Faulting, fracturing and in situ stress prediction in the Ahnet Basin, Algeria — a finite element approach

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Abstract

Many low-efficiency hydrocarbon reservoirs are productive largely because effective reservoir permeability is controlled by faults and natural fractures. Accurate and low-cost information on basic fault and fracture properties, orientation in particular, is critical in reducing well costs and increasing well recoveries. This paper describes how we used an advanced numerical modelling technique, the finite element method (FEM), to compute site-specific in situ stresses and rock deformation and to predict fracture attributes as a function of material properties, structural position and tectonic stress. Presented are the numerical results of two-dimensional, plane-strain end-member FEM models of a hydrocarbon-bearing fault-propagation-fold structure. Interpretation of the modelling results remains qualitative because of the intrinsic limitations of numerical modelling; however, it still allows comparisons with (the little available) geological and geophysical data.

In all models, the weak mechanical strength and flow properties of a thick shale layer (the main seal) leads to a decoupling of the structural deformation of the shallower sediments from the underlying sediments and basement, and results in flexural slip across the shale layer. All models predict rock fracturing to initiate at the surface and to expand with depth under increasing horizontal tectonic compression. The stress regime for the formation of new fractures changes from compressional to shear with depth. If pre-existing fractures exist, only (sub)horizontal fractures are predicted to open, thus defining the principal orientation of effective reservoir permeability. In models that do not include a blind thrust fault in the basement, flexural amplification of the initial fold structure generates additional fracturing in the crest of the anticline controlled by the material properties of the rocks. The folding-induced fracturing expands laterally along the stratigraphic boundaries under enhanced tectonic loading. Models incorporating a blind thrust fault correctly predict the formation of secondary syn- and anti-thetic mesoscale faults in the basement and sediments of the hanging wall. Some of these faults cut reservoir and/or seal layers, and thus may influence effective reservoir permeability and affect seal integrity. The predicted faults divide the sediments across the anticline in several compartments with different stress levels and different rock failure (and proximity to failure). These numerical model outcomes can assist classic interpretation of seismic and well bore data in search of fractured and overpressured hydrocarbon reservoirs. © 2000 Elsevier Science B.V. All rights reserved.

Keywords: Ahnet basin; fracture modelling; hydrocarbon reservoir; stress prediction

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1. Introduction

Natural fracture systems are important contributors to reservoir permeability, and sometimes porosity, in many hydrocarbon reservoirs. Low-efficiency hydrocarbon reservoirs that have very low matrix permeabilities are productive largely because delivery of fluids to well bores is controlled by natural fractures. In addition to the enhancement of flow and storage of fluids in low-permeability and low-porosity rocks, fractures and faults may be necessary to allow primary migration of hydrocarbons from source rocks and to rupture seals in pressure cells (Hunt, 1990).

Faults play an important role in creating hydrocarbon traps and in the formation of sealed compartments in hydrocarbon reservoirs. When a fault cuts a reservoir sequence it is desirable to predict the likely sealing behaviour of the fault system (Knipe, 1997; Yielding et al., 1997). Evaluating fault seals (e.g. juxtaposition, clay smear, cataclasis, cementation) forms an important aspect of hydrocarbon exploration and production. Fault-seal assessment requires knowledge of the distribution and the origin of sealing properties along individual faults, as well as an understanding of the geometry of the faults under evaluation.

A known pattern of hydrocarbon distribution and the orientation of effective fracture permeability may suggest strategies for maximising recovery. Boreholes parallel to the trend of maximum hydrocarbon volume and perpendicular to the strike of effective fractures will maximise primary recovery (Major and Holtz, 1997). For low-productivity reservoirs, in which reservoir permeability is controlled by faults and natural fractures, it is important, therefore, to know (1) the spatial distribution of faults and fractures (if present), (2) their orientation and (3) how permeable they are.

Although there are some geophysical methods of identifying subsurface fractures (e.g. cross-hole tomography (Saito and Ohtomo, 1989) and seismic reflection analysis of shear waves (Mueller, 1992)), these are generally quite expensive and commonly are not economically justifiable in mature, relatively low-productivity reservoirs. However, fracture detection using borehole-imaging logs (Major and Holtz, 1997) and mapping of microfractures by scanned cathodoluminescence imaging (Laubach, 1997) can be a cost-effective and highly reliable method of determining the presence of fractures in the subsurface and, more importantly, the orientation of fractures that control reservoir permeability. Unfortunately, the portion of the reservoir sampled by boreholes usually is extremely small, and a reservoir can be significantly fractured even if there is no evidence for these fractures in borehole data.

