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3D Geomechanical Study in a Deep-water Block in KG Offshore Basin – Some Facts & Findings

Abstract

Deep water blocks in KG offshore basin has some oil and gas fields which are now being contemplated for monetization. Considering the significantly large operational cost of this project, efforts are being made to plug all the possible loopholes which may lead to non-productive time during drilling. Usually one of the major contributors to this down time is wellbore instability, which if not checked, may even lead to well abandonment. Sanding and reservoir compaction / subsidence are another concerns, as these wells will be non-serviceable and all the completions will be sub-sea.

The study has revealed some of the geomechanical facts prevalent in three of the fields in this block and has provided some vital information besides predicting mud weight window for the upcoming wells. To start with, the wells have shown variations in the profiles for overburden gradient due to variations in water depths. The rate of change of pore pressure in shale has remained gradual and under-compaction has been the key reason for generation of over-pressure in shale. In wells with thicker columns of hydrocarbon the effects of hydrocarbon buoyancy is seen clearly and modeled accordingly. In one of the fields, instances of fluid influx at shallower depths have been modeled as centroid effect with an estimated down dip limit to match the influx.

The stress direction on the basis of breakout analysis is NW-SE, which is also the strike of interpreted faults in this block. Risk assessment with respect to reservoir compaction and surface subsidence has been done and it has been found to be low given the pressure depletion, reservoir thickness and rock compressibility for these fields. Analytical sanding analysis suggests that there is a high risk of sand production during the life of the field. Very low rock strength due to unconsolidation is likely to have almost zero sand-free drawdown even at original reservoir pressure.

Introduction

This discovery lies in deep water area of KG Offshore basin (Fig-1) where water depth varies from 300m to 650m. The stratigraphy of this block consists of both slope depositional and deep water depositional systems. The main reservoir in this block is of Pliocene age.

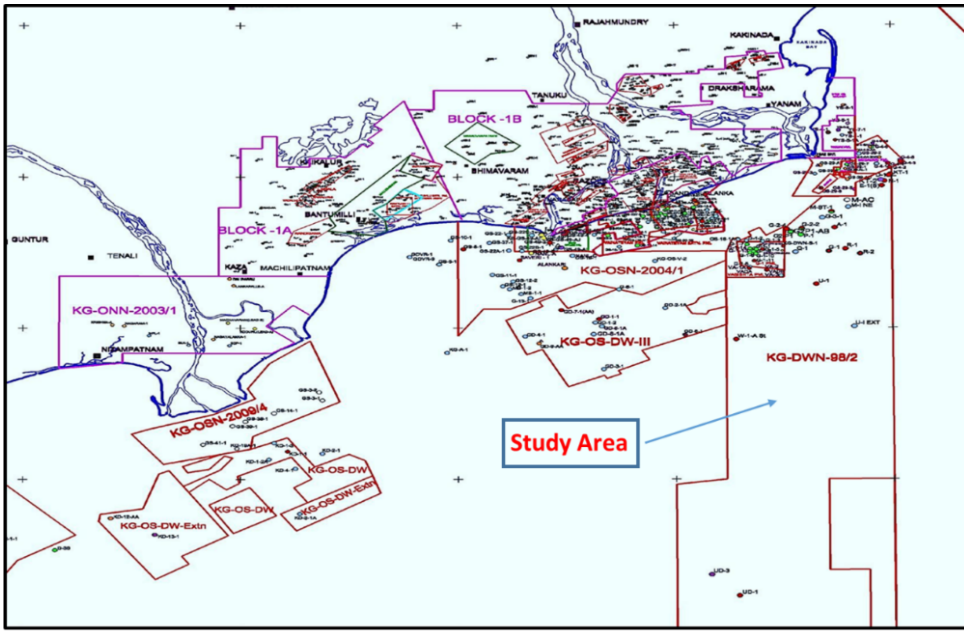

Fig1: KG Basin

Wellbore stability issues become all the more important in deep water setting where the pore pressure is usually high and the fracture pressure typically low, thus providing a narrow drilling margin for the drillers to operate within. Lack of knowledge of pre-drill pore pressure and fracture pressure may lead to severe instability issues which may create catastrophic situations.

