method that can be used is inverted emulsion oil based mud (IEOBM). Although this has its negative effects, such as increased reaming time and low ROB [1-3].

When a brine influx occurs, the balance of salt in the aqueous phase of the OBM becomes disturbed and solid salt (normally NaCl) may crystallise. The crystallised salt has a high surface area and is very hydrophilic and will effectively remove emulsifier and oil wetting agent from the mud. If the brine contains significant magnesium chloride, this will partly react with the lime to form a gelatinous precipitate of magnesium hydroxide, which is also very effective at stripping emulsifier from the fluid. In both cases, a large decrease in emulsion stability (ES) may be seen [10].

1.2 The Scopes of the Project

1.2.1 The Project Aim

The aim of this project is to study that the main of Zechstein formation, which cause the challenges that are to be encountered during the drilling phase. It focuses on investigating and analysing the radical changes in the mechanical, physical and chemical factors of the drilling surrounding and the exposure of Zechstein sequences to drilling fluids. Furthermore, providing remedy procedures that can be used to mitigate any challenges.

1.2.2 The Project Objectives

The aim of project can be satisfied by the outlined objectives:

1) Identify the encountered challenges and their associated characteristics.
2) Study the stresses of the salt formation before penetration and the elastic and plastic stresses of the adjacent formation of the wellbore.
3) Determine the most appropriate drilling fluid density based on the estimation of creep rate.
4) Study the influence of the drilling fluid salinity and saturation level on the gauge hole diameter.
5) Review of the most common drilling fluid that are used to drill Zechstein formations.
6) Recommend appropriate drilling fluid type and density.

The major compositions of Zechstein formations are carbonate and salt rocks such as sulphate and chloride [14]. Zechstein has similarities in the chemical and physical properties with the other underlying salt formation around the world, for instances the Cumbrian Coast Group (CCG) have similar properties as Zechstein and it is predicted that CCG may be linked to it [16]. It has also been estimated that Zechstein depositional age is approximately 251.2 ± 3.4 million years ago [5].

2.2 Stratigraphy Zechstein Evaporite Sequence

The Zechstein sequence in the Southern North Sea (SNS) is a Permian evaporite formation, containing four major cycles of deposition, not all of which may be present in a particular well [17]. The final three cycles contain not only halite, anhydrite and carbonates but also magnesium and potassium salts, which are soluble in a saturated sodium chloride brine. These salts are typically: Carnallite ($K\ Mg\ Cl_3\ 6H_2O$); Bischofite ($Mg\ Cl_2\ 6H_2O$) and Polyhalite ($K_2\ Ca_2\ Mg\ (SO_4)_4.2H_2O$) [17]. However, according to Warren and Clark [4, 12], Zechstein consists of different cycles and these cycles are subdivided into two parts; a classic carbonate evaporite cycles (Z1-Z3) which form a marine lower part, and then the upper part which consists of other two rudimentary cycles (Z4 and Z5) known as a playa-type [13, 18]. Each cycle in the marine lower part is made up of claystone, carbonate (dolomite & calcite), gypsum ($CaSO.\ 2H_2O$), halite ($NaCl$), potassium (K) and magnesium (Mg) consecutively [12, 15, 18]. Furthermore, each cycles defines a major succession of Arctic and seawater evaporation in the arid Southern Permian Basin [13, 15]. The playa-type cycles consist of quite thin sabkha which contains claystone, potash salt and halite [13] Sea Fig. 2.2.

The geological time scale can be used to estimate depositional time of Zechstein sequence, and it can also indicate the depth and the sequences order that will be encountered during drilling operations [5, 13, 15, 18]. At any location in the North Sea basin, the absolute depth and thickness of formation are highly variable based on whether the location is close to the basin centre or around the edge [4].Zechstein formation becomes thicker towards the North Sea basin centre, while approaching the edges become much thinner. The typical depth and thickness of Zechstein supergroup are encountered approximately 1000 to 2000 m deep and about 1000 m thick [19].