The orientation of natural fractures that control reservoir permeability is governed by the regional stress field. Borehole breakouts, earthquake focal mechanism solutions and stress measurements can give the direction of the maximum principal horizontal stress (Zoback, 1992). Fractures and faults parallel to the regional maximum horizontal compressive stress will be more permeable than fractures perpendicular to this stress. The parallel fractures will tend to be open and will define the principal orientation of effective reservoir permeability. Fractures with other orientations will tend to be squeezed shut by horizontal compressive stress and, therefore, will contribute less to reservoir permeability. Moreover, induced fractures created during drilling will tend to propagate parallel to the orientation of maximum compressive stress (e.g. Major and Holtz, 1997).

Basic fracture information, including reliable data on fracture strike, is often exceedingly sparse, hindering efficient development through optimised well placement or directional drilling. As exploration and development move into increasingly challenging and deeper reservoirs where natural fractures are key to successful completion, accurate and low-cost information on fracture orientation and other fracture attributes will be critical to reducing well costs and increasing well recoveries. Modern, advanced numerical modelling techniques may provide such information. In this paper we investigate the potential of the finite element method in the calculation of site-specific stresses and fracture attributes and in the prediction of faulting and related formation of differently pressured compartments in hydrocarbon reservoirs. This study also intends to demonstrate the usefulness of mechanical modelling to test hypotheses on the geometry of structural traps, and to under-
stand better the fault mechanics and the mechanical properties of reservoir rocks.

The reservoir structure investigated, located in the Ahnet Basin, Algeria, is approached from a larger-scale point of view, applying geomechanical modelling methodologies from finite element modelling (FEM) analyses of tectonic problems on the basin-, crust- and lithosphere-scale (e.g. Van Wees and Stephenson, 1995; Beckman et al., 1996, 1997; Van Wees et al., 1996). The modelling remains qualitative because of the intrinsic limitations of large-scale modelling (in space and time); however, it still allows comparisons with geological and geophysical data. This will allow us to constrain the principal parameters, to gain more insight into the causes and effects of rock deformation processes, and to predict fracture attributes as a function of structural position and tectonic stress.

2. Case study: hydrocarbon reservoir in the Ahnet Basin (Algeria)

In order to test the predictive potential of finite element analyses of hydrocarbon reservoir related structural problems, an anticlinal reservoir structure located in the Ahnet Basin (Algeria) in the northern part of the African continent (Fig. 1) has been selected as a case study. The structure is of Variscan age and most likely formed as a fault propagation fold (Klitsch, 1970; Beuf et al., 1971; Boudjema, 1987). An east-west-running seismic reflection line (Fig. 2) traverses the northern part of the reservoir structure, running perpendicular to most of the mesoscale reverse faults observed in the structure (Badsi, 1992). A small map (Fig. 2, inset) of the top of the main reservoir sandstone gives an impression of the spatial structure and dimensions of this gas-bearing reservoir.

The anticline reservoir structure comprises five stratigraphic units of Palaeozoic age (Beicip-Sonatrach, 1970; Badsi, 1992), lying on top of a Precambrian sandstone basement and covered by Mesozoic carbonates. The Palaeozoic units comprise, from bottom to top: (5) a Cambro-Ordovician layer of predominantly sandstones; (4) a thick layer of Silurian shales; followed by (3) a Lower and Middle Devonian layer with alternating sandstones and shales, and a distinct unit of condensed carbonates at the top; this is overlaid by (2), a thick layer of predominantly Upper Devonian Frasnian sandstone; and finally (1), the alternating sequences of sandstones and shales from the Upper Devonian Famennian series.

The source rocks of the reservoir are mainly the marine shales in the Silurian and Frasnian units (Tissot et al., 1972; Klemme and Ulmishek, 1991). Secondary sources may exist in the middle sections of the Silurian and in the Cambro-Ordovician (Badsi, 1992). The reservoir rocks are mainly constituted by the sandstones of the Cambro-Ordovician (Macgregor, 1996).

