Gas generation - a major cause of deep Gulf Coast overpressures

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Abstract:

The generation of natural gas from deep wells is a major cause of overpressures, according to research on wells situated on the Gulf Coast. At depths of greater than 10,000 feet, compaction does not occur nor does it cause overpressures. The study determined the density-porosity profile and analyzed the generation of hydrocarbon.

Full Text:

Compaction is generally regarded as the principal cause of overpressuring and hydrocarbon expulsion in sedimentary basins. However, recently available shale porosity data on individual Gulf Coast wells suggests that in many cases compaction plays no role in either of these processes.

The evidence for this is that shale porosity is either constant or increasing at the depths where overpressures occur and where hydrocarbons are being generated. In the absence of a decrease in porosity with sediment load (depth), gas generation becomes the principal cause of overpressuring and hydrocarbon migration. This can have important implications in modeling overpressures in the Gulf Coast.

The shale porosity data also indicate that there are some misconceptions about shale porosity-depth curves. For example, under hydrostatic conditions shale porosities below 30% tend to decrease linearly (not exponentially) with depth to a point below which there is no further decrease.

The depth below which there is no further compaction varies with the internal surface areas of the shale (clay mineral content). Shales with small internal surface areas (eg. those composed of very fine-grained quartz, carbonates or kaolinite) stop compacting at porosities of about 3%. Shales with 20% mixed layer water adsorbing clays stop compacting at porosities of about 10%.

The cessation of compaction has nothing to do with overpressuring. This phenomenon occurs with normally pressured shales. The two stage, linear, composition-dependent compaction is thus a "normal" compaction trend. If overpressures develop they may be able to increase porosity by decompacting the sediments. These statements are not the current perception in the industry.

The purpose of this article is to show some of the evidence that compaction is not occurring in the deeper (> 10,000 ft) sections of these wells and that gas generation is the major cause of overpressures at depths where compaction no longer OCCURS.

Traditional methods of estimating shale porosities such as from sonic logs are not suitable in many Gulf Coast wells due to extensive clay mineral hydration around the borehole which artificially increases the porosities.(1) Also, densities estimated from sonic logs tend to be distorted by barium sulfate in the drilling mud.(2) Consequently, a direct method of determining porosities was developed by H. Hinch of Amoco. It involves measuring the uptake of a liquid (Varsol) into the shale pores. The method was found to give porosities within [+ or -] 1.5% of the helium uptake method used by some service laboratories. The resulting porosities correlate closely with those obtained by the borehole gravity meter, whose measurements are not affected by hydration around the well bore. Hinch(1) describes details of the method. Density-porosity profile Fig. I contains the shale dry bulk density and porosity measurements (black dots) for the Amoco Lena Buerger well in Frio County, Tex.

Note that starting at a depth of 2,000 ft the density increases and porosity decreases along straight line segments until they reach relatively constant values of 3% porosity and 2.7 g/cc density at a depth of about 9,500 ft. From here to total depth at 17,500 ft in a basalt intrusive there is no systematic decrease in porosity indicating that no compaction is occurring.

We define this two stage compaction model as the normal compaction curve for this well. The low porosities are due to the sediments containing mainly carbonates and red shales with kaolinite, both of which have very low mineral surface areas.

If this well contained water adsorbing mixed layer clays, the two straight line segments would still occur but Stage 2 would be displaced to a higher porosity depending on the content of such clays.

Some geologists have speculated that the Stage 2 density and porosity lines in Fig. 1 represent undercompaction. However, undercompacted shales are universally within overpressured compartments, and there is no evidence that this well was ever overpressured.d.(2)

Overpressures can be recognized by drillstem tests, mud weights, and resistivity logs. The Lena Buerger well was drilled with 9 lb/gal mud to total depth. There was persistent lost circulation in the well, and there was no observed shift from normal to low resistivities. All these observations indicated normal hydrostatic pressure through the entire well.

This type of two stage normal compaction model was first recognized by Hollis Hedberg(3) in undisturbed Tertiary shales of the Eastern Venezuelan basin. Subsequently, a few additional examples were published by Bradley,(4) Hinch,(5) and most recently Powley.(2)

The paucity of additional cases may be due to the fact that the two stage model can only be recognized by direct porosity and density measurements on samples from single wells. Composites of data from several wells generally show only a scatter of points.

Fig. 2 shows the two stage normal compaction density and porosity profiles along with a pressure-depth plot for a well in Bastian Bay field, Plaquemines Parish, La. Here the shale porosity at hydrostatic pressure reaches a minimum of 10%. Porosity curves for about 50 Gulf Coast wells extending from South Texas to eastern Louisiana show that the minimum in most of them ranges between 9-12% with the median at 10%.(2) This 10% median correlates with an average mineral composition of 20% mixed layer water adsorbing clays based on about 400 analyses by Bradley of Amoco.

The difference in the Stage 2 minimum porosities of 3% in Fig. 1 and 10% in Fig. 2 is due to the water adsorbing clays in the latter having 80,000 times the surface area of the minerals in the former. Consequently, they adsorb a much greater volume of fixed water.

Note particularly in Fig. 2 that there is an overpressured and undercompacted shale section starting below the seal at about 16,000 ft. This is nearly 5,000 ft below the beginning of the minimum porosity in Stage 2. Since no systematic reduction in porosity is occurring in Stage 2, the observed overpressure does not appear to be related to the compaction of shales. This leaves the generation and expulsion of gas as the most likely cause of these deep overpressures.

A current model we are developing shows that secondary shale porosity (undercompaction) may occur under topographic highs below a seal horizon. Such porosity can be viewed as the mathematical inverse of normal compaction. Under normal compaction stress in the rock matrix increases more rapidly than pore pressure.

