Corrosion of multiphase flow pipelines: the impact of crude oil

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Abstract: The control of multiphase flow corrosion during oil production is a challenging task. In this review, the impact of crude oil on pipeline corrosion is broadly discussed, with the notion to reduce corrosion risks of pipelines in aggressive field conditions. First, the properties, emulsion stability, and multiphase flow patterns of crude oil fluids are concisely summarized and correlated to the corrosion behavior. Second, for proper evaluation of the corrosiveness of the oil-brine mixtures, related corrosion test methods and experimental techniques are critically evaluated. Third, the effects of crude oil on corrosion inhibition are conceivably attributed to four aspects, i.e. the entrainment of water, the wetting by crude oil, the partitioning effect, and the modification of the corrosion product layers. Fourth, the presence of crude oil may consume more corrosion inhibitors; however, the inhibitors can produce additional benefits on corrosion mitigation in oil-brine mixed conditions, such as altering the surface wettability to hydrophobic and enhancing the entrainment of water. Finally, some ideas to reduce pipeline corrosion are proposed and future research viewpoints are discussed.

Keywords: corrosion inhibition; crude oil; emulsion; flow pattern; pipeline corrosion.

1 Introduction

1.1 Field corrosion problem in oil production

For several decades, crude oil has been playing a basic role in the industrial development and economic activities of our lives. Advancement in the crude production process has made much more effective and safety is no doubt of great importance. Therefore, great efforts have been made to properly design the production and transportation systems facing different field conditions. Corrosion is one of the greatest threats that may sharply reduce the service life of the facilities and pipelines. Internal corrosion is a direct reason for pipeline damages (Nesic & Sun, 2010; Papavinasam, Revie, Friesen, Doiron, & Panneerselvan, 2006; Smith, Curry, & Rush, 1951). Once pipeline leakage happens, the industry has to bear all the consequences, from security, to environmental, to economic aspects. Hence, the corrosion issue must be seriously taken into consideration during crude oil production and transportation.

Crude oil explored from reservoirs generally contains water (to be exact, brine solution). When the aqueous phase gets in contact with the steel surface, electrochemical corrosion occurs. The production water after separation at the treatment stations generally contains small or trace amount of crude oil. The contamination by crude oil may also affect the corrosion performance of the water re-injection pipelines. Crude oils serve as an important role in pipeline corrosion during the entire process of oil production and water re-injection. However, the influence of crude oil on pipeline corrosion was not well understood in the existing corrosion prediction models (Nesic, 2007; Nyborg, 2010). If the steel surface is totally wetted by crude oil, a beneficial effect on corrosion mitigation can be observed. Therefore, the wettability of crude oil and water on steel surface is critical for triggering corrosion (Smart, 1993; Schmitt, 1998). In a flow condition, corrosion at the bottom of the line is generally observed (Larsen, 2013), owing to a preferential wetting of the pipeline bottom by the aqueous phase. Water cut is a key factor affecting the internal corrosion risk of pipelines (Craig, 1996). However, the corrosion performance of steel in different oil-brine mixed fluids is very complex. According to field experience, corrosion has been observed in a wide range of water cuts (Efird, 1991; Graig, 1998). A small amount of water may induce corrosion problems. In other cases, pipelines that transport production fluids with relatively high water cuts (for example, up to 50 wt%) have been reported to be free from corrosion (Li, Tang, Ayello, Cai, & Nesic, 2006). It seems closely dependent on the properties and types of the crude oil. Clearly, an evaluation of the
corrosiveness of the production fluids is necessary for the design of the oil production and transportation pipelines.

Currently, many studies have focused on the corrosion performance of mild steel in simulated oil production fluids. The roles of some corrosive species, such as Cl (Eliyan, Mahdi, & Alfantazi, 2012; Jiang, Nesic, Kinsella, Brown, & Young, 2013; Liu, Mao, & Zhou, 2014), HCO3 (Davies & Burstein, 1980), and Ac (Amri, Gulbrandsen, & Nogueira, 2010; Singer, Hinkson, Zhang, Wang, & Nesic, 2013), as well as CO2 and H2S gases (Nesic, 2007), were widely investigated. The mechanism of corrosion product layer formation (Ingham et al., 2012; Zhang, Wang, Wang, & Han, 2012), localized attack (Nyborg, 1998; Xia, Chou, & Szklarska-Smialowska, 1989), and the environmental performance of mild steel in aqueous phase solutions containing CO2 or H2S has been deeply described. Besides the electrochemical aspects, the influence of crude oil on corrosion must be taken into consideration when a field corrosion problem was encountered. Although a series of profound research have demonstrated the influence of flow rate on pipeline corrosion in aqueous fluids (Ruzic, Veidt, & Nesic, 2006; Schmitt, Bosch, Mueller, & Siegmund, 2000; Zheng, Che, & Liu, 2008), to date, it remains hard to address clearly the corrosion mechanism of steels in such an oil-containing heterogeneous corrosive media. Recognition of the role of crude oil becomes a key issue to tackle with the field corrosion problem of pipelines.

### 1.2 New demands for corrosion management

In recent years, with the wide application of new enhanced oil recovery (EOR) methods, the production fluids become more aggressive to carbon steel. Different from conventional oil production, the EOR technique generally acidified the production fluids by the presence of acid gases, such as CO2 and H2S gases, whose partial pressures in the gas phase are extraordinarily high compared with those from conventional oil production. According to a field analysis in the Shengli oilfield (Wang, Liu, Han, & Zhang, 2015; Zhang et al., 2012), a partial pressure of CO2 gas in the EOR pipeline was up to 0.3 to 1.0 MPa, referencing a pH value lower than 4.0. Therefore, an extremely high corrosion rate of mild steel has been observed in such environments. For example, Wang et al. observed a corrosion rate higher than 1.0 mm/year in the presence of free water under simulated CO2-EOR conditions (Wang, Han, Zhang, & Wang, 2014a; Wang, et al., 2014c). Although CO2 injection can make a considerable increase in crude production, the corrosive production fluid damages pipelines. In another case, an extremely high corrosion rate of mild steel up to 20 mm/year was experimentally determined in crude oil, brine, and supercritical CO2 mixed conditions (Farelas, Choi, & Nesic, 2013). Clearly, the ingress of CO2 gas significantly increases the corrosion risk of pipelines, which is still a challenging issue for field application of the CO2-EOR technique (DeBerry, Clark, & Yost, 1979; Singh, 2010). The presence of a significant amount of H2S gas in the production fluids may also deteriorate the corrosion problem (Nesic & Sun, 2010). H2S gas is generally derived from the reservoirs. The injection of high-temperature steam during exploration of high-viscosity crude oils is an important source for H2S gas generation (Lin et al., 2014; Zhu et al., 2010).

Corrosion control is an economic issue. The use of corrosion-resistant alloy (CRA) is effective to reduce the corrosion damage of facilities and pipelines. However, it is very expensive to widely use CRA for long-distance transportation pipelines. Hence, low-Cr-bearing steels were evaluated for their possible use as pipelines (Guo, Xu, Zhang, Chang, & Lu, 2012; Zhang et al., 2012). As an alternative, coating materials can also be selected for extending the service life of pipelines (Wang, et al., 2014b). Unfortunately, in-line preparation of high-quality coatings or protective films is not an easy task. It seems that corrosion inhibitors are still the most effective method for corrosion control, even though the presence of crude oil may affect the inhibition performance of these chemical agents (Gulbrandsen & Kvarekval, 2007; Horsup, Clark, Binks, Fletcher, & Hicks, 2010).

Pursuit for economic and effective corrosion control methods is the goal of oil production companies. An attractive way to reduce corrosion using the inhibition role of crude oil has been suggested since the 1970s (Wicks & Fraser, 1975). According to this method, corrosion can be sharply mitigated with an optimization of the processing parameters during oil production. Corrosion prevention is clearly an economical task. Engineers and scientists have made great efforts, from different point of views, on advancing the knowledge of corrosion in crude oil-brine solutions. However, currently, the fundamentals of the inhibition role of crude oil are not enough for guiding field application (Store, Passade-Boupat, Bonis, & Adams, 2011). If the crude oil effect is not considered, the predicted corrosion rate will be overestimated (Hernandez, Hernandez, Rincon, & Vera, 2002b; Nyborg, 2010). This idea of using crude oils to reduce pipeline corrosion in oil production has become significantly important in dealing with aggressive CO2 and H2S corrosion, which is valuable for the evaluation of corrosion risk and the proper selection of pipeline materials.
1.3 Purpose and structure of this article

In this article, the corrosion behavior of mild steel in multiphase flow conditions is summarized according to previous research progress in the scientific community. The role of crude oil in pipeline corrosion is emphasized. The following issues are elaborately discussed.

1. Which factors are important for understanding the multiphase flow corrosion phenomena?
2. How is the corrosiveness of the oil-brine mixtures measured?
3. What is the inhibition mechanism for crude oil on pipeline corrosion?
4. Is corrosion inhibitor still effective in the oil-containing conditions?
5. What should we do next?

From this review, we hope the readers will become interested, push for more fundamental research, and share field experience related to pipeline corrosion in crude oil production.