The material properties of the sedimentary layers and basement incorporated in the numerical models are listed in Table 1. All properties, except the cohesion, have been measured directly from borehole rock samples. No data are available for the cohesion of the sediments and basement. For each unit two rock cohesion values are adopted which differ by one order of magnitude and serve as representative end-member values (Carmichael, 1989).

The present-day intraplate stress field in the northern part of the African plate is generated by active plate boundary processes connected with the on-going inter-plate N–S convergence between the African and European plates (Zoback, 1992). As a result, the intraplate stress field in northern Africa is uniformly oriented over wide areas with a predominant NNW-SSE direction of the maxi-
Fig. 2. Interpreted seismic reflection line running east-west through the anticline reservoir structure. Upper left inset figure shows a structural map of the top of the main gas reservoir.
Table 1
Material properties (see Fig. 3)

<table>
<thead>
<tr>
<th>Stratigraphic unit</th>
<th>Lithology</th>
<th>Density (kg m$^{-3}$)</th>
<th>Young's modulus (GPa)</th>
<th>Poisson's ratio</th>
<th>Cohesion (MPa)</th>
<th>Friction angle (deg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Famennian sandstone/shales</td>
<td>2500</td>
<td>27.5</td>
<td>0.20</td>
<td>2/20</td>
<td>31</td>
<td></td>
</tr>
<tr>
<td>2. Frasnian sandstone</td>
<td>2480</td>
<td>27.5</td>
<td>0.25</td>
<td>3/30</td>
<td>33</td>
<td></td>
</tr>
<tr>
<td>3. Lower/Middle Devonian sandstone/shales</td>
<td>2500</td>
<td>27.5</td>
<td>0.20</td>
<td>2/20</td>
<td>31</td>
<td></td>
</tr>
<tr>
<td>4. Silurian shales</td>
<td>2530</td>
<td>27.0</td>
<td>0.15</td>
<td>1/10</td>
<td>10</td>
<td></td>
</tr>
<tr>
<td>5. Cambro-Ordovician sandstone</td>
<td>2480</td>
<td>28.0</td>
<td>0.25</td>
<td>3/30</td>
<td>30</td>
<td></td>
</tr>
<tr>
<td>6. Precambrian basement sandstone</td>
<td>2480</td>
<td>28.0</td>
<td>0.25</td>
<td>5/50</td>
<td>50</td>
<td></td>
</tr>
</tbody>
</table>

Horizontal compression. Consequently, the anticline structure has been, and still is, subjected to horizontal compression (Chiarelli, 1978).

3. Finite element model

Primarily based on the seismic cross-section (Fig. 2), but also incorporating surface geology field data and correlating the little available borehole data, a two-dimensional finite element model of the anticline has been constructed (Fig. 3). Tests with meshes of different size showed that a model with spatial dimensions of at least 100 km length by 40 km depth is required to avoid interference with numerical problems typically occurring at the edges. To reduce the number of elements, and thus the computation time, the size of the elements is increased away from the region of interest (the reservoir). This has led to a total of almost 30,000 elements and 15,000 nodes. The elements used are three-node, isoparametric triangles, with linear shape functions and thus constant strain and stress. The finite element code used for the elasto-plastic calculations is Tecton (Melosh and Raefsky, 1980). Modified versions of Tecton allow the implementation of pre-existing faults in models [slippery node approach (Melosh and Williams, 1987)] if necessary with friction on the fault plane (Beekman et al., 1996).

In all models the upper surface is free to deform horizontally and vertically. The lower boundary is restricted to move vertically but allowed to deform horizontally. In order to subject the anticline hydrocarbon trap structure to a horizontal compressional stress field [mimicking Alpine compression (Chiarelli, 1978)], a horizontal shortening up to a total of 500 m is applied in incremental steps of 5 m, equally divided over the two vertical edges. Please note that, since there are only rate-independent rock deformation processes, the rate at which the shortening is applied (the loading velocity) is unimportant. However, the shortening still must be applied in small incremental steps to track the load-history-dependent plastic strains and to gain a better convergence behaviour in the non-linear models. The total applied shortening is equivalent to a bulk horizontal shortening of 0.5%. This satisfies the implicit demand that the reservoir structure is not allowed to deviate too much from its initial geometry, because the model is constructed on the base of the final (present-day) geometry.

