12</td>
<td>0.68</td>
<td>3200</td>
<td>9000</td>
</tr>
<tr>
<td>Pipe-in-Pipe High Efficiency</td>
<td>0.05</td>
<td>0.28</td>
<td>5300</td>
<td>9000</td>
</tr>
<tr>
<td>Glass Syntactic Polyurethane</td>
<td>0.03</td>
<td>0.17</td>
<td>7000</td>
<td>9000</td>
</tr>
</tbody>
</table>
9.4.2 Wet Insulations

Wet pipeline insulations are those materials that do not need an exterior steel barrier to prevent water ingress or the water ingress is negligible and does not degrade the insulation properties. The most common types of this are:

- Polyurethane
- Polypropylene
- Syntactic Polyurethane
- Syntactic Polypropylene
- Multi-layered
- Other

The main materials that have been used for deepwater insulations have been polyurethane and polypropylene based. Syntactic versions use plastic or glass matrix to improve insulation and greater depth capabilities. Insulation coatings with combinations of the two materials have also been used. Table 9.5 gives the properties of these wet insulations.

As can be seen from the table, the insulation is buoyant and must be compensated by the steel pipe weight to obtain lateral stability of the deepwater pipeline on the seabed.

9.5 Heat Transfer Analysis Example

In order to suggest insulation materials and thickness for the network of pipelines, the heat transfer going through the pipes must be calculated for each pipe. The main aspect of heat

---

**TABLE 9.4 Properties of Dry Insulations**

<table>
<thead>
<tr>
<th>Insulation Material</th>
<th>k-factor @ 75°F (Btu-in/hr-ft²-°F)</th>
<th>Density (lbs/ft³)</th>
<th>Compressive Strength (psi)</th>
<th>Service Temperature (°F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCPUF</td>
<td>Aged 3 to 6</td>
<td>10 to 65</td>
<td></td>
<td></td>
</tr>
<tr>
<td>OCPUF</td>
<td>2 to 4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PIF</td>
<td>0.190</td>
<td>1.8 to 2</td>
<td>19 to 24</td>
<td>−297 to 300</td>
</tr>
<tr>
<td>Polystyrene</td>
<td>0.259</td>
<td>6</td>
<td>20</td>
<td>−297 to 165</td>
</tr>
<tr>
<td>Fiberglass</td>
<td>0.24</td>
<td>3.5 to 5.5</td>
<td></td>
<td>0 to 850</td>
</tr>
<tr>
<td>Mineral Wool</td>
<td>0.25</td>
<td>8.7</td>
<td></td>
<td>1292</td>
</tr>
<tr>
<td>VIP</td>
<td>0.036−0.055</td>
<td>3.7−9.0</td>
<td></td>
<td>320</td>
</tr>
<tr>
<td>Insulation Material</td>
<td>k-factor (Btu/hr-ft²-°F) Density (lbs/ft³)</td>
<td>Water Depth (feet)</td>
<td>Service Temperature (°F)</td>
<td></td>
</tr>
<tr>
<td>Polyurethane (PU)-Solid</td>
<td>0.035 72</td>
<td></td>
<td>240</td>
<td></td>
</tr>
<tr>
<td>Polypropylene (PP)-Solid</td>
<td>0.039 56</td>
<td>9000</td>
<td>290</td>
<td></td>
</tr>
<tr>
<td>Syntactic PU</td>
<td>0.021−0.026</td>
<td>38−53</td>
<td>300−9000</td>
<td>131−240</td>
</tr>
<tr>
<td>Syntactic PP</td>
<td>0.023−0.039</td>
<td>37−50</td>
<td>240</td>
<td></td>
</tr>
<tr>
<td>Syntactic Phenolic</td>
<td>0.014</td>
<td>31</td>
<td>392</td>
<td></td>
</tr>
<tr>
<td>Syntactic Epoxy</td>
<td>0.017−0.024</td>
<td>37−45</td>
<td>6000−9000</td>
<td>160−212</td>
</tr>
</tbody>
</table>
transfer through the pipe occurs through conduction of the insulation material. The basic equation for radial heat transfer can be found in textbooks (Holman, 1981). Normally it is assumed that convective heat transfer and conductive heat transfer through the pipe material are negligible. While heat transfer calculations for pipelines under steady flow conditions are straightforward, numerical computer simulators are required and available for pipelines under transient flow conditions. Guo et al. (2004) presented analytical solutions that can be easily used to carry out the required steady state and transient heat transfer analyses for single pipes. These solutions are included in Appendix B of this book. An application example with the analytical solutions is presented in this section.

Suppose a set of data in Table 9.6 is applicable to a design pipeline. Sensitivity analyses can be performed with the analytical temperature models to investigate the effects of thermal conductivity, time, and fluid flow rate on the temperature profile in a pipe.

Figure 9.1 illustrates steady temperature profiles calculated using different values of thermal conductivity of the insulation. In this situation, it appears that a thin layer (1.27 cm) of insulation with thermal conductivity of less than 1 W/m·°C will allow a total temperature drop of less than 1°C over the 1000 m pipeline.

Figure 9.2 presents the calculated transient temperature profiles for a start-up process. It shows that the transient temperature profile approaches the steady temperature profile after one half hour of fluid flow at a constant rate. Figure 9.3 demonstrates the calculated

<table>
<thead>
<tr>
<th>Insulation Material</th>
<th>k-factor (Btu/hr-ft²-°F)</th>
<th>Density (lbs/ft³)</th>
<th>Water Depth (feet)</th>
<th>Service Temperature (°F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polyurethane (PU)-Solid</td>
<td>0.035</td>
<td>72</td>
<td></td>
<td>240</td>
</tr>
<tr>
<td>Polypropylene (PP)-Solid</td>
<td>0.039</td>
<td>56</td>
<td>9000</td>
<td>290</td>
</tr>
<tr>
<td>Syntactic PU</td>
<td>0.021–0.026</td>
<td>38–53</td>
<td>300–9000</td>
<td>131–240</td>
</tr>
<tr>
<td>Syntactic PP</td>
<td>0.023–0.039</td>
<td>37–50</td>
<td></td>
<td>240</td>
</tr>
<tr>
<td>Syntactic Phenolic</td>
<td>0.014</td>
<td>31</td>
<td></td>
<td>392</td>
</tr>
<tr>
<td>Syntactic Epoxy</td>
<td>0.017–0.024</td>
<td>37–45</td>
<td>6000–9000</td>
<td>160–212</td>
</tr>
</tbody>
</table>

**Table 9.6 Base Data Used in the Heat Transfer Analyses**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal conductivity of insulation</td>
<td>1.0</td>
</tr>
<tr>
<td>Outer radius of pipe</td>
<td>0.100</td>
</tr>
<tr>
<td>Inner radius of pipe</td>
<td>0.095</td>
</tr>
<tr>
<td>Thermal gradient outside the insulation</td>
<td>0.005</td>
</tr>
<tr>
<td>Thermal gradient angle from pipe axis</td>
<td>0</td>
</tr>
<tr>
<td>Specific heat of fluid</td>
<td>41,800</td>
</tr>
<tr>
<td>Fluid density</td>
<td>1000</td>
</tr>
<tr>
<td>Insulation thickness</td>
<td>0.0127</td>
</tr>
<tr>
<td>Fluid flow rate</td>
<td>0.0005</td>
</tr>
<tr>
<td>External temperature at fluid entry point</td>
<td>100</td>
</tr>
<tr>
<td>Fluid temperature at fluid entry point</td>
<td>100</td>
</tr>
<tr>
<td>Pipe length</td>
<td>1000</td>
</tr>
</tbody>
</table>

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**Figure 9.1** Calculated temperature profiles under steady fluid flow conditions.

**Figure 9.2** Calculated temperature profiles during a fluid flow start-up process.
transient temperature profiles after an increase in fluid flow rate from \(0.005 \text{ m}^3/\text{s}\) to \(0.05 \text{ m}^3/\text{s}\). Although a 10-times higher value of thermal conductivity is utilized, it still shows that the transient temperature profile approaches the steady temperature profile after one half hour of flow at the new rate. Figure 9.4 shows the calculated transient temperature profiles during a pipeline shutdown process. It indicates that after a reduction in fluid flow rate from \(0.1 \text{ m}^3/\text{s}\) to \(0.01 \text{ m}^3/\text{s}\), the transient temperature profile approaches the steady temperature profile after one half hour of flow at the new rate.

Paraffin (wax) deposition is a serious problem in the oil industry because it causes plugging of the wellbore, production facilities, and transportation pipelines. This problem is described in Part III of this book. Oil composition, pressure, and temperature are factors affecting paraffin deposition. For a given oil composition, paraffin deposition is a strong function of temperature and weak function of pressure except in the near-critical-point region where it is also sensitive to pressure. It is vitally important to predict the locations where paraffin deposition occurs in pipelines. The prediction can be used for flow assurance management in the oil production and transportation operations.

Paraffin deposition is usually evaluated in laboratories using Wax Appearance Temperature (WAT) at different pressures. The WAT curve draws a boundary between wax-region and wax-free region in the pressure-temperature (P-T) diagram. If the in-situ condition (temperature and pressure) of pipeline falls in the wax region, paraffin deposition is expected to occur at the point. Figure 9.5 shows an example P-T diagram generated

**Figure 9.3** Calculated temperature profiles after a flow rate increase.

\[
k = 10 \text{ W/m-K}
\]

Flow rate increased from \(0.005 \text{ m}^3/\text{s}\) to \(0.05 \text{ m}^3/\text{s}\)

Time (hour):
- \(>0.05\)
- \(0.020\)
- \(0.010\)
- \(0.005\)
- \(0\)

External Temperature
Flow rate reduced from 0.1 m³/s to 0.01 m³/s

External Temperature

\( k = 10 \text{ W/m-K} \)

**Figure 9.4** Calculated temperature profiles after a flow rate reduction.

**Figure 9.5** P-T diagram to identify paraffin deposition interval in a wellbore.
with the analytical solution and a hydraulics model using the data by Ahmed Hammami et al. (1999). This plot shows that the P-T profile falls in the two regions (wax and wax-free) across the WAT curve. The cross-point is at length of about 600 m. This means that paraffin deposition could occur in the upper (low temperature and pressure) section of the pipeline above 600 m. A better insulation is required to prevent the paraffin deposition.

References

CHAPTER 10

Introduction to Flexible Pipelines

10.1 Introduction

Flexible pipes have been used in the oil industry since 1972, when Coflexip was awarded a patent to build a high pressure, flexible steel pipe. The first application was used in drilling as a 15,000 psi Kill and Choke line. Since then, flexible pipe designs have improved to produce the flowlines and risers that are now used in the offshore oil industry.

For deepwater, the flexible pipes are used mainly for dynamic risers from a subsea pipeline end manifold (PLEM) or riser tower to a floating production system such as an FSO, FPSO, and TLPs. The other uses are static risers, static flowlines, subsea jumpers, topside jumpers, and expansion joints. Flexible pipes are used for versatile offshore oil and gas applications including production, gas lift, gas injection, water injection, and various ancillary lines including potable water and liquid chemical lines.

The main advantages of flexible pipelines are:

- Ease and speed of installation
- No large spans because it follows the contours of the seabed
- Almost no maintenance for life of the project
- Good insulation properties are inherent
- Excellent corrosion properties
- No field joints because the pipe is of continuous manufacture
- No need of expansion loops
- Can be made with enhanced flow characteristics
- Sufficient submerged weight for lateral stability
- Accommodates misalignments during installation and tie-in operations
- Diverless installation is possible—no metrology necessary
- Load-out and installation is safer, faster, and cheaper than any other pipe application
- Retrievalability and reusability for alternative application, thus enhancing overall field development economics and preserving the environment
- Fatigue life longer than steel pipe

The codes that are used for the design of flexible pipe are:

- API SPEC RP 17B—“Recommended Practice for Flexible Pipe”
- API SPEC RP 17J—“Specification for Unbonded Flexible Pipe”
API SPEC RP 17K—“Specification for Bonded Flexible Pipe”
ISO 10420—“Flexible Pipe Systems for Subsea and Marine Riser Applications”
API Spec RP 2RD—“Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs)”

Since there are only three manufacturers, and the manufacturing of flexible pipe requires wrapping of many intertwining layers of high strength stainless steel carcass and special polymers, the material price of a flexible line is hundreds of times more expensive than an equivalent high strength carbon steel pipe. Consequently, general use is limited to special applications and in small quantities compared to use of high strength carbon steel pipe. Ultra-deepwater use of flexible pipe is limited, due to the inability of these pipes to withstand high external hydrostatic pressure. Presently, the maximum depth at which flexible pipes have been used is 2000m.

The main flexible pipe layers are shown in Figure 10.1. The material make-up of each layer is described below.

Layer 1: **Carcass.** The carcass is a spirally wound interlocking structure manufactured from a metallic strip. The carcass prevents collapse of the inner liner and provides mechanical protection against pigging tools and abrasive particles.

Layer 2: **Inner liner.** This is an extruded polymer layer that confines the internal fluid integrity.

Layer 3: **Pressure armor.** This consists of a number of structural layers comprised of helically wound C-shaped metallic wires and/or metallic strips. The pressure armor layers provide resistance to radial loads.

Layer 4: **Tensile armor.** The tensile armor layers provide resistance to axial tension loads. This is made up of a number of structural layers consisting of helically wound flat metallic wires. The layers are counter wound in pairs.

Layer 5: **Outer sheath.** The outer sheath is an extruded polymer layer. Its function is to shield the pipe’s structural elements from the outer environment and to give mechanical protection.

These are the primary layers. Some of the other layers that are not shown are the anti-wear layers and insulation layers. The anti-wear layers are non-metallic layers that are

![Figure 10.1 Flexible pipe layers.](image)
inserted between the structural elements to prevent wear and tear between the structural elements. Additional layers of material with low thermal conductivity can be applied in order to obtain specific thermal insulation properties of the pipe.

All the flexible pipes have the same fundamental concept. Some variation may occur in choice of materials in case of special operating environments such as high pressures, high temperatures, sour service (high H₂S and/or CO₂ content), deep water, etc.

The end fitting of the flexible pipe is extremely important as it seals the different layers preventing any water ingress and also allows it to be connected to other pipeline appurtenances. The common end fittings that are used are:

- Flanges
- Grayloc connectors
- Hydraulic subsea connectors

Another device that is used at the end of the flexible pipes is the bend restrictor. This is used to prevent excessive bending because most flexible pipes have a minimum allowable bend radius. Any bending beyond this would comprise the integrity of the flexible pipe.

10.2 Flexible Pipe Manufacturers

The three flexible pipe manufacturers in the world are:

- NKT Flexibles
- Wellstream
- Technip (formerly Coflexip)

10.2.1 NKT Flexibles

NKT Flexibles, located in Broendby, Denmark, is a worldwide supplier of flexible subsea pipes. This company, originally a power cable manufacturer, made its first flexible pipe in 1967. The NKT flexible pipe is an unbonded structure consisting of helically wound metallic armor wires or tapes combined with concentric layers of polymers, textiles, fabric strips, and lubricants. For each product type all layers in the flexible pipe design are described in terms of dimensions and type of material.

Some of NKT Flexibles’ features are:

- Unrivalled process technology and experience from more than 30 years of flexible pipe manufacturing
- State of the art manufacturing facility
- Full compliance with API 17J
- Focus on flexible pipe manufacturing as core business

NKT Flexibles performs total riser and flowline system design, engineering, procurement, manufacture, testing, documentation, and delivery. NKT flexible pipe has been qualified by Bureau Veritas and can manufacture flexible pipe to meet special requirements such as insulation and sour service. Flexible pipes are certified by API according to ISO 9001:2000, API Q1, and API Monogram.
NKT Flexible Pipe Classes

The present pipe size range is from 2.5 inches to 16 inches inner diameter. Design pressures are from 15,000 psi for the smallest pipe bores to 4000 psi for the largest. NKT Flexibles is the industry leader in design and manufacture of flexible pipes for high temperature applications with design temperatures as high as 130°C for both static and dynamic service. The NKT flexible pipes are classed as follows:

- Low Pressure Smooth Bore
- Low Pressure Rough Bore
- High Pressure Smooth Bore
- High Pressure Rough Bore

These classes determine the layers that are included in the fabrication of the flexible pipe.

10.2.2 Wellstream

Wellstream was founded in 1985 and is a designer and manufacturer of high quality spoolable pipeline products, systems, and solutions for fluid transportation. Wellstream has pioneered enabling technologies for deep and ultra-deepwater developments, shallow water, and onshore applications through research and development.

Wellstream has supplied flexible pipe for water depths up to 1000m for more than 10 years. In 1999, Wellstream products were the first to be qualified for service in ultra-deepwater extending the operational envelope to 2000m.

Suited to riser and flowline applications, Wellstream’s manufacturing capability ranges from 2-inch ID to 24-inch OD to reel or carousel. Typical product designs provided by Wellstream are:

- Low internal pressure
- High pressure
- Thermal resistance
- High external pressure
- For corrosive internal fluids
- Prevention of external abrasion

10.2.3 Technip

Technip Flexible Pipe (formerly Coflexip) has the largest market share in the world for this product. They have designs to cover all aspects of deepwater applications including corrosion resistance, high temperature, and pressure. They also have a product that can be used for LNG. Other special products include actively heated flexible pipe.

10.3 Basics of Flexible Riser Analysis and Design

The design of the flexible riser is critical to the offshore field development as it provides the means to transfer hydrocarbon fluids from the subsea unit on the seabed to the floating production or storage unit on the sea surface. The main design code followed is API RP 2RD.
The most common commercial finite element software used for the analyses are:

- Flexcom-3D
- Orcaflex
- Flexriser
- Seaflex

Complex floating body motions and loadings are combined in the dynamic analyses of the flexible riser. This is mainly a large deflection analysis subjected to dynamic boundary conditions and non-linear hydrodynamic loading. The input data required for the analyses consists of:

- Flexible pipe data
- Vessel response data
- Environmental data
- End boundary conditions
- Attached buoyancy units data

The design of the riser system is an iterative process. To begin with, a riser configuration must be assumed and analyzed. Some of the common configurations (see Figures 10.1 and 10.2) used are:

![Figure 10.2 Some of the S-configurations of risers.](image-url)
The selected configuration is then subjected to a combination of environmental loadings and vessel motions with the riser empty and full to determine the global dynamic response. As this is a tension dominated structure, it is imperative under all circumstances that the riser remain in tension. Compression may cause bird-caging and will adversely affect the integrity of the riser and reduce service life.

Finally, the detail static and dynamic analyses of local areas are performed to enable the design of various components such as bend stiffeners, bend restrictors, buoyancy modules, subsea buoyancy arches, and end connectors/flanges.
References

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Technical Bulletin—“Technip.”
PART II

Pipeline Installation

Various methods have been used in subsea pipeline installations. This part of the book provides a brief description of these methods and focuses on engineering aspects of controlling bending stress and stability of pipeline during the installation. It includes the following chapters:

Chapter 11: Pipeline Installation Methods
Chapter 12: Installation Bending Stress Control
Chapter 13: Pipeline On-Bottom Stability Control
CHAPTER 11

Pipeline Installation Methods

11.1 Introduction

With the discovery of offshore oil fields in the shallow waters of the Gulf of Mexico during the late 1940s, offshore pipeline installation was invented. The first "offshore" pipeline in the Gulf of Mexico was constructed in 1954. Now, offshore fields are being discovered in water depths of 10,000 feet and the pipeline installation technology is keeping up. The most common methods of pipeline lay installation methods are:

- S-lay (Shallow to Deep)
- J-lay (Intermediate to Deep)
- Reel lay (Intermediate to Deep)

Shallow water depth ranges from shore to 500 feet. Intermediate water depth is assumed to be 500 feet to 1000 feet. Deepwater is water depths greater than 1000 feet. Offshore magazine produces a survey of most of the pipeline lay barges that work in the US every year. This survey does not cover all the lay barges of all the countries that do offshore work, but it does cover the bigger international ones Heerema, Saipem, Stolt, Technip, Allseas, McDermott, Global, and Subsea 7.

Other methods that have been used for pipeline installation are tow methods consisting of:

- Bottom tow
- Off-bottom tow
- Mid depth tow
- Surface tow

Tow methods can be used for installing pipelines from shallow water depths to deep-water depths depending on the design requirements.

11.1.1 Pipeline Installation Design Codes

The most commonly used offshore pipeline installation codes are:

- DnV OS F101 (Det Norske Veritas)
- API RP 1111 (American Petroleum Institute)
In the Gulf of Mexico, other codes that include sections relating to offshore pipelines are:

- ASME B31.4—Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids
- ASME B31.8—Gas Transmission and Distribution Systems

11.2 Lay Methods

11.2.1 S-Lay

The most common method of pipeline installation in shallow water is the S-lay method. A typical S-lay configuration is shown in Figure 11.1. In the S-lay method, the welded pipeline is supported on the rollers of the vessel and the stinger, forming the over-bend. Then it is suspended in the water all the way to the seabed, forming the sag-bend. The over-bend and sag-bend form the shape of an “S.”

In the S-lay method, tensioners on the vessel/barge pull on the pipeline, keeping the whole section to the seabed in tension. The reaction of this pull is taken up by anchors installed ahead of the barge or, in the case of a dynamically positioned (DP) vessel, by thrusters. These barges/vessels are fitted with tension machines, abandonment and recovery (A&R) winches, and pipe handling cranes. The firing line for welding the pipe may be placed in the center of the barge or to one side. The firing line consists of a number of stations for welding, NDE, and field joint application. The field joint station is located after the NDE station and the tension machines.

The S-lay barge/vessels can be classed into the following:

- 1st Generation
- 2nd Generation
- 3rd Generation
- 4th Generation
First generation S-lay barges are mainly flat-bottom spud barges used for very shallow water, swamps, and inland waters.

Second generation lay barges are also flat-bottomed barges with anywhere from four-to fourteen-point moorings used for station keeping. These are the most common, and a large number of these exist throughout the world. The S-lay barge spread in this case consisted of:

- anchor handling vessels
- supply vessels
- pipe barges
- tugs

Third generation S-lay barges are the semi-submersibles that use anchors for station keeping. The first barge of this generation was the Viking Piper constructed in 1975. This vessel was used as a lay barge in the North Sea for only a short period. Now only a couple of this generation of lay barges exist.

Fourth generation S-lay barges are vessels that use dynamic positioning systems for station keeping. These barges can be used to lay deepwater pipelines. S-lay vessels of this generation belonging to Allseas are:

- the Lorelay, and
- the Solitaire

Figure 11.2 Semi-sub S-lay barge–LB 200.
Both vessels have DP capability and are, therefore, not limited by the use of anchors for station keeping. Both vessels have laid pipelines in deepwater. The Lorelay lays in shallow water to deepwater, while the Solitaire lays pipeline from intermediate water depth to deepwater. The Solitaire is able to compete with the J-lay method of installation on depth and pipe diameter, but has the advantage of the quicker production rate associated with S-lay over J-lay. However, S-lay in deepwater induces a higher strain than for J-lay and can be as high as 0.45% in the overbend.

11.2.2 J-lay

To keep up with the discovery of deepwater oil and gas fields, the J-lay system for pipeline installation was invented. In this system, lengths of pipe are welded in a near vertical or vertical position and lowered to the seabed. The J-lay configuration is shown in Figure 11.4. In this configuration, the pipeline from the surface to the seabed is one large radius bend resulting in lower stresses than an S-lay system in the same water depth. There is no over-bend, and a large stinger required in S-lay to support the pipe in deepwater is eliminated. The horizontal forces required to maintain this configuration are much smaller than required for an S-lay system. This lends itself for DP shipshape vessels and derrick barges to be equipped with a J-lay tower. Large J-lay towers have been installed on the world’s largest heavy lift vessels—Saipem’s S7000 and Heerema’s Balder—as well as smaller towers on other vessels such as Stolt’s Polaris, McDermott’s DB 50, and Technip’s Deep Blue. Normally, the J-lay process is slower than S-lay, but since the large J-lay towers are capable of handling prefabricated quad joints (160 feet long), the speed of pipelaying is increased.
The J-lay method is normally used in water depths greater than 500 feet. These water depths are normally too great for moored lay vessels to operate, because the required tensions and pipe bending stresses are too large.
11.2.3 Reel Lay

Reel pipelay is a method of installing pipelines in the ocean from a giant reel mounted on an offshore vessel. Pipelines are assembled at an onshore spool-base facility and spooled onto a reel which is mounted on the deck of a pipelay barge. The first application of the reeled pipeline was on D-Day when the allies were supplied with fuel across the English Channel using a small diameter pipeline unreeled from a vessel. Commercial application of reeled pipeline technology was not available until the early 1970s when Santa Fe Corporation built the first reel vessel.

Reel technology also provides a safer and more stable work environment, thus speeding pipeline installation. Reeled pipelines can be installed up to 10 times faster than conventional pipelay. The greater speed allows pipelines to be laid during a short weather window. This can extend the normal construction season. Reel pipelay can be used on pipelines up to 18 inches in diameter.

The reel method reduces labor costs by permitting much of the welding, x-raying, corrosion coating, and testing to be accomplished onshore, where labor costs are generally lower than comparable labor costs offshore. After the pipeline is reeled onto the drum of the pipelaying vessel, it is taken to the offshore location for installation. The reeled pipeline can be installed in an S-lay method or J-lay method depending on the design of the reel vessel and the depth of water. Reel vessels can have vertical reels or horizontal reels.

Horizontal reel vessels lay pipelines in shallow to intermediate water depths using a stinger and S-lay method. The station-keeping of vessels with horizontal reels can be by anchors or DP.

The vertical reel vessel can normally install pipelines from the intermediate water depths to deepwater and station-keeping is always DP. For deepwater, the J-lay configuration is used and no stinger is required.
The pipe is unreeled, straightened, de-ovalized, and connected to the wire rope from the seabed pre-installed hold back anchor. The sagbend stresses are controlled by the tensioning system on the reel vessel. The vessel moves ahead while it slowly unreels the pipeline.
from the drum. When the end of the pipeline on the drum is unreeled, a pullhead connected to a wire rope is attached. The end of the pipeline is lowered to the seabed by paying out the A&R wire rope from the reel vessel slowly in a controlled method always maintaining sufficient tension in the pipeline. A buoy is attached at the end of the A&R cable. The reel vessel returns to the spool base to load more welded pipeline on the reel drum. On returning, it pulls the end of the pipeline using the A&R cable, removes the pullhead, and welds it to the pipeline on the drum. It then begins the unreeling process again.

The main disadvantages of the reeling method are:

- Connecting the ends of the pipeline segments
- Amount of time to re-reel the pipeline to remove a buckle
- Establishing a spool base close to the location where the pipeline is to be laid
- Concrete-coated pipelines cannot be reeled
- Only specifically designed pipe-in-pipe pipelines can be reeled
- The pipeline is plastically deformed and then straightened. Some thinning of the wall and loss of yield strength of the material in localized areas can occur (Bauschinger effect)

11.3 Tow Methods

In the tow methods, the pipeline is normally constructed at an onshore site with access to the water. These methods can be used for installing pipelines across inland lakes, across wide rivers, and offshore.

In the case of an offshore pipeline, the advantage of these methods is that the pipeline is welded onshore with an onshore pipeline spread. Once the pipeline is complete and hydrotested, the pipeline is dewatered and moved into the water, while being attached to a tow vessel (a large anchor handling vessel). It is then towed to a location offshore where each end is connected to pre-installed facilities. This could be cheaper than using a laybarge spread to install the pipeline offshore. The advantage occurs mainly if several small lines need to laid and can be bundled inside a larger pipe. However, a case-by-case analysis is required to determine the risk versus the reward. The pipeline can be made up either perpendicular or parallel to the shoreline.

For a perpendicular launched pipeline, a land area that can accommodate the longest section of the fabricated pipeline must be leased. A launch way consisting of a line of rollers or rail system needs to be installed leading from the shore end right into the water. First, all the sections that make up the pipeline are fabricated and tested. Then, the first section of pipeline is lifted by side booms and placed on the rollers on the launch way. The cable from the tow vessel is attached and the section is pulled into the water, leaving sufficient length onshore to make a welded tie-in to the next section. In this manner, the whole single pipeline is fabricated and pulled into the water. A hold-back winch is always used during these pulls to maintain control and, if need be, to reverse the direction of pull.

In the parallel launch method, the land area acquired along the shore is normally the total length of the pipeline to be towed. This could be longer than that acquired during perpendicular launch. No launch way is needed. After the sections of the pipeline are welded and tested, the sections are strung along the shoreline. The pipeline sections are
welded together to make up the length of pipeline to be towed. The completed pipeline is moved into the water using side-boom tractors and crawler cranes for the end structures. The front end is attached to the tow vessel, while the rear end is attached to a hold back anchor. The anchored tow vessel winches in the tow cable in such a manner that it gradually moves the pipeline laterally into the water, while the curvature is continuously monitored. When the whole length of pipeline and its end structures make one straight line, the tow vessel begins to tow the pipeline along the predetermined tow route.

For pipelines that are to be towed into deepwater, pressurized nitrogen can be introduced into the pipeline to prevent collapse or buckling under external hydrostatic pressure. A depth of 3000 feet can be achieved. Greater depths would require a stop for another recharge of pressurized nitrogen from the surface. This has never been done.

### 11.3.1 Bottom Tow

As the name indicates, the bottom tow method pulls the pipeline along the seabed to its final location. The length of a single section of pipeline is limited by the available bollard pull of the vessel used. The bollard pull must be greater than the total submerged weight of the pipeline, plus the partially submerged weight of the end structures, times the friction coefficient of the soil. For an estimate, the initial friction coefficient is taken as unity. Two to three vessels can be used in tandem to obtain additional bollard pull capability.

A thorough sea-bottom survey of the pipeline all the way from the shoreline to the pipeline's final resting place offshore must be conducted. If the pipeline is launched parallel to the shore, then the whole shallow water area near shore along the length of the pipeline must be surveyed.

An additional abrasion-resistant coating is required on the bottom half of the pipeline to protect the normal corrosion-resistant coating like FBE. If concrete weight coating is required for stability, then this can be that coating. An additional thickness may be required to allow for abrasion. Several abrasion-resistant coatings that adhere to FBE are available on the market. However, abrasion testing may be required to select the appropriate coating. Additionally, a slick coating on the bottom half of the pipe can reduce friction and reduce the bollard pull requirement during tow.

For pipelines in shallow water, a trench may be required due to regulatory requirements or for pipeline stability. In this case, a subsea trenching plow can be attached ahead of the pipeline prior to pulling it into its final location. This will require additional bollard pull. A trench can be prepared prior to pulling the pipeline in. For reasonably straight pipelines this is not a problem. But pulling a pipeline into a curved trench is difficult.

The ends of a bottom-towed pipeline are normally connected by deflect-to-connect method. In this method, the end sections of the pipeline are made to float a few feet above the seabed by providing additional buoyancy for this length and attaching anchor chains at discrete spacing along this length. The buoyancy and chains are attached onshore with chains strapped over the buoyancy pipe during towing and deployed at the pipeline's final location. This length can then be pulled laterally by attaching cables to the end of the pipeline from the facility. Once the pipeline end structure is secured at the facility, the connection can be made by flanges (in diving depth) or by hydraulically activated connectors (in deepwater).
The disadvantages of bottom tow are:

- An extensive bottom survey along the tow route is required.
- The route must not cross existing pipelines. Otherwise, additional costs will be incurred for installing and removing structures to protect existing pipelines.
- Subsea transponder systems are required to locate the pipeline during tow and to place it in its final destination.
- The pipeline lying along the beach or near-shore can be subjected to large wave forces from storms, and this could compromise pipeline integrity. A pipe anchor system is required on standby for this emergency.
- In crossing shallow water areas, a chase vessel is required to keep fishing vessels from crossing the bottom-towed pipeline.

11.3.2 Off-Bottom Tow

In the off-bottom tow method, the submerged pipeline is buoyant and floats above the seabed at a predetermined height during the towing. This is achieved in the same manner as described in the above section for connecting the ends of bottom-towed pipeline. The buoyancy and chains are attached in discrete modules for the length of the pipeline.

The advantage of this method over bottom tow is that existing pipelines can be crossed by placing concrete mats placed over these pipelines and allowing the hanging chains to drag over the mats. No extensive protection structure is required. However, buoyancy and chains are required for the entire length of the pipeline. If several pipelines are needed for field development, the buoyancy and chains can be recovered and used again.

Only a nominal thickness of abrasion-resistant coating is required. This can even be additional FBE coating if no concrete coating is needed. For concrete coated pipelines, no additional thickness is required.

The seabed survey needs to consider only obstacles that are higher than the height of the floating pipeline and sudden steep seabed cavities.

Launching of the pipeline with attached buoyancy and chains is the same as in bottom tow. Chains are secured over the pipeline or buoyancy during launch. Once the pipeline and end structures are fully submerged, the tow is temporarily stopped to deploy the chains and trim buoyancy if required.

11.3.3 Mid-depth Tow

In the mid-depth tow method, the entire length of pipeline is kept at a considerable height above the seabed during towing. To achieve this, discrete buoyancy, chains, and a large tension applied to the pipeline are required. The tension is applied by two tow vessels pulling in opposite directions at each end of the pipeline. Once the pipeline reaches its desired height, the front tow vessel applies more thrust while the back tow vessel cuts back on its reverse thrust. A third vessel monitors the height of the pipeline in the middle by using a subsea transponder system. This vessel sends its signal to the two tow vessels, which see the height in real time and adjust their thrusts appropriately to keep the pipeline within the desired height range. This method is not suited for very long pipelines (greater than 3 miles).
In this method, only a near shore survey and final infield pipeline route survey are required. Additionally, some discrete areas where the pipeline can be parked in case of emergency must be identified. This method is ideal for areas with extensive rocky outcrops, many existing pipelines, or other obstructions along the tow route.

The launching methods from shore are the same, and a temporary stop to trim the buoyancy and chains is required near-shore prior to start of the mid-depth tow.

### 11.3.4 Surface Tow

Surface tow of pipelines is similar to mid-depth tow except that the pipeline will not require any chains. The two vessels, one at each end, keep the pipeline in tension while it is towed on the surface. Only a survey of the final pipeline route is required. This method can be used for shallow water. For deep water, a sophisticated controlled flooding and/or buoyancy removal system is required. Not many pipelines are installed by this method.

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Technip Website – [www.technip.com](http://www.technip.com)
CHAPTER 12

Installation Bending Stress Control

12.1 Introduction

The dynamic stresses which occur during pipeline installation are normally less than 30% of the static stresses in shallow water. As the petroleum industry moves into deepwater environments, the dynamic stresses are more significant. Careful analysis of the dynamic stresses becomes essential for defining the limiting weather conditions that could cause overloading or fatigue failure of a pipeline. In this chapter we describe how to control the magnitude of pipeline installation stresses that can occur under various installation conditions. These stresses include lay stresses, overbend stress, sagbend stress, and horizontal bending stress.

