Chair of Drilling and Completion Engineering

Master Thesis

Wellbore Stability Analysis for Post- and Pre-salt Drilling in Brazil´s Campos Basin

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Leoben, November 2014

Affidavit

I, Thomas Jaritz, hereby confirm that my master thesis entitled “Wellbore Stability Analysis for Post- and Pre-salt Drilling in Brazil´s Campos Basin” is written by my own. All sources and materials applied are listed and specified.

Eidesstattliche Erklärung

Hiermit bestätige ich, Thomas Jaritz, dass meine Abschlussarbeit mit dem Titel „Wellbore Stability Analysis for Post- and Pre-salt Drilling in Brazil´s Campos Basin” von mir eigenhändig verfasst wurde. Verwendete Quellen und Hilfsmittel wurden angeben.

Leoben, November 2014

Thomas Jaritz

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Abstract

Wintershall has the intention to develop fields in the Maromba area of the Campos basin, which are part of the BC-20A concession. Petrobras, the national oil and gas company of Brazil, is operator with 70% interest of this concession, divesting 30-35% of their interest.

Brazil´s Campos basin is one of the most challenging basins to develop. Close pore to fracture gradients, salt and pre-salt drilling, poor hole cleaning as well as high differential stresses are only some issues, which require not only high development cost, but also well-founded knowledge and innovative technology to bring the wells on stream. The thesis will cover the wellbore stability analysis, in particular of the Maromba area 100 km apart from Cabo Frio and the deep water area of the Campos basin.

Data from four different exploration wells have been evaluated. Those wells were drilled in the shallow water of the Santos basin and the deep water of the Campos and Espírito Santo basin. The Santos and the Espírito Santo basin are attached to the Campos basin and located southwest and northwest of it. Beside the analyses of the wellbore stability problems, the pore and fracture pressures as well as the stratigraphic columns are elaborated. Based on the acquired data, recommendations concerning the drilling fluids, casing setting depths, drilling times as well as wellbore instability indicators are made to prevent problems and associated costs.

Raising the mud weight is one of the main statements of the read literature to solve wellbore stability problems. However, some of the conclusions move away from this well practiced and industry wide recommended method.

Nevertheless, only potential wellbore instabilities could be assumed. For more precise predictions of the wellbore instabilities series of laboratory tests with rock and fluid samples need to be done. Those tests should include stress checks, rock-fluid interaction and the mineralogical composition of all different formations. Moreover, core analyses and logging information of the formations would be of particular

importance. Thus, bedding directions, local stress regimes, wellbore behaviors and inhomogeneities could be identified over a long sequence.

Kurzfassung

Wintershall hat die Absicht, Erdölfelder im Maromba Bereich des Campos Beckens zu erschließen. Dieser Bereich ist Teil der BC-20A Konzession. Petrobras, das nationale Öl- und Gasunternehmen von Brasilien, gehören 70% dieser Konzession. Davon möchte das Unternehmen 30 bis 35% veräußern.

Das Campos Becken ist bekannt als eines der weltweit Anspruchsvollsten hinsichtlich Bohrtechnik. Geringe Poren- und Bruchdruckunterschiede, mächtige Salzschichten, schlechter Bohrgutaustrag sowie hohe mechanische Differenzspannungen sind nur einige Probleme, die neben hohen Entwicklungskosten auch fundiertes Wissen und innovative Technologien erfordern, um eine erfolgreiche Bohrung durchführen zu können. Diese Abschlussarbeit befasst sich mit der Analyse der Bohrlochstabilität, insbesondere im Maromba Bereich, 100 km entfernt von Cabo Frio und dem Tiefwasserbereich des Campos Beckens.

Daten aus vier verschiedenen Explorationsbohrungen werden ausgewertet. Diese Bohrungen wurden im seichten Wasser des Santos Beckens und dem Tiefwasserbereich des Campos und Espírito Santo Beckens durchgeführt. Das Santos und Espírito Santo Becken befinden sich südwestlich und nordwestlich vom Campos Becken. Neben der Analyse der Bohrlochstabilität werden sowohl Poren- und Bruchdruck als auch die stratigraphischen Schichten ausgearbeitet. Basierend auf diesen Daten werden Empfehlungen bezüglich der Bohrspülung, Bohrrohrabsetztiefe, Bohrdauer sowie Instabilitätsindikatoren gegeben, um erhöhte Kosten zu vermeiden.

Eine der Hauptaussagen der gelesenen Literatur, um Bohrlochinstabilitäten zu lösen, ist, das Bohrspülungsgewicht zu erhöhen. Manche meiner Empfehlungen und Schlussfolgerungen folgen dem nicht.

Jedoch konnten nur mögliche Bohrlochinstabilitäten angenommen werden. Für exakte Vorhersagen müsste eine Reihe von Tests an Gesteins- und Bohrschlammproben durchgeführt werden. Diese Tests sollten Belastungsprüfungen, Gesteins- und Bohrschlamminteraktionen sowie eine mineralogische Ausarbeitung

aller verschiedenen Formationen umfassen. Kernanalysen und Formationsmessungen wären von besonderer Bedeutung. Dadurch könnten Schichtungsrichtungen, lokale Stressfelder, Bohrlochverhalten und Inhomogenitäten identifiziert werden.

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1 Introduction

As offshore drilling is extremely complex in terms of technical, geological, logistical and financial issues, all unknown parameters have to be investigated before starting a drilling operation. Brazil´s Campos basin is one of the most challenging basins to develop. Close pore to fracture gradients, salt and pre-salt drilling, poor hole cleaning as well as high differential stresses are only some of the major issues, which require not only high development cost, but also well-founded knowledge and innovative technologies to bring the wells on stream. For new offshore developments the lack of experience and expertise has to be compensated by analyzing all manner of complexities, risks and hazards which may occur.

1.1 Problem Description

Wintershall is currently studying the development of fields in the Maromba area of the Campos basin, which are part of the BC-20A concession. Petrobras, the national oil and gas company of Brazil, is operator with 70% interest of this concession, wanting to divest 30-35% of their interest. The Maromba area is very new for Wintershall, thus the lack of experience in this area has to be compensated by investigating many drilling and geological unknowns to optimize the drilling efficiency for the possible development in the future Thus, this thesis presents the work of the wellbore stability analysis of the Campos basin, focused on the shallow and deep water area and its characteristics.

The Maromba field contains a 16° API, 25 cP oil in the Maastrichtian sandstone of the shallow water area, proven with four well penetrations. It was announced as commercial discovery of 470 MMbbl OOIP by Petrobras in December 2006. **Fig. 1.** shows the location of the BC-20A concession. It is surrounded by existing productions and developments. The Peregrino field produces nearly 100,000 bbl/d of 14° API, 160 cP crude oil from the Maastrichtian sandstones. The Papa Terra field started in October 2013 with the production of the Maastrichtian sandstones. The field produces about 110,000 BFPD with an expected peak production of up to

135,000 bbl/d of 15° API, 200 cP oil. The Tubarao Azul field produces from the Albian carbonates approximately 7,000 boe/d of 20° API (Berchelmann 2014).

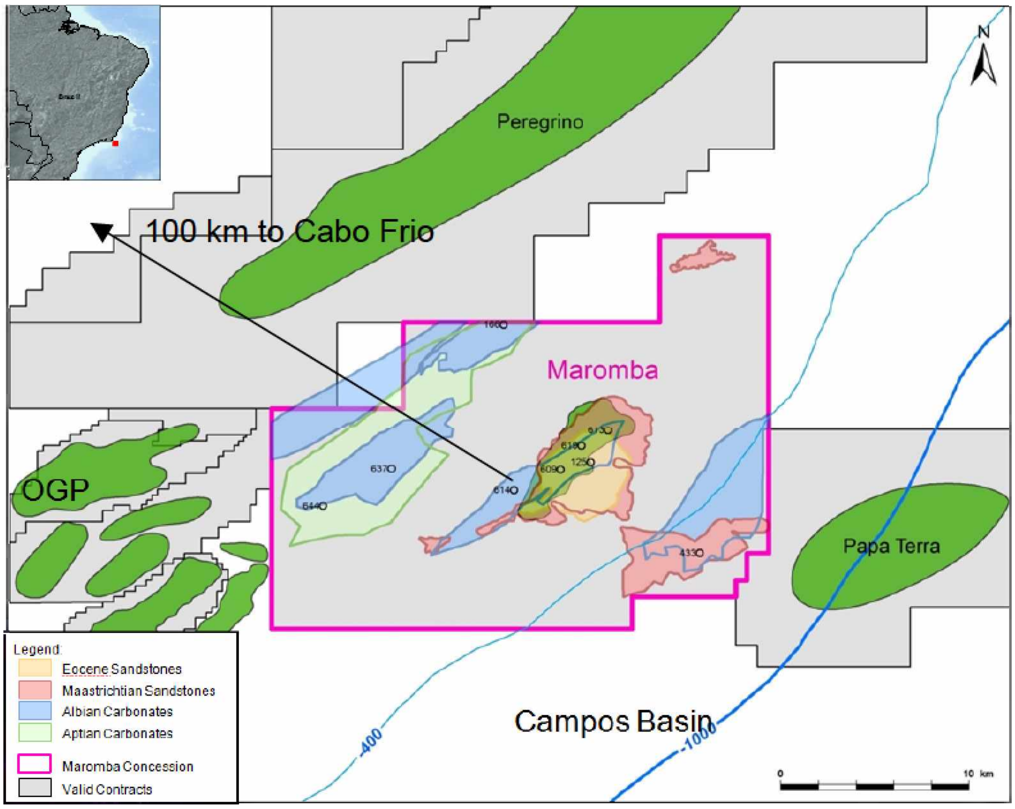


Figure 1: Location of the Maromba concession with its surrounding production fields

1.2 Thesis Objectives and Methodology

The thesis will cover the wellbore stability analysis of the Campos basin. In particular, the Maromba area 100 km apart from Cabo Frio and the deep water area should be analyzed. The first step is to make a literature review of the geology, the drilling challenges and the wellbore stability issues of the shallow, as well as, deep water area of the Campos basin, focusing on pre- and pos-salt layers. Next, potential wellbore problems have to be analyzed by using the end of well and daily drilling reports. Due to the fact that wellbore problems during drilling through shale, salt and subsalt layers are likelier to occur, a special focus will be put on these lithologies. Finally, well planning recommendations concerning the drilling fluids, casing setting depth, required drilling costs and time as well as wellbore instability indicators are made, based on data analyses and evaluations of the recaps, geology and formation pore and fracture pressures.

2 Literature Review

2.1 Geology

Approximately 140-130 million years ago during the Lower Cretaceous the Gondwana super-continent started to breakup, starting with rifting and evolving from Late Lower Cretaceous into a full drifting phase (**Fig. 2.**) (Mohriak et al. 2008).

The separation as well as the marine environment started to occur in the south and progressed towards the north. The Atlantic margin between South America and Africa is restricted by major transversal faults and divided into the North African-, Equatorial- and South American sector (Clemente 2013).

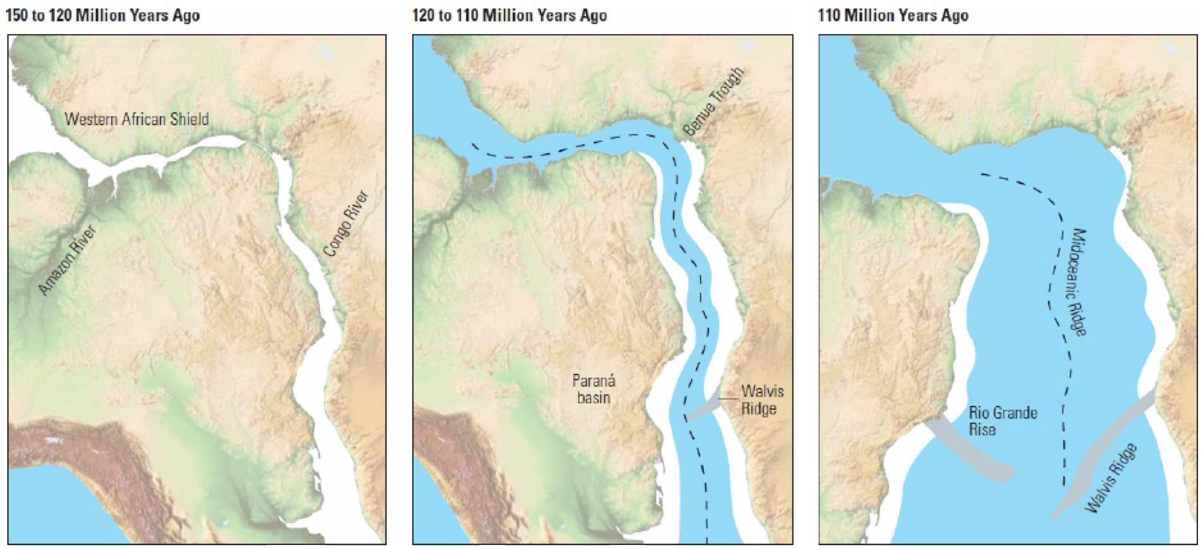


Figure 2: Rift to drift phase between 150 and 110 million years ago (Beasley et al. 2010)

2.1.1 Brazilian Sector

The Brazilian Sector extends from the Equatorial margins to the north and the South Atlantic margin to SE, covering an area of approximately 1,700 x 3,000 km. Regional transversal faults of E-W direction and smaller extensional faults of NE-SW and NW-SE direction separate the sector (Mohriak et al. 2008). The most important basins in SE Brazil are the Espírito Santo, Campos and Santos basins. They are located mainly offshore in shallow to deep waters (Clemente 2013).

Figure 3: Brazil´s basins (Berchelmann 2014)

2.1.2 Campos Basin

The Campos basin, one of Brazil´s most successful oil bearing area, is 400 km wide and 250 km long (100,000 km^2). The major part of the basin is located offshore with a minor part onshore in the area of the lake Lagoa Feia. Westwards, the basin is confined by the Campos Fault which forms the hinge line (Clemente 2013). The basin is a typical rift passive margin (**Fig. 4.**) controlled by salt tectonics.

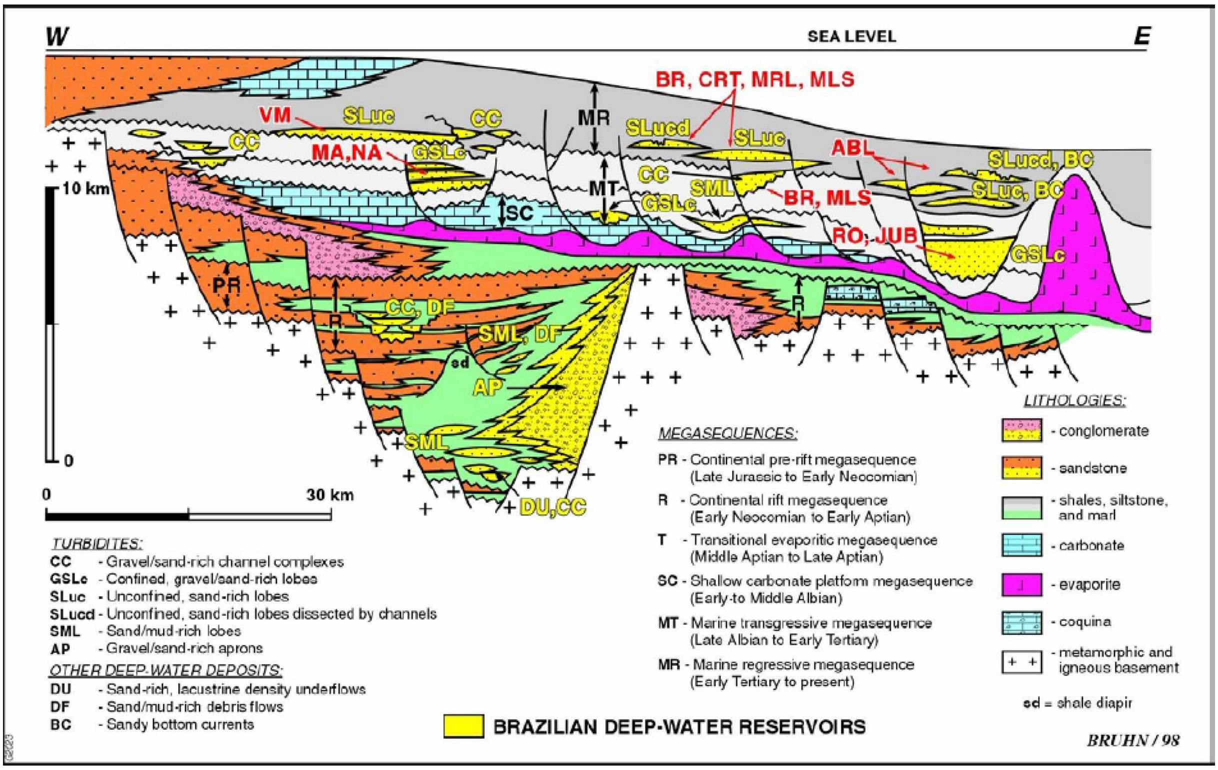


Figure 4: Generalized geological section of Brazil´s Campos basin (Bruhn 2003)

Petroleum System

Due to rich source rocks, excellent migration path ways, good reservoir and seal properties as well as a good timing of oil migration and trap forming, the Campos basin is named as world class petroleum system (Guardado et al. 2000).

The main source rocks are the Banenian/Aptian lacustrine shales of the Lagoa Feia group, which could reach up to 300 meter thickness. The rocks have an excellent TOC of 2-6% and consist of lipid-rich algae and bacteria. Some spots even have a TOC content of 9%. The very high HI of up to 900 mg HC/mg TOC indicates an oilprone Type I kerogen. The produced hydrocarbons are a mixture of biodegraded and non-biodegraded oils with API gravities from 17° to 37° (Guardado et al. 2000).

The lacustrine carbonate reservoirs of the Coqueiros formation (shelly limestones named as coquinas **Fig. 36.**) and of the Macabu formation (microbialites) form the main presalt reservoirs with locally underlying reservoirs in the basalts of the Cabiúnas formation. The main post-salt reservoirs are the shallow marine carbonates of the Quissamã formation and the Upper Cretaceous to Miocene turbidites of the Carapebus formation.

Appendix A shows the change in stratigraphy of the Campos basin from shallow water to deep water (Winter et al. 2007). From left to right the chart lists the timetable, the sedimentary environment, the formation names, the thickness and the deposition sequence. For the stratigraphy the dots patterns show clastic rocks: yellow dots patterns are sandstones and yellow dot lenses are turbidites. Blue brick patterns are carbonates and the grey colors with dashes are open marine turbiditic claystones and siltstones.

2.1.3 Salt and Pre-salt Geology

The salt and pre-salt geology is related to the breakup of the ancient Gondwana supercontinent. This breakup created an opening for the nascent Atlantic Ocean, which is responsible for thick salt occurrences in the southern parts of Brazil´s basins. Before the drifting phase three rifting phases occurred, which formed basins parallel to the plate margins. These basins developed lakes and were filled with fresh water, volcanic sediments and continental sediments. The basins then subsided and favorable conditions for source rock generation were present. Barriers, that restricted the circulation of the Atlantic Ocean, were formed during the continuing pull apart of the continental plates. During the Aptian age the arid climate evaporated the water. This process produced thick salt layers in the basin, later on covered with sediments. At Middle to Late Cretaceous the drifting phase began by injecting of oceanic crust at the mid-ocean ridge. In addition, carbonate platforms started to develop (Beasley et al. 2010).

Salt layers appear as autochthonous and allochthonous. The allochthonous salt gets detached from autochthonous salt layers, which stays at its generated stratigraphic level, and rise through overlying rock layers. Afterwards the salt spreads laterally. Hydrocarbon accumulation is possible below both types (Beasley et al. 2010).

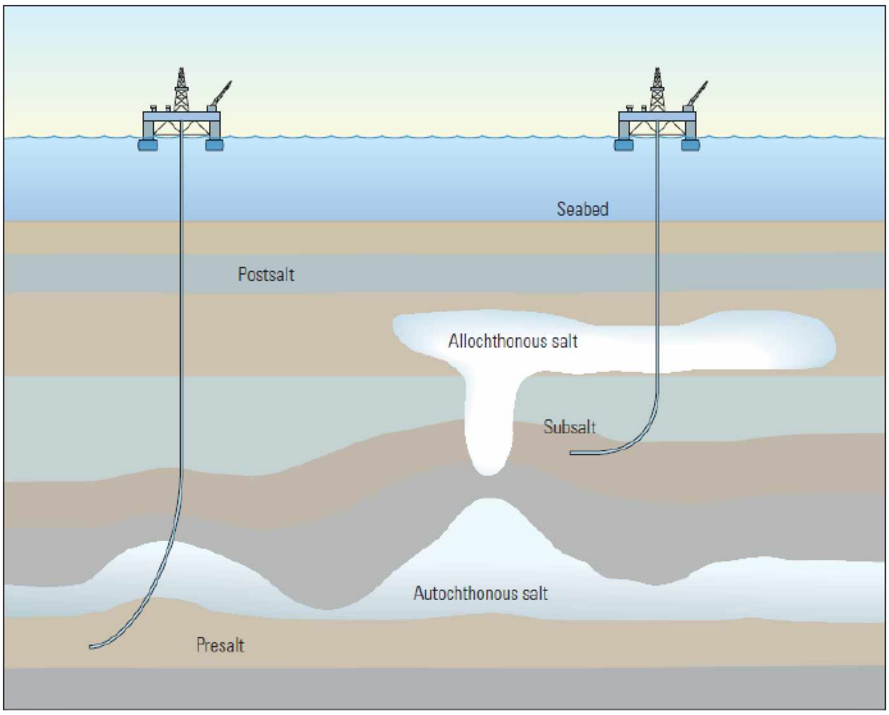


Figure 5: Autochthonous as well as allochthonous salt layers (Beasley at al. 2010)

2.1.4 Maromba Field

The Maromba field is located in the southern part of the Campos basin, 100 km away of Cabo Frio. Hydrocarbon reservoirs in this field are, from shallow to deep, the post-salt Middle Eocene sandstones, the Maastrichtian sandstones of the Carapebus formations and the Albian carbonates of the Quissamã formation. The pre-salt reservoir is the Aptian carbonate of the Coquinas formation. The main hydrocarbon accumulation is expected to be in the Maastrichtian turbiditic sandstone, which is located underneath a cone of volcanic rocks, trapped in a four-way structural trap. The deposition occurred in fault related intra-sloped troughs. The Albian carbonates are located just above the salt layer. The hydrocarbons are trapped in a mixed structural and stratigraphic trap (Berchelmann 2014). The salt layer consists of hyalite halite and white anhydrite. The Aptian carbonates are the sub-salt hydrocarbon bearing formations consisting of coquinas, which are shelly limestone bivalves (Clemente 2013).

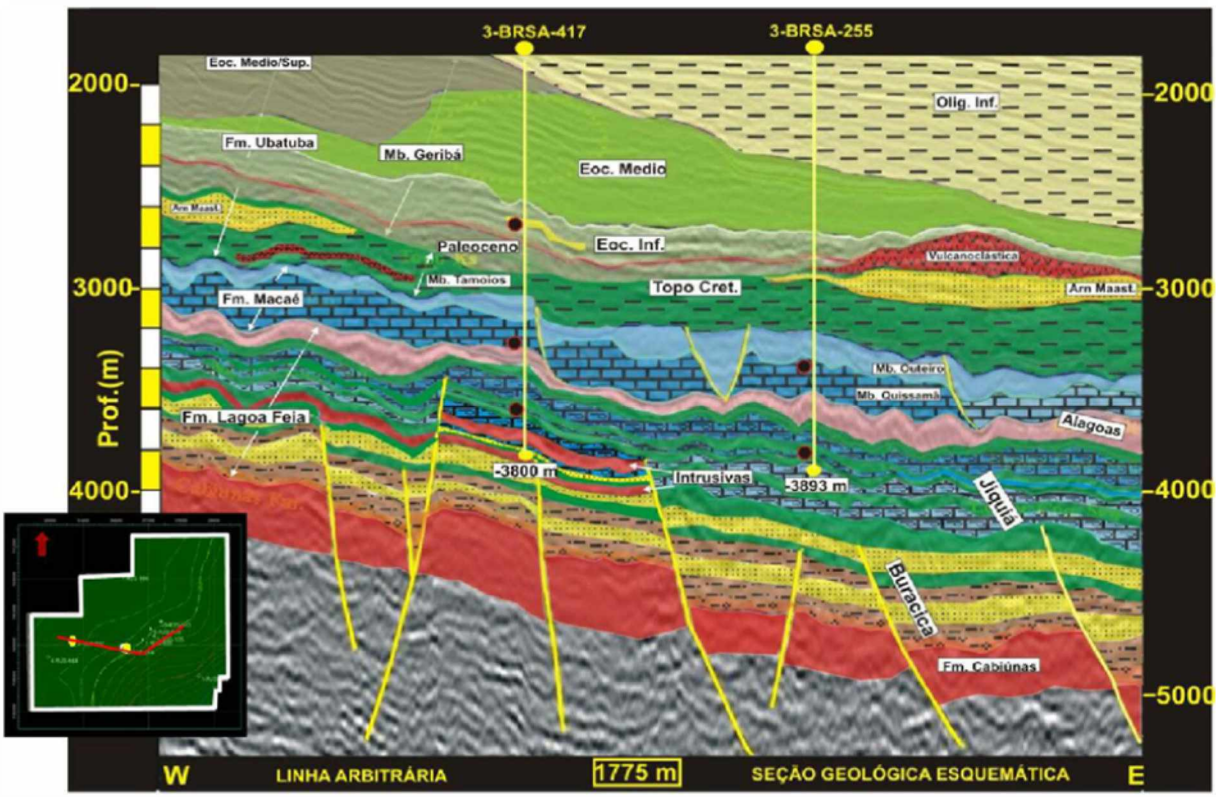


Figure 6: 2-D seismic of Campos´ shallow water area (Berchelmann 2014)

2.2 Campos Basin Developments

First exploration of the Campos basin began in 1971 with a jack up rig in 49 meter water depth, off Brazil´s southeastern coast. In the next three years another eight vertical wildcat wells were drilled. The first hydrocarbon bearing formation was found in 1972 at 58 meter water depth, but the reservoir was not commercial. However, the first commercial pay was found in Albian carbonates of the Garoupa field. It was the ninth offshore wildcat drilled with a drillship in a water depth of 124 meter. The target was at 3,750 meter, which was reached with four casing strings and a 7” liner. The first major discovery was the Namorado field. It is a clastic turbidite reservoir drilled in a water depth of 166 meter. By the mid-1980s the first prodelta deep-marine siliciclastic turbiditic reservoirs were targeted. This led to the giant hydrocarbon discovery of the field Albacora in 1984, followed by Marlim in 1985, Barracuda in 1989 and Roncador in 1996 (Juiniti et al. 2003 and Baesley et al. 2010).

