Investigation of the Effect of Modern Drilling Technology on Wellbore Stability in the Tertiary and Jurassic in North-Western Germany

Master's Thesis

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Affidavit

I declare in the lieu of oath that I composed this thesis in hand by myself using only literature cited at the end of this thesis.

Melanie Mikula

Leoben, October 2007

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Any project, no matter how individual, will almost certainly require input, assistance or encouragement of others: My thesis is no exception.

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Abstract

Borehole stability is a main contributor to the drilling of a well within a planned time and budget frame. ExxonMobil Production Germany (EMPG) was recently confronted with wellbore instabilities and related, previously unknown, troubles despite long experience with the geology in the north-west of Germany. The task of this work is to investigate the influence of modern drilling technologies on wellbore stability in Tertiary and Jurassic formations in North-Western Germany.

Initially, changes in applied drilling technologies are identified which were implemented in the past two decades: the replacement of kelly and rotary table by topdrive systems, directional drilling in the tophole section, shale inhibition by oil-based mud substitutes instead of KCl-containing water-based muds, reduced roundtrips due to high-performance bits as well as increased pump capacity and efficiency.

Those serve as basis for the comparison of old and recent wells including, among others, the theoretical number of borehole-string contacts, calculated by real data; the detailed composition of the bottomhole assembly; the actual borehole volume in various muds compared with the theoretical volume for information on cave-ins; the number of roundtrips for bit replacement, and the range of pump rates and pressures as listed in morning reports.

The findings of this comparison are then evaluated regarding their influence on wellbore stability. In the next step, parameters termed "positive" are excluded, leaving only those with a negative effect on borehole instability. Finally project-specific recommendations on how to avoid future stability problems are given: decreased borehole wall contacts, on account of using a static vertical drilling system and a topdrive, are considered "negative" - no past wellbore instabilities were reported in reference wells drilled with kelly and rotary table. It is thus recommended to prolong reaming periods and include roller reamers into the drill string to ensure additional borehole wall conditioning. Insufficient mud weight, not modern drilling technologies, was another reason for cavings which can be avoided by increasing the density. Water-based mud including salt can lead to severe shale instabilities. The use of modern water- or oil-based muds, however, is proposed as they yield improved shale inhibition and stabilize the borehole wall.

Kurzfassung

Ein Hauptfaktor, der bestimmt, ob ein Bohrprojekt zeit- und budgetgemäß abgeteuft wird, ist Bohrlochstabilität. In jüngerer Vergangenheit traten trotz bekannter Geologie Probleme auf, welche den Anlass für diese Arbeit gaben. Diese untersucht den Einfluss geänderter Bohrtechnologien auf die Bohrlochstabilität in Formationen des Tertiär und Jura in Nordwestdeutschland.

Dafür werden eingangs die Änderungen in der Bohrtechnologie, die im Laufe der letzten zwei Jahrzehnte implementiert wurden, identifiziert: der Ersatz von Kelly und Drehtisch durch Topdrive-Systeme, die Verwendung von Richtbohrwerkzeugen im Bohrloch-Oberbau, der Einsatz von hoch inhibierenden statt konventionellen Ton-Salz-Spülungen zur verbesserten Toninhibierung, der Einbau von Hochleistungs-Meißeln mit geringerem Verschleiß und folglich verringerten Roundtrips sowie verbesserte Bohrlochhydraulik.

Diese Erkenntnisse dienen anschließend dem Vergleich von vergangenen und rezenten Bohrprojekten, der unter anderem die Berechnung der Anzahl der Bohrlochkontakte unter Verwendung von Drehtisch bzw. Topdrive, eine Schätzung des Auskesselungs-Volumen in Bohrungen mit verschiedenen Spülungen, die Anzahl der Roundtrips zum Meißeltausch und deren Einfluss auf die Anzahl der Bohrlochkontakte, und die Spanne von Pumpraten und –drücken aus Tagesberichten beinhaltet. Die Ergebnisse dieser Analyse werden danach hinsichtlich ihres Einflusses auf die Bohrlochstabilität bewertet. Es werden weiter nur Bohrtechnologien weiter betrachtet, die negative Auswirkungen auf die Bohrlochstabilität hatten.

Zuletzt werden projektspezifische Empfehlungen gegeben, wie Probleme mit Bohrlochstabilität zukünftig verhindert werden könnten. Ein Abwärtstrend in der Anzahl der Bohrlochkontakte durch Verwendung von Topdrive und Vertikalbohrsystemen anstelle von Drehtisch und Kelly wird „negativ“ bewertet, da in der Vergangenheit keine Bohrlochstabilitätsprobleme auftraten. Längere Räum-Perioden und Rollenräumer im Strang werden empfohlen um die Anzahl der Kontakte zwischen Bohrstrang und Bohrlochwand zu erhöhen. Eine unzureichende Spülungsdichte, nicht aber Probleme mit geänderter Technologie, waren andererseits Ursache für Ausbrüche der Bohrlochwand, welche mit beschwerter Spülung verhindert werden können. Die Verwendung von öl- oder moderner wasserbasischer Spülung wird aufgrund effektiverer Toninhibierung hingegen als positiver Effekt gesehen und trägt in wasserreaktiven Formationen zu verbesserter Bohrlochstabilität bei.

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Abbreviations and Nomenclature

Abbreviation	Expression	Units
API	American Petroleum Institute	
BHA	Bottomhole Assembly	
BHW	Borehole Wall	
CMC	Carboxymethyl Cellulose	
CPT	Cloud Point Temperature	[°C]
DP	Drill Pipe	
ECD	Equivalent Circulating Density	[kg/l]
EMPG	ExxonMobil Production Germany	
FC	Fresh water Clay-based mud	
FIT	Formation Integrity Test	
FL	Fluid Loss	[ml/30 min]
HHP	Hydraulic Horse Power	
HPHT	High Pressure High Temperature	
HSE	Health, Safety and Environment	
HWDP	Heavy-Weight Drill Pipe	
ID	Inner Diameter	[in]
LOT	Leak-Off Test	
MD	Measured Depth	[m]
NPT	Non-Productive Time	[hr]
OBM	Oil-Based Mud	
OD	Outer Diameter	[in]
PAC	Polyanionic Cellulose	
PDC	Polycrystalline Diamond Cutter	
PHPA	Partially Hydrolyzed Polyacrylamide	
POH	Pulling Out of Hole	
Poly	Polymer-containing water-based mud	
RD	Rotary Drilling	
RIH	Running In Hole	
ROP	Rate of Penetration	[m/hr]
RPM	Rotations Per Minute	[min^{-1}]
SC	Salt water Clay-based mud	
SG	Specific Gravity	[1]
SPM	Strokes Per Minute	[min^{-1}]
SPP	Stand Pipe Pressure	[bar]

TAME	Thermally-Activated Mud Emulsion	
TDD	Topdrive Drilling	
WOB	Weight On Bit	[t]

c	Cohesion of material	[MPa]
E	Young's modulus	[MPa]
g	Gravitational constant	[m/s²]
h	Depth	[m]
HP	Horse power	[HP]
k, m	Material constants in Druger-Prager criterion	[1], [MPa]
n	Pore pressure efficiency	[1]
Δp	Excess fluid pressure from the borehole, pressure differential	[MPa]
$p_{failure}$	Pressure/stress leading to rock failure	[MPa]
p_{loss}	Pressure loss	[bar]
p_m	Drilling mud or wellbore pressure	[MPa]
p_{pump}	Pump pressure	[bar], [psi]
p_w	Pore pressure	[MPa]
q_m	Drilling mud flow rate	[lpm], [gpm]
T	Rock tensile strength	[MPa]
T_w	Wall temperature while drilling	[°C]
T_∞	Initial formation temperature	[°C]
Vt	Steady-state creep	[1]
α	Angle between σ_H and projection of borehole axis and horizontal plane	[°]
α_T	Rock coefficient of thermal expansion	[°C^{-1}]
β	Angle between borehole axis and vertical direction	[°]
ε	Creep strain	[1]
ε_e	Instantaneous elastic strain	[1]
$\varepsilon_1(t)$	Transient creep	[1]
$\varepsilon_3(t)$	Accelerating creep	[1]
η	Efficiency	[1]
θ	Polar angle in borehole cylindrical coordinate system	[°]
μ_p	Plastic viscosity	[cp]
ν	Poisson's ratio	[1]

ρ_{mud}	Drilling mud density	[kg/l]
ρ_s	Sediment density including pore space	[kg/m³]
σ_{bd}	Fracture breakdown stress	[MPa]
σ_H	Maximum horizontal stress	[MPa]
σ_h	Minimum horizontal stress	[MPa]
σ_{min}	Minimum stress without indication of direction	[MPa]
σ_n	Normal stress acting on failure plane	[MPa]
σ_{oct}	Octahedral normal stress	[MPa]
σ_r	Radial stress	[MPa]
σ_{reop}	Fracture reopening stress	[MPa]
σ_t	Tangential stress	[MPa]
σ_v	Vertical, lithostatic or overburden stress	[MPa]
σ_x, σ_y, σ_z, τ_{xy}, τ_{xz}, τ_{yz}	Stress tensor in borehole Cartesian coordinate system	[MPa]
σ_r, σ_t, $\sigma_{v'}$, $\tau_{tv'}$, τ_{rt}, $\tau_{rv'}$	Stress tensor in borehole cylindrical coordinate system	[MPa]
$\sigma_{1\ldots3}$	Principal stresses	[MPa]
$\sigma_{1'\ldots3'}$	Effective principal stresses	[MPa]
τ	Shear stress	[MPa]
τ_{oct}	Octahedral shear stress	[MPa]
τ_0	Yield point	[lb/100 ft²]
φ	Angle of internal friction	[°]

1 Introduction

Despite high oil prices and related record profits in recent years, the pressure on exploration and production (E&P) companies to outperform their industry competitors as well as last year's results is increasing. The strong Euro weakens the effect of high oil prices (in US $) and relatively higher European taxes lower the rentability of E&P projects compared with those in the United States. Drilling costs are a big potential to cut expenses as they represent approximately 60 % of the total project costs in North-Western Germany: saving time at the rig without neglecting safety standards eventually increases the net present value of a project. The focus of optimization is often non-productive time, i.e. time where the bit does not rotate to "make hole". It is caused by both planned work on the rig site, e.g. a roundtrip to change the bottomhole assembly as well as necessary maintenance, and unplanned incidents such as stuck pipe, lost drill string components in the hole etc. The latter cannot be accounted for in the project's planning phase and hence induces delays and unexpected cost increases. This kind of non-productive time is often referred to as "lost time".

ExxonMobil Production Germany (EMPG) recently experienced wellbore stability problems at varying depths during drilling, which induced lost time. Swelling shales and caving sands (Tertiary) reduced open hole diameters or plugged the well; Jurassic sediments, mainly shales, displayed extraordinary reactivity with water-based mud which led to instable borehole walls. It was of particular interest to both engineers and geologists to determine the main drivers for those wellbore instabilities. While geology was documented in the operating area and excluded to be a reason, the impact of modern drilling technologies was unknown. Are topdrive systems, downhole motors or more powerful pumps and higher related pump rates and pressures (partially) responsible for borehole stability problems?

The objective of this thesis is to find an answer to this question by investigating the influence of modern drilling technology on borehole stability in North-Western Germany, focusing on Tertiary and Jurassic sections. The first two chapters contain background information on the geology in the investigated area, mechanical and chemical wellbore instability in general as well as the changes in drilling technology over the past two decades. Current "trouble wells" are subsequently compared with old reference wells, based on the identified changes in drilling technologies. Information on the wells is taken from morning reports, time-versus-depth curves, mud reports, geophysical logs (caliper and gamma ray logs) as well as geological end-of-well reports and project planning documents. Evaluations of the findings, conclusions on the reasons for wellbore instabilities, obtained by the method of exclusion, and ultimately project-specific recommendations on potential future operational improvements constitute the final part of this work.

2 Background

2.1 The Geology of North-Western Germany

2.1.1 The Jurassic

This Mesozoic period comprises the time span between approximately 195 and 135 million years ago /1/, /2/. It is subdivided into Lias (Lower or "Black" Jurassic), Dogger (Intermediate or "Brown" Jurassic) and Malm (Upper or "White" Jurassic).

Due to regional tectonic events, it is not possible to give an average depth at which Jurassic rocks can usually be found in North-Western Germany. There are even areas where no Jurassic formations exist. Therefore, the detailed stratigraphy has to be investigated separately for every field. On the other hand, those specific tectonic events have been responsible for the generation of hydrocarbons in North-Western Germany; without the partially exceptional burial of source rock, the sediments would have never reached the "oil" and "gas window", respectively, where pressures and temperatures are sufficient for the production of hydrocarbons /3/.

Rocks encountered in Lias are mainly shaly sandstones, intermingled with rare oil shales. The dark color indicates that the marine environment rather lacked oxygen. Dogger is mainly built of clays and iron-bearing sandstones out of marine iron, resulting in a brownish color. In Malm mainly salts, sands, dolomites, sandy calcareous stones and ooliths were deposited. The carbonates were largely diagenetically formed from riffs, sponges and algae. In general, it can be stated that the Jurassic climate seems to have been largely warm with only slightly cooler Polar Regions. This might also explain the abundance of light colored carbonates at the end of the period.

In Germany, the North-West is one of the two main areas where Jurassic sediments can be found. They were formed beginning with Lias where vast parts of Germany were flooded by the Jurassic Sea. Unlike in the South-East, deposition was hardly ever disturbed and yielded thick layers of continuous sediments. The sea was rather shallow with depths that amounted up to only several decades of meters at maximum. In Malm, the South-West German Jurassic Sea was separated from the North-Western part. Dark heaving shales and brown sandstones were displaced by white carbonate sediments. At the end of the Jurassic period, a regression drained South Germany whereas sedimentation in a narrow and deep basin at brackish-saline conditions continued in the North-West. Subsequent evaporation left marlstone including several hundred meters of halite. These processes partly created today's salt domes which are typically found in North-Western Germany.

2.1.2 The Tertiary

The Tertiary is informally the geologic period between approximately 65 and 2 Million years ago. This makes it the second youngest after the Quaternary /1/, /4/. One distinguishes between Paleogene, consisting of Paleocene (65 – 58 million years), Eocene (58 – 36 million years) and Oligocene (36 – 24 million years), and Neogene, composed of Miocene (24 – 6 million years) and Pliocene (6 – 1,8 million years) (Table 2.1). The formal name “Tertiary” was removed from geologic timetables in 2004 by the International Stratigraphic Commission; “Tertiary” is only used to denominate the entire period between the end of the Cretaceous and the beginning of the Quaternary.

Tertiary sediments are mainly clastic and poorly consolidated. Marls and calcareous rocks are the dominant rocks formed during the Paleocene, sandstones and tuffites during Eocene and Oligocene. Also Miocene and Pliocene were dominated by sandstones. Dropping temperatures beginning at the Oligocene could explain why organic and chemical depositions can rarely be found.

With the beginning of the Paleocene, flooding from the North set North-Western Germany under water. The Eocene transgression mainly left a lowered continent, creating lake and swamp as well as river sediments and creating lignite, mainly in Central Germany. This makes the Tertiary the second most important coal forming age after the Carboniferous in this region.

Repeated flooding during the Oligocene and subsequent regression left today’s land and separated the North Sea Basin. The North Sea and continental Northern Germany were significantly lower in altitude than the rest of Germany. This difference was filled with sediments that reach thicknesses of up to 3.000 m along the German North Sea coast. Salt domes created during Jurassic and Cretaceous continued rising in the shape of diapirs.

In the more recent Tertiary, the sea approached its current boundaries by a general uplift. Hence, marine sediments are more or less only found in proximity to current coasts.

Only Northern Germany remained more or less continuously flooded. Sediments in this region are thick and entirely of marine origin between Paleocene and Pliocene.

	Era	Period	Series	Absolute Time [Ma]	Lithology
Phanerozoic	Cenozoic	Quaternary	Holocene	0.01	Sands, gravel
			Pleistocene	1.8	
		"Tertiary": Neogene	Pliocene	6	Sands, sandstones
			Miocene	24	Sands, sandstones
		"Tertiary": Paleogene	Oligocene	36	Sandstones, tuffites
			Eocene	58	Sandstones, tuffites
			Paleocene	65	Marls, calcareous rocks
	Mesozoic	Cretaceous		135	Sandstones, slates, shales, carbonates
		Jurassic	Malm	195	Salts, sandstones, carbonates
			Dogger		Clays, iron-bearing sandstones
			Lias		Shaly sandstones, marls
		Triassic	Keuper	225	Salts, slates
			Muschelkalk		Salts, anhydrites
			Bunter		Sandstones
	Paleozoic	Perm	Zechstein	235	Dolomite, carbonate (e.g. Staßfurth), shales on top
			Rotliegend	285	Sandstones, conglomerates, salts
		Carboniferous		350	Shales, sandstones with coal seams
		Devonian		405	
		Silurian		440	
		Ordovician		500	
		Cambrian		570	
Precambrian				4,000	

Table 2.1: Geologic timetable, adapted for Central Europe/North-Western Germany, modified from Brinkmann /1/

2.2 Wellbore Stability

2.2.1 Mechanical Aspects

Generally, it can be said that borehole stability is directly proportional to mud weight /5/. In Figure 2.1 it can be seen that mud pressure has to exceed the pore pressure but not the fracture pressure at a given depth. This ensures that no formation fluids can flow into the wellbore in an uncontrolled manner but also that the rock is not hydraulically fractured by excess mud pressure.

It has been previously shown that the mud pressure required to support the borehole exceeds that required to balance and contain reservoir fluids, due to the in situ rock stresses which are greater than the formation pressure /6/. On the other hand, borehole instability is directly related to exposure time, drilling fluid reactivity, water loss, viscosity and temperature changes throughout the drilling process. At the rig site wellbore instability can be recognized by tight hole conditions, high torque and high drag as well as pack off (eventually resulting in no more circulation), fill on bottom, cavings which can be detected from the surface by edgy big chunks of rock at the shale shakers (visually distinguishable from smoother and smaller cuttings, cf. Figure 2.2 and Figure 2.3).

Wellbore stability is controlled by the in situ stress system. The latter can be described by the three principal stresses which are defined by being orthogonal to each other and oriented in a way that no shear stresses result: σ_v, σ_H and σ_h. σ_v is the lithostatic pressure or vertical stress and can be calculated by

$$\sigma_v = \rho_s \cdot g \cdot h \tag{2.1}$$

where ρ_s is the sediment density including pore space and pore fluids, h is the depth and g the gravitational constant.

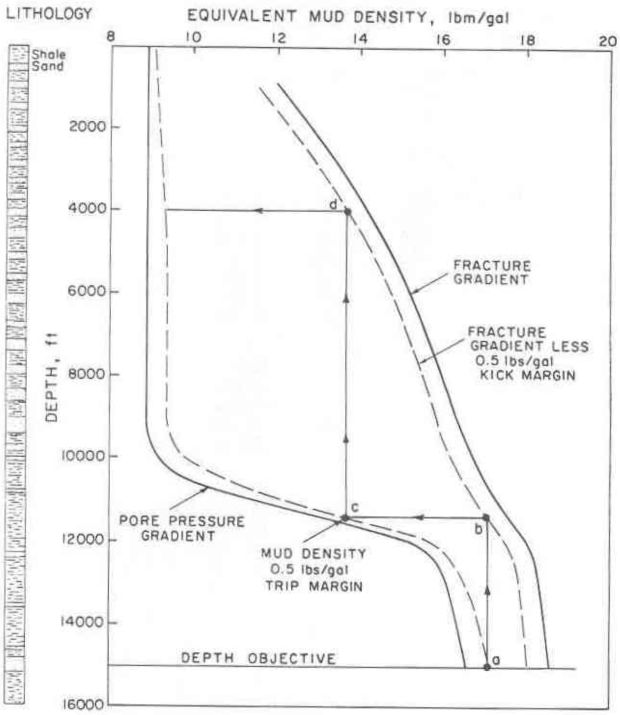

Figure 2.1: Mud weight window: pore pressure and fracture gradients including required mud densities vs. depth, in Bourgoyne et al. /20/

Figure 2.2: Sloughing rock chunks, frequently associated with more ductile rocks, rounded by tumbling /7/

Figure 2.3: Fine rock bit cuttings /7/

A good approximation for the geostatic gradient σ_v/h in North-Western Germany is 0,23 bar/m. As a principal stress, the vertical stress causes two principal stresses which are majorily determined by the physical properties and bedding conditions of the rock. In absence of dominating tectonic forces, the two horizontal stresses are assumed to be equal and can be computed by

$$\sigma_H = \sigma_h = \frac{\nu}{1-\nu}\sigma_v \qquad (2.2)$$

where ν = Poisson's ratio /8/. Normally in North-Western Germany the three principal stresses are σ_v (or σ_1, vertical principal stress), σ_H (or σ_2, maximum horizontal principal stress) and σ_h (or σ_3, minimum horizontal principal stress) where

$$\sigma_1 > \sigma_2 > \sigma_3 \qquad (2.3)$$

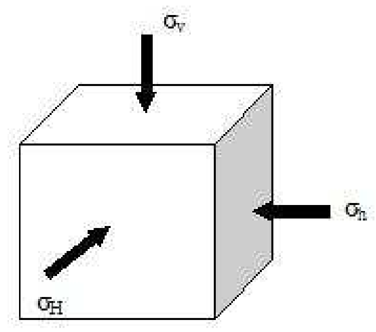

Figure 2.4: Sketch of principal stresses acting on a rock cube

σ_v can be calculated by the sediment density (see equation 2.1). σ_h is typically determined by Leak-Off Tests (LOT). σ_H has to be calculated by using e.g. Aadnøy's relation /9/:

$$\sigma_H = \frac{1}{2}(p_{failure} + p_w) \tag{2.4}$$

where $p_{failure}$ is the pressure (or stress) leading to rock failure and p_w is the pore pressure.

Before a well is drilled, the surrounding rock mass is in equilibrium. It will be destroyed by the excavation of the well. Around the borehole, tangential and radial stresses are created for linear-elastic conditions whereof the tangential can approach values double the original horizontal stresses at the borehole wall. The radial stresses are determined by the pressure that is exerted onto the borehole wall by the drilling fluid and augment with increasing distance from the wellbore until being equal to the horizontal stress in the undisturbed formation. On the other hand, the tangential stresses decline away from the wellbore. The lithostatic or vertical stress is only depending on the depth of burial and thus not influenced by any excavation. In the most profound case, drilling-induced stresses in vertical wells directly at the borehole wall can be described by

$$\sigma_r = p_m \tag{2.5}$$

$$\sigma_t = 2\sigma_{H,h} - p_m \tag{2.6}$$

$$\sigma_v = \rho_s \cdot g \cdot h \tag{2.7}$$

where σ_r stands for radial stress and σ_t for tangential stress.

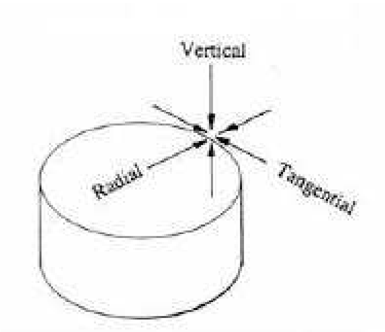

Figure 2.5: Stresses acting on the borehole wall, in Aadnøy /9/

Drilling hence leads to a modification in the stress system; the adjacent rock must now take the loads that were previously carried by the removed rock in order to re-establish the equilibrium. This redistribution yields a stress concentration around the wellbore which can lead to rock failure, depending on the rock strength. Figure 2.6 depicts the changes in stresses around the borehole wall at different pressures: the vertical stress remains constant independent of the mud pressure. The radial stress is related to mud pressure. The tangential stress falls with increasing mud pressure as the mud column supports the wellbore stability more and more. In the ideal case, tangential and radial stresses are equal, i.e. the mud pressure equals the original in-situ horizontal stress.

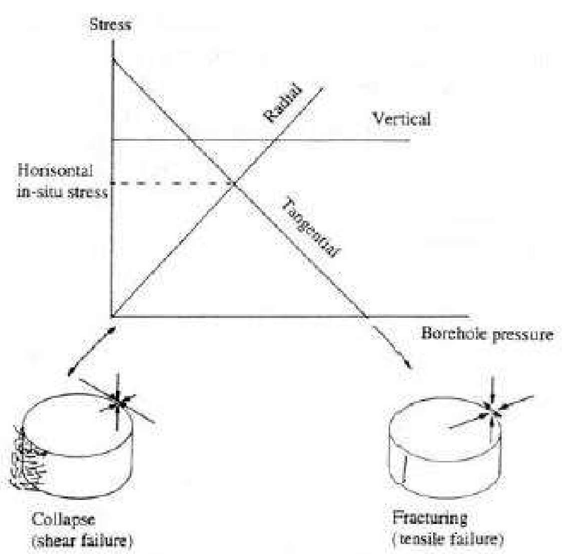

Figure 2.6: Stresses at the borehole wall at different mud pressures, in Aadnøy (1997) /9/

According to Aadnøy /9/ two principal failure scenarios can be deduced from Equations (2.5 – 2.7):

- Tensile failure due to exceeding the tensile strength of the rock by too high mud pressures
- Shear failure by exceeding the shear strength of the rock on account of insufficient mud pressures. One can further distinguish between brittle failure, leading to hole enlargement or collapse, and ductile failure, yielding a reduction in hole size /6/.

A drilling engineer can adjust the static stress concentration by modifying the magnitude of applied internal wellbore pressure, that is, mud pressure. Even though it is traditionally designed to prevent an uncontrolled flow of formation fluids into the wellbore, it must also be able to counteract rock strength and field stresses. A larger portion of the mud weight is required to support the borehole wall than to balance and contain fluids /6/. Dynamic effects such as friction pressure losses due to circulation or fluid flow around tight clearances between BHA and the open hole additionally impair the stress distribution at the borehole wall.

The calculation of drilling-induced stresses requires geotechnical parameters such as vertical and horizontal stresses as well as pore pressure and rock specific data (e.g. rock strength) have to be gathered. Table 2.2 depicts potential sources of information for their determination.

Mechanical factor	Information source
Vertical stress	Density logs, regional gradients
Horizontal stresses	Microfracturing, pressure integrity test, extended leak-off test, elliptical breakouts
Pore pressure	Repeated formation test, log overlays, gas units
Rock specific data (type and strength)	Cuttings analysis, open hole logs, core samples, hole collapse occurrence

Table 2.2: Sources of information for determining geological factors /7/

The minimum horizontal stress can be obtained by extended leak-off tests: after formation breakdown and fluid leak off, pumping at a slow rate is continued /7/ in order to make the fracture grow past the near wellbore region. The fluid pressure reflects the fracture propagation pressure. The intermediate stress can, additionally to equation 2.4, also be computed for example from equation (2.8):

$$\sigma_H = 3\sigma_{\min} - \sigma_{bd} + T - p_w \tag{2.8}$$

Where σ_H represents the maximum stress in the horizontal stress plane, σ_{min} the minimum stress, σ_{bd} the fracture breakdown stress, T the rock tensile strength in terms of stress and p_w the formation pore pressure. Since the rock tensile strength is hardly ever known, equation (2.9) is often simplified by applying σ_{reop}, the fracture reopening gradient:

$$\sigma_H = 3\sigma_{\min} - \sigma_{reop} - p_w \tag{2.9}$$

Wellbore Orientation and Stress Fields

In an extensional stress regime ($\sigma_v>\sigma_H>\sigma_h$), wells in the direction of minimum horizontal principal stress result in the least chance to compressive shear failure (breakout) /10/. The most stable deviation angle from the vertical depends on the ratio of σ_H to σ_v; the higher the ratio, the higher the deviation angle for minimizing breakout. In strike-slip stress regimes ($\sigma_H>\sigma_v>\sigma_h$) horizontal wells perpendicular to the maximum horizontal stress are the least prone to failure; the higher the ratio σ_H to σ_v, the closer the drilling direction should be to the azimuth of σ_H. When σ_H and σ_h are equal, a vertical well is the most stable to drill; in case of $\sigma_H/\sigma_v = 1$, it does not matter in which direction the wellbore is drilled.

Theoretical Description of the Stress Field around an Arbitrarily Inclined Wellbore

Zhou et al. (1996) presented this approach as “concept of minimum stress anisotropy around the inclined borehole wall” /11/. This implies that if the tectonic stress regime is known, the most stable drilling configuration, given by inclination and azimuth can be determined. An analytical solution of the stress field around an arbitrarily oriented wellbore can be obtained based on the assumptions that the principal stresses in the upper Earth crust generally act in the vertical and two orthogonal horizontal directions and that rock is isotropic and behaves like a linear plastic material up to the point of failure. First, the stress tensor has to be rotated from the global in situ coordinate system to a local borehole coordinate system, i.e. σ_x, σ_y, σ_z, τ_{xy}, τ_{xz} and τ_{yz} are expressed in terms of sine- and cosine-functions of the angles

- α which is the angle between σ_H and the projection of the borehole axis and the horizontal plane
- β being the angle between borehole axis and vertical direction

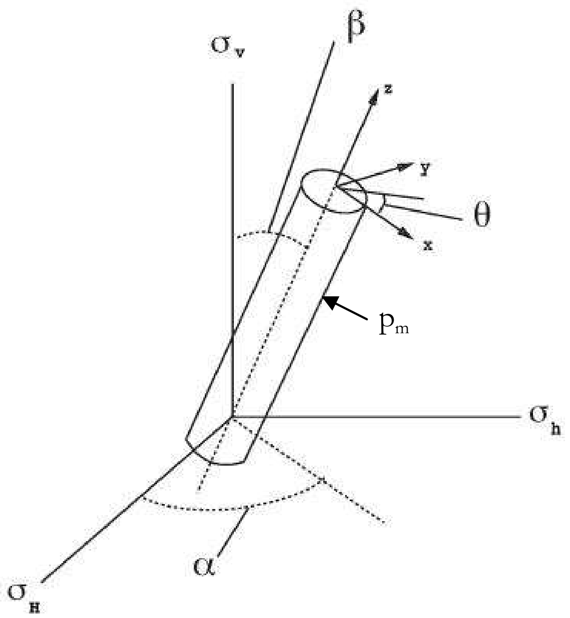

Figure 2.7: Borehole orientation and coordinate system used in the equations below, in Zhou et al. /11/

For an arbitrarily oriented wellbore, the stress tensor in the global in-situ coordinate system has first to be rotated to a local borehole coordinate system. It is given by

$$\begin{Bmatrix} \sigma_x \\ \sigma_y \\ \sigma_v \\ \tau_{yv} \\ \tau_{xv} \\ \tau_{xy} \end{Bmatrix} = \begin{Bmatrix} \sin^2\beta & \cos^2\beta\cos^2\alpha & \cos^2\beta\sin^2\alpha \\ 0 & \sin^2\alpha & \cos^2\alpha \\ \cos^2\beta & \sin^2\beta\cos^2\alpha & \sin^2\beta\sin^2\alpha \\ 0 & -\sin\alpha\cos\alpha\sin\beta & \sin\alpha\cos\alpha\sin\beta \\ -\sin\beta\cos\beta & \sin\beta\cos\beta\cos^2\alpha & \sin\beta\cos\beta\sin^2\alpha \\ 0 & -\sin\alpha\cos\alpha\cos\beta & \sin\alpha\cos\alpha\cos\beta \end{Bmatrix} \cdot \begin{Bmatrix} \sigma_v \\ \sigma_H \\ \sigma_h \end{Bmatrix} \tag{2.10}$$

Next, following equations describe the stress field directly at the wall of the wellbore:

$$\sigma_r = p_m \tag{2.11}$$

$$\sigma_t = \sigma_x + \sigma_y - p_m - 2(\sigma_x - \sigma_y)\cos 2\theta - 4\tau_{xy}\sin 2\theta \tag{2.12}$$

$$\sigma_{v'} = \sigma_v - \nu\left[2\,(\sigma_x - \sigma_y)\cos 2\theta + 4\tau_{xy}\sin 2\theta\right] \tag{2.13}$$

$$\tau_{tv'} = 2(-\tau_{xz}\sin\theta + \tau_{yz}\cos\theta) \tag{2.14}$$

$$\tau_{rt} = 0 \tag{2.15}$$

$$\tau_{rv'} = 0 \tag{2.16}$$

where p_m is the fluid pressure in the borehole, θ the polar angle in the borehole cylindrical coordinate system, ν is the Poisson's ratio, and σ_r, σ_t, $\sigma_{v'}$, $\tau_{tv'}$, τ_{rt}, $\tau_{rv'}$ is the stress tensor in borehole cylindrical coordinates.

