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# Tidal Pressure Response and Surveillance of Water Encroachment

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### Abstract

A review of the tidal response in petroleum reservoirs is given. It is caused by periodic changes in overburden stress induced by the ocean tide. The "tidal efficiency factor" is derived by two different approaches and is in line with a recent well test in the Ormen Lange gas field.

For small geomechanical pertubations, like the tidal effect, we show that a simplified coupling of geomechanics and fluid flow is possible. The coupling is easy to implement in a standard reservoir simulator by introducing a porosity varying in phase with the tide. Simulations show very good agreement with the theory.

The observation of the tidal response in petroleum reservoirs is an independent information provider, i.e., it provides information in addition to the (average) pressure and its derivative from a well test. The implementation of the tidal effect in a normal reservoir simulator gives us the possibility to study complex multiphase situations and to evaluate the potential of the tidal response as a reservoir surveillance method. The case studies presented here focus on the possibility to observe water in the near-well area of a gas well.

### Introduction

The main objective of this work is to investigate if the tidal pressure response in petroleum reservoirs can be used for reservoir surveillance, in particular to detect saturation changes in the near-well area, e.g., to detect water encroachment towards a gas well. The literature seems sparse in this area. Also, our approach of simplified coupling of geomechanics and fluid flow for small geomechanical effects, and the possibility to implement this in a normal reservoir simulator has to our knowledge not been discussed in the litterature. Several authors have derived a tidal efficiency factor, but a review and comparison study seems to be missing.

### **Tidal effect**

The gravitational pull from the moon and the sun works on both the earth itself, the ocean and the atmosphere. From a point within the earth, e.g., inside a petroleum reservoir, the three effects add up to total tidal dilatation  $\Delta e_t$  as a sum of the three independent partial effects. These are are the solid earth tide dilatation,  $\Delta E$ , the barometric tidal dilatation  $\Delta B$  and the ocean tide dilatation  $\Delta O$ , and  $\Delta e_t = \Delta E + \Delta B + \Delta O$ , Ref. 1. The components will have a different magnitude (amplitude), efficiency, frequency and phase.<sup>2</sup>

### Tidal response in petroleum reservoirs

During transient well tests, a gauge is placed in the well to continuously record the pressure and the temperature. Modern production wells are often equipped with permanent downhole gauges to monitor well and reservoir behavior.

An important part of a transient well test is the shut-in period when the well is closed in and pressure gradually builds up. If this period is long enough, it is quite common to observe small and periodic pressure variations. These variations occur on a semidiurnal time scale, repeating every half day. In addition, other variations with similar but longer periods, e.g., daily, may also be seen. The sinusoidal variation in reservoir pressure observed in well-test data coincides with the periodic variation in the gravitational pull on the earth by the moon and the sun. In transient well-test analysis the tidal effect appears as unwelcome perturbations troubling the interpretation mainly at the late time periods.

At a reservoir located below the sea floor, the three tidal mechanisms discussed are active at the rock-fluid systems. The ocean tide is, however, by the magnitude of its effects on the reservoir, the dominant source of perturbation.<sup>1</sup> The tide gives a certain pressure variation on the sea floor. A much smaller pressure variation is observed in the reservoir. The ratio of the pressure variation at these two locations is known as the tidal efficiency factor. It is further discussed below.

The first observations of the tidal phenomenon in porous media are dated to the 1880s. The majority of the observations were made in mines and open water wells in which even the smallest periodic fluctuation of water level was easily detectable and recordable.<sup>3</sup> The effect was first detected in petroleum reservoirs with the advent of highly sensitive pressure gauges. In 1976 Kuruana<sup>5</sup> presented the first work relating the periodical pressure oscillation during testing of wells in Timor Sea with the ocean tides. In 1978 Arditty *et al.*<sup>6</sup> developed a theory which described the pressure variation in

closed well systems caused by earth tides and studied the parameters which determined the amplitude. Hemala and Benalves<sup>1</sup> provided in 1986 an overview of tidal effects from the petroleum engineering point of view, and proposed some applications of the effect to predict fluid heterogeneities in reservoir. McKee, Bumb, and Horner<sup>3</sup> presented in 1991 a theory for calculating bulk compressibility from the tidal efficiency factor.

Inspired by Hemala and Benalves' proposal, Wanell and Morrison<sup>7</sup> suggested in 1990 a practical method of measuring vertical permeability and Dean *et al.*<sup>8</sup> introduced a method to monitor compaction and compressibility changes in an offshore chalk reservoir by measuring the tidal effect in the reservoir. Netland *et. al.*<sup>9</sup> published in 1996 a method for monitoring compaction not limited to a specific reservoir rock, through a more complex expression for the compaction modulus. In 1997 Pinilla *et al.*<sup>10</sup> presented a model coupling aspects of geomechanics, tide and fluid flow in porous media. Smit and Sayers<sup>11</sup> presented in 2005 a general derivation of the tidal efficiency factor and discussed how the tidal response can assist 4D seismic monitoring.

# Theory

### **Compressibility definitions**

Three types of compressibilities are often cited in the characterization of a porous medium. This is bulk compressibility,  $C_b$ , representing the relative changes in bulk volume of the medium; solid grain compressibility,  $C_{sg}$ , representing the relative changes in matrix volume of the medium; and pore volume compressibility,  $C_p$ , representing the relative change in pore volume.