Until spring 2013 the number of wells drilled totalized with more than 2,780, resulting in 49 producing oilfields (Ferreira & Warszawski 2013).

Petrobras, the leading oil and gas operator of this basin, has reached in 2014 an average offshore Campos basin production of 1,457 Mbpd crude oil and NGL and 23,055 Mm^3/d natural gas (Petróleo Brasileiro S.A. 2014).

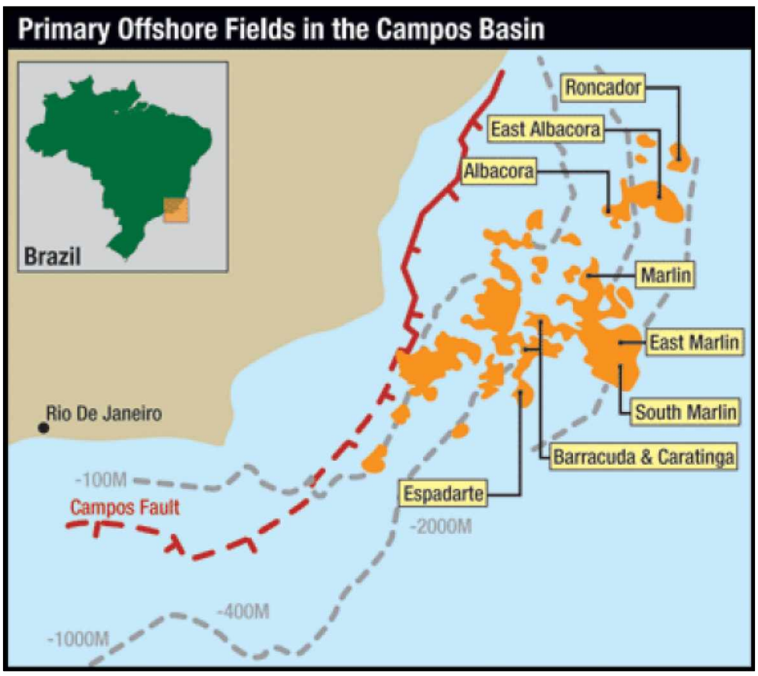


Figure 7: Primary offshore fields in the Campos basin (Energy Tribune 2014)

2.3 Drilling Challenges

The Campos basin is home of several giant offshore fields, which are very well known as some of the most challenging to develop for oil and gas production. In the 2005 paper of Paes et al., the drilling challenges are divided into two categories. The minor part, which accounts for 20% of all problems, is vibration related. The majority of the problems are geopressure and hydraulic related. They are responsible for 80% of all problems.

Drilling vibrations lead to the following problems (Paes et al. 2005):

- MWD/BHA failure
- Excessive bit wear
- Low ROP
- Poor MWD communication
- Drill string fatigue

Geopressure and hydraulic problems result in (Paes et al. 2005):

- Lost circulation
- Well control incidents
- Hole collapse
- Poor hole cleaning
- Lost down-hole tools
- Stuck pipe or casing
- Excessive reaming
- Tight hole
- Excessive torque and drag

The stated problems cause NPT, high drilling costs as well as a low drilling efficiency. In particular, fields like the Barracuda-Caratinga, Marlim, Roncador, Marlim Sul and Marlim Leste are the most challenging in the basin (Paes et al. 2005).

Another issue in some areas of the Campos basin is the huge temperature gradient jump within the deeper formations. Abnormal temperature gradients from 40°C/km or even 45°C/km are common. An average temperature gradient of 30°C/km is normal worldwide. Most of those anomalies are credited to the presence of salt domes. BHA sensor failures as well as increased thermal stress fields are created at the borehole wall (Jose 2001).

Moreover, reservoirs overlaid by 2,000-3,000 meter of salt sections are not unusual. The complex salt tectonics, with massive salt domes located in the deep water area, have high temperature and differential stress conditions, which result in (Maia et al. 2005):

- High drilling costs
- Stuck pipe
- Collapse of casing
- Decrease of drilling efficiency

2.4 Wellbore Stability Overview and Issues

Aadnoy and Ong (2003) state that in drilling ´Wellbore stability issues were not seriously addressed until 1980. Bradley (1979) published his famous paper "Failure of Inclined Boreholes", which initiated interest for the topic in the industry`.

This chapter presents an overview of wellbore behavior, including the rock/fluid interactions during drilling.

2.4.1 Introduction

Wellbore instability is one of the main critical issues during drilling. Problems caused by wellbore instability will significantly increase the overall drilling time and associated costs of wells. Thus, predrill wellbore analysis is of vital importance, in particular for new geological areas.

Prior to the execution of drilling operations, the chemical reactions as well as the rock strength in respect to the in-situ stresses of the rock are in equilibrium (but not for geological time steps). During drilling the rock will undergo mechanical chances in tensile, compaction and shear loads as well as chemical interactions. Excessive changes and reactions can lead to borehole deformations, fractures, collapse or dissolution, to prevent those issues, many factors need to be examined, some can be controlled while others can pose bigger problems (**Tab. 1.**) (Amoco n.d.).

Table 1: Controllable and uncontrollable factors influencing wellbore stability (modified from Salehi et al. 2010)

Controllable Factors	Uncontrollable Factors
ECD	In-situ stresses
Drilling fluid type	Rock lithology
Drilling fluid chemistry	Pore fluid chemistry
Well orientation, direction relative to stress field	Rock porosity
	Rock permeability
Mud temperature	Compressibility
Borehole size	Initial rock temperature
Drill pipe size	Rock strength
Flow rate	Rock mechanical properties
OH exposure	Initial pore pressure
Drilling operations	Natural fractures
Solids control equipment	Rock thermal properties
Hole cleaning	Geothermal gradient

However, Osisanya in his 2011 presentation grouped the wellbore instability causes as followed:

- Mechanical
- Rock-chemical interaction
- Man-made (drilling practices)

All three causes are described in the following chapters.

2.4.2 Rock Mechanical Issues

Before discussing the mechanical issues, the rock and wellbore stress states have to be described. The stresses inside a rock are the effective minimum horizontal stress σ_h, effective maximum horizontal stress σ_H and effective overburden stress σ_v. As a result of drilling through the rock, the in-situ stresses near the wellbore can be explained as hoop stress σ_θ, radial stress σ_r and axial stress σ_z. **Fig. 8.** shows the stresses at the borehole wall (Matthäi 2014).

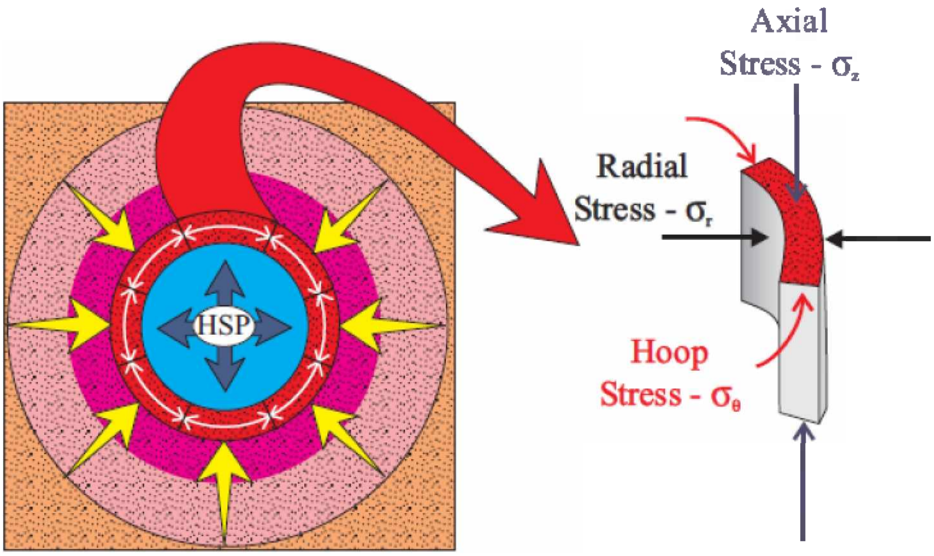


Figure 8: Wellbore stress state (Amoco n.d.)

The hoop stress is equally distributed for vertical wells with equal horizontal stresses. For unequal horizontal stresses and deviated wells the hoop stress has its maximum perpendicular to the maximum stress acting on the wellbore wall. The axial stress, which is oriented along the wellbore path, is the same as the vertical stress, if the well is vertical with equal horizontal stresses. For a deviated well the axial stress is the result of the overburden and horizontal stresses. Radial stress acts perpendicular to the wellbore wall and is the difference of wellbore to pore pressure (Amoco n.d.). Mechanical wellbore failure occurs as soon as the stress concentration in one point exceeds the rock strength. That can be shown graphically in a Mohr Coulomb failure envelope.

Breakouts at the borehole wall occur, if the stress around the wall exceeds the compressive strength of the rock. The maximum hoop stress is oriented in the direction of the minimum horizontal stress, perpendicular to the maximum horizontal stress σ_H. Fractures will develop once the stress around the wall exceeds the tensile failure requirement. The fractures will approximately develop parallel to σ_H because of the minimum compressive stress concentration at this point (Tingay 2008).

Another wellbore failure is shear displacement, which occurs if naturally existing fractures next to the borehole wall get reopened by high mud pressures. The reopening relieves stresses and the opposite faces of the fractures start to shear (Addis et al. 1993).

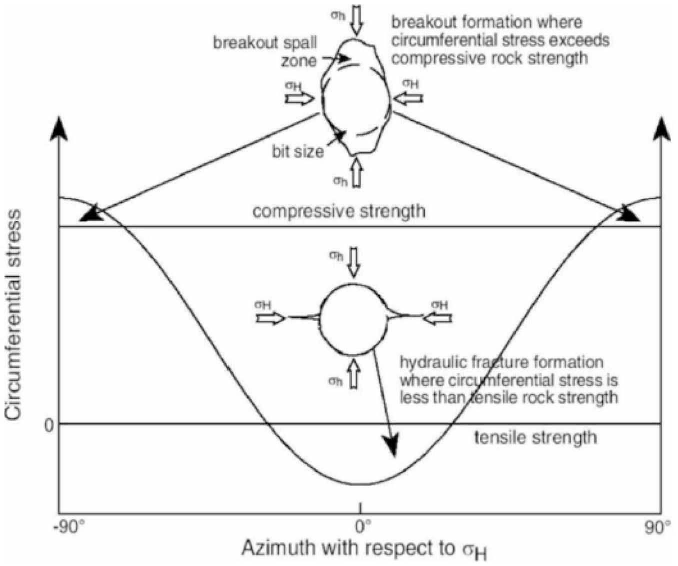


Figure 9: Schematic cross-section of borehole breakout and drilling-induced fractures. Breakouts are oriented parallel to the minimum horizontal stress and fractures are oriented parallel to the maximum horizontal stress (Tingay 2008)

Controllable parameters for the hoop, axial and radial stress are (Amoco n.d.):

- Mud weight
- ECD
- Mud filter cake
- Well path-inclination and azimuth
- Temperature differences
- Time

Uncontrollable parameters for the hoop, axial and radial stress are (Amoco n.d.):

- Unfavorable in-situ conditions
- Adverse formations
- Constrained wellbore trajectory

The first controllable parameter is the mud weight/ECD. An increase will lead to a decrease of the hoop and an increase of the radial stress. For a decrease of the mud weight/ECD it is vice versa. **Fig. 10.** shows the radial and hoop stress behavior during mud weight chances in the Mohr Coulomb failure envelope (Amoco n.d.). If the stress envelope exceeds the stability envelope, failures will occur.

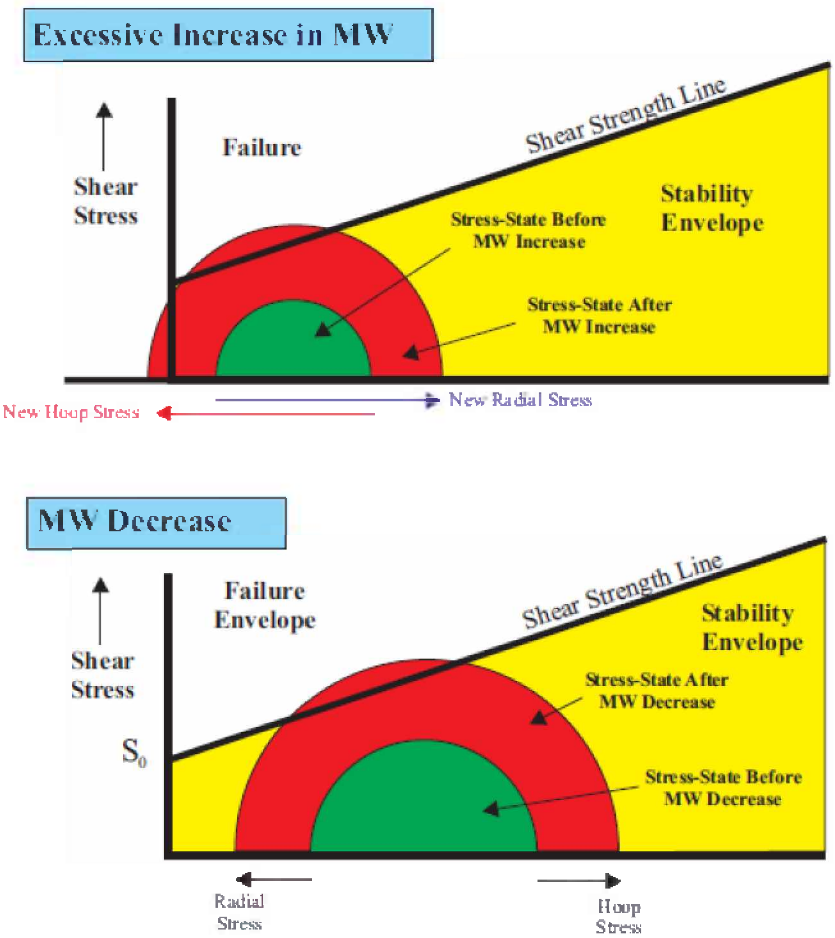


Figure 10: Mohr Coulomb failure envelope during mud weight chances (Amoco n.d.)

Secondly, the filter cake separates the drilling fluid from the formation fluid. Without a filter cake the radial stress decreases to zero, caused by the wellbore pressure increase to hydrostatic mud pressure. The drilling mud composition controls the permeability, quality and time it takes to generate the cake. It is assumed that little or no filter cake will be built up across any shales or claystones because of their low permeabilities (Amoco n.d.).

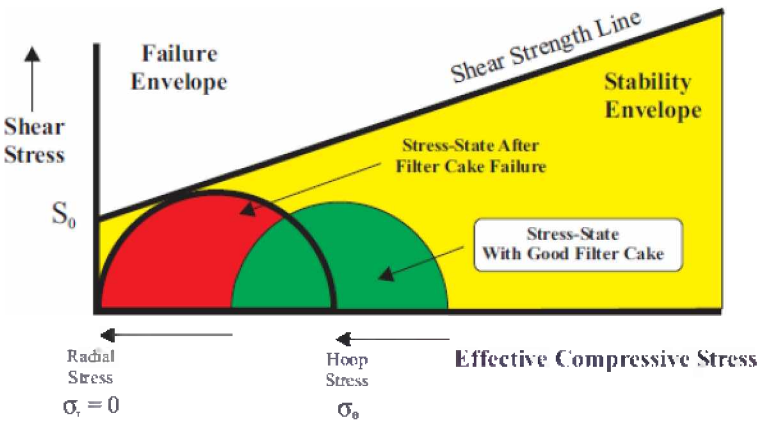


Figure 11: Mohr Coulomb failure envelope for good (green cycle) and bad (red cycle) filter cake development (Amoco n.d.)

As highlighted above, the inclination and azimuth of the wellbore influence the stability of the wellbore as well. By increasing the inclination, the radial stress remains constant, but the hoop stress increases at the perpendicular sides of the wellbore wall. This is caused by the vertical stress of the overburden rocks (Amoco n.d.).

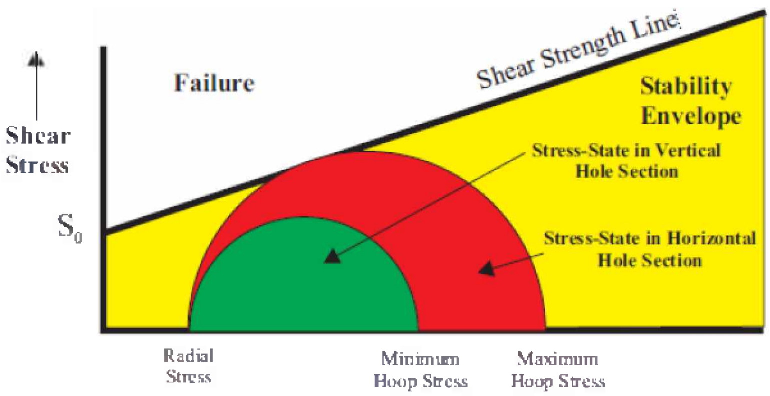


Figure 12: Mohr Coulomb failure envelope for a borehole during chances in inclination (Amoco n.d.)

Fig. 13. shows a mud weight window for drilling in a conventionally stressed earth ($S_v > S_H > S_h$). The blue curves indicate the compressional failure limits and the red curve the tensile failure limits. As inclination increases the safe mud weight window decreases (Addis et al. 1993).

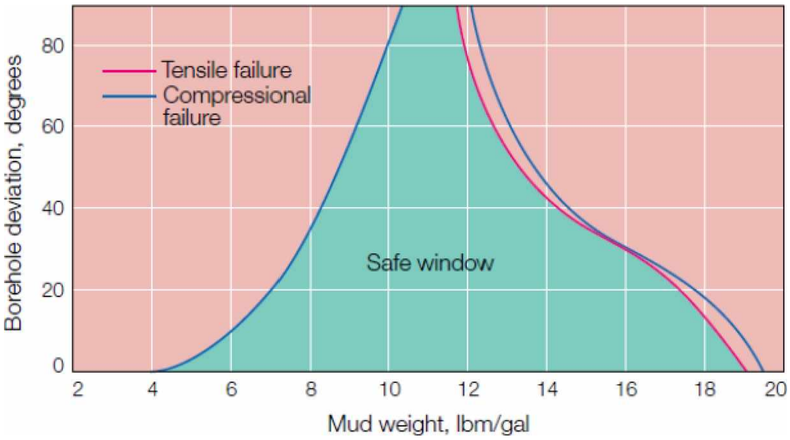


Figure 13: Mud weight vs. borehole deviation (Addis et al. 1993)

In addition, temperature differences in high temperature wells have an effect on the hoop stress as well. Cooler mud reduces the hoop stress, which can lead to tensile failure, if the mud weight is high enough and close to the fracture gradient. On the other hand, if the mud heats the formation, the hoop stress gets increased. Those behaviors promote shear failure or caving (Amoco n.d.).

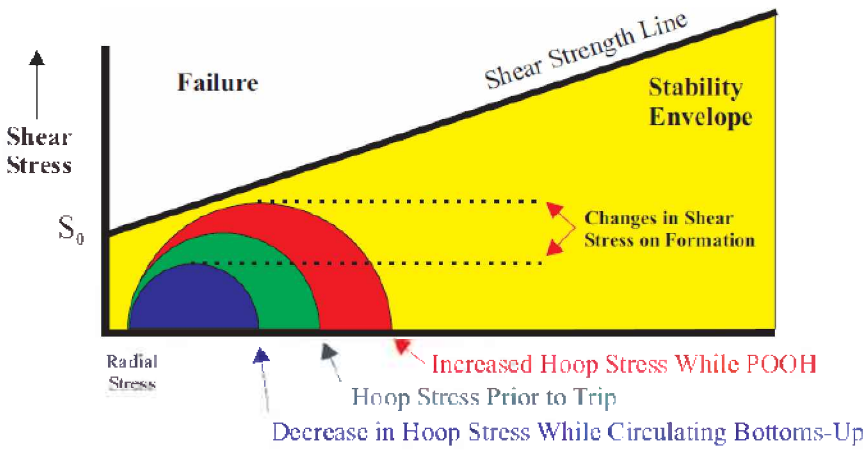


Figure 14: Variation of hoop stresses in a high temperature well (Amoco n.d.)

The results of mechanical wellbore issues are breakouts, fractures, hole closures in plastic shale and salt sections, hole enlargements, mechanical abrasions and inherently sloughing shales (Peng and Zhang 2007). Those instabilities lead to stuck equipment (pipe, casing or logging tool), ineffective hole cleaning, ledges, breakouts, high torque, severe stick-slip or drill string failures (Amoco n.d.).

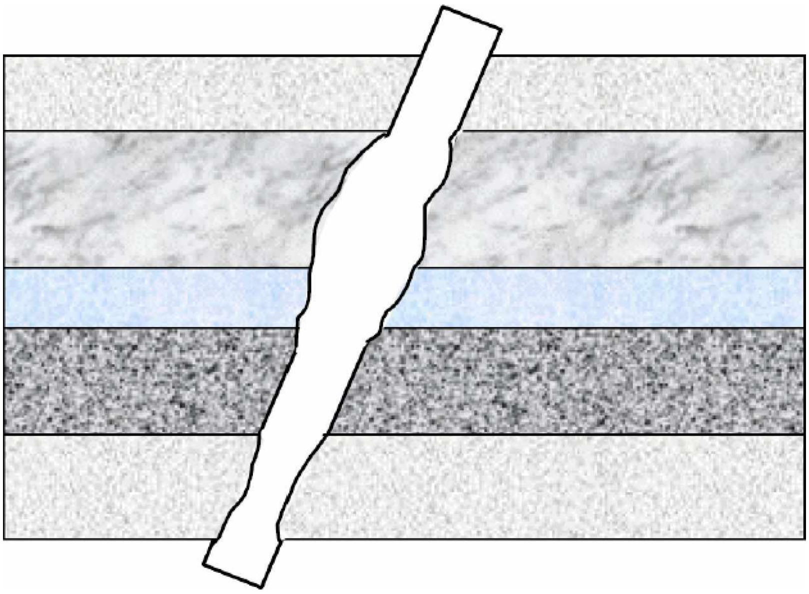


Figure 15: Schematic plot of stress-induced wellbore instabilities (Peng and Zhang 2007)

2.4.3 Rock-Chemical Interaction

The most formation drilled worldwide consists of shale, which is responsible for over 70% of all wellbore stability problems. Those problems are tight hole, stuck pipe, collapse, poor hole cleaning, fracturing, plastic flow, lost circulation, hole enlargement and well control. Shales have a very low permeability and are fine-grained sedimentary rocks consisting of silt and clay size laminated minerals. The types vary from clay-rich gumbo to highly cemented shaly siltstone. The major difference to other rocks is the water sensitive behavior, except salt formations. Following factors influence the stability of shales (Lal 1999):

- Advection
- Capillary pressure
- Osmosis
- Pressure diffusion

Typically, during overbalanced drilling operations the hydrostatic pressure of the mud is greater than the formation pressure. This pressure difference causes advection, which transports drilling fluids into shale formations. However, a good filter cake would protect the wellbore, but it is not able to develop since the filter cake is more permeable than the shale. Even the particles of the fluid are too big to plug the pore throats.

Nevertheless, not only advection causes shale instability. If the drilling fluid overcomes the capillary pressure, which develops at the drilling and pore fluid interface, it will invade the shale formation as well. The capillary pressure is expressed as.

$$(1)\ P_C = 2 * \sigma * cos\left(\frac{\theta}{r}\right)$$

σ is the interfacial tension, r the pore throat radius and θ the contact angle between drilling and formation fluid. Water based mud in contrast to oil based mud will mostly overcome the capillary pressure of water-wet shales. Oil based mud will increase the capillary pressure, resulting in no invasion of drilling fluids (Amoco n.d.).

