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ABSTRACT

PORE PRESSURE PREDICTION FROM SEISMIC DATA FOR WELL PLANNING IN BLOCK 22

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Several gas prospects are recognised in formations of Miocene and younger age in Block 22, which is situated to the north of Tobago in water depths of 600 to 4200 ft. The block is covered by a recent 3D seismic survey (fig 1). No wells have yet been drilled on the block. Seismic stacking velocities have been used to create 3D volumes of estimated pore pressure over the prospects, and hence to estimate pore pressure profiles in advance of drilling the first wells. Calibration is provided by wells to the south which have been tied to the 3D survey by 2D lines shot at the same time as the 3D survey and with the same parameters.

Fig 1. 3D surveyarea in green, nearest wells and possible drilling location red circles.

The methodology followed is similar to that described by Snijder et al (2002). Pore pressures have been predicted from seismic velocities using Eaton's equation:

$$P_p = S_v - (S_v - P_h)(V_{obs}/V_{norm})^3$$

where P_p is pore pressure, S_v is total vertical stress, derived from well density data and water depth, P_h is hydrostatic pore pressure (normal gradient 0.44 psi/ft), V_{norm} is the velocity on a normal compaction curve defined from well data, and V_{obs} is the observed (interval) velocity at the location of interest. In addition fracture gradients have been estimated using proprietary Ikon Science algorithms.

Despite issues of log quality in some of the wells, there are enough good data to establish the overall density and seismic velocity trends in the Pliocene and Pleistocene (fig 2); the scatter around these trends was used as an input to the uncertainty estimation for calculated pressure. An issue for calibration is the limited number of fluid and fracture pressure observations available: one Drill Stem Test (DST) in Well A and two in Well B, plus a number of Leak-Off and Formation Integrity Tests (LOP-LO and LOP-LTs). Some additional inferences can be made from mud weight in combination with the fluid pressure data. Fig 3 illustrates the calibration for Well A. The predicted pore pressure is in good agreement with the DST at 3500 ft but in the deeper part of the borehole the lithology becomes more variable, with resulting departures from the normal compaction trend.

The 3D seismic dataset is of good quality, and accurate picking of velocities was possible, though strong anisotropic effects are present. Velocities were picked on a dense grid over the prospects, and after slight smoothing output on a 100 m x 100 m grid. They were converted to interval velocities using the Dix formula for an ensemble of slabs parallel to seabed and a few hundred msec thick. Lateral smoothing was applied to each layer and the difference between smoothed and unsmoothed velocities used as an estimate of the uncertainty in interval velocity; this captures the increase in uncertainty with decreasing interval thickness inherent in the Dix formula, but not the effect of possible systematic mispicks in the stacking velocity (eg due to following a multiple trend), which are therefore implicitly assumed not to be present.

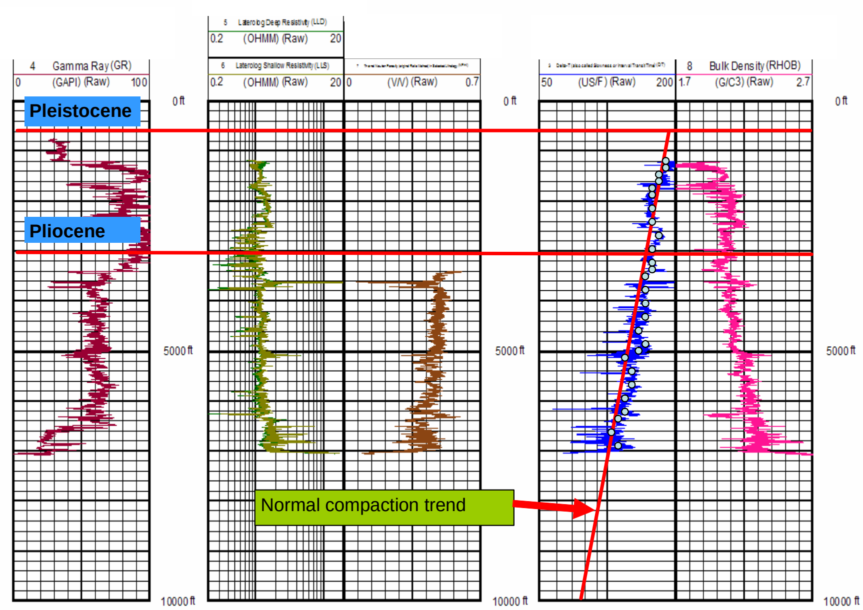

Fig 2. Sonic velocity (blue) and density (magenta) trends in well A.

