Distribution and mechanisms of overpressure generation and deflation in the late Neoproterozoic to early Cambrian South Oman Salt Basin

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ABSTRACT

Late Neoproterozoic to early Cambrian intra-salt Ara reservoirs of the South Oman Salt Basin represents a unique self-charging petroleum play with respect to hydrocarbon and overpressure generation and dissipation. Reservoir bodies (termed ‘stringers’) are isolated in salt and frequently contain low-permeable dolomites that are characterized by high initial production rates because of hard overpressures. A database of more than 30 wells has been utilized to understand the distribution and generation of overpressures in intra-salt reservoirs that can be separated by up to 350 m of salt. A temporal relationship of increasingly overpressured reservoirs within stratigraphically younger units is observed, and two distinctly independent trends emerge from the Oman dataset; one hydrostatic to slightly above hydrostatic and one overpressured from 17 to 22 kPa m−1, almost at lithostatic pressures. Structural, petrophysical and seismic data analysis suggests that overpressure generation is driven by fast burial of the stringers in salt, with a significant contribution by thermal fluid effects and kerogen conversion. Structural and geometric information indicates that present-day hydrostatic stringers have been overpressured in their earlier geologic evolution. Evidence for these initial overpressures in currently hydrostatic reservoirs is provided by hydrocarbon-veined cores from halite overlying the reservoirs. A proposed pressure deflation mechanism can be related to the complex interplay of salt tectonics and fast deposition of early Cambrian to Ordovician age clastics.

Key words: intrasalt reservoirs, Neoproterozoic to Cambrian South Oman Salt Basin, overpressure generation and deflation

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INTRODUCTION

Overpressures still represent one of the major challenges of modern hydrocarbon exploration because of their impact on safety, prospect risking and ranking, cost-effective drilling and field development strategies. Overpressure in this context refers to the difference between the fluid pressure measured in a stratigraphic unit and the ‘normal’ hydrostatic fluid pressure in the pore structure of this unit. They are encountered in many areas worldwide and have been described frequently in clastic Tertiary delta sequences, from carbonates of the Caspian region and from the North Sea Basin (e.g. Huffman & Bowers 2002). The mechanisms for generating overpressures have been discussed extensively in the literature (e.g. Swarbrick et al. 2002 for review). These include compaction disequilibrium because of rapid sedimentation which is regarded as a major cause of nonhydrostatic pore pressures in low-permeability layers such as shale (Neuzil & Pollock 1983; Audet & McConnell 1992; Luo & Vasseur 1995). Further main mechanisms are attributed to fluid phase changes (kerogen conversion, aquathermal expansion), mineral transformations (e.g. smectite to illite transition) and lateral pressure transmission (Swarbrick et al. 2002).

Each of these mechanisms can produce significant overpressures if the geological conditions are favourable.
However, in order for the fluid pressures to rise, the pressures have to be contained by rocks with sufficiently low permeability. Overpressures are transient and gradually leak away over long periods of time when the generation mechanism ceases to operate. In cases of low-permeable rocks (such as salt and shales), this process may take hundreds of millions of years (Swarbrick et al. 2002).

Many authors have suggested that hydrocarbon generation can lead to fluid overpressure (Barker 1990; Forbes et al. 1992; Luo & Vasseur 1996). Kerogen maturation (‘kerogen to gas’) is still considered by some authors to represent the major contributing factor to deep overpressured basins that statistically are in most cases high-per pressured gas basins (Holm 1998). For calculation of volume increase during kerogen conversion, most studies employed simple fluid state approaches or assumed constant fluid density. To date, there is still no general consensus as to the relative importance of mechanisms chiefly influence pressure development during hydrocarbon maturation (Swarbrick et al. 2002). A more recent approach was presented by Hansom & Lee (2005) who utilized a combination of basin hydrology simulation including temperature and pressure distribution with thermal maturation simulation. The above model uses the Arrhenius kinetic model to simulate conversion processes that result in an increase in fluid volume and overpressures. In their model, the excess pore pressure generated rose by 40% during oil generation and up to 150% during contemporaneous oil and gas (methane) generation. The addition of hydrocarbons, even though they are more compressible than water, will act like as an additional source of fluid and thus increase the fluid pressure. In some instances, such as the North Sea, where undercompaction does not appear to be the single main pressure engine, the presence of a thick regional seal together with hydrocarbon expulsion and cracking may provide a plausible mechanism for generating hard overpressures.