To meet the drilling challenges in this deep water regime, a comprehensive geomechanical study was carried out for wellbore stability and trajectory optimization to drill the planned oil and water injection wells in these three fields. The study was mainly focused on creation of 1D and 3D MEM in order to predict the safe mud-weight window for drilling of the upcoming wells. However it was also proposed to do an analytical risk assessment pertaining to fault reactivation, reservoir compaction / surface subsidence and sand production without coupling the 3D MEM with the reservoir model.

The creation of 3D MEM is based on the 1D MEM of offset wells and the structural framework of these fields with inputs such as bathymetry maps, seismic interpreted surfaces, faults and well tops for all the fields. This 3D model is populated with scalar properties like density, static elastic rock moduli, pore pressure and effective stress ratio from the 1D MEM of offset wells. The Finite element (FE) numerical technique is employed to understand the initial in-situ stresses and overburden in the reservoir. This technique will basically initialize the model to gravity loading and calculate principal stresses viz. vertical, minimum and maximum horizontal stresses. This way independent 3D MEM's for all the three fields have been constructed.

Method

1D MEM

The principal constituents of 1D geomechanical model are three principal stresses, namely vertical stress (Sv), maximum principal horizontal stress (SHmax) and minimum principal horizontal stress (Shmin) besides pore pressure (Pp) and the rock strength (UCS). When the horizontal stresses are not equal (a frequent condition in the Earth's crust) stress anisotropy is created and wellbore instability can be pronounced if wells are slanted or highly deviated. Pore pressure is a very important parameter in the geomechanical modeling and can be directly related to fracture gradient, especially in depleted formations. Rock strength is also a major input in the calculation of wellbore collapse. Vertical stress, minimum horizontal stress, pore pressure and rock strength can be estimated from various measurements. Maximum horizontal stress is the most challenging one and can be back calculated knowing all the above parameters coupled with observed rock failure, either breakouts or drilling induced tensile failure.

3D MEM

The workflow of 3D MEM starts with the creation of a structural framework of the field which is then populated with density, mechanical rock properties, pore pressure and stresses. The direct property modeling through variograms and krigging can be done for rock related properties such as density, UCS, elastic moduli, etc. but stress related properties such as overburden or pore pressure cannot be populated along the structural grids as they are not the rock properties. The stress related properties are simulated by setting up a finite element model (FEM) which finds the stress magnitudes with their direction which are consistent with those estimated at the well points.

The combination of the material properties, the pore pressure and the initial stress state may not be in equilibrium when the finite element model is run at first. During this first step, gravity is applied instantaneously to the whole model and the vertical stress is calculated. For every finite element in the FE model, the full stress tensor is calculated using the vertical stress combined with the knowledge of the horizontal stress orientation, and the effective stress ratios for Shmin and SHmax. These initialized stresses will be calibrated with that derived from 1D geomechanical model.

To make sure that the 3D geomechanical model properly captured the individual aspects of the 1D models and could propagate them across the study, the in-situ stresses and pore pressure profile have been extracted for all the offset wells from the 3D model and compared with the existing 1D geomechanical model results.

Results

1. *Variations in overburden due to varied water depths*

The block under study has varied water depths which has resulted in variations in overburden stress. This is depicted in Fig-2. As expected the well with deeper water depth has low overburden compared to the one where water depth is shallow. The variation of overburden with water depth, although not very significant in shallow water regime, may be very critical in deep water where the fracture pressure will be significantly different in an already narrow mud-weight window.

