Feasibility of Using Ambient Fluctuations of Pore Pressure to Characterize Gas Saturation and Other Formation Properties

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FEASIBILITY OF USING AMBIENT FLUCTUATIONS OF PORE PRESSURE TO CHARACTERIZE GAS SATURATION AND OTHER FORMATION PROPERTIES

A Thesis
Presented to
the Graduate School of
Clemson University

In Partial Fulfillment
of the Requirements for the Degree
Master of Science
Environmental Engineering

by
Viviana Leticia Heim
August 2016

Accepted by:
Dr. Lawrence Murdoch, Committee Chair
Dr. Stephen Moysey
Dr. Ronald Falta
Dr. Scott DeWolf
ABSTRACT

Water levels in wells usually fluctuate in response to periodic loads caused by barometric pressure or tides, and this response depends on the characteristics of the well and the elastic and fluid flow properties of the formation. The fluctuations in wells produced by variations in barometric pressure or tides are typically small, on the order of 1 cm of water or less, but they can be measured using readily available pressure transducers. Theoretical analyses are available that link the phase lag and amplitudes of the periodic pressure fluctuations in wells to formation characteristics. This has led to a method for interpreting water level fluctuations in wells to estimate formation properties as an alternative to pumping or slug tests. This method is appealing because it requires minimal labor and can be used to characterize temporal changes in properties, such as permeability changes following earthquakes, for example.

Pressure fluctuations in wells should be sensitive to changes in gas saturation, which would make this technique attractive for monitoring storage of CO₂ or natural gas, production of natural gas, air sparging for remediation, or other subsurface process where the gas content may change. Small changes in pressure in deep wells are often only detectable when the well is shut-in, or isolated from the atmosphere, a configuration that is not included in the available analyses. Moreover, these analyses assume that the well is perfectly coupled to the formation, whereas many wells are enveloped by a low permeability skin that will likely affect the response to periodic loads.

The objective of this thesis is to evaluate the feasibility of analyzing ambient fluctuations of pressure in wells to estimate gas content and other formation
characteristics, for wells that may be shut in and affected by well skin. A method is proposed that considers the effects of fluid compressibility when the wellhead is sealed from the atmosphere or tidal influences. The skin factor, which is commonly used in well testing analysis, is also included in the analysis of ambient pressure fluctuations.

Two different cases were studied in this work. One case used data from three producing wells in shut-in conditions located in Oselvar site, an offshore oil/gas reservoir, where a periodic load was applied by variations in pressure on the seafloor caused by the ocean tides. Another case study used data measured in a monitoring well in a confined aquifer near Clemson, South Carolina. Barometric pressure caused periodic variations in applied load at the ground surface. Data were analyzed when the well was open and when it was sealed to the atmosphere.

The approach for analyzing the observed data involves characterizing the phase lag and amplitude ratio between the observed pressure fluctuations and the periodic applied loads. The theoretical analysis was used to create a plot relating phase shift, storage coefficient, amplitude ratio, shut-in correction term and transmissivity for different values of skin factor. The plot appears to be a convenient and practical tool to estimate formation properties and well skin, although numerical inversion of the data is also possible.

The ocean tides show strong signals in deep formations, with different responses according to different locations. The estimated formation transmissivity in Oselvar site is between 0.4E-6 and 1.9E-6 m²/s, and is similar to the known value for the site, in the order of 0.8E-6 m²/s. The values of gas saturation found were between 0 and 0.04, always
with the maximum gas content near wells A-1 and A-2. Well A-3 has the lower gas content values. The skin factor ranges between 0 and 2 for Oselvar site, and the theoretical shut-in correction factor is in the order of 0.43.

In the case of Clemson site, the pressure data is dominated by the confining unit, with an estimated transmissivity of 0.5E-6 to 3.2E-6 m²/s, while values of transmissivity obtained by slug tests are between 0.8E-6 and 3.1E-6 m²/s. Gas is not detected in the near well area, and the skin factor is in the order of 10 or higher. The theoretical shut-in correction factor is 0.11, while the one estimated graphically is 0.03.

The consistency on the calculated formation property values at the Oselvar site over time and space supports the conclusion that the proposed methodology is feasible to be used in deep wells to determine gas saturation and other formation properties. In addition, the graphical method provides a practical tool to evaluate the skin and shut-in effects. The method looks encouraging, but from the results at the Clemson site the need arises to evaluate the effect of heterogeneities on the formation response to surface load.
DEDICATION

To Darian, my partner, for everything.

To my parents, Aldo and Alicia, for their *joie de vivre* and for being my guide in life.

To my siblings, nieces and nephew, for their unconditional support.
ACKNOWLEDGMENTS

I would like to thank to the Argentinean President's Cabinet and the BEC.AR. Program, because this experience would not have happened without their funding and support. Thank you to all the people involved for believing in us.

I would like to thank to my advisor, Dr. Lawrence Murdoch for his support and guidance throughout the course of this work. I also want to acknowledge to my committee members, Dr. Ronald Falta, Dr. Stephen Moysey and Dr. Scott DeWolf for their valuable input on this thesis, with special thanks to Dr. DeWolf for his help.

I would like to acknowledge to Dong Energy because of all the data provided. Special thanks to Bill Harrar and Matteo Galli.
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**LIST OF SYMBOLS**

- \( h_f \) = Fluid pressure head fluctuation in the formation
- \( h_o \) = Complex amplitude of pressure head fluctuation in the formation
- \( A_F \) = Formation pressure response amplitude
- \( A_L \) = Loading pressure amplitude
- \( A_R \) = Amplitude ratio
- \( A_W \) = Well pressure response amplitude
- \( A_f \) = Formation head response amplitude
- \( A_{we} \) = Cross sectional area of the well
- \( A_x \) = Well fluid level response amplitude
- \( B'_b \) = Confined modulus of elasticity
- \( B_s \) = Barometric efficiency
- \( C_a \) = Air compressibility
- \( C_b \) = Bulk compressibility
- \( C'_b \) = Confined bulk compressibility
- \( C_{pc} \) = Bulk compressibility due to change in confining pressure
- \( C_{pp} \) = Bulk compressibility due to change in pore pressure
- \( C_e^f \) = Effective compressibility of the formation
- \( C_e^w \) = Effective compressibility of the wellbore
- \( C_f \) = Fluid compressibility
- \( C_g \) = Gas compressibility
- \( C_o \) = Oil compressibility
- \( C_p \) = Pore volume compressibility
- \( C_{pc} \) = Pore compressibility due to change in confining pressure
- \( C_{pp} \) = Pore compressibility due to change in pore pressure
- \( C_s \) = Solid grain compressibility
- \( C_w \) = Water compressibility
- \( D_h \) = Hydraulic diffusivity
- \( D_p \) = Pneumatic diffusivity
- \( Ke_{r_1}, Ke_{i_1} \) = Real and imaginary parts of the modified Bessel function of the second kind, order one
- \( K_f \) = Hydraulic conductivity of formation
- \( K_s \) = Hydraulic conductivity of skin
- \( P_F(t) \) = Periodic formation response function
- \( P_{F_0} \) = Complex amplitude of formation pressure signal
- \( P_L(t) \) = Periodic loading function
- \( P_W(t) \) = Periodic well response function
- \( P_c \) = Confining pressure
- \( P_p \) = Pore pressure
List of Symbols (Continued)

\( P_{w_0} \) = Complex amplitude of well pressure signal
\( S^* = S \frac{r_w^2}{r_c^2} \)
\( S_F \) = Skin factor
\( S_g \) = Gas saturation
\( S'_o \) = Initial oil saturation
\( S_s \) = Specific storage
\( S'_w \) = Initial water saturation
\( T^* = T \frac{\tau}{r_w^2} \)
\( T_e \) = Tidal efficiency
\( T_{ef} \) = Tidal efficiency factor
\( V_T \) = Total volume
\( V_b \) = Bulk volume
\( V_p \) = Pore volume
\( V_s \) = Solid grain volume
\( e_f \) = Fluid volumetric strain
\( e_p \) = Pore volumetric strain
\( e_t \) = Tidal deformation
\( r_c \) = Casing radius
\( r_e \) = Radius of influence
\( r_w \) = Well radius
\( s_f \) = Drawdown due to flow outside the skin
\( s_s \) = Drawdown due to flow across the skin
\( s_w \) = Total drawdown at the well
\( x_o \) = Complex amplitude of fluid level oscillation

\( \alpha_w = \left( \frac{\omega S}{r_w} \right)^{1/2} \)
\( \delta_{ij} \) = Kronecker delta
\( \rho_w \) = Water density
\( \sigma_T \) = Total stress
\( \sigma_e \) = Effective stress
\( \sigma_m \) = Mean normal stress
\( \tau_F \) = Formation response period
\( \tau_L \) = Load period
\( \tau_W \) = Well response period
\( \tau_f \) = Formation head response period
\( \tau_x \) = Well fluid level response period
\( \omega_F \) = Formation response angular frequency
\( \omega_L \) = Load angular frequency
\( \omega_W \) = Well response angular frequency
\( \omega_f \) = Formation head response frequency
\( \omega_x \) = Well fluid level response frequency
\( \phi_F \) = Formation response phase
\( \phi_L \) = Load phase
\( \phi_W \) = Well response phase
\( \phi_f \) = Formation head response phase
\( \phi_x \) = Well fluid level response phase
\( A \) = Amplification factor
\( B \) = Bulk modulus
\( BRFs \) = Barometric Response Functions
\( E \) = Elastic or Young’s modulus
List of Symbols (Continued)

\( F(t) \) = Step response function
\( G \) = Shear modulus
\( K \) = Hydraulic conductivity
\( Ker, Kei \) = Real and imaginary parts of the modified Bessel function of the second kind, order zero
\( L \) = Depth to transducer location
\( Q \) = Volumetric flowrate
\( S \) = Storage coefficient or storativity
\( T \) = Transmissivity
\( e \) = Bulk volumetric strain
\( f(t) \) = Impulse response function
\( g \) = Acceleration of gravity
\( k \) = Permeability
\( n \) = Porosity
\( t \) = Time
\( v \) = Poisson’s ratio
\( x \) = Well fluid level
\( z \) = Formation thickness
\( \gamma \) = Loading efficiency
\( \varepsilon \) = Strain
\( \lambda \) = Lame constant
\( \sigma \) = Stress
\( \varphi \) = Shut-in correction factor
\( \chi \) = Poroelastic parameter
\( \phi \) = Phase shift
CHAPTER 1

INTRODUCTION

Most pore space in the subsurface is saturated with water, but gas or non-aqueous liquids are present with water in many important settings. Air occurs with water in the vadose zone, and air bubbles may be trapped in the shallow saturated zone (Stephens 1995). Pore spaces can also contain other substances like methane, natural gas, carbon dioxide, or oil, among others, either naturally or as a result of anthropogenic activities (Farmer 1965; Falta et al. 2009; Yaws 2014). Natural gas occurs alone or in reservoirs associated with hydrocarbon liquids (Smil 2015). Carbon sequestration is a process in which CO₂ is captured and stored underground, in aquifers, reservoirs or oil fields as a way to mitigate global warming or for enhanced oil recovery (Terry 2001; Benson & Cole 2008). Gas sparging is an in situ remediation technique that involves the injection of pressurized gas into saturated materials. In some applications, air is injected to promote the volatilization of hydrocarbons and the subsequent removal of contaminants by extraction of the vapors (Suthersan 1997). Other gases are injected to meet other needs. For example, ozone is injected to oxidize contaminants in situ (Choi et al. 2002).

The capability of measuring gas content in the subsurface is important for several reasons, including the tracing of human processes of gas injection (as the air sparging remediation (Suthersan 1997) or CO₂ sequestration techniques mentioned before (Terry 2001; Benson & Cole 2008)), or to determine the location and content of deposits of natural gas for methane production (Holder & Angert 1982). The available methods for monitoring gas distribution in the subsurface encompass a broad range of cost,
complexity, accuracy, and resolution. Low cost sentinel technologies, like *geochemistry* (geochemical methods to characterize gas concentrations in fluid samples), may be incapable of providing quick and reliable measurements (Larter & Aplin 1995). However, campaign technologies with higher resolution like seismic or other geophysical methods, are too expensive to deploy for routine operations (Kuster & Toksöz 1974). New approaches and technologies are trying to improve the resolution of sentinel technologies while reducing costs of monitoring methods. This thesis describes such a new approach that relies on ambient fluctuations in pore pressure.

**AMBIENT FLUCTUATIONS OF PORE PRESSURE**

Pore pressures in aquifers and reservoirs fluctuate in response to small, naturally occurring loads that change with time. A *stress*, $\sigma$, is a force applied to a surface area, and the resultant *strain*, $\varepsilon$, is the deformation of the materials under the action of the applied forces (Detournay & Cheng 1993; Cheng 2016). Stress in materials forming the subsurface can change as the result of natural processes. Some of these processes are periodic such as those arising from the relative movement of sun and moon with respect to Earth, the ocean and Earth tides, and those resulting from atmospheric pressure fluctuations. Others are aperiodic like the loading caused by pressure fronts in the atmosphere, or the deformation due to slow tectonic movements or faster seismic waves (Merrit 2004).

Gravitational pull from the sun and moon generates tides in the solid earth and oceans. *Ocean tides* are sea-level oscillations varying periodically due to the relative position between astronomic bodies and the Earth. The range of sea level oscillation
depends on latitude, bathymetry, coastline configuration, and other factors (Hicks 2006). Far from ocean coasts the same interaction modifies the gravitational acceleration, \( g \), acting on the surface and subsurface of the Earth, leading to strains known as Earth tides (Merrit 2004).

Changes in the density of the atmosphere induced by variations in temperature cause diurnal oscillations of barometric pressure, while seasonal temperature variations produce seasonal changes in barometric pressure. Aperiodic perturbations can result from storms or frontal movement of air masses (Merrit 2004).

Tidal and barometric periodic loading can be described by a time-varying harmonic function characterized by amplitude, \( A_L \), period, \( \tau_L \), and phase, \( \phi_L \) (Hicks 2006):

\[
P_L(t) = A_L \cos(\omega_L t + \phi_L),
\]

where \( t \) is time.

**Figure 1-1**: Periodic loading function \( P_L(t) \) and its characteristic components: amplitude, \( A_L \), period, \( \tau_L \), and phase, \( \phi_L \).
The load angular frequency, $\omega_L$ is defined as:

$$\omega_L = \frac{2\pi}{\tau_L} \quad 1-2$$

Tidal and barometric pressure changes are approximately periodic, with periods that are diurnal ($\tau_L = 24 \text{ hrs}$) or semi-diurnal ($\tau_L = 12 \text{ hrs}$). Most of the tidal signal can be characterized using 7 harmonics (Table 1-1), but there are many more harmonics that are used for a thorough description of the tidal response. Barometric pressure also varies with a diurnal period, but it also fluctuates over periods that are longer and shorter than 1 day. The theoretical relative magnitudes of the various constituents identify the dominant components (Table 1-1). They are calculated giving the value 1.00 to $M_2$, since it is usually the largest constituent.