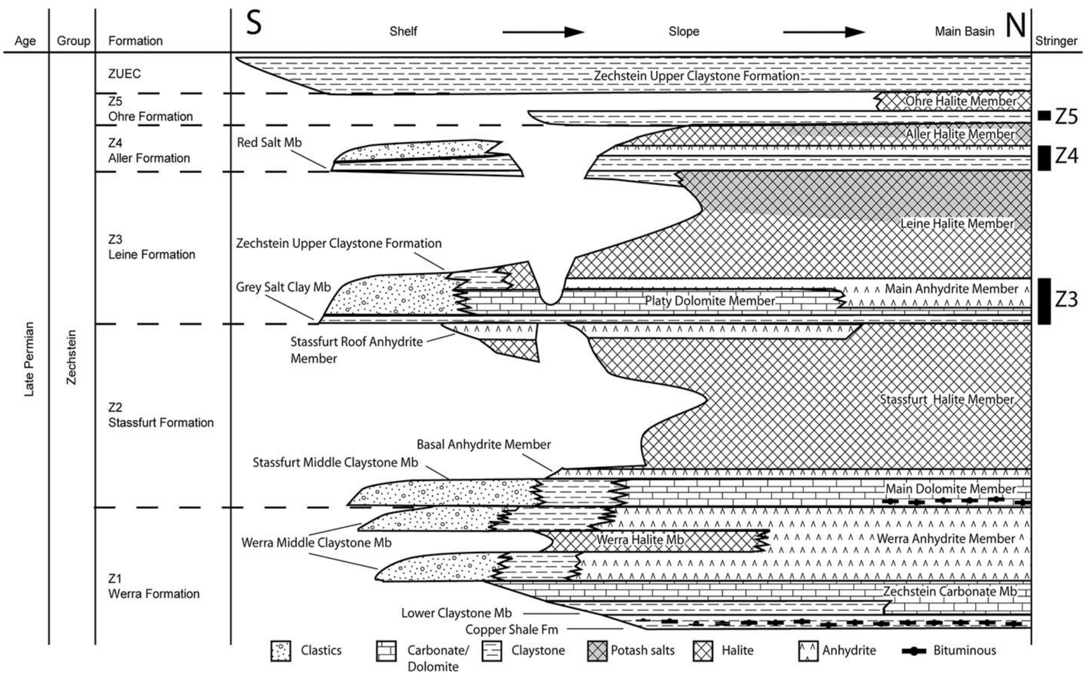


Figure 2.2: Stratigraphic diagram of Zechstein Sequences (Late Permian) from Z1 to Z5 [4].

2.3 Industrial Significance of Zechstein

Despite the number of uncertainties that are associated with Zechstein formations, the influence of Zechstein however is considered to be significant in the discovery of oil and gas.

These formations are typically considered to be an excellent trap for hydrocarbons due to their low permeability and poor porosity [4, 17]. These traps are believed to be the cap rocks of most North Sea reservoirs located with Permian, Carboniferous and Devonian formation. Furthermore, the recoverable hydrocarbons expected to be produced from these sequences are shown in Fig. 2.3 approximately 0.25 and 0.5 billion bbl of oil in each of Devonian and Permian respectively, and for oil-equivalent gas are 1 billion bbl in Carboniferous and 8.5 billion bbl in Permian [13, 17]. However, the figures indicate that Permian sequences contain the largest accumulations of hydrocarbons which are mostly gas, see Fig. 2.3. Thus, Permian is considered to be the most preferable reservoirs to be drilled through Zechstein.

In order to determine the appropriate density (MW) that can be used to maintain wellbore stability and overcome the creeping rate in formation, the following graph is determined by Eq. (13) showing the rate of shrinkage at various temperature.

As seen in Fig. 3.6, if the temperature is increased, the creep rate will increase. The creep rate increases abruptly for temperatures from 150 to 400 °F. If the temperature is higher than 400 °F, salt formation becomes almost completely plastic and will flow readily if differential pressure is applied.

It can be drawn from Fig. 3.6 that the borehole shrinkage rate significantly increases at high temperature. Moreover, the hydrostatic pressure plays an important role in reducing the shrinkage rate when the temperature of the wellbore is determined as being high. Therefore, an optimum resolution to overcome the borehole creeping rate is to apply high density drilling fluid (MW), associated with the cooling operation. However, the density should not exceeds the fracture gradient which is thought to be equal to the overburden pressure for salt 1 psi/ft (19 ppg) [31].

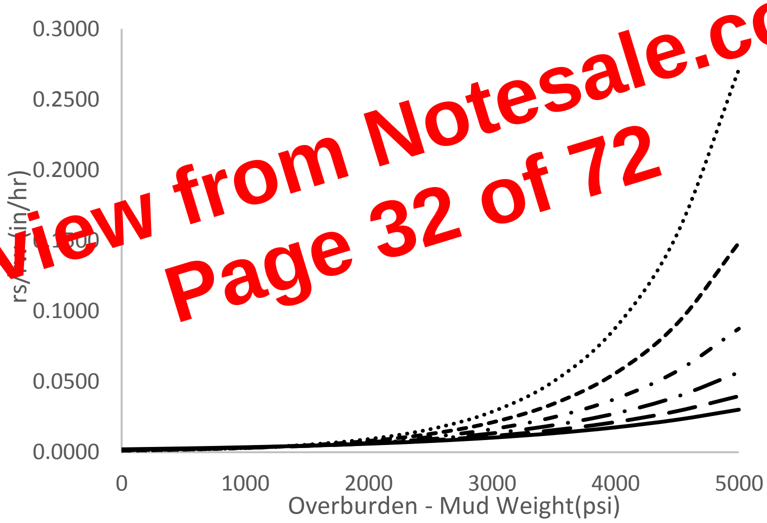


Figure 3.6: The impact of temperature on salt-creep rate. Dotted line 400 °F, dashed line 350 °F, dash dot 300 °F, long dash dot 250 °F, long dash 200 °F, solid 150 °F.