At time zero, all models are prestressed with their own gravitational stress field computed in an earlier run but without any pre-existing faults included (Fig. 4a). The vertical displacements caused by the prestressing ('the model subsides under its own weight', Fig. 4b) are being corrected by force balancing (Fig. 4c).

4. Modelling results

Modelling results will be presented and discussed for two end-member cases of a series of models that comprise a blind thrust fault which dips to the east and becomes horizontal at a depth of ca 12 km. The free parameter in this series is the static friction along the thrust fault. The two end-members represent models with infinitely high
4.1. Structural deformation

The two end-member models respond in dramatically different ways to the applied horizontal shortening. The infinite friction model (hereafter referred to as the ‘non-fault model’) essentially responds by flexural amplification of the initially present, anticline structure (Fig. 5b and c). Uplift of the surface across the anticline typically is several tens of metres. In contrast, the internal deformation of the anticline structure within the zero friction model (the ‘fault model’) is governed to a high degree by slip along the blind thrust fault in the underlying basement (Fig. 6b and c). Close examination of the horizontal displacements reveals that the dipping basement fault becomes somewhat steeper under the applied horizontal compression. This leads to some gravitationally induced downwards sliding of the hanging wall.
Fig. 4. Model response due to initial gravitationally derived body force loading. (a) Applied boundary conditions. (b) Vertical displacements in the top central part (the reservoir) of the model. It demonstrates the self-compaction of the model under its own weight. Surface displacements exceed 500 m. (c) Vertical displacements after correction for gravitational compaction.

At the surface this is evidenced by several metres of subsidence of the area overlying the tip of the thrust fault (Fig. 6b).

A deformational feature that both end-member models have in common is a mechanical decoupling of the stratigraphic sediments above the Silurian shale layer from the units and the basement underlying the shale. In both models this leads to flexural slip over the mechanically weak shale layer across the entire anticline. Similar interlayer slip over a strong layer-parallel anisotropy produced by the presence of interbedded, weak cherts has been observed, for instance, in detached folds in west Virginia (Dunne, 1986). Decoupling is more pronounced in the non-fault model (Fig. 5c), where the flexural amplification produces a flexural slip of some tens of metres on the western flank of the anticline.

4.2. In situ stresses

The weak mechanical properties of the shale layer are also expressed by the low differential stress $\sigma_2 - \sigma_3$ this layer sustains in both end-member models, especially when compared with the immediately under- and over-lying sandstone.
units (Figs. 7a and 8a; please note different contouring range). Jumps in differential stress magnitude at both the top and bottom interfaces of the Silurian shale unit vary laterally and may reach maximum values of several tens of megapascals. In fact, both models show that abrupt changes in stress magnitude also occur at every other stratigraphic interface, although substantially less large. This, obviously, is the result of differences in the material properties between the layers, in particular the density and the elastic properties.

In both end-member models the differential stress increases roughly linearly with depth due to the increase of lithostatic pressure with depth. This increase with depth is more or less homogeneous in the non-fault model (Fig. 7a), only being perturbed by the shale layer (although differential stress increases with depth even within this layer). This is also true for the fault model (Fig. 8a), but here the differential stress distribution is also more intensely perturbed in the anticline, evidently as the result of slip along the thrust fault in the underlying basement. There is a complex pattern of alternating areas with lower and higher...
differential stress magnitudes in the shallow units across the anticline, particularly in the western flank.

4.3. Proximity to rock failure

The proximity to failure is defined as the local ratio between the effective stress and the failure stress (yield stress). Where this ratio is one, the effective stress has reached the yield limit and rock failure occurs. Owing to local strain redistribution (like fault slip), the stress may relax and descend below the yield limit (ratio less than one), thus bringing the rock out of failure. On-going model loading will increase the effective stress again and bring it back to the yield limit (‘stick-slip’-like behaviour). The proximity to failure parameter may help to identify which parts of a model are far away from yielding and thus can be considered to be mechanically strong and stable. More interestingly, the proximity to failure also reveals which parts of a reservoir are close to failure or are already failing, for instance by generating new fractures or by opening existing fractures.