<table>
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<tr>
<th>Name</th>
<th>Description</th>
<th>Relative magnitude</th>
<th>Period (hs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$M_2$</td>
<td>Principal lunar semidiurnal</td>
<td>1.00</td>
<td>12.42</td>
</tr>
<tr>
<td>$S_2$</td>
<td>Principal solar semidiurnal</td>
<td>0.46</td>
<td>12.00</td>
</tr>
<tr>
<td>$O_1$</td>
<td>Lunar diurnal</td>
<td>0.41</td>
<td>25.82</td>
</tr>
<tr>
<td>$K_1$</td>
<td>Lunar diurnal</td>
<td>0.40</td>
<td>23.93</td>
</tr>
<tr>
<td>$N_2$</td>
<td>Larger lunar elliptic semidiurnal</td>
<td>0.20</td>
<td>12.66</td>
</tr>
<tr>
<td>$P_1$</td>
<td>Solar diurnal</td>
<td>0.19</td>
<td>24.07</td>
</tr>
<tr>
<td>$L_2$</td>
<td>Smaller lunar elliptic semidiurnal</td>
<td>0.03</td>
<td>12.19</td>
</tr>
</tbody>
</table>

Tidal variations in $g$ result in changes in the body force on Earth materials. This alters the stresses and causes strains in the subsurface. Tidal variations in sea level, and variations in barometric pressure, alter the vertical stress applied to the ground surface, or
the seabed, and this also changes the stress state and results in strains in the subsurface. The maximum relative variation in $g$ resulting from earth tides is between $10^{-8}$ and $10^{-7}$, and the resulting strains are of this magnitude.

Variations in seabed pressure caused by tides are on the order of 10 kPa (~1m of water) in the open ocean, but tidal fluctuations can be up to 100 kPa (~10m of water) and they are essentially zero in some locations (Strout & Tjelta 2005). Diurnal variations in barometric pressure are commonly in the range of 0.1 kPa. Barometric pressure may change by several kPa due to severe storms or weather fronts.

The strains resulting from changes in the surface load due to tides or atmospheric pressure depend on the elastic modulus (or Young’s modulus), $E$, of the subsurface material. Young’s modulus ranges from less than 0.01 GPa for soft sediments to 10 GPa or more for competent rock. Barometric pressure changes of 0.1 kPa would cause strains of $10^{-7}$ in soft sediment, but the strains in competent rock would be much smaller, approximately $10^{-10}$. Variations of 10 kPa, due for example to ocean tides, would cause strains in the range of $10^{-8}$ to $10^{-5}$, depending on the elastic modulus.

Strains in the solid skeleton of an aquifer or reservoir will alter the pore pressure, and this can be detected at monitoring wells tapping aquifers or production wells in oil and gas reservoirs. Periodic surface loading cause the pore pressure, $P_p$ (stress on the fluid) in the formations to fluctuate (Cooper et al. 1965; Bredehoeft 1967; Hsieh et al. 1987). Increases in pore pressure cause fluid to flow into wells until the pressure in the well equilibrates with the pressure in the formation, whereas decreasing fluctuations cause fluid to flow away from wellbores (Cooper et al. 1965; Hsieh et al. 1987).
The responses to natural stresses can be measured and analyzed together with the original stresses, some of the formation properties mentioned before can be calculated.

FORMATION AND WELL RESPONSES TO EXTERNAL LOAD: CONCEPTUAL MODELS

Oscillations of pressure in fluids can be measured in monitoring wells with the use of pressure transducers. Transient well tests – buildup, drawdown, pulse tests – are an important diagnostic tool to determine properties and parameters of formations (Chaudhry 2004; Kamal 2009). Permanent downhole gauges are installed in production wells in petroleum reservoirs to measure pressure and temperature during regular operation and during transient well tests. Water monitoring wells in aquifers are used for similar type of tests, in order to determine the properties and characteristics of the underlying aquifers (Chaudhry 2004; Kamal 2009). Understanding how the subsurface and wells respond to different types of loads is key to making use of monitoring data to evaluate fluids and formation properties.

A two-stage conceptual model is considered to describe the response of formation and wells to a load applied at the ground surface (e.g. ocean tide or atmospheric pressure change):

Stage 1. An instantaneous load is imposed on the formation. This causes an abrupt increase in the pore pressure in the formation by an amount that is less than the imposed load. The pressure in the well will either increase by an amount equal to the applied load if the well is open to the atmosphere or seabed, or the pressure will remain unchanged if the wellhead is sealed.
Stage 2. Fluid flows either into or out of the well in response to the pressure difference between the wellbore and the formation. This causes the pressure in the well to change that eventually equilibrates with the pressure in the formation. The time required for equilibration depends on the volume of fluid that must flow to equilibrate the pressure as well as on the flow rate, which depends on the hydraulic diffusivity.

Other important idealizations are that the response is confined such that there is no change in the saturated thickness. In addition, the inertial effects of the fluid column moving inside the well are neglected, which is appropriate as concluded by Bredehoeft (1967). The conceptual model is first developed for a step-like change in load, but subsequently it is extended to periodic surface loading.

A step change in ocean tide or atmospheric pressure increases the total stress, \( \sigma_T \), at the land surface. The load is near immediately transmitted downward grain to grain. The formation responds to the applied stress with an opposed increase in the stress on the pore fluid (increasing the pore pressure, \( P_p \)), and also on the formation framework, boosting the stress on the solid material (effective stress, \( \sigma_e \)). This is known as the Skempton effect (Cheng 2016), and \( \alpha \) is the Biot coefficient.

Consider the case of a formation responding to a step-like change in load (Figure 1-2), where ⬤ denotes a point within the formation where the pressure is being measured. The red signal is the step-like change in total stress, and the dark and light blue signals are the pore pressure and effective stress responses respectively. It can be seen that the
amplitude of the load signal ($A_L$) and the formation response amplitude ($A_F$) differ, with $A_F$ being smaller due to the Skempton effect.

![Skempton Effect diagram](attachment:skempton_effect.png)

**Figure 1-2:** Formation response to an imposed step-like change in load.

Now consider the change of the fluid pressure in an open well, (Figure 1-3). Measuring the pressure at a point inside the well (●), a step-like change in pore pressure equal to the total stress will be obtained only if no flow is allowed (yellow signal in Figure 1-3, where the well response amplitude, $A_W$, equals to $A_L$). As the burden in the formation is distributed between fluid and solid matrix, the pore pressure response in the formation (dark blue line) is smaller than the pore pressure response in the well (yellow line), and therefore $A_F < A_W$. Consequently, when drainage is permitted the difference between fluid pressure changes ($\Delta P_p$) at both locations generates a flow of fluid from the well to the formation (Butler et al. 2011). Fluid flow causes the pressure in the wellbore to decrease eventually equilibrating with the pressure in the formation (Figure 1-4).
A different behavior occurs when the wellhead is sealed. In this case, the applied load causes no change in fluid pressure in the well during the instant it is applied (Figure 1-5). The pressure in the formation increases, just as it does for the previous case, except
now the pressure in the formation is greater than the pressure in the well. The difference in pore pressure generates a flow from the formation to the well, gradually increasing the pressure in the well (Figure 1-6) (Butler et al. 2011). The rising fluid level in the well will compress the gas in the headspace and this will cause the pressure to rise even faster than it would if the well was open.

![Diagram](image)

\[ \Delta \sigma_T = \Delta \sigma_e + \alpha \Delta P_p \]

**Figure 1-5:** Closed well undrained response to an imposed step-like change in load.

The step-load used above provides a simple conceptualization and is the basis for theoretical analyses. Furbish (1991) proposed that the response to a load imposed by a step-like change in atmospheric pressure necessarily reflects the form of the *step response function*, \( F(t) \), of the system (Furbish 1991). He compared this response with the recovery from a slug test, and concluded that a continuously varying atmospheric load has basically the same consequences in a well as a continuous series of slug and bail tests. He also defined an *impulse response function*, \( f(t) \), which is the first derivative of the step response function, and that wholly indicates how the formation responds to
loading. This approach allowed him to derive two different solutions for the impulse response function from the set of governing equations of slug tests.

\[ \Delta \sigma_T = \Delta \sigma_e + \alpha \Delta P_p \]

**Figure 1-6**: Closed well drained response to an imposed step-like change in load.

The pressure response in the formation \((P_F)\) and inside the well \((P_W)\) to a periodic loading (e.g. Equation 1-1) will also be periodic, with periods \(\tau_F\) and \(\tau_W\) respectively, and time-varying harmonic signals as:

\[ P_F(t) = A_F \cos(\omega_F t + \phi_F), \]

where \(A_F\) is the amplitude and \(\phi_F\) is the phase of the formation response, and:

\[ P_W(t) = A_W \cos(\omega_W t + \phi_W), \]

where \(A_W\) is the amplitude and \(\phi_W\) is the phase of the well response. The angular frequencies are:

\[ \omega_F = \frac{2\pi}{\tau_F}, \text{ and} \]
The pressure time series analysis to estimate formation and fluid properties is based on the ratio between the amplitudes of the responses and the difference in the phases of the signals.

\[ \omega_W = \frac{2\pi}{\tau_W} \]

**Figure 1-7:** \( P_L, P_F, P_W \) are load, formation and wellbore pressures as function of time. \( A_L, A_F, A_W \) are their amplitudes, \( \Delta t \) is the time delay and \( \phi \) is the phase shift between formation and well signals, and \( \tau_L, \tau_F, \tau_W \) are the periods.

**PREVIOUS WORK**

The response of wells to natural stresses has been of interest for more than half a century, since the pioneering work of Jacob (1940) established a theoretical foundation for this process, and many useful concepts and methods for aquifer and reservoir characterization have been developed since then (Jacob 1940). In this section, a review of the previous work regarding the use of ambient fluctuations of pore pressure to characterize formations is presented.
The rigorous analysis of water level fluctuations in wells induced by natural stresses started with Jacob (1940), who introduced the term *barometric efficiency*, $B_e$.

$$B_e = \frac{nC_w}{C'_b + nC_w} \tag{1.7}$$

where $n$ is *porosity*, $C_w$ is *water compressibility* and $C'_b$ is the *confined bulk compressibility*.

Jacob defined the barometric efficiency as the constant of proportionality between the barometric fluctuations observed in a well and the variations in atmospheric pressure at that specific location. Furthermore he introduced the concept of *tidal efficiency*, $T_e$, as the ratio between the magnitude of the fluctuations of the water-level in the wells and the actual fluctuations in tide producing them. His analysis was done for a uniform load over the entire aquifer surface, and under the assumption that no lateral movement of water has taken place. This implies that there was no time lag between well and formation responses, i.e.,:

$$T_e = \frac{C'_b}{C'_b + nC_w}. \tag{1.8}$$

Tidal efficiency ($T_e$) and barometric efficiency ($B_e$) are related since their summation is equal to unity:

$$B_e + T_e = 1. \tag{1.9}$$

He also recognized that $B_e$ and $T_e$ were related to the *storage coefficient*, $S$, defined a few years earlier by Theis (1938) as the volume of water of a certain density released from storage within the column of aquifer underlying a unit-surface area during a decline in head of unity (Theis 1938). For a confined aquifer, the storage coefficient is
equal to the product of the aquifer thickness, $z$, and the specific storage, $S_s$, which is the volume of ground water that an aquifer absorbs or expels from a unit volume when the pressure head decreases or increases by a unit amount (Fetter 2001):

$$S_s = \rho_w g (C'_b + nC_w), \quad 1-10$$

where $\rho_w$ is water density and $g$ is the acceleration of gravity.

$$S = zS_s \quad 1-11$$

Jacob (1940) stated that $B_e$ and $T_e$ may be taken as an index of the elasticity of aquifers, and they can be used to computed the theoretical storage coefficient for a homogeneous elastic artesian aquifer with incompressible solids, uniform thickness and infinite areal extent using tidal and barometric data from monitoring wells.

Jacob’s work was expanded upon in the next two decades by Melchior. In 1956 (Melchior 1956) he indicated that the tidal fluctuations found in two deep wells (Turhout, Belgium and Kiabukwa, Belgian Congo) were the result of tidal dilatation, and calculated the theoretical magnitude of that dilatation. He also performed harmonic analysis of the water level fluctuations and found that the amplitudes of the larger waves agreed well when compared with predicted values from equilibrium tide theory. Melchior (1960) analyzed tidal fluctuations from previous investigators, concluding that the well was responding to the dilatation produced by the Earth tide (Melchior 1960). The same conclusion was made in Melchior et al. (1964) for water-level measurements taken in a well near Basecles, Belgium (Melchior et al. 1964). An unexplained phase shift, $\phi$, was

---

*a* Elasticity is the property of solid materials to deform under the application of an external force, and to return to their original shape and size after the force is removed (Timoshenko & Goodier 1951).
found between the harmonic components obtained from the analysis and the individual theoretical dilatations. In his analyses he represented the aquifer as a finite cavity.

Cooper et al. (1965) derived a solution for the nonsteady drawdown in the aquifer due to a harmonic motion of the water level, which was used to derive an expression for the amplification factor, $A$ (Cooper et al. 1965).

$$A = \left| \frac{x_o}{h_o} \right|$$

The amplification factor was defined as the modulus of the ratio between the complex amplitude of the water level oscillation in the well bore ($x_o$) and the complex amplitude of the pressure head fluctuation in the aquifer ($h_o$), both signals having the same frequency. They showed that the amplification factor depends on the dimensions of the well, the transmissivity, $T$, storage coefficient, and porosity of the aquifer, and also on the period of the applied stress (seismic waves in their case) and the inertial effects of the water in the well. Cooper et al. (1965) presented several amplification curves for differing open well dimensions and aquifer properties.

Bredehoeft (1967) showed that analytical studies of the water-level fluctuations caused by Earth tides can be used to compute the specific storage and the porosity of a confined aquifer (Bredehoeft 1967). He considered aquifer transmissivities in excess of about $10^{-4} m^2/s$, so based on Cooper et al. (1965) study he assumed that the change in fluid head in the formation ($h_f$) due to tides was equal to the change in water level in the well. By an Earth tide deformation analysis, he demonstrated that the change in water head produced by the tidal deformation, $e_t$, for an artesian system, is related with the specific storage as:
\[
\Delta h_f = \frac{e_t}{S_s}
\]

Then if Poisson’s ratio, \( \nu \), is known, tidal deformation can be computed from equilibrium tide theory, and by measuring the change in water head inside the well an estimate of specific storage can be obtained from Equation 1-13.