12.2 Lay Stresses

During pipeline installation, the bending stress in the pipe should be checked against that which is allowable by the code or specification. As illustrated in Figure 12.1 for S-laying, two regions of pipeline can be identified: the overbend region and the sagbend region. The overbend region extends from the tensioner on the barge deck, over the barge ramp, and down the stinger to the lift-off point when pipe is no longer supported by the stinger. The sagbend region extends from the inflection point to the touch-down point. Bending stresses in the two regions are major concerns during pipeline installation. In J-lay there is only the sagbend area. Reel lay falls into one or the other of these two categories depending on the method of pipe installation. Additionally, the reeling process puts the pipeline into one cycle of plastic deformation and straightening.

To have an understanding of installation bending stress/strain control, one must examine the basic differential equation that describes pipelay analysis, specifically the sagbend. This is the non-linear bending equation and is given by

\[-q = EI \frac{d}{ds} \left( \sec \theta \frac{d^2 \theta}{ds^2} \right) - T_s \sec 2\theta \frac{d\theta}{ds} \]
where

\[ q = \text{unit submerged weight of pipe} \]
\[ EI = \text{pipe bending stiffness} \]
\[ T_o = \text{effective lower pipe tension} \]
\[ s = \text{distance along pipe span} \]
\[ \theta = \text{angle at distance } s \]

\[ \sin \theta = \frac{dy}{ds} \]

The above equation is applicable to both deep and shallow water and is valid for small and large deflection. Finite-difference and perturbation methods have been successfully used to provide solutions.

Finite Element (FE) solution methods, both linear and non-linear, exist for the pipelay analyses. Any general non-linear finite element program is capable of analyzing the pipeline during lay installation. Most lay barge/vessel companies have developed their own software applicable to their vessels. But most general finite element programs have the capability of simulating pipe lay analyses. The most common finite element computer programs available on the market for analyses are:

- OFFPIPE (specific for pipe installation)
- ANSYS (General FE program)
FLEXCOM-3D (specialized for offshore pipeline, catenary riser analyses, moorings, etc.)

ORCAFLEX (specialized for offshore pipeline, catenary riser analyses, moorings, etc.)

The pipeline installation codes are given in Section 11.1.1. These codes give equations that determine the allowable stresses and strains for pipelay analyses. Some of the equations are empirical based on tests performed on the pipe section under external pressure and bending.

### 12.2.1 Overbend Stress

The overbend occurs mainly on the laybarge/vessel and the stinger. The setting of the rollers to obtain a radius of curvature is the main control of the overbend. This curvature, combined with axial tension, gives global stress on the pipe in the overbend. Local stresses occur at the rollers where the reaction force is assumed to be a point load on the pipeline. The local stresses can be analyzed using a finite element program such as ANSYS, NASTRAN, etc. In shallow water, this may not require a detailed analysis, but in deep water, the reaction loads from the rollers are substantial and must be examined in detail.

Dynamic loads increase the reaction on the last few rollers on the stinger. By redistributing loads to the other rollers, these stresses can be reduced. Optimum roller heights can be obtained through a number of simulations of laying conditions. Some barges monitor the reaction loads on the stinger to help them control the overbend stresses.

The bending stress in the overbend region can be calculated using the following equation:

\[
\sigma_a = \frac{ED}{2R_{cv}}
\]  

(12.1)

where

- \(\sigma_a\) = axial bending stress
- \(E\) = steel modulus of elasticity
- \(D\) = pipe outer diameter
- \(R_{cv}\) = pipeline radius of curvature.

Therefore, the minimum radius of curvature can be determined as:

\[
R_{cv} = \frac{ED}{2\sigma_yf_D}
\]  

(12.2)

where

- \(\sigma_y\) = minimum yield stress
- \(f_D\) = design factor, usually 0.85.

In order to control the bending stress in the overbend region to be below the minimum yield stress with a safety factor, the required minimum curvature of the stinger should be calculated using Equation (12.2).
12.2.2 Sagbend Stress/Strain

The bending stress in the sagbend region is also caused by pipeline curvature. The curvature is normally computed using elastic rod theory in a small strain, large displacement formulation, with axial and torque deformations neglected. The stresses occur with S-lay, J-lay, shore pulls with buoyancy, surface and subsurface tows, and expansion devices subjected to environmental loading. Methods of analyzing sagbend stresses include beam method, nonlinear beam method, natural catenary method, stiffened catenary method, finite element method, and method for thick concrete coating. Computer programs are frequently needed for predicting the lay stresses.

The beam method is also referred to as the small deflections method, i.e., the theory is applicable for small deflections only, i.e., $\frac{dy}{dx}$ is much less than unity (Wilhoit, 1967; Palmer, 1974). The method is applicable to shallow-water pipelines.

The nonlinear beam method considers the nonlinear-bending equation of a beam to describe the bending of pipeline span (Bryndum et al., 1982). It is applicable in both shallow water and deepwater. It is valid for small and large deflections. The finite-difference method of approximations has been used to provide the solution.

The natural catenary method has been used to describe the pipeline span configuration away from its ends (Plunkett, 1976). Because the boundary conditions on pipeline span are not satisfied, the method is limited to pipeline segments of very small stiffness. The method is applicable to pipelines in deepwater or where the tension is very large such that the tension term is predominant over the stiffness term.

The stiffened catenary method differs from the natural catenary method in that the boundary conditions are satisfied (Palmer, 1975). The method gives accurate results of pipeline configuration even in the regions near the ends. But it is limited to deep water and where the pipe stiffness is small.

The finite element method is applicable in all water depths for small or large deflections (Martinsen, 1998). The pipeline span is modeled as a system of connected finite beam elements. The bending equations in the system are solved using matrix techniques. The accuracy of the method is affected by selection of the pipe-element length.

The method for thick concrete coating was developed for certain pipeline installations where it is necessary to increase the pipe submerged weight sufficiently to withstand hydrodynamic forces at the seabed (Powers and Finn, 1969). In this situation, when the pipe is bent, the bending stresses are intensified at the field joints where the pipe stiffness is low.

The sagbend is more interesting from a solid mechanics point of view. The addition of external hydrostatic forces creates the possibility of collapse for an empty pipe. The most common offshore codes that are used to limit the allowable stress/strain during pipe laying are:

- API RP 1111, and
- DnV OS F101 2000

API RP 1111 has the following interaction equation for buckling under external pressure and bending that must be satisfied:

$$\frac{\varepsilon}{\varepsilon_b} + \frac{(P_e - P_i)}{P_c} \leq g(\delta)$$
where,

\[ \varepsilon = \text{strain in pipe} \]
\[ \varepsilon_b = \text{critical strain under pure bending} = \frac{t}{2D} \]
\[ P_o = \text{external hydrostatic pressure} \]
\[ P_i = \text{internal pressure} \]
\[ P_c = \text{collapse pressure (for details see API RP1111 Section 4.3.2.1)} \]
\[ g(\delta) = \text{collapse reduction factor} = (1 + 20\delta)^{-1} \]

\[ \delta = \frac{D_{\text{max}} - D_{\text{min}}}{D_{\text{max}} + D_{\text{min}}} = \text{ovality} \]

\( D_{\text{max}}, D_{\text{min}} \) are the maximum and minimum diameters at the same cross-section.

The strain, \( \varepsilon \), in the pipe can be written as

\[ \varepsilon \leq \left[ g(\delta) - \frac{(P_o - P_i)}{P_c} \right] \frac{t}{2D} \]

During installation, the allowable strain is limited by a safety factor, \( f_1 \) such that

\[ f_1 \varepsilon_1 \leq \varepsilon \]

where

\( \varepsilon_1 \) is the maximum installation bending strain.

API RP 1111 recommends that, \( f_1 = 2.0 \). The API equations are limited to pipes with a \( D/t \) ratio not greater than 50.

Normally, in the computation of wall thickness of pipelines in deepwater, the maximum bending strain is assumed to be 0.2%. In many cases, the allowable strain can be computed knowing all the other factors. In several cases, it has been shown that the strain can be much greater than 0.2% and still satisfy the inequality.

DnV 2000 has a similar equation for pipeline subjected to longitudinal bending strain and external hydrostatic pressure, and is given by

\[ \left( \frac{\varepsilon_d}{\varepsilon_c} \right)^{0.8} + \frac{p_e}{p_c} \frac{\gamma_e}{\gamma_{sc} \gamma_m} \leq 1 \]

where

\( p_e = \text{external pressure} \]
\( p_c = \text{collapse pressure} \]
\( \varepsilon_d = \text{design compressive strain} \]
\( \varepsilon_c = \text{critical compressive strain} \]
\( \gamma_e, \gamma_{sc}, \gamma_m \) are resistance factors of strain, safety class, and material, respectively.
DnV 2000 interaction equation is considered more conservative than the API RP 1111 one. DnV’s ovality formula is given by

\[ f_o = \frac{D_{\text{max}} - D_{\text{min}}}{D} \]

This is twice that of the definition given by API RP 1111. Therefore, one must be careful in using the value in the equations in both codes.

Additionally, in DnV 2000 collapse pressure, \( p_c \) (Eq. 5.18 in the code) is a function of ovality which seems logical. However, some tests performed on larger, thicker wall pipes indicate that the results lie closer to the API RP 1111 equation. The API RP 1111 collapse pressure is not a function of ovality and is easier to use.

In deepwater, controlling the sagbend stresses during installation is imperative because a collapse of pipe under a combination of external pressure and bending can lead to buckle propagation. A propagating buckle can travel along the pipe for long distances. To prevent this from happening, buckle arrestors are placed at a pre-determined spacing along the pipe. Buckle arrestors are short pup-pieces of thicker walled pipe. Buckle arrestors can be welded as part of the pipeline for S-lay and J-lay situations or bolted on for reeled pipelay conditions.

The propagating pressure, \( P_p \), for a pipeline can be computed using API RP 1111 formula:

\[ P_p = 24S\left(\frac{t}{D}\right)^{2.4} \]

where \( S \) is the specified minimum yield stress of the pipe material.

A minimum safety factor of 1.25 is used on the external over pressure when compared with the propagation pressure. This equation is empirical, obtained mainly from experiments on pipes under external pressure.

Installing deepwater pipelines filled with water eliminates the collapse due to external pressure. This reduces the wall thickness required to resist collapse. A few advantages of laying the line filled with water are that it is very stable on the seabed and can be hydrotested right away. Only a few pipelines have been installed in this manner. The tension requirement of pipeline increases when filled with water for water depths up to approximately 2300 m. Therefore, most contractors lay pipelines in the dry condition.

Increasing the tension can control the sagbend stress. In shallow water barges, the increase in tension must be taken up by the anchors. This may lead to slippage depending on the soil conditions on the seabed. Also, the increase in tension leads to a longer suspended span, which may not be desirable. This also leads to higher residual tension of the pipeline on the seabed. On the seabed, spanning of the pipeline over undulation increases with increased tension. Therefore most barges want to use the optimum amount of tension.
References


Callegari M., Bruschi R., “Concurrent Design of an Active Automated System for the Control of Stinger/Pipe Reaction Forces of a Marine Pipelaying System.”


CHAPTER 13

Pipeline On-Bottom Stability Control

13.1 Introduction

Pipelines installed on the seabed are subjected to hydrodynamic forces. Waves and steady currents that are characteristics of all offshore areas subject the pipeline on the seabed to drag, lift, and inertia forces. For lateral stability, the pipeline resting on the seabed must resist these forces and at a minimum be at equilibrium.

Drag and inertia forces act together laterally on the pipeline, tending to move the pipeline. Lift force acting vertically tends $F_l$, lift force to effectively reduce the submerged weight of the pipeline. Traditionally, sliding friction between the pipeline and soil provided the resistance of the pipeline on the seabed. Forces acting on the pipeline resting on the seabed are shown in Figure 13.1.

The traditional method of pipeline stability is given by the following:

$$\frac{\mu(W_S - F_l)}{F_T} > 1$$

Figure 13.1 Forces acting on the pipeline resting on the seabed.
where

\[ \mu = \text{soil-pipe friction} \]
\[ W_s = \text{submerged weight} \]
\[ F_l = \text{lift force} \]
\[ F_T = \text{total horizontal force from waves and currents} \]

In general, the larger the submerged weight, the higher the frictional resistance. However, later methods for determining the stability include the depth of embedment of the pipeline. Additional resistance is provided by the soil and, therefore, reduces the required submerged weight of the pipeline.

As the pipeline is resting on the seabed, soil characteristics play an important role in the lateral, as well as the vertical, stability of the pipeline. The importance of vertical stability of the pipeline is mainly in buried pipelines in soils with a high liquefaction potential.

### 13.2 Hydrodynamic Parameters

The drag force, \( F_d \), due to water particle velocities is given by

\[ F_d = \frac{1}{2} \rho C_D D (U + V)^2 \]

where

\[ F_d = \text{drag force/unit length} \]
\[ \rho = \text{mass density of seawater} \]
\[ C_D = \text{drag coefficient} \]
\[ D = \text{outside diameter of pipeline (including the coatings)} \]
\[ U = \text{water particle velocity due to waves} \]
\[ V = \text{steady current} \]

The lift force, \( F_l \), is determined by the same equation as that for the drag force with the lift coefficient, \( C_L \), replacing \( C_D \), the drag coefficient.

The inertia force, \( F_i \), due to water particle acceleration is given by

\[ F_i = \rho C_M \frac{\pi D^2}{4} \left( \frac{du}{dt} \right) \]

where

\[ F_i = \text{inertia force/unit length} \]
\[ \rho = \text{mass density of seawater} \]
\[ C_M = \text{drag coefficient} \]
\[ D = \text{outside diameter of pipeline (including the coatings)} \]
\[ \frac{du}{dt} = \text{water particle acceleration due to waves} \]

The traditional stability method uses Morison’s equation to determine the combined forces, \( F_T \), on the given by
In linear wave theory, wave velocity and acceleration are sinusoidal functions in time. Therefore, the maximum force can be obtained using calculus or by stepping through a wave cycle and computing the forces at discrete phase angles.

In reality the waves are non-linear, and methods using spectral analysis to obtain velocities and accelerations may be more appropriate. The most common spectral models that are used to describe sea state are:

- Pierson-Moscowitz (P-M)
- Bretschneider (Bret)
- JONSWAP (Joint North Sea Wave Project -JS)

The spectral formulation can be generally expressed as

\[ S_{\eta\eta}(\omega) = Bf(H_s, \omega_p, \omega) \phi\left(\frac{\omega}{\omega_p}\right) \text{ with } \phi\left(\frac{\omega}{\omega_p}\right) = \exp f(\sigma, \omega, \omega_p) \]

where

\[ \omega_p = 2\pi f_p \text{ (} f_p \text{ is the peak frequency of the spectrum)} \]
\[ \omega = 2\pi f \]
\[ \gamma^\phi = \text{spectrum peakedness factor} \]
\[ H_s = \text{significant wave height} \]

The values for \( B \) and \( \gamma \) for the three spectra are given in Table 13.1.

The P-M spectrum is used for fully developed sea state in deepwater that is not fetch or duration limited. JS is developed for the North Sea and can be used for fetch-limited seas.

The surface wave spectrum can be transformed to bottom velocity spectrum using a specific transfer function. From the bottom velocity spectrum, a mean bottom velocity and a related significant bottom velocity can be obtained.

The values for the hydrodynamic coefficients \( C_D, C_L, \) and \( C_M \) given in DnV’s 1981 Pipeline Design Guidelines are 0.7, 0.9, and 3.29, respectively. However, tests on static pipes have led to producing graphs to determine the values of these coefficients with respect to Reynold’s number for steady currents and Keulegan-Carpenter number \( (KC = U_m T/D, \max \text{ velocity and period, } T) \) for steady currents combined with wave-induced currents. Figures 13.2 and 13.3 present the graphs for \( C_D \) and \( C_L \) obtained by Hydraulics Research Station (HRS) for pipelines in an estuary (tidal currents).

<table>
<thead>
<tr>
<th>Spectral Model</th>
<th>( B )</th>
<th>( \gamma )</th>
<th>( \omega_p )</th>
<th>( \omega_p/\omega_s )</th>
</tr>
</thead>
<tbody>
<tr>
<td>P-M</td>
<td>5</td>
<td>1</td>
<td>( \omega_p )</td>
<td>0.710</td>
</tr>
<tr>
<td>Bret</td>
<td>5</td>
<td>1</td>
<td>0.857 ( \omega_s )</td>
<td>0.710</td>
</tr>
<tr>
<td>JS</td>
<td>3.29</td>
<td>3.3</td>
<td>( \omega_p )</td>
<td>0.781</td>
</tr>
</tbody>
</table>

Note: \( \omega_s \) is the significant frequency \((= 2\pi f_s = 2\pi T_s)\).
13.3 Soil Parameters

Traditionally, lateral stability of the pipeline on soil was determined using soil friction coefficient and ranged from 0.7 to 1.0 for sand and 0.3 to 0.5 for clay without considering the embedment.

Now, a more rigorous approach is taken by computing the embedment and factoring the additional resistance provided by the soil. A reduction in drag and lift forces occurs when there is embedment. This embedment takes place when small oscillations of the pipeline occur under wave action.

The amount of embedment of the pipeline in soil depends on the bearing capacity of the soil, $q_f$, given by

$$q_f = \frac{1}{2} \gamma BN_\gamma + cN_c + z\gamma N_q$$

where

$q_f = \text{ultimate bearing capacity}$

$\gamma = \text{soil submerged weight}$

$B = \text{width of embedment}$

---

**Figure 13.2** Drag coefficient.
$z$ = depth of embedment
$c$ = cohesion $= 0$ for sands
$N_y$, $N_c$, $N_q$ = dimensionless bearing capacity factors $= f(\varphi)$ (angle of friction)
$N_q = 0$ for no embedment
$= 1$ for $\varphi = 0$

The pipeline embedment into the seabed is shown in Figure 13.4.

For clays with zero embedment

$$q_f = c N_c$$

for sands with zero embedment

$$q_f = \frac{1}{2} \gamma BN_y$$

13.3.1 Cohesive Soils

Clays are classified by their consistency and are measured by their shear strength as given in Table 13.2.
Cone penetrometer testing (CPT) gives characteristics of both clay and sand. In the field, the shear strength can be obtained by performing Torvane tests.

Several methods have been proposed for determining the embedment of the pipeline into clayey soils. Models have been developed by the PIPESTAB project in 1987 and by the American Gas Association/Pipeline Research Committee (AGA/PRC) in 1992. In both these models, the total soil resistance consists of a frictional term, $F_f$, and an additional resistance due to pipeline embedment, $F_p$, given by:

$$ F_R = F_f + F_p; \quad F_f = \mu F_c; $$

where

$F_R$ = total soil resistance
$F_c$ = contact force = $(W_i - F_l)$
$\mu$ = soil-pipe friction = 0.2

An empirical model for clayey soil resistance due to penetration, $F_p$, is proposed by Verley & Lund, given by

$$ F_p = 4.13G^{-0.392} \left( \frac{z}{D} \right)^{1.31} $$

and

$$ \left( \frac{z}{D} \right)_{\text{max}} = 1.15G^{0.54} \left( \frac{a}{D} \right)^{0.17} = (0.3 \text{ max}) $$

<table>
<thead>
<tr>
<th>Consistency</th>
<th>Shear Strength Range (ksf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Very soft</td>
<td>0.0 to 0.25</td>
</tr>
<tr>
<td>Soft</td>
<td>0.25 to 0.5</td>
</tr>
<tr>
<td>Firm</td>
<td>0.5 to 1.0</td>
</tr>
<tr>
<td>Stiff</td>
<td>1.0 to 2.0</td>
</tr>
<tr>
<td>Very Stiff</td>
<td>greater than 2.0</td>
</tr>
</tbody>
</table>
where
\[ D = \text{outside diameter of pipeline (including the coatings)} \]
\[ z = \text{penetration of pipe into soil} \]
\[ S_u = \text{undrained shear strength} \]
\[ G = \frac{S_u}{(D \gamma_s)} \]
\[ \gamma_s = \text{unit soil weight} \]
\[ a = \text{amplitude} = H_s/2 \]

13.3.2 Noncohesive Soils

For sands, Standard Penetration Test gives a measure of the relative density, \( D_r \). Sands are classified by compactness as given in Table 13.3.

The embedment of the pipeline in sands is based on bearing capacity equation given earlier, with cohesion set to zero:

\[ q_f = \frac{1}{2} \gamma BN_\gamma + z \gamma N_q \]

The bearing capacity factors \( N_\gamma \) and \( N_q \) are related to internal angle of friction and can be found in most soil mechanics textbooks (e.g., Foundation Analysis and Design, Joseph E. Bowles). Some authors (Vesic, Hansen, Meyerhof) have suggested ways of improving the value of these factors.

The ultimate lateral soil resistance, \( q_{ult} \) can be obtained by

\[ q_{ult} = z \gamma N_q \]

The suggested values to be used for bearing capacity factors for lateral resistance are given by Hansen.

13.4 Stability Analysis Guidelines

The most common and industry accepted methods for determining the on-bottom stability of submarine pipelines are:

- PRCI (AGA) Pipeline Stability Program
- DnV RP E305

<table>
<thead>
<tr>
<th>Compactness</th>
<th>Relative density, ( D_r ) (%)</th>
<th>SPT</th>
<th>Friction angle, degrees</th>
<th>Submerged weight, pcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>Very loose</td>
<td>0-15</td>
<td>0-4</td>
<td>0-28</td>
<td>&lt;60</td>
</tr>
<tr>
<td>Loose</td>
<td>15-35</td>
<td>4-10</td>
<td>28-30</td>
<td>55-65</td>
</tr>
<tr>
<td>Medium</td>
<td>35-65</td>
<td>10-30</td>
<td>30-36</td>
<td>60-70</td>
</tr>
<tr>
<td>Dense</td>
<td>65-85</td>
<td>30-50</td>
<td>36-41</td>
<td>65-85</td>
</tr>
<tr>
<td>Very Dense</td>
<td>85-100</td>
<td>&gt;50</td>
<td>&gt;41</td>
<td>&gt;75</td>
</tr>
</tbody>
</table>
13.4.1 PRCI Pipeline Stability Program

The three levels of analyses that can be performed by this software are:

- Simplified Static – Level 1
- Simplified Quasi-Static – Level 2
- Dynamic Time Domain – Level 3

The simplified static method employs the traditional method using the airy wave theory, Morison’s equation for wave force, and soil-pipe friction factor. This is normally used in getting a quick result for preliminary design of pipeline stability. Reduction of wave force due to embedment can be specified.

Level 2 is accepted for most detail design stages, because pipe embedment and additional lateral resistance are taken into account. Soil information is required for this analysis. Wave spectrum is transferred to the seabed and additional embedment during a storm is considered. Safety factors are computed for four levels of probabilistic waves in a storm.

In Level 3, the pipeline is allowed to move and the stress due to movement and factor of safety over time is computed. This is used mainly in cases of existing pipelines that were not designed to the 100-year storm or initially buried pipelines that are subsequently exposed to waves and currents.

13.4.2 DnV RP E305

This guideline recommends three levels of analysis:

- Simplified Stability Analysis
- Generalized Stability Analysis
- Dynamic Analysis

The Simplified Stability Analysis is similar to Level 1 in the previous section. The differences are that friction factors for sand and clay are given and a calibration factor for submerged weight as a function of Keulegan-Carpenter number is given. A safety factor of 1.1 is inherent in the calibration factor.

The Generalized Stability Analysis is based on the use of a set of non-dimensional parameters and for particular end conditions. This method assumes the following:

- Hydrodynamic forces modified for wake effects
- No initial embedment
- No prior loading
- Pipe is rough
- Soil resistance due to penetration under cyclic loading is included
- Medium sand soil
- Uses JONSWAP wave spectrum
- No reduction of hydrodynamic forces due to embedment

The response of the pipeline in waves is controlled by the following non-dimensional parameters:
Load parameter, \[ K = \frac{U_s T_u}{D} \]
Pipe weight parameter, \[ L = \frac{W_s}{0.5 \rho_w D U^2 s} \]
Current to wave velocity ratio, \[ M = \frac{U_c}{U_s} \]
Relative soil weight (sand soil) \[ G = \left( \frac{\rho_s}{\rho_w} \right) \rho_w = \frac{\rho_s}{\rho_w} - 1 \]
Shear strength parameter (clay soil) \[ S = \frac{W_s}{(D S_u)} \]
Time parameter \[ T = \frac{T_1}{T_u} \]

where

- \( U_s \) = significant bottom wave velocity perpendicular to the pipe
- \( U_c \) = steady current
- \( T_u \) = zero up-crossing period
- \( T_1 \) = duration of the sea state
- \( \rho_s \) = mass density of sand soil
- \( \rho_w \) = mass density of seawater
- \( W_s \) = submerged weight
- \( D \) = outside diameter
- \( S_u \) = shear strength of clay

The validity of this method is for the following range of parameters:

- \( 4 < K < 40 \)
- \( 0 < M < 0.8 \)
- \( 0.7 < G < 1.0 \) (for sand soil)
- \( 0.05 < S < 8.0 \) (for clay soil)
- \( D \geq 0.4 \text{ m} \) (16 inches)

This method is used for larger pipelines.

This DnV RP E305 does not give a method for dynamic analysis, but just recommendations on what aspects should be accurately modeled. It also gives recommended lateral displacement of the pipeline.

### 13.5 Trenching/Jetting

The need for pipelines to be trenched or lowered below the natural seabed level is based on the following:

- Regulations
- High seabed velocity

In the Gulf of Mexico, all pipelines in water depths less than 200 feet are to be buried with a cover of three feet. All pipelines that approach the shore are buried, due to both regulations and the fact that the seabed velocity is very high in shallow water. It would be uneconomical to provide concrete weight coating for stability during a 100-year return period storm.

Lowering of the pipeline below the seabed can be performed by the following methods:

Jetting
Plowing
In theory, jetting consists of fluidizing the seabed soil so that the heavier pipeline sinks in. The jetting plough is placed over the pipeline and high-pressure water jets from nozzles blast the surrounding soil away from the pipeline. Jetting disperses the local soil away from the pipeline and creates a wide trench. In most cases, the soil is not returned immediately and the pipeline gets covered in time depending on the bottom sediment load. Jetting is done in sands and soft clays, but in hard clays plowing may be required.

Mechanical plows have also been used to cut trenches below pipeline, allowing the pipeline to be gradually lowered into them. Initial development was of a pre-trenching plow. The trench was made first, and the pipeline was then laid or pulled into the trench. This was not very successful because the trench had to be quite wide or the subsequent installation of the pipeline had to be very accurate. Further development has resulted in the more common post-trenching plow. In this case the plow is deployed over the pipeline after the pipeline is installed on the seabed. These plows are capable of lifting the pipeline, trenching, and then lowering the pipeline into the trench as the plow is moved or moves forward.

For shallow water areas (up to 60 feet of water depth) that have rock, coral, or very hard soils, a mechanical device called the “Rocksaw” can be used. This is a pre-trenching device. The depth of trench can be 10 feet and the width up to 8 feet. As it is in shallow water, the pipeline can be pulled into the trench from shore or from a moored pull barge offshore.

References


PART III

Pipeline Commissioning and Operations

After installation, a pipeline undergoes testing and commissioning stages. Certain procedures should be followed during testing and commissioning. Then the pipeline is ready to operate for transporting the production fluids. As the pressure in the oil/gas reservoirs is declining with time, the composition of the produced fluids (water cut and gas-liquid ratio) changes. Flow assurance engineering becomes essential. Pigging operations are conducted to clean the pipeline and identify pipeline defects. This part of the book addresses technical issues during pipeline management from pipeline testing to daily operations. It includes the following chapters:

Chapter 14: Pipeline Testing and Pre-commissioning
Chapter 15: Flow Assurance
Chapter 16: Pigging Operations
CHAPTER 14

Pipeline Testing and Pre-commissioning

14.1 Introduction

From its fabrication to startup, a pipeline system has to pass a series of tests. Some of these, such as the Factory Acceptance Test (FAT), are done onshore at the fabrication yards with individual components. The FAT mainly consists of the inspection, testing, and reporting of the system according to the drawings, specifications, and requirements of the contract. Pipe sections must pass the FAT before they are accepted. Some of the tests, such as the pipeline hydrotest, are mainly done offshore with either a portion of the whole pipeline system or the whole pipeline system. The hydrotests are conducted to check the mechanical strength of the pipeline system and the integrity of the connections. The hydrotest is one of the pipeline pre-commissioning activities. Pre-commissioning is performed after the pipeline system is installed and all the tie-ins are completed to assess the global integrity, qualify the system as ready for commissioning and startup, confirm the safety to personnel and environment, and confirm the operational control of the pipeline system.

Why are all the tests done offshore necessary? The subsea pipeline system typically consists of pipeline and riser. A jumper is usually used to connect the pipeline and the riser, as shown in Figure 14.1. A Pipeline jumper is a short section of pipe which can be either rigid or flexible. The jumper is tied with the riser and the pipeline with connectors and PLET (Pipeline End Termination). The PLET is used to support a pipeline connector and/or a pipeline valve. At the subsea end, the pipeline is tied to a manifold or a well through a jumper which is installed between one connector at the PLET and one connector on the manifold or on the tree, as shown in Figure 14.1.

When the subsea pipeline system is installed, because of the various connections along the pipeline system, it is necessary to make sure the pipe sections are leakproof and have the required mechanical strength to withstand the designed pressure with the specified level of safety. Pipeline may get damaged during the transportation and installation process, and its mechanical strength may thus be reduced. The various connections along the pipeline system may not be tied in properly, and leaks may occur under high pressure conditions. All the above mentioned potential problems must be detected by performing pressure testing and corrected properly before the pipeline is put into service to prevent any operational accidents (environmental and safety impacts).
Before the pipeline system can be used, it must also be cleaned and gauged. During fabrication and installation, debris may be left inside the pipeline. If the debris is not removed, it can plug and damage valves and chokes. Pipeline internal dimensions and internal integrity also need to be checked for proper operations. For example, the pipeline has to be checked to make sure that no deformations have occurred during the installation and no internal restrictions exist. Otherwise, operational pigs may not pass the deformed pipe sections.

This chapter will cover the main activities associated with subsea pipeline testing and pre-commissioning.

### 14.2 Pipeline Pre-commissioning

The pipeline pre-commissioning consists of the following activities:

- Flooding
- Cleaning and gauging
- Hydrotesting
- Leak tests

#### 14.2.1 Pipeline Flooding, Cleaning, and Gauging Operations

After the pipeline is laid, it must be verified that the line is internally clean and free from restrictions or debris and will withstand its design pressure. This verification process generally involves flooding the line with treated fluids and sending a cleaning pig down the line to clear out any accumulated debris followed by a gauging pig to prove it is of full bore over the entire length. The cleaning and gauging can be carried out with a single pig. Thus, the main objectives of the flooding, cleaning, and gauging operation are to:

- Fill the pipeline with a suitable pressure testing medium
- Verify the cleanliness of the pipeline
- Verify the pipeline integrity by gauging to make sure no buckles or obstructions exist

![Schematic of a typical subsea pipeline system.](image)
The pipeline should be filled with clean filtered water. Suspended material in the water should be removed by a filter capable of removing all particles larger than a specified size (50–100 microns). A meter with sufficient accuracy should be used to measure the quantity of water injected into each pipe section. Knowing the quantity of water injected is critical for leak detection. Chemicals, like biocide, are usually injected into the test water with a certain concentration, which will depend upon the test conditions. If the test water will stay in the pipeline for a relatively long time, corrosion inhibitor will also need to be injected into the pipeline to protect the pipeline from excessive corrosion. All the chemicals injected must be compatible with the water so that no solids will form inside the line.

While filling the pipeline, a series of pigs (pig train), separated by a slug of fluids, shall be passed through the pipeline at a specified minimum velocity. The pig train consists of cleaning pigs and gauging pigs. The best choices for cleaning pigs are pigs with discs, conical cups, spring mounted brushes, and bypass ports. Discs are effective at pushing out solids while also providing good support for the pig. Conical cups provide excellent sealing characteristics and long wear. Spring-mounted brushes provide continuous forceful scraping for removal of rust and other build-ups on the pipe wall. Bypass ports allow some of the flow to bypass through the pig and help minimize solids built up in front of the pig. The pig should also include a magnetic cleaning assembly to clean any metal debris. Some applications may use a bidirectional disc pig when the water used to fill the line has to be pushed back to its source after completion of the test. Bidirectional pigs may be used if there is a fear of the pig getting stuck and there is an option to reverse flow and bring the pig back to the launch point.

Gauging pigs are used to determine whether there are unacceptable reductions/obstructions in a line. These reductions can be caused by ovality due to overburden, or by dents and buckles. A conventional gauging pig is a cup type pig with a slotted aluminum gauging plate. The slotted aluminum plate will bend out of the way when it encounters an excessive reduction. If the pig comes out with a damaged plate, it is usually run again and if the plate is damaged again, it is assumed there is an unacceptable reduction in the line. The restriction must be located and removed. After removing the restriction, the gauging pigs should be run again to verify that the repairs are done properly and the line is indeed free of obstructions.

A typical pipeline flooding, cleaning, and gauging pig train is shown in Figure 14.2. Two cleaning pigs and one gauging pig are shown. Depending upon the individual cases, more cleaning and gauging pigs can be used. For hydrotesting and pre-commissioning the Yacheng pipeline, four cleaning pigs and two gauging pigs were used (Karklis et al., 1996).

There are two key issues associated with the flooding, cleaning, and gauging operations. One is the control of the pig train velocity at the downhill section. The other is the cleanliness of the pipeline. For the pig train, there are recommended traveling velocities by the manufacturers, normally 3–6 miles per hour. But at the downhill sections, due to the gravity effect, the pig train will travel at higher than the recommended velocity. To help control the velocity, if the pipeline is not very long, it is possible to pressurize the whole pipeline with air. But if the pipeline is too long, this option can be quite expensive. The biggest concern of the flooding, cleaning, and gauging operations is that the pig train may get stuck because of debris. To mitigate this risk, it is very critical to have stringent controls of pipe cleanliness at every stage, from pipe manufacture to installation.
14.2.2 Pipeline Hydrotesting and Leak Testing

The hydrotests are conducted mainly to verify the mechanical strength of pipeline or pipeline sections. Hydrotesting is carried out by pressurizing the system to a specified internal pressure and holding it for a certain period of time to check whether or not there is a pressure drop. If the pressure drops within the hold period, it is assumed that a leak or leaks may exist somewhere in the system. After the holding period is over, the pressure is released and a complete visual inspection follows. Standard codes, such as ASME B31.4, ASME B31.8, and API RP 1110, provide guidance on how to perform pressure tests of gas and liquid pipelines.

