Naturally Fractured Reservoirs

Lessons Learned from 100 Fractured Fields

Shahab Gerami, Fall 2010

Outline

- **Complexity in development of fractured reservoirs**
- **Fractured carbonate reservoir types**

Complexity in Development of Fractured Reservoirs

- Because of the fundamental differences between the conventional and fractured reservoirs, mistaking a fractured reservoir for a conventional reservoir early in the field-development phase can lead to mistakes in exploitation strategy that have profoundly negative effects on reservoir performance.

- Most wells completed in newly discovered fractured reservoirs produce at high IP. If investment decisions are made, as they sometimes are, by assuming that those high production rates can be maintained over extended periods of time, the field may be economically doomed from the start.

- When wells in fractured reservoirs are flowed at excessively high rates, GOR can increase rapidly instead of remaining low as in a properly managed field. This eventually leads to a rapid decline in reservoir pressure. Rapid pressure decline can change the delicate balance of recovery mechanisms that feed matrix oil into the fractures and drastically decrease recovery factor.

- Finally, if an incorrect secondary recovery technique is chosen, ultimate recovery may be further reduced. The most common example of poor reservoir management is waterflooding a fractured reservoir. The inevitable early water breakthrough leaves a large amount of unrecovered oil behind in bypassed matrix blocks.

Fractured Carbonate Reservoir Types

According to J. Allan and Q. Sun (SPE 84590)

Fractured reservoirs are classified based on the interaction between the relative porosity and permeability contributions from both the fracture and matrix systems.

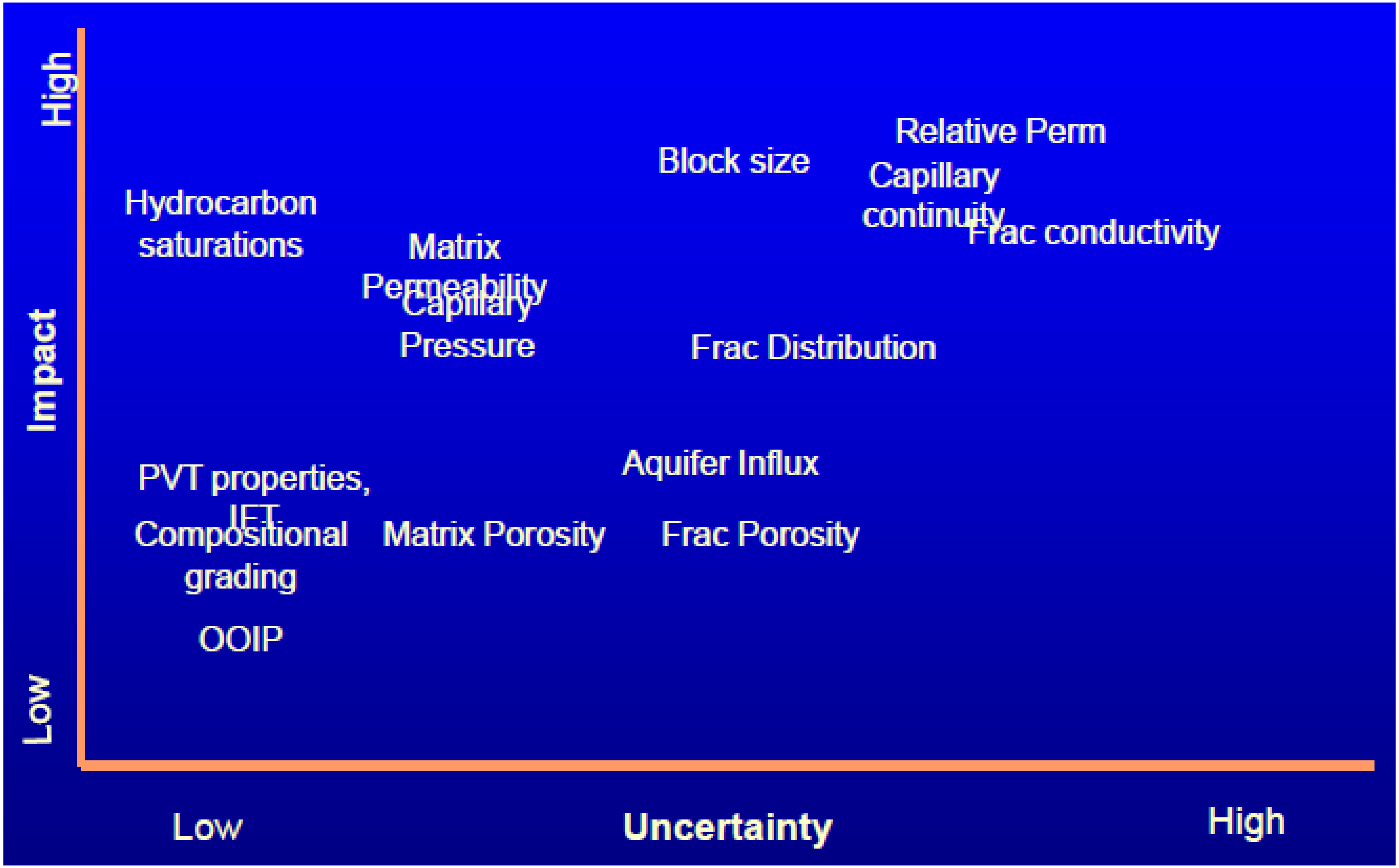
- **Type I :** Type I reservoirs have little matrix porosity and permeability. Fractures provide both storage capacity and fluid-flow pathways.