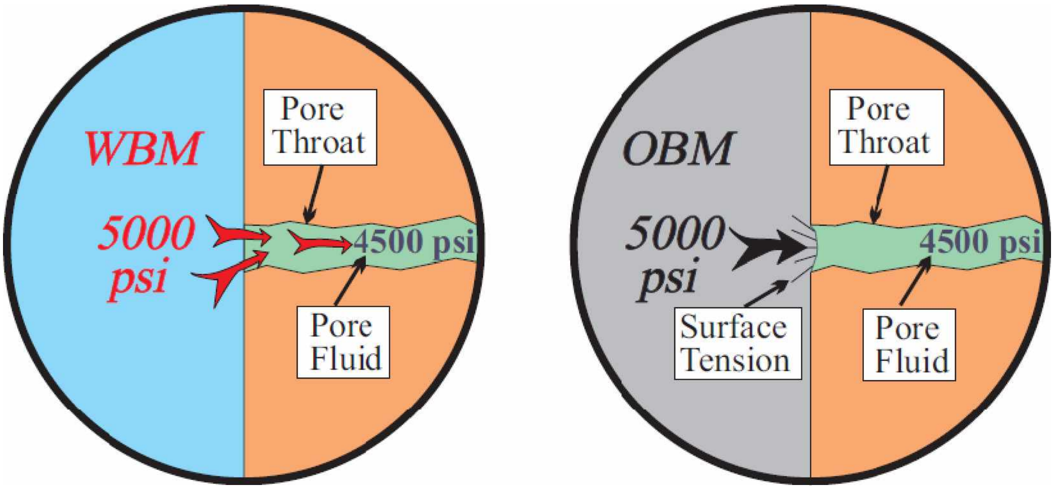


Figure 16: Schematic illustration of water based mud compared with oil based mud, regarding the different capillary pressures (Amoco n.d.)

In addition, if the salinity concentration (activity) between both fluids is imbalanced, shale instabilities due to osmosis occur. This is a phenomenon where water from a lower salinity fluid gets transported to a fluid with higher salinity, through a semi-permeable layer. So, if the salinity of the drilling fluid is lower than the formation fluids, water will flow into the shale formation and thereby increase the pore pressure and plastic behavior. As a result, the stability of the shale gets reduced. On the other hand, if the pore water gets transported into the drilling fluid, the formation will get dehydrated and brittle. This increases the hoop stress and thereby the chance of shear failure. Hence, monitoring the water phase salinity of OBMs and the salinity of WBM is of major importance during drilling though water sensitive formations.

The next stability influencing factor is pressure diffusion. It is the near wellbore pressure change with time, as drilling fluid invades the shale and compresses the pore fluid. A steady-state pressure distribution is reached as soon as the pressure inside the borehole wall stays constant. This pressure diffusion can be enhanced by surge effects during running a pipe in the wellbore, compressing the drilling fluid (Lal 1999).

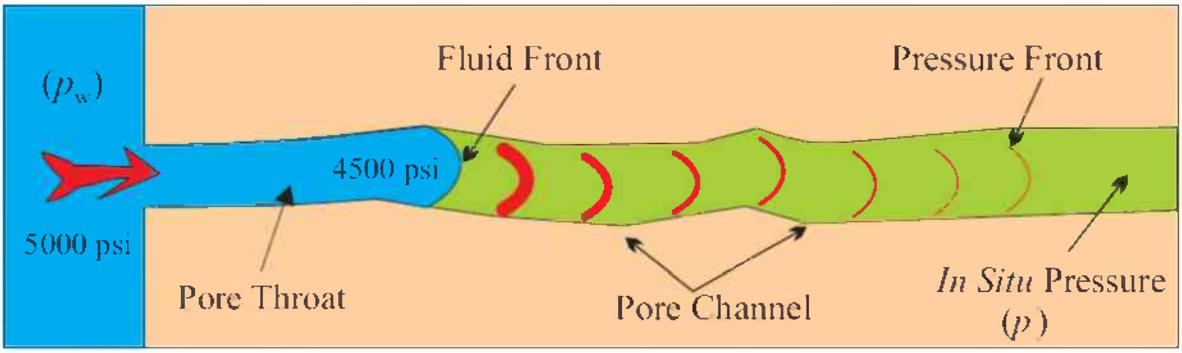


Figure 17: Traveling distance of the pressure front depends on the pressure differences and the permeability of the shale (Amoco n.d.)

Generally, if water enters the shale formation, the swelling pressure and the weakening of the shale are related to the clay minerals. Shales with a high concentration of negatively charged ions generate more swelling and weaknesses. These processes destroy the cement bond between the clay plates and the shale gets pushed into the wellbore. On the other hand, brittle shales react very sensitive on pressure alternation. The flexing motion caused by the pressure alternation will weaken the thin shale plates.

2.4.4 Man-made Issues

Man-made wellbore problems can be divided into:

- Lack of pre-planning
- Drilling practices

A lack of proper well planning can cause major wellbore instabilities. The main focus should be on the selection of the BHA design, mud system, casing setting depths, drilling process and wellbore inclination and azimuth with respect to the in-situ stress field and faulted zones (Osisanya 2011).

Insufficient, or lack of good drilling practices will influence the wellbore stability as well. Such as poor hole cleaning will result in cuttings accumulation between the drillstring and the borehole wall. This increases the annular pressure losses and as a result the ECD. Furthermore, high surge or swab pressures have to be avoided during running in or out the open hole section. Drillstring vibrations need to be observed as well. They influence the wellbore stability and are divided into three types (Osisanya 2011):

- axial
- torsional
- lateral

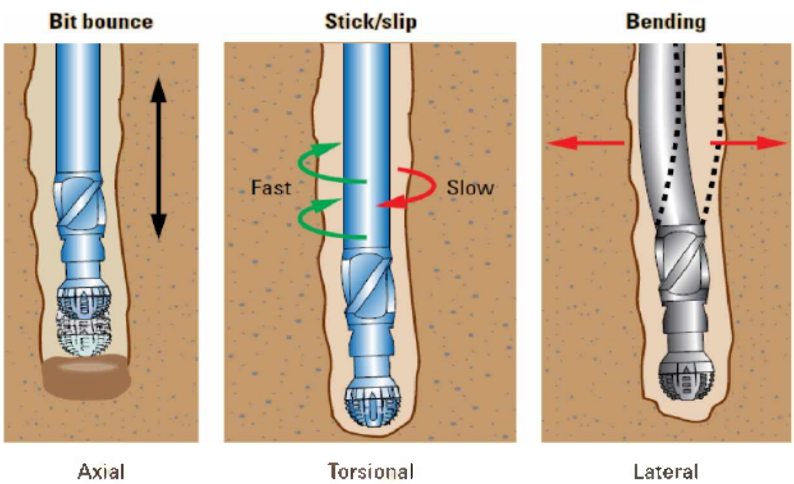


Figure 18: Three major types of vibrations resulting from the interplay of the borehole deviation, BHA and drill string design, bit type and hole condition (Osisanya 1999)

3 Data Analyses and Evaluation

This chapter comprises the data analyses and evaluation, to come up with comprehensive information to elaborate well planning recommendations for the development of fields.

3.1 Data Acquisition

For the Campos basin, many of the general geological and drilling documents are obtainable. Nevertheless, recaps and daily drilling reports are of particular importance to analyse wellbore instabilities in this area. Thus, data from four different exploration wells are evaluated. Those wells were drilled in the shallow water of the Santos basin and the deep water of the Campos and Espírito Santo basin. The Santos and the Espírito Santo basin are attached to the Campos basin and located southwest and northwest of it (**Fig. 3**). Beside the analyses of the wellbore instability problems, the geological areas of concern as well as the pore and fracture pressures have to be elaborated. All of that work is done for the shallow and deep water area of the Campos basin.

3.2 Drilling Recaps and Daily Reports Evaluation

Two EOWRs as well as daily drilling reports are available of Wintershall´s shallow water wells drilled in the Santos basin block BM-S-14. The exploration well 1-WINT-001-SPS was drilled with a semi-submersible drilling unit in a water depth of 235 meter. The target depth was 4,821 meter, reached with a 7” liner. The second exploration well 1-WINT-2-RJS was drilled in a water depth of 138 meter. The target was reached at 3,575 meter. Two other recaps are available from wells in the Espírito Santo as wells as Campos basin, both drilled in deep water between 2,465 and 2,887 meter.

3.2.1 Wellbore Stability Issues

A lot of different wellbore instabilities were encountered during the drilling process. The following table on the next page (**Tab. 2.**) lists all of them.

Table 2: Wellbore instabilities encounter during drilling in the Campos, Santos and Espírito Santo basin

Wellbore Stability Issues			
Well Name	Depth RKB [m]	Lithology/Formation	Problems/Indicators
1-WINT-001-SPS	2,100	Limestones interlayered with course sandstones, Santos formation	Tight spot, 70 klbs overpull, wipe through
WINT-001-SPS	611-2,214	Limestones interlayered with claystones in the upper part and courser sandstones in the lower part, Marambaia, Iguape and Santos formation	Washouts, up to 32" in the 17-1/2" section
1-WINT-001-SPS	4,085-4,095	Shales, siltstones and fine-grained sandstones, Itajaí formation	Tight spot, 10 klbs drag
1-WINT-001-SPS	4,640	Shales, Itajaí formation	Tight spot, jar free with 50 klbs up and down
1-WINT-001-SPS	4,620-4,686	Shales, Itajaí formation	Tight spot, 40 to 60 klbs drag
1-WINT-001-SPS	4,600-4,819	Shales and course to medium grained poorly sorted sandstones, Itajaí formation	Very gauge tight hole
1-WINT-2-RJS	2,393-2,782	Conglomerates, sandstones, siltstones with some interlayered volcanic rocks, Santos formation	Severe stick and slips
1-WINT-2-RJS	2,430	Sandstone, Santos formation	String vibrations
1-WINT-2-RJS	2,570	Volcanic rocks, Santos formation	String vibrations
1-WINT-2-RJS	2,870	Sandstones, Santos formation	High shocks and lateral vibrations
1-WINT-2-RJS	3,130	Volcanic rocks, Itajaí formation	Severe stick and slips
1-WINT-2-RJS	3,150	Volcanic rocks, Itajaí formation	400 psi pressure drop, stuck pipe
1-WINT-2-RJS	3,160	Volcanic rocks. Itajaí formation	Loss of 350 psi
1-WINT-2-RJS	3,200	Volcanic rocks and claystones, Itajaí formation	Pressure drop and increase of 100 psi
1-WINT-2-RJS	3,200-3,470	Volcanic rocks from 3,200 to 3,330 and sandstones from 3,330 to 3,470, Itajaí formation	Severe stick and slips
1-ESSO-2-ESS	3,031	Shales	Tight spot
1-ESSO-2-ESS	4,145-4,242	Shales	Ream undergauge hole
1-ESSO-2-ESS	3,688-5,100	Sandstones with shales	High vibrations and stick and slips
1-SHELL-14-RJS	3,680-4,199	Claystones with layers of Micaceous shales and rare pyrite, Campos formation	Mud losses
1-SHELL-14-RJS	3,680-4,199	Claystones with layers of Micaceous shales and rare pyrite, Campos formation	Washouts
1-SHELL-14-RJS	4,206-4,208	Cenomanian Claystones and sandstones, Campos formation	180 bbl/h mud losses
1-SHELL-14-RJS	4,199-4,612	Cenomanian claystones and sandstones, Campos formation	Washouts
1-SHELL-14-RJS	4,278	Cenomanian claystones and sandstones, Campos formation	Hole closure

While comparing the different wellbore problems in those three basins, four major instability types were observed:

- Tight hole
- Vibrations, especially stick and slip
- Washouts
- Mud Losses

Fig. 19. shows the frequency of encountered wellbore problems of all four wells.

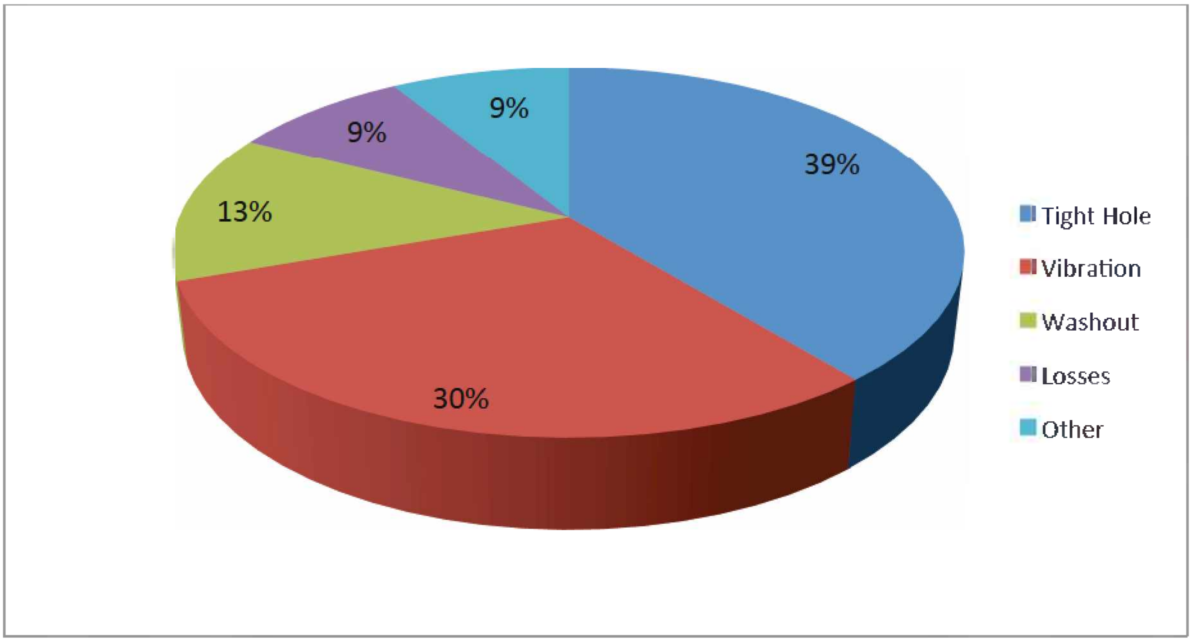


Figure 19: Frequency of encountered wellbore problems

As it is seen above, the greater part of the problems are tight holes and vibrations. They account for 69% of all problems. Washouts and losses are responsible for 22% of all encountered problems.

The following figure has been created to correlate the listed problems between the basins (**Fig. 20**). In particular, shale formations below 3,000 meter show the same behavior over all basins.

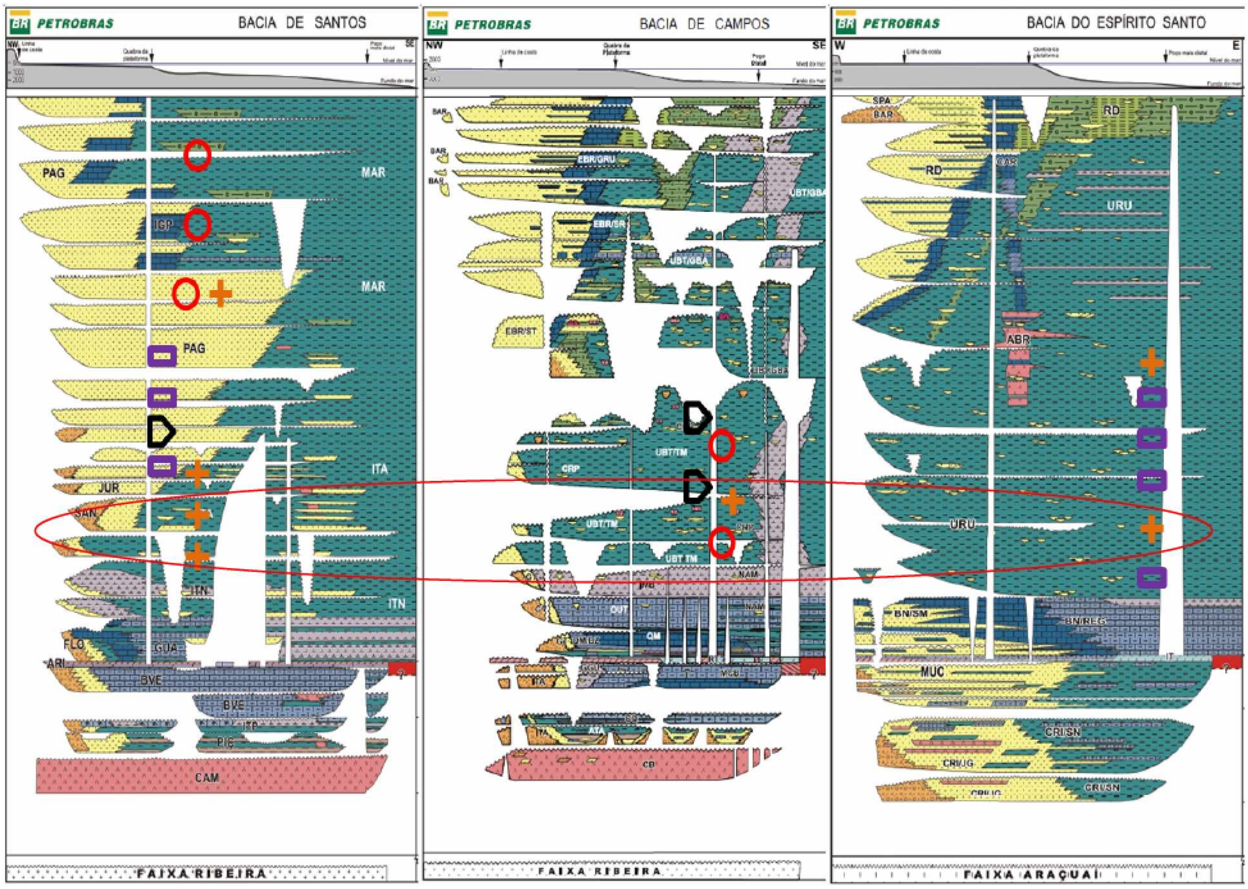


Figure 20: Indication of wellbore instabilities of the Santos, Campos and Espírito Santo basin (modified from France et al. 2007, Moreira et al. 2007 and Winter et al. 2007)

Wellbore problem key:

Tight Hole

Vibration

Washout

Losses

As seen above, the conductor and surface section of all four wells show nearly no instabilities. This is not only related to the stable formations and good drilling processes, the exposure time of the mud to the formation is also very short.

Hole closure problems were encountered in all three basins, especially in shale formations below 3,000 meter. The red cycle in **Fig. 20.** indicates this area. However, the Cenomanian claystones and sandstones of the Campos formation show hole closure problems as well, compared with severe mud losses of 180 bbr/hr and washouts. Other washouts were recognized in the well 1-WINT-001-SPS. The whole 17-1/2” section, consisting of limestone formations interlayered with claystones for the upper part and courser sandstones for the lower part, got washed out up to 32”. Furthermore, the exploration well next to 1-WINT-001-SPS had mud losses in the volcanic rocks of Santos´ Itajaí formation, which led to a stuck pipe. The fourth major problem during drilling in those basins was vibration. Mainly stick and slip vibrations occurred and reduced the ROP and thereby increased the drilling costs. Beside ROP and drilling costs, vibrations influence the wellbore stability as well by destabilizing the wellbore wall. The following figure illustrates the depth where problems were encountered (**Fig. 21.**). Only washouts appeared in shallow depth. All other problems occurred in depth below 2000 meter.

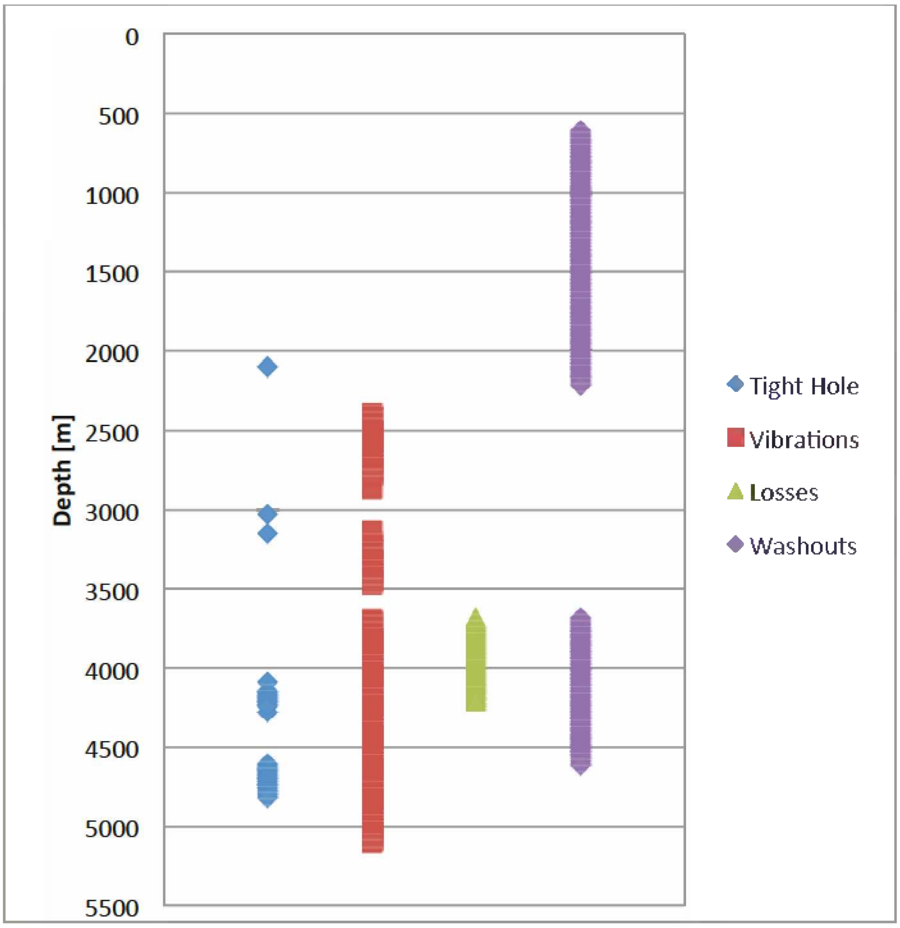


Figure 21: Depth of encountered wellbore problems

3.2.2 Mud Systems

Tab. 3. lists all used mud systems. Special focuses are on sections where clay swelling, losses or washouts were encountered.

Table 3: Mud system comparison of wells drilled in the Campos, Santos and Espírito Santo basin

Mud System Comparison				
Well Name	Depth RKB [m]	Section	Mud Type	Mud Density
1-WINT-001-SPS	260-322	36"	Seawater / Gel Sweeps / Kill mud	Hi Vis Sweeps 8.7 ppg / Kill Mud 12.5 ppg / Pad Mud 9.7 ppg
1-WINT-001-SPS	322-625	26"	Seawater / Gel Sweeps / Kill mud	Hi Vis Sweeps 8.7 ppg / Kill Mud 12.5 ppg / Pad Mud 10 ppg
1-WINT-001-SPS	625-2,228	17-1/2"	Gel / Seawater / Starch	8.6 - 9.5
1-WINT-001-SPS	2,228-4,380	12-1/4"	WBM Clayseal - 12% NaCl / 3% KCL / Bridging Agents	9.2 - 10.1
1-WINT-001-SPS	4,380-4,821	8-1/2"	WBM Clayseal - 12% NaCl / 3% KCL / Bridging Agents	13.0 ppg - reduced to 11.8 ppg before running liner
1-WINT-2-RJS	162.5-234	36"	Seawater / Sweeps	No information
1-WINT-2-RJS	234-517	26"	Seawater / Sweeps	No information
1-WINT-2-RJS	517-1,393	17-1/2"	Sea water - gel / Sweeps	8.8 - 9.5 ppg
1-WINT-2-RJS	1,393-2,838	12-1/4"	WBM / KCL - Polymer	9.4 - 10.0 ppg
1-WINT-2-RJS	2,838-3,706	8-1/2"	WBM / KCL - Polymer	10.1 - 11.0 ppg
1-ESSO-2-ESS	2,465-2,511	36"	Seawater / Sweeps	8.5 ppg
1-ESSO-2-ESS	2,511-3,688	17-1/2"	Seawater / Sweeps	8.5 ppg / Hole displacement 11 ppg
1-ESSO-2-ESS	3,688-5,100	12-1/4"	WBM / KCL - Polymer	9.1 - 9.15 ppg
1-SHELL-14-RJS	2,887-2,973	36"	Seawater	No information
1-SHELL-14-RJS	2,973-3,668	17-1/2"	Seawater / Sweeps	No information
1-SHELL-14-RJS	3,668-4,199	12-1/4"	WBM / LCM pills	No information
1-SHELL-14-RJS	4,199-4,610	8-1/2"	WBM / LCM pills	9.0 ppg
1-SHELL-14-RJS	4,610-5,226	6"	WBM / DuoVis composition	9.0 ppg

All four wells use nearly the same mud system. The first two to three sections where drilled with seawater and high viscous sweeps to clean the hole. After the riser was installed the mud system changed to water based mud with bridging agents and KCL as inhibitor. LCM pills were pumped during mud losses.

3.2.3 Casing Setting Depths

The casing setting depths differ widely between the wells. That can be seen between the two deep water wells of the Campos and Espírito Santo basin (**Fig. 22.**). Those setting depths are of major importance regarding the wellbore stability. The following table lists all casing setting depths of the four wells.

Table 4: Casing setting depths comparison

Casing Setting Depths			
Name	Depth [m]	Section	Formation
1-WINT-2-RJS	162.5	Water	
	221	30"	Marambaia
	508	20"	Marambaia
	1,380	13-3/8"	Iguape
	2,831	9-5/8"	Santos
	3,700	8-1/2" OH	Itajaí
1-WINT-001-SPS	260	Water	
	308	30"	Marambaia
	611	20"	Marambaia
	2,214	13-3/8"	Santos
	4,369	9-5/8"	Itajaí Shale
	4,819	7"	Itajaí
1-ESSO-2-ESS	2,465	Water	
	2,511	30"	no information
	3,688	13-3/8"	no information
	5,100	12-1/4" OH	no information
1-SHELL-14-RJS	2,887	Water	
	2,973	36"	no information
	3,668	13-3/8"	no information
	4,199	9-5/8"	no information
	4,610	7"	no information
	5,226	6" OH	Macaé

To reach TD without drilling related lost times and wellbore instabilities, a compromise between mud/formation exposure times, costs and pore to fracture pressure margins have to be made during the planning phase.

