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# 17 Design Criteria and Methodology for Modern Oil–Water Separation Systems

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**Abstract**

The development, verification, and qualification of gravity separator design guidelines should have the highest focus in sub-sea projects as the design of sub-sea processing presents challenges not normally experienced by the process development team. Despite the fact that footprint real estate is easily obtained, new limitations are imposed because sub-sea installation traditionally occurs through the moonpool of a drilling rig, or with vessels with limited lifting capacity. Although large separators are found on platform processes, seabed processes should be as compact as possible. The purpose of this chapter is to present an overview of current understanding in how oil/water separator efficiency may be influenced by various parameters. The ability to predict separator performance based on fluid characterization is discussed. Additionally, the chapter includes a comparison between theoretical models for separation performance and laboratory experience. The main conclusions to be drawn are:

- Traditional design rules for topside separators are based on over-simplified models, and are not sufficient for sub-sea use.
- More comprehensive approaches exist, based on more data describing the fluids involved and their behavior. This will involve testing with high pressure test cells. These approaches give a better understanding and a more correct separator design, but there is still a need to establish the missing link between pressurized test cell behavior (laboratory scale) and large scale dynamic behavior.
- The mixing of water continuous wells with oil continuous wells normally gives complex emulsions that are hard to separate in a gravity separator. No reliable method to account for these effects is identified in this study and should be established experimentally.

**17.1 INTRODUCTION**

The gravity separation process is a key part of almost any realistic sub-sea processing scheme. In the major part of the potential sub-sea processing projects seen to date the gravity separator is well suited for doing the job alone. The performance of the gravity-settling sections of the cyclonic separators will still be crucial to the total performance of the system.

This chapter will demonstrate that the complexity of the fluids and production systems makes it difficult to calculate the exact performance of a separator, and that the design guidelines in use today are normally over-simplified. This is why the development, verification, and qualification of gravity separator design guidelines should have the highest focus in the sub-sea projects.

Conceptual solutions for sub-sea production and processing have been on the drawing board for decades, yet the concepts have been slow to gain acceptance. This is related to a combination of risk aversion within the oil industry and risk ignorance amongst suppliers. Both parties see significant market advantages with qualified solutions for sub-sea systems yet active effort towards pushing the products in the direction of a risk reduced production train has been difficult.

One potential cause of this conflict is related to operational problems observed at surface production facilities. Typical facilities have production start-up challenges that are very difficult

to analyze even with surface access. These can range from mechanical to chemical sourced problems such as:

- Accumulation of well cleanup products in the separation train
- Mechanical failures in rotary equipment caused, indirectly, by misinterpreted reservoir fluid analyses
- Incorrect process flow sheets
- Under-instrumentation

Typically the solution to these types of problem on surface facilities has been to form a multiparty task force involving the original suppliers, the relevant operator staff, and one or more specialist consulting firms. These are then given the opportunity to perform various activities designed to solve the operator's problem.

The reservoir production environment has a different set of rules for its problem solving activities. These are very relevant to sub-sea-processing as they include the sub-sea wellhead solution set. Facilities for well diagnostics have to be requested long in advance and typically have a 1-year life cycle. In fact, the increased expense and complexity of sub-sea well diagnostics has resulted in a controversy as to the effect of such solutions on ultimate field recovery.

This chapter reviews the current state of the art on separator performance modeling. The paper focuses on two-phase oil–water gravity separation. However, gas is an important factor as it will influence the inlet conditions and, additionally, it is most likely that there will be a gas pocket in the separator. This is the case even when an upstream degasser is applied or when the wellhead pressure is above the saturation pressure.

### 17.1.1 THE IMPORTANCE OF CHARACTERIZATION

The interaction between heavy and solid crude oil constituents, such as asphaltenes, resins, waxes, sand, and salt, for example, forms the basis for the stabilization of crude oil emulsions. In fact, many of the heavy organics are present in a state not unlike solid particles. Resins and the other, lighter, polar components contribute by stabilizing the dispersions and inhibiting coagulation. (There is a trade-off as these systems show less tendency towards well plugging by adhesion or sedimentation because of these naturally occurring dispersants.)

This condition is strongly altered by the presence of water. In the flowing system, fresh interfacial areas are created and polar molecules, such as resins, are more strongly attracted to these. Hence these diffuse quickly to the surfaces and, in turn, form a protective coating on the droplet surfaces. Decisive factors determining the final attachment positions of the resins are (1) the hydrophilic/lipophilic balance of these molecules and (2) the corresponding properties of the solid surface. It can be imagined that a very hydrophobic particle surface and a very polar water–oil interface would extract different types of resin for different activities. However, highly interfacially active resins will show preference for the water–oil interface not only over less hydrophobic resin molecules but also over asphaltenes.

As a consequence of the transport process, the resin concentration in the bulk fluid is reduced. This, in turn, changes the solubility conditions of the resulting precipitation of asphaltene particles which then tend to accumulate at the droplet surfaces. The second layer further enhances both droplet rigidity and emulsion stability. Central to this stabilization process are mechanisms related to steric hindrance.

Depending upon the surface chemistry of the particles, other solids, including sand, clays, and even crystallized salts, can be attracted to the surfaces. These inorganic solids further enhance

the droplet protection mechanisms. Changes in the interfacial conditions due to ageing of the water–oil emulsion should also be borne in mind.

### 17.1.1.1 Coalescence

Coalescence is defined as the combination of two or several droplets to form a larger drop. When these droplets approach each other a thin film of the continuous phase will therefore be trapped between the droplets, and it is obvious that the properties of this film will determine the stability of the emulsion (Brown, 1968). In the Brown model, the mechanism of coalescence occurs in two stages: film thinning and film rupture. In order to have film thinning there must be a flow of fluid in the film and a pressure gradient. It is obvious that the rate of film thinning is affected by:

- Phase rheology
- Interfacial tension
- Dilation properties (viscosity and elasticity)
- Droplet size
- Fluid chemistry

Many authors have provided notable research into the modeling of these systems (de Vries, 1958; Frank and Mysels, 1960; Lang, 1962; Liem and Woods, 1974; Lin and Slattery, 1982; Malhorta, 1984; Zapryanov et al., 1983).