2 Key parameters of crude oil fluids related to corrosion

2.1 Physical and chemical properties of crude oil

2.1.1 Classification of crude oil

Crude oil is a complex mixture of hydrocarbons that naturally occurs in reservoir rocks. It contains hydrocarbons, heterocyclic and metal organic compounds, high-molecular-weight organic compounds, and a series of nitrogen-, sulfur-, and oxygen-containing organic compounds. For different purposes, crude oil is broadly grouped by their density, geochemical parameters, live crude properties, hydrocarbon compounds, and so on. From previous literatures regarding corrosion in crude oil-containing environments, two methods of classification were generally referenced. The first one is to classify crude oils according to American Petroleum Institute (API) gravity. The API gravity is a factor inversely proportional to the density of crude oil. A heavy crude oil has an API gravity lower than 20, a medium crude oil has an intermediate API gravity of 20–34, and a light crude oil has a API gravity higher than 34. There are some crude oils with API gravity below 10 (with a density higher than 0.99 relative to pure water), which are called extreme heavy crude oils. These ranges are not absolutely defined and can be slightly varied according to different references. It has been generally accepted that heavier oils are more protective than lighter ones with regard to corrosion.

Another way to classify crude oils is based on the proportions of the organic compounds (Sokolova, Abryutina, Punanov, & Petrov, 1992), such as paraffins, aromatic compounds, and naphthenic compounds. According to a detailed identification of the roles of chemical compounds in corrosion, these compounds may present profound effect on the wettability of crude oil and the chemistry of the brine solutions (Efird, Smith, Blevins, & Davis, 2004).

Most recently, based on the ability to inhibit corrosion and the alteration of steel wettability, Richter, Babic, Tang, Robbins, and Nesic (2014) grouped crude oil into four categories. For category I, the crude oils both inhibit corrosion and alter the wettability of the steel; for category II, the crude oils inhibit corrosion but do not alter the wettability of the steel; for category III, the crude oils do not inhibit corrosion but alter the wettability of the steel; for category IV, the crude oils neither inhibit corrosion nor alter the wettability of the steel. This method can reflect the corrosion mechanisms of steels in oil-brine mixtures. However, there is no direct link between the corrosion performance and the intrinsic characteristics of crude oils.

2.1.2 Viscosity and density

The viscosity and density of crude oil are two dependent factors. They are important for corrosion prediction because the entrainment of water in crude oil is very dependent on them (Xu, 2007). A low viscosity leads to an easy separation of water from the mixtures. The oil-water mixture is usually heated to a temperature high enough to lower its viscosity, shortening the time for water separation (Arnold & Stewa, 1999). The often large difference between the density of crude oil and water is also beneficial for water separation, reducing the tendency of entrainment of water in crude oil. At a certain temperature, heavier oil is more viscous. The correlation among dynamic viscosity of crude oil, API gravity, and temperature has been well established. As suggested in a recent study (Sanchez-Minero, Sanchez-Reyna, Ancheyta, & Marroquin, 2014), the dynamic viscosity ($\mu_{\text{oil}}$, in centipoise) can be expressed as

$$\mu_{\text{oil}} = a \exp\left(\frac{b}{T^1}\right),$$

(1)
where $T$ is the absolute temperature (in kelvin) and $a$ and $b$ are coefficient factors as functions of API gravity and can be estimated from the following relations:

$$a = 3.9 \times 10^{-5} \text{API}^3 - 4.0 \times 10^{-3} \text{API}^2 + 0.1226 \text{API} - 0.7626 \quad (2)$$

$$b = 9.1638 \times 10^6 \text{API} \quad (3)$$

Here, API represents the gravity of crude oil (in °API).

As opposed to density, crude oil viscosity is very dependent on crude oil-brine mixtures. It is strange that the viscosity of crude oil is rarely mentioned during corrosion studies.

According to previous suggestions (De Waard, Smith, & Craig, 2003), the entrainment of water in crude oil can be estimated by API gravity. They defined the critical water break value $W_{\text{break}}$ as the amount of water that can be entrained in crude oil. A linear relation has been expressed as $W_{\text{break}} = -0.0166 \times \text{API} + 0.83$. For the water cut in an oil-brine mixture below $W_{\text{break}}$, the water phase is totally entrained in the oil phase, avoiding pipeline corrosion problems. This is an empirical formula based on field data analysis of well tubing corrosion from two oilfields (De Waard et al., 2003). The phenomenon of sharp increase in corrosion rate at a certain water cut has been experimentally verified by many laboratory tests (Carew, Al-Sayegh, & Al-Hashem, 2000; Craig, 1996; Efird & Craig, 1989; Papavinasam, Dotron, Panneerselvam, & Revie, 2007). This critical water cut of corrosion rate break (CRB) is defined as the critical water break value or the emulsion inversion point (EIP). Table 1 summarizes the critical water cuts for CRB in different oil-brine mixed conditions. Clearly, the CRB value for some specific crude oils has failed to comply with its correlation with API gravity. For example, some heavy and medium crude oils presented a critical break value in corrosion rate at water cut below 10%. Besides crude oil density, there must be other key factors in determining pipeline corrosion. This is a very complex issue. However, it makes little sense to directly correlate the corrosion rate value with the density and viscosity of crude oil.

### 2.1.3 Crude oil chemistry

Crude oil contains a variety of hydrocarbons and different types of organic compounds. The corrosion behavior of steels is very sensitive to some specific compounds in crude oil-brine solutions. A number of crude oils are selected as models to clarify the inherent roles of chemical constituents during corrosion. According to a comparison among three geochemical types of kerogen oils, the aromatic chains are more protective than paraffinic chains in crude oils (Lotz et al., 1991). A recent study also confirmed the weak influence of paraffin on corrosion of mild steel (Yang, Richter, Robbins, & Nesic, 2012). Lotz et al. (1991) also pointed out that immature hydrocarbons dispersed in the water phase can reduce the corrosion rate more markedly than mature hydrocarbons. The immature crude oil generally contains a larger amount of surface-active compounds compared with the mature one. The role of these beneficial compounds in corrosion is viewed to behave like corrosion inhibitors (Efird et al., 2004; Lotz et al., 1991; Store et al., 2011). Therefore, the influence of crude oil chemistry on corrosion has been mainly attributed to water-soluble, surface-active compounds. Further, there are experimental data supporting the direct correlation of steel corrosion rate with the nitrogen and sulfur content in crude oils (Efird & Jasinski, 1989; Hernandez, Duplat, Vera, & Baron, 2002a; Hernandez, Nesic, Weckman, & Ghai, 2006), revealing their beneficial effect on corrosion protection.

To advance the understanding of crude chemistry effect on corrosion, some specific compounds were extracted from crude oils for inhibition tests (Hernandez, Bruzual, Lopez-Linares, & Luzon, 2003; Mendez, Duplat, Hernandez, & Vera, 2001). Saturates, aromatics, resins, and asphaltene (SARA) were separated from a Venezuelan crude oil (Mendez et al., 2001), and then corrosion and adsorption behavior were measured for each extracted compound in brine solutions. During corrosion tests, a high stir rate of 500 rpm was used to generate homogeneous oil-brine mixture with addition of a small amount of crude oil or the extracted components (Mendez et al., 2001; Rincon, Hernandez, Case, & Salazar, 1999). Based on their result, the resins were found to have the highest inhibition efficiency and adsorption coverage. However, according to a qualitative characterization of the polar function groups in these compounds, it is suggested that the aromatic compounds present the best inhibition effect in resin crude oils (Mendez et al., 2001). Based on a statistical analysis of the experimental data (Hernandez et al., 2002a), the sulfur content and nitrogen content were found to be the most decisive factors affecting the corrosiveness of aqueous solutions dispersed with asphaltene and paraffinic crude oils, respectively. This has been further confirmed by the corrosion analysis regarding other crude oils, which is related to the alteration of brine chemistry (Efird et al., 2004). In the condition of crude oil behaving as continuous phase, the polar functional groups in the resin or asphaltene seem helpful in the formation of stable emulsions. Asphaltene extracted from Arab heavy crude oils was evaluated to be much inhibitive to
Table 1: Summary of the critical water cuts for CRB in different oil-brine mixed conditions.

<table>
<thead>
<tr>
<th>Crude oil</th>
<th>Brine solution</th>
<th>Flow parameters</th>
<th>CRB</th>
<th>References</th>
</tr>
</thead>
<tbody>
<tr>
<td>API gravity</td>
<td>Viscosity (mPa s) at °C</td>
<td>CO₂ pressure (MPa)</td>
<td>Temperature (°C)</td>
<td>Stirring rate for mixing (rpm)</td>
</tr>
<tr>
<td>n.a.</td>
<td>n.a.</td>
<td>4.1</td>
<td>60</td>
<td>200</td>
</tr>
<tr>
<td>11</td>
<td>n.a.</td>
<td>Acid 0.5</td>
<td>5.2</td>
<td>85</td>
</tr>
<tr>
<td>29</td>
<td>n.a.</td>
<td>Acid 0.53</td>
<td>5.2</td>
<td>85</td>
</tr>
<tr>
<td>59</td>
<td>n.a.</td>
<td>Acid 0.28</td>
<td>5.2</td>
<td>85</td>
</tr>
<tr>
<td>44.5</td>
<td>0.73 at 40°C</td>
<td>Kerogen I</td>
<td>0.56</td>
<td>75</td>
</tr>
<tr>
<td>37</td>
<td>3.98 at 40°C</td>
<td>Kerogen II</td>
<td>0.56</td>
<td>75</td>
</tr>
<tr>
<td>24.3</td>
<td>129 at 40°C</td>
<td>Kerogen III</td>
<td>0.56</td>
<td>75</td>
</tr>
<tr>
<td>22.5</td>
<td>65.8 at 40°C</td>
<td>Kerogen I</td>
<td>0.56</td>
<td>75</td>
</tr>
<tr>
<td>24.7</td>
<td>6.57 at 40°C</td>
<td>Kerogen II</td>
<td>0.56</td>
<td>75</td>
</tr>
<tr>
<td>30</td>
<td>n.a.</td>
<td>SARA and Sulfur: 0.57</td>
<td>0.49</td>
<td>80</td>
</tr>
<tr>
<td>31.9</td>
<td>n.a.</td>
<td>SARA and Sulfur: 0.67</td>
<td>0.49</td>
<td>80</td>
</tr>
<tr>
<td>n.a.</td>
<td>n.a.</td>
<td>3.4 and 20.5 (H₂S: 20%)</td>
<td>80; 90</td>
<td>1000</td>
</tr>
<tr>
<td>11</td>
<td>n.a.</td>
<td>SARA and Sulfur: 2.6</td>
<td>0.49</td>
<td>80</td>
</tr>
<tr>
<td>30.9</td>
<td>n.a.</td>
<td>SARA and Sulfur: 1.45</td>
<td>0.49</td>
<td>80</td>
</tr>
<tr>
<td>8.1</td>
<td>n.a.</td>
<td>SARA and Sulfur: 1.6</td>
<td>0.49</td>
<td>80</td>
</tr>
<tr>
<td>15.3</td>
<td>n.a.</td>
<td>SARA and Sulfur: 0.5</td>
<td>0.49</td>
<td>80</td>
</tr>
<tr>
<td>20.7</td>
<td>n.a.</td>
<td>SARA and Sulfur: 1.1</td>
<td>0.49</td>
<td>80</td>
</tr>
<tr>
<td>49</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
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<tr>
<td>56</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td>42</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
</tbody>
</table>
Table 1 (continued)