The most often used definitions of compressibility are as follows,  $^{\rm 12}$ 

$$C_{bc} = -\frac{1}{V_b} \left( \frac{\partial V_b}{\partial P_c} \right)_{P_p}, \qquad (1)$$

$$C_{bp} = \frac{1}{V_b} \left( \frac{\partial V_b}{\partial P_p} \right)_{P_c}, \qquad (2)$$

$$C_{pc} = -\frac{1}{V_p} \left( \frac{\partial V_p}{\partial P_c} \right)_{P_p}, \qquad (3)$$

$$C_{pp} = \frac{1}{V_p} \left( \frac{\partial V_p}{\partial P_p} \right)_{P_c}, \qquad (4)$$

and

$$C_{sgc} = C_{sgp} = C_{sg} = \begin{bmatrix} -\frac{1}{V_b} \left(\frac{\partial V_b}{\partial P_c}\right)_{P_p} = \frac{1}{V_p} \left(\frac{\partial V_p}{\partial P_p}\right)_{P_c} \end{bmatrix}_{A(P_c - P_p) = 0}.$$
(5)

The first subscript denotes the type of compressibility; b for bulk, p for pore volume and sg for grain. The second subscript represents the changing pressure; c for confining, p for pore pressure and the subscript outside of the parenthesis indicates the pressure, pore or confining, to be maintained constant.

The two bulk compressibilities,  $C_{bc}$  and  $C_{bp}$ , and grain compressibility  $C_{sg}$  can be measured directly from specimen volumetric deformation;  $C_{bc}$  is measured under constant pore pressure and changing confining pressure, while  $C_{bp}$  is measured under constant confining pressure and changing pore pressure. These two values are not the same, but often differ by an insignificant amount, i.e.,  $C_{bc} \approx C_{bp}$ .

The compressibility  $C_{pp}$  is normally used for reservoir reserve calculation. This is because it is the pore pressure that most affects the porosity and hence the pore volume and not the horizontal in-situ stress, which would be equivalent to the confining pressure. In reservoir simulators  $C_{pp}$  describes how the porosity changes with changing pore pressure.

The difference between  $C_{pc}$  and  $C_{pp}$  ( $C_{pc}$  being larger) is the grain compressibility, which often is ignored. Pore volume compressibility, either  $C_{pc}$  or  $C_{pp}$ , the fundamental compressibility from the reservoir engineering perspective, can only be determined indirectly through measurement of volumetric changes of the pore fluid.

The relationship between all of the above compressibilities can theoretically be derived if elasticity is assumed,<sup>12</sup>

This is just another way of writing the Biot<sup>14</sup> correlations

$$C_{bp} = \alpha C_{bc},$$

$$C_{pc} = \frac{\alpha C_{bc}}{\phi},$$

$$C_{pp} = \frac{\left[\alpha C_{bc} - \phi C_{sg}\right]}{\phi},$$
(7)

where  $\alpha = 1 - C_{sg} / C_{bc}$  is called the Biot coefficient.

#### The tidal efficiency factor

The ratio between the tidal pore pressure response in the reservoir and the tide pressure change at the sea bottom is referred to as the tidal efficiency factor. In the literature, various expressions for this factor is found. One of the first to make such a correlation was C. E.  $Jacob^4$  in 1940 in the field of hydrology. The purpose of this section is to derive this expression from first principles. Later on, the theoretical derived factor will be compared with observed values in an Ormen Lange well test.

The basic assumption to derive the tidal efficiency factor is the model of a linear elastic medium.<sup>13</sup> We also assume an isotropic medium and an isothermal process. Then we have

$$\sigma_{ij} = 2G\varepsilon_{ij} + \lambda e\delta_{ij} + \alpha P_p \delta_{ij}, \dots \tag{8}$$

where  $\varepsilon_{ij}$  and  $\sigma_{ij}$  are the components of the bulk strain tensor and total stress tensor, respectively; *G* is shear modulus defined by  $G = E/[2(1+\nu)]$ , where *E* is Young's modulus, *v* is the Poisson ratio for the solid skeleton under drained conditions,  $\lambda$  is the Lame constant which is related to other properties by  $\lambda = 2\nu G/(1-2\nu) = 1/C_{bc}-(2/3)G$ ;  $\delta_{ij}$  is the Kroneckerdelta, *e* is the bulk volume strain defined by

$$e \equiv \varepsilon_{xx} + \varepsilon_{yy} + \varepsilon_{zz},$$

where the subscripts denote component in the bulk strain tensor and  $\alpha$  is the Biot coefficient. Note that only two of the three engineering constants *G*, *E* and *v* are independent.

Eq. 8 gives a relation between strain, stress and pore pressure expressed in terms of stress since stress satisfies the equilibrium equation  $\sum_{i} (\partial \sigma_{ii} / \partial x_{j}) = 0$ . The mean normal stress is defined as

$$\sigma_m \equiv \frac{\sigma_{xx} + \sigma_{yy} + \sigma_{zz}}{3}.$$
 (9)

From Eqs. 8 and 9, substituting for  $\lambda$ , we get

$$\sigma_m = \frac{1}{C_{bc}} e - \alpha P_p. \tag{10}$$

Differentiating Eq. 10 gives

$$de = \alpha C_{bc} dP_p + C_{bc} d\sigma_m$$

Now using Eq. 7 and the fact that  $de \equiv dV_b/V_b$ , Ref. 14, gives

$$\frac{dV_b}{V_b} = C_{bp} dP_p + C_{bc} d\sigma_m.$$
(11)

This is an expression for a relation between the pressure response in a porous medium and the change in mean normal stress, from a linear elastic medium model.

