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 1½ inch.
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![Diagram of offshore pipeline system]

**Figure 1.1 Uses of offshore pipelines.**

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:
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

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**TABLE 1.1 Sample Pipeline Sizes**

<table>
<thead>
<tr>
<th>Project No.</th>
<th>Project Name</th>
<th>Pipeline Diameter (in)</th>
<th>Wall Thickness (in)</th>
<th>D/t</th>
<th>Design Criterion</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Zinc</td>
<td>4</td>
<td>0.438</td>
<td>10</td>
<td>Internal pressure</td>
</tr>
<tr>
<td>2</td>
<td>GC 108-AGIP</td>
<td>6</td>
<td>0.562</td>
<td>12</td>
<td>Internal pressure</td>
</tr>
<tr>
<td>3</td>
<td>Zinc</td>
<td>8</td>
<td>0.500</td>
<td>17</td>
<td>Internal pressure</td>
</tr>
<tr>
<td>4</td>
<td>Amerada Hess</td>
<td>8</td>
<td>0.500</td>
<td>17</td>
<td>Internal pressure</td>
</tr>
<tr>
<td>5</td>
<td>Viosca Knoll</td>
<td>8</td>
<td>0.562</td>
<td>15</td>
<td>Internal pressure</td>
</tr>
<tr>
<td>6</td>
<td>Vancouver</td>
<td>10</td>
<td>0.410</td>
<td>26</td>
<td>External pressure</td>
</tr>
<tr>
<td>7</td>
<td>Marlim</td>
<td>12</td>
<td>0.712</td>
<td>18</td>
<td>External pressure</td>
</tr>
<tr>
<td>8</td>
<td>Palawan</td>
<td>20</td>
<td>0.812</td>
<td>25</td>
<td>External pressure</td>
</tr>
<tr>
<td>9</td>
<td>Palawan</td>
<td>24</td>
<td>0.375</td>
<td>64</td>
<td>Internal pressure</td>
</tr>
<tr>
<td>10</td>
<td>Marlim</td>
<td>26</td>
<td>0.938</td>
<td>28</td>
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</tr>
<tr>
<td>11</td>
<td>Palawan</td>
<td>30</td>
<td>0.500</td>
<td>60</td>
<td>Internal pressure</td>
</tr>
<tr>
<td>12</td>
<td>Shottonman</td>
<td>36</td>
<td>1.225</td>
<td>29</td>
<td>Internal pressure</td>
</tr>
<tr>
<td>13</td>
<td>Talinpu</td>
<td>56</td>
<td>0.750</td>
<td>72</td>
<td>Internal pressure</td>
</tr>
<tr>
<td>14</td>
<td>Marlim</td>
<td>38</td>
<td>1.312</td>
<td>29</td>
<td>External pressure</td>
</tr>
<tr>
<td>15</td>
<td>Shottonman</td>
<td>44</td>
<td>1.500</td>
<td>29</td>
<td>Internal pressure</td>
</tr>
<tr>
<td>16</td>
<td>Talinpu</td>
<td>56</td>
<td>0.750</td>
<td>64</td>
<td>Internal pressure</td>
</tr>
</tbody>
</table>

Notes:
1. Buckle arrestors required.
2. Pipelines with D/t over 30.5 float in water without coating.

- 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.
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
**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):

**Figure 1.7** Bottom tow for pipeline installation.
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- 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 (>C_{20}H_{42}) 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). Asphalten precipitation from crude oils can cause serious problems in the reservoir, wellbore, and in the production facilities. Asphaltenes 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., asphaltenes, 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

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