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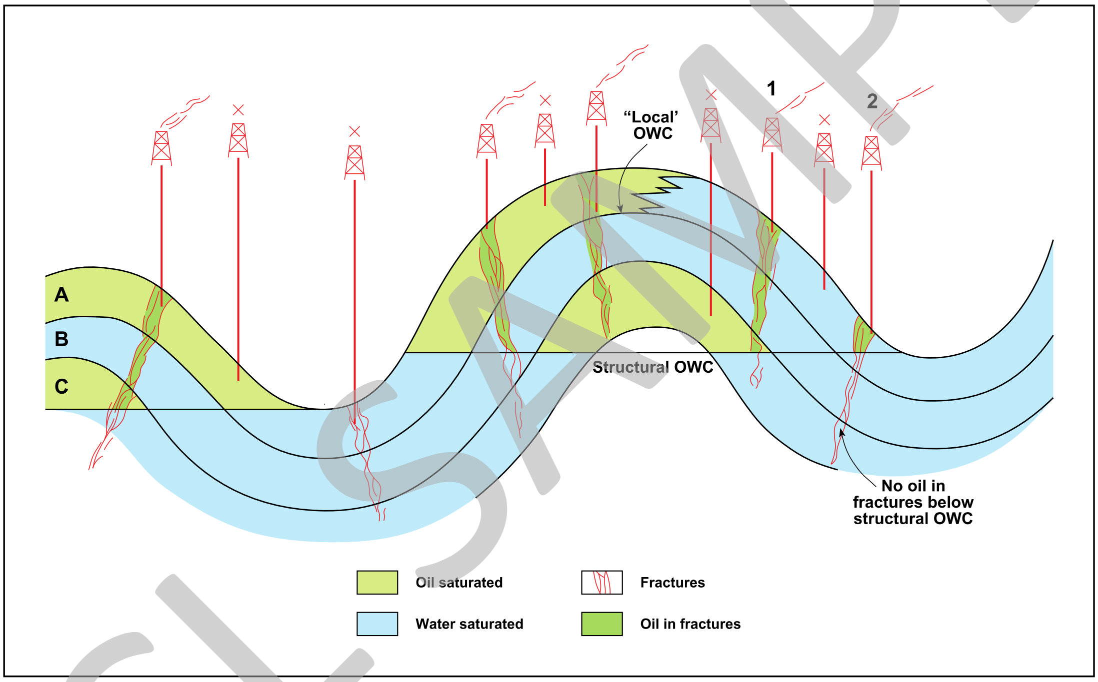

October 2017

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Tectonically Fractured Carbonate Reservoirs - A Synthesis of Analogues

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1. FRACTURED CARBONATE SYSTEMS - INTRODUCTION

Approximately 50% of all carbonate-reservoired oil and gas fields worldwide are naturally fractured. This number is high compared to their siliciclastic counterparts. It is therefore important to not only be able to predict fractures in carbonates, but also to understand their impact on production.

Fractures can impact on reservoir quality and producibility in many different ways, and it should not be presumed that this is always positive. Nelson (2001) characterised the impact of fractures into four key groups (Figure 1):

- where fractures provide both the reservoir porosity and permeability with minimal contribution from matrix porosity (Type 1)
- dual porosity reservoirs in which fractures provide the key reservoir permeability with the main porosity provided by the matrix (Type 2)
- where fractures assist permeability in an already producible reservoir (Type 3)
- matrix porosity reservoirs in which the main porosity and permeability is in the matrix with a minor fracture component that may, in some cases, inhibit porosity and permeability (Type 4).

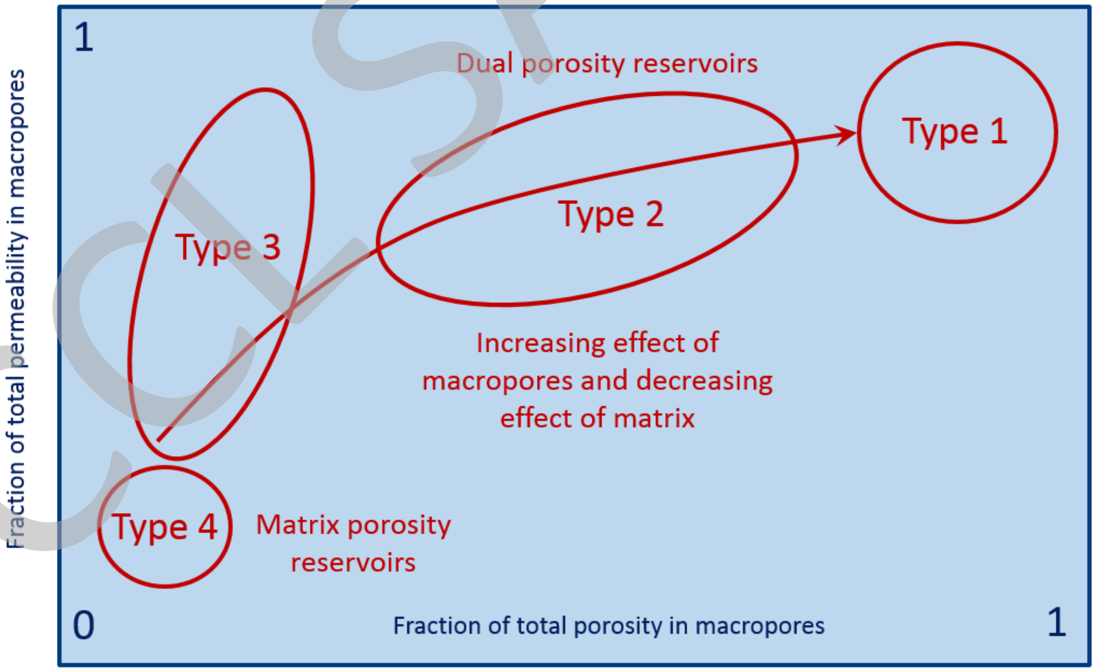

Figure 1 Nelson (2001) characterisation of fractured reservoirs.

The type of fracture network present will have a big impact on how the reservoir will perform. For example if fractures are predicted to provide all reservoir porosity and permeability with little or no contribution from matrix, one might expect early water break-through if offtake was too fast and a development strategy would be designed to avoid this. If, however, the reservoir has a significant matrix component to storage and production, as well as a natural fracture system, the reservoir would be developed in quite a different way.

It is important to understand the impact of fractures at every stage of field life, from exploration through to production. For example at the exploration stage, the presence or absence of fractures will undoubtedly affect the commerciality of a prospect. At the development stage, understanding the contribution of fractures will impact on the design of the facilities and maximum flow-rates. At the production stage, the type of fracture system present will influence the secondary recovery methods adopted (i.e. water-flood viability).

The analogues provided in this report aim to highlight the varying impact of fractures in carbonate reservoirs.

The aims of this report are to provide a summary overview of fractured carbonate fields which are **successfully producing at sustainable economic rates**. Although this analysis is extremely powerful as analogue data, it is important to note that sometimes, it may be more useful or instructive to know why analogues fail or are disappointing. This is out with the scope of the present study.