Alternatively, we may derive this expression by realising that the bulk volume is a function of both confining pressure and pore pressure. Then we have

Eqs. 11 and 12 are equal with  $\sigma_m = -P_c$ .<sup>14</sup>

We also need an expression for the change in pore volume strain. We know that  $V_b = V_p + V_s$ , or  $de = \phi de_p + (1-\phi)de_s$ . Putting this into Eq. 11, solve with regards to  $dV_p/V_p$  and use the definitions for compressibilities, we get for the change in pore volume strain,  $de_p$ ,

$$de_{p} \equiv \frac{dV_{p}}{V_{p}} = C_{pp}dP_{p} - C_{pc}dP_{c}.$$
 (13)

At isothermal conditions, the fluid density is only a function of pore pressure,  $\rho = \rho$  (*P*). Assuming a constant fluid mass it follows that

$$de_{f} \equiv \frac{dV_{f}}{V_{f}} = \frac{1}{V_{f}} \frac{dV_{f}}{dP_{p}} dP_{p} = -C_{f} dP_{p}$$
. ....(14)

In a reservoir the fluid will fill the pore volume completely and any change that the pore volume implies a change in fluid volume. Therefore, by setting  $de_f = de_p$ , we obtain an expression for the tidal efficiency factor

$$\frac{dP_p}{d\sigma_m} = \frac{C_{pc}}{C_f + C_{pp}}.$$
(15)

If we instead, as some authors may have done, set  $de_f = de$ , use the definitions for compressibility and assume that grain compressibility is much smaller than pore compressibility, we obtain

$$\frac{dP_p}{d\sigma_m} = \frac{\phi C_{pc}}{C_f + \phi C_{pp}}.$$
 (16)

Eqs. 15 and 16 are the two basic expressions for the tidal efficiency factor found in the literature. We think that Eq. 15 is more valid than Eq. 16.

The change in mean normal stress is not necessarily the same as change in tidal load. Usually, one assumes no damping, i.e. that the mean normal stress amplitude is the same as the sea bottom tide pressure amplitude  $d\sigma_m = dP_{tide}$ . It is common in oilfield compaction studies to assume a uniaxial description, i.e., that the compaction is only in the vertical direction and that the strain in the horisontal directions is zero.<sup>8</sup>

Chen *et al.*<sup>14</sup> showed that  $C_{pc}$  and  $\sigma_m$  will be different for different boundary conditions. For the uniaxial case  $\sigma_m = \sigma_{zz}$  and  $C_{pc}$  is replaced by  $(1+\nu)/(3 (1-\nu))C_{pc}$ ; for the biaxial case,  $\sigma_m = (\sigma_{yy} + \sigma_{zz})/2$  and  $C_{pc}$  is replaced by  $2/3(1+\nu)C_{pc}$ ; and for the triaxial case,  $\sigma_m = (\sigma_{xx} + \sigma_{yy} + \sigma_{zz})/3$  and the compressibility is just  $C_{pc}$ . Grain compressibility is assumed much smaller than pore compressibility in these relations. The expression without this assumption is shown in Pinilla *et al.*<sup>10</sup> and Smit and Sayers<sup>11</sup>. Thus for the uniaxial case, Eq. 15 can be written as

$$\frac{dP_p}{d\sigma_{zz}} = \frac{1+\nu}{3(1-\nu)} \frac{C_{pc}}{C_f + C_{pp}} \dots (17)$$

Dean *et al.*<sup>8</sup> write  $d\sigma_m = (1+\nu)/(3(1-\nu))d\sigma_{zz}$  and keep  $C_{pc}$  as it is.

As mentioned, different expressions for  $dP_p/d\sigma_m$  have been suggested in the litereature, most of them as Eq. 15 or Eq. 16. Refs. 3, 4, 8, 9, 10, 15 suggest Eq. 15. They all assume that the change in pore strain is equal to change in fluid strain. Not all the papers specify the equation for the different conditions, but most of them do. Ref. 7 ends up with Eq. 16. No damping of the signal is discussed, but using porosity as a damping factor give good results when comparing with observed data.

# Simplified coupling of geomechanics and fluid flow

Following Chen *et al.*<sup>1413</sup> we have for the conservation of fluid mass,

and for the solid mass,

$$\nabla \cdot [\rho_s(1-\phi)\mathbf{v}_s] + \frac{\partial [(1-\phi)\rho_s)]}{\partial t} = 0.$$
(19)

Furthermore, Darcy's law states that

$$\phi(\mathbf{v} - \mathbf{v}_s) = -\frac{k}{\mu} \nabla P_p. \qquad (20)$$

Putting Eq. 20 into Eq. 18 and assuming no solid mass transport,  $\mathbf{v}_s = 0$ , but that the solid is able to stay in it's position, which means that  $\nabla \cdot \mathbf{v}_s \neq 0$ , Eq. 18 becomes

$$\nabla \cdot (\rho \frac{k}{\mu} \nabla P_p) = \phi \rho \nabla \cdot \mathbf{v}_s + \frac{\partial (\phi \rho)}{\partial t}.$$
 (21)

Eq. 19, with  $\mathbf{v}_s = 0$ , may be written as<sup>14</sup>

and since the solid mass is constant and  $(1-\phi)$  is equal to solid volume divided by bulk volume, Eq. 22 becomes

$$\nabla \cdot \mathbf{v}_s = \frac{1}{V_b} \frac{dV_b}{dt}.$$
 (23)

Further, putting Eq. 23 into Eq. 22 we get

$$\nabla \cdot (\rho \frac{k}{\mu} \nabla P_p) = \phi \rho \frac{1}{V_b} \frac{dV_b}{dt} + \frac{d(\phi \rho)}{dt}.$$
 (24)