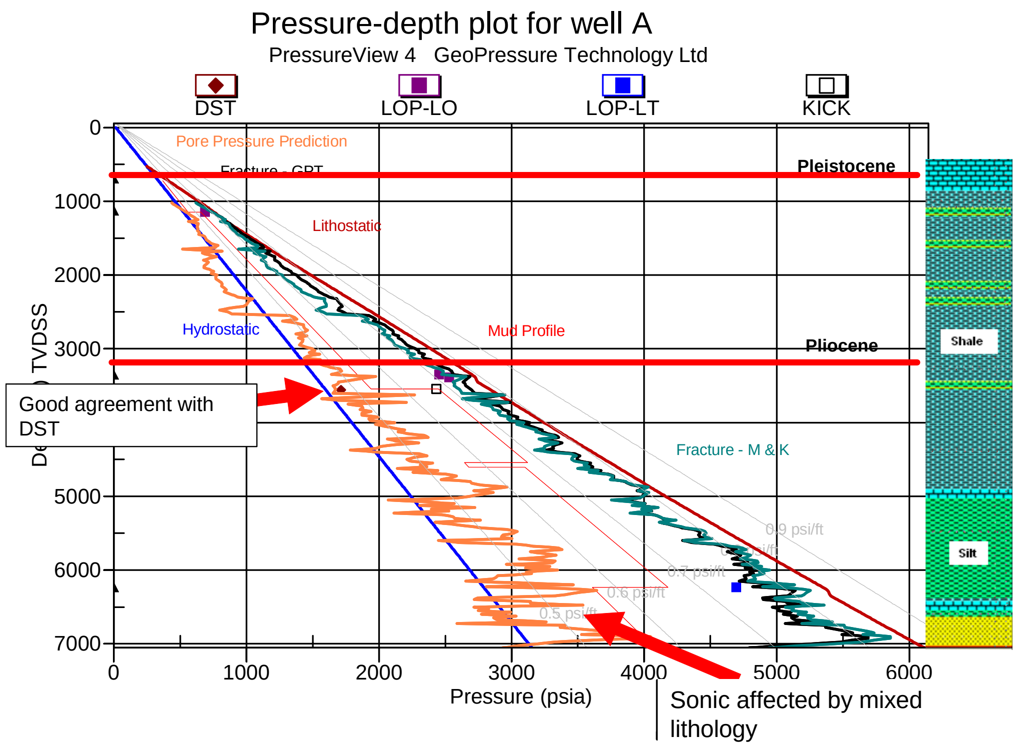

Fig 3. Blue – hydrostatic pressure, orange – predicted pore pressure, red – pressure from mud weight, green/black – fracture pressure (two different algorithms), dark red – lithostatic pressure.

Cross-plotting the seismic interval velocity against the sonic log velocity at the calibration wells allowed a multiplicative correction to be made to the seismic values to match the wells. After calculation of pore pressure from Eaton's equation, a calibration factor was derived at the wells and applied to the pressure volumes. The various uncertainty distributions in the inputs, calculated as mentioned previously, were combined to create a 3D uncertainty volume in a Monte Carlo simulation.

A section through the pore pressure volume over Location Z is shown in fig 4.

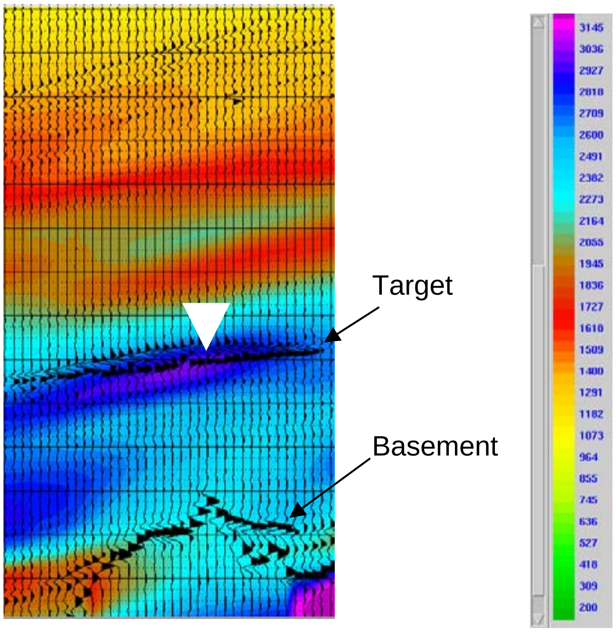

Fig 4. S –N section through pressure volume (colour) over Location Z, with reflectivity superimposed as wiggle trace.

There is an indication of increased pressure in the prospect, below which pressure falls towards the basement; values below the basement reflector are meaningless as there are no seismic events on which stacking velocities can be picked. The higher apparent pressures at prospect level may be an artefact of seismic velocity reduction due to the presence of gas, and the low pressures at and above the basement are likely to be due to the presence of mixed lithologies, resulting in a higher seismic velocity than expected from the shale compaction curve. Fig 5 shows a slice through the volume extracted on the picked top reservoir event over Location Z.