Attempts at predicting critical film thicknesses for the final rupture phase have resulted in three conclusions. The first was given by Schedluko and Manner (1968) who developed an expression for the critical film thickness for surface fluctuations with the assumption that the system is described only by van der Waals forces:

$$d_C = \left( \frac{A\pi}{32K^2\gamma_0} \right)^{0.25} \quad (17.1)$$

where  $A$  is the Hamaker constant,  $\gamma_0$  is the interfacial tension, and  $K$  is the wave number of the surface fluctuations. The second and third conclusions were given by Vrij (1966) who derived two alternative expressions for  $d_C$  and large and small thickness models. For a large thickness

$$d_C = 0.268 \left( \frac{A^2 R^2}{\gamma_0 \pi f} \right)^{0.14} \quad (17.2)$$

where  $R$  is the droplet radius and  $f$  is  $f(d)$ . For a small thickness

$$d_C = 0.22 \left( \frac{AR^2}{\gamma_0 f} \right)^{0.25} \quad (17.3)$$

Like many of the models for droplet behavior, the thick film model shows nonphysical behavior at extremes of interfacial tension and/or droplet diameter.

## 17.1.2 INDIGENOUS STABILIZING COMPONENTS

### 17.1.2.1 Saturates and Aromatics

The saturates (or aliphatics) are the nonpolar compounds containing no double bonds and include both the alkanes and the cycloalkanes. Wax is a sub-class of the saturates. The aromatics consist of all compounds with one or more benzene rings. These ring systems may be linked up with naphthene rings and/or aliphatic side chains.

### 17.1.2.2 Resins

This fraction is comprised of polar molecules often containing heteroatoms such as nitrogen, oxygen, or sulfur. This fraction is operationally defined, and one common definition of resins is as the fraction soluble in light alkanes such as pentane and heptane, but insoluble in liquid propane. Naphthenic acids are a part of this fraction.

### 17.1.2.3 Asphaltenes

Asphaltenes are polar molecules that can be regarded as similar to the resins, but with higher molecular weight, typically 500 to 1500 g/mole. The asphaltene fraction, like the resins, is defined as a solubility class, namely the fraction of the crude oil precipitating in light alkanes such as pentane, hexane, or heptane. The precipitate is soluble in aromatic solvents such as toluene and benzene. The asphaltene fraction contains the largest percentage of heteroatoms (O, S, N) and organometallic constituents (Ni, V, Fe) in the crude oil. The structure of asphaltene molecules is believed to consist of polycyclic aromatic clusters, substituted with varying alkyl side chains. The molecular weight of asphaltene molecules has been difficult to measure due to the tendency of asphaltenes to self-aggregate, but molecular weights in the range 500 to 2000 g/mole are believed to be reasonable.

## 17.2 SEPARATOR PERFORMANCE

### 17.2.1 PRODUCTION RELATED CHALLENGES

As they rise from the reservoir and undergo differential separation process in the production tubing, the reservoir fluids undergo significant changes in properties. This is indicated in [Figure 17.1](#). Heavy components become less soluble and become apparent as asphaltenes, waxes, scale, for example. These small particles may agglomerate to form much larger particles, which can accumulate on the production train. Otherwise, these provide the basis for particle stabilization in emulsion or foaming systems.

Ideally, the separation process should be simplest at “nearest to reservoir” conditions to achieve maximal benefit from:

- Maximal density differences between the oil and water phases
- Minimal effects of carbonate scale deposition by removing the water
- Minimal emulsion effects on flowline capacity

Separation curves are shown in [Figure 17.2](#).

Determining the source of the stabilizing mechanism is very important. Different mechanisms require different production chemicals or production solutions. Efforts to identify water production, asphaltene deposition, and, ultimately, the correct solution to a problem in production

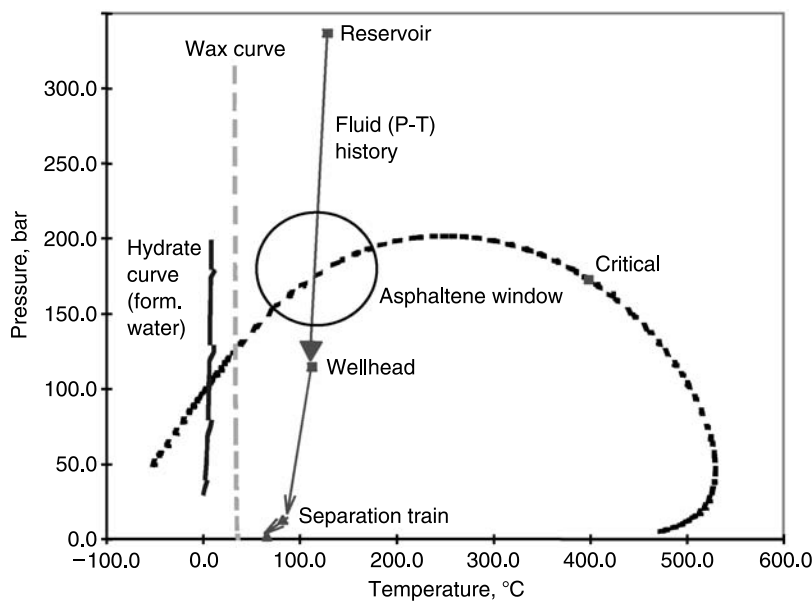


FIGURE 17.1 Phase envelope for a typical emulsion-forming oil.

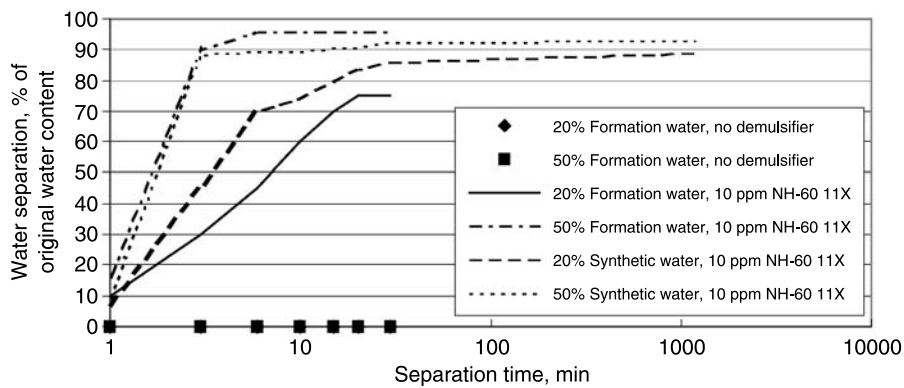
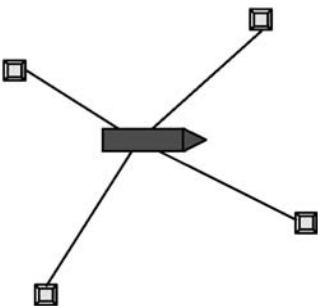


