PRESSURE ANALYSIS OF WELL 6407/2-2 IN NORTH SEA

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Abstract
Pressure analysis of well 6407/2-2 in North Sea was considered in this study. Two research questions guided the study. Survey research design was used to report secondary data obtained from well in the North Sea. The findings from table 1 reveal that at maximum depth of 3300 m the pressure level is 14800psi and at a minimum depth level of 300m, pressure is 1500psi. This indicates that pressure increases with depths. The geothermal gradients in North Sea suggest that sediments in the region are thermally mature for hydrocarbon generation. The average depth to oil floor in the basin is 3626m, suggesting that wells to be drilled in the region should be drilled up to a total depth of 3626m and beyond.

Keywords: Pressure Analysis and Well

Introduction

Well 4607/2-2 is located east on the Halten Terrace off shore Mid Norway. The well tested the southern (Gamma) fault compartment of a horst with true vertical closure below the base cretaceous level. The gas/condensate discovery well 6507/11-1 was located on the northern (Alpha) compartment of the same structure. The primary target of the well was the middle Jurassic sandstone; secondary target was early Jurassic sandstone.

Wildcat well 4607/2-2 was spudded with the semi-submersible installation Treasure Sega on 17 May 1983 and drilled to TD at 3351, 71m into the Triasssic Grey Beds. After drilling the 26 hole, the well was observed flowing and mud weight was corrected. No other major problems occurred during drilling. After having drilled out of 13 3/b" casing shoe a comment plug was set from 1960- 1995m, and one from 340m-400m, due to temporarily plugging and abandonment of the well caused by strike. The strike was efficient (no drilling progress was obtained) for 13 days, from June 6th to June 19th. The well was drilled with mud down to 865m, with gypsum/polymer mud from 865m to 1995m, and with lignosulphonate mud from 1996m to TD.

The well proved mainly claystone down to the Middle Jurassic Sandstone. The Cainozoic with a total thickness of 1709m overlies the Sandstone. The Cainozoic with a total thickness of 1709m overlies the Late Cretaceous where the topmost Maastrichtian is missing. Two hundred and forty meter of Late Cretaceouss and 81.5 of Early Cretaceous is preserved, separated by an unconformity ranging in age from Middle Santonian to Albian. High gas readings were experienced in the upper part of the Cretaceous together with heavier hydrocarbons detected for the first time in the well. A study of wire line logs, sidewalls cores and hole response indicate that the gas was overpressured, and trapped in a non-reservoir lithology. Base cretaceous encountered at 2409.5m. The upper Jurassic was developed with 11.5m of hot shales speck formation and 39.5m of silty claystones of the Melke Formation. As in other wells in the area, the Middle Jurassic Sandstone was divided by a shaly interval into an upper unit of very good reservoir properties (Garn Formation) and a lower unit of less good characteristics (IIE Formation). The upper unit was found to be gas bearing with a gas/water contact at 2516.5m. All potential reservoir sequence below this depth were water bearing. The formation "Coal Unit" was 383 in thick and consisted of interbedded carbonaceous claystone/shale, fine sand and silt. It contained a total of 50m of coals and shale layers.

Twelve cores were cut, all in the middle Jurassic sequence. Segregated FMT samples were collected at 2486m (gas), 2539.5m (water) and 2546m (water). The well permanently abandoned on 31st July as a gas/condensate appraisal well on the Midgard Discovery.

Literature Review

Formation Pressure

Formation pressure is the pressure of fluid contained in pore space of rock, and there are three (s) categories of formation pressure which are; normal pressure, abnormal pressure and subnormal pressure.

Normal Pressure

Normal pressure is the hydrostatic of water column from the surface to the subsurface formation. The concentration of salt in water affects the normal pressure. Higher salt concentration in water, higher specific gravity of water will be. Therefore, the normal pressure can vary from slight salt 0.433 psi/ft (8.33ppei) to highly concentrate salt 0.478psi/fr (9.2ppei) based on salt concentration in water.

Abnormal Pressure

The abnormal pressure is the pressure greater than the pressure column of water. Generally, the abnormal pressure zones are good reservoir which oil companies are looking for. This kind of pressure can create well contact problem.

Subnormal Pressure

The subnormal pressure is the pressure that is less than normal pressure and is possibly because of lost circulation problems. In the formation pressure evaluation sheet (enccosre 11) most of the significant parameters in pressure detection are plotted. Mud weight leak off and drill stem test result and FMT pressure readings versus depth are showing in Normal pore pressure and composition trend are found above the near base pliiocere unconformity (Top Hordaland group). A mud weight of slightly above 1.3 g (am^3 was adequate to balance the formation pressure). The dxc suggests a slight increase in pre pressure in the lower part of the Tertiary, and the mud weight was increased to 1.4g/am^3 before the $3/8^{11}$ casing was set with shore at 1966m.