- **Type II:** Type II reservoirs have low matrix porosity and permeability. Matrix provides some storage capacity and fractures provide the fluid-flow pathways.

- **Type III (microporous):** Type III reservoirs have high matrix porosity and low matrix permeability. Matrix provides the storage capacity and fractures provide the fluid-flow pathways.

- **Type IV (macroporous):** Type IV reservoirs have high matrix porosity and permeability. Matrix provides both storage capacity and fluid flow pathways, while fractures merely enhance permeability.

Key Subsurface Uncertainties and their impacts on Recovery Factor



C&C Reservoirs' Digital Reservoir Analogs System

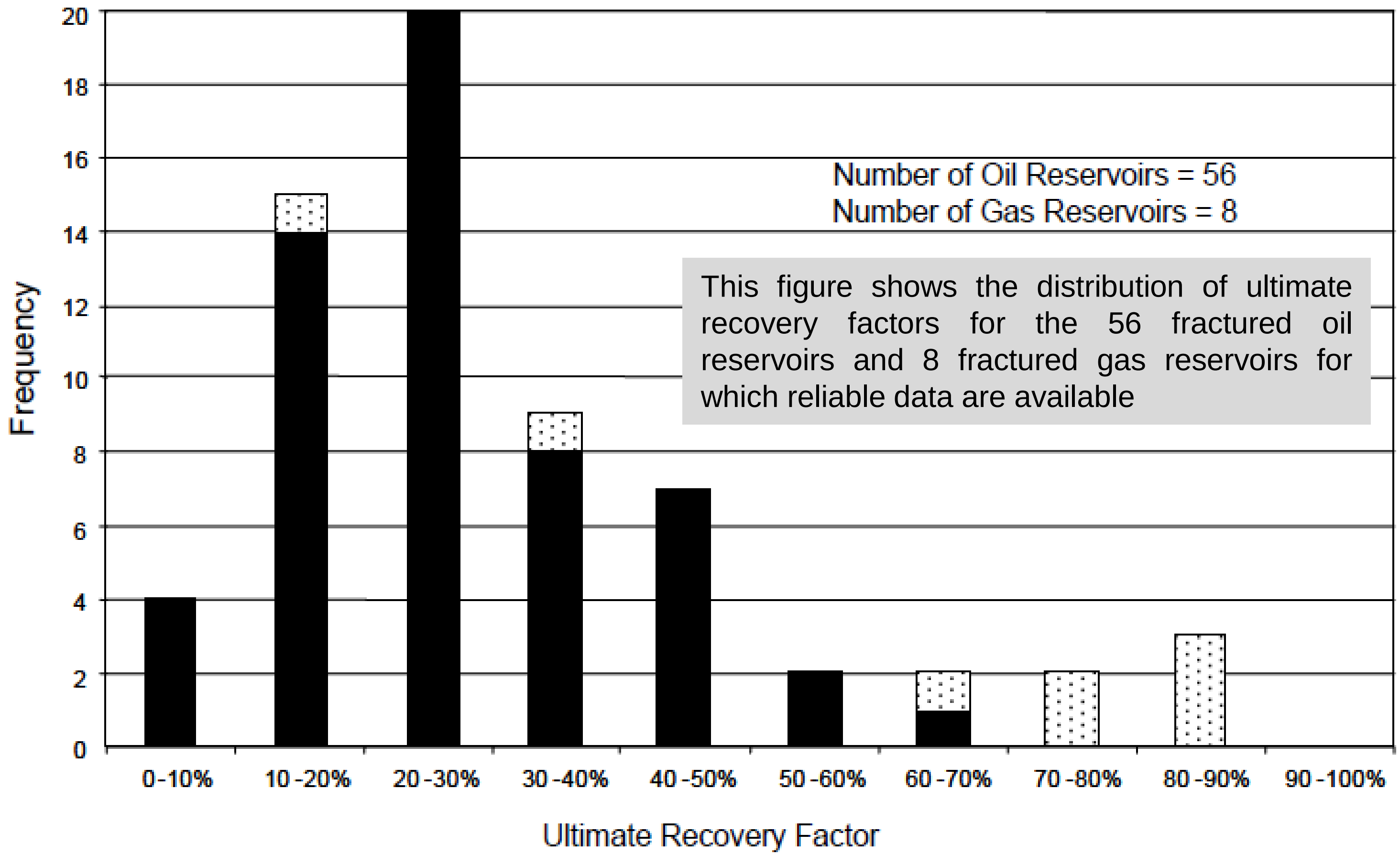
- Contains nearly one thousand producing reservoirs worldwide.
- There are more than one hundred fractured reservoirs which can be analyzed and compared based on their:
  - depositional facies,
  - reservoir architecture,
  - rock properties,
  - fracture networks,
  - fluid types,
  - reservoir development strategies,
  - EOR techniques and
  - production histories.

[Ref.]: The Digital Analogs System, version 3.0 (www.ccreservoirs.com)