Mineral transformation is another process that can contribute to an early build-up of overpressures. In evaporite settings, this is especially valid for the dewatering of thick gypsum beds to anhydrite (Warren 2006). The depth of transformation varies between a few metres to more than a kilometre, depending on temperature, pressure and pore-water salinities. At larger burial depth, pressure solution contributes to overpressures in carbonates through the generation of porosity-occluding subsurface cements. Stylolization usually affects limestones after a minimum depth of 500 m of burial. Where dolomites are associated with limestones, the former tend to be more resistant to pressure solution.

Calculations of aquathermal effects in sedimentary basins have shown that these are negligible over a wide range of sedimentation rates and associated temperatures in high-pressure basins (Swarbrick et al. 2002). Nevertheless, although aquathermal pressuring is unlikely to be an important pressure generation mechanism, it may be important in some cases. Where reservoir rocks are sealed within near perfect seals early in their burial history, aquathermal effects can generate significant overpressures.

The generation and dissipation mechanisms of overpressures encountered in reservoirs (and source rocks) isolated in salt are to date only known from the North Sea Basin (Permian Zechstein floaters in salt, Williamson et al. 1997) and the Precambrian to Cambrian Ara Formation of Oman which forms part of the South Oman Salt Basin (SOSB). The latter system forms a unique setting in which both reservoirs and source rocks constitute self-charging pressure cells, sealed by salt. Such large rock inclusions encased in salt (so-called rafts, floaters or stringers) are of broad economic interest as they can constitute profitable hydrocarbon reservoirs, but may also represent potential drilling risks because of their hard fluid overpressures (Williamson et al. 1997; Al-Styabi 2005; Schoenherr et al. 2007a, 2008).

The study of such stringer bodies also has strongly influenced our understanding of the internal deformation mechanisms in salt diapirs (Taiot & Jackson 1987, 1989; Talbot & Weinberg 1992). Stringer geometries and associated deformation were extensively studied in surface piercing salt domes (Kent 1979; Jackson et al. 1990; Peters et al. 2003; Reuning et al. 2009), and within mining galleries in structurally shallow levels of various salt diapirs (Richter-Bernburg 1980; Talbot & Jackson 1987; Geluk 1995; Behlau & Mingerzahn 2001). Additionally, recent improvements in seismic imaging now allow the illustration and analysis of large-scale 3D stringer geometries (van Gent et al. 2011; Strozyk et al. in press). All these studies reveal highly complex stringer geometries, such as open to isoclinal folding, shear zones and boudinage over a wide range of scales. These observations give valuable insights into the processes occurring during final diapir evolution. However, most salt structures have undergone a combination of passive, reactive and active phases of salt tectonics (Mohr et al. 2005; Warren 2006; Kukla et al. 2008; Reuning et al. 2009) which complicates the interpretation of their stringer geometries. Moreover, the influence of stringer deformation is of major importance for the understanding of the diagenetic and fluid pressure evolution and hence reservoir properties of such stringer plays (Schoenherr et al. 2008; Reuning et al. 2009).

Here, we use seismic and well data made available by Petroleum Development Oman (PDO) with the objective to present for the first time an evolutionary model for this unique overpressure system. Key questions to be answered were:

(1) Which of the numerous mechanisms of overpressure generation apply to the Neoproterozoic SOSB and to intra-salt carbonate reservoir and source rock sequences in general?
What are the controlling factors for overpressure dissipation in the SOSB?
What are the conditions for pressure deflation and leakage of hydrocarbons into rock salt?