<table>
<thead>
<tr>
<th>Crude oil</th>
<th>Brine solution</th>
<th>Flow parameters</th>
<th>CRB</th>
<th>References</th>
</tr>
</thead>
<tbody>
<tr>
<td>API gravity</td>
<td>Viscosity (mPa s) at °C</td>
<td>Chemistry</td>
<td>CO₂ pressure (MPa)</td>
<td>Temperature (°C)</td>
</tr>
<tr>
<td>38</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td>33</td>
<td>n.a.</td>
<td>Paraffin: 2.1% Asphaltene: 1.3%</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td>29</td>
<td>n.a.</td>
<td>Paraffin: 1.9% Asphaltene: 5.0%</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td>23</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td>11</td>
<td>n.a.</td>
<td>Paraffin: 13.2% Asphaltene: 12%</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
<tr>
<td>41</td>
<td>1.1</td>
<td>n.a.</td>
<td>pH: 4.6</td>
<td>n.a.</td>
</tr>
<tr>
<td>37</td>
<td>1.8</td>
<td>n.a.</td>
<td>pH: 5.2</td>
<td>n.a.</td>
</tr>
<tr>
<td>29.3</td>
<td>4</td>
<td>n.a.</td>
<td>pH: 5.7</td>
<td>n.a.</td>
</tr>
<tr>
<td>28</td>
<td>n.a.</td>
<td>n.a.</td>
<td>8</td>
<td>90</td>
</tr>
<tr>
<td>28</td>
<td>n.a.</td>
<td>n.a.</td>
<td>12</td>
<td>65</td>
</tr>
<tr>
<td>29.3</td>
<td>13.7 at 60°C</td>
<td>n.a.</td>
<td>1</td>
<td>60</td>
</tr>
</tbody>
</table>

The API gravity is generally at 15°C. n.a., not available in the referenced paper; OCP, open circuit potential.
corrosion (Ajmera, Robbins, Richter, & Nesci, 2011), relating to its adsorption and persistence on the steel surface.

On the basis of previous understandings, focused studies have been made regarding the influences of some subclass compounds on the corrosion inhibition and the wettability behavior of crude oil. Four classes of compounds were evaluated by Ayello, Robbins, and Richter (2011). Aromatic compounds were found to be ineffective for corrosion inhibition and presented little effect on the wettability of crude oil. However, the authors speculated that aromatics may become helpful for reducing the corrosion risk in water-in-oil (w/o) dispersion flows, possibly owning to their positive effect on the stabilization of emulsions or dispersions. Oxygen-containing compounds, especially the high-molecular-weight organic acids, were verified to be the most effective agents in reducing the corrosion rate and alternating the wettability of steel surface. This was attributed to the accumulation of surface-active compounds at the steel surface. Not all the sulfur- and nitrogen-containing compounds present significant effect on corrosion inhibition and wettability, as the effect relies on the adsorption of these active compounds on the steel surface.

2.2 Stability of crude oil emulsions

2.2.1 Formation of emulsion during crude oil production

The formation of emulsion needs to meet the following three criteria (Abdel-Raouf, 2012). First, two immiscible liquids must be brought in contact; second, surface-active components must present as the emulsifying agent, which is essential for stabilizing the interface between oil and water; third, a sufficient mixing or agitating effect must be provided to disperse one liquid into another as droplets. During crude oil production, brine generally comes out together with crude oils. The solubility of water phase in crude oil is very low, from 0.1 to 2.0 mol% as a function of the production temperature (Graig, 1998). A variety of surface-active compounds can be detected in crude oil, such as SARA, especially, the asphaltenes, which act as natural emulsifiers. During crude oil production, the droplet sizes have a broad range, from 0.1 to 50 μm in diameter. Generally, the smaller the average size of the dispersed droplets, the longer the emulsion time is kept (Kokal, 2005). In this view, the emulsion was divided into three types, i.e. tight, medium, and loose emulsions. The separation of a tight emulsion requires longer time, whereas water is much easier to break from a loose emulsion. In most cases, medium and loose emulsions were encountered during crude oil production.

2.2.2 Emulsion inversion point

At low water cuts, the water droplets can be totally dispersed in the continuous oil phase if a w/o emulsion forms. With increasing water cut, a change of the emulsion structure from w/o to o/w occurs. This critical water cut is defined as the EIP (Fingas & Fieldhouse, 2004; Papavinasam et al., 2007; Xu, 2007). According to Ostwald’s model, the maximum water cut forming a w/o emulsion cannot exceed 74 vol% (De Waard et al., 2003; Xu, 2007). Actually, this critical inversion water cut is generally observed between 60 and 80 wt% (Fingas & Fieldhouse, 2004; Kokal, 2005), depending on the stability of the emulsion. A method to determine the EIP was suggested by measuring the conductivity between two close pins positioned in a flow pipe (ASTM, 2010). Alternatively, the EIP can also be determined by changes of the viscosity as a function of water cuts. It has demonstrated that the w/o emulsion presented a highest value of viscosity at the critical water cut of EIP (Fingas & Fieldhouse, 2004; Kokal, 2005). At a same crude oil-brine system, the...
formation of a tighter emulsion often relates to a higher EIP.

A corresponding parameter to EIP of an emulsion is the phase inversion point (PIP) of an oil-brine dispersion system. The dispersion mentioned here is not an emulsion. It is a state of water droplets entrained in the crude oil or, inversely, oil droplets entrained in the water phase. The PIP refers to the critical water cut below which the water phase can be well dispersed and entrained into the flowing oil phase as small droplets. Different from EIP, PIP is a flow-dependent parameter and can be determined in a pipe flow tests by measuring the changes in pressure drop (Nädler & Mewes, 1997; Xu, 2007). At the PIP, the continuous phase of the flow is changed from crude oil to water. The input water cut at PIP has been demonstrated to decrease with the increase of the oil viscosity (Nädler & Mewes, 1997). There are many existing models to estimate the PIP in oil-brine dispersions, which is closely correlated with the density and viscosity of crude oil (Xu, 2007). This can explain the dependence of the critical water break on API gravity, as proposed by De Waard et al. (2003). The experimentally measured PIP values are generally varied within a wide range of water cuts, depending on many testing factors, such as viscosity, flow rate, inclination, temperature, and so on (Xu, 2007). The commonly reported PIP values are from 30 to 40 wt% (Fingas & Fieldhouse, 2004; Xu, 2007), which are similar to the critical water cut for CRB in most oil-brine mixed flow conditions (Carew et al., 2000; Choi et al., 1989).

Determination of the critical water cut of CRB is a basis of understanding the corrosion phenomenon in oil-brine mixed conditions. Many attempts have been made to directly measure the corrosion rate variations of steel samples as a function of the water cuts in oil-brine mixtures (Choi et al., 1989; De Waard et al., 2003; Efird & Jasinski, 1989; Lotz et al., 1991; Papavinasam et al., 2007; Rincon et al., 1999). Most of the experiments were conducted in a high-pressure autoclave. Some of the data were collected from field conditions (De Waard et al., 2003). One assumption of these research is the formation of an emulsion during the tested periods because a high stirring rate is often used for keeping the stability of emulsions, as indicated in Table 1. However, these studies rarely characterized the state and stability of the corrosive emulsions. Investigation on the microstructures and the viscosity changes of the emulsions is very helpful in understanding the corrosion phenomenon in this complex system (Wang, et al., 2014c). Therefore, to understand the nature of steel corrosion in oil-brine mixtures, it is necessary to correlate the stability of emulsions with corrosion phenomenon.

### 2.2.3 Process of water separation from w/o emulsion

Emulsion is metastable in nature. Once it forms, the two immiscible liquid phases (oil and brine) are prone to separate from each other. There are three processes for water separation from the emulsion (Abdel-Raouf, 2012). The first step is the flocculation or aggregation of dispersed drops in the emulsion; the second step is the coalescence of two or more emulsion drops to form a single larger drop, which is an irreversible process; the third step is phase separation, i.e. emulsion breakdown. Many factors may affect the stability of emulsions (Abdel-Raouf, 2012; Kokal, 2005), including the content of surface-active compounds, the presence of solid particles, pH value of the brine solution, the averaged size of dispersed drops, viscosity, and temperature. Also, aging of crude oil may decrease the stability of w/o emulsions (Filho, Ramalho,
Spinelli, & Lucas, 2012), thus influencing the corrosiveness (Papavinasam et al., 2007).