The two principal areas of economically sustainable fractured carbonate production are the Zagros fold-and-thrust belt of Arabia and fractured reservoirs of Mexico. In addition, useful insights into fractured carbonate reservoirs can be obtained from fields in the Adriatic area, and also fields such as the Keystone field (USA), Nido-B3 well (SE Asia), West Kangean field (SE Asia) and Meillon field (SW France).

It should be noted that only fractured reservoirs which are considered to have a **tectonic origin** are considered in this report. Fractured **karst** reservoirs also form an important reservoir type worldwide, but this is outside the scope of this present report.

All data, figures and analyses presented within this report are based on publically available data.

Summary of observations

It is observed that a clear distinction needs to be made between those carbonate reservoirs where fractures and matrix contribute to reservoir storage (TYPE 2 reservoirs) and reservoirs where storage a delivery of hydrocarbons is from fractures only (TYPE 1 reservoirs).

TYPE 1 reservoirs (fracture only):

- Storage and productivity of hydrocarbons is restricted to fractures alone. Matrix to these reservoirs is very low permeability, and variably water-wet. For example, Ain Zalah field in northern Iraq has relatively light oil (31.5°API), but the matrix is water-wet. In the Ebano-Panuco fields, Mexico, heavy oils dominate (10-13°API); however, the matrix is variably oil saturated, depending on pore-throat sizes of the matrix. This can result in "false" OWCs with some intervals being 100% water-saturated within the oil leg.

- The distribution of fractures is often not straightforward, and the crest of the structure is NOT ALWAYS the location of the highest density of fractures. In Ain Zalah field (northern Iraq), the highest productivity is offset from the crest due to multi-stage structuration. In Northeast Mexico, oil production is associated with fracture corridors that were created through large-scale internal shearing associated with a compressional phase – often there is no obvious local-scale structural closure to these highly productive fracture zones. The importance of "flanking" pools should not be underestimated.

- Connectivity of fractures is clearly dependant on this structural history and nature of the host rocks. Ain Zalah is an example where there is well-developed connectivity between fractures since flowing in any well affects other wells. It is thought that there is a network of fine fractures connecting larger, productive fractures. On the other hand, the examples of Northeast Mexico, demonstrate that fracture corridors of 100-200m width and 1-2km length are relatively "isolated", but can produce 100MMBO. It is probable that these fracture corridors share a regional OWC.

- Examples such as Ain Zalah Field (northern Iraq) demonstrate that the TYPE 1 fractured carbonate reservoirs sit above a TYPE 2 reservoir, and this connection recharges fractures in the upper reservoir.

- Fracture porosity is <1%.

TYPE 2 reservoirs (fracture and matrix, dual porosity):

Clearly, where a structure is tangential to the facies belts, there is significant potential for lateral variations in reservoir quality; it cannot be assumed that these fields are simple layer-cake reservoir systems.

Lower porosity reservoirs are best illustrated from Kirkuk with the poorest quality reservoir in the white, hard, dense, marble-like back-reef to reef facies (0-4% porosity where unaltered and 4-10% porosity where recrystallised, and up to 5mD permeability; Daniel, 1954). Similarly, in Agha Jari the lagoonal facies which are richly foraminiferal are compact and low porosity (2-4%).

Matrix pore systems tend to be developed as isolated vugs or as micropores, with relatively little well-connected mesoporosity, accounting for the low permeabilities such as in Masjed-e-Suleyman (Richardson, 1924). Primary porosities are enhanced by dissolution, recrystallization, dolomitisation and small-scale fracturing. This results in differences of the pore systems in different fields, which in turn, may locally improve productivity. For example, Gachsaran has more large pores than in Haft Kel and Agha Jari, which results in a generally higher rate of production (Slinger and Crichton, 1959). Large voids are also illustrated by records of a 4.27m timber spacer turning round in pore space and returning to surface in the Kirkuk field (Daniel, 1954) but it is not thought that such caverns are commonly developed.

Field	Facies	Matrix porosities	Permeability
Kirkuk, Iraq (NE margin)	Fore-reef facies	18-36% (highest matrix values are recorded from the play fairway).	50-1000mD
Kirkuk	Slope facies	4-20%	
Kirkuk	Basinal limestones	8-18%	Up to 10mD
Kirkuk	Back-reef to reef facies	0-4% porosity where unaltered and 4-10% porosity where recrystallised	up to 5mD permeability
Masjed-e-Suleyman and Agha Jari, Iraq	Recrystallized facies (similar to Kirkuk) form optimum reservoir	15-20%	Low k, rarely above 1md. Isolated vugs and micropores with relatively little well-connected mesoporosity
Haft Kel	Mud-dominated ramps	16%	
Lali	Mud-dominated ramps	7%	
Agha Jari	lagoonal facies	2-4%	

Table 2 Reservoir properties for Cenozoic Asmari fields. Data sources are discussed in the text.

1984). The high production zones in Gachsaran and Bibi Hakimeh both lie on the N 20°E trend as defined by surface mega-lineaments (McQuillan, 1984; Figure 8).