**GEOLOGICAL SETTING**

The SOSB that constitutes the geologically oldest presently known commercial hydrocarbon province worldwide is one of three late Neoproterozoic to early Cambrian subsurface salt basins of the interior Oman. They belong to a belt of restricted evaporitic basins, which span from Oman to Iran (Hormuz Salt) and Pakistan (Salt Range) and further to the East Himalaya (Mattes & Conway Morris 1990; Allen 2007; Reuning et al. 2009). The western margin of the SOSB is formed by the ‘Western Deformation Front’ (Fig. 1), a structurally complex zone with transpressional character (Immerz et al. 2000). The eastern margin is constituted by the so-called ‘Eastern Flank’ (Fig. 1), a structural high (Amthor et al. 2005).

The formation of the SOSB started with the sedimentation of the Huqf Supergroup from the Late Neoproterozoic until the Early Cambrian (approximately 725–530 Ma) on crystalline basement (Gorin et al. 1982). Evaporite sedimentation dominated the Ediacaran to Early Cambrian Ara Group that, together with the siliciclastic Nimr Group, form the uppermost part of the Huqf Supergroup (Fig. 2). Radiometric dating of ash beds brackets the age of the Ara Group in the SOSB between approximately 547 and 540 Ma, encompassing the Precambrian to Cambrian boundary (Amthor et al. 2003; Bowring et al. 2007). In contrast to the underlying Nafun Group, the Ara Group is characterized by tectonic compartmentalization, strong subsidence and an onset of volcanism associated with sedimentation in a retro-arc setting between the subducting margin of eastern Gondwana and the East African Orogen (Allen 2007). During deposition of the Ara Group, the SOSB was subdivided into three N–S trending palaeogeographic domains. The Northern and Southern Carbonate Domains were separated by a deeper stratified basin with a water depth of up to several hundred metres (Mattes & Conway Morris 1990; Amthor et al. 2005). At least six cycles of inter-layered carbonates and evaporites were deposited in the carbonate domains of the SOSB, termed A1 to A6 (Fig. 2) from bottom to top (Al-Siyabi 2005). Increases in salinity led to the depositional succession carbonate-sulphate-halite, which in turn proceeded into the succession halite-sulphate-carbonate during the following brine-level rise and highstand (Mattes & Conway Morris 1990; Schröder et al. 2003, 2005).

These carbonates formed partially isolated platforms that are completely encased by evaporites and hence form the stringers in the salt. The thickness of the Ara Salt varies between 10 and 150 m in the A1 to A4 cycles and can exceed 1000 m in the halokinetically stronger influenced A5 and A6 sequences (Schröder et al. 2003). The sulphate layers encasing the 20–220 m thick carbonate units are up to 20 m thick. Bromine geochemistry of the Ara salt (Schröder et al. 2003; Schoenherr et al. 2008) and marine fossils (Amthor et al. 2003) clearly indicate a seawater source for the Ara evaporites. The gypsum, later replaced by anhydrite, formed in shallow hypersaline salinas (Schröder et al. 2003). The shallow-water carbonate ramp facies consists of grainstones and laminated stromatolites, while the platform margin is formed by stromatolites and thrombolites. The slope facies includes organic-rich laminated dolostones, and the basinal facies is dominated by
Fig. 2. Top: Chronostratigraphic summary and burial history of rock units in the subsurface of the Interior Oman. The geochronology was adopted from Al-Husseini (2010). The lithostratigraphy of the lower Huqf Supergroup was adapted from Allen (2007) and Rieu et al. (2007). The lithostratigraphy of the upper Huqf Supergroup and the Haima Supergroup was adapted from Boserio et al. (1995), Droste (1997), Blood (2001) and Sharland et al. (2001). The lithostratigraphic composite log on the right (not to scale) shows the six carbonate to evaporite sequences of the Ara Group, which are overlain by siliciclastics of the Nimr Group and further by the Mahatta Humaid Group. Sedimentation of the siliciclastics on the mobile evaporite sequence led to strong halokinesis, which ended during sedimentation of the Ghudun Formation (Al-Barwani & McClay 2008). Bottom: Burial graph (modified after Visser 1991) indicates major phases of uplift and subsidence. Note fast burial associated with clastic sedimentation in the Cambrian and Ordovician during the salt-tectonic and postsalt tectonic eras. Grey line represents iso-VRE curve (0.62) for base of oil generation window in this area (after Visser 1991).
sapropelic laminites (Al-Siyabi 2005). During seawater highstands, oil kitchen areas have been formed in the deeper, periodically anaerobic to dysaerobic parts of the basin (mainly slope and basinal mudstones). Density stratification of seawater allowed preservation of a sufficient amount of organic material in the bottom layers (Mattes & Conway Morris 1990). The main reservoir facies of the A4 interval comprises ‘crinkly’ laminites of the outer ramp and stromatolites and thrombolites of the inner ramp (Schröder et al. 2005). The existence of A-norsterane biomarkers unequivocally confirms that the hydrocarbon accumulations originate from within the Ara group (Grosjean et al. 2009). The SOSB stringer play thus represents a unique self-charging and self-contained petroleum system.