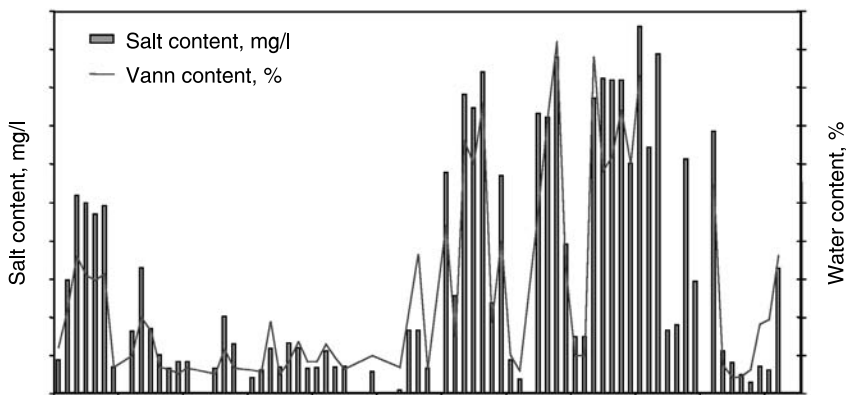
FIGURE 17.2 Separation curves for a particle (salt, scale, and asphaltene) emulsion system.

chemistry can be expensive. Published material is available which describes the efforts to locate problem wells in networked fields with as many as 150 wells (with as many as five completion zones per well) producing through a common export line from individual fields.

The system described in Figure 17.3 is then quite simple. The driving force can be dramatic as Figure 17.4 indicates. The operator risked incurring a multi-million dollar loss when the salt content exceeded refinery tolerances (in the middle of Figure 17.4).



**FIGURE 17.3** Typical seabed arrangement.



**FIGURE 17.4** Final result after initial water breakthrough.

**17.2.2 INLET CONDITIONS**

**17.2.2.1 Critical Droplet Size Evaluation**

In summary, the design of a conventional gravity separator is very much controlled by four factors:

- The insecurity in fluid properties (which is controllable)
- The insecurity in droplet sizes which the separator is exposed to (can be predicted approximately)
- The insecurity in phase continuity and the presence of complex emulsions
- The insecurity in inlet device performance with respect to free gas carry under and/or the ability to release dissolved gas to form small bubbles

The first of the uncertainties can be controlled by reviewing the reservoir data as well as conventional separation tests. The influence of fluid chemistry on separation problems has been evaluated in several joint industry projects. As is the nature of such projects much of the data and experience remains unpublished, but indications from the open literature (e.g., Friedemann, 1997; Osa and Holt, 2001) are that methods exist for the reliable onshore evaluation of production chemicals.

The second of the uncertainties is related to inlet droplet size. This is the result of flow energy and, as such, very much the result of the final installed design. A system can still be evaluated from a sensitivity analysis based on existing droplet generation models (see Section 17.2.2.2). Experience with gas droplet models for evaluating isokinetic sampling systems indicates that this is a relevant method. (The experimental separation efficiencies derived from field data indicate a trend relationship identical to that for droplet generation.) The influence of cyclones and other inlet devices on droplet size is difficult to model but, in general, cyclones will reduce the droplet size (see Section 17.2.2.3) and might thus increase the time required for oil–water separation.

A potential problem for a recycled system is the danger of accumulating droplets in the discharge water. The system is limited to a maximum oil-in-water content. The oil limit is very much determined by the rate of accumulation of very small oil droplets in the recycle loop. In this case a study based on a determination of critical droplet sizes within the system can be proposed. A model can be built up using cut-off distributions and removal efficiencies for each of the units. The model might then be usable to evaluate the feasibility of using a purge stream to reduce the “steady-state” oil-in-water content of the injection water stream. Although the results will be very qualitative, they should be very indicative.

### 17.2.2.2 Droplet Generation

Phase densities have a strong effect on separation both directly in the form of droplet settling rates and indirectly via the driving forces for droplet formation. Typically, droplet generation models are multiple functions of the phase densities. For example, van der Zande (1998), Arntzen and Andresen (2001), and Urdahl et al. (2001), respectively, list equations for droplet generation and for droplet agglomeration. The equations listed all show functionalities of the form:

$$D_{\max} = f(\tilde{E}, \rho_{\chi}, \xi, \sigma) \quad (17.4)$$

where  $\tilde{E}$ ,  $\rho_{\chi}$ ,  $\xi$ , and  $\sigma$  represent applied energy, continuous phase density, droplet concentration, and interfacial tension. Chokes, pumps, and shear stresses, for example, can supply energy. A simple and understandable example is given for surfactant-stabilized droplets in an impeller-based mixer (Skelland and Slaymaker, 1992):

$$\frac{d_{32}}{d_I} = 0.05C_s(1 + 2.316\varphi)\left(\frac{d_I}{T}\right)^{-0.75} N_{\text{Fr}}^{-0.13} N_{\text{We}}^{-0.6} \quad (17.5)$$

where

- $C_s$  = correction factor
- $d_{32}$  = Sauter mean droplet diameter
- $\varphi$  = dispersed phase volume fraction
- $d_I$  = impeller diameter
- $T$  = tank diameter
- $N_{\text{Fr}}, N_{\text{We}}$  = Froude number and Weber number, respectively

The work by Skelland and Slaymaker goes on to relate these values to time dependent droplet diameters. This work provides a functionality that is important to consider in systems with recycle streams.



### 17.2.2.3 Effect of Upstream and Downstream Equipment

As indicated, droplet sizes in two-phase flow are very much a result of flow shear. For example, the reason for using cyclonic devices for separating solids from liquids is because they directly attack the gravity term in Stokes' law:

$$v_t = \frac{2R_{\text{droplet}}^2 g (\rho_w - \rho_0)}{9\mu} \quad (17.6)$$

Here  $v$  is the velocity,  $R$  the droplet radius, and  $\mu$  the viscosity. The functionality for this is described by the relationship:

$$g = \frac{v_{\text{tangential}}^2}{R_{\text{cyclone}}} \quad (17.7)$$

Unfortunately, the relationship for droplet size as a function of flow shear is:

$$R_{\text{droplet}} \propto v_{\text{tangential}}^{-1.2} \quad (17.8)$$

Combined, the settling velocity (in the gravity separator) for such cyclonic devices used for degassing and degassing the feed of a gravity will be described as:

$$v_t \propto \frac{R_{\text{droplet}}^2 (\rho_w - \rho_0)}{v_{\text{tangential}}^{2.4} \mu} \quad (17.9)$$

where  $R_{\text{droplet}}$  is the droplet radius upstream the process. Using upstream cyclones (e.g., degasser, Figure 17.5) the coalescer device will have to compensate completely for these cyclones.