Even when a small amount of water is separated from the emulsion and persistently contacts with the internal pipe wall, pipelines may suffer from serious electrochemical corrosion. Therefore, determination emulsion stability is one of the most important tests for corrosion prediction (Wang et al., 2014c; Wang et al., 2015). There are numerous methods available for determining emulsion stability (Kokal, 2005). By far, the most common method is the simple bottle test, which is directly observing the separated phase volume as a function of time at certain temperatures. Besides the experimental methods, the time of water break from w/o emulsion can be theoretically estimated according to Stokes equation and coalescence of droplets (Arnold & Stewa, 1999). Understanding emulsion stability is helpful for corrosion prediction. Corrosion can be managed by changing the transporting parameters to keep the stability of w/o emulsions (Wang et al., 2015).

2.3 Fluid properties of oil-water two-phase flow

2.3.1 State of oil and water in pipelines

There are several methods to identify the flow patterns in crude oil-brine mixture transportation pipelines. According to the degree of mixing, the crude oil-water two-phase flow patterns can be classified as stratified flow, semi-mixed flow, and dispersed flow (Shi, Cai, & Jepson, 1999). Owing to the discrepancy in density, water phase is prone to be transported beneath crude oil in the pipeline fluids. As proposed by Vedapuri et al. (Shi et al., 1999), oil-water flow has been treated as a three-phase stratified flow with a water layer at the bottom, an oil layer on top, and a mixed layer at the center of the pipe. Therefore, corrosion generally happens at the bottom part of the pipeline in lamellar flow conditions.

The flow patterns closely depend on the water cut and the mixing flow velocity (Arirachakaran, Oglesby, Malinowsky, Shoham, & Brill, 1989). Direct contact of water with steel surface is essential for triggering corrosion. Therefore, more details of the flow characteristics related to the contact state of water with pipe wall should be emphasized. As shown in Figure 2, there are at least five types of contacting conditions. The first type is the water phase totally entrained as droplets in the crude oil flow, avoiding direct contact with steel surface. Obviously, in this condition, corrosion is completely inhibited. The second type relates to the direct contact of some large water droplets with steel surface. However, the water droplets can move away or slip from one site to another on the steel surface. In this condition, an intermittent water/oil wetting is encountered. Therefore, corrosion may occur at certain sites, but it is also significantly inhibited by flowing crude oils. For the third type in Figure 2C, the accumulation of water droplet becomes obvious. A water layer may locally form at the bottom of pipelines, and it is not easy to remove by flowing crude oils, leading to a long-term exposure of steel surface to corrosive brine solution. In this way, corrosion may be observed at the sites contacting with the water phase. In Figure 2D, a lamellar type flow is illustrated, where corrosion will happen at the bottom part of the pipeline as mentioned above. As the water cut increases, such as for the fifth condition shown in Figure 2E, the bottom of the pipelines may partially contact with crude oil phase or droplets. This condition generally relates to a high flow velocity and a relatively high water cut. The presence of crude oil patches at the bottom of pipelines may affect the localized corrosion behavior. This classification is based on the flow pattern analysis by Charles et al. (1961), which seems helpful for the corrosion analysis in an oil-brine mixed solution contacting with the internal pipe wall. The movement of water droplets in crude oil was also previously considered for modeling corrosion in crude oil-brine mixtures (De Waard et al., 2003).

2.3.2 Water-wetting behavior on steel surfaces

Water wetting is essential for corrosion initiation on steel surfaces in an oil-brine mixed condition (Cai et al.,...
It should be noted that contacting and wetting are two different processes. In Figure 2, the contacting possibility of water phase (or water droplet) with steel surfaces has been illustrated. Actually, the tendency of water to displace crude oil from steel surface can be estimated by comparing the surface energies of all these interfaces. The Young’s equation (4) is generally used to express the relations between these interfacial tension forces,

\[ \gamma_{ow} - \gamma_{ws} = \gamma_{sw} \cos \theta, \]

where \( \gamma_{ow} \) is the interfacial energy between the oil and the steel surface, \( \gamma_{ws} \) is the interfacial energy between the water and the steel surface, and \( \gamma_{sw} \) is the interfacial energy between the oil and the water, and \( \theta \) is the contact angle at the oil-water-steel interface measured through the water. If the contact angle is between 0° and 90°, the steel surface will be preferentially wetted by water, presenting a hydrophilic characteristic; if the contact angle is between 90° and 180°, displacement of water by crude oil should be expected, referring to a hydrophobic surface. Therefore, a number of studies have focused on the measurement of the contact angle and its relation to corrosion (Ajmera et al., 2011; Ayello, Robbins, Richter, & Nešić, 2013; Foss, 2009; Papaviniasam et al., 2007). An alternative method to measure the wettability is a spreading test by examining the conductivity of a group of probes in oil-water mixtures. The merit of this wettability spreading method is that it can be conducted in higher pressure and flow conditions.

It has been recognized that a hydrophobic surface is beneficial for mitigating steel corrosion in oil-brine mixtures. According to previous understanding, wettability plays a predominant role in affecting the S-curve behavior of corrosion rate in oil-brine mixture solutions (Craig, 1996). The S-curve behavior has been observed in many crude oil-brine systems. At relatively low water cuts, corrosion rate is extremely low; at medium water cuts, corrosion rate increases sharply with water cuts, presenting a corrosion break phenomenon; at relatively high water cuts, corrosion rate gradually reaches to a higher value comparable to that observed in brine solution. According to Craig (1996), the sharp transition of corrosion rate at medium water cuts may be attributed to an intermittent water/oil wetting of the steel surface. Many factors may change the wetting behavior of oil and water contacting with steel surface, such as the surface properties (Foss, Gulbrandsen, & Sjoblom, 2010), the viscosity of crude oil, temperatures, the partial pressure of CO₂ gas (Emera & Sarma, 2007; Papaviniasam et al., 2007), some chemical agents in crude oil (Ayello et al., 2013), and corrosion inhibitors (Foss et al., 2010; Li, Richter, & Nešić, 2014). Many studies also pointed out that the wettability behavior may be greatly changed under flow conditions (Efird et al., 2004; Nesic & Carroll, 2003). Clearly, a direct correlation between the corrosion rate and the wettability behavior, which is based on the typical contact angle measurements, has limited beneficial impact on the understanding of the corrosion mechanisms. It is necessary to build a method for in situ observation of the wetting behavior of water droplets and their spreading at the steel surface during corrosion in crude oil-brine mixtures.

Intermittent wetting of the steel surfaces is a common state of oil-water fluid during production. It seems that intermittent oil wetting is beneficial for mitigating corrosion compared to the complete water-wetting condition (Cai et al., 2012). However, little attention has been paid to the corrosion mechanism in oil/water intermittent wetting conditions. It is significantly important to clarify the relation of corrosion with wettability of steel surface under flow conditions.

### 2.3.3 Entrainment of water in crude oil fluids

The internal corrosion of pipelines is directly connected to water wetting. The area where water is settled is likely to cause corrosion problems. To entrain water droplet into crude oil fluids, a critical flow velocity is needed (with a minimal velocity of 1 m/s for most crude oils), which increases with pipe diameter (Wicks & Fraser, 1975). When the water cut is below 30%, the entrainment of water in crude oil seems easy (Fingas & Fieldhouse, 2004; Lotz et al., 1991; Nesic & Carroll, 2003; Xu, 2007). Recently, the critical velocity for the entrainment of water in crude oil has been experimentally determined in different water cut conditions by mapping the phase wetting characteristics in a horizontal pipe and a prediction model has been developed (Cai et al., 2012). Based on Cai et al. (2012), a higher flow velocity is required for the formation of dispersion in oil-brine mixtures with larger water cuts. In this case, increase of flow velocity is beneficial for reducing corrosion risks. However, continuous oil dispersion cannot be formed, and a higher flow velocity will enhance the corrosion of pipeline. This observation agrees with some previous results that in a condition with 40% water cut, an enhanced corrosion was observed with increasing the flow velocity (even up to 1.8 m/s), which has been attributed to local turbulence and the staying time of water droplets on steel surface (Choi et al., 1989). Wang et al. (2015) also measured an enhanced corrosion rate as increasing flow velocities in oil-brine mixture flows with a water cut of 95% (Wang et al., 2015). Obviously, without
the formation of crude oil-based dispersions, a higher flow velocity is detrimental to pipeline corrosion, which can be referenced from corrosion mechanisms in single aqueous flow conditions (Heitz, 1991; Schmitt et al., 2000).

Besides flow velocity and water cut, the stability of water-entrained system during crude oil transportation may be dependent on such factors as viscosity and density of crude oil, temperature, and existence of surfactants, which determine the separation of water from production fluids. Therefore, heavy and viscous crude oils are prone to entrain a larger volume of water. An enhancement effect of surfactants on the mixing of oil and water has also been noted (Shi et al., 1999), which may reduce the corrosion risk of pipelines by the entrainment of water at a lower flow velocity. In flowing conditions, the water droplet size may range from tens of micrometers to several millimeters (Sarica & Zhang, 2008). The droplet size in flowing dispersions is obviously larger than that in emulsions.