Recovery Efficiency in Fractured Reservoirs

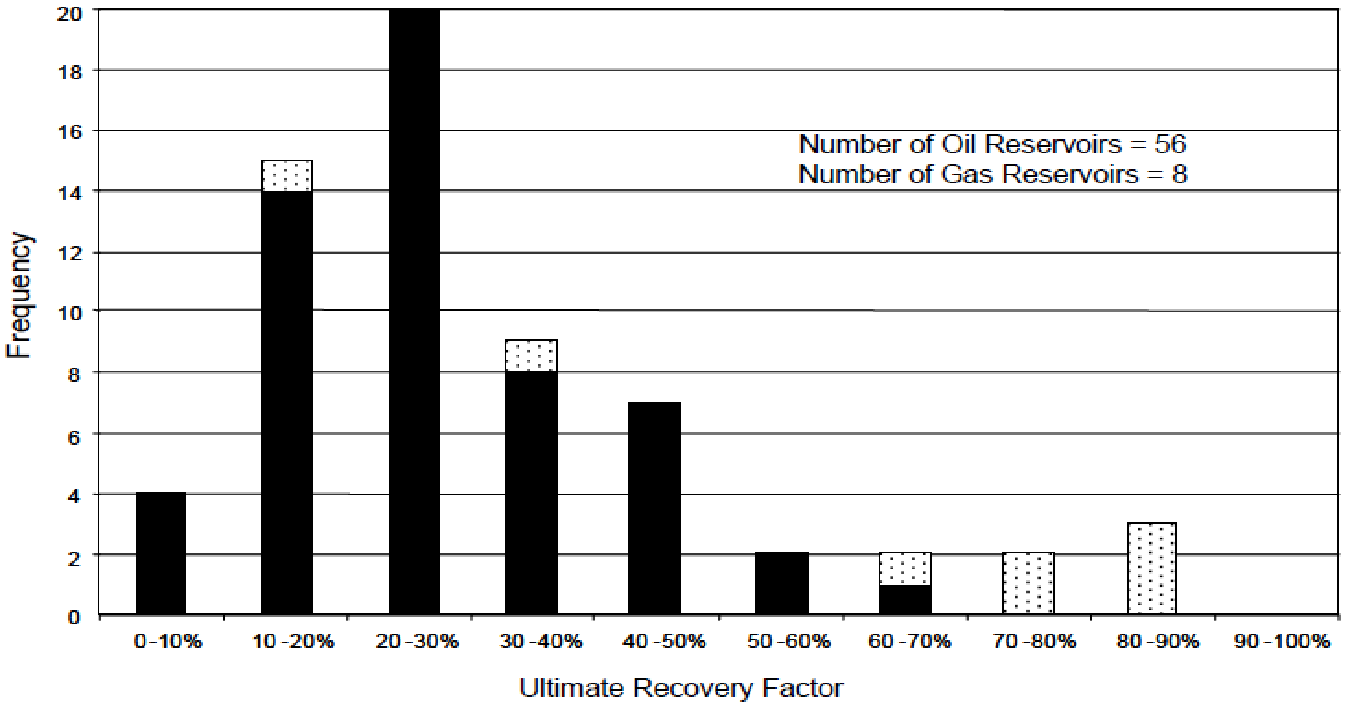
According to J. Allan and Q. Sun (SPE 84590)

➢Data obtained on the 100 fractured reservoirs examined in this study indicate that overall, their ultimate recoveries are somewhat lower than those of many conventional reservoirs, but they still compare favorably with some conventional reservoir types.



