Optimising development and production of naturally fractured reservoirs using a large empirical dataset

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Abstract: Naturally fractured reservoirs are important contributors to global petroleum reserves and production. Existing classification schemes for fractured reservoirs do not adequately differentiate between certain types of fractured reservoirs, leading to difficulty in understanding fundamental controls on reservoir performance and recovery efficiency. Three hundred naturally fractured reservoirs were examined to define a new classification scheme that is independent of the type of fracturing and describes fundamentally different matrix types, rock properties, fluid storage and flow characteristics.

This study categorises fractured reservoirs in three groups: (1) Type 1: characterized by a tight matrix where fractures and solution-enhanced fracture porosity provide both storage capacity and fluid-flow pathways; (2) Type 2: characterized by a macroporous matrix which provides the primary storage capacity where fractures and solution-enhanced fracture porosity provide essential fluid-flow pathways; and (3) Type 3: characterized by a microporous matrix which provides all storage capacity where fractures only provide essential fluid-flow pathways. Differentiation is made between controls imparted by inherent natural conditions, such as rock and fluid properties and natural drive mechanisms, and human controls, such as choice of development scheme and reservoir management practices.

The classification scheme presented here is based on reservoir and production characteristics of naturally fractured reservoirs and represents a refinement of existing schemes. This refinement allows accurate comparisons to be made between analogous fractured reservoirs, and trends and outliers in reservoir performance to be identified. Case histories provided herein demonstrate the practical application of this new classification scheme and the benefits that arise when applying it to the understanding of naturally fractured reservoirs.

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Naturally fractured petroleum reservoirs, although generally less common and more poorly understood than conventional reservoirs, are very important contributors to world oil and gas reserves and production (Aguilera 1983, 1995). Naturally fractured reservoirs (herein referred to as ‘fractured reservoirs’) are often perceived as short-lived with high flow rates, and suffering from rapid production declines, early gas or water breakthrough and low ultimate recovery factors (Nelson 1985). Consequently, due to this perception, reservoir engineers often look unfavorably on fractured reservoirs since recovery techniques must be judiciously applied to avoid production problems. These perceptions are associated with increased cost and risk of developing a fractured reservoir.

Many of these perceptions derive from negative experiences associated with the historical development of fractured reservoirs. When appropriate modern development methods are applied, ultimate recovery factors from fractured reservoirs can compare favorably with conventional reservoirs (Allan and Sun 2003). Many historical development and production problems in fractured reservoirs stemmed from poor understanding of the inherent fracture-matrix dual-porosity system (van Golf-Racht 1982). This was often compounded by the lack of an objective, consistent and empirical-based classification scheme which made accurate characterization and analysis of the reservoir difficult (Spence et al. 2014).

The first widely used fractured reservoir classification was presented by McNaughton and Garb (1975) who defined three types of fractured reservoirs: (A) reservoirs with the great majority of their storage capacity in the rock matrix; (B) reservoirs with their storage capacity split between fractures and matrix; and (C) reservoirs with their storage capacity entirely within the fractures. Aguilera (1983) divided Type B reservoirs into two subcategories: Type B-I and Type B-II. Type B-I reservoirs have low matrix porosity but sufficient matrix permeability to allow oil trapped in matrix blocks to be effectively produced. Type B-II reservoirs have low matrix porosity and permeability. Although matrix blocks may be oil saturated, their permeability is too low to provide effective delivery to the fractures.

This classification scheme was subsequently modified by Nelson (2001) who defined four fractured reservoir types. Type I reservoirs, in which fractures provide both essential storage capacity and permeability, and which commonly suffer from rapid production decline and early water encroachment. Type II reservoirs, in which the rock matrix provides essential storage capacity and fractures provide essential permeability. Type II reservoirs are defined as exhibiting poor recovery when matrix permeability is low because matrix permeability does not deliver oil to the fracture network efficiently. When these types of reservoir are produced at too high a rate, the fractures drain quickly with no oil contribution from the matrix, and water encroachment may halt production. Conversely, with higher matrix permeability Type II reservoirs can make excellent producers since the matrix can adequately supply the fracture network. In Type III reservoirs, fractures contribute additional permeability to reservoirs that are already economically producible. Type III reservoirs are often produced as ‘conventional’ (i.e. non-fractured) reservoirs when the importance of the fracture network is not recognized. Type IV reservoirs, in which fractures do not provide significant additional storage capacity or permeability but only create permeability anisotropy, are often highly compartmentalized. When flow predictions from standard core or log analyses do not match reservoir performance, cemented fractures probably act in the capacity of flow barriers.
While Nelson’s classification has been widely adopted and utilized at a conceptual level, it has several limitations that make practical application of the scheme difficult:

(1) Nelson’s classification is focused on the type of fracturing in terms of its storage capacity and role as fluid conduits (open fracture) or flow barriers (closed fractures) rather than the reservoir as a whole, and thus does not account for other intrinsic matrix properties that often have a large impact on reservoir performance.

(2) Distinguishing between Type II and III requires a subjective determination of ‘economically producible’. This is often difficult to make; and can be subjective as one person’s ‘economic’ is unlikely to be another’s.

Limitations of the existing schemes make comparison of production performance between fields difficult when large data sets are used. While the basis for Nelson’s classification is the relative contribution of matrix and fractures to the total fluid production, we posit that the matrix properties define the various fractured reservoir types. Owing to the lack of an objective and consistent definition of matrix properties, identifying the correct analogues using Nelson’s classification can be difficult, particularly for Type II and Type III fractured reservoirs. For many reservoirs, there is significant overlap in these categorizations and indeed, different zones or areas of a single reservoir may fit into different classifications.

The objective of this study is to create a classification scheme that is practical for the optimization of development and production of fractured reservoirs by accurately describing their reservoir and production characteristics. These characteristics include the rock matrix properties, such as lithology, diagenesis and pore type, and the performance of fractures as fluid conduits. This classification also describes the effects on reservoir performance and recovery efficiency of intrinsic reservoir and fluid properties and natural drive mechanisms, v. the extrinsic choice of development schemes and reservoir management practices. This new classification scheme is tested against case histories with both low- and high-side outcomes of various development methods and reservoir management techniques.

Methodology

The data used in this study is a proprietary compilation of 310 global fractured reservoirs compiled from peer-reviewed scientific literature and represents continuing research on global trends in fractured reservoirs that began in the 1990s (Fig. 1). Crucially, the information used to compile this fractured reservoir knowledge base has been consistently standardized and parameterized into c. 450 variables for each reservoir, including reservoir and fluid properties, drive mechanism, resources and recovery, well rate and EUR, development scheme and production performance at both reservoir and well level (Sun et al. 2021). This allows consistent and appropriate comparisons to be made on an equal basis between fractured reservoirs.

The 310 fractured reservoirs examined in this study have combined recoverable reserves of 230 BBOE. For those fields where ultimate recovery can be reliably determined, ultimate recovery factors can be said to range 7–65% with a mean average of 33% (Fig. 2). Initial well rates range from 100 to 8000 BOPD (mean average 3700 BOPD) and well EUR ranges from 0.32 to 15 MMBO (mean average 8 MMBO). As most fractured reservoirs have relatively low primary recovery factors, Improved Oil Recovery (IOR) and Enhanced Oil Recovery (EOR) techniques are widely employed within this dataset as a means to improve recovery efficiency, but the results are highly variable with both low- and high-side outcomes occurring (Fig. 3). This dataset therefore covers a broad spectrum of available data on fractured reservoirs and is taken to be representative of both the natural variability inherent to these reservoirs, and of the variability of outcomes when IOR and EOR methods are applied.

To understand the production behaviour of fractured reservoirs, a fractured reservoir in this study is defined as one whose permeability is enhanced by the presence of naturally occurring fractures. Fractured reservoirs are herein classified as:

(1) Type 1: characterized by a tight matrix where fractures and solution-enhanced fracture porosity provide both storage capacity and fluid-flow pathways;

(2) Type 2: characterized by a macroporous matrix (>20 µm pore size) which provides the primary storage capacity where fractures and solution-enhanced fracture porosity provide essential fluid-flow pathways; and

(3) Type 3: characterized by a microporous matrix (<20 µm pore size) which provides all storage capacity where fractures only provide essential fluid-flow pathways.