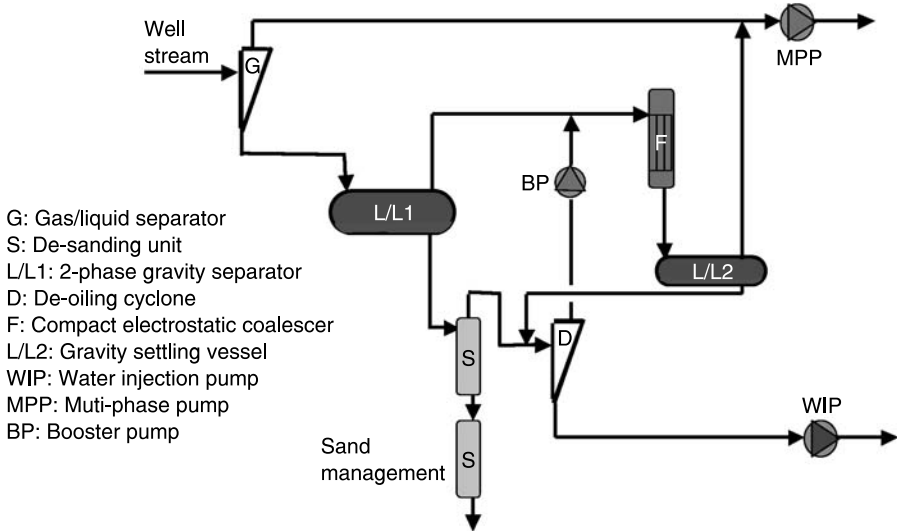


FIGURE 17.5 Simplified SPC flow process.

### 17.2.3 DENSITY DEPENDENT VARIABLES

It should be noted then that the functions used to estimate the applied energy (flow related shear) and interfacial tension in Equation 17.1 are typically of the form:

$$\sigma = [P (\rho_I - \rho_v)]^4 \quad (17.10)$$

and

$$\rho_{\text{gas,rel}} = \text{polynomial}(\rho, T, Z \dots)$$

$$\rho_{\text{liq,rel}} = \text{function}(P_c, T_c, Z_c \dots)$$

where the viscosity polynomials are all strongly density dependent. Note that the practice is to extend the liquid polynomial models for use with both phases. The resulting model has a weak (direct) density functionality, and may show strong inaccuracies as the components approach their freezing points (Reid et al., 1988; Calsep, 1991).

The benefit of downhole and sub-sea separation processes is then clearly dependent upon the relative behavior of the oil phase and water phase density and interfacial tensions as the oil degases. Without taking into account the surface chemistry effects on particle stabilization, relatively dead heavy oils would, in theory, show little benefit from downhole and sub-sea separation, as the water–oil phase densities are similar.

Early removal of water shows other benefits, which are directly related to the viscosity of the oil phase. This is often handled using a simple hyperbolic model, such as that proposed by the Taylor-based model of Pal:

$$\mu_{\text{rel}} \propto k_0 \left( 1 + \frac{wc}{k_3 + wc} \right)^{2.5} \quad (17.11)$$

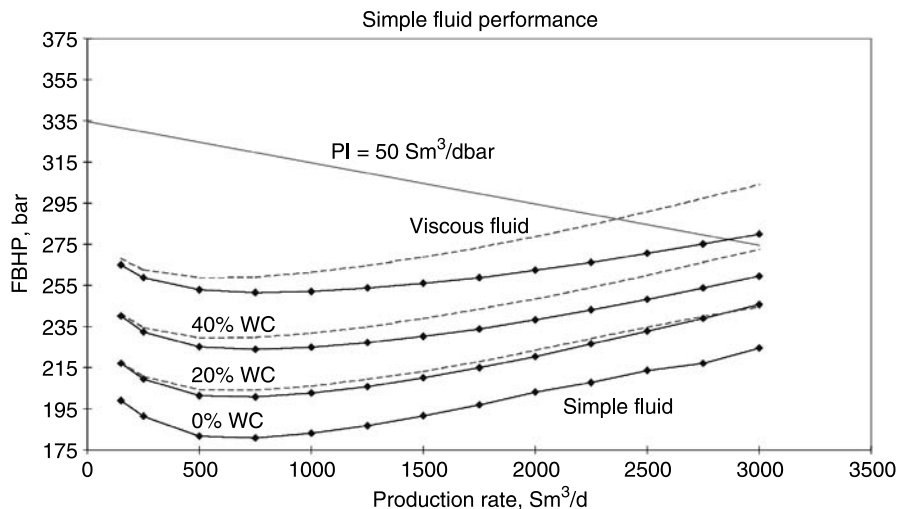
where the value of  $k_3$  roughly indicates the phase inversion point. This yields one of the strongest benefits of sub-sea and sub-sea processing – increased flow line capacity. As illustrated in Figure 17.6, production potential can be substantially increased by early removal of water.

### 17.2.4 VISCOSITY MODELS FOR OIL/WATER EMULSIONS

Pal (1993) has carried out considerable work with emulsion and dispersion viscosities. Although his work is often generalized to describe flow line generated emulsions, it does not show the very clear functionality often attributed to him.

Three important conclusions (in addition to his viscosity model) can be derived from his work into flowline pressure-drop and metering:

- The apparent friction factors for the flowing unstable emulsions are lower than expected from the viscosity behavior, while that for stable emulsions are consistent with the reported relative viscosity data and are calculable using single-phase flow methods.
- The observed meter-factors for unstable emulsions are not consistent with those of single-phase flow, while those for stable emulsions are consistent.
- The apparent viscosity increase for stable emulsions is a strong function of droplet size. Viscosities increase radically with decreasing droplet size and the fluids show strong non-Newtonian behavior.



**FIGURE 17.6** Effect on production potential of emulsion viscosities. Calculations are performed on a 15 km sub-sea tieback.

Pal (1993), Krawczyk et al. (1991), and Skelland and Slaymaker (1992) relate the droplet and viscosity behavior to chemical surfactant behavior. The simple experiments of Skelland and Slaymaker show a very strong relationship between steady-state droplet diameters and surfactant concentrations.

The last observation may explain the poor results experienced for processes with strong recycle streams. These may be accumulating large numbers of very small droplets, which, in combination with the increase in stabilizing compounds, occur with these recycles. These, in turn, contribute to a viscous dispersion band in the separator. Such a system may be so “stiff” that flow short-circuiting occurs within the separator.