Based on equations (2.11-2.16), the effective principal stresses on the wellbore wall, which are also perpendicular to each other, in the local wellbore coordinate system, can be expressed by

$$\sigma_{1'} = \frac{1}{2}(\sigma_t + \sigma_{v'}) + \frac{1}{2}\sqrt{(\sigma_t - \sigma_{v'})^2 + 4\tau_{tv'}^2} - n\,p_p \tag{2.17}$$

$$\sigma_{2'} = \frac{1}{2}(\sigma_t + \sigma_{v'}) - \frac{1}{2}\sqrt{(\sigma_t - \sigma_{v'})^2 + 4\tau_{tv'}^2} - n\,p_p \tag{2.18}$$

$$\sigma_{3'} = \sigma_r = p_m \tag{2.19}$$

where $\sigma_{1'}$, $\sigma_{2'}$, $\sigma_{3'}$ are the effective maximum, intermediate and minimum principal stresses in the borehole cylindrical coordinate system, respectively; σ_r, σ_t, $\sigma_{v'}$ and $\tau_{tv'}$ is the stress tensor in borehole cylindrical coordinates given by equations (2.11-2.16). Equations (2.17-2.19) presume that the effective fluid pressure is the minimum principal stress. If $p_m = \sigma_r = \sigma_{3'}$ is a principal stress, it follows that also the other two $\sigma_{1'}$ and $\sigma_{2'}$ are principal stresses. In this case

$$\sigma_{1'} = \sigma_t - n\,p_p \quad and \quad \sigma_{2'} = \sigma_{v'} - n\,p_p \tag{2.20}$$

where n is the pore pressure efficiency. In general the wellbore is stable as long as the tangential stress at the borehole wall does not exceed the rock compressive strength and the radial pressure (i.e. mud pressure) is sufficient to balance pore pressure.

Failure Criteria

Several criteria have been developed which help predict stress conditions where rock failure occurs, e.g. Drucker-Prager, Mogi, Tauber or Mohr-Coulomb /6/, /12/. For explanation purposes, the latter has been chosen and will be discussed in more details below.

Mohr-Coulomb Criterion

The Mohr-Coulomb failure criterion only takes the maximum and minimum principal stress, σ_1 and σ_3, into account and thus implicitly omits the influence of σ_2 despite the proof that it has a strengthening effect on rock /6/. Hence it is considered too conservative for computing the required mud weight; In addition, it predicts larger wellbore breakouts than occur in reality. Equation (2.21) (Mohr-Coulomb criterion) tells that rock failure in compression takes place when the shear stress τ that is developed on a specific plane a-b (Figure 2.8a) reaches a value that is sufficient to overcome the natural cohesion in the rock, as well as the frictional force that opposes motion along the failure plane:

$$\tau = c + \sigma_n \tan\varphi \tag{2.21}$$

where τ = shear stress, c = cohesion of the material and σ_n = normal stress acting on failure plane and φ = angle of internal friction. As Equation (2.21) will always first be satisfied in a plane that lies in the direction of σ_2, the σ_2 value will not influence τ or σ_n which explains why σ_2 has no effect on failure. Figure 2.8b shows the strength envelope of shear and normal stresses.

Mohr criterion assumes that at failure the shear and normal stresses across the failure plane are related by

$$\tau = f(\sigma_n) \tag{2.22}$$

where f is a function that can be obtained experimentally. Relation (2.22) can be represented by a curve in the τ-σ space; a linear form of Mohr's criterion is equivalent to Coulomb's criterion. σ_1 and σ_3 are again used to construct Mohr's circle, assuming that the fracture plane strikes into the direction of σ_2. The difference between the two failure criteria is that Mohr extended the failure criterion into 3D. Still, a linear failure relation as given by relation (2.22) is often named Mohr-Coulomb criterion.

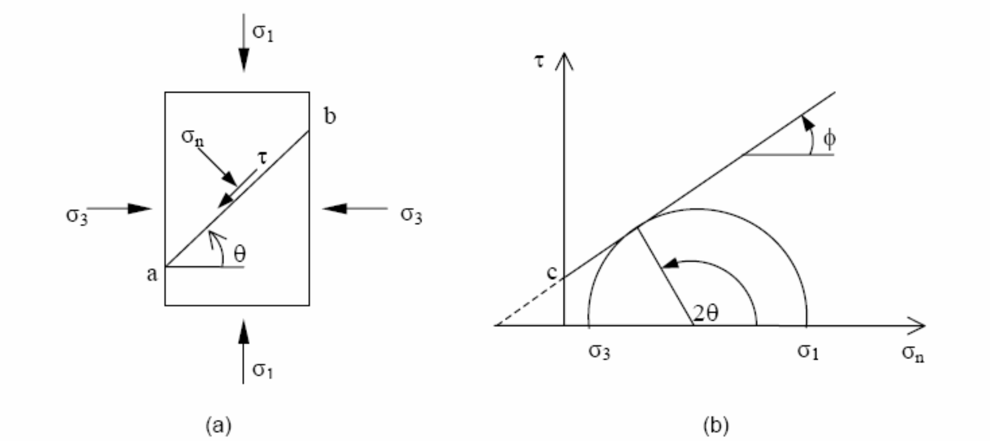

Figure 2.8: Mohr-Coulomb failure criterion: a) Shear failure on plane a-b. b) Strength envelope in terms of shear and normal stresses, in Al-Ajmi (2006) /6/

When polyaxial failure tests are done (e.g. Karman test) to determine the rock failure envelope (Mohr function) it is common practice to sketch occurring stresses into a shear stress vs. normal stress diagram, called "Mohr circle" (see Figure 2.9).

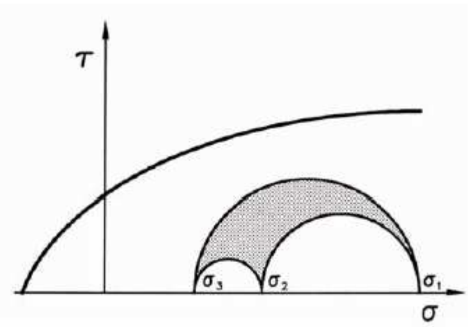

Figure 2.9: Example of a MOHR function in a shear stress – normal stress diagram, in Strauß et al. (2003) /13/

The multitude of Mohr circles at rock failure conditions defines a "failure envelope". For directional drilling that means if a stress state results in a Mohr circle below the failure envelope, the rock loading is considered stable.

It is important for triaxial tests that the maximum stress is applied axially. It has been shown that the tangential stress is of largest influence for wellbore stability /13/; hence, the applied radial pressure can equal the mud pressure, which in turn should exceed the simulated pore pressure in order to perform the measurements under realistic overbalanced conditions. Despite the theory of effective stresses, i.e. a reduction in effective stress with growing pore pressure, it can be expected that an increasing pore pressure also affects wellbore stability negatively. Figure 2.10 shows that the original stress state, denoted σ_1 and σ_3, lies below the failure curve and i.e. is stable. In case of an increase in pore pressure p_w, the shear stress remains constant since only the rock grains but not the pore fluid can transfer it.

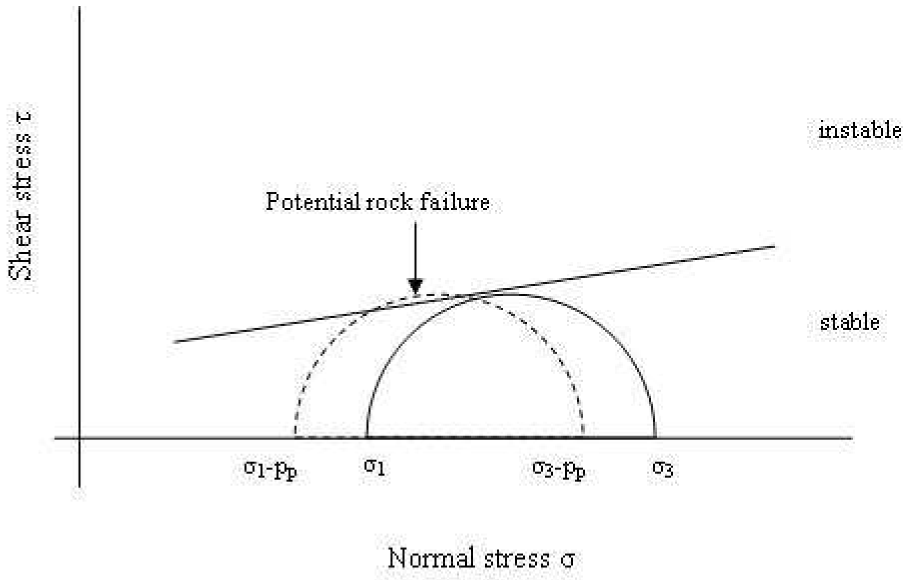

Figure 2.10: Theory of pore pressure increase, depicted by MOHR circle

The effective stresses however decrease by p_w, which shifts the Mohr circles to the left. If the failure curve was rock specific and thus constant, this increase in pore pressure would lead to exceeding rock strength and failure. A downward shift of the failure curve itself occurs in shales as soon as the clay hydration process begins and weakens the rock. Again failure happens due to exceeding the failure curve.

Laboratory experiments showed that high pore pressure induced earlier rock failure under axial loading /13/. First, the test specimen was pressurized up to the desired pore pressure and then subject to axial compression. Part of the pore fluids was squeezed back out of the specimen. A change in length could be measured. It is assumed that there is radial expansion with increasing pore pressure despite the inability to measure it with the specific experimental setup. Thus, the near-wellbore formation suffers from an increase in volume with increasing pore pressure which can only happen towards the wellbore. Frequently this is confused with swelling formations. Elastic behavior of the formation can be presumed in case the expansion is reversible, i.e. a return to original state with declining pore pressure. Opposing Figure 2.10, the decrease in axial strength is not equal the amount of pore pressure increase. This can be explained by the layered structure of the rock and the orientation of its single layers in the test specimen. The pore pressure acts like a tensional stress on the layers in radial direction. If no stabilizing pressure stabilizes the rock, it disintegrates more easily. Cohesive forces between the mineral grains are additionally lowered with increasing pore pressure and pore volume. It can be expected that the problem is more severe in boreholes whose axes are (nearly) parallel to the layering, e.g. horizontal wells. Therefore it is indispensable that the drilling mud helps avoid or at least delay a pore pressure rise and maintain slightly overbalanced drilling conditions. In order not to induce wellbore instability on purpose, it is suggested to avoid pressure spikes caused by e.g. suddenly shutting in the pumps or swabbing. Sudden pressure changes were proven to lead to fracturing and disintegration of shales /13/. The pressure in the wellbore should be lowered in a way that allows balancing of the pore pressure.

Drucker-Prager Criterion (Extended von Mises Criterion)

The Drucker-Prager criterion was originally developed for soil mechanics linear relationship between τ_{oct} (octahedral shear stress) and σ_{oct} (octahedral normal stress) /6/:

$$\tau_{oct} = k + m\sigma_{oct} \tag{2.23}$$

$$\tau_{oct} = \frac{1}{3}\sqrt{(\sigma_1 - \sigma_2)^2 + (\sigma_2 - \sigma_3)^2 + (\sigma_3 - \sigma_1)^2} \tag{2.24}$$

$$\sigma_{oct} = \frac{\sigma_1 + \sigma_2 + \sigma_3}{3} \tag{2.25}$$

where m, k are material constants and can be estimated from the intercept and the slope of the failure envelope plotted in the σ_{oct} and τ_{oct} plane. Drucker-Prager criterion includes σ_2 and does not require too many input parameters. However, it tends to overestimate the influence of σ_2 resulting in insufficiently high mud weight predictions.

Mogi Criterion

Mogi criterion considers the effect of σ_2 based on true triaxial tests, i.e. polyaxial where $\sigma_3 > \sigma_2 > \sigma_1$. Mogi noted that σ_2 has an impact on rock strength and that brittle fractures occur along a plane striking in the σ_2 direction. The criterion's drawback is its power-law form with two parameters that cannot be related to standard parameters, such as c (cohesion) and φ (angle of internal friction).

Time-Dependent Behavior – Mechanical Aspects

The period shortly after applying load to a saturated rock is termed consolidation which is gradually replaced by creep. The latter is “characterized by stress and time dependent strains at stress levels below the failure stress” /14/. It can be identified from strains occurring under constant effective stresses; however, varying effective stresses can also contribute to creep. It originates from viscoelastic effects in the solid framework and may occur in dry and saturated rocks. Following relations are characteristic for creep:

$$\dot{\sigma}_1(t) = 0 \tag{2.26}$$

$$\dot{\sigma}_2(t) = 0 \tag{2.27}$$

$$\dot{\sigma}_3(t) = 0 \tag{2.28}$$

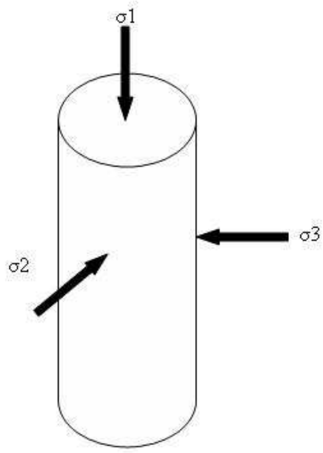

Figure 2.11: Principal stresses acting on borehole (sketch)

Creep strain can be represented by:

$$\varepsilon = \varepsilon_e + \varepsilon_1(t) + Vt + \varepsilon_3(t) \tag{2.29}$$

where ε_e = instantaneous elastic strain, $\varepsilon_1(t)$ = transient creep, Vt = steady-state creep, and $\varepsilon_3(t)$ = accelerating creep. At the primary stage, time-dependent deformation decreases with time and can be related to minor propagation of micro cracks. In the secondary or steady-state phase, the deformation rate is constant and the crack grows stably. The tertiary creep stage is characterized by accelerated strain rate that eventually leads to failure and is associated with unstable crack propagation (see Figure 2.12) /15/.

Laboratory tests were conducted at 80% and 90%, respectively, of the estimated differential stress at which failure would occur. Even if steady-state creep was not fully established, extrapolation towards infinite time yielded conservative estimates for steady-state axial creep rates. Those were compared with the total axial strain at failure stress which was determined by consolidated-undrained triaxial compression tests. It was found that if failure was anticipated to occur at approximately the same level of total axial strain, it would have required ten (for 90% failure stress) and twelve days (for 80% failure stress) to reach the failure strain. This conclusion implies that even at 80% of the expected peak failure stress, the rock could have failed within a time span which was “not unreasonable for open hole conditions” despite the conservative method for estimation of steady-state creep which “may result in an overestimation” /14/.

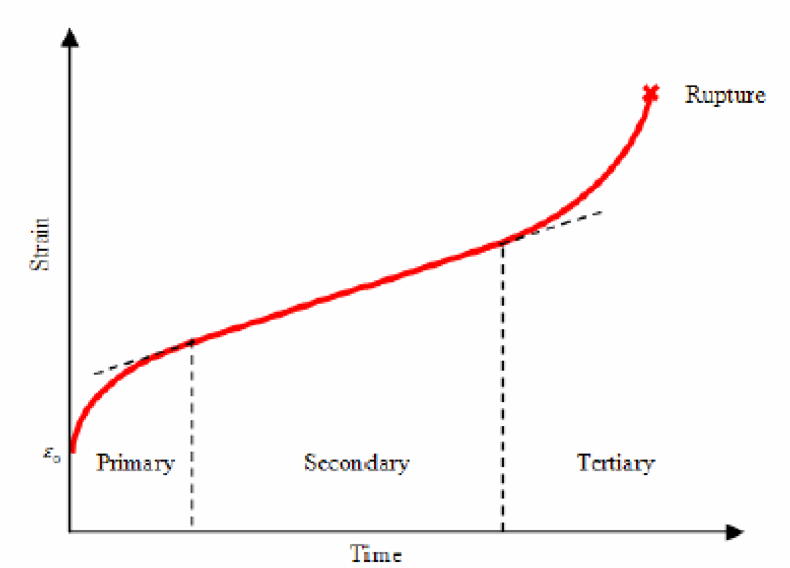

Figure 2.12: Stages of creep under constant stress, in Park et al. (2007) /15/

2.2.2 Chemical Aspects: Shale Behavior

Initially it should be stated that the term “shale” refers to everything from clays, being extremely reactive to water, to completely lithified materials such as claystones and slates, which are completely inert. Despite the fact that those materials behave quite differently when encountered during the drilling process, “it is desirable to develop a simple means of characterizing them.” /16/

The tophole section of wells in North-Western Germany typically comprises Quaternary to Upper Triassic formations and penetrates reactive shales especially in the Tertiary and Jurassic. Those are known to be sensitive rocks on account of their extreme reactivity with water. Due to their microstructure they can absorb water from the drilling mud into their crystalline lattice, leading to an expansion in volume depending on the specific minerals constituting the shale, respectively. The results are so-called “swelling clays” or “sloughing shales” that render the borehole wall instable and primarily yield borehole excavations or tight hole conditions. Those subsequently require extended reaming and circulation in order to re-establish a gauge hole. In case of inadequate pump pressure or insufficient mud, a phenomenon called balling up occurs /17/: a mass of sticky consolidated material, usually cuttings, accumulate on large-diameter drill string components, e.g. bits or stabilizers. They also tend to close the flow paths of the bit and those around the BHA which can be detected from the surface by pressure spikes. In case of severe balling up the pressure build up can suffice to cause tensile rock failure and subsequent lost circulation. If adhering to the drill string, hydrated shales can result in high torque that approaches or transcends the rig's maximum rotating capability; a common consequence is stuck pipe.

Shale Mineralogy

Shales are formed by the compaction of sediments which includes the expression of water during the burial by subsequent layers, provided that the water is able to escape easily to permeable formations. The degree of compaction is proportional to the depth of burial. Younger sediments in general soften and disperse when mixed with water whereas older shales have mostly undergone diagenesis, i.e. an alteration of clay minerals, secondary cementation, etc., which left them hard and insensitive to water. The feature that distinguishes all kinds of shales is their "dispersibility in water – soft clays disperse readily, harder shales disperse slowly when agitated, lithified materials will not disperse at all unless milled."/16/

Shales majorily consist of clays (aluminum silicates) and can be roughly classified into kaolinite or smectite-rich clays, which usually also contain illite, chlorite, kaolinite, smectite and combinations of smectite/illite as well as kaolinite/illite. They are built by tetraeders and octaeders alternating in layers (see Figure 2.13).

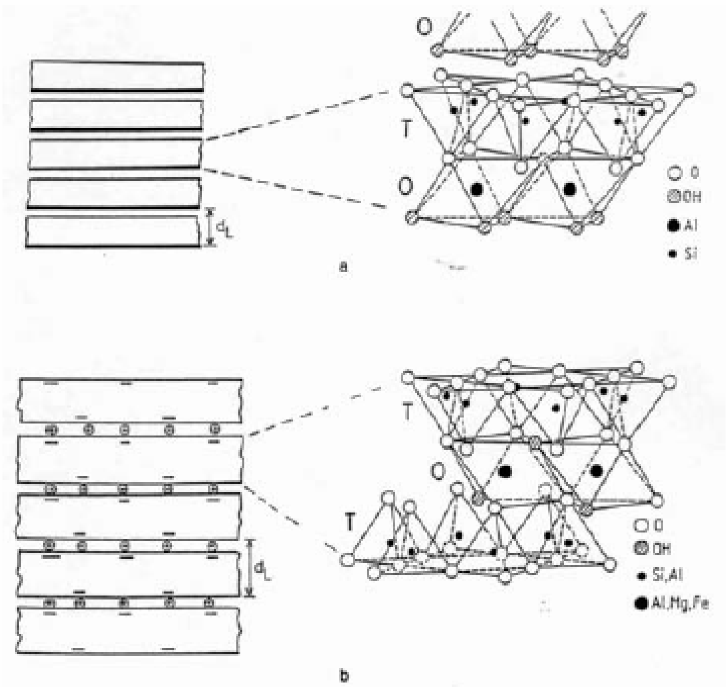

Figure 2.13: 3D sketches of a) 2-layer minerals and b) 3-layer minerals, in Strauß et al. (2003) /13/

Depending on the number of tetraeder and octaeder layers, one distinguishes between 2-layer (1:1) minerals, also named kaolinite (e.g. kaolinite, dickite, nakrite) and serpentine minerals. Two tetraeder layers surrounding one octaeder layer entitle 3-layer (2:1) minerals (e.g. talcum, pyrophyllite, montmorillonite, illite). Among their special properties is the large specific surface due to small particle sizes which makes them extraordinarily reactive. Furthermore, 3-layer minerals can all exchange cations between the layers, whereas in 2-layer minerals exchangeable cations are only found on their outer surface.

Due to their special mineralogical properties, 2:1 clays can establish hydrates in aqueous solutions depending on the water partial pressure and the concentration of electrolytes. As the dry clay is electro-neutral from the outside, only water without charge can be stored between the clay platelets. The higher the water partial pressure and the lower the electrolyte concentration, the more water layers can be absorbed between the silicate layers (one to four layers) as shown in Figure 2.14. In water or lean electrolyte systems, more than four water layers can form which deform or destroy the crystalline lattice. In general, up to two water layers are considered strongly bonded and do not influence the rock strength, two to six layers are called “loosely bound”, more than six layers are seen as free molecules. The strength of the rock decreases proportionally with the number of intracrystalline water layers. The more water is imbibed, the more plastic the rock behavior; the rock can “flow” along the layer boundaries. If the layers separate, a colloidal dispersion is formed of isolated silicates or layer “packages”. The inter-layer cations form a diffuse ion layer surrounding the particles. The higher the temperature and the lower the concentration of the electrolyte, the more cations join that diffuse ion layer. Eventually, more cations cause the decrease in adhesion between the silicate layers.

Swelling is the increase in volume and weight due to absorption of water or another solution and based on clay structure, the distribution of charges and surrounding cations. Swelling can either be unlimited or limited: unlimited swelling expresses itself in ever increasing volume and weight; in limited swelling, the weight and the pore pressure of the clay increase because the available volume for expansion is restricted. Two swelling mechanisms have been identified: surface hydration (also crystalline swelling) and osmotic swelling. First is normally of no influence in drilling since clays have already established their equilibrium with present pore water. The driving force of the latter is the difference in the concentration of ions between the clay mineral surface and the pore fluids. Since the cations between the clay layers are held back by the negative clay surface, only water between the layers can trigger the balance of concentrations and is thus drawn towards the clay surface. It diffuses the ions, thereby giving rise to the double-layer repulsive potential. It follows that osmotic swelling is depending on the charges on the clay surface, the exchangeable cations and the concentration of the electrolyte. Therefore it can be reversed if the concentration of salts in the external water is higher than in the clay mass. Depending on the hydraulic-chemical conditions the rock is either dehydrated or swells and is dispersed. In tight formations, osmotic interactions between mud and pore fluids dominate while in highly permeable rocks, hydraulic effects do.

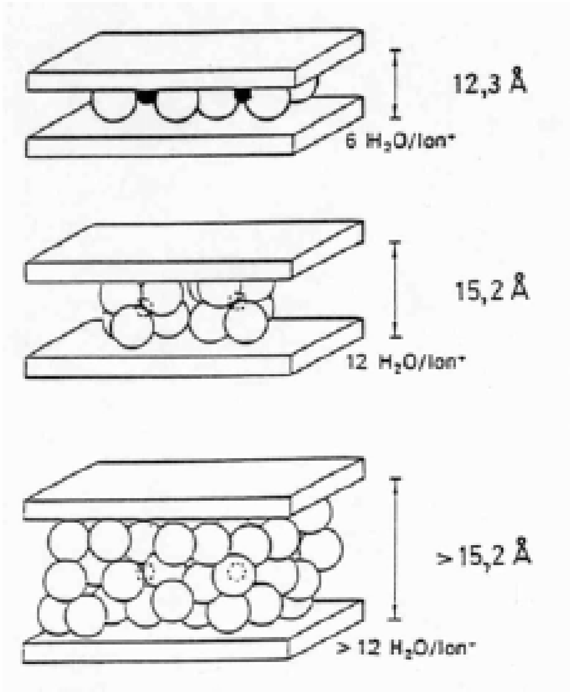

Figure 2.14: Hydration of 3-layer mineral, in Strauß et al. (2003) /13/

Osmotic swelling causes softening and significant volume increases, reaching a maximum in sodium montmorillonite: its cation permits expansion of the lattice so that osmosis does not only take place between the mineral's layers, but also between its particles. With divalent cations, e.g. Ca^{2+}, Mg^{2+}, osmosis happens between the particles only.

At any given depth the water content of the shale is determined by the effective stress (i.e. overburden load minus pore fluid pressure) and the swelling pressure will be equal to the effective stress. As soon as a borehole is drilled the lateral effective stress is zero; instead of a swelling pressure there is a suction of equal magnitude. Resulting, the shale imbibes water from the drilling fluid and expands laterally into the wellbore. The degree of expansion depends on the clay mineral content of the shale, and is, as mentioned ahead, maximum for sodium montmorillonite /16/.

Interaction between Shales and Mud - Destabilization

Rock strength is related directly to the water content of shale; modification of the pore pressure is a fundamental parameter altering the effective stress state of the wellbore /16/, /18/. Hence the driving forces in the interaction between clay and mud are the hydraulic gradient mud pressure-pore pressure as well as the potential differential between mud and pore fluid.

As no or only a thin filter cake is established at the borehole wall due to the low permeability of shales, the mud pressure acts directly on the formation, causing an increase in pore pressure in the near-wellbore area. How fast and to what extend it occurs depends mainly on the properties of the mud as well as on the petrophysical properties of the rock. Circulating for example clear liquids through the hole caused severe erosion whereas colloidal suspensions damaged the wellbore significantly less. The reasons were more favorable rheological conditions and the inhibition of the formation by a filter cake.

In case of an electrolyte concentration gradient out of the formation, water is absorbed by the shale, resulting in a volume increase or pore pressure buildup. Two different modes of failure because of swelling were observed in laboratory experiments:

- Constriction of the hole due to a soft swollen zone: the uptake of water is sufficiently high to cause plastic deformation. This failure mode was recorded in dispersible shales submerged in fresh water.
- Heaving of hard fragments: this occurred with saturated NaCl solutions in dispersible shales and with fresh water in older, less dispersible shales. The imbibition of water was less due to the suppression of interlayer osmotic swelling. As a consequence, the shale "heaved" into the borehole in firm fragments.

The laboratory tests proved that swelling could only be eliminated by diesel oil due to no free water /16/.

Time-Dependent Shale Behavior

Wellbore stability problems in shales cannot only be explained by the interaction between drilling mud and formation /13/; in order to conduct a detailed analysis, time-dependent, intrinsic effects such as shale consolidation due to hydraulic communication as well as creep have to be considered. In addition, two extrinsic mechanisms should be discussed: shale-fluid interaction, i.e. a change in shale behavior after extended contact with a non-native fluid, and temperature effects caused by mud temperature variations which "may alter the stresses and which may also affect the mechanical properties of the formation" /14/. This guarantees that realistic drilling conditions are implemented into the evaluation.

Hydrodynamic consolidation results from hydraulic communication between formation pore water and drilling mud. It is characterized by permeability, rock frame stiffness, fluid stiffness and porosity. To prevent any communication, a filter cake with a lower permeability than the surrounding formation must be established, sealing the borehole wall. Otherwise pore and mud pressure equalize over time, leading to zero radial effective stress; the mud pressure will penetrate further into the formation with time. Shale permeability mainly controls this development. There are however two cases where immediate pore pressure changes may be set up in the shale before any net flow of water. These are triggered by drilling-induced stresses:

- Plastic yielding of the shale around the borehole perimeter: drilling leaves the near wellbore area with a lower pore pressure which rises gradually until equilibrium with the wellbore is achieved. However, this leads to reduced effective stresses and thus “brings the rock to a more unstable situation.” It can be an explanation for delayed failure frequently experienced in shales. Moreover it points out the importance of shale permeability in wellbore stability evaluation.
- Boreholes in shales with anisotropic stresses, e.g. in formations with anisotropic horizontal stresses or around deviated wellbore.

3 Modern Drilling Technologies

In EMPG as well as in any other E&P company, various changes in applied drilling technologies have been realized in the past two decades. Partly, they were required by health, safety and environment (HSE) standards through state regulations or the companies' own safety policies, partly in order to keep up with both the state of the art and competitors. Recent borehole stability problems triggered questions about the influence of those advanced drilling technologies. How could wells drilled in familiar fields suddenly suffer from borehole instability issues where none were observed before? The observation that the field's geology could certainly not have changed within decades directed the search for the cause to the applied drilling techniques. Changes in the way how wells were drilled 20 years ago and today should be investigated, yet without any judgment on their impact and its weight.