Fig. 1. Map of the world showing location of the 310 fractured reservoirs analyzed in this study.
Key characteristics of each Type are given in Table 1. This classification is based on the characteristics of the rock matrix and is not defined by the type or characteristics of fracturing, as in some widely adopted classifications (Stearns and Friedman 1972; Nelson 2001), but is representative of the reservoir as a whole; comprising rock properties (lithology and diagenesis), fluid storage (matrix pore type and porosity value) and flow characteristics (matrix and fracture permeability).

The fractured reservoir classification described here has some overlap with McNaughton and Garb (1975) and Nelson (2001), but it differs in its greater simplicity, objectivity and practicality (Table 2). This scheme lacks a reliance on arbitrary porosity-permeability cut-offs and focuses on fractures as fluid conduits rather than flow barriers. Additionally, this classification scheme incorporates element of diagenetic modification into the rock matrix, such as karstification and hydrothermal dissolution, that are not described by other schemes.

Type 1 from this scheme is comparable to Type C of McNaughton and Garb and Type I of Nelson. Type 2 represents a broad spectrum of macroporous reservoirs with low to moderate matrix porosities and generally low permeabilities, including Types A and B of McNaughton and Garb, and Type II and Type III of Nelson. Type 3, as described here, has little overlap with the existing schemes. It represents reservoirs that have been made ‘economically viable’ using water-flooding and horizontal drilling technology to improve oil recovery in low permeability microporous reservoirs. As this classification scheme focuses on reservoir and production characteristics of naturally fractured reservoirs, rather than focusing on the type of fracturing, Nelson’s Type IV is not relevant since cemented fractures do not enhance the permeability of the reservoir.

Type 1 fractured reservoirs

Type 1 fractured reservoirs include any rock type where the matrix is tight. Fractures and solution-enhanced fracture porosity provide both storage capacity and fluid-flow pathways. Karstification and hydrothermal dissolution are common diagenetic processes and serve to enlarge pre-existing fracture networks and create cavernous, channel and breccia porosity. Fracture networks are generally extensive, consisting of both small-scale microfractures and larger-scale joints (Belaidi et al. 2016).

Forty-four reservoirs have been characterized as Type 1 by this study, representing about 14% of the total population. Fracture porosity ranges from 0.3–3.5% with an average of 1.4% and bulk porosity ranges from 0.8–5.8% with an average of 3.2%. Bulk porosity is herein defined as the average total porosity of all porosity types: fractures, solution-enhanced fracture porosity and karstic porosity. Well test...
permeability which reflects fracture density and connectivity, and flow capacity averages 184 mD with a maximum of 3700 mD.

The most prominent aspect of Type 1 fractured reservoirs is a lack of matrix contribution to the total reserves and production. Bulk porosity used for volumetric calculation is more accurately obtained through mass balance determination. Reservoir performance and recovery efficiency depend to a large extent upon distribution of fracture networks and how microfractures, joints and faults interact. Type 1 fractured reservoirs are very sensitive to production rates, and hence require bespoke development schemes and reservoir management practices to achieve an optimal recovery.

Production characteristics

Production characteristics of Type 1 fractured reservoirs are primarily controlled by lithology, size of the reservoir and natural drive mechanism. Type 1 fractured basement reservoirs are largely disconnected from regional aquifers and consequently have a relatively weak natural drive dominated by solution gas (Table 3). This is reflected by these reservoirs only experiencing limited water production from perched aquifers, which are the main source of formation water production prior to water injection (Dang et al. 2011). Ultimate recovery factor ranges 23–39% and there is a positive correlation between ultimate recovery factor and oil column height (Fig. 4). Large reservoirs with thick oil columns that are completed for production significantly above the oil-water contact are characterized by steady pressure decline and uniform rise in oil-water contact throughout production. These reservoirs can support relatively high flow rates without water coning, and hence recover more oil before water breakthrough occurs (e.g. Bach Ho Field, Vietnam, and La Paz Field, Venezuela). Type 1 solution-gas drive basement reservoirs are very susceptible to rapid rise in gas-oil ratio (GOR), which if not addressed can severely limit oil recovery (e.g. Zeit Bay Field, offshore Egypt).

In contrast to Type 1 fractured basement reservoirs, Type 1 fractured carbonate reservoirs are generally well connected with regional aquifers, and hence more prone to water incursion since all oil is stored in fractures. High production rate, and therefore drawdown, during early production of a reservoir almost always leads to precipitous pressure decline and water incursion, swiftly followed by rapid production decline as high water-cut wells are shut-in. Owing to these challenges in managing water production, ultimate recovery factors range 13–55% (Table 3), reflecting differing quality of reservoir management practice. Higher ultimate recovery (>40%) is commonly associated with smaller aquifer-drive reservoirs (e.g. Amposta Marino Field, Spain, and Nagylengyel Field, Hungary) or larger solution-gas drive reservoirs (e.g. La Paz Field in Venezuela). Smaller aquifer-drive reservoirs are typically easier to manage and control water-cut, and larger solution gas reservoirs have more energy to control production in a manageable way. Optimization of production rates is essential to realize higher ultimate recoveries. Lower ultimate recovery (20% and less) results from higher viscosities (e.g. Gela and Rospo Mare fields, Italy) or excessively high production rates and early water breakthrough (e.g. Luebe Field, China, and Emma Field, USA) where early cessation of production occurs.

Within the population of studied Type 1 fractured reservoirs, water injection is widely utilized to maintain reservoir pressure above the bubble point for both basement and carbonate reservoirs (Table 3). If production and injection rates are carefully balanced

Table 1. Fractured reservoir classification into Type 1, Type 2 and Type 3 with characteristics, lithology, matrix and fracture properties and range of ultimate recovery factors

| Classification | Characteristics | Lithology | Matrix Properties | Fracture Properties | Ultimate Oil Recovery Factor |
|----------------|-----------------|-----------|------------------|---------------------|-----------------------------|
| Type 1         | Tight matrix: fractures and solution-enhanced fracture porosity provide both storage capacity and fluid-flow pathways | Basement, dolomite and limestone | Negligible matrix porosity and permeability | Bulk porosity range from 0.8–5.8% (average 3.2%); well test permeability average 184 mD (maximum 3700 mD) | Range from 13–55% (average 31%) |
| Type 2         | Macroporous matrix provides the primary storage capacity while fractures and solution-enhanced fracture porosity provide essential fluid-flow pathways | Limestone, dolomite, sandstone and volcanics | Porosity range from 4–20% (average 11%); air permeability average 5 mD (maximum 100 mD) | Fracture porosity range from 0.1–1.5% (average 0.95%); well test permeability average 103 mD (maximum 3280 mD) | Range from 7–65% (average 35%) |
| Type 3         | Microporous matrix provides all storage capacity while fractures only provide essential fluid-flow pathways | Chalk, chalky limestone, diatomite, chert and siltstone | Porosity range from 5 to 34% (average 20%); air permeability average 2 mD (maximum 5 mD) | Fracture porosity range from 0.1–2% (average 0.9%); well test permeability average 62 mD (maximum 1800 mD) | Range from 8–57% (average 30%) |

Table 2. Comparison in fractured reservoir classification among McNaughton and Garb (1975), Nelson (2001) and this study

| McNaughton and Garb (1975) | Nelson (2001) | This Study |
|-----------------------------|---------------|------------|
| Type C - storage capacity entirely within fractures | Type I - fractures provide both essential storage capacity and permeability | Type 1 - tight matrix: fractures and solution-enhanced fracture porosity provide both storage capacity and fluid-flow pathways |
| Type B - storage capacity split between fractures and matrix | Type II - rock matrix provides essential storage capacity and fractures provide essential permeability | Type 2 - macroporous matrix provides the primary storage capacity while fractures and solution-enhanced fracture porosity provide essential fluid-flow pathways |
| Type A - great majority of storage capacity in the rock matrix | Type III - fractures provide permeability assistance to reservoirs that are already economically producible | Type 3 - microporous matrix provides all storage capacity while fractures only provide essential fluid-flow pathways |
| Not included in the classification | Included in Type 2 of this classification | Not included in the classification |
| Not included in the classification | | |
Table 3. List of 16 type-examples for Type 1 fractured oil reservoirs. These are chosen based on availability of high-quality data and as representative of key characteristics of this Type. Field name, reservoir unit, country, hydrocarbon column height, lithology, bulk porosity, well test permeability, viscosity, drive mechanism, secondary recovery/EOR method, STOIIP and ultimate recovery factor are given for each reservoir.

