Petroleum Res. J. Vol. 13 (2001); P. 79-82, 5 Figs.

Improving the Success Rate of Development Wells in a Fractured Cretaceous Carbonate Reservoir

- a keynote paper -

Jean Borgomano, Stephen Bourne, Tony Cortis, Karen Foster, Lex Rijkels, Ben Stephenson, Julian Bessa, Marcel Braas, Julio Carrera, Henk Leegte, Eduardo Vargas, Antonio Vizamora.*

تحسين معدلات نجاح الآبار المطورة خلال صخور جيرية متشققة في مكامن العصر الطباشيري

جين بورقومانو وستيفن بورني وتوني كيرتس وكارن فوستر وآخرون

الحقل الذي تمت دراسته يمثل مكمناً ينتمي إلى العصر الطباشيري ذا إمرارية منخفضة ومتشقق وغير متجانس. إن العامل الحاسم في نجاح الآبار المطورة والتي تستهدف مناطق الاسترداد الإضافي من المكامن ذات التركيبة الصخرية الملتحمة، أوجد الحاجة إلى اعتراض الشبكة الواسعة الانتشار من التشققات المفتوحة. ويمكّن الوصول إلى هذه الشبكة من التشققات جزءاً كبيراً من هذه الرواسب اللاحمة والمسامية من تفريغ محتواها.

تشرح هذه الورقة تقنية جديدة لتحديد: أولا مناطق الاسترداد الإضافي من المكمن ضمن مواضع مسامية غير سميكة. ثانياً مناطق ذات إحتمالية عالية لكونها تحتوي على تشققات واسعة الانتشار. إن توزيع مسامية الصخر الأصلية قد تم إستنتاجه باستخدام المؤشرات السيزمية التي تم دمجها في نماذج المكامن الساكنة ذات الثلاثة أبعاد. وبالتوازي، فإن خرائط إمرارية التشقق قد تم تعيينها من حسابات الجهد وبالتالي ربطت مع نماذج هذه الرواسب لأجل محاكاة ديناميكيته.

لإجازة اختبار النماذج التحتسطحية الممكنة، فإن معدلات الإنتاج من كل الآبار المنتجة تم مطابقتها تاريخياً بأحد النماذج التي تتفق مع البيانات الاستاتيكية المتوفرة، أجرى المشغّل إختباراً ناجحاً للنموذج عن طريق تنشيط وإعادة استكمال الآبار القديمة. وقد مكّن العمل شركة شل أن تتجاوز مستهدفات الانتاج لسنة 1999 ف، مما زاد بقدر كبير من إحتمالية نجاح التطوير المستقبلي للآبار وأن فلسفة بناء النماذج لها تأثيرات كبيرة لصخور جيرية مشابهة من ناحية كونها متشققة طبيعياً.

Abstract: *The Cretaceous field studied is a low-permeability, heterogeneously naturally fractured reservoir. A critical success factor for development wells, which target areas of enhanced reservoir matrix quality, is the requirement to intercept an extensive network of open natural fractures. Tapping into such a fracture network enables a larger volume of porous matrix to be drained. This article describes new technology to identify (1) areas of enhanced reservoir quality within a thin porous interval (ca. 10m) and (2) areas with a high probability of being extensively fractured. Matrix porosity distribution was derived from seismic attributes and incorporated into 3D static reservoir models. In parallel, fracture*

* Shell EPTAR, Volmerlaan 8, Postbus 60, 2280 AB Rijswijk, Netherlands.

permeability maps were determined from stress calculations and subsequently combined with matrix models for dynamic simulation. To validate and select possible subsurface models, rates from all producing wells (that vary by a factor 10) were history matched with one model that is consistent with available static data. Successful blind tests of the model through reactivation and re-completion of old wells have been carried out by the operator. These have enabled Shell to exceed production targets for 1999 and have significantly increased the probability of success for future development wells. The subsurface modelling philosophy has substantial implications for similar naturally fractured carbonates.

