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Research paper

Prediction of pore pressure and fracture pressure in Cauvery and Krishna-Godavari basins, India

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ABSTRACT

Geoscientific data from several wells drilled in onshore and offshore parts of the Cauvery and Krishna-Godavari basins, two main hydrocarbon producing basins located in the east coast of India, have been used to determine pore pressures and fracture pressures in the subsurface formations. We have estimated pore pressure based on Zhang's porosity model. Variations of normal compaction curves across the basins are demonstrated here. This study also proposes simple relationships among the parameters used in Eaton's equation for estimating the fracture pressure. Relations established based on the available data in this current study are compressional and shear sonic velocities against bulk density, Poisson's ratio against depth, and the overburden stress against depth. These empirical relationships can be used to predict fracture gradient for the future drilling locations in these basins. The pore pressure in Cauvery basin is shown to be almost hydrostatic in nature, which is due to normal sedimentation rate. High sedimentation rate in the Miocene section of the KG basin is found to be the main reason for overpressure development.

1. Introduction

Pore pressure (the fluid pressure in the pore spaces of the subsurface formation) and fracture gradient are two important aspects to be considered in hydrocarbon exploration and development scenarios for safety, cost effectiveness and the efficiency of the overall drilling programme (Jayasinghe et al., 2014). Hydrostatic pressure (normal pore pressure) exerted by a static column of fluid varies according to the density of the fluid (Osborne and Swarbrick, 1997). Pore pressure above or below the hydrostatic pressure is considered to be abnormal pressure. Abnormally high pore pressure may result in a drilling hazard if the precautionary measures are not taken care. Prediction of pore pressure is essential in well planning, selection of casing point, drilling cost, safety, drilling procedures, and completions (Law and Spencer, 1998; Ruth et al., 2002). The most reliable and direct pressure measurement can be obtained mainly from the drill stem test (DST), modular dynamic test (MDT), and repeat formation test (RFT). Mud weight (MW) can be used as a proxy for the pore pressure where direct pressure measurement data is not available (Law and Spencer, 1998; Ruth et al., 2002). Fracture pressure is defined as the optimum pressure at which new fractures develop in a rock formation. Fracture gradient is calculated by dividing the fracture pressure by true vertical depth (Zhang, 2011). Fracture pressure can be obtained directly from leak-off test (LOT). Knowledge of fracture gradient is essential in mud designing, cementing, matrix and fracture acidizing, hydraulic fracturing, and fluid injection in secondary recovery (Eaton, 1969). Drilling induced fractures happen when the pressure due to the mud weight exceeds the fracture pressure at a given depth and results into mud loss from the well bore into the induced fractures (Zhang, 2011; Kankanamge, 2013). Lost circulation during drilling is a troublesome and expensive problem (Eaton, 1969).

The main objectives of the study are: (a) to demonstrate the occurrences and magnitudes of overpressures in several stratigraphic formations across the Cauvery and Krishna Godavari (KG) basins, east coast of India, (b) to show the effect of pore pressure on the porosity and to suggest calibrated normal compaction trends, (c) to identify the top of overpressure zones and its variation across the basins and (d) to establish empirical relationships to estimate the vertical stress and the minimum horizontal stress for these basins.

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It is a common phenomenon that porosity decreases exponentially with increase in depth in any sedimentary sequence in case of normal compaction. The results of under-compaction are higher pore pressure and more porosity than that of normally compacted sediments (Zhang, 2011). The starting depth of the porosity reversal is known as top of overpressure zone or top of the under-compaction. Several pore pressure prediction models available (cf. Heppard et al., 1998; Flemings et al., 2002; Holbrook et al., 2005) consider porosity-dependent effective stress relationship. Porosity model (Zhang, 2011) is applied here to estimate the pore pressure (described in Section 5.1). This model also proposes porosity as a function of effective stress and pore pressure, particularly for the overpressure generated by under-compaction and hydrocarbon-cracking (Zhang, 2011).

Formation will fracture when the pressure in the borehole exceeds the minimum in-situ stress within the rock. The fracture will propagate in a direction perpendicular to the minimum principal stress. Minimum stress refers to the minimum principal in-situ stress and is generally equal to the fracture closure pressure. Thus, it measures the lower bound of the fracture gradient. Therefore, the minimum stress method (Zhang, 2011) is applied here for estimating the fracture gradient using the wireline log data.

Besides pore pressure, other parameters required to estimate the fracture gradient are Poisson's ratio and overburden stress (described in Section 5.2). Density, compressional and shear sonic logs from drilled wells are required to estimate Poisson's ratio and overburden stress. This work attempts to generate basinwide empirical relations so that the above parameters can be estimated even there where the full set of data is not available. Therefore, these relations can be used as predictive tools to estimate the fracture pressures in these basins.