| Field Name       | Reservoir Unit                  | Country     | HC Column Height (ft) | Lithology          | Bulk Porosity (%) | Well Test Permeability (mD) | Viscosity (cP) | Drive Mechanism                  | Secondary Recovery/EOR Method | STOIIP (MMBO) | Ultimate RF (%) |
|------------------|---------------------------------|-------------|-----------------------|--------------------|-------------------|--------------------------|----------------|-------------------------------|--------------------------------|----------------|-----------------|
| Amposta          | Montsia                         | Spain       | 636                   | Limestone          | 1.8               | NA                       | 6.15           | Aquifer                       | None                           | 110            | 51              |
| Augila Nafoora   | Basement (Main Block)           | Libya       | 1550                  | Basement           | NA                | NA                       | 1.92           | Aquifer/solution gas           | Water injection                 | 5170           | 29              |
| Bach Ho          | Basement                        | Vietnam     | 6443                  | Basement           | 2.5               | 43                       | 0.43           | Solution gas                  | Water injection                 | 4772           | 35              |
| Dongshengpu      | Anshan                          | China       | 1575                  | Basement           | 3.81              | 80                       | 5.34           | No significant drive           | Water injection                 | 110            | 38              |
| Emma             | Ellenburger                     | USA         | 450                   | Dolomite           | NA                | 54                       | 0.5            | Aquifer/solution gas           | None                           | 230            | 20              |
| Gela             | Taormina                        | Italy       | 1378                  | Dolomite           | 4                 | NA                       | 85             | Aquifer                       | None                           | 1305           | 13              |
| La Paz           | Basement                        | Venezuela   | 6000                  | Basement           | 1.6               | 1.9                      | 6.6            | Solution gas                  | None                           | 843            | 39              |
| Liubei           | Wumishan                        | China       | 820                   | Dolomite           | 2.7               | 2.1                      | 6.6            | Solution gas                  | None                           | 1590           | 44              |
| Meyal            | Chorgali-Sakesar                | Pakistan    | 1149                  | Dolomitic limestone | NA                | NA                       | 2.9            | Aquifer                       | Water injection                 | 60             | 41              |
| Nagy lengyel     | Ugod-Main Dolomite (Blocks I-Iv) | Hungary     | 1115                  | Limestone/dolomite | 1.5               | 3800                     | 19             | Aquifer                       | CO₂ immiscible injection        | 103            | 55              |
| Rospo Mare       | Cupello                         | Italy       | 492                   | Limestone          | 1.2               | 50 000                   | 250            | Aquifer                       | None                           | 540            | 17              |
| Wangzhuan        | Taishan                         | China       | 666                   | Basement           | 5.6               | NA                       | 1.35           | No significant drive           | Water injection                 | 56             | 27              |
| Xinglongtai      | Archean Buried Hill (Xinggu-7 Block) | China | 7612                  | Basement           | 6.3               | NA                       | 0.52           | Solution gas                  | None                           | 271            | 23              |
| Yanling          | Wumishan                        | China       | 800                   | Dolomite           | 3.55              | 2200                     | 16             | Aquifer                       | Water injection                 | 124            | 32              |
| Zeit Bay         | Basement                        | Egypt       | 1050                  | Basement           | NA                | 400                      | 0.84           | Solution gas/gas cap expansion/gravity drainage | Hydrocarbon gas injection | 208            | 31              |

NA = Not available
and continuously monitored, produced water can be minimized for an extended period of production to optimize ultimate recovery (Fig. 5a, e.g. Bach Ho Field, offshore Vietnam). During this period of low water production, the extensive use of preventative measures to control water coning, such as intermittent water injection, modifying injection pattern, water plugging and high water-cut wells shut-in, is crucial to achieve higher recoveries (Dang et al. 2011).

In contrast, when water injection programs are poorly planned and badly executed, water incursion can lead to a cessation of production within a few years of initial water breakthrough (Fig. 5b, e.g. Liubei and Wangzhuang fields, China). Amongst Type 1 fractured reservoirs, where individual wells experience either high water-cut or ‘watering out’, this is the result of either water injection or the presence of an extensive aquifer (or both). Once individual wells produce mostly water, costly reservoir management interventions may be required to maintain production (Xuan et al. 2018).

Maintaining a good balance between pressure maintenance and low water-cut is key to optimal oil recovery (Dang et al. 2011). For longevity of production it is critical to produce Type 1 fractured reservoirs under low pressure drawdowns and at sustainable rates. Several reservoir management measures have proved to be effective in preventing production problems or repairing reservoir damage, such as reinjection of produced gas into gas caps to re-pressurize reservoirs, shutoff or recompleting individual wells to eliminate water or gas channeling, and shutting in entire reservoirs to allow fluid contacts to re-equilibrate to planar configurations. Horizontal wells can prevent gas and water channeling by spreading production over a broader lateral area, thus minimizing local drawdown. Since well productivity depends on fracture density and the number of intersecting fracture sets, high-angle and horizontal wells are particularly effective as they maximize the chance of intersecting multiple fractured zones.

**Case histories**

Two case histories with positive (Bach Ho Field, Vietnam) and negative (Liubei Field, China) reservoir management outcomes are discussed here as examples of best practices, and pitfalls, of optimizing production in Type I fractured reservoirs.

**Triassic-Cretaceous Granitic Basement Reservoir, Bach Ho Field, Vietnam**

The Bach Ho Field produces oil from a horst structure with 80% of reserves contained in fractured granitic basement and the remaining 20% in onlapping and overlying Oligo-Miocene sandstones. Production began in 1986 from the Oligo-Miocene reservoir, initially at 6000 BOPD. Field production increased significantly after the basement reservoir was brought onstream in 1988, plateauing at 268 000 BOPD during 2002 (Fig. 5a). The basement reservoir was initially produced under solution-gas drive, but ultimately this was proved to be inefficient, and reservoir pressure fell steadily. Pilot water injection began in 1993 to arrest the observed pressure decline and first water breakthrough occurred in 1997. Full-scale water injection was successfully implemented during 1997–01. The success of water injection resulted from monitoring and adjustment of both injection and production rate. The well pattern was continually adjusted to improve sweep efficiency. Whenever water-cut in individual wells reached 5–15%, they were converted into gas lift production, which greatly extended production duration and increased cumulative output of watered-out wells (Dang et al. 2011). Measures to maintain a stable rate of production included oil rate control and intermittent production of high water-cut wells. As a result of good reservoir management practices, relatively stable production has been maintained over a long period of time (Fig. 5a), leading to an ultimate recovery of 35%. It has been estimated that an extra c. 170 MMBO (4% incremental recovery) could be recovered in the late-production phase of the basement reservoir by postponing water injection to allow the reservoir to fall below the bubble point pressure and create a secondary gas cap (Lang et al. 2008). Gravity-drainage drive would primarily displace oil from the microfractures into the surrounding macrofractures. Once the gas cap was large enough, water injection could be resumed.

**Precambrian Karstic Dolomite Reservoir, Liubei Field, China**

The Liubei Field produces oil from a karstic dolomite reservoir with a tight matrix and strong drive from an underlying aquifer. Production
began in June 1978 and reached a peak of 16,700 BOPD in 1979 (Fig. 5b). Wells were drilled into the top of the reservoir and completed open hole. High initial production rates led to rapid pressure and production decline. A water injection program undertaken in October 1978 to reverse the pressure only served to create a water incursion problem: high-speed channeling of injected water along fractures blocked the free movement of oil in nearby microfractures and vugs causing poor sweep efficiency (Zhang and Zhang 1991). To improve drainage of the bypassed oil, both the production and injection rates were reduced substantially between 1980 and 1982. These measures were ineffective for the same reasons, and an observed rise in water-cut after 1983 caused further reduction in production rates. By the end of 1988, water-cut had reached 78.8% when most (90%) of the oil column had watered-out and production rate fell to 2,534 BOPD. At the cessation of production, in 2002, the Liubei Field had a truncated production life and achieved a sub-optimal ultimate recovery rate - v. applicable analogues - of only 19%.

Comparing the outcome of development at Bach Ho Field to Liubei Field, it is evident that maintaining production under low drawdowns, managing water injection/production in a dynamic way and preventing water coning is key to optimal recovery.