The fluid transport part of Eq. 24 can be written as

$$\frac{d(\phi\rho)}{dt} = \phi\rho(\frac{1}{\rho}\frac{d\rho}{dt} + \frac{1}{\phi}\frac{d\phi}{dt}).$$
(25)

Finally, putting Eq. 25 into Eq. 24 gives

$$\nabla \cdot \left(\rho \frac{k}{\mu} \nabla P_p\right) = \phi \rho \left(\frac{1}{V_b} \frac{dV_b}{dt} + \frac{1}{\rho} \frac{d\rho}{dt} + \frac{1}{\phi} \frac{d\phi}{dt}\right) \dots (26)$$

We now have to identify the dependencies of the different properties. Chen *et al.*<sup>14</sup> derived an expression for coupling of fluid flow and geomechanics and Pinilla *et al.*<sup>10</sup> added the tidal effect through a physical approach with porosity dependent on pore pressure,  $P_p$ , and confining pressure,  $P_c$ , both time dependent. From  $\phi = V_p/V_b$ , it follows that  $(1/V_b)dV_b/dt + (1/\phi)d\phi/dt = (1/V_p)dV_p/dt$ . Expanding  $dV_p$  on the right-hand side,

$$dV_{p} = \left(\frac{\partial V_{p}}{\partial P_{c}}\right)_{p_{p}} dP_{c} + \left(\frac{\partial V_{p}}{\partial P_{p}}\right)_{p_{c}} dP_{p},$$

and with the compressibility definitions, Eqs. 1-4, we get

$$\frac{1}{V_b}\frac{dV_b}{dt} + \frac{1}{\phi}\frac{d\phi}{dt} = C_{pp}\frac{dP_p}{dt} - C_{pc}\frac{dP_c}{dt}.$$
 (27)

Next, we want this physical change to be equal to just a change in porosity. We do this by defining a new porosity  $\phi_{sim}$ , to be introduced in the numerical reservoir simulator model, by setting

The right hand side of Eqs. 27 and 28 are equal, and from Eq. 26 we then get the new flow equation

This differs from the flow equations of Chen *et al.*<sup>14</sup> and Pinilla *et al.*<sup>10</sup>, who used the change in bulk volume to couple geomechanical and fluid behavior. Here, all the geomechanics is put into an expression for porosity. The remaining task is to find the expression for the new porosity that can be used for implementation in the reservoir simulator.

For tidal effects,  $P_p$  and  $P_c$  are only time dependent, and we can set  $dP_p(t)=\Delta P_p^{\text{const}}df(t)$  and  $dP_c(t)=\Delta P_c^{\text{const}}dg(t)$ , where superscript 'const' denotes a constant amplitude or pressure change, and f(t) and g(t) are two arbitrary functions of time. Then Eq. 28 becomes

$$\frac{1}{\phi_{\rm sim}} \frac{d\phi_{\rm sim}}{dt} = C_{pp} \Delta P_p^{\rm const} \frac{df}{dt} - C_{pc} \Delta P_c^{\rm const} \frac{dg}{dt} \dots \dots (30)$$

Integrating over time gives

where  $\phi_0 = \phi_{sim}(t=0)$ . Using Taylor expansion, assuming that the argument of the natural logarithm is small  $(\exp(x) \approx 1+x)$  and the fact that confining pressure will oscillate, the expression becomes

$$\phi_{\rm sim} = \phi_0 \bigg( 1 - C_{pc} \Delta P_c^{\rm const} \sin(\frac{2\pi t}{T}) \bigg) \bigg( 1 + C_{pp} \Delta P_p^{\rm const} f(t) \bigg) . \quad \dots \quad (32)$$

This is an expression for porosity which needs to be implemented. Here *T* is the tidal period and  $\Delta P_c^{\text{const}}$  is the amplitude of the oscillating confining pressure. We have assumed that the only change in the overburden or confining pressure is the tide, but we could also use the expression for compaction of the reservoir over a longer period. The function

f(t) takes fluid pressure drop into account. Assuming this to be normalised,  $\Delta P_p^{\text{const}}$  is the amplitude of the oscillating pore pressure and  $\phi_0$  is the reference porosity. The function f(t) will usually be very small compared to the confining part, see below for comparison of the two terms using Ormen Lange data. Eq. 32 is the key result that has been implemented in the reservoir simulator. (For simplicity we have assumed a constant amplitude of the confining pressure  $\Delta P_c^{\text{const}}$ . However, the theory and the implementation is not limited to this.)

# Tidal pressure response as a function of fluid saturation and pressure

The fluid pressure response to a stress change is a function of pore compressibility, fluid compressibility and stress change. Eq. 15 can be expressed as

The fluid compressibility,  $C_{f}$ , is a function of the compressibilities of the fluids in the system and the relative amount of each,

$$C_{f} = C_{g}S_{g} + C_{o}S_{o} + C_{w}S_{w},.....(34)$$

where  $S_g$ ,  $S_o$  and  $S_w$  are gas, oil and water saturations and  $C_g$ ,  $C_o$  and  $C_w$  are gas, oil and water compressibilities. This follows from the definition of fluid compressibility,  $(1/V_f)dV_f/dP_p$  knowing that  $V_f=V_w+V_o+V_g$ . Thus, the same stress field create different pressure response for fluids with different compressibility. For a gas water system, we can simplify Eq. 33 and Eq. 34 as

$$dP_p \approx \frac{C_{pc}}{C_f} d\sigma_m,$$

and

$$C_f \approx C_g S_g$$
,

since  $C_p << C_g$  and  $C_w << C_g$ . Thus, having a water flooded area with  $S_w = 0.75$  and a gas area with  $S_w = 0.25$ , the pressure response in the water flooded area will be three times that in the gas area. Further, as the gas compressibility is highly dependent on pressure  $C_g(P)$ , the tidal pressure response for a system with gas present, will also vary with reservoir pressure P,