Several formation pressure measurements were made from the middle Jurassic sandstone and down to the Jurassic Grey beds, providing an overall saltwater gradient of 1.09/am, except for the overpressure caused by the gas column in the reservoir. In the hydrocarbon bearing zone a gas gradient of 0.29 psi/m can be established, as opposed to a gradient of 1.46 psi/m in the water zone. The GWC can be interpolated at 2516.5m. Pressure communication seems to exist between the middle and the lower Jurassic sandstone.

Development and Advances in Formation Pressure

Development:

Pressure is one of the primary factors controlling hydrocarbon generation, sediment diagenesis and migration of hydrocarbons and other pore fluids (Mwankwo, 2007). Pressure evaluation of the study area, with the available corrected bottom hole temperature data, the

geothermal gradient of the sediments were determined with the calculated temperature gradient values, the oil window estimated for each well was suggested. An oil window in a sedimentary basin is a zone of active oil generation.

Bell (2012) postulated that formation pressure prediction involves quantifying pore pressure from rock properties variation in particular changes in velocity or receptivity. Tingay et al (2005) states that formation pressure in North Sea formation commonly exhibit magnitudes approaching the lithostatic gradient and have repaid on set across fallt and the shales resulting in numerous blow out and kicks.

Accurate pore pressure prediction is the basis for the drilling fluid density program, and is necessary for well safety and rapid drilling rate, with prevention of kicks as accomplished by carrying out sufficient mud density assurance which avoids the principal cause of differential pressure sticking; pore pressure prediction is the basis for selecting casing setting depths, cement slurry density, avoiding lost circulation and making fracture gradient calculations.

Swabrick et al (2002) stated that over pressure in clastic sedimentary basins is created by two main groups of mechanisms; (1) stress applied to a compressible rock (disequilibrium lateral compression); and (2) fluid expansion and or increase in fluid volume (notably gas generation, where large volume changes occur, but also smectite dehydration).

Purpose of the Study

This research work is concerned with how pressure varies with Lithology as regards to depth. The findings were based on the analysis of well 6407/2-2 unweathered core samples and the geothermal regime in the sedimentary basing of North Sea. Specifically, the study sought to determine the data analysis of pressure along the depth.

Methods

Survey research design was used to report secondary data obtained from well in the North Sea.

Lithology

The Balder Formation represents a series of pyroclastic ash layers and tuffaceous clay stones, recognized in cuttings as variegated light green, green to dark green, grey and grayish brown, occasionally black mottled with devitrified glass shards and waxy, non-calcareous claystone, the claystone is dominantly silty, firm and micro micaceous.

Upper Boundary

The boundary to the overlying Hordaland Group is marked by an increase in t-values, and a slight reduction both in the formation density and resistivity.

Lista/Sele Formation (Lower part of the Rogaland Group)
Depth interval : 2035-2088m
Thickness : 53m
Age : Late Paleocene

Lithology

The kimmeridge Clay Formation is characterized by a high uranium content recognized by high gamma ray readings, and is composed of a dark grey to black bituminous claystone/shale. It is predominantly firm, subfissible, micro-micaceous and non to slightly calcareous.

Upper Boundary

The kimmeridge Clay Formation is unconformable overlain by an Early Cretaceous limestone characterized by high resistivity and formation density and low gamma ray and readings.

Heather Formation Eq

Depth interval : 2421-2460.5m
Thickness : 39.5m
Age : Early Oxfordian – Callovian (2417-2450m)
Bathonian (2450-2460.5m)

Data Analysis

Table 1: Data Analysis of Pressure along Depth

DEPTH	TEMPERATURE	PRESSURE
300	5.0	1500
600	15.0	2900
900	25.0	4300
1200	36.0	5800
1500	46.5	7300
1800	57.0	8700
2100	68.0	10,20
2400	78.0	11,60
2700	85.0	1300
3000	100.0	1450
3300	110.0	14,8(
3600		

Table 1 reveals that at maximum depth of 3300 m the pressure level is 14800psi and at a minimum depth level of 300m, pressure is 1500psi. This indicates that pressure increases with depths.

Discussion

With respect to pressure generated in shales, were porocity is low, temperature are increasing and clay mineral diagnosis and hydrocarbon generation are ongoing transmitted to any associated sands, particularly sands of restricted extent such as turbites. Sands that are laterally extensive may allow the dissipation of this pressure if a leak or exit point is established via continues reservoir or fault networks to shallower levels. Examples of reservoirs that have less pressure than the surrounding shales and are laterally draining pressure (and fluids) include the Paleocene fans of the central North sea (Dennis et al, 2005) other processes that generate pressure in sand include hydrocarbon buoyancy, osmosis, and flushing with meteoric waters driven by hydraulic head.

The upper boundary of the section is defined by the shaly drake formation equivalent lying above the latter shows both higher gamma ray and resistivity reading. The formation density is also higher and cause a pronounced split to the compensated neither curve.

Recommendation

The geothermal gradients in North Sea suggest that sediments in the region are thermally mature for hydrocarbon generation. The average depth to oil floor in the basin is 3626m, suggesting that wells to be drilled in the region should be drilled up to a total depth of 3626m and beyond.

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