Subsequent deposition of continental siliciclastics on the mobile Ara-Salt led to strong salt tectonic movements (Al-Barwani & McClay 2008). Differential loading formed clastic pods and salt diapirs, which led to folding and further fragmentation of the carbonate platforms into isolated stringers floating in the Ara-Salt (Figs 3 and 4). Early stages of halokinesis started already in the early Cambrian with deposition of the siliciclastic Nimr Group, sourced from the uplifted basement high in the Western Deformation Front (Figs 1–4). The main phase of salt tectonic movements continued during the deposition of the lower part of the Haima Supergroup (Mahatta Humaid Group) until salt ridge rise could not keep pace with the massive sedimentation of the early Ordovician Ghudun Formation (Figs 2 and 3). Later

Fig. 3. (A) Un-interpreted seismic line crossing the study area. (B) Interpretation of the seismic line shown in A. The formation of salt pillows and ridges is caused by passive downbuilding of the siliciclastic minibasin (Nimr Group) leading to strong folding and fragmentation of the salt embedded carbonate platforms and the formation of the Ara stringers.
halokinetic movements because of reactivation of basement faults or salt dissolution were of only local importance (Al-Barwani & McClay 2008). Maximum burial depths (temperatures), somewhat higher than the present 3 to >5 km (60–125°C), were reached during Ordovician to early Silurian times (Fig. 3) with a peak in hydrocarbon generation during the early Paleozoic (Visser 1991; Terken et al. 2001; Schoenherr et al. 2007a,b). Fluid properties within the carbonate stringers are highly variable with a wide range in gas/oil ratios and API units (approximately 23°C to 52°C; Grosjean et al. 2009). Catogenesis likely was retarded by the relatively low geothermal gradient of about 20°C km⁻¹ in salt basin and the very high overpressures in some of the stringers (Al-Siyabi 2005; Schoenherr et al. 2007a,b, 2008). The carbonate stringers have undergone intense diagenetic modifications with locally extensive cementation by halite and solid bitumen (Al-Siyabi 2005; Schoenherr et al. 2008). Pore lining and filling solid bitumen is a common diagenetic phase that represents one of the greatest risks for hydrocarbon exploration in the area (Al-Siyabi 2005; Schoenherr et al. 2007a,b, 2008).

Overpressures in the South Oman Salt Basin

Pore pressure data analysis

It has been shown in other parts of the world, especially the North Sea Basin, that careful data analysis and quality control of pressure and leak-off data is an important first step for studying the pressure generation mechanisms within a basin (Gaarenstroom et al. 1992; Bloch et al. 1993).

To date, more than 70 wells drilled by PDO have penetrated evaporite and intrasalt carbonate sequences in the SOSB. For the purpose of this study, data from the main producing stringer intervals A1 to A4 have been rigorously checked for test type and test quality. The final database that was utilized for further analysis and interpretations consequently only included valid data from Repeat Formation Tester (RFT) and production test tools. Individual tests have been screened using field test reports.

‘Brine correction’, which takes into consideration the additional (capillary) pressures produced by the hydrocarbon fill of a reservoir, is in many basins essential for providing a common reference pressure to correlate and to interpret pore pressures and aquifer continuity on a basin scale. This correction was carried out for selected wells to assess the magnitude of pressure difference. Depending on the hydrocarbon column and geometry of the trap, additional pressures calculated at top reservoir range between 164 and 533 kPa which can be neglected given the overall pressure magnitudes and depths.