BACKGROUND

The studied field is located offshore and has been operated by Shell on behalf of the National Oil Corporation since 1993. A significant proportion of the in-place volumes (ca. 8,400 MMbbl) occurs within low-permeability fractured Cretaceous platform carbonates as a light (29° API), sour crude (1,000 ppmv-26,000 ppmv). Throughout 1999, the reservoir was the subject of an asset-focussed research program. This study had the following aims: (1) to achieve a 'short-term' operational/financial impact for the operating company, (2) to develop Shell technology applicable to complex carbonate fields; and (3) to deliver the higher potential business impact of the asset to the greater Shell Group. This paper summarises the important results of this asset study undertaken by an integrated team comprising SEPTAR and regional staff.

TECHNICAL CHALLENGES

The carbonate platform sequence is *ca.* 1000′ thick and found at a depth between ca. 15,000′ and 17,500′ TVDss. It comprises three distinct formations. These are deformed by a series of strike-slip faults to create a low-relief anticlinal structure. The uppermost formation is a laterally extensive deposit which forms a thin sheet (ca. 100′ thick) of low-porosity and tight carbonates (average $\phi < 3$ %; average $k < 0.01$ mD) representing the shallowest part of the platform sequence. The main flow unit within this formation corresponds to a 30 ft thick layer of leached, bioclastic packstones with moderate reservoir porosity (average ϕ = ca. 6.1 %). The requirements of a successful development well are to intercept a dense network of open fractures (production rate) connected to a large volume of porous matrix (connected production volume) (Fig. 1).

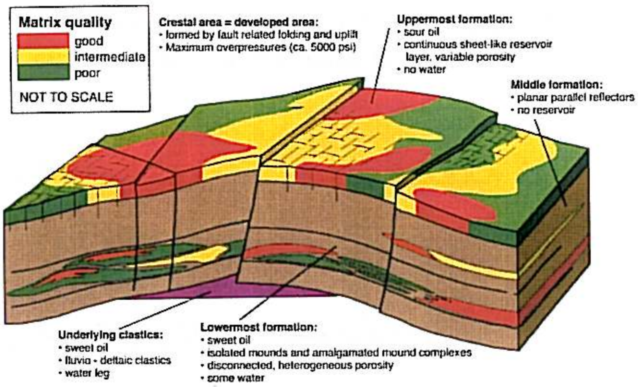

Fig. 1. Schematic picture of the field showing the major reservoir zones and flow units in relation to the stratigraphy, structure and fracture network.

To achieve this, the original development strategy was to target faults, as it was thought at that time that the intensity of tensile fracturing was likely to be greatest in the immediate vicinity of faults interpreted from seismic, with the width of the damage-zone related to fault displacement. This resulted in the "halo-concept" *i.e.* porous intervals inter-linked by a network of fractures with the highest density at the fault or fold related feature. To date, the operating company has drilled 12 dedicated wells of which four account for 92% of the total asset production. A 1996 review highlighted that the reservoir had to be appraised while being developed as there was still insufficient knowledge at that time to define in detail a proven development concept.

Subsequently in 1998, an asset-related study was initiated to increase the understanding of the sub-surface and to maximise the value of the asset. This asset-related study focussed upon developing new technology to achieve the primary subsurface critical success factors for development of a single formation. These were prediction of matrix reservoir quality and prediction of tensile fracture distribution. In the light of these data the development concept has undergone a paradigm shift from a focus on the entire interval to that of a manageable-risk uppermost formation-only development. It is intended that development wells into the uppermost formation will target matrix "sweet-spots" and natural fracture networks developed away from faults.

INTEGRATED WORK FLOW

The overall strategy of the study was to identify regions of good matrix quality (porosity) and determine the open fracture distribution through forward modelling. Multiple alternative subsurface scenarios were validated through well-production history-matches of the models. The philosophy used in static reservoir modelling was to build voxel volumes of matrix properties (ϕ and k) that could be merged with fracture permeability predictions for dynamic simulation in Shell's dynamic simulation package MoReS (Fig. 2). The reservoir architecture models were based on stratigraphic correlation of 41 wells and rock fabric analysis of the 4 available cores.