Type 2 fractured reservoirs

Two hundred and five Type 2 case histories were reviewed to characterize the rock matrix and fracture properties that define this Type. Type 2 fractured reservoirs consist of dolomite, limestone, sandstone and volcanics, and are characterized by low to moderate matrix porosity of 4–20% (average 11%) and generally low air permeability of 0.2–100 mD (average 5 mD) (Fig. 6). Matrix porosity provides the primary storage capacity while fractures and solution-enhanced fracture porosity provide essential fluid-flow pathways. The predominant matrix porosity types include intercrystalline, interparticle, intergranular, moldic and vuggy. Karstification and hydrothermal dissolution are common diagenetic processes in this Type and serve to enlarge pre-existing pore networks and create cavernous and breccia porosity. These effects further complicate the fracture-matrix dual-porosity system. Fractures raise average production-derived permeability by one to two orders of magnitude above the value that would be derived from the matrix alone. Well test permeability averages 103 mD with a maximum of 3,280 mD.

Type 2 is the most common fractured reservoir type in this study, representing about 66% of the total population. Fracture-matrix bimodal porosity adds a significant complexity to the recovery.
mechanism. Proper understanding of how these two porosity systems interact is critical to optimal recovery.

**Production characteristics**

The production characteristics of Type 2 fractured reservoirs are closely related to fracture density, rock matrix properties and natural drive mechanisms. High and sustainable well productivities are dependent upon a combination of dense fracturing and good matrix porosity - a result of high fracture permeability recharging fractures rapidly with matrix oil (McQuillan 1985). Ultimate recovery factors range from 7–65% (Table 4). As would be expected, there is generally a positive correlation between ultimate recovery factor and mobility index (Fig. 7). With higher matrix permeability and lower viscosity, ultimate recovery factor improves as the matrix permeability can adequately recharge fractures. Reservoirs with unfavorable reservoir and fluid properties (mobility index < 0.1 mD/cP) tend to have lower recovery efficiencies (Fig. 7). However, the scattered recovery factor distribution for a given mobility index reflects the human impact on reservoir performance and recovery efficiency as discussed below and in the case histories.

Many of the production characteristics result from the brittle nature of Type 2 fractured reservoir lithologies. Fracture networks in these types of rock matrix tend to be extensive and are commonly connected to updip or underlying regional aquifers. High production rates during the early production of a reservoir almost always leads to a rapid water incursion and premature production decline (e.g. Nido and West Linapacan A fields, Philippines). From the studied Type 2 fractured reservoirs, water injection has been widely implemented to maintain reservoir pressure, but it has met with mixed success (Table 4). There is a tendency for injected water to channel along fractures, leaving the matrix block un-swept.

For efficient, long-life production, it is critical to produce Type 2 fractured reservoirs at optimal rates so that the rate at which oil is produced from the fractures is matched to the rate at which water is imbibed into the matrix. Water-cut and movement of the oil-water contact must be carefully monitored and production rate reduced when either rises too rapidly (Orlopp 1988). When properly managed, many aquifer drive reservoirs have achieved good ultimate recovery factors (>40%) without the need for secondary recovery programs (e.g. Walio, Kasim and Salawati-A fields, Indonesia and Casablanca Field, Spain) (Table 4).

Many Type 2 fractured reservoirs have either solution gas, gas cap expansion and/or gravity drainage drive in combination with some element of an aquifer drive (Table 4). Solution-gas drive reservoirs tend to be much longer-lived than aquifer drive reservoirs and can be produced for many decades with little risk of water incursion. The principal risk factor in these cases is decline in reservoir pressure which can result in unintentional gas-cap formation when an undersaturated reservoir drops below the bubble point pressure, or because of unwanted gas-cap expansion in a saturated reservoir (Saidi 1996).

Reservoirs with a gas-cap expansion drive are susceptible to precipitous pressure decline when overproduced. Downward gas-cupping and upward water coning through fractures leave high residual oil saturations in unswept areas of the matrix and can significantly reduce ultimate recovery factor. Early initiation of gas reinjection for the purpose of pressure maintenance above the bubble point is critical for maximizing oil recovery (McQuillan 1985). Optimization of production rate is also essential to prevent the formation of pressure sinks that allow gas and water incursion into the oil column. When gas-cap expansion occurs along a uniform front, gravity drainage can be induced in the gas-swept portion of the oil column, and hence significantly increases recovery factor.

Many gravity-drainage drive Type 2 fractured reservoirs were originally undersaturated and first produced by other drive mechanisms. The Cantarell and Empire Abo fields were originally solution-gas drive reservoirs and the Yates Field was produced by weak aquifer drive (Table 4). In all three fields, the natural drive mechanisms were weak and secondary gas caps formed unintentionally when reservoir pressure dropped below the bubble point. As the gas caps expanded, the gas-oil contacts moved downward through the oil column and gravity drainage became the primary drive mechanism. In all three fields, the formation of secondary gas caps was the result of poor planning. However, the unintended switch to gravity drainage was tremendously beneficial, greatly increasing oil production and ultimate recovery factor (to 45%, 60% and 36%, respectively). Once it became apparent that gravity drainage was increasing productivity, the gas caps were artificially expanded in all three fields by reinjection of produced gas at Empire.
| Field Name       | Reservoir Unit            | Country | HC Column Height (ft) | Lithology     | Matrix Porosity (%) | Air Permeability (mD) | Viscosity (cp) | Drive Mechanism                                      | Secondary Recovery/EOR Method                          | STOIIP (MMBO) | Ultimate RF (%) |
|------------------|--------------------------|---------|-----------------------|---------------|---------------------|-----------------------|---------------|------------------------------------------------------|--------------------------------------------------------|---------------|-----------------|
| **A.J. Bermudez**| Middle Jurassic-Upper Cretaceous | Mexico  | 4839                  | Dolomite     | 5.6                 | 0.6                   | 9.5           | Solution gas                                        | Water injection/gas injection                          | 8635          | 36              |
| **Abkatun**      | Cantarell                | Mexico  | 2789                  | Dolomite     | 9                   | 3.1                   | 0.59          | Solution gas/gas cap expansion/                      | Water injection                                       | 5045          | 45              |
| **Akal**         | Cantarell                | Mexico  | 7218                  | Dolomite     | 7                   | NA                    | 2.6           | Aquifer/solution gas/gas cap expansion/gravity drainage | Nitrogen immiscible injection                         | 30000         | 46              |
| **Al Huwaisah**  | Shuaiba                   | Oman    | 171                   | Limestone    | 21                  | 20                    | 1.2           | Aquifer                                              | None                                                   | 1566          | 25              |
| **Albion-Scipio**| Trenton-Black River       | USA     | 600                   | Dolomite     | 3                   | 1                     | 0.97          | Solution gas/gas cap expansion/gravity drainage      | Water injection                                       | 200           | 45              |
| **Ardmore**      | Zechstein                | UK      | 780                   | Dolomite     | 12                  | NA                    | 0.75          | Aquifer                                              | None                                                   | 261           | 31              |
| **Ashtart**      | El Garia                 | Tunisia | 860                   | Limestone    | 17                  | 2.5                   | 0.56          | Solution gas                                        | Water injection                                       | 944           | 37              |
| **Barnhart**     | Ellenburger              | USA     | 397                   | Dolomite     | 4                   | 4                     | NA            | Solution gas                                         | None                                                   | 116           | 17              |
| **Bati Raman**   | Garzan                   | Turkey  | 689                   | Limestone    | 18                  | 58                    | 592           | No significant drive                                 | Water injection/gas injection                          | 1850          | 10              |
| **Bever Lodge**  | Duperow                  | USA     | 13                    | Dolomite     | 13                  | 3.6                   | 0.23          | Solution gas                                         | Water injection                                       | 230           | 33              |
| **Bever Lodge**  | Mission Canyon (Madison) | USA     | 68                    | Limestone    | 6                   | 2.1                   | 0.23          | Solution gas                                         | Water injection                                       | 175           | 33              |
| **Bibi Hakimeh** | Asmari                   | Iran    | 5300                  | Dolomitic limestone | 9                  | 1                     | 1.3           | Aquifer/solution gas/gas cap expansion/gravity drainage | Hydrocarbon gas injection                             | 12400         | 31              |
| **Bouri**        | Farwah (Jidr-Jizani)     | Libya   | 730                   | Limestone    | 14                  | 10                    | NA            | Aquifer/solution gas/gas cap expansion/gravity drainage | Water injection                                       | 5000          | 40              |
| **Breedlove**    | Fasken                   | USA     | 210                   | Dolomite     | 9                   | NA                    | NA            | Aquifer                                              | None                                                   | 76            | 50              |
| **Cabin Creek**  | Interlake                | USA     | 400                   | Dolomite     | 15                  | 5                     | 1.26          | Solution gas                                         | Water injection                                       | 480           | 23              |
| **Cactus**       | Agua Nueva-Tamaulipas    | Mexico  | 3609                  | Dolomitic limestone | 7                  | 16                    | 4.6           | Aquifer/solution gas/gas cap expansion/gravity drainage | Water injection                                       | 2069          | 20              |
| **Casablanca**   | Middle Jurassic-Lower Cretaceous | Spain  | 879                   | Limestone    | 4                   | 10                    | 1.1           | Aquifer                                              | None                                                   | 356           | 40              |
| **Charleston**   | Intercalke               | USA     | 220                   | Dolomite     | 12                  | 1                     | NA            | Aquifer                                              | None                                                   | 88            | 22              |
| **Cottonwood Creek** | Phosphorita (Eravy)      | USA     | 6500                  | Dolomite     | 7                   | 0.5                   | 2.75          | Solution gas                                         | Water injection                                       | 230           | 30              |
| **Elk Horn Ranch** | Mission Canyon (Madison) | USA     | 125                   | Dolomite     | 16                  | 25                    | 0.23          | Aquifer                                              | None                                                   | 50            | 44              |
| **Empire Abo**   | Abo                      | USA     | 1044                  | Dolomite     | 6.4                 | 50                    | 0.39          | Solution gas/gas cap expansion/                       | Gas recycling                                          | 383           | 60              |
| **Gachsaran**    | Asmari                   | Iran    | 7516                  | Dolomitic limestone | 9                  | 4                     | 1.35          | Solution gas/gas cap expansion/                       | Hydrocarbon gas injection                             | 3300          | 31              |
| **Haft Kel**     | Asmari                   | Iran    | 2286                  | Dolomitic limestone | 8                  | 1                     | 0.4           | Aquifer/solution gas/gas cap expansion/gravity drainage | Hydrocarbon gas injection                             | 8575          | 23              |
| **Kasim**        | Kais                     | Indonesia | 470                | Limestone    | 21                  | 38                    | 1.79          | Aquifer                                              | None                                                   | 88            | 65              |
| **Kirkuk**       | Main Limestone           | Iraq    | 2265                  | Limestone    | 15                  | 6                     | 4.3           | Solution gas/gas cap expansion/                       | Water injection                                       | 37285         | 60              |
| **Krisna**       | Batunja (Lower)          | Indonesia | 593            | Limestone    | 23                  | 100                   | 2.22          | No significant drive                                  | Water injection                                       | 120           | 44              |
| **Ku**           | Cantarell                | Mexico  | 2769                  | Dolomite     | 9                   | NA                    | 1.8           | Aquifer/solution gas/gas cap expansion/gravity drainage | Nitrogen immiscible injection                         | 5884          | 53              |
| **Kuleshov**     | A4                       | Russia  | 384                   | Limestone    | 18                  | 195                   | 0.97          | Aquifer/solution gas                                  | Water injection                                       | 986           | 50              |