The result is that the grains move closer together, the grain contacts dissolve, the dissolved material precipitates on the pore walls, and porosity decreases. If pore pressure increases more rapidly than rock stress, however, the pore walls will dissolve and precipitate out grain contacts which will elongate and allow grains to effectively move further apart, increasing porosity. Our models show this can happen in some circumstances under topographic highs in seals. This process could explain secondary shale porosity development of the kind observed below 16,000 ft in the Plaquemines Parish well.

Overpressures in the Gulf Coast may or may not lead to undercompaction. The Plaquemines Parish well in Fig. 2 shows an increase in shale porosity (undercompaction) on becoming overpressured, but the well in Fig. 3 in Sheridan field of Colorado County, Tex., shows no change in porosity with overpressure.(2)

There is a straight line increase in dry bulk density and decrease in shale porosity down to about 8,700 ft, where Stage 2 starts (Fig. 3). An overpressured compartment containing about 5,000 psi excess pressure starts at around 12,000 ft, which is more than 3,000 ft below the beginning of the constant porosity Stage 2.

There is no evidence of undercompaction occurring with the overpressures. Porosities and densities are essentially the same at 17,000 ft as at 8,700 ft. Again, it is difficult to see how compaction can play any significant role in the development of these overpressures since there is no systematic reduction in porosity or increase in density starting around 8,700 ft.

Hydrocarbon generation

Previous investigators have found a close correlation between the generation of hydrocarbons and the development of overpressures.(6 7 8 9) We found the same correlation in Gulf Coast wells.

For example, in the De Witt County, Tex., well (Fig. 4) the top of Stage 2 is at about 9,600 ft. The shut-in pressure at 10,500 ft is about 8,000 psi and at TD it is around 12,000 psi. These numbers are equivalent to pressure/depth gradients of 0.76 and 0.83 psi/ft, respectively. These overpressures start and increase within the interval where there is no systematic decrease in porosity indicating no compaction.

The petroleum generation and expulsion curve for the De Witt well is based on a quantitative basin analysis model by Yukler and Dow(10) on a nearby well. Their model showed that the oil generation window for a mixed Type II, III kerogen began at a depth around 10,000 ft and peaked at a depth around 11,800 ft. The oil generation phased out around 14,700 ft. However, active gas generation continued down to 18,000 ft. The increase in overpressure with depth in this well correlates directly with the increase in gas generation computed by their model. This suggests that gas generation is causing the overpressure.

Similar results were obtained in determining the petroleum generation intervals in the West Delta and Vermilion Parish, La., wells in Fig. 4. Both intervals were calculated using Arrhenius kinetics for Type III (terrestrial) kerogen which is typical of the Gulf Coast Tertiary.

In both cases the peak in hydrocarbon generation coincided with the highest pressure depth gradients measured in the wells thereby indicating gas generation is causing the overpressures. In both of these overpressured intervals there was no systematic decrease in porosity so compaction could not be the cause of the over-pressures. All three wells reached the minimum porosity content of about 10% based on water adsorbing clay mineral contents averaging 20%.

A statistical analysis of porosity data for shales from 20 wells throughout the Texas and Louisiana Gulf Coast was carried out to determine if the shale porosity data fit a two stage linear curve better than a one stage exponential curve. Correlation coefficients (R) and coefficients of determination [R.sup.2]) were obtained for both curve fits.

If the porosity is decreasing exponentially with depth rather than in two linear stages one would expect to see a better coefficient of determination [R.sup.2]) for the former compared to the latter. However, the two stage linear plot fit the data much better than the commonly used one stage exponential plot in all 20 wells.

For example, the R2 one stage exponential coefficient for the De Witt well (Fig. 4) is 0.834 compared to a combined two stage linear coefficient of 0.955.

A simple one-dimensional model for gas generation in the Gulf Coast was developed assuming a total organic carbon (TOC) content of 1.5% and Type III (terrestrial) kerogen in the shales. It was found that pressures well in excess of lithostatic could be generated by methane production in a shale with 10% porosity buried to a depth exceeding 10,000 ft.

Overpressured undercompacted shales are more common offshore than onshore in the Gulf Coast. Most of the drilling under the salt on the Gulf Coast slope so far is showing undercompacted sediments with some subsalt formations that are extremely overpressured. This extreme overpressuring is expected at depths > 15,000 ft where the drilling is well into the gas generation window with salt providing an impenetrable barrier to the upward flow of both oil and gas.

Consequently, most of the gas being generated at greater depths is being trapped under the salt seal at pressures approaching lithostatic. This is a dynamic situation in which seal rupture is followed by a cycle of fluid movement, a pressure drop, resealing, and pressure buildup from the continuous generation of gas.(11)

The few porosity profiles shown in this article are part of a much larger study which shows that the two stage linear porosity change with no compaction in the second stage is common in the Texas-Louisiana Gulf Coast. This means that the one stage exponential porosity-depth relation still used in most basin modeling today may not always be valid. Consequently, it becomes important to make some direct shale porosity measurements on individual wells to define the type of porosity profile that actually exists before proceeding with a basin modeling program.

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John M. Hunt joined Jersey Production Research Co. (now Exxon) in 1948. During the next 16 years he built the first substantive industry group in petroleum geochemistry in the U.S. He became chairman in 1964 of the Department of Chemistry and Geology at Woods Hole Oceanographic Institution, where he is a scientist emeritus. More than 100 of his papers have been published, and he is the author of the Petroleum Geochemistry and Geology textbook, also published in Russian and Chinese.

In 1982 he became the first American to receive the Geochemical Society's Treibs Medal. He has been an AAPG distinguished lecturer and associate editor and has lectured on petroleum geochemistry in 28 countries. He now lectures for Oil and Gas Consultants International, Tulsa. He has a PhD from Penn State University.

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