Bredehoeft (1967) proposed to calculate porosity by using specific storage and Jacob’s barometric efficiency, \( B_e \), (Equations 1-7 and 1-10) as:

\[
n = \frac{B_e S_S}{\rho_w g C_w}
\]

The value of porosity represents an average for the aquifer volume in the vicinity of the well. Bredehoeft pointed out that Melchior’s representation of the aquifer as a finite cavity was unrealistic, underestimating the magnitude of aquifer response. Marine (1975) used Bredehoeft’s method to calculate porosity in the crystalline metamorphic rock system and in the coastal plain sediments at the Savannah River, South Carolina (Marine 1975). Water-level fluctuations in wells due to Earth tides were recorded and used for the calculations. The high values of porosity obtained using this approach caused Marine to conclude that the method seems to present practical difficulties for wells in sediments and in slightly fractured metamorphic rock.

Van der Kamp and Gale (1983) presented a more rigorous expression for the change in pressure in the formation due to surface loading, which included the compressibility of the solid grains (Van Der Kamp & Gale 1983). They defined the loading efficiency, \( \gamma \), as the undrained response of pore pressure to a surface load change when horizontal displacements of fluid are negligible.
The efficiency factor, \( \gamma \), is given by

\[
\gamma = \frac{\beta (1 + \nu)}{3(1 - \nu) - 2\alpha \beta (1 - 2\nu)}
\]

with \( \beta \):

\[
\beta = C_b - \frac{C_s}{C_b - C_s + n(C_w - C_s)}
\]

where \( C_b \) is the **bulk compressibility**, and \( C_s \) is the **solid grain compressibility**. \( \alpha = 1 - \frac{C_s}{C_b} \) is the Biot coefficient.

They showed that \( \gamma \) reduces to Jacob’s expression for tidal efficiency if the solids are incompressible \((C_s = 0)\). Their results suggested that the high porosity values from Marine (1975) may be due to neglecting the compressibility of the solids. Their analysis indicated that if the amplitude of the Earth tide response is higher than 1 mm of water-level change, then the compressibility of the solids cannot be neglected. They derived an expression for the specific storage, which includes the effect of compressibility of the solid grains, and which is valid when horizontal deformation is negligible.

\[
S_s = \rho_w g [(C_b - C_s)(1 - \lambda') + n(C_w - C_s)]
\]

\[
\lambda' = \frac{2\alpha (1 - 2\nu)}{3(1 - \nu)}
\]

Narasimhan et al. (1984) studied earth tide data from three geothermal reservoirs in the United States (Narasimhan et al. 1984). They criticized Bredehoeft’s analysis and stated that one cannot directly estimate specific storage from Earth tide response because specific storage quantifies a drained behavior, and confined aquifers respond in an undrained fashion to gravitational influence of moon and sun. They recognized that the phase shift between the water level fluctuation in a well and the Earth tide observed by
Melchior et al. (1964) could exist even when the amplitude response is approximately one, depending on the period of the disturbance. But it was several decades later that this effect was successfully analyzed by Hsieh et al. (1987) by expanding on the approach described by Cooper et al. (1965). Hsieh et al. (1987) showed that water flow between the formation and the well was responsible for the phase lag, and the rate of flow was related to the aquifer transmissivity. This was important because it led to a method for estimating transmissivity using the phase lag.

According to Hsieh et al. (1987), the phase lag is:

\[ \phi = \arg \left( \frac{x_a}{h_a} \right) \]  

They concluded that their solution was rather insensitive to the storage coefficient, so the transmissivity of the aquifer could be calculated for a known harmonic disturbance and well dimensions, by assuming an estimate of the storage coefficient. Later in this thesis, Hsieh’s analysis is explained in detail and expanded to include conditions associated with a well that is shut in, and a well that is affected by skin.

Hsieh et al. (1988) reexamined Bredehoeft’s analysis and reaffirmed its correctness, explaining that the undrained tidal dilatation does not require simultaneous tidal loading and undrained response (Hsieh et al. 1988). Instead it can be considered as the sum of two processes: drained tidal loading, and increase in pore pressure under constant total stress and zero horizontal strain.

Rojstaczer (1988) presented a theoretical response of wells in partially confined aquifers to periodic atmospheric loading (Rojstaczer 1988). His analysis was based on the frequency of the well responses (high-, intermediate-, and low-frequency responses), and
on five dimensionless parameters, which partly govern the phase and attenuation of the response. Fitting of the response was used to get the dimensionless parameters which yielded estimates of vertical *pneumatic diffusivity*, $D_p$, of the unsaturated zone, lateral *permeability*, $k$, of the aquifer, and vertical *hydraulic diffusivity*, $D_h$, of the overlying saturated materials. Rojstaczer and Agnew (1989) studied the theoretical static-confined response of wells (negligible water table drainage and well bore storage) to Earth tides and atmospheric pressure changes (Rojstaczer & Agnew 1989). They defined two hydraulic diffusivities governing pressure diffusion, one for each disturbance, and concluded that the hydraulic diffusivity in the case of surface loading is slightly smaller than for applied strains (tidal or tectonic). Rojstaczer and Riley (1990) derived a solution for the response of unconfined wells to Earth tides and periodic atmospheric loading, which they showed to be qualitative similar to the one under partially confined conditions (Rojstaczer & Riley 1990). They estimated pneumatic diffusivity of the unsaturated zone and vertical hydraulic conductivity of the aquifer.

Rather than the frequency domain analysis made by Rojstaczer (1988), Furbish (1991) presented a solution for the loading-response problem in the time domain. He proposed to treat the loading and unloading of an arbitrary time series of atmospheric pressure as equivalent to a continuous series of slug and bail tests. The impulse response function, $f(t)$, as defined, can then be inferred from the solution of the governing flow equations for conditions set by slug tests. He showed that a smooth, continuous record of the aquifer response to atmospheric pressure consists of the superimposition of individual
responses to successive pulses, which are equivalent to a succession of slug and bail tests. He suggested the possibility of filtering raw water-level records using serial convolution.

\[ x(t) = \int_{0}^{\infty} f(u) P_L(t - u) du \]  

Equation 1-20

where \( x(t) \) is the fluid level in the well and \( f(t) \) is the impulse response function.

Using the convolution of a response function has an advantage over the harmonic analyses described above in that it will remove the barometric effects to more clearly highlight other hydrologic effects in water level time series. Rasmussen and Crawford (1997) built on the approach by Furbish (1991) to develop a procedure to remove barometric effects and to identify different mechanisms by which barometric pressure affects water levels (Rasmussen & Crawford 1997). Three types of barometric response functions, BRFs, were found that provide information about whether the aquifer is confined or unconfined, the presence of borehole storage or skin effects, and the air diffusivity coefficient within the unsaturated zone. Toll and Rasmussen (2007) developed a computer program that automatically removes the effects of barometric pressure and Earth tides from water level observations using regression deconvolution (Toll & Rasmussen 2007). Butler et al. (2011) expanded this concept further by developing a new analytical solution that includes a leaky confining unit (Butler et al. 2011). The analytical solution is used to calculate \( P_L \) in Equation 1-20 by fitting theoretical water-level responses to field-determined BRFs.

Langaas et al. (2005) investigated the potential of using the tidal pressure response in petroleum reservoirs to detect saturation changes in the near-well area (Langaas et al. 2005). They studied the Ormen Lange gas field, a reservoir located below
the sea floor where the ocean tides are considered the dominant periodic applied stress. They derived an expression for the tidal efficiency factor, $T_{ef}$, as the ratio between the tidal pore pressure response in the reservoir and the tidal pressure change at the sea bottom. This expression is equivalent to the loading efficiency ($\gamma$) derived by Van der Kamp and Gale (1983). By a coupling of geomechanics and fluid flow, they derived an expression for a porosity varying periodically with pore pressure and confining pressure (both periodic functions of time). They implemented the periodic fluctuating porosity in a reservoir simulator, and compared the simulated tidal pressure response with the theoretical tidal pressure response. They concluded that the implementation of the tidal effect in the reservoir simulator could be done through a time-dependent porosity function, using it as a reservoir surveillance method.

Sato (2006) examined the use of tidal signals observed in wells for monitoring geological sequestration of CO$_2$ (Sato 2006). He studied pressure fluctuations in closed wells as a result of Earth tides, and estimated a poroelastic parameter, $\chi$, which is a function of the fluid compressibility, $C_f$, and hence of the saturation of CO$_2$ in the pore space.

$$\chi = -\frac{e_t}{\Delta P_p} = \frac{1}{\alpha} (nC_f + (\alpha - n)C_b)$$  \hspace{1cm} (1-21)

He performed a field test consisting of the injection of CO$_2$ in the subsurface through an injection well, and the monitoring of CO$_2$ migration in three monitoring wells located at different distances away from the injection well. The conclusions made from the tracing of CO$_2$ during the injection period were that the migration of the gas could be
monitored with reasonable accuracy by analyzing the Earth tide pressure response in the monitoring wells.

In 2006 Elkhoury et al. used the response of water levels in wells to solid Earth tides to measure the in situ permeability over a 20-year period (Elkhoury et al. 2006). They applied the Hsieh et al. (1987) method to estimate aquifer transmissivity, and from it, the in situ permeability. They concluded that the variations of permeability observed over time indicated that the permeability is not a fixed quantity, but rather a dynamically controlled parameter. Manga et al. (2012) explained the mechanisms by which permeability can change at such small transient stresses, based on field observations and lab experiments (Manga et al. 2012). The mechanisms studied as responsible for enhance the permeability were: particle, drops and bubbles mobilization. A combination of poroelastic processes (as depressurization of fractures) and geochemical processes (chemical disequilibrium of rock pushed by changes in temperature, stress, fluid pressure, or invasion of new fluids) were identified as possible mechanisms causing the enhanced permeability to return to approximately the prestimulated value.

The revision of the previous work reveals that pore pressure fluctuations in monitoring wells can be used as a complimentary method for formation properties estimation. Fluid pressure measurements are commonly made in monitoring wells, and therefore in many cases this gives the possibility of using available data as input information, without installing additional equipment. When pressure data is not available, pressure transducers must be deployed to collect it. Compared to field tests, seismic and
geochemistry methods, the cost of this technique is among the lowest in order to
determine gas saturation ($S_g$) and other formation properties.

Also the literature review showed that fluid pressure fluctuations due to natural stress changes has long been studied in shallow wells, but limited information has been found on their effects on deep wells.

It was not found from the literature review any preceding work seeking to estimate the effects of skin in wells from ambient fluctuations of pore pressure. Neither was found in the previous work a comparison between open and closed well responses to natural loading, which allows the quantification of the shut-in effects on fluid pressure.

OBJECTIVE

The objective of this work is to evaluate the feasibility of extending the analysis of pressure fluctuations to deeper wells. In particular, it includes the study of small pressure fluctuations and the interpretation of the pressure data to estimate the following formation properties and well factors:

- Gas saturation ($S_g$)
- Transmissivity ($T$)
- Specific storage ($S_s$)
- Skin factor ($S_F$)
- Shut-in correction factor ($\phi$)
APPROACH

A conceptual model of formation, open and shut-in well responses to a step-like change in surface load is developed. It is the first step in order to understand and compare the different processes that have place in the formation-well systems when a load is applied. Then, this analysis is used to explain the response to periodic surface loading.

Subsequently, the development of the governing equations is presented. It includes the development of the expression of loading efficiency which is the basic concept in order to study formation response to surface loading. It also includes an analysis of the volumetric flowrate and pressure in a well during shut-in, and the development of a shut-in factor which characterizes this effect. Added to this, an analysis of the skin effect in wells is done, and the development of the skin factor affecting the flow between formation and wellbore is presented. Both effects, shut-in and skin, are incorporated into the analysis of the well response to applied loads.

Pressure data was collected at two different sites. The first site is an offshore oil and gas reservoir named Oselvar, located in the Norwegian North Sea. The data collected at this site includes fluid pressure from three producing wells. The loading signal data in this case is the ocean tide. The second site is a confined aquifer located near Clemson, SC. The data collected here includes groundwater pressure fluctuations measured with transducers in a well screened in the confined aquifer. Two different data sets were collected, one set with the well open to the atmosphere and another with the well sealed. The loading signal in this case is the oscillating barometric pressure.

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Information provided by Dong Energy.
A method for data analysis and evaluation of formation properties, and well skin and shut-in factors is derived. This method is an extension of the method presented by Hsieh et al. (1987). The raw data collected required further processing (filtering, detrending, and gaps filling) before the method could be applied. After data processing, and analysis, the evaluation of formation properties and well factors is performed, and the results and conclusions are presented.
CHAPTER 2
GOVERNING EQUATIONS

The development of the governing equations involves three sections. The first introduces the poroelastic concepts (e.g., bulk modulus, $B$ and Poisson’s ratio, $\nu$) needed as a basis for the development of the loading efficiency expression. The second section includes the development of the loading efficiency expression defined by Van der Kamp and Gale (1983), stating all the assumptions made. The third section involves the analysis of volumetric flowrate and pressure in a well during shut-in, and the effect of well skin. New definitions of the concepts of amplitude ratio, phase shift and loading efficiency are given, including the shut-in and skin effects.

POROELASTICITY THEORY

In this work, the Earth is assumed to be a porous elastic medium, which responds linearly to tidal and atmospheric pressure fluctuations. This means that an external force applied on its surface (e.g., ocean tide, atmospheric pressure) or a change in body force applied internally (e.g., Earth tide) will cause deformation and change the stress state (Detournay & Cheng 1993; Cheng 2016). The main parameters of poroelasticity theory, the relationship between them, and the constitutive law relating stress ($\sigma$) and strain ($\varepsilon$) are presented in this chapter, as they are used in the development of the main concepts that this thesis involves.

Due to their multiple components, stress and strain are tensors rather than single real numbers. Figure 2-1 shows the stress acting on the sides of an infinitesimal small
cube. $\sigma_{ij}$ is defined as the stress acting on the i-plane, oriented on the j-direction. The components of the stress tensor with equal indices, $i = j$, are denoted as normal stresses ($\sigma_{xx}$, $\sigma_{yy}$, $\sigma_{zz}$), while the components with different indices, $i \neq j$, are called shear stresses ($\sigma_{xy}$, $\sigma_{xz}$, $\sigma_{yx}$, $\sigma_{yz}$, $\sigma_{zx}$, $\sigma_{zy}$) (Cheng 2016).