(continued)
| Field Name | Reservoir Unit | Country | HC Column Height (ft) | Lithology | Matrix Porosity (%) | Air Permeability (mD) | Viscosity (cp) | Drive Mechanism | Secondary Recovery/EOR Method | STOIIP (MMBO) | Ultimate RF (%) |
|------------|----------------|---------|----------------------|-----------|---------------------|-----------------------|---------------|----------------|-------------------------------|-------------|----------------|
| Lisbon     | Leadville (Redwall) | USA    | 1870                 | Dolomite  | 5.5                 | 22                    | NA            | Solution gas/gas cap expansion/ gravity drainage | Gas recycling | 91           | 56            |
| Maloob-Zaap | Cantarell     | Mexico  | 2493                 | Dolomite  | 9                   | NA                    | 14.5          | Solution gas/gas cap expansion/ gravity drainage | Nitrogen immiscible injection | 12 280       | 36            |
| Mansuri    | Asmari         | Iran    | 420                  | Dolomitic limestone | 24         | 10                   | 1.18          | Aquifer/solution gas | None              | 3315         | 30            |
| Masjidi-s-Suleiman | Asmari | Iran    | 1520                 | Dolomitic limestone | 13         | 0.25                 | 3.5           | Solution gas/gas cap expansion/ gravity drainage | None              | 5300         | 26            |
| Midale     | Charles (Midale Beds) | Canada | 604                  | Dolomite  | 20                   | 7                    | 3.4           | No significant drive | Water injection/CO₂ miscible injection/WAG miscible flood | 515          | 42            |
| Naft Khanh-Naft Shahr | Kalsur | Iran-Iraq | 1082                 | Dolomitic limestone | 14         | 5                    | 2.48          | Aquifer/solution gas | None              | 834          | 40            |
| Nido-B     | Nido           | Philippines | 711                 | Limestone  | 9                    | 0.5                   | 1.87          | Aquifer | None              | 42           | 35            |
| Ostashkovich | Zadon-Yelets | Belarus | 623                  | Dolomite  | 8.8                  | 10                    | 2.5           | Solution gas | Water injection | 473          | 45            |
| Parentis   | Upper Jurassic-Lower Cretaceous | France | 1345                 | Dolomite  | 11                   | 100                   | 2.3           | No significant drive | Water injection | 560          | 41            |
| Parsi      | Asmar          | Iran    | 4670                 | Dolomitic limestone | 15         | 2.4                  | 0.73          | Aquifer/solution gas | Gas recycling | 12 650        | 30            |
| Poza Rica  | Tamabra        | Mexico  | 820                  | Limestone  | 11                   | 30                    | 19            | Aquifer/solution gas | Gas recycling | 4810         | 44            |
| Ragusa     | Taormina       | Italy   | 1719                 | Dolomite  | 4                    | NA                    | 315           | Aquifer | gas cap expansion | None              | 480          | 33            |
| Raman      | Mardin-Raman-Garzan | Turkey | 902                 | Limestone  | 14                   | 10                    | 30            | Aquifer | None              | 600          | 20            |
| Renqu      | Wuminshan      | China   | 3028                 | Dolomite  | 4                    | 1                     | 8.21          | Capillary imbibition | Water injection | 2662         | 32            |
| Sabiriyah  | Maududd       | Kuwait  | 745                  | Limestone  | 21                   | 31                    | 2.5           | Solution gas | Water injection | 7446         | 28            |
| Salawati-A | Kais           | Indonesia | 580                 | Limestone/ dolomite | 17         | NA                   | 3.5           | Aquifer | None              | 75           | 48            |
| Sidi El Itayem | El Garia | Tunisia | 407                  | Limestone  | 12                   | 4                     | 0.44          | Aquifer | None              | 140          | 29            |
| Sito Grande | Tamaulipas-Tamabra | Mexico | 1575                 | Dolomite  | 8                    | NA                    | 8.3           | Solution gas | Water injection | 1153         | 32            |
| Turner Valley | Turner Valley (Rundle Pool) | Canada | 5650                 | Dolomite  | 8                    | 4                     | 2.4           | Solution gas | Gas cap expansion | 1313         | 15            |
| Usa        | Carboniferous-Lower Permian | Russia | 1122                 | Limestone  | 19                   | 39                    | 710           | Aquifer | Steam injection/hot water injection | 4034         | 15            |
| Vega       | Siracusa       | Italy   | 1017                 | Limestone/ dolomite | 6          | NA                   | 2500          | Aquifer | None              | 1000         | 7             |
| Virden     | Lodgepole (Nvs Unit) | USA    | 150                  | Limestone/ dolomite | 10         | 35                    | 3.52          | No significant drive | Water injection | 195          | 40            |
| Walio      | Kais           | Indonesia | 561                 | Limestone/ dolomite | 23         | 7                     | 2             | Aquifer | None              | 410          | 49            |
| West Edmond | Frisco (Huron) | USA    | 680                  | Limestone  | 7                    | 3                     | 0.6           | Solution gas | Water injection/gas injection | 400          | 30            |
| West Linapacan A | Linapacan Limestone | Philippines | 1097                 | Limestone  | 14                   | NA                    | NA            | Aquifer | None              | 111          | 8             |
| Weyburn    | Charles (Midale Beds) | Canada | 459                  | Dolomite  | 15                   | 10                    | 3.4           | No significant drive | Water injection/CO₂ miscible injection | 1400         | 43            |
| Xan        | Coban B        | Guatemala | 176                 | Dolomite  | 14                   | 200                   | 30            | Aquifer | None              | 460          | 39            |
| Yates      | San Andres     | USA    | 450                  | Dolomite  | 18                   | 100                   | 7.6           | Aquifer/solution gas | Water injection/gas cap expansion/ gravity drainage | 4500         | 36            |
| Yihezhuang | Majiagou-Badou | China  | 1093                 | Dolomite  | 2.5                  | 8.4                   | 2.51          | Solution as | Water injection | 122          | 32            |

NA = Not available
Abo and Yates, CO2 injection at Yates, and N2 injection at Cantarell (Table 4).