Based on Fig 3.6 the highest allowable differential pressure between the density of the drilling fluid (MW) and overburden is 2000 psi. This pressure compensates for a contraction rate lower than 0.01/hr. Therefore, drilling fluid density is determined by the depth of formation. As can be seen in (Fig. 3.7 & Eq. (15)).

$$MW = \left[\left(overburden\ gradient - \frac{2,000}{Depth}\right)/0.052\right] \tag{15}$$

CHAPTER 4 *DRILLING FLUID DESIGN*

Unlike most of reactive formations, Zechstein evaporite sequences consist of many different salts that are highly soluble in polar solvents such as water. Moreover, Zechstein like any salt formation is extremely mobile when subjected to differential stress. There are two important parameters which have a great influence on Zechstein most related problems (creep and washout), these are fluid type and mud weight (density) [1, 3, 36].

4.1 Drilling Fluid Type

Mud system choice must be able to solve two issues – the chemical compositions of water and the selection of OBM versus WBM [2].

4.1.1 Water-Base Systems

There are several types of water based drilling fluids that are used during the drilling phase. Depending on the depth of well to be drilled and the increase of pressure and temperature, it can vary from basic system to more complex system.

4.1.1.1 Salt-Saturated Saltwater System

Salt-saturated drilling fluid is modelled to drill salt formation and mitigate hole enlargement of the wellbore while drilling salt formations. This enlargement results from the salt in the wellbore dissolving into the "unsaturated salt" water phase of the drilling fluid. However, this type of the drilling fluid is mainly used to drill halite formations and it requires the surface and wellbore temperatures to be very similar to prevent salt re-crystallisation. Since the drilling fluid contains similar salt ion as the formation this will reduce the excessive leaching out [8].

When considering the use of a saturated salt drilling fluid in low-density environments, it is important to be aware that the natural weight of saturated sodium chloride is 10 ppg. The minimum density of a saturated sodium chloride drilling fluid is about 10.5 ppg [37].

The temperature limitation of this system is less than 300°F (149°C). If bottom-hole temperatures greater than 300°F (149°C) are anticipated, alternative high-temperature water-base products must be used or the system should be displaced with a synthetic or oil-base drilling fluid [37].

On the other hand, this system is that it cannot be used to drill all sequences within Zechstein, such as unsteady thick salt section of sylvite, bischofite and carnallite, and

According to Carter and Smith [9], the saturation of mixed salt drilling fluid cannot be maintained at bottomhole due the effect of temperature cycling on the solubility of salts during circulation of drilling fluid. This process is pictured in Fig. This figure suggests that the fluid saturation downhole will be dependent on how much excess salt exist at the surface.

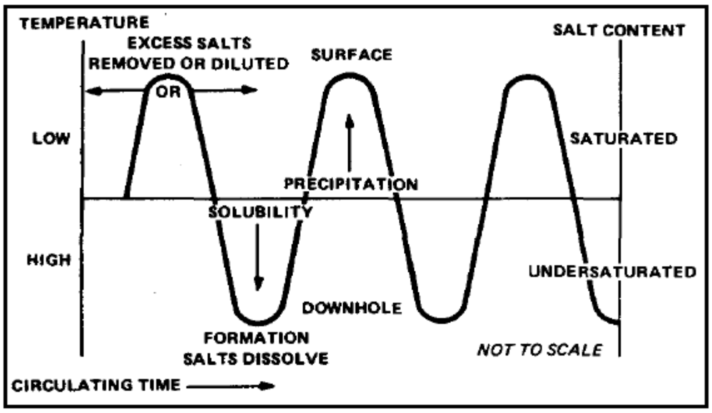


Figure 4.4: The temperature cycling effect on the solubility of salt content 1 bbl of drilling fluid as it circulates through system [9].

4.1.1.3 Heated Mixed Saltwater System

Preheated mixed saltwater system was firstly invented by Muecke 1993. It is designed with a view to prevent the influence of temperature difference on saturated salt-water system by heating the drilling fluid to temperatures close to subsurface temperature [10].

The drilling fluid is regulated by the addition of potassium chloride and Magnesium Chloride prior to heating. Drilling fluid alkalinity is modified by the addition of lime [Ca $(OH)_2$]. The viscosity was improved using a polymer Xanthan gum and a starch that has been modified to be calcium-resistant, in additions to methods such as filtration [10].