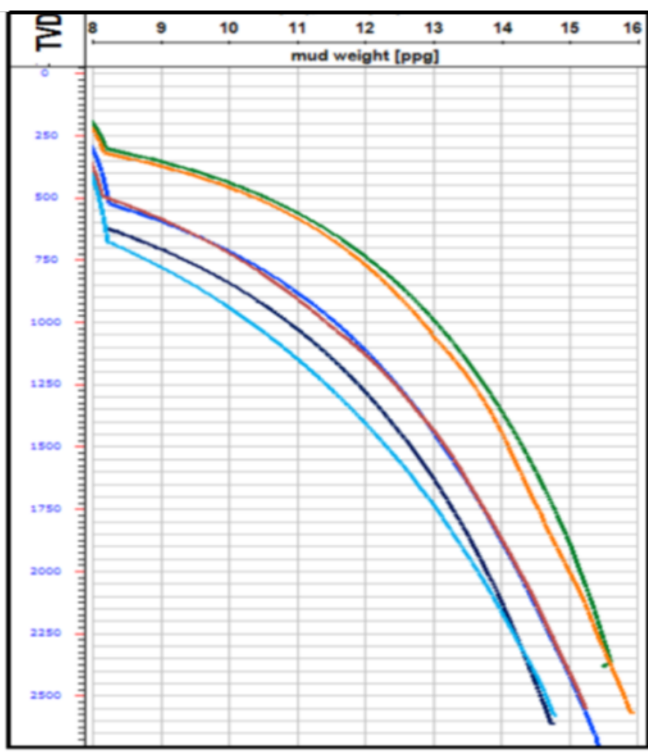

Fig2: Variations in overburden

2. *Centroid effect in shallow reservoir*

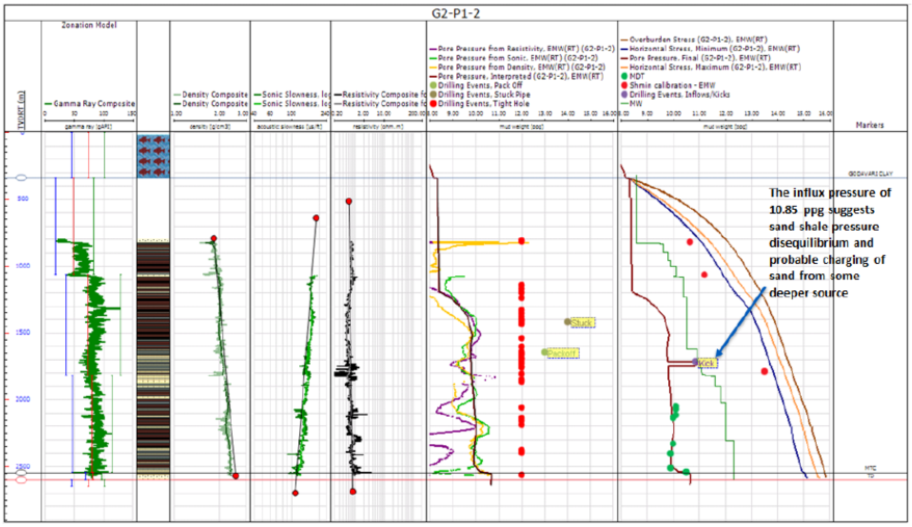

Fig3: Pressure surge at a shallow depth due to centroid effect

The influx seen at a shallow depth during drilling of wells in one of the fields has been modeled as a centroid effect due to sand-shale pressure disequilibrium and the same is believed to have some connectivity with some deeper reservoir. In this model the estimated down-dip limit has been used to match the influx pressure (as there was strong confidence on shale pore pressure based on normal compaction trend line method and measured pressure data). The modeled surge pressure is shown in Fig-3.

3. *Buoyancy effect on pore pressure*

The buoyancy effect of hydrocarbon on pore pressure is exhibited in Figs-4 & 5. Presence of hydrocarbon increases the pore pressure at the top of the reservoir and the increase will depend on the thickness of the reservoir and the density of the hydrocarbon. Because of this increase in pore pressure in the top part compared to bottom of the reservoir, the pore pressure gradient becomes negative. The buoyancy effect has been modeled to match the actual wire-line pressures available in this section and shown in Figs- 4 & 5.