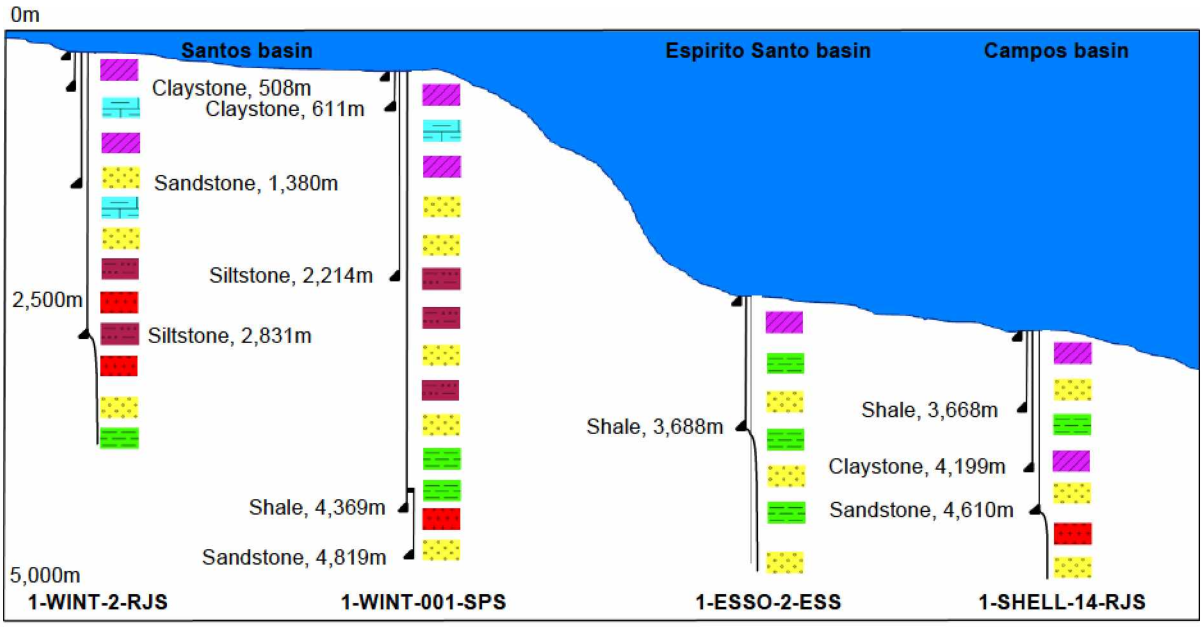
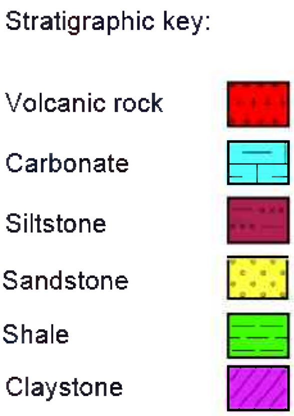


Figure 22: Casing setting depths of all four wells. The water depths range from 162.5 to 2,887 meter



3.3 Mud Systems Comparison

The mud systems used (Chapter 3.2.2 Mud Systems) for drilling the wells in the basins had severe problems with swelling shales, washouts, vibrations and losses. Improper mud selections cause wellbore instabilities, which may lead to not reaching the target. Thus, investigating mud systems to improve the performance is of major interest.

The main tasks of drilling fluids are (Skalle 2011):

- Remove cuttings from the drill bit and bring them to surface (formation information)
- Maintain a stable wellbore through inhibitions
- Cool and lubricate the bit and drill string
- Avoid losses
- Overcome formation pressure
- Build good quality filter cake across porous zones

He et al. published 2014 a paper about shale-fluid interaction and drilling fluid design. This interaction causes different shale behaviors like swelling, fracturing or dispersion. However, those behaviors are influenced by the shale composition. For shales with high smectite content and laminated structures, swelling will be the dominant mechanism (**Fig. 31.**). On the other hand, thermal alteration leads to high illite and low smectite content. The high illite content changes the shale properties to a very brittle structure (**Fig. 33.**).

Figure 23: Brittle wellbore behavior (Batchelor & Marks 2010)

With appropriate inhibited WBM or by using OBM the interaction between the fluid and the shale can be minimized. **Appendix B** shows shales with high smectite content in interaction with different drilling fluids. Those shales have a high tendency for dispersion and swelling. The second figure of **Appendix B** shows strong laminated shales with high illite contents of 10-17%. They are characterised by low dispersion tendencies, but show high abilities to fracture in interaction with fluids. For both shale types, WBM with KCL/amine inhibition and OBM show the best results (He et al. 2014).

2009, Donham and Young published a paper about water based drilling fluid design in comparison with oil based fluids. They state that 'non-aqueous fluids are still universally recognized as being the most efficient fluid to drill with. This is primarily due to the absence of contact between the drilling formation and water, and due to the inherent oil wetting and lubricity characteristics of the fluids'.

However, some OBMs are more expensive than WBMs and thereby not always a good choice for expected loss circulation zones. The break even point between higher mud costs and drilling time (drilling cost) savings has to be calculated during the planning phase. Furthermore, environmental issues and more complex cutting displacement procedures, regarding offshore developments, have to be considered as well.

Over the last years several different mud systems have been used in the Maromba area. Some of them are (Day 2014):

- KCL/glycol/polymer mud
- Dispersed mud
- Salt saturated mud
- Synthetic OBM

All of them have different limitations. Thus, a successful use of one fluid type for all different formation is not possible. KCL/glycol/polymer mud systems are used in shale and claystone formation. The inhibited system prevents rock/fluid interaction. Thus, the borehole is more likely to stay stable. Dispersed mud systems are used in boreholes, where high mud weights are required. Salt saturated mud systems are used for drilling through salt sections. Synthetic OBM systems have very good lubrication and low rock/fluid interaction characteristics.

For salt sections, as they are expected in the Maromba area, other wellbore stability issues and fluid systems have to be considered as well. Salt layers are known to creep or to form washouts by dissolution (**Fig. 24**). To counteract those behaviors, correctly formulated mud systems have to be used.

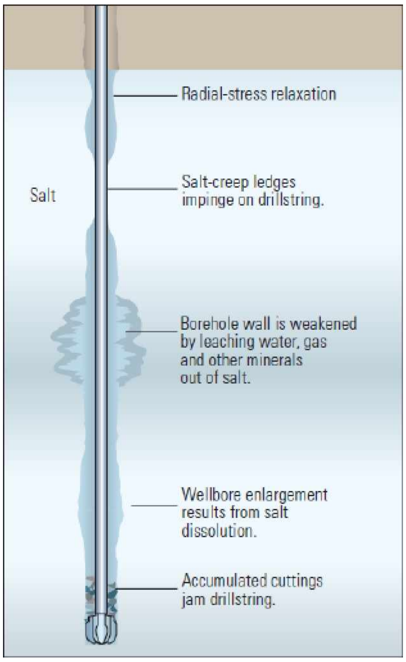


Figure 24: Potential wellbore stability problems during salt drilling (Clyde et al. 2005)

Undersaturated WBM or seawater based mud increases the ROP significantly, but can also lead to hole enlargements by dissolving the salt at the borehole wall. Nevertheless, seawater based mud systems offer high cost saving opportunities for the drilling process. On the other hand, salt saturated mud systems could result in slow ROP, bit balling and packoff issues (Clyde et al. 2005).

To drill salt saturated in high temperature salt layers, the mud should be oversaturated at surface. Moreover, salt in solution with the mud will precipitate during moving up the annulus based on the decreasing solubility with decreasing temperature. Those salt crystals will get removed by the shakers, leaving undersaturated mud to be recirculated.

To overcome those issues, salt has to be added on a continuous basin or the crystal structure of the precipitating salt has to be changed with additives like potassium ferrocyanide (do not use in wells with temperatures above 400 °C). Thus, new formed crystals (needle like structures smaller than the mesh size) are able to pass the screen of the shakers (Day 2014).

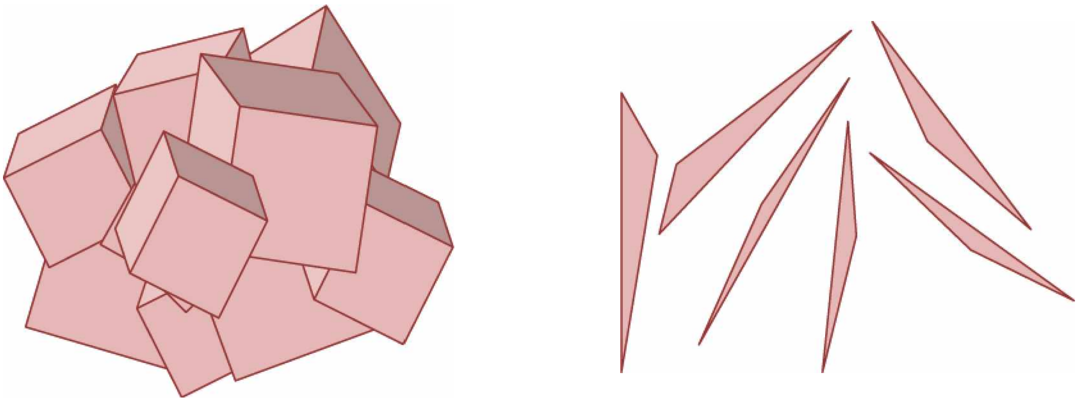


Figure 25: Normal salt structure on the left side. Potassium ferrocyanide treated salt structure on the right side.

3.4 Geological Areas of Concern

To establish proper wellbore stability recommendations, the next step is to identify geological areas of concern. This is done by creating a stratigraphic column for the shallow water and deep water geology, based on a 2-D seismic (**Fig. 6.**), the stratigraphic map of the Campos basin (**Appendix A**) and the geological descriptions of the recaps.

3.4.1 Shallow Water Issues

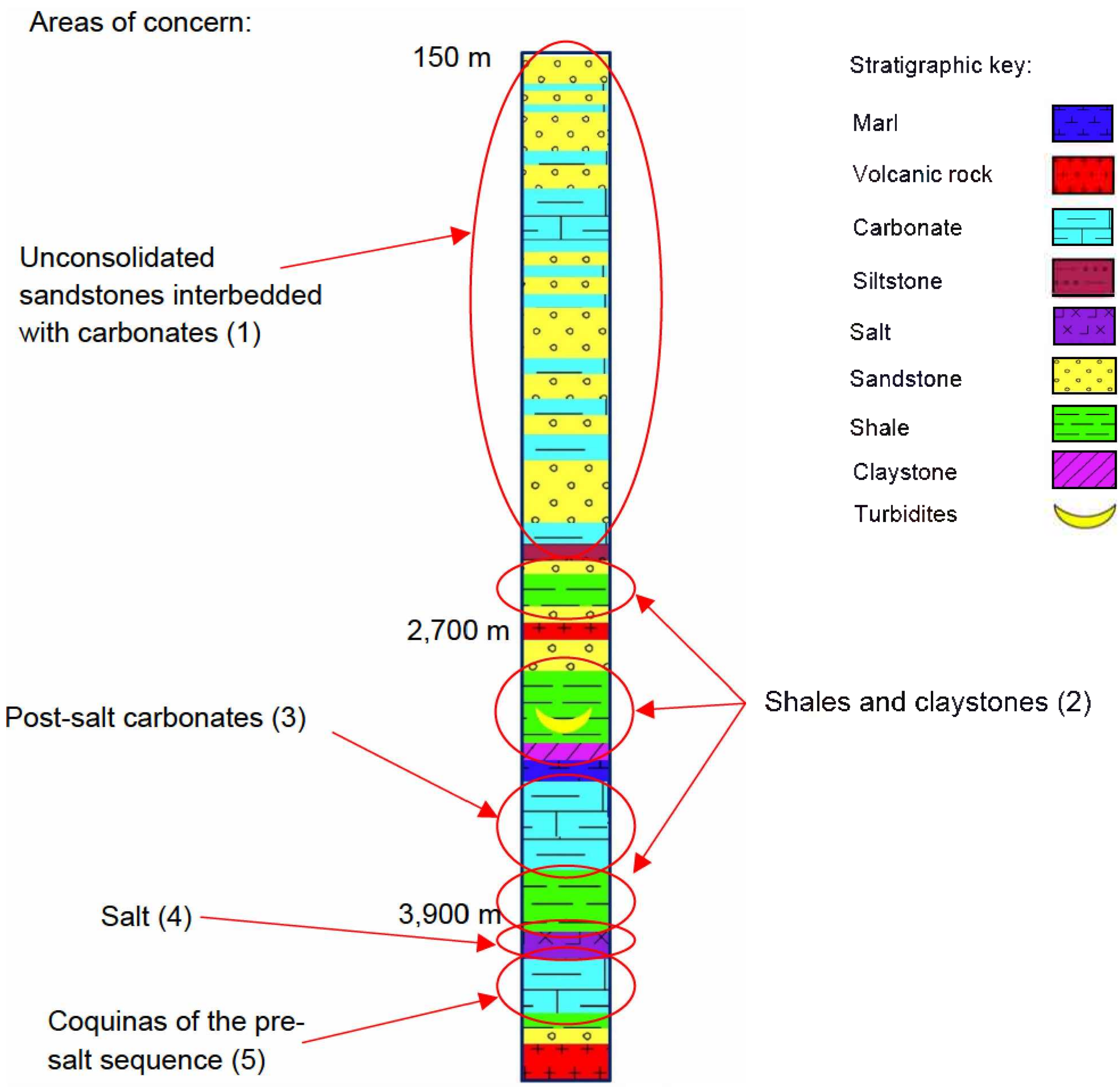


Figure 26: Stratigraphic column of the shallow water geology, 150 meter below sea level

ad. 1.)

The upper part of the shallow water geology is assumed to be dominated by horizontal sequences of alternating sandstone and limestone layers. The sandstones are weak to moderate consolidated and consist mainly of quartz grains. The limestones include fractures and vugs as well as loose fossils like shells, corals or foraminifers.

The shallow water well 1-WINT-001-SPS and 1-WINT-2-RJS of the Santos basin show similar lithologies. One of those wells had severe washouts of up to 32” in the 17-1/2” section.

Schematic illustration of the wellbore section:

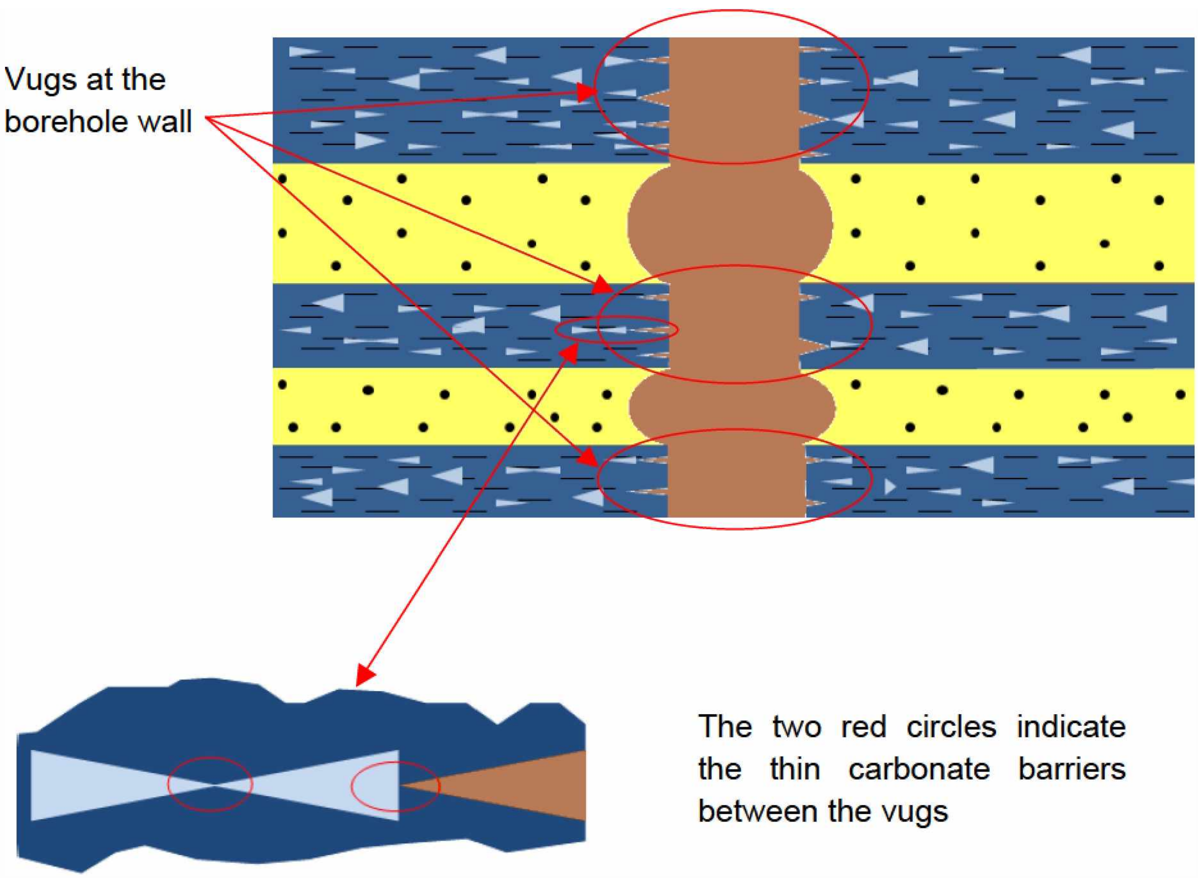


Figure 27: Wellbore instabilities of sandstones interbedded in vuggy fractured limestone layers.

As highlighted above, the vugs of the limestone layers as well as the unconsolidated grains of the sandstones have potential wellbore instabilities. To avoid the dissolution of the limestone (lime barrier between the vugs) and thereby the further opening and interconnecting of vugs, correct mud chemistry has to be elaborated.

Another major issue are the unconsolidated sandstone layers. In this section the mud has to build up a good filter cake and the fluid velocity has to be low enough to minimize the tendency to mobilize grains and to prevent washouts. Hence, hydraulic as well as chemical parameters need to be engineered.

ad. 2.)

Shales are formed from clay minerals and silt-sized particles. The types of clay minerals have to be known to treat the shales in an appropriate way. Clay minerals have a large specific surface area, due to their small mineral size and sandwich-like structure. The four different mineral types are smectite, illite, chlorite and kaolinite. All of them absorb cations and water to their external surfaces. The difference between smectite and the other three types is that smectite, in addition, absorbs water and cations with its internal surfaces of the crystalline structure (Daemen and Schultz 1995). Due to that fact, shales with high smectite content are much more water sensitive and tend to be very ductile. On the other hand, shales with high illite content react more brittle. Both shales have to be treated in another way. Dypvik as well as Browne et al. investigated smectite/illite compositions behavior of clays with respect to temperature. The charts below illustrate the increasing illite content with increasing temperature. The reason is the temperature related smectite to illite transformation. Above 100 °C more than 70% of the clay minerals consist of illite.

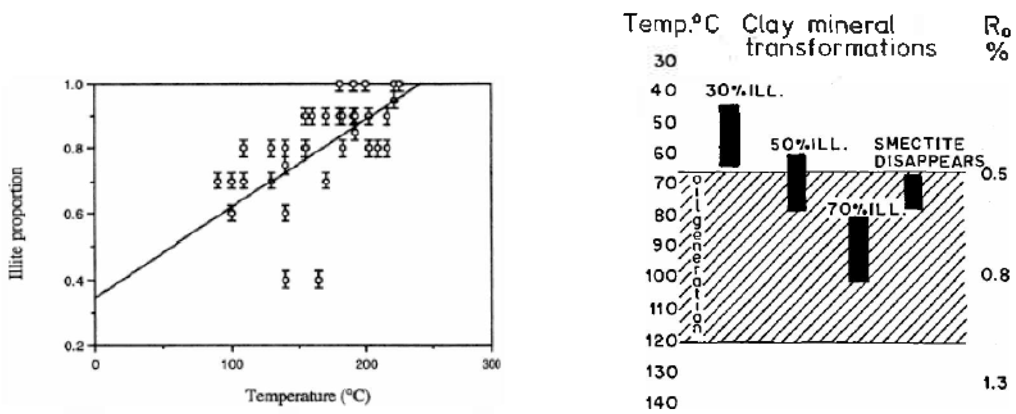


Figure 28: The left chart shows the Illite proportion vs. temperature (Browne et al. n.d.). The other side illustrates the illite content vs. temperature of ten wells from the North Sea (Dypvik 1983)

The shale layers of Campos´ shallow water area are assumed to be in depth between 2,500 and 3,900 meter.

Cardoson and Hamza published 2014 a paper about the heat flow of the Campos basin. The paper provides seafloor temperatures and target depth temperatures from 76 oil wells as well as a geothermal gradient map.

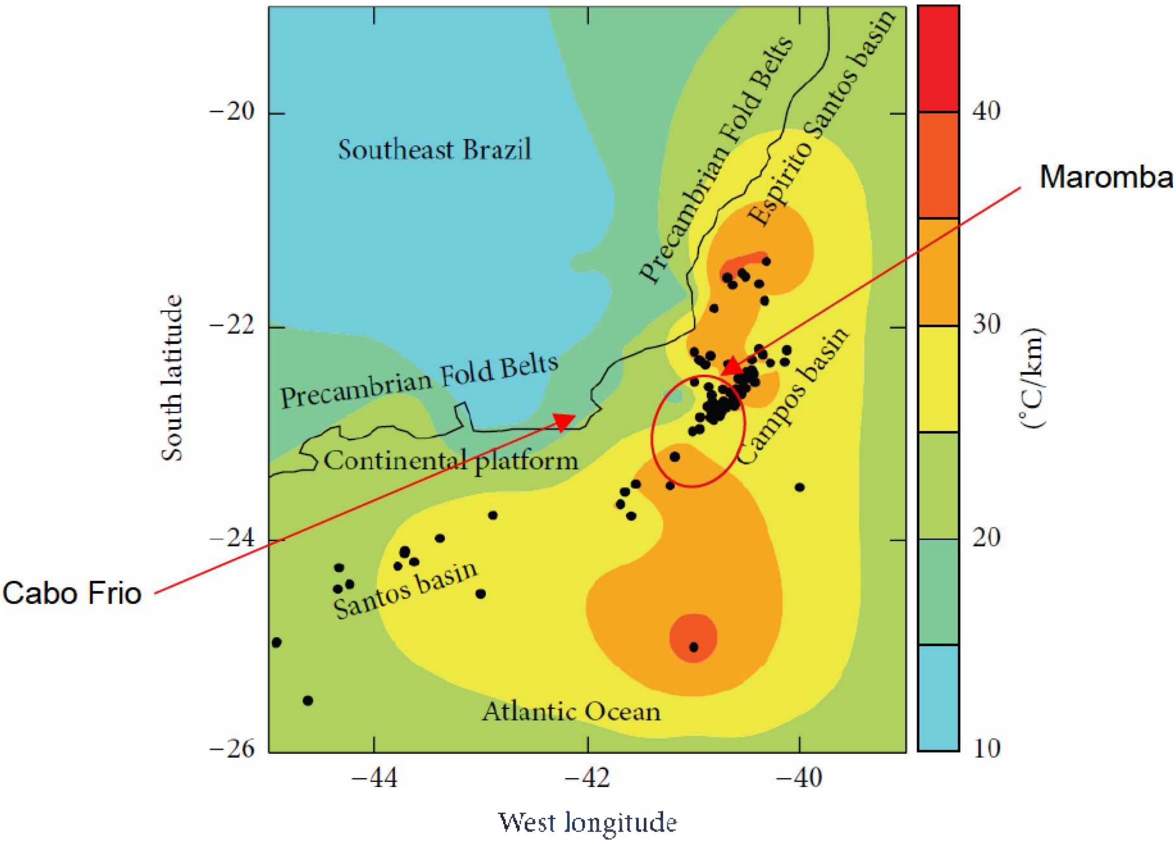


Figure 29: Geothermal gradient map of the Campos basin (Cardoso and Hamza 2014)

With the information provided from Cadoso and Hamza the subsurface temperatures are calculated. For 150 meter of water depth a sea floor temperature of 14.7 °C is taken, based on the data shown in **Appendix C**. **Fig. 29.** shows, that the geothermal gradient for the Maromba area is between 25 and 35°C/km. Thus, an average geothermal gradient of 30 °C/km is assumed.