**Figure 2-1:** Stress components acting on a small cube.

The stress tensor in Cartesian coordinates acting on the cube has three normal stress and six shear stress components, and can be written as:

$$
\sigma_{ij} = \begin{pmatrix}
\sigma_{xx} & \sigma_{xy} & \sigma_{xz} \\
\sigma_{yx} & \sigma_{yy} & \sigma_{yz} \\
\sigma_{zx} & \sigma_{zy} & \sigma_{zz}
\end{pmatrix}, \quad \text{with } i, j = x, y, z \tag{2-1}
$$

Stress is considered positive when it is compressive, and negative when tensile. If the cube is in static equilibrium, the sum of all stress components in each direction and the total momentum are zero, implying that:

$$
\sigma_{ij} = \sigma_{ji}. \tag{2-2}
$$

The mean normal stress, $\sigma_m$ (Jaeger et al. 2007) is defined as:
\[ \sigma_m = \frac{\sigma_{xx} + \sigma_{yy} + \sigma_{zz}}{3} \]  

The expression for the strain tensor is also a 3x3 matrix,

\[ \varepsilon_{ij} = \begin{pmatrix} \varepsilon_{xx} & \varepsilon_{xy} & \varepsilon_{xz} \\ \varepsilon_{yx} & \varepsilon_{yy} & \varepsilon_{yz} \\ \varepsilon_{zx} & \varepsilon_{zy} & \varepsilon_{zz} \end{pmatrix}, \quad \text{with } i, j = x, y, z, \]

and the bulk volumetric strain, \( e \), is defined as:

\[ e = \frac{\Delta V_b}{V_b} = \varepsilon_{xx} + \varepsilon_{yy} + \varepsilon_{zz}, \]

where \( V_b \) is the bulk volume.

The general linear relationship between stress and strain for a linear porous solid is Hooke’s law (Detournay & Cheng 1993; Cheng 2016), and can be written as:

\[ \sigma_{ij} = \lambda e \delta_{ij} + 2G \varepsilon_{ij} + \alpha P_0 \delta_{ij}, \]

where \( \lambda \) is the Lame constant, \( \delta_{ij} \) is the Kronecker delta, and \( G \) is the shear modulus (or modulus of rigidity). The Kronecker delta takes values of 0 and 1 depending upon:

\[ \delta_{ij} = \begin{cases} 1, & \text{if } i = j \\ 0, & \text{if } i \neq j \end{cases} \]

Shear modulus and Lame constant are related to Young’s modulus, \( E \), and to Poisson’s ratio, \( \nu \). Young’s modulus is defined as the ratio of stress to strain for a uniaxial stress (only \( \sigma_{zz} \neq 0 \)), and Poisson’s ratio is the ratio of lateral expansion to longitudinal contraction (Timoshenko & Goodier 1951).

\[ \lambda = \frac{E\nu}{(1 + \nu)(1 - 2\nu)} \]

\[ E = \frac{\sigma_{zz}}{\varepsilon_{zz}} = \frac{G(3\lambda + 2G)}{\lambda + G} \]
Then, the shear modulus is:

\[
G = \frac{E}{2(1 + \nu)} \tag{2-11}
\]

The bulk modulus, \(B\), characterizes the resistance of a substance to uniform compression, and it is defined as the inverse of the compressibility of a substance. To characterize a porous medium three types of compressibility are used: pore volume compressibility, \(C_p = \frac{1}{B_p}\), that represents the relative changes in pore volume, solid grain compressibility, \(C_s = \frac{1}{B_s}\), that represents the relative changes in the volume of the solid matrix, and bulk compressibility, \(C_b = \frac{1}{B_b}\), that represents the relative changes in the bulk volume of the medium. Depending on which pressure is changing, confining pressure, \(P_c\), or pore pressure, \(P_p\), the most often used definitions of compressibility are (Zimmerman 1991):

Bulk compressibility when confining pressure is changing:

\[
C_{bc} = \frac{1}{V_b} \left( \frac{\partial V_b}{\partial P_c} \right)_{P_p} \tag{2-12}
\]

Bulk compressibility when pore pressure is changing:

\[
C_{bp} = -\frac{1}{V_b} \left( \frac{\partial V_b}{\partial P_p} \right)_{P_c} \tag{2-13}
\]

Pore volume compressibility when confining pressure is changing:

\[
C_{pc} = \frac{1}{V_p} \left( \frac{\partial V_p}{\partial P_c} \right)_{P_p} \tag{2-14}
\]
Pore volume compressibility when pore pressure is changing:

\[ C_{pp} = -\frac{1}{V_p} \left( \frac{\partial V_p}{\partial P_p} \right)_{P_c} \]  

2-15

where \( V_p \) is the pore volume.

Solid grain compressibility when confining pressure or pore pressure are changing:

\[ C_{sc} = C_{sp} = C_s = \left[ \frac{1}{V_b} \left( \frac{\partial V_b}{\partial P_c} \right)_{P_p} - \frac{1}{V_p} \left( \frac{\partial V_p}{\partial P_p} \right)_{P_c} \right]_{\Delta(P_c-P_p)=0} \]  

2-16

Relationships between the compressibilities are as follows:

\[ C_{bp} = \alpha C_{bc} \]  

2-17

\[ C_{pc} = \frac{\alpha C_{bc}}{n} \]  

2-18

\[ C_{pp} = \frac{(\alpha C_{bc} - nC_s)}{n} \]  

2-19

The rock compressibility commonly used in reservoir engineering is \( C_{pc} \) (Sulak 1991; Cook & Jewell 1996). The difference between both pore compressibilities is given by the grain compressibility \( C_s \), which in this work is ignored assuming the grains as incompressible \( (C_s \approx 0; \text{ e.g. Equations 2-18 and 2-19}) \). Then \( \alpha = 1 \), and:

\[ C_{pp} = C_{pc} = C_p, \]  

2-20

\[ C_{bp} = C_{bc} = C_b, \quad \text{and} \]  

2-21
LOADING EFFICIENCY

The loading efficiency is the change in fluid pressure that occurs in response to a change in total stress under undrained conditions. In this application, “undrained” means that there is no flow of water induced by stress changes. Therefore the pore volume change will be identical to the change in fluid volume, and the magnitude of the pore pressure response depends on the compressibilities of the fluid and porous matrix (Detournay & Cheng 1993; Cheng 2016). In this work the term tidal efficiency factor ($T_{ef}$) by Langaas et al. (2005) and the term loading efficiency ($\gamma$) defined by Van der Kamp and Gale (1983) for incompressible rock grains are considered identical, and the latter is adopted. The surface loadings are the ocean tide and barometric pressure fluctuations, with strain only in the vertical direction.

Lame constant can be expressed as a function of bulk compressibility and shear modulus. Starting from Equations 2-8 and 2-11, and using the defined compressibilities the expression gives:

$$\lambda = \frac{2\nu G}{(1-2\nu)} = \frac{1}{C_b} - \frac{2}{3}G$$

2-23

The mean normal stress follows from Equations 2-3, 2-6, and Equation 2-23:

$$\sigma_m = \frac{1}{C_b} e + \alpha P_p$$

2-24

Solving Equation 2-24 for $e$ and differentiating, is obtained an expression relating the change in mean normal stress and the pressure response in a porous material:
\[ de = \frac{dV_b}{V_b} = C_b (d\sigma_m - \alpha dP_p) \] \hspace{1cm} 2-25

The volumetric response of a porous medium to loading can be described in terms of the bulk volumetric strain, \( \Delta V_b/V_b \), and in terms of the pore volumetric strain, \( \Delta V_p/V_p \).

The expressions for the increments in bulk and pore volumetric strains (Detournay & Cheng 1993; Cheng 2016), \( de \) and \( d\epsilon_p \), are:

\[ de = \frac{dV_b}{V_b} = C_b (dP_c - dP_p) \] \hspace{1cm} 2-26

\[ d\epsilon_p = \frac{dV_p}{V_p} = C_p (dP_c - dP_p) \] \hspace{1cm} 2-27

If the grains are incompressible, \( \alpha = 1 \), and Equations 2-25 and 2-26 are equal with \( \sigma_m = P_c \).

Assuming a constant fluid mass and isothermal conditions, an increment in fluid volumetric strain, \( de_f \), is given by:

\[ de_f = \frac{dV_f}{V_f} = \frac{1}{V_f} \frac{dV_f}{dP_p} dP_p = C_f dP_p \] \hspace{1cm} 2-28

For a formation in which the pore volume is occupied completely by fluid, any change in pore volume implies a change in fluid volume. Consequently, \( de_f = d\epsilon_p \), and the expression for the loading efficiency can be obtained:

\[ \gamma = \frac{dP_p}{d\sigma_m} = \frac{C_p}{C_p + C_f} \] \hspace{1cm} 2-29

For the uniaxial case, i.e., compaction only in the vertical direction and strains in horizontal directions equal zero, Chen et al. (1995) showed that \( \sigma_m = \sigma_{zz} \) and \( C_p \) is
replaced by \( C'_p = \frac{1+v}{3(1-v)} C_p \) (Chen et al. 1995). Finally, the loading efficiency expression for the uniaxial case with incompressible grains is:

\[
\gamma = \frac{dP_p}{d\sigma_{zz}} = \frac{C'_p}{C'_p + C_f}
\]  

This is the same expression derived by Van der Kamp and Gale (1983) in Eq. (29) for incompressible rock grains, with \( C'_p = \frac{1}{nB_b} \). \( B'_b = \frac{3(1-v)}{1+v} B_b \) is the confined modulus of elasticity.

The loading efficiency as defined in this work is the ratio between the pore pressure response in the formation and the change in surface load. Then, for a periodic load with amplitude \( A_L \) that produces a formation response with amplitude \( A_F \), the loading efficiency is given by:

\[
\gamma = \frac{A_F}{A_L} = \frac{C'_p}{C'_p + C_f}
\]  

The fluid compressibility depends on the relative amount of the fluids in the porous material and their individual compressibilities. If \( S_i \) is the saturation of substance \( i \), and \( C_i \), is the compressibility of substance \( i \), then the compressibility of the fluid is defined as:

\[
C_f = \sum_i C_i S_i
\]  

The analysis outlined above provides a means to estimate loading efficiency from the pressure response in a formation to a periodic surface load. Also, if the porosity, Poisson’s ratio and bulk modulus of the formation are known, Equations 2-31 and 2-32 can be used to estimate gas saturation in the near well area.
Several authors have studied the case of periodic fluctuations in wellbore pressure due to surface load for the case of open wells (Jacob 1940; Van der Kamp & Gale 1983; Rojstaczer 1988; Rojstaczer & Agnew 1989, Rojstaczer and Riley 1990, Furbish 1991; Rasmussen & Crawford 1997). But limited information has been found regarding the effect of volumetric flowrate between well and formation for the case of shut-in wells. Following is developed an analysis of the effects of volumetric flowrate and pressure in a well during shut-in conditions.

VOLUMETRIC FLOWRATE AND PRESSURE IN A WELL DURING SHUT-IN

Small periodic fluctuations in wellbore pressure are common and Cooper et al. (1965) demonstrated that the period of the fluctuation in the wellbore is the same as the period of the load that caused it. The pressure in the wellbore typically lags behind the load change in the formation because of the time required for fluid to exchange between the wellbore and the formation. The magnitude of the lag increases as the fluid diffusivity of the formation decreases.

Wellbore pressures are commonly measured with a transducer, and there are some subtle effects that arise from using this type of sensor. Some transducers are sealed and measure pressure relative to an absolute reference, whereas others contain a small tube connected to the atmosphere, so they measure pressure relative to an atmospheric reference. Assuming that a sealed transducer is used, changes in fluid pressure measured by the transducer are equal to the sum of changes in the depth of fluid above the transducer and the pressure in the head space above the fluid. Many water wells are open to the atmosphere, so the pressure in the head space is equal to atmospheric pressure.
Some water wells, and many deeper wells completed in oil and gas reservoirs are isolated from the atmosphere. This occurs commonly when the pumps are turned off and wells are said to be “shut-in”. In these cases, the pressure in the headspace above the liquid will change as the fluid level changes. For example, the pressure in the headspace will increase as the level of the liquid in the well rises.

The pressure head measured by a transducer will be equal to or less than the height of the fluid column over the transducer when a well is shut-in. This is important when the transducer measurement is used to estimate the change in the volume of fluid in the well. When the well is shut-in, changes in pressure head measured by a transducer will be less than changes in the fluid height by an amount that is equal to the change in the fluid pressure in the headspace. The change in fluid pressure in the headspace will depend on the compressibility and volume of the fluid in the headspace.

The permeability \((k)\) of formations is uniform in the vicinity of some wells, but variations in permeability are common adjacent to wells. In some cases, the permeability adjacent to the well is less than it is in the formation as a result of clogging of pores during drilling or related processes. In other cases, the permeability adjacent to a well may be greater than that of the formation as a result of hydraulic fracturing. The altered zone around a well is called “skin”, and the effect of the skin on the pressure in the well is commonly characterized using a skin factor, \(S_F\). A positive skin factor means that the permeability of the formation in the vicinity of the well is less than that of the formation.

A positive skin factor will restrict the exchange of fluid between the well and the formation. This will increase the time that the fluid pressure variation in the well lags
behind the fluid pressure variation in the formation. It will also decrease the magnitude of the pressure change in the well. A large positive skin factor may suppress the magnitude of the fluctuation enough so it is essentially undetectable.

There has been considerable interest in interpreting the small fluctuations in pressure in a well. An analysis by Hsieh et al. (1987) describes the water level in an idealized well that is open to the atmosphere and that lacks a skin. The purpose of this analysis is to build on the analysis of Hsieh et al.(1987) to include the effects of a shut-in wellbore and a well skin. This is important because it would allow the technique to be used in wells that are isolated from the atmosphere, particularly wells completed in oil and gas formations. Moreover, extending the analysis to include effects of a skin will broaden the applications. The analysis could be used to monitor progressive changes in well skin during operation, which would be useful data during the management of well fields. It could also be included in applications were fluctuations of wellbore pressure are used to estimate changes in formation properties following earthquakes. It would be convenient, for example, to evaluate whether the changes caused by earthquakes affect the formation properties or the wellbore skin.

ANALYSIS

The analysis will consider a vertical well in a uniform, confined formation. It will follow the approach described by Hsieh et al. (1987), but modifications will be introduced to accommodate the wellbore design and wellbore skin.