The data plots provided in Fig. 5 clearly show two formation pressure ‘populations’:

1. One at near hydrostatic pressures with a mean pore-pressure coefficient λ = 0.49.
2. One at near-lithostatic pressures with a mean pore-pressure coefficient λ = 0.87. Gradients range from 17 kPa m⁻¹ to a maximum of 22.0 kPa m⁻¹.

One field shows a gradient of 12.8 kPa m⁻¹ (see Discussion below).

Comparison of the data on a well to well basis and on common trends or structures suggests a large degree of compartmentalization of the respective reservoirs across most fields. This is interpreted from a lack of common hydrostatic gradients and hydrocarbon contacts. There are cases however where data suggest communication between hydrostatic reservoir intervals while overpressured reservoirs are isolated (Fig. 4).

Leak-off pressure data analysis and prediction

In general, the relationship between the vertical and minimum horizontal stresses, and the failure envelope of a rock type as a function of depth, is a method for establishing the conditions under which a trap will fail as a function of increasing fluid pressure. The commonly performed leak-off tests, usually carried out at casing shoe to estimate the formation strength, provide the most readily available data to assess formation strength. Leak-off pressure (LOP) measurements can be shown to be greater than the minimum principal stress.

Because of the unknown tensile strength of the rocks and the inherent measurement errors, LOP measurements are not a good measure of the minimum principal stress by
themselves. However, if quality controlled LOP data are plotted together with RFT data from a regional dataset in an overpressured area (Gaarenstroom et al. 1992), then a pattern such as shown in Fig. 5 can be observed.

The LOP data from 17 SOSB wells (Fig. 5) show a distribution in which 60% of the data plot at 22–23 kPa m\(^{-1}\) (Median 22.5) and 40% of the data plot at 23–25 kPa m\(^{-1}\) (Median 24.7). The mean value of all data is 23.5 kPa m\(^{-1}\).

Only tests that could clearly be identified as ‘leak-off’ and not ‘limit tests’ have been included in the database and pressure/depth graphs.

Note that there is little overlap between the RFT and LOP data suggesting that the lower bound of the LOP data defines the maximum fluid pressure that the rock can hold. Indeed, in highly overpressured terrains, leaky traps correspond to those with fluid pressures which lie on this lower bound of the LOP data. Failure by hydraulic fracturing would be expected to occur when the fluid pressure (\(P_f\)) exceeds the sum of the minimum principal stress (\(\sigma_3\)) and the tensile strength of the rock. The minimum horizontal stress envelope, encompassing minimum LOP data and maximum RFT data, has a gradient of 22 kPa m\(^{-1}\) in the SOSB (Fig. 5).

Overburden stress has been carefully calculated using average formation densities determined from density logs. Combining this with measurements of differential stress from subgrain size piezometry shows that the minimum and maximum principal stress in the salt surrounding the stringers is within the thick line drawn in Fig. 5 (little is known of the orientations of the principal stress in salt).

Overpressures and structure
In considering the evolution of overpressured basins, the role of tectonics cannot be overemphasized. Especially in large salt basins like the SOSB or the North German Basin, a complex structural evolution can only be handled by linking palinspastic restoration with multi-dimensional basin modelling (Mohr et al. 2005; Kukla et al. 2008).

Considering structuration, it is important to note that all A3-aged stringers drilled so far in the SOSB have been overpressured with only one exception in the northern part of the licensed cluster. In contrast, A2-aged reservoirs have been encountered both overpressured and hydropressured (Figs 4 and 6) where hydropressured wells occur in the central basin and a strongly overpressured domain occurs further south (Figs 4 and 6).

Based on the available map database, a regional 3D overview of the respective stringer intervals, shown in Figs 4 and 6, confirms their heterogeneous size and distribution. A2 shows a separation in one exploration cluster comprising a connected central/northern area with hydropressured wells and a southern area with disconnected A2 ‘rafts’. These show different magnitudes of overpressures which suggest that they represent individual pressure cells. The large siliciclastic pod (Nimr to Mahatta Humaid Group)
on A2 level represents a striking feature in this area (Figs 3, 4 and 6). Regionally less widespread are A3 stringers in the south of this minibasin.