After 200 m of applied shortening, in both end-member models the uppermost sandstone/shale layer of Fammenian age and the Silurian shale unit are failing over the entire width of the model (Figs. 7b and 8b). The other Devonian sandstone/shale (unit 3) is by now also prone to
Fig. 7. Modelling results for the ‘non-fault model’ (Fig. 5a). (a) Principal stress difference $\sigma_1 - \sigma_3$. Where the stress exceeds the upper contouring limit, elements are coloured light grey. (b) The proximity to failure, defined by the ratio between effective stress and failure stress. When the ratio is one (light grey coloured elements), rocks are failing.

Fig. 8. As Fig. 7, but results are displayed for the ‘fault model’ (Fig. 6a).
fail, whereas the two sandstone layers and the basement sandstones still remain far away from yielding. This clearly illustrates the weakening effect that the presence of shales has on the mechanical deformation of individual stratigraphic layers within the models, expressed, for instance, in the sometimes slightly lower values for the friction angles of the rocks of each unit (Table 1).

There are also some clear differences in the failure proximity distributions of both models. In the non-fault model (Fig. 7b), the stress-induced flexural uplift of the anticline leads to some additional rock failure in the crest of the anticline, most likely caused by flexural bending stresses. The effective stress is obviously increased sufficiently to reach the yield limit, even in parts of the Frasnian sandstone. Failure proximity ratios, naturally, can also vary within a unit, as is demonstrated on the flanks of the anticline, where in both the Frasnian sandstone and the Devonian sandstone/shale the lower parts of each layer are out of (although close to) failure and the upper parts are in failure (Fig. 7b). If, in these parts of the model, failure implies fracturing, this predicted inter- and intra-layer spatial variation of fracturing along stratigraphic interfaces has direct consequences for vertical and horizontal connectivity of permeable, fracture-controlled parts of hydrocarbon reservoirs. This is also true for the fault model (Fig. 8b), where slip along the basement thrust fault and related changes in the stress field have led to a laterally alternating series of failing (fractured) and not-failing (not-fractured) compartments within the upper three units on the western flank of the anticline.

4.4. Rock failure: faulting, fracturing and plastic deformation

The failure proximity plots essentially show where, inside the anticline structure, the rocks are failing and where not under the applied gravitational and compressional loading. The three panels in Figs. 9 and 10 concentrate on the rocks in failure, and attempt to unravel the way in which the rocks are failing (by either plastic or ductile flow, localised faulting, fracturing) and try to extract fracture attributes such as fracture orientation and fracture mode [extension fractures (joints, veins), shear fractures (small faults), pressure solution (stylolites)]. Other fracture attributes, like fracture length and fracture density (or intensity), cannot be assessed because the FEM does not allow modelling of individual fractures.

In the numerical calculations, all deformation directly related with failure of rocks is simulated by plastic flow because it is technically impossible to create new discrete fracture and fault planes numerically during a model run. However, using available geological knowledge of the deformation processes involved with failure of different types of rock, the calculated plastic deformation in the models can be interpreted geologically as either brittle failure or as viscous flow. For instance, from a geological and geomechanical point of view it is more likely that the Silurian shales will deform by some viscous flow process than that they will yield in a brittle manner, whereas the opposite is true for the more competent sandstone units in the models. The calculated spatial distribution of yielding also needs to be interpreted geologically. Calculated plastic strain can occur in either intense and highly localised bands, which can be interpreted as faults, or in less intense and more diffuse bands, in which case it can be interpreted as natural fracturing.

In both end-member models (and all other models investigated for that matter) the Silurian shale layer already yields completely by gravitational loading only, thus even without any shortening applied yet. Associated deformation is interpreted as non-brittle flow (which can be plastic and/or viscous), with effective strains in the order of 1% and more after some 200 m of applied model shortening (Figs. 9a and 10a).

In the non-fault model (Fig. 9a), the low intensity and diffuse fracture mode seems to be the only brittle deformation mechanism active in the shallow, sandstone-dominated units in yielding. Fracturing starts at the surface of the model over the whole width and expands downwards under increased compressional loading. Additional fracturing develops in the crest of the anticline, obviously due to stress-induced flexural uplift and amplified folding of the anticline structure. This fracturing slowly propagates in a lateral, as well
as a vertical, direction under enhanced horizontal loading.