A periodic applied load causes a head change in the formation of $h_f$ (Figure 2-2). The head change is given by:
\[ h_F(t) = A_F \cos(\omega_F t + \phi_F), \]  

where \( A_F \) is amplitude and \( \phi_F \) is phase of the head change signal, and frequency is:

\[ \omega_F = \frac{2\pi}{\tau_F}, \]

with \( \tau_F \) being the period of the response signal in the formation. Using the Euler formula where it is implied that the only interest is in the real part,

\[ h_F(t) = h_o e^{i\omega_F t}, \]

where the formation head complex magnitude, \( h_o \), is:

\[ h_o = A_F e^{i\phi}. \]

A transducer on the wall of a sealed monitoring well would measure \( h_F \). However, the load applied to the aquifer will cause flow if the well is perforated so fluid can be
exchanged between the wellbore and the formation. The fluid level in the well \( (x) \) will vary with the same frequency as \( h_f \) (Cooper et al. 1965), but it will lag behind \( h_f \). The magnitude of the fluctuations in \( x, A_x \), may also differ from the one of \( h_f \). The variation in \( x \) is therefore:

\[
x(t) = A_x \cos(\omega_x t + \phi_x)
\]

where \( A_x \) is amplitude and \( \phi_x \) is phase of the water level change signal, and frequency is:

\[
\omega_x = \frac{2\pi}{\tau_x},
\]

with \( \tau_x \) being the period of the response signal in the well. In complex form the water level signal is

\[
x(t) = x_o e^{i\omega_x t},
\]

where the water level complex magnitude, \( x_o \), is:

\[
x_o = A_x e^{i\phi_x}.
\]

The amplitude ratio, \( A_R \), is the modulus\(^c\) of the complex number \( \frac{x_o}{h_o} \):

\[
A_R = \left| \frac{x_o}{h_o} \right| = \left| \frac{A_x e^{i(\phi_x - \phi_f)}}{A_f} \right|
\]

and the phase shift, \( \phi = \phi_x - \phi_f \), is the argument of the complex number \( \frac{x_o}{h_o} \):

\[
\phi = \arg \left( \frac{x_o}{h_o} \right)
\]

The flow out of the well will cause drawdown, \( s_w \), which increases as the pressure head decreases. Under ideal conditions where the fluid at the top of the well casing is air,\(^c\)

\[^c\] See Appendix A, Modulus and argument of complex numbers.
and the well is open to the atmosphere and lacks a low permeability skin, the water level in the well \((x)\) is:

\[
x = h_f - s_w
\]

which follows from Hsieh Eqn. (5) where the variable names have been retained. The idealized conditions assumed by Hsieh et al. (1987) are likely met by many water wells that have been thoroughly developed.

**EFFECTS OF SHUT-IN**

For the case in which the well is filled with two fluids of differing densities, one fluid is above the other. The height of the denser fluid is \(x\), and the overall height of the well is \(L\). The density and compressibility of the denser fluid are \(\rho_1\) and \(C_1\), respectively, and those of the lighter fluid are \(\rho_2\) and \(C_2\) (Figure 2-2).

A transducer in the well would likely be placed in fluid 1 and it would measure a fluctuating signal like:

\[
P_1 = P_w(t) = P_{wo}e^{i\omega w t},
\]

where \(P_{wo}\) is the complex magnitude of the pressure signal in the well:

\[
P_{wo} = A_w e^{i\phi_w}.
\]

The pressure at point 1 is given by:

\[
P_1 = g \int_0^L \rho dz + P_2
\]

where \(\rho\) is density and \(P_2\) is the pressure at the top of the well. Using the average density of each phase, Equation 2-46 becomes:
\[ P_1 = g\left[(\bar{\rho}_1 x) + (L - x)\bar{\rho}_2\right] + P_2 \]  

The \textit{volumetric flowrate}, \( Q \), during shut-in assuming that only the fluid 1, the denser fluid, is exchanged with the formation, is:

\[ Q = \frac{dV_1}{dt} \]  

The \textit{cross sectional area of the well}, \( A_{we} \), is:

\[ A_{we} = \pi r_w^2 \]  

where \( r_w \) is the \textit{well radius}. So:

\[ V_1 = A_{we} x \]  

From the chain rule:

\[ \frac{\partial P_1}{\partial t} = \frac{\partial P_1}{\partial V_1} \frac{\partial V_1}{\partial t} = \frac{\partial P_1}{\partial V_1} Q, \text{ and} \]  

\[ \frac{\partial P_1}{\partial V_1} = -\frac{\partial x}{\partial V_1} = -\frac{\partial x}{\partial V_1} A_{we}, \]  

the compressibilities of each phase are:

\[ C_1 = -\frac{1}{V_1} \frac{\partial V_1}{\partial P_1}, \quad \text{and} \]  

\[ C_2 = -\frac{1}{V_2} \frac{\partial V_2}{\partial P_2}. \]  

Rearranging Equations 2-53 and 2-54, and summing both compressibilities multiplied by the volumes of each phase:

\[ C_1 V_1 + C_2 V_2 = -\frac{\partial V}{\partial P}, \]
where is assumed that the change in pressure is the same over the well bore, so \( \partial P_1 = \partial P_2 = \partial P \). This requires that changes in pressure caused by density changes can be ignored.

Dividing through by the cross sectional area \( (A_{we}) \) and the height of the well bore \( (L) \):

\[
C_1 \frac{x}{L} + C_2 \left( 1 - \frac{x}{L} \right) = -\frac{1}{V_T} \frac{\partial V_T}{\partial P} = C_e^w
\]

where \( C_e^w \) is the effective compressibility of the wellbore, which is the weighted average of the compressibilities of the fluids in the wellbore.

Taking the derivative of Equation 2-47 with respect to \( x \) and dividing by the cross sectional area:

\[
\frac{\partial P_1}{\partial V_1} = \frac{\partial P_1}{\partial x} \frac{1}{A_{we}} = \frac{g}{A_{we}} (\bar{\rho}_1 - \bar{\rho}_2) + \frac{dP_2}{dV_1}
\]

Multiplying both sides of the equation by \( Q \), and using Equation 2-51 yields:

\[
\frac{\partial P_1}{\partial t} = \frac{\partial P_1}{\partial V_1} Q = \left[ \frac{g}{A_{we}} (\bar{\rho}_1 - \bar{\rho}_2) + \frac{dP_2}{dV_1} \right] Q.
\]

Assuming that the change in pressure is the same through the wellbore, and that only \( V_1 \) is changing, then:

\[
\frac{\partial P_2}{\partial V_1} = \frac{\partial P}{\partial V_T} = \frac{1}{V_T} \frac{1}{C_e^w} = \frac{1}{A_{we} L} \frac{1}{C_e^w}
\]

Substituting Equation 2-59 into Equation 2-58 results in:

\[
\frac{\partial P_1}{\partial t} = \left[ \frac{g}{A_{we}} (\bar{\rho}_1 - \bar{\rho}_2) + \frac{1}{A_{we} L} \frac{1}{C_e^w} \right] Q,
\]

which can be rearranged as:
Differentiating Equation 2-41 with respect to time, results in:

\[
\frac{\partial P_1}{\partial t} = i\omega P_{wo} e^{i\omega t} \tag{2-62}
\]

Finally, replacing Equation 2-62 into Equation 2-61, and substituting \( A_{we} = \pi r_w^2 \) results in:

\[
Q = \varphi \pi r_w^2 i\omega \frac{P_{wo}}{g\bar{\rho}_1} e^{i\omega t}, \tag{2-63}
\]

where \( \varphi \) is:

\[
\varphi = \frac{1}{\left(1 - \frac{\bar{\rho}_2}{\bar{\rho}_1}\right) + \frac{1}{g\bar{\rho}_1 L\bar{c}_w^w}}. \tag{2-64}
\]

The pressure head is assumed to vary as a periodic function of time with a period of \( \tau \). The expression in Equation 2-63 is equivalent to Eqn. (5) in Hsieh et al. (1987), where \( \varphi \) can be viewed as a correction term. Hsieh et al. assumed the wellbore was open, whereas here has been assumed it is sealed. If fluid 2 is air and fluid 1 is water then the density ratio is approximately 0.001 so the term in parentheses is essentially 1. If the wellbore is open, then \( \varphi \) is large and the second term in the denominator is zero. As a result, \( \varphi \to 1 \) when the wellbore is open, which gives the result in Hsieh et al. (1987), Eqn. (5).

**SKIN EFFECT**

According to Eqn. (6) in Hsieh et al. (1987), the water level in the well is given by Equation 2-43. The steady state drawdown due to flow across a skin is:
\[ s_s = \frac{Q}{2\pi z K_s} \ln \left( \frac{r_s}{r_w} \right) \]  \hspace{1cm} (2.65)

where \( r_s \) is the \textit{radius of the skin} and \( K_s \) is the \textit{hydraulic conductivity of the skin}. The drawdown from the outside of the skin to the radius of influence is:

\[ s_f = \frac{Q}{2\pi z K_f} \ln \left( \frac{r_e}{r_s} \right) \]  \hspace{1cm} (2.66)

where \( r_e \) is the \textit{radius of influence} of the well, and \( K_f \) is the \textit{hydraulic conductivity of the formation}.

The total drawdown at the well, \( s_w \), is the sum of the two terms, therefore:

\[ s_w = \frac{Q}{2\pi z K_s} \ln \left( \frac{r_s}{r_w} \right) + \frac{Q}{2\pi z K_f} \ln \left( \frac{r_e}{r_s} \right). \]  \hspace{1cm} (2.67)

Factoring and rearranging yields:

\[ s_w = \frac{Q}{2\pi z K_f} \left[ \frac{K_f}{K_s} \ln \left( \frac{r_s}{r_w} \right) + \ln \left( \frac{r_e}{r_s} \right) + \ln \left( \frac{r_s}{r_w} \right) - \ln \left( \frac{r_s}{r_w} \right) \right], \]  \hspace{1cm} (2.68)

which can be simplified to obtain:

\[ s_w = \frac{Q}{2\pi z K_f} \left[ \ln \left( \frac{r_e}{r_w} \right) + \ln \left( \frac{r_s}{r_w} \right) \left( \frac{K_f}{K_s} - 1 \right) \right], \]  \hspace{1cm} (2.69)

which can also be rewritten as:

\[ s_w = \frac{Q}{2\pi z K_f} \left[ \ln \left( \frac{r_e}{r_w} \right) + S_F \right], \]  \hspace{1cm} (2.70)

where \( S_F \) is the \textit{skin factor}:

\[ S_F = \ln \left( \frac{r_s}{r_w} \right) \left( \frac{K_f}{K_s} - 1 \right). \]  \hspace{1cm} (2.71)

The drawdown resulting from a periodic flow is given by Hsieh et al (1987), Eqn. (7) as:
\[ s_w = \frac{Q_0 e^{i \omega_w t}}{2\pi T} f(\alpha_w), \]

where the dimensionless parameter \( \alpha_w \) is:

\[ \alpha_w = \left( \frac{\omega S}{T} \right)^{1/2} r_w, \]

and the function \( f(\alpha_w) \) is defined as:

\[ f(\alpha_w) = \{ [\Phi Ker(\alpha_w) - \Psi Kei(\alpha_w)] + i[\Psi Ker(\alpha_w) + \Phi Kei(\alpha_w)] \}, \]

with \( Ker(\alpha_w) \) and \( Kei(\alpha_w) \) being Kelvin functions of order zero, and \( Ker_1 \) and \( Kei_1 \) being Kelvin functions of order one, where \( \Phi \) and \( \Psi \) are given by:

\[ \Phi = \frac{-[Ker_1(\alpha_w) + Kei_1(\alpha_w)]}{2^{1/2} \alpha_w [Ker_1^2(\alpha_w) + Kei_1^2(\alpha_w)]} \]

\[ \Psi = \frac{-[Ker_1(\alpha_w) - Kei_1(\alpha_w)]}{2^{1/2} \alpha_w [Ker_1^2(\alpha_w) + Kei_1^2(\alpha_w)]} \]

Now, assuming the well has a skin and following Equation 2-70, the drawdown is:

\[ s_w = \frac{Q_0 e^{i \omega_w t}}{2\pi T} [f(\alpha_w) + S_F] \]

where \( Q_0 e^{i \omega_w t} = Q \). Replacing \( Q \) with expression 2-63:

\[ s_w = -\frac{\varphi r_w^2 \omega P_w e^{i \omega_w t}}{2T g \rho_1} [f_1(\alpha_w) - S_F] \]

with:

\[ f_1(\alpha_w) = \{ [\Psi Ker(\alpha_w) + \Phi Kei(\alpha_w)] - i[\Phi Ker(\alpha_w) - \Psi Kei(\alpha_w)] \} \]

According to Cooper et al. (1965), the head change in the formation, \( h_f \), is:
where \( P_{Fo} = A_F e^{i \phi_F} \) is the complex amplitude of pressure in the formation.

Following Equations 2-44 and 2-45, the magnitude of the water level fluctuations inside the well can be expressed as pressure fluctuations:

\[
x = x_0 e^{i \omega_w t} = \frac{P_{wo}}{g \bar{\rho}_1} e^{i \omega_w t}
\]

Replacing Equations 2-78, 2-80 and 2-81 into Eqn. 2-43 gives:

\[
\frac{P_{wo}}{g \bar{\rho}_1} e^{i \omega_w t} = \frac{P_{Fo}}{g \bar{\rho}_1} e^{i \omega_F t} + \frac{\varphi r^2_w \omega P_{wo}}{2T g \bar{\rho}_1} [f_1(\alpha_w) - S_F]
\]

The frequencies of the water level change and the head in the formation are equal, \( \omega_w = \omega_F = \omega \) (Cooper et al. 1965). Canceling \( e^{i \omega_w t} \), \( e^{i \omega_F t} \) and \( g \bar{\rho}_1 \), it is:

\[
P_{wo} = P_{Fo} + \frac{\varphi r^2_w \omega P_{wo}}{2T} [f_1(\alpha_w) - S_F]
\]

and rearranging, the amplitude ratio will be:

\[
\frac{P_{wo}}{P_{Fo}} = (E + iF)^{-1}
\]

where \( E \) and \( F \) are defined as:

\[
E = 1 - \frac{\varphi r^2_w \omega}{2T} ([\Psi \text{Ker}(\alpha_w) + \Phi \text{Kei}(\alpha_w)] - S_F)
\]

and

\[
F = \frac{\varphi r^2_w \omega}{2T} [\Phi \text{Ker}(\alpha_w) - \Psi \text{Kei}(\alpha_w)].
\]

According to Hsieh et al. (1987), the terms \( \text{Ker}_1(\alpha_w) \) and \( \text{Kei}_1(\alpha_w) \) can be approximated by \(-1/(2^{1/2} \alpha_w)\), leading to \( \Phi \approx 1 \) and \( \Psi \approx 1 \). Then \( E \) and \( F \) can be approximated by:
\[ E \approx 1 - \frac{\varphi r_w^2 \omega}{2T} [\text{Kei}(\alpha_w) - S_F] \quad 2-87 \]

\[ F \approx \frac{\varphi r_w^2 \omega}{2T} \text{Ker}(\alpha_w) \quad 2-88 \]

According to Equations 2-41 and 2-42, and using Equations 2-80 and 2-81, the amplitude ratio is:

\[ A_R = \left| \frac{P_{wo}}{P_{fo}} \right| = \left| \frac{A_w}{A_F} \right| = (E^2 + F^2)^{-1/2} \quad 2-89 \]

and the phase shift is:

\[ \phi = \arg \left( \frac{P_{wo}}{P_{fo}} \right) = \tan^{-1} \left( \frac{\text{Im}(P_{wo}/P_{fo})}{\text{Re}(P_{wo}/P_{fo})} \right) = -\tan^{-1}(F/E) \quad 2-90 \]

where \( \phi = \phi_w - \phi_F \).