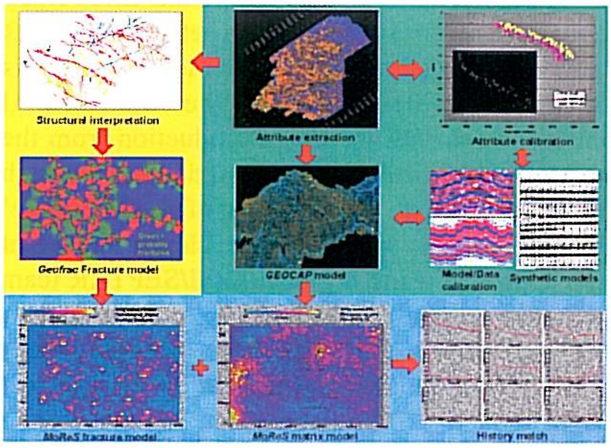

Fig. 2. Representation of the integrated workflow used to model the subsurface, which could also be applied to other fractured carbonates. The yellow, green and blue backgrounds represent the fracture, matrix and dynamic simulation (MoReS) workflows respectively.

Attribute analysis on the seismic response of the main reservoir from reflection and inversion cubes was carried out to provide a quantitative measurement of reservoir quality (ϕ*h). This was both integrated with and constrained by synthetic modelling. The ϕ*h map was imported into the static reservoir model and five different matrix property models were generated for reservoir simulation in MoReS: two different porosity scenarios (high & low) with each two permeability scenarios (high & low), based on possible ϕ/k relationships derived from recently acquired core data. An additional porosity scenario was generated by interpolating from well porosity logs in Shell's static reservoir modelling package (GEOCAP).

The fracture prediction methodology is based on a novel technique, which calculates the stress perturbation over the field due to slip on faults. This stress calculation predicts regions of effective tension, which are those most likely to be fractured. A fracture map is then "grown" in a semi-deterministic manner, constrained by BHI data from 12 wells, and rock-strength parameters. Different scenarios were modelled to address the uncertainty in remote stress, fault geometry and fracture type. These scenarios were upscaled to MoReS and combined with the matrix properties. Figure 3 shows how MoReS was used to discriminate between the matrix and fracture scenarios to find the optimum history match.

RESULTS

Only a few combined scenarios, from more than 25, match historical production data, as shown in figure 4. Both the matrix and the fracture model are important in the simulated well response, but only one scenario matches all wells. It is based on a seismic porosity map with a vuggy ϕ-k relation, and an extensive, well-connected, tensile fracture network (Figs 3, 4). That so many wells could be matched simultaneously without local adjustments greatly increases the confidence of predicting reservoir quality and fractures outside of the currently developed area. An initial

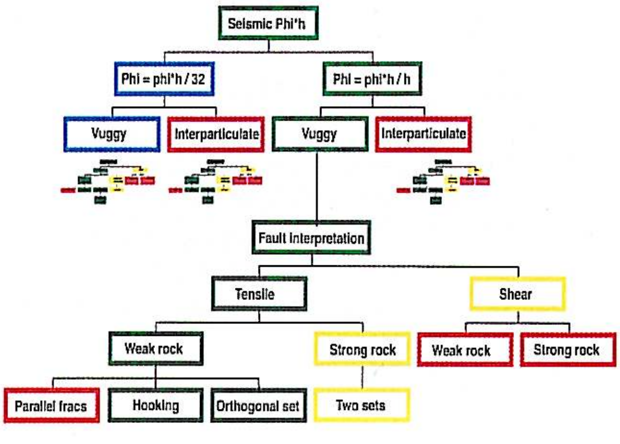

Fig. 3. Field-wide scenarios were used to match the production history of all wells, plotted here schematically as a tree of simulator ingredients. Green scenarios match and red do not.