For Type 2 fractured reservoirs, optimization of flow rate and careful management of water injection and production are the most critical elements for maximizing recovery factor (Yu and Li 1989). Depressurization recovery by means of reducing water injection or shutting-in production has proved to be effective in recovering oil stranded in medium-small fractures, and in lower permeability reservoirs (Withjack 1985). Other successful improved recovery methods include nitrogen immiscible injection, gas recycling, hydrocarbon gas injection and CO2 miscible flood (Table 4). The following section examines both successful management cases, and unsuccessful ones, in detail.

Case histories

Four case histories are presented to demonstrate the impact of reservoir management programs on reservoir performance and recovery efficiency: Renqiu Field, China, Sitio Grande and Cactus fields, Mexico, and Bibi Hakimeh Field, Iran.

Precambrian-Ordovician Karstic Dolomite Reservoir, Renqiu Field, China

The Renqiu Field produces oil from a Type 2 fractured karstic dolomite reservoir with a matrix porosity of 4% and air permeability of 1 mD. Natural energy is provided by relatively weak aquifer drive. The field began production in 1975 and reached plateau production of c. 260 000 BOPD during 1977–80 (Fig. 8a). Water injection was introduced to maintain reservoir pressure in December 1976. Owing to the inherent interconnectivity of fracture systems, water coning occurred faster than anticipated. Water encroachment along fractures led to a rapid rise in water-cut and early ‘watering-out’ of producers (Horn 1990). To counter this trend, production was slowed and well spacing was reduced. In time, production rates were optimized to match the imbibition rate (i.e. the rate at which water in the fracture system exchanges with oil in the reservoir matrix). Large fractures were plugged with cement to prevent water coning. Implementation of these reservoir management programs has resulted in an estimated ultimate recovery factor of 32% (Yu and Li 1989).

This example provides a type case of where effective reservoir management methods were adopted early enough, and with sufficient speed, to adapt to changing reservoir conditions. Because the fracture permeability and matrix-fracture connectivity are relatively high in Type 2 reservoirs, it is critical that sufficient reservoir monitoring is in place to adopt an adaptive strategy. Further, this example illustrates that corrective measures, such as plugging of even large fractures with cement, can still be effective, even after damage to the reservoir’s performance through water incursion has occurred.

Cretaceous Dolomite Breccia, Sitio Grande & Cactus Fields, Mexico

The Sitio Grande Field produces oil from a Type 2 fractured dolomite breccia reservoir with a mean average matrix porosity of 8%. The field came onstream in 1972 under solution-gas drive and within two years attained peak production of 93 000 BOPD (Fig. 8b). High production rates were made possible by adequate fracture connectivity and a thick oil column. Owing to a weak natural drive combined with the offtake of associated gas, reservoir pressure fell rapidly to near bubble point (Santiago-Acevedo 1980). Peripheral water injection began in 1977, aiming to reverse the pressure decline, and dramatically increased production to a second peak of 92 000 BOPD (Fig. 8b). High production rates continued under water injection until the early 1980s. During the second peak period, waterflooding was responsible for 40% of field production. Successful implementation of water injection has led to an estimated ultimate recovery factor of 32%.

The Cactus Field, adjacent to Sitio Grande, produced oil from a similar carbonate reservoir with the same drive mechanism. It began production at about the same time and reached peak production in 1978 (Fig. 8c). In contrast to Sitio Grande however, the reservoir pressure dropped below bubble point, necessitating earlier water injection. Because the fracture system at Cactus was better connected than at Sitio Grande, the injected water channelled along fractures and water influx led to a decline in reservoir pressure and oil production that were never mitigated (Santiago-Acevedo and Mejia-Dautt 1980), leading to an ultimate recovery factor of only 20%.

The comparison of these two near-neighbor analogues provides a good opportunity to evaluate the human impact on
reservoir performance. Timely and effective water injection at Sitio Grande was successful in arresting pressure decline and increasing production, whereas water injection designed to reverse pressure decline at Cactus only served to create a water incursion problem: high-speed channeling of injected water along fractures blocked the free movement of oil in the matrix.

**Tertiary Dolomitic Limestone Reservoir, Bibi Hakimeh Field, Iran**

The Bibi Hakimeh Field produces oil from a Type II fractured dolomitic limestone reservoir with a mean average matrix porosity of 9% and mean average air permeability of 1 mD. Natural drive energy is provided by gas-cap expansion.
augmented by gravity drainage, partial aquifer support and weak solution gas. The field began production in 1964 and achieved a peak of 445 000 BOPD in 1971 from wells that produced through fractures at individual well rates of more than 34 000 BOPD. However, this rate was sustained for less than two years. By 1973, overproduction from the more densely fractured parts of the reservoir caused terminal pressure decline, resulting in gas incursion from above and water incursion from below, and leaving high unrecoverable residual oil saturations in the invaded zone. By 1978 field production had declined dramatically to less than 200 000 BOPD (Fig. 8d).

Gas injection and water injection secondary recovery programs were both considered as mitigation measures, but as the reservoir was oil-wet with a water imbibition efficiency of only 5%, gas injection was determined to be the optimum method for improving recovery (McQuillan 1985). Gas injection began in 1977 aiming to reverse the pressure decline, but the damage had been done. The gas-oil contact had fallen by more than 1200 ft, the oil-water contact had risen by 400 ft, and production from many of the producers was restricted by water-cut, gas incursion or both. Although the reservoir has a theoretical maximum oil recovery factor of 60% under gas injection, the ultimate recovery factor is estimated at 31% due to problems caused by reservoir management mistakes. If gas injection had been initiated earlier, water and gas incursion could have been contained and the ultimate recovery factor would have been significantly higher (McQuillan 1985). This example reiterates the need for early and decisive intervention.

**Type 3 fractured reservoirs**

Sixty-one Type 3 fractured reservoir examples were reviewed to characterize the rock matrix and fracture properties. Type 3 fractured reservoirs consist of primary chalk, chalky limestone, diatomite, chert and siltstone, and are characterized by high matrix porosities of 5–34% (average 20%) and low air permeabilities of 0.1–5 mD (average 2 mD) (Fig. 6). Matrix porosity provides almost all storage capacity in these reservoirs and fractures provide essential fluid-flow pathways. Type 3 fractured reservoirs are characterized by a microporous matrix (<20 μm pore size) with rare solution-enhanced pores. Preservation of matrix porosity is enabled by hydrocarbon saturation in structurally higher positions (Brewster et al. 1986). Fractures raise average production-derived permeability by one to two orders of magnitude above matrix values. Well test permeability averages 62 mD with a maximum of 1800 mD.

**Production characteristics**

Production characteristics of Type 3 fractured reservoirs are primarily controlled by fracture density and imbibition characteristics. Because of the low matrix permeability, a large proportion of field production is obtained from wells that intersect the most highly fractured reservoir and from the most highly fractured intervals in an individual well. Fractures tend to be localized around faults and areas of maximum curvature, and generally do not connect either to downdip or underlying aquifers. In addition, porosity and permeability in many Type 3 fractured reservoirs decreases dramatically off-structure (Brewster et al. 1986), preventing the reservoirs from connecting laterally with regional aquifers. This has important implications since it means that these reservoirs are usually not prone to widespread water incursion. Natural drive energy is provided mainly by solution gas, gas cap expansion and compaction (Table 5).