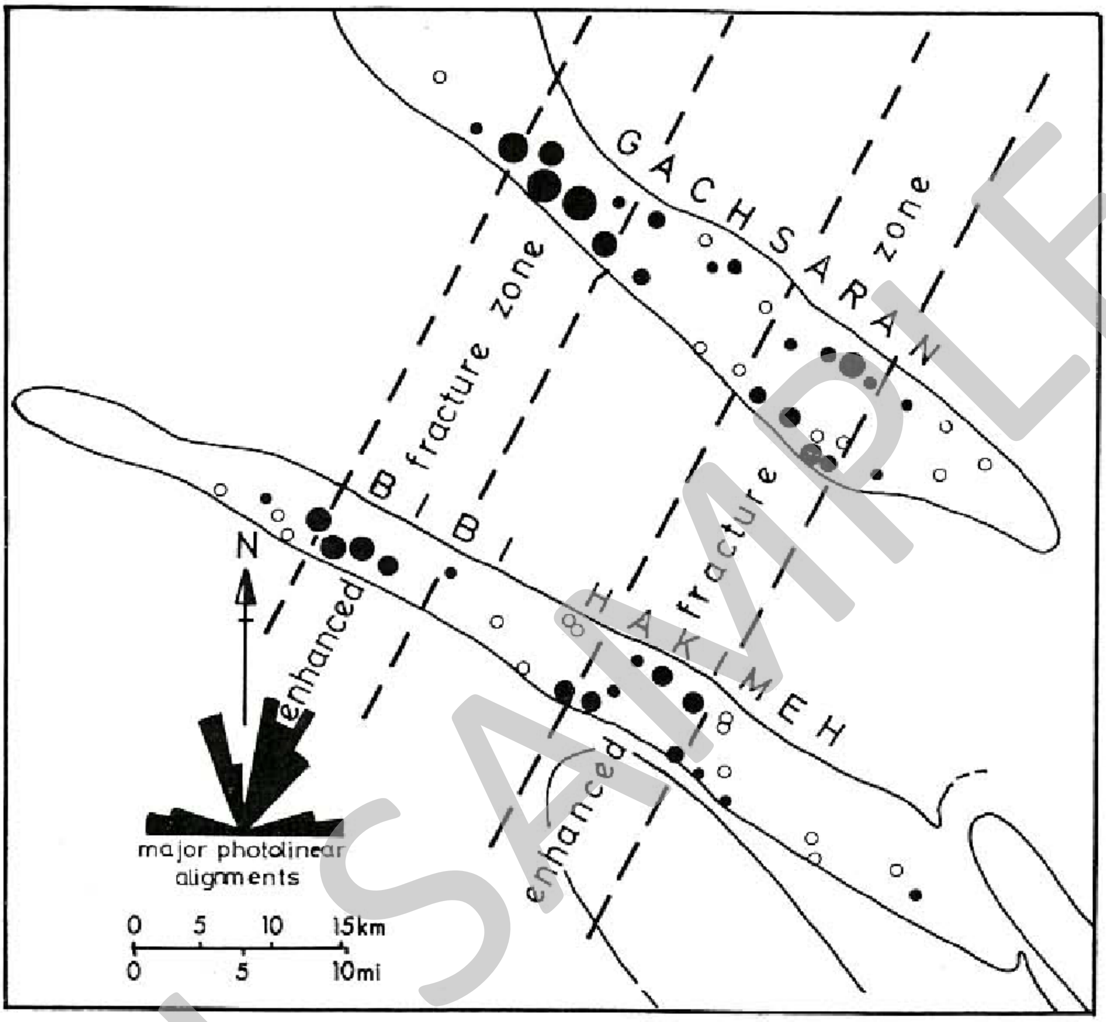

Figure 8 "Form line" map of the Gachsaran and Bibi Hakimeh oil fields. The areas of solid circles are proportionate to maximum allowable production rates at the time. The open circles represent non-commercial or non-producing wells. Note that the high productivity sits in zones on trend with major basement features where there has been enhanced fracturing. **McQuillan (1984).**

Masjed-e-Suleyman is similarly heterogeneous, with the Bibian sector being the most productive, because here the ratio of porosity to fractures is least. Following this sector, the Naftak sector is second in importance, whilst the Asiab sector in the NW shows the worst production characteristics because it is the worst-fractured area with only 3% of total porosity being represented by fractures (Gibson, 1948). McQuillan (1984) suggested that the heterogeneous reservoirs were caused by the main fracturing being related to SW-NE oriented basement structures over which the anticlines were flexed during the Late Neogene, although he did not have a suggestion

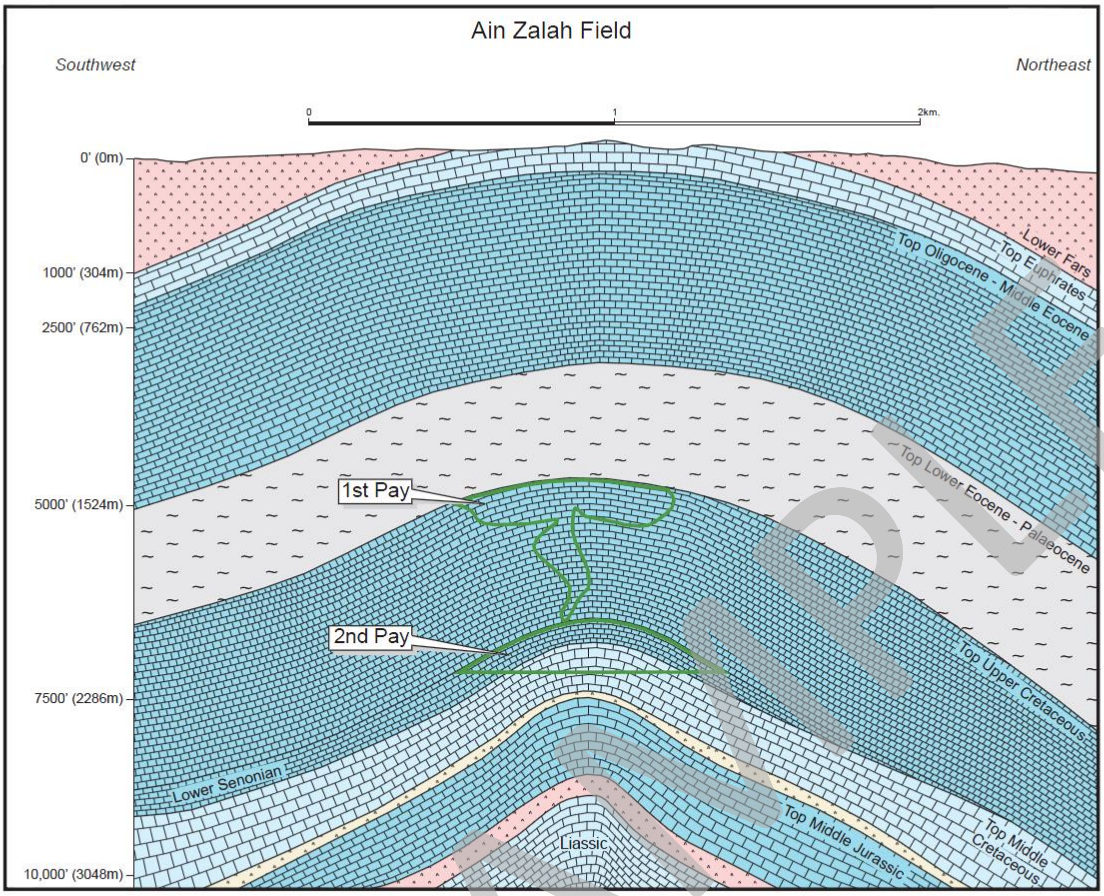

Figure 12 SW-NE cross section through the Ain Zalah field, NW Iraq. Reproduced from Aqrawi et al. (2010) after various sources.

Fracturing: Fractures form both the storage and delivery system of the Ain Zalah field, i.e. a TYPE 1 fractured reservoir (Daniel, 1954). As a consequence, wells have high productivity, but only for a short period. The two pays are connected via fractures identifiable by reservoir pressure and other field observations.

Since little coring has been undertaken in the field, fracture distribution has been inferred from mud-loss data. Typical mud losses are relatively low (300-1000 barrels/day; Daniel, 1954) – these were interpreted by IPC to indicate an abundance of fine fractures which were wide enough to allow drilling mud to pass through them, but which became blocked before *substantial* volumes of drilling mud could pass through them (Aqrawi et al., 2010).

3. FRACTURED BASINAL CARBONATE RESERVOIRS OF NORTHEAST MEXICO (TYPE 1 FRACTURED RESERVOIRS)

3.1. Summary

In northern Mexico there has been significant production from the Ebano-Panuco area, where fractured deeper water Cretaceous basinal carbonates provide the principal production. According to Magoon et al. (2001) this now largely historic reservoir system represents 2.5% of total national production, and amounts to some 1,200mmbo (CCL spreadsheeting, 2017). In these systems, porosities typically range from 10-13% and there is a recovery factor of approximately 10-13%. Direct historical accounts (such as from Muir, 1936) and a basic statistical understanding of production (i.e. drainage of only about 1% of the BRV) indicate that both storage and flow come from the fracture system alone with no matrix contribution, thus clearly placing these reservoirs into Nelson’s Type 1 classification. This is possibly because the produced oils are very heavy (typically 10-13° API) such that any oil held in the matrix porosity does not support the fracture network. Production in terms of stratigraphy is dependent on field location and structural position, and comes from the Agua Nueva and San Felipe formations (approximately Turonian-Santonian, possibly early Campanian), and the upper part of the Tamaulipas Formation of Cenomanian to as old as ?Aptian age. Field areas (and STOOIP) are large, with traps being complex anticlinoria with multiple culminations, and within these and around their flanks, are productive ‘Pools’ that relate more to fracture corridors than to stratigraphic or facies elements. The precise origin of these fracture corridors is uncertain but it is considered most likely in this analysis, that they relate to internal shearing during easterly-vergent Eocene compression, of a slab of largely competent tight and dense limestone (i.e. the Cretaceous basinal carbonates) that are sandwiched between incompetent Upper Jurassic shales (Pimienta Formation) and later Cretaceous marls (Méndez Formation) as these beds override and jostle above an irregular half-graben topography that is punctuated by half-graben and footwall highs. In some cases, in the absence of an obvious structural closure, lateral seals into impermeable limestone are cited as defining field limits; but there is also significant evidence that at a regional scale, oil is kept in place and reservoir pressures were maintained by the