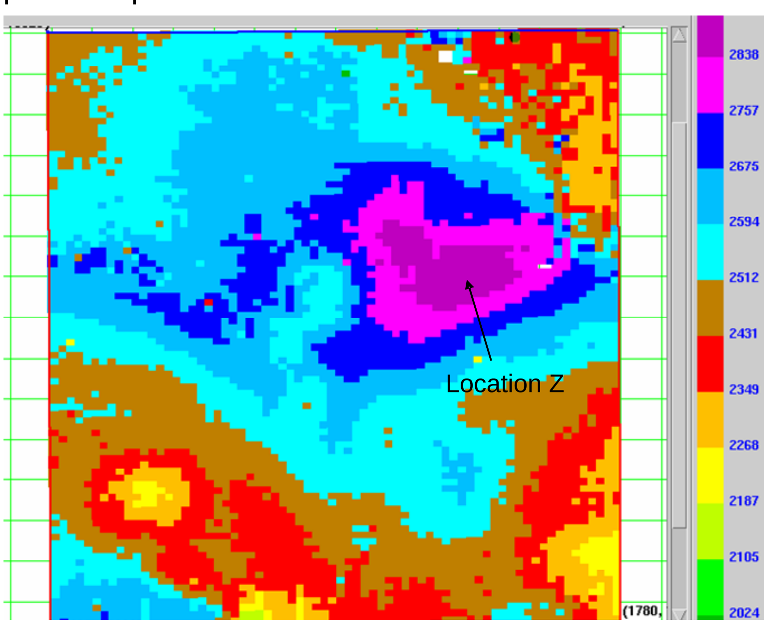

Fig 5. Slice through pore pressure volume at top reservoir.

There is perhaps evidence here of higher pressure in the area around the proposed drilling location, but the uncertainty in the pressure is calculated to be about 250 psi so the effect may not be real. The indicated pressures are well below the fracture pressure (fig 6), which is consistent with the absence of any seismic indication for gas leaking from the prospect to shallower levels.

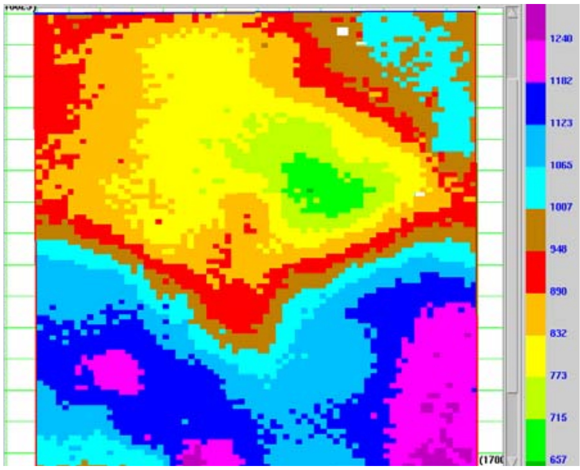

Fig 6. Predicted difference between fracture pressure and pore pressure at top reservoir.

Profiles of predicted pressure have been extracted from the cube at possible well locations (fig 7), and will be used as an input to well planning.

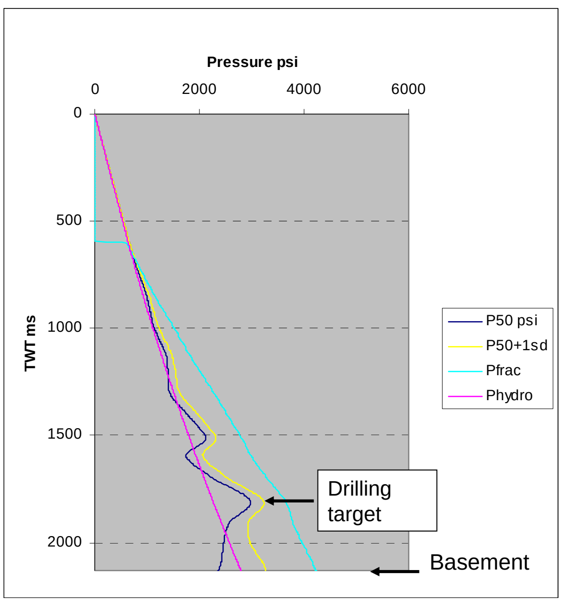

Fig 7. Predicted pore pressure (blue), prediction plus one standard deviation from Monte Carlo simulation (yellow), predicted fracture pressure (cyan) and hydrostatic gradient (magenta).

At this stage there are clearly significant uncertainties attached to the pore pressure cubes. Once we have local calibration on the block from the first exploration wells, it will be possible to reduce considerably the error bars on pressure prediction for the rest of the area.

Reference

Snijder, J., Dickson, D., Hillier, A., Litvin, A., Gregory, C. and Crookall, P. (2002). 3D pore pressure prediction in the Columbus Basin, offshore Trinidad & Tobago. *First Break*, **20**, 283 – 286.