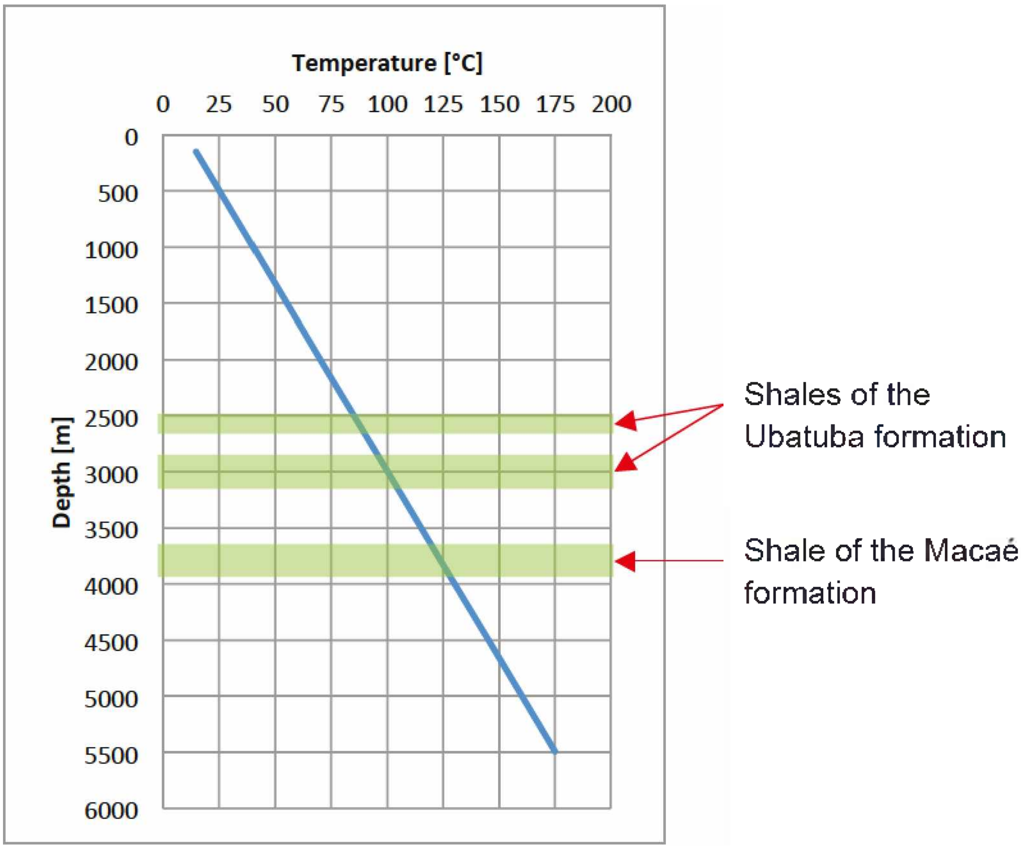


Figure 30: Temperature vs. depth plot of the Maromba area, calculated with data based on the publication of Cardoso and Hamza 2014

The first shale layer at 2,500 meter has a temperature around 80 °C. Parts of the smectite minerals will already be converted into illite. Thus, the shale is expected to behave ductile as well as brittle. The other two shale layers, which have a temperature above 100 °C, are expected to be hard and brittle with micro-fractures and low water content. Smectite minerals will already be disappeared. The following two figures show the different shale behaviors.

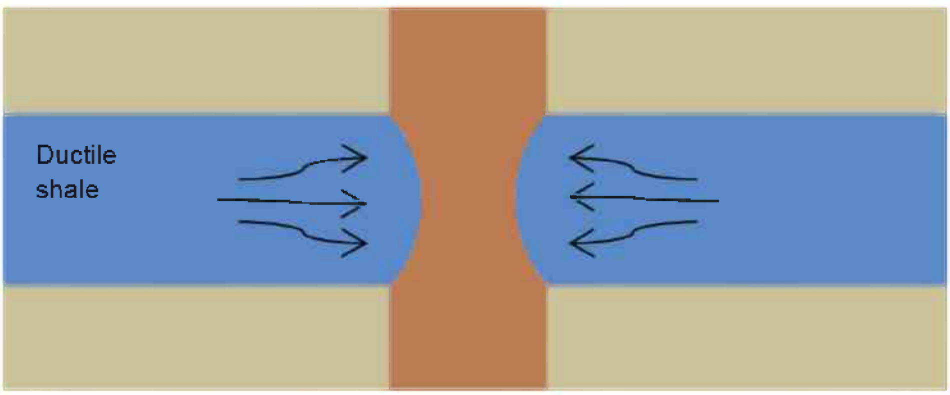


Figure 31: Schematic illustration of ductile shale behavior in a wellbore

Ductile shale formations will narrow the hole, if the chemical balance does not meet the needs. This leads to high torque and drag, poor hole cleaning, pipe sticking, difficulty of casing landing or stuck equipment. Proper mud weight and inhibition need to be applied to reach the target through shale layers.

Brittle shales tend to form cavings, which are rock fragments from the wellbore. This is particularly caused by mud pressure alternation, which is present during operations like tripping or switching the mud pumps on and off. The flexing motion weakens the thin shale layers and thereby cavings are formed. An increase of the mud weight will result in greater flexing motion of the thin shale layers.

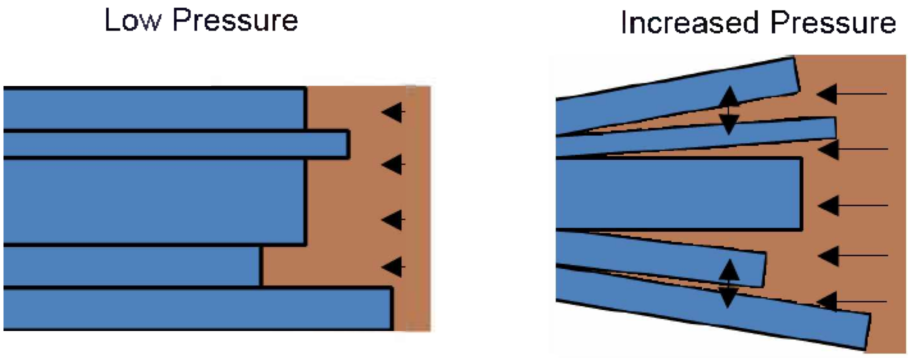


Figure 32: Brittle shale flexing behavior during low and high mud pressures

Normally the cavings get transported to surface. Nevertheless, the hole enlargement (reduction of annular velocity) could result in a drillstring packoff. Caving analysis is of major importance to manage wellbore instabilities and to determine the optimal remedial action in real time. Caving rates as well as the appearance have to be monitored. The caving appearance indicates which shale problem is present.

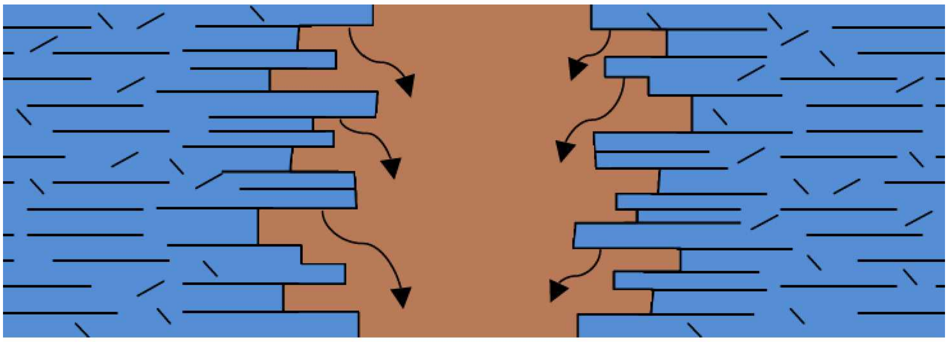


Figure 33: Schematic illustration of unsupported shale ledges of brittle shales

Natural fractured cavings have flat and parallel faces, but the bedding direction is not parallel to it. On the other hand, weak plane cavings show bedding directions parallel to the faces. Splintered cavings appear as concave, flat, slightly twisted and are planar in structure (Osisanya 2011). They indicate pressured shale instabilities. Raising the mud weight and reducing the ROP are good remedial actions for pressured shales. However, raising the mud weight may promote an unstable borehole (as indicated in **Fig. 32.**).

Figure 34: Splintered cavings (Kumar et al. 2012)

Angular cavings have a rough surface structure with curved faces. They are formed by stress-related borehole breakouts (Osisanya 2012).

Figure 35: Larger angular cavings (Batchelor & Marks 2010)

ad. 3. and 5.)

The lower part of the post-salt carbonate section is represented by the Macaé group. This group consists of the Goitacas, Quissamã, Outeiro, Imbetiba and Namorado formation. They are of the Albian-Cenomanian age and dominated by shallow marine carbonates. Within the Maromba area the Macaé group consists of the Outeiro formation in the upper part and the Quissamã formation in the lower part (**Fig. 6**). The Outeiro formation is characterized by limestones with thick banks of calcarenites, oolites and oncolites. The Quissamã formation consists of dolomites and limestones. Those dolomites have a complex system of pores, vugs, channels, breccias and caverns (Clemente 2013 and Winter et al. 2007).

The pre-salt carbonates of the Maromba area are represented by the middle part of the Lagoa Feia group. This part consists mainly of porous limestones, which are made of coquinas of bivalves (Clemente 2013). The coquina carbonates are one of the most important sub-salt reservoirs.

Figure 36: Coquina from the Anastasia formation of Florida, USA (John n.d.)

Due to the explained characteristics of the pre- and post-salt carbonates, major mud losses could be present within those formations.

ad. 4.)

The uppermost part of the Lagoa Feia group is the Retiro formation. It represents the salt section and is made of anhydrite and halite (Ranger et al. 1994 and Winter et al. 2007). Both are evaporates and were formed during the rifting phase of the Gondwana supercontinent. Regarding the Maromba area, mainly halite with some layers of anhydrite is assumed to form the autochthonous salt section. Well known wellbore problems during salt drilling are salt movement as well as dissolution.

The creeping behavior is influenced by the thickness of the salt, formation temperature, mineralogy, water content, impurities and the differential stresses. Regarding the salt mineralogy, most mobile salts are chloride and sulphate salts, containing a considerable amount of water. On the other hand, halite moves very slow and anhydrite is known as immobile. Secondly, creep rates start to increase sharply for temperatures above approximately 100 °C (Barker et al. 1994 and Poiate et al. 2006).

For the Maromba area a salt temperature of above 125 °C is expected. By using the wrong drilling fluid system, BHA and casing design, the halite interlayered with immobile anhydrite could lead to hole enlargements. Those could result in point loading and stuck or fractured pipe.

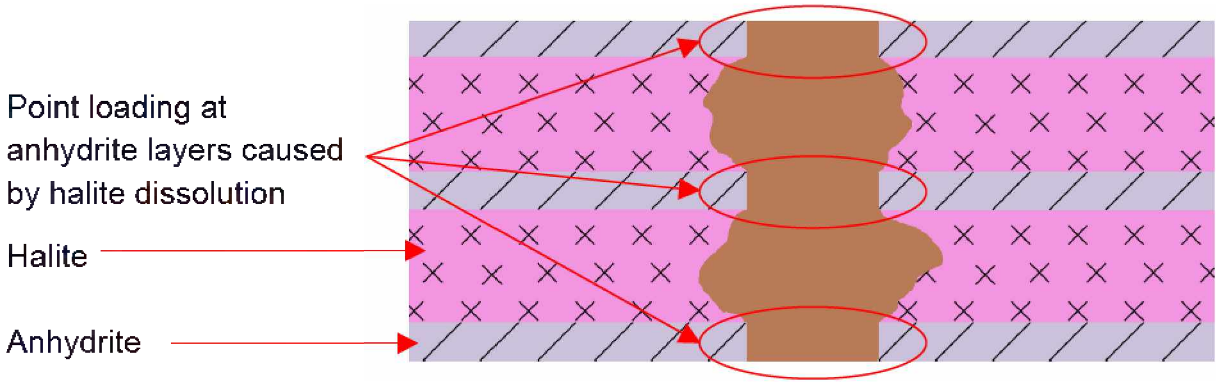


Figure 37: Illustration of potential point loading wellbore problems in the salt sequence

Another potential wellbore problem is caused by water trapped below the anhydrite within the halite layers. That situation has a strong influence on the halite. Creeping and plastic behavior is very likely to occur. The following figure illustrates that.

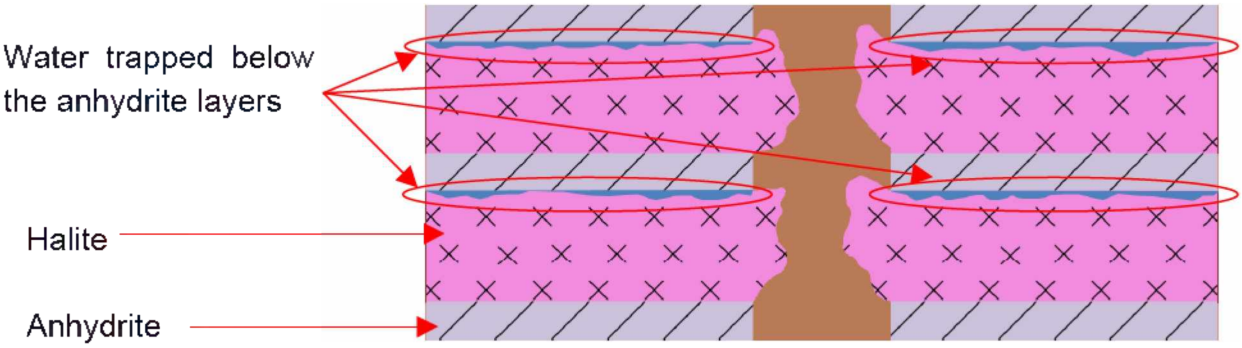


Figure 38: Water trapped below the anhydrite layers leads the halite to creep into the wellbore

3.4.2 Deep Water Issues

The stratigraphic map (**Appendix A**) and the recap of Shell´s deep water well of the Campos basin are used to elaborate the following stratigraphic column.

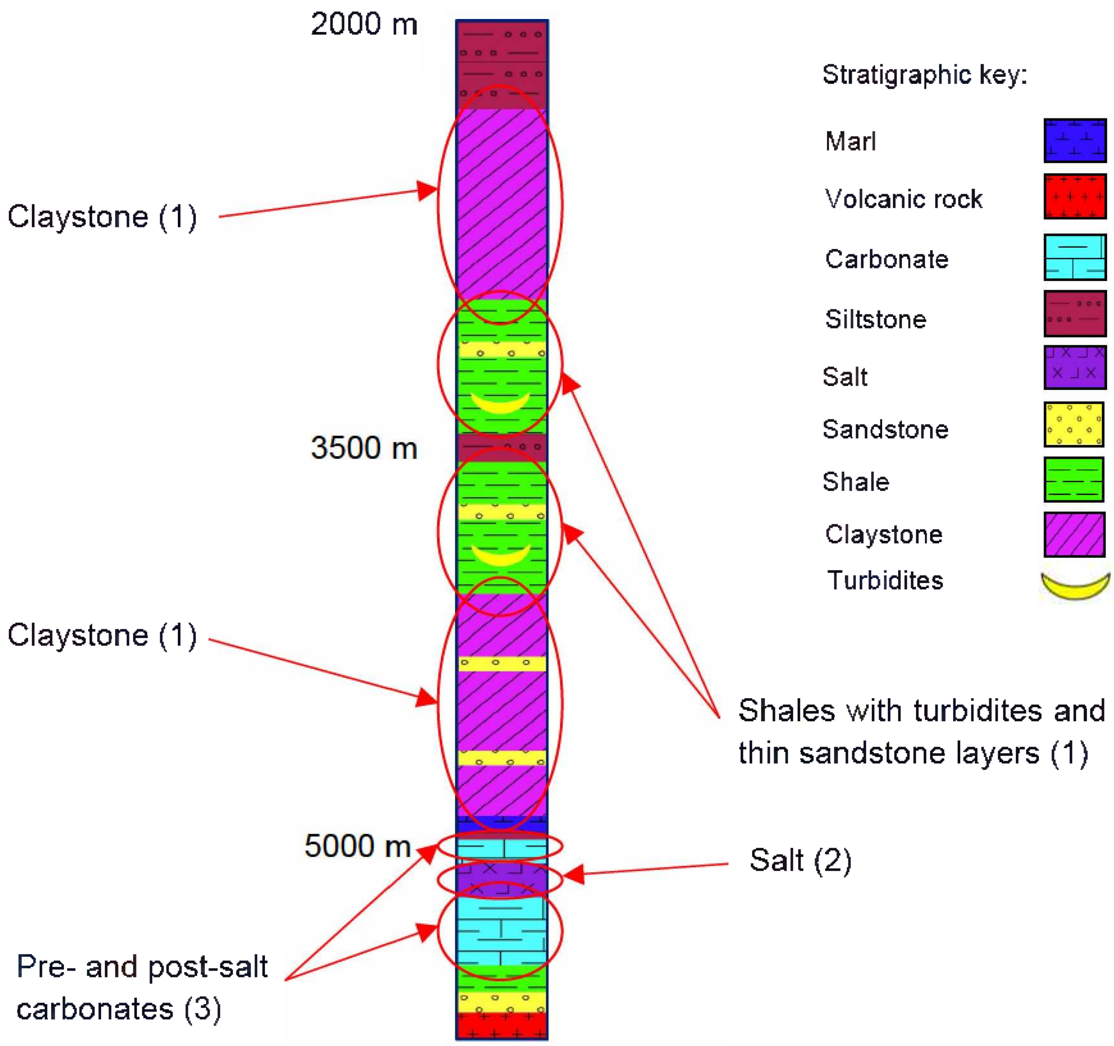


Figure 39: Stratigraphic column of the deep water geology, 2000 meter below sea level

Major differences in the geology and the thickness of the rock layers are observed by comparing the deep water stratigraphic column with the shallow water one. In particular, the post-salt sequence between 2,000 and 4,900 meter differs fundamentally. In contrast to the shallow water lithology a huge amount of claystones and shales are present. On the other hand, sandstone as wells as carbonate layers are nearly absent over the whole post-salt sequence, expect of some very thin sand layers and turbidites within the claystone and shale formations.

The deeper part of the lithology is very similar to the shallow water one. The salt layer is surrounded by carbonates with some sand and shale layers below.

ad. 1.)

The shale and claystone formations are assumed to be located below the uppermost siltstone, between 2,300 and 4,900 meter. To gather more formation behavior information, without having any samples, the formation temperature has to be calculated. This is done by using a seabed temperature of 4 °C and a geothermal gradient of 40 °C/km, based on the recap of 1-SHELL-14-RJS.

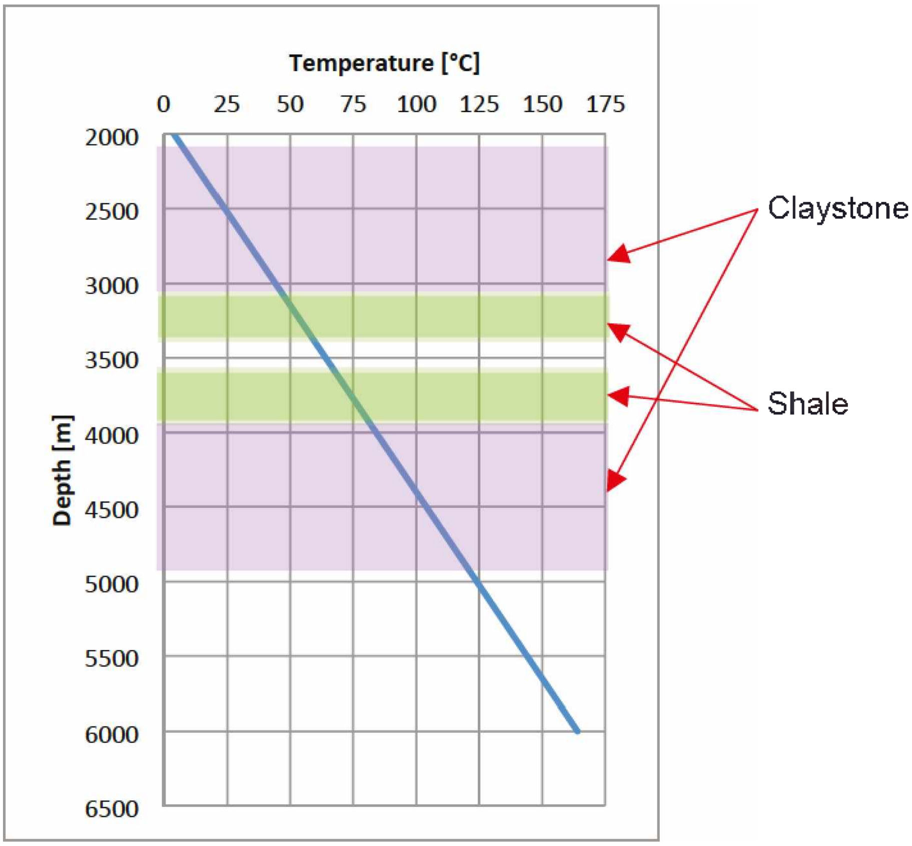


Figure 40: Temperature vs. depth plot of the deep water area, calculated with data based on the 1-SHELL-14-RJS recap

The upper shale and claystone formation are in a temperature window below 65 °C. Thus, a lot of smectite minerals will be present. A very ductile and water sensitive behavior is expected for that interval (**Fig. 31**). As it is already stated above, potential wellbore instabilities due to ductile formations will result in high torque and drag, poor hole cleaning, pipe sticking, difficulty of casing landing or stuck equipment.

The lower shale and claystone formation are in a temperature window between 70 and 120 °C. Those formations are expected to be ductile and brittle. With increasing depth the temperature will increase as well, which will lead to a more brittle and less ductile behavior (**Fig. 33**). Potential wellbore instabilities are cavings and hole enlargement, which could lead to low annular velocities and a packoff of the drillstring.

2. and 3.)

The salt layers as well as the surrounding pre- and post-salt carbonates are expected to have the same characteristics as the similar shallow water formations. The explanation is stated at the previous pages chapter 3.4.1 Shallow Water Issues.

3.5 Pore and Fracture Pressure

To come up with proper casing setting depths for the shallow and deep water area, the pore and fracture pressures have to be acquired.

3.5.1 Shallow Water Area

The following figure shows the pore and fracture pressures of the shallow water area. The plot is created with the aid of Wintershall´s shallow water wells from the Santos basin. The green triangles and the blue diamonds indicate the pore pressures, the red squares show the leak off pressures and the purple crosses the fracture pressures of those two wells.

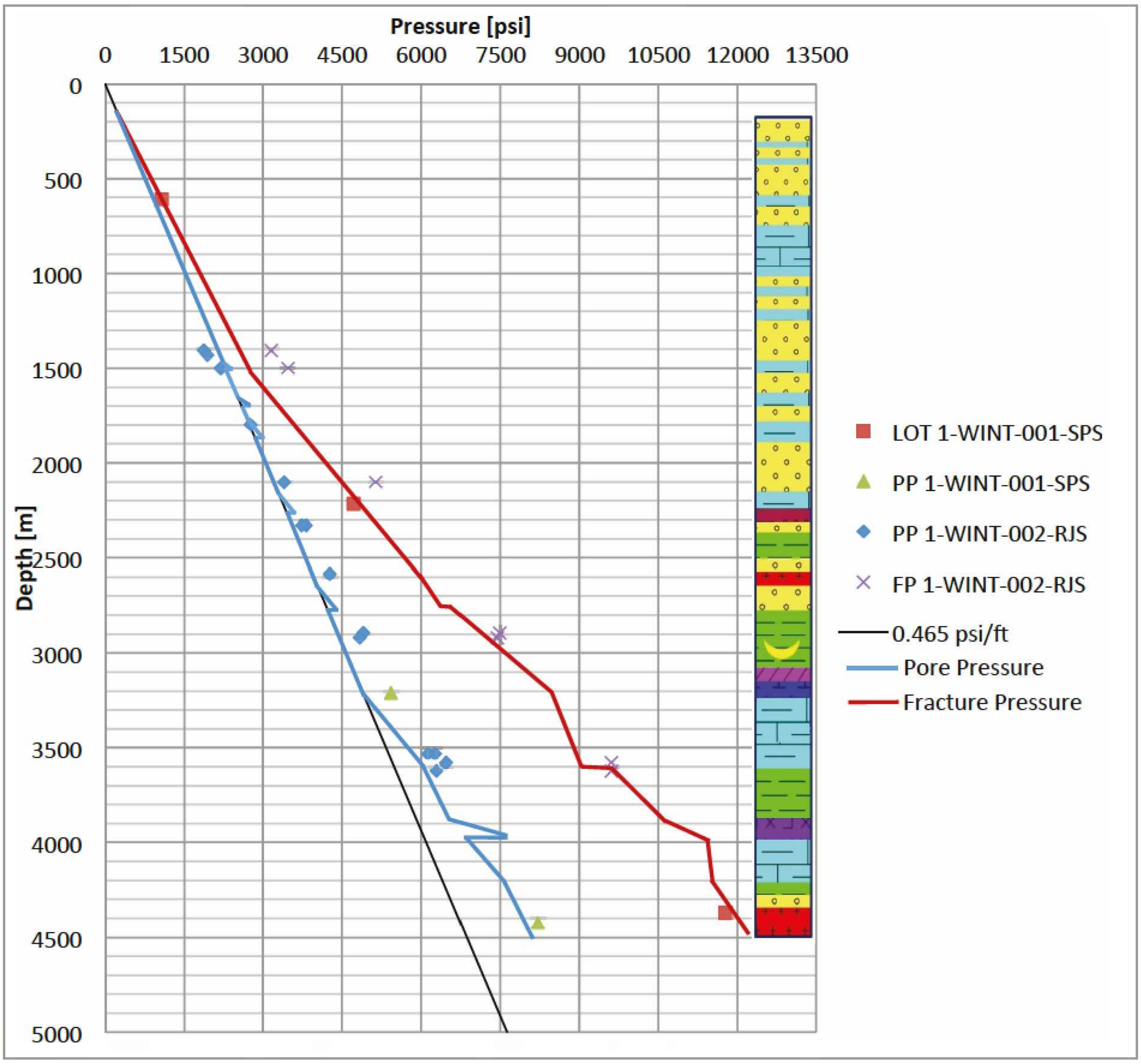


Figure 41: Pressure vs. depth plot of the shallow water area, based on Wintershall´s pore and fracture data from the two shallow water wells drilled in the Santos basin

Besides using the pressure data from Wintershall´s shallow water wells the following assumptions are made to compile the chart:

- The unconsolidated section between 150 and 1,500 meter has a pore pressure gradient of 0.465 psi/ft and a lower fracture gradient than the sections below.
- Carbonate formations have a higher pore pressure and lower fracture pressure, based on internal fractures.
- The Maastrichtian sandstones show an increase in pore pressure and a slightly lower fracture pressure.
- Marls, siltstones, claystones, volcanic rocks and shales have a normal pressure gradient of 0.465 psi/ft and a normal fracture gradient, correlated with the data from Wintershall´s shallow water wells.
- The salt layer is characterized by a pore pressure increase compared to a one and a half pound kick. The fracture gradient shows an increase as well.