150 to 190m (Pemex, 2012b). Conventional concepts of traps may however be very risky in the general Ebano-Pánuco area, however. Undoubtedly the productive fields sit within a structurally elevated area but it is largely the SSE-plunging nose of a major anticlinorium and there is relatively little or no structural closure to the N, such that it is almost impossible to justify the existence of a regional oil-water contact as related to a four-way dip closure trap. Moreover, production is clearly related to localised elongate, narrow, but vertically significant zones of enhanced fracturing within the overall palaeostructure, rather than to a more standard 'layer cake' concept of reservoir stratigraphy.

The developed area (i.e. productive area: CC) in the Pánuco Block covers a surface of 140 sq km (Pemex, 2012a). The developed area of the Altamira Block covers 8.51 sq. km (Pemex, 2012b).

Oil-Water Contacts

According to Muir (1936) in the Panuco-Topila area the oil-water contact was at 832m below sea-level in the early stages of development. In the Tancoco district (southern Cacalilao), and throughout the various sectors in Cacalilao, the initial salt-water level was about 686m below sea-level, or 146m *higher* than in Pánuco (Figure 24).

Column Height

The Cacalilao Field is described as having a 700' (215m) oil column within it (Muir, 1936). In the Altamira Block, impregnated thicknesses in the range of 150 to 190m are noted (Pemex, 2012b). Calculated columns in Pánuco are much larger, nearly 350m (Figure 24).

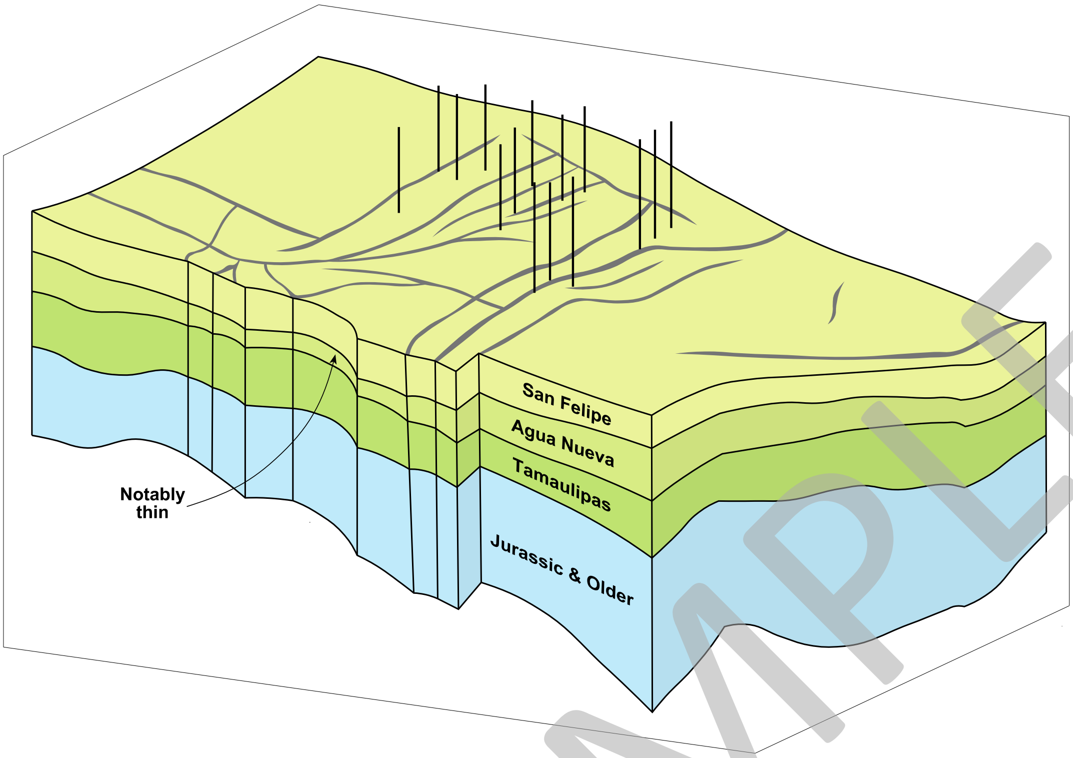

Figure 29 3-D diagram of the Altamira Block stratigraphy, showing thinning of the Agua Nueva and to some extent the San Felipe, over a top-Tamaulipas palaeohigh. After Pemex (2012b).

were uneven above a complex template, it is most probable that the whole of the rigid/brittle 'Cretaceous' stratigraphy was displaced laterally in between relatively plastic shales of the Pimienta Formation, and overlying marls of the Méndez and Tamesí formations. As such the compression/shearing reacted indirectly to underlying basement elements and in other areas would have simply cross-cut slabs of limestone in order to accommodate stresses. Some of this behaviour is also indicated in the Pemex block model (Figure 29).