A more detailed 3D-analysis of the areas characterized by hydropressed and overpressed stringer domains revealed that large structural boundaries separate the northern hydropressed A2 domain from the southern overpressed domain between which pressure differentials of up to 12 kPa m$^{-1}$ can be maintained (Fig. 6).

The hydropressed stringers close to the centre of the siliciclastic minibasins are structurally highly segmented (Figs 4 and 6). A strong influence of minibasin formation on stringer breakage was also predicted by finite-element modelling (Li et al. in press). Seismic sections show that stringers underneath the clastic pods nearly touch the flanks of the minibasins (Fig. 4). As a consequence, pressures and hydrocarbons could have bled off into the overlying formations of the Haima Supergroup (Fig. 2) during the early structural evolution.

Pressures and the sealing capacity of rock salt

It has been an observation in the SOSB since about 15 years that retrieved salt cores were occasionally stained black (Fig. 7). In some cases, up to 10 m of vertical salt core section contained hydrocarbons mostly above stringer intervals (Schoenherr et al. 2007a). Petrographic and fluid inclusion analysis confirmed that halite samples contain bands with μm-sized fluid inclusions, which alternate with thin fluid inclusion-free bands. Hydrocarbon-impregnated microcracks are frequently filled with solid bitumen (Fig. 8), and samples also contain fluid inclusion trails with oil inclusions and gas bubbles. Microstructural analysis further shows evidence for crystal plastic deformation and dynamic recrystallization (Schoenherr et al. 2007a). Subgrain-size piezometry following the method of Schléder & Urai (2005) indicates a maximum differential paleostress of <2 MPa (Schoenherr et al. 2007a) in rock salt adjacent to carbonate stringers. The experimentally derived dilatancy criterion by Popp et al. (2001) indicates that at a differential stress of <2 MPa, rock salt can dilate only at near-zero effective stresses (Fig. 7). This is only possible at great depth when fluid pressure in the rock salt is very close to the minimum principal stress $\sigma_3$.

A model for the pore-fluid connectivity in the deeply buried SOSB has been proposed by Schoenherr et al. (2007a), based on the results of Lewis & Holness (1996), who measured the equilibrium water-halite dihedral angles at grain boundary triple junctions in experiments. If the dihedral angle is higher than 60°, small amounts of pore fluids in the halite are distributed in micrometre-sized isolated fluid inclusions, and the permeability is reduced to zero. At temperatures and pressures corresponding to a depth of approximately 3 km in a ‘normal’ geothermal gradient, the dihedral angle decreases to 60° and below, leading to a redistribution of the pore fluid into a thermodynamically stable three-dimensional network of
connected, fluid-filled, channels at grain boundary triple junctions (Fig. 8). If halite contains several per cent of brine in connected triple-junction tubes, and this brine is at pressures less than lithostatic, halite should compact and expel some of the brine, thereby decreasing its permeabil-

ity. This will lead to an interconnected, brine-filled porosity along the triple junction tubes with a near-lithostatic fluid pressure.

**DISCUSSION**

The data presented above can be integrated to represent a model for the burial, pressure conditions (and hence fluid movement) and ultimately the sealing potential of rock salt embedded with a unique self-charging carbonate source rock and reservoir petroleum system in the deep subsurface of southern Oman.

Figure 9 displays our preferred model for the burial and fluid pressure path of an Ara formation reservoir stringer. Compaction and cementation leads to nearly zero porosity in rock salt below a burial depth of 30 m (Casas & Lowenstein 1989), marking the change from diagenetic open to closed system conditions in the underlying carbonate platform. The isolation of the stringer sequence leads to an increase of fluid pressures by a disequilibrium compaction mechanism. Salt-sealed overpressured intervals can be as shallow as a few hundreds of metres below the surface because of the salt’s very low permeability (Hunt 1990). The pressure boundaries between a salt seal and a reservoir beneath can be very abrupt, which represents a potential operational risk when drilling through laterally constrained ‘stringers’ or ‘rafts’ of overpressured anhydrite and dolomite enclosed in halokinetic salt. Compaction of the encased stringers is increased because of the higher mean stress than in a salt-free sequence because of the very high principal stress. However, compared to mud-rich siliciclastic systems, the effects of disequilibrium compaction are reduced because of the very early onset of cementation in carbonates, e.g.,
during reflux dolomitisation. This will lead to a rapid development of close to lithostatic pressures in the stringers, constrained by the minimum stress in the salt indicated in the diagram.