Having interpreted that the main mode of rock failure in the non-fault model is fracturing, the next step is to determine the orientation and mode of the fractures, both controlled by direction and relative magnitude of the principal stresses. Because all our numerical models are two-dimensional plane-strain, the out-of-plane stress is always a principal stress and perpendicular to the model, and the other two principal stresses must therefore lie in the plane of the model. By subsequently comparing the out-of-plane principal stress with the two in-plane principal stresses and assuming Andersonian stress conditions (Anderson, 1951) it is possible to determine the actual state of stress, i.e. compressive, strike-slip, or normal stress system, dependent on whether the vertical principal stress is the smallest, intermediate or largest principal stress respectively.

When discussing the relationship between fractures and principal stresses, two distinct cases must...
be recognised: (1) reactivation of pre-existing fractures or (2) formation of new fractures. In the first case the fractures were formed during previous phases of deformation of the area of interest, and may have any orientation. In this case only those fractures that are critically stressed and that strike subparallel to the direction of maximum compressive stress will tend to be open and will define the principal orientation of effective reservoir permeability. Fractures with other orientations will tend to be squeezed shut by maximum compressive stress and, therefore, will contribute less to reservoir permeability. When assuming the Mohr–Coulomb failure criterion also to be the criterion for critical fracture stress, the location and orientation of open fractures can be deduced immediately from Fig. 9b, which displays the dip angle of the maximum compressive stress in areas with critically stressed fractures. Open fractures will be subvertical everywhere ($\sigma_1$ subhorizontal) where rock failure occurs, and will be oriented east–west, parallel to the section and to $\sigma_1$ (the maximum compressive principal stress).

The orientation and mode of new fractures can be determined by using Anderson’s theory on the mechanics of faulting (Anderson, 1951). By apply-
ing the condition that near the free surface one of the principal stresses is (sub)vertical. Anderson (1951) showed that the three major classes of new fractures and faults (extensional, shear and compressional) result from the three principal classes of inequality that may exist between the principal stresses. This concept can be grasped readily by examining a section through the Coulomb failure surface in principal stress space (as shown in Fig. 11a) at some arbitrary value of \( s_v \). A six-sided figure, symmetrical about the line \( s_v = s_h \), is obtained (Fig. 11b) that completely describes the fracture criterion at this value of \( s_v \) (see Scholz, Orientations and other attributes of both pre-existing and new fractures are more or less similar 1990). Sides I and II of the figure are the loci of failure for the conditions where \( s_v \) is the largest principal stress, therefore producing normal faults and/or extensional fractures (joints, veins) that strike parallel to the largest horizontal principal stress and that dip \( \phi = 45^\circ \pm 45^\circ \) (Table 1)). For sides III and IV, \( s_v = s_h \) is the intermediate principal stress, thus defining conditions for strike-slip faulting and/or shear fracturing on vertical conjugate planes. The dihedral angles of conjugate shear fractures are bisected by the maximum horizontal principal stress direction (Fig. 11c) and the angle magnitude is given by \( \theta = \pi/4 - \phi/2 \) (about 30°). Sides V and VI define compressional faulting for the condition of \( s_v \) the smallest principal stress, producing fractures (stylolites) perpendicular to the maximum horizontal compression and dipping \( \theta = \pi/4 - \phi/2 \) (about 30°).

Fig. 9c displays the spatial distribution of the three major fracture classes in the non-fault model. Under the current state of stress (after 200 m of applied shortening), new fractures that are formed in the competent rocks of the anticline will be mainly shear fractures and some stylolites in the crest. The modelling results indicate that no open fractures, which control fracture permeability, will be formed in the non-fault model. A similar analysis can be carried out for the thrust fault model (Fig. 10). Here, besides distributed rock failure (fracturing), intense rock failure also occurs that is localised in several planar bands, which are interpreted as secondary mesoscale faults. A large, anticlastic fault cuts the basement of the hanging wall of the main thrust and propagates through the overlying Palaeozoic sediments up to the surface (Fig. 10a). This secondary fault develops an antithetic branch at the top of the Silurian shale unit, which is also observed on the seismic section (Fig. 2). More secondary faults, somewhat smaller and oriented synthetic as well as antithetic, are predicted at shallow levels in the crest of the anticline. The modelling also predicts the initiation of a second, large antithetic fault east of the crest and which propagates downwards through the basement and eastwards towards the main thrust.

