

Elementary: Dry Well Analysis solves a Mystery

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Summary

When evaluating the exploration potential of a block, it is easy to get caught up looking at the size of the prospect, the estimated reservoir properties and the charge/seal/trap configuration. Often the previous dry wells drilled in the region barely merit a second glance. However not only are these wells of critical importance in evaluating the hydrocarbon potential of a block, but also careful evaluation of sparse data can yield additional information on reservoir pressures, aquifer drive, fracture density and hydrocarbon prospectivity.

In this presentation, an anticline exposed at surface, within an exploration block, had been drilled only around the margins, despite relatively easy access to the crest. Was this a ridiculous mistake by the geologist and drillers, or did they know something that we did not? And if the wells were drilled that way on purpose, what could the reasoning behind them have been? Dry well analysis provided a surprising answer to all of these questions.

Introduction

Dry well analyses have been carried out many times in the past, but seem to have fallen out of favor in recent times. The successful application of dry well analysis to a project demonstrated how integration between the exploration geologist, reservoir engineer and production technologist can be critical in applying the lessons learned from so-called “dry wells” to identifying exploration targets and risk factors.

A recent study in the Middle East, adjacent to one of the world’s premier petroleum provinces, was undertaken in an area where only three fields had been discovered. A dry well analysis was undertaken as part of an ongoing bid round evaluation in the region. A total of 29 wells had been drilled in the three blocks, with further wells drilled adjacent to the blocks.

The target reservoir interval comprised two thick, Cretaceous limestone packages, the older one of which passed into basinal shales to the northwest. These limestones sandwich a 40 metre thick (non-reservoir) shale interval, which is believed to act as a seal. Average porosities in the limestones range from around 3% to 8%, but both limestone intervals are commonly heavily fractured. The fracture porosity is thought to contain a large proportion of the STOIIIP. A quick look would indicate that both limestones should produce hydrocarbons.

The initial results of the dry well analysis showed that several of the wells produced gas in the ranges of 1-10 million standard cubic feet per day (MMscf/d), and most of the wells had shows of oil and/or gas. Three fields had producible hydrocarbons, two gas fields with an oil rim, and one oil field with a gas cap. Plotting the producing wells (with a cutoff of 1 MMscf/d) against depth of burial, a striking pattern emerged. The wells only produced significantly where the top reservoir was more than 500 m below sea level.

Methodology

Data were accessed from a database, one which could easily be accessed commercially. Wells were selected based on location and degree of penetration to assure their suitability for analysis. The individual wells were analyzed in detail. Initially an Excel spreadsheet was created to summarize all the available data. This included tops for the various formations, petrophysical properties including porosity and permeability, size of potential closure, and any production data, shows and other comments. The tops were then used to show the depth of burial of each formation relative to sea level. Finally maps were created plotting the variables against one another and conclusions drawn as below.

Discussion

Initially it was thought that there might be some regional pattern to the distribution of hydrocarbons. However the key map was the one that plotted the depth of burial against the hydrocarbon production or characteristics. It was clear that only wells accessing formations buried more than 500 m below sea level were producing, while those at around 200 m below sea level had some limited production, and those with less burial had shows only.

Discussion with the reservoir engineer yielded a surprising conclusion. The reservoirs in this region were sometimes located above sea level. The pressures at such elevations were so low that the weight of the drilling fluid was sufficient to prevent any flow from the reservoir. This explained the shows from reservoirs that otherwise had producible properties. In addition, this explained the peculiar drilling patterns observed in the producing fields. The drillers had drilled at the margins of the structure in order to minimize the head of drilling fluid, thereby maximizing the chance of production.

The simple solution to such a situation was to install beam pumps.. Using this equipment allowed the reservoirs to be produced at the extremely low reservoir pressures, for a relatively small outlay.

Conclusions

Much of the well data is either incomplete or ambiguous. By combining regional knowledge of reservoir, structural style with drilling practices, the data could be effectively translated into a description of critical risk factors. Overall the dry well analysis demonstrated that such an approach can yield excellent results, despite the often variable data quality. It was key to get the reservoir engineers involved, as an interpretation of the DST's is needed to understand the pressure regime extant in any one prospect.

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