Finally the loading efficiency can be expressed as a function of the amplitude of the amplitude ratio:

\[ \gamma = \frac{A_F}{A_L} = \frac{A_w}{|A_R| A_L} \quad 2-91 \]

The amplitude of the groundwater pressure variation in wells \( A_w \) is measured with transducers. The amplitude of the periodic surface load can be measured or estimated theoretically. Then, the loading efficiency for a formation-well system with volumetric flowrate, including skin and shut-in effects can be calculated using Equation 2-91, for a computed value of amplitude ratio.
PRESSURE TIME-SERIES ANALYSIS

Four types of data sets are used in this work, including collected data: fluid pressure in open well, fluid pressure in closed well and barometric pressure, and synthetic data: ocean tide pressure. Fluid pressure data from wells is collected by using pressure transducers that are installed inside the wells below the fluid at a fixed depth, and are configured to measure fluid pressure for a desired data logging interval. Ocean tide pressure is estimated by theoretical calculations based on tidal theory.

The first step in the analysis of the time-series is to plot the data sets with the objective of finding tidal and barometric fluctuations reflected on the well pressure data. This requires basic knowledge of the characteristics of the loading signals as amplitude, $A_L$, frequency, $\omega_L$, and phase, $\phi_L$, and also understanding on how the formation and well responds to those signals.

The raw data usually contain gaps created by errors in the transmission between the transducers and the datalogger, and require further processing before being suitable for analysis.

The steps for time-series analysis are:

1. Apply one-hour average to all data sets, allowing a much easier comparison and handling of the data. Also, the standard interval for tidal analysis is hourly spaced data.
2. Use cubic spline interpolation to fill random gaps of information produced by transmission errors.

3. Filter the data by removal of the low-frequency components (detrending) and high-frequency components, according to the range of frequencies that compose the signal under analysis. This is done by applying a 0.25 octave bandwidth Butterworth filter over the desired frequencies.

4. Plot loading signals and well signals superimposed on the same graph, in order to compare amplitudes, frequencies, and phase lag.

**GRAPHICAL ANALYSIS**

*ESTIMATION OF $\gamma, T, K, AND S_s*$

The graphical analysis includes the use of processed time-series. The steps to get the loading efficiency and formation properties by using this method are:

1. Make an X-Y plot of data points setting the vertical input as $A_w$, and the horizontal input as $A_L$. Plotting one periodic signal against the other will result in a Lissajous figure (Al-Khazali & Askari 2012). When both sinusoidal signals have the same frequency, the figure is an *ellipse*, with the special cases of a *circle* when $A_w = A_L$, and $\phi = 90^\circ$, and a *line* when $\phi = 0^\circ$. In this particular case, the well response signal have the same frequency than the disturbing signal that generate them ($\omega_w = \omega_l$) (Cooper et al. 1965), then the Lissajous curve described by the data points will be an ellipse.

2. Calculate ellipse parameters by using a MATLAB code to get the best fit of the curve. This code reads the vectors containing $A_w$ and $A_L$ data, and computes
the five ellipse parameters \((x_0, y_0, a, b \text{ and } p_0)\) which describe the parametric equations (DeWolf 2009):

\[
x = x_0 + a \sin(p + p_0) \tag{3-1}
\]

\[
y = y_0 + b \cos(p) \tag{3-2}
\]

From these five parameters the canonical equation of the ellipse (on its principal axes \(\xi, \eta\)) can be obtained:

\[
\left(\frac{\xi}{c}\right)^2 + \left(\frac{\eta}{d}\right)^2 = 1 \tag{3-3}
\]

with the semimajor axis \((c)\) and semiminor axis \((d)\) being:

\[
c = \sqrt{\frac{1}{2} \left[ a^2 + b^2 + \sqrt{a^4 + b^4 - 2a^2b^2 \cos(2p_0)} \right]} \tag{3-4}
\]

\[
d = \sqrt{\frac{1}{2} \left[ a^2 + b^2 - \sqrt{a^4 + b^4 - 2a^2b^2 \cos(2p_0)} \right]} \tag{3-5}
\]

3. Calculate the ratio \(\frac{A_w}{A_L}\) from the tilt of the ellipse, which is given by the angle \((\psi)\) between the semimajor axis and the X axis:

\[
\tan(2\psi) = \frac{2ab \sin(p_0)}{a^2 - b^2}. \tag{3-6}
\]

This helps to ensure that the value \(\frac{A_w}{A_L}\) found is the one that relates the two signals with same frequency, and to discard data points which could be the result of disturbances other than the ones under analysis.

4. Calculate phase shift \((\phi)\) using Lissajous method (Al-Khazali & Askari 2012) as:
Figure 3-1: Lissajous method for computing phase shift, $\phi$: a) The ellipse runs from lower left to upper right. b) The ellipse runs from upper left to lower right.

where “a” is the distance from the X axis to the point where the ellipse crosses the Y axis, and “b” is the height of the ellipse, also measured from the X axis.

5. Assuming an intermediate value of storativity, $S$, calculate $S^* = S \frac{r_w^2}{r_c^2}$.

Enter to Figure 5-24 with $S^*$ and $\phi$, and estimate $\phi/T^*$ and the amplitude ratio, $A_R$ for a given skin factor, $S_F$. With the estimation of the shut-in correction term, $\varphi$, and knowing the dimensions of the well and the period of the signal, it is possible to calculate transmissivity ($T^*$) from $T^* = T_T/r_c^2$.

Calculate hydraulic conductivity ($K$) using transmissivity and thickness of the formation.

6. Calculate the loading efficiency ($\gamma$) by using Equation 2-88, with $A_R$ obtained in step 5, and the ratio $\frac{A_w}{A_L}$ from step 3.
7. Estimate a value of specific storage \( S_s \) from Equation 3-7, using \( \gamma \) calculated in step 6, and a known value of confined pore compressibility \( C_p' \). This implies to determine independently Poisson’s ratio \( (\nu) \), rock compressibility \( C_p \) and porosity \( (n) \).

\[
S_s = \frac{\rho_f^e \gamma n C_p'}{\gamma}
\]

where \( \rho_f^e \) is an effective density of the formation fluid, depending on the case study.

**ESTIMATION OF GAS SATURATION**

The estimation of gas saturation \( (S_g) \) is made by the use of the loading efficiency value \( (\gamma) \) calculated by the graphical analysis previously developed. From Equation 2-30, the compressibility of the fluid \( (C_f) \) is calculated using a known value of confined pore compressibility \( C_p' \) (Poisson’s ratio \( (\nu) \), rock compressibility \( (C_p) \) and porosity \( (n) \) might be determined independently).

Once the value of \( C_f \) is obtained, two different scenarios are studied in this work to calculate gas saturation: (A) confined aquifer, in which case the presence of air around the well intake can be estimated, (B) oil-gas reservoir, in which case the content of gas, water and oil needs to be calculated.

For case (A) gas saturation can be determine directly from Equation 2-32 as:

\[
S_g = \frac{C_f - C_w}{C_a - C_w}
\]
where \( C_w \) is water compressibility, and \( C_a \) is air compressibility at aquifer pressure and temperature.

For case (B) the determination of gas saturation requires one intermediate step, due to the fluid compressibility is a function of three different substances: oil, water and gas. To resolve this problem a formation effective compressibility, \( C_e^f \), is defined, which characterizes all the fluid other than gas, and then is a function of the initial oil saturation, \( S_o^i \), and the initial water saturation, \( S_w^i \):

\[
C_e^f = C_o S_o^i + C_w S_w^i
\]

where \( C_o \) is the oil compressibility. Finally, the gas saturation for case (B) will be estimated as follows:

\[
S_g = \frac{C_f - C_e^f}{C_g - C_e^f}
\]

where \( C_g \) is the gas compressibility at reservoir pressure and temperature.
CHAPTER 4
CASE STUDIES

Fluid pressure data from wells located at two different sites was collected using pressure transducers. Both sites and case studies are presented below.

OSELVAR FIELD

Oselvar is an offshore oil field discovered in 1991 in the Norwegian continental shelf of the North Sea. It is located in the south part of the North Sea, close to the border with Great Britain, and 250 km southwest of the city of Stavanger, Norway.

![Oselvar Field Location](source: Google Earth)

**Figure 4-1:** Oselvar offshore oil field location (📍) in the Norwegian continental shelf of the North Sea, between Norway and Great Britain. *Source: Google Earth*

**OSELVAR DEVELOPMENT**

Oselvar Field has been developed with three production wells at a water depth of 62 meters, and the produced oil and gas is transported to the Ula Field platform for
further processing. Ula platform is at 23 kilometers distance from Oselvar, and is connected to it via subsea multi-phase pipeline. The production of the site started on April 2012, and the estimated reserves at Oselvar stand at 38 million barrels of oil and 4 billion cubic meters of natural gas. Dong Energy is the operator of the field with 40% of interest in the project.

Figure 4-2: Oselvar development consists of three horizontal production wells (A-1 H, A-2 H, A-3 H) drilled in the top of the oil rim, to a depth of 3115 m below mean sea level.

The geology of the site consists of fine sands in a mud-dominated system. Several faults have been found in the zone near the wells. Figure 4-3 shows in colors the mapped faults near the production wells.
Figure 4-3: Production wells A-1 H, A-2 H and A-3 H together with the mapped faults (in colors) present at the site.

Wells A-1 H, A-2 H and A-3 H are horizontal wells drilled to a depth of 3115 m below mean sea level or 3115 True Vertical Depth subsea (TVDss) (information provided by Dong Energy). In this work, the wells are assumed vertical, and are named A-1, A-2 and A-3 for convenience.

The gas-oil contact (GOC) is found at 3096 m TVDss, and the oil-water contact (OWC) is at 3150 m TVDss (information provided by Dong Energy).

Figure 4-4 shows a conceptual model of the subsea reservoir, which includes the three production wells (assumed vertical) and the interfaces of contact between the different fluids occupying the pore space.
Figure 4-4: Conceptual model of subsea oil-gas reservoir in Oselvar site. Wells A-1, A-2 and A-3 are assumed vertical, to a depth of 3115 m below mean sea level. Gas-oil contact (GOC) is found at 3096 m, and the oil-water contact (OWC) is at 3150 m.

The average porosity observed in the proximities of the three wells is $n = 0.18$ (information provided by Dong Energy). Poisson’s ratio is assumed $\nu = 0.25$, and the radii of the wells are $r_w = 0.07 \text{ m}$ (Solvang et al. 2014).

Oil, water and gas compressibility and viscosity are calculated at reservoir pressure and temperature, at the well depth (3115 m TVDss). The reservoir pressure is 395 bar, and the reservoir temperature is $131.6 \, ^\circ\text{C}$. Assuming ideal gas behavior, the gas compressibility is calculated as the inverse of the reservoir pressure. The gas density is calculated at reservoir pressure and temperature conditions. Fluids and rock properties are presented in Table 4-1. Average permeability, initial water and oil saturations, and reservoir thickness near each production well are presented in Table 4-2.

\begin{footnote}
Information provided by Dong Energy.
\end{footnote}
**Table 4-1:** Oil, water, gas, and rock properties.

<table>
<thead>
<tr>
<th>Fluid/Rock</th>
<th>Compressibility, $C_i$ (1/Pa)</th>
<th>Density, $\rho_i$ (kg/m$^3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>4.59E-9</td>
<td>835.8</td>
</tr>
<tr>
<td>Water</td>
<td>3.98E-10</td>
<td>1000</td>
</tr>
<tr>
<td>Gas</td>
<td>2.53E-8</td>
<td>188.3</td>
</tr>
<tr>
<td>Rock</td>
<td>2.8E-10 to 4.4E-10</td>
<td>2000</td>
</tr>
</tbody>
</table>

**Table 4-2:** Average permeability, initial water and oil saturations, and net oil reservoir thickness near production wells.

<table>
<thead>
<tr>
<th>Well</th>
<th>Oil Permeability, $k$ (1E-15 m$^2$)</th>
<th>Initial Water Saturation, $S_{iw}$ (dimensionless)</th>
<th>Initial Oil Saturation, $S_{io}$ (dimensionless)</th>
<th>Net Reservoir Thickness, $z$ (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-1</td>
<td>1 to 2</td>
<td>0.45</td>
<td>0.55</td>
<td>18</td>
</tr>
<tr>
<td>A-2</td>
<td>1 to 2</td>
<td>0.62</td>
<td>0.38</td>
<td>35</td>
</tr>
<tr>
<td>A-3</td>
<td>0.6 to 1</td>
<td>0.60</td>
<td>0.40</td>
<td>10</td>
</tr>
</tbody>
</table>

**THE BOTTOMS**

The Bottoms is a teaching field used for educational purposes located in Clemson University Campus, adjacent to Lake Hartwell. The area used to be flooded by the Seneca River until the construction of a dam in 1950. At present, the ground elevations in the Bottoms are lower than the water level in Lake Hartwell, and a pumping station prevents flooding in the area. The site is used as a wellfield for undergraduate and graduate students enrolled in Hydrogeology and Environmental Engineering classes.
Figure 4-5: Location of the Bottoms at Clemson University Campus, adjacent to Lake Hartwell. Source: Google Earth

Figure 4-6: Wellfield at the Bottoms, Clemson University Campus. Source: Google Earth
A cross section of the subsurface under the wellfield (dotted green line in Figure 4-6) is represented in Figure 4-7. A confined aquifer can be found at a depth of 6 m, and the thickness of the aquifer is approximately 3 m.

Figure 4-7: Cross section of the Clemson University wellfield with wells CBL-7 and CBL-4.

MONITORING WELLS AND DEPLOYED EQUIPMENT

One well was used to monitor the water pressure at the Bottoms, CBL-7. It is screened in the confined aquifer, and the well radius is: \( r_w = 0.05 \, m \).

A set of pressure transducers was installed at a fixed depth of 3.14 m below the water surface, to measure water pressure. Another sensor was deployed above the water surface to measure the pressure at the top of the well. The devices were configured to measure fluid pressure at a desired data logging interval of 10 minutes.