Orientations and other attributes of both pre-existing and new fractures are more or less similar in both end-member models. Except, in the fault model, the model-wide pattern of fracturing is perturbed by a lateral series of compartments without fractures, located in the stratigraphic units above the Silurian shale and present only in the western flank of the anticline (Fig. 10b). Also, in the vicinity of some of the new mesoscale faults, a fault-induced perturbation of the local stress field has led to a rotation of the maximal principal stress from subhorizontal to subvertical and, therefore, also to a change in the mode of fracturing from shear or compressional fracturing to extensional fracturing (Fig. 10c).

5. Discussion

In the geomechanical analysis presented, the methodology used in numerical modelling recognizes that field data (such as in situ stresses, material properties and geological features) will never be known completely. The models remain simple, with assumed data that are consistent with known field data and hydrocarbon-engineering judgement. It is futile to expect the models to be forms of the mechanisms that may occur within particular hydrocarbon systems. More insight into these mechanisms may help to improve strategies for maximising hydrocarbon recovery, for instance
Fig. 11. After Scholz (1990). (a) In principal stress space ($\sigma_1, \sigma_2, \sigma_3$), the Mohr–Coulomb failure criterion takes the form of an irregular hexagonal cone around the space diagonal (the pressure axis). (b) A cross-section through a Mohr–Coulomb failure surface at $\sigma_v$ constant (assuming Andersonian stress conditions). Each side of the resulting figure defines the relations between the three principal stresses. Dependent on whether $\sigma_v$ is the largest, intermediate or smallest principal stress, a different class of faulting/failuring can be identified. (c) Shows these different classes in map view (assuming a friction angle $\phi = 30^\circ$, which is typical for most rocks).
by optimising well placement or directional drilling.

The model simplifications, e.g. constant density with depth (no porosity or thermal effects), no fluid flow and pore pressure effects, and prescribed displacements as boundary conditions, are acceptable within this concept. Because of these assumptions, and because of the little data available to test the model results against, the model outcomes must be interpreted qualitatively. Nevertheless, comparisons with available geological and geophysical data are still allowed. Unfortunately, for our case study no industrial data were released on in situ stress magnitudes, on the presence of fractures, nor on the orientations and other attributes of possible fractures. Consequently, the model outcomes for these parameters remain predictions that hopefully can be tested in the future when fracture data become available. Our modelling at least demonstrates that the finite element method can be used to predict several fracture attributes by computing stresses and strains, and by applying well-established rock fracture laws. Moreover, predicted fracturing patterns and attributes are supported by other modelling results. For instance, the blind thrust fault model with zero friction predicts mesoscale faults to form only in the western half of the anticline, which is confirmed by the seismic data. Several faults are computed at their correct locations, and, for one mesoscale fault, branching is predicted to occur at the upper interface of a shale layer, which conforms with observations. Despite the fit between model predictions and observations, more and better quality data are required of the case study reservoir (or any reservoir, for that matter) to better assess the potential and quality of the finite element method as a numerical tool for the prediction of natural fracturing of hydrocarbon reservoirs.

In all geologic situations, there is an in situ state of stress in the ground before a geologic construction is deformed. This initial state must be included in the models because it can influence the subsequent behaviour of the model. Ideally, information about the initial state comes from field measurements, but, when these are not available, an attempt can be made to reproduce this in situ state for a range of possible conditions and constraining factors (e.g. the system must be in equilibrium). In our models, the initial in situ vertical stresses are equal to the lithostatic weight of the overburden: \( \sigma_{zz} = \rho g z \), where \( g \) is gravitational acceleration, \( \rho \) is the mass density of the material, and \( z \) is the depth below the surface. The in situ horizontal stresses are given by the natural ratio between horizontal and vertical stress:

\[
\frac{\sigma_{xx}}{\sigma_{zz}} = \frac{n}{(1-n)}
\]

where \( n \) is Poisson’s ratio. This formula is derived from the assumption that gravity is suddenly applied to an elastic mass of material in which lateral movement is prevented. Of course, if we had enough knowledge of the geologic history of a structure, we might simulate the whole process numerically, so as to arrive at the initial state of stress for our models. This approach usually is not feasible. A compromise is made by installing a set of stresses in the model, and run the model until an equilibrium state is obtained that serves as the initial in situ state of stress. All finite element models are constructed on the basis of seismic sections, borehole data and surface geology, which are representative only for the present-day geometry of the reservoir. For the modelling results to remain valid, the models are not allowed to deform to such an extent that their final geometry substantially deviates from the initial geometry. The amount of shortening applied to the models, therefore, remains small: less than 0.5%. As explained in the previous paragraph, it usually is not feasible to model the entire geological deformation history of a specific structure. In our case study, the first-order geometry of the structural trap is the result of a fault propagation fold of Variscan origin. Such a structure can be geometrically restored to its prefolding geometry. Restored sections can be used to construct new finite element models that can simulate at least part of the geologic history of a structure and, therefore, can produce more reliable predictions on the present-day stress, strain and rock failure patterns within a hydrocarbon reservoir.