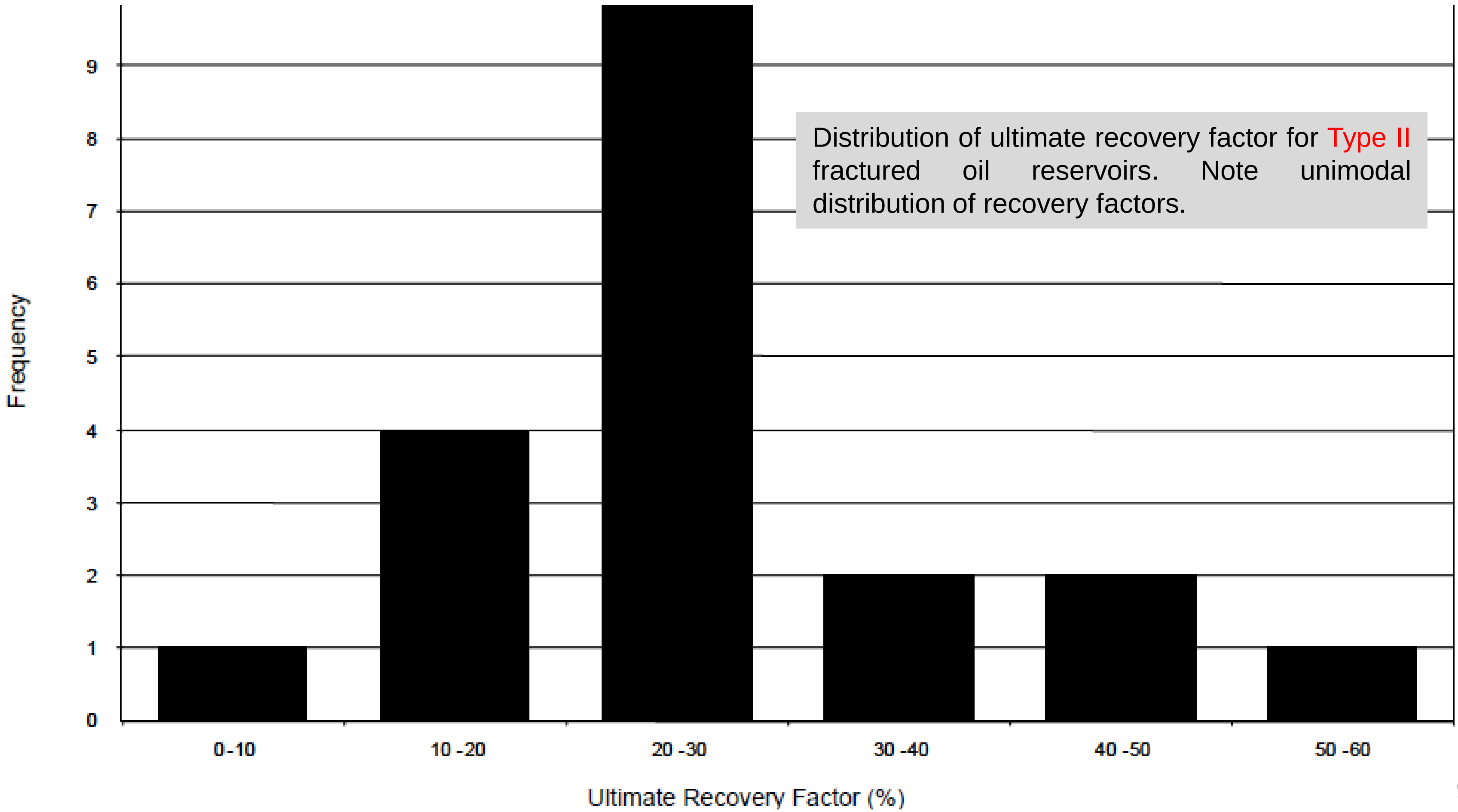
Overall View

- ➢The Type I, II, III and IV fractured oil reservoirs have an average ultimate recovery factor of 26%.
  - ✓Two thirds of the oil reservoirs have recovery factors >20%, which is certainly high enough to be commercially attractive.
- ➢The 8 fractured gas reservoirs have an average ultimate recovery factor of 61%.
  - ➢Three quarters of the gas reservoirs have recovery factors >60%.
  - ➢The low recovery factors in two of the gas reservoirs are caused by water encroachment into fractured depletion drive reservoirs.