### 2.4 Characteristics of oil-water-gas three-phase flow

#### 2.4.1 Oil-water-gas three-phase flow patterns

Three-phase gas-oil-water flow patterns are actually a combination of gas-liquid and oil-water flow patterns. There are several methods to identify the characteristics of flow patterns in this three-phase flow. If water and crude oil are mixed well during transportation, the flow pattern can be viewed similar to the gas-liquid two-phase flow patterns (Sarica & Zhang, 2008). Based on the classification of gas-liquid two-phase flow patterns, generally, eight kinds of flow patterns were identified (Efird, 2011; Kang, Wilkens, & Jepson, 1996), i.e. bubbly, smooth stratified, wavy stratified, rolling wave, plug flow, slug flow, pseudo slug, and annular flow. When the distribution of oil and water in pipe is further considered, 12 individual three-phase flow patterns can be identified (Sarica & Zhang, 2008). During oil production, slug flow is the most common flow patterns. Therefore, the corrosion phenomenon related to slug flow were preferentially investigated in horizontal, inclined, and vertical pipes, including the effect of superficial gas velocity (Kang, Jepson, & Gopal, 1999; Maley, 1997), wall shear stress (Wang, Cai, Bosch, Jepson, & Hong, 2002; Zheng et al., 2008), slug frequency (Kang et al., 1996; Maley, 1997; Wang et al., 2015), and Froude number (Chen & Jepson, 1999; Kang et al., 1996). Owing to the similarities in flow patterns between the gas-liquid flow and the oil-water-gas three-phase flow (Sarica & Zhang, 2008), most previous efforts have been made in correlating corrosion with flow characteristics in the gas-liquid two-phase flow conditions. For a given multiphase flow that contains crude oil, visualization of the flow patterns is still a challenging issue. This may be another important reason for correlating corrosion with flow patterns in gas-liquid two-phase flow conditions without the presence of crude oil. Note that the flow pattern greatly depends on the oil content and viscosity of the mixtures. Therefore, further studies should be relevant to the conditions of crude oil production. Other methods to determine flow patterns by pressure drop (Sotgia, Tartarini, & Stalio, 2008), wetting behavior (Cai et al., 2012), or phase density distribution (Hoffmann & Johnson, 2011) are helpful for corrosion analysis in an oil-water-gas three-phase flow.

#### 2.4.2 Influence of gas flow on liquid slug behavior

The multiphase flow patterns are decisively related to the presence of gas and the value of the gas flow rate. The flow pattern is generally described as a function of the oil-water mixing velocity and the superficial gas velocity. Obviously, there are at least two functionalities of gas flow affecting the multiphase flow patterns. The first one is its effect on the frequency of liquid slugs, which is one of the key factors in characterizing flow patterns. Experimental results indicated that a higher gas flow rate produces lower frequencies of the liquid slugs at a constant liquid velocity (Kang et al., 1999; Villarreal, Laverde, & Fuentes, 2006; Wang et al., 2015). A lower slug frequency reduces the corrosion rate of pipelines. A sharp increase in the wall shear stress has been observed when the liquid slug goes through (Yang, Brown, Nesic, Gennaro, & Molinas, 2010), which may induce the damage of corrosion products (Schmitt et al., 2000). It is also observed that a higher gas flow rate would reduce the pressure drop of a segment of pipelines (Wang et al., 2015), which is consistent with the decrease in shear stress at the flow/pipe wall interface, thus reducing the pipeline corrosion. Another reason for the mitigation of corrosion rate under low frequency of liquid slug may be attributed to a reduction of water wetting. To date, the correlation between slug frequencies and corrosion behavior was mainly investigated in the gas-brine two-phase flow conditions or the oil-brine-gas three-phase flow conditions with very high water cuts. In such multiphase flow conditions, the oil and brine phases are simply viewed as a single, well-mixed liquid phase (Sarica & Zhang, 2008).

However, in most cases, the oil phase is not completely dispersed into the brine phase and vice versa. Therefore, corrosion would be locally different around the internal pipe wall. A higher corrosion rate may be observed at the
bottom of pipelines, which is prone to water-wetting. To avoid bottom-of-the-line corrosion in a multiphase flow condition, the free water must be totally entrained into crude oil. In an oil-brine two-phase flow condition, a higher mixing velocity is helpful to reduce pipeline corrosion by the entrainment of water via flow turbulence (Cai et al., 2012; Shi et al., 1999; Wicks & Fraser, 1975). However, without the presence of crude oil, a higher liquid flow rate may induce an enhancement in corrosion rate in liquid-gas flow conditions (Kang et al., 1999). Therefore, it is interesting to understand the role of gas flow in affecting the corrosion of the pipeline. Recently, it has been suggested that a higher gas-to-liquid ratio may be beneficial in reducing the multiphase flow corrosion, owing to a rolling effect of the high gas flow rate on the liquid film (Wang et al., 2015). A critical gas-to-liquid ratio was theoretically determined by resolving the Froude number ($F_r$), which can be expressed as

$$F_r = \frac{\text{Inertial force}}{\text{Gravity}} = \frac{v_f - v_t}{\sqrt{gh_{\text{eff}}}}, \quad (5)$$

where $v_t$ represents the velocity of the forward-facing part of a liquid slug, $v_f$ is the velocity of liquid film at the pipe bottom, $g$ is the acceleration of gravity, and $h_{\text{eff}}$ is the effective height of liquid film. Actually, the Froude number has been suggested years ago to understand the multiphase flow corrosion behavior (Kang et al., 1999; Shi et al., 1999). The authors defined the strength of the slug proportional to the Froude number calculated in the liquid film ahead of the slug. Based on this assumption, a relationship between gas-to-liquid ratio, liquid flow rate, and the Froude number was built, from which a critical gas-to-liquid ratio can be identified as an indicator for the gas rolling effect (Wang et al., 2015). As can be seen in Figure 3, below this critical ratio, a higher corrosion risk of the pipelines may be encountered. Therefore, the Froude number is an important parameter in characterizing the gas-liquid multiphase flow patterns.

### 3 Evaluation of the corrosiveness of oil-brine mixtures

#### 3.1 Challenges for corrosion measurement in heterogeneous solutions

Corrosion is an electrochemical process. Available testing methods for corrosion studies are mostly developed on the basis of the recording of electrochemical reactions, which means an electrolyte is needed and the anode and cathode have to be electrically connected. The presence of crude oil in a testing solution can decrease the conductivity of the corrosive media (Craig, 1996; Lotz et al., 1991; Wang et al., 2014c), inducing some problems in terms of the accuracy and reliability of the electrochemical data. Therefore, efforts have been made to overcome such an uncertainty (Jasinski & Efird, 1987). However, it is still not an easy task for electrochemical tests in a w/o emulsion system. For example, greatly scattered electrochemical impedance spectroscopy (EIS) data were generally observed in badly conductive systems (Lotz et al., 1991; Wang et al., 2014c). In most cases, the corrosion behavior of steels in a badly conductive solution is properly evaluated by weight loss measurements, as illustrated in Table 1. This simple method makes it hard to uncover the corrosion mechanisms in oil-brine systems.

Another challenge in conducting corrosion experiments in an oil-brine mixed condition is keeping the solution system as similar as possible to field conditions. A number of methods are proposed to mimic the oil-water mixed conditions. For the oil-water fully dispersed flow conditions, a flow loop connected with a stirring reservoir is generally used to test the CRB phenomenon as a function of water cut. The crude oil and the water phase are mixed together to form a dispersion or an emulsion in the reservoir, and then the mixture is injected into the flow pipe by a pump. This method has been widely accepted for corrosion tests in an oil-water well dispersed fluid or emulsions.
Considering the role of flow patterns in corrosion, for both oil-water two-phase flow and oil-water-gas three-phase flow, a large-scale flow loop system should be built. Details of the current progresses of multiphase flow corrosion measurements are summarized in Section 3.3. There are also many challenges in flow control during long-term corrosion tests. Although the multiphase flow corrosion behavior has been widely studied, the relations between surface wetting and corrosion phenomenon are rarely focused on. Oil-water intermittent wetting of internal pipe wall is the most common condition in oil production. No quantitative method has been developed for corrosion measurement at periodic wetting conditions of the steel surface.

As a conclusion, corrosion measurement in oil-brine mixed conditions has two challenging aspects, i.e. first, the development of fast-responding methods suitable for badly conductive oil-brine mixtures; second, the quantitative experimental modeling of oil-wetting applicable to field conditions.

### 3.2 Methods for corrosion measurements

As discussed above, the methods for corrosion measurement in oil-brine mixed conditions is one of the bottlenecks for uncovering the underlying corrosion mechanisms. Listed below are some corrosion test methods in oil-brine mixed conditions.

#### 3.2.1 Electrochemical method

Although the limitations of electrochemical test has been noted in bad conductive solutions, this method is still used in high water cut conditions, especially for the condition of water or brine as continuous phases. Conventional electrochemical techniques, such as the linear polarization resistance (LPR) test (Foss, 2009; Gulbrandsen & Kvarekval, 2007; Mendez et al., 2001), EIS (Lotz et al., 1991; Mendez et al., 2001; Wang, et al., 2014c; Zhang & Cheng, 2009) and potentiodynamic polarization test (Jasinski & Efird, 1988; Zhang & Cheng, 2009) are all suggested to evaluate the corrosion process of pipeline steels in oil-brine mixture solutions. EIS measurement is often used to determine the electrochemical resistance or interfacial behavior, owing to its high sensitivity to the surface reactions. The electrical resistance of the testing solutions (between the working electrode and the counter-electrode) can be derived from EIS data (Lotz et al., 1991; Wang, et al., 2014c). It is also suggested that the coverage of steel surface by crude oil can be calculated by measuring the interfacial capacitance from EIS tests (Mendez et al., 2001). In most cases, EIS measurements, as well as other electrochemical testing methods, were used to evaluate the corrosion resistance of steel to corrosive oil-brine mixtures. It has been experimentally proved that EIS measurement is impossible when the crude oil phase becomes continuous (Lotz et al., 1991; Wang, et al., 2014c). In this condition, other electrochemical signals are also hard to read from the conventional three-electrode electrochemical system (Wang, et al., 2014c).