Before conducting the tests, it is necessary to establish the specifications for the test procedures and equipment. The procedure specifications should include the following:

- A description of the pipe sections to be tested (lengths, elevation, tie-ins, etc.)
- Test medium (seawater is used for subsea pipelines)
- Chemicals to be mixed with the test medium (biocide and corrosion inhibitors)
- Mixing process of the chemicals with the test medium including the chemical concentrations
- Test pressures
- Test holding time
- Process of pressurizing
- Description of all testing equipment
- Description of testing instrument
- Monitoring and recording of test pressure
- Procedure for depressurizing and discharge of test medium

The test pressure is recommended to be set at no less than 1.25 times the internal design pressure for both hydrostatic testing and leak testing. The holding time is recommended to be at least 4 hours for hydrostatic testing and at least 1 hour for leak testing.

A complete description of the test equipment and instruments is very important for the success of the tests. The following is a partial list of the devices needed for the tests:

**Figure 14.2 Typical flooding, cleaning, and gauging pig train.**
• A high-volume pump that can fill the line at high enough velocity to remove debris and to push the pigs
• A filter that would remove all particles larger than a certain size to ensure the test fluid is clean
• A meter to measure the quantity of water filled
• Injection pumps for chemical injections
• A variable speed, positive displacement pump to pressurize the line. The pump should have a known volume per stroke and should have a stroke counter
• A pressure recorder that would continuously record the test pressure for the whole test period. The pressure measuring equipment should have an accuracy and repeatability of ± 0.1%
• A temperature measurement device that is properly calibrated and should continuously measure the fluid temperature. The device should be able to read in increments of no less than 0.1°F (0.05°C)
• A temperature device to measure the ambient temperature
• Pressure relief valves
• Pig transmitter device or remote pig signaling system

When planning the hydrotesting and leak testing, a few issues must be taken into account. The tests should be planned so that nowhere in the test segment does the pressure level produce hoop stress near or above the specified minimum yield stress (SMYS). This will require the test pressure to be determined by taking into full account the effect of the pipeline profile and external conditions. If the test pressure is relatively high because of the high design pressure, the pressure relief valves have to be properly checked and set at the right pressure to protect the pipeline and the involved personnel. When launching a suite of pigs from a test-head launcher and receiving into a similar receiver, there is always concern that not all the launched pigs have been successfully launched or received into the terminal. It is necessary to install a pig transmitter device or some kind of remote pig signaling system on the final pig to confirm the pig launch and reception.

How the test results will be reported and what will be reported should be defined before performing the tests. The test records should include the details of the test operations and details of any failures. The failure report should include the exact location of each failure, the type of failure, the causes for the failure, and the recommended repair methods. When the tests are finished, all waste should be disposed of in the correct manner which should be defined in the company’s waste management and disposal policy.

14.2.3 Pipeline Dewatering, Drying, and Purging

For offshore gas transmission pipelines, after successful hydrotesting and leak testing and before introducing gas, the pipelines have to be dewatered, dried, and purged. For offshore liquid pipeline, the water is usually displaced by diesel or dead oil and it is not necessary to dry the pipeline. The process of dewatering, drying, and purging can be quite complicated, depending upon the application. This is because after the tests, the pipeline is full of seawater and the water has to be sufficiently displaced from the pipeline. Otherwise hydrate may form inside the pipeline when the hydrocarbon is introduced. Another reason for displacing the water is that many products react with water to form acids and other
corrosive compounds which would corrode the pipeline. This is especially true if the gases contain carbon dioxide. Thus, displacing the water from the pipeline, which is also called dewatering, is a necessary step for pipeline pre-commissioning. If the pipeline is very short, it may be economical to just inject enough methanol or glycol to treat the water to mitigate hydrate without the need for displacing the water.

The primary function of a dewatering pig train is to displace water efficiently, leaving behind a minimum quantity of fluids for subsequent drying. A typical dewatering system involves a displacement fluid supply, a dewatering pig train, and a valve for water flowrate control. For relatively short pipelines, the pig train may consist of a small number of mechanical pigs which can be driven with nitrogen or air. Sometimes produced gas may be used to push the pig train. Nitrogen is also used for dewatering the stainless steel pipelines. For long pipelines, a typical dewatering pig train may include a number of pigs and fluid slugs. The fluid slugs serve different functions, like providing lubrication of the pig seals and preventing forward slippage of the driving gas. The speed of the pig train is controlled by adjusting the water flowrate at the outlet while the pressure is controlled at the inlet by the gas. A typical dewatering pig train is shown in Figure 14.3.

The dewatering train for the Zeepipe system (Falk et al., 1994) consisted of 10 mechanical pigs, which were separated by slugs of various liquids. Two slugs of water-based gel were at the front of the train. The purpose of the gel slugs was to lubricate the first pigs to decrease wear. Behind the gel slugs were four batches of methanol which were used to coat the pipe wall to inhibit the water that was left behind. Three batches of methanol gel were at the rear of the train to prevent gas bypassing forward into the train due to imperfect sealing.

The performance of the gel slugs in the pig train will impact the efficiency of the dewatering operation. There are a couple of gel systems available (Schreurs et al., 1994). One is the water-based gel system, which is a mixture of polymers and crosslinkers. The other is methanol or hydrocarbon gel systems. The gel slugs should satisfy the following function requirements (Schreurs et al., 1994):

- The gel slugs should minimize fluid bypass across pig seals. The slugs should prevent water from backward bypassing and prevent gas from forward bypassing
- The fluids in the gel slugs should be compatible with the pigs and the pipeline materials
- Gels should be strong enough to sustain any shearing and dilution, thereby preserving their rheological properties through the whole operation
- Gels should be chemically stable at the operating conditions for the whole operation, which can last for weeks

![Figure 14.3 Typical dewatering pig train.](image-url)
After dewatering operations, the pipeline may still have enough water to cause problems during startup, and a drying operation is required to further remove the residual amount of water in the pipeline. Of course, if the pipeline is going to transport water-wet gas, there is no need to dry the pipeline. If the pipeline is stainless steel, the dewatering operations are normally carried out with nitrogen and thus, no need to dry the pipeline.

There are two common methods for drying pipeline: air drying and vacuum drying. Air drying techniques have been extensively discussed in literature. The main advantages of air drying are:

- All free water can be removed from the pipeline
- Very low dew points can be achieved down to as low as $-90^\circ F$
- The drying process is relatively short

Unfortunately, air drying techniques are not well suited for offshore pipelines because the equipment requires a large area.

Vacuum drying is based upon the fact that the water will boil at low temperatures if the pipeline pressure is reduced to the saturated vapor pressure for the ambient temperature. Thus, by reducing the system pressure, it is possible to cause the water to boil and be removed from the pipeline as a gas with a vacuum pump. A typical vacuum drying pressure curve is shown in Figure 14.4.

The vacuum drying process can be divided into three stages. The first stage is the evacuation phase in which the pipeline pressure is drawn down from atmospheric to the saturated vapor pressure by removing the air from the pipeline. The saturated vapor pressure is a function of the pipeline temperature. This phase is also called drawdown phase.

As the pressure approaches the saturated vapor pressure, water starts to evaporate and the pressure is more or less maintained as a constant. As the pressure tries to fall, more
water evaporates and thus the pressure stays constant. This vapor is sucked out of the pipeline by the vacuum pump. This process continues until all free water in the pipeline has evaporated. This phase is also called boiling phase.

When all free water in the pipeline has evaporated, the pressure in the pipeline will start to fall because there is no more water to evaporate and maintain the equilibrium. All the air in the pipeline has been evacuated, and the pipeline pressure can be directly correlated to the dew point. This phase is called final drying phase.

Water evaporation requires heat input. In subsea pipeline, the heat has to come from the surrounding water. If the pipeline is insulated, the heat transfer process from the surrounding water to the pipeline can be quite slow. Thus, the vacuum pump must be properly sized so that the water will not be forced to evaporate faster than the pipeline can absorb the heat of evaporation from the surroundings. Otherwise, ice can form inside the pipeline.

The main advantages of the vacuum drying method are:

- All free water can be removed from the pipeline
- Very low dew points can be achieved
- No large space is needed for equipment
- No significant amount of waste will be produced

The main disadvantages of vacuum drying are that the drying process can be quite long and the method is not suitable for very long or small bore pipelines.

After drying and before gas-up, the pipeline may need to be purged using nitrogen for the following reasons:

- To further verify the line dryness
- To provide a barrier before the introduction of hydrocarbons

Even though hydrocarbon can be directly introduced after vacuum drying without the risk of achieving an explosive mixture, the nitrogen purging operations provide an extra safety margin.

After the pre-commissioning, the pipeline is ready for commissioning and startup.

References

CHAPTER 15

Flow Assurance

15.1 Introduction

The most severe operational hazards of offshore pipelines are the risks associated with the transportation of multiphase fluids. When water, oil, and gas are flowing simultaneously inside the pipeline, there are quite a few potential problems that can occur: water and hydrocarbon fluids can form hydrate and block the pipeline; wax and asphaltenes can deposit on the wall and may eventually block the pipeline; with high enough water cut, corrosion may occur; with pressure and temperature changes along the pipeline and/or with incompatible water mixing, scales may form and deposit inside the pipeline and restrict the flow; and severe slugging may form inside the pipeline and cause operational problems to downstream processing facilities. The challenge that engineers will face is, thus, how to design the pipeline and subsea system to assure that multiphase fluids will be safely and economically transported from the bottom of the wells all the way to the downstream processing plant. The practice of identifying, quantifying, and mitigating of all the flow risks associated with offshore pipelines and subsea systems is called flow assurance.

Flow assurance is critical for deepwater pipeline and system operations. In deepwater, the seawater temperature is usually much colder than the surface air temperature. When pipeline is submersed in the deep water, if there is no thermal insulation layer surrounding the pipe wall, the fluid heat can be quickly lost to the water. This is especially true if the water current around the pipeline is strong. With an un-insulated pipeline, the heat transfer coefficient at the outer pipe wall can be significant due to the forced convection by the seawater movement (current). If the fluid temperature inside the pipeline becomes too low due to the heat loss, water and hydrocarbon (oil and gas) may form hydrate and block the flow. Furthermore, if the fluid temperature is low enough, wax may start to precipitate and deposit on the pipe wall. Thus, effective preservation of fluid heat is one of the most important design parameters for offshore pipeline.

In deep water, the pipeline is normally followed by a production riser which goes from the sea bottom to the surface processing facilities (topsides). The deeper the water is, the longer the production riser is. With a long riser, the pipeline operating pressure will be higher due to the hydrostatic head in the riser. For the same fluid temperature, with higher operating pressure, it is easier for the fluids to form hydrate. With pipeline and riser production system, if the flow conditions are such that severe slugging occurs, the slugs will be proportional to the riser length. The longer the riser, the longer the severe slugs.
How to optimize the pipeline and subsea system design to mitigate the flow assurance issues is a challenge. Flow assurance risks can be managed through robust system design, like heavy thermal insulation, high grade materials, and sophisticated mitigation systems, which would normally drive up the capital cost (CAPEX). On the other hand, flow assurance risks can also be managed through operations, like extensive chemical inhibition, extensive pigging, and flow monitoring, which will drive up the operating costs (OPEX). To balance the CAPEX and OPEX costs, the economics and system uptime are the key parameters.

Flow assurance, as a discipline, is still relatively new. There are many fundamental flow assurance phenomena which are not well understood. The main objectives of this chapter are to describe the fundamental flow assurance concepts and to summarize the mitigation practices used in industry for the flow assurance risks. In the subsequent sections, the major flow assurance issues and some critical parameters that would impact the identifying, quantifying, and mitigating of the flow assurance risks associated with subsea pipeline operations will be covered.

15.2 Fluid Sampling and Characterizations

One of the most critical steps in identifying and quantifying flow assurance risks is fluid sampling. Whether or not there will be any flow assurance risks in subsea pipeline must be determined from the fluid sample analysis: What is the fluid composition? Is there a potential for wax deposition? Is the potential for asphaltene deposition high, medium, or low? Will the fluid gel when the temperature is low enough after system shutdown? How much energy will be required to re-mobilize the fluid once it is gelled? All these questions can be answered only by lab or flowloop measurements of the fluid samples. Thus, it is very important to sample the representative fluid that will be transported by pipeline. No matter how accurate the lab measurements and interpretations are, if the fluids do not represent the real production fluids, wrong conclusions may be drawn. Any flow assurance mitigation strategies based upon wrong conclusions will work improperly and the pipeline and subsea system will encounter severe operational risks.

Water samples are also very critical in establishing flow assurance risks. These include scaling, hydrate formation tendencies, corrosivity, compatibility with other water (injected water or water from different production zones), material metallurgy, and design of the water handling equipment. One special challenge associated with flow assurance risk assessment is that there is no water available for sampling because the exploration wells may never reach the aquifer zones. Without water samples, it is very difficult to make accurate flow assurance risk assessments. A lot of times, water samples from nearby fields have to be used, resulting in high levels of uncertainty in the development of the flow assurance mitigation strategies.

15.2.1 Fluid Sampling

There are a lot of discussions in literature on fluid sampling and handling (API RP 44, RP 45, Ostrof, 1979, Chancley, 1987). Fluid samples can be obtained from downhole and/or from surface separator. The downhole samples are the primary samples for PVT measurements, and surface separator samples are usually treated as back-up and can be used as
bulk samples for process or reservoir design. It is a good practice to collect at least two downhole samples with one serving as a back-up and collect at least three one-gallon samples from the separator. A certain amount of stock tank oil samples are needed for other crude oil analyses (geochemical and crude assay).

For fluid sampling plans, it is important to know the pros and cons of all available fluid sampling tools. Will drillstem testers (DST) or wireline testers be used? For wireline testers, will RCI (reservoir characterization instrument) or MDT (modular formation dynamics tester) be used? The key is how we can obtain the most representative fluid samples from downhole and transport it unaltered to the surface and to the lab for measurements and analysis. To achieve this, it is important to obtain fluid samples from the main production zone.

Once zone or zones to be sampled are determined, the next question is how to make sure the formation fluids will be sampled with the least mud contamination. During the drilling, with over-balanced drilling, the drilling fluids will penetrate into the formation to form a damaged zone just outside the wellbore. The fluid sampling tool needs to be able to penetrate through the damaged zone to get to the virgin formation fluids. Since it is very difficult to completely avoid mud filtrate contamination during the sampling, it is important that the tool be able to monitor the mud contamination level and thus whether or not the samples are acceptable can be determined. When the fluids are flowing into the tool, the pressure drop between the formation pressure and the pressure in the sample chamber should be kept low so that the fluids will not change phases during the sampling. Gas can come out oil when the fluid pressure is below the bubble point. Gas may leak out the tool during the transportation. It is also important to make sure there is no solid, like asphaltene, deposition that may stick onto the chamber wall and not be completely recovered. Otherwise the sampled fluids may not accurately represent those in the formation.

When the sampled fluids are transported from downhole to surface, the pressure of the fluids may drop due to the temperature drop. Whether or not this pressure drop would cause the pressure to be below the bubble point will need to be checked out.

### 15.2.2 PVT Measurements

Once the fluid samples are in the lab, numerous tests will be performed to measure the fluid properties. Compositional analysis of the downhole sample would be performed through at least C36+, including density and molecular weight of the Heptanes plus. Pressure-Volume Relations are determined at reservoir temperature by constant mass expansion. This measurement provides oil compressibility, saturation pressure, single phase oil density, and phase volumes. The compositions and gas formation volume factors for the equilibrium reservoir gas during primary depletion can be obtained by performing differential vaporization at reservoir temperature. Gas viscosities are then calculated from the composition. Undersaturated and depleted oil viscosity at reservoir temperature can be measured by using capillary tube viscometry.

The following parameters will normally be measured for black oil:

- Stock tank oil density (API gravity)
- Bubble point pressure
- FlashGOR
15.2.3 Specific Flow Assurance Analysis

Other than the PVT measurements, the fluid samples are also used for specific flow assurance measurements. For wax deposition evaluation: the compositional analysis through C70+ will be performed. Measurements, such as, wax appearance temperature (WAT) for the dead oils, shear rate, pour point, molecular weight, and total acid number (TAN) would normally be done. For asphaltene analysis, asphaltene titration would be done to determine the stability of asphaltenes. Titration of stock tank oil is normally done with n-heptane or n-pentane while monitoring the percent of asphaltene precipitates to determine stability. If light oil and heavy oil mixed together during transportation, tests would be required to determine the tendency towards asphaltene precipitation of the mixed oil. Even though the hydrate curves of reservoir fluids are usually modeled by software, it is also desirable to confirm the models by performing lab measurements.

Crude oils also have to be tested for foaming tendency and emulsion forming tendency. It is also necessary to evaluate how the water oil emulsion stability can be affected by shearing resulting from pumping and lifting mechanisms. It is also very desirable to measure the live oil water emulsion viscosity at both operating and seabed conditions with water cut ranging between 0 and 100%. The existing public emulsion viscosity models are not universal, and different oil most likely will form emulsions with quite different rheology behavior. Thus, it is important to measure the emulsion viscosity in the lab. The measurement of live oil water emulsion viscosity is quite expensive, and only a few labs are available to do the tests.

There are also chemical screening tests with water samples for corrosion and scale analysis.

15.2.4 Fluid Characterizations

Applications of equation of state and fluid characterizations have been discussed extensively over the last few decades, and excellent papers are available in literature for reference.
(Katz and Firoozabadi, 1998; Pedersen et al., 1985, 1989, 1992, 2001; Riazi and Daubert, 1980; Huron and Vidal, 1979; Mathias and Copeman, 1983; Peneloux et al., 1982; Peng and Robinson, 1976, 1978; Reid et al., 1977; Soave, 1972; Sorensen et al., 2002; and Tsonopoulos et al., 1986).

No matter how many tests we do, the measured parameters will not be able to cover all the application ranges we need. Thus, fluid models (equation of state) that can predict the fluid PVT behavior at different pressure and temperature conditions will be needed in pipeline design. Normally cubic equation of state models are used, like the SRK (Soave-Redlich-Kwong) (Soave, 1972), PR (Peng-Robinson) (Peng and Robinson, 1976), and modified PR (Peng and Robinson, 1978) models. The preferred models would be able to accurately predict the fluid behavior at conditions that cover the whole pressure range of reservoir and topsides processing pressures and the whole temperature range of reservoir and seabed temperatures.

To develop a model to predict the PVT behavior of oil and gas condensate mixture using a cubic equation of state, the critical temperature, the critical pressure, and the acentric factor must be known for each component of the mixture. Unfortunately, oil or gas condensate mixtures may contain thousands of different components. It is thus not practical to develop a model that would cover all the individual components. Some of the components must be grouped together and represented as pseudo-components. A common approach is to characterize the fluids using C7+, which consists of representing the hydrocarbons with seven or more carbon atoms as a reasonable number of pseudo-components. For each pseudo-component, the parameters of critical pressure, critical temperature, and acentric factor have to be determined (Pedersen et al., 1992). The characterized models are then fine-tuned using the PVT parameters obtained from lab measurements.

It is difficult to tune the model that will match all the lab-measured PVT parameters accurately. One or a few parameters can be tuned to match the lab data well, and the rest of the parameters may not match the lab data well enough. Judgment may be needed to decide which are the critical PVT parameters for the applications. Effort should be made to try to tune the critical parameters to match the lab data well.

15.3 Impacts of Produced Water on Flow Assurance

In offshore production pipeline, there usually exists water together with oil and gas. Water is produced from the reservoir and because water is an excellent solvent, it has dissolved plenty of chemical compounds and gases inside the formation. Water also contains suspended solids and impurities. Inside the reservoir formation, water and the chemical compounds are usually in equilibrium. As water is produced from the formation into the pipeline, because of the changes of pressure and temperature, the equilibrium is destroyed and some compounds would become insoluble and start to precipitate from water and form all kinds of scales. When free water directly contacts the pipeline wall of carbon steel, water would dissolve metal and cause corrosion problems to the pipeline. When water and gases flow together in the pipeline, at certain pressure and temperature conditions, they would form hydrate which can potentially block the pipeline. Produced water presents major flow assurance problems for deep subsea pipelines.

Proper water sampling, handling, and analysis are very critical for flow assurance risk assessment. Many of the water properties, like dissolved gases, suspended solids, and pH
values would change with time and would change with pressure and temperature. Both lab and on-site analysis are necessary to get accurate water analysis (API RP 45, 1968, Ostroff, 1979). The main ions in water that are of importance for flow assurance are listed below.

The main negative charged ions (anions) in water are:

- Chloride Cl\(^{-}\)
- Sulfide HS\(^{-}\)
- Sulfate SO\(_4^{2-}\)
- Bromide Br\(^{-}\)
- Bicarbonate HCO\(_3^{-}\)
- Carbonate CO\(_3^{2-}\)

And the main positive charged ions (cations) in water are:

- Sodium Na\(^{+}\)
- Potassium K\(^{+}\)
- Calcium Ca\(^{2+}\)
- Magnesium Mg\(^{2+}\)
- Strontium Sr\(^{2+}\)
- Barium Ba\(^{2+}\)
- Iron Fe\(^{2+}\) and Fe\(^{3+}\)
- Aluminum Al\(^{3+}\)

Cations and anions can combine and form different substances. When pressure and temperature change, the solubility of each ion will change. The excessive ions will precipitate from water and form solids, like scales. For example, calcium and carbonate would form calcium carbonate scale.

\[
Ca^{2+} + CO_3^{2-} \rightarrow CaCO_3 \downarrow
\]

Similarly, barium and sulfate can form barium sulfate scale.

\[
Ba^{2+} + SO_4^{2-} \rightarrow BaSO_4 \downarrow
\]

Water with dissolved salts is also an excellent electrolyte that is required for corrosion to occur. When free water is high enough to wet the inner pipe wall, corrosion may occur. The more salts or ions in the water, the more conductive the water is and the severer the corrosion will be.

It is well known that when free gas and water are mixed together at a certain pressure and temperature, hydrate will form. Hydrates are solids that are similar to ice. Hydrocarbon and free water often co-exist inside the offshore pipelines. When the pipeline pressure is high enough and/or fluid temperature is low enough, hydrates will form. If hydrates form inside the offshore pipeline, the pipeline flow can be blocked by the hydrates. Once the pipeline is blocked by hydrates, it can take weeks or months to dissociate the hydrates. Hydrate plugging is one of the major flow assurance risks in the deepwater production system.

Water can significantly change the multiphase flow characteristics inside the pipeline and cause severe slugs to occur. For example, for the same total liquid flowrate and the
same gas oil ratio, the total amount of gas inside the pipeline will be much less with water cut of 90% than with water cut of 0%. With less gas flow, the liquid inventory inside the pipeline will be higher and it is harder for the gas to carry the liquid out of the riser due to less gas energy. Thus, it is easier to form severe slugs.

More detailed descriptions on scales, corrosion, hydrates, and severe slugging will be given in sections below. But based upon the above brief discussions, it is obvious that produced water has significant impacts on flow assurance risks. The most effective way to mitigate flow assurance risks in production pipelines is to dispose of the water subsea and make sure no water will get into the pipeline. Unfortunately, the most effective way may not be the most economical way, nor the most practical way. Currently, the most common ways to mitigate flow assurance risks in offshore pipelines are thermal insulation and chemical inhibitions. But if the amount of water flowing inside the pipeline can be reduced (downhole separation and/or seafloor processing), the amount of chemicals needed for inhibition will also be less, resulting in less operation costs.

15.4 Gas Hydrates

Gas hydrates are crystalline compounds that occur when small gas molecules contact with water at certain temperatures and pressures. Hydrates are formed when the gas molecules get into the hydrogen-bonded water cages. The physical properties of hydrates are similar to those of ice (Sloan, 1998). But hydrates can form at temperatures well above 32°F in pressurized systems. Commonly found hydrates are composed of water and light gas molecules, like methane, ethane, propane, carbon dioxide, and hydrogen sulfide.

Three hydrate crystal structures have been identified (Sloan, 1998). They are called Structures I, II, and H. The properties of Structures I and II hydrates are well defined. Structure H hydrates are relatively new, and their properties are less well defined. All hydrates contain a lot of gas. A lot of research is being conducted to study hydrates as a potential energy resource (Makogon, 1997).

At certain pressure and temperature conditions, when water molecules form structures that consist of cavities, small gas molecules would get into the cavities to form hydrates. But how the gas molecules get into the cavities and how hydrates form are not well understood (Sloan, 1998). However it is believed that the formation of the hydrate nuclei usually happens at the gas water interface. The crystals then grow by surface sorption of gas and water molecules (Makogon, 1997). How quickly the hydrate would form and grow depends upon the diffusive flux of the gas and water molecules. If hydrate is forming at the gas water interface and the water and gas molecules are abundant, the hydrate would grow the highest (Makogon, 1997). That is why hydrate blocks usually occur during re-start-up of pipeline flow where the flow turbulence and agitations would enhance the flux of gas and water molecules.

Gas hydrates are like solids, and their physical properties are similar to those of ice. When hydrates form inside the pipeline, the flow can be blocked by hydrate plugs. Once a hydrate plug is formed, it can take up to weeks and months to dissociate the plugs. It is thus very important to design and operate an offshore pipeline system free of hydrate risks. Hydrates can very easily form downstream of choke where fluid temperature can drop into the hydrate formation region due to Joule-Thompson cooling effects.
15.4.1 Gas Hydrate Formation Curve

Figure 15.1 shows a typical gas hydrate curve. On the left side of the curve is the hydrate formation region. When pressure and temperature are in this region, water and gas will start to form hydrate. On the right side of the curve, is the non-hydrate formation region. When pressure and temperature are in this region, water and gas will not form hydrate. Quite a few factors impact the hydrate curve. Fluid compositions, water compositions, and water salinity all affect the hydrate curve. Increasing salinity would shift the curve left and reduce the hydrate formation region.

Figure 15.1 demonstrates that with the initial system in the non-hydrate region, if system pressure is increased while keeping the system temperature constant, hydrate would eventually form. The same is true by reducing the system temperature at a constant system pressure. Hydrate curve is very useful for subsea pipeline design and operations. It provides pressure and temperature conditions that the system should maintain to avoid hydrate formation. Hydrate curves can be calculated by using PVT software. But the key for accurate hydrate curve calculations is to have accurate fluid and water compositions. Again, fluid sampling and analysis are critical for flow assurance risk assessment. If the hydrate temperature is over-conservatively calculated by a few degrees, millions of dollars may be wasted in the thermal insulation design.

15.4.2 Hydrate Inhibitors

Thermodynamic Inhibitors. As shown in Figure 15.1, no hydrate would form in operating conditions that are on the right-hand side of the hydrate curve. It would therefore help to shift the hydrate curve left so that the non-hydrate region would be larger, and thus the risks for hydrate formation would be smaller. But, for a given pipeline design, the fluid and water compositions are normally specified and the hydrate curve is thus fixed. To shift the hydrate curve left, thermodynamic inhibitors can be used. Thermodynamic inhibitors would not affect the nucleation of hydrate crystals and the growth of the crystals into blockages. They only change the pressure and temperature conditions of hydrate forma-
tion. With inhibition, the hydrate formation temperature will be lower or the hydrate formation pressure will be higher. Thus, by applying thermodynamic inhibition, the operating conditions can be shifted out of the stable hydrate region.

Two kinds of thermodynamic inhibitors are commonly used: methanol and monoethylene glycol (MEG). For oil systems, methanol is used the most. Figure 15.2 shows how the hydrate curve shifts with different amounts of methanol inhibition. For system pressure of 1000 psia, the hydrate formation temperature for fresh water is about 62°F. By adding 10 wt% methanol into the fresh water, the hydrate formation temperature is reduced to 54°F. With 20 wt% methanol, the hydrate formation temperature is further reduced to about 44°F. It is obvious that methanol is very effective for hydrate inhibition.

We know that thermodynamic inhibitors can be used to reduce the hydrate formation temperature. But for a given condition, how much inhibitor will be needed? If it is known how much temperature needs to be reduced, the amount of inhibitor needed in the free water can be estimated using the following equation (Hammerschmidt).

\[
W_i = \frac{100M_i\Delta T_b}{(C_i + M_i\Delta T_b)} \tag{15.1}
\]

where

- \(W_i\) = weight percent of the inhibitor in liquid
- \(C_i\) = constant, 2335 for methanol and 2000 for MEG
- \(M_i\) = molecule weight of methanol or MEG
- \(\Delta T_b\) = hydrate sub-cooling which is the temperature needs to be reduced by inhibitor.

For example, for a system pressure if the hydrate formation temperature without inhibition is 65°F and the system operating temperature is 50°F. The hydrate sub-cooling is the difference of the hydrate formation temperature and the system operating temperature and equals to 15°F for this case. The above equation can only calculate the required methanol and MEG in the free water phase. Some methanol or MEG will get lost in gas phase and hydrocarbon liquid phase. The amount of methanol or MEG injected will need to be higher than that calculated by Equation 15.1. More details on how to

\[\text{Figure 15.2 Gas hydrate curve with different amount of methanol inhibition.}\]
estimate the amount of methanol or MEG lost in vapor and condensate can be found in literature (Sloan, 1998).

By adding methanol in the liquid phase, the water concentration in the liquid phase is reduced and the hydrate formation temperature is lowered. The more methanol is added, the more the hydrate formation temperature is lowered. On the other hand, to have the same sub-cooling, the more water that is added, the more methanol is required. The need for large amounts of methanol may cause problems in storage and handling because of its flammability and toxicity and will result in high chemical OPEX. Furthermore if a large amount of methanol is carried over into the export lines, it will cause problems for downstream processing. Compared to methanol, MEG is less flammable, but is more expensive and less available.

Salt can also affect the hydrate formation conditions. By adding more salt into the water, the hydrate formation curve will shift to the left, as shown in Figure 15.3. The impact of salt on hydrate curve can be significant. By adding 2 mole% NaCl into the fresh water, the hydrate formation temperature will be 4–5°F lower. If the salt concentration is increased to 8 mole%, the hydrate formation temperature will be more than 25°F lower. However, even though salt solution can be used for hydrate inhibition, too much salt can cause salt deposition and scale deposits in the process facilities. Salt solution is also corrosive and can cause corrosion problems to equipment.

**Low Dosage Hydrate Inhibitors (LDHI).** As discussed above, high water flow will require large amounts of methanol or MEG for hydrate inhibition, resulting in high OPEX. To mitigate the high dosage problems, more effective hydrate inhibitors than methanol and MEG are needed for high water flow. The inhibition mechanisms of the new chemicals must be different from the traditional thermodynamic inhibitors to be more effective at low dosage. The chemicals that would effectively inhibit hydrate at low dose rates are called low dosage hydrate inhibitors (LDHI). Two kinds of LDHI are most popular in the oil industry: one is kinetic hydrate inhibitor and the other is anti-agglomerate (Fu, 2002; Mehta et al., 2003; Kelland et al., 1995).

Kinetic hydrate inhibitors tend to slow down the hydrate nucleation process and delay the formation and growth of hydrate crystals for an extended period of time (Fu, 2002).

![Impact of salt on hydrate formation curve](image)

**Figure 15.3** Gas hydrate curves with different salt concentrations.
But kinetic inhibitors can only delay the kinetics and cannot completely prevent the nucleation process. Thus, kinetic inhibitors can only prevent hydrate from forming for a finite time. Once this period of time has lapsed, there is a very rapid conversion of the remaining water into large hydrate and blockage may occur (Mehta et al., 2003). Thus, when designing the hydrate mitigation strategies for subsea system, it is very critical to make sure the fluid residence time in the pipeline during steady-state flow is less than the “hold-time,” which is the time before hydrates start to form rapidly. The “hold-time” of some kinetic inhibitors can be about 24–48 hours.

Another important parameter for kinetic inhibitors is the sub-cooling. It is reported that kinetic inhibitors can only work up to 15–23°F sub-cooling (Fu, 2002). For deepwater applications, the sub-cooling is normally larger than 25°F and the applications of kinetic inhibitors are severely limited.

Anti-agglomerates (AA) are polymers and surfactants that tend to prevent the formation and accumulation of large hydrate crystals into a hydrate blockage so that a transportable slurry can be maintained. It will not delay the nucleation of hydrate crystals, but will keep the crystals in hydrocarbon phase by reducing the growth rate of the crystals. The hydrate crystals will be transported with hydrocarbon as slurry flow. Anti-agglomerate has no sub-cooling limitation as do kinetic inhibitors and can be effective at sub-coolings of greater than 40°F (Mehta et al., 2003). Since the crystals have to be carried out of flowline, a liquid hydrocarbon phase is required to suspend the crystals.

15.4.3 Hydrate Mitigation Strategies

As mentioned above, the most effective way to mitigate hydrate is to get rid of water. If there is no water flowing in the pipeline, there is no hydrate risk. But, in the real world, getting rid of water may not be the most practical or most economical way. Some other methods have to be utilized.

**Thermal insulation.** Based upon the hydrate formation curve, as long as the fluid temperature is above the hydrate formation temperature, no hydrate will be formed. Thus, a very good way to mitigate the hydrate risk is to maintain the fluid temperature inside the pipeline above the hydrate formation temperature. However, for pipelines in deep water, the water temperature is normally very low and can be below 40°F depending upon the water depth, and steel pipe is not a very good thermal insulator. Thus, it is necessary to put thermal insulation material around the pipeline to prevent the heat from being lost to the surroundings.

There are a few different insulation methods available in the industry. One is to directly cast insulation materials onto the outer surface of the pipeline (cast-in-place). The insulation materials for this application may be a layer of homogeneous material or may consist of multiple layers, with each layer being a different material. Single layer insulation is most used for cases where the insulation thickness is not excessive. For the large insulation thickness cases, multiple layer insulation is required due to mechanical and installation reasons.

Another popular insulation method is pipe-in-pipe, where the hydrocarbon pipeline is put into another concentric pipeline. The annulus between the two pipelines is either completely or partially filled with insulation material. Pipe-in-pipe thermal insulations
normally provide better insulation than cast-in-place methods. But pipe-in-pipe methods are also normally more expensive.

Bundles are also used for thermal insulation. Hydrocarbon pipelines and some other pipelines that flow hot water are bundled together. The heat is transferred from the hot water to the hydrocarbon fluids. Thus, the fluid temperature is kept above the hydrate formation temperature.

A couple of industry deepwater pipelines were intentionally buried under the seabed to use soil as a thermal insulation material. But due to the burial process, excessive water will exist in the covering soil and convection may be significant. Burying the pipeline alone will not be enough for thermal insulation. Some extra insulation will be needed.

Thermal insulation is not very effective in mitigating the hydrate risks of gas pipelines. Because the density of gas is much smaller compared to liquid, the thermal mass (density times the heat capacity) of gas is also much smaller than that of liquid. Thus, it is not very effective to thermally insulate the gas pipeline.