The process of heating the drilling fluid is relatively simple, containing a generator for supplying steam, tubing and heat exchanger, see Fig. 4.5. The drilling fluid is recirculated in the suction tank. Then it is pumped into tubing exchanger at rate of 350 gpm together with a steam feed rate of 7 gpm [10].

The heating process requires 7 hours and 550 gal of diesel to raise the temperature of 50 m^3 of volume from 0 $^{\circ}$C to 70 $^{\circ}$C. An additional 154 gal/day of diesel to maintain the diesel working temperature [10].

4.1.2.1 Inverted Emulsion Drilling fluid system

The concept of development of inverted emulsion system is to overcome the obstacles caused by the mixed saltwater drilling fluid such as its incapability for producing a gauge hole [39].

Because using continues oil phase salt becomes less susceptible to ionize and drilling gauge hole could be achieved if the influence of hydraulics is reduced. Besides, the emulsified water solubility is suppressed by adding $CaCl_2$ & /or NaCl to resist the salinity level in mud [9].

Invert emulsion drilling fluids, which are used to drill through Zechstein, are typically mixtures of two immiscible liquids: oil (or synthetic) and brine (CaCl and NaCl dissolved in water) [9, 39]. They may contain 50% or more brine. This brine is broken up into small droplets and uniformly dispersed in the external non-aqueous phase [39]. These droplets are kept suspended in the oil (or synthetic) and prevented from coalescing by surfactants (emulsifier) that act between the two phases. Lime is added to oil- and synthetic base drilling fluids for alkalinity and calcium to treat carbon dioxide (CO_2) or hydrogen sulphide (H_2S) contamination and maintain stable emulsions. Furthermore, weight material also used, barite is the most common weight material used in inverted drilling fluid [9]. However, according to Muecke [10] drilling through Zechstein requires high density mud, thus hematite may be used for providing higher hydrostatic pressure. Other additives may also added such as wetting agent, viscosifier [39].

The electrical stability is an indication of how well (or tightly) the water is emulsified in the oil or synthetic phase. Higher values indicate a stronger emulsion and more stable fluid. To achieve the electrical stability of this drilling fluid, it must have high concentration of $CaCl_2$ or alternatives such as sodium chloride or potassium chloride, to suppress the influence of other electrolytes that are dissolvable in drilling fluid [39]. However, even maintaining a high concentration of $CaCl_2$ the excessive dissolution of magnesium chloride from bischofite & carnallite can still affect the stability of the drilling fluid [9].

Although this drilling fluid has proven its ability for prevention of hole washouts, its related obstacles have restricted its utilization in drilling Zechstein formation due to its susceptibility to break down when it is invaded by a large brine kick which increases the pump rate and promote the increase of the equivalent circulation density (ECD) resulting in losses [10].

an appropriate drilling fluid [29, 44]. Therefore, the density of the drilling system is engineered by predicting the pore gradient and the fracture gradient. If drilling fluid pressure (density times the vertical depth) falls below pore pressure in an impermeable formation, then a kick is expected and the well may even collapse [44]. If mud pressure exceeds the fracture pressure, a fracture is formed and this can highly occur in dolomite section, followed by lose of circulation.

In a long salt section of an open hole, the window between pore pressure and fracture gradient can be very narrow, see Fig. 4.6. In some cases, pore pressure at some point can be greater than the leak of pressure, thus resulting in loss circulation or kick and possibly develop blowout.

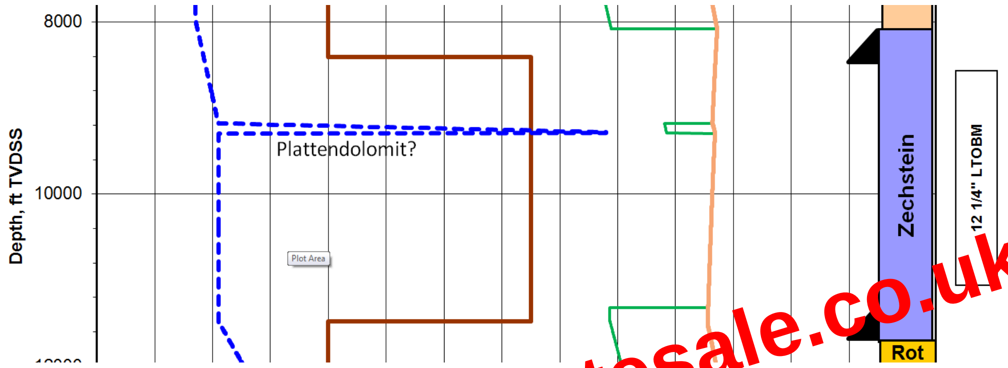


Figure 4.7: Pore pressure and fracture of Zechstein section in Humphrey field [47].

There are two opinions regarding the appropriate mud to drill the Zechstein salts [41]:

- If brine kick, normally occurs in the Platten dolomite at 17-18.5 ppg, is expected from seismic or previous drilling experience. Salt saturated WBM should be used.
- If brine kick is not detected, the OBM or IOBM can be used with a density not below 14 ppg.