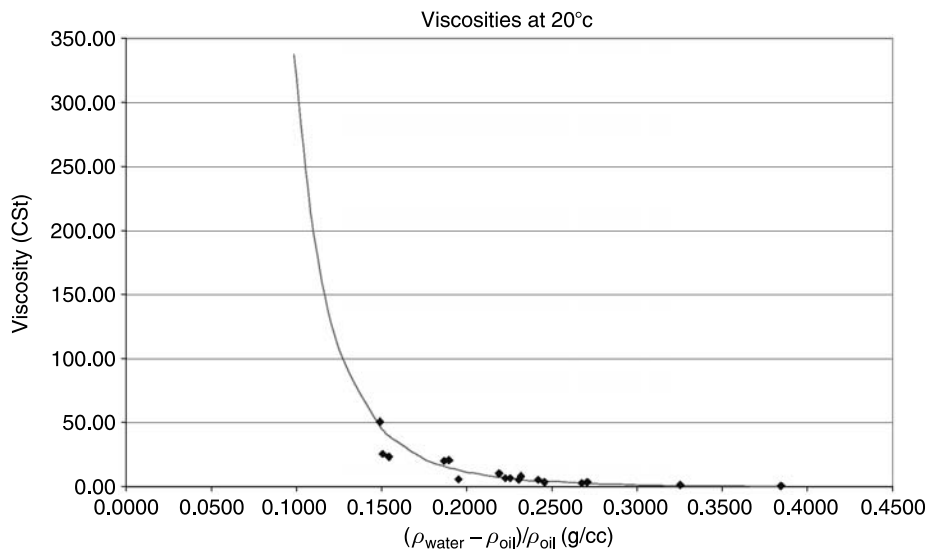
These models are also utilized to describe other systems such as waxy crudes, magma flows, etc. Studies of these systems (e.g., Wardaugh and Boger, 1991) indicate that transitions from high shear to low shear for systems with stable droplets can give extremely high apparent viscosities. This effect is also seen in work with monodisperse particles.

All of this is quite important because (as illustrated in Figures 17.6 to 17.9) the design equations for the system are very sensitive to viscosity data (which is very difficult to predict using an equation of state) and also to surface active chemicals (such as asphaltenes and saponifiers). It is difficult to predict the behavior of the latter if geochemical information is not available.

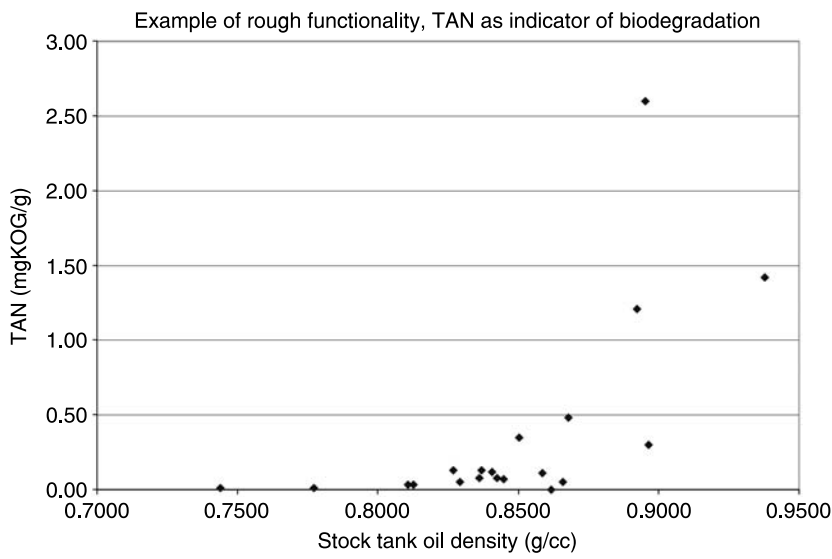
## 17.2.5 LIQUID–LIQUID SEPARATION MODELS

### 17.2.5.1 Traditional Sizing

The traditional method for estimating separator size is based on simplistic assumptions. An example can be taken from the exploration well test separator. The design method used to size these simple devices is based on Stokes’ law separation for all of the phases and an assumed droplet size of 100 microns. The droplet generation functions illustrated previously show strong

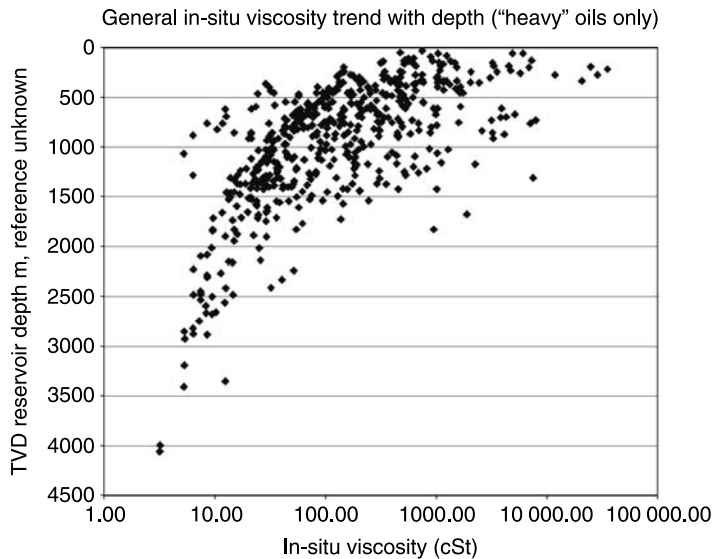


**FIGURE 17.7** Example of correlation between stock tank oil density and viscosity.



**FIGURE 17.8** Relationship between the density of a heavy oil and its degree of biodegradation. The illustration is based on TAN as an indicator of biodegradation.

rate dependence as well as strong functionality with pressure and density. Experience with these separation devices showed strong fall-off of efficiency with increasing rate (a factor that has been a driving force for the use of isokinetic sampling techniques during gas well tests). The resulting sizing equations are little better than the American Petroleum Institute 12J separation time guidelines used previously (Table 17.1). Alternatives to these exist, such as those suggested



**FIGURE 17.9** Consistent relationship for viscosity, illustrating the relationship between reservoir depth (and temperature) and *in situ* viscosity. (Source, US Department of Energy.)

TABLE 17.1 American Petroleum Industry Separation Time Guidelines	
Oil Density (g/cc)	Residence Time (min)
<0.85	3
>0.85	5 to 10

in the Campbell gas processing series (Campbell, 1988), where the settling time is given as:

$$\alpha \mu_0 / (\rho_w - \rho_0) / C(wc, \Delta_0) \tag{17.12}$$

where the function  $C(wc, \Delta\rho_0)$  has a functionality similar to that of hindered droplet settling:

$$C(wc, \Delta\rho_0) = \left\{ a + b / \left[ (\rho_w - \rho_0) \rho_0 \times \left( 1 - \frac{wc}{100} \right)^{1/4} \right] \right\}^4 \tag{17.13}$$

Figure 17.10 shows the relationship between density function and settling rate factor, as derived from Campbell.