At a certain point in time, the hydrocarbon generation window will have been reached, and an additional contribution of pressure generated by this mechanism will further add to the overpressure magnitude as modelled by Hansom & Lee (2005). The oil pressure in the carbonate reservoirs increases until it is equal to the fluid pressure in the interconnected porosity of the Ara Salt plus the capillary entry pressure (Figs 8 and 9).

In our model, the oil pressure in the stringers slightly exceeded the minimum principal stress in the salt (near lithostatic fluid pressure) at some stage in the geologic evolution. During this process, the oil pressure is high enough to open the grain boundaries and to displace the brine in the pore throats of the salt, causing a diffuse dilatancy. Most likely, this violation of the minimum stress criterion marks the ultimate sealing capacity of halite in the deep subsurface whereby its permeability increases by orders of magnitude (Popp & Minkley 2010). It is important to note that the sealing capacity is regained, if the fluid pressure drops below the minimum principal stress, at which point rock salt will re-seal to maintain the fluid pressure close to lithostatic values (Fig. 9).

Hydrocarbon-impregnated black rock salt in and adjacent to hydrostatic and overpressured reservoirs hence shows that it has repeatedly lost and then regained its sealing capacity. It also confirms that currently hydrostatic reservoirs have been overpressured in the past. The black staining is caused by intragranular microcracks and grain boundaries filled with solid bitumen formed by the alteration of oil (Fig. 8).

In triaxial deformation experiments of Lux (2005), rock salt became permeable by the formation of grain boundary cracks at low rates of fluid-pressure increase. If the fluid pressure \( P_f \) is increased rapidly to a sufficiently high excess...

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**Fig. 9.** Schematic figure illustrating mechanisms of overpressure generation and pressure deflation in the Ara Stringers. The hydrostatic pressured stringers become overpressured as soon as the stringers are sealed by impermeable salt. Hydrocarbon generation inside the self-charging stringers causes an additional fluid pressure increase. If the overpressured stringers come in contact with a siliciclastic minibasin, they will deflate and return to hydrostatic pressures (A). When the connection between the minibasin and the stringers is lost, they regain overpressures because of further oil generation and burial (A'). If hydrocarbon generation in undeflated stringers stops relatively early, the fluid pressures do not reach lithostatic pressures (B). If hydrocarbon generation continues, the fluid pressures exceed the lithostatic pressure (red star), leading to dilation and oil expulsion into the rock salt (C, D and E). A stringer enclosed by black-stained salt below the lithostatic gradient likely indicates a later deflation event causing either a complete (C) or partial (E) loss of overpressures. Alternatively, stringers at overpressures but below the lithostatic gradient (E) might be explained by regional cooling or some other hitherto unexplained mechanism.
pressure \((P_f > s3)\), rock salt leaks by hydrofracturing. Peach & Spiers (1996) proposed that this process could also occur under low effective stress during natural deformation of rock salt at great depth and high pore-fluid pressures. Based on our observations and calculations, we infer that the oil pressure did not rise to significantly higher values because this would have generated discrete hydrofractures which to date have not been observed in the SOSB instead of features interpreted to be caused by diffuse dilation.

Two other mechanisms that likely contributed to the observed overpressures are gypsum dewatering and hydrothermal processes. Petrographic evidence indicates that anhydrite largely replaced primary gypsum in the Ara succession (Schröder et al. 2003). The anhydrite layers encasing the 20–220 m thick carbonate units are up to 20 m thick. Dewatering of gypsum to anhydrite is accompanied by the release of approximately 60% water per unit volume gypsum (Hardie 1967). In the presence of highly saline porewater, anhydrite to gypsum transformation can start at burial depth of a few metres and is completed at less than approximately 125 m depth (Bäuerle et al. 2000). A significant fraction of the generated water hence might have escaped before the stringers were completely sealed by salt. The contribution to overpressure generation therefore remains difficult to quantify.