4.2.9 Theoretical Design Selection of the Drilling Fluid Density (MW)

The approach of designing a drilling fluid density was discussed in the previous section, which appears to be satisfactory in obtaining the operative density for drilling in salt sections. However, it was argued by Leyendecker (1975) that the pore pressure is not existent in salt formation due to low porosity, and that the fracture gradient is determined to be higher than the overburden [48]. Therefore, under this premise the traditional safe mud weight window can no longer be determined. The density of the drilling fluid has to be determined based on creep behaviour.

$$\sigma_\theta = C_1 + \frac{C_2}{r^2} \quad \text{(A7b)}$$

$$\sigma_z = 2\mu\, C_1 \quad \text{(A7c)}$$

By introducing boundary condtions, allows evaluation of the intergation constants

$\sigma_r = -p_w \quad (hydrostatic\ pressure) @\ r = r_w$

$\sigma_z = -g_o z\ (overburden\ pressure) @\ r = \infty$

And as salt creep occur over geological time. Therefore, $\sigma_r = \sigma_\theta = \sigma_z$and by applying these boundary condition, yields the following;

$$\frac{\sigma_r}{z} = -g_o + \left(\frac{r_w}{r}\right)^2 \left(\frac{g_o - p_w}{z}\right) \quad \text{(A8a)}$$

$$\frac{\sigma_\theta}{z} = -g_o - \left(\frac{r_w}{r}\right)^2 \left(\frac{g_o - p_w}{z}\right) \quad \text{(A8b)}$$

$$\frac{\sigma_z}{z} = -g_o \quad \text{(A8c)}$$

Therefore, mean and octahedral stresses can be expressed as following;

$$\frac{\sigma_{Oct}}{z} = \frac{1}{3}\left(\frac{\sigma_z}{z} + \frac{\sigma_\theta}{z} + \frac{\sigma_r}{z}\right) = -g_o \quad \text{(A9a)}$$

$$\frac{\tau_{Oct}}{z} = \frac{1}{3}\sqrt{\left(\frac{\sigma_z - \sigma_\theta}{z}\right)^2 + \left(\frac{\sigma_z - \sigma_r}{z}\right)^2 + \left(\frac{\sigma_\theta - \sigma_r}{z}\right)^2} \quad \text{(A9b)}$$

$$\frac{\tau_{Oct}}{z} = 0.817 \left(\frac{r_w}{r}\right)^2 \left(\frac{g_o - p_w}{z}\right) \quad \text{(A9c)}$$

However, when $r_w = r$ the maximum octahedral stress appears at the borehole. And it is given as following:

$$\frac{(\tau_{Oct})_{max}}{z} = 0.817 \left(\frac{g_o - p_w}{z}\right) \quad \text{(A10)}$$

For maintaining the elastic behaviour of salt formation the magnitude of the maximum of octahedral stress should be less than or equal to the magnitude of elastic stress

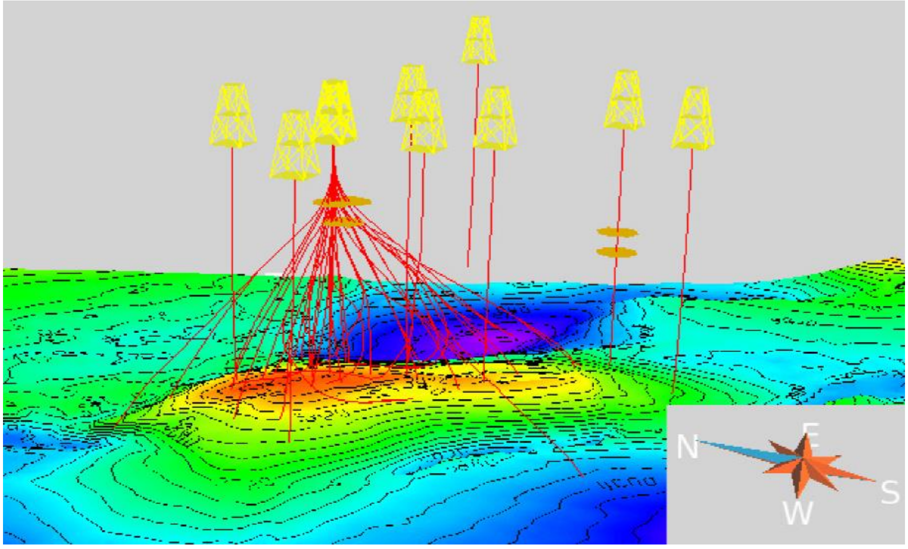
$$\frac{g_o z - \tau_{oe}}{0.817} \le p_w \le g_o z + \frac{\tau_{oe}}{0.817} \quad \text{(A11)}$$