3.5.2 Deep Water Area

The figure on the next page shows the pore and fracture pressures of the deep water area. The plot is created with the help of Shell´s deep water well data, which was drilled in a water depth of 2,887 meter in the Campos basin. The blue diamonds show the pore pressures and the red squares the fracture pressures of that well. In addition to those data, the following assume are made:

- The unconsolidated section between 2,000 and 3,000 meter has a pore pressure gradient of 0.465 psi/ft and a lower fracture gradient than the sections below.
- Marls, siltstones, claystones, volcanic rocks, the thin sandstone layers and shales have a normal pressure gradient of 0.465 psi/ft and a normal fracture gradient, correlated with the data from Shell´s deep water well.
- Carbonate formations have a higher pore pressure and lower fracture pressure, because of internal fractures.
- The salt layer is characterized by a pore pressure increase compared to a one and a half pound kick. The fracture gradient shows an increase as well.

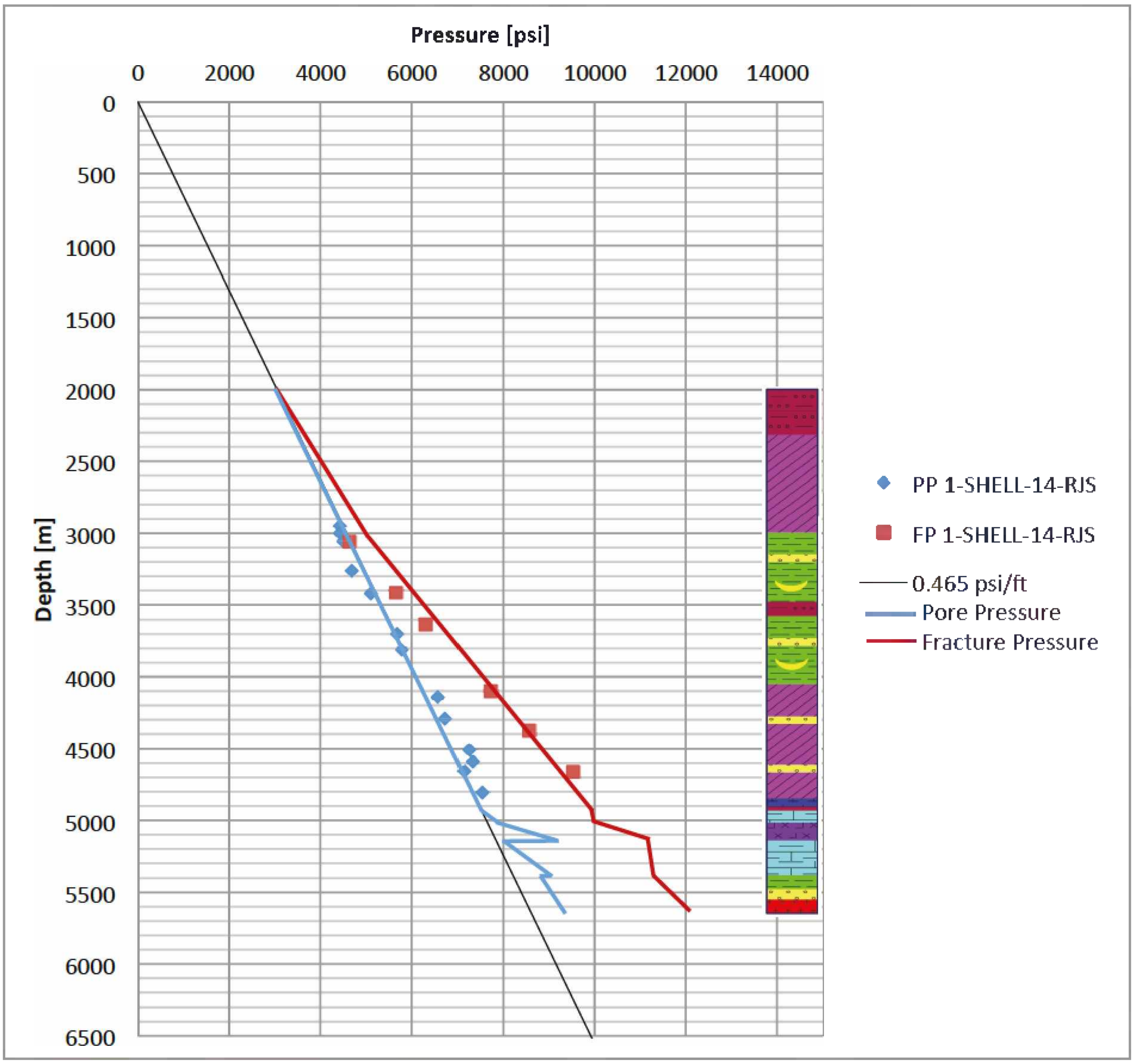


Figure 42: Pressure vs. depth plot of the deep water area, based on Shell´s pore and fracture data from the deep water well drilled in the Campos basin

3.6 Findings of the Shallow Water Area

The shallow water analyses and evaluations are based on recaps and daily drilling reports of two wells of the Santos basin, the stratigraphic map (**Appendix A**) and several papers listed in chapter 7 References. The findings are presented per casing section. Moreover, the areas of concern, which are the basis for the recommendations, are highlighted as well.

3.6.1 36" Section (TD 322 & 234 meter)

The 36" section is also called the conductor section and was drilled around 80 meter below the seafloor. No wellbore related problems were encountered in this section. Seawater with high viscous sweeps was used as mud system. Due to the unconsolidated formation the pore to fracture pressures are very close together.

3.6.2 26" Section (TD 625 & 517 meter)

The 26" section is very similar to the conductor section. The mud system consisted of seawater with high viscous sweeps, taking returns to the seabed. The pore to fracture pressures are close together, but no wellbore problem was encountered. After setting the 20" casing the BOP and riser were installed.

3.6.3 17-1/2" Section (TD 2,228 & 1,393)

In this section the mud system changed to seawater/gel based mud. High viscous pills were incorporated as the hole was drilled deeper. The limestones interlayered with claystones in the upper part and courser sandstones in the lower part showed severe washouts of up to 32" over the whole section length. A tight spot at 2,100 meter was encountered as well. On the other hand, no losses or abnormal pore and fracture pressures were present.

3.6.4 12-1/4" Section (TD 4,380 & 2,838 meter)

Both wells used a WBM system with KCL as inhibitor. 1-WINT-001-SPS had a tight spot at 4,085-4,095 meter within the shale, siltstone and fine-grained sandstone of the Itajaí formation. Well 1-WINT-2-RJS encountered high string vibrations in the sandstones at 2,430 meter and the volcanic rocks at 2,570 meter.

3.6.5 8-1/2" Section (TD 4,821 & 3,706 meter)

In this section the mud system of both wells was the same as in the previous section (WBM system with KCL inhibition). A lot of different wellbore stability problems were encountered. The well 1-WINT-001-SPS had a lot of problems with shales in depths between 4,620 meter and TD (4,821 meter). Creeping shales caused very tight hole sections and spots. At 4,640 meter a tight spot caused a jar operation. Well 1-WINT-2-RJS had the most problems within the volcanic rocks. Over the hole length, but especially between 3,130 and 3,470 meter, severe stick and slip vibrations were encountered. At 3,150 meter a pressure drop of 400 psi was recorded before the pipe got stuck.

As it is shown in the chapters above, the wellbore problems in those wells increased with increasing depth. Washouts, hole closure, vibrations and sudden pressure drops are the present wellbore problems. However, both wells reached their target.

3.6.6 Identified Areas of Concern

After developing the stratigraphic column (**Fig. 26**) the areas of concern are acquired. Those areas are:

- The unconsolidated sandstones interbedded with carbonates in the upper part (150-2,250 meter). Potential wellbore problems are mud losses based on the dissolution of the limestone and washouts in the unconsolidated sandstone layers.
- The shale and claystone layers in the post-salt section. Shale characteristics are related to the composition of smectite and illite minerals, which depends on the temperature. With increasing temperature the illite concentration within the shale will increase as well, leading to a more brittle and less ductile behavior.
- The pre- and post-salt carbonates. Potential wellbore problems are mud losses due to the dissolution of the carbonates. Thereby vugs and channels get interconnected.
- The salt section consisting of halite interbedded with anhydrite. Halite dissolution and plastic behaviors are potential wellbore problems.

3.7 Findings of the Deep Water Area

The deep water analyses and evaluations are based on recaps and daily drilling reports of two wells drilled in the Campos and Espírito Santo basin at a water depth between 2,511 and 2,887 meter, the stratigraphic map (**Appendix A**) and several papers listed in chapter 7 References.

3.7.1 36" Section (TD 2,511 & 2,973 meter)

The 36" section was drilled with a mud system consisting of seawater as well as high viscous sweeps. No wellbore instabilities were encountered in this short section.

3.7.2 17-1/2" Section (TD 3,688 & 3,668 meter)

The second section of the well was very similar to the 36" section. The same seawater mud system was used with high viscous sweeps, taking returns to the surface. Creeping shales at 3,031 meter were causing a tight spot. The BOP and riser got installed after cementing the casing.

3.7.3 12-1/4" Section (TD 5,100 & 4,199 meter)

The third section was drilled with a WBM system and KCL as inhibitor. Pure shales as well as shales in sandstone and claystone formations caused the most problem. The well 1-ESSO-2-ESS encountered a tight hole section from 4,145-4,242 meter as well as high vibrations, in particular stick and slip vibrations, over the whole last section length from 3,688 to 5,109 meter. The second well 1-SHELL-14-RJS had wellbore problems as well. Washouts and mud losses were present over the whole section length. Due to that, LCM pills were pumped during drilling.

3.7.4 8-1/2" Section (TD 4,610 meter)

The used mud system was the same as the previous one. The claystones and sandstones showed major wellbore problems. Between 4,206 and 4,208 meter severe mud losses of 180 bbr/h were recognized. In addition, washouts over the whole section length and a tight spot at 4,278 meter were present. To counteract the severe losses, LCM pills were pumped.

3.7.5 6" Section (TD 5,226 meter)

The last section of Shell´s well was drilled with a WBM system. No wellbore problems were encountered.

3.7.6 Identified Areas of Concern

The deep water geology shows major differences compared to the shallow water one. After developing the stratigraphic column (**Fig. 39**) the areas of concern are acquired. Those areas are:

- The huge shale and claystone layers, which reach from 2,300 to 4,900 meter. Potential wellbore problems could be caused by the very ductile and water sensitive behavior for the upper part and the brittle behavior for the deep ones.
- The unconsolidated formation in the upper part. Potential wellbore issues are washouts of the formations.
- The pre- and post-salt carbonates. Potential wellbore problems are mud losses due to the dissolution of the carbonates and thereby the interconnection of vugs and channels.
- The salt section consisting of halite interbedded with anhydrite. Halite dissolution and plastic behavior are potential wellbore problems.

4 Well Planning Recommendations

A considerable amount of work, decisions and conclusions were made in order to come up with the appropriate results and recommendations for casing setting depths, mud systems, drilling costs/time and wellbore instability indicators of Brazil´s Campos basin.

Raising the mud weight is one of the main statements of the read literature to solve wellbore stability problems. However, some conclusions of this thesis move away from this well practiced and industry wide recommended method.

4.1 Shallow Water Area

Essential requirements for safe drilling operations are accurate casing settings depths. They influence open hole times and thereby the rock and fluid interaction. The following conditions are considered, to compile the casing setting depths:

- Formation pore and fracture pressure
- Mud weight
- Potential wellbore instabilities
- Maastrichtian sandstone as the target formation
- Target depth above salt ~ 2,800 meter TVD
- At least 7” casing/liner at target depth
- Open hole times
- Seafloor at 150 meter

The mud weight is kept as low as possible to have minor pressure differences. Thus, mud invasion into the formation, the risk of differential sticking as well as the fluid loss gets reduced. The calculations of the mud weight consider:

- Zones of potential wellbore instabilities
- 5% safety margin for the highest pore pressure value within the section
- Formation fracture pressure

4.1.1 Casing Setting Depth and Drilling Fluid Selection

With the generation of the following EMW versus depth plot and the stated considerations above, the casing setting depth scenario was developed.

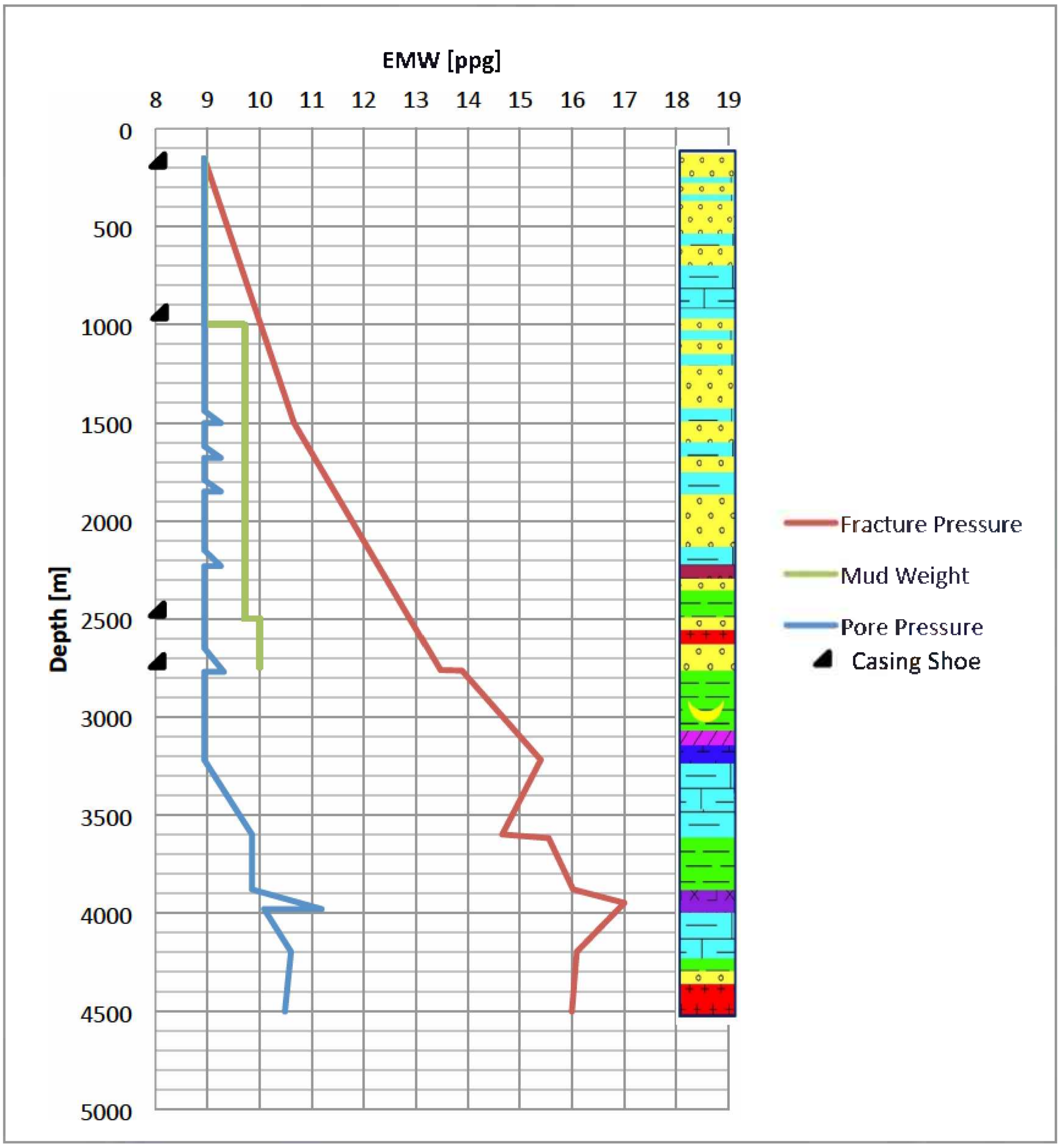


Figure 43: EMW versus depth for the shallow water area (stable salt)

One of the most important drilling components to work against wellbore problems, next to the casing setting depths, is the drilling fluid system. A main task of the drilling fluid is, as highlighted in Chapter 3.3 Mud Systems Comparison, to maintain a stable wellbore. This is done mechanically by mud weight (pressure) and chemically by different kind of additives and types of drilling fluids.

- **Section 1, 36" Hole**

  The conductor section is very short and consists of 30" casings with a low-pressure housing on top. This section has a length of 80 meter and is set 230 meter below sea level. No major wellbore instabilities are expected, although unconsolidated sandstones will be present.

  The drilling fluid should be seawater (approximately 8.94 ppg) with high viscous pills. The high viscous pills should include prehydrated bentonite to form a filter cake. Before POOH and running casing the drilling fluid density should be slightly increased, to stabilize the wellbore until the cement is in place.

- **Section 2, 26" Hole**

  The surface section is drilled through sandstones with interbedded limestones. Washouts of the unconsolidated sandstones and limestone dissolution are potential instabilities. Those instabilities lead to low annular velocities, bad hole cleaning and fluid losses. Although the section could be drilled longer with this mud weight, the following safety considerations lead to set the casing at 1,000 meter into a thick carbonate layer:

  - Potential washouts of sandstone layers
  - Dissolution of carbonates due to seawater based mud system
  - No thick carbonate layer below 1,000 meter
  - Installing BOP and marine riser

  Carbonates are not the preferred casing setting formation. Nevertheless, no shales or similar formations are present. If a shale formation is detected around 1000 meter, the casing should be set there.

  As no riser is installed and the drilling fluids as well as the cuttings are returned to the seabed, the recommended fluid system is seawater with high viscous pills. The pills should be pumped every 12 meter and include prehydrated bentonite. This will form a filter cake around the wellbore and thereby reduce the washouts and dissolution. However, the filter cake will get washed away by seawater, but as no riser is installed, this will be the best approach to work against the instabilities. LCM should be on the rig for potential losses. Before POOH, the hole should get displaced by a slightly higher mud weight.

- **Section 3, 17-1/2”**

  The intermediate section is drilled with a 17-1/2” bit. The casing is set at 2,500 meter into the lower end of a shale formation, above the Maastrichtian sandstones. Thereby all potential washout and fluid loss/dissolution zones will be isolated. In addition, the Maastrichtian sandstones can then be drilled with a higher mud weight, to overcome the pore pressure increase.

  Due to the similar formations as above, this section has the same potential wellbore problems as the previous one. To avoid washouts, a proper filter cake needs to be formed at the borehole wall. Dissolution of the limestone has to be avoided with a high pH value of the mud. The recommendation is to use a seawater based lime mud system of 9.75 ppg with 0.5-2 lbm/bbl lime and a pH of 10.5 to 11.5. In addition, 5-8 lbm/bbr prehydrated bentonite should be added to the low lime mud to form a good filter cake. The shale formation at the end of the section is assumed to develop no problems, based on the very short interaction time. For this section, LCM should be available on the rig, if any fluid loss zones are encountered.

- **Section 4, 12-1/4” Hole**

  The last section should get drilled with a 12-1/4” bit and completed with a 9-5/8” liner. This section is assumed to reach the target zone at 2750 meter, which is the Maastrichtian sandstone. Washouts within the sandstone intervals as well as fluid losses at the volcanic rock interval are potential wellbore instabilities.

  To overcome those issues the following mud system is recommended. As it is shown in **Fig. 43.**, a mud weight of 10 ppg will offer a slightly higher margin during drilling into the reservoir zone. A seawater based mud system with 5-8 lbm/bbr prehydrated bentonite is recommended to form a good filter cake and to minimize the formation damage across the reservoir interval. LCM should be available based on the potential fluid losses within the volcanic rocks.

The following table shows the recommended casing setting depths and sizes for the shallow water area.

Table 5: Casing setting depth for the shallow water area

Casing Setting Depths, Water Depth 150 meter			
Hole Size [in]	Casing Size [in]	Depth Below Sea Level [m]	Vertical Length [m]
36	30	230	80
26	20	1,000	850
17-1/2	13-3/8	2,500	2,350
12-1/4	9-5/8	2,750	250

4.1.2 Time and Cost Estimation

The required drilling time has a major impact on the well cost estimation. The assumed drilling, casing, cementing, evaluation and BOP parameters, to calculate the drilling time, are listed in **Appendix D**. In addition, the well is supposed to be vertical without a horizontal section and the influence of bad weather as well as the completion time is not considered. The following figure shows the time versus well depth and the time versus bit depth plot for the shallow water area (**Fig. 44.**).

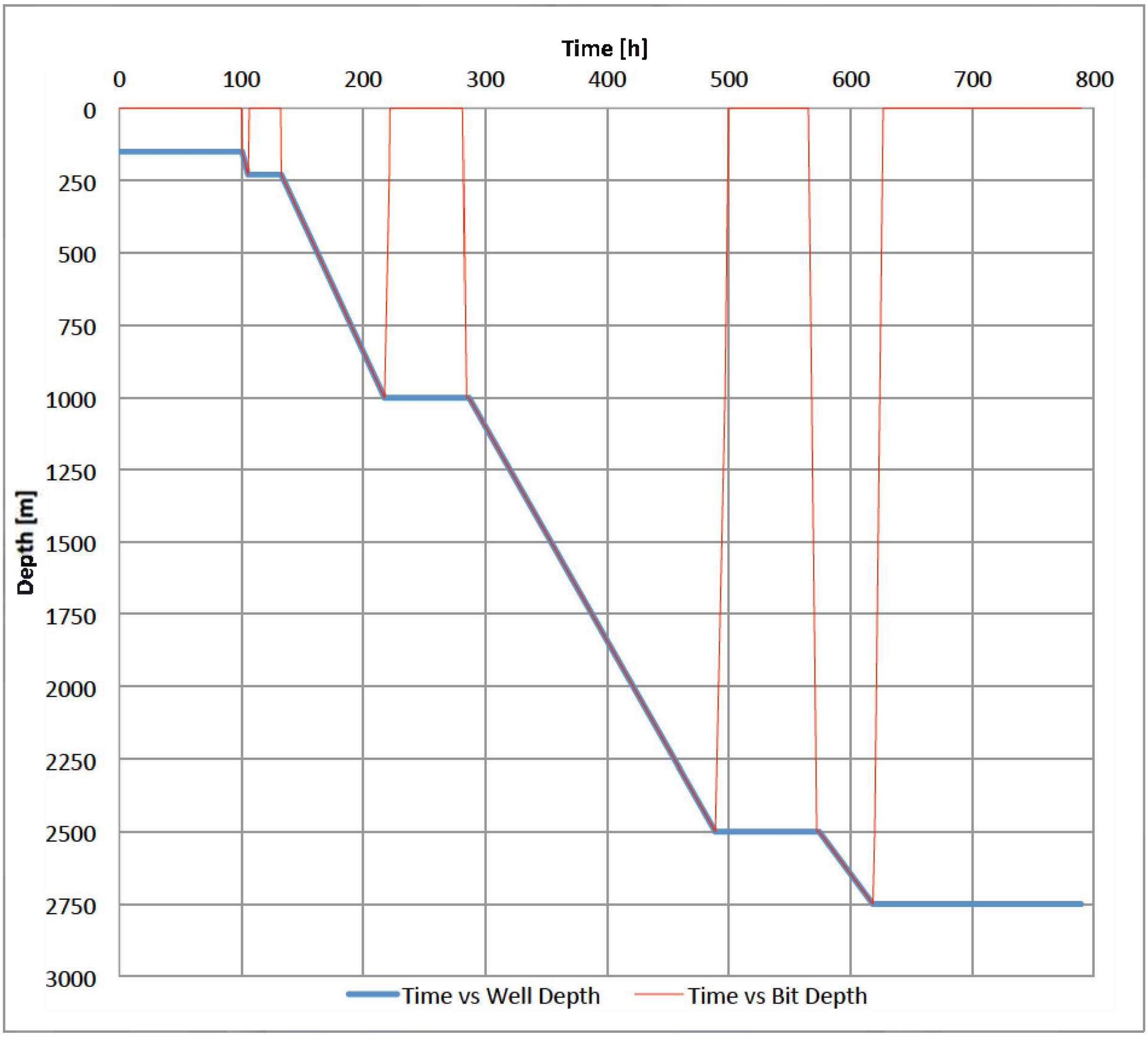


Figure 44: Time versus depth for the shallow water area

Based on these assumptions 789 hours (32.9 days) are required to drill and evaluate the 2.750 meter deep well. For the shallow water area a daily rate of 350.000 US$ is used, resulting in 11.515.000 US$ well costs.