Initially the well was left open to the atmosphere in order to take characterize the open well pressure response to barometric loading. After that the well was isolated from the atmosphere in order to analyze and compare the behavior of the groundwater response to natural stress changes for both cases, open and closed well. The fluid properties are presented in Table 4-3.
<table>
<thead>
<tr>
<th>Fluid/Rock</th>
<th>Compressibility, $C_i$ (1/Pa)</th>
<th>Density, $\rho_i$ (kg/m$^3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>4.6E-10</td>
<td>1000</td>
</tr>
<tr>
<td>Air</td>
<td>9.9E-6</td>
<td>1.2</td>
</tr>
</tbody>
</table>

**Table 4-3:** Water and air properties in well CBL-7.
CHAPTER 5
ANALYSIS AND RESULTS

This chapter presents the calculation of different formation properties for Oselvar and Bottoms sites, based on pressure measurements collected from monitoring and producing wells. The data analysis and derivation of results are organized in three sections for each case study. The first section consists on the description of the raw data series and their detrending to visualize the periodic signals they contain due to environmental influences. A signal characterization is then performed to determine the amplitude, period and phase of the filtered loading and response pressure signals. Lissajous curves are presented for each data set in order to calculate phase shift between loading and response. The second section includes a plot of amplitude ratio versus phase shift for several values of skin factor. This plot is used to calculate transmissivity, amplitude ratio and skin factor, and shows how the different skin factors affect the characteristics of the responses. The third section consists of the numerical results for the formation properties, including the estimated values of gas saturation, transmissivity, hydraulic conductivity and specific storage.

DATA SERIES AND LISSAJOUS CURVES

OSELVAR FIELD

Raw data series of fluid pressure measurements are presented for the three wells in Oselvar reservoir, for two different moments in time: October-November 2012 (Figure 5-1) and June 2013 (Figure 5-2). These two segments of measurements were selected for
analysis because they are shut-in periods in which a general increasing tendency of the pressure is observed at wells A-1, A-2 and A-3. The signals for these periods do not present perturbations derived, for example, from the industrial operation of the wells, and are therefore appropriate for this analysis. Pressure for well A-3 is in the range between 370 and 380 bar in both moments in time, but for wells A-1 and A-2 decreases notably from 2012 to 2013. It goes from 340-360 bar (A-2) and 325-350 bar (A-1) in 2012, to 300-325 bar (A-2) and 270-305 bar (A-1) in 2013.

Figure 5-1: Raw pressure data measured in wells A-1, A-2 ad A-3 in Oselvar oil and gas reservoir. Period October-November 2012.
At first glance it is impossible to detect the small pressure fluctuations resulting from the ocean tide. A filter for the M$_2$ component of the tide (the dominant tidal component) is applied to visualize the detrended tidal and response signals (Figure 5-3 and Figure 5-4) for the whole segments of data, and observe how the wells are responding to the applied load.
Figure 5-3: Detrended pressure data ($M_2$ component filtered) of wells A-1, A-2, A-3 and ocean tide. Period October-November 2012.

Figure 5-4: Detrended pressure data ($M_2$ component filtered) of wells A-1, A-2, A-3 and ocean tide. Period June 2013.

One week of each data series is isolated and plotted (Figure 5-5 and Figure 5-6), with the purpose of having a detailed view of the signals. The tidal amplitude ($A_L$) in both cases fluctuates periodically between 0.015 to 0.05 bar, with a period ($\tau_L$) of 12.421 hours, corresponding to $M_2$ tidal component.
In both cases (Figure 5-5 and Figure 5-6) A-3 signal has the higher amplitude ($A_W$) which is approximately 0.005 bar. The amplitude and phase of the responses in wells A-1 and A-2 are very similar, and therefore both signals are almost overlapping. In 2012 the amplitude is approximately 0.002 bar, and in 2013 it is around 0.001 bar. There is a phase shift between the tide and the wells, and between well A-3 and the other two wells (Figure 5-5), which is notably increased in 2013 (Figure 5-6).

**Figure 5-5**: 1 week of detrended pressure data ($M_2$ component filtered) of wells A-1, A-2, A-3 and ocean tide. 2012.
The Lissajous method is used in this work to calculate phase shift. It involves plotting the load and response pressure signals one against the other, to obtain a Lissajous ellipse. This graphical method is selected because it provides a way to fingerprint the change in properties over time and location, through the direct comparison of the shapes and tilts of the different ellipses. The data points and the Lissajous ellipses they describe are presented for each well in the following figures.
Figure 5-7: Pressure data points and Lissajous ellipse for well A-1. Period October-November 2012.

Figure 5-8: Pressure data points and Lissajous ellipse for well A-2. Period October-November 2012.
Figure 5-9: Pressure data points and Lissajous ellipse for well A-3. Period October-November 2012.

Figure 5-10: Pressure data points and Lissajous ellipses for wells A-1, A-2 and A-3. Period October-November 2012.
**Figure 5-11:** Pressure data points and Lissajous ellipse for well A-1. Period June 2013.

**Figure 5-12:** Pressure data points and Lissajous ellipse for well A-2. Period June 2013.
The calculated phase shift, $\phi$, and $A_W/A_L$ ratio for each well are presented in Table 5-1. The phase shifts are measured considering the loading signal as reference.
Table 5-1: Phase shift, $\phi$, and $A_W/A_L$ calculated with Lissajous method.

<table>
<thead>
<tr>
<th>Well</th>
<th>$\phi$ (degrees)</th>
<th>$A_W/A_L$ (bar/bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-1 2012</td>
<td>-30</td>
<td>0.04</td>
</tr>
<tr>
<td>A-2 2012</td>
<td>-29</td>
<td>0.04</td>
</tr>
<tr>
<td>A-3 2012</td>
<td>-26</td>
<td>0.13</td>
</tr>
<tr>
<td>A-1 2013</td>
<td>-41</td>
<td>0.03</td>
</tr>
<tr>
<td>A-2 2013</td>
<td>-51</td>
<td>0.03</td>
</tr>
<tr>
<td>A-3 2013</td>
<td>-41</td>
<td>0.14</td>
</tr>
</tbody>
</table>

CLEMSON SITE

Raw data series of water pressure measurements are presented for one well (CBL-7) in a confined aquifer at the Bottoms, at the Clemson University Campus. For this site, the pressure response in the wellbore was measured for open and sealed well conditions (Figure 5-15 and Figure 5-16 respectively). For the shut-in case, the wellhead pressure was also measured, and it is shown on Figure 5-16 as well. Groundwater pressure for open well CBL-7 is in the range 1.15-1.17 bar, while for closed well it is 1.16 to 1.19 bar. The head space pressure is higher than the barometric pressure in around 3E-3 bar for the whole period under analysis. Diurnal and semidiurnal frequencies can be identified directly from the raw data, but in this work just the diurnal (1 cycle per day) frequency is filtered and analyzed.
As in the case of Oselvar data, at first glance it is impossible to detect the small pressure fluctuations caused by the barometric pressure changes. Then, a filter for the
diurnal component of the signal is applied. This allows to visualize the detrended barometric and response signals (Figure 5-17 and Figure 5-18) for the whole segments of data, and observe how the well is responding to the applied load.

**Figure 5-17:** Detrended pressure data (filtered for 1CPD) of well CBL-7 and barometric pressure. Open well.

**Figure 5-18:** Detrended pressure data (filtered for 1CPD) of well CBL-7 and barometric pressure. Closed well.
One week of each data series is isolated and plotted (Figure 5-19 and Figure 5-20) to have a detailed view of the signals. The barometric amplitude ($A_L$) in both cases is in the range between 0.8E-3 to 1.5E-3 bar, with a period ($\tau_L$) of 24 hours (diurnal).

The amplitude of the response in the open well case is calculated as the difference between the groundwater pressure and the barometric pressure. This amplitude is approximately 0.2E-3 bar.

![Figure 5-19: 1 week of detrended pressure data (filtered for 1CPD) of well CBL-7 and barometric pressure. Open well.](image)

When the well is open, the expected behavior of the periodic response signal is contrary to the loading signal. If the surface load increases, the water level decreases and then, the fluid pressure decreases. If the surface load decreases, the water level increases and the fluid pressure increases too. The response signal for well CBL-7 open (Figure 5-19) shows a weird behavior, with a response that has a variable frequency, and that differs from the expected behavior opposed to the loading signal. This can also be
observed in the signal for the complete period (Figure 5-17), which shows sometimes a negative phase and sometimes a positive phase with respect to the loading signal. A positive phase shift implies that the well response occurs before the load, which has no physical sense. There is also a particular event around date 9/9 in which the well response exceeds the loading signal and is opposed to it. This event is the consequence of the movement of the transducer, which was removed from the well for data collection and then redeployed. After the study of the signals of CBL-7 open, it was decided to include in the analysis only the portions of data with a negative phase shift, avoiding segments that are not representative of the phenomenon under analysis.

When the well is sealed, the amplitude of the pressure response due to water level changes is measured directly because the well is isolated from the atmosphere. Then, no further calculations are required on the groundwater data obtained by the transducer. The amplitude of the closed well pressure response is almost identical to the amplitude of the barometric load.
The phase shift between signals is difficult to be detected from the time plots, and then it is also calculated by using the Lissajous method. The data points and corresponding Lissajous ellipses are presented in the following figures for well CBL-7, open and closed.
Figure 5-21: Pressure data points and Lissajous ellipse for well CBL-7. Open well, 1CPD.

Figure 5-22: Pressure data points and Lissajous ellipse for well CBL-7. Closed well, 1CPD.
The calculated phase shift, $\phi$, and $A_W/A_L$ ratio for CBL-7 open and closed are presented in Table 5-2.

<table>
<thead>
<tr>
<th>Well</th>
<th>$\phi$ (degrees)</th>
<th>$A_W/A_L$ (bar/bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CBL-7 Open</td>
<td>-20.92</td>
<td>0.17</td>
</tr>
<tr>
<td>CBL-7 Closed</td>
<td>0</td>
<td>1.00</td>
</tr>
</tbody>
</table>

AMPLITUDE RATIO VS PHASE SHIFT GRAPHS

Using the modified version of Hsieh et al. (1987) method, amplitude ratio and phase shift can be plotted in the same graph for different values of $S^* = S r_w^2/r_c^2$ and $\varphi/T^*$, where $T^* = T \tau/r_c^2$. The radius of the casing, $r_c^2$, is always equal to the radius of the well, $r_w^2$, in this work.
Three different datasets were selected, corresponding to three different values of skin factor: $S_F = 0$, $S_F = 2$, and $S_F = 10$. This plot (Figure 5-24) relates amplitude ratio, phase shift, transmissivity, storativity, and skin effect.

**Figure 5-24:** Amplitude ratio versus phase shift as a function of $S^* = S \tau_0^2 / \tau_2^2$ and $\varphi/T^*$, where $T^* = T \tau / \tau_2$, for three different values of skin factor: $S_F = 0$, $S_F = 2$ and $S_F = 10$.

**ESTIMATED FORMATION PROPERTIES**

Formation properties are calculated using the plot in Figure 5-24 with the measured phase shift, and assuming an intermediate value of storativity of 1E-5. Amplitude ratio ($A_R$), transmissivity ($T$), loading efficiency ($\gamma$), gas saturation ($S_g$), specific storage ($S_s$) and hydraulic conductivity ($K$) in the near well zones for both case studies are estimated. Different values of skin factor are evaluated, depending on the range of the phase shift existing between the load and response.
For the cases of shut-in wells (Oslevar well and CBL-7 closed) it is necessary to determine the correction term, $\varphi$, to be used for transmissivity calculations. For Oslevar reservoir, the total length above the transducer ($L$) was assumed to be the depth of the wells, that is 3115 m. Then, the fluid level was assumed to be 10% of the total length. The denser fluid in this case is considered to be a mix between oil and water. Using the initial saturations of oil and water (Table 4-2), effective values of density and compressibility are estimated ($\bar{\rho}_1$ and $C_1$). Fluid 2 is, in this case, the gas in the reservoir.

For the wells in Bottoms site, the total length ($L$) and the fluid level above the transducer are measured. The denser fluid is water and the lighter is air.

| Table 5-3: Fluid densities ($\bar{\rho}_1$, $\bar{\rho}_2$) and compressibilities ($C_1$, $C_2$) used to calculate effective compressibility in the wellbore ($C_w^e$). Fluid level ($x$) and total length ($L$) above transducer. Calculated correction term for shut-in wells ($\varphi$) for each site. |
|---|---|---|---|---|---|---|---|---|
| Site | $x$ (m) | $L$ (m) | $C_1$ (Pa$^{-1}$) | $C_2$ (Pa$^{-1}$) | $\bar{\rho}_1$ (kg/m$^3$) | $\bar{\rho}_2$ (kg/m$^3$) | $C_w^e$ (Pa$^{-1}$) | $\varphi$ |
| Oslevar | 311 | 3115 | 2.9E-9 | 2.5E-8 | 909.7 | 188.3 | 2.3E-8 | 0.43 |
| Bottoms | 1.84 | 3.14 | 4.6E-10 | 9.9E-6 | 1000 | 1.2 | 4.1E-6 | 0.11 |

**Oslevar Field**

The values of the estimated properties and skin factors for Oslevar site are shown on Table 5-4 to Table 5-7, together with the amplitude ratio and loading efficiency for each well. The transmissivity value provided by Dong Energy is $T = 0.8E-6$ m$^2$/s.
Table 5-4: Amplitude ratio ($A_R$), transmissivity ($T$), loading efficiency ($\gamma$), gas saturation ($S_g$), specific storage ($S_s$) and hydraulic conductivity ($K$) in Oselvar wells for a skin factor of $S_F = 2$. Period 2012.

<table>
<thead>
<tr>
<th>Well</th>
<th>$A_R$</th>
<th>$T$ (m$^2$/s)</th>
<th>$\gamma$</th>
<th>$S_g$</th>
<th>$S_s$ (m$^{-1}$)</th>
<th>$K$ (m/s)</th>
<th>$S_F$</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-1</td>
<td>0.65 ± 0.22</td>
<td>1.3x10$^{-6}$ ± 2.3x10$^{-6}$</td>
<td>0.06 ± 0.02</td>
<td>0.00 ± 0.06</td>
<td>4.0x10$^{-6}$ ± 2.3x10$^{-6}$</td>
<td>0.7x10$^{-7}$ ± 1.3x10$^{-7}$</td>
<td>2</td>
</tr>
<tr>
<td>A-2</td>
<td>0.67 ± 0.26</td>
<td>1.4x10$^{-6}$ ± 5.3x10$^{-6}$</td>
<td>0.07 ± 0.03</td>
<td>0.01 ± 0.07</td>
<td>3.9x10$^{-6}$ ± 2.6x10$^{-6}$</td>
<td>0.4x10$^{-7}$ ± 1.5x10$^{-7}$</td>
<td>2</td>
</tr>
<tr>
<td>A-3</td>
<td>0.72 ± 0.19</td>
<td>1.6x10$^{-6}$ ± 3.6x10$^{-6}$</td>
<td>0.18 ± 0.05</td>
<td>0.00 ± 0.02</td>
<td>1.4x10$^{-6}$ ± 0.6x10$^{-6}$</td>
<td>1.6x10$^{-7}$ ± 3.6x10$^{-7}$</td>
<td>2</td>
</tr>
</tbody>
</table>

Table 5-5: Amplitude ratio ($A_R$), transmissivity ($T$), loading efficiency ($\gamma$), gas saturation ($S_g$), specific storage ($S_s$) and hydraulic conductivity ($K$) in Oselvar wells for a skin factor of $S_F = 0$. Period 2012.