Thermal insulation is a very good hydrate mitigation strategy for oil pipeline, especially, when the pipeline is in operation. By using insulation, it is easy to keep fluid flowing temperature everywhere along the pipeline above the hydrate temperature. But no matter how much insulation is put on the pipeline, after a long pipeline shutdown, the fluid temperature will fall below the hydrate formation temperature and eventually cool down to the seawater temperature. Thus, thermal insulation itself is not enough for hydrate mitigation for long pipeline shutdowns. Other mitigation strategies, like pipeline depressurization or dead oil displacement, will be needed. But thermal insulations do provide a certain period of cool down time so that no other mitigation operations are needed. Cool down time is defined as the time, after pipeline shutdown, before the fluid temperature drops down to the hydrate formation temperature for a given pipeline shutdown pressure. Thus, operations, like pipeline depressurization or dead oil displacement would have to finish within the cool down time. Otherwise, hydrate will form inside the shut down pipeline.

There is another important parameter called “no-touch” time or “hand-free” time. “No-touch” time is defined as the time within which no action needs to take place after a pipeline shutdown. That is why it is also called “hand-free” time. “No-touch” time is always shorter than the cool down time. It is the difference between the cool down time and the time needed to perform the operations, like pipeline depressurization. This “no-touch” time provides a very valuable period for the operator to diagnose the problems that cause pipeline shutdown. If the problems are found and fixed within the “no-touch” time, the pipeline can be re-started with no need to use other hydrate mitigation operations. If the problems cannot be fixed within the “no-touch” time period, operators will need to perform operations to mitigate hydrate. The longer the “no-touch” time, the longer the time available for the operator to fix the problems and the less need to perform extra operations. But the longer the “no-touch” time, the thicker the needed insulation layer.

**Chemical inhibitions.** Thermodynamic inhibitors, like methanol and MEG, and LDHIs, like kinetic inhibitors and anti-agglomerates, are often used for hydrate mitigations. Chemical inhibitors are not normally used continuously for oil systems, instead they are used after shutdown or during re-startup. Thermodynamic inhibitors are usually used continuously for gas pipelines because gas pipelines are normally not insulated.
After the “no-touch” time, methanol and MEG are used to inhibit the fluids in the subsea system, like trees, well jumpers, and manifolds. But it is difficult to estimate the amount of water in the system after shutdown, and thus it is difficult to know how much methanol is needed to completely inhibit the fluids. Thus, in practice, methanol or MEG is used to completely displace the fluids in the subsea system. A certain amount of methanol is bullheaded into the well (usually above the surface controlled subsurface valve) to protect the upper portion of the wellbore from forming hydrate. Fluids in pipelines are usually not displaced by methanol because the pipelines are usually too long and too much methanol will be required.

**Electric Heating.** Recently, more research has been conducted on hydrate mitigation using electric heating (Lervik et al., 1997). Electric heating can be divided into two categories: direct electric heating and indirect electric heating. With direct electric heating, electric current flows axially through the pipe wall and directly heats the flowline, while with indirect heating, electric current flows through a heating element on the pipe surface and the flowline is then heated through thermal conduction.

Electric heating can be used as a mitigation method for pipeline hydrate problems. After shutdown, electric heating can be used to keep the pipeline fluid temperature above the hydrate formation temperature and no hydrate will form. Electric heating can also be used as an intervention/remediation strategy for hydrate problems. Once a hydrate plug is formed, electric heating can be used to melt the hydrate. In this way, the hydrate will be melted much faster than using pipeline depressurization. Shell’s Na Kika project in the Gulf of Mexico used electric heating as a hydrate remediation method (March et al., 2003).

**Hot-Oil Circulation.** Hot-oil circulation is a popular strategy for hydrate mitigation during system re-startup. After a long shutdown, the fluid in the pipeline is cold (seawater temperature). If the pipeline is re-started up with cold fluid in it, hydrate risk is very high. To reduce the hydrate risk, hot oil is first circulated through the pipelines (looped pipelines are required) to displace the cold fluid and also warm up the pipelines. The time required to warm up the pipelines depends upon the hot oil discharge temperature, hot oil circulation flowrates, and pipeline length. Usually it would take up to 5–10 hours to warm up the subsea pipeline.

**System Depressurization.** Pipeline depressurization is used to mitigate hydrate plug after a long shutdown. From the hydrate formation curve, for a given temperature, non-hydrate region can be reached by reducing the pressure. After a long shutdown, the fluid temperature will eventually reach the seawater temperature. Based upon the hydrate curve, the hydrate formation pressure at the seawater temperature can be determined. Thus, the pipelines can be depressurized (also called pipeline blowdown) below the hydrate formation pressure. Once the pipeline pressure is below the hydrate formation pressure, no hydrate will form and the system can be continued to be shut down.

System depressurization is also often used to melt a hydrate plug formed in a pipeline. When the system pressure is below the hydrate formation pressure, the hydrate plug will start to dissociate. The hydrate plug dissociation process is fairly slow. It can take up to weeks or even months to completely melt a long hydrate plug. That is why it is very important to design and operate subsea pipeline out of hydrate region. For safety reasons, it is always better to be able to depressurize the pipeline from both sides of the hydrate plug.
15.5 Wax Depositions

Crude oil is a complex mixture of hydrocarbons which consists of aromatics, paraffins, naphthenics, resins, asphaltenes, diamondoids, mercaptans, etc. When the temperature of crude oil is reduced, the heavy components of oil, like paraffin/wax (C18–C60), will precipitate and deposit on the pipe wall. The pipe internal diameter will be reduced with wax deposition, resulting in higher pressure drop. Wax deposition problems can become so severe that the whole pipeline can be completely blocked. It would cost millions of dollars to remediate an offshore pipeline that is blocked by wax.

15.5.1 Fundamental Concepts

Crude Cloud Point or Wax Appearance Temperature. Wax solubility in aromatic and naphthenic is low, and it decreases drastically with decreasing temperatures. Thus, it is easy for wax to precipitate at low temperature. The highest temperature below which the paraffins start to precipitate as wax crystals is defined as crude cloud point or wax appearance temperature. Since light ends can stabilize the paraffin molecules (Meray et al., 1993), the cloud point of live oil with pressure below the bubble point is usually lower than the cloud point of the dead oil or stock tank oil. The cloud point of live oil is more difficult to measure than that of dead oil. Thus, the cloud point of dead oil samples is often used in offshore pipeline thermal insulation design. This approach is conservative and can practically result in millions of dollars of extra cost in thermal insulation.

When measuring the cloud point, the key is to preheat the oil sample to a high enough temperature to solubilize all the pre-existing wax crystals. There are quite a few techniques available for cloud point measurement: viscometry, cold finger, differential scanning calorimetry, cross polarization microscopy, filter plugging, and Fourier transform infrared energy scattering, etc. The cloud points measured using different techniques may differ by more than 10 degrees (Monger-McClure et al., 1999; Hammami and Raines, 1997).

Crude Pour Point. When the waxy crude is cooled, paraffins or waxes will precipitate out of the crude oil once the temperature is below the cloud point. The precipitated wax may deposit on the pipe wall in the form of a wax-oil gel (Venkatesan et al., 2002). The gel deposit consists of wax crystals that trap some amount of oil. As the temperature gets cooler, more wax will precipitate and the thickness of the wax gel will increase, causing gradual solidification of the crude. When the wax precipitates so much and forms wax gel, the oil will eventually stop moving. The temperature at which oil sample movement stops is defined as the pour point. When crude gets so cold that it stops moving inside the offshore pipeline after shutdown, depending upon the characteristics of the gel, crude oil may not be able to be re-mobilized during re-startup. Thus, it is very important to check the re-start up pressure of the crude by cooling the crude down to below the pour point. Because the seawater temperature can be below the pour point of the crude, wax gel may form after long pipeline shutdown. It is critical to make sure the pipeline will be able to be re-started up after long shutdown.

15.5.2 Wax Deposition Mechanisms

Extensive research has been conducted to try to understand and model the wax deposition process which is a complex problem involving fluid dynamics, mass and heat transfers, and
thermodynamics (Burger et al., 1981; Brown et al., 1993; Creek et al., 1999; Hsu et al., 1999; Singh et al., 1999). It is widely accepted that molecular diffusion of paraffin is one of the dominant deposition mechanisms. Whether or not Brownian motion, gravity settling, and shear dispersion play significant roles in wax deposition is still a research topic.

**Molecular Diffusion.** When waxy crude is flowing in offshore pipeline, the temperature at the center of the pipeline is the hottest while the temperature at the pipe wall is the coldest, resulting in a radial temperature profile. Since the wax solubility in the oil is a decreasing function of temperature, when the temperature is lower than the cloud point, wax crystals will come out of solution. Thus, the radial temperature gradient will produce a concentration gradient of wax in oil with the wax concentration in the oil lowest close to the pipe wall. The concentration gradient would thus result in mass transfer of wax from the center of the pipe to the pipe wall by molecular diffusion. Wax mass transfer can be described by the Fick’s law as:

\[
\frac{dm_w}{dt_w} = \rho_w D_w A_d \frac{dC_w}{dr} \quad (15.2)
\]

where

- \( m_w \) = mass of the deposited wax on the pipe wall
- \( t_w \) = time
- \( \rho_w \) = density of the solid wax
- \( D_w \) = diffusion coefficient of liquid wax
- \( A_d \) = deposition area
- \( C_w \) = volume fraction concentration of wax in liquid oil
- \( r \) = radial coordinate

The diffusion coefficient is expressed by Burger et al. (1981) as a function of oil viscosity:

\[
D_w = \frac{K_w}{\nu} \quad (15.3)
\]

where

- \( K_w \) = constant
- \( \nu \) = oil dynamic viscosity

The constant in Equation 15.3 is often adjusted to match modeled deposition rates with experimental ones.

**Other Proposed Mechanisms.** There are a few wax deposition mechanisms that are not widely accepted, like Brownian diffusion, shear dispersion, and gravity settling. Once the temperature is below the cloud point, wax crystals will precipitate out of solution and be suspended in the oil. The suspended wax crystals will collide with each other and with oil molecules due to Brownian motion. Because of the wax concentration gradient, it is possible that the net effect of Brownian motions is to transport the wax crystals in the direction of decreasing concentration. It is thus suggested that wax deposition can occur due to the Brownian diffusion of wax crystals. But quite a few existing wax deposition models do not take into account the Brownian diffusion.
Gravity settling as one of the possible wax deposition mechanisms is based upon the argument that the wax crystals tend to be denser than the oil and would thus settle in a gravity field and deposit on the bottom of the pipelines. But experiments with horizontal and vertical flows showed that there was no difference in the amount of wax deposited for the two flow configurations. Thus, it is not yet clear how significant a role gravity would play for wax deposition.

Burger et al. (1981) and Weingarten and Euchner (1986) reported possible wax deposition by shear dispersion. They claimed that shear dispersion played a role in wax deposition mainly in laminar flow and proposed the following equation for the deposition rate.

\[
\frac{dm_s}{dt} = k_w C_s A_d \gamma
\]  

(15.4)

where

- \( m_s \) = mass of the deposited wax due to shear dispersion
- \( k_w \) = constant
- \( C_s \) = the concentration of solid wax at the pipe wall
- \( A_d \) = deposition area
- \( \gamma \) = shear rate

But Brown et al. (1993) performed experiments with zero heat flux across the pipe wall (thus no molecular diffusion) and showed no wax deposition due to shear dispersion. Brown et al. concluded that shear dispersion does not contribute to wax deposition.

### 15.5.3 Wax Mitigation Strategies

**Thermal Insulation.** For subsea production pipeline, the most widely used wax mitigation method is to include enough thermal insulation to maintain the fluid temperature everywhere along the pipeline above the wax appearance temperature during normal or “steady-state” operations. For transient operations, like shutdown, the fluid temperature inside the pipeline will cool down with time and eventually will reach the seawater temperature within a transient time that is about 12 to 36 hours depending upon the insulation design. Once the pipeline cools down to seawater temperature, there is no temperature gradient between the bulk fluid and the pipe wall and no wax will deposit. During the cooldown transient time, the fluid temperature can be lower than the wax appearance temperature and some wax will deposit onto the pipe wall. Since the transient time is relatively short, the amount of wax deposited will be very small, because wax deposition is a slow process. Furthermore the wax deposited during shutdown will be remelted once the pipeline reaches normal operation again.

To be conservative for the insulation design, the wax appearance temperature of dead oil is normally used. But for subsea pipeline insulation design, the most important drivers are hydrate mitigation and system cooldown time. If the subsea pipeline insulation design satisfies the hydrate mitigation and cooldown time requirements, it will normally also satisfy the requirement that fluid temperature be above the wax appearance temperature.
during steady-state flow. Details on subsea thermal insulation are provided in a different chapter of this book.

**Pigging.** Another popular wax mitigation method is to regularly pig the pipeline to remove deposited wax from pipe walls. For some subsea pipelines, especially export lines where hydrate is not a concern, pigging would normally be the main wax management strategy. There are numerous types of pigs, like simple spheres, foam pigs, and smart pigs.

The pig is sent down into the pipeline from a pig launcher and is pushed by the production crude or any other fluids, like dead oil or gas. The pig mechanically scrapes the wax from the pipe wall and re-deposits it back into the crude in front of the pig. A regularly scheduled pigging program is very critical for the success of pigging operations. If the pigging operation is not scheduled frequently enough, too much wax may have deposited onto the pipe wall. During the pigging operation, a pig may get stuck inside the pipe due to the excess amount of wax in front of it. The pigging schedule program will be developed based upon wax deposition modeling and will be fine-tuned as more on the wax deposition rate is understood in field operations.

**Chemical Inhibition/Remediation.** Wax chemical inhibitors can be divided into two different types: one is to prevent/delay the formation of wax crystals and thus reduce the wax appearance temperature and also prevent the wax from depositing onto the pipe wall; the other is to decrease the wax pour point and thus delay the waxy crude solidification when the crude cools down.

The mechanisms whereby chemicals inhibit wax formation and deposition are not well understood. It seems to be accepted that with absorption of polymers and additives onto the surface of wax crystals, it is possible to keep them from agglomerating and to keep the wax crystals dispersed, thus reducing the wax deposition rate. Groffe et al. (2001) performed lab and field studies on wax chemical inhibition. They developed novel chemicals that would have an ability to interfere with the wax crystal growth mechanism and were capable of keeping or making the crystals smaller so that they may cause the settling process much slower. The chemical, if possible, would also be able to absorb onto the metal surfaces and make them oleophobic. They claimed, based upon their lab work, that the chemical they developed was able to lower the WAT of a waxy crude by almost 10°C. It was also noted that the chemical has anti-sticking properties and was able to reduce the amount of wax deposited onto adhering metal surface.

Wang et al. (2003) tested eight different commercial wax inhibitors and found that all the inhibitors reduced the total amount of wax deposited. They noticed that the inhibitors that depress the WAT the most also are most effective in reducing wax deposition. But the inhibitors could only effectively decrease the deposition of low molecular weight wax (C34 and below) and had little effect on the deposition of high molecular weight wax (C35—C44). They claimed that although the total amount of wax formed was reduced, the absolute amount of high molecular wax was increased. Thus, the net effect of many of the commercial wax inhibitors is to form harder wax which will be more difficult to remove.

With waxy crudes, when the temperature is lowered the wax crystallizes gradually in the form of needles and thin plates. With further crystallization, these needles and thin plates turn into 3-dimensional networks and cause solidification of crude (Groffe et al., 2001). Chemicals of specific polymers and surfactants can prevent formation of these networks by
retarding the growth of waxy crystals, resulting in many tiny crystals. Thus, by changing the crystal structure, the ability of wax crystals to intergrow and interlock is reduced, making the pour point of the crude lower.

15.6 Asphaltene Depositions

Asphaltenes are defined as the compounds in oil that are insoluble in n-pentane or n-hexane, but soluble in toluene or benzene. That is, asphaltene solids would precipitate when excess n-pentane or n-hexane is added to the crude oil. Asphaltene solids are dark brown or black and, unlike waxes, will not melt. But like waxes, with changes in pressure, temperature, and composition, asphaltenes tend to flocculate and deposit inside reservoir formation, well tubing, and production flowlines. Mixing reservoir fluids with a different gas (injected gas or gas-lift gas) or mixing two oil streams can also induce asphaltene precipitations (Wang et al., 2003).

15.6.1 Asphaltene Precipitation

The saturation of asphaltenes in crude oil is a key parameter to determine whether or not asphaltene would cause any problems. If asphaltenes are always under-saturated in crude oil, that is, asphaltenes are stable then no precipitation will occur. On the other hand, asphaltene precipitation would occur if they are highly super-saturated in crude oil. The saturation of asphaltenes in crude oil can change from under-saturated to super-saturated if the pressure, temperature, and composition change. During oil production, temperature and pressure changes between reservoir and production pipeline can be quite significant. Similarly, fluid composition can also change significantly during production: gas can separate from the oil when the oil pressure drops below the bubble point or gas-lift gas can be injected into the oil stream. Thus, during oil production and transportation, asphaltenes precipitation inside the production system is a potential risk.

A parameter that is closely related to asphaltene stability in oil is solubility. Solubility parameters of oil and asphaltenes are key input data for most of the thermodynamic models for asphaltene phase behavior. The solubility parameter is defined as:

\[
\delta_i^2 = \frac{\Delta u^v}{v_m}
\]

(15.5)

where

- \(\delta_i\) = solubility parameter
- \(\Delta u\) = cohesive energy per mole (the energy change upon isothermal vaporization of one mole of liquid to the ideal gas state)
- \(v_m\) = molar volume

Solubility parameter is a measure of the cohesive energy density or the internal pressure that is exerted by molecules within a solution. When two liquids with quite different molecules are mixed together, the liquid with higher solubility parameter will tend to “squeeze” the molecules of the liquid with a lower solubility parameter out of the solution.
matrix, resulting in two immiscible phases. On the other hand, if two liquids with similar solubility parameters are mixed, it is more likely for the two liquids to be miscible to one another (Burke et al., 1990).

The solubility parameter of asphaltene and the solubility parameter of crude oil will strongly affect how much asphaltene will be soluble in the crude oil. If the solubility parameter of the crude oil is similar to the solubility parameter of asphaltene, more asphaltene will be soluble in the crude. Solubility parameter is a function of temperature (Barton, 1991). Increasing the temperature tends to decrease the asphaltene solubility parameter (Hirschberg et al., 1984; Buckley et al., 1998).

The pressure effect on asphaltene solubility depends upon the pressure being above the bubble point or below the bubble point. de Boer et al. (1992) and Hirschberg et al. (1984) studied the pressure dependence of asphaltene solubility and presented similar plots of asphaltene soluble in oil as a function of pressure, as shown in Figure 15.4. When the pressure is above the bubble point, the fluid composition is constant, but with decreasing pressure, the density of crude decreases due to oil expansion, and so does asphaltene solubility as shown in Figure 15.4. The asphaltene solubility reduces to a minimum when pressure is approaching the bubble point. Below the bubble point, gases start to evolve from the live oil and the oil density increases. The asphaltene solubility also increases with decreasing pressure. The loss of light ends improves the asphaltene stability in crude oil.

The solubility parameter of a mixed system, like crude oil that consists of many components, can be calculated based upon the solubility parameter of the individual component (de Boer et al., 1992):

![Figure 15.4](image.png)
\[ \delta_m = \sum_{i=1}^{n_c} f_i \delta_i \]  
\[ (15.6) \]

where

\[ \delta_m = \text{solubility parameter of mixed system} \]
\[ f_i = \text{the volume fraction of } i^{\text{th}} \text{ component} \]
\[ \delta_i = \text{solubility parameter of } i^{\text{th}} \text{ component} \]
\[ n_c = \text{total number of components in the system} \]

During production, fluid composition will change as a function of pressure and temperature. Especially when the pressure is below the bubble point, gas starts to come out of solution. Similarly, gases, like CO2 can be added to crude for enhanced oil recovery, and gases can also be added into crude through gas-lift operations. All those operations can change crude oil compositions and the crude oil solubility parameters, and thus may potentially induce asphaltene precipitation.

Assuming the asphaltene and crude oil are in equilibrium (no asphaltene precipitation), the maximum volume fraction of asphaltenes soluble in the crude is given by the Flory-Huggins theory (Hirschberg et al., 1984; Burke et al., 1990) as the following:

\[ (\phi_a)_{\text{max}} = \exp \left\{ \frac{V_a}{V_L} \left[ 1 - \frac{V_L}{V_a} - \frac{V_L}{RT} (\delta_a - \delta_L)^2 \right] \right\} \]
\[ (15.7) \]

where

\[ \phi_a = \text{volume fraction of asphaltenes in oil} \]
\[ V_a, V_L = \text{molar volume of asphaltenes and liquid oil phase, respectively} \]
\[ \delta_a, \delta_L = \text{solubility parameter of asphaltenes and liquid oil, respectively} \]
\[ T = \text{temperature} \]
\[ R = \text{ideal gas constant} \]

The properties of liquid oil (molar volume and solubility parameter) can be calculated from proper equation of state, while the properties of asphaltenes have to be estimated from experimental data.

### 15.6.2 Onset of Asphaltene Precipitation

Asphaltene solubility parameter can also be affected by other components in the oil, like resins (Hirschberg et al., 1984). Asphaltenes and resins are heterocompounds and form the most polar fraction of crude oil. Resins have a strong tendency to associate with asphaltenes, and they help reduce the asphaltene aggregation. On the other hand, if normal alkane (pentane or heptane) liquids are added to crude oil, the crude oil becomes lighter and resin molecules desorb from the surface of asphaltenes in an attempt to re-establish the thermodynamic equilibrium that existed in the oil before the addition of normal alkane liquids. Because of the de-sorption of resins, asphaltene micelles start to agglomerate to reduce overall surface free energy (Hammami et al. 1999). If sufficient quantities of normal alkane are added to the oil, the asphaltene molecules aggregate to
such an extent that the particles would overcome the Brownian forces of suspension and begin to precipitate.

Hammami et al. (1999) performed experimental studies on the onset of asphaltene precipitation using a solids detection system (SDS), which consists of a visual PVT cell and fiber optic light transmission probes. The sample oil is first charged into the PVT cell and the pressure of the cell is then lowered isothermally at programmable rates. At each equilibrium pressure, the sample volume is measured and the corresponding density is calculated. The power of the transmitted light is continuously measured. The power of transmitted light is inversely proportional to oil density. When the pressure is above the bubble point, decreasing pressure will result in reduced oil density and thus increased power of transmitted light. The power of transmitted light is also inversely proportional to the particle sizes. If particle sizes increase, as asphaltenes flocculate, the power of transmitted light will decrease. If sufficient gas bubbles exist in the oil, the power of transmitted light will decrease dramatically. Thus, the experiments would stop at the bubble point.

If the crude oil has no asphaltene precipitation and deposition problems, Hammami et al. claimed that the power of transmitted light would more or less linearly increase as the pressure is decreased isothermally from above the bubble point. This is due to the decrease in fluid density with decreasing pressure when the pressure is above the bubble point. When the bubble point is approached, the power of transmitted light would drop dramatically to noise level, as shown in Figure 15.5. If the crude oil has asphaltene precipitation and deposition problems, the trend of the power of the transmitted light is quite different from that of oils without asphaltene deposition problems as pressure is reduced. As the pressure is reduced from above the bubble point, the power of transmitted

\[ \text{Laser Power (arbitrary unit)} \]

\[ \text{Crude with no asphaltene problem} \]

\[ \text{Asphaltene onset point} \]

\[ \text{Crude with asphaltene problem} \]

\[ \text{Bubble point} \]

\[ \text{Bubble point} \]

\[ \text{Pressure} \]

**Figure 15.5** Power of transmitted light as a function of pressure during pressure depletion.
light would initially increase more or less linearly and then it would reach a plateau with further pressure reduction. After the plateau, the power of transmitted light would gradually decrease and eventually drop to the noise level when the bubble point is reached, as shown in Figure 15.5. The pressure at which the power of transmitted light is deviated from the straight line is defined as the onset point of asphaltene precipitation.

Improved prediction of the onset of asphaltene precipitation may be achieved using refractive index (RI) to characterize crude oils and their mixtures with precipitates and solvents (Buckley et al., 1998; Wang et al., 2003). The RI is calculated based upon the measurement of the total internal reflection angle (critical angle) as shown in Figure 15.6, and is expressed as:

\[
RI = \frac{1}{\sin \theta_c}
\] (15.8)

RI is a function of fluid composition and density. For different fluids, the RI will be different. Based upon experimental studies, Buckley et al. (1998) noticed that the onset of asphaltene precipitation occurred at a characteristic RI, and the RI can be correlated with the solubility parameter as shown in Figure 15.7. Based upon Figure 15.7, for most of the normal alkanes and some aromatics, the relationship between solubility parameters and \( \frac{RI^2 - 1}{RI^2 + 2} \) is more or less linear.

For a mixture of crude oil and precipitant (like n-alkane), the RI of the mixture is between the RI of the crude oil and the RI of the precipitant, and can be determined based on the RIs and the volume fractions of the crude oil and the precipitant. The precipitation of asphaltenes will occur only when the mixture RI is below a critical RI called PRI. By studying the mixtures of crude oil and n-Heptane for ten different oils, Buckley et al. found that the mixture RI ranged between 1.47 and 1.57 while the PRI was more or less a constant of about 1.44. The asphaltene content in those sample oils ranged between 1.2
and 10.9 wt% and no correlation between the asphaltene content and either RI or PRI was found.

With the asphaltene onset RI (PRI) known, whether or not a crude oil would have asphaltene precipitation problems at a given pressure and temperature condition can be determined by measuring the corresponding RI. If the measured RI is larger than PRI, there will be no precipitation risk. On the other hand, if the measured RI is smaller than PRI, asphaltene precipitation is possible. Unfortunately, the RI of live oil under pressure and temperature cannot be easily measured.

The RI of live crude oils under pressure can be estimated from the RI of stock tank oil and gas-oil ratio (Buckley et al., 1998) as

\[
K = \frac{RI^2 - 1}{RI^2 + 2}
\]

for n-alkanes and aromatics (from Buckley et al., 1998).

and 10.9 wt% and no correlation between the asphaltene content and either RI or PRI was found.

With the asphaltene onset RI (PRI) known, whether or not a crude oil would have asphaltene precipitation problems at a given pressure and temperature condition can be determined by measuring the corresponding RI. If the measured RI is larger than PRI, there will be no precipitation risk. On the other hand, if the measured RI is smaller than PRI, asphaltene precipitation is possible. Unfortunately, the RI of live oil under pressure and temperature cannot be easily measured.

The RI of live crude oils under pressure can be estimated from the RI of stock tank oil and gas-oil ratio (Buckley et al., 1998) as

\[
\left( \frac{RI^2 - 1}{RI^2 + 2} \right) (p) = \frac{1}{B_o} \left( \frac{RI^2 - 1}{RI^2 + 2} \right)_{STO} + 7.52 \times 10^{-6} \frac{R_i}{B_o} \sum_{i=1}^{m} x_i R_i
\]  

(15.9)

where

- **STO** = stock tank oil
- **B_o** = formation volume factor
- **R_i** = gas-oil ratio
- **x_i** = mole fraction of \( i^{th} \) component in the gas
- **R_i** = molar refraction of \( i^{th} \) component in the gas

Figure 15.8 shows how the RI of live oil may change with pressure. For pressure above the bubble point, the RI of live oil decreases with pressure. The RI of live oil will reach a minimum around the bubble point. Below the bubble point, RI increases with decreasing pressure. When the RI is below the PRI, asphaltenes become unstable and flocculation may occur.
15.6.3 Screening of Crude Oils for Asphaltene Precipitation—de Boer Plot

The above mentioned refractive index measurement and transmitted light power measurements are sound experimental methods for detecting the onset of asphaltenes precipitation. But these tests take time. In 1992, de Boer et al. published a simple method for screening crude oils on their tendency for asphaltene precipitation (de Boer et al., 1992). By correlating crude properties, like solubility parameter, molar volume, and asphaltene solubility in oil, with the density of the crude at in-situ conditions, de Boer et al. was able to develop an asphaltene supersaturation plot, called de Boer plot which has the difference of reservoir pressure and bubble point pressure as the $y$-axis and the in-situ crude density as the $x$-axis. A simplified de Boer plot is shown in Figure 15.9. For given crude and reservoir conditions, the difference of reservoir pressure and bubble point pressure and the crude densities at reservoir conditions can be calculated. Then, Figure 15.9 can be used to quickly assess the risk level of asphaltene precipitation during production.

Based upon field experiences, de Boer et al. (1992) concluded that asphaltene deposition problems are encountered with light crude oils that are high in C1-C3 (>37 mole%) and have a relatively low C7+ content (<46 mole%), with high bubble point pressure (>10 MPa) and a large difference between reservoir and bubble point pressures. The asphaltene content in those light oils is low (<0.5 wt%). The heavy crude oils that have high asphaltene content tend to have fewer problems with asphaltene deposition. This is especially true if the reservoir pressure is close to the bubble point pressure.

15.6.4 Asphaltene Prevention and Remediation

Two kinds of methods are currently being used for asphaltene remediation. One is a mechanical method, which includes pigging, coiled tubing operations, and wireline
cutting. The other is to use chemical solvents to dissolve deposited asphaltenes. Chemical inhibitors that are used to prevent asphaltenes from deposition in a production system include pipelines and wellbores.

Pigging can be used to remove asphaltenes inside manifolds and pipelines, provided the manifold and pipeline system can handle pigs. Compared to waxes, asphaltenes are brittle and hard, and thus special pigs are required. Pigs with disks and cups should be used; spheres and foam pigs will not be efficient for removing asphaltene solids. For a successful pigging operation, pigging frequency is important. If the time between pigging operations is too long, too much asphaltene depositions can occur inside the pipeline. Excessive asphaltene deposition can cause pigs to get stuck. On the other hand, pigging operations often require production shutdown and unnecessary pigging operations will result in production loss. Since there is no reliable way to predict how much asphaltenes will deposit inside a pipeline with time, pigging frequency can be optimized only by learning system behavior. It is safest to start at high pigging frequency and monitor the amount of asphaltene solids removed. Once the system behavior is better understood, the pigging frequency can be optimized.

Wireline cutting can be used to remove asphaltene solids inside the wellbore, provided the wellbore can be easily accessed. Coiled tubing systems can be used to remove asphaltene solids inside the wellbore and pipelines. The limitation with coiled tubing is that if the solid deposition is too far away from the coiled tubing deployment point, coiled tubing cannot be used.

Even though asphaltenes are not soluble in alkanes, they are very soluble in aromatic solvents, like benzene. Products of aromatics and alcohol mixtures are available from chemical companies that can be used to remove asphaltene deposits. It is always critical to test the chemicals first to assess their effectiveness for a specific deposit. Chemical solvents

![Figure 15.9 de Boer crude oil supersaturation plot (based upon de Boer et al., 1992).](image-url)
are often squeezed into formation to fight asphaltene deposit problems near the wellbore region, which cannot be easily accessed by mechanical means.

Chemicals, like blends of aromatics, surfactants, and oil and water soluble alcohols, are developed to inhibit asphaltene precipitation. Some of the chemicals would increase the surface tension of crude oils, and thus help keep asphaltenes from precipitating in the treated hydrocarbon. Some of the chemicals would help supply resins in the oil to stabilize the asphaltene molecules. Again, whether or not an inhibitor is effective for a specific asphaltene problem can be determined only by testing. It is often true that a product effective for dissolving deposits may not be a good inhibitor.

15.7 **Inorganic Precipitates—Scales**

Waxes and asphaltenes are precipitates from crude oils. In this section, potential precipitates from water (inorganic precipitates—called scales) will be discussed. Like wax and asphaltene depositions, scales can potentially cause serious flow assurance concerns by plugging production facilities and topsides processing devices, jamming control valves, and restricting flows in tubing and pipelines. Scales can also form inside the formation and can potentially reduce productivity by plugging the formation. Thus, it is important to understand how scales are formed and how to mitigate the scale problems.

15.7.1 **Fundamental Concepts**

**Common Scales.** The most common scales occurring in the oil industry are calcium carbonate, barium sulfate, strontium sulfate, and calcium sulfate.

Calcium carbonate \((\text{CaCO}_3)\) is also called calcite scale. Calcite scale is formed when the calcium ion is combined with the carbonate ion.

\[
Ca^{+2} + CO_3^{-2} \rightarrow CaCO_3 \downarrow
\]  

(15.10)

where

\[
Ca^{+2} = \text{calcium ion}
\]

\[
CO_3^{-2} = \text{carbonate ion}
\]

Calcium carbonate is a solid and can potentially precipitate from solution to form scale. Similarly, when the calcium ion is combined with the bicarbonate ion, calcium carbonate will also be formed.

\[
Ca^{+2} + 2(HCO_3^{-1}) \rightarrow CaCO_3 \downarrow + CO_2 + H_2O
\]  

(15.11)

where

\[
HCO_3^{-1} = \text{bicarbonate ion}
\]

Barium sulfate is formed when the barium ion is combined with the sulfate ion:

\[
Ba^{+2} + SO_4^{-2} \rightarrow BaSO_4 \downarrow
\]  

(15.12)
where

\[ Ba^{+2} = \text{barium ion} \]
\[ SO_{4}^{-2} = \text{sulfate ion} \]

Like calcium carbonate, barium sulfate is a solid and can potentially precipitate from solution to form scale.

Strontium sulfate is formed when the strontium ion is combined with the sulfate ion:

\[ Sr^{+2} + SO_{4}^{-2} \rightarrow SrSO_{4} \downarrow \]  \hspace{1cm} (15.13)

where

\[ Sr^{+2} = \text{strontium ion} \]

Calcium sulfate can precipitate from water if the calcium ion is combined with the sulfate ion:

\[ Ca^{+2} + SO_{4}^{-2} \rightarrow CaSO_{4} \downarrow \]  \hspace{1cm} (15.14)

Calcium sulfate scales include anhydrite (\(CaSO_4\)) and gypsum (\(CaSO_4 \cdot 2H_2O\)).

Carbonate scales tend to form from formation waters with reduced pressure, increased temperature, and/or increased pH value. Sulfate scales tend to form when formation waters mix with seawater because seawaters normally have high sulfate concentrations.

Some less common scales, like calcium fluoride (\(CaF_2\)), are reported in the literature (Yuan et al., 2003). Calcium fluoride is extremely insoluble and there are not currently many chemicals available to effectively treat it.