Owing to the low matrix permeability and weak natural energy drive, primary recovery factors are generally low (6–28%) with a mean average of 14%. Application of secondary recovery techniques is essential for maximizing the ultimate recovery. Many different techniques have been applied, often in combination (Table 5), but have met with mixed success as reflected by the range of observed ultimate recovery factors in this population (8–57%). All higher recovery factors (greater than 35%) occur in well-fractured chalk or chalky limestone with favorable imbibition characteristics (e.g. Ekofisk Field, Norway and Yibal Field, Oman), where effective secondary recovery programs have been adopted (Table 5). As would be expected, there is generally a positive correlation between ultimate recovery factor and rock/fluid properties (Fig. 9). Lower ultimate recoveries (less than 25%) result from unfavorable imbibition characteristics, and poor reservoir and fluid properties (Fig. 9). Many reservoirs with a lower recovery factor produce under primary recovery. In poorly fractured reservoirs, in which bypassed oil is commonly left behind in the matrix, ultimate recovery factors are generally low regardless of the imbibition characteristics (e.g. Kraka, Valdemar and Dan fields, Denmark).

Reservoirs with good imbibition characteristics could be described as water-wet. They imbibe water easily during primary production by aquifer drive or during secondary recovery by water injection. Since the imbibed water efficiently forces oil out of the matrix and into fractures, water-wet reservoirs with well-developed natural fractures tend to have good ultimate recovery factors. Reservoirs with poor imbibition characteristics are generally described as oil-wet or mixed-wettability. They do not imbibe water easily. As water enters an oil-wet reservoir during production, it displaces oil in the fractures, but not in the matrix, leaving large portions of the matrix blocks un-swept. This can significantly reduce recovery factors.

One of the key challenges to developing Type 3 fractured reservoirs is the selection of appropriate secondary recovery programs to keep reservoir pressure above the bubble point. Water injection has proved to be the most effective secondary recovery method in reservoirs with favorable imbibition characteristics (Table 5). Methods to control water-cut and improve sweep efficiency include horizontal and infill drilling, optimizing production and injection rate, modifying injection pattern, water plugging and profile modification. For oil-wet and mixed-wettability reservoirs, gas injection has proved to be an effective secondary recovery program (e.g. Fahud, Natih and Safah fields, Oman). In several Type 3 fractured reservoirs gas injection has been used to intentionally expand the gas caps to induce gas-oil gravity drainage. This is a very efficient drive mechanism that is easily capable of raising recovery factors to more than 50% for both Type 2 and 3 fractured reservoirs.

**Case histories**

Two case studies are presented here to demonstrate the substantive effect that wettability can have on ultimate recovery factor in Type 3 fractured reservoirs: Ekofisk Field, Norway, and Natih Field, Oman.

**Upper Cretaceous-Tertiary Chalk Reservoir, Ekofisk Field, Norway**

The Ekofisk Field produces oil from several water-wet primary chalk reservoirs. The field began production in 1971, established a first period of plateau production in 1976 under solution-gas and compaction drive, and then experienced a steep decline (Fig. 10a). Re-injection of excess gas into several crestal wells began in 1975 and continued for several decades, increasing oil recovery by an incremental 3% of STOIIP (Christian et al. 1993). Fieldwide water injection was implemented in 1987, peaked in 1996 and has continued to the present day. This has increased oil recovery by an incremental 28% of STOIIP (Christian et al. 1993). These reservoirs
Table 5. List of 25 type-examples for Type 3 fractured oil reservoirs. These are chosen based on availability of high-quality data and as representative of key characteristics of this Type. Field name, reservoir unit, country, hydrocarbon column height, lithology, matrix porosity, air permeability, viscosity, drive mechanism, secondary recovery/EOR method, STOIIP and ultimate recovery factor are given for each reservoir.

| Field Name       | Reservoir Unit       | Country       | HC Column Height (ft) | Lithology                  | Matrix Porosity (%) | Air Permeability (mD) | Viscosity (cP) | Drive Mechanism                        | Secondary Recovery/EOR Method | STOIIP (MMBO) | Ultimate RF (%) |
|------------------|----------------------|---------------|-----------------------|----------------------------|---------------------|-----------------------|---------------|----------------------------------------|-------------------------------|----------------|-----------------|
| Dan              | Chalk Group          | Denmark       | 1040                  | Chalk                      | 28                  | 1.75                  | 0.58          | Solution gas/gas cap expansion         | Water injection               | 2800           | 28              |
| Ekofisk          | Tor-Ekofisk          | Norway        | 1265                  | Chalk                      | 30                  | 1.5                   | 1             | Solution gas/compaction                | Water injection/ hydrocarbon gas injection | 6900           | 52              |
| Eldfisk          | Hod-Tor-Ekofisk      | Norway        | 1050                  | Chalk                      | 30                  | 1.5                   | 0.11          | Solution gas/compaction                | Water injection               | 2800           | 31              |
| Fahud            | Natih                | Oman          | 1575                  | Chalky limestone           | 29                  | 5                     | 2.2           | Gas cap expansion/ gravity drainage    | Water injection/ hydrocarbon gas injection | 6027           | 30              |
| Halfdan          | Chalk Group          | Denmark       | 590                   | Chalk                      | 28                  | 1.5                   | NA            | Solution gas/gas cap expansion         | Water injection               | 1615           | 38              |
| Hod              | Hod-Tor              | Norway        | 630                   | Chalk                      | 33                  | 1.4                   | NA            | Solution gas/compaction                | None                           | 333            | 19              |
| Idd El Shargi    | North Dome           | Qatar         | 570                   | Chalky limestone           | 23                  | 1.5                   | 2.5           | No significant drive                   | Water injection               | 2618           | 26              |
| Kraka            | Chalk Group          | Denmark       | 275                   | Chalk                      | 28                  | 2                     | NA            | Solution gas/gas cap expansion         | None                           | 350            | 12              |
| Lekwair          | Kharab-Shuaiba       | Oman          | 394                   | Chalky limestone           | 28                  | 2                     | 0.8           | Aquifer/solution gas                   | Water injection               | 1440           | 39              |
| Lisburne         | Wahoo (Lisburne)     | USA           | 900                   | Limestone/ dolomite        | 10                  | 1                     | 0.9           | Solution gas/gas cap expansion         | Gas recycling                | 1800           | 9               |
| Machar           | Chalk Group          | UK            | 4495                  | Chalk                      | 22                  | 0.22                  | 0.4           | Solution gas                            | Water injection               | 500            | 24              |
| Mansuri          | Ilam                 | Iran          | 1270                  | Chalky limestone           | 12                  | 0.8                   | NA            | Solution gas                            | None                           | 9034           | 8               |
| Natih            | Natih                | Oman          | 728                   | Chalky limestone           | 19                  | 2.6                   | 1.5           | No significant drive                   | Water injection/ hydrocarbon gas injection | 3000           | 21              |
| Norman Wells     | Ramparts             | Canada        | 1150                  | Chalky limestone           | 8.4                 | 4                     | 1.32          | Solution gas                            | Water injection               | 680            | 47              |
| Point Arguello   | Monterey             | USA           | 1735                  | Chert/siltstone            | 15                  | 0.1                   | 2.5           | Solution gas/gravity drainage          | Gas recycling                | 2350           | 9               |
| Reitbrook        | Reitbrook Beds       | Germany       | 295                   | Chalky limestone/ chalk    | 25                  | 1.5                   | 30            | Aquifer/gas cap expansion              | Gas recycling/hydrocarbon gas injection | 243            | 8               |
| Safah            | Shuaiba              | Oman          | 125                   | Chalky limestone           | 22                  | 4                     | 0.3           | Solution gas/gas cap expansion         | Water injection/ hydrocarbon gas injection | 1077           | 40              |
| Sidi El Kilani   | Abiod                | Tunisia       | 656                   | Chalky limestone           | 22                  | 0.5                   | NA            | No significant drive                   | Water injection               | 126            | 39              |
| Skjold           | Chalk Group          | Denmark       | 1798                  | Chalk                      | 23                  | 1                     | 0.93          | Solution gas/capillary imbition        | Water injection               | 790            | 41              |
| South Belridge   | Belridge Diatomite (Monterey) | USA | 1200              | Diatomite                  | 60                  | 1.5                   | 3             | Solution gas                            | Water injection               | 2500           | 28              |
| Tor              | Tor-Ekofisk          | Norway        | 1050                  | Chalk                      | 21                  | 0.6                   | NA            | Solution gas/compaction                | None                           | 812            | 22              |
| Tyra             | Lower Chalk Group    | Denmark       | 341                   | Chalk                      | 35                  | 4.1                   | NA            | Solution gas/gas cap expansion         | Gas recycling                | 345            | 20              |
| Valdemar         | Tuxen-Sola           | Denmark       | 500                   | Chalk                      | 25                  | 0.4                   | 0.58          | Aquifer/solution gas                   | None                           | 725            | 14              |
| Valhall          | Hod-Tor              | Norway        | 656                   | Chalk                      | 42                  | 3.7                   | 0.4           | Solution gas/compaction                | Water injection               | 2700           | 34              |
| Yibal            | Shuaiba              | Oman          | 312                   | Chalky limestone           | 25                  | 1                     | 0.64          | Aquifer/solution gas                   | Water injection               | 3800           | 57              |

NA = Not available
responded well to waterflooding, the production decline was reversed, and a secondary production peak was reached in 2002. Successful implementation of water injection led to an estimated ultimate recovery factor of 52%. Recovery efficiency for Ekofisk might have been poorer if a different secondary recovery program had been chosen or if water injection had been poorly planned and badly executed.