<table>
<thead>
<tr>
<th>Well</th>
<th>$A_R$</th>
<th>$T$ (m$^2$/s)</th>
<th>$\gamma$</th>
<th>$S_g$</th>
<th>$S_s$ (m$^{-1}$)</th>
<th>$K$ (m/s)</th>
<th>$S_F$</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-1</td>
<td>0.81 ± 0.13</td>
<td>1.6x10$^{-6}$ ± 2.3x10$^{-6}$</td>
<td>0.05 ± 0.01</td>
<td>0.01 ± 0.05</td>
<td>5.0x10$^{-6}$ ± 1.8x10$^{-6}$</td>
<td>0.1x10$^{-7}$ ± 1.3x10$^{-7}$</td>
<td>0</td>
</tr>
<tr>
<td>A-2</td>
<td>0.82 ± 0.15</td>
<td>1.7x10$^{-6}$ ± 5.0x10$^{-6}$</td>
<td>0.05 ± 0.02</td>
<td>0.03 ± 0.05</td>
<td>4.8x10$^{-6}$ ± 2.1x10$^{-6}$</td>
<td>0.5x10$^{-7}$ ± 1.4x10$^{-7}$</td>
<td>0</td>
</tr>
<tr>
<td>A-3</td>
<td>0.85 ± 0.11</td>
<td>1.9x10$^{-6}$ ± 3.4x10$^{-6}$</td>
<td>0.15 ± 0.03</td>
<td>0.00 ± 0.01</td>
<td>1.7x10$^{-6}$ ± 0.5x10$^{-6}$</td>
<td>1.9x10$^{-7}$ ± 3.4x10$^{-7}$</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 5-6: Amplitude ratio ($A_R$), transmissivity ($T$), loading efficiency ($\gamma$), gas saturation ($S_g$), specific storage ($S_s$) and hydraulic conductivity ($K$) in Oselvar wells for a skin factor of $S_F = 2$. Period 2013.

<table>
<thead>
<tr>
<th>Well</th>
<th>$A_R$</th>
<th>$T$ (m$^2$/s)</th>
<th>$\gamma$</th>
<th>$S_g$</th>
<th>$S_s$ (m$^{-1}$)</th>
<th>$K$ (m/s)</th>
<th>$S_F$</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-1</td>
<td>0.48 ± 0.25</td>
<td>0.7x10$^{-6}$ ± 1.1x10$^{-6}$</td>
<td>0.06 ± 0.03</td>
<td>0.00 ± 0.10</td>
<td>4.2x10$^{-6}$ ± 3.6x10$^{-6}$</td>
<td>0.4x10$^{-7}$ ± 0.6x10$^{-7}$</td>
<td>2</td>
</tr>
<tr>
<td>A-2</td>
<td>0.25 ± 0.27</td>
<td>0.4x10$^{-6}$ ± 0.4x10$^{-6}$</td>
<td>0.14 ± 0.08</td>
<td>0.00 ± 0.08</td>
<td>1.9x10$^{-6}$ ± 3.0x10$^{-6}$</td>
<td>0.1x10$^{-7}$ ± 0.1x10$^{-7}$</td>
<td>2</td>
</tr>
<tr>
<td>A-3</td>
<td>0.47 ± 0.28</td>
<td>0.7x10$^{-6}$ ± 1.1x10$^{-6}$</td>
<td>0.30 ± 0.08</td>
<td>0.00 ± 0.01</td>
<td>0.9x10$^{-6}$ ± 0.3x10$^{-6}$</td>
<td>0.7x10$^{-7}$ ± 1.1x10$^{-7}$</td>
<td>2</td>
</tr>
</tbody>
</table>
### Table 5-7: Amplitude ratio ($A_R$), transmissivity ($T$), loading efficiency ($\gamma$), gas saturation ($S_g$), specific storage ($S_s$) and hydraulic conductivity ($K$) in Oselvar wells for a skin factor of $S_F = 0$. Period 2013.

<table>
<thead>
<tr>
<th>Well</th>
<th>$A_R$</th>
<th>$T$ (m$^2$/s)</th>
<th>$\gamma$</th>
<th>$S_g$</th>
<th>$S_s$ (m$^{-1}$)</th>
<th>$K$ (m/s)</th>
<th>$S_F$</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-1</td>
<td>0.71 ± 0.15</td>
<td>1.1x10$^{-6}$ ± 0.1x10$^{-6}$</td>
<td>0.04 ± 0.01</td>
<td>0.04 ± 0.08</td>
<td>6.2x10$^{-6}$ ± 2.9x10$^{-6}$</td>
<td>0.6x10$^{-7}$ ± 0.5x10$^{-7}$</td>
<td>0</td>
</tr>
<tr>
<td>A-2</td>
<td>0.53 ± 0.19</td>
<td>0.6x10$^{-6}$ ± 0.5x10$^{-6}$</td>
<td>0.06 ± 0.03</td>
<td>0.01 ± 0.07</td>
<td>4.0x10$^{-6}$ ± 2.8x10$^{-6}$</td>
<td>0.2x10$^{-7}$ ± 0.1x10$^{-7}$</td>
<td>0</td>
</tr>
<tr>
<td>A-3</td>
<td>0.68 ± 0.19</td>
<td>0.1x10$^{-6}$ ± 1.2x10$^{-6}$</td>
<td>0.21 ± 0.02</td>
<td>0.00 ± 0.01</td>
<td>1.2x10$^{-6}$ ± 0.1x10$^{-6}$</td>
<td>0.1x10$^{-7}$ ± 1.2x10$^{-7}$</td>
<td>0</td>
</tr>
</tbody>
</table>

**CLEMSON SITE**

The values of the estimated properties and skin factors for the Bottoms are shown on Table 5-8, together with the amplitude ratio and loading efficiency for well CBL-7 open and shut-in. The transmissivity of the confining unit calculated with a slug test is between $T = 0.8E-6$ to $3.1E-6$ m$^2$/s.

### Table 5-8: Amplitude ratio ($A_R$), transmissivity ($T$), loading efficiency ($\gamma$), gas saturation ($S_g$), specific storage ($S_s$) and hydraulic conductivity ($K$) in Bottoms wells for a skin factor of $S_F = 10$. Open and closed well.

<table>
<thead>
<tr>
<th>Well</th>
<th>$A_R$</th>
<th>$T$ (m$^2$/s)</th>
<th>$\gamma$</th>
<th>$S_g$</th>
<th>$S_s$ (m$^{-1}$)</th>
<th>$K$ (m/s)</th>
<th>$S_F$</th>
</tr>
</thead>
<tbody>
<tr>
<td>CBL-7</td>
<td>0.33 ± 0.49</td>
<td>0.5x10$^{-6}$ ± 4.3x10$^{-6}$</td>
<td>0.51 ± 0.37</td>
<td>0.00 ± 0.01</td>
<td>1.6x10$^{-6}$ ± 4.3x10$^{-6}$</td>
<td>0.2x10$^{-6}$ ± 1.4x10$^{-6}$</td>
<td>10</td>
</tr>
<tr>
<td>Open</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CBL-7</td>
<td>1.00 ± 0.59</td>
<td>3.2x10$^{-6}$ ± 3.1x10$^{-6}$</td>
<td>1.00 ± 0.42</td>
<td>0.00 ± 0.01</td>
<td>0.8x10$^{-6}$ ± 0.4x10$^{-6}$</td>
<td>1.1x10$^{-6}$ ± 1.0x10$^{-6}$</td>
<td>10</td>
</tr>
<tr>
<td>Closed</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Using the calculated value of transmissivity for open well, it is possible to estimate the shut-in correction term for Bottoms site as:

$$\varphi = \left(\frac{\varphi}{T^*}\right)_{closed} \left(T^*\right)_{open} \quad (5-1)$$
given that the correction term in the open well case is $\varphi = 1$. The estimated shut-in correction term for closed well at the Bottoms is:

<table>
<thead>
<tr>
<th>Well</th>
<th>$(\varphi)_{\text{closed}}$</th>
<th>$(T^*)_{\text{open}}$</th>
<th>$\varphi$</th>
</tr>
</thead>
<tbody>
<tr>
<td>CBL-7 Closed</td>
<td>0.001</td>
<td>30</td>
<td>0.03</td>
</tr>
</tbody>
</table>

Table 5-9: Shut-in correction term calculated from figure Figure 5-24, for well CBL-7 at the Bottoms.
Pore pressure in wells responds to natural stresses like barometric and tidal fluctuations. This response depends on the elastic and fluid flow properties of the formation, as well as the characteristics of the well (i.e., wellbore radius, casing radius, open well, closed well).

Pressure transducers can be installed in monitoring wells to measure fluid pressure. Pressure transducers can also be used to measure barometric pressure outside the wells. Ocean tides can be measured or estimated using tide theory.

If the loading signal and its response in the well can be measured, then it is possible to use this information as a means to calculate the formation response to loading. The amplitude response defined by Hsieh et al. (1987) relates the response in a well to the response in a given formation, and can be used to estimate the loading efficiency of the formation.

There is also a time lag between the response in the formation and the well response, that is the result of the time required for the fluid to flow into and out of the well to equilibrate the fluid pressure imbalance due to surface loading. This time lag is visualized as a phase shift between the periodic signals that describes the barometric or tidal loading, and the response signal. Hsieh developed a method to calculate the transmissivity of a formation from the phase shift between well and formation responses to Earth tides, given an estimate of the storage coefficient.
This thesis extends the work done by Hsieh by analyzing the effects of well skin and shut-in on the response of wells to natural stresses. A new method is proposed, which includes the definition of a shut-in correction term, \( \varphi \), that considers the effects of fluid compressibility at the wellhead. The drawdown caused by the skin around the well is added to the drawdown in the formation due to the periodic fluid flow between formation and well. The skin factor, \( S_F \), is included in the expression for total drawdown at the well. The shut-in correction term, \( \varphi \), is also included in the analysis, considering a system with two fluids (the denser fluid is at the bottom of the formation-well system, and is the only exchanged fluid). When the well is open, \( \varphi \rightarrow 1 \) and the expressions for phase shift and amplitude ratio are equivalent to Hsieh expressions. When the well is shut-in, \( \varphi \) takes values between 0 and 1.

Data series for four wells were analyzed in this work, collected in two different sites and for different well configurations. Oselvar pressure data sets correspond to three producing wells in shut-in conditions located in an offshore oil/gas reservoir. Clemson pressure data sets were measured in a monitoring well screened in a confined aquifer, for two different conditions, open and shut-in well.

A plot relating phase shift, storage coefficient, amplitude ratio, shut-in factor and transmissivity for different values of skin factor was developed. This plot seems to be a convenient and practical tool in order to estimate very quickly some of the properties and factors it relates, but it is also very useful as a way to evaluate the effect of well skin on the magnitude of formation properties. Gas saturation, transmissivity, and specific storage were calculated for the two formations under analysis, by the use of this graphical
method. It requires the determination of phase shift by Lissajous method and the calculation of the ratio between well and formation pressure amplitudes. Given an estimate of the storage coefficient, the formation properties and well factors mentioned before were calculated.

The consistency of the different values of formation properties calculated over time and space, support the conclusion that the proposed methodology is feasible to be used to determine gas saturation and other formation properties using pore pressure fluctuations due to natural stresses. The ocean tides showed strong signals in deep formations, with different responses according to different locations. From the modified analysis applied to open and shut-in wells, is observed that the estimated formation properties in Oselvar site \( T = 0.4E-6 \) to \( 1.9E-6 \) m\(^2\)/s are similar to known values for the site \( T = 0.8E-6 \) m\(^2\)/s. In the case of Clemson site, it is observed that the pressure data is dominated by the confining unit, when the estimated properties \( T = 0.5E-6 \) to \( 3.2E-6 \) m\(^2\)/s are compared with values of transmissivity obtained by slug tests \( T = 0.8E-6 \) to \( 3.1E-6 \) m\(^2\)/s).

It can also be concluded that the graphical method provides a convenient and practical tool to evaluate the effects of skin on the walls of wells, and it also provides insights on the effect of shut-in on the well response to surface loading.

The method looks encouraging, but from the results at the Clemson site the need arises to evaluate the effect of heterogeneities on the formation response to surface load. Future work can be conducted in order to further explore the potential of this method.

Collection of pressure data in wells can be done for longer periods of time and using
several transducers, to avoid gaps and disturbances on the data. Ocean tides can be measured instead of calculated using tidal theory, providing more accurate and realistic information. A numerical model can be developed to evaluate the effect of heterogeneities, and to study complex multiphase problems. Automatization is envisioned too through the use of a moving window inversion analysis of the data. It gives the possibility of analyzing very long data sets in a short period of time, showing phase and amplitude of the signals as a function of time. It also provides an estimate of the uncertainty in the calculations.
APPENDICES
Appendix A

Modulus and argument of complex numbers

Given the complex number \( z = x + yi \), the modulus, \( r \), of \( z \) is:

\[
  r = |z| = \sqrt{x^2 + y^2} \tag{A-1}
\]

The argument of the complex number \( z \), \( \varphi \), is:

\[
  \varphi = \text{arg}(z) = \begin{cases} 
  \tan^{-1} \left( \frac{y}{x} \right) & \text{if } x > 0 \\
  \tan^{-1} \left( \frac{y}{x} \right) + \pi & \text{if } x < 0 \text{ and } y \geq 0 \\
  \tan^{-1} \left( \frac{y}{x} \right) - \pi & \text{if } x < 0 \text{ and } y < 0 \\
  \frac{\pi}{2} & \text{if } x = 0 \text{ and } y > 0 \\
  -\frac{\pi}{2} & \text{if } x = 0 \text{ and } y < 0 \\
  \text{indeterminate} & \text{if } x = 0 \text{ and } y = 0 
\end{cases} \tag{A-2}
\]

Then, \( z \) can be expressed as:

\[
  z = r(\cos \varphi + i \sin \varphi) = re^{i\varphi} \tag{A-3}
\]
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