3.1 Topdrive and Pipe Handling Systems

Since the early 1990's drilling rigs of EMPG's predecessors and its drilling contractors KCA Deutag Drilling GmbH and ITAG TIEFBOHR GmbH & Co. KG have been equipped with topdrive systems.

A topdrive is defined to be "a device similar to a power swivel that is used in place of the rotary table to turn the drill stem" /17/. Modern topdrives combine an elevator, power tongs, a swivel, and the hook. The topdrive system retains the rotary table to provide a place to set the slips in order to suspend the drill stem when drilling stops; it is no longer used to rotate the drill stem and bit. State-of-the-art rigs are additionally equipped with a mechanized means of making and breaking connections, called iron roughneck. It was introduced following a survey by the Norwegian Petroleum Directorate (NPD) in the early 90s, induced by severe work-related accidents in the years before. The result was named "Hands Off Working" and forbade manual work in a radius of 1,2 m around the borehole /19/.

In rotary drilling, which was the standard technique in the past, a hole is drilled by rotating the bit and simultaneously applying a downward force by the weight of the drill string. The rotary motion is imparted by a rotary table at the surface. It consists of a rotating machine inside a rectangular steel box, with an opening for the master bushing which further bears and turns the kelly bushing. The latter permits vertical movement of the kelly while the stem is turning. The opening must be large enough for passage of the largest bit to be run in the hole. The lower portion of the opening is contoured to accept slips that grip the drill string and prevent it from falling into the hole while a new joint of pipe is added to the drill string. The rotation itself is generated by the rig's power aggregates (diesel-electric or electric from public network) and transmitted to the rotary table by a drive-shaft assembly, drawworks sprockets, drive-shaft sprockets, and locking devices /20/.

3.1.1 Making a Connection When Drilling

Drilling with a Topdrive System

The following single steps have been identified to make a connection during the drilling process using a topdrive:

1) Set slips around drill pipe.
2) Break connection with topdrive.
3) Lift topdrive.
4) Pick up new triple from derrick with elevator.
5) Stab new triple into last box and make connection with iron roughneck.
6) Connect last drill pipe in triple with topdrive.
7) Drill length of triple (approximately 28,5 m).
8) Start at 1).

Rotary Drilling

A detailed list of steps to make a connection in rotary drilling should enable a direct comparison with the drilling with a topdrive system.

1) Set slips around drill pipe.
2) Open and lay down elevator.
3) Open the hook, connect with swivel and kelly.
4) Make connection kelly-single drill pipe by rotary tongs.
5) Unset slips, lower drill pipe into hole until kelly bushing lands in master bushing.
6) Drill length of kelly (approximately 9,5 m).
7) Lift drill string until last connection over rotary table, set slips.
8) Break connection at kelly saver sub, put kelly into rathole.
9) Open hook and remove swivel, pick up elevator.
10) Pick up new single drill pipe from mousehole.
11) Stab new drill pipe into last box and make connection by rotary tongs.
12) Lower until new last connection over rotary table.
13) Start again at 1).

Simply by investigating the number of work steps, it becomes obvious that making a connection in rotary drilling required moving the drill string in the wellbore more frequently than with a topdrive. the drill stem had to be lifted and lowered the length of the kelly in order to add a new drill pipe. For topdrive systems, this is not necessary – the number of borehole wall conditioning with topdrive systems is reduced compared to conventional rotary rigs.

Wellbore Conditioning

One of the main differences between rigs with topdrive systems and those with rotary table and kelly is the ability to constantly rotate the string while circulating, be it on the upward or downward motion. The kelly/rotary table configuration restricts the upward drill string rotation to the length of the kelly; further lifting of the string causes the kelly bushing to be pulled out of the rotary table and stops the transfer of rotation to the drill stem.

Frequently, hole sections have to be cleaned after drilling by reaming. This becomes necessary when the hole quality is not satisfying, because of e.g. an under-gauge hole or insufficient cuttings removal. Often, reaming is performed to remove ledges or tight spots in the wellbore. In formations which are known to depict plastic behavior, i.e. certain shales in the North-West German Lias, it is tried to keep the borehole in gauge by reaming before casing is installed. Reaming is a process in which the driller rotates and moves the drill string up and down; it can be accompanied by circulating drilling fluid to clear the hole of debris, which is referred to as washing /17/. The tool used to smooth and enlarge the borehole wall is called reamer. It is often integrated into the drill string and additionally helps stabilize the bit and straighten the wellbore.

Drilling with a topdrive reduces reaming to after a stand is drilled (approximately 28,5 m) and before a new one is added. Kelly drilling in contrast implies improved wellbore conditioning: by only adding a single connection at a time and hence frequently pulling the kelly out of hole, the walls are worked on continuously and thus tend to be smoother.

Drilling with a topdrive constantly leaves the bit bottomhole, permitting a faster drilling process, yet risking prolonged well conditioning thereafter.

Rotational Speeds

Based on morning reports average rotational speeds in drilling with a kelly were higher than modern ones. Previously, the entire string was rotated by the rotary table at approximately 150 min^{-1}. Today, only 80 min^{-1} are typical with an extra number of rotations delivered directly to the bit by the downhole motor. The latter depends entirely on the motor design and the pump rate with which the stator in the downhole motor is rotated.

In order to assess the quantity of borehole wall contacts caused by both topdrive and rotary drilling, a method to compute those contacts was developed based on reported gross ROP, drill string rotations per minute as well as rotation method, i.e. topdrive or rotary table.

Following input parameters are needed for the calculations:

- Average reported gross ROP [m/hr]
- Length of DP [m] and kelly [m]

- RPM of drill string, i.e. of rotary table or topdrive system, not including additional RPM at the bit by downhole motor
- RPM when pulling out of hole (POH) and running in hole (RIH), respectively, [min^{-1}]: the same value for all wells under investigation can be used
- String velocity when POH and RIH, respectively [m/s]
- Number of reaming trips (up and down movements)

Following equations were used for calculating the borehole wall contacts:

$$Rotations\ per\ meter\left[m^{-1}\right] = \frac{RPM\ Drilling\left[hr^{-1}\right]}{net\ ROP\left[\frac{m}{hr}\right]} \tag{3.1}$$

$$Rotations\ POH/RIH\ \left[m^{-1}\right] = \frac{RPM\ POH/RIH\left[hr^{-1}\right]}{tripping\ string\ velocity\left[\frac{m}{hr}\right]} \tag{3.2}$$

$$Contacts\ drilling\ [1] = Rotations/meter\ \left[m^{-1}\right] * length\ DP[m] \tag{3.3}$$

In topdrive drilling, the length of the drill pipe which is used in equation 3.3 has to be that of a triple.

Rotary Drilling:

$$\begin{aligned} Contacts\ POH\ [1] = {} & Number\ ream.\uparrow *(length\ kelly * rotat.POH \\ & + length\ DP) + number\ POH * (length\ kelly * rotat.POH \\ & + length\ last\ \ pipe\ above\ rotary\ table) \end{aligned} \tag{3.4}$$

$$\begin{aligned} Contacts\ RIH\ [1] = {} & Number\ ream.\downarrow *(length\ kelly * rotat.\ RIH \\ & + length\ DP) + length\ DP \end{aligned} \tag{3.5}$$

Topdrive Drilling:

$$\begin{aligned} Contacts\ POH/RIH\ [1] = {} & Number\ ream.\uparrow / \downarrow *length\ triple \\ & * rotat.\ POH/RIH \end{aligned} \tag{3.6}$$

Two additional assumptions have been made:

- The drill string above the BHA, which is of smaller OD, touches the wellbore wall at least partially and thus contributes to conditioning it, even in vertical wells.
- If during POH or RIH less than 1 rotation per meter results from fast tripping speeds or too little string rotation, it is assumed that the string touches the wall once at the reference point.

Figure 3.1 shows the result of calculated borehole wall contact calculations during drilling operations: two wells were chosen where one was drilled with rotary table and kelly (represented by red line) and the other with topdrive (blue line). In order to assess the amount of wall conditioning, an exemplary interval of 100 m of length was analyzed with five reference points at 25 m distance each (the last point was shifted to 99 m for computation purposes). The reference points represent the perimeter of the wellbore which ensures that also partial contacts with the drill string at the given depth, e.g. the drill string leaning to either side, are counted. A sketch of the drill string in the borehole is attached in the Appendix.

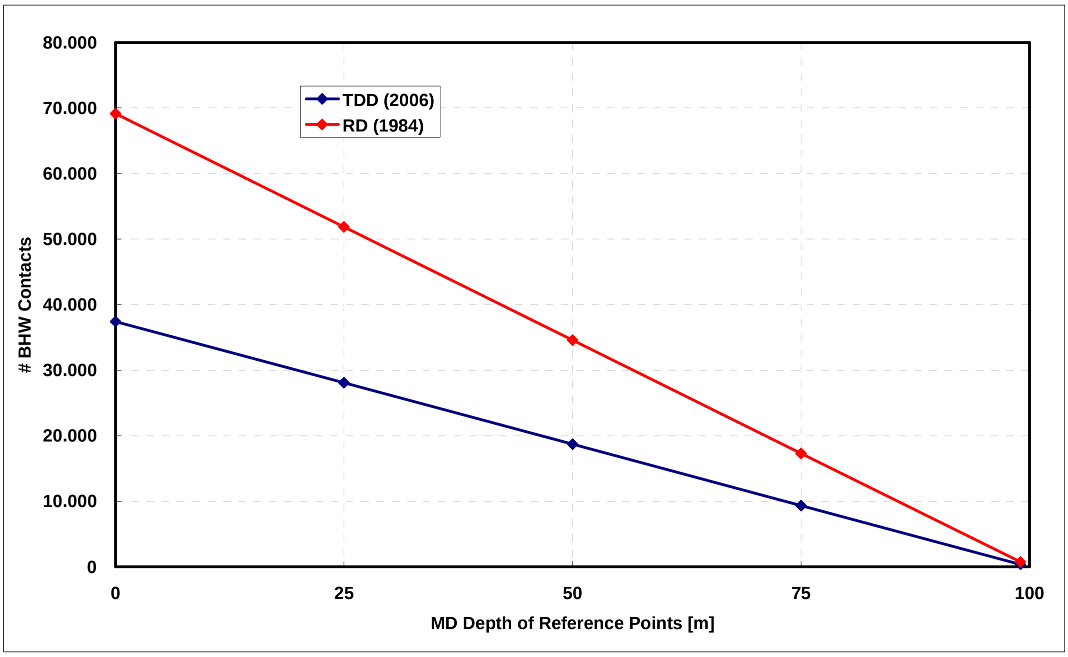

Figure 3.1: Number of theoretical borehole wall contacts in drilling with rotary table and kelly compared with topdrive system

It should be noted that the developed model delivers semi-quantitative results; those should rather indicate the qualitative trend of borehole wall contacts rather than comparing exact numbers. Reported gross ROP and RPM are averaged data over varying geological intervals obtained from morning reports; those only contain one single operations parameter, e.g. RPM, WOB, pump rate or pressure, for a time span of 24 hours. However, as all data from different wellbores all suffer from the same range of inaccuracy or error, they can be compared among each other.

Chapter Summary

In conclusion it has been found that topdrive drilling increases the ROP, simultaneously leaving the borehole in a worse quality due to a dropping wall conditioning during drilling. On the other hand it must be stated that fast drilling through reactive shales reduces their exposure time with water and thus the total damage drilling mud causes; in those hole sections drilling with topdrives should be advantageous over kelly drilling.

3.2 Wellbore Orientation - Directional Drilling

Directional drilling signifies controlling the orientation of a wellbore in space which is described by the angle of inclination (i.e. the deviation from vertical) and the azimuth (the northing of the borehole in plan view). It enables reaching subsurface areas laterally remote from the point where the bit enters the earth. Modern directional drilling is mostly initiated by kicking off with a bent included in the motor itself as bent housing. The bent element, triggering the deviation from vertical, can be deflected to angles between 0 and 2° where 1-1.2° are common practice. Deflection angles exceeding 2° restrict drilling to rotating the bit only as the drill string would rupture. Adaptation of inclination or/and azimuth are done in the so called sliding mode where rotary motion is transferred to the bit even if the string is not rotated: a rotor, which is connected to the bit, is integrated into the motor housing and is turned by mud circulation due to its special configuration with a stator. Depending on where the tool face points at, i.e. how side forces are applied onto the bit, inclination is either build up or dropped down and azimuth is changed. Sliding drilling is performed until a desired inclination or azimuth are achieved which are measured by a pendulum and compass, respectively, in the BHA. Information is transmitted uphole by mud pulses which can be decoded on the surface which requires shutting in pumps. As soon as direction and deviation from vertical are determined and agreed upon, rotary drilling is resumed – the entire drill string is rotated, maintaining inclination and azimuth. More recently, rotary steerable systems have been developed for controlling the direction but also exact verticality of wellbores. Their special feature is continuous rotation of the drill string; directional drilling is accomplished by hydraulically-activated pads that exert a side force on the BHA, resulting in a change of inclination and/or azimuth. Sliding drilling periods with a static string can be avoided. Moreover, the entire wellbore is constantly worked on by the rotating drill string and especially the tool's pads.

Chapter Summary

It can be concluded that directional drilling imposes loads on the near wellbore area which depend on the wellbore inclination, azimuth and the inherent stress field, described by σ_v, σ_H and σ_h. Resulting stresses at the borehole wall can be calculated by the relations given in chapter 2.2.1 ("Theoretical Description of the Stress Field around an Arbitrarily Inclined Wellbore") and then have to be compared with an appropriate failure criterion, e.g. Mohr-Coulomb. If the produced stress configuration exceeds the failure curve, which is inherent to the rock, wellbore instability can be expected.

If downhole motors are used to control the wellbore path, the number of borehole wall conditioning during sliding drilling periods is reduced to the contact with the bit; rotary steerable systems require drill string rotation and thus work the wall continuously.

3.3 Drilling Mud Systems

The ongoing development of more sophisticated chemicals and synthetic drilling muds has brought changes in the way wells are drilled. The predecessors of EMPG nearly exclusively employed fresh- and salt-water clay-base muds in the tophole section, i.e. the interval between the surface and the 13 3/8" casing shoe. Shale formations were typically drilled with KCl water-based or oil-based mud. Today, various other types such as water-based muds containing polymers and other chemicals are being used, providing a tailor-made fluid system in order to drill through any kind of formation. One aspect is the design of filtration properties, i.e. filter cake thickness and the volume of filtrate. The filter cake should be thin and slick, preventing filtration of the aqueous mud phase into the formation and pore pressure build up. The latter is restricted to the area directly around the wellbore in case there is void pore space and permeability due to either natural pore space connections or drilling-induced microfractures. By choosing the sizes of mud solids according to pore throat sizes along the borehole they can bridge pore openings after the first spurt losses and create a tight barrier between mud and formation. One can also adjust those properties by adding filtration reducers which can either act on the clay solids to improve their filtration control characteristics, or directly by acting as a colloid or viscosifier. Common fluid loss control agents are lignosulfonate and lignite which deflocculate flocculated bentonite and thereby reduce fluid loss. Lignosulfonate also tends to protect bentonite from contaminating ions (e.g. calcium and magnesium) which can induce flocculation. Lignite eliminates the problem by precipitating the ions; it is also employed as replacement for bentonite in case of viscosity issues. Alternatively, water-soluble polymers such as starch, carboxylmethyl cellulose (CMC), polyanionic cellulose (PAC) or polyacrylate (if higher thermal stability is required) can be added /21/. Simultaneously, however, most also affect flow properties (i.e. are viscosifiers).

Wells in the North-West German basin penetrate long intervals of water-sensitive clays and shales which tend to absorb water into their crystal lattice, resulting in pore pressure build up. A way to avoid problems is the usage of "inhibitive muds": they largely reduce the ability of active clays to imbibe water and accordingly make them insensitive to the contact with it. Inhibitive muds prevent formation solids from readily disintegrating into extremely small particles and entering the mud (dispersion) by building a sealing layer on the surface of clay formations. They decrease the shale's effective permeability, prevent a pore pressure build up and balance salt concentrations in the rock and the mud filtrate /13/.

3.3.1 Salts in Water-Based Mud

Generally, the addition of salt to a water-based mud reduces the hydration of shales by lowering the activity of the water phase, i.e. limiting the number of ions available for reaction compared to all ions in solution and thus osmotic swelling. A lower activity of the water phase can be detected by a higher concentration of salt. In addition,, the electrolytes can base exchange with ions on the clay structure, converting the clay to a less reactive state /21/.

KCl

The efficiency of the K^+ ion is based on its size: it fits exactly between the layers of clays where it is bound tightly to the negatively-charged silicate layers. Thereby it limits the remaining cohesion forces which usually attract water molecules; the tendency of clays to hydrate is restricted and the resulting K^+-clays can only absorb little water. KCl is especially efficient as an additive in montmorillonite-rich clays. Excessive addition of KCl in turn might lead to wellbore instabilities: it drains pre-saturated clay, makes it brittle and eventually causes its collapse. The disadvantage of KCl mud is its inability to cover the borehole wall with a filer cake to reduce its permeability. As a result large volumes of mud can enter the formation /13/, /20/.

NaCl, $CaCl_2$, $CaBr_2$, Formates (MCOOH) and Acetates (MCH^3COOH), $M=Na^+$, K^+, Cs^+)

Even if the efficiency of Na^+ is inferior to K^+, its higher solubility is among its advantages. Highly-concentrated NaCl muds show high viscosities which reduce filtration. NaCl acts as an inhibitor in mud if combined with additives, which alter the properties of the borehole surface (e.g. silicates). Concentrated Ca^{2+}-muds also inhibit by high viscosities, reducing filtration. In addition, they support the balancing of osmotic pressures. Formates and acetates act in the same way as Ca^{2+} by increased filtrate viscosities and high osmotic pressures. Especially KCOOH is useful in inhibitive muds as it reduces the swelling pressure beside the clay's water content /13/.

3.3.2 Oil-Based Mud Substitutes on Water Basis

Since even salt cations, e.g. K^+, can be replaced by others in clays, alternative ions were searched for /10/, /13/. Nowadays, polymers with (multi)functional groups of positive charge have been employed in drilling muds. To discuss the polymer's effect on shales, one has to distinguish between high and low molecular weight polymers. First, such as PHPA (partially hydrolyzed polyacrylamide), with molecular weights > 10.000 [g/ml], are too large to enter the crystal structure but do adsorb on multiple sites on adjacent individual clay particles, preventing their destabilization through dispersion. Laboratory tests where bentonite samples were submerged in PHPA solution for two weeks showed that the specimen was not entirely wetted after the period, i.e. that the polymer formed an impermeable, yet time-limited, film around it.

Low-molecular weight polymers, e.g. PAC, can enter the formation matrix but usually too slowly compared to pore pressure build up processes; hence they are only stabilizing cuttings and viscosify the water phase, thereby reducing water inflow to the formations. Generally many additives sold as shale stabilizers function as viscosifiers.

M-I Swaco's "UltraDril" system is presented in more detail as it is used by EMPG: it contains three key components /22/: The shale-hydration suppressant is a water soluble, complex amine-based molecule which fits between clay platelets, thus "tends to collapse the clay's hydrated structure and thereby greatly reduces the clay's tendency to imbibe water from an aqueous environment" /22/. It requires minimum salinity for functionality. The shale-dispersion suppressant is a low-molecular weight copolymer which, with its specific weight and charge density, imparts encapsulation by limiting water penetration into the clays. The cationic charge provides improved clay-surface binding on the polymer and tolerance to high salinity and hardness." The accretion suppressant consists of a blend of surfactants and lubricants that are designed to coat the cuttings and all metal surfaces. Hereby they reduce the tendency of cuttings to adhere on metal components, preventing any build up of drill solids below the bit, as well as agglomeration of hydrated cuttings with each other.

3.3.3 Other Inhibitive Water-Based Muds

Saccharides and methylene glycosides are environmentally friendly, low-molecular weight polymers that increase the viscosity of drilling fluids and prevent their filtration into formations /13/. Moreover they reduce the water activity, thus creating an osmotic pressure dehydrating shales. Because saccharides are susceptible to bio-degradation, methylene glycosides, another type of carbon hydrates, have been developed alternatively. (Poly-) Glycerol, e.g. glycerin, and (poly-) glycols with molecular weights > 10.000, also increase the viscosity of the filtrate and limit the invasion into the formation. "Clouding" or TAME (thermally-activated mud emulsion) glycols present another inhibition mechanism; they are water soluble below a certain temperature (cloud point temperature CPT) and form a separate emulsion phase above it. The mud bottomhole circulation temperature is lower than the CPT, i.e. the glycol is water soluble and can enter the formation. As soon as the pumps are shut in, the wellbore warms to the bottomhole static temperature (BHST) which corresponds to the geothermal temperature. By design of the glycol itself and salt concentration in the mud the CPT equals the BHST so that a separate emulsion phase is formed which prevents further filtration and lowers the mud pressure onto the formation. A combination of polyols (polyglycerol, polyglycols or methylene glycosides) and salts (NaCl, $CaCl_2$) proved to be especially efficient. In effect, multiple inhibition mechanisms, i.e. osmotic stabilization and increase of shale membrane efficiency, act simultaneously and support both cuttings and wellbore effectively.

An example is Baroid's "PerformaDril" contains "PerformaTrol", a shale stabilizer, and GEM GP, a glycol additive /23/.

Alternatively water soluble silicates are employed for inhibition: they enter the shale and form insoluble connections in the presence of polyvalent cations (e.g. Ca^{2+}, Mg^{2+}). At a pH ≤ 7, silicates tend to develop a gel structure that keeps filtrate from invading the rock and pore pressure down. Silicate based muds in shales reduce filtration but tolerate water transport through osmosis/diffusion; this effect can be improved by adding salts (e.g. NaCl). Thus, they are especially recommendable in fractured or faulted shales.

3.3.4 Oil-Based Mud

By regulations, oil-based mud can only be used when the surface casing is set in order to protect shallow freshwater reservoirs. Despite higher costs and more stringent pollution control procedures compared to water-based muds, it proved to be the most effective fluid system in inhibiting clays and is usually preferred because of its composition: diesel or mineral oil is the major component, commingled with brine and additives. Laboratory tests investigating the pore pressure build up of test specimens in several drilling muds concluded that oil-based mud was the highest inhibitive since its existing phase differences and resulting surface stresses prevent it from entering the low-permeable shale matrix. Osmotic flow governs the interaction between shale and mud and "the chemical potential differences between the" oil-based mud "and the shale result in the selective transport of water into or out of the shale" /13/.However, only an insignificant portion of the aqueous phase was able to disperse less than 0,1% of the shale sample in lab tests. Even subsequent contact with water could not destroy the oil film and harm the specimen /18/.

Chapter Summary

Based on the sophisticated chemistry compared to past fresh- or salt water bentonite muds, it can be presumed that modern water-based muds cannot be blamed for current wellbore stability problems.

However, considerably lower filtration volumes of oil-based muds lead to a superior performance in shales which makes them preferred fluid system in clay formations. Resulting, oil-based mud can avoid rock weakening effects discussed in the previous chapters on water-based mud. It cannot be the factor responsible for recent wellbore stability negatively.

3.4 Bit Types

Similar to the developments in all areas concerning drilling oil and gas wells, bit types and their performance properties have changed based on extensive research. Longer lasting as well as more efficient drilling tools are around nowadays; it was recognized that especially an increased stand time would diminish the number of roundtrips that were once required to exchange worn, broken or under-gauge bits. By improving the life time of a bit, faster gross ROP could be accomplished, implying reduced open hole times. This is especially beneficial in instable or water-reactive formations where it is crucial to protect the wellbore from collapse as soon as possible by installing casing.

The main types are drag and roller cone bits. The design features of drag bits include the number and shape of the cutting blades or stones, the size and location of fluid courses, and the metallurgy of the bit and cutting elements /20/. They destroy the rock by ploughing or shearing rock chips from the bottom of the well, comparable to a farmer's plough. The cutting blades can either be made of steel, diamonds or polycrystalline diamonds. Their main advantage over roller cone bits is the lack of moving parts which typically require strong, clean bearing surfaces. That distinguishes them especially in smaller hole sizes where no space is available for designing strength into both the bit cutter elements and the bearings of a rolling cutter. Drag bits can be made out of a single piece which reduces the chance of bit breakage and junk in the wellbore. Changing the shape of drag bits enables to design for various rock strengths: "fishtail" bits with long blades are generally used in soft, unconsolidated formations; in abrasive and harder rocks, bits with shorter blades and a smoother shape should be employed. Since drag bits with steel cutting elements are dulling rapidly in hard rocks and their cleaning in gummy formations is problematic, they have been vastly replaced by other cutter types, e.g. polycrystalline diamond cutters (PDC). Those consist of sintered polycrystalline diamonds, bonded into a cemented tungsten carbide substrate in a high-pressure/high-temperature process. The bit matrix contains many small diamond crystals with randomly oriented cleavage planes in order to prevent the propagation of any shock-induced breakage through the entire cutter. They are best performing in non-abrasive and not "gummy" soft to medium-hard formations. Hydraulic cleaning is accomplished by jets or so called water courses. Beside the life of the cutting elements, the stand time of roller cone bits is largely influenced by their bearings. The most inexpensive bearing assembly consists of a roller-type outer bearing, a ball-type intermediate and a friction-type nose bearing. The outermost bearing is most heavily loaded and thus tends to wear and fail first. The intermediate bearing carries mainly axial or thrust loads and also serves to hold the cone in place. It is supported by the nose bearing. In the standard design, this kind of bearing assembly is lubricated by the drilling mud, leaving passages for solids to enter and destroy it. Sealed bearing assemblies are kept in a lubricated environment by grease seals, a grease reservoir and a compensator plug, allowing the grease pressure to be balanced with the hydrostatic fluid pressure bottomhole. The absence of abrasive material in the bearing compensates the reduction in its capacity due to the required space for the grease seals. The most advanced design eliminates roller bearings and substitutes them by journal bearings. Their biggest advantage is the increased contact area through which weight is transferred to the cone. Further strengthening of the remaining components is possible because of fewer components. In order to function properly effective grease seals are required besides special metallurgy and close tolerances during manufacture. Their increased cost is offset by significantly longer runs, reducing time spent on tripping operations.

Chapter Summary

Concluding, it can be seen that advanced bit bearing technology resulted in extended standing times of bits and thus diminished tripping to recover broken or worn tools. The introduction of synthetic diamond drags bits, lacking moving parts, excluded the possibility of broken bearings and provided tools able to handle nearly all formations, except abrasive sandstones or “gummy” shales. In total, improved bit technology manipulated non productive time positively.

3.5 Pump Rates and Pressures

New drilling technologies enable faster drilling, identified by higher ROP. This on the other hand also requires enhanced hole cleaning which commonly restricts the growth of ROP as shown in Figure 3.2: there is a certain threshold weight on bit (WOB) before penetration into the rock begins. Then, ROP increases until the bit starts foundering because of inefficient hole cleaning. By optimizing the bottomhole cleaning efficiency through improved bit hydraulics as well as higher circulated fluid volumes, the rate of drilling can be maximized. Higher mud volumes have to be circulated today compared to two decades ago in order to comply with faster drilling campaigns. Moreover, higher pump rates can be realized with larger drill pipe OD (6 5/8” instead of 5”).

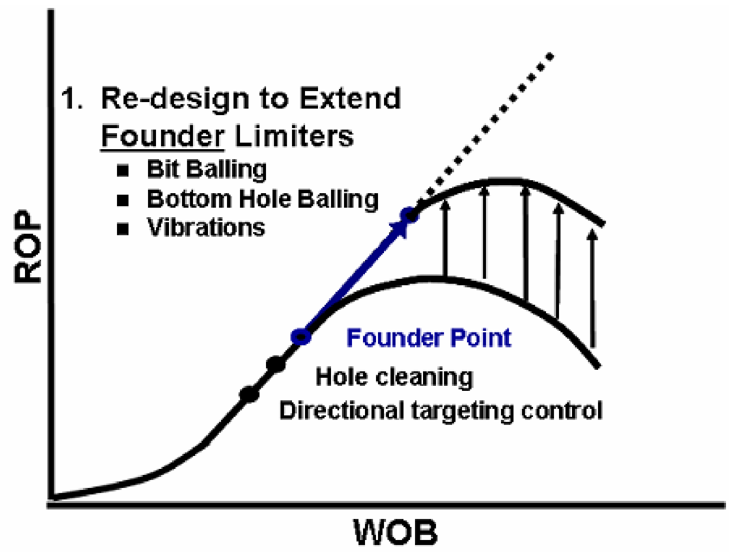

Figure 3.2: Rate of penetration versus weight on bit relation /25/

It is expected that higher mud volumes related with growing ROP would result in increasing equivalent circulating densities (ECD) which in turn could endanger borehole stability, namely by tensile fracturing by outstripping formation fracture gradients. This effect was investigated by employing a spreadsheet with data taken from recent and old wellbores. The following input parameters were considered: pump rate, bit diameter, drill pipe dimensions, ROP, mud density, plastic viscosity, viscosimeter readings (R_{600} and R_{300}), gel strength and grain diameter. Based on relations provided in the literature /20/, an effective mud density was computed which indicates the actual mud weight including cuttings at a certain pump rate. Table 3.1 displays the results of two cases:

Parameter	Recent Well		Old Well	
Pump rate	4.000	lpm	2.500	lpm
Bit diameter	16,00	in	17,50	in
DP OD	6,675	in	5,000	in
ROP	20,00	m/hr	10,00	m/hr
Mud density	10,75	ppg	9,58	ppg
Plastic viscosity	53,00	cp	5,00	cp
Gel strength	15,00	lb/100 ft²	6,00	lb/100 ft²
Cuttings transport velocity	1,41	ft/s	0,15	ft/s
Transport ratio	0,70		0,16	
Feed rate of cuttings	43,98	in³/s	26,30	in³/s
Eff ann mud density	12,06	ppg	11,83	ppg

Table 3.1: Investigation of effect of varying pump rates and ROP on effective annular mud densities

Despite nearly doubled pump rates and ROP, it was found that the effective annular mud density in an example recent well was not significantly higher than in the past; the increase between static and circulating density with nowadays' higher pump rates was relatively small. The assumption that larger circulated volumes in connection with higher ROP would remarkably load the borehole wall and thus worsen wellbore stability had to be abandoned. Above calculations, however, do not take pump output pressures into consideration.

Modern pumps enable higher output pressures. The hydraulic power output of a conventional pump nowadays ranges between 1.600 and 2.000 HP. At a given flow rate of 800 gpm, this results in a pump pressure

$$p_{pump} = \frac{1.714 * HP}{q_m} = \frac{1.714 * 1.600}{800} = 3.428\ psi = 233{,}2\,bar \qquad (3.10)$$

In comparison an old pump with a power rating of 800 HP, despite the same flow rate, could have only delivered 116,6 bar. This leads to the conclusion that the hydraulic power available at the bit is clearly larger today than in the past, maximizing the bit performance and its ROP, despite growing parasitic pressure losses in the drill string.