A hydrothermal influence is indicated for at least one of the Ara stringers by extremely high bitumen reflectance values, which point to maximum paleo-temperatures of more than 100°C above the maximum burial temperatures (Schoenherr et al. 2007b). The influx of hydrothermal fluids into the carbonate stringers is considered a possible contribution to the overpressures (Schoenherr et al. 2007b), but might have been of only local importance.

The observed 3D geometrical distribution of the two pressure domains suggests that the siliciclastic minibasins may have acted as a pressure valve at some point in time during sedimentary downbuilding into the salt (Fig. 9). The duration of the deflation event would have been restricted in time, but both timing and duration cannot be constrained at present. The geometrical position of the individual stringer bodies in relation to the clastic sequences thus determines the pressure history through time. In one of the hydrocarbon fields mentioned above, an intermediate pressure gradient of 12.8 kPa m\(^{-1}\) has been observed. Separate hydrocarbon phases and pressure gradients in up-dip fields suggest that the stringer sequence is currently disconnected. Structural modelling indicates however that these have been connected in the past (Li et al., in press) and that deflation has occurred during connection with the minibasins. Subsequent movement of the stringer has led to breakage, re-sealing and re-pressuring of the stringer. Present-day intermediate overpressures thus reflect the additional pressure re-charged by kerogen maturation since the leakage event (Fig. 9).

The pressure data from fields being very close to the minimum principal stress in the surrounding salt suggest that these reservoirs are at present leaking fluids into the surrounding salt or are very close to doing so. However, the pressure data of many other overpressured fields are up to 5 MPa below the minimum principal stress in the surrounding salt and therefore at pressure significantly below leaking (Fig. 5). If we assume that these have all leaked at one point in the past, the deflation to the present-day pressures is puzzling. It may be explained by regional cooling or some other hitherto unexplained mechanism (Fig. 9).

**CONCLUSIONS**

1. The Late Neoproterozoic to early Cambrian SOSB contains a unique self-charging system with respect to hydrocarbon and overpressure generation and dissipation. Reservoir intervals of low-permeable dolomites and anhydrites frequently contain hard overpressures and are fully enclosed in large Ara salt diapirs. The vertical and lateral distribution of pressure and hence reservoir compartmentalization could be quantified based on a quality-controlled unique dataset comprising structural, petrophysical and seismic data.

2. Pressure generation and deflation mechanisms are controlled by salt tectonic, microstructural (grain boundary network) and thermo-kinetic (burial and kerogen conversion) constraints and parameters.

3. The sequence of events includes initially fast burial and early overpressure generation by disequilibrium compaction, thermal fluid effects and kerogen conversion. Pyrobitumen confirms local contribution by a high-temperature hydrothermal event.

4. Pressure deflation responsible for presently hydro pressured reservoirs is conceivable by structural configurations to adjacent clastic minibasins or by further isolation and fluid injection into surrounding rock salt once minimum principal stress levels have been reached to dilate the salt. This is witnessed by black, hydrocarbon-stained cores of Ara salt directly above and below some of the stringer reservoirs.

5. The processes revealed in this study are considered significant for other evaporite basins.

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REFERENCES


Overpressure generation and deflation

361


CONTENTS

343 Geologically driven pore fluid pressure models and their implications for petroleum exploration. Introduction to thematic set
S. O’Connor, R. Swarbrick and R. Lahann

349 Distribution and mechanisms of overpressure generation and deflation in the late Neoproterozoic to early Cambrian South Oman Salt Basin
P.A. Kukla, L. Reuning, S. Becker, J.L. Urai and J. Schoenherr

362 Overpressure generation by load transfer following shale framework weakening due to smectite diagenesis
R.W. Lahann and R.E. Swarbrick

376 Velocity modeling workflows for sub-salt geopressure prediction: a case study from the Lower Tertiary trend, Gulf of Mexico
J. Taylor, T. Fishburn, O. Djordjevic and R. Sullivan

388 Integrating a hydrodynamically-titled OWC and a salt-withdrawal depositional model to explore the Ula Trend
S. O’Connor, H. Rasmussen, R. Swarbrick and J. Wood