$$dP_p \approx \frac{C_{pc}}{C_g(P)S_g} d\sigma_m.$$

#### **Propagation of information**

We make use of the standard analytical solution to the onedimensional diffusion equation below. In the limit where  $C_{bc} << C_f$ , we have<sup>11</sup>

$$\frac{\partial P}{\partial t} = D \frac{\partial^2 P}{\partial x^2}, \quad D = \frac{k}{\mu \phi C_f},$$

in one spacial dimension. Here D is the diffusivity. The solution gives an estimate of the propagation of any pressure perturbation in the reservoir. Solving for a periodic pressure variation of the form

$$\Delta P_c(t) = \Delta P_c^{\text{const}} \sin(2\pi \frac{t}{T}),$$

where T is the period of the imposed signal, gives

$$\Delta P(x,t) = \Delta P_c^{\text{const}} \exp\left(-x\sqrt{\frac{\pi}{TD}}\right)$$

$$\times \sin\left(2\pi \frac{t}{T} - x\sqrt{\frac{\pi}{TD}}\right).$$
(35)

It follows that the signal has decayed to a factor  $\delta$  of its initial magnitude at a distance:

$$x_{\delta} = -(\ln \delta) \sqrt{\frac{TD}{\pi}} \qquad (36)$$

Using Ormen Lange data from Table 1 (with  $S_g = 0.8$ ) and  $\delta=0.1$ , we get x=439 m. For a two-phase system, the permeability needs to be multiplied by the relative permeability of gas, which for  $S_g=0.8$  was 0.876 during simulations. This means that any pressure perturbation will travel in the reservoir and that the signal has decayed to 10% some 440 m away from the start position. This "propagation of information" may imply a potential for using the tidal pressure response in petroleum reservoirs towards reservoir surveillance, e.g., detecting a change in saturation in the near well area. Below, the potential to detect water influx towards a gas well is studied via reservoir simulation.

#### Ormen Lange gas field

Ormen Lange is a large gas field offshore mid-Norway. The field is developed as a subsea-to-beach concept with a new gas plant at Aukra. Hydro is the developer and Shell will be the operator. The other partners are Petoro, Statoil, Dong and ExxonMobil. The planned production start is October 2007.

Remote operations of the field requires tight well and reservoir surveillance. Each well will be equipped with a wet gas meter and a water fraction meter, as well as permanent downhole gauges. Information about the free formation water encroachment and production is important, and various "information providers" for water in the well and in the near well area have been identified. The starting point of this work was to explore if the tidal pressure response had some surveillance potential.<sup>16</sup>

#### Tidal pressure response during a well test

The latest appraisal well, 6305/4-1, is located in a welldefined fault polygon. A production test was run to obtain information about fault sealing capacity and to detect possible pressure depletion. The test had a 16 hours main flow period and a 30 hours buildup period. Ahmed<sup>17</sup> describes the test and the intepretation. Figure 1 shows the time derivative of the pressure buildup with a wavy pattern that indicates the periodic tidal pressure response.



Figure 1: 6305/4-1 well test data. Pressure vs. time derivative of the buildup.

Various methods exist to extract the tidal pressure response. An independent method to our own<sup>18</sup> confirmed our conclusions of seeing a tidal pressure response with an amplitude of  $7.0 \times 10^{-4} - 7.5 \times 10^{-4}$  bar with a peak around 07:30 hours. Clearly, the tidal pressure response in the Ormen Lange gas is on the borderline of being detectable with today's state-of-art pressure gauge resolution.

Tidal tables indicate a tidal amplitude of about 0.5 m with a peak around 07:00 hours during the buildup. This observation supports the presumption that the reservoir pressure reacts without time delay to the tide variation some 2800 m above.

For the simulations and other calculations we have used the dataset in Table 1, which can be representative for Ormen Lange.

Porosity	0.3
Initial water saturation (6305/4-	0.4
1 well)	
Initial water saturation (typical	0.2
production well)	
Initial reservoir pressure at	289 bar
2913 mTVD	
Gas compressibility (in	2.80×10 <sup>-3</sup> bar <sup>-1</sup>
simulations)	
Water compressibility	4.7×10 <sup>-5</sup> bar <sup>-1</sup>
Pore compressibility, C <sub>pc</sub>	7.2×10 <sup>-5</sup> bar <sup>-1</sup>
Tidal Amplitude	0.05 bar
Poisson ratio	0.16
Permeability, horisontal	500 mDarcy
Permeability, vertical	50 mDarcy
Gas viscosity (in simulations)	0.0242 cP
Tidal period	12 hours

Table 1: Typical Ormen Lange data

The theoretical tidal pressure response follows from Eq. 17. With Table 1 data and 0.4 water saturation the amplitude is  $9.36 \times 10^{-4}$  bar. This is somewhat higher than the measured value of  $7.0 \times 10^{-4} - 7.5 \times 10^{-4}$  bar. The reasons for this can be many. First of all, there is uncertainty regarding

the change in overburden. We have based the estimate on a tide table. To get the correct value of the change in overburden one needs a pressure gauge on the sea bottom. There is also some uncertainty in the effective Poisson ratio, compressibilities and the water saturation. The small Ormen Lange height/width ratio supports the uniaxial loading assumption.