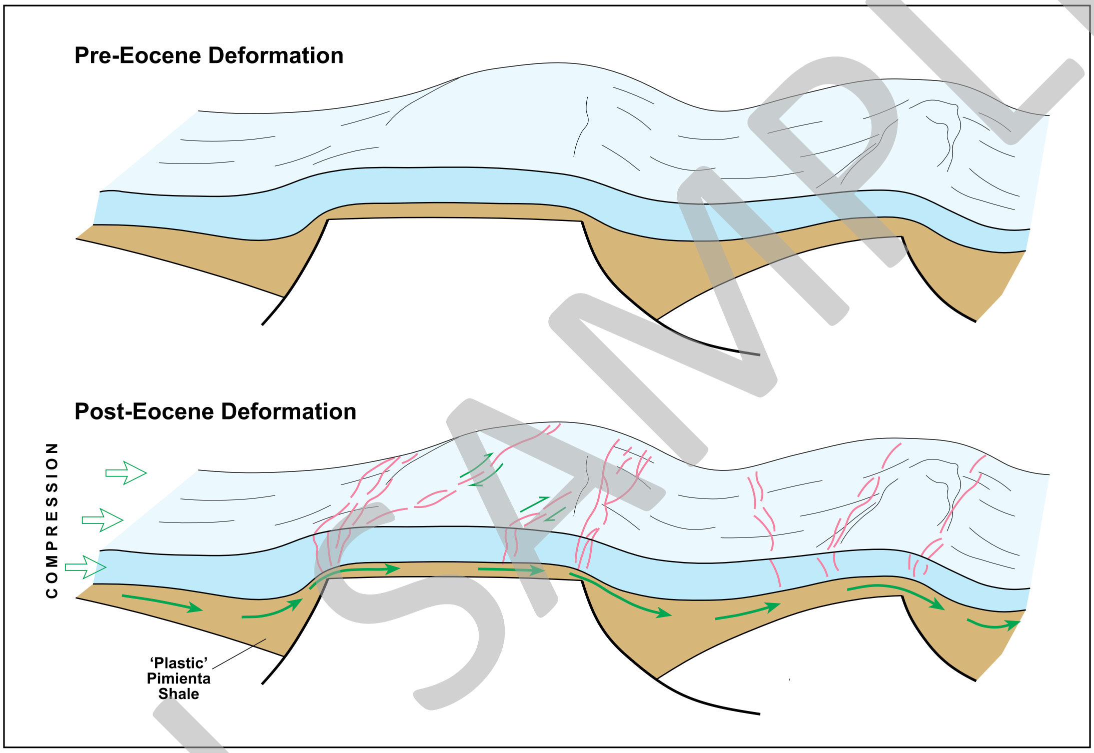

Figure 34 Suggested model for fracturing of the Cretaceous carbonates. Prior to the Eocene deformation, carbonate facies drape over a pre-existing structural template. Later compression resulted in fracturing where the rigid slab had to rise up over or manoeuvre around, the basement highs.

Organisation of Oil Saturations in the Reservoir(s)

Re-interpretation of the data in Muir (1936) allows the creation of a model that covers may aspects of these types of reservoirs in both the Tampico area and to some extent, with what we know from similar types of reservoir in southern Mexico (Figure 35). Firstly, as noted in Figure 24, oil water contacts are commonly significantly 'beneath' the complexities of individual closures where the minimum structural closure (e.g. as contoured on top-Tamaulipas Limestone, or top-Agua Nueva) is significantly above the

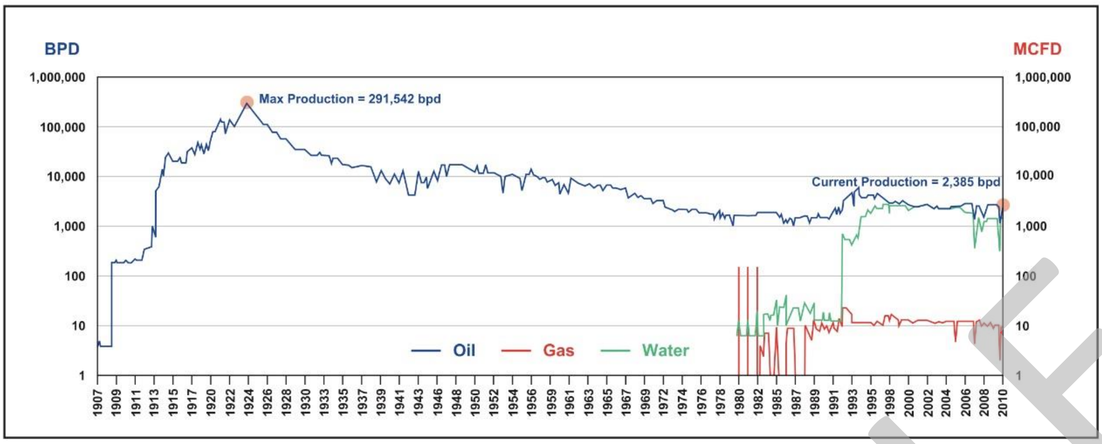

Figure 37 Historical Production in the Pánuco Block after Pemex (2012b).

3.11. Recovery Factors

As noted earlier, an issue with calculating recovery factors is that from the outset, only small geographical areas of the closures actually produce, and the question that should be asked is whether it is these areas alone that are evaluated or the total BRV of the four-way dip closure.

Using 'standard' practise of evaluating the full four-way dip closure, and calculation of OOIP, Pánuco Block fields were calculated to have original volumes of 6,858.67 mmb of oil and 21.060.76 mmmcf of gas (Pemex, 2012a). This gives the 2012 recovery factor in the Pánuco Block of 10.2% (Pemex, 2012a).

The 2012 recovery factor in the Altamira Block is calculated rather similarly, at 13% (Pemex, 2012b).

Using published data for different fields and pools where both the oil recovered and estimated original in place are given, results in the below graph for the fractured basinal carbonate reservoirs of the Tampico Embayment (Figure 38). A surprisingly straight-line relationship results from this exercise that would suggest that a standard 10% recovery factor can be applied to oil in place.