3.5.1 Thermal Effects

Usually, stress analysis around boreholes only considers the three principal stresses and their interactions. However, a wide range of forces is imposed on the rock around the wellbore: in-situ stress redistributions due to rock excavation, hydraulic pressure variations from inside to outside and vice versa, and, among others, temperature variations /10/. Those thermally-induced stresses yet tend to be neglected as they frequently only occur time delayed.

During circulation, the near wellbore rock is cooled relatively to its static temperature, which corresponds to the static geothermal gradient at a given depth. Cold mud, at surface ambient temperature, is pumped down the drill string, thereby cooling the system. The mud type, i.e. water-based or oil-based system, among other factors determines the outlet temperature. The parameters for the preparation of Figure 3.3 are equal except the mud type used for computation. It was created using Landmark's WellCat® in order to assess thermal stresses due to heat exchange during circulation and no circulation phases. The example operation was set up based on realistic operating parameters and tubular hardware (data were obtained from morning reports). Detailed information hereto is attached in the Appendix.

Regarding thermal effects the borehole wall has to withstand higher temperature changes than before. Moreover, temperature reversals between static and dynamic conditions impose higher thermal stress changes to the formation.

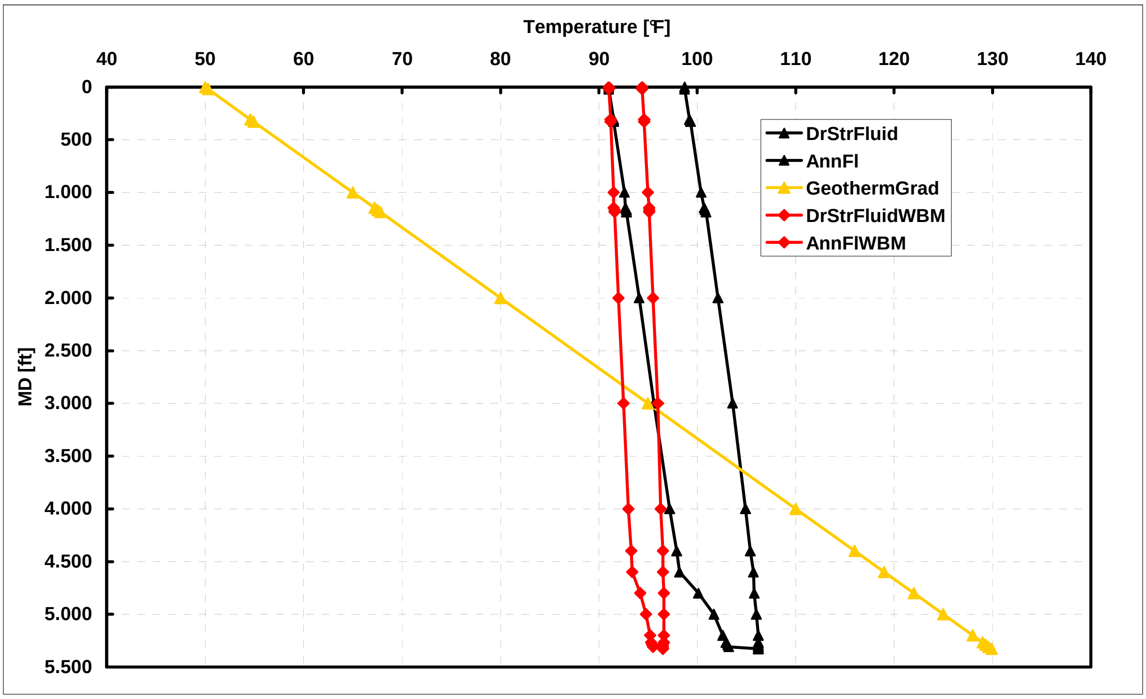

Figure 3.3: Typical temperature vs. depth profile for drilling operations using water-based and oil-based mud for comparison, created by Landmark's "WellCat®" (red line represents WBM, black line OBM)

Figure 3.3 depicts that oil-based muds have a higher heat capacity; they heat up more when pumped down. Despite relatively higher cooling rates in the annulus, the outlet temperatures are approximately 10°F above water-based muds'. In other words: the circulation of oil-based muds does not cool the surrounding formation as much as water-based muds do. This implies that the difference between static and pumping-related thermal stresses is of a smaller magnitude with oil-based muds.

Exact figures can be easily computed by employing equations (3.11) – (3.13) which describe how tangential and axial stresses at the borehole wall of a vertical wellbore in a homogenous, isotropic field with equal horizontal stresses ($\rho_H = \rho_h$) are calculated:

$$\sigma_r = \rho_m gh \tag{3.11}$$

$$\sigma_t = (2\rho_H - \rho_m)gh - \frac{\alpha_T E}{1-\nu}(T_\infty - T_w) \tag{3.12}$$

$$\sigma_v = \rho_s gh - \frac{\alpha_T E}{1-\nu}(T_\infty - T_w) \tag{3.13}$$

where ρ_H = maximum horizontal stress in density units, ρ_m = mud density, α_T = rock coefficient of thermal expansion, E = Young's Modulus, ν = Poisson's ratio, T_∞ = initial formation temperature, T_w = wall temperature while drilling, and ρ_s = overburden density.

The concentration of stresses due to the hole excavation appears immediately (two times the horizontal in-situ stresses minus the internal pressure for the tangential stress).

Figure 3.5 depicts the three principal stresses at the borehole wall which are caused by the excavation of rock. It is obvious that increasing mud temperature would result in a tensile tangential stress; cooling on the other hand induces a compressive tangential stress, which by exceeding the rock compressive strength can eventually lead to rock failure.

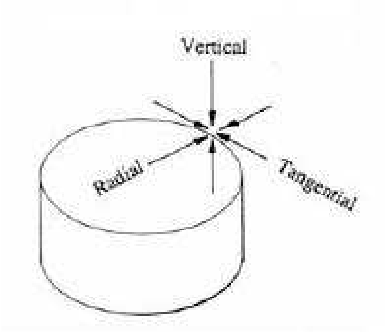

Figure 3.4: Radial, tangential and vertical (= axial) stresses at the borehole wall, in Aadnøy /9/

In practice this means that as soon as the pumps are shut in and the circulation is interrupted, the wall warms up and the tangential and axial stress values decrease. Static periods of sufficient length for re-heating of the borehole are caused by events such as logging, especially in the lower part of the open hole; down there, the difference between static and dynamic temperatures is maximum (see Figure 3.3). Large differentials between static and circulation conditions could rupture the rock. Concluding from Figure 3.3 one could assume that drilling with oil-based mud reinforces the wellbore because less cooling and heating of the rock than with water-based drilling fluids.

Temperature fluctuations related to mud circulation do not change the stress anisotropy around the wellbore as the temperature difference should alter the tangential and vertical stresses by an equal amount. Even if temperature changes do not exceed the elastic deformation range, a constant alteration of loading between static and dynamic conditions can lead to mechanical rock failure /11/.

Relation (3.12) suggests that an increase in tangential stress resulting from a borehole wall warm up can be offset by a larger mud weight (= ρ_m). However, this measure simultaneously implies the danger to exceed the equivalent fracture mud weight during subsequent circulation.

Figure 3.5 displays the interaction between temperature differential dynamic-static conditions and tangential stresses: the higher the temperature difference between circulating and non-circulating periods, the larger the resulting tangential stresses at the borehole wall. By comparing the stresses occurring with oil- and water-based muds based on the results from Figure 3.3, it was found that the latter cause higher thermally-induced tangential stresses; this can be explained by the fact that oil-based muds cool the bottom of the hole less – the temperature differential, as shown below, is smaller. The detailed calculation input parameters are attached in the Appendix, section d.

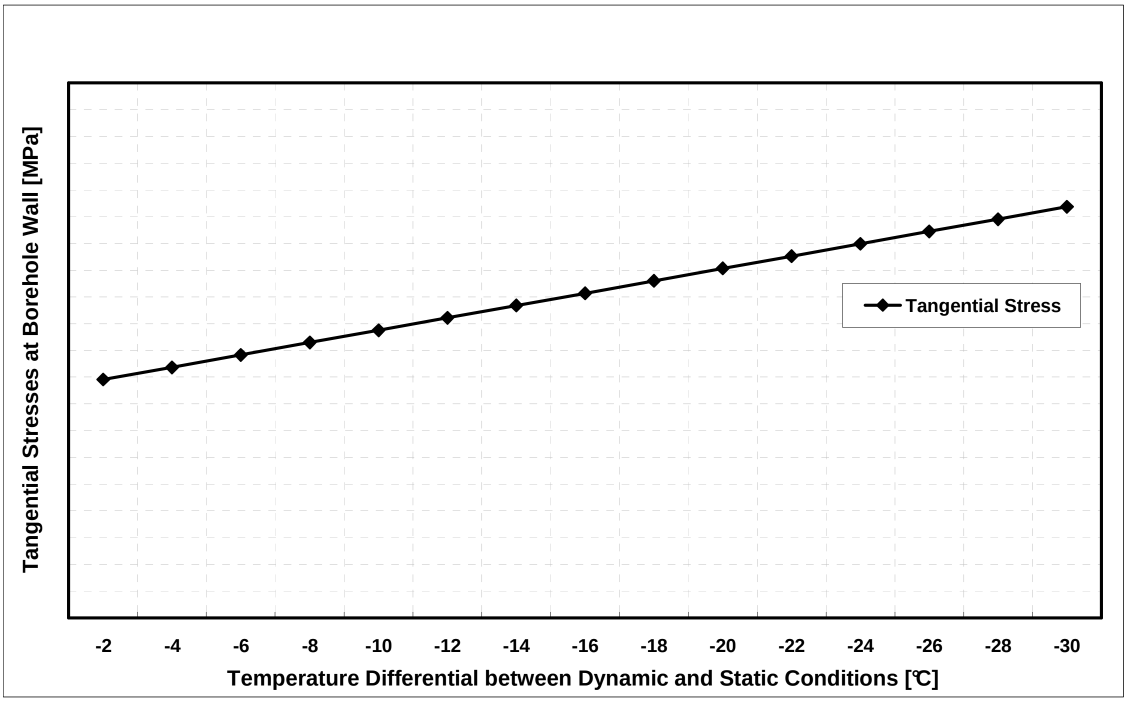

Figure 3.5: Tangential stresses versus temperature differential between dynamic and static conditions

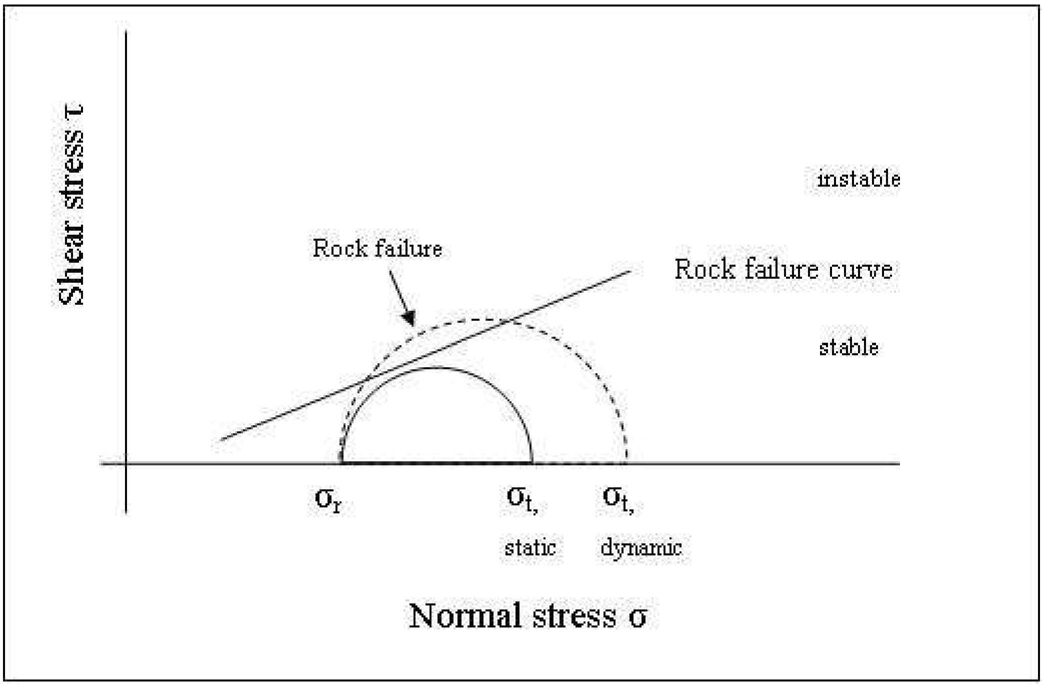

Figure 3.6: Effect of changes in tangential stresses due to thermal loading depicted by MOHR circle

Figure 3.6 intends to describe the impact of stress alterations at the borehole wall. The radial stresses only depend on the mud pressure (see equation 3.11) and do not change with increasing temperature. The tangential stresses, however, increase with larger temperature differentials between static and dynamic conditions, as shown in Figure 3.5. The initial MOHR circle (under static conditions, i.e. no circulation) lies below the failure curve – the state is considered stable. By circulating mud and cooling the wellbore, the tangential stress can grow sufficiently to produce a MOHR circle intersecting the failure curve where immediate rock failure occurs.

3.5.2 Borehole Ballooning

Reversible mud losses and gains during drilling are described by the term "borehole ballooning" /26/. Despite the factor that it is a familiar phenomenon, it often causes complications for the driller in correctly identifying and dealing with lost circulation or kick situations /27/.

Typically three mechanisms of borehole ballooning are named whereof the first two apply in formations occurring in North-Western Germany:

- Variations in the temperature of the drilling fluid: due to temperature increase in great depths, the drilling fluid expands in volume, which may be incorrectly interpreted as formation fluid influx. Temperature decrease on the other hand results in fluid contraction and potential misinterpretation as mud loss, respectively.
- Elastic deformation of the borehole walls: mud pressure decrease induces borehole volume decrease (the opposite also applies). Eventually, elastic deformation is linked to mud gains and losses, respectively.
- Opening and closing of natural fractures intersected during drilling: only applies in naturally-fractured formations.

Ballooning happens to occur in sections where the clearance between drill string and borehole is small enough to form a sealed volume. For example, clay balling of BHA components is likely to cause partial wellbore ballooning by plugging the annulus; subsequent mud circulation leads to ballooning which is visible as pressure spikes. As the pumps are shut down or the flow rate is decreased, the wellbore contracts again. If circulation is continued and the elastic rock limits are exceeded, i.e. the fracture pressure, the rock is hydraulically fractured and mud initially flows into the formation. Whether wellbore instability results or not, depends on the specific mechanical rock properties, i.e. Young's modulus and Poisson ratio.

Literature sources note that in low-permeable rocks ballooning volumes will be higher, with lower filtration volumes as more of the wellbore pressure will be able to provide longer support for at the wellbore wall /27/. For high-permeable rocks with high filtrate losses, the opposite is true: lower ballooning volumes will occur. However, mud cake build up will decrease the permeability with time and thus also cause a higher effective support of the wellbore.

Figure 3.7 investigates the development of radial and tangential stresses with growing pressure differentials. The latter do not only represent increases in mud weight but also in ECD or in pressure applied from the surface.

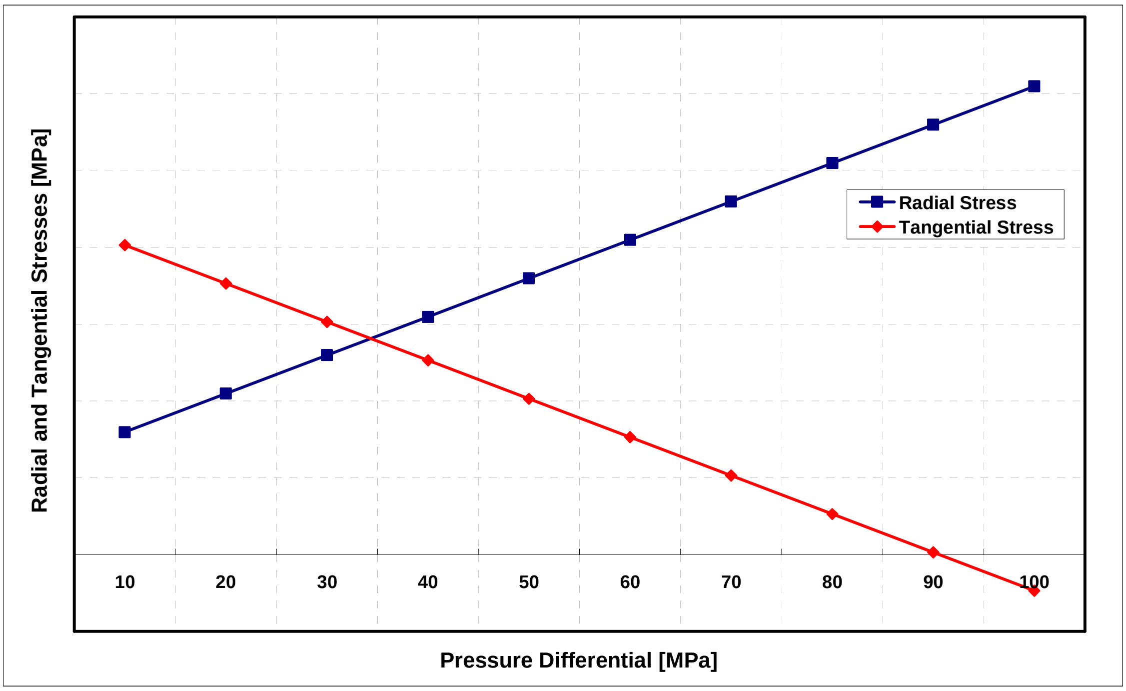

Figure 3.7: Radial and tangential stresses versus increasing pressure differentials

It can be seen that heavier muds result in higher radial stresses. On the other hand, they mean decreasing tangential stresses up to the point where the mud pressure suffices to fracture the rock due to tension.

In Figure 3.8 MOHR circles are employed to depict how growing mud weights influence wellbore stability: pressure differentials by increasing pump pressure or weighting up the mud induce a growth of radial stresses with simultaneously decreasing tangential stresses. In case the latter become small enough, the shape of the MOHR circle changes as shown in the figure below and potentially intersects the failure curve, initiating immediate rock failure.

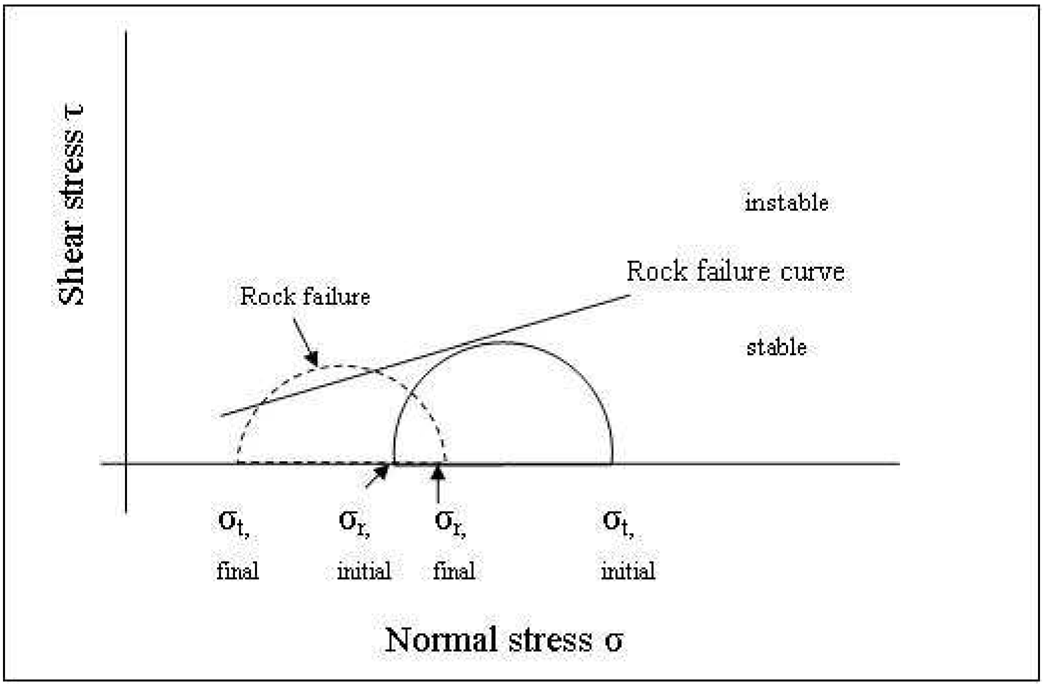

Figure 3.8: Effect of changing radial and tangential stresses due to pressure differentials, depicted by MOHR circle

In order to investigate the effect of wellbore ballooning on stability during operations, one could compare the number of pressure spikes and occurring cave-ins between wells with similar setup and geology on site. With this method it could be concluded how many pressure changes a formation can take before becoming instable. However this analysis will not be performed for the current problem due to a lack of data.

Chapter Summary

During the past two decades, pump capacity and efficiency have grown, which can be identified by increased pump rates and pressures or less equipment. Simultaneously, this development allowed faster drilling as higher pump rates promise better hole cleaning and enable higher ROP. Larger ID drill pipes additionally reduced parasitic pressure losses; kinetic energy is now saved which is diverted as enhanced hydraulic horsepower at the bit or jet impact force.

However, larger circulation volumes induce thermal stresses which have not been well integrated into wellbore stability studies. During pumping phases increased cooling of the near wellbore area is caused. Subsequent warming when pumps are shut in, e.g. while logging, tripping etc., affects rock strength negatively. If resulting tangential stresses exceed rock compressive strength, failure happens and eventually fragments break out. Excessive pump rates and pressures damage the rock due to thermally-induced stresses.

3.6 Chapter Summary

Table 3.2 summarizes all the findings of Chapter 3: Modern Drilling Technologies. Technology changes signified "-"name effects that represent deteriorations compared to the past, those "+" improvements.

Technology	Before	After	Effect	+	-
Drill string rotation	Kelly and rotary table	Topdrive system	Decreasing borehole contacts		x
			Less rotations/minute		x
Directional drilling	Straight BHA	BHA with downhole motors and bent housing for directional drilling	Deteriorate cuttings transfer in large-diameter sections during sliding drilling		x
		Vertical Drilling Systems (VDS)	Deteriorate borehole wall conditioning due to continuous sliding drilling Deteriorate cuttings transfer in large-diameter sections during sliding drilling		x
Drilling muds	WBM with salts for shale inhibition	WBM with polymers for shale inhibition	Partial replacement of oil-based muds for inhibition purposes	x	
		WBM with saccharine, glycerol, glycol and silicates for shale inhibition	Partial replacement of oil-based muds for inhibition purposes	x	
Bit types	Roller-cone bits	Advanced bearing technology in roller-cone bits	Prolonged standing times mean less tripping and shorter open hole times	x	
		Advanced bearing technology in roller-cone bits	Prolonged standing times mean less tripping but also less borehole wall conditioning		x
		Synthetic diamond bits (PDC)	No moving parts, long standing time and less tripping	x	
		Synthetic diamond bits (PDC)	No moving parts, long standing time but also less borehole wall conditioning		x
Pump rates		Higher pump capacities	Higher ROP due to enhanced cuttings removal	x	
			Higher cooling rates of the formation due to higher pump rates		x

Table 3.2: Table of changes in drilling technologies

The change in drill string rotation to topdrive systems implied decreasing borehole wall contacts due to the number of drill string hoisting and lowering (see chapter 3.1.1) as well as reduced drill string RPM, also resulting in less contacts between string and wellbore. For the relatively stable formations in the Tertiary and Jurassic in North-Western Germany, these changes have a negative effect as the borehole tends to behave plastically, i.e. shrink, which often ends in casing running troubles.

Directional drilling with downhole motors has a negative effect on borehole stability which is even severe in the top hole section with relatively large annular cross sections and hence low mud flow velocities: cuttings removal is corrupted due to a static string during sliding drilling which eases the continuous loading of the borehole. Growing mud weights due to cutting loading could eventually result in hydraulic fracturing.

For shale inhibition, water-based muds with salts have been largely replaced by water-based muds containing synthetic polymers. They prevent shale hydration, dispersion and accretion by selectively employing polymers and are a modern alternative to oil-based muds whose use and disposal always raise environmental concerns. In general they enable improved shale inhibition and borehole stability compared to past water-based systems which were often composed of a single type of salt and could not tackle all water-shale-related effects properly.

Modern roller-cone bits with advanced bearing technology and PDC bits without moving parts have prolonged standing times and thus require less tripping. This is positive for wellbore stability due to reduced open hole times where the borehole is unsupported by casing. Less tripping, however, also lessens borehole wall conditioning which ensures a smooth and gauge wellbore wall.

Concerning pump rates it was found that modern pumps exhibit higher capacities and thus can circulate increased mud volumes. This enables faster drilling as cuttings removal is enhanced at even higher ROP and simultaneously ensures shorter open hole times. Contrariwise raised pump rates imply higher cooling rates of the surrounding rock and hence elevated thermal stresses. Constant cooling and subsequent heating of the formation could potentially exceed rock strength and result in wellbore instability.

4 Analysis of Wells with Wellbore Stability Problems

Three example wells where wellbore instabilities recently caused serious troubles will subsequently be compared with offset wells drilled in the past. The difference and basis for analysis is applied drilling technology (see chapter 3) and its changes which are summed up in Table 3.2.

The selected projects are analyzed and compared by the changes in technology identified in the previous chapter. The data sources for this comparison are given below:

Analyzed parameter or property	Data source
Borehole wall conditioning	Morning reports
Drilling mud systems	Morning reports, mud reports
Drilling performance	Morning reports, time-vs.-depth curve
Borehole hydraulics	Morning reports
Comparison of open hole time	Morning reports
Correlation of parameters	Caliper logs, gamma ray logs, morning reports, mud reports

It is essential to mention that the data in morning reports are given for a time span of 24 hours. This implies a certain inaccuracy for e.g. mud properties or operational data such as pump rates and pressures or RPM. As all wells are compared based on a similar data quality, the lack of accuracy or data error is similar, too, which makes a comparison is valid.

The last section of each analysis sums up the findings and subsequently draws conclusions.

4.1 Oythe Z3

The vertical well Oythe Z3 was completed in 2006 as a replacement for collapsed vertical Oythe Z2 which produced sweet tight gas from Carboniferous sandstones.

The following offset wells were chosen for the investigation of the effect of advanced drilling technology due to their proximity:

Offset well	Drilling year	Distance surface location, direction	Distance reservoir location, direction
Oythe Z2	1968	0,1 km, W	0,3 km, W
Goldenstedt Z9	1981	0,8 km, W	0,9 km, W
Goldenstedt Z11	1980	1,2 km, N	1,3 km, N

Table 4.1: Offset wells for Oythe Z3 analysis

Reported Troubles

It was believed that penetrating the instable shale package between Lower Cretaceous and Upper Triassic should not pose difficulties. Drilling operations were done without incidents until continuously higher overpull was reported and more and more of the wellbore wall started to collapse. Prolonged reaming and circulating could remove some of the cuttings and cavings. During one of those wellbore cleaning attempts, however, the formation was hydraulically fractured by overloading the annulus with cuttings at insufficient pump rates. The result was a total fluid loss which could be partially recovered after shutting in the pumps. The logging tool later got stuck at approximately 680 m; the caliper log between 680 and 500 m revealed massive breakouts; big rock chunks were observed across the shale shakers which were identified to be mainly of Jurassic origin, i.e. from Dogger and Lias. After days of reaming and circulating it was decided to drill a sidetrack without the VertiTrak system using oil-based mud to prevent further stability issues. The sidetrack could be drilled to total depth without further incidents.

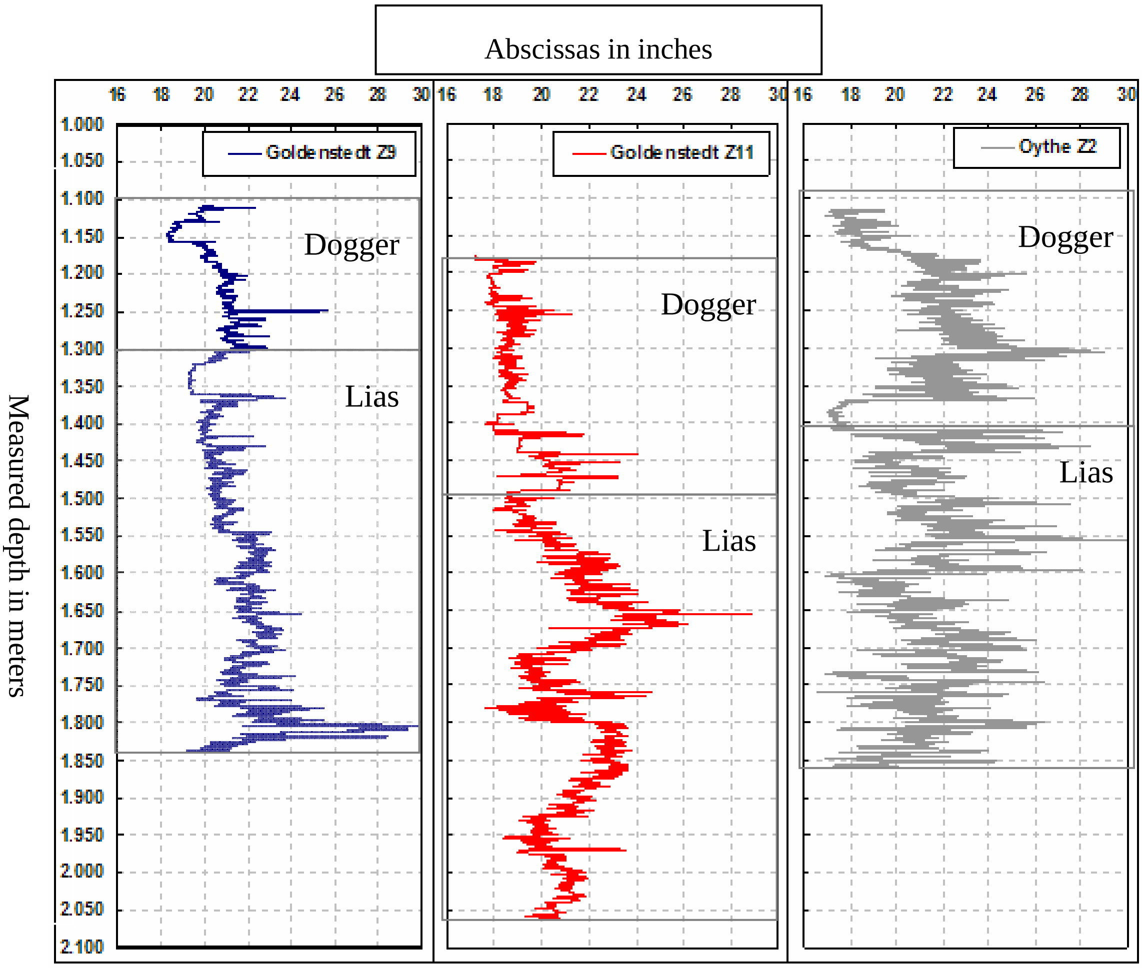

Figure 4.1: Jurassic caliper logs: Goldenstedt Z9, Goldenstedt Z11 and Oythe Z2 (from left to right)

Figure 4.1 displays caliper logs of the 16” sections in Oythe Z3’s offset wells. Dogger and Lias intervals are marked separately to ease the comparison. It is obvious that none of the three wells had gauge wellbore diameters in the interval in discussion; all suffered from more or less severe breakouts and cavings like Oythe Z3.