1.2 Plastic Stress in Wellbore

Salt rocks plastically deform under triaxial compression if could not be controlled under elastic behaviour [33]. Nevertheless, wellbore stability could be possibly maintained even if the stresses of adjacent formation of wellbore are plastic [49]. Because at particular distance from the wellbore some formations still exist under elastic stresses and bridging activity occurs, stopping the wellbore from being collapsing. Although

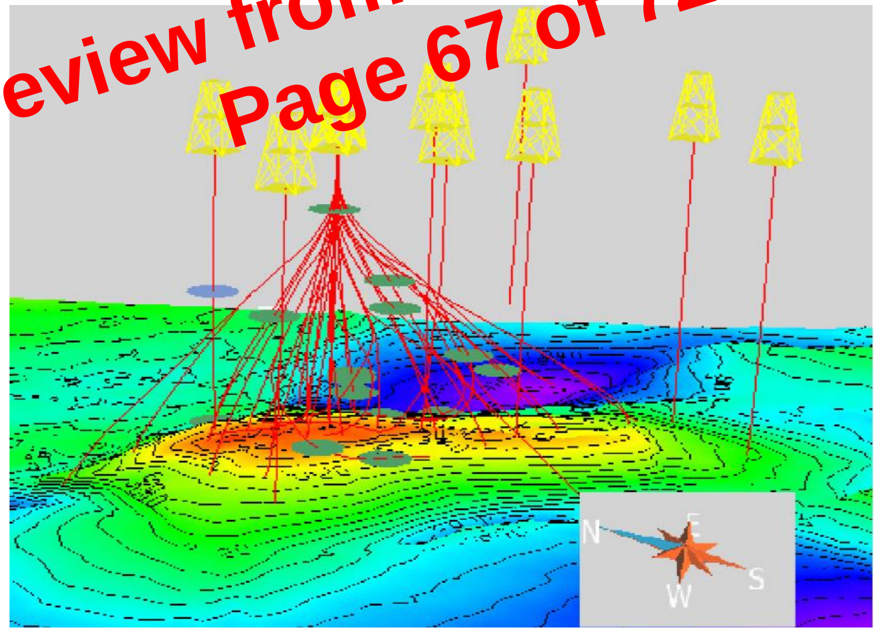
APPENDIX B OVERVIEW OF INSTABILITY PROBLEMS ON HUMPHREY FIELD

1) Washouts



From this graph it can be noticed that washouts happened at the top section of the salt formation. Washouts can happen if the drill bit stuck for long time in the same location as the drilling fluid flowing from the nozzle and washing the salt formation. This can occur due to low penetration rate (ROP)