Recovery Factors for Type II Fractured Oil Reservoirs

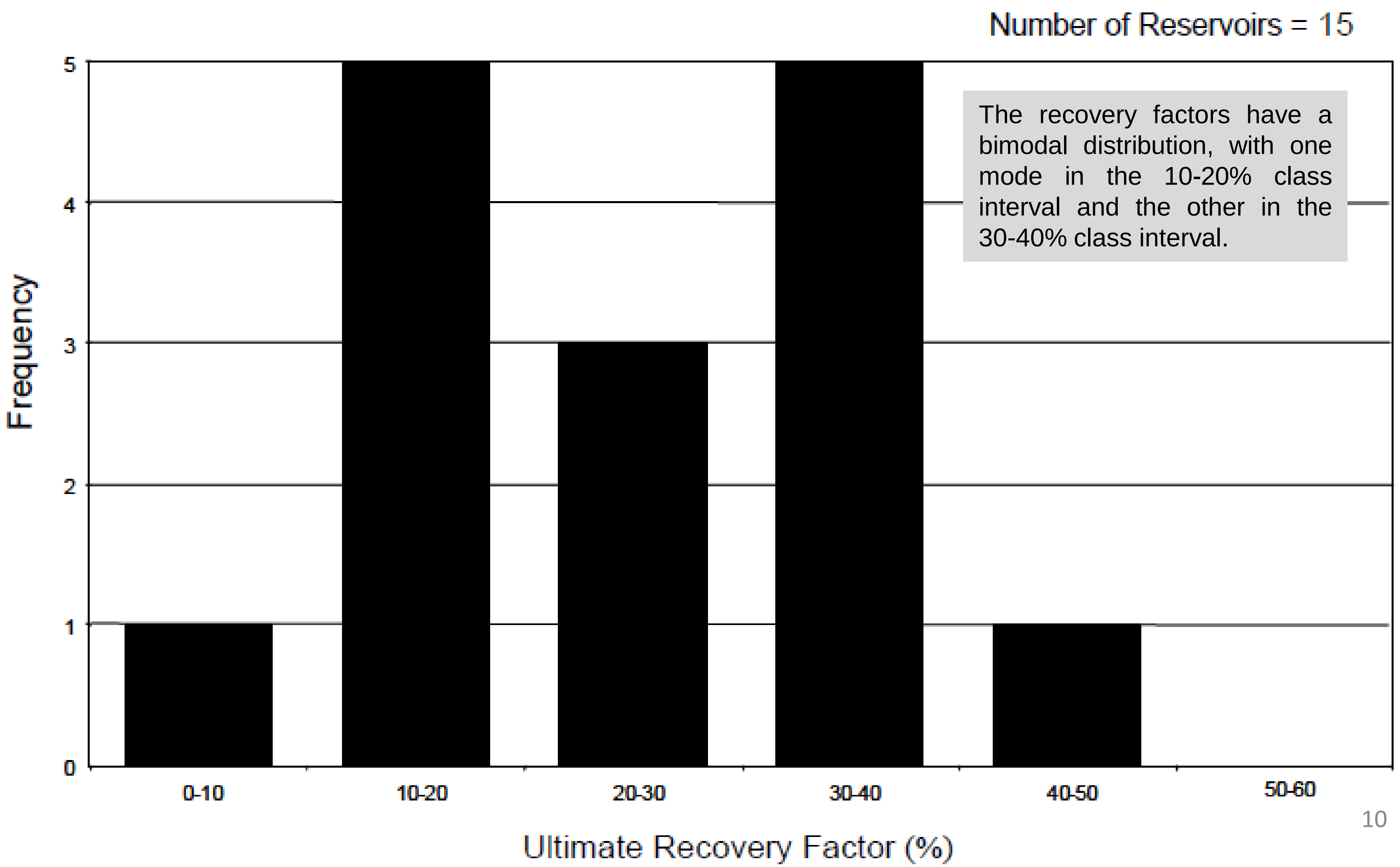
Ultimate recovery factors for the 20 of the 26 **Type II** oil reservoirs for which reliable data are available range from 9 to 56% with an average value of 26%.



Distribution of ultimate recovery factor for Type II fractured oil reservoirs. Note unimodal distribution of recovery factors.

Recovery Factors for Type III Fractured Oil Reservoirs

Ultimate recovery factors for the 15 of the 20 **Type III** oil reservoirs for which reliable data are available range from 7.6 to 44% with an average value of 24%



Factors Controlling RF in Type II Fractured Oil Reservoirs

- Type II reservoirs have low matrix porosity and permeability.
- Matrix provides some storage capacity and fractures provide the fluid-flow pathways.
- Type II fractured oil reservoirs most commonly occur in brittle rocks such as dolomite, tight limestone, tight sandstone and volcanics.

- Cross plots of ultimate recovery factor versus core porosity, air permeability, production-derived permeability, oil viscosity, mobility ratio, API gravity, well spacing, net/gross ratio and residual water saturation **showed little correlation** between these parameters and recovery efficiency.
- This suggests that in **tight Type II** reservoirs, recovery factor is more dependent upon the nature of the fracture network than on the matrix properties of the rock or fluid properties of the oil.
- The fracture network in these brittle lithologies tends to be extensive, it is commonly connected to downdip or underlying regional aquifers. As a result, 16 of the 20 Type II reservoirs for which recovery factors are available have water drives or combination drives that include water drive as one of the components.