# Implementation in reservoir simulator

MoReS is a reservoir simulator developed and used by Shell.<sup>19</sup> It has an inherent programming language, which makes it easy to extend the standard functionality. Eq. 32 shows that the tidal effect may be included in a reservoir simulator with a periodic fluctuating porosity. Rewriting Eq. 32 gives

$$\phi_{\rm sim} = \phi_0 \bigg( 1 - C_{pc} \Delta P_c^{\rm const} \sin(\frac{2\pi t}{T}) \bigg) (1 + C_{pp} \Delta P_p) \dots (37)$$

The right parenthesis is just the normal dependency of porosity on pressure, automatically implemented in most reservoir simulators, the linear compaction model. By specifying the pore volume compressibility in the MoReS input, MoReS will adjust the porosity with changing pressure; porosity increases with increasing pore pressure. The left parenthesis is the extra term caused by the tide effect.

The normal compaction term will work such as to modify the porosity perturbation set in the tide term. At a given point in time the sinus function has its minimum, giving a maximum porosity. This leads to a lowering of the reservoir pressure, which through the compaction term slightly modifies the porosity downwards. The magnitudes of the two terms can be compared from the Ormen Lange data in Table 1. Assuming that the tide stress effect is as for a uniaxial loading, the "tide term" becomes

$$\frac{1+v}{3(1-v)}C_{pc}\Delta P_{c}\approx 1.7\times 10^{-6},$$

which rises the pressure with some  $1.0 \times 10^{-3}$  bar. The corresponding "compaction term" becomes

$$C_{nn}\Delta P_P \approx 7.2 \times 10^{-8}$$
.

This shows that the compaction term modify the porosity perturbation introduced by the tide term with some 4%.

To avoid problems of knowing when MoReS applies the compaction term during the range of operations within each timestep, the easy solution is to set the "pore volume compressibility" in the MoReS input to zero, and rather apply this compaction term simultaneosly with the tide term function created.

The function was written such as to implement Eq. 37, updating the porosity at each timestep. The time steps were kept small with a maximum timestep length of 10 minutes, since CPU was not an issue in these simulations.

#### Simple reservoir models

Some simple reservoir models were built to study the tide effect for various scenarios. The 1D model is shown in Figure 2, the 2D model in Figure 3, and the 3D model in Figure 4.

The volumes for the three models are the same. Horisontal dimensions are 2000 m  $\times$  2000 m and reservoir height is 50 m. The 1D model is divided into 100 equal gridcells. The 2D and 3D models have local grid refinement such that the block size is recursively halved and ending at a dimension of 6.25 m at the innermost gridblocks. A well is placed at the center of the model. To ensure full symmetry, the well is constructed as a "snake" well perforating all the 4 innermost gridblocks in all layers.



Figure 2: 1D model with gas-water interface.



Figure 3: 2D model with gas within 100 m close to the well.



Figure 4: 3D model 1/3 filled with water.

Relative permeabilities and PVT properties were taken from other Ormen Lange reservoir simulation models.

#### Consistency check 1: Simulated vs theoretical response.

A homogeneous saturation distribution with  $S_w=0.4$  was used. All grid cells obtained the same pressure fluctuation, and

a steady state situation was established immediately, see Figure 5.



Figure 5: 2D model with homogeneous gas saturation at  $S_g$ =0.6. Pressure fluctuation in gridblock (3,1), (5,1), (6,2), (7,2) and (4,4) during first 2 days of simulation.

Subtracting the mean value of the fluctuation makes it easier to read the amplitude. Figure 6 shows the bottom hole pressure of the well plotted like this.



Figure 6: 2D model with homogeneous gas saturation at  $S_g$ =0.6. BHP variation around mean value.

The theoretical tidal pressure response follows from Eq. 17. With Table 1 data, the amplitude is  $9.36 \times 10^{-4}$  bar. The simulations give  $9.3 \times 10^{-4}$ , which is within the uncertainty of the estimated PVT data, see Figure 6.

#### **Consistency check 2: Effect of saturation**

Figure 7 shows the theoretical and simulated tidal pressure response at different gas saturations, given a homogeneous saturation distribution. The theoretical curve follows Eqs. 36 and 37. The match is again within the uncertainty of parameters used for the theoretical curve.



Figure 7: Theoretical and simulated tidal pressure response at different gas saturations.

#### Consistency check 3: Simulation vs 1D analytical solution

The diffusion of the tidal pressure response can be illustrated by artificially just perturbing the porosity of the left-most gridcell in the 1D-model. The model has here a homogeneous saturation with gas saturation of 0.8. Due to diffusion the steady state amplitude in the perturbed cell becomes some 15% of its normal size. Figure 8 shows the steady state amplitude in the neighbouring cells relative to the leftmost cell together with the predicted decay of the 1D analytical solution, Eq. 35. The match is excellent. The amplitude (or the information) has decayed to 10% after 440 m. With a gas saturation of 0.6, this distance increase to 505 m.



Figure 8: 1D model where the porosity is pertubed in the leftmost cell only. Relative amplitude vs analytical solution.

## Simulating water influx

Via this extension of a normal reservoir simulator, it is possible to study the tidal pressure response in complex multiphase, fully dynamical situations. To start simple, our approach can be described as "quasi-static", where saturations are tried kept constant during the simulation. To assist this, the simulations are done with zero capillary pressure and also with the force of gravity turned off. For the timescale of the tidal pressure response (a few days), this is typically a good approximation of a fully dynamic situation. All scenarios looked at here is for a gas-water system. The implementation is equally valid for a three-phase system (oil, gas, water).

#### Water-gas interface in 1D model

The typical setup is shown in Figure 2, with the left part filled with gas. The gas phase has an initial water saturation of 0.2, and the water phase mimicks a water-flooded zone with a residual gas saturation of 0.25. The steady-state tidal pressure response amplitude is calculated for various volume fractions of gas.