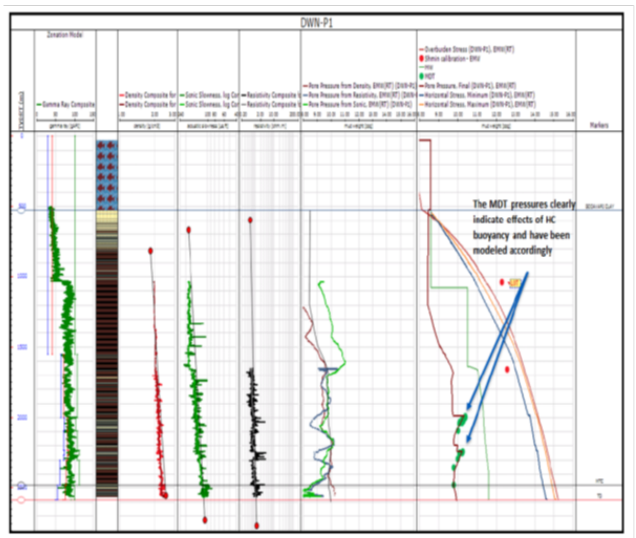

Fig4: Buoyancy effect on pore pressure

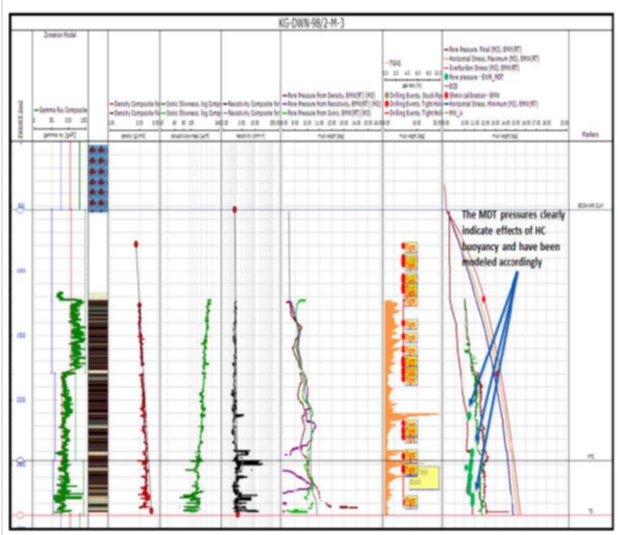

Fig5: Buoyancy effect on pore pressure

4. *Stress orientation*

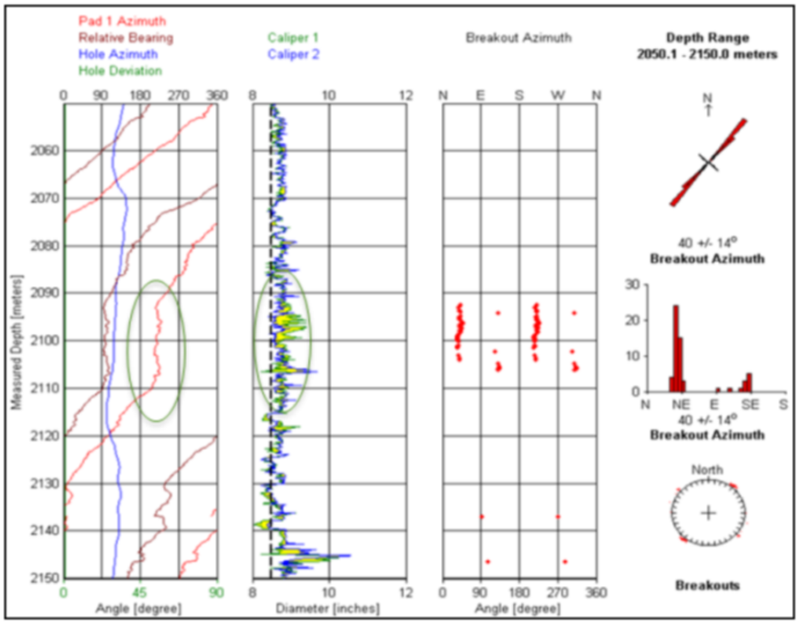

Fig6: Stress direction from 4-arm caliper

Based on the breakouts observed on 4-arm caliper in one of the wells (refer to Fig-6), the orientation of minimum horizontal stress appears to be NE-SW. The relative bearing and caliper-1 azimuth are seen to be locked in the breakout section, which again confirms that this section is a breakout and not a washout. Hence it may be concluded that the orientation of maximum horizontal stress in this block is approximately NW-SE. This is further corroborated by the strike of interpreted faults in this block, which is also NW-SE.

5. Wellbore stability

Borehole stability issue does not appear to be a concern here. The pore pressure is largely hydrostatic with a marginal increase in shale pressure below a certain depth. However the pressure surge observed in some of the wells at shallow depths supposedly due to centroid effect is a major concern and needs to be taken care of.

6. Reservoir compaction and surface subsidence

Due to high porosity of the reservoir rock, the effects of pressure depletion on reservoir compaction needs to be quantitatively estimated. The increase of mean effective stress due to pressure depletion could cause a reduction in pore volume and bulk rock volume, hence the reservoir may compact depending on rock compressibility and pressure depletion values. The reservoir compaction can be conveniently characterized by the vertical strain in a reservoir, related to uniaxial compressibility. This can be expressed as the change in height (relative to initial height) caused by an increase in effective stress due to a reduction in reservoir pressure under constant overburden. Knowledge of the net vertical reservoir thickness, pressure depletion, and average uniaxial compressibility coefficient enables an estimation of compaction. There is also a relation between subsidence and compaction which was shown to be dependent on effective reservoir radius, distance from nucleus of strain, reservoir depth of burial and elastic properties of the rock, besides the compaction factor.

Based on the envisaged production profile of these three fields along with other required parameters it has been seen from the above model that there will be insignificant compaction and subsidence in all the three fields during their production phase provided the water injection schemes are reliably followed. The P10, P50 and P90 scenario for compaction and subsidence for one of the fields is shown in Fig-7 & 8.