4.2 Deep Water Area

The following conditions are considered to determine the casing setting depths for the deep water area:

- Formation and fracture pressure
- Mud weight
- Potential wellbore instabilities
- Target depth below salt section ~ 5400 meter TVD
- At least a 7" casing at target depth for a stable salt scenario
- Drilling duration times
- Seafloor at 2000 meter

Due to the potential wellbore instabilities in the salt section, two different cases are discussed:

- Unpressured stable salt (although the open hole time due to logging and reservoir testing is long)
- Pressured unstable salt

The mud weight program considers the following conditions:

- Wellbore problems
- 5% safety margin for the highest pore pressures value within the section
- Formation fracture pressure
- Small pressure margin
    - Reduce losses
    - Reduce risk of differential sticking
    - Reduce mud invasion

4.2.1 Casing Setting Depth and Drilling Fluid Selection

The generated EMW versus depth plot shows the casing setting depths for a stable salt scenario.

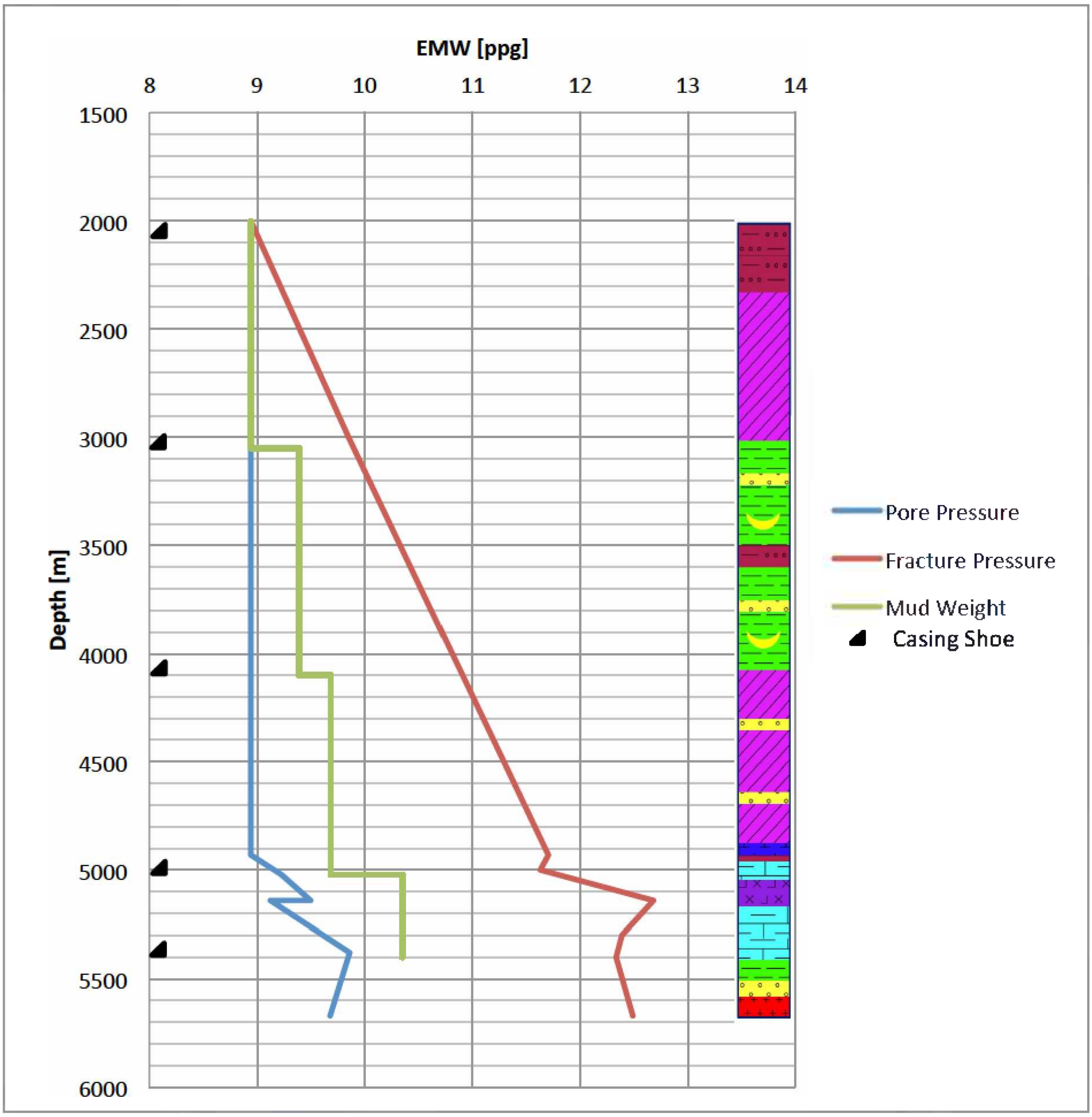


Figure 45: EMW versus depth for the deep water area (stable salt)

- **Section 1, 36" Hole**

  The conductor section consists of 30" casings with a low-pressure housing on top. This section has a length of 80 meter and is set 2,080 meter below sea level.

No major wellbore instabilities are expected, although unconsolidated siltstones will be present. The section should be drilled with seawater (approximately 8.94 ppg) and high viscous pills. The high viscous pills should include prehydrated bentonite to form a filter cake at the borehole wall. Before POOH and running casing, the drilling fluid should be displaced by a slightly higher mud weight to stabilize the wellbore until the cement is in place.

- **Section 2, 26" Hole**

  The surface section is drilled through siltstones and claystones. Potential rock-fluid interactions have to be avoided. Although the section could be drilled longer with this mud weight the following considerations lead to set the casing at 3,050 meter into the top of the shale formation:

  - Open hole time
  - Until now no BOP and marine riser installed
  - Shales have favorable casing setting properties

  As no riser is installed and the drilling fluids as well as the cuttings are returned to the seabed, the recommended fluid system is seawater (approximately 8.94 ppg) with high viscous pills. The pills should be pumped every 12 meter and include prehydrated bentonite. This will form a thin filter cake across porous formations of the wellbore. Thus, the interaction of the formations with the drilling fluid as well as the washouts at the unconsolidated sections will get reduced. Nevertheless, the filter cake will get washed away by seawater, but as no riser is installed, this will be the best approach to work against those instabilities. Before POOH, the hole should get displaced by a slightly higher mud weight.

- **Section 3, 17-1/2"**

  The first intermediate section is drilled with a 17-1/2" bit. The casing is set at 4,100 meter, directly below the shale formation. Thereby all potential active shale formations get isolated. In addition, the huge volume of mud needed in the long 17-1/2" section is another factor for setting the casing.

The shales are assumed to be water sensitive and ductile at the top of the section and will get more brittle with increasing depth. If wellbore instabilities happen within the brittle shales, increasing the mud weight will increase the instabilities as well. This is base on the micro-fractured shales, which will be forced open even wider with increasing weight. Thus, the flexing motion of the interbedded shales will increase. Flexing motion is created during switching the pumps on and off, leading to a weakening of the shale cohesion. To overcome those issues the following mud system is elaborated. An inhibited seawater based mud system of 9.4 ppg with KCL as inhibitor and 5-8 lbm/bbr prehydrated bentonite is recommended. The bentonite will develop a filter cake around the sand and siltstones. The potassium ions of the KCL exchange with the calcium and sodium ions of the shales. Thus, the structure of the shales gets converted to a more stable one. For the deeper brittle shales, Soltex, which is blown asphalt, should be added by 4-6 lbm/bbr during drilling through this formation. The Soltex particles will go into the micro-fractures and stop the shale layers from flexing.

- **Section 4, 12-1/4” Hole**

  With the isolated shales above, the second intermediate section gets drilled with a 12-1/4” bit. The end of this section is the top of the salt section at approximately 5,020 meter.

  This section consists mainly of claystones. Again an inhibited seawater based mud system of 9.65 ppg with KCL, prehydrated bentonite of 5-8 lbm/bbr and Soltex of 4-6 lbm/bbr is recommended.

- **Section 5, 8-1/2” Hole**

  The last section reaches the reservoir at 5,400 meter with a 7” liner through the salt section.

  This section consists of an unpressured stable salt formation and the pre-salt carbonates. A mud weight of 10.25 ppg is recommended for this section. The mud system should consist of a salt saturated seawater based mud system. Nevertheless, salt will equalize the salinities at downhole conditions, leading to a slightly enlarged hole. In addition, the mud composition will slightly dissolve the carbonates below the salt. But as it is the reservoir zone, dissolution and thereby forcing the interconnection of vugs is no issue.

The table below shows the setting depths and casing sizes for the first case.

Table 6: Casing setting depths for a stable salt section of the deep water area

Casing Setting Depths Case 1, Water Depth 2000 meter			
Hole Size [in]	Casing Size [in]	Depth Below Sea Level [m]	Vertical Length [m]
36	30	2,080	80
26	20	3,050	1,050
17-1/2	13-3/8	4,100	2,100
12-1/4	9-5/8	5,020	3,020
8-1/2	7	5,400	380

The second case assumes a salt layer with a higher formation pore pressure and very reactive salt minerals.

- **Section 5, 8-1/2" Hole**

  Based on the very reactive pressured salt formation, the 7" liner has to be set directly below the salt section at 5,140 meter. Thus, the section gets isolated before drilling the reservoir.

  If the salt is pressured, the mud weight has to be increased. In addition, creeping behavior is very likely to occur, based on the water content within the salt. At least a weight of 11 ppg has to be used to overcome the one and a half pound kick. Even a further increase is maybe necessary. The rest of the mud system stays as explained above.

- **Section 6, 6" Hole**

  The last section should get drilled with a 6" bit. Afterwards a 5" liner can be set.

This short section should be drilled with a low lime mud of 10.3 ppg. No other specific additives need to be used in this section regarding the potential wellbore problems. Wellbore damage has to be avoided.

Fig. 46. shows the increased pore pressure and the elaborated mud weights.

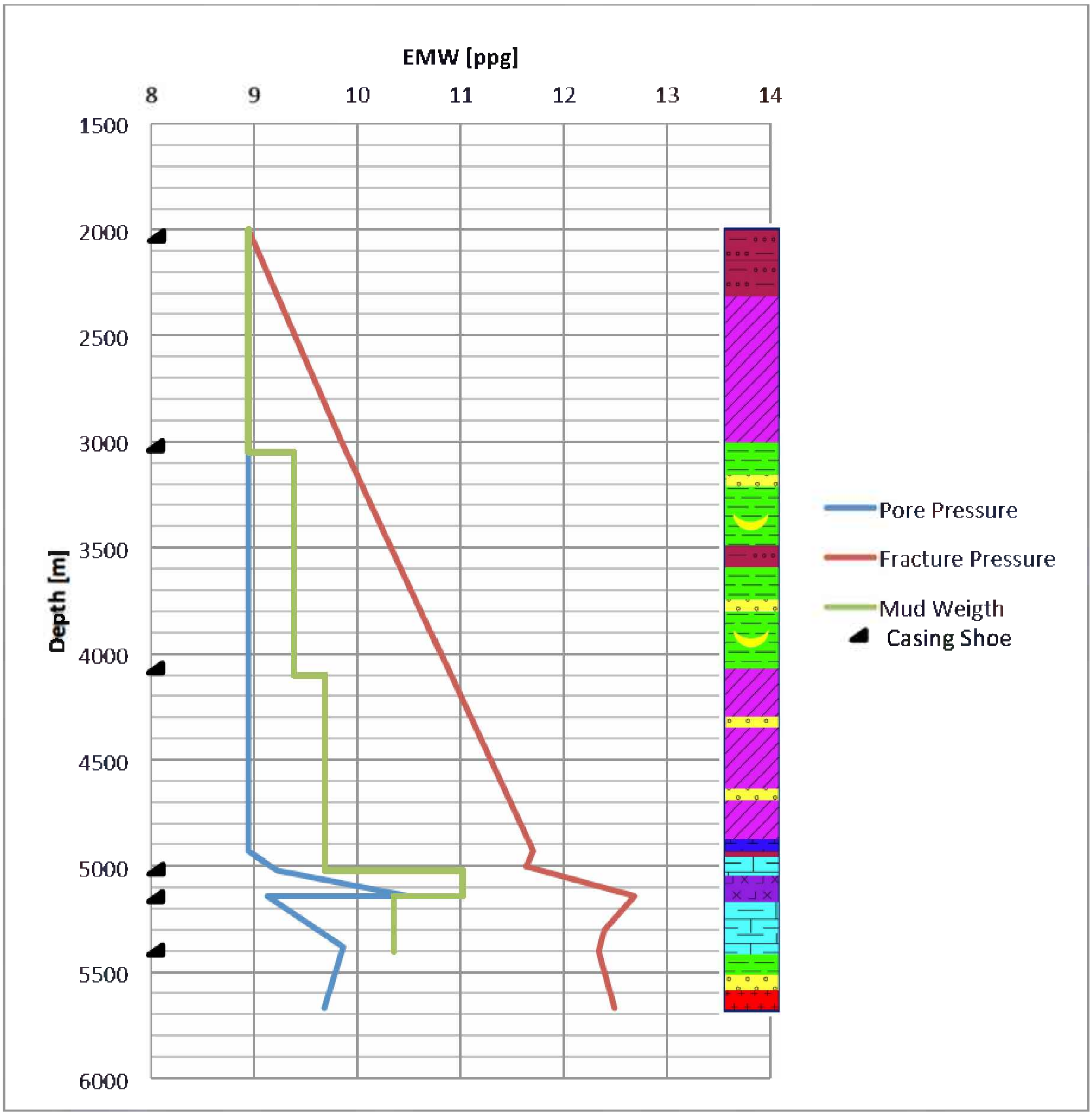


Figure 46: EMW versus depth for the deep water area (unstable salt)

Tab. 7. lists the casing setting depths and sizes for this case.

Table 7: Casing setting depths for an unstable salt section of the deep water area

Casing Setting Depths Case 2, Water Depth 2000 m			
Hole Size [in]	Casing Size [in]	Depth Below Sea Level [m]	Vertical Length [m]
36	30	2,080	80
26	20	3,050	1,050
17-1/2	13-3/8	4,100	2,100
12-1/2	9-5/8	5,020	3,020
8-1/2	7	5,140	120
6	5	5,400	260

The decision to set the addition liner depends on the creeping behavior and has to be made during the drilling operation.

4.2.2 Time and Cost Estimation

The assumed drilling, casing, cementing, evaluation and BOP parameters, to calculate the drilling time, are listed in **Appendix D**. In addition, the well is supposed to be vertical without a horizontal section and the influence of bad weather as well as the completion time is not considered. The figure below shows the time versus well depth and the time versus bit depth plot for the deep water area with a stable salt section (**Fig. 47.**).

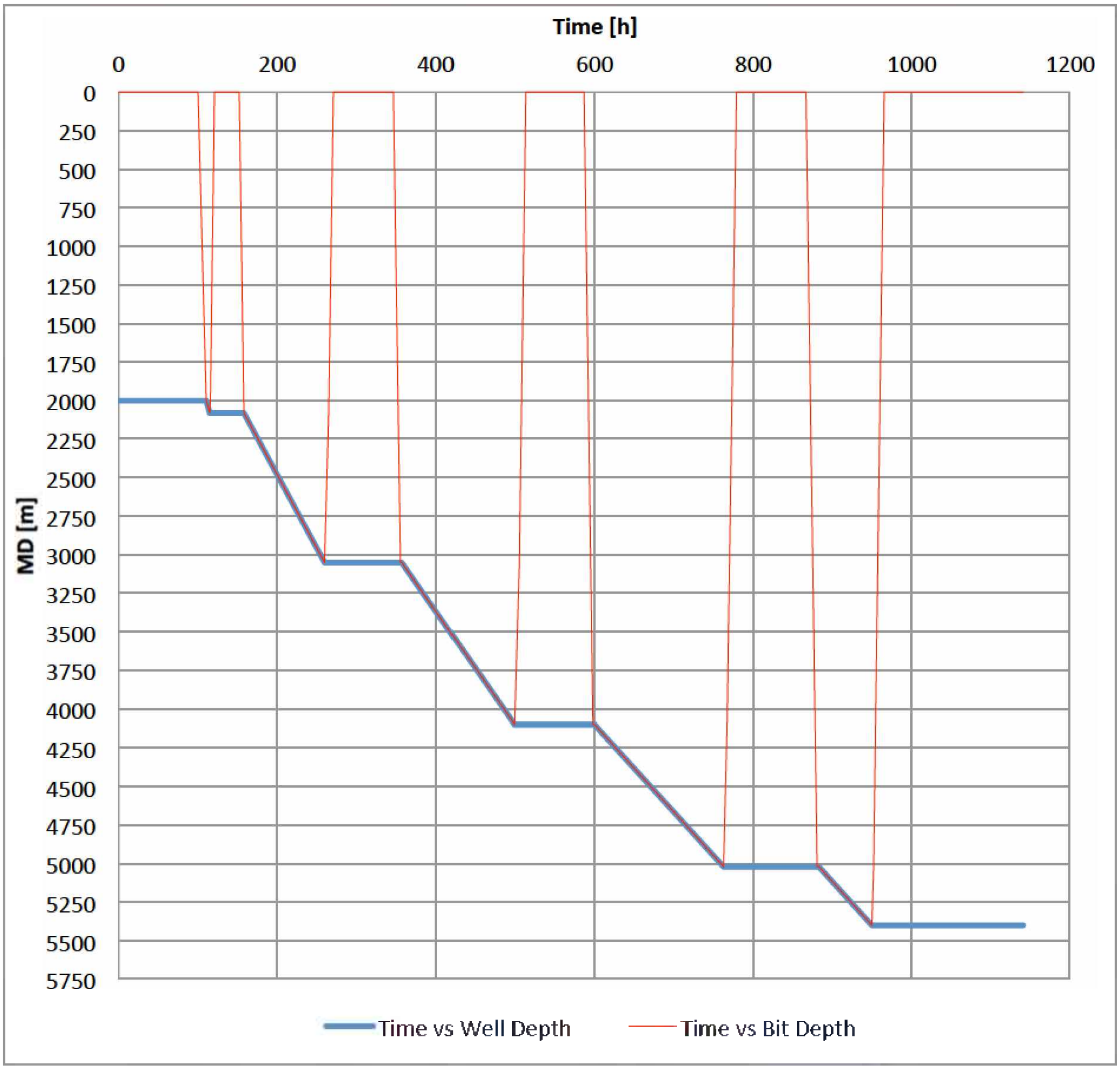


Figure 47: Time versus Depth plot for a stable salt section

Based on these assumptions 1.141 hours (47.5 days) are required to drill and evaluate the 5.400 meter deep well. For the deep water area a daily rate of 500.000 US$ is used, resulting in 23.750.000 US$ well costs.

For the unstable salt case an additional liner has to be set, which result in 1.222 hours (50.9 days) overall drilling time. Based on that, the well costs increase from 23.750.00 US$ to 25.450.000 US$.

Fig. 48. shows the time versus well depth and time versus bit depth plot for the unstable salt case of the deep water well.

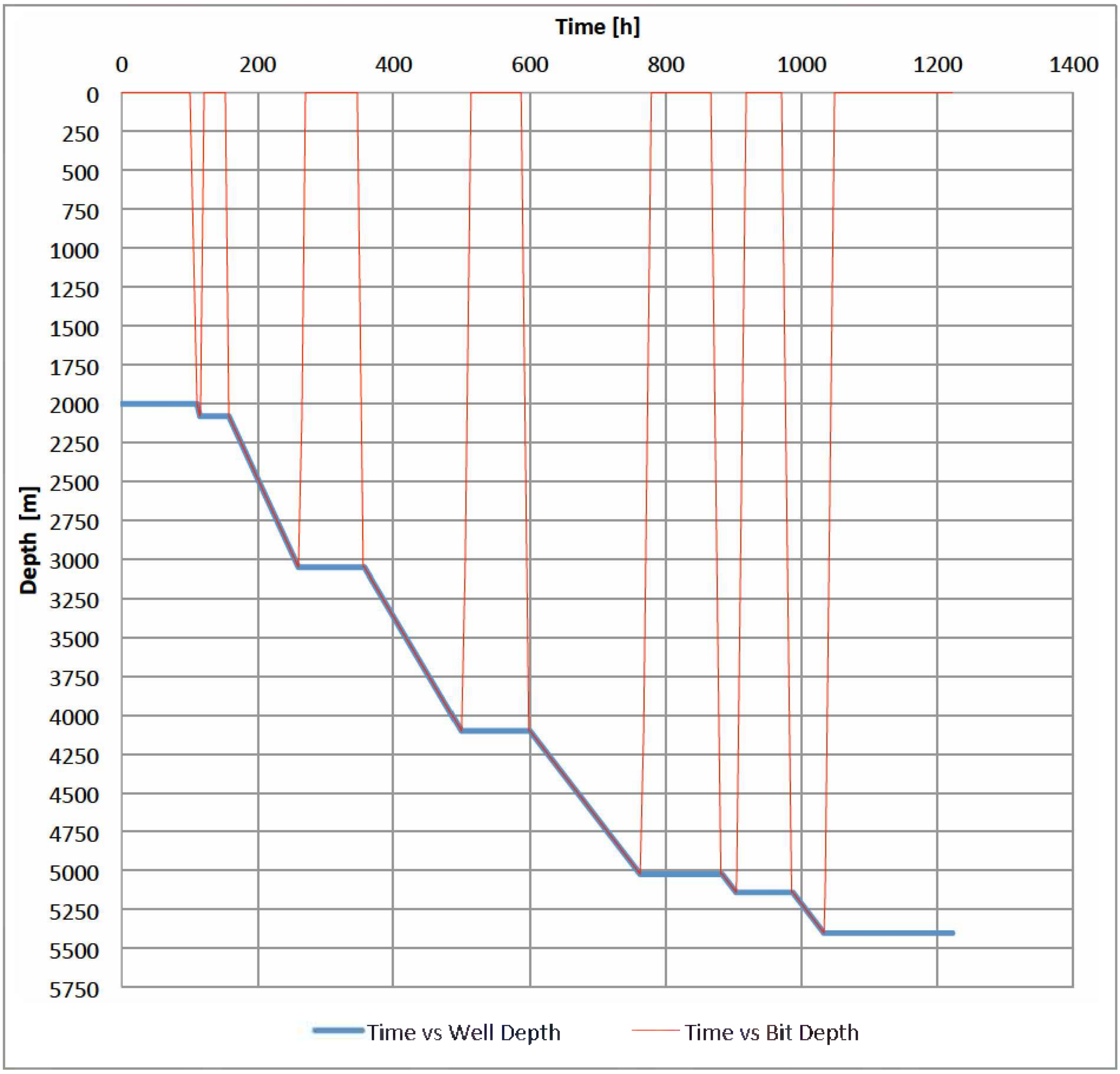


Figure 48: Time versus depth plot for an unstable salt section

4.3 Wellbore Instability Indicator

4.3.1 Unconsolidated Formations Instabilities

The unconsolidated sand and siltstones of the upper part of the Campos basin are potential areas of washouts, which result in hole enlargements of the open hole section. The washout problems increase with time and are caused by:

- Unconsolidated formations
- High bit jet velocity
- Erosion by the drilling fluid, especially with turbulent annular flow
- Abrasion by the drill string components (Stabilizer, Mud motor, DC etc.)

The annular velocity is affected by washouts. With increasing borehole diameter the annular velocity will decrease, which could lead to poor cutting displacement, resulting in cutting´s plug, which could result in drill string packoff. Indicators of hole washout are decreasing cutting volumes at the shaker, higher lag times and higher torque on connections. After drilling, caliper logs show the exact positions and severity of the washouts.

4.3.2 Carbonate Related Instabilities

The carbonates of the Campos basin have interconnected and non-interconnected fractures, vugs, channels, breccias, caverns and banks of calcarenites, oolites and oncolites. Potential wellbore instabilities are mud losses, which have to be distinguished between:

- Initial mud losses. Small amounts, due to the drilling related opening of vugs, channels etc. at the borehole wall.
- Dissolution related mud losses. Lime barriers between the vugs, channels etc. get dissolved. Hence, interconnected channels will develop, which lead to massive losses.

Indicators for carbonate related wellbore instabilities are low pH values of the mud as well as decreasing mud tank volumes.

4.3.3 Salt Related Instabilities

Pressured or unpressured salt formations could lead to:

- Hole enlargement by dissolution of the wellbore wall, which increases with increasing temperature
- Hole closure due to plastic flow of salt

Carbide lag time tests indicate enlarged holes, based on the lower annular velocity through enlarged areas. Indicators for creeping salts are high torque and drag as well as an increase in pump pressure, based on the decreasing annular area.

Pressured halite interlayered with not creeping anhydrite could also lead to point loading at the drillstring or casing (**Fig. 37.**).

4.3.4 Clay Minerals Related Instabilities

Clay rich formations like shales or claystone generate the majority of all wellbore instability problems during drilling operations. Based on their composition the behavior tends to be ductile or brittle.

Indicators for ductile shale behavior are:

- Higher torque
- Higher drag
- Increased pump pressure
- Increased drilling rate
- Rapid decrease in drilling rate due to bit balling

Indicators for brittle shale behavior are:

- Reduced annular velocity based on washouts
- Poor hole cleaning
- Cavings at shaker

- Bit does not reach the bottom again. Caused by caving accumulation during making the connection.

Ductile shales could cause stuck equipment, pipe sticking and difficulty of casing landing. During drilling through brittle shales, problems like a packed off drillstring is possible. To recognize brittle shale instabilities immediately, caving analysis is recommended during drilling through the lower shale formations. Caving rates as well as the appearance should be monitored.