**Solubility.** Solubility is a parameter used to assess how much a substance can stay in a solution without precipitation and is defined as the maximum amount of a solute that can be dissolved in a solvent under given physical conditions (pressure, temperature, pH, etc.). The higher the solubility of a compound, the larger the amount of the compound that can dissolve in a solution. The solubility of a compound can change when pressure, temperature, and/or compositions change. Different compounds have different solubility. It is well known that the solubility in water of calcium carbonate, barium sulfate, strontium sulfate, or calcium sulfate is relatively small. That is why these compounds tend to precipitate from water to form scales.

**Saturation Ratio (SR).** Saturation ratio is defined as the ratio of the ion product to the ion product at saturation conditions. For example, for calcium carbonate (\(CaCO_3\)),

\[ SR = \frac{C_{Ca^{+2}} \times C_{CO_3^{-2}}}{(C_{Ca^{+2}} \times C_{CO_3^{-2}})_{saturation}} \]  \hspace{1cm} (15.15)

where

\[ C_{Ca^{+2}} = \text{concentration of } Ca^{+2} \text{ in solution} \]
\[ C_{CO_3^{-2}} = \text{concentration of } CO_3^{-2} \text{ in solution} \]
For a given solution:

\[ SR = 1, \] the solution is saturated with \( CaCO_3 \).

\[ SR < 1, \] the solution is undersaturated with \( CaCO_3 \) and precipitation will not occur.

\[ SR > 1, \] the solution is supersaturated with \( CaCO_3 \) and precipitation can potentially occur.

A concept that is used more often than saturation ratio is called saturation index (SI) which is defined as:

\[
SI = \log_{10} (SR)
\]  

And if

\[ SI < 0, \] the scaling ions are undersaturated in the solution at the given condition and no scale precipitation.

\[ SI = 0, \] the scaling ions are at equilibrium in the solution.

\[ SI > 0, \] the scaling ions are supersaturated in the solution at the given condition and scale precipitation is possible.

### 15.7.2 Factors Affecting Scale Precipitation

The major factors affecting the scale precipitation from water are pressure, temperature, pH value, and dissolved solids in water. The following table summarizes the impacts of these factors for the common scales in the oil industry (Templeton, 1960; Jacques and Bourland, 1983; Carlberg and Matches, 1973; Kan et al., 2001; Rosario and Bezerra, 2001).

Even though the main reasons for carbonate scales to form inside wellbore are pressure drop inside tubing (increased pH due to the escape of CO\(_2\)) and high downhole temperature, the main cause for sulfate scales to form is the mixing of different waters. Mixing waters from different fields, from different wells at the same field, from different laterals in the same well, and mixing of formation water and seawater can potentially induce scales to form in the production facilities.

Scale is one of the major flow assurance concerns in deepwater production. There are large pressure and temperature changes throughout the production system (from reservoir to topsides). These pressure and temperature changes may induce scales. Fluids with formation water from different formations and wells are normally mixed in the production pipeline system. Different formation waters may have different compositions, and scales may form when these waters are mixed. For fields where seawater is injected for pressure maintenance, scales may become serious when different seawater factions are being produced into the production system.

### 15.7.3 Scale Prevention and Control

The main means of scale control is chemical inhibition, which includes both continuous chemical injection and periodic scale squeeze into formation. Scale inhibitors prevent scale deposition and they do not normally re-dissolve the deposits that have already formed. So the key function of a scale inhibitor is prevention, not remedy. Scale control strategies can be different at different stages of field life (Jordan et al., 2001). At early life, only connate
water or aquifer water breaks through. The most likely scales will be carbonate scales which will be the main focus for scale control strategy. Scale severity will increase with increased water cut. If seawater is injected at later field life, sulfate scales can be formed when the injected seawater breaks through and mixes with formation water. Strategies at this stage would include controlling both carbonate and sulfate scales. With production, the seawater fraction in the produced water will increase with time, and the severity of sulfate scales will change accordingly.

When chemical inhibitors are used for scale control, inhibitors will work with one or more of the following three main mechanisms (Yuan, 2002; Graham et al., 1997):

Crystal nucleation inhibition
Crystal growth retardation
Dispersion of small scale crystals in the flowing fluid

**TABLE 15.1 Summary of Major Factors Impacting Scale Precipitations**

<table>
<thead>
<tr>
<th>Scales</th>
<th>Temperature Effects</th>
<th>Pressure Effects</th>
<th>pH Value Effects</th>
<th>Dissolved Solids Effects</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calcium Carbonate</td>
<td>Less soluble with increased temperature.</td>
<td>Less soluble with reduced pressure.</td>
<td>Less soluble with increased pH value.</td>
<td>Less soluble with reduced total dissolved solids in water.</td>
</tr>
<tr>
<td>Barium Sulfate</td>
<td>For common temperature range, solubility increase with increased temperature.</td>
<td>Less soluble with reduced pressure.</td>
<td>Little impact.</td>
<td>More soluble with increased dissolved salt.</td>
</tr>
<tr>
<td>Strontium Sulfate</td>
<td>Less soluble with increased temperature.</td>
<td>Less soluble in NaCl brines with reduced pressure.</td>
<td>Little impact.</td>
<td>More soluble with increased NaCl content.</td>
</tr>
<tr>
<td>Calcium Sulfate</td>
<td>Less soluble with increased temperature for the common reservoir temperature range.</td>
<td>Less soluble with reduced pressure.</td>
<td>Little impact.</td>
<td>More soluble with increased water salinity.</td>
</tr>
</tbody>
</table>
An inhibitor molecule works against crystal nucleation by interacting directly with the scaling ions in the brine, and thus prevents the ions from agglomerating into nuclei. Inhibitor molecules can also retard crystal growth by either adsorbing onto the crystal surface (the growth sites) or fitting into the crystal lattice to replace one of the scaling ions (usually the anion). By doing so, it distorts the crystal lattice or the growth steps thus preventing the crystal from growing rapidly in a regular morphology.

If small scale crystals have already formed in solution, an inhibitor may also prevent the crystals from adhering to each other and to other surfaces by dispersing them in the fluid. The small crystals are hence carried along with the fluid, and scale deposition is minimized. A particular inhibitor often inhibits scale formation with a primary inhibition mode. Some are better at exhibiting one particular inhibition mechanism than the other.

Testing and selecting the right inhibitor for a given scale problem are very critical for successful scale control (Yuan, 2003; Rosario and Bezerra, 2001; Graham et al., 2003; and Jordan et al., 2001). The most important step for screening an inhibitor is water sampling. With representative samples available, water chemistry data which is the most important information needed to diagnose and analyze the scaling potential of produced waters can be obtained. Water chemistry data include concentrations of ions (anions and cations, like calcium, barium, strontium, bicarbonate, and sulfate) and pH. Accurate chemistry data of the produced water under system conditions (in-situ), along with system information such as production data, temperature, and pressure as well as gas composition are essential for assessing scale risks and for testing inhibitors.

Obtaining representative water samples requires good practices. For a new oil/gas field, original formation water samples should be collected. Water samples must be preserved and stabilized at the time of sampling. Samples without preservation often go through changes including precipitation of scaling ions, evolution of carbon dioxide (CO₂), and pH drift. If a sample is collected without using a pressurized container, pH and bicarbonate should be determined immediately on-site. This is because both will drift rapidly, resulting from CO₂ evolution from the solution. It is also important to determine whether or not the samples have been contaminated by drilling muds and completion fluids before performing analysis. Finally, the water chemistry data should be reviewed by an expert to ensure the quality.

Once water chemistry data is available, the scale prediction can be performed using simulation packages. There are a few commercial simulation packages available (Kan et al., 2001; Rosario and Bezerra, 2001; Yuan et al., 2003). Based upon the simulations, the nature of scale and potential amount of scale that will precipitate can be assessed. And proper scale control technologies/strategies can be eventually developed. A very successful story on how to develop a new scale inhibitor for a specific field problem in the Gulf of Mexico was reported by Yuan et al. in 2003.

A successful scale inhibitor has to have the following properties:

- It must inhibit scale formation at threshold inhibitor levels under a range of brine, temperature, and pressure conditions.
- It should have good compatibility with the produced water to avoid the formation of solids and/or suspensions. Some scale inhibitors will react with calcium, magnesium, or barium ions to form insoluble compounds which can precipitate to form scales, thus, creating new problems.
It should have good compatibility with the valves, wellbore, and flowline materials, e.g., low corrosivity on metals. Thus, a corrosivity test is necessary. It should be compatible with other chemicals, like corrosion inhibitors, wax inhibitors, and hydrate inhibitors. The scale inhibitor should be physically compatible with other chemicals so no solids will form. The scale inhibitor should also be compatible with other chemicals so their individual performance will not be significantly interfered. It was reported by Kan et al. (2001) that hydrate inhibitors (methanol and glycols) would impact the solubility of sulfate minerals and the effectiveness of scale inhibitors may be impacted.

It must be thermally stable under the application temperature and within the residence time. This can be challenging for some fields with high formation temperatures.

Its residuals in produced brine must be detectable for monitoring purposes.

For controlling scales in wellbore and in pipelines, scale inhibitor is required to be injected continuously so it can inhibit the growth of each scale crystal as it precipitates from the water. To have the maximum effectiveness for inhibiting further growth, scale inhibitor must be present in the water upstream of the point where scale precipitation occurs. That is why in a lot of cases scale inhibitor is injected at the bottom of the wellbore.

If scale is a risk in formation, especially near the wellbore region, it is not practical to continuously inject inhibitor into formation. Scale squeeze operations to bullhead inhibitor into formation are required. Scale squeeze has been used extensively in North Sea fields for quite a long time (Graham et al., 2003) and is relatively new in South Africa and Gulf of Mexico operations. Extensive literature is available on scale squeeze operations (Lynn and Nasr-El-Din, 2003; Collins et al., 1999; Bourne et al., 2000; Graham et al., 2003; and Jordan et al., 2001).

If sulfate scales are due to seawater injection, an alternative scale control strategy is to partially remove the sulfate ions from injected seawater. Sulfate removal can be achieved by using a de-sulfation plant (Davis and McElhiney, 2002; Vu et al., 2000; and Graham et al., 2003). Sulfate removal plants can reduce sulfate content from the typical level of 2700–3000 ppm to a value in the range of 40–120 ppm. With the much reduced sulfate ions in the seawater, the tendency for sulfate scale formation will be significantly reduced. However, even with the sulfate removal operation, scale squeeze and/or scale control in the production stream may still be required. But the squeeze frequency will be reduced.

Scale Removal. Once scales are formed in the production facilities, they can be removed either by mechanical means, such as pigging, or by dissolving using chemicals. When brush or scraper pigs are run through the pipeline, they can mechanically remove some of the scale deposits on the pipe wall. But if the deposits, which may contain scales, waxes, and/or asphaltenes, are too hard, pigging may not be very effective.

Acids can react with scales and dissolve scale deposits on the pipe wall. For calcium carbonate scales, either hydrochloric acid or chelating agents can be used. Calcium sulfate scale is not soluble to hydrochloric acid. Inorganic converters, like ammonium carbonate \((\text{NH}_4)_2\text{CO}_3\), can be used to convert it into calcium carbonate which can then be dissolved using hydrochloric acid. Since it is quite possible that hydrocarbons can deposit on the surface of the scales and hydrocarbons can interfere with the acid reaction with the
scales, it is necessary to pre-wash the scales using hydrocarbon solvents. Furthermore, to keep the acid from dissolving the pipe wall, a corrosive inhibitor is also necessary to be added to the acid.

15.8 Corrosion

With gas, oil, and water flowing through offshore pipeline, one of the important flow assurance issues is corrosion. This is because an aqueous phase is almost always present in the oil and gas fluids. When enough water is flowing through the pipeline, water would wet the pipe inner surface and corrosion can occur. The corrosivity of the liquid phase depends upon the concentrations of CO$_2$ and H$_2$S, temperature, pressure, flow regime, and flowrates. Corrosion can occur in subsea production systems with different forms: galvanic corrosion, pitting, cavitation, stress corrosion cracking, hydrogen embrittlement, corrosion fatigue, etc. Corrosion can result in the loss of millions of dollars if a subsea pipeline is not properly protected. Pipeline engineers need to understand corrosion fundamentals to design sound strategies that will effectively control corrosion and protect the pipelines.

15.8.1 Corrosion Fundamentals (Cramer and Covino, 1987; Fontana and Greene, 1967)

The phenomena associated with corrosion in gas, oil, and water multiphase flow are very complex, involving the chemistry of the produced fluids, the metallurgy of the pipeline material, and the multiphase flow hydraulics. During their refining process, metals absorb quite a significant amount of extra energy. Because of the extra energy, metals are unstable in aqueous environments. With the right chemical process, metals would corrode and return to their original lower energy, stable states. Different metals have different energy stored, and thus have different corrosion tendency. The metals used for subsea pipeline and well tubulars are not homogeneous, and potential differences of these inhomogeneous materials are the primary cause of corrosion.

Corrosion that involves conductive water is called wet corrosion and is an electrochemical process. There are four basic fundamental elements in a corrosion process:

- An anode
- A cathode
- An electrolyte
- A conducting circuit

Figure 15.10 shows the corrosion process. When a piece of metal is put in a conductive fluid, like water, due to the potential differences among different materials, a portion of the metal surface is easier to corrode than the rest. This portion of metal is called an anode, where metal dissolves into the conductive fluid. Thus, during corrosion, metal is lost by dissolving into solution. The chemical reaction is described as:

$$Fe \rightarrow Fe^{+2} + 2e$$

(15.17)
By losing 2 electrons, the iron atom becomes an iron ion that is positively charged. The electrons left behind would travel to another area on the metal surface, which is called the cathode where the electrons are consumed by reaction with ions in the electrolyte. For example, if the electrolyte is conductive water:

\[
2H^+ + 2e = H_2 \uparrow
\]

where

\[
H^+ = \text{hydrogen ion}
\]
\[
H_2 = \text{hydrogen gas}
\]

To complete the electric circuit, a conductive solution to conduct current from the anode to the cathode is needed. The conductive solution is called the electrolyte. Water with dissolved solids is a good electrolyte. A path is also needed to conduct the current from the cathode to the anode. The metal itself provides the path and completes the electric circuit. Thus, the anode, the cathode, the electrolyte, and the electron conductor form the essential elements (corrosion cell) for metal corrosion.

The environment for subsea pipeline systems is favorable for formation of corrosion cells. The metals used for the pipeline system can serve as anode, cathode, and the metallic conductor between the two. The water, either produced or injected seawater, provides the electrolyte required to complete the electron circuit. Pipeline consists of dissimilar metals that may have different tendencies to corrode with the higher tendency metal to be the anode and the lower tendency metal to be the cathode. Even with the same metal, due to the inhomogeneity, one local metal area (anode) can be more corrosive than the other (cathode).

The amount of gas dissolved in water greatly impacts its corrosivity. Water with no dissolved gases will normally cause no corrosion problems. On the other hand, if gases, like...
oxygen, carbon dioxide, and hydrogen sulfide, are dissolved in water, the water would be very corrosive. The corrosion reactions involved with the three gases can be expressed as the following:

For carbon dioxide:
At the anode

\[ Fe \rightarrow Fe^{+2} + 2e \quad (15.19) \]

At the cathode

\[ CO^2 + H_2O \rightarrow H^+ + HCO_3^- \rightarrow 2H^+ + CO_3^{-2} \quad (15.20) \]

Combining the above two equations, we have

\[ Fe^{+2} + CO_3^{-2} = FeCO_3 \quad (15.21) \]

For oxygen:
At the anode

\[ Fe \rightarrow Fe^{+2} + 2e \quad (15.19) \]

At the cathode

\[ O_2 + 2H_2O \rightarrow 4OH^- \quad (15.22) \]

Combining the two equations:

\[ 4Fe^{+2} + 6H_2O + 3O_2 \rightarrow 4Fe(OH)_3 \rightarrow Fe_2O_3 + 3H_2O \quad (15.23) \]

For hydrogen sulfide
At the anode

\[ Fe \rightarrow Fe^{+2} + 2e \quad (15.19) \]

At the cathode

\[ H^2S + H_2O \rightarrow H^+ + HS^- + H_2O \rightarrow 2H^+ + S^{-2} + OH^- \quad (15.24) \]

By combining the above two equations, we have:

\[ Fe^{+2} + S^{-2} \rightarrow FeS \quad (15.25) \]

From the above discussion, it is clear that there are a few parameters that would control the corrosion reactions: the reactions at the cathode and anode, the flow of electrons from the anode to the cathode, and the conductivity of the electrolyte. These controlling factors
are the main parameters dealt with in almost all corrosion prediction models (de Waard and Lotz, 1993; Nesic et al., 1995). If the reactions at both anode and cathode can be reduced, for example, by using corrosion inhibitors to slow down the ion transport in the electrolyte, the corrosion rate will be slowed down. Similarly, if the electrolyte is less conductive due to the removal of dissolved oxygen, carbon dioxide, or hydrogen sulfide, the corrosion rate will also be reduced. The conductivity of the electrolyte can be reduced by adding chemicals to increase the pH value of the electrolyte. These are the methods that are widely used in the industry for corrosion control (Strommen, 2002; Kolts et al., 1999).

15.8.2 Corrosion Forms

Corrosion can occur in different forms and can be caused by a variety of different reasons.

**Pitting Corrosion.** Pitting corrosion is formed when localized holes or cavities are created in the material due to metal loss. Pitting corrosion can occur if protective film is not uniformly applied to the metal surface. Poorly applied film areas are more easily corroded. Pitting corrosion is very disastrous because it is difficult to detect. One single pit can cause material fatigue, stress corrosion cracking, and may even cause catastrophic failure of subsea pipelines.

**Galvanic Corrosion.** Galvanic corrosion is referred to as the corrosion due to two dissimilar materials coupled in a conductive electrolyte. With galvanic corrosion, one metal which is generally more corrosive becomes the anode, while the less corrosive one becomes the cathode. The anode metal in galvanic corrosion will corrode more rapidly than it would alone, and the cathode metal will corrode more slowly than it would alone. The larger the potential difference between the two metals, the more rapidly the anode will corrode. A very important factor that would impact galvanic corrosion is the ratio of the exposed area of the cathode to the exposed area of the anode. A small anode to cathode area ratio is highly undesirable. Under this condition, current is concentrated in a small anodic area and rapid loss of the dissolving anode will occur. Galvanic corrosion principles can be used favorably to protect the important system by scarifying a dedicated system that will corrode away. This principle is used in so-called cathodic protection systems where steel is connected to a more corrosive metal, like zinc, and is protected. The steel is the cathode and the zinc is the anode.

**Cavitation Corrosion.** Cavitation occurs when vapor bubbles are repeatedly formed and subsequently collapsed in a liquid on a metal surface. The explosive forces associated with the bubble collapses can damage any protective films and result in increased local corrosion. Cavitation can also cause mechanical damage to system parts, like pump impellers. Cavitation is less likely to occur in offshore pipelines.

**Hydrogen Attacks.** In sour systems, hydrogen can diffuse into metal to fill any voids that may exist in the material. As corrosion continues, hydrogen atoms continue to diffuse into the voids to form hydrogen molecules, increasing the pressure in the voids. Depending upon the hardness of the material, the voids would develop into blisters, which is called hydrogen blistering, or into cracks which is called sulfide stress cracking. Due to stress cracking, materials can fail at stress levels below their yield strength. If materials contain elongated defects that are parallel to the surface, hydrogen can get into the defects and create cracks. Once the cracks on different planes inside the metal are connected, the
effective wall thickness is reduced. This kind of hydrogen attack is called hydrogen induced cracking. Crolet and Adam (2000) reported a form of hydrogen cracking called stress-oriented, hydrogen-induced cracking (SOHIC). SOHIC, which is a hybrid of sulfide stress cracking and hydrogen-induced cracking, is found to be associated with refining in the vicinity of welds that are not stress-relieved. After shutdown, subsea pipelines would experience much colder temperatures compared to normal operation temperatures. The reduced temperature causes thermal contraction and results in increased tensile stress. If the welds were done with imperfections, the welds tend to experience localized corrosion.

15.8.3 Corrosion Control

There are a few methods available for the corrosion control of subsea pipelines: using CRAs (corrosion resistant alloys) instead of carbon steel, applying corrosion inhibitors, isolating the metal from the electrolyte, and using cathodic protection. One or more of these methods may be used together. Cathodic protection and chemical inhibition can both be used to protect a subsea pipeline.

CRA steel is often used to replace carbon steel for corrosive applications. But CRAs are normally more expensive than carbon steel. Thus, whether or not CRAs should be used depends upon overall economics. But in subsea application, the very critical, high impact components, like trees, jumpers, and manifolds, are often made of CRAs. But pipelines, especially long pipelines, are often made of carbon steel and continuous corrosion inhibitor injection is utilized to protect the pipeline.

Corrosion inhibitors are chemicals that, when added to an environment, would effectively reduce the corrosion rate of a metal that is exposed to that environment. Corrosion inhibitors would react with metal surfaces and adhere to the inner surface of the pipeline and protect the pipe from corrosion. The active compounds in the inhibitor help form a film layer of inhibitor on the surface and prevent the water from touching the pipe wall. A minimum inhibitor concentration is required to provide high inhibition efficiency. But inhibitor concentration that is significantly higher than the minimum required concentration provides little or no additional benefits. Some inhibitors can also slow down the diffusion process of ions to the metal surface and increase the electrical resistance. For example, some specific inhibitors can help slow down the reaction at cathode by forming a deposit layer on the cathode area to increase the resistance and limit the ion diffusion process.

In order for the inhibitor to be distributed evenly around the inner pipe wall perimeter, the fluids inside the pipeline must have a certain high flowing velocity. If the fluid velocity is too low, the inhibitor may not be able to reach the upper portion of the pipe wall and the inhibitor will only form a protective film around the lower portion of pipe wall. On the other hand, if the velocity is too high and causes high near wall shear stress, the protective film may be removed from the pipe wall. For smooth pipeline, the efficiency of corrosion inhibitors can be as high as 85–95%, but can drop if the shear stress increases drastically at locations such as fittings, valves, chokes, bends, and weld beads. These irregular geometries cause flow separation and reattachment of the flow boundary and increase the rates of turbulence.
In gas/condensate pipeline, adding the hydrate inhibitors, like glycol or methanol, can also help reduce the corrosion rate (Strommen, 2002). This is because the hydrate inhibitors absorb free water and make the water phase less corrosive.

The protective layer to isolate the pipe wall from water can also be achieved by using plastic coating and plastic liners. Water injection pipelines and well tubings often use plastic liners to control corrosion problems.

As we discussed in the previous section, one element of the corrosion cell is the current flow. If we stop the current flow from the anode to the cathode, the corrosion is stopped. This is the principle of cathodic protection, which is one of the widely used corrosion control methods in subsea pipeline. The key for the cathodic protection to work is to provide enough current from an external source to overpower the natural current flow. As long as there is no net current flow from the pipeline, there is no pipeline corrosion.

It is well known that different metals have different tendencies for corrosion in seawater. By connecting more corrosive metal to the subsea pipeline, the pipeline metal is forced to be the cathode while the more corrosive metal is the anode, which will corrode away. In this way, pipeline corrosion is significantly reduced. The galvanic anodes used in cathodic protection are usually made of alloys of magnesium, zinc, or aluminum which are much more active in seawater than steel pipeline.

With proper design, cathodic protection is one of the most reliable corrosion control methods.

15.9 Severe Slugging

One of the flow assurance issues in subsea pipeline is related to production delivery. From the processing point of view, it is always desirable that the fluids coming from the pipeline are stable in composition and in flow. If the flow arriving topside is not stable, the processing system may experience upsets that often result in shutdown of the whole subsea production system (Song and Peoples, 2003).

A typical subsea production system usually consists of subsea pipeline and the production riser. Depending upon water depth, the riser length ranges from less than one hundred feet, as in shallow water production systems, to a few thousand feet, as in deepwater production systems. With a longer production riser, more energy will be required to deliver stable flow to the processing system. For deepwater production fields, especially at the late field life stage when the reservoir pressure is low and the total production rate is reduced, the gas and liquid velocities in the pipeline are not high enough to continuously carry the fluids out of the riser, resulting in intermittent (unstable) fluid delivery to the processing devices.

When the liquid cannot be continuously produced out of the riser, the liquid will accumulate at the riser base to form a liquid column, called liquid slug. The liquid slug will completely block the gas flow. When the gas pressure behind the slug is high enough, the liquid slug will be pushed out of the riser, resulting in a huge amount of liquid flowing into the processing separator. This phenomenon is called severe slugging. The liquid slug with little or no gas in it would often cause upsets (like high liquid level) in the separator if the separator and its control system are not adequately designed. When liquid slug is being produced, there is little or no gas flowing to the compressors. This can cause compression system problems.
15.9.1 Severe Slugging Description

Typical severe slugging would occur in a pipeline riser configuration shown in Figure 15.11. The pipeline section coupled with the riser is normally inclined downward. The pipeline sections upstream of the downward inclined section maybe upward inclined, horizontal, or downward inclined.

When gas and liquid flowrates are low, the liquid cannot continuously flow out of the riser and start to fall back from the riser and accumulate at the riser base, as shown in Figure 15.11 (a). This stage is called severe slugging formation or severe slugging generation. During this stage, there is almost no liquid and gas production and no fluid flowing into the separator. While liquid is accumulating at the riser base, gas and liquids are continuously flowing into the riser base from the pipeline inlet. Thus, the liquid column or slug formed at the riser base would continue to grow into the riser and also grow against the flow direction into the pipeline. Depending upon the GOR and other parameters, like system pressure and temperature, the slug inside the pipeline can be a few times longer than the riser height. Since the liquid slug prevents the gas from entering the riser, the pressure behind the slug is building up by the gas flow.

As more and more liquid accumulates at the riser base, the liquid slug would eventually reach the riser top and start to produce the liquid slug, as shown in Figure 15.11 (b). This

![Figure 15.11 Schematic of classical severe slugging formation process.](image-url)
stage is called slug production. During this phase, the liquid is producing into the separator at high velocity and little or no gas is being produced. Because of the high velocity liquid flow and huge amount of liquid associated with the slug, the separator may reach high liquid level and cause trips or upsets.

When the liquid slug is being produced, the gas will eventually enter the riser, as shown in Figure 15.11 (c). When gas enters the riser, the difference between the separator pressure and the gas pressure behind the slug becomes higher and higher as the liquid slug becomes shorter and shorter inside the riser. The liquid slug is being produced or being pushed by the gas at higher and higher velocity. This stage is called liquid blowout.

After the liquid slug is produced, the huge gas pocket behind the slug will be blown out of the riser and charge into the separator. This stage is called gas blowdown (Figure 15.11 (d)). During this stage, little or no liquid would flow into the separator, and low liquid level may be reached that would eventually cause system upsets and shutdown. The gas blowdown stage in severe slugging can cause as big a problem as the slug production stage.

Once the gas is blown out of the riser, the pipeline system pressure is reduced. The liquid would again fall back from the upper portion of the riser and start to accumulate at the riser base. This is the start of the next severe slugging circle. In summary, severe slugging is undesirable because it would cause a period of no liquid and gas production followed by high liquid and gas flows, resulting in large pressure and flow fluctuations which would often cause processing device shutdown. Once the processing system is shut down, the subsea production system including trees and pipelines will have to be shut down.

### 15.9.2 Severe Slugging Prediction

Since severe slugging can cause production system shutdown, it is very critical to be able to correctly predict the onset of severe slugging. For a proper design of a subsea pipeline system, the multiphase flow characteristics inside the pipeline must be checked for the whole field life and the processing devices and their control systems must be designed to be able to handle the delivered flow from the pipeline. Whether or not severe slugging is a risk will significantly impact the design philosophy of the processing and control system.

Pots et al. (1987) presented a model to predict the onset of severe slugging:

\[
\pi_s = \frac{W_g}{W_l} \frac{ZRT}{M_g g L (1 - H_l)} \leq 1
\]

where

- \(\pi_s\) = Pots’ number, dimensionless
- \(W_g, W_l\) = gas and liquid mass flowrate, respectively
- \(Z\) = gas compressibility factor
- \(R\) = gas universal constant
- \(T\) = pipeline temperature
- \(M_g\) = gas molecular weight
- \(L\) = pipeline length
- \(g\) = accelerational gravity
- \(H_l\) = average liquid holdup inside the pipeline
Severe slugging is expected when the Pots’ number is equal to or less than unity. Pots’ model can be used to determine the onset of severe slugging, but the model cannot predict how long the severe slugs will be and how fast severe slugs will be produced into the separator. For subsea pipeline design, transient multiphase flow simulators are often used to determine the important flow parameters, like pressure, temperature, flow velocity, flow regime, slug frequency, and slug size.

Figures 15.12 through 15.14 show typical pipeline inlet pressure, outlet pressure, and outlet gas flowrate as function of time during severe slugging flow (from Song and Kouba, 2000). Those are simulation results for a pipeline of 19” ID with flowrate of 50 mb/d and GOR of 500 scf/stb. Figure 15.12 shows how the pipeline inlet pressure changes with time during severe slugging. The inlet pressure fluctuates between 890 psia and 970 psia. The severe slugging occurs once every 20 hours. When the severe slugs are being pushed out from the pipeline outlet, the pipeline outlet pressure also increases as shown in Figure 15.13. Before the severe slugs are produced, the pipeline outlet pressure is about 150 psia which equals to the platform pressure.

Figure 15.14 shows how the outlet gas mass flowrates change with time during severe slug flow. Before the slug is pushed out of the pipeline, the gas mass flow is a constant and the gas flowrate equals the steady-state flowrate. Once the liquid slug is pushed out, the huge gas pocket behind the liquid slug is produced, resulting in a much higher gas mass flowrate as shown in the figure. Once the gas pocket is produced, for a period of time, no gas is flowing out. The same behavior can be expected for the outlet liquid flow.

15.9.3 Severe Slugging Elimination

There are a few methods that can be used to effectively mitigate severe slugging problems.

**Favorable Pipeline Bathymetry.** A pipeline bathymetry is preferred if the pipeline flow is going upwards. In other words, the water depth at the pipeline outlet is preferred to be
shallower than that at the inlet. This is because the multiphase slug flow is much less severe with an upwardly inclined pipeline than with a downwardly inclined pipeline. Pipeline A, shown in Figure 15.15 will tend to have more severe slugging problems than Pipeline B. Thus, it is important that, at the pipeline design stage, favorable pipeline routing is chosen, if possible, to eliminate severe slugging risks.

Increasing Gas Flow. One of the main reasons that severe slugging occurs is that the gas velocity is too low to carry the liquid out of the riser. If more gas can be introduced into the pipeline riser system, the gas velocity will be increased and the gas will also help lift the liquid out of the riser by reducing the fluid mixture density. Song and Peoples (2003) reported that at a West Africa subsea field when a well is diverted from the production pipeline into the test pipeline for testing, the flow inside the production pipeline would change to severe slugging flow due to the reduced production. But if enough extra gas is

Figure 15.13 Pipeline outlet pressure as a function of time for severe slugging flow (GOR = 500 scf/stb, Qo = 50 mb/d, 19” pipe size).

Figure 15.14 Outlet gas mass flowrate as a function of time for severe slugging flow (GOR = 500 scf/stb, Qo = 50 mb/d, 19” pipe size).
added into the flowline before the well is shifted out for well testing, the gas can help stabilize the flow inside the pipeline and no severe slugging will occur. They developed a plot showing the required total liquid and total gas flowrates for continuous stable flow for different water cut, as shown in Figure 15.16. For a given liquid flowrate, if the total gas flowrate is high enough that the flowing condition is above the curve, no severe slugging will occur. Otherwise, severe slugging will occur. The individual points in the figure are field measurements. This information, together with well test data, was used by operations personnel to estimate when severe slug flow was likely. The primary mitigating measure that the operations personnel undertook to avoid slugging was to increase gas flow inside the pipeline.

**Gas-Lift Riser.** If enough gas can be injected at the riser base to change the flow inside the riser to hydrodynamic slug flow, churn flow, or annular flow, the severe slugging problem can be mitigated. With hydrodynamic slug flow or churn flow, the slugs are much shorter than the slugs in the severe slugging flow. Topside separators are normally sized to handle the hydrodynamic slugs and no system shutdown is likely. If sufficient gas is injected at the riser base to change the flow to annular flow, the flow will be even more stable. But to reach annular flow, a significant amount of gas will be needed and may not be practical.

**Topsides Choking.** Severe slugging can be mitigated by choking the flow at the top of the riser. Choking the flow would increase system pressure and make the system “stiffer.” With increased system pressure, the gas becomes less compressible. Thus, when the liquid slug formed at the riser base blocks the gas flow, the gas pressure behind the liquid slug would increase more quickly and be able to push the liquid slug out of the riser faster. In this way, the liquid accumulation time is shorter and the liquid slugs will consequently be smaller. So the severe slugs are minimized. But choking would increase the system back pressure and thus reduce the overall production.

**Subsea Separation.** Song and Kouba (2000) performed studies on severe slugging elimination using subsea separation. It is understood that the favorable condition for severe slugs to form is that gas and liquid simultaneously flow through a long riser at low velocities. It is very difficult to change fluid velocity that is controlled by production rates and pipe size. But, it is possible to separate the gas from the liquid and let the gas and the
liquid flow through two different pipelines or risers. In this way, the gas and the liquid will not be flowing simultaneously through the riser and severe slugging can, thus, be avoided. Seafloor separation becomes one of the methods that can potentially solve the severe slugging problems associated with deepwater production. Based upon their studies, Song and Kouba concluded:

- Subsea separation can help mitigate severe slugging. By separating the gas from the liquid, it is possible to eliminate severe slugs. This is especially true for riser base separation.
- Subsea separation can boost production by reducing the back pressure assuming single-phase liquid pump is used to boost the liquid.
- There is an optimum separator location for subsea applications. For certain flowrates and pipe sizes, it is more effective to put the separator at the riser base than at the wellhead.
- For the purpose of eliminating severe slugs, the requirement for the subsea separation efficiency is not very high. Based on the study, for the riser base separation, as long as the separation efficiency is higher than 75%, severe slugs can be eliminated.

One disadvantage associated with riser base separation is that two risers will be required.

References

API RP 45: API Recommended Practice for Analysis of Oil-Field Waters, American Petroleum Institute, Dallas (1968).


16.1 Introduction

The term pig was originally referred to Go-Devil scrapers driven through the pipeline by the flowing fluid trailing spring-loaded rakes to scrape wax off the internal walls. One of the tales about the origin of the name pig is that the rakes made a characteristic loud squealing noise. Pipeline operators now describe any device made to pass through a pipeline for cleaning and other purposes with the word pig. The process of driving the pig through a pipeline by fluid is called a pigging operation.