Well Specifics

Oythe Z3 was the first EMPG well where Baker Hughes’ vertical drilling system “VertiTrak” was used. It was decided to use this tool in order to prevent the forming of ledges in the tophole section which would later affect torque and drag negatively. It limited off-bottom pump rates during reaming to 2.500 l/min to avoid an unfolding and damaging of its steering pads during tripping. Also a special procedure to add pipes was prepared. Distinct rules for operations were set before drilling through the Lower Cretaceous and the Jurassic:

- Pressure peaks had to be avoided as the formation was believed to be sensitive.
- Water addition to the mud had to be restricted to a minimum.
- The maximum ROP should not exceed 20 m/hr in order not to cause ECD problems through annular cutting overloading.
- To protect water-sensitive shales from pressure spikes circulation was initiated by string rotation and slow pumping. As soon as circulation was established, string rotation had to be stopped in order not to damage VertiTrak’s steering pads, and pump rate had to be increased steadily only thereafter.
- Reaming or borehole conditioning had to be done cautiously to prevent pressure surges.
- The string had to be tripped out rotating and circulating in case of slight overpull (maximum 5 t), the pump rate had to be determined by the directional driller in order not to damage VertiTrak.

To avoid shale-related instability problems the bentonite mud was replaced by M-I Swaco’s “UltraDril” mud in the Lower Cretaceous (see chapter 3.3.3).

4.1.1 Reported gross ROP and Borehole Wall Conditioning

Well name	Quaternary, Tertiary	Cretaceous	Dogger	Lias	Average Jurassic
	[m/hr]				
Oythe Z2	28,14	25,70	14,16	10,07	11,64
Goldenstedt Z11	8,60	7,29	4,05	2,83	3,69
Goldenstedt Z9	9,82	10,00	7,89	4,55	4,59
Oythe Z3	15,15	16,59	17,30	20,37	18,50

Table 4.2: Comparison of reported gross ROP for subsequent formations in Oythe Z3 and its offset wells

From Table 4.2 it is apparent that Oythe Z3 was the fastest well regarding drilling time if all formations are averaged.

Figure 4.2 shows the significantly higher reported gross ROP of Oythe Z3 in the shaly Dogger and Lias formations (drilling days 8-12). Moreover it can be seen that only the NPT of 5 days, caused by cementing the 18 5/8" section, prolonged the total time on site. It has to be noted that the remaining drilling time in Goldenstedt Z11 and Z9 is not plotted here as it is of no further interest for the analysis.

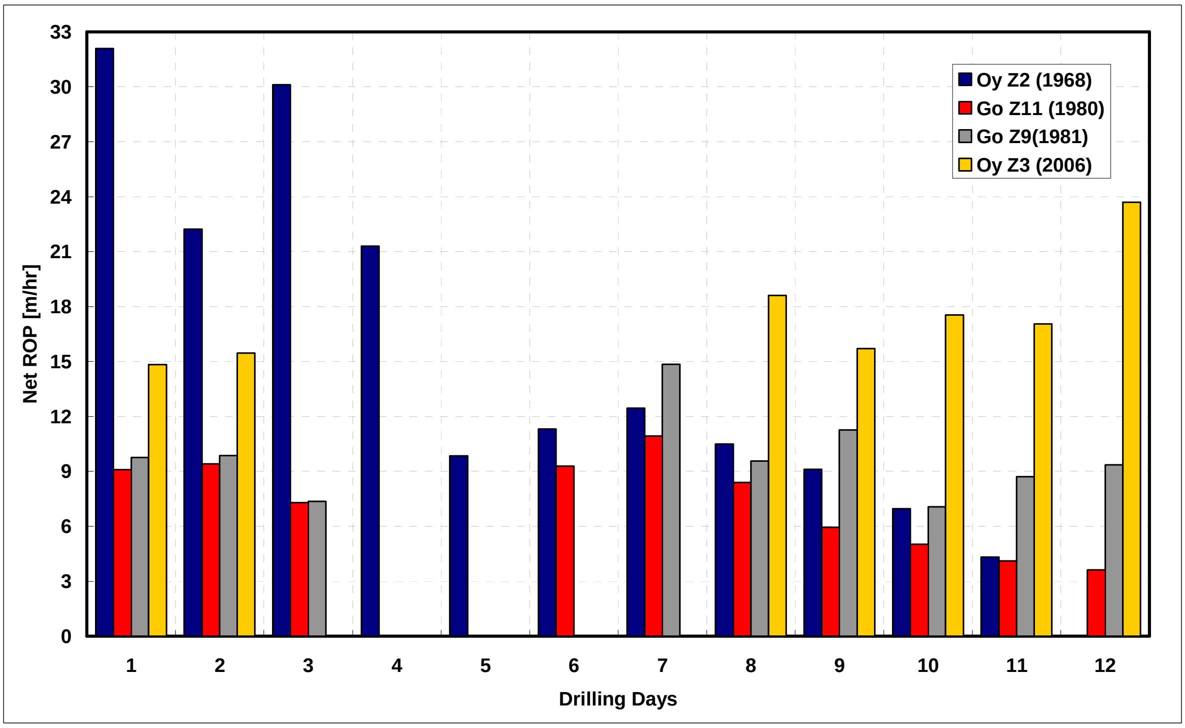

Figure 4.2: Comparison of reported gross ROP and development of MD, respectively, vs. drilling days for Oythe Z3 and its offset wells

In this section, Dogger and Lias are looked at in detail: they are of special interest for the analysis as they were the origin of most wellbore instabilities. It is interesting that especially in Lias the drilling speed more than doubled over time.

As discussed in chapter 3.1.1, a higher reported gross ROP implies that the borehole wall is conditioned less frequently by the drill string. This can be seen Figure 4.3: Oythe Z3, which was drilled with significantly higher ROP, saw the least number of borehole wall contacts, Goldenstedt Z11 had approximately 12 times, Goldenstedt Z9 10 times and Oythe Z2 four times more contacts. Additionally, the topdrive also limited the number of vertical pipe movement and VertiTrak reduced the string rotations during "oriented vertical drilling" to zero. This eventually led to a less frequently conditioned wellbore.

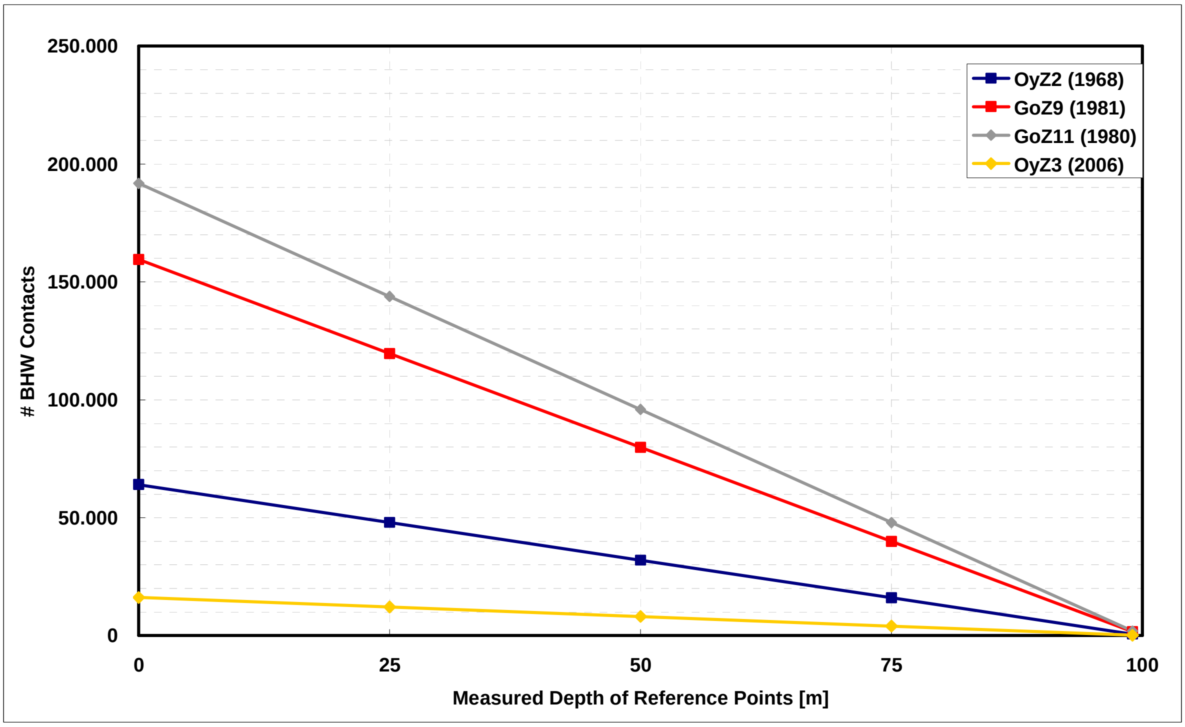

Figure 4.3: Calculated borehole wall contacts with drill string along an example interval of 100 m for Oythe Z3 and offset wells

4.1.2 Directional Drilling and BHA

All analyzed wells were planned to be vertical. The difference between Oythe Z3 and its offset wells was the premier application of a vertical drilling system during the second interval (16” hole section) to ensure a perfectly vertical wellbore at all times. The VertiTrak system operates in sliding mode with steering pads engaged and bit rotation provided by a high-power downhole motor /28/. Integrated near-bit inclinometers continuously measure hole inclination and transmit the data to the surface. In case a deviation from vertical is detected, a control sub activates internal hydraulic pumps which are engineered to deliver the necessary steering force to each of the three pads. Those in turn counteract any deviation tendencies and push the wellbore back to verticality. On the manufacturer’s website it is said that the VertiTrak system “keeps a wellbore vertical automatically, without compromising critical drilling parameters - flow rate, WOB or bit speed” /28/. WOB does not have to be kept below critical values as the tool constantly measures inclination and corrects potential deflections immediately. In conventional direction drilling operations, such continuous control would require shutting in pumps frequently in order to perform directional measurements. Depending on pump rate requirements various downhole motors as power sections are available.

Table 4.3 compares the BHA and other string elements of the four analyzed wells. In addition, to the 10” vertical drilling system, a near-bit stabilizer (15 15/16” OD) and two 15 ¾” string stabilizers were incorporated into the BHA at Oythe Z3. It was found that Oythe Z2 was drilled without stabilizers until after the 13 3/8” casing was set. Goldenstedt Z9 and Z11 were equipped with one bit and two string stabilizers of 17 7/16”.

Well	Bit [in]	Additional	Stabilizers [in]	Drill Collars [in]	HWDP [in]	DP [in]
Oyth Z2	17 ½	-	-	54 m: 11 ¼ x 3 120 m: 9 ¼ x 3 ½	-	5
Gold Z11	17 ½	-	Bit stabilizer: 17 7/16 String stabilizer: 2*17 7/16	152,7 m: 9 ½ x 3	55,3 m: 5	5
Gold Z9	17 ½	-	Bit stabilizer: 17 7/16 String stabilizer: 2*17 7/16	13,5 m: 11 ¾ x 3 ½ 155,6 m: 9 ½ x 3	54,6 m: 5	5
Oyth Z3	16	10” VertiTrak	Bit stabilizer: 15 15/16 String stabilizer: 2*15 3/4	111,5 m: 9 ½ x 3	28,4 m: 6 ⅝	6 ⅝

Table 4.3: Overview of BHA and string components in Oythe Z3 and its offset well

4.1.3 Drilling Mud Systems

The theoretical analysis of drilling mud systems concluded that modern water-based muds can inhibit shales effectively. Hence, M-I Swaco’s “UltraDril” was used for Oythe Z3. The detailed working principle of this mud was discussed in chapter 3.3.2. Table 4.4 sums up mud properties obtained from morning and mud reports, respectively. To underscore the importance of filtration volumes and the development over time, Figure 4.4 shows API fluid loss data obtained from mud and morning reports separately for Dogger and Lias formations.

Well	Quaternary, Tertiary			Cretaceous			Dogger			Lias		
	Type	Density [kg/l]	API Filtrate [ml]	Type	Density [kg/l]	API Filtrate [ml]	Type	Density [kg/l]	API Filtrate [ml]	Type	Density [kg/l]	API Filtrate [ml]
Oyth Z2	Freshwater clay	1,16	-	FC	1,18	53,9	FC	1,20	60,8	FC	1,17	56,6
Gold Z11	-“-	1,14	-	FC	1,16	10,6	FC	1,23	6,6	FC	1,23	6,6
Gold Z9	-“-	1,16	-	FC	1,13	5,4	FC	1,16	6,7	FC	1,17	5,8
Oyth Z3	-“-	1,09	-	FC / Poly	1,08/ 1,29	9,0/ 1,8	Poly	1,29	1,2	Poly	1,29	1,2

Table 4.4: Overview of mud properties per formation for Oythe Z3 and its offset wells

It can be deducted from the table that filtrate volume was continuously reduced in the past as its negative influence on water-sensitive shales was better understood. Shale inhibition today is based on several chemicals which are mixed in the mud before drilling (e.g. M-I’s “Polypac ULV” or “Polypac Regular” as filtration reduction agents); in the past filtration reducers, mainly cellulose which In addition, also acted as a viscosifier, were only added during drilling as soon as stability-related problems occurred. In the meantime the basic freshwater clay-based mud acted onto the formation, inducing pore pressure build up and borehole wall damage. Partial inhibition was accomplished by the addition of salt, e.g. KCl. Despite the improvement in mud technology and shale inhibition, it was impossible to prepare the second interval of Oythe Z3 for the running and cementing of the 13 3/8” casing. Why could casing in reference wells be installed despite less sophisticated mud systems? Investigating caliper logs of all reference wells, it was found that the wellbores in Oythe Z2, Goldenstedt Z11 and Z9 had diameters well above gauge (> 17 ½”). It seems like the simple bentonite muds with small contents of filtration reduction agents in combination with the constant conditioning of the borehole wall yielded oversized holes without narrow passages. On account of the fact that the caliper log could not be run deeper than 679 m in Oythe Z3, no complete log is available and no definite conclusions can be drawn.

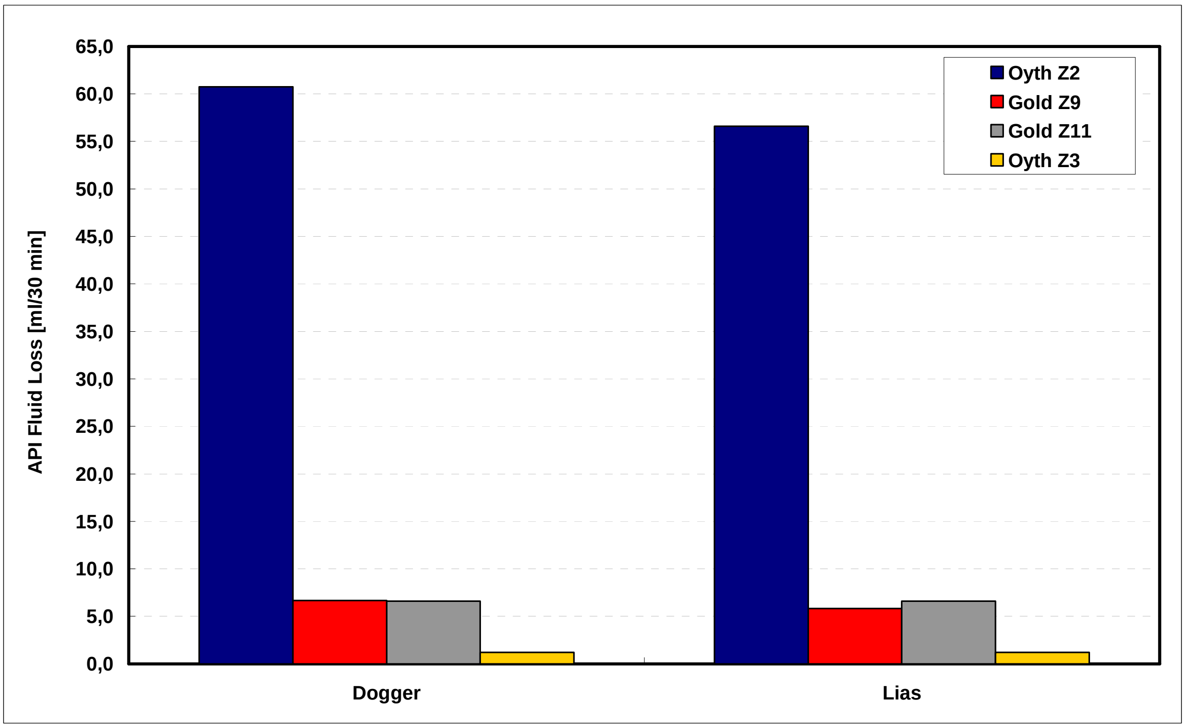

Figure 4.4: Graphical comparison between API filtration volumes in Oythe Z3 and two of its offset wells

Doetlingen Ost Z2

In order to exclude a negative influence of the mud on borehole stability, an offset well with UltraDril had to be found. Doetlingen Ost Z2 was the first EMPG well where it was used, replacing conventional bentonite mud from the lower section of the Upper Cretaceous (approximately 1.064 m in the Turon formation). Despite a deeper burial of all its formations, it has been chosen as reference for the mud system performance. This decision is justified by similar properties like apparent rock strength and mineralogy which mainly determine the interaction between mud, bit and rock. Furthermore the geological layering does not differ significantly. In addition,, a report on experience with UltraDril in North-Western German wells was helpful to better understand its working principle /29/.

For Doetlingen Ost Z2 a caliper log for the interval in question (16” section) was investigated to learn about the condition of the borehole wall before cementing, i.e. the location of potential break-outs. It should further support conclusions about how UltraDril inhibits reactive shales in Dogger and Lias, independent of a vertical drilling system. From the log it could be seen that with exceptions the mud system produced a perfectly gauge hole, even in water-sensitive Lias; break-outs were only detected in sandy intervals and the change to a packed, i.e. stiff BHA. Overpull during tripping was mainly induced by Lias epsilon formation which, acting like a gumbo shale, typically suffers from swelling and related hole size reduction /30/. In general, however, overpull during reaming trips before casing was not severe. 13 3/8” casing could eventually be installed through the entire section without trouble. These observations allow an evaluation of UltraDril performance without vertical drilling system, which was not available for Oythe Z3 as for its sidetrack both mud system and vertical drilling system were exchanged.

4.1.4 Drilling Performance

While all reference wells were drilled with 17 ½” roller cone bits, a 16” PDC bit was used for the entire second interval except for drilling through the cement and out of the 18 5/8” casing. Analyzing the number of roundtrips which were required to exchange worn down or broken bits it was found that roller cone bits typically remained downhole for 1 – 1,5 days (Oythe Z2) up to 3 – 5 days (Goldenstedt Z11 and Z9). In Oythe Z3, however, the entire 16” interval was drilled with one PDC bit, maintaining equally high ROP in all formations. Based on this observation one can conclude that the amount of borehole conditioning due to roundtrips for bit exchanges significantly decreased between 1968 and 2006; for wellbore stability issues this means that the borehole wall was worked on more in the past simply due to dull or broken bits and thus was more frequently conditioned before casing running.

4.1.5 Borehole Hydraulics

In order to assess the changes in pump technology a list of pumped volumes and pump pressures was created for Oythe Z3 and its offset wells based on information obtained from morning reports. While the increase in flow rates was unexpectedly rather minor, growing pump pressures were noticed over time. Table 4.5 gives a summary for average pump rates and pressures for Dogger and Lias. Moreover, ECD has been calculated for both formations based on bottom depth and average pump pressures. The increase in mud density by circulation is roughly 1-2% in all cases. Figure 4.5 displays the trend in pump pressures over time, clearly underscoring the above mentioned growth.

To better understand the effects on drilling a spreadsheet was created which could calculate pressure losses in the system "drill string – bit – annulus". It eventually delivered data concerning pressure drops along the drill string, across the bit and up the annulus. Additionally, the hydraulic horsepower at the bit (in HP/in² of bit area) was computed to investigate its magnitude under past and present pumping and bit parameters. Based on Table 4.6, two conclusions can be drawn: the pump horsepower requirement to compensate pressure losses in the system has grown over time. This could be counteracted with better performing and more mud pumps. Second, it is apparent that there has been a major improvement in hydraulic bit performance which eventually might have resulted in faster drilling, i.e. increased reported gross ROP and decreasing borehole wall contacts.

Well	Formation (basis)	Reported pump rate [l/min]	Reported pump pressure [bar]	ECD [kg/l] at 2.000 m
Oythe Z2	Dogger	3.776,7	138,3	1,18
	Lias	3.666,0	140,0	
Goldenstedt Z11	Dogger	3.160,0	155,0	1,24
	Lias	3.123,3	175,8	
Goldenstedt Z9	Dogger	3.700,0	177,5	1,18
	Lias	3.700,0	191,7	
Oythe Z3	Dogger	3.500,0	220,0	1,31
	Lias	3.650,0	238,0	

Table 4.5: Overview of pump rates and pump pressures for Oythe Z3 and its offset wells

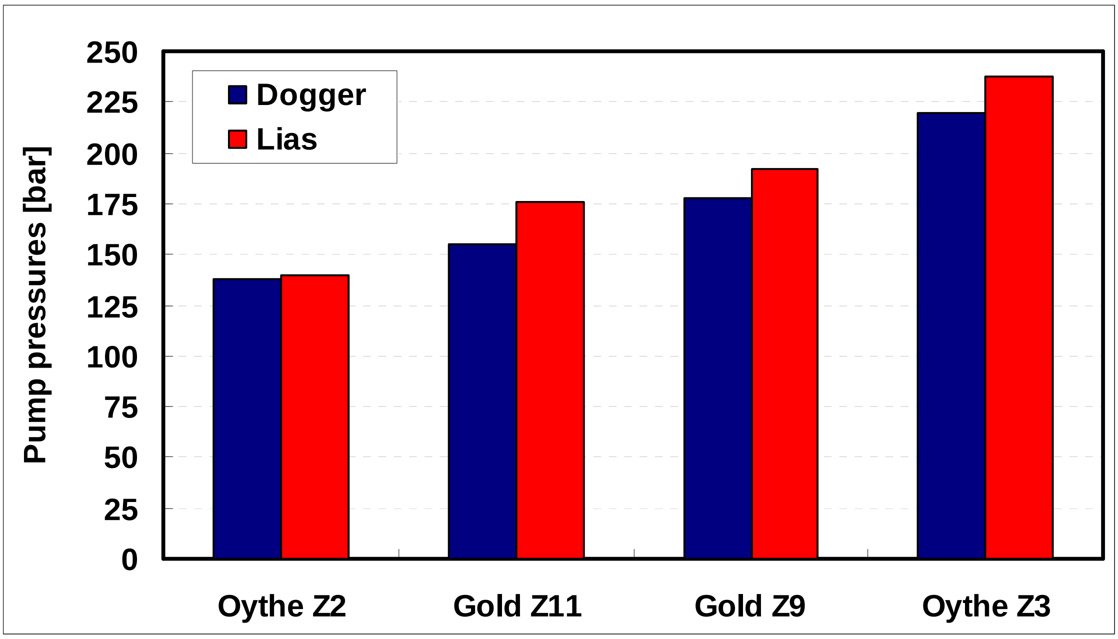

Figure 4.5: Reported pump pressures in Dogger and Lias for Oythe Z3 and its offset wells

It has to be stated that the calculations did neither include surface lines nor the exact drill string elements (heavy-weight drill pipes, drill collars, downhole motors etc.) as the comparison was made only between string elements found in all four wells (drill pipes, bit geometry, pumping equipment). The large difference between reported pump pressure and total pressure drops in the system for Oythe Z3 can be explained by the additional pressure requirements due to high-power downhole motors and vertical drilling system: a brochure by the provider states a maximum operating differential pressure of 80 bar /31/. Detailed calculation input data and results for Goldenstedt Z11 and Oythe Z3 can be found in the Appendix.

Well	SPP	Pump power	Δp at bit	HHP at bit
	[bar]	[HP]	[bar]	[HP/in²]
Oythe Z2	101,44	631,85	37,14	0,96
Goldenstedt Z11	128,56	727,68	71,94	1,69
Goldenstedt Z9	169,14	1.134,23	96,06	2,68
Oythe Z3	153,32	1.204,38	81,00	3,17

Table 4.6: Overview of results of hydraulic calculations for Oythe Z3 and its offset wells for Lias formation

4.1.6 Comparison of Open Hole Time

It is commonly understood that the longer a borehole stands "open" before casing is installed, the more severe wellbore instabilities can become. A rule of thumb says that after four weeks of no action, a wellbore collapses on its own.

Therefore a quick comparison between the open hole times (OHT) in the 16" respectively 17 ½" sections of Oythe Z3 and its reference wells was done to see whether there was a significant difference between past and present projects. Table 4.7 shows that Oythe Z3 did not stay open longer than the other wells; Goldenstedt Z11 for example stayed uncased even longer, due to its depth, and was filled with less inhibiting mud. Doetlingen Ost Z2 was included in the analysis because of UltraDril which was used as a mud system as later in Oythe Z3. The inhibition quality in the latter must have been similar to equal.

Well	Mud	Δ depth [m]	Approximate OHT [hr]	OHT/meter [hr/m]
Oythe Z2	FC	1.800	288	0,16
Goldenstedt Z11	FC	1.870	648	0,35
Goldenstedt Z9	FC	1.647	504	0,31
Doetlingen Ost Z2	Poly	1.895	480	0,25
Oythe Z3	Poly	1.572	480	0,30

Table 4.7: Comparison of open hole times in Oythe Z3 and its offset wells

In order to relate open hole time to the depth interval drilled a value called "open hole time per meter", in hours/meter, was computed. It depicts that one meter in Goldenstedt Z11 was uncased more than double as long than Oythe Z2; still no additional or unknown wellbore stability problems occurred.

4.1.7 Correlation of Parameters

Correlation of API Fluid Loss, Mud Density and Caliper Logs

After assessing a large amount of data, it was tried to put them in relation in order to eventually detect correlations. It was thought to be most fruitful to investigate the interaction between API fluid loss volumes, mud densities and caliper log as wellbore instabilities in shales are mainly determined by an absorption of water into the formation and subsequent pore pressure buildup. For this purpose digital versions of the old paper logs as well as mud properties were plotted against measured depth for all three reference wells. An example graph is attached in the Appendix. No caliper log for Oythe Z3 (wellbore 1) was available as the logging tool could not be run deeper than Upper Cretaceous.

Due to no obvious relation between any of the three parameters and the fact that only little changes in filtration volume occurred during drilling, it was concluded that changes in fluid loss or mud density in the analyzed wells were too insignificant to indicate a trend; no predictions regarding wellbore instability could be obtained.

Correlation of Borehole Wall Contacts and Caliper Logs

It was also tried to bring the number of borehole contacts and wellbore stability in connection. Based on input data from morning reports, it was found that Oythe Z3 saw the least contacts with the drill string which is readily explained by the way how the vertical drilling system VertiTrak functions /31/: when its steering pads are activated and touch the borehole wall, no more drill string rotation is allowed in order not to rupture or tear off the pads; only the bit is turned by the downhole motor which is also part of the special BHA. Despite protecting the borehole wall by not continuously banging the drill string against it, the filter cake that thickens over time is no longer scratched off. The number of borehole contacts certainly determines the thickness of the filter cake and eventually the diameter of the wellbore.

4.1.8 Summary of Analysis

Reported gross ROP and Borehole Wall Conditioning

The comparison of reported gross ROP in all four wells indicates that Oythe Z3 was drilled in significantly less time with the bit on bottom than its reference wells. This decrease as well as the use of a topdrive system implies that the borehole wall was less conditioned than it used to be in the past; it remained raw and undamaged as opposed to the offset wells.

Directional Drilling and BHA

Oythe Z3's first 16" wellbore was drilled using the vertical drilling system VertiTrak. To ensure improved straightness of the hole, a low-clearance BHA was run. As VertiTrak implies drilling in sliding mode, additionally less borehole wall contacts happen which are now reduced to the bit rotations and vertical movement of the string before making connection; the developing filter cake is not removed by the drill string and grows in thickness. A maximum filter cake thickness of 0,3 mm was measured with the API method. This test mostly does not reflect realistic downhole situations, dominated by pressure, temperature and drill string dynamics. With a maximum stabilizer OD of 15 15/16" (0,4048 m) in a 16" (0,4064 m) wellbore only an annulus of 0,5 mm thickness remains, if the maximum measured filter cake thickness is included. This clearance was sufficient to initiate hydraulic fractures caused by bit and stabilizer balling, observed as temporary fluid losses into the formation in the morning reports. Subsequently decreased mud pressure resulted in further instability of the wellbore which was seen as massive cuttings from cavings across the shale shakers.

Drilling Mud Systems

UltraDril, an oil-based mud substitute on water basis was employed from top Lower Cretaceous, replacing a simple bentonite mud. It enables two-way shale inhibition by controlling hydration and dispersion. As no log could be run to total depth in Oythe Z3, no results regarding caliper could be gained. To evaluate the mud system's performance independently, Doetlingen Ost Z2 was looked at in more detail. Its 16" caliper log clearly confirms the superior shale inhibition achieved by UltraDril, indicated by a close-to-gauge hole: the difference between the theoretical and the measured wellbore volume only amounts up to 6 % (273 m^3 vs. 258 m^3). For comparison, in Oythe Z3 where the 16" sidetrack was drilled with oil-based mud, the difference was 9 % (269 m^3 vs. 246 m^3).