#### 3.2.2 Weigh loss measurement

There is no doubt that weight loss measurement is generally viewed as a standard method for other corrosion tests. Nearly in all the published papers about steel corrosion in oil-brine mixed conditions, weight loss measurement was involved. In addition to composition of the solution, many other factors may decide the measurement of its corrosiveness, such as test duration, impeller type, and solution volume. These factors are closely related to the preparation and the stability of emulsions or the state of oil-brine mixtures, which may change during corrosion tests. It seems that in autoclave testing, the selection of a propeller type of stir impeller is more effective for mixing because the propeller produces mixing along the axis direction, i.e. vertical direction. Separation of water and oil may happen in a long-term immersion test in stagnant oil-brine mixtures (Wang, et al., 2014c). In contrast, in a highly stirred condition, a long-term test may produce more stable emulsion, totally changing the initial state of the mixtures. Clearly, during the measurement of corrosion rates, these factors must be carefully considered.

#### 3.2.3 Conductivity measurement

The estimation of corrosiveness of oil-brine mixtures by measuring their conductivity was suggested in 1990s (Craig, 1996). This method is helpful for quantitatively determining the corrosiveness of a w/o emulsion. There are a number of methods to measure the solution resistance, for example, a direct measurement of the conductivity and a calculation of EIS data. By measuring the conductivity of the oil-brine mixed solutions (in flow conditions or nearly stagnant conditions) as a function of water cuts, a critical water cut of the conductivity jump can be observed (Papavinasam et al., 2007; Wang, et al., 2014c). The value of water cut has been related to EIP or PIP in different conditions (see Table 1).
Measurement of the conductivity was also used in determination of the local wettability of the oil-water two-phase flow (Cai et al., 2012; Li et al., 2006). It continuously recorded the signals from a series of tiny conductivity pins, which were mounted in the internal pipe wall. This is one of the possible methods for correlating water wetting with flow conditions (such as water cut, flow rates, oil properties, and brine composition).

3.2.4 Corrosion probes

The presence of crude oil in testing fluids brings some technical challenges for the application of corrosion probes. The most important issue is the heterogeneous coverage of the probe head (or the steel surface) by crude oil, leading to invalidity for corrosion detection. Therefore, corrosion probes used in crude oil-brine mixture fluids should be specially designed. Several types of corrosion probes have been used in corrosion measurement in oil-brine mixed conditions. The electrochemical probes are much sensitive to the presence of crude oil. To overcome this weakness, the dielectric materials between testing electrodes were modified to be ionically conductive (Jasinski & Efird, 1987). Therefore, the LPR tests can be used for corrosion tests in crude oil-containing solutions, even in the condition of w/o emulsions (Jasinski & Efird, 1988).

In recent years, a kind of corrosion probes called “wire beam electrode” or “multi-electrode array” were developed (Gui, James, & Sridhar, 2012; Tan, Bailey, & Kinsella, 2001), revealing the current maps at the steel surface. This technique has been found to be effective in detecting the localized attack behavior during corrosion of steels in oil-brine mixtures. However, for an in-depth understanding of the corrosion propagation at the steel surface in such a heterogeneous solution, the resolution needs to be greatly improved because the entrained water droplets are generally sized in the micrometer scale.

Besides, some commercial corrosion probes have also been tried in the corrosion evaluation in oil-brine mixed conditions for a variety of purposes. Detailed information can be found in related references (Wang, et al., 2014c; Wang et al., 2015).

3.2.5 Other complementary methods

Detection of the concentration of ferrous ion in aqueous solutions is an indirect method to estimate the degree of corrosion damages. This method has been widely used in the field conditions, which was also accepted in multiphase flow experiments (Li et al., 2006). However, the correlation between ferrous ion concentration and corrosion is still as straightforward as it seems. At the same time, the release of ferrous ion may induce a feedback effect on corrosion behavior in CO₂-containing environments (Bian, Wang, Han, Chen, & Zhang, 2015). Therefore, it seems to be effective only for a rough comparison of the corrosion performance.

3.3 Laboratory-scale setup for field corrosion simulation

It is essential to collect corrosion data from the field conditions. However, it is hard to develop a general rule or to uncover the mechanisms based on these scattered data because too many variables will be involved during corrosion. Therefore, laboratory-scale simulation of field conditions is required. For different purposes, there are several kinds of experimental setups for the simulation of field conditions. The most commonly mentioned test method is the control of CO₂ partial pressure and temperature in brine solutions to mimic the corrosion behavior of steels in the production water. When crude oils are introduced into the testing systems, it is important to keep the stability of the oil-brine mixtures. This was generally accomplished using an autoclave with high stirring rate (Farelas et al., 2013; Lotz et al., 1991) or a small-scale flow loop (Papavinasam et al., 2007). There are also several other apparatus for specific modeling of the multiphase flow conditions, such as the doughnut cell (Li et al., 2014), the horizontal rotating cylinder (Nesic & Carroll, 2003), and rotating cage methods (Collier et al., 2012). Most of these techniques use corrosion measurement as a way to determine phase wetting. If the correlation between corrosion and the flow pattern characteristics needs to be elucidated, a large-scale flow loop is needed to model the actual field conditions.

Currently, several multiphase flow loops have been built for corrosion tests in research institutions and petroleum companies. They were generally designed for simulating different field conditions, as described in several references (Kouba & Jepson, 1990; Li et al., 2006; Nyborg, 1998; Wang et al., 2015; Zheng et al., 2008). As illustrated in Figure 4, these setups were generally designed as closed loops and contained several functional parts. The separator serves as the starting reservoir of the oil, water, and gas flows. At the same time, it also takes the function of a separation treatment container of the three phases after corrosion tests. The dynamical system contains the oil pump, the water pump, and the gas pump (or
The presence of crude oil may sharply reduce corrosion of the pipelines that transport production fluids. The inhibition effect of crude oil on corrosion can be simply attributed to the block of corrosive species directly contacting with the steel surfaces. According to the flow conditions, the inhibition effects can be classified into five oil-water mixing states, as illustrated in Figure 5, where the inhibition mechanism is closely related to the water cuts of the mixtures. At a relatively low water cut, the water phase can be totally entrained into crude oil by forming a w/o emulsion or a w/o dispersion. If the water cut further increases, free water may be separated at the pipeline bottom. At this time, wettability is the crucial factor affecting steel corrosion. The intermittent wetting of the steel surface by crude oil may reduce the average corrosion rate. Preferential adsorption of crude oil on the steel surface is another mechanism for mitigating corrosion in relatively high water cut conditions where free water presents. Another possible role of crude oil is the partitioning of some corrosion inhibitive agents from crude oil into aqueous solutions, which may behave like corrosion inhibitors. Besides the influence of crude oil on the fluid properties, some specific organic species in the crude oil may be incorporated into the corrosion product layer (Castillo et al., 2000). A detailed review of the corrosion inhibition mechanisms mentioned above follows.
4.1 Corrosion inhibition by water entrainment

4.1.1 Formation of stable water-in-oil emulsion

If the fluid can form a w/o emulsion during production, corrosion will not be a problem. Therefore, an investigation of the emulsion state of the oil-brine mixtures at wellheads is essential for predicting the corrosion risk of the gathering and transportation pipelines. A simple notion for the corrosion risk analysis has been suggested based on the assumption that corrosion would only occur when free water was separated from a w/o emulsion (Wang, et al., 2014c). Hence, a relation among transportation distance ($L_T$), transportation velocity ($v_T$), and time for water separation from a w/o emulsion ($t_w$) can be described as

$$L_T = v_T \times t_w$$

(6)

According to this simple notion, corrosion could be avoided if the w/o emulsion is transported to the destinations before water separation. It is expected that a higher flow velocity is helpful in reducing the corrosion risk of pipelines. Clearly, it is important to determine the time of water separation from a w/o emulsion. As mentioned in Section 2.2.4, there are experimental and theoretical methods to estimate the stability of the emulsions. The formation of a w/o emulsion is relied on the actual field conditions, such as the water cuts of fluids, properties of crude oil, and production environment. At some extreme conditions, the water droplets are completely entrained in crude oil, but they are not fine enough to form a w/o emulsion. The main difference between an emulsion and a dispersed flow is their stability. Free water will be separated within a very short period from a w/o dispersed fluid when the flow velocity is lower than the critical one for entrainment of these large water droplets. As presented in Figure 2A and B, water cut is an important factor in analyzing the corrosion probability of pipelines. The generally observed PIP water cut is related to the possible onset of corrosion, which is dependent on the flow rates. In most cases, both w/o emulsion and w/o dispersion coexist in an oil-brine mixed fluid, i.e. the dispersion can be viewed as a destabilized emulsion. There is no clear identification of the corrosion phenomenon in these two states of crude oil-brine mixtures in previous studies. The maximum diameter of water droplet that can be sustainably entrained in the flowing crude oils can be estimated by a balance between the turbulent kinetic energy and the droplet surface energy (Barnea, 2001; Li et al., 2006).