17.2.5.2 The Shell Model

Shell has presented a new model for the design of separators (Polderman et al., 1997) which looks at the flux of the dispersed phase through an interface. The limiting flux can be established

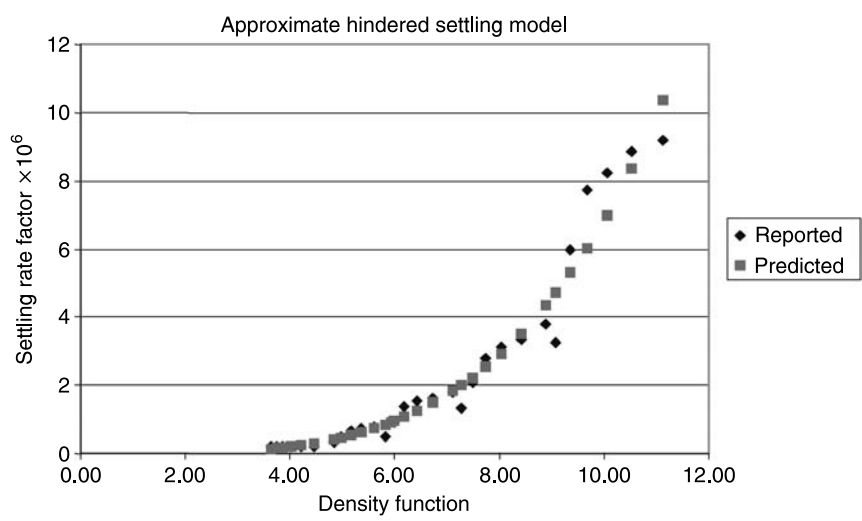


FIGURE 17.10 Modified settling model derived from Campbell.

by a batch test in a droplet characterization rig (DCR) or in the field.

$$\frac{Q_l}{A_{\text{interface}}} = \frac{h_d}{a + bh_d} \tag{17.14}$$

$$\frac{dh_d}{dt} = \frac{Q_l}{A_{\text{interface}}} \tag{17.15}$$

$$\frac{h_d}{dh_d/dt} = a + bh_d \tag{17.16}$$

where

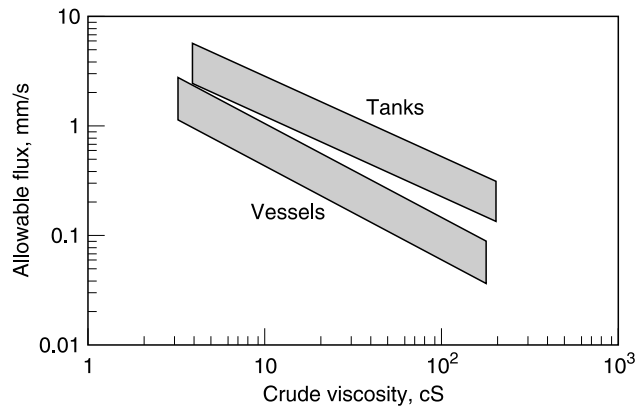
- $Q_l$  = liquid flux of dispersed phase
- $h_d$  = height of emulsion band
- $A_{\text{interface}}$  = horizontal cross-sectional area of the vessel
- $a$  and  $b$  = empirical constants

Generalized charts for separator loading can be calculated with this method as given by Polderman et al. in Figure 17.11. As can be seen, the proposed allowable flux span is 1:3, indicating the uncertainty of the method.

17.2.5.3 The Hartland Model

A recent model that has been shown to be very applicable to describing oilfield separation processes is that of Jeelani and Hartland. The settling velocity is given by:

$$v_0 = \frac{12\mu_C(1 - \varepsilon_0)}{0.53\rho_C\varphi_0} \left[ -1 + \sqrt{1 + \frac{0.53\rho_C\Delta\rho g\varphi_0^3(1 - \varepsilon_0)}{108\mu_C^2(1 + 4.56\varepsilon_0^{0.73})}} \right] \tag{17.17}$$



**FIGURE 17.11** Dispersed phase flux chart. (From Polderman et al., 1997.)

The rate of coalescence, the drainage from the dense packed layer, can be found by:

$$\Psi_i = \frac{\varepsilon_P [2H_0 (1 - \varepsilon_0) - v_0 t_i]}{(1 - \varepsilon_P) (3\tau_0 + t_i)} \tag{17.18}$$

where

- $\mu_C$  = viscosity of the continuous phase
- $\varepsilon_0$  = the holdup fraction of the dispersed phase at  $t = 0$
- $\varphi_0$  = initial average droplet size
- $\rho_C$  = density of the continuous phase
- $\Delta\rho$  = density difference between continuous and dispersed phase
- $g$  = gravitational force
- $\varepsilon_P$  = the holdup fraction of the dispersed phase in the dense packed layer at  $t_i$
- $H_0$  = total height of the emulsion at  $t = 0$
- $\tau_0$  = coalescing time at  $t = 0$

This model accounts for both settling and coalescence in the dense packed layer (see [Figure 17.12](#)). The nice feature of this model is the inclusion of emulsion stability due to various chemical components and mechanisms through the  $\tau_0$ , coalescing time. Hindered settling is modeled based on a representative droplet diameter. These two parameters can be experimentally tuned in a DCR and the model has been shown to give good description of separator performance in simple flow conditions, i.e., with single well, no complex emulsions. Still, some work remains to link the chemical characterization data to the coalescence time in the model, i.e., to reliably predict the parameter based on fluid characterization.

Neither of the models presented above take into account droplet size distribution. The effect of the dispersion bed is also unclear as the majority of the models utilized the continuous-phase viscosity as the reference viscosity.

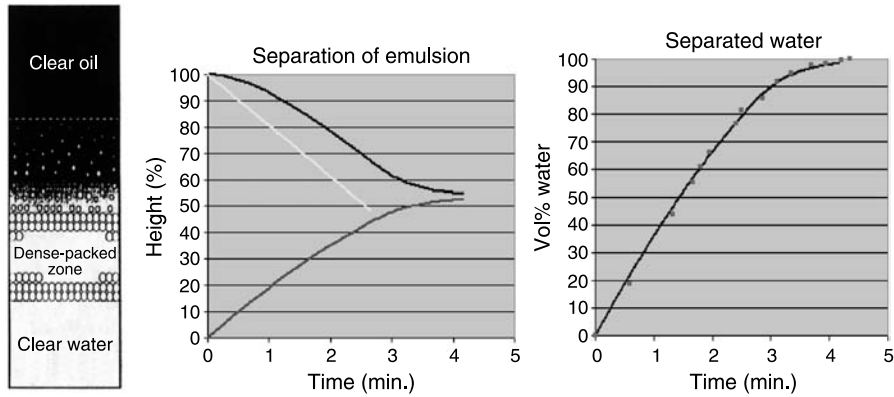


FIGURE 17.12 Hartland model versus experimental data.