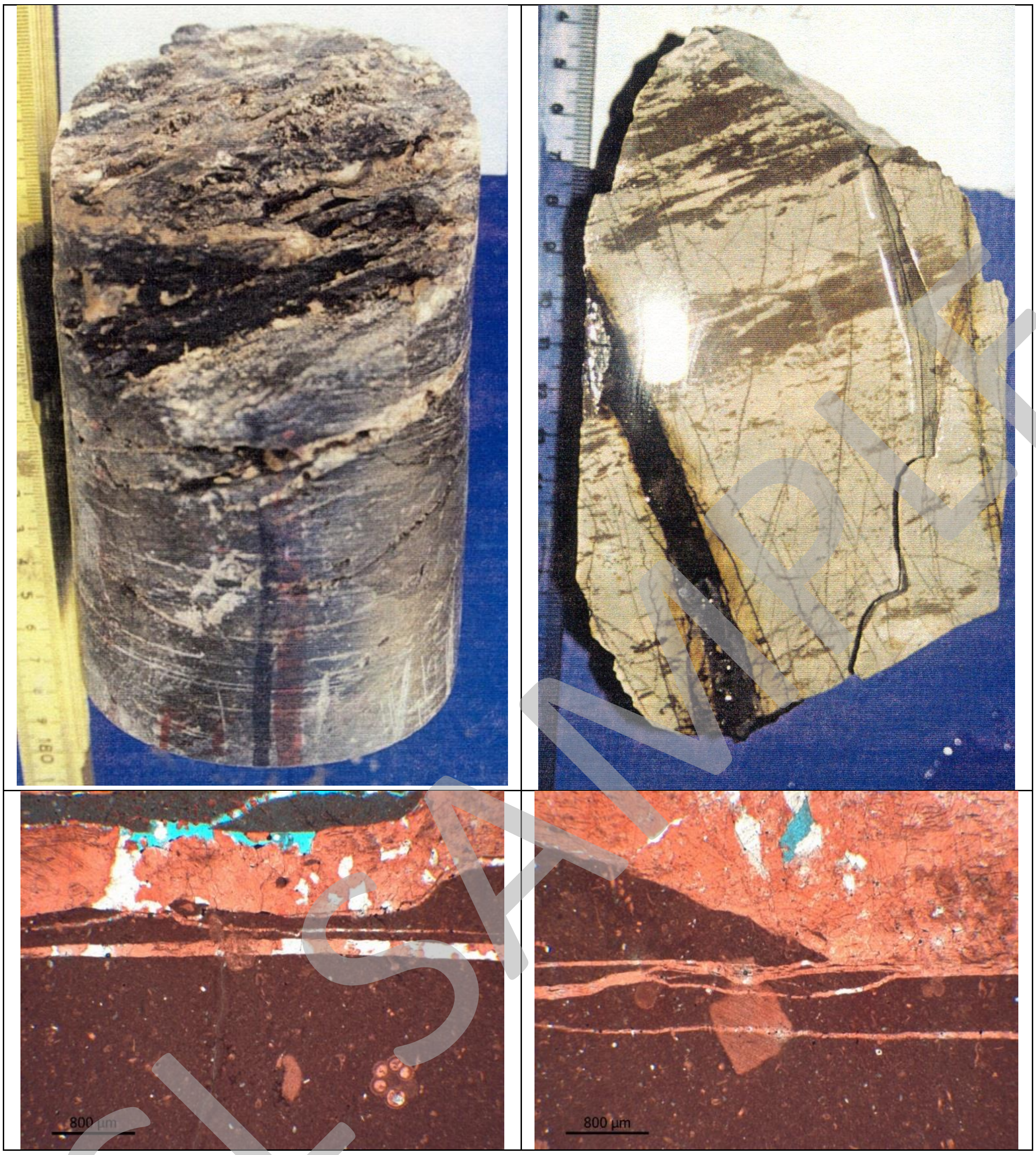

Figure 42 (top left) Offshore Sureste example showing major fracturing and oil stain within fractures. (top right) Onshore Sureste example showing oil-stained fractures and heavy oil staining of areas of likely slightly coarser porosity. (bottom) offshore Sureste examples showing largely calcite cemented fractures but retaining some open porosity.

4.4. Production characteristics

Many of the fields in SE Mexico which produce from fractured basinal carbonates also produce from other stratigraphic intervals, and as a consequence it is often difficult to separate out the reservoir and production characteristics of the fractured basinal facies. However, an attempt has been made to do this, using data provided online by CNH for key fields.

ESE orientation, with the majority being located towards the SW flank of the field (Solis et al., 2005).

Fracture intensity is at its highest in the central and SW flanks of the field. It has been suggested by Solis et al. (2005) that this relates to increased salt movement in the southwestern part of the field, and thus more prolonged structural deformation.

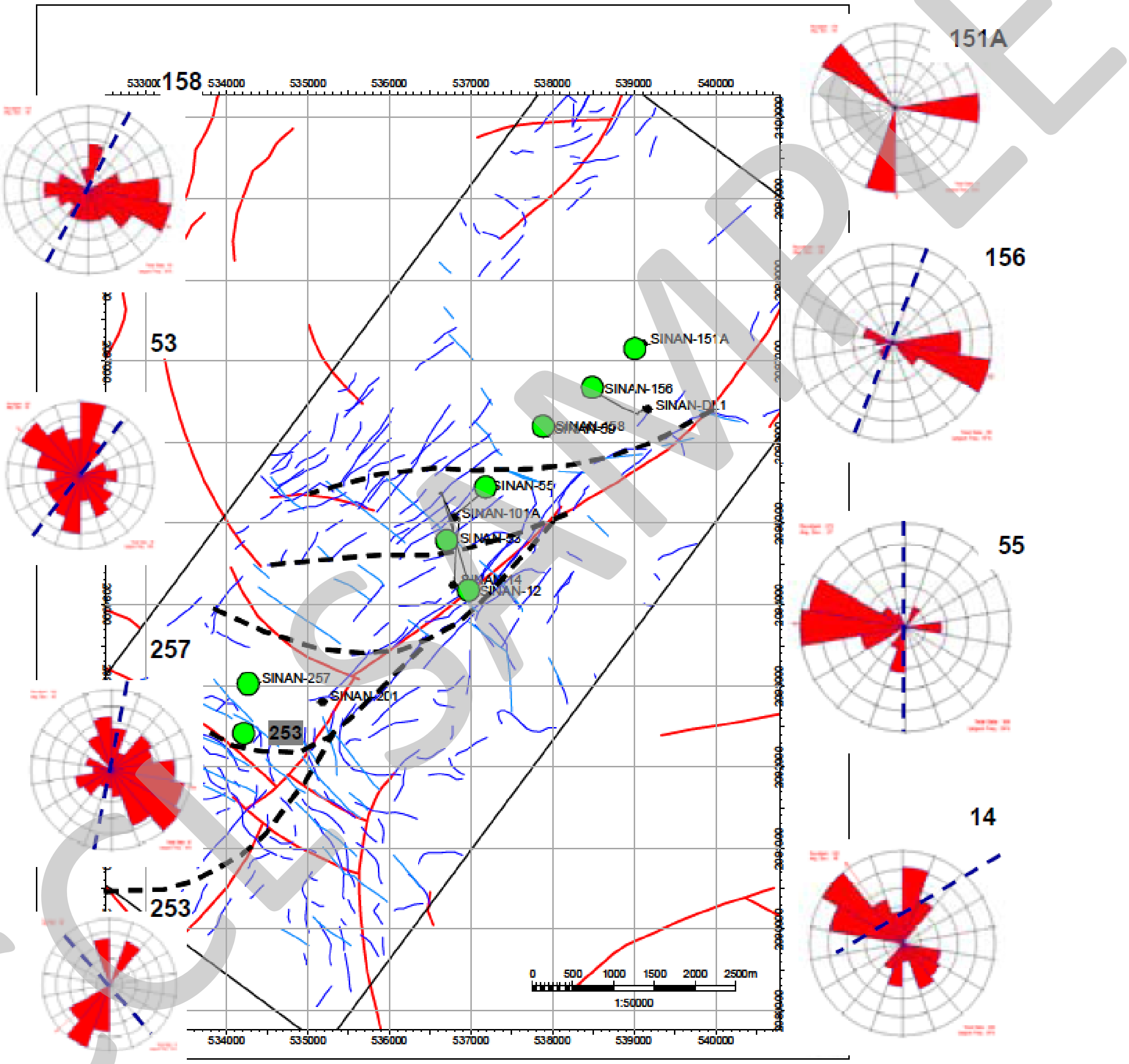

Figure 51 Fracture orientation for the Middle Cretaceous reservoirs in the Sinan field. From Solis et al. (2005), reproduced with permission from SPE.

As a consequence of the integrated work flow, it was therefore possible to prioritise areas of higher fracture intensity for future drilling, with particular focus on the SW and central sectors (Figure 51). And with a better understanding of the orientation of open fractures, well trajectories could be better planned (Solis et al., 2005).

the productivity of these reservoirs, as the oil produces from interconnected fracture systems (Zelilidis et al., 2003; Sejdini et al., 1994). NE-SW trending faults and their associated structures are the dominant pathways for hydrocarbons in Albania, with migration along vertical faults and fracture networks (Graham Wall et al., 2006). These faults also facilitate reservoir storage for example in open fractures and permeable brecciated fault zones (Graham Wall et al., 2006). The fractures occur as sheared pressure-solution surfaces, sheared veins, sheared and open joints, fragmented rock, and breccia zones (Graham Wall et al., 2006; Figure 60). The Late Cretaceous to Eocene succession is some 600 to 700m thick. The pay is divided into four different packages (Zaka et al., 1996):

Zone	Thickness (m)	Lithology	Effective porosity (%)	Fracture density per m	Permeability (mD)	Comments
1st package (Eocene)	150	70% micrite 30% bioclastic	0.5-2.0	20-30	20-200	Poor to moderate reservoir quality.
2nd package (Paleocene)	100	40% micrite, 60% bioclastic	1.0-4.0	30-40	50-300	Good reservoir quality.
3rd package Uppermost Cretaceous	250	30% micrite, 70% bioclastic	3.0-10.0	50-60	Average 600	Excellent reservoir quality. The main oil producer in the area.
4th package basal Upper Cretaceous	200	70% micrite, 30% bioclastic	0.5-2.0	20-30	20-200	Poor to moderate Reservoir quality.