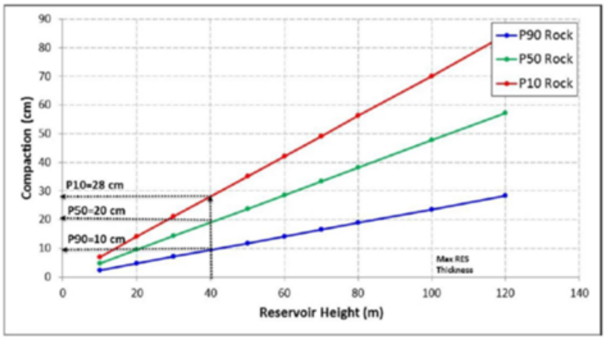

Fig7: Reservoir compaction scenario in one of the fields

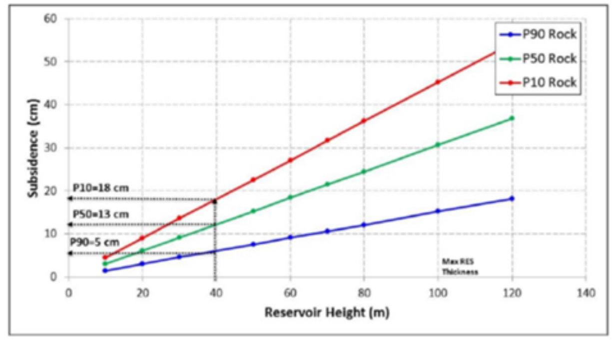

Fig8: Surface subsidence scenario

7. Sanding prediction

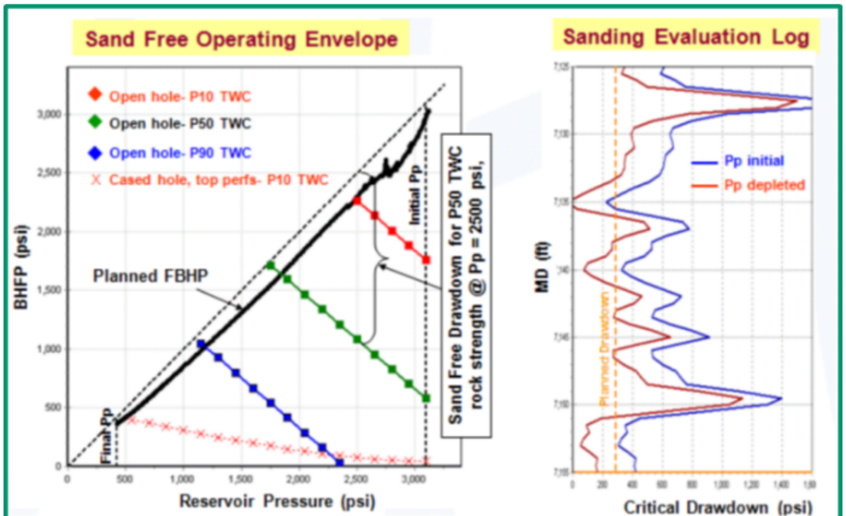

Fig9: Sand incursion scenario in one of the wells

An attempt has also been made to see the possibility of sanding by analytical approach on a single well basis which is based on elastic properties and requires Thick Wall Cylinder (TWC) strengths from tests and/or analytical estimations. TWC strengths from cores and/or logs are scaled up to reservoir dimensions using an Effective Strength Factor (ESF). The method determines the Critical Flowing Bottom Hole Pressure (CFBHP) that causes well or perforation collapse at any stage during the production life of the well.

Based on current data and analysis, it is observed that any rock with TWC < 1000 psi has tendency to fail immediately. Rocks with TWC between 1250 to 2250 psi have drawdown limits as highlighted in below envelop. Rocks with TWC > 2500 psi seem have greater degree of allowable drawdown. However such zones are very limited. In summary, based on current modelling the risk of sanding is high. Predictions for sand free operating envelops were made for reservoir formations and are shown in Fig-9.

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8. Fault slippage & reactivation

Fault slip analysis of all the faults has been done to see their stability. In this analysis faults from the 3D static model have been subjected to present day stress conditions to see if they have a tendency to slip or not. If the ratio of shear to effective normal stress on the fault plane crosses the coefficient of friction of the rock, then the faults are known as critically stressed and they are likely to slip, which may also lead to their reactivation.

The in-situ stresses and pore pressure from 3D geomechanical model have been extracted to each fault plane and they are resolved to calculate effective normal and shear stresses upon them. They are then subjected to Mohr-Coulomb analysis to see if they cross the failure line. In this case none of the faults is seen to be critically stressed and the minimum pressure requirement for their slippage / reactivation is 700 psi over and above the reservoir pressure.

Conclusions

1. Pore pressure surge at shallow depths and buoyancy effects in some of the wells have been successfully modeled.
2. Variations in water depth and sediment thickness have significant effect on the mud-weight window. The window gets narrower when water depth increases.
3. The present day stress orientation is NW-SE which is in agreement with orientation of young fault system.
4. The risk of reservoir compaction and surface subsidence appears to be low with the given pressure depletion, reservoir thickness and rock compressibility.
5. Sand incursion is likely to happen in the early stage of production due to low compressive strength of the rock and the allowable drawdown for sand free production is almost close to zero.
6. The faults in the field are stable and a pore pressure increase of around 700 psi over and above the reservoir pressure is required to reactivate them.

Acknowledgment

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