5 Discussion

Wellbore instabilities exist on a worldwide basis and mostly result in an increase in NPT with associated costs. Moreover, wellbore instabilities during drilling operations are a major safety issue. Thus, instability analyses as well as proper planning and execution are of great interest.

The findings, results and recommendations of the thesis are based on four different drilling recaps as well as the stated literature of chapter 7 References. Two of the recaps are from the shallow water of the Santos basin and the others are from the deep water area of the Campos and Espírito Santo basin, which are located next to each other. However, only potential wellbore instabilities could be acquired, as no laboratory tests of rocks from the Campos basin could be executed. Based on that, no local stress regimes or bedding planes directions are known. Hence, it was not possible to elaborate the well path (inclination and azimuth) with the lowest likelihood of wellbore instabilities. In addition, rock-fluid interaction tests would help to find unstable formations and to come up with more accurate recommendations concerning the mud systems.

As parts are already stated above, for more precise predictions of the wellbore instabilities a series of laboratory tests with rock and fluid samples need to be done. Those tests should include stress checks, rock-fluid interaction and the mineralogical elaboration of all different formations. Moreover, core analyses and logging information of the formations would be of particular importance. Thus, bedding directions, local stress regimes, wellbore behaviors and inhomogeneities could be identified over a long sequence.

Despite those facts, the acquisition of all wellbore problems of the four recaps gave good forecasts, which formation is more unstable than another and what kind of wellbore problem is likely to occur. In addition, comparing the acquired problems with general rock behaviors and the elaborated geological lithology of the deep and shallow water area of the Campos basin, gave good approaches for the potential wellbore instabilities.

Lastly, a large part of the reviewed literature recommends increasing the mud weight as remedial action during wellbore instabilities. According to my opinion the mud weight should be used to overcome formation pore pressure and not to try to stabilize the wellbore by increasing the mud weight during instabilities. Otherwise the formation is likely to fail in tension or shear displacement. In particular, the caving rate of brittle shale formation will start to increase, based on the weakening of the flexing motion.

6 List of Abbreviations and Symbols

AAPG	American Association of Petroleum Geologists
AIME	American Institute of Mining, Metallurgical, and Petroleum Engineers
API	American Petroleum Institute
bbl	Barrel
bbl/d	Barrels per Day
bbl/h	Barrels per Hour
BFPD	Barrels of Fluid per Day
BHA	Bottom Hole Assembly
boe/d	Barrels of Oil Equivalent per Day
BOP	Blow Out Preventer
bpd	Barrels per Day
$CaCl_2$	Calcium Chloride
cP	Centipoise
DC	Drill Collar
E	East
ECD	Equivalent Circulating Density
Eds	Editors
EMW	Equivalent Mud Weight
EOWR	End of Well Report
et al.	And Others [Lat.]
etc.	And So Forth [Lat.]
Fig	Figure
GmbH	Gesellschaft mit beschränkter Haftung (German)
HC/mg	Hydrocarbon per Milligram
HI	Hydrogen Index
Hi Vis	High Viscosity
IADC	International Association of Drilling Contractors
ill	Illite
in	Inch
IPTC	International Petroleum Technology Conference
KCL	Potassium Chloride
klbs	Kilopound
km	Kilometer
km^2	Square Kilometer
LCM	Lost Circulation Material
lbm/bbr	Pound per Barrel
lbm/gal	Pound Mass per Gallon
m	Meter

M	Thousand
mg	Milligram
MM	Million
m^3/d	Cubic Meter per Day
N	North
NaCL	Sodium Chloride
NE	Northeast
NGL	Natural Gas Liquids
NNE	North-Northeast
no	Number
NPT	Non-Productive Time
NW	Northwest
n.d.	No Date
OBM	Oil Based Mud
OH	Open Hole
OMC	Offshore Mediterranean Conference
OOIP	Original Oil In Place
OTC	Offshore Technology Conference
P	Pressure
p	Page
pH	Potential of Hydrogen
PHPA	Partially-Hydrolyzed Polyacrylamide
POOH	Pulling Out Of Hole
ppg	Pounds per Gallon
psi	Pound-force per Square Inch
psi/ft	Pound-force per Square Inch per Foot
Pw	Wellbore Pressure
regd	Required
RKB	Rotary Kelly Bushing
R_0	Vitrinite reflectance
ROP	Rate Of Penetration
S	South
SE	Southeast
S_H	Maximum Horizontal Stress
S_h	Minimum Horizontal Stress
SPE	Society of Petroleum Engineers
SSE	South-Southeast
S_V	Vertical Stress
SW	Southwest
Tab	Table
TD	Target Depth

TOC	Total Organic Carbon
TVD	Total Vertical Depth
U.S.	United States
U.S.A.	United States of America
vol	Volume
W	West
WBM	Water Based Mud
2-D	Two-Dimensional
“	Inch
°	Degree
°C	Degree Celsius
°C/km	Degree Celsius per Kilometer
%	Percent
$	Dollar

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8 Appendix

8.1 Appendix A – Geology

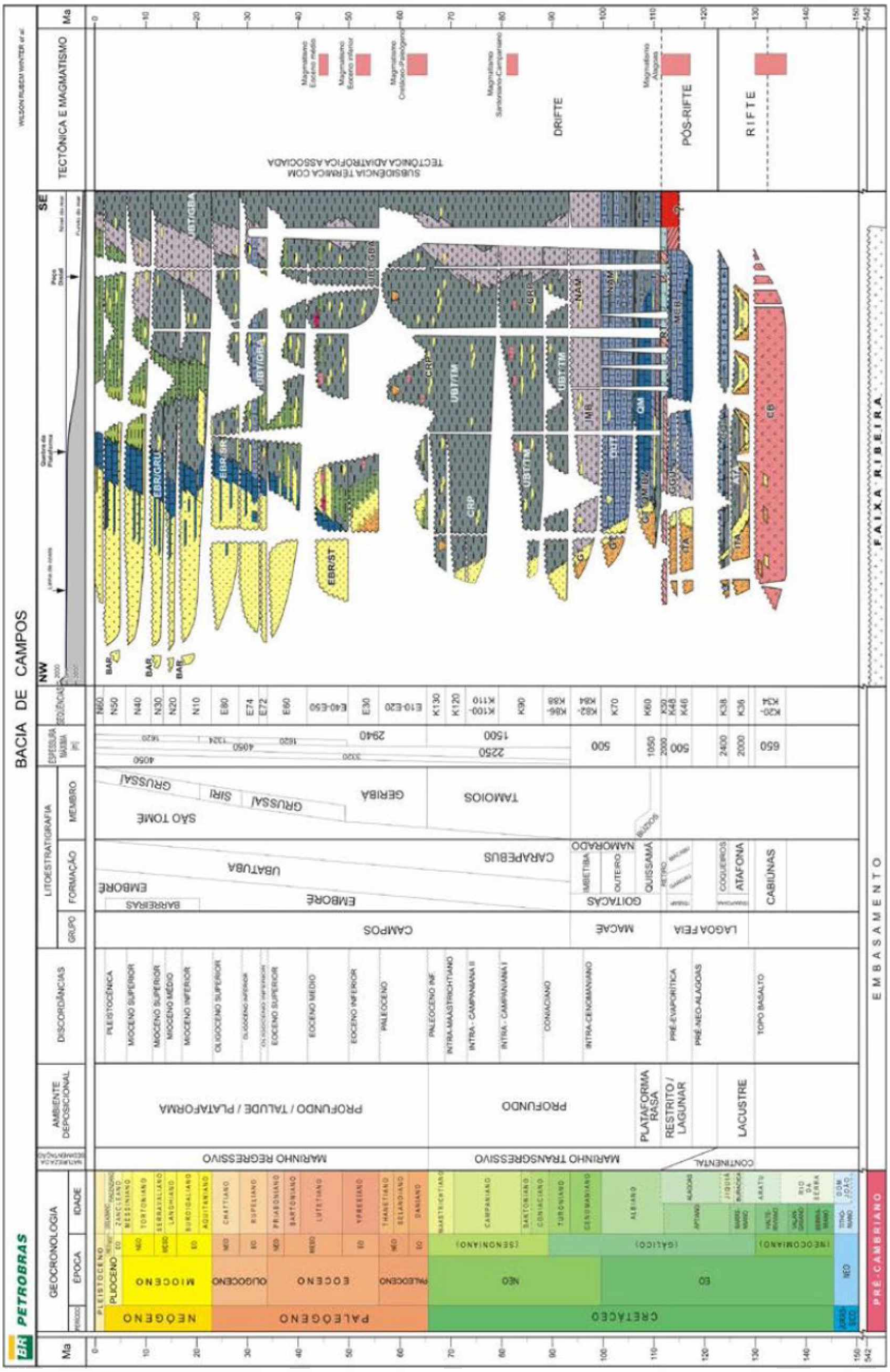

Figure 49: Stratigraphic chart of the Campos basin (Winter et al. 2007)

8.2 Appendix B – Shale-Fluid Interaction

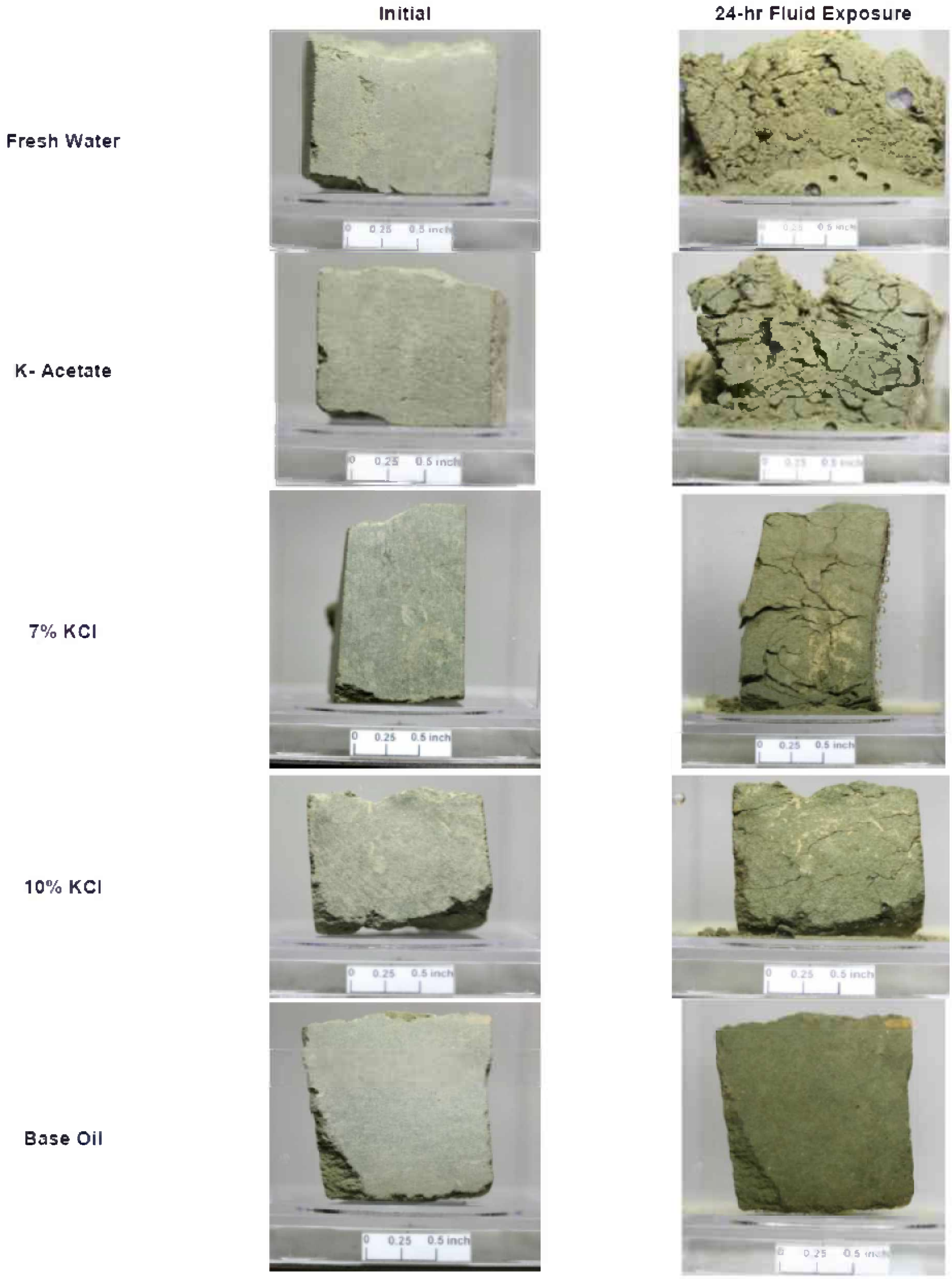

Figure 50: Shales with high smectite content exposed to different fluids (He et al. 2014)

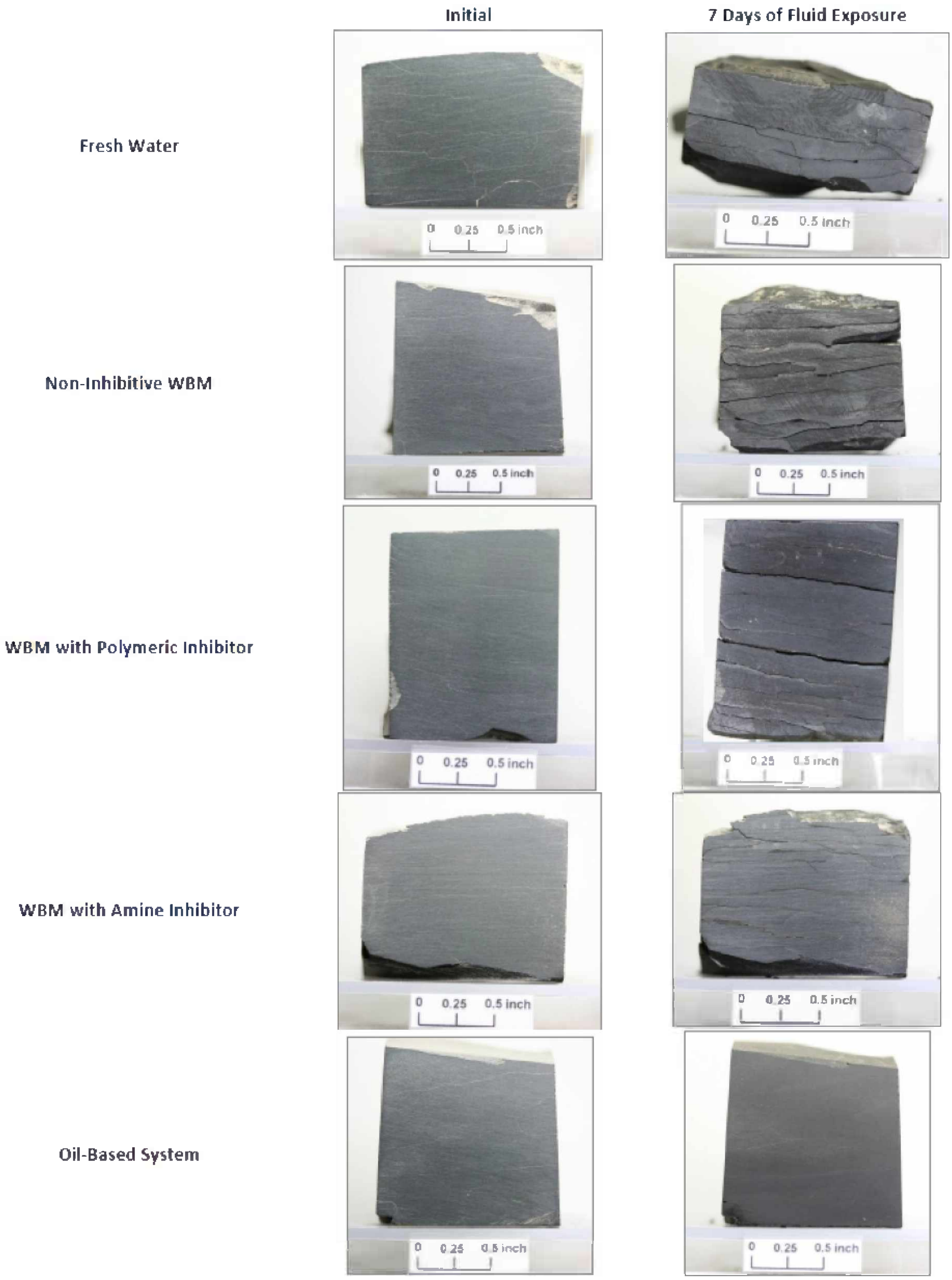

Figure 51: Shales with high illite content exposed to different fluids (He et al. 2014)

8.3 Appendix C – Temperature Campos Basin

Well ID	Latitude	Longitude	Depth (m)	BHT (°C) Measured	BHT (°C) Corrected	Error	Z_{SF} (m)	T_{SF} (°C)
1-RJS-5B	−22.2042	−40.3867	3897	111.1	124.4	6.2	80	16.4
1-RJS-13	−22.6970	−40.8284	2209	67.8	75.1	3.8	90	16.2
1-RJS-23	−22.6376	−40.8345	2972	85.6	96.0	4.8	93	16.1
1-RJS-26	−22.5577	−40.8612	2585	72.2	81.1	4.1	71	16.7
1-RJS-27	−22.2646	−40.8448	1687	66.7	71.9	3.6	56	17.1
1-RJS-28A	−22.7517	−40.6958	2672	81.7	90.9	4.5	145	14.8
1-RJS-32	−22.5125	−40.4232	3825	111.7	124.8	6.2	298	12.2
1-RJS-33	−23.7614	−42.8883	3135	87.8	98.8	4.9	149	14.7
1-RJS-36	−22.3514	−40.8904	1951	65.6	71.9	3.6	56	17.1
1-RJS-38	−22.7094	−40.6531	2848	88.9	98.8	4.9	180	14.1
1-RJS-41	−22.6953	−40.7176	3541	107.2	119.6	6.0	108	15.7
4-RJS-42	−22.4372	−40.4360	3359	96.1	107.9	5.4	136	15.0
1-RJS-43	−22.7396	−40.8700	3530	95.0	107.3	5.4	100	15.9
1-RJS-44	−22.6128	−40.6573	2804	97.8	107.6	5.4	118	15.5
1-RJS-45	−22.6980	−40.6007	3282	89.4	100.9	5.0	284	12.4
1-RJS-46	−22.4773	−40.5134	3344	95.6	107.4	5.4	125	15.3
1-RJS-47E	−22.5792	−40.7234	3819	116.7	129.8	6.5	105	15.8
1-RJS-48	−22.3053	−40.9468	3545	110.0	122.4	6.1	50	17.3
1-RJS-49	−22.7846	−40.8009	3192	88.9	100.1	5.0	105	15.8
1-RJS-50	−22.4540	−40.4731	3218	107.2	118.5	5.9	132	15.1
1-RJS-52	−22.2519	−40.3531	3520	107.2	119.5	6.0	130	15.2
1-RJS-53	−22.6296	−40.5474	3300	90.6	102.2	5.1	284	12.4
1-RJS-54	−22.5700	−40.5058	3494	101.7	113.9	5.7	254	12.8
4-RJS-55	−22.8131	−40.7775	3075	77.8	88.6	4.4	114	15.6
1-RJS-56	−21.5938	−40.3867	5000	154.4	168.1	8.4	32	17.8
1-RJS-57	−21.4934	−40.5444	4202	148.3	162.1	8.1	28	17.9
1-RJS-58	−21.6038	−40.6354	3796	125.0	138.1	6.9	24	18.0
3-RJS-59	−22.4731	−40.4689	3252	99.4	110.8	5.5	150	14.7
1-RJS-60	−22.4050	−40.4520	3704	109.4	122.2	6.1	118	15.5
4-RJS-62A	−22.7722	−40.7675	3201	87.8	99.1	5.0	109	15.7
1-RJS-63A	−22.7945	−40.7344	3206	80.0	91.3	4.6	122	15.4
1-RJS-64A	−22.8344	−40.7518	3205	81.1	92.4	4.6	132	15.1
1-RJS-65	−22.7305	−40.7669	3449	97.2	109.3	5.5	103	15.8
1-RJS-66	−22.3251	−40.1457	4490	128.9	143.0	7.1	200	13.7
1-RJS-68	−22.9722	−41.0108	2667	80.6	89.8	4.5	98	16.0
1-RJS-69	−22.5098	−40.9939	2297	77.2	84.9	4.2	57	17.1
1-RJS-70	−22.2301	−40.9954	2355	83.3	91.2	4.6	39	17.6
1-RJS-71	−22.3170	−40.9319	3504	106.7	119.0	5.9	54	17.2
1-RJS-73	−22.7714	−40.8014	3187	91.1	102.3	5.1	130	15.2
1-RJS-74	−22.7512	−40.7989	3189	99.4	110.6	5.5	101	15.9
1-RJS-75	−22.3034	−40.4504	3605	109.4	122.0	6.1	106	15.8
1-RJS-76	−22.5733	−40.6008	4870	134.4	148.3	7.4	122	15.4
1-RJS-78	−22.7419	−40.8122	3240	98.3	109.7	5.5	110	15.7
1-RJS-79	−21.5245	−40.5132	3761	133.9	146.9	7.3	26	18.0
3-RJS-80	−22.4446	−40.4783	3170	102.8	114.0	5.7	121	15.4
1-RJS-82	−21.8235	−40.8087	2282	86.1	93.7	4.7	24	18.0
1-RJS-83	−22.5043	−40.5401	3252	106.1	117.5	5.9	124	15.3
1-RJS-84	−22.4229	−40.5046	3326	105.0	116.7	5.8	115	15.5
1-RJS-85	−22.6102	−40.6079	3994	118.3	131.8	6.6	141	14.9
1-RJS-88	−22.4628	−40.4658	3257	99.4	110.9	5.5	170	14.3
1-RJS-89	−22.8458	−40.9379	2760	86.1	95.7	4.8	117	15.5
1-RJS-90	−22.3342	−40.2792	3503	103.3	115.6	5.8	126	15.3
1-RJS-91	−23.2109	−41.1755	2890	95.6	105.7	5.3	111	15.6
1-RJS-92	−22.7929	−40.8364	3127	91.1	102.1	5.1	99	15.9
1-RJS-93	−22.8412	−40.7963	2988	90.0	100.5	5.0	115	15.5
1-RJS-94	−21.5334	−40.6822	2704	111.1	120.5	6.0	23	18.1
1-RJS-95	−22.6685	−40.6278	4439	128.9	143.0	7.1	179	14.1
1-RJS-96A	−21.3834	−40.3158	4003	144.4	157.9	7.9	53	17.2
1-RJS-97C	−21.7498	−40.3318	3992	121.7	135.2	6.8	46	17.4
1-RJS-99	−23.7681	−41.5889	4245	107.2	121.1	6.1	154	14.6
1-RJS-100	−23.5431	−41.6448	3122	84.4	95.4	4.8	146	14.8
1-RJS-101	−22.4765	−40.5828	4603	167.2	181.3	9.1	114	15.6
1-RJS-102A	−22.4480	−40.5660	5049	152.2	165.8	8.3	108	15.7
1-RJS-105	−23.4693	−41.5478	3380	103.9	115.8	5.8	131	15.2
1-RJS-106	−22.7641	−40.7404	2780	99.4	109.1	5.5	115	15.5
1-RJS-107	−23.6564	−41.6900	3898	118.9	132.2	6.6	150	14.7
1-RJS-108	−22.3445	−40.6733	4958	147.2	161.0	8.0	67	16.8
1-RJS-111	−22.7978	−40.8058	3168	96.1	107.2	5.4	130	15.2
1-RJS-113	−22.9523	−40.9423	2971	85.0	95.4	4.8	100	15.9
1-RJS-114	−22.8488	−40.8432	3072	95.0	105.8	5.3	112	15.6
1-RJS-115	−22.8682	−40.8145	3096	84.4	95.3	4.8	113	15.6
1-RJS-116	−22.7294	−40.6195	3990	118.3	131.8	6.6	296	12.2
1-RJS-117	−22.2137	−40.1260	4087	114.4	128.1	6.4	119	15.4
3-RJS-120	−22.5806	−40.5271	3180	98.9	110.1	5.5	233	13.1
4-RJS-121	−22.5718	−40.5546	3217	96.1	107.4	5.4	178	14.1
1-RJS-125	−23.4852	−41.2235	2496	81.1	89.6	4.5	168	14.3

Figure 52: Temperature summary of 76 oil wells of the Campos basin (Cardoso and Hamza 2014)

8.4 Appendix D – Time Estimation Parameters

Table 8: Drilling time estimation parameters

Drilling Job Parameters	Value	Unit
Rig Up	4	days
Rig Down	4	days
Make Up BHA	4	h
Brake Up BHA	4	h
Slip to Slip Connection	3	min
Weight to Weight Connection	6	min
Stand Length	20	m
Cased Hole Pipe Movement	1	m/s
Open Hole Pipe Movement	0.1	m/s
ROP	20-6	m/hr

Casing Job Parameters	Value	Unit
Rig Up Time for Casing Job	3	h
Rig Down Time for Casing Job	3	h
Casing Job	6	Joints/h

Cementing Job Parameters	Value	Unit
Additional Safety	60	min
Pumping Rate	180	gal/min

Evaluation Job Parameters	Value	Unit
Rig Up Time for Evaluation	3	h
Rig Down Time for Evaluation	3	h
Run In for Evaluation	12	h
Run Out for Evaluation	12	h

BOP Job Parameter	Value	Unit
BOP Work Time	20	h