Figure 9 shows the early-time response in the 10 gridcells closest to the gas-water interface. Here the gas-water interface is at 100 m (between cell 5 and cell 6). A stable steady state solution is reached within 2 days of simulation time. For this system of only 5% volume of gas, all the gridcells with gas phase get the same amplitude but with an amplitude larger than without water in the system. A clear amplitude gradient of some 60 m is seen in the water phase.



Figure 9: Tidal pressure response in 1D model around the gaswater interface as function of simulated time. Gas volume is 5% (interface is between cell 5 and cell 6).

The steady state amplitude along the 1D model for this system is shown in Figure 10, labelled "5% gas". Figure 10 also shows the result from other volume fractions of gas (with correspondingly changed location of the gas-water interface). Several important observations can be extracted from this plot:

Close to the interface, the gas amplitude has an increased value. With 10% or more gas in the 1D system, the increase in the gas amplitude close to the interface is around 10%. The water phase shows a higher reduction in amplitude close to the interface, with some 40% reduction in the gridcell closest the interface. The amplitude gradient is sharper in the water phase as compared to the gas phase. At some distance from the interface the water gets an increase in amplitude as compared to value deep into the water phase (or with only water in the system). The gas seems to get a corresponding reduction in amplitude at some distance from the interface (shown below).

To get a detectable increase in amplitude in the gas phase, the gas volume needs to be small. With 5% (100m\*2000m\*50m) and 3% (60m\*2000m\*50m) gas volume, the maximum gas amplitude increases with 12% and 19%, respectively, as compared to its value with only gas. For the smallest volume (3%) this high value is more or less constant in the gas phase. The 2D and 3D simulations below give some additional insight to this issue.



Figure 10: Tidal pressure response amplitude along 1D model, with various volume fractions of gas.

The fact that the gas phase gets a small decrease in amplitude some 400 m from the gas-water interface is shown in Figure 11, which is the reverse of the effect seen in the water phase. For comparison reasons, we have plotted the relative increase in amplitude in the gas phase with the decay of Eq. 35. For a two-phase system with the tide affecting all parts, the decay in amplitude is more rapid than predicted by the 1D analytical solution. The information has decreased to 10% some 250 m from the interface.



Figure 11: 1D model with 40% gas: Tidal pressure increase in gas phase relative to value at the interface. The 1D analytical model of one-phase diffusion is shown for comparison.

#### Water encroachment towards a gas well

By simulations, we next want to calculate the tidal pressure response for a gas well, having a waterfront in the near well area. Figure 3 shows the 2D model with water fully surrounding the well ( $360^\circ$  encroachment angle) and water at the closest 100 m from the well. The simulation is again done in a quasi-static mode, initialising the model with a given saturation distribution. In all cases, the central gas volume is kept quadratic. The encroachment angle is varied between  $360^\circ$  and  $90^\circ$ , as shown in Figure 12.

Figure 13 shows the tidal pressure response amplitude in the gas well as a function of distance to the water front. The distance is the closest distance, e.g., 100 m in Figure 3. When water is fully surrounding the well like this at full reservoir height, water at a distance of 100-200 m may theoretically be detected via the increased tidal response in the gas well. With decreasing encroachment angle, the response decreases. Assuming a 10% increase in amplitude is sufficient, the simulations indicate that water with a  $270^{\circ}$  encroachment angle can be detected around 100 m from the well. Correspondingly, water with a  $180^{\circ}$  encroachment angle can be detected around 50 m from the well. The simulations show that water at a  $90^{\circ}$  encroachment angle will be hard to detect. At  $180^{\circ}$  and  $270^{\circ}$  encroachment angle, the tidal amplitude in the well is not monotically increasing with decreasing distance to the water. The reason for this is probably due to a balance between the area of the gas-water interface close to the well, and the distance to the interface.



Figure 12: Water encroachment towards a gas well.



Figure 13: Amplitude in a gas well as a function of (closest) distance to water. 360°, 270°, 180°, 90° encroachment angle.

It is also of interest to study how the height of the water front affects the tidal pressure response of a gas well. Figure 4 shows the 3D model with a relative water height of 1/3. In the simulation the water is fully surrounding the well ( $360^{\circ}$  encroachment angle) and the distance to the water (at the closest) is kept at a fixed distance from the well.

Figure 14 shows the amplitude as a function of relative water height. When the water is close to the well (at 50 m),

the simulations suggest a close to linear decrease in amplitude with decreasing water height. Including cases with water more distant from the well, the picture becomes a bit more complex. The results may be affected by the gridding, how the well's pressure is calculated from the gridblock pressure, as well as vertical permability (which is kept at 50 mD here). Numerical dispersion may have a higher impact in the 3D model, which can explain the small discrepancy between the 2D and 3D results at full water height with water at 100 m and 200 m distance. With only gas in the model, the 2D and 3D models give exactly the same result.



Figure 14: Amplitude in a gas well as a function of relative height of approaching water. Closest distance to water is varied from 50 m to 200 m. The result from the 2D model is included.

#### Summary and conclusions

A practical review of the tidal pressure response in petroleum reservoirs is given. An expression for the "tidal efficiency factor" has been derived and the calculated tidal pressure response is in line with recent observations from an Ormen Lange well test. The response depends on the saturation distribution in the near well area, and may in principle be used for reservoir surveillance purposes.

A simplified coupling is derived between geomechanics and reservoir fluid flow, valid for small geomechanical effects. It is shown that the simplified coupling can be implemented correctly in a standard reservoir simulator through a timedependent porosity function. Several consistency checks show that the implementation works excellent.