Table 7 Reservoir characteristics of the four main reservoir packages (Zaka et al., 1996)

Initial flow rates range from 200 to 3,000 BOPD per well, with highest productivity from horizontal or deviated wells. Productivity often drops rapidly, e.g. from 3,000 BOPD to 600 BOPD within a year. Wells tend to fall into two categories:

- Average rates of around 500 BOPD in year one.
- Rates of less than 100 BOPD in year one.

Good wells are thought to have established some form of contact with the natural fracture network, whilst the poor wells have failed to encounter such a network.

In the fore-reef talus drilled by Nido-B3, closely-spaced, parallel, vertical hairline fractures are present which are oil stained and cross-cut all earlier fabrics, including stylolites. There are a complimentary sets of random and horizontal fractures; these sets divide the core into blocks a few mm to a few cm in diameter, whilst offsets are rare. Fracturing is best developed in the less argillaceous limestones, which may have helped to diffuse stress. These small fractures form a significant reservoir and conduit capable of producing in excess of 10,000 BOPD out of reservoir with very poor matrix porosity and permeability, although there is a rapid decline in flow, and water cut commences shortly after the start of production.

It is notable that this fracture style is different to the other fractured reservoir analogues in that fine fractures combine to give a high flow rate.

Critical geological factors for production:

- Rapid pressure decline due to dominantly fractured reservoir
- Strong water drive invasion; field being shut-in for 95% of the time
- Hydrofractures radiate from pinnacle centre; horizontal drilling proposed
- High initial flow rates (10,000 bopd); oil is corrosive due to H_2S
- Poor matrix reservoir properties
- Early 3-D seismic surveys were shot to resolve detail in these small fields

6.3. West Kangean field, Indonesia

The ***West Kangean*** gas field offshore Indonesia (East Java Basin) is a good analogue for fractured reservoirs that were formerly deep, now uplifted. It consists of Middle-Late Eocene fractured carbonates of the Ngimbang Formation. These carbonates were deposited on a large, shallow-water platform that developed above a fault-controlled basement high. The lower part of the Ngimbang Formation consists of shelfal/bank limestones, while the upper part consists of reef related build-ups (Kohar, 1985).

7. COMPARISON OF PROPERTIES OF TECTONICALLY FRACTURED CARBONATE RESERVOIRS

This study is comprised of the analysis of 74 naturally fractured marine carbonate reservoirs from around the world (Table 8). The associated excel spreadsheets for this dataset are also available separately. The source of the data for this analyses is all publically available: from peer-reviewed publications, Company websites etc. The data sources for each entry are documented in the accompanying spreadsheet.

The data herein is plotted as a function of "depositional setting", as this has a bearing on how the reservoir behaves. "Deep-water" fractured reservoirs are characterised by reservoirs that are fine-grained, micritic, with relatively little or no effective matrix porosity, whereby the main hydrocarbon storage and delivery is provided by fractures. These have been differentiated from the "deep-water chalk" fractured reservoir examples, as these have fundamentally different reservoir properties. The chalk examples are typically Type 2 fractured reservoirs – oil is stored in the matrix (which is highly microporous, but has very poor permeability), but deliverability is through fractures. If these reservoirs are not fractured, they will not produce the stored hydrocarbons. The final category is the "shallow-water" fractured reservoirs. These examples mainly fall into the TYPE 2 fractured reservoir category (good matrix porosity, but generally poor matrix perm), although there are a few examples where the matrix porosity is relatively low (but still hydrocarbon-bearing). Deliverability, none-the-less, is through fractures.

It should be noted that only examples where the fracturing is considered to have a **tectonic origin** have been included in this analyses. A further category of "karst-fractures" could be added to this analyses, but this is outside of the scope of the present report.