4.2 Corrosion inhibition by oil wetting

4.2.1 Intermittent oil wetting

If crude oil is present as the continuous phase in the oil-brine mixtures, keeping the pipeline surface free from water wetting, corrosion can certainly be avoided. As illustrated in Figure 2B and C, at a relatively high water cut that the total entrainment of water droplets becomes oil more stably and persistently. However, to ensure a low-pressure drop in the onshore production pipelines, turbulent flow is not an optimum choice. Therefore, the stirring effect from turbulent flow during crude oil transportation is very weak. Things may be different for the offshore production process. As known from Table 1 and related references, the corrosion measurements in a w/o emulsion are commonly conducted in an autoclave with very high stirring rates to keep the stability of the emulsions. This probably produces both flowing and emulsifying effects. During the entire corrosion test period, the oil-brine mixture remains highly emulsified. It seems that corrosion tests under stagnant or slightly stirred conditions might be more appropriate for estimating the corrosiveness of the w/o emulsion fluids.
impossible, the steel surface may be wetted intermit-tently or periodically by the oil and aqueous phases. The oil-water two-phase flow loop test indicated that the corrosion rate was retarded under intermittent conditions when compared with full water wetting (Li et al., 2006). However, it should be noted that the corrosion inhibitive agents in crude oil may also decisively affect the mitigation of corrosion rate measured in an intermittent wetting condition (Cai et al., 2012).

In a stagnant condition, the wettability of steel surface is dependent on the interfacial tensions of oil and water on steel surfaces. In a flow condition, the intermittent wetting behavior closely depends on the flow pattern characteristics (Nesic & Carroll, 2003). Several research have demonstrated that with increasing flow rate, the steel surface can be changed from water wetting to intermittent wetting or oil wetting (Nesic & Carroll, 2003; Cai et al., 2012). From the view of flow characteristics, the intermittent wetting behavior of steel surfaces reflects the degree of water entrainment in crude oil. A high gas-to-liquid ratio is also used to manage the wetting behavior of the bottom of pipelines, thus reducing the pipeline corrosion in multiphase flow conditions (Wang et al., 2015). This is consistent with the notion that corrosion can be mitigated in an oil-pre-dominant oil-brine mixed flow by increasing turbulence (Wicks & Fraser, 1975).

### 4.2.2 Crude oil adsorption

The covering effect of crude oil at the steel surface is widely accepted as the origin for corrosion inhibition. However, a thin layer of crude oil at the steel surface is unstable to prevent corrosion for a longer time. For example, Wang, et al. (2014c) found that a pre-formed crude oil layer can only persist for about 15 min in a stagnant condition. Note that this observation is dependent on crude oil chemistry and experimental conditions. In their experiments, Wang, Zhang, Wang, et al. use crude oil with an API gravity of 29.3, and all the tests were conducted at 60°C. In a flow condition, the removal of crude oil layers becomes much easier. Three factors may contribute to the persistence of a crude oil layer on steel surfaces. The first one is the properties of steel surfaces. The wettability of a steel surface may be varied during corrosion owing to the formation of corrosion product layers (Papavinasam et al., 2007). If a surface is preferential to oil-wetting, an improved protectiveness of the steel surface will be expected. The second factor is the properties of crude oil. Ayello et al. (2013) pointed out that some large molecular compounds in crude oils are capable of forming a hydrophobic layer on the surface, thereby changing the wettability of the surface and producing substantial inhibition roles. According to the analysis based on SARA crude oils (Hernandez et al., 2002a), sulfur- and nitrogen-based compounds may serve as the pre-adsorbed species in the crude-oil phase. Besides crude oil chemistry, the viscosity of crude oil and environmental temperature are also viewed as important factors affecting the adsorption of crude oil on steel surface and preventing corrosion.

The heterogeneous adsorption of crude oil on the steel surface may induce localized corrosion. The degree of localized corrosion may be different from the averaged corrosion rate in oil-brine mixed conditions (Choi et al., 1989), but this phenomenon and its mechanisms have not been clearly addressed. The non-uniform corrosion phenomenon of steel surface in a crude oil-brine mixture was visualized using the wire beam electrode system (Tan et al., 2001). The adsorption of crude oil also greatly varied the erosion-corrosion mechanism maps in oil-water-sand three-phase flow conditions, depending on flow velocity and impact angle (Stack & Abdulrahman, 2012).

### 4.3 Corrosion inhibition by crude oil partitioning

The partitioning effect of crude oil was proposed to understand the inhibitive effect of the aqueous phase solutions because crude oil generally consists of a number of soluble, active surfactant agents that may behave like the corrosion inhibitors when dissolved into the aqueous solutions (Efird et al., 2004; Hernandez et al., 2002a). Based on research of Venezuela crude oils, some of these crude oils had inhibiting properties, significantly reducing corrosion rate and SCC susceptibility (Rincon et al., 1999). Only 1 to 5 vol% crude oil was mixed into the brine solutions, which had induced a sharp decrease in the corrosion rates over an order of magnitude (Castillo et al., 2000). This was attributed to the surface adsorption of beneficial organic compounds, which were derived from the partitioning of crude oils (Hernandez, Duplat, et al., 2002a; Mendez et al., 2001). The sulfur- and nitrogen-containing compounds were viewed as important variables that performed the inhibitive effect in corrosive brine solutions (Efird et al., 2004; Hernandez et al., 2002a). These polar organic compounds may determine the acid number of crude oil, which is crucial to corrosion in oil refinery conditions (Barrow, McDonnell, Feng, Walker, & Derrick, 2003). A relation between the corrosion rate and the acid number was also observed in the
crude oil-brine mixtures (Efird et al., 2004). Another work identified nitrogen- and oxygen-containing compounds as inhibitive species capable of partitioning to the brine phase (Hernandez et al., 2003). Store et al. (2011) found that mainly nitrogen-containing compounds were dissolved into the brine phase, and they also pointed out that although the partitioning effect can be correlated to the decrease of corrosion rate, it is still impossible to directly correlate corrosion inhibition with the nitrogen content of crude oil. Results from Arba heavy crude-oils tests revealed that asphaltenes have little partitioning in the aqueous phase and thereby have no influence on the corrosiveness of the brine solution. In contrast, they play a strong role in modifying the wettability of the steel surfaces and the persistency of the adsorbed oil layers (Ajmera et al., 2011).

4.4 Impact of crude oil on corrosion product layers

The presence of crude oil may change the properties of corrosion product layers. Numerous results have shown the influence of crude oil on the surface morphology of carbon steels after corrosion tests (Carew et al., 2000; Farelas et al., 2013; Heuer & Stubbins, 1998). Generally, a rougher surface was observed in oil-brine mixtures with a higher water cut (Castillo et al., 2000). Efird and Jasinski (1989) presented a linear relationship between the corrosion rate and the particle size of the corrosion products formed in different crude oils, which was also demonstrated by other works (Castillo et al., 2000), clearly indicating the modification of crude oil on the microstructures of the corrosion layers. Castillo et al. (2000) attributed the inhibition role of crude oil mainly to the formation of a protective corrosion product layer in oil-brine mixtures, in which the presence of sulfur-rich scales were viewed as an indication for the incorporation of organic compounds into the corrosion products. A direct evidence of the incorporation of hydrocarbon compounds into corrosion products was first confirmed by the scanning electron micrographic image of a local dark region on the steel surfaces after corrosion test in oil-brine mixtures (Mendez et al., 2001); using energy-dispersive X-ray spectroscopy analysis, the authors confirmed that the dark spot is mainly composed of hydrocarbons. In erosion-corrosion conditions, the presence of crude oil may also reduce the severity of localized attack, performing a smoother surface morphology (Stack & Abdulrahman, 2012). This effect is more predominant when the sand impact velocity is low.

5 Performance of corrosion inhibitors

As the water cut increases during oil production, the corrosion inhibitors are widely used to reduce pipeline corrosion. These inhibitors may perform an effective role in mitigating CO₂ corrosion in the aqueous solutions. However, their performance in the oil-water-gas multiphase flow conditions is not clear enough to select correctly the dosage of inhibitors, as the presence of crude oil may totally change the adsorption behavior of corrosion inhibitors. Although the corrosion inhibitor can be adsorbed on the steel surface performing its function in multiphase flow conditions, it has demonstrated that the effectiveness is highly dependent on flow characteristics, such as the Froude number (Seal et al., 2000). Crude oil almost exists in the whole process of oil production and water re-injection. There are three possible roles of crude oil in affecting the performance of corrosion inhibitors: (1) crude oil may present a poisoning effect by consuming more dosage of corrosion inhibitors; (2) inhibitors may alter the wettability of steel surfaces, thus possibly enhancing the preferential adsorption of protective hydrocarbon layers; (3) as a type of surfactant agent, the corrosion inhibitors may also change the surface tension of the water and oil phases, enhancing the entrainment of water in crude oil. Below are the summaries of the three aspects of corrosion inhibitors during corrosion in multiphase flow conditions.

5.1 Consumption at the unwanted surfaces

To effectively perform its inhibition role, the corrosion inhibitor should reach a critical concentration and be well dispersed in the corrosive solutions, properly adsorbing on the steel surfaces. Obviously, a lower critical concentration is welcomed for field application. When crude oil was presented in the fluids, the surface-active inhibitor molecules may accumulate on the oil-water interface. In an o/w emulsion, the surface area of oil-water interface is determined by the oil droplet sizes. If the unwanted surface area is very large, the droplet may deplete significant amount of corrosion inhibitors from the corrosive aqueous phase, resulting in a potential risk of inhibition failure and an increase in the inhibitor dosage. According to this notion, the concentration of corrosion inhibitors accumulated in the emulsion can be calculated to estimate the depletion of corrosion inhibitors in the aqueous phase (Gulbrandsen & Kvarekval, 2007; Horsup et al.,
2010). However, the depletion may highly depend on the structure of the inhibitor molecules.