The two end-member models represent limiting cases of a series of models in which the friction
along the blind thrust fault in the basement varies. Analyses of similar models with friction on the listric segment of the basement fault to ensure thrust behaviour, indicate only fault activity to occur for friction coefficients of less than 0.4 (equivalent to an angle of internal friction of 20°). For friction coefficients of 0.4 and more the listric part of the thrust fault remains locked, at least during the first 500 m of applied horizontal model shortening, because naturally the fault, or parts of the fault, can still become active under enhanced horizontal compression. When fault activity occurs it varies in space and under increased tectonic loading (through ‘time’). This is illustrated for a friction coefficient of 0.3 in Fig. 12, which displays increments in fault slip along the listric segment of the thrust fault (horizontal axis) and under increased tectonic loading (vertical axis).

Fluid flow and pore pressures, not included in the numerical models, play an important role in the evolution of hydrocarbon reservoirs (e.g. Miller, 1995; Osborne and Swarbrick, 1997). Restricted fluid flow resulting in too much pore fluid in too little space causes overpressures, and because changes in pore pressure also change in situ total stresses, and vice versa, high pore pressures (overpressures) can cause natural hydraulic fractures and keep them open for extended time.

Fig. 12. Fault activity diagram. Every wiggle trace shows slip increment (by wiggle amplitude) as a function of increasing compressional loading (vertical axis). Each trace represents a discrete point (solid dots in Fig. 3) of the listric segment of the blind thrust fault. Trace 1 is for the fault tip, trace 72 is where the thrust fault becomes horizontal. A (static) friction coefficient of 0.3 has been assigned to the listric part of the thrust fault, the horizontal segment remains frictionless to ensure thrust behaviour.
periods. Such fractures may occur in tectonically extensional, neutral, or compressional settings. Because the pore pressure and the in situ total stresses do not vary independently, then whether fractures form, their orientation, and the pore-pressure magnitudes causing the fractures depend on the geological processes that cause overpressure and on the rocks’ mechanical properties.

There are two fundamentally different ways that geologic processes cause overpressures (Miller, 1995): one is pore volume decrease by mechanical loading, and the other is pore-fluid volume decrease that can occur independently of burial depth changes. Compaction disequilibrium and tectonic loading are examples of the first mechanism; Darcy-type inflow and diagenetic reactions are examples of the second mechanism. Other mechanisms, such as aquathermal expansion and porosity reduction via diagenetic cements, are hybrid overpressure source mechanisms. As a rock’s burial depth changes, these mechanisms act simultaneously to change in situ stresses. However, different mechanisms can affect in situ stresses differently, and the total change in the stresses ultimately depends on the relative strength of each mechanism. In our numerical models the only overpressure source mechanism present is tectonically induced lateral compression of the hydrocarbon trap. Pore pressure increase in tectonically compressive settings enhances the change of horizontal fracturing.

A good knowledge of the tectonic history and structural framework of sedimentary basins that contain hydrocarbon reservoirs is essential when predicting tectonic overpressures in such basins. Fractures that open in response to pore pressures that are changing on a geological time scale are stable and will remain open as long as there are no large changes in the geological processes that led to their formation. The effects of tectonic processes are most important in basins that are tectonically active today. Overpressure build-up due to local tectonic processes can be very rapid, and decrease of pressure can be similarly rapid if large volumes of fluid driven by seismic valving or pumping escape up fault planes that rupture seals in pressure cells (Hunt, 1990; Sibson, 1990). Our modeling results show that the finite element method, besides computing in situ stresses and predicting fracture attributes, is also able to predict the position and orientation of faults that cut reservoir layers and affect the integrity of reservoir seals. Therefore, it may also be used to identify potentially overpressured compartments in hydrocarbon reservoirs rapidly.

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