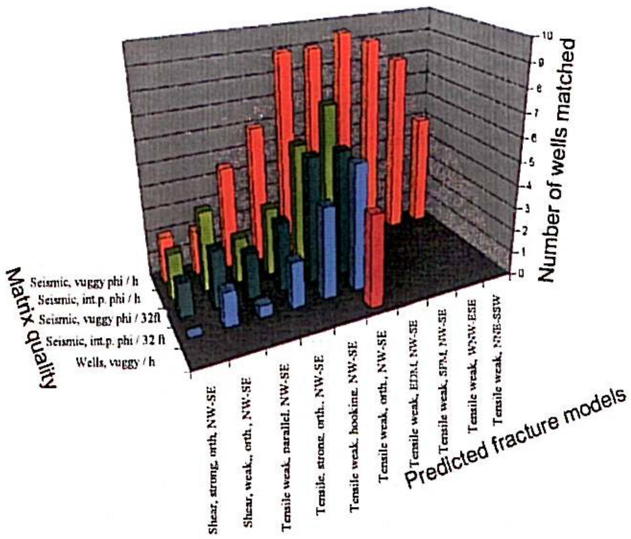

Fig. 4. Each bar represents one simulation scenario - a combination of a matrix ϕ/k model (one axis) and a fracture prediction (other axis). The height of the bar indicates how many wells are matched in the flow simulation (vertical axis). Its colour indicates the match of the matrix model with the well logs (hot colour = better match). The best history match is obtained with a matrix model based on seismic porosity prediction, and tensile fractures in a weak rock under NW-SE remote stress.

blind test of the model was carried out in July 1999 through a re-completion of an existing well. The test proved successful when an existing 30° well was perforated and stimulated to remove the skin. Post-stimulation production was predicted via simulation of the fractured matrix model and interpretation of a previous build-up. It is expected that the new subsurface model developed in this study will be further tested with a future appraisal well. Three potential locations were identified for new development wells in the field (Fig. 5).

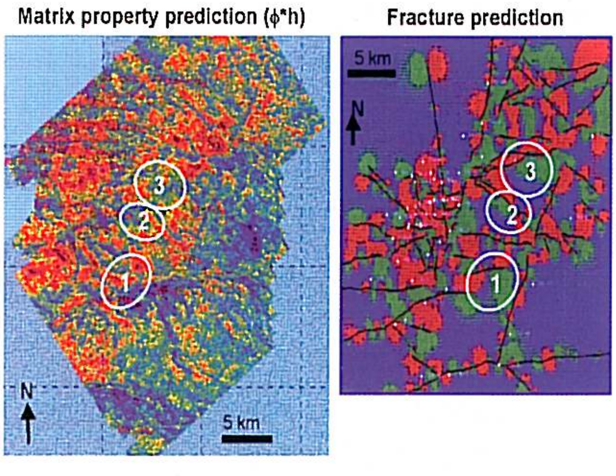

Fig. 5. Infill well ranking based on seismic attribute (ϕ*h) and fracture prediction maps. Wide areas of high matrix porosity (hot colours) overlapping regions of effective tension (green) away from major faults.

CONCLUSIONS

One of the main learning points from this study is that the integration of disciplines is crucial to the modelling of naturally fractured reservoirs as outlined schematically in figure 1. Through integration, all the critical subsurface parameters were combined in simulation models that were tested against production history. Both matrix and fracture distributions must be correctly described to obtain a history match. For instance, if the matrix model were based solely on well logs, the match between the logs and the model would be perfect, but a dynamic history match would never be achieved. It is only when we use the seismic ϕ*h map, combined with the effective fracture permeability map, both of which give a reasonable match individually, that the history match is good and consistent with the static data (Fig. 4).

A key factor in the success of this asset-study has been the close collaboration between SEPTAR staff in The Netherlands and the local staff. This success is measured in the operational environment with increased production from the reservoir with well re-entries, and in the research environment with the evolution of 'leading-edge' technology. The results to date, clearly show that the approach using a global/local/SEPTAR team represents a model for other assets requiring fast-track evolution of leading-edge technology that can be immediately applied in an operational environment.

Asset-focussed evolutionary-research on the reservoir is being furthered throughout 2000, with a drive to further 'sweat the existing asset' with new potential for stimulation and completion of old wells in the license area.