Previous results also pointed out that the partitioning behavior of the corrosion inhibitors is crucial for the determination of in situ inhibitor availability (Horsup et al., 2010), according to the investigation on three kinds of corrosion inhibitors. The concentration of the inhibitor in the aqueous phase did not decrease after equilibration with heptol in the absence and presence of electrolyte, indicating that these inhibitors do not partition in the hydrocarbon phase. The partitioning behavior was demonstrated to be closely related to temperature, salinity, and oil type. Clearly, in evaluating the effectiveness of a corrosion inhibitor in multiphase flow conditions, it is essential to measure the partitioning ratio of inhibitors in the oil phase.

### 5.2 Altering the wettability

Pre-adsorption of the inhibitor molecules at the steel surface may change the wettability from hydrophilic to hydrophobic, increasing the probability of oil wetting. Foss et al. have investigated the influence of corrosion inhibitors on the wetting behavior of bare steel surface (Foss, Gulbrandsen, & Sjøblom et al., 2008), iron carbonate layer (Foss, Gulbrandsen, & Sjøblom, 2009), and ferric-covered surfaces (Foss et al., 2010). They found that both oleic imidazoline and phosphate ester alter the wettability from hydrophilic to hydrophobic, while cetyltrimethylammonium bromide increases the water wetting. Schmitt (1998) measured the contact angle of oil and water droplets in a high-pressure condition. The results showed that a clean steel surface and a corroded steel surface covered with FeCO₃ scale both present hydrophilic wetting properties. The addition of fatty amine and imidazoline-based inhibitors under the FeCO₃ scale formation condition produced a hydrophobic surface. Through a detailed analysis of the changes of contact angle as a function of inhibitor concentrations, it further revealed that the fatty amine-type inhibitor is more effective in switching the wettability of steel surfaces compared with the quaternary ammonium chloride inhibitor (Li et al., 2014). The mechanism was attributed to a regular adsorption of inhibitor molecules, with the hydrophilic head being adsorbed onto the steel surface and the hydrophobic tail being left in the bulk solution. However, contradictory results of wetting tests may be obtained for different surface properties (Foss, Gulbrandsen, Sjøblom, 2009; Li et al., 2014). Note that wettability is highly dependent on the properties of the steel surface.

### 5.3 Enhancing the entrainment of water

As discussed above, the corrosion risk can be reduced by controlling the flow characteristics, i.e. totally entraining the water droplets in the crude oil phase. Clearly, this method is only suitable for the multiphase flow conditions with relatively low water cuts. The addition of corrosion inhibitors was proved to be beneficial to entraining of water in crude oil. Li et al. (2014) observed that the addition of both fatty amine inhibitor and quaternary ammonium chloride inhibitor can significantly shift the critical oil-wetting transition velocity to lower values, reducing the corrosion risk of pipelines. To have an effect on water entrainment, the concentration of the inhibitors should be higher than the critical micelle concentration. However, a much higher concentration is less effective in further reducing the critical transitional velocity. This was explained based on the adsorption of inhibitor molecules at the oil-water droplet interface, which sharply reduced the interfacial tension.

Emulsion stability can be changed with the addition of corrosion inhibitors. This was also attributed to the tailoring of oil-water interface by the adsorption of inhibitor molecules. Horsup et al. (2010) presented the phase inversion behavior with the addition of corrosion inhibitors in different oil-brine solutions by measuring the conductivity of the mixtures. At certain inhibitor concentrations, the phase inversion mainly relied on the oil type and salinity of the solutions. Addition of some oils would convert the oil-brine mixtures from oil-in-water emulsions to water-in-oil emulsions. In these conditions, additional beneficial effects on inhibiting corrosion would be expected with the addition of corrosion inhibitors. One should note that as a type of surface-active agents, corrosion inhibitors may also decrease the stability of the emulsions. However, there are no suitable criteria for identifying the role of corrosion inhibitors in specific crude oils, which must be assessed case by case in the field conditions.

### 6 Some suggestions for reducing corrosion risk

Based on the present knowledge of the multiphase flow corrosion behavior in crude oil production, the following several items should be complied to mitigate the corrosion of pipelines.

1. During crude oil transportation, it is important to keep the stability of the water-in-oil emulsions. This idea is suitable for the low-water-containing fluids, but
the aqueous phase is extremely corrosive, e.g. CO$_2$-EOR production fluids and H$_2$S-containing fluids. In these conditions, the emulsion state of the fluids at the wellhead should be evaluated, from which the water separation time can be estimated. Therefore, the critical transportation velocity is determined according to the distance from the single well to the treatment stations. Demulsifiers are prohibited from being injected into the pipelines at any point. Mixing the emulsion fluids with free-water-containing fluids from other production wells must be avoided. One should also note that a lower temperature is beneficial to keep the emulsion stable. In some conditions, the transportation of oil-brine mixtures at critical velocity is impossible, i.e. water may settle down during pipeline transportation. Methods to enhance emulsion stability should be considered. For example, the use of stirring emulsifier and addition of surfactant agents can be effective in avoiding water separation from oil-brine mixtures. Based on our primary laboratory test, addition of a small amount of surfactant chemicals such as OP-10 emulsifier (CAS No. 9041-29-6) was effective for stabilizing w/o emulsions for CO$_2$-EOR production in the Shengli oilfield. The location of the emulsion controller is flexible, relying on stations and pipeline surroundings. However, these practical methods to enhance the emulsification of the oil-brine mixtures are not highly recommended because this may need water separation at the treatment stations, which is very difficult. Using a cleaning pig is an alternative for periodically removing water accumulation at the bottom of the pipeline. This requires experience in field operation and management.

2. In pipeline design, it is necessary to consider the entrainment of water. First, a higher liquid flow velocity may destabilize the water layer at the pipeline bottom, changing the wettability performance. Therefore, the diameter of the pipeline should meet the requirement of the entrainment of flowing water. However, a smaller diameter would induce a higher pressure drop, thus consuming more energy. There must be an optimized value between the requirement of water entrainment and the energy consumed. Second, a higher gas-to-liquid ratio may induce an easier entrainment of water, which is beneficial for corrosion mitigation. However, if the water phase is incompletely entrained in crude oil, a high flow velocity is harmful for corrosion protection. Therefore, controlling multiphase flow pipeline corrosion needs careful evaluation of the flow state.

3. The use of chemical inhibitors is still a competitive method for reducing corrosion in multiphase flow conditions. If the pipeline is persistently wetted by the aqueous phase and the corrosion cannot be controlled through the management of the flow characteristics, other corrosion protection methods must be considered. Compared with corrosion-resistant steels and coating materials, the addition of corrosion inhibitors is an economic, effective, and flexible method for corrosion control even in the presence of crude oil. Evaluation of effectiveness is important for the selection of corrosion inhibitors and the dosage that needs to be added. In this condition, on-site corrosion monitoring techniques should be introduced.

7 Challenges for fundamental research

Although the pipeline corrosion phenomenon in various aqueous solutions have been widely reported, the fundamental aspects of corrosion in multiphase flow pipelines remain challenging. This has restricted the corrosion management in field conditions of crude oil production. From the viewpoint of practical applications, some fundamental questions still need to be answered to better combat the corrosion problem in crude production conditions. However, an insight into the corrosion phenomenon in oil-brine mixed conditions seems very complex. To the authors’ best knowledge, some scientific issues are listed below, which have obviously hindered the field application of some possible corrosion control methods.

- Determining the critical size of water droplets that triggers water wetting of the steel surface in a w/o emulsion.
- Quantitatively correlating the corrosion rate with water-wetting behavior, especially the relation of corrosion with flow parameters in oil-water intermittent conditions.
- Localized attack in the presence of crude oil, including initiation of pitting beneath oil layers and propagation of corrosion around a crude oil droplet.
- Development of experimental methods for fast evaluation of corrosion inhibitors in multiphase flow conditions.
- Corrosion mechanism of steels in supercritical CO$_2$-oil-water mixed conditions and the related fluid behavior in high-pressure conditions.
8 Conclusions

The influence of crude oil on the pipeline corrosion in oil-water-gas multiphase flow conditions was reviewed. Based on the present knowledge on this interdisciplinary topic, the corrosion phenomenon and related mechanisms were correlated to the fluid properties, the interfacial behavior, and the reactions at steel surfaces. The following conclusions can be drawn:

- The fluid characteristics were demonstrated to influence the complex corrosion phenomenon in different crude production conditions. For the parameters characterizing crude oil, the density, viscosity, and crude chemistry were believed to be the predominant factors. For the oil-water two-phase flow conditions, the influence of emulsion stability, the water entrainment, and the wetting behavior were very impressive during corrosion. For the oil-water-gas three-phase flow conditions, which were generally treated as liquid-gas two phase flows, the influence of gas flow rate on the flow patterns and the corrosion risk should be noted.

- The methods for corrosion measurements in oil-brine mixed conditions were summarized. The evaluation of steel corrosion in oil-containing multiphase flow conditions needed to be further developed. The modeling of field corrosive environments in the laboratory scale is still challenging.

- The mechanisms of crude oils in pipeline corrosion were summarized as follows: (1) formation of w/o emulsion or the entrainment of water in crude oil; (2) surface wetting and preferential adsorption of crude oil; (3) corrosion-inhibiting agent partitioned from crude oil to the aqueous phase; (4) beneficial modification of the corrosion product layers through the presence of crude oil.

- The performance of corrosion inhibitor in crude oil production conditions was discussed. The presence of crude oil may consume more chemical drugs in order to produce effective inhibition. The addition of corrosion inhibitors into oil-brine mixed fluids may produce additional benefits for reducing the corrosion risk of pipelines, such as changing the wetting behavior of steel surface and entraining more water in the crude-oil phase.

- Corrosion control by designing the fluid parameters should be a suitable and economic method for reducing damages in crude production pipelines with high corrosion risk.

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