2) Stuck pipe



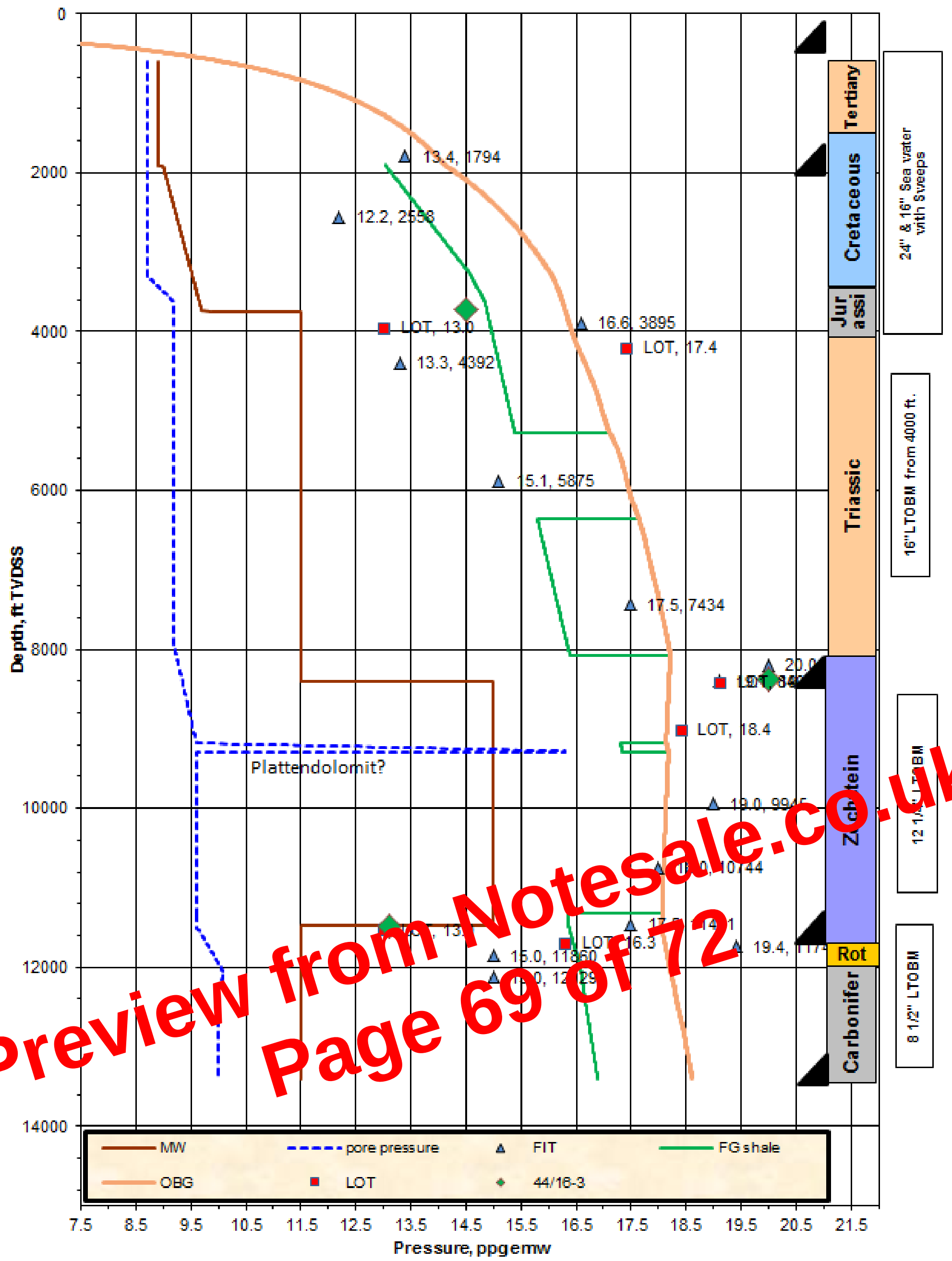


Figure 6.1: Humphrey Pore and Frac Summary Plot

OPERATOR: GDF SUEZ EP UK
RIG: Jack-Up - MONARCH

SURFACE LOACTION
54° 26' 52.088" N - 02° 09' 41.830" E
UTM: 6,033,800.00 mN - 445,634.00 mE

ELEVATIONS
ROTARY TABLE (ft) 131 ft
WATER DEPTH (ft) 94 ft

MDRT	TVDRT	TVDSS	AGE	STRATIGRAPHY
131 ft	131 ft	0 ft		SEA BED
			TERTIARY - RECENT	QUATERNARY
945 ft	945 ft	814 ft	TERTIARY - RECENT	TERTIARY
1,740 ft	1,740 ft	1,609 ft	CRETACEOUS	CHALK GROUP
3,103 ft	3,103 ft	2,972 ft	CRETACEOUS	BLACK BAND MEMBER
3,276 ft	3,276 ft	3,145 ft	JURASSIC	SPEETON CLAY
3,563 ft	3,563 ft	3,432 ft	JURASSIC	LIAS GROUP
4,024 ft	4,024 ft	3,893 ft	TRIASSIC	TRITON ANHYDRITIC
4,347 ft	4,347 ft	4,216 ft	TRIASSIC	KEUPER ANHYDRITIC
4,586 ft	4,586 ft	4,455 ft	TRIASSIC	DUDGEON SALIFEROUS
4,929 ft	4,929 ft	4,798 ft	TRIASSIC	DOWSING DOLOMITIC
5,265 ft	[illegible]	[illegible]	TRIASSIC	MUSCHELKALK HALITE
5,999 ft	5,999 ft	5,868 ft	TRIASSIC	ROT HALITE
6,491 ft	6,491 ft	6,360 ft	TRIASSIC	BUNTER SST
6,935 ft	6,935 ft	6,804 ft	TRIASSIC	BUNTER SHALE
8,147 ft	8,147 ft	8,016 ft	PERMIAN	Z4 ALLER HALITE
8,559 ft	8,559 ft	8,428 ft	PERMIAN	ROTER SALZTON
8,657 ft	8,657 ft	8,526 ft	PERMIAN	Z3 LEINE HALITE
9,640 ft	9,640 ft	9,509 ft	PERMIAN	HAUPTANHYDRIT
9,777 ft	9,777 ft	9,646 ft	PERMIAN	Z2 STASSFURT HALITE
11,425 ft	11,425 ft	11,294 ft	PERMIAN	BASALANHYDRIT
11,520 ft	11,520 ft	11,389 ft	PERMIAN	HAUPTDOLOMIT
11,640 ft	11,640 ft	11,509 ft	CARBONIFEROUS	SILVERPIT
12,073 ft	12,073 ft	11,942 ft	CARBONIFEROUS	L KETCH 2 MEMBER
12,254 ft	12,254 ft	12,123 ft	CARBONIFEROUS	L KETCH 1 MEMBER
12,532 ft	12,532 ft	12,401 ft	CARBONIFEROUS	WESTOE
12,994 ft	12,994 ft	12,863 ft	CARBONIFEROUS	MURDOCH SST
13,128 ft	13,128 ft	12,997 ft	CARBONIFEROUS	CAISTER
13,260 ft	13,260 ft	13,123 ft		