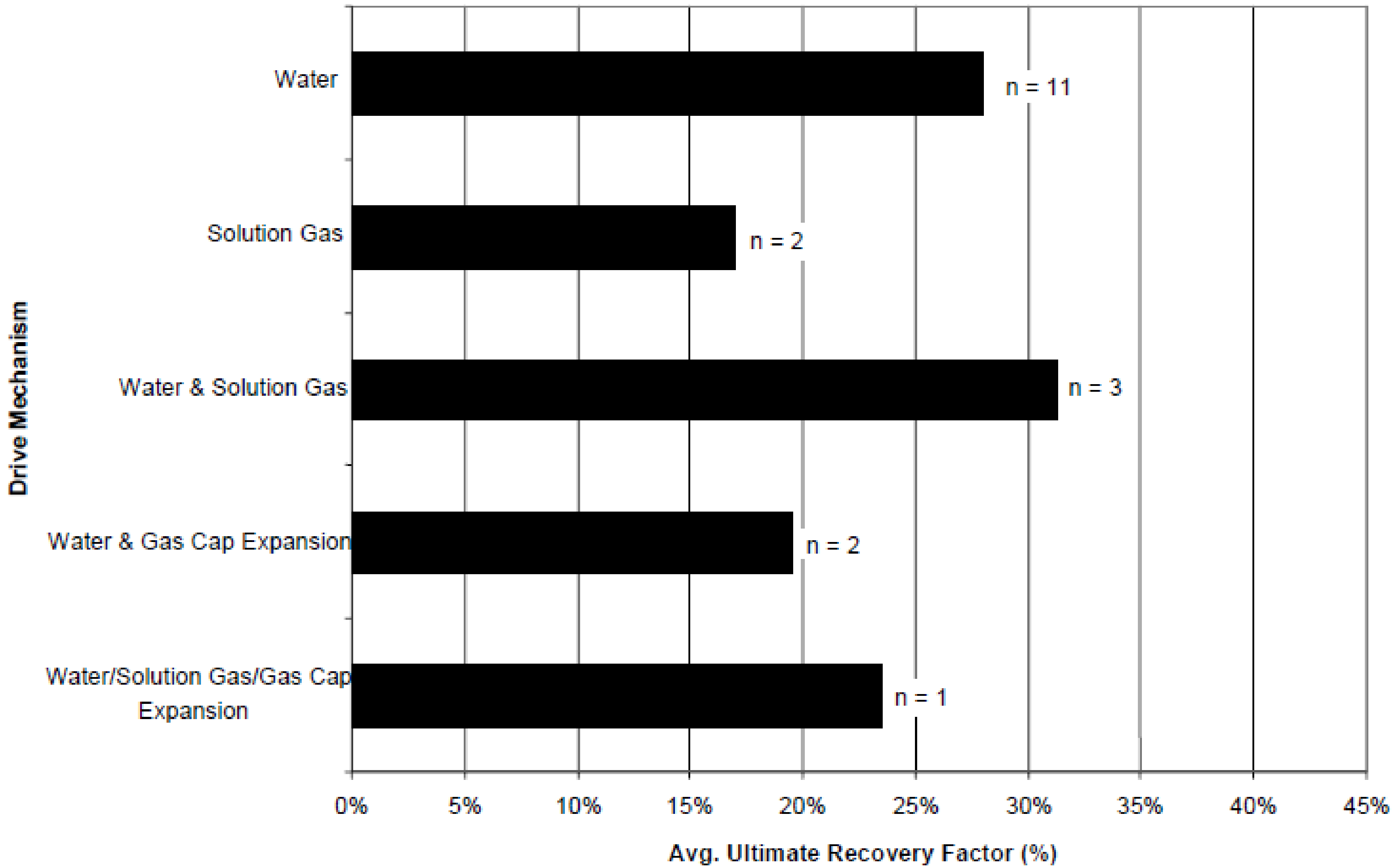
Type II Fractured Oil Reservoirs

Field	Country	Basin	Hydrocarbon Type	Reservoir Lithology	Drive Mechanism	Secondary Recovery/ EOR Technique	Ultimate Recovery Factor (%)
Altamont-Bluebell	USA	Uinta	Light oil	Sandstone	Solution gas	Microbial injection	-
Amposta Marino	Spain	Gulf of Valencia	Heavy oil	Limestone	Strong bottom water	Unassisted primary recovery	56.0%
Augila-Nafoora	Libya	Sirte	Light oil	Basement	No data	No data	22.0%
Bibi Hakimeh	Iran	Zagros	Medium oil	Limestone/dolomite	Water/ gas cap expansion	Gas injection	15.0%
Casablanca	Spain	Gulf of Valencia	Light oil	Limestone/dolomite	Strong bottom water	Unassisted primary recovery	47.5%
Dineh-Bi-Keyah	USA	Colorado Plateau	Light oil	Volcanics	Solution gas	None	-
Gachsaran	Iran	Zagros	Light oil	Limestone/dolomite	Water/ solution gas	Gas injection	26.6%
Gela	Italy	Caltanisetta	Heavy oil	Dolomite	Strong bottom water	Unassisted primary recovery	11.0%
Haft Kel	Iran	Zagros	Light oil	Limestone/dolomite	Water/ solution gas	Gas injection	27.0%
Jatibarang	Indonesia	Northwest Java	Medium oil	Volcanics	Solution gas	None	-
La Paz	Venezuela	Maracaibo	Light oil	Limestone	Solution gas	Water injection	-
Lama	Venezuela	Maracaibo	Light oil	Limestone	Water/ solution gas/ gas cap expansion	No data	23.5%
Liubei	China	Bohai	Light oil	Dolomite	Water	Water injection (poor efficiency)	20.0%