Although pigs were originally developed to remove deposits, which could obstruct or retard flow through a pipeline, today pigs are used during all phases in the life of a pipeline for many different reasons. During pipeline construction, pigging is used for debris removing, gauging, cleaning, flooding, and dewatering. During fluid production operations, pigging is utilized for removing wax in oil pipelines, removing liquids in gas pipelines, and meter proving. Pigging is widely employed for pipeline inspection purposes such as wall thickness measurement and detection of spanning and burial. Pigging is also run for coating the inside surface of pipeline with inhibitor and providing pressure resistance during other pipeline maintenance operations. Figure 16.1 shows pipeline deposits displaced by a pig. This chapter describes how to apply different pigging techniques to solve various problems in the pipeline operations.

16.2 Pigging System

A pigging system includes pigs, a launcher, and a receiver. It also includes pumps and compressors, which are not discussed here because they have to be available for transporting the product fluids anyway. Obviously pigs are the most essential equipment. Although each pipeline has its own set of characteristics that affects how and why pigging is utilized, there are basically three reasons to pig a pipeline: 1) to batch or separate dissimilar products; 2) to displace undesirable materials; and 3) to perform internal inspections. The pigs used to accomplish these tasks fall into three categories:

A. Utility Pigs, which are used to perform functions such as cleaning, separating, or dewatering.
B. In-Line Inspection Tools, which provide information on the condition of the line, as well as the extent and location of any problems.

C. Gel Pigs, which are used in conjunction with conventional pigs to optimize pipeline dewatering, cleaning, and drying tasks.

16.2.1 Utility Pigs

Utility pigs can be divided into two groups based upon their fundamental purpose: 1) cleaning pigs used to remove solid or semi-solid deposits or debris from the pipeline, and 2) sealing pigs used to provide a good seal in order to either sweep liquids from the line, or provide an interface between two dissimilar products within the pipeline. Within these two groups, a further subdivision can be made to differentiate among the various types or forms of pigs: Spherical Pigs, Foam Pigs, Mandrel Pigs, and Solid Cast Pigs.

Spherical pigs, or spheres, are of either a solid composition or inflated to their optimum diameter with glycol and/or water. Figure 16.2 shows some spheres. Spheres have been used for many years as sealing pigs. There are four basic types of spheres: inflatable, solid, foam, and soluble. Soluble spheres are usually used in crude oil pipelines containing microcrystalline wax and paraffin inhibitor. Spheres normally dissolve in a few hours. The dissolving rate depends on fluid temperature, fluid movement, friction, and absorbability of the crude. If the line has never been pigged, it is a good idea to run the soluble pig. If it hangs up in the line, it will not obstruct the flow. Inflatable spheres are manufactured of various elastomers (polyurethane, neoprene, nitrile, and Viton) depending on their applications. An inflatable sphere has a hollow center with filling valves that are used to inflate the sphere with liquid. Spheres are filled with water, or water and glycol, and inflated to the desired size. Spheres should never be inflated with air. Depending on the application and material, the sphere is inflated 1%-2% over the pipe inside diameter. As the sphere
wears from service, it is resized, extending its life. In small sizes the sphere can be manufactured solid, eliminating the need to inflate it. The solid sphere does not have the life of an inflatable sphere because it cannot be resized. Spheres can also be manufactured from open cell polyurethane foam. They can be coated with a polyurethane material to give better wear. For cleaning purposes they can have wire brushes on the surface. The advantages of the foam sphere are that they are lightweight, economical, and do not need to be inflated. Spheres in general are easy to handle, negotiate short radius 90’s, irregular turns, and bends. They go from smaller lateral lines to larger main lines and are easier to automate than other styles of pigs. Spheres are commonly used to remove liquids from wet gas systems, serve to prove fluid meters, control paraffin in crude oil pipelines, flood pipeline to conduct hydrostatic test, and dewater after pipeline rehabilitation or new construction. Special design considerations for the pipeline should be considered when using spheres. They should never be run in lines that do not have special flow tees installed.

Foam pigs, also known as Polly-Pigs, are molded from polyurethane foam with various configurations of solid polyurethane strips and/or abrasive materials permanently bonded to them. Figure 16.3 demonstrates a foam pig and how it works.

Foam pigs are molded from open cell polyurethane foams of various densities ranging from light density (2 lbs/ft³), medium density (5-8 lbs/ft³), to heavy density (9-10lbs/ft³). They are normally manufactured in a bullet shape. They can be bare foam or coated with a 90-durometer polyurethane material. Coated pigs may have a spiral coating of polyurethane, various brush materials, or silicon carbide coating. If the pig is of bare foam, it will have the base coated. The standard foam pig length is twice the diameter. Foam pigs are compressible, expandable, lightweight, and flexible. They travel through multiple diameter pipelines, and go around mitered bends and short radius 90° bends. They make abrupt turns in tees so laterals can be cleaned. They also go through valves with as little as a 65% opening. The disadvantages of foam pigs are that they are one-time use products; shorter length of runs, and high concentrations of some acids will shorten life. Foam pigs are also inexpensive. Foam pigs are used for pipeline proving, drying and wiping, removal of thick soft deposits, condensate removal in wet gas pipelines, and pigging multiple diameter
lines. Foam pigs coated with wire brush or silicon carbide are used for scraping and mild abrasion of the pipeline.

A mandrel pig has a central body tube, or mandrel, and various components can be assembled onto the mandrel to configure a pig for a specific duty. Figure 16.4 demonstrates some mandrel pigs.

The pig is equipped with wire brushes or polyurethane blades for cleaning the line. The mandrel pig can be either a cleaning pig, sealing pig, or a combination of both. The seals and brushes can be replaced to make the pig reusable. Cleaning pigs are designed for heavy scraping and can be equipped with wire brushes or polyurethane blades. These pigs are designed for long runs. Bypass holes in the nose of the pig control the speed or act as jet ports to keep debris suspended in front of the pig. The cost of redressing the pig is high, and larger pigs require special handling equipment to load and unload the pig.

![Figure 16.3](image1.png)

**Figure 16.3** (a) A foam pig; (b) An ideal foam pig cleaning the pipeline (courtesy of *Montauk Service, Inc.*).

![Figure 16.4](image2.png)

**Figure 16.4** Some mandrel pigs used in pipeline pigging operations (courtesy of *Girard Industries, Inc.*).
Occasionally the wire brush bristles break off and get into instrumentation and other unwanted places. Smaller size mandrel pigs do not negotiate 1.5D bends.

Solid cast pigs are usually molded in one piece, usually from polyurethane; however, neoprene, nitrile, Viton, and other rubber elastomers are available in smaller size pigs. Figure 16.5 demonstrates some solid cast pigs. Solid cast pigs are considered sealing pigs although some solid cast pigs are available with wraparound brushes and can be used for cleaning purposes. The solid cast pig is available in the cup, disc, or a combination cup/disc design. Most of the pigs are of one-piece construction but several manufacturers have all urethane pigs with replaceable sealing elements. Because of the cost to redress a mandrel pig, many companies use the solid cast pig up through 14 inches or 16 inches. Some solid cast designs are available in sizes up to 36 inches. Solid cast pigs are extremely effective in removing liquids from product pipelines, removing condensate and water from wet gas systems, and controlling paraffin build-up in crude oil systems.

16.2.2 In-Line Inspection Tools

In-line inspection tools are used to carry out various types of tasks including:

- Measuring pipe diameter/geometry
- Monitoring pipeline curvature
- Determining pipeline profile
- Recording temperature/pressure
- Measuring bend
- Detecting metal loss/corrosion
- Performing photographic inspection
- Detecting crack
- Measuring wax deposition
- Detecting leak
- Taking product samples, and
- Mapping

Figure 16.5 Some solid cast pigs used in pipeline pigging operations (courtesy of Apache Pipeline Products, Inc.).
A typical in-line inspection tool is an ultrasonic tool shown in Figure 16.6. Ultrasonic in-line inspection tools are used for measuring metal loss and detecting cracks in pipelines. Ultrasonic tools are especially suitable if there are high requirements regarding sensitivity and accuracy, which is especially relevant in offshore pipelines. Ultrasound tools are also well suited with regard to the range of wall thicknesses usually experienced in offshore lines.

16.2.3 Gel Pigs

Gel pigs have been developed for use in pipeline operations, either during initial commissioning, or as a part of a continuing maintenance program. Figure 16.7 shows how gel pigs work. The principal pipeline applications for gel pigs are as follows:

- Product separation
- Debris removal
- Line filling/hydrotesting
- Dewatering and drying
Condensate removal from gas lines
• Inhibitor and biocide laydown
• Special chemical treatment, and
• Removal of stuck pigs

Most pipeline gels are water-based, but a range of chemicals, solvents, and even acids can be gelled. Some chemicals can be gelled as the bulk liquid and others only diluted in a carrier. Gelled diesel is commonly used as a carrier of corrosion inhibitor in gas lines. The four main types of gel used in pipeline applications are: batching, or separator gel; debris pickup gel; hydrocarbon gel; and dehydrating gel. The gel can be pumped through any line accepting liquids. Gel pigs can be used alone (in liquid lines), in place of batching pigs, or in conjunction with various types of conventional pigs. When used with conventional pigs, gelled pigs can improve overall performance while almost eliminating the risk of sticking a pig. Gel pigs do not wear out in service like conventional pigs. They can, however, be susceptible to dilution and gas cutting. Care must be taken when designing a pig train that incorporates gel pigs to minimize fluid bypass of the pigs, and to place a conventional pig at the back of the train when displacing with gas. Specially formulated gels have also been used to seal gate valves during hydrostatic testing. Gels have been developed with a controlled gelation time and a controlled viscosity for temporary pipeline isolation purposes.

16.2.4 Launcher and Receiver

Pigs generally need specially designed launching and receiving vessels (launcher and receiver) to introduce them into the pipeline. The launcher and receiver are installed at the upstream and downstream of the pipeline section being pigged, respectively. The distance between the launcher and receiver depends on the service, location of pump (liquid product) or compressor (gas product) stations, operating procedures, and the materials used in the pig. In crude oil pipeline systems, the distance between launcher and receiver can be as long as 500 miles for spheres and 300 miles for pigs. The amount of sand, wax, and other materials carried along the pig can affect the proper distance. In gas transmission service, the distance between the launcher and receiver can be as long as 200 miles for spheres and 100 miles for pigs, depending on the amount of lubrication used.

The launcher and receiver consist of a quick opening closure for access, an oversized barrel, a reducer, and a neck pipe for connection to the pipeline. Pigs can be located using fixed signalers along the pipe or electronic tracking systems mounted inside the pig.

A typical configuration of a pig launcher for liquid service is illustrated in Figure 16.8. The horizontal barrel holds the pig for loading. Figure 16.9 shows a typical configuration of a pig receiver for liquid service. The horizontal barrel holds the pig for unloading.

A barrel diameter 2 inches larger than the diameter of pipeline has been recommended for both launchers and receivers. The barrel length should be 1.5 times the pig length and long enough to hold 10 or more spheres.

Typical configurations of pig launchers and receivers for gas service are depicted in Figures 16.10 and 16.11, respectively. The inclined barrels should be long enough to hold 10 or more spheres. In large-diameter gas pipelines, the barrel diameter can be 1 inch larger than the pipeline.
16.3 Selection of Pigs

The purpose of operational pigging is to obtain and maintain efficiency of the pipeline. The pipeline’s efficiency depends on two things: first, it must operate continuously, and second, the required throughput must be obtained at the lowest operating cost. The type of pig to be used and its optimum configuration for a particular task in a particular pipeline should be determined based upon several criteria including:
- Purpose of pigging
  - type, location, and volume of the substance to be removed or displaced
  - type of information to be gathered from an intelligent pig run
  - objectives and goals for the pig run
- Line contents
  - contents of the line while pigging
  - available vs. required driving pressure
  - velocity of the pig

**Figure 16.10** A typical configuration of a pig launcher for gas services.

**Figure 16.11** A typical configuration of a pig receiver for gas services.
Characteristics of the pipeline
- the minimum and maximum internal line sizes
- the maximum distance the pig must travel
- the minimum bend radius, and bend angles
- additional features such as valve types, branch connections, and the elevation profile

Cleaning Pigs. Cleaning pigs are designed to remove solids or accumulated debris in the pipeline. This increases efficiency and lowers operating cost. They have wire brushes to scrape the walls of the pipe to remove solids. Pigs 14 inches and smaller normally use rotary wire wheel brushes. These brushes are easy to replace and inexpensive. Special rotary brushes are used on some larger pigs. Larger pigs have wear-compensating brushes. These brushes can be individually replaced as needed and are mounted on either leaf springs, cantilever springs, or coil springs. The springs push the brushes against the pipe wall. As the wire brushes wear, the force of the spring keeps them in contact with the pipe wall, compensating for brush wear. Many different brush materials are available. Standard brushes are made of fine or coarse carbon steel wire. For pipelines with internal coatings, Prostran is the material of choice. Some services require a stainless steel brush. Special brush designs, such as the pit cleaning brush, are also available. When soft deposits of paraffin, mud, etc., need to be removed, the urethane blade is an excellent choice. The blade design is interchangeable with the brushes. Bypass ports are installed in the nose or on the body of the pig. These ports are used to control fluid bypass. If the ports are on the body of the pig, the flow will also pass through the brushes and keep them clean. As the fluid passes through the ports on the nose of the pig, it helps keep the debris in front of the pig stirred up and moving. Plugs are used to regulate the bypass. The sealing elements are either elastomer cups or discs. They are used as a combination cleaning and sealing element to remove soft deposits. Cups are of standard or conical design. Specialty cups are available for some applications. The cup and disc material is normally manufactured from a polyurethane material, which gives outstanding abrasion and tear resistance but is limited in temperature range. Neoprene, nitrile, EPDM, and Viton are available for higher temperature applications.

The best choices for cleaning applications are normally pigs with discs, conical cups, spring-mounted brushes, and bypass ports. Figure 16.12 shows details of two pigs of this type. Discs are effective for pushing out solids and providing good support for the pig. Conical cups provide sealing characteristics, good support, and long wear. Spring-mounted brushes provide continuous forceful scraping for removal of rust, scale, and other build-ups on the pipe wall. Instead of brushes, polyurethane scraper blades can also be selected for cleaning waxy crude oil lines because the scraper blades are easier to clean than brushes. Bypass ports allow some of the flow to pass through the pig. This can help minimize solids build-up in front of the pig. For a new pipeline construction, it is a good practice to include a magnetic cleaning assembly in the pig.

Gauging Pigs. Gauging pigs are used after constructing the pipeline to determine if there are any obstructions in the pipeline. Obstructions can be caused by partially closed valves, wrinkle bends, ovality caused by overburden, dents caused by rocks underneath the pipe, third-party damage, buckles caused by flooding, earthquakes, etc. Gauging pigs assure that any ovality of the line is within accepted tolerance. The gauging plate may be mounted on the front or rear of the pig and is made of a mild steel or aluminum. The
plate may be slotted or solid. The outside diameter of the plate is 90-95% of the pipe’s inside diameter. Gauging runs are normally done during new construction and prior to running a corrosion inspection pig. The best practice is to choose inspection tools that can provide critical information about the line, such as determining the location (distance), o’clock position, and severity of a reduction.

**Caliper Pigs.** Caliper pigs are used to measure pipe internal geometry. They have an array of levers mounted in one of the pig cups. The levers are connected to a recording device in the pig body. The body is normally compact, about 60% of the internal diameter, which combined with flexible cups allows the pig to pass constrictions up to 15% of bore. Caliper pigs can be used as gauging pigs. The ability of a caliper pig to pass constrictions means minimal risk of jamming. This is very important for subsea pipelines where it would be very difficult and expensive to locate a stuck pig.

**Displacement Pigs.** Displacement pigs displace one fluid with another based on a sealing mechanism. They can be bidirectional or unidirectional in design. They are used in the testing and commissioning phase of the pipeline, i.e., hydrostatic testing, line fills, and dewatering, etc. Line evacuation and abandonment is another application for the displacement pig. Bidirectional (Figure 16.13) pigs can be sent back to the launch site by reversing flow if they encounter an obstacle. They are also used in the filling and dewatering associated with hydrostatic testing when the water used to fill the line must be pushed back to its source after completion of the test.

The best choice of displacement pigs is normally pigs with multi-lipped conical cups (Figure 16.14). Conical cups can maintain contact with the pipe wall even in out-of-round pipe which is more common in large-diameter pipelines. Conventional cups and discs usually cannot maintain a seal in out-of-round pipe. Multi-lipped cups have numerous, independent sealing lips on each cup, which significantly improves their ability to maintain a seal.
Profile Pig. A profile pig is a gauging pig with multiple (usually three) gauging plates. One plate is mounted on the front, one in the middle, and one on the rear of the pig. It is normally used before running an ILI (In Line Inspection) tool to assure the tool’s passage around bends and through the pipeline.

Transmitter Pigs. Occasionally pigs will get stuck in a line. The location of the stuck pig can be found by using a detector pig with a transmitter in its body. The transmitter emits a
signal so it can be located with a receiver. Transmitters are normally mounted into a mandrel, solid cast, or Polly-Pig.

**Special Pigs.** Many applications require special pigs. Manufacturers in the pigging industry have made special pigs for many applications. Figure 16.15 illustrates that a special pig can be used for spraying corrosion inhibitor to the upper side of pipe interior. Dual Diameter Pigs are designed for pigging dual diameter pipelines. They are usually mandrel pigs fitted with solid discs for the smaller line and slotted discs for the larger line. If it is a cleaning pig, the brushes will support it in the line and keep the pig centered. The Polly-Pig is also widely used in this application.

Other special pigs include pinwheel pigs, which use steel pins with hardened tips. They were developed to remove wax and scale from a pipeline. Magnetic cleaning pigs were developed to pick up ferrous debris left in the pipeline.

There are many pig configurations to choose from, but some configurations will not work in some pipelines. It is very important to compare pipeline information to the pig specifications. The best way to stay out of trouble is to provide the pipeline specifications to the pig manufacturer and ask them to recommend a pig.

### 16.4 Major Applications

Major applications of pigging are found during pipeline construction, operation, inspection, and maintenance. Depending on application type and pipeline conditions, different kinds of pigs are chosen to minimize the cost of pigging operations. Tiratsoo (1992) presents a comprehensive description of applications of pigging in the pipeline industry.

#### 16.4.1 Construction

During pipeline construction, it is quite possible for construction debris to get inside the pipeline. The debris could harm downstream equipment such as filters and pumps. The only way to remove possible debris is to run a pig through the pipeline. Typically, debris
removal is done section by section as the lay barge moves forward. An air-driven cleaning pig is usually sent through the pipeline section to sweep out the debris. Features of the cleaning pig should be selected based on anticipated pipeline conditions. The most effective way to clear debris is by the use of a magnetic cleaning assembly which can be mounted on conventional pigs. Removal of this type of debris is a must before attempting to run corrosion inspection pigs.

Pipelines subjected to subsea conditions may buckle in certain sections. The place for a buckle to occur during pipe laying is most likely the sag bend just before touchdown on the seabed. To detect the buckle, a gauging pig is pulled along behind the touchdown point. If the pig encounters a buckle, the towing line goes taut, indicating that it is necessary to retrieve and replace the buckled section of pipeline. Features of the gauging pig should be selected based on anticipated pipeline conditions. Caliper pigs can be used as gauging pigs after completion of construction. The ability of caliper pigs to pass constrictions can reduce the possibility of jamming, which is vitally important for subsea pipelines where it would be very difficult and expensive to locate a stuck pig.

Upon completion of construction, the pipeline should be cleaned to remove rust, dirt, and millscale that contaminate product fluids. These contaminate also reduce the effectiveness of corrosion inhibitor. A typical cleaning operation would consist of sending through a train of displacement pigs with different features suitable to pipeline conditions. Gel slugs are used to pick up debris into suspension, clearing the pipeline more efficiently. Corrosion inhibitor can also be added to the interior of the pipeline in the trip of cleaning pigging.

After cleaning, the pipeline is flooded with water for hydrotesting. Air must be completely removed so that the pipeline can be efficiently pressurized. Pigging with displacement pigs is normally the best solution for flooding a pipeline. Use of bi-directional batching pigs is favorable for the afterward-dewatering operation.

Upon a successful hydrotest, water is usually displaced with air, nitrogen, or the product fluid. Since dewatering is the reverse process of flooding, a bidirectional batching pig used to flood the pipeline, left during the hydrotest, can be used to dewater the pipeline. In cases of gas service pipelines, it is necessary to dry the pipeline to prevent formation of hydrates and waxy solids. For this purpose, methanol or glycol slugs can be sent through the pipeline between batching pigs. An alternative means of drying the pipeline is to vacuum the pipeline with vacuum pumps.

16.4.2 Operation

During fluid production operations, pigging is utilized to maintain efficiency of pipelines by removing wax in oil pipelines and liquids (water and condensate) in gas pipelines. Sometimes pigging operations are for meter proving. Pipeline wax is characterized as long-chain paraffin formed and deposited in pipelines due to changes in pressure and temperature. Accumulation of wax in pipeline reduces the effective pipeline hydraulic diameter and hence efficiency of the pipeline. A variety of cleaning pigs are available to remove wax. Most of them work on the principle of causing a bypass flow through the body of the pig over the brushes or scrapers and out to front. Pigs used for removing wax should be selected to have features inducing the bypass flow. The action of the pig also polishes wax
remaining on the pipe wall, leaving a surface for low flow resistance of product fluids. To remove hard scale deposits, aggressive and progressive pigs are the best choice. They can be used with cleaning fluids that attack the deposits and/or help to keep the deposits in suspension while being pushed out of the line. This is a very special application that would normally be provided by a pipeline cleaning service company. Samples of deposits are usually required for chemical analysis and to determine what cleaning fluids are best suited. Sometimes chemical cleaning is used for removal of specific types of pipe deposits. Chemical cleaning is a process of using pigs in conjunction with environmentally friendly detergent-based cleaning fluids and is almost always done by pipeline cleaning service companies. The detergents help to suspend solid particles and keep them in a slurry, thus allowing removal of large volumes of solids in one pig run. Samples of material to be removed from the line are required in order to select the best cleaning fluid. The cleaning fluids are captured between batching and cleaning pigs, and normally a slug of the fluid is introduced in front of the first pig.

In gas service pipelines, liquid water and/or gas condensate can form and accumulate on the bottom of the pipeline. The liquid accumulation reduces flow efficiency of the pipeline. It can also develop slug flow, causing problems with the processing facilities. Different types of displacement and cleaning pigs are available to remove the liquids. Because gas is the drive fluid, the pigs used for removing the liquids in the gas pipeline should be selected to have features of good sealing. Spheres are usually the preferred choice for liquid removal from wet gas systems. Most of these systems are designed to automatically (remotely) launch and receive spheres. A large number of spheres can be loaded into the automatic launcher and launched at predetermined frequencies. At the receiving end of the line is a slug catcher to capture all the liquid pushed in by a sphere. If more liquid is brought in than the slug catcher can handle, the plant normally shuts down. Thus spheres are launched at a frequency that prevents exceeding the capacity of the slug catcher. Pipeline systems are normally designed for use with spheres or pigs but not both. Pipelines designed for spheres may require modifications of launchers and receivers in order to run conventional pigs.

To clean pipelines with known internal corrosion, special pigs are available equipped with independent scraping wires that will go into a pit to break up and remove deposits that prevent corrosion inhibitors from getting to the corroding area. Brushes on conventional pigs will not extend into a pit. To clean internally coated pipelines, the preferred choice is a pig with discs and cups because these will normally remove deposits from the coating due to the “Teflon-like” characteristics of epoxy coatings. Conventional cleaning pigs with “prostran” brushes or polyurethane blades can also be used on internally coated pipelines.

16.4.3 Inspection

A variety of intelligent pigs have been employed for pipeline inspection purposes, including detection of not only dents and buckles but also corrosion pitting, cracks, spanning and burial, and measurement of wall thickness. The information obtained from the pigging operations is used for assessment of pipeline safety and integrity.

Magnetic-flux leakage pigs have been used for detection of dents and buckles, and measurement of pipe ovality and wall thickness over the entire pipe surface. The principle
of magnetic-flux leakage detection relies on measurement of metal loss, and hence the size of defect. Usually a series of survey runs over years are required to establish trends. Magnetic-flux leakage pigging can be utilized in liquid and gas pipelines.

Ultrasonic intelligent pigs are used to make direct measurement of wall thickness of the entire pipe surface. They are better suited to liquid pipelines and cannot be used in gas pipelines without a liquid couplant.

Pipeline spans have traditionally been found by external inspection using side-scan sonar or ROVs. In recent years, neutron-scatter pigs have been employed to detect spanning and burial in subsea pipelines with lower cost and better accuracy.

### 16.4.4 Maintenance

Pigging is also run for maintenance of pipelines, for coating the inside surface of pipeline, providing pressure resistance, and installing barrier valves. Traditionally, the internal surfaces of pipe joints are pre-coated with a smooth epoxy liner, leaving the welds uncoated. Recently, a pigging system has been developed to coat the entire internal surface of pipeline by first cleaning the surface and then pushing through a number of slugs of epoxy paint.

Shutting down offshore, especially deepwater, pipelines for maintenance is very expensive. With advanced technology, it is possible to carry out some maintenance jobs without shutting down the pipeline. In cases where there are not enough isolation valves, a pressure-resisting plug may be pigged into the pipeline to seal off downstream operation.

Corrosion inhibitors are normally injected into the line on a continuous basis and carried through the line with the product flow. Sometimes inhibitors are batched between two pigs, but there is no way to guarantee the effectiveness of this method, especially at the twelve o’clock position. Special pigs have been developed that spray inhibitor onto the top of the pipe as they travel through the pipe. This is done by using a siphoning effect created by bypass flow through an orifice specifically designed to pick up inhibitor from the bottom of the pipe.

### 16.5 Pigging Procedure

**Pressure and Flow Rate.** Any pigging operation should follow a safe procedure that is suitable to the given pipeline conditions. Operating pigging pressures and fluid flow rates should be carefully controlled. Velocity of driving fluid is usually between 3 feet per second and 5 feet per second during pigging. Recommended ranges of operating pressures and flow rates are presented in Table 16.1.

**Pre-Run Inspection.** The pig must be in good condition if it is to do the job it was selected to do. If the pig has been run before, it should be inspected to assure that it will run again without stopping in the pipeline. Measure the outside diameter of the pig’s sealing surface. This diameter must be larger than the inside pipe diameter to maintain a good seal. Inspect the sealing surfaces to assure there are no cuts, tears, punctures, or other damage that will affect the pig’s ability to run in the pipeline. The unrestrained diameter of brush pigs should also be measured to assure that the brushes will maintain contact with the pipe wall during the complete run. When using brush-type mandrel cleaning pigs, the
brushes should be inspected for corrosion or breakage. Every precaution should be taken to prevent these brushes from breaking in the pipeline. Loose bristles can damage valves, instrumentation, and other pipeline equipment. All components of brush-type mandrel pigs should be checked to be certain that they are tight and in good condition.

**Pig Launching and Receiving**. Pig launchers are used to launch the pig into the pipeline, and pig receivers are used to receive the pigs after they have made a successful run. The design of these pig traps will depend on the type of pig to be run and pipeline design conditions. Provisions in the station design should include handling equipment for pigs 20 inches and larger. Caution should be taken for liquid spillage from the pig traps.

The following pig launching procedures can be used as guidelines for developing operating procedures. Since company policies vary regarding whether the pig launcher is left on stream or isolated from the pipeline after the pig is launched, the operator should verify that the trap is isolated from the pipeline and depressurized before commencing any part of the launch procedure.

To launch pigs, make sure that the isolation valve and the kicker valves are closed. In liquid systems, open the drain valve and allow air to displace the liquid by opening the vent valve. In natural gas systems, open the vent and vent the launcher to atmospheric pressure. When the pig launcher is completely drained (no pressure left), with the vent and drain valves still open, open the trap (closure) door. Install the pig with the nose firmly in contact with the reducer between the barrel and the nominal bore section of the launcher. Clean the closure seal and other sealing surfaces, lubricate if necessary, and close and secure

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**TABLE 16.1 Recommended Pigging Pressures and Flow Rates**

<table>
<thead>
<tr>
<th>Pipe Inner Diameter (in)</th>
<th>Typical Pigging Pressure (psig)</th>
<th>Liquid Flow Rate (GPM)</th>
<th>Gas Flow Rate (SCFM)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Launching</td>
<td>Running</td>
<td>3 FPS</td>
</tr>
<tr>
<td>2</td>
<td>100 to 200</td>
<td>40 to 100</td>
<td>20</td>
</tr>
<tr>
<td>3</td>
<td>100 to 150</td>
<td>35 to 85</td>
<td>60</td>
</tr>
<tr>
<td>4</td>
<td>75 to 125</td>
<td>30 to 80</td>
<td>110</td>
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<td>8</td>
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<td>25 to 70</td>
<td>460</td>
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<td>10</td>
<td>30 to 60</td>
<td>25 to 50</td>
<td>720</td>
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<td>20 to 45</td>
<td>1040</td>
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<td>14</td>
<td>20 to 50</td>
<td>15 to 40</td>
<td>1400</td>
</tr>
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<td>16</td>
<td>15 to 45</td>
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</tr>
<tr>
<td>18</td>
<td>15 to 40</td>
<td>10 to 30</td>
<td>2300</td>
</tr>
<tr>
<td>20</td>
<td>10 to 25</td>
<td>5 to 20</td>
<td>2900</td>
</tr>
<tr>
<td>24</td>
<td>10 to 25</td>
<td>5 to 20</td>
<td>4100</td>
</tr>
<tr>
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<td>10 to 20</td>
<td>5 to 15</td>
<td>6500</td>
</tr>
<tr>
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<td>9400</td>
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<td>5 to 10</td>
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<tr>
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<td>12,800</td>
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<td>10 to 20</td>
<td>5 to 10</td>
<td>16,700</td>
</tr>
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<td>10 to 20</td>
<td>5 to 10</td>
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<td>10 to 20</td>
<td>5 to 10</td>
<td>26,200</td>
</tr>
<tr>
<td>72</td>
<td>10 to 20</td>
<td>5 to 10</td>
<td>37,700</td>
</tr>
</tbody>
</table>
the closure door. Close the drain valve. Slowly fill the trap by gradually opening the kicker valve and venting through the vent valve. When the filling is completed, close the vent valve to allow pressure to equalize across the isolation valve. Open the isolation valve. The pig is ready for launching. Partially close the main line valve. This will increase the flow through the kicker valve and behind the pig. Continue to close the main line valve until the pig leaves the trap into the main line as indicated by the pig signaler. After the pig leaves the trap and enters the main line, fully open the main line valve. Close the isolation valve and the kicker valve. The pig launching is complete.

To receive pigs, make sure the receiver is pressurized. Fully open the bypass valve. Fully open the isolation valve and partially close the main line valve. Monitor the pig signaler for pig arrival. Close the isolation valve and bypass valve. Open the drain valve and the vent valve. Check the pressure gauge on the receiver to assure the trap is completely depressurized. Open the trap closure and remove the pig from the receiver. Clean the closure seal and other sealing surfaces, lubricate if necessary, and close and secure the trap (closure) door. Return the receiver to the original condition.

**Freeing a “Stuck” Pig.** The goals of “pigging” a pipeline include not only running pigs to remove a product or to clean the line, but to do the work without sticking the pig. Getting the pig stuck rarely happens in pipeline that is pigged routinely, but can happen when pigging a pipeline that has been neglected or never pigged before. It is a good practice to run a low density (2 lb/ft³) foam pig in any “suspect” pipeline and examine the foam pig for wear patterns, tears, gouges, etc. The pigging project should be continued only after feeling comfortable that the line is piggable. If a pig becomes stuck, it is important to identify the cause. Retrieving the pig is the first priority. When bidirectional pigs are used, stuck pigs may be recovered with reverse flow.

Pig tracking is normally done on critical projects and when attempting to locate stuck pigs. A pig tracking system consists of a transmitter mounted on the pig, an antenna, and a receiver that records and stores each pig passage. In addition, the operator can see and hear the signal of the pig passing under the antenna. The antenna and receiver are simply laid on the ground above and in line with the pipe and the passage of the pig is heard, seen, and recorded. Inexpensive audible pig tracking systems are also available; however, they cannot be used to find a stuck pig because they rely on the noise the pig makes as it travels through the line. Sometimes a pig without a transmitter fails to come into the receiver because it gets stuck somewhere in the line. When this happens, the pig cups usually flip forward and flow continues around the stuck pig. In order to find the stuck pig, another pig with a transmitter is launched and tracked closely at all points that are readily accessible. When the transmitter pig passes one tracking point but never reaches the next point, it is assumed the transmitter pig has reached the stuck pig and they are both stuck. The line is then walked, carrying the antenna and receiver until the transmitter pig is pinpointed. Both pigs and the debris ahead of the pigs is then removed by cutting the pipe behind and well ahead of the stuck pig.

**References**

APPENDIX A

Gas-Liquid Multiphase Flow in Pipeline

A.1 Introduction

Offshore pipelines consist of export pipelines and infield pipelines. Export pipelines transport oil or gas from either platform or FPSO (Floating Production, Storage, and Offloading) to beach for further processing. The flow inside the export pipeline is usually gas-condensate flow or oil flow with a little amount of water. The infield pipelines transport wellstream either from the manifolds or from the wells to the platform or FPSO. The flow in the infield pipeline is usually gas-oil-water multiphase flow for oil fields or gas-condensate-water flow for gas fields. Thus, to properly design offshore pipelines, it is critical to understand the impacts of multiphase flow. All of the flow assurance issues associated with offshore pipeline operations are related to the multiphase flow inside the pipeline.

Pressure drop is one of the most critical parameters for pipeline sizing. For single-phase flow, pressure drop is mainly controlled by the Reynolds number that is a function of the fluid viscosity, fluid density, fluid velocity, and pipeline size. For gas-oil-water three-phase flow, the pressure drop inside the pipeline is governed by the flowing properties of all the fluids:

- Density of oil, water, and gas
- Viscosity of oil, water, and gas
- Velocity of oil, water, and gas
- Volume fraction of oil, water, and gas
- Interfacial tension between fluids
- System pressure and temperature

When oil, water, and gas are flowing inside the pipeline simultaneously, the three phases can distribute in the pipeline in many configurations due to the density difference among the fluids. These phase configurations are called flow regimes or flow patterns, differing from each other in the spatial distribution of the interfaces of water-oil, water-gas, and oil-gas. Different fluid interfaces result in different hydrodynamics of the flow, as well as mechanisms of the momentum, heat, and mass transfer among the fluids. Since flow in
different flow regimes may induce different pressure drops, for proper pipeline sizing, it is important to correctly predict the flow regime.

This chapter covers the fundamentals of multiphase flow. Common terminologies used in multiphase flow will be defined. Flow regimes for both horizontal pipeline and vertical pipeline will be classified. Flow regime transitions and flow modeling will also be discussed.