Drilling Performance, Borehole Hydraulics

It seems that the bit type does not have any influence on wellbore stability. Only the frequency which it has to be replaced with by new bits touches the topic: reduced tripping results in decreased borehole wall conditioning. By analyzing pumped volumes and pressures in connection with hydraulic performance of the bit, it was found that larger pump capacities allowed higher values of hydraulic horsepower per bit area. This mainly resulted in the ability to drill faster, again influencing the number of borehole wall contacts and conditioning of the filter cake.

Comparison of Open Hole Time, Correlation of Parameters

A comparison of open hole times related to depth intervals did not show a trend; the time span between drilling out of the last casing string and running the next has more or less remained equal. However, there is a difference in how this open hole time accumulates: in Goldenstedt Z11 and Z9, it was caused by slow drilling and more frequent roundtrips in order to exchange bits. In Oythe Z3 though, more time was sacrificed for e.g. reaming and circulation or re-drilling.

4.1.9 Conclusions

It is concluded that none of the changed drilling technologies alone led to the collapse of Oythe Z3. Based on the findings the combination of highly-inhibitive UltraDril mud and statically-operating VertiTrak might have lead to instabilities which is supported by literature /29/: the mud produced a nearly-gauge borehole whose walls were barely worked on because of a non-rotating drill string when the bit was on bottom. BHA components, large in diameter, caused high-velocity channels where the mud could pass. Larger annular cross sections (e.g. around drill pipe) then led to decreases in mud velocity and the settling of cuttings (i.e. balling up) on lower string components with larger diameters, i.e. the string stabilizers. This is supported by computing the average annular mud velocities opposite of the string and bit stabilizers as well as the drill collars or heavy weight drill pipes: at a pump rate of 3.800 liters per minute, the average mud velocity amounts up to 50,5 ft/s opposite the 15 3/4” stabilizers in the 16” wellbore. Opposite the 9 ½” drill collars just on top of the string stabilizer, the average mud velocity decreases to 2,4 ft/s. Further up the annulus, opposite the 6 5/8” heavy weight drill pipes, the mud velocity is only 1,9 ft/s.

Subsequent attempts to re-establish circulation and resulting pressure spikes were sufficient to fracture the formation and induce lost circulation which eventually initiated further cavings and breakouts. The bottom line was the total collapse of the borehole.

The drilling of Oythe Z3 took 136 instead of the planned 120 days; the setting depth for the 13 3/8” casing was scheduled to be compassed after 23 days but in fact was only reached after 46 days. The difference of 23 days between planned and actual time was due to borehole instabilities in the original wellbore, cementing the original borehole and subsequent sidetracking.

It has to be mentioned, however, that despite a delay of 23 days after the 13 3/8” section, the entire project was finished with a lag of only 16 days and an end depth which was 90 m below the planned. This was mainly due to faster drilling progress in all intervals below the 13 3/8” casing. Also the ROP in the 13 3/8” interval was higher than planned. Without wellbore stability problems in the tophole section, the project could even have been finished ahead of time.

4.2 Preyersmuehle Sued Z1

Preyersmuehle Sued Z1 was completed in 2006 and should develop gas in an isolated block in Rotliegend, south-west of Preyersmuehle-Hastedt Z1 (1983). The first sections (18 5/8", 13 3/8" and 9 5/8") were planned vertical with inclined penetration of Rotliegend sandstones.

Table 4.8 lists reference wells which were chosen for the subsequent analysis due to their proximity.

Offset well	Drilling year	Distance surface location, direction	Distance reservoir location, direction
Preyersmuehle-Hastedt Z1	1984	1,5 km, NNE	1,3 km, NNE
Worth Z1	1988	2,8 km, N	2,6 km, N
Boetersen Z6	1993	4,0 km, WNW	4,1 km, WNW

Table 4.8: Offset wells for Preyersmuehle Sued Z1

Reported Troubles

While designing Preyersmuehle Sued Z1 unconsolidated sands in Oligocene and Eocene, namely Neuengamme and Bruessel sands were identified as potential hazards. Consequences were found to be massive cave-ins and thus inefficient cementation as well as danger of getting stuck. Indeed, difficulties were experienced at approximately 280 m (Bruessel sands) while the 18 5/8" casing was run: it could not be pushed any deeper despite circulation. Thus the casing equipment was rigged down and an underreamer was picked up in order to enlarge the wellbore between 219 and 315 m to 28". Subsequently the 23" BHA had repeated problems to be run past 280 m and through the entire Lower Eocene 2-1 and Paleocene, respectively, without circulation.

During the circulation of high-viscous pills, large volumes of cuttings, shaped like cave-ins, were transported to surface until base Paleocene. After another reaming trip and problems passing 280 m, the wellbore was circulated at 4.300 l/min for several hours. The casing shoe was chamfered and subsequently circulated into the wellbore.

Figure 4.6 shows caliper logs of the 23" sections in Preyersmuehle Sued Z1 and Boetersen Z6. The remaining two offset wells are not displayed here as their Upper Tertiary formations were covered by casing. It is apparent that the logs are similar between 175 and 325 m where massive breakouts occurred. This interval comprises the weak and unconsolidated Neuengamme and Bruessel sands. Despite the similarity, one has to consider the size of cavings which were significantly larger in Preyersmuehle Sued Z1 (cf. at a depth of approximately 300 m: 42 inch breakouts in Preyersmuehle Sued Z1 versus 38 inches in Boetersen Z6).

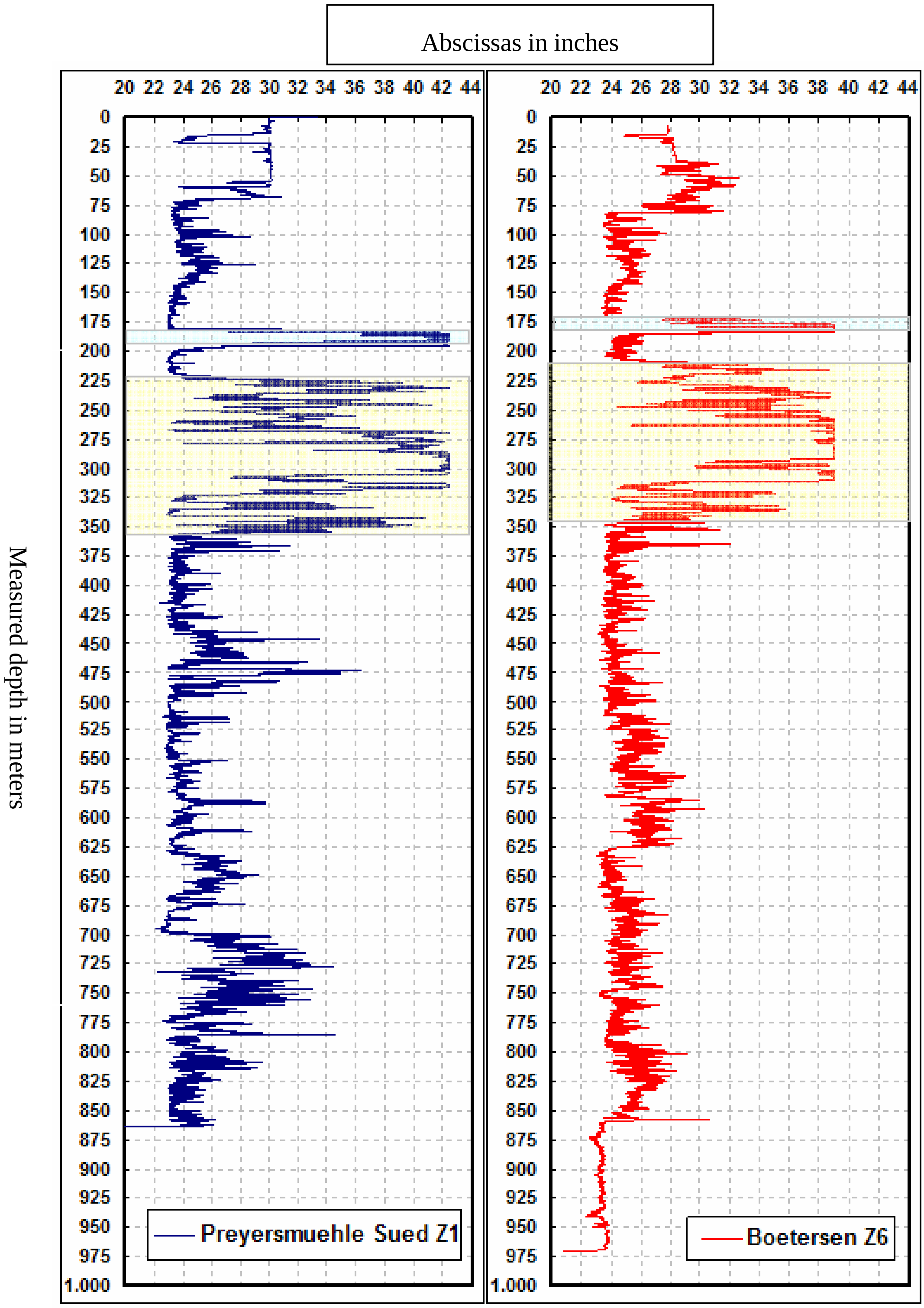

Figure 4.6: Tertiary caliper logs: Preyersmuehle Sued Z1 and Boetersen Z6 (blue box represents Neuengamme sand interval, yellow box Bruessel sands)

4.2.1 Reported gross ROP and Borehole Wall Conditioning

Table 4.9 lists averaged reported gross ROP divided into Quaternary and Tertiary, Upper Cretaceous as well as average 23” interval. The latter is obtained by averaging drilling time of the entire 23” section and is therefore not the mean of the first two columns. It was found that drilling rates were similar in Preyersmuehle-Hastedt Z1 and Worth Z1, being the closest reference wells. The Cretaceous intervals were drilled at only half the velocity of before without mentioned restrictions. Boetersen Z6 was the well whose 23” section was cased fastest and where no wellbore stability or other problems were documented, despite comparatively higher reported gross ROP.

Well name	Quaternary, Tertiary	Upper Cretaceous	Average interval
	[m/hr]		
Preyersmuehle-Hastedt Z1	9,86	4,76	7,92
Worth Z1	9,78	4,79	8,40
Boetersen Z6	13,88	14,80	7,22
Preyersmuehle Sued Z1	13,30	12,03	12,90

Table 4.9: Comparison of reported gross ROP for subsequent formations in Preyersmuehle Sued Z1 and its offset wells

In order to investigate the influence of reported gross ROP on the (theoretical) number of borehole wall contacts, average reported gross ROP for the 23” sections were used to create Figure 4.7, which again represents a 100 m exemplary interval along the wellbores of the four analyzed wells.

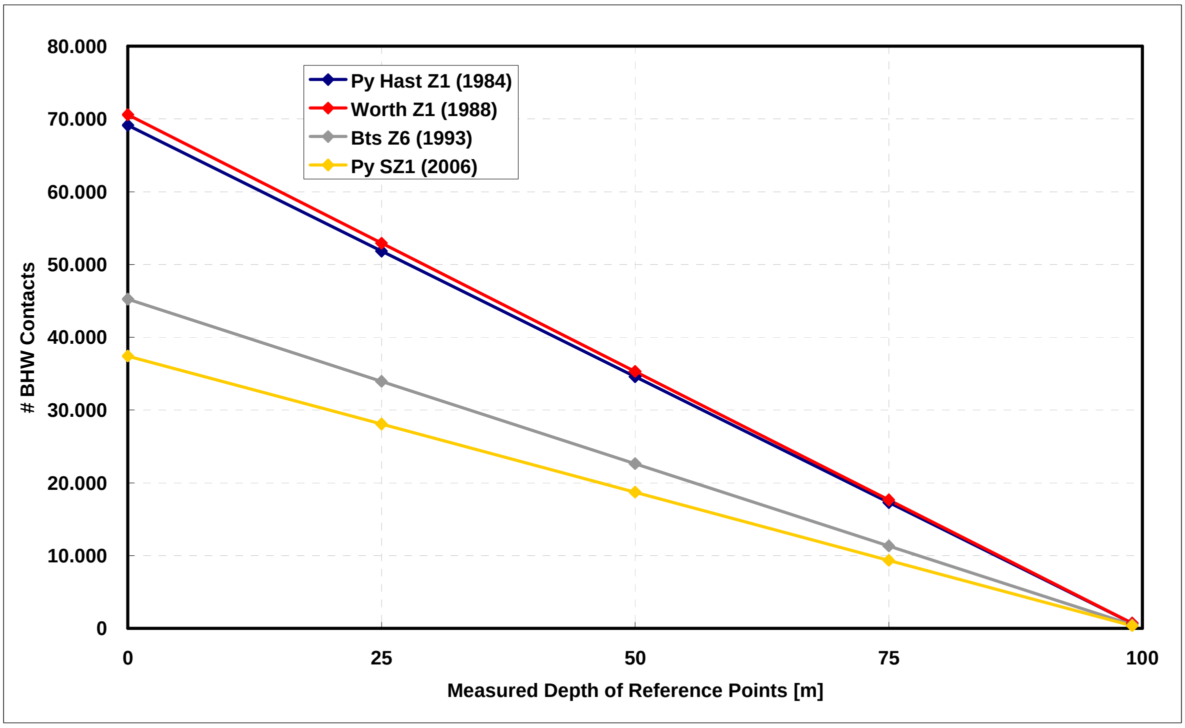

Figure 4.7: Calculated borehole wall contacts with drill string along an example interval of 100 m for Preyersmuehle Sued Z1 and offset wells

All parameters, e.g. running in or pulling out of hole speed, except for reported gross ROP and RPM were left equal. This ensures the comparison of data based on information gained from morning reports. Preyersmuehle Sued Z1 had the least computed number of contacts between drill string and wellbore wall because of above average reported gross ROP and lower RPM (due to the application of a rig with topdrive system).

4.2.2 Directional Drilling and BHA

The four analyzed wells can be considered vertical despite slight inclination angles ranging between 0,7° (Boetersen Z6) and 2,9° (Worth Z1). Those were not planned but resulted out of drilling without directional control. Preyersmuehle Sued Z1 had a deviation from vertical of 0,2° at the 18 5/8" casing setting depth; a kick-off was only performed in a lower section. As the BHA in all wells consisted of a bit stabilizer, a spacer between a string stabilizer, a drill collar and another string stabilizer, they are not listed.

4.2.3 Drilling Mud Systems

Despite the fact that all wells were drilled with fresh water clay-based mud, detailed mud properties for the entire 23" interval are listed for further analysis in Table 4.10. It is apparent that mud densities as well as fluid loss and the resulting filter cake thickness were lower in Preyersmuehle Sued Z1 than in its reference wells; this is especially true from the Upper Cretaceous on where emphasis was put on controlling the fluid loss in order to prevent lost circulation into permeable calcarenites of the Maastrichtian. In order to establish a filter cake and mitigate losses, the solids content was kept high deliberately by cutting the centrifuge power. Formation shales induced an increase in viscosity which was counteracted by the addition of water and gypsum mud whereof the latter has in inhibiting effect (see chapter 3.3.3). Despite significantly higher filtration volumes throughout the entire 23" interval, Boetersen Z6 did not suffer from any swelling shales in the Tertiary. Between 62 and 663 m the fluid loss volume doubled without any effort to lower it again; even though gypsum was added, it kept on growing until reaching a maximum of 58 ml/30 min at casing depth (1.035 m). No fluid loss-reducing agents were added in the course of drilling. It is therefore assumed that a reduction in filtration volume was not a priority as shales did not play a major role; this also applies for Worth Z1. Clay balling was reported in Preyersmuehle-Hastedt between 266-458 m (Upper Tertiary). However, sticky shales could be removed and did not reoccur afterwards. It is concluded that water-sensitive shaly formations were not the source of NPT but continuously lost circulation in the Maastrichtian, both during drilling or cementing.

Well	Bit [in]	Mud system	Density [kg/l]	Fluid loss [ml/30 min]	Filter cake [mm]
Preyersmuehle-Hastedt Z1	23	Fresh water clay-based	1,07 – 1,20	10,0 – 35,0	1,5 – 3,5
Worth Z1	23	Fresh water clay-based	1,10 – 1,18	14,8 – 37,8	1,0 – 3,0
Boetersen Z6	23	Fresh water clay-based	1,06 – 1,16	16,0 – 58,0	2,0 – 4,0
Preyersmuehle Sued Z1	23	Fresh water clay-based	1,05 – 1,12	6,8 – 7,4	0,4 – 1,2

Table 4.10: Overview of mud systems in Preyersmuehle Sued Z1 and its offset wells

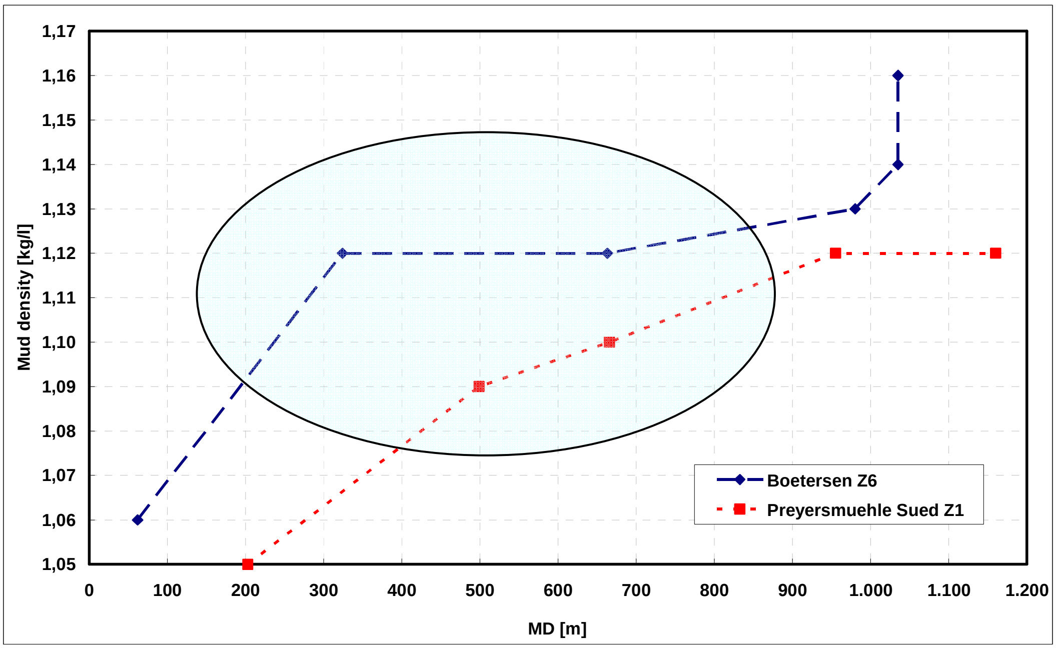

Figure 4.8: Graphical comparison between mud densities in Preyersmuehle Sued Z1 and Boetersen Z6

As the trouble in Preyersmuehle Sued Z1 occurred mainly in the Upper Tertiary, a comparison between reported mud weights across the Tertiary was performed. From Figure 4.8 it can be seen that the mud weights in Boetersen Z6 was always higher. Still, its caliper does not look as rugged and washed out as Preyersmuehle's. The oval circles the depth interval of interest.

Both Preyersmuehle-Hastedt Z1 and Worth Z1 experienced serious circulation losses in depths around 1.100 m (calcarenites in the Maastrichtian, Upper Cretaceous). It was required to cement those loss intervals multiple times in order to run casing and perform cementing. In Preyersmuehle-Hastedt Z1 flow into the wellbore was initially experienced after a sudden drop in mud weight from 1,14 to 1,07 kg/l. By increasing the mud density back to 1,13 kg/l, it could be stopped and the 18 5/8" casing could be run in hole; the total lost volume amounted up to 112 m³. No such incidents occurred in Boetersen Z6. Due to named problems, detailed information on mud weight and rheological properties was collected while planning Preyersmuehle Sued Z1 (cf. Table 4.11). This way it was hoped to identify critical mud weights which allowed safe operations without mud losses.

Well name	Depth [m]	Density [kg/l]	PV [cp]	YP [lb/100 ft²]	API FL [ml/30 min]
Worth Z1	813	1,12	7	19	
	994	1,13	8	24	37,2
	1.196	1,16	8	30	14,8
Losses at	1.196	1,18	12	38	16,2
Preyersmuehle-Hastedt Z1	695	1,07	2	28	35
	861	1,11	1	47	29
	993	1,12	8	16	29
	1.104	1,12	-	-	-
Losses at	1.110	1,15	-	-	-
	1.127	1,14	1	50	30
Bötersen Z6	980	1,13	6	30	36
	1.035	1,14	5	27	35
Losses during cementing	1.035	1,16	8	44	50

Table 4.11: Detailed list of mud properties of offset wells for Preyersmuehle Sued Z1

4.2.4 Drilling Performance

The sequence of bit types in hole and their replacement is analyzed in detail in order to determine the bit-related number of roundtrips and borehole wall contacts. The table does not include bits which were used for redrilling or reaming. Preyersmuehle-Hastedt Z1 and Worth Z1 were both drilled to 266 m (17 ½” bit) and 289 m (23” bit), respectively, underreamed and cased with 24 ½” conductors.

Well	Bit diameter [in]	Bit type	# runs	Removed at
Preyersmuehle-Hastedt Z1	17,5	Roller cone	1	266
	28	Underreamer	1	266
	23*	Roller cone	1	266
	23	Roller cone	1	929
	23	Roller cone	1	1.104
	23	Roller cone	2	Casing setting depth
Worth Z1	23	Roller cone	1	289
	28	Underreamer	1	289
	23*	Roller cone	2	294
	23	Roller cone	1	768
	23	Roller cone	1	Casing setting depth
Boetersen Z6	23	Roller cone	1	264
	23	Roller cone	2	Casing setting depth
Preyersmuehle Sued Z1	23	Tooth roller cone	1	613,5
	23	Tooth roller cone	1	Casing setting depth
	29	Underreamer	1	29
	28	Underreamer	1	315

Table 4.12: Overview of bits for Preyersmuehle Sued Z1 and its offset wells (*bit used for drilling out cement)

For the subsequent section, 23” bits were used for all wells to depths between 1.035 m (Boetersen Z6) and 1.196 m (Worth Z1). In Preyersmuehle Sued Z1, two underreamer runs are reported: the first to scratch off shale pockets in the 32” conductor casing. The second was designed to enlarge the interval between 219 and 315 m (Bruessel sands) where the casing had not been run past during the first try.

4.2.5 Borehole Hydraulics

Well	Avg. reported pump rate [l/min]	Reported pump pressure [bar]	ECD [kg/l] at 800 m
Preyersmuehle-Hastedt Z1	4.398	93,5	1,14
Worth Z1	5.015	103,5	1,14
Boetersen Z6	3.868	133,0	1,14
Preyersmuehle Sued Z1	4.000	162,6	1,13

Table 4.13: Overview of pump rates and pump pressures for Preyersmuehle Sued Z1 and its offset wells

Table 4.13 lists average pump rates and pressures as well as ECD based on input data from morning reports. It can be seen that Preyersmuehle Sued Z1 had a slightly lower ECD than its reference wells.

Table 4.14 depicts a list of pump rates and pressures from Preyersmuehle Sued Z1 and Boetersen Z6, obtained from the morning reports. They were compared because their 23” sections were approximately equally long and did not contain 24 ½” conductors to cover unconsolidated Neuengamme and Bruessel sands. Continuous data were not available which would allow a more accurate comparison. It can be seen that the pump pressures in Preyersmuehle Sued Z1 were significantly higher in shallow formations (e.g. 205 bar at 203 m versus 120 bar in 324 m in Boetersen Z6). In order to investigate the origin of those higher pressures, system pressure losses were calculated. The result was astonishing: the different bit nozzle configuration with one 14/32” and three 16/32” nozzles was mainly to blame for the higher pump pressures reported; the difference to the bit in Boetersen Z6 with one 20/32” and three 18/32” nozzles were approximately 70 bars.

Well	MD [m]	Q [l/min]	p_{pump} [bar]
Boetersen Z6	324	4.180	120
	663	4.180	160
	980	4.180	175
	1.035	4.000	175
Preyersmuehle Sued Z1	203	4.000	205
	499	4.000	190
	666	4.000	110
	955	4.000	153
	1.160	4.000	155

Table 4.14: Comparison of pump rates and pressures between Preyersmuehle Sued Z1 and Boetersen Z6

The remaining difference can be explained by different system layout and different sized drill string components. Moreover annular mud velocities were calculated for wellbore diameter - drill pipe OD.

Well	DP OD [in]	Borehole ID [in]	Q [l/min]	Annular velocity [m/s]
Boetersen Z6	5	23	4.180	0,175
	5	Cavity: 39	4.180	0,057
Preyersmuehle Sued Z1	6 5/8	23	4.000	0,168
	6 5/8	Cavity: 42	4.000	0,049

Table 4.15: Annular and cavity mud velocities

The expected explanation that excessive pump pressures resulted in washouts had to be abandoned.

4.2.6 Comparison of Open Hole Time

The comparison of open hole times and the indicator "open hole time/meter" gives another hint why Boetersen Z6 succeeded: it remained uncased only half as long as Preyersmuehle Sued Z1 and even less than 50% compared with the other reference wells.

Well	Mud	Δ depth [m]	Approximate OHT [hr]	OHT/meter [hr/m]
Preyersmuehle-Hastedt Z1	FC	1.127	480	0,43
Worth Z1	FC	1.196	576	0,48
Boetersen Z6	FC	1.035	168	0,16
Preyersmuehle Sued Z1	FC	1.160	336	0,29

Table 4.16: Comparison of open hole times in Preyersmuehle Sued Z1 and its offset well

4.2.7 Correlation of Parameters

API Fluid Loss, Mud Density and Caliper Logs

As derived from the gamma ray and caliper logs, no water-reactive shales were found in the interval where difficulties with running the casing occurred. Therefore it was considered unlikely beforehand that API fluid loss, mud density and caliper logs could indicate correlations. Nevertheless, these curves were plotted to prove that no relation is imminent.

4.2.8 Summary of Analysis

Reported gross ROP and Borehole Wall Conditioning

Preyersmuehle Sued Z1 had the highest reported gross ROP on average (Quaternary to Upper Cretaceous) and through Cenozoic and Upper Cretaceous, respectively. Compared with its closest offset wells, Preyersmuehle-Hastedt Z1 and Worth Z1, this implied a nearly three-fold increase in Upper Cretaceous formations and acceleration by approximately a third in Quaternary and Tertiary. Rising reported gross ROP resulted in less borehole wall contacts and thus decreasing hole quality. Moreover it implied the creation of larger cuttings volumes which, due to constant pump rates, implied increased loading of the mud and therefore higher equivalent circulation densities in both shallow, unconsolidated and deeper, consolidated formations.

Directional Drilling and BHA

All four wells analyzed in this section were planned vertical. Actual inclinations which ranged between 0,7° and 2,9° were not intended. No difference could be found in the composition of the BHA.

Drilling Mud Systems

The difficulties with installing the casing occurred in Mid Eocene Bruessel sands which are known for being hardly consolidated and thus instable. Since the combined gamma ray/caliper logs indicate that there are no shales involved and no shale-related problems were encountered in the offset wells, it is believed that the type of mud system did not trigger the casing running problems. Lost circulation issues in the reference wells of Preyersmuehle Sued Z1 indicate that the mud weight was too high for the low-pressure Maastrichtian formations and induced loss-prevention cementations. Those could be counteracted by decreasing the mud density, pump rate and thus ECD.

Drilling Performance, Borehole Hydraulics

By analyzing used bit types and their sequence, more information about the wellbore geometry was gained. 24 ½” casings were run in Preyersmuehle-Hastedt Z1 and Worth Z1 to cover formations to a depth of 266 and 289 m, respectively. Boetersen Z6 was drilled without surface casing; however, no problems with little consolidated Tertiary sands were reported. After trouble with installing 18 5/8” casing, the wellbore was enlarged from 23” to 28” in Preyersmuehle Sued Z1 between 219-315 m. Why underreaming was not started higher up, is unclear as the caliper log shows several tight spots especially between 200 and 220 m

The magnitude of pump rate and pressure especially in Bruessel sands (Mid Eocene) was analyzed as large cave-ins were observed in unconsolidated Neuengamme and Bruessel sands in both Preyersmuehle Sued Z1 and Boetersen. By evaluating bit pressure losses, it was found that smaller nozzles were to blame for the higher reported standpipe pressures in Preyersmuehle Sued Z1.

Comparison of Open Hole Time, Correlation of Parameters

The comparison of open hole times between the four wells revealed that Boetersen Z6 was drilled and cemented in only half the total drilling time of Preyersmuehle Sued Z1; its open hole time was therefore much shorter. Even if shales were found not to be the reason for trouble, this finding was considered crucial as longer open hole times in general affect wellbore stability negatively.

The attempt to correlate API fluid loss, mud density and caliper log did not yield any results; the mud filtration properties in Preyersmuehle Sued Z1 were reduced before penetrating low-pressure Maastrichtian formations and therefore well below its reference wells.

4.2.9 Conclusions

The gamma ray and caliper log clearly indicate that extreme washouts were situated in sandy formations in the Upper and Mid Tertiary (Neuengamme and Bruessel sands as well as Lower Eocene sands) in Preyersmuehle Sued Z1. Interestingly enough, cave-ins were also reported in Boetersen Z6 in similar depths.

From the detailed analysis of mud weights, it was found that Boetersen Z6 was drilled with heavier mud along the entire 23” interval. It is thus concluded that both insufficiently high mud densities and open hole times which were double as long led to reported wellbore instabilities in Preyersmuehle Sued Z1. In general Preyersmuehle Sued Z1 did not suffer from fast drilling or high pump pressures but from insufficient mud weights which resulted in large cavings in the Tertiary due to rock shear failure.

The installation and cementing of the 18 5/8” casing was planned to be finished after ten days. Actually, it took 20 days before drilling of the next interval could be resumed. The lag of ten days was caused by wellbore stability problems which impeded running casing at the first attempt, subsequently required rigging down casing installation equipment, underreaming to 28” and chamfering of the casing shoe. On account of higher than planned ROP and no further trouble, the project lag could be reduced from ten to six days at total depth.

4.3 Doetlingen Ost Z1

The investigation of borehole stability-related issues of Doetlingen Ost Z1 (1999) and Z2 (2005) allowed deeper insights into the behavior of the same shales in varying mud systems.

Reported Troubles

From the lower Cretaceous on Doetlingen Ost Z1 was drilled with a conventional bentonite mud containing approximately 100 g/l KCl for inhibition. Moreover, a filtration reduction agent, namely CMC was added in order to reduce the risk of pore pressure buildup in Lias shales. Nonetheless massive problems due to wellbore instabilities were encountered, e.g. overpull during tripping, clay balling and hole size reduction. Break-out cuttings were circulated to the top when drilling Upper Triassic formations; long sections in Lias had to be redrilled in order to tackle swelling shales. The drill string eventually got stuck during surface line repair work when no circulation was possible.