With the tidal effect incorporated in the reservoir simulator, it is possible to study complex multiphase problems and to evaluate the monotoring of the tidal response as a reservoir surveillance method. We have concentrated on forecasting water encroachment towards Ormen Lange type gas wells.

The simulations results show that:

- With a 1D interface between gas and water, the gas amplitude is typically 10% higher close to the water and drops faster than Eq. 35 away from the interface. If the gas volume is small enough, the amplitude in the gas phase will increase beyond the 10%.
- With water at full height around the well and a 360° encroachment angle, the tidal response increases rapidly with decreasing distance to the water. Assuming a 10%

increase is needed, water at a distance of 100-200 m should be detectable. With lower encroachment angle, water needs to be closer to be detectable, about 100m for  $270^{\circ}$  and 50 m for  $180^{\circ}$ .

 With water at full encroachment but reduced water height, the response seems to decrease roughly linearly with decreasing water height.

The tidal response may carry information in addition to the observation of reservoir pressure from transient well tests. Also, additional information may be extracted from an observation well. The potential towards reservoir surveillance of a gas-water system is perhaps limited, but may increase if future pressure gauges come with higher resolution and simultaneous observation of tidal responses from many wells could be systemized and correlated in real time. The only additional investment needed is a pressure gauge at the sea bottom to accurately measure the change in overburden pressure.

# Nomenclature

- $\Delta B$  = Barometric tidal dilatation, dimensionless
- $C_{bc}$  = Bulk compressibility with respect to confining pressure with constant pore pressure, Lt<sup>2</sup>/m
- $C_{bp}$  = Bulk compressibility with respect to pore pressure with constant confining pressure, Lt<sup>2</sup>/m
- $C_f$  = Fluid compressibility, Lt<sup>2</sup>/m
- $C_g = \text{Gas compressibility, } Lt^2/m$
- $\overline{C_o}$  = Oil compressibility, Lt<sup>2</sup>/m
- $C_{pc}$  = Pore compressibility with respect to confining pressure with constant pore pressure, Lt<sup>2</sup>/m
- $C_{pp}$  = Pore compressibility with respect to pore pressure with constant confining pressure, Lt<sup>2</sup>/m
- $C_{sg}$  = Grain compressibility, Lt<sup>2</sup>/m
- $C_{sgc}$  = Grain compressibility with respect to confining pressure with constant pore pressure, Lt<sup>2</sup>/m
- $C_{sgp}$  = Grain compressibility with respect to pore pressure with constant confining pressure, Lt<sup>2</sup>/m
- $C_w$  = Water compressibility, Lt<sup>2</sup>/m
- $D = \text{Diffusivity}, L^2/t$
- e = Bulk volume strain, dimensionless
- E = Youngs modulus, m/Lt<sup>2</sup>
- de = Change in bulk strain, dimensionless
- $de_f$  = Change in fluid strain, dimensionless
- $de_p$  = Change in pore strain, dimensionless
- $\Delta \dot{E}$  = Earth tidal dilatation, dimensionless
- $\Delta e_t$  = Total dilatation, dimensionless
- dh = Ocean tide amplitude measured in length, L
- $g = \text{Earths gravitational pull, } L/t^2$
- g(t) = Arbitrary function of time, dimensionless G = Shear modulus, m/Lt<sup>2</sup>
- f(t) = Arbitrary function of time, dimensionless
  - k = Permeability, L<sup>2</sup>
- $\Delta O$  = Oceans tidal dilatation, dimensionless
- $P_c$  = Confining pressure, m/Lt<sup>2</sup>
- $P_p$  = Pore pressure, m/Lt<sup>2</sup>
- $\Delta P_p^{\text{const}}$  = Amplitude of pore pressure change, m/Lt<sup>2</sup>
- $\Delta P_c^{\text{const}}$  = Amplitude of confining pressure change, m/Lt<sup>2</sup>
  - $S_g = \text{Gas saturation, fraction}$ 
    - $S_o = \text{Oil saturation, fraction}$

- $S_w$  = Water saturation, fraction
- T = Period of imposed signal, t
- t = Time, t
- $V_b$  = Bulk volume, L<sup>3</sup>
- $V_f$  = Fluid volume, L<sup>3</sup>  $V_p$  = Pore volume, L<sup>3</sup>
- $V_s$  = Grain volume, L<sup>3</sup>
- x = Distance, L
- $\alpha$  = Biot coefficient defined as  $\alpha = 1 C_{bc}/C_{sg}$ , dimensionless
- $\phi$  = Porosity, fraction
- $\phi_{\rm sim}$  = Porosity used in the simulations, fraction
  - $\phi_0 = \phi_{sim}(t=0)$
  - $\delta$  = Decay factor, dimensionless
- $\delta_{ij}$  = Kronecker delta ( $\delta_{ij}$  =l for i=j,  $\delta_{ij}$  =0 for  $i\neq j$ )
- $\varepsilon_{ij}$  = Component of bulk strain, dimensionless
- $\lambda = Lame's \text{ constant, } m/Lt^2$
- $\mu = \text{Viscosity}, \text{m/Lt}$
- v = Poisson ratio, dimensionless
- $\rho = \text{Fluid density, m/L}^3$
- $\rho_s =$ Solid density, m/L<sup>3</sup>
- $\sigma_{ij}$  = Component of total stress, m/Lt<sup>2</sup>
- $\sigma_m$  = Mean normal stress, m/Lt<sup>2</sup>
- $\mathbf{v} =$  Fluid velocity vector, L/t

 $\mathbf{v}_{s}$  = Solid velocity vector, L/t

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