17.2.5.4 The Hafskjold Model

Hafskjold et al. (1999) developed an empirical model for oil/water separation in pipes and tanks that accounts for droplet-size distribution. The model accounts for settling using a model for hindered settling that is dependent on the droplet diameter. Coalescence is calculated as the product between number of collisions and the probability of coalescence given a collision. Then these are summarized over all droplet classes. In general, the model by Hafskjold et al. is based on the following volume balance:

$$\frac{\Delta V_{i,n}}{\Delta t} = u_i \frac{\Delta V_{i,(n-1) \text{ or } (n+1)}}{\Delta z} - u_i \frac{\Delta V_{i,n}}{\Delta z} + \text{source} \tag{17.19}$$

where the left-hand side represents change in volume of drops of class  $i$  in control volume  $n$  during time  $\Delta t$ , the two first terms on the right-hand side represents the volume of drops of class  $i$  flowing in from control volume  $n - 1$  or  $n + 1$  and out of control volume  $n$ . The source term is given by:

$$\text{source} = v_i^c - v_i^a \tag{17.20}$$

where  $v_i^c$  is the volume of droplets of size class  $i$  created by coalescence, and  $v_i^a$  is the volume of droplets of size class  $i$  destroyed by coalescence.

There are five adjustable variables in this empirical model. These are related to the coalescence rate and the fluid. The model can be applied to analysis and improvement of existing separator processes, as well as design of new equipment.

17.3 EXPERIMENTAL VERIFICATION OF SEPARATOR PERFORMANCE

In order to reduce risk in separator design, experiments have been proposed in the following steps:

- Fluid characterization:
  1. American Petroleum Institute, reservoir dept. characterization



2. Bottle tests
3. DCR 1, simple
4. DCR 2, twin/triple (two to three wells)
5. DCR 3, high pressure; repeat steps 3 and 4
- Qualification/fluid characterization:
  - 6a. LP flow test with model oils
  - 6b. Flow test in HP/HT flow loop (Porsgrunn type)

The experimental steps are described below. Note that the combination of experiments and tests are used to scale up from sample to real conditions. The experimental work should also be combined with modeling.

### 17.3.1 SAMPLING, PVT, AND ASSAY STUDY RESULTS

It is essential that the oil sample be collected without air contact. To ensure realistic inlet conditions for the test separator detailed assessment of fluid flow and droplet size distribution must be carried out. Samples and studies designed to emulate multi-well flow conditions should be included to provide for a worst-case assessment. In this case, a phased approach should be considered. The crude oil assay contains important information for the evaluation. Particular concerns are:

- High total acid number or iodine values
- Problems with excess water
- High values for S, Vd, and Ni
- Asphaltene contents over 1%

(See also [Section 17.4.](#))

### 17.3.2 BOTTLE TESTS

Bottle tests are standard in order to find properties of the fluid. These are important for simple screening, but because of the simple methodology, the test process does not accurately emulate the production process. Droplet characterization rigs provide an improved model of the production process.

### 17.3.3 DROPLET CHARACTERIZATION RIGS 1 TO 3

Droplet characterization rigs are classified DCR1, 2, and 3. DCR1 is just an advanced bottle test that includes a certain approach to inlet shear. The fluids are pumped through a valve and into a container or PVT cell. After filling the cell, the change in free water level is monitored. The thickness of the emulsion layer may also be tracked with additional equipment.

The second type of droplet characterization rig, DCR2, is similar to DCR1 but also provides a certain insight into the effect of mixing wells by allowing for mixing of more than one emulsion stream before the mixture flows in the capture cell. DCR3 is the third type of rig. It is similar to DCR1 and DCR2, except that it operates at high pressure.

There are many low-pressure rigs (DCR1 and DCR2), and they are cheap to build and operate. On the other hand, fewer high-pressure units (DCR3) exist, and they are also expensive to build.

### 17.3.4 DYNAMIC FLOW-LOOP TESTS

The best-known way to validate separator performance prior to installation is to carry out a scaled test with real fluids at real operating pressure and temperature. However, prior to such high-pressure tests, low-pressure tests should be carried out to optimize the design.

The purpose of a flow-loop test is to:

- Investigate the effect of free gas and released gas
- Investigate the dynamic behavior of the gravity separator
- Verify the effect of mixing wells with different water cuts/complex emulsions
- Verify the retention time and the geometry
- Verify the pressures and water cuts
- Investigate the impact of continuous sand flushing
- Investigate the impact of one selected demulsifier
- Investigate the impact of level settings
- Uncover unknown scale effects

## 17.4 DATA SOURCES

As is indicated in the preceding text, methods exist to allow the operators and vendors to design and deliver systems more appropriate to the field's fluid behavior. Typically, the supplier is often restricted by the information (or lack of it) which the operator supplies. To make a proper system design the vendor should be supplied with:

- A compositional analysis for all fluids, detailing:
  1. Trace elements
  2. Reservoir conditions
  3. Surface and stabilized fluid properties
  4. Formation water description including scaling potential
- A copy of the relevant reservoir fluid studies (including any special studies):
  1. Viscosity studies
  2. Differential liberation, miscibility, etc.
  3. Wax
  4. Asphaltene
- A copy of a relevant crude-oil assay data:
  1. Metals
  2. Sulfur
  3. Iodine number
  4. Acid number
  5. Viscosities
- Emulsion separation studies if performed

These give the vendor access to the majority of the fluid data required to meet the operator's needs for information about emulsion forming tendencies. Proper equipment sizing can then be based on "rules of thumb" and experience with the various stabilizing mechanisms for emulsions.