Name of Field	Country	Reservoir Formation	Reservoir age	Depositional setting
Ain Zalah	Iraq	Shiranish (First Pay)	Cretaceous	Deep Water
Ballsh- Hekal	Albania	Unnamed	Cretaceous to Eocene	Deep Water
Butmah	Iraq	Shiranish	Cretaceous	Deep Water
Cakran	Albania	Unnamed	Cretaceous to Eocene	Deep Water
Delvina	Albania		Cretaceous to Eocene	Deep Water
Giddings	USA	Lower Austin	Cretaceous	Deep Water
Gorisht-Kocul	Albania		Cretaceous to Eocene	Deep Water
Visoka	Albania		Cretaceous to Eocene	Deep Water
Shpirag	Albania		Cretaceous to Eocene	Deep Water
Taq Taq	Iraq	Shiranish	Cretaceous	Deep Water
West Katakolo	Greece	Unnamed	Cretaceous	Deep Water
Cacalilao	Mexico (Tampico E-P)	Lower Tamaulipas	Cretaceous	Deep Water
La Laja	Mexico (Tampico E-P)	Lower Tamaulipas	Cretaceous	Deep Water
Limon	Mexico (Tampico E-P)	Lower Tamaulipas	Cretaceous	Deep Water
Ebano Chapacao	Mexico (Tampico E-P)	Lower Tamaulipas	Cretaceous	Deep Water
Salinas	Mexico (Tampico E-P)	Lower Tamaulipas	Cretaceous	Deep Water
Tamaulipas Constituciones	Mexico (Tampico E-P)	Lower Tamaulipas	Cretaceous	Deep Water
Altamira	Mexico (Tampico E-P)	Lower Tamaulipas	Cretaceous	Deep Water
Panuco	Mexico (Tampico E-P)	Lower Tamaulipas	Cretaceous	Deep Water
Topila	Mexico (Tampico E-P)	Lower Tamaulipas	Cretaceous	Deep Water
Alux	Mexico (Surest Basin)		Cretaceous	Deep Water
Ayin	Mexico (Surest Basin)		Cretaceous	Deep Water
Bolontiku	Mexico (Surest Basin)		Cretaceous	Deep Water
Caparosso-Pijije-Escuintle	Mexico (Surest Basin)		Cretaceous	Deep Water
Chinchorro	Mexico (Surest Basin)		Cretaceous	Deep Water
Citam	Mexico (Surest Basin)		Cretaceous	Deep Water
Hayabil	Mexico (Surest Basin)		Cretaceous	Deep Water
Kab	Mexico (Surest Basin)		Cretaceous	Deep Water
Kax	Mexico (Surest Basin)		Cretaceous	Deep Water
Kix	Mexico (Surest Basin)		Cretaceous	Deep Water
Luna-Palapa	Mexico (Surest Basin)		Cretaceous	Deep Water
May	Mexico (Surest Basin)		Cretaceous	Deep Water
Mayacaste	Mexico (Surest Basin)		Cretaceous	Deep Water
Mison	Mexico (Surest Basin)		Cretaceous	Deep Water
Och	Mexico (Surest Basin)		Cretaceous	Deep Water
Palangre	Mexico (Surest Basin)		Cretaceous	Deep Water
Sen	Mexico (Surest Basin)		Cretaceous	Deep Water
Tizon	Mexico (Surest Basin)		Cretaceous	Deep Water
Uech	Mexico (Surest Basin)		Cretaceous	Deep Water
Yum	Mexico (Surest Basin)		Cretaceous	Deep Water
Dan	Denmark	Ekofisk/Tor	Palaeocene/U. Cretaceous	Deep Water CHALK
Ekofisk	Norway	Ekofisk/Tor	Palaeocene/U. Cretaceous	Deep Water CHALK
Eldfisk	Norway	Ekofisk/Tor/Hod	Palaeocene/U. Cretaceous	Deep Water CHALK
Kraka	Denmark	Ekofisk & Tor	Palaeocene/U. Cretaceous	Deep Water CHALK
Machar	UK	Ekofisk & Maureen/Tor/Hod	Palaeocene/U. Cretaceous	Deep Water CHALK
Sidi El Kilani	Tunisia	Upper Aboid	U. Cretaceous	Deep Water CHALK
Skjold	Denmark	Ekofisk and?	Palaeocene (Danian)/U. Cretaceous	Deep Water CHALK
Valhall	Norway	Tor/Lower Hod*	Cretaceous	Deep Water CHALK
Zinnia	Tunisia	Upper Aboid	Cretaceous	Deep Water CHALK
Agha Jari	Iran	Asmari	Cenozoic	Shallow Water
Ain Zalah	Iraq	Qamchuqa	Cretaceous	Shallow Water
Bibi Hakimeh	Iran	Asmari	Cenozoic	Shallow Water
Dukhan	Qatar	Arab C and D	Jurassic	Shallow Water
Fahud	Oman	Natih	Cretaceous	Shallow Water
Gachsaran	Iraq	Asmari	Cenozoic	Shallow Water
Gela	Italy	Taormina/ Villagonia	Triassic	Shallow Water
Haft Kel	Iran	Asmari	Cenozoic	Shallow Water
Idd El Shargi North Dome	Qatar	Shu'aiba	Cretaceous	Shallow Water
Keystone	USA	San Andres	Permian	Shallow Water
Lali	Iran	Asmari	Cenozoic	Shallow Water
Lama	Venezuela		Cretaceous	Shallow Water
Lisburne	USA	Wahoo	Carboniferous	Shallow Water
Mara- La Paz	Venezuela	Cogollo	Cretaceous	Shallow Water
Masjed-e-Suleyman	Iran	Asmari	Cenozoic	Shallow Water
Meillon	France	Mano and Meillon	Jurassic	Shallow Water
Natih	Oman	Natih	Cretaceous	Shallow Water
Nido	Philippines	St Paul	Cenozoic	Shallow Water
Pennel	USA	Red River	Ordovician	Shallow Water
Rosario	Venezuela	Aguardiente/Apon	Cretaceous	Shallow Water
Taq Taq	Iraq	Qamchuqa	Cretaceous	Shallow Water
Urdaneta West	Venezuela	Cogollo	Cretaceous	Shallow Water
Vega	Italy		Triassic	Shallow Water
West Kangean	Java	Ngimbang	Cenozoic	Shallow Water
Yibal	Oman	Shu'aiba	Cretaceous	Shallow Water

Table 8 Tectonically fractured carbonate fields that were included in this analyses. Note that the data is derived from publically available sources (publications; company websites); however, all subsequent analysis is performed in house by CCL.

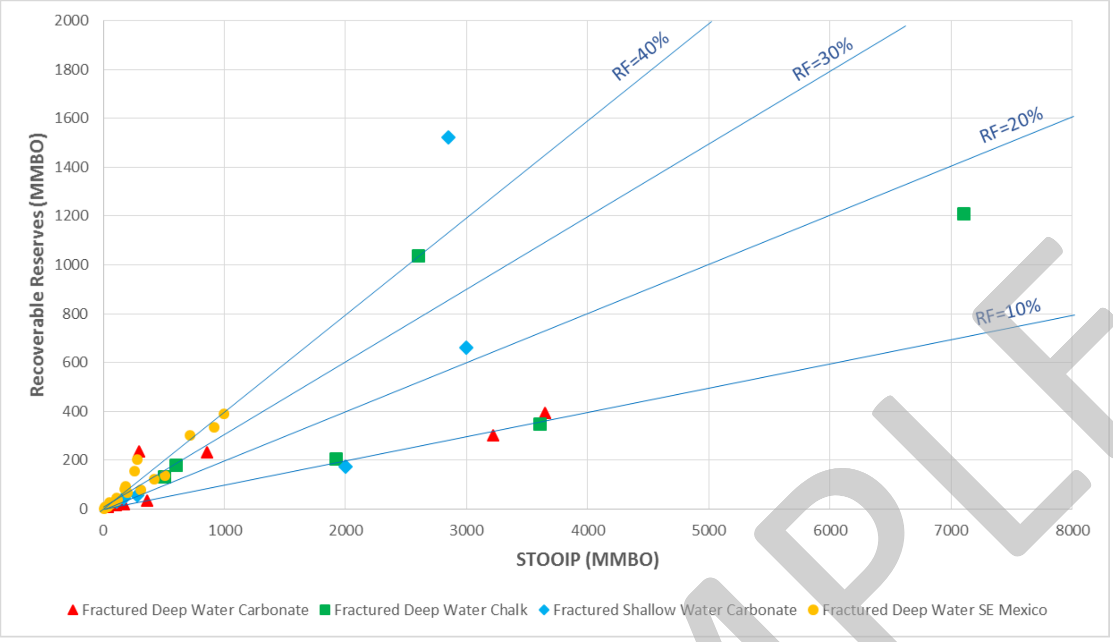

Figure 83 Zoomed in view of STOOIP vs recoverable reserves for fractured carbonate fields with recoverable reserves <2000MMBO. Corresponding recovery factors have been annotated onto this plot.

7.7. Oil API vs Recoverable reserves

Figure 84 and Figure 85 plot the data for oil gravity vs recoverable reserves. Geologic principles might suggest that there should be a relationship between oil gravity and recoverable reserves, with higher API oils likely to result in higher recoverable reserves. But these plots clearly highlight that basic fundamental factors such as GRV, N:G, porosity, permeability most likely have a more controlling influence than oil API.

What the plots do highlight is that most data points sit between 30°APIl and 40°API, which is not surprising. The fractured reservoir type also does not really exhibit many trends, other than deep-water fractured reservoirs tending to have lower volumes of recoverable reserves (as discussed in the previous sections).

- Fractures curve outwards towards the core surface or towards an existing fracture.
- Disc fractures exploit planes of fissility or bedding.
- Fractures perpendicular to the core have circular slickensides.
- Line of chipping or gouging up the side of the core produced by scribe knife.
- Fractures post-date natural and drilling induced fractures.

Examples of fractures induced by handling or during storage:

- Desiccation fractures show consistent geometrical relationship with core.
- Hammer marks are present in the core at the fracture origin.
- The fracture is clean with no drilling mud.
- Fractures post-date natural, drilling and coring-induced fractures.

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