Despite jarring it could not be freed anymore. Thus it was finally decided to back off and sidetrack. 30 m of BHA components (including the 16” roller cone bit) could not be retrieved during fishing operations. The sidetrack was begun in Cenoman formation, base Upper Cretaceous and reached verticality before the end of the 16” section. For improved shale inhibition, oil-based mud was used with the result that no further trouble was reported before running the 13 3/8” casing.

Well Specifics

Based on geological end of well reports it was ensured that their geology is comparable, i.e. by comparing bottom depths of various formations. Jurassic layers were looked at in more details since they were known to be troublemakers. An overview of formation depths is given in Table 4.17.

Both projects were executed in the last decade, with modern topdrive-bearing rigs and pump systems. All analysis parameters were looked at with an emphasis on mud systems which were believed to be the major driver for wellbore stability problems in this example.

Formation	Approximate depth of formation bottom [m]	
	Doetlingen Ost Z1	Doetlingen Ost Z2
Quaternary	48	60
Tertiary	487	?
Upper Cretaceous	1.292	1.283
Lower Cretaceous	1.320	1.318
Dogger α – Lias ζ	1.365	1.362
Lias ε	1.404	1.405
Lias δ	1.542	1.540
Lias γ	1.647	1.645
Lias β	1.788	1.791
Lias α	1.931	1.933
Upper Triassic	2.356	2.361

Table 4.17: Overview of layering and formation bottom depths in Doetlingen Ost Z1 and Z2

Figure 4.9 displays the 16” interval caliper logs of the sidetrack of Doetlingen Ost Z1 and the main wellbore of Z2. The sidetrack was drilled with OBM which is rather obvious analyzing the caliper log: nearly no breakouts can be found from a depth of 1.450 m on; the curve is rather smooth compared to Doetlingen Ost Z2 where UltraDril was used for the first time.

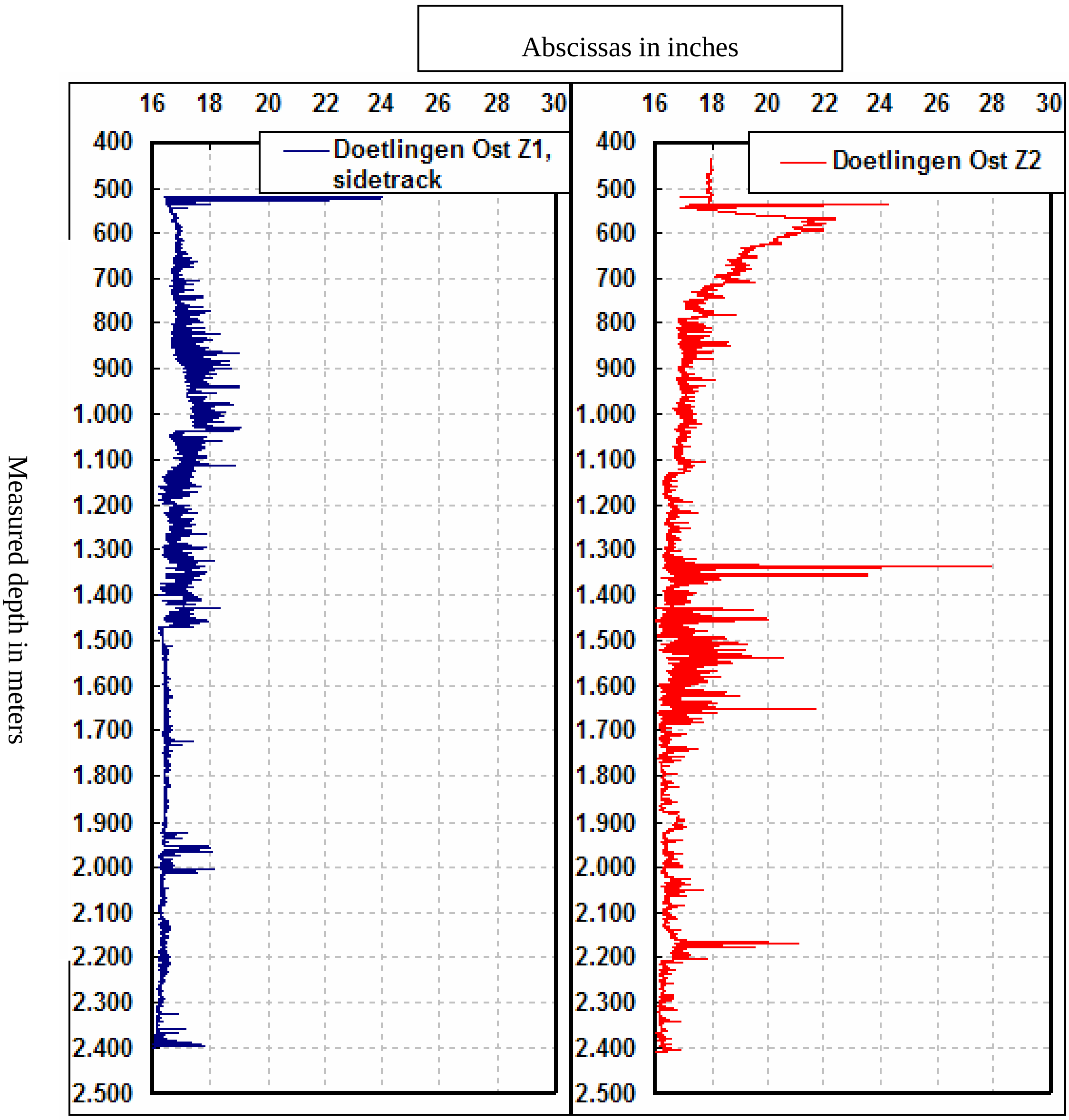

Figure 4.9: Jurassic caliper logs: Doetlingen Ost Z1 and Z2

4.3.1 Reported gross ROP and Borehole Wall Conditioning

Both wells were drilled with modern rigs and topdrives; therefore connection making was the same. Again reported gross ROP were compared in the three wellbores to make conclusions about borehole wall conditioning during drilling. Doetlingen Ost Z1 was drilled by far faster in all sections than its reference wells. Its sidetrack resembled Doetlingen Ost Z2 in drilling speed in the Cretaceous whereas in the Jurassic, reported gross ROP was also significantly higher; however, this did not lead to instability.

Well name	Quaternary, Tertiary	Cretaceous	Jurassic	Average
	[m/hr]			
Doetlingen Ost Z1	17,22	17,08	15,03	7,44
Doetlingen Ost Z1, sidetrack	-	9,53	15,08	8,35
Doetlingen Ost Z2	11,65	9,64	9,07	7,97

Table 4.18: Comparison of reported gross ROP for subsequent formations in Doetlingen Ost Z1 and its offset wells

The average reported gross ROP for the entire 16" wellbore section was used to create Figure 4.10. It compares the calculated number of contacts between the string and borehole wall. All parameters were equal except for average reported gross ROP.

It is important to outline that this also includes Upper Triassic intervals where Doetlingen Ost Z1 suffered from a significant deceleration in drilling speed and therefore experienced more string contacts than its reference wells. The graph leads to the conclusion that from a borehole conditioning point of view, it should have had superior borehole wall quality.

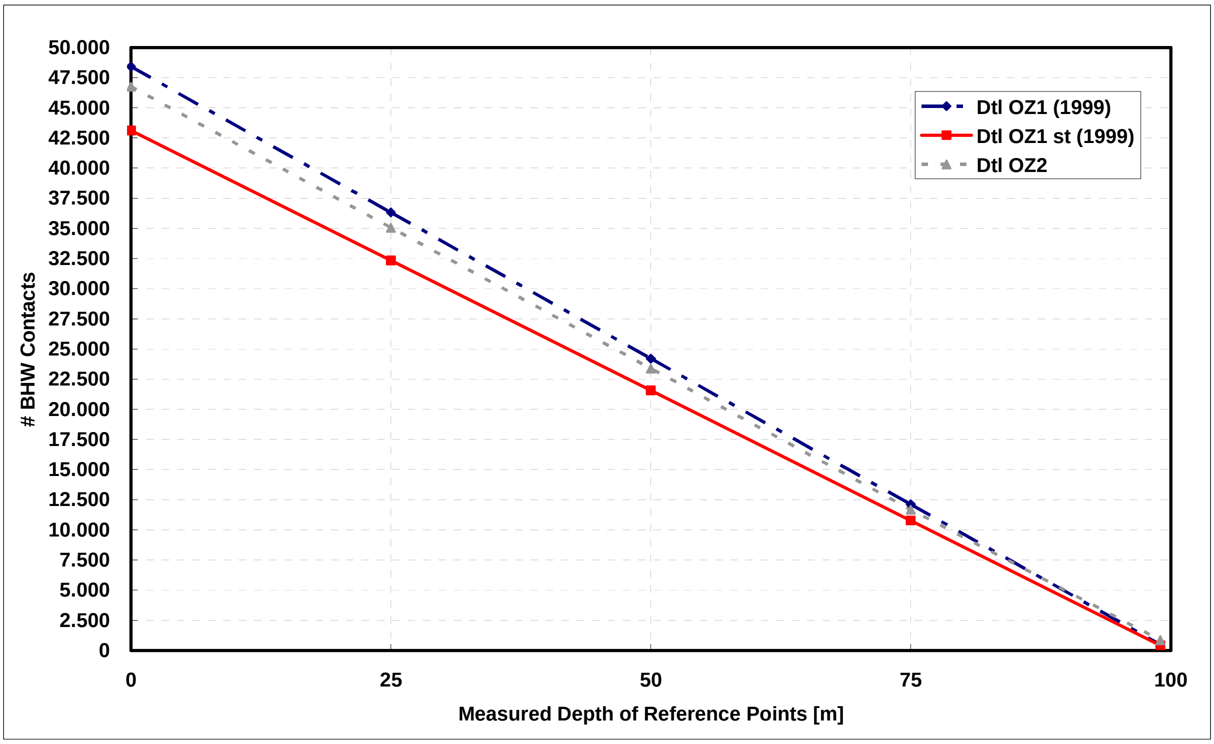

Figure 4.10: Calculated borehole wall contacts with drill string along an example interval of 100 m for Doetlingen Ost Z1 and offset wells

The influence of the number of wellbore conditioning trips during drilling on theoretical borehole wall contacts was investigated but determined to be small due to fast vertical movement. To compensate for faster drilling, seven reaming trips of 28,5 m length (one triple) would have been necessary in Doetlingen Ost Z2.

4.3.2 Directional Drilling and BHA

The difference regarding directional drilling is that Doetlingen Ost Z2 was deviated from vertical in the at 567 m (Upper Cretaceous), reaching inclinations of up to 15,5° in Lias formation. Doetlingen Ost Z1 was planned to be vertical in the uppermost sections (23”, 16” and 12 ¼” intervals) but an unplanned kick-off through sidetracking at 1.031 m. At the setting depth of the 13 3/8” casing the wellbore approached 0° inclination again and was only 20 m away from the plan. The deviation from vertical was in both cases initiated by the use of downhole motors and bent housings.

4.3.3 Drilling Mud Systems

Table 4.19 shows some details regarding mud properties. The drilling fluids were changed at 1.395 m (Doetlingen Ost Z1), 1.031 m (sidetrack) and 1.064 m (Doetlingen Ost Z2), respectively.

Well	Bit [in]	Mud system	Density [kg/l]	Fluid loss [ml/30 min]	Filter cake [mm]
Doetlingen Ost Z1	16	Fresh water clay-based Salt water clay-based	1,13 – 1,16 1,21 – 1,22	API: 19 – 24 4,2 – 4,4	1,6 – 1,9 0,6 – 0,8
Doetlingen Ost Z1, sidetrack	16	Oil-based mud	1,25	HPHT: 1,8 – 3,6	1,0 – 1,4
Doetlingen Ost Z2	16	Fresh water clay-based UltraDril	1,08 – 1,25 1,26	API: 3,8 – 5,8 2,1 – 2,6	0,5 – 0,6 0,5

Table 4.19: Overview of mud systems in Doetlingen Ost Z1 and Z2

The fluid loss data for Doetlingen Ost Z1, sidetrack, bear the indication “HPHT” – high pressure/high temperature because the conventional API filter press test would not yield any measurable volume of filtrate and filter cake after 30 minutes. Therefore the fluid loss test for the sidetrack was performed at a pressure of 32 bar and a temperature of 150°C. API and HPHT measurements cannot be compared among each other. Nevertheless a comparison between fluid loss data of Doetlingen Ost Z1 and Z2 was made in order to investigate the differences between the two water-based muds. The dashed line in Figure 4.11 represents OBM data and is not analyzed further. It is shown that water loss with UltraDril was mostly 50% less than with the filtration-controlled, salt water clay-based mud used in Doetlingen Ost Z1. This might be an indicator why the latter suffered from massive cavings and failed. The filter cake thicknesses in both cases were similar in magnitude. The drop in filtration volume in Doetlingen Ost Z1 occurred due to adding CMC to the mud before penetrating water-reactive Lias $\gamma - \alpha$ shales.

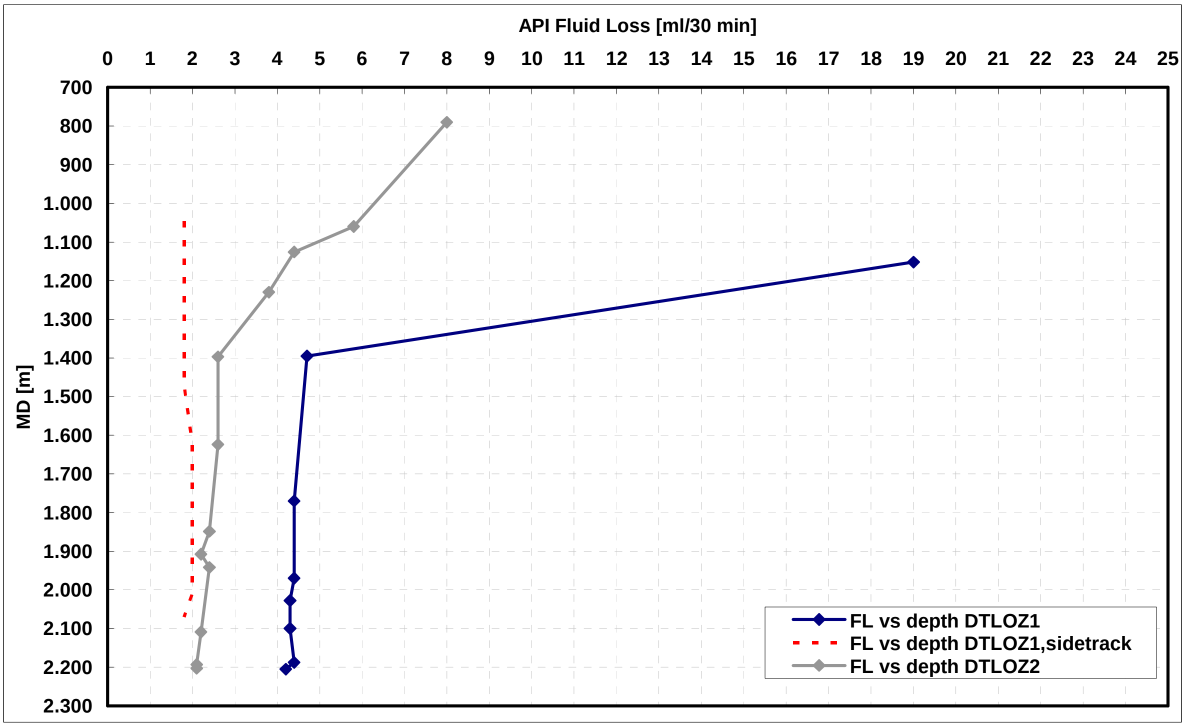

Figure 4.11: Comparison between API fluid loss data from Doetlingen Ost Z1 and its offset wells

4.3.4 Drilling Performance

Well	Bit diameter [in]	Bit type	# runs	Removed at
Doetlingen Ost Z1	16	Tooth roller cone	1	1.970 m
	16	Roller cone	1	Back off depth
Doetlingen Ost Z1, sidetrack	16	Tooth roller cone	2	Casing setting depth
Doetlingen Ost Z2	16	Tooth roller cone	1	1.126 m
	16	PDC	1	1.908 m
	16	Tooth roller cone	1	2.203 m
	16	PDC	1	Casing setting depth

Table 4.20: Overview of bits for Doetlingen Ost Z1 and its offset wells

In both cases modern bits were employed in the 16” interval which did not require roundtrips for replacement due to broken or worn components. The bit changes in Doetlingen Ost Z2 were caused by picking up a high-speed downhole motor and a corresponding PDC bit. Due to problems with directional drilling a roller cone bit was run next. It was eventually replaced by another PDC bit which drilled to casing setting depth. Only one roller cone bit was used for Doetlingen Ost Z1 and its sidetrack.

4.3.5 Borehole Hydraulics

Table 4.21 lists averaged pump rates and pressures for the entire Jurassic interval. The small pump pressure in Doetlingen Ost Z2 can be explained by the 6 5/8” OD (4 7/8” ID) drill pipe that was used as opposed to the 5” OD (3 and 3 ½” ID, respectively) pipe in Doetlingen Ost Z1 plus sidetrack. The calculation results of parasitic pressure losses in the system “drill string-bit-annulus” of 350 m length in case all input parameters but drill pipe geometry are left constant are shown in Table 4.22. The last column is meant to relate absolute parasitic pressure losses to each other. Running larger ID drill pipes leads to a significant improvement regarding hydraulics: more energy is available as hydraulic horsepower at the bit, or in other words, less pump pressure is required to maintain a constant hydraulic performance per area at the bit.

Well	Avg. pump rate [l/min]	Avg. pump pressure [bar]
Doetlingen Ost Z1	3.508	236,0
Doetlingen Ost Z1, sidetrack	3.811	258,3
Doetlingen Ost Z2	3.800	209,0

Table 4.21: Overview of pump rates and pump pressures for Doetlingen Ost Z1 and its offset wells

DP OD [in]	DP ID [in]	Calculated parasitic Δp [bar]	Relative Δp [%]
5	3	185	100
5	3 ½	133	72
6 5/8	4 7/8	96	52

Table 4.22: Results of parasitic pressure loss calculations for Doetlingen Ost Z1 and Z2

4.3.6 Comparison of Open Hole Time

Table 4.23 compares open hole times between Doetlingen Ost Z1, its sidetrack and its offset well. It should be recalled that Doetlingen Ost Z2 was deviated from vertical in the Upper Cretaceous.

Well	Mud	Δ depth [m]	Approximate OHT [hr]	OHT/meter [hr/m]
Doetlingen Ost Z1	SC	1.685	336	0,20
Doetlingen Ost Z1, sidetrack	OBM	1.388	288	0,21
Doetlingen Ost Z2	Poly	1.895	480	0,25

Table 4.23: Comparison of open hole times in Doetlingen Ost Z1 and its offset well

Despite a relatively longer time between drilling out of the casing shoe and cementing its new string and equal API test results, Doetlingen Ost Z2 was stable as opposed to Doetlingen Ost Z1. The stability of the sidetrack, drilled with oil-based mud, is not surprising. Concluding it seems that the “right” mud system was the key to success.

4.3.7 Correlation of Parameters

Correlation of API Fluid Loss, Mud Density and Caliper Logs

Unfortunately, no caliper log was available for the Jurassic in Doetlingen Ost Z1 due to sidetracking immediately after recovering the major part of the fish. Therefore only the log from the sidetrack could be compared regarding mud properties. As expected no correlation between HPHT fluid loss, mud density and the shape of the caliper log was found as the hole was drilled with oil-based mud and thus no cave-ins were observed. The same procedure was performed for Doetlingen Ost Z2. Also in this case no correlation between fluid loss and mud density data and the cave-ins in the caliper log could be determined. As with the previous example, a gun-barrel hole with excavations of only 6% was produced; changes in filtration volume between 2,1 and 2,6 ml/30 min were too insignificant for conclusions anyway.

4.3.8 Summary of Analysis

Reported gross ROP and Borehole Wall Conditioning, Directional Drilling and BHA, Drilling Performance

In order to prove the similarity of both wells concerning technology, reported gross ROP, directional drilling, bit types, pumping parameters, open hole times as well as relations between mud and caliper logs were analyzed. Despite directional drilling in Doetlingen Ost Z2 (see chapter 4.3.2), it was found that the wellbores were comparable which could be proved by their stratigraphic profiles. Reported gross ROP was higher in Doetlingen Ost Z1 and its sidetrack but decreased in the latter in the Upper Triassic whereas in Doetlingen Ost Z2 a lower but continuous reported gross ROP of 7-10 m/hr was recorded. Considering the entire 16” section (Upper Cretaceous to Upper Triassic), Doetlingen Ost Z1 had the most theoretical borehole wall contacts based on the lowest average reported gross ROP. From this view point it should have had a slick and thin filter cake and an intact wellbore wall. On the other hand more roundtrips and thus frequent conditioning were done in Doetlingen Ost Z2 due to bit performance problems. Eventually this left the well in gun-barrel hole condition. Any conclusion still has to include the performance of UltraDril compared with conventional bentonite (i.e. clay-based) mud.

Drilling Mud Systems

Doetlingen Ost Z2 was comparably well inhibited as the sidetrack of Doetlingen Ost Z1, drilled with oil-based mud. This is proven by the caliper log that allows the derivation of theoretical cave-in volumes (measured less theoretical borehole volume). The mud program which was created ahead of drilling lists 10% as an additional volume which is required to compensate cave-ins; the actual was only 6% (with UltraDril) and 10% (with oil-based mud). No caliper log was run for Doetlingen Ost Z1 due to the drill string being stuck. Therefore the dimensions of its cave-ins in Lias cannot be determined. From the morning reports it is obvious, though that it was certainly larger than 10% as massive volumes of edgy-shaped cuttings, identified as cave-ins, were observed at the shale shakers after prolonged circulation periods and pumping highly viscous pills.

Borehole Hydraulics, Comparison of Open Hole Time, Correlation of Parameters

It can be said that pumping parameters were in the same order of magnitude and thus not the reason for wellbore stability problems in Doetlingen Ost Z1. Regarding open hole time per meter and used mud type, it was found that UltraDril inhibited Lias shales in an optimum way since, despite longer open hole time, no wellbore stability problems were reported. Additionally it was found that UltraDril delivered an even more caliper hole than oil-based mud with an extra borehole volume of only 6% as opposed to 10%. As expected no correlation between mud properties and caliper logs could be found as both Doetlingen Ost Z1 sidetrack and Z2 were caliper holes as well as steadily low API filtration volumes.

4.3.9 Conclusions

It is concluded that the used mud system in Doetlingen Ost Z1 led to sidetracking. It was attempted to counteract both shale hydration and dispersion by adding KCl and CMC to the saltwater clay-based mud. After a 30-minute pump shut-in neither circulation nor string movement were possible. It is educed that instable Lias shales dropped onto the BHA and large-diameter string components and plugged as well as tightened it. This is backed by enormous volumes of edgy cuttings, identified as Lias shale cavings that were already observed across the shale shakers during previous circulation periods.

The lost time, induced by instable Lias shales which dropped onto BHA components and required a back off and fishing as well as sidetracking, amounts up to roughly 14 days (time of getting stuck to time of reaching back-off depth with sidetrack).

5 Recommendations

Introduction

This chapter reviews the conclusions by wellbore and gives recommendations on how to reduce or prevent wellbore stability problems in future operations.

5.1 Oythe Z3

It is concluded that the gauge borehole and large, static directional drilling tools were to blame for subsequent wellbore instabilities: the tight clearance between VertiTrak components and wellbore wall accelerated mud and cuttings flow whereas the larger annuli opposite the drill collars and heavy-weight drill pipes, respectively, decelerated the flow by a multiple; the static drill string additionally enabled cuttings settling, i.e. balling up. All attempts to clear this barrier by pumping only resulted in a pressure build up below the bottleneck and finally in hydraulic fracturing of the rock.

If exact verticality is desired and closed loop drilling systems such as VertiTrak are applied, it is recommended to adapt operations: it is proposed to increase the amount of drill string rotation to aid proper cuttings removal when directional drilling stops. It is suggested to increase the amount of reaming before making connections in order to mitigate reduced wellbore conditioning due to static directional drilling. It could even be tried to drill in “kelly mode”, i.e. only adding one pipe at a time with intermediate reaming. Moreover, extra wall conditioning tools, e.g. roller reamers, could be incorporated into the drill string to increase the number of borehole wall contacts during reaming.

In case that the wellbore does not have to be 100% vertical but slight inclination is acceptable, it is recommended to use downhole motors and conventional directional measurement systems for directional control; drilling in rotary mode will condition the borehole wall continuously and support conventional operations. The only drawback with this solution is the time consumed by shutting in the pumps and performing the inclination measurements. Whether a vertical drilling system or a downhole motor is used, depends on the vertical requirements, the time required to drill the section and last but not least, the costs related with either technology.

5.2 Preyersmuehle Sued Z1

Too low mud densities and long open hole times led to cavings and casing running problems in Preyersmuehle Sued Z1. This was clearly indicated by analyzing density data from mud reports and by comparing drilling durations from morning reports.

Increasing mud weight would have prevented the creation of cavings. As shown in the caliper logs, Boetersen Z6 did also suffer from breakouts, yet not as severe as those in Preyersmuehle Sued Z1. This indicates that not even higher mud weights such as used in Boetersen were sufficient to counteract cavings and that the ideal mud density would have to be above.

Mud properties should previously be adjusted for optimum cuttings carrying under both static and dynamic conditions. In case of heavy rock chunks due to cavings, which cannot be kept in suspension, it might be useful to constantly move the drill string in order to prevent settling on the BHA and avoid the danger of getting stuck; one might even consider tripping out parts of the string. Furthermore, pumping highly-viscous pills, as done in Preyersmuehle Sued Z1, could further support the removal of rock fragments from downhole.

5.3 Doetlingen Ost Z1

The comparison of Doetlingen Ost Z1, its sidetrack and Doetlingen Ost Z2 revealed that the mud system was the key to success in the reference wells and the reason for the wellbore instabilities in Doetlingen Ost Z1; its simple water-based mud containing KCl for shale inhibition did not sufficiently inhibit water-sensitive Lias shales which collapsed and led to sidetracking.

Adding KCl to accomplish concentrations above 100 g/l does not enhance shale inhibition but only increases mud weight. Thus it is recommended to switch to either oil-based mud substitutes on water basis, e.g. UltraDril or similar, or to use non-aqueous fluids (so called oil-based muds) if no environmental concerns exist. The mud should be conditioned in order to guarantee the establishment of gel strength which keeps the cuttings in suspension when the pumps are shut in. In order to mitigate the danger of stuck pipe, string movement, both rotating and vertical, is suggested which could prevent the accumulation of cuttings on large-diameter components, e.g. the BHA. Even pulling out of hole can be a potential solution to protect the drill string. However, movement causes shearing of the mud which in turn leads to a destruction of gel structure and gravity settling of cuttings. Measures discussed above intent to prevent stuck pipe, not to keep rock fragments in suspension.

6 Conclusions

This work investigated the influence of modern drilling technologies on wellbore stability based on research covering the North-West German geology, mechanical and chemical aspects of borehole stability and technological changes over the past decades.

The theoretical comparison between previous and recently implemented drilling technologies revealed that topdrive systems trigger less borehole wall conditioning due to the fact that no lifting of the string is done before adding new drill pipe; in rotary drilling, the string has to be hoisted the length of the kelly in order to remove the latter before adding new pipe. Drilling with a topdrive system theoretically requires no upward motion of the drill string as was necessary with a rotary rig. Simultaneously, a topdrive system can increase the gross ROP by reducing the number of work steps required to add drill pipe to the drill stem.

It was found that drilling directionally, i.e. in sliding mode, reduces the number of borehole wall contacts to the number of bit rotations and impairs cuttings transport due to no string rotation.

Sophisticated mud chemistry implies that modern highly inhibitive water-based muds prevent shale hydration and dispersion more effectively than KCl or other salt-rich water-based muds; still, their performance is inferior to oil-based muds'.

Bits with either modern bearing technology or without any moving parts, i.e. drag bits, extend standing times and thus diminish tripping as well as manipulate non-productive time positively.

More powerful pumps can circulate mud at higher rates per minute compared to the past, cooling the near wellbore area more and inducing higher thermal stresses. Frequent temperature reversals due to static and dynamic conditions can impair wellbore stability. Simultaneously, higher pump rates support higher ROP due to more efficient hole cleaning; faster drilling reduces open hole times.

Applying this information to the analysis of actual recent and past drilling projects, well-specific conclusions and recommendations can be made. The investigation of actual drilling projects shows that new drilling technologies were not to blame for wellbore instabilities.

Oythe Z3 – Operational Measures Required

- It is concluded that none of the changed drilling technologies alone led to the collapse of Oythe Z3. Based on the findings the combination of highly-inhibitive UltraDril mud and statically-operating VertiTrak lead to instabilities which is supported by literature /29/: the mud produced a nearly-gauge borehole whose walls were barely worked on because of a non-rotating drill string when the bit was on bottom. BHA components, large in diameter, caused high-velocity channels where the mud could pass. Larger annular cross sections (e.g.

around drill pipe) decreased mud velocity. Computing the average annular mud velocities opposite of the string and bit stabilizers as well as the drill collars or heavy weight drill pipes indicates the magnitude of velocity decrease: at a pump rate of 3.800 liters per minute, the average mud velocity opposite the 15 3/4” stabilizers in the 16” wellbore amounts up to 50,5 ft/s. Opposite the 9 ½” drill collars, just on top of the string stabilizer, the average mud velocity decreases to 2,4 ft/s. Further up the annulus, opposite the 6 5/8” heavy weight drill pipes, the mud velocity is only 1,9 ft/s. This represents 21 and 1,3 fold decreases in average mud velocities which were certainly sufficient for cuttings settling and balling up on the uppermost stabilizer. Pressures above the tensile strength of the rock were produced by trying to break this barrier by mud circulation, which led to hydraulic fracturing. This is backed by reported pressure peaks and subsequent fluid losses due to their invasion into the formation.

Lost Time

- The drilling of Oythe Z3 took 136 instead of the planned 120 days; the setting depth for the 13 3/8” casing was scheduled to be drilled after 23 days but in fact was only reached after 46 days. The difference of 23 days between planned and actual time was due to borehole instabilities in the original wellbore, plugging the original borehole by cement and sidetracking. It should be mentioned, however, that despite a delay of 23 days after the 13 3/8” section, the entire project was finished with a lag of only 16 days and a total depth which was 90 m below the planned; faster drilling progresses in all sections following the 13 3/8” casing could make up for lost time, precisely seven days.