**TABLE 17.2**  
**Typical Data Provided to Process Supplier**

Component	Mol %
Nitrogen	0.00
Carbon dioxide	45.07
Hydrogen sulfide	5.37
Methane	5.44
Ethane	0.98
Propane	2.85
i-Butane	1.24
n-Butane	1.80
Hexane+	36.41
Total	100.00
Pour point, °C	12
Wax content (wt%)	Not supplied
Density at 15 °C (kg/m <sup>3</sup> )	862
Kinematic viscosity at 15 °C (cSt)	7.60
Sulfur (wt%)	Not supplied
Hydrogen sulfide (ppm wt)	Not supplied

**TABLE 17.3**  
**Results from a Reservoir Fluid Study**

Pressure (MPa)	$R_s(\text{Sm}^3/\text{Sm}^3)$	$B_o(\text{m}^3/\text{Sm}^3)$	$u_o(\text{cP})$
36	130	1.366	0.79
33	130	1.373	0.74
31	130	1.378	0.70
28	130	1.386	0.65
26.1*	130	1.391	0.62
23	114	1.349	0.67
21	104	1.321	0.71
19	93	1.294	0.76
16	78	1.254	0.84
14	68	1.227	0.91
11	53	1.186	1.05
8	36	1.145	1.24
6	26	1.118	1.40
3	10	1.078	1.76
1	0	1.050	2.54

*Note:* Asterix denotes the bubble point for the liquid.

The data presented in Tables 17.2 and 17.3 are normally available to the reservoir engineering department but not released to the process engineers. Indeed, the well test engineers are the first to properly test the fluids for any unusual behavior. In one relevant case (Friedemann, 1997) the crude assay samples were the only ones in which water was observed. A later review of the

well-test pressure behavior indicated that the well tests produced at 50% water cuts. Because the observed salinity was at or near saturation, this form of stability represented a threat of significant price penalties from both the tanker owners as well as the refineries.

The data in Table 17.3 are of very great importance for sub-sea and downhole processing. This is because the information gives the system designers fluid property data at the correct operating condition. These data are also important for tuning the fluid property models of the process simulators.

## 17.5 ALTERNATIVE SEPARATOR DESIGN

Conventional gravity separators are devices designed to provide for phase disengagement by encouraging stratified flow. This is done by using large diameter devices with typical length to diameter ratios ( $L/D$ ) of 3 to 5. The result is a device designed to optimize footprint, but not necessarily weight or installability.

From a multiphase flow viewpoint the long slim device gives advantages in that droplet rising/settling distances are much shorter. The challenge is then to hold the flow rates so that the system is within the stratified flow region. Once that flow regime is achieved, the liquid levels are a result of the same physics, which yields holdup.

This puts a challenge on the control system, as the sensitivity of the level sensing system will be important, as indicated in Section 17.6.2. The advantage is that long slim separators may offer more efficient separation volumes than traditional gravity separators. Therefore an investigation of the pros and cons for installation of long thin vessels should be performed.

## 17.6 CONTROL SYSTEMS

The challenges of remote and sub-sea field operations are made more difficult by a lack of direct access to operational data. Insufficient planning for problem-solving solutions often challenges traditional topside facilities. Typically, operating companies may be challenged with crash-course diagnostic activities to determine the causes of repeated equipment failures. Although the topside systems are easily accessible, the diagnostic activities are made even more difficult. This places an emphasis on control system design.

Traditionally, the system buffer for the level control system is the gas in the gravity separator. Two factors that influence the need and use for separator control are:

- Instability of the inlet flow (slugging)
- Quality of the separation

Both of these are strongly influenced by fluid property models and (in the case of oil–water systems) the rheology of production induced emulsions.

### 17.6.1 SLUGGING

Gas and liquid flow can operate within different flow regimes (annular, slug, stratified, bubbly) depending on the flow rates. Slug flow has a special characteristic, as it is an unstable regime where liquid slugs are followed by gas pockets. The length (and resultant volumes) of hydrodynamic slugs can vary dramatically from a few to very many pipe diameters and can include internal gas as well. Gravity and cyclonic separators will have to handle such hydrodynamic slugs.

A more severe case can occur with so-called terrain slugs. These are created by liquid collecting in the lower parts of a flowline, and then transported through the flow line. Note that flow regime maps cannot predict this type of slug.

Many different methods exist for estimating slug lengths. These vary from the use of simple tubing diameter based methods and include complex dynamic simulations. It is the experience of the author that the latter method is to be preferred as it allows for the inclusion of nonsteady state analyses because the result of a start-up, shutdown, restart sequence can often give surprising effects on the slugging behavior of a system. The slug period of terrain slugs will vary from minutes to hours, while hydrodynamic slugs typically have a period of a few seconds.

The control system required for a specific field depends on the flow line profile and diameter, but also on the separator design. Smaller equipment or cyclones are more sensitive to slugs, and therefore more dependent on the control system.

As mentioned, to get terrain slugs, the terrain must be hilly with dips, and the flow line must have a certain length, much longer than the slug length. By placing the sub-sea separator next to the wellhead one will avoid terrain slugs. Furthermore, in a real application, a transient computer simulation should be performed in order to estimate the slug sizes.

### 17.6.2 LEVEL CONTROL

Recall the Hartland model presented in Section 17.2.5.3. The model predicts how the quality of the fluid, and the inter-phase levels, change with time. A level sensor should indicate the region of dense packed zone, but also the profile of the water cut.

The required accuracy on the water cut profile depends on specifications. There are several qualified level sensors to measure the oil–water interface inside a sub-sea separator. The two different level monitoring systems installed in Troll Pilot are also capable of giving the concentration profile. However, these profilers can not reliably distinguish 1% oil-in-water from 0% oil-in-water, or 1% water-in-oil from 0% water-in-oil. Nevertheless, accounting for knowledge of the fluids and their separation behavior compared to the level profile readouts, likely oil and water qualities can be deduced.

A level sensor operating in a liquid-filled vessel with a sensitivity of 10 cm will give an acceptable resolution when placed in a 3 m diameter tank. The same device mounted in a tank of 1 m diameter will need a higher resolution.

## 17.7 CONCLUSIONS

Sub-sea separation calls for highly reliable separator equipment. To ensure the best possible performance for the entire life of a field, a detailed characterization of the oil–water emulsion should be carried out at proper pressure and temperature. Chemicals to be used should be tested with the oil in the same manner.

Traditional design rules for topside separators are based on over-simplified models, and are not sufficient for sub-sea use, while the more comprehensive approach (see [Section 17.2.5.3](#)) gives a better understanding and a more correct separator design. However, there is still a need to establish the missing link between pressurized test cell behavior (laboratory scale) and large-scale dynamic behavior.

The complex emulsions formed by commingling different well streams with different water cuts are hard to predict in terms of separability. To ensure no disastrous effects of mixing well streams, a proper high pressure test should be carried out to explore the separator efficiency under

the most unfavorable conditions. In particular, the inlet devices should be carefully examined to ensure efficient performance throughout the field lifetime.

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