In the last decade or so, pipeline flow simulations using multiphase flow simulators have gained significant popularity. Both steady-state and transient simulators have been used for pipeline design and for pipeline operation simulations. This chapter addresses mathematical models used in pipeline simulations and discusses factors affecting the simulation accuracy.

A.2 Multiphase Flow Concepts

This section introduces commonly used multiphase flow variables. Pressure loss and recovery concepts will also be discussed. Finally, water-oil emulsion viscosity will be briefly discussed.

A.2.1 Basic Flow Variables

Superficial velocity. The superficial velocity of liquid or gas is defined as the ratio of the liquid or gas volumetric flowrate to the total pipeline cross-sectional area, i.e.,

\[
U_s = \frac{Q}{A_f}
\]

where

- \(U_s\) = liquid superficial velocity
- \(U_g\) = gas superficial velocity
- \(Q\) = liquid and gas volumetric flowrate, respectively
- \(A_f\) = pipeline flow cross-sectional area

Mixture velocity. The fluid mixture velocity is defined as the sum of the superficial gas and liquid velocities.

\[
U_m = U_s + U_g = \frac{Q_f + Q_g}{A}
\]

where

- \(U_m\) = fluid mixture velocity.

Liquid holdup. Liquid holdup is defined as the ratio of the liquid volume in a pipeline segment to the whole volume of the pipeline segment.
where

\[ H_l = \frac{V_l}{V} \quad (A.4) \]

\( H_l \) = liquid holdup
\( V_l \) = pipeline segment volume occupied by liquid
\( V \) = whole pipeline segment volume

Liquid holdup is a function of both space and time.

**Gas void fraction.** Gas void fraction is defined as the ratio of the gas volume in a pipeline segment to the whole volume of the pipeline segment

\[ \alpha_g = \frac{V_g}{V} \quad (A.5) \]

where

\( \alpha_g \) = gas void fraction
\( V_g \) = pipeline segment volume occupied by gas

From the above two equations, it is obvious that the sum of the liquid holdup and gas void fraction equals one.

\[ H_l + \alpha_g = 1 \quad (A.6) \]

**Average gas and liquid velocities.** If the superficial velocity and liquid holdup are known and the liquid holdup would not change longitudinally, the average gas and liquid velocities can be calculated as:

\[ u_g = \frac{Q_g}{A_g} = \frac{Q_g}{A_\alpha_g} = \frac{Q_g}{A(1 - H_l)} = \frac{U_{sg}}{1 - H_l} \quad (A.7) \]

\[ u_l = \frac{Q_l}{A_l} = \frac{Q_l}{A H_l} = \frac{U_{sl}}{H_l} = \frac{U_{sl}}{1 - \alpha_g} \quad (A.8) \]

where

\( u_l, u_g \) = average liquid and gas velocity, respectively
\( A_l, A_g \) = pipeline cross-sectional area occupied by liquid and gas, respectively

**Slip velocity.** Due to the density difference, when gas and liquid flow simultaneously inside a pipeline, the gas phase tends to flow faster than the liquid phase. The gas is “slipping” away from the liquid. The slip velocity is defined as the difference of the average gas and liquid velocities.

\[ u_s = u_g - u_l = \frac{U_{sg}}{1 - H_l} - \frac{U_{sl}}{H_l} \quad (A.9) \]
In homogeneous gas and liquid two-phase flow, there is no slippage between gas and liquid, and the slip velocity equals zero. Then, the liquid holdup can be easily calculated as:

\[ H_l = \frac{U_{sl}}{U_{sl} + U_{sg}} = \frac{Q_l}{Q_l + Q_g} \]  

(A.10)

**Water cut.** In the oil industry, a parameter commonly used by the petroleum engineers is called water cut, which is defined as the ratio of the water volumetric flowrate to the total water and oil volumetric flowrates, i.e.,

\[ f_w = \frac{Q_w}{Q_w + Q_o} = \frac{Q_w}{Q_l} \]  

(A.11)

where

- \( f_w \) = water cut
- \( Q_o, Q_w \) = oil and water volumetric flowrate, respectively

**Mixture density.** The density of gas and liquid homogeneous mixture is expressed as:

\[ \rho_m = \rho_l H_l + \rho_g (1 - H_l) \]  

(A.12)

where

- \( \rho_m \) = gas-liquid mixture density
- \( \rho_l, \rho_g \) = liquid and gas density, respectively

**Mixture viscosity.** If the gas and liquid mixture is homogeneous, the viscosity of the mixture can be calculated by:

\[ \mu_m = \mu_l H_l + \mu_g (1 - H_l) \]  

(A.13)

where

- \( \mu_m \) = gas-liquid mixture viscosity
- \( \mu_l, \mu_g \) = liquid and gas viscosity, respectively

The liquid viscosity can be the viscosity of water, oil, or water-oil mixture. Normally, the water-oil mixture viscosity can be calculated based upon the water cut:

\[ \mu_l = \mu_o (1 - f_w) + \mu_w f_w \]  

(A.14)

### A.2.2 Pressure Loss and Recovery

In single phase flow, as the flow goes through upward and downward sections, pressure loss due to the elevation change is fully recovered when the flow goes through the downward section. As shown in Figure A.1 (a), when fluid flows from A to B, the pressure at B is
lower than the pressure at A due to the elevation change (pressure loss). But as the flow continues from B to C, the pressure gained at C due to the elevation change is equal to the pressure loss from A to B. Therefore, with single phase flow, the pressure lost in the upward flow can be fully recovered in downward flow.

But the same conclusion may not always hold true in gas-liquid two-phase flow. As shown in Figure A.1 (b), the flow regime in the upward flow section (from A to B) may not be the same as the flow regime in the downward flow section (from B to C). With different flow regimes, the liquid holdup in each section may not be the same. Thus, the pressure loss in the upward flow section may not be fully recovered in the downward flow section.

### A.2.3 Water-Oil Emulsion Viscosity

When mixing inside the pipeline, water and oil, especially heavy oil, can form emulsion. Water-oil emulsion is a heterogeneous system which consists of either water droplets dispersed in a continuous oil phase (W/O) or oil droplets dispersed in a continuous water phase (O/W) (Becher, 2001).

For oil-in-water (O/W) emulsion, water is the continuous phase and the viscosity of O/W emulsion is dominated by water viscosity. For water-in-oil (W/O) emulsion, oil is the continuous phase and the viscosity of W/O emulsion is a strong function of the water cut and can be magnitudes higher than either the oil viscosity or water viscosity. There are quite a few parameters that can affect the emulsion viscosity. They are: oil and water viscosity, water cut, oil and water interfacial shear stress, water and oil physical properties, chemical surfactants, and any solid phase as wax or asphaltenes, and system temperature (Woelflin, 1942; Yan and Masliyah, 1993; Benayoune et al., 1998).

Over the years, quite extensive research has been conducted to try to develop simplified correlations for the water oil emulsion viscosity (Becher, 2001). But since there are so many parameters that affect the emulsion viscosity, none of these correlations can be universally applied to engineering calculations. Instead, the best way to determine water oil emulsion viscosity is to perform lab measurements of emulsions of different water cut at elevated pressure and temperature conditions. The oil sample should be from the live crude to be transported through the pipeline.
Only a couple of the correlations will be listed here for reference. For the diluted system with the concentration of the dispersed phase less than 10%, the classic Einstein equation can be used:

\[
\mu_i = \mu_e (1 + 2.5f_d)
\]  

(A.15)

where

- \(\mu_i\) = emulsion viscosity
- \(\mu_e\) = viscosity of the continuous phase
- \(f_d\) = the volume fraction of the dispersed phase (less than 0.1)

For concentrated emulsions, Pal and Rhodes (1985) proposed the following correlation:

\[
\mu_i = \mu_e \left[ 1 + \frac{f_d/f_c}{1.187 - f_d/f_c} \right]^{2.492}
\]  

(A.16)

where

- \(f_c\) = the concentration of the dispersed phase at which the emulsion viscosity \(\mu_i\) is 100 times the viscosity of the continuous phase \(\mu_e\).

### A.3 Flow Regime Classifications

Due to the physical property (mainly density) difference between liquid and gas, different flow patterns or flow regimes can occur when gas and liquid flow simultaneously inside the pipeline. The flow regimes differ from each other by having different gas-liquid interfaces. The mechanisms of mass, momentum, and energy transfer between phases are different in different flow regimes. Thus it is important to know the different flow regimes in both horizontal and vertical flows.

#### A.3.1 Horizontal Gas-Liquid Flow Regimes

The classification of flow regime is quite arbitrary, largely depending upon the individual’s observations. For a given flow situation, different people may have different definitions of flow regime. Numerous flow regimes are defined in the literature. But for horizontal gas-liquid concurrent flow, the most widely accepted flow regimes (Collier, 1972; Bergles et al., 1981; Song, 1994) are shown in Figure A.2.

When gas and liquid are flowing concurrently inside a horizontal or near horizontal pipeline, at low gas and liquid velocities, the gas and liquid will completely segregate from each other. The gas will flow on top of the liquid. The gas-liquid interface is smooth. This flow regime is called stratified smooth flow.

Starting from the stratified smooth flow, when gas flow and/or liquid flow increases, some waves will be generated at the gas liquid interface. The gas liquid interface becomes wavy. This flow is called stratified wavy flow.

If gas flow is further increased, the waves at the gas liquid interface will grow. Some of the waves will be large enough to touch the upper inner pipe wall and block gas flow.
Waves that are large enough to fill the pipe and block gas flow are called liquid slugs. This flow is defined as slug flow. In slug flow, the liquid inventory in the pipe is not uniformly distributed along the pipe axis, with slugs being separated by gas zones. The gas zones contain a stratified liquid layer flowing at the bottom of the pipe. The liquid slugs may be aerated by small gas bubbles.

If the gas flow is increased even further, the gas will flow as a core in the center of the pipe and the liquid will flow as a ring around the pipe wall. The liquid ring may not be uniform along the entire circumference, but is thicker at the bottom of the pipe than at the top. Some small liquid droplets may be contained in the gas core. This flow is called annular flow.

With very low gas flow and high liquid flow, the gas will flow as discrete bubbles within a continuous liquid phase. The gas bubbles are usually not uniform in size and most of the bubbles flow at the upper portion of the pipe due to the buoyancy effects. This flow is called dispersed bubble flow.

A.3.2 Vertical Gas-Liquid Flow Regimes

The common flow regimes associated with upward vertical gas-liquid concurrent flow are shown in Figure A.3. When gas flowrate is very low, the gas tends to flow as discrete bubbles in a continuous liquid phase. This flow is called bubble flow. The gas bubbles are not uniform in size and in shape and tend to flow in the center of the pipe with a zigzag pass. When the gas flowrate is increased, the gas bubble density becomes higher and some
of the fast traveling larger bubbles catch up with the smaller ones and become even larger. At some point, large gas bubbles with a bullet front shape, called Taylor bubbles, appear as shown in Figure A.3. This flow is called slug flow. Because the density of the gas is small, the pressure drop across the gas bubble is not enough to support the liquid film surrounding the gas bubble and the liquid film falls down. The falling liquid film is caught up by the liquid slugs which separate successive Taylor bubbles. In the liquid slugs, there may be small entrained gas bubbles. In slug flow, the liquid holdup along the pipe axis is not uniform, but intermittent.

Another flow regime in vertical upward gas liquid two-phase flow is called churn flow. Churn flow is formed by the breakdown of the Taylor bubbles in slug flow. As the Taylor bubbles flow upward, the bubbles become narrow and their shapes are distorted as shown in Figure A.3. At the same time, the liquid slugs between Taylor bubbles are penetrated by gas bubbles and start to fall downward. As the liquid falls down, the liquid forms a bridge at a lower position and is lifted again by the gas. This sequence repeats itself as fluids flow upward. Thus, in churn flow, the liquid slugs have oscillatory motions.

Even though churn flow is identified as one of the flow regimes in vertical two-phase flow, there is no existing model that can practically describe the chaotic physics. Thus, there is yet no practical usefulness in identifying the churn flow.

If the gas flowrate is very high, the gas will flow as a core in the center of the pipe and liquid will flow as a film along the pipe’s inner wall. This flow is called annular flow. Inside the gas core, some liquid droplets are entrained. These entrained droplets enhance the interaction between gas and liquid. It is very important to predict the amount of liquid droplets that can be entrained in the gas core for thermal-hydraulics analysis.

If the gas flowrate is even higher, the interfacial friction at the gas liquid interface in the annular flow is so high that the liquid film will be destroyed by the gas. Thus, all the liquid
flows as discrete droplets in the gas phase. This flow is called mist flow. Mist flow can be treated as homogeneous flow.

## A.4 Horizontal Gas-Liquid Flow Regime Maps

The preceding flow regime classifications are based upon visual observations of the phenomena occurring inside experimental pipelines. For engineering applications, visual observations may not always be available, and simple methods that can be used to predict flow regimes inside the pipeline for a given set of flow parameters are needed. Flow regime maps to define the various flow regime transitions were thus developed based upon either experimental data or mechanistic models.

For horizontal gas liquid two-phase flow, Mandhane *et al.* (1974) developed a flow regime map using superficial gas and liquid velocities as coordinates. The map, shown in Figure A.4, was based upon about 6000 experimental data points from pipelines of diameters between 1.27 cm and 16.51 cm.

With given flow conditions (pressure, temperature, volumetric flowrates, and pipeline sizes), the flow regime can be determined by using the map with superficial gas and liquid velocities. Again, the Mandhane map is good only for horizontal gas liquid two-phase flow.

A much more widely used flow regime map for horizontal gas liquid two-phase flow was developed by Taitel and Dukler (1976). The map was based upon mechanistic models, and the flow regime transitions are governed by different flow parameters in dimensionless form, as shown in Figure A.5.

In Taitel and Dukler's map, the flow regimes are defined by the transition curves. Curves A and B are defined by the coordinates $F$ and $X$. Curve C is defined by the coordinates of $K$ and $X$ while Curve D by $T$ and $X$. Parameters $X$, $F$, $K$, and $T$ are defined as:

![Mandhane Flow Regime Map](image)

**Figure A.4** Mandhane flow regime map for horizontal flow (Mandhane, 1974).
Figure A.5 Taitel-Dukler flow regime map for horizontal flow (Taitel-Dukler, 1976).

\[
X = \left[ \frac{(dP/dx)_g}{(dP/dx)^g_l} \right]^{1/2}
\]

\[
F = \sqrt{\frac{\rho_g}{(\rho_l - \rho_g)g}} \frac{U_g}{\sqrt{Dg \cos \theta_p}}
\]

\[
T = \left[ \frac{(dP/dx)^g_l}{(\rho_l - \rho_g)g \cos \theta_p} \right]^{1/2}
\]

\[
K = \left[ \frac{\rho_g U_g^2 U_l}{(\rho_l - \rho_g)g \nu_l \cos \theta_p} \right]^{1/2}
\]

where

\( (dP/dx)_g \) = pressure gradient for single-phase gas flow

\( (dP/dx)^g_l \) = pressure gradient for single-phase liquid flow

\( \theta_p \) = pipeline inclination angle

\( \nu_l \) = liquid kinematic viscosity

A.5 Flow Regime Transitions in Horizontal Gas-Liquid Flow

In offshore multiphase flow pipelines, flow regimes may vary spatially due to pipeline elevation changes. The flow regime may also change with time over the whole field life due to gas, oil, and water flowrate changes. It is possible that the flow changes from stable flow to unstable flow when flowrates decline over time. How to predict the flow regime transitions is one of the most important research topics in multiphase flow. Over the decades, numerous papers on flow regime transitions have been published (Bontozoglou, 1991; Kocamustafaogullari, 1985; Jones and Prosperetti, 1985; Johnston, 1984, 1985; Kowalski, 1987; Kordyban, 1961, 1977; Kordyban & Ranov, 1970; Ruder et al., 1988; Ooms et al., 1985; Wallis and Dobson, 1973; Mishima and Ishii, 1980; Bishop and Deshpande, 1986; Crowley et al., 1991; Fan et al., 1992; Bendiksen and Espedal, 1992; Kang and Kim, 1993; Taitel and Dukler, 1976; Lin and Hanratty, 1986, 1987; Andritsos et al., 1989; Andritsos and Hanratty, 1987).
A.5.1 Transition from Stratified Flow to Slug Flow

Taitel and Dukler (1976) presented a model to predict the transition from stratified flow to slug flow. In their model, the motion of the wave at the gas-liquid interface was neglected. Song (1994) stated, based upon experimental observations, that at the transition, the water depth inside the pipe can be higher than the pipe radius and the gas velocity is not very high. Thus, the velocity of the solitary wave at the interface can be substantial compared with the gas velocity at the transition. A transition model was then developed by modifying Taitel and Dukler’s model without neglecting the motion of solitary waves at the interface.

When a solitary wave is generated on the surface of a layer of motionless water, as shown in Figure A.6, the wave velocity of this solitary wave can be expressed as (Friedichs and Hyers, 1954; Long, 1956; Stoker, 1957):

\[ u_w = \sqrt{gh_1} \]  

(A.17)

where

- \( u_w \) = velocity of the solitary wave
- \( h_1 \) = equilibrium water depth

As shown in Figure A.6, the pressure at the wave peak is lower than the pressure on the liquid surface where there is no wave due to the so-called Bernoulli effect. Thus, there is a pressure difference between the wave crest and flat liquid surface. This pressure difference tends to make the wave grow. On the other hand, the gravitational force of the wave tends to cause the wave to decay. Therefore, the condition for the wave to grow and to become a liquid slug is

\[ p - p' \geq (h_l - h_i)\left(\rho_l - \rho_g\right)g\cos\theta_p \]  

(A.18)

where

- \( p \) = gas pressure on the flat liquid surface
- \( p' \) = gas pressure at the wave crest

![Figure A.6 Stratified wavy flow in slightly inclined pipe.](image-url)
\( h' \) = liquid height at the wave crest  
\( \theta_p \) = pipeline inclination angle  

Because of the wave motion, gas velocity relative to the wave will be reduced. By neglecting the gas gravitational force, the gas flow can be described as:

\[
p - p' = \frac{1}{2} \rho_g \left[ (u'_g - u_w)^2 - (u_g - u_w)^2 \right]
\]  

(A.19)

where

\( u'_g \) = gas velocity at the wave crest  
\( u_g \) = gas velocity on the flat liquid surface

By assuming the gas density does not change significantly with time and with distance, the gas continuity equation can be expressed as

\[
u'_g - u_w = \frac{A_g}{A'_g} (u_g - u_w)
\]  

(A.20)

where

\( A_g \) = cross-sectional area occupied by gas at the equilibrium depth  
\( A'_g \) = cross-sectional area occupied by the gas at the wave crest

From Equations A.19 and A.20, one can get:

\[
p - p' = \frac{1}{2} \rho_g \left( \left( \frac{A_g}{A'_g} \right)^2 - 1 \right) (u_g - u_w)^2
\]  

(A.21)

Eliminating the pressure from Equations A.18 and A.21 yields

\[
(u_g - u_w)^2 \geq \frac{2(b'_l - b_l)(\rho_l - \rho_g)A_g^2 g \cos \theta_p}{(A_g^2 - A'_g^2) \rho_g}
\]  

(A.22)

For small disturbances, neglecting the higher orders, one can get:

\[
A'_g = A_g + \frac{dA_g}{db'_l}(b'_l - b_l)
\]  

(A.23)

and

\[
A'^2_g = A^2_g + 2A_g \frac{dA_g}{db'_l}(b'_l - b_l)
\]  

(A.24)
Equation A.24 can be expressed as:

\[ A_g^2 - A_s^2 = -2A_g \frac{dA_l}{dh_l} (b'_l - b_l) \]  \hspace{1cm} (A.25)

From Equations A.22 and A.25, eliminating the liquid height at the wave crest gives

\[ (u_g - u_w)^2 \geq \frac{A_g^2}{A_s^2} \left( \frac{\left( \rho_l - \rho_g \right) A_s g \cos \theta_p}{\frac{dA_l}{dh_l} \rho_g} \right) \]  \hspace{1cm} (A.26)

and the transition criterion can be expressed as:

\[ u_g \geq \frac{A_g'}{A_s} \left( \frac{\left( \rho_l - \rho_g \right) A_s g \cos \theta_p}{\frac{dA_l}{dh_l} \rho_g} \right)^{1/2} + u_w \]  \hspace{1cm} (A.27)

Equation A.27 differs from the original Taitel-Dukler model by the solitary wave velocity. Taitel and Dukler (1976) speculated the following relation:

\[ \frac{A_g'}{A_s} = 1 - \frac{b_l}{D} \]  \hspace{1cm} (A.28)

Thus, Equation A.27 becomes:

\[ u_g \geq \left( 1 - \frac{b_l}{D} \right) \left( \frac{\left( \rho_l - \rho_g \right) A_s g \cos \theta_p}{\frac{dA_l}{dh_l} \rho_g} \right)^{1/2} + u_w \]  \hspace{1cm} (A.29)

Equation A.29 gives the criterion for the transition from stratified flow to slug flow.

Another popular model for the transition from stratified flow to slug flow is based on the classical Kelvin-Helmholtz instability (Song, 1994). When a gas flows parallel to a liquid surface and the interface becomes disturbed, the aerodynamic pressure will develop a component that is high at the troughs and low at the crests. When the gas velocity is high enough, the pressure difference will become sufficiently large enough to overcome the stabilizing effect of the gravity and the perturbation will grow and the flow will become unstable. This phenomenon is called the Kelvin-Helmholtz instability (Lamb 1932; Milne-Thomson, 1963).

For long waves of small amplitude in horizontal flow, the criterion for the classical Kelvin-Helmholtz instability is given by:

\[ u_g - u_l \geq \left( \frac{\left( \rho_l - \rho_g \right) b_s g}{\rho_g} \right)^{1/2} \]  \hspace{1cm} (A.30)
where

\( h_g \) = the height of gas column.

Equation A.30 is similar to Equation A.29.

### A.5.2 Transition from Slug Flow to Annular Flow

Equation A.29 shows the criteria for waves on the liquid surface to become unstable. If the equilibrium liquid level is high enough, there is sufficient liquid in the system for the slug to form. Otherwise, the waves will be swept up around the pipe wall to form annular flow (Taitel and Dukler, 1976). When the wave becomes unstable with increasing amplitude, more liquid is needed to sustain the wave. The liquid has to come from the equilibrium liquid film adjacent to the wave. For slug flow to form, the wave needs to touch the upper pipe wall to block the gas flow. Thus, the liquid level of the equilibrium liquid film has to be no less than the pipeline centerline. If the height of the liquid film is less than the centerline, the wave trough will reach the bottom before the wave peak can reach the top pipe wall and no slugs can form. Based upon the above reasoning, Taitel and Dukler (1976) proposed the following transition criteria between slug flow and annular flow:

\[
\frac{h_l}{D_i} \geq 0.5
\]

(A.31)

where

\( D_i \) = pipeline inner diameter.

Barnea et al. (1982) modified this criterion based upon the observations that liquid holdup inside the liquid slugs at the transition is less than 1.0 and proposed the new criterion as:

\[
\frac{h_l}{D_i} \geq 0.35
\]

(A.32)

### A.5.3 Transition from Stratified Smooth Flow to Stratified Wavy Flow

When the gas flowrate is high enough, waves will be generated on the liquid surface. How the waves are generated is very complicated and is not yet completely understood. Taitel and Dukler (1976) used the Jeffreys theory (1925, 1926) for the transition between stratified smooth flow and stratified wavy flow to get:

\[
\left( u_g - c \right)^2 + \frac{4\nu_l g (\rho_l - \rho_g)}{s_c \rho_g} > 0
\]

(A.33)

where

\( c \) = wave propagation velocity
\( \nu_l \) = liquid kinematic viscosity
\( s_c \) = a sheltering coefficient (0.01 is used by Taitel and Dukler)
The wave propagation velocity is much smaller than the gas velocity at the transition. The ratio of the wave velocity to the liquid velocity is a function of the Reynolds number of the liquid. At the transition, this ratio approaches 1.0 to 1.5. For simplicity, Taitel and Dukler used a ratio of 1.0 and assumed that the wave propagation velocity equals the liquid velocity. Thus, the transition between smooth flow and wave flow is given as:

\[
ug \geq \left[ \frac{4 \nu_l (\rho_l - \rho_g) g \cos \theta_p}{sp_g u_l} \right]
\]  
(A.34)

### A.5.4 Transition between Slug Flow and Dispersed Bubble Flow

In slug flow, large gas bubbles exist between successive liquid slugs. If the liquid flow is high enough and the gas flow is low, the gas bubbles will shrink and the liquid level will approach the top pipe wall. When the liquid turbulence is large enough to overcome the buoyant force that tends to keep the gas at the top to form large bubbles, the transition to dispersed bubble flow will occur.

The buoyant force of the gas can be expressed as:

\[
F_b = g \cos \theta (\rho_l - \rho_g) A_g
\]  
(A.35)

where

- \( F_b \) = gas buoyant force.

Taitel and Dukler (1976) proposed the following equation for the estimation of the liquid turbulence force:

\[
F_t = \frac{1}{2} ho_l u_l^2 \left( \frac{f_l}{2} \right) s_i
\]  
(A.36)

where

- \( F_t \) = liquid turbulence force
- \( f_l \) = liquid friction factor
- \( s_i \) = perimeter of gas liquid interface

At the transition, the turbulence force is much larger than the buoyant force. Thus, the criterion for the transition between slug flow and dispersed bubble flow can be expressed as:

\[
u_l \geq \left[ \frac{4 A_g g \cos \theta_p (\rho_l - \rho_g)}{S_i f_l (\rho_l / \rho_l)} \right]^{1/2}
\]

(A.37a)
A.6 Modeling of Multiphase Flow in Horizontal Pipeline

The major objectives of multiphase modeling are to calculate the pressure drop and liquid holdup inside the pipeline. After we define the common flow regimes and the flow regime transition criteria, we are ready to perform modeling calculations of multiphase flow in pipeline.

In all the modeling calculations, we assume the multiphase flow in the pipeline is in steady-state and fully developed and all the flow parameters are independent of time.

A.6.1 Stratified Flow Model

In steady-state stratified flow, the equilibrium liquid level in the liquid film is a constant. The gas and liquid can be treated as two separate flows, and the so-called “two-fluid” model can be utilized.

Figure A.7 shows the horizontal gas-liquid stratified flow model. The gas is flowing on top of the liquid. From the control volume shown in the figure, assuming the velocities are constant along the flowing direction, the momentum equation for the liquid can be expressed as (Song, 1994):

\[
\left( p + \rho_l g \frac{h_l}{2} \right) A_l - \left( p + \rho_l g \frac{h_l}{2} + \frac{dp}{dx} \Delta x \right) A_l + \tau_{is_i} \Delta x - \tau_{is_l} \Delta x = 0
\]  

(A.37b)

where

\[ p \] gas pressure
\[ \Delta x \] length of the control volume along the axis
\[ \tau_{is_i}, \tau_{is_l} \] shear stress at the interface and around the pipe wall occupied by the liquid, respectively
\[ s_i, s_l \] pipe perimeter at the interface and wetted periphery, respectively

The above equation can be simplified as:

\[
-A_l \frac{dp}{dx} + \tau_{is_i} - \tau_{is_l} = 0
\]  

(A.38)

---

**Figure A.7** Horizontal gas-liquid stratified flow.
In the above equation, the shallow water approximation is assumed. Thus, the liquid pressure for the control volume is

$$p_l = p + \rho_l g \frac{h_l}{2} \quad (A.39)$$

Similarly, the momentum equation for the gas phase:

$$-A_g \frac{dp}{dx} - \tau_{i;g} - \tau_{g} = 0 \quad (A.40)$$

By eliminating the pressure from the two momentum equations, we have:

$$\tau_g \frac{s_g}{A_g} - \frac{s_l}{A_l} + \tau_{i;g} \left( \frac{1}{A_g} + \frac{1}{A_l} \right) = 0 \quad (A.41)$$

The shear stresses are evaluated using the following equations:

$$\tau_l = f_l \frac{\rho_l u_l^2}{2}, \quad \tau_g = f_g \frac{\rho_g u_g^2}{2}$$

$$\tau_i = f_i \frac{\rho (u_g - u_l)^2}{2} \quad (A.42)$$

where

$$f_l, f_g, f_i = \text{friction factor of liquid wall, gas wall, and at interface, respectively.}$$

Based upon the suggestion by Taitel and Dukler (1976), the friction factors can be calculated as, for turbulent flow:

$$f_l = 0.046 \left( \frac{D_l u_l}{v_l} \right)^{-0.2}, \quad f_g = 0.046 \left( \frac{D_g u_g}{v_g} \right)^{-0.2}$$

$$f_i = f_g = 0.046 \left( \frac{D_g u_g}{v_g} \right)^{-0.2}$$

where

$$D_l, D_g = \text{liquid and gas hydraulic diameter, respectively.}$$

The hydraulic diameters are defined as:

$$D_l = \frac{4A_l}{s_l}, \quad D_g = \frac{4A_g}{s_g + s_i} \quad (A.44)$$
In the above analysis, it is assumed that the gas flows faster than the liquid. If the liquid flows faster than the gas, the term in Equation A.41, for the friction force at the interface will be negative. Thus, by taking into account both cases, we have:

\[
\tau_g \frac{s_g}{A_g} - \tau_l \frac{s_l}{A_l} + \tau_i \frac{s_i}{A_i} \left( \frac{1}{A_g} + \frac{1}{A_l} \right) = 0
\]  

(A.45)

where

+ = gas flows faster than liquid
- = liquid flows faster than gas

Equation A.45 can be solved for the equilibrium liquid depth for stratified flow. To simplify the calculation, the following dimensionless quantities are introduced:

\[
h_{ld} = \frac{h_l}{D}, \quad s_{gd} = \frac{s_g}{D} = \cos^{-1}(2h_{ld} - 1)
\]

\[
s_{ld} = \frac{s_l}{D} = \pi - s_{gd}, \quad s_{id} = \frac{s_i}{D} = \left(1 - (2h_{ld} - 1)^2\right)^{1/2}
\]

\[
A_{ld} = \frac{A_l}{D^2} = \frac{1}{4} \left[\pi - \cos^{-1}(2h_{ld} - 1) + (2h_{ld} - 1)[1 - (2h_{ld} - 1)^2]^{1/2}\right] \quad \text{(A.46)}
\]

\[
A_{gd} = \frac{A_g}{D^2} = \frac{\pi}{4} - A_{ld}
\]

The shear stresses can also be expressed in these dimensionless parameters and the superficial velocities:

\[
\tau_l = 0.023 \left(\frac{\pi}{4} \frac{U_l}{A_{ld}}\right)^{1.8} \frac{\rho_l}{A_{ld}^2} \left[\frac{4D}{(\pi - s_{gd})v_l}\right]^{-1/5}
\]

\[
\tau_g = 0.023 \left(\frac{\pi}{4} \frac{U_g}{A_{gd}}\right)^{1.8} \frac{\rho_g}{A_{gd}^2} \left[\frac{4D}{(s_{id} + s_{gd})v_g}\right]^{-1/5}
\]

(A.47)

\[
\tau_i = 0.023 \left(\frac{\pi}{4}\right)^{1.8} \left[\frac{4DU_g}{(s_{id} + s_{gd})v_g}\right]^{-1/5} \rho_g \left[\frac{U_g}{A_{gd}} - \frac{U_l}{A_{ld}}\right]^2
\]

Substituting Equations A.46 and A.47 into A.45, we have:

\[
\rho_g U_g^{1.8}[(s_{gd} + s_{id})v_g]^{1/3} \frac{s_{gd}}{A_{gd}^3} - \rho_l U_l^{1.8} \nu_l^{0.2} s_{ld}^{1/2} A_{ld}^2 + \rho_g U_g^{-0.2} [(s_{gd} + s_{id})v_g]^{1/3} s_{id} \left[\frac{U_g}{A_{gd}} - \frac{U_l}{A_{ld}}\right]^2 \left(\frac{1}{A_{gd}} + \frac{1}{A_{ld}}\right) = 0
\]  

(A.48)
This is the equation for horizontal, steady-state stratified flow with turbulent liquid flow. For given gas and liquid volumetric flowrates and pipeline diameter, the equilibrium liquid depth can be solved from the above equation. Once the liquid depth is known, the liquid holdup can be calculated. The pressure drop can be calculated using either Equation A.38 or A.40.

If the liquid flow is laminar instead of turbulent, the friction factors can be evaluated as:

\[
    f_l = 16 \frac{\nu_l}{D_l u_l} \quad f_g = 16 \frac{\nu_g l}{D_g u_g} \quad f_i = f_g
\]  

Equation A.48 would change to:

\[
    \rho_g U_g \left[ \left( s_{gd} + s_{id} \right) \nu_g \right] \frac{s_{gd}}{A_{gd}^3} - \rho_l U_l \nu_l \frac{s_{id}}{A_{id}^3} = 0
\]

\[
    \rho_g \left[ \left( s_{gd} + s_{id} \right) \nu_g \right] s_{id} \left[ \frac{U_g}{A_{gd}} - \frac{U_l}{A_{ld}} \right] \left( \frac{1}{A_{gd}} + \frac{1}{A_{ld}} \right) = 0
\]  

Equation A.50 is the stratified flow equation for laminar flow. When Equations A.48 and A.50 are solved, multiple solutions for the liquid depth at low superficial velocities may exist. It is suggested that the minimum value should be used.

A.6.2 Slug Flow Model

Slug flow is one of the most complicated multiphase flows in pipeline. Extensive research has been conducted over the last few decades to try to develop mechanistic models for slug flow calculations. The first widely cited slug flow model was developed by Dukler and Hubbard in 1975. Xiao et al. (1990) presented a comprehensive mechanistic model for slug flow. More recently, Zhang et al. (2003) presented a unified mechanistic model for gas-liquid slug flow in pipeline. The unified model is claimed to be applicable to all the pipeline inclinations from $-90^\circ$ to $+90^\circ$ from horizontal. The approaches used by Zhang et al. (2003) will be presented here.

Figure A.8 shows a schematic of gas-liquid slug flow in inclined (near-horizontal) pipeline. There are a few assumptions associated with slug flow. They are:

- The flow is steady-state and fully developed
- There is no gas bubble in the film region
- Liquid droplets are entrained in the gas packet on top of the film region
- There is no slippage between the gas and liquid droplets in the gas packet
- There is no slippage between the gas bubbles and liquid in the slug body

As described by Dukler and Hubbard (1975), when the liquid slug travels downstream, the slug will pick up fluids from the film region in front of it. When the slow moving liquid film is overrun by the slug and is accelerated to the slug velocity, a mixing eddy forms in the slug front. Because of the mixing eddy, the fluid particle movement in the slug front is chaotic.
Liquid also sheds away from the slug body at the back and forms the liquid film region behind the slug. The liquid in the film decelerates from the slug velocity and is picked up by the successive slug. With steady-state, fully established slug flow, fluids picked up from the front equal the fluids shedding away from the back. Because the slug picks up fluids from the front, the slug front velocity is higher than the average slug velocity. The slug front velocity is also called translational velocity, $u_T$.