Recommendations

- When using multiple previously unknown drilling technologies it is recommended to analyze their effects on each other. In the case of Oythe Z3, the negative interaction between the performance of the mud and the vertical drilling system could have been mitigated by operational measures: adding only singles (drilling in “kelly mode”) and prolonging reaming periods to move the drill string more frequently along the wellbore wall, as well as including additional large OD tools into the string to enhance working the borehole wall, e.g. roller reamers.
- If accurate verticality is not the priority, the application of downhole motors with conventional directional measurement systems could be a viable and cost-attractive alternative.

Preyersmuehle Sued Z1 – Insufficiently High Mud Densities

- The analysis of drilling data from Preyersmuehle Sued Z1 and its offset wells Preyersmuehle-Hastedt Z1, Worth Z1 and Boetersen Z6 led to the conclusion that insufficiently high mud weights along the entire 23” interval caused shear failure and caving of the borehole wall. The corresponding caliper log shows massive caverns between 181-196 m (Neuengamme formation) and 224-355 m (Bruessel formation) which were identified as sandy formations by gamma ray logs. Moreover longer open hole times worsened the problem and made more of the borehole wall collapse.

- Problems while running the casing could be explained by ledges and cavities formed due to those cavings. The casing got stuck on one of those and could not be run any deeper, not even by applying weight. After underreaming and further difficulties with running drill pipe past 280 m, the casing shoe was chamfered and was eventually installed under circulation.

Lost Time

- The installation of the 18 5/8” casing was planned to be finished after ten days. Actually, it took 20 days before drilling of the next interval could be resumed. The lag of ten days was caused by wellbore stability problems which impeded running casing at the first attempt, subsequently required rigging down casing installation equipment, underreaming of a length of 96 m to 28” and chamfering the casing shoe. On account of higher than planned ROP and no further trouble, the project lag could be reduced from ten to six days at total depth.

Recommendations

- Increasing mud weights should be the first measure to counteract borehole instabilities due to compressive shear failure, e.g. wellbore breakouts. Adjusting the density of the mud could be a first measure to prevent caving.
- Additionally, it should be tried to reduce open hole times which in Preyersmuehle Sued Z1, compared to Boetersen Z6, increased the available time for wellbore damage.

Doetlingen Ost Z1 – Inappropriate Shale Inhibition by Mud System

- The purpose of analyzing Doetlingen Ost Z1, its sidetrack and its offset well Doetlingen Ost Z2 was to directly compare the influence of varying mud systems on wellbore stability. Nevertheless, the entire spectrum of data analyses was performed as before.
- It is concluded that no other parameter but the used mud system is to blame for the wellbore instabilities and related lost time by sidetracking. Due to spatial proximity, all wellbores penetrated rock layers which were similar in both composition and thickness. The sidetrack of Doetlingen Ost Z1 and Doetlingen Ost Z2 were both inclined wells in Cretaceous and Jurassic; the sidetrack approached verticality at the 13 3/8” casing setting depth. It was found that pump rates and pressures were in the same range.
- Despite the shortest open hole time per meter, Doetlingen Ost Z1 experienced instable borehole walls with eventual collapse, which could not even be prevented by the addition of

KCl and CMC to the mud. On the other hand caliper logs of the sidetrack of Doetlingen Ost Z1 and Z2 proved outstanding shale inhibition accomplished by oil-based mud and UltraDril. The usage of the latter resulted in the smallest caving volume (6% versus 10% with OBM). No such information was available for Doetlingen Ost Z1 as no logging was performed prior to collapse.

Lost Time

- The lost time, induced by instable Lias shales which dropped onto BHA components and required a back off and fishing as well as sidetracking, amounts up to roughly 14 days (time of getting stuck to time of reaching back-off depth with sidetrack). No detailed information on the planned duration for the 16" section could be obtained.

Recommendations

- A measure to avoid comparable troubles in the future is the replacement of conventional salt water clay-based mud by oil-based mud substitutes, e.g. UltraDril, or non-aqueous fluids, i.e. OBM. In addition, the mud system should be conditioned to establish gel strength in order to keep cuttings in suspension when pumps are stopped to prevent settling on BHA and eventually stuck pipe.
- Vertical and rotational string movement is additionally recommended, even if the mud gel structure is destroyed by shearing. It can prevent the accumulation of cuttings on large-diameter string components, especially BHA. One might even consider pulling out of hole to protect the string from getting stuck on the bottom of the hole.

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A Appendix

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Period	Epoch	Stage		North-Western Germany	Lithology
Tertiary	Neogene	Pliocene			
		Miocene			
	Paleogene	Oligocene	Upper		
			Lower	Neuengamme Sands	
		Eocene	Upper		
			Mid	Bruessel Sands	Bruessel sands
			Lower	Lower Eocene 4	
				Lower Eocene 3	α, β sands
				Lower Eocene 2	
				Lower Eocene 1	
		Paleocene			
Cretaceous	Upper Cretaceous	Maestrichtian	Upper		Calcarenites, flintstones
			Lower		
		Campanian			
		Santonian			
		Coniacian			
		Turonian			
		Cenomanian			

Table A.1: Detailed stratigraphic profile of Tertiary and Upper Cretaceous in North-Western Germany /1/

Period	Epoch	Stage		North-Western Germany	Lithology
Jurassic	Malm	Tithonian			
		Kimmeridgian			
		Oxfordian			
	Dogger	Callovian			
		Bathonian			
		Bajocian			
		Aalenian			
	Lias	Toarcian	Lias ζ		
			Lias ε		
		Pliensbachian	Lias δ		
			Lias γ		
		Sinemurian	Lias β		
		Hettangian	Lias α		

Table A.2: Detailed stratigraphic profile of Jurassic in North-Western Germany /1/

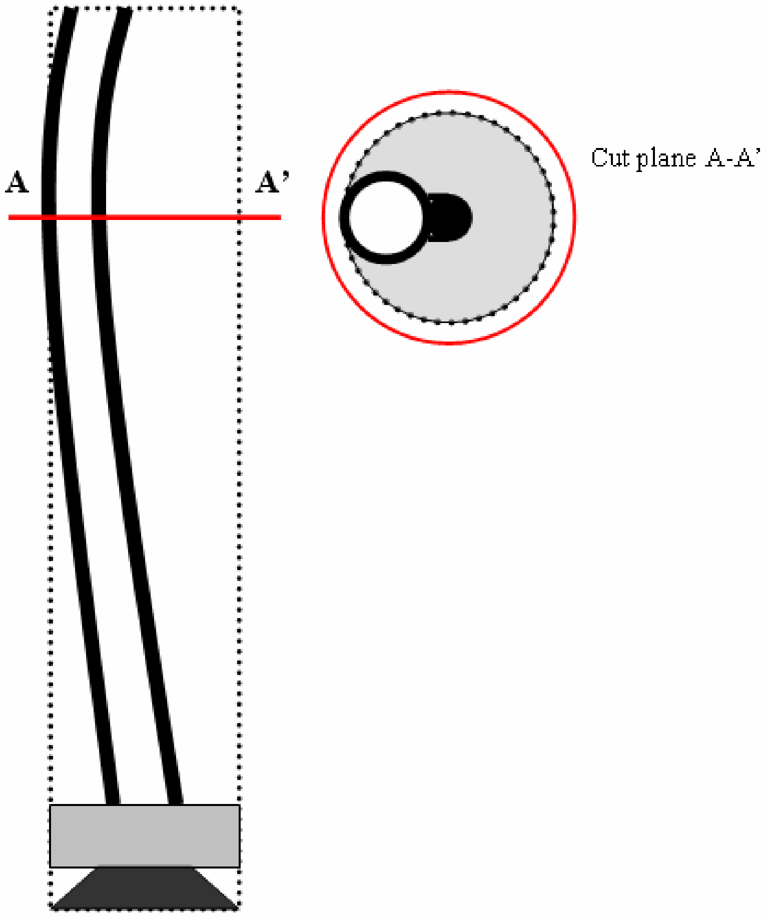

Figure A.1: Sketch showing configuration of drill string and BHA in wellbore used for borehole wall contact calculations (in front and top view at cut line)

Wellbore geometry	18 5/8" surface casing in 23" hole	Setting depth: 355,4 m
	16" open hole	End depth: 1.624 m
Drill string components	9 ½" drill collars	Length: 145,1 m
	6 5/8" heavy-weight drill pipes	Length: 28,35 m
	6 5/8" drill pipes	Length: 1.450,54 m
	16" PDC bit	Nozzles: 6x 13/32", 2x 12/32"
Drilling fluids	Inlet temperature	91°F
	Oil-based mud substitute on water basis	Density: 8,36 ppg
		Plastic viscosity: 35,00 cp
		Yield point: 30,00 lbf/100 ft²
	Oil-based mud	Density: 7 ppg
		Plastic viscosity: 32,00 cp
		Yield point: 24,00 lbf/100 ft²
Operational parameters for simulation	Operation type	Drilling
	Previous operation	Undisturbed (static)
	Rotating/circulating hours	120 hours
	Average circulation rate	930 gpm
	Number of trips	1
	Circulation on bottom before POH	1 hour

Table A.3: Input data for WellCat® temperature profile calculation example

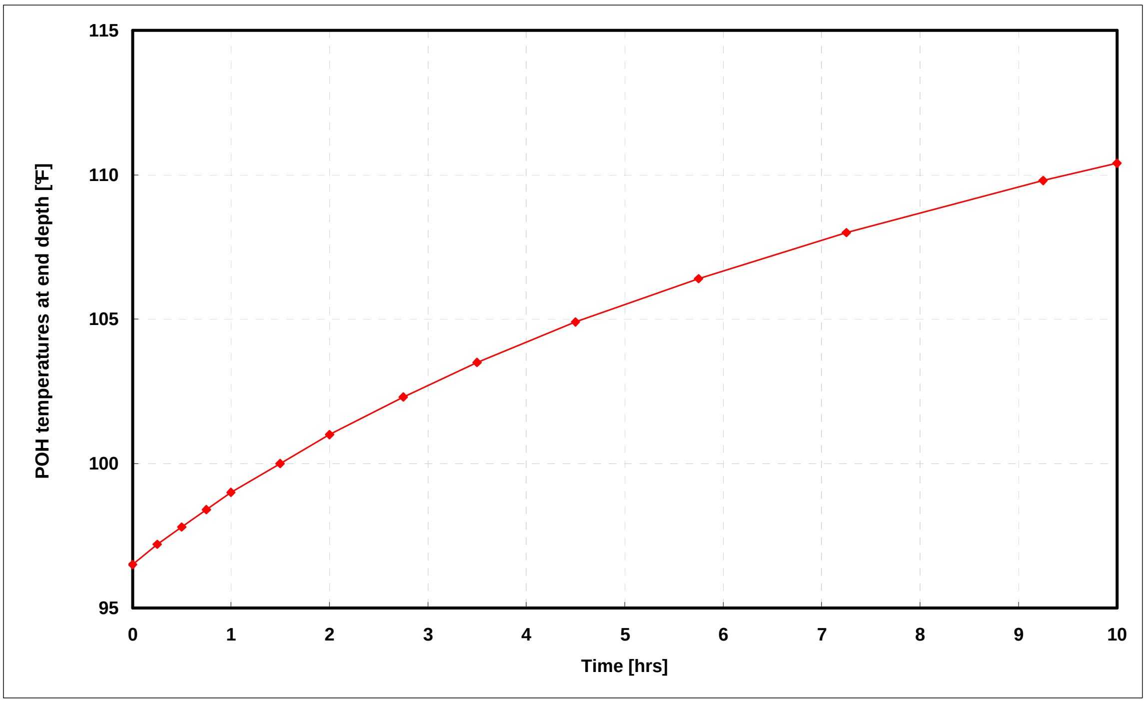

Figure A. 2: POH temperatures at end depth vs. time after tripping for 10 hours: temperature increase due to static mud column vs. time

Depth	2.000	m			
$\rho_H = \rho_h$	1.750	kg/m^3			
ρ_s	2.650	kg/m^3			
α_T	1,20E-05	°C^{-1}			
E	2,50E+10	Pa			
ν	0,35				
ρ_{mud}	1.110	kg/m^3			
T_∞	54,44	°C			
T_w [°C]	ΔT [°C]	$\sigma_{t,dynamic}$ [MPa]	$\Delta\sigma_t$ [MPa]	$\sigma_{v,dynamic}$ [MPa]	$\Delta\sigma_v$ [MPa]
52,44	-2,00	47,81488	0,92308	51,06992	-0,92308
50,44	-4,00	48,73795	1,84615	50,14685	-1,84615
48,44	-6,00	49,66103	2,76923	49,22377	-2,76923
46,44	-8,00	50,58411	3,69231	48,30069	-3,69231
44,44	-10,00	51,50718	4,61538	47,37762	-4,61538
42,44	-12,00	52,43026	5,53846	46,45454	-5,53846
40,44	-14,00	53,35334	6,46154	45,53146	-6,46154
38,44	-16,00	54,27642	7,38462	44,60838	-7,38462
36,44	-18,00	55,19949	8,30769	43,68531	-8,30769
34,44	-20,00	56,12257	9,23077	42,76223	-9,23077
32,44	-22,00	57,04565	10,15385	41,83915	-10,15385
30,44	-24,00	57,96872	11,07692	40,91608	-11,07692
28,44	-26,00	58,89180	12,00000	39,99300	-12,00000
26,44	-28,00	59,81488	12,92308	39,06992	-12,92308
24,44	-30,00	60,73795	13,84615	38,14685	-13,84615

Table A. 4: Calculation of tangential and axial stresses in dependence of the temperature differential static-dynamic

Figure A.3: Components of Baker Hughes INTEQ VertiTrak® /28/

Goldenstedt Z11 – Lias				Oythe Z3 – Lias		
q_{pump}	3.123	l/min		3.650	l/min	
η	0,8			0,95		
DP OD	5,000	in		6,675	in	
DP ID	4,276	in		4,875	in	
Length	2.000	m		2.000	m	
Bit	17,5	in	Non Jet	16,0	in	Non Jet
ρ_{mud}	1,23	kg/l		1,29	kg/l	
μ_p	15,00	cp		45,00	cp	
τ_0	20,00	lb/100 ft²		28,00	lb/100 ft²	
Bit nozzles	3 *	18		6 *	13	
	0 *	12		2 *	12	
$p_{loss,string}$	54,20	bar	42,16%	67,44	bar	43,99%
$p_{loss,ann}$	2,42	bar	1,88%	4,88	bar	3,18%
$p_{loss,bit}$	71,94	bar	55,96%	81,00	bar	52,83%
TOTAL	128,56	bar	100,00%	153,32	bar	100,00%
HHP at bit	2,12	HP/in² bit area		3,33	HP/in² bit area	
Pump power	727,68	HP		1.204,38	HP	

Table A.5: Input data and results of pressure loss calculations comparing Goldenstedt Z11 and Oythe Z3 regarding pump pressure requirements and HHP at the bit

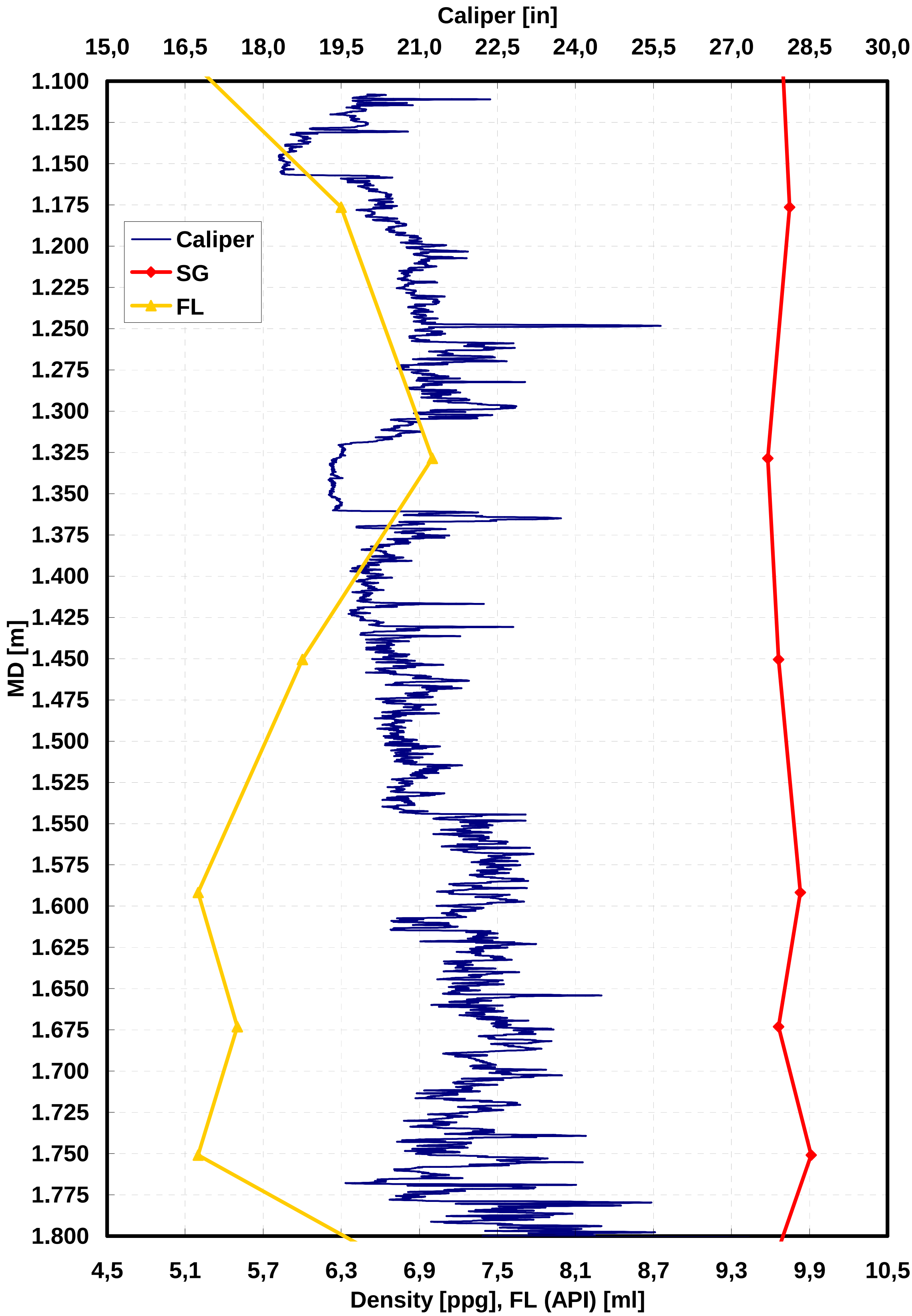

Figure A.4: Attempt to correlate API fluid loss, mud density and caliper log over depth for Goldenstedt Z9

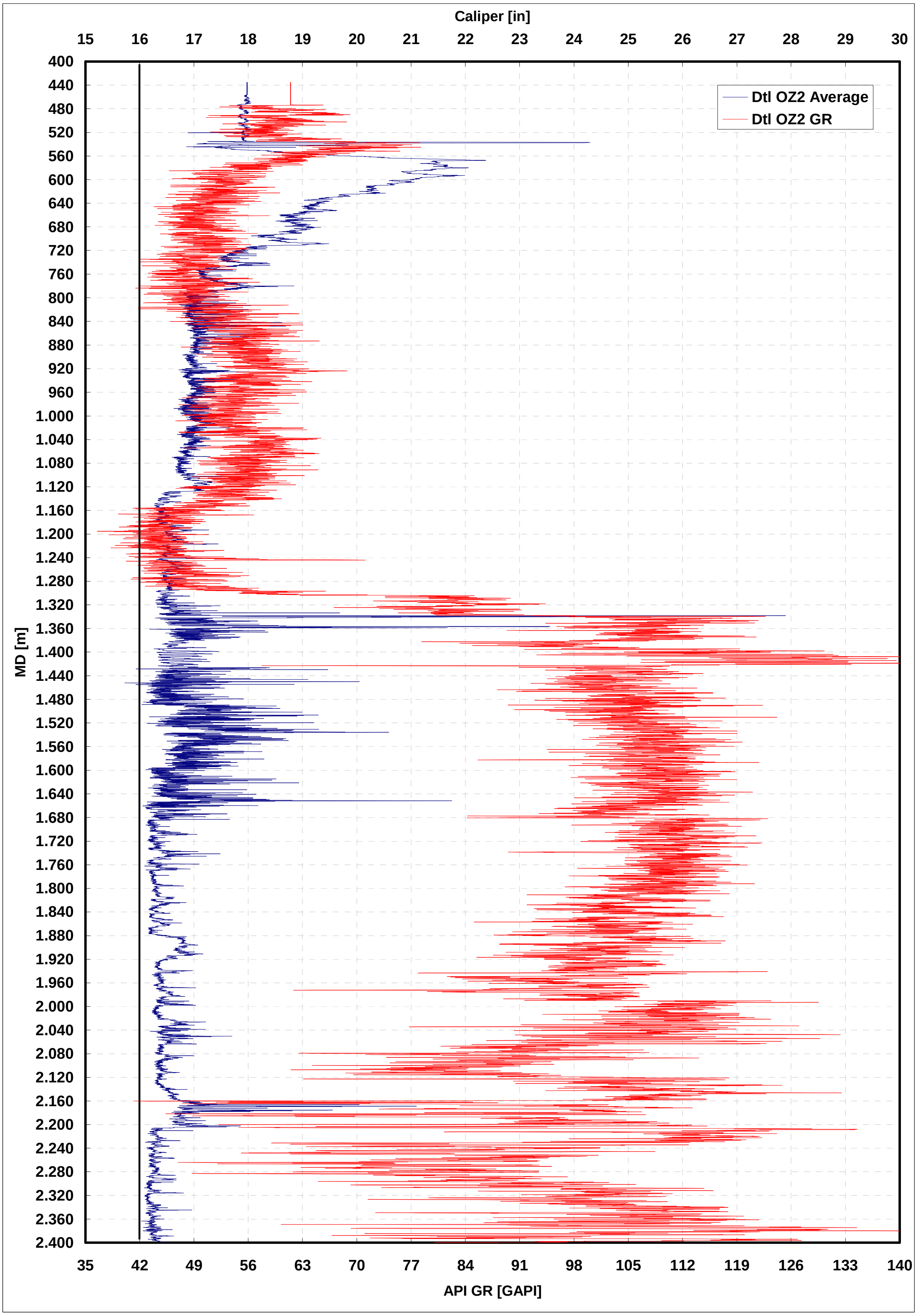

Figure A. 5: Caliper (blue line) and gamma ray (red line) logs of Doetlingen Ost Z2, 16” interval to a depth of 2.407 m

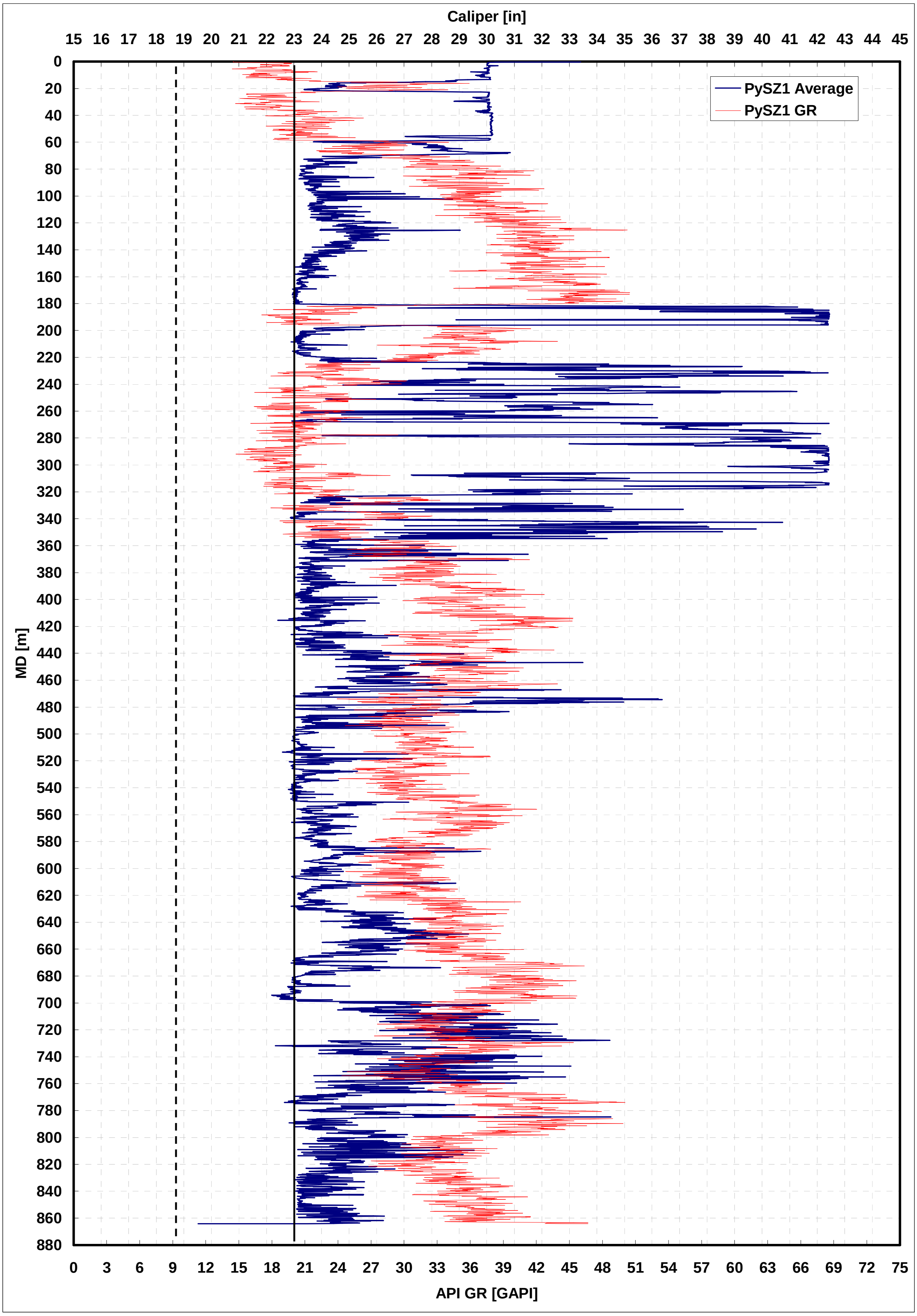

Figure A. 6: Caliper (blue line) and gamma ray (red line) logs of Preyersmuehle Sued Z1, 23” interval to a depth of 867 m

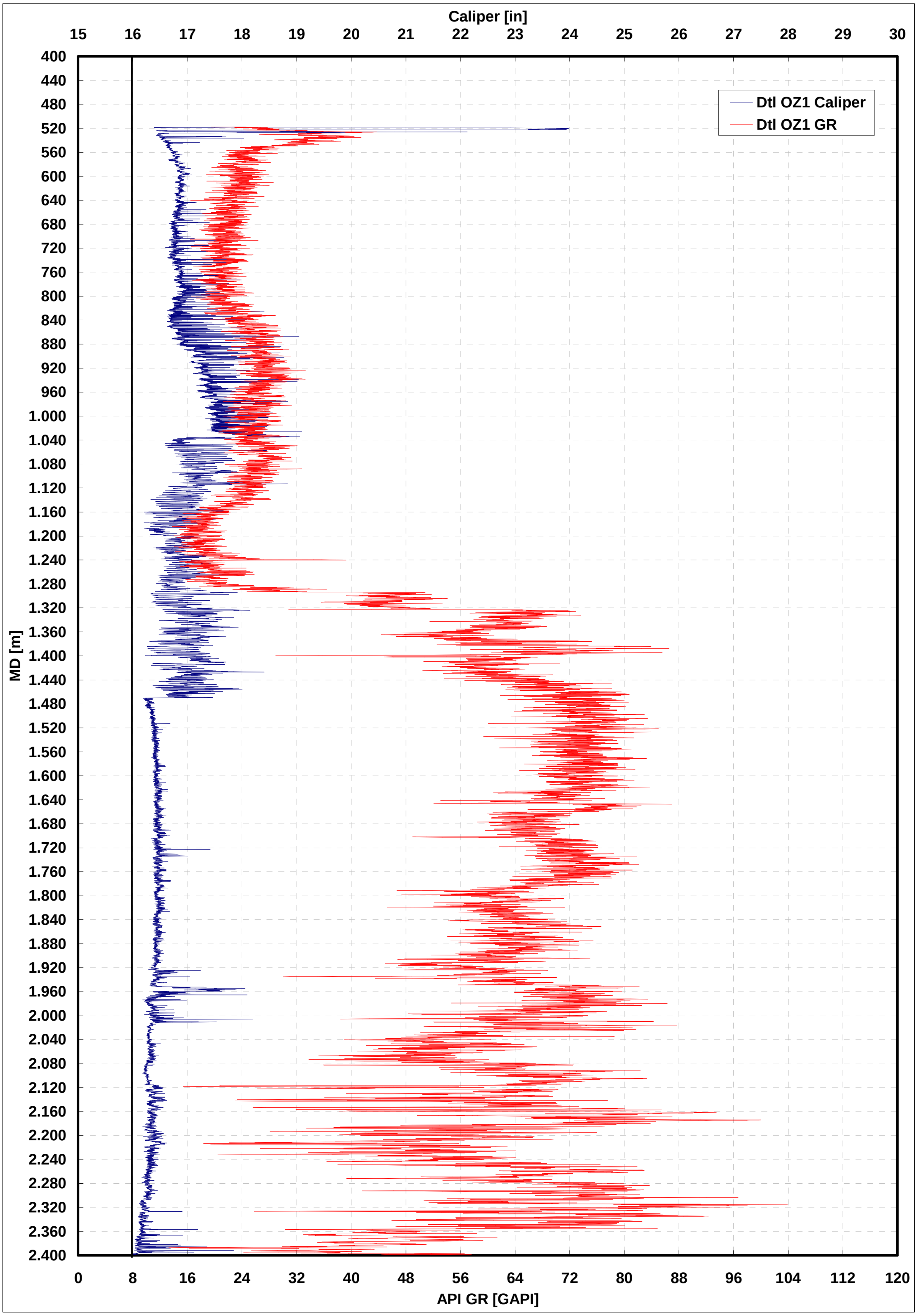

Figure A. 7: Caliper (blue line) and gamma ray (red line) logs of Doetlingen Ost Z1, 16” interval to a depth of 2.398 m