We have analysed 26 exploratory wells (10 wells from the Cauvery and 16 wells from the KG Basins) to estimate pore pressure and fracture pressure, and correlate these parameters with the observed values acquired during the well operations. These wells are distributed across the basins (Figs. 1 and 2) and many of them terminated in the basement. These data provide opportunity to analyse both lateral and vertical variations in petrophysical properties of rocks in these two basins. Geoscientific and engineering data, such as wireline log suite, litholog, LOT, DST, MDT, and MW maintained during drilling, were used during the course of this study. All the analyses were carried out for the two basins separately. The results presented here provide acceptable estimates from the available data in a short time.

2. Tectonics and sedimentation

The Cauvery and KG basins are located in the east coast of India (Figs. 1 and 2). These are well known as prolific oil and gas producers. The gneiss and granites of Archaean age form the basement of the sedimentary rocks in both the basins. These basins developed during the separation of Antarctica from India at the time of break-up of the Gondwanaland. The histories of evolution of these basins are quite similar. However, the sedimentation patterns over time differ from each other.

2.1. The Cauvery basin

The Cauvery basin is the southernmost basin in east coast of India. This basin covers an area of about 25,000 sq km onland and 30,000 sq km in the offshore area (Phaye et al., 2011). This basin is classified as pericratonic rift basin (Sastri et al., 1981; Biswas et al., 1993; Chari et al., 1995; Biswas, 2012), formed due to the fragmentation of Gondwanaland during Late Jurassic/Early Cretaceous period (Jafer, 1996; Phaye et al., 2011). Cauvery basin has 6 major sub-basins namely Ariyalur-Pondicherry, Tranquebar, Nagapattinam, Tanjore, Ramnad-Palk bay and Gulf of Mannar (Fig. 1). Gulf of Mannar is the southernmost part of the Cauvery basin and is outside the map area. The major horsts, which separate these sub-basins, are Kumbakonam-Madanam-Portonovo high, Pattukottai-Mannargudi-Vedaranyam-Karaikal high and Mandapam-Delft high (Phaye et al., 2011). NE-SW trending major horsts and grabens formed during the rifting phase. Total sediment fill is about 5–6 km in the Cauvery basin (Srikant and Shanmugam, 2014).

Sedimentation during the early rifting stage in the Cauvery basin is marked by the deposition of fluvial coars clastics in Late Jurassic/Early Cretaceous period. Marine influence increased during the late syn-rift stage with the deposition of fine clastics (Paranjape et al., 2014). Middle to late Cretaceous post-rift marine mixed siliciclastic and carbonate sequences are recorded in the basin (Paranjape et al., 2014). Rate of sedimentation during the rifting period is reported to be about 50 m/m.y. (Ramani et al., 2000).

2.2. The KG basin

The KG basin is located in the central part of the east coast of India. This basin covers an area of approximately 100,000 sq km (Bastia, 2004) spanning in both onshore and offshore. Around 5–7 km of sediment column, ranging in age from Permo-Carboniferous to Recent, is identified in the KG basin. This basin was a major intracratonic rift within Gondwanaland until Early Jurassic (Husain et al., 2000; Rao, 2001). The oldest sedimentary sequence in this basin is classified as pre-rift fill which is Permo-Carboniferous in age. Late Jurassic to Early Cretaceous period marks the syn-rift phase of the basin (Prasad et al., 2008; Padhy et al., 2013). During this time the NE-SW trending horsts and graben systems (Fig. 2) formed due to extensional faulting (Prasad et al., 2008). Syn-rift system is mainly characterized by fluvio-lacustrine depositional environment. The first definite marine transgression occurred during Aptian (Husain et al., 2000). The post rift and drift phase commenced from Late Cretaceous (Prasad et al., 2008). Indian plate moved rapidly towards north with a counter clockwise rotation and collided with the Eurasian plate during Late Eocene (Srivastava and Chowhan, 1987). Major delta progradation started due to the uplift of the hinterland. During Miocene, hard collision of India-Eurasia forming the Himalayan Orogen resulted in rapid sedimentation in the basin. Rate of sedimentation during Upper Cretaceous to Miocene is reported as 70–125 m/m.y. in the KG basin (Rao and Mani, 1993; Raju et al., 1994; Anitha et al., 2014).

3. Petroleum system

Oil and gas are being produced from number of fields, both onshore and offshore, in the Cauvery and KG basins. Several source and reservoir rocks of various geological ages are proven in these basins.

3.1. The Cauvery basin

Multiple petroleum systems of both Cretaceous and Tertiary ages are proven in onland and offshore parts of the Cauvery basin. Albian-Aptian shale deposited during syn-rift stage under mixed environment of both continental as well as marine is considered to be the main source rock in the Cauvery basin (Husain et al., 2000). Post rift shales deposited during Late Cretaceous act as secondary sources. The main reservoir, Upper Cretaceous Nannilam sands (Husain et al., 2000), were deposited under marine environment (Avadhani et al., 2006; Srikant and Shanmugam, 2014). Campanian fans in offshore part of the basin are also proven to be hydrocarbon