Gas is trapped inside the slug due to the mixing process at the slug front. The higher the gas velocity, the more the gas is entrained. Thus, the liquid holdup inside the slug body is usually less than one.

Slug flow can be divided into two regions, as shown in Figure A.8. One region is called the film region and consists of liquid film at the bottom and gas packet at the top. The other region is called the slug region and consists of the slug body and gas bubbles in the body. The sum of the film region and the slug region is called the slug unit. If it is treated as a series of slug units flowing together, slug flow is a normal “continuous” flow (continuous from unit to unit), just like any other flow patterns. But at any point, slug flow, in nature, is intermittent with gas packets and liquid slugs alternating.

Because the slug front travels at the translational velocity, at one stationary point, one would observe only this velocity, not the fluid particle velocity. Thus, with a coordinate system moving at the translational velocity, continuity equations can be applied. Choosing a control volume consists of the film region, the gas and liquid continuity equations can be expressed as:

$$ (1 - H_{IS})(u_T - u_S) = (1 - H_{IF} - H_{IC})(u_T - u_C) $$

(A.51)

where

$H_{IS} =$ liquid holdup inside the slug body  
$H_{IF} =$ liquid holdup inside the liquid film
\( H_{IC} \) = liquid holdup inside the gas core or gas packet
\( u_T \) = slug translational velocity
\( u_S \) = slug velocity which equals to the mixture velocity
\( u_C \) = gas core velocity

\[
H_{IS}(u_T - u_S) = H_{IC}(u_T - u_C) + H_{IF}(u_T - u_F) \quad (A.52)
\]

where
\( u_F \) = liquid film velocity.

By combining A.51 and A.52, one gets

\[
u_S = H_{IF}u_F + (1 - H_{IF})u_C \quad (A.53)
\]

By definition, the slug unit length equals to the sum of film region length and slug length.

\[
l_U = l_F + l_S \quad (A.54)
\]

and

\[
l_U = u_T t_U \quad (A.55)
\]

where
\( t_U \) = time required for the slug to travel a distance of slug unit

\[
l_S = u_T t_S \quad (A.56)
\]

where
\( t_S \) = time required for slug to travel a distance of the slug region

\[
l_F = u_T t_F \quad (A.57)
\]

where
\( t_F \) = time required for the slug to travel a distance of the film region

Again, using a coordinate that moves at the translational velocity, the liquid mass balance can also be expressed as:

\[
Q_t t_U = AH_{IS}u_S t_S + A(H_{IF}u_F + H_{IC}u_C)t_F \quad (A.58)
\]

Based upon Equations A.54–A.58, one can get:

\[
l_d U_d = l_S H_{IS} u_S + l_F (H_{IF} u_F + H_{IC} u_C) \quad (A.59)
\]
Similarly, for the gas phase:

\[ l_U U_g = l_S (1 - H_{IS}) u_S + l_F (1 - H_{IF} - H_{IC}) u_C \]  \hspace{1cm} (A.60)

The liquid holdup in the gas core is related to the liquid entrainment fraction which is defined as:

\[ f_E = \frac{H_{IC} u_C}{H_{IF} u_F + H_{IC} u_C} \]  \hspace{1cm} (A.61)

Again using the whole film region (both gas packet and liquid film) as the control volume, one can write the momentum equation for the liquid based upon the momentum into the control volume and momentum out of the control volume. The momentum equation for the liquid film is expressed as:

\[ \frac{(p_2 - p_1)}{l_F} = \frac{\rho_f (u_T - u_F)(u_S - u_F)}{l_F} + \frac{\tau_{i\delta} - \tau_{FSF}}{H_{IF} A} - \rho_f g \sin \theta_p \]  \hspace{1cm} (A.62)

where

\[ p_1, p_2 = \text{pressure at the right and left boundaries of the film region, respectively.} \]

Similarly, the momentum equation for the gas packet is:

\[ \frac{(p_2 - p_1)}{l_F} = \frac{\rho_c (u_T - u_C)(u_S - u_C)}{l_F} - \frac{\tau_{i\delta} + \tau_{CSF}}{(1 - H_{IF}) A} - \rho_c g \sin \theta_p \]  \hspace{1cm} (A.63)

where

\[ \rho_c = \text{gas core density}. \]

The gas core density is related to the gas and liquid densities through

\[ \rho_c = \frac{\rho_g (1 - H_{IF} - H_{IC}) + \rho_f H_{IC}}{1 - H_{IF}} \]  \hspace{1cm} (A.64)

By eliminating the pressures from Equations A.62 and A.63, one can get the combined momentum equation:

\[ \frac{\rho_f (u_T - u_F)(u_S - u_F)}{l_F} - \frac{\rho_c (u_T - u_C)(u_S - u_C)}{l_F} - \frac{\tau_{FSF}}{H_{IF} A} + \frac{\tau_{CSF}}{(1 - H_{IF}) A} + \tau_{i\delta} \left( \frac{1}{H_{IF} A} + \frac{1}{(1 - H_{IF}) A} \right) - (\rho_f - \rho_c) g \sin \theta = 0 \]  \hspace{1cm} (A.65)

The above equations are the governing equations for slug flow. Before the equations can be solved to get the liquid holdup, pressure drop, and other slug flowing parameters, a few closure equations are still needed.
The shear stresses can be evaluated as:

\[
\tau_F = f_F \frac{\rho_l u_F^2}{2}, \quad \tau_C = f_C \frac{\rho_g u_C^2}{2}, \quad \tau_i = f_i \frac{\rho_C (u_C - u_F)|u_C - u_F|}{2}
\]  

(A.66)

Zhang et al. presented an equation to link the shear stress at the pipe wall with the shear stress at the gas-liquid interface:

\[
\tau_F = \frac{3\mu_f u_F}{h_F} = \frac{\tau_i}{2}
\]  

(A.67)

where

\( h_F \) is the average liquid film height in the film region, and is defined as

\[
h_F = \frac{2A H_{lF}}{s_F + s_i}
\]  

(A.68)

The friction factors at the pipe wall can be estimated as:

\[
f = m Re^{-n}
\]  

(A.69)

For laminar flow (Reynolds number less than 2000), \( m = 16 \) and \( n = 1 \). For turbulent flow (Reynolds number larger than 3000) and smooth pipe wall, \( m = 0.046 \) and \( n = 0.2 \).

The Reynolds numbers for the film and gas core are defined as:

\[
Re_F = \frac{4H_{lF} A u_F \rho_l}{s_F \mu_f}
\]  

(A.70)

\[
Re_C = \frac{4(1 - H_{lF}) A u_C \rho_g}{(s_C + s_i) \mu_g}
\]  

(A.71)

The liquid holdup in the gas core is neglected in Equation A.71.

For the pipe perimeter calculations, Zhang et al. proposed the following geometry relations.

\[
\Theta_l = \Theta_{l0} \left( \frac{\sigma_{water}}{\sigma} \right)^{0.15} + \frac{\rho_g}{\rho_l - \rho_g} \frac{1}{\cos \theta} \left( \frac{\rho_l U_{dL}^2 D}{\sigma} \right)^{0.25} \left( \frac{U_{g}^2}{(1 - H_{lF})^2 g D} \right)^{0.8}
\]  

(A.72)

where

\( \Theta_l, \Theta_{l0} \) = pipe wall fraction wetted by liquid with curved and flat gas-liquid interfaces, respectively

\( \sigma_{water}, \sigma \) = water and liquid surface tension, respectively

and
Another closure equation on the liquid entrainment in the gas core is needed. The correlation by Olieman et al. (1986) for vertical pipe is presented here:

\[
\frac{f_E}{1 - f_E} = 10^{\beta_0} \rho_f^{\beta_1} \rho_g^{\beta_2} \mu_l^{\beta_3} \mu_g^{\beta_4} \sigma^{\beta_5} D^{\beta_6} U_f^{\beta_7} U_g^{\beta_8} g^{\beta_9}
\]  
(A.75)

Equation A.75 is based upon data regression and all the coefficients are constants and are given below:

\[
\begin{align*}
\beta_0 &= -2.52, \quad \beta_1 = 1.08, \quad \beta_2 = 0.18, \quad \beta_3 = 0.27, \quad \beta_4 = 0.28 \\
\beta_5 &= -1.80, \quad \beta_6 = 1.72, \quad \beta_7 = 0.70, \quad \beta_8 = 1.44, \quad \beta_9 = 0.46
\end{align*}
\]

\[
\frac{s_{F}}{s_{I}} = \pi D \Theta_l
\]  
(A.73)

\[
\frac{D^2}{4} \left( \frac{\pi \Theta_l - \sin(2\pi \Theta_l)}{2} - H_{lF} A \right) + H_{lF} A D \sin(\pi \Theta_l)
\]  
(A.74)

\[
H_{lS} = \frac{1}{1 + \left( \frac{u_S}{8.66} \right)^{1.39}}
\]  
(A.76)

Equation A.76 is based upon data regression and all the coefficients are constants and are given below:

Another closure equation on the liquid entrainment in the gas core is needed. The correlation by Olieman et al. (1986) for vertical pipe is presented here:

Zhang et al. proposed a model to calculate the holdup inside the slug body. The simpler correlation by Gregory et al. is presented here.

The slug velocity is the sum of the superficial gas and superficial liquid velocities. Another parameter that must be calculated independently is the slug translational velocity. Zhang et al. proposed the following equation based upon Bendiksen’s work in 1984.

\[
u_T = C u_S + 0.54 \sqrt{gD} \cos \theta_p + 0.35 \sqrt{gD} \sin \theta_p
\]  
(A.77)

Zhang et al. also proposed the following equation for the slug length:

\[
l_S = (32 \cos^2 \theta_p + 16 \sin^2 \theta_p) D
\]  
(A.78)

From the above equation, for horizontal flow, the slug length equals 32 times the pipe diameter, and for vertical flow, the slug length is 16 times the pipe diameter. Slug flow parameters can now be solved from all the above equations. Trial and error must be used. It is suggested to start with guessing a value for the film length.

\section{A.6.3 Annular Flow Model}

In steady-state annular flow, the majority of the gas and liquid are segregated with gas flows as a core in the center of the pipe and liquid flows as a film around the pipe wall, as
shown in Figure A.9. Some liquid droplets are entrained in the gas core. As for stratified flow, annular flow can be calculated by using the two-fluid model. It is also assumed that there is no gas bubble in the film region.

Similar to Equations A.38 and A.40, the momentum equation for the film and for the gas core can be written as:

\[-A_F \frac{dp}{dx} + \tau_i s_i - \tau_F s_F - A_F \rho_g g \sin \theta_p = 0\] 

(A.79)

and

\[-A_C \frac{dp}{dx} - \tau_i s_i - A_C \rho_C g \sin \theta_p = 0\] 

(A.80)

Since the gas core is surrounded by the liquid film, there is no gas wall shear stress term in the momentum equation for the gas core.

Equations A.79 and A.80 can be combined by eliminating the pressure:

\[\frac{\tau_F}{A_F} s_F - \tau_i s_i \left( \frac{1}{A_F} + \frac{1}{A_C} \right) + (\rho_l - \rho_C) g \sin \theta_p = 0\] 

(A.81)

The shear stresses are defined in Equations A.66, A.69, A.70, and A.71. For annular flow:

\[s_F = \pi D, \quad s_i = \pi (D - 2 \delta_l)\] 

(A.82)

where

\[\delta_l = \text{average film thickness}\]

Since it is assumed that there is no gas bubble in the liquid film, the film liquid holdup can be calculated as:

\[H_{IF} = \frac{4 \delta_l (D - \delta_l)}{\pi D^2}\] 

(A.83)
And the liquid holdup in the gas core can be calculated as:

\[ H_{hl} = \frac{f_E U_{sl}(1 - H_{IF})}{U_g + f_E U_{sl}} \]  
(A.84)

Equation A.84 is based upon the definition of the liquid droplet entrainment fraction. Thus, the gas core velocity can be calculated as:

\[ u_C = \frac{U_g}{1 - H_{IF} - H_{IC}} \]  
(A.85)

The liquid film velocity can be calculated as:

\[ u_F = \frac{U_{sl} - H_{IC} u_C}{H_{IF}} \]  
(A.86)

The last correlation needed to solve for annular flow is the friction factor at the interface. The correlation suggested by Xiao et al. (1990) is presented here:

\[ f_i = f_c \left[ 1 + 2250 \left( \frac{\delta_l/D}{\rho_C(u_C - u_F)^2 \delta_l} \right) \right] \]  
(A.87)

The core friction factor can be calculated using Equation A.69. Thus, the description of annular flow is completed. To solve for the flow parameters, it is suggested to start by guessing an average film thickness, \( \delta_l \). With the guessed average film thickness, if Equation A.81 is satisfied, the guessed film thickness is the right one and the corresponding flow velocities, liquid holdups, and pressure drops can be calculated using the proper equations.

A.6.4 Dispersed Bubble Flow Model

In dispersed bubble flow, the gas flows as discrete bubbles in a continuous liquid phase. If it is assumed that there is no slippage between the gas bubbles and the liquid, dispersed bubble flow can be treated as a pseudo single-phase flow. The parameters, such as density and viscosity, can be evaluated using the non-slip liquid holdup as discussed in Section A.2. Once the parameters are evaluated, single-phase flow equations can be used for pressure drop calculations.

References


APPENDIX B

Steady and Transient Solutions for Pipeline Temperature

B.1 Assumptions

The following assumptions are made in model formulation:

1) friction-induced heat is negligible
2) heat transfer in the radial direction is fully controlled by the insulation fluid
3) specific heat of fluid is constant

B.2 Governing Equation

Figure B.1 depicts a small element of pipe with an insulation layer. Such a pipe can be a well tubing or pipeline.

Consider the heat flow during a time period of $\Delta t_f$. Heat balance is given by

$$q_{in} - q_{out} - q_R = q_{acc} \quad (B.1)$$

\[ \text{Figure B.1 Sketch illustrating convection and conduction heat transfer in a pipe.} \]
where

\( q_{in} \) = heat energy brought into the pipe element by fluid due to convection, J

\( q_{out} \) = heat energy carried away from the pipe element by fluid due to convection, J

\( q_R \) = heat energy transferred through the insulation layer due to conduction, J

\( q_{acc} \) = heat energy accumulation in the pipe element, J

These terms can be further formulated as

\[ q_{in} = \rho_f C_p v A_f T_{f,l} \Delta t_f \]  \hspace{1cm} (B.2)

\[ q_{out} = \rho_f C_p v A_f T_{f,l+\Delta L} \Delta t_f \]  \hspace{1cm} (B.3)

\[ q_R = 2\pi R_n k_n \Delta L \frac{\partial T_f}{\partial r} \Delta t_f \]  \hspace{1cm} (B.4)

\[ q_{acc} = \rho_f C_p A_f \Delta L \Delta \bar{T}_f \]  \hspace{1cm} (B.5)

where

\( \rho_f \) = fluid density, kg/m\(^3\)

\( C_p \) = specific heat at constant pressure, J/kg-C

\( v \) = the average flow velocity of fluid in the pipe, m/s

\( A_f \) = cross-sectional area of pipe open for fluid flow, m\(^2\)

\( T_{f,l} \) = temperature of the flowing-in fluid, C

\( \Delta t_f \) = flow time, s

\( T_{f,l+\Delta L} \) = temperature of the flowing-out fluid, C

\( R_n \) = inner-radius of insulation layer, m

\( k_n \) = thermal conductivity of the insulation layer, W/m-C

\( \Delta L \) = length of the pipe segment, m

\( \frac{\partial T_f}{\partial r} \) = radial-temperature gradient in the insulation layer, C/m

\( \Delta \bar{T}_f \) = the average temperature increase of fluid in the pipe segment, C

Substituting Equations (B.2) through (B.5) into Equation (B.1) gives

\[ \rho_f C_p v A_f \Delta t (T_{f,l} - T_{f,l+\Delta L}) - 2\pi R_n k_n \Delta L \frac{\partial T_f}{\partial r} \Delta t_f = \rho_f C_p A_f \Delta L \Delta \bar{T}_f \]  \hspace{1cm} (B.6)

Dividing all the terms of this equation by \( \Delta L \Delta t_f \) yields

\[ \rho_f C_p v A_f \frac{(T_{f,l} - T_{f,l+\Delta L})}{\Delta L} - 2\pi R_n k_n \frac{\partial T_f}{\partial r} = \rho_f C_p A_f \frac{\Delta \bar{T}_f}{\Delta t_f} \]  \hspace{1cm} (B.7)

For infinitesimal of \( \Delta L \) and \( \Delta t_f \), this equation becomes

\[ v \frac{\partial T_f}{\partial L} + \frac{\partial T_f}{\partial t_f} = -\frac{2\pi R_n k_n}{\rho_f C_p A_f} \frac{\partial T_f}{\partial r} \]  \hspace{1cm} (B.8)
The radial-temperature gradient in the insulation layer can be formulated as

$$\frac{\partial T_f}{\partial r} = \frac{T_f - (T_{f,0} - G \cos(\theta)L)}{s} \quad (B.9)$$

where

$T_{f,0} = \text{temperature of the medium outside the insulation layer at } L = 0, \degree C$

$G = \text{geothermal gradient, } \degree C/m$

$\theta = \text{inclination time, degree}$

$s = \text{thickness of the insulation layer, m}$

Substituting Equation (B.9) into Equation (B.8) yields

$$\nu \frac{\partial T_f}{\partial L} + \frac{\partial T_f}{\partial t_f} = aT_f + bL + c \quad (B.10)$$

where

$$a = -\frac{2\pi R_w k_n}{\rho_f C_p s A_f} \quad (B.11)$$

$$b = aG \cos(\theta) \quad (B.12)$$

and

$$c = -aT_{f,0} \quad (B.13)$$

**B.3 Solutions**

Three solutions are sought in this study:

Solution A: Steady flow;
Solution B: Transient flow with static fluid as the initial condition; and
Solution C: Transient flow with steady flow as the initial condition

Solution A gives temperature profile during normal operation conditions; Solution B simulates temperature change during a start-up process; and Solution C yields temperature trend during a shut-down process.

**B.3.1 Steady Heat Transfer**

If the mass flow rate is maintained for a significantly long time, a steady heat transfer condition between the system and its surroundings is expected. Under steady flow conditions, the temperature at any point in the system is time-independent. Therefore, Equation (B.10) becomes
\[ v \frac{dT_f}{dL} = aT_f + bL + c \quad (B.14) \]

This equation can be solved with boundary condition

\[ T = T_{f,s} \text{ at } L = 0 \quad (B.15) \]

To simplify the solution, Equation (B.14) is rearranged to be

\[ \frac{dT_f}{dL} + \alpha T_f + \beta L + \gamma = 0 \quad (B.16) \]

where

\[ \alpha = -\frac{a}{v} \quad (B.17) \]
\[ \beta = -\frac{b}{v} \quad (B.18) \]

and

\[ \gamma = -\frac{c}{v} \quad (B.19) \]

Let

\[ u = \alpha T_f + \beta L + \gamma \quad (B.20) \]

then

\[ T_f = \frac{u - \beta L - \gamma}{\alpha} \quad (B.21) \]

and

\[ \frac{dT_f}{dL} = \frac{1}{\alpha} \frac{du}{dL} - \frac{\beta}{\alpha} \quad (B.22) \]

Substituting Equations (B.21) and (B.22) into Equation (B.16) gives

\[ \frac{1}{\alpha} \frac{du}{dL} - \frac{\beta}{\alpha} + u = 0 \quad (B.23) \]

Integration of this equation with the method of separation of variables yields

\[ -\frac{1}{\alpha} \ln (\beta - \alpha u) = L + C \quad (B.24) \]
where $C$ is a constant of integration. Substituting Equation (B.20) into Equation (B.24) and rearranging the latter result in

$$T_f = \frac{1}{\alpha^2} \left[ \beta - \alpha \beta L - \alpha \gamma - e^{-\alpha (L + C)} \right]$$

(B.25)

Applying boundary condition (B.15) to Equation (B.25) gives the expression for the integration constant

$$C = -\frac{1}{\alpha} \ln \left( \beta - \alpha^2 T_f, - \alpha \gamma \right)$$

(B.26)

### B.3.2 Transient Heat Transfer during Starting-Up

The temperature profile along the pipe during the starting-up process can be obtained by solving Equation (B.10) with the method of characteristics, subject to the initial condition

$$T_f = T_{f,0} - G \cos(\theta)L \quad \text{at} \quad t = 0 \quad \text{(B.27)}$$

Consider a family of curves defined by the equation

$$dt_f = \frac{dL}{v} = \frac{dT_f}{aT + bL + c}$$

(B.28)

The characteristics are

$$L = vt_f + K$$

(B.29)

We also have from Equation (B.28)

$$\frac{dT_f}{dL} = \frac{aT_f + bL + c}{v}$$

(B.30)

Using notations (B.17), (B.18), and (B.19), Equation (B.30) becomes

$$\frac{dT_f}{dL} + \alpha T_f + \beta L + \gamma = 0$$

(B.31)

which is exactly Equation (B.16). Its solution is the same as Equation (B.25), i.e.,

$$T_f = \frac{1}{\alpha^2} \left[ \beta - \alpha \beta L - \alpha \gamma - e^{-\alpha (L + A)} \right]$$

(B.32)

where $A$ is an arbitrary constant of integration. This constant is different on each characteristic curve. Further, each characteristic curve has a different value of $K$. Hence,
as $K$ varies, $A$ varies and we may write $A = f(K)$, where $f$ is an arbitrary function to be determined. Writing $A = f(K)$ in Equation (B.32) yields

$$T_f = \frac{1}{\alpha^2} \left[ \beta - \alpha \beta L - \alpha \gamma - e^{-\alpha(L+f(K))} \right] \quad (B.33)$$

Eliminating $K$ using Equation (B.29), gives:

$$T_f = \frac{1}{\alpha^2} \left[ \beta - \alpha \beta L - \alpha \gamma - e^{-\alpha[L+f(L-v_f)]} \right] \quad (B.34)$$

Now applying the initial condition (B.27) gives

$$T_{f,0} - G \cos(\theta)L = \frac{1}{\alpha^2} \left[ \beta - \alpha \beta L - \alpha \gamma - e^{-\alpha[L+f(L)]} \right] \quad (B.35)$$

which gives

$$f(L) = - L - \frac{1}{\alpha} \ln \left[ \beta - \alpha \beta L - \alpha \gamma - \alpha^2 (T_{f,0} - G \cos(\theta)L) \right] \quad (B.36)$$

Therefore,

$$f(L - vtf) = -(L - vtf) - \frac{1}{\alpha} \ln \left[ \beta - \alpha \beta (L - vtf) \right] - \alpha \gamma - \alpha^2 \left[ T_0 - G \cos(\theta)(L - vtf) \right] \quad (B.37)$$

Substituting Equation (B.37) into Equation (B.34) results in the solution to Equation (B.10) subject to the initial condition (B.27). This solution is valid for $L - vtf > 0$. For points at which $L - vtf < 0$, $L - vtf = 0$ should be used.

### B.3.3 Transient Heat Transfer during a Flow Rate Change

The temperature trend along the pipe during a flowrate change (shutting-down is a special case) process can be obtained by solving Equation (B.10) with a new velocity $v'$ corresponding to a new flow rate. The general solution is still given by Equation (B.34) with new parameters corresponding to the low velocity, i.e.,

$$T_f = \frac{1}{\alpha'^2} \left[ \beta' - \alpha' \beta' L - \alpha' \gamma' - e^{-\alpha'[L+f(L-v')]} \right] \quad (B.38)$$

where

$$\alpha' = - \frac{a}{v'} \quad (B.39)$$

$$\beta' = - \frac{b}{v'} \quad (B.40)$$
and

\[ \gamma' = -\frac{c}{\nu'} \quad (B.41) \]

The initial condition is defined by Equation (B.25), i.e.,

\[ T_f = \frac{1}{a^2} \left[ \beta - \alpha \beta L - \alpha \gamma - e^{-\alpha(L+C)} \right] \text{at } t_f = 0 \quad (B.42) \]

where the constant \( C \) is given by Equation (B.26).

Now applying the initial condition (B.42) to Equation (B.38) gives

\[ \frac{1}{a^2} \left[ \beta - \alpha \beta L - \alpha \gamma - e^{-\alpha(L+C)} \right] = \frac{1}{a^2} \left[ \beta' - \alpha' \beta' L - \alpha' \gamma' - e^{-\alpha'(L+f(L))} \right] \quad (B.43) \]

which yields

\[ f(L) = -L - \frac{1}{\alpha'} \]

\[ \times \ln \left\{ \beta' - \alpha' \beta' L - \alpha' \gamma' - \left( \frac{\alpha'}{\alpha} \right)^2 \left[ \beta - \alpha \beta L - \alpha \gamma - e^{-\alpha(L+C)} \right] \right\} \quad (B.44) \]

Therefore,

\[ f(L - vt_f) = -(L - vt_f) - \frac{1}{\alpha'} \ln \left\{ \beta' - \alpha' \beta' (L - vt_f) - \alpha' \gamma' - \left( \frac{\alpha'}{\alpha} \right)^2 \right\} \]

\[ \left[ \beta - \alpha \beta (L - vt_f) - \alpha \gamma - e^{-\alpha[(L-\nu t_f)+C]} \right] \quad (B.45) \]

Substituting Equation (B.45) into Equation (B.38) results in the solution to Equation (B.10) subject to the initial condition (B.42).
C.1 Introduction

The strength of old pipelines declines because of a number of reasons, with corrosion being the major one. This is especially true when the pipeline is not well corrosion-protected. Corrosion mechanisms include electrochemical corrosion, chemical corrosion, and stress-promoted corrosion. Pipeline pitting (cavity) due to failure of corrosion protection is most common. Figure C.1 shows a typical cavity due to corrosion. Stress concentration around the pitted area results in degradation of pipeline strength (pressure rating). This document presents expressions of stress concentration factors (SCF) around spherical pits of various geometries based on Sun’s work (2003). The de-rated strength of pipeline is equal to the strength of new pipeline divided by the SCF.

C.2 Classification of Cavities

To simplify the stress concentration analysis of corrosion cavity on pipeline walls, spherical-surface cavities are classified into three categories: shallow, medium, and deep cavities.

Figure C.1 A typical spherical cavity on a pipeline wall.
A simplified diagram for a spherical surface cavity is shown in Figure C.2 where \( t \) is the wall thickness of the pipeline; \( d \) and \( h \) are the diameter and depth of the corrosion cavity, respectively. When \( h \) is equal to \( d/2 \), the cavity is exactly hemispherical and is classified as medium cavity. Shallow cavity is defined as a cavity with \( h \)-value being less than \( d/2 \), while deep cavity is defined as the one with \( h \)-value being greater than \( d/2 \).

C.3 Analytical SCF Model for Medium Cavity

Using the same approach adopted by Wang (2001) for SCF analysis, Sun (2003) derived the following expression for pipe with a hemispherical cavity:

\[
SCF = \frac{27 - 15\nu}{14 - 10\nu} \left( 1 - k_1 \frac{a^3}{t^3} - k_2 \frac{a^5}{t^5} \right)
\]  

where the constants \( k_1 \) and \( k_2 \) are given by:

\[
k_1 = -\frac{27 - 15\nu}{14 - 10\nu} \cdot \frac{5 - 4\nu^2}{(6 - 4\nu)(1 + \nu)} + 2.5
\]  

and

\[
k_2 = \frac{27 - 15\nu}{14 - 10\nu} \cdot \frac{5 - 4\nu^2}{(6 - 4\nu)(1 + \nu)} - 1.5
\]
C.4 Analytical SCF Model for Shallow Cavity

Sun (2003) derived the following expression for pipe with a shallow spherical cavity:

\[
SCF = \frac{b^2 \cdot \gamma - (a - b) \cdot \sqrt{b^2 - (a - b)^2}}{b^2 \gamma - a^2 \beta - (a - b)^2 (tg \gamma - tg \beta) + \frac{a^3 (4m - 5mv + 3a^2 n)}{(7 - 5v)}} \cdot \frac{27 - 15v}{14 - 10v}
\]

(C.4)

where the constants are given by

\[
a = \frac{d^2 + 4b^2}{8b}
\]

(C.5)

\[
b = a - b + t
\]

(C.6)

\[
m = \frac{\sin \gamma - \sin \beta}{a - b} + \frac{\beta - \gamma}{b}
\]

(C.7)

\[
n = \frac{3 \sin \gamma - 3 \sin \beta - \sin^3 \gamma - \sin^3 \beta + \frac{\beta}{a^3} - \frac{\gamma}{b^3}}{3(a - b)^3}
\]

(C.8)

\[
\beta = \arccos \left( \frac{a - b}{a} \right)
\]

(C.9)

\[
\gamma = \arccos \left( \frac{a - b}{b} \right)
\]

(C.10)

C.5 Analytical SCF Model for Deep Cavity

Sun (2003) derived the following expression for pipe with a deep spherical cavity:

\[
SCF = \frac{\left(\pi \cdot b^2 - b^2 \cdot \psi + (b - a) \cdot \sqrt{b^2 - (b - a)^2}\right) \cdot \left[(27 - 15v)/(14 - 10v)\right]}{(b^2 - a^2) \cdot (\pi - \psi) - a^2 (\psi - \omega) + (b - a)^2 (tg \psi - tg \omega) + \frac{a^2 (4w - 5vw + 3a^3 u)}{(7 - 5v)}}
\]

(C.11)

where

\[
a = \frac{d^2 + 4b^2}{8b}
\]

(C.12)

\[
b = a - b + t
\]

(C.13)

\[
u = \frac{3 \sin \omega - 3 \sin \psi + \sin^3 \psi - \sin^3 \omega + \pi - \psi - \pi - \psi}{3(h - a)^3} + \frac{\pi - \psi}{a^3} - \frac{\pi - \psi}{b^3}
\]

(C.14)
\begin{align*}
  w &= \pi - \omega - \frac{a(\sin \psi - \sin \omega)}{b - a} - \frac{a(\pi - \psi)}{b} + \frac{3(\psi - \omega)}{4 - 5\nu} \\
  \psi &= \arccos \left( \frac{b - a}{b} \right) \\
  \omega &= \arccos \left( \frac{b - a}{a} \right)
\end{align*}

(C.15) (C.16) (C.17)

**C.6 Illustrative Example**

Consider an X-60 steel pipeline with an outside diameter of 30 inches and wall thickness of 1.0 inch. The pipeline is classified as a thin-wall pipe because the diameter/thickness ratio \( \frac{D}{t} = 30 \) is greater than 20. According to Equation (6.1), the yield strength of 60 ksi corresponds to a net internal pressure of

\[
  P = \frac{2tS_y}{D} = \frac{(2)(1.0)(60,000)}{30} = 4000 \text{ psi}
\]

Suppose a spherical cavity were present on the surface of the pipeline due to corrosion pitting. Assume the cavity had an open diameter of \( d = 0.1 \) inch and depth of \( h = 0.75 \) inch. Since \( h > d/2 \), the cavity is classified as a deep cavity. The following calculations are made to determine SCF:

\[
  a = \frac{d^2 + 4b^2}{8b} = \frac{(0.1)^2 + 4(0.075)^2}{8(0.075)} = 0.054 \text{ inch}
\]

\[
  b = a - h + t = 0.054 - 0.075 + 0.5 = 0.48 \text{ inch}
\]

\[
  \psi = \arccos \left( \frac{h - a}{b} \right) = \arccos \left( \frac{0.075 - 0.054}{0.48} \right) = 1.53 \text{ rad}
\]

\[
  \omega = \arccos \left( \frac{h - a}{a} \right)
\]
\[
\begin{align*}
&= \arccos\left(\frac{0.075 - 0.054}{0.054}\right) \\
&= 1.18 \text{ rad}
\end{align*}
\]

\[
u = \frac{3 \sin \psi - 3 \sin \omega + \sin^3 \psi - \sin^3 \omega}{3(b - a)^3} + \frac{\pi - \psi}{a^3} - \frac{\pi - \psi}{b^3}
\]

\[
\begin{align*}
&= \frac{3 \sin(1.53) - 3 \sin(1.18) + \sin^3(1.53) - \sin^3(1.18)}{3(0.075 - 0.054)^3} + \frac{3.14 - 1.53}{(0.054)^3} - \frac{3.14 - 1.53}{(0.48)^3} \\
&= 9505 \text{ inch}^{-3}
\end{align*}
\]

\[
w = \pi - \omega - \frac{a(\sin \psi - \sin \omega)}{b - a} - \frac{a(\pi - \psi)}{b} + \frac{3(\psi - \omega)}{4 - 5\nu}
\]

\[
\begin{align*}
&= 3.14 - 1.18 - \frac{\sin(1.53) - \sin(1.18)}{0.075 - 0.054} - \frac{0.054(3.14 - 1.53)}{0.48} - \frac{3(3.14 - 1.18)}{4 - 5(0.3)} \\
&= 2.007 \\
(27 - 15\nu)/(14 - 10\nu) &= (27 - 15(0.3))/(14 - 10(0.3)) \\
&= 2.045
\end{align*}
\]

\[
\begin{align*}
&= \frac{a^2(4w - 5\nu w + 3a^3 u)}{(7 - 5\nu)} = \frac{(0.054)^2(4(2.007) - 5(2.007)(0.3) + 3(0.054)^3(9505))}{(7 - 5(0.3))} \\
&= 0.005
\end{align*}
\]

\[
SCF = \frac{\left(\pi \cdot b^2 - b^2 \cdot \psi + (b - a) \cdot \sqrt{b^2 - (b - a)^2}\right) \cdot [(27 - 15\nu)/(14 - 10\nu)]}{(b^2 - a^2) \cdot (\pi - \psi) - a^2(\psi - \omega) + (b - a)^2(tg\psi - tg\omega) + \frac{a^2(4w - 5\nu w + 3a^3 u)}{(7 - 5\nu)}}
\]

\[
\begin{align*}
&= \frac{\left(3.14(0.48)^2 - (0.48)^2(1.53) + (0.075 - 0.054)(0.48)^2 - (0.075 - 0.054)^2\right)[2.045]}{((0.48)^2 - (0.054)^2)(3.14 - 1.53) - (0.054)^2(1.53 - 1.18) - (0.075 - 0.054)^2(tg(1.53) - tg(1.18)) + 0.005} \\
&= 2.055
\end{align*}
\]

Therefore, the pipe will start to yield near the corrosion pit at a net internal pressure of

\[
P_{\text{yield}} = \frac{P}{SCF} = \frac{4000}{2.055} = 1946 \text{ psi}
\]
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