**Middle Cretaceous Chalky Limestone Reservoir, Natih Field, Oman**

The Natih Field produces oil from a chalky limestone reservoir. The field began production in 1967 under a weak natural energy drive and established plateau production in 1969–70. The field went into rapid pressure and production decline after this (Fig. 10b).
primary production profile is similar to that of Ekofisk and pressure-maintenance water injection was tried to achieve a similar result. However, unlike at Ekofisk, it did not arrest the production decline, primarily due to the overall mixed wettability of the reservoir (van Dijkum and Walker 1991). After the failure of this water-injection program, crestal gas injection began in 1982 to induce gravity drainage (Al Salhi et al. 2001). This served to stem the production decline, but was not able to reverse it, as water injection did at Ekofisk. Because of the poor response to water injection, the Natih Field achieved an ultimate recovery factor of only 21%. The field might have achieved a greater ultimate recovery if a different secondary recovery program had been chosen (e.g. crestal gas injection only). This indicates the importance of adopting appropriate secondary recovery programs during the early stage of a field development.

Implications for development strategy

The fractured reservoir classification scheme presented here has wide implications for field development strategy. While permeability enhancement by natural fractures is critical to defining a fractured reservoir, it is matrix properties that define the various fractured reservoir types. Using an objective and consistent definition of rock matrix properties, such as porosity type and poroperm characteristics (Fig. 6), this study categorizes fractured reservoirs as Type 1 (tight matrix), Type 2 (macroporous matrix) and Type 3 (microporous matrix). This classification scheme describes the unique behaviour of the 310 fractured reservoirs examined by this study into discrete groups that perform similarly within the constraints of the definition. This forms the basis for the ‘Types’ and while it is possible to sub-divide these types further (for instance, into Type 1 basement and Type 1 carbonate), this classification scheme attempts to make the subdivision of fractured reservoirs at the highest possible level, in order to have the widest practical application.

Existing fractured reservoir classifications do not adequately differentiate certain types of fractured reservoirs as the definition and delineation for the different types of fractured reservoirs is qualitative in nature, relying on arbitrary porosity-permeability cut-offs and subjective judgement of commerciality. Consequently, it is difficult to apply these classification schemes for the understanding of fundamental controls on reservoir performance and recovery efficiency. The fractured reservoir classification scheme presented in this study is based on reservoir and production characteristics, including rock matrix properties and fractures in the capacity of both storage and fluid conduit. As there is little overlap between the various types of fractured reservoirs (Fig. 6), it can be easily implemented to optimize development and production in naturally fractured reservoirs, particularly during the early stage of a field development when direct measurement information is limited.

Nineteen fractured reservoir examples from around the world indicate that Type 1, Type 2 and Type 3 fractured reservoirs defined in this study are comprised of fundamentally different rock types and characterized by different natural drive mechanisms, and hence render different development scheme choices. Within this new classification scheme differentiation is made between controls imparted by inherent natural conditions, such as rock and fluid properties and natural drive mechanisms, v. human controls, such as choice of development schemes and reservoir management practices. Differentiation of these controls allows reservoir performance and recovery efficiency to be understood in context, and for fractured reservoirs to be classified in term of their intrinsic whole-rock properties. Best practices and lessons learned from the global analogues for each of the fractured reservoir types can be used to validate development concepts, quantify resource assessments, and calibrate production performance.

Conclusion

Systematic and in-depth analysis of a global dataset of 310 fractured reservoirs has prompted the creation of a new classification scheme for fractured reservoirs. This new classification scheme is independent of the type of fracturing and embraces fundamentally different matrix types, including its rock properties, fluid storage and flow characteristics. Within this scheme, rock matrix properties, including lithologies and pore types, are demonstrated to exert a primary control on production performance and recovery efficiency. Optimal field development plans should take into consideration of both the lithological characteristics and fractured reservoir types. Type 1 fractured reservoirs are characterized by a tight matrix where fractures and solution-enhanced fracture porosity provide both storage capacity and fluid-flow pathways. Production characteristics of Type 1 fractured reservoirs are primarily controlled by lithology, size of the reservoir and natural drive mechanism. Type 1 fractured basement reservoirs are largely disconnected from regional aquifers and consequently have a relatively weak natural drive dominated by solution gas. Large reservoirs with a thick oil column that are completed for production significantly above the oil-water contact can support higher flow rates without water coning, and hence recover more oil before water breakthrough occurs. It is critical to develop basement reservoirs under low pressure drawdowns and at sustainable rates. However, solution-gas drive basement reservoirs are very susceptible to rapid rise in gas-oil ratio (GOR), which if not addressed can severely limit oil recovery. In contrast, Type 1 fractured carbonate reservoirs are generally well connected with regional aquifers, and hence more prone to water incursion since all oil is stored in fractures. High production rate, and therefore drawdown, during early production of a reservoir almost always leads to precipitous pressure decline and water incursion, swiftly followed by rapid production decline as high water-cut wells are shut-in. Optimization of production rates is essential to realize higher ultimate recoveries. Water and gas injections have been widely adopted injection strategies to maintain reservoir pressure above the bubble point for both basement and carbonate reservoirs. When production and injection rates are carefully balanced and continuously monitored, the amount of produced water can be kept low for an extended period of production, and hence optimize the ultimate recovery.

Type 2 fractured reservoirs include dolomite, limestone, sandstone and volcanics and are characterized by low to moderate matrix porosities, diverse pore types and generally low air permeabilities. Permeability enhancement by naturally occurring fractures is critical to the delivery of commercial production rates. Fracture networks in these brittle lithologies tend to be extensive and are commonly connected to downdip or underlying regional aquifers. High production rates can lead to rapid water incursion and premature production decline. The production rates must be optimized so that the rate at which oil is produced from the fractures is matched to the rate at which water is imbibed into the matrix and microfractures. When properly managed, many aquifer-drive Type 2 fractured reservoirs have achieved good ultimate recovery factors without the need for secondary recovery programs. Water injection has been widely implemented to maintain reservoir pressure, but it has met with a mixed success. There is a tendency for injected water to channel along fractures, leaving the matrix block un-swept. Optimization of flow rate and careful management of water injection and production are the most critical elements for maximizing recovery factor. Gravity drainage has proved to be an effective recovery mechanism for many large solution-gas or gas-cap expansion drive carbonate reservoirs with thick oil columns.

Type 3 fractured reservoirs include chalk, chalky limestone, diatomite, chert and siltstone and are characterized by high matrix porosities and low air permeabilities. Fractures tend to be localized
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around faults and areas of maximum curvature, and generally do not connect to downdip or underlying aquifers. Natural drive energy is provided mainly by solution-gas, gas-cap expansion, and compaction. Application of secondary recovery techniques is essential for maximizing the ultimate recovery. Water injection has been widely implemented, but its success depends upon fracture density and imbibition characteristics of the reservoir rock. Higher recovery efficiency commonly occurs in well-fractured water-wet chalk or chalky limestone, whereas lower recovery efficiency results from unfavorable imbibition characteristics, poor reservoir and fluid properties or limited development of natural fractures.

The new classification presented in this study is demonstrated to better describe performance of naturally fractured reservoirs of different types and allows differentiation and better understanding of controls imparted by inherent natural conditions, and by human intervention on reservoir performance and recovery efficiency.

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