POTENTIAL HAZARDS

- Conductor stuck while RIH and set high. No cement returns.
- Gumbo attack present all over SNS. 44/12-a face it twice. Pack off. Tuff: Can skewed the top chalk pick for surface casing setting depth. Tight spots common during tripping and bit *balling*.
- Losses in 50% of wells in immediate area. Seapage losses or total losses in Terciary. Brine influx: avoid ballooning cycle of the chalk (influx/losses)
- Change mud system in the middle of the [illegible] wellbore stability.
- Tight hole occ[illegible] in [illegible] of the [illegible] wells and salt grab [illegible]. Rothali[illegible] and [illegible]schelkalk where salt/clay in[illegible]ce represe[illegible] the majority of the problems.
- Hole wash out while drilling with WBM.
- Bed dip and [illegible] ca[illegible] to d[illegible] their origin[illegible] plan
- Bunter sandstone is abrasive formation, bit design issue. Gas/oil shows into Bunter sandstone.
- Tight spots and back-reaming into Bunter Shale.
- Tight hole will be faced. Wireline logging through the salt can be a problem: prefer LWD data. Mg/K salt flows, salt movement. Gas peak associated to Plattendolomit. Potential Brine influx. Overpressure zone.
- Losses, total dynamic losses expected in the Hauptdolomit and Werraanhydrit. Fracture zone. Presence of lower Leman sandstone with low pore pressure.
- Reduce mud weight before Carboniferous section. Avoid supercharging formation with LCM and heavy mud. Evaporite in Silverpit: May not be an issue in Vertical well. Sudden and severe losses can occurs: fractures. Abrasive formation. Coal: may be an issue depending of the number of coal layers. During well test only observe CO2 circa 1-2.6% and Nitrogen. No H2S observed.

HOLE SIZE	BIT RECORD	FLUID PROGRAM	INC	BHA MWD / LWD	BHA DRIVE SYSTEM	CASING / CEMENTING PROGRAM	WELL CONTROL EQUIPMENT
36"	1 x 36" Mill Tooth Bit	Seawater with 10 ppg PHB sweeps	0.00°	DIR	ROTARY	30" Conductor Pipe at 620 ftBRT; 310 ppf, 1.75" WT, X-56; Cement Tuned Light 12.7 ppg to Sea Bed	
24"	1 x 24" Mill Tooth Bit	Seawater with 10 ppg PHB sweeps	0.00°	DIR / GR	MOTOR	20" Surface Casing at 1,892 ftBRT; Shoe set at +/- 150 ft into to Chalk; 129.29 ppf, 0.625" WT, X-56; Cement Tuned Light 12.5 ppg to MLH	Vetco KFDJ 500 Diverter
16"	1 x 16" TCI Bit	Water Based Mud Seawater with hi-vis sweeps		DIR / GR	ROTARY		
	1 x 16" PDC Bit	10.5 - 12.5 ppg LTOBM	0.00°	DIR / GR / SONIC / RES	RSS	13 ⅜" Intermediate Casing at 8,467 ftBRT; Shoe set +/- 300 ft into top Zechstein; 72 ppf, P110, VAM 21; Top of Cement: 1,000 ft above Bunter Sandstone FM	QOP 21 ¼" 2K BOP (Double Ram); Hydril / MSP 21 ¼" 2K Annular
12 ¼"	1 x 12 1/4" PDC Bit	15.0 ppg LTOBM	0.00°	DIR / GR / SONIC / RES	RSS	9 ⅝" Production Casing at 11,583 ftBRT; Shoe set +/- 30 ft into top WERRA; 53.5 ppf, P110, VAM 21 in Cased Hole; 53.5 ppf, VM110HC, VAM 21 in OH; Top of Cement: Up to 500 ft above 13 ⅜" Shoe	Shaffer / SL 13 ⅝" 10K BOP (2 x Double Ram); Hydril / GX 13 ⅝" 5K Annular
8 ½"	1 x 8 1/2" PDC Bit; Core 180 ft; 1 x 8 1/2" PDC Bit	10.5 - 11.5 ppg LTOBM	0.00°	DIR / GR; WIRELINE: GR / RES / DEN / NEUTRON / SONIC IMAGE LOG RCI PRESSURE FLUID SAMPLE	RSS	Contingent 7" Liner for DST purposes; 32 ppf, P110, Vam Top HC	Shaffer / SL 13 ⅝" 10K BOP (2 x Double Ram); Hydril / GX 13 ⅝" 5K Annular

WELL SCHEMATIC
PLANNED CONTINGENCY