Maozhou	China	Bohai	Light oil	Dolomite	Water	Water injection (poor efficiency)	27.5%
Maxi	China	Bohai	Light oil	Sandstone	Water/ solution gas	Water injection/ hydraulic fracturing	40.0%

Type II Fractured Oil Reservoirs

Field	Country	Basin	Hydrocarbon Type	Reservoir Lithology	Drive Mechanism	Secondary Recovery/ EOR Technique	Ultimate Recovery Factor (%)
Nido	Philippines	Northwest Palawan	Medium oil	Limestone	Strong bottom water	Unassisted primary recovery	35.0%
Paris	Iran	Zagros	Light oil	Limestone/dolomite	Water/ gas cap expansion	Gas injection	24.0%
Ragusa	Italy	Iblean Plateau	Heavy oil	Dolomite	Water	No data	30.0%
Renqiu	China	Bohai	Medium oil	Dolomite	Water	Water injection	25.0%
Samgori	Georgia	Kura	Light oil	Volcanics	Water	No data	-
Spraberry Trend	USA	Midland	Light oil	Sandstone	Solution gas	Horizontal drilling/ hydraulic fracturing/ water injection (poor efficiency)	9.0%
Tirrawarra	Australia	Cooper	Light oil	Sandstone	Solution gas	Gas injection/ hydraulic fracturing	25.0%
Vega	Italy	Ragusa	Heavy oil	Limestone/dolomite	Water	No data	15.0%
West Cat Canyon	USA	Santa Maria	Heavy oil	Dolomite	Fluid expansion & pore volume contraction/ solution gas/ gravity drainage	No data	-
Yanling	China	Bohai	Medium oil	Dolomite	Water	Water injection (poor efficiency)/ gas (N2) injection	18.5%
Yihezhuang	China	Bohai	Light oil	Limestone/dolomite	Weak water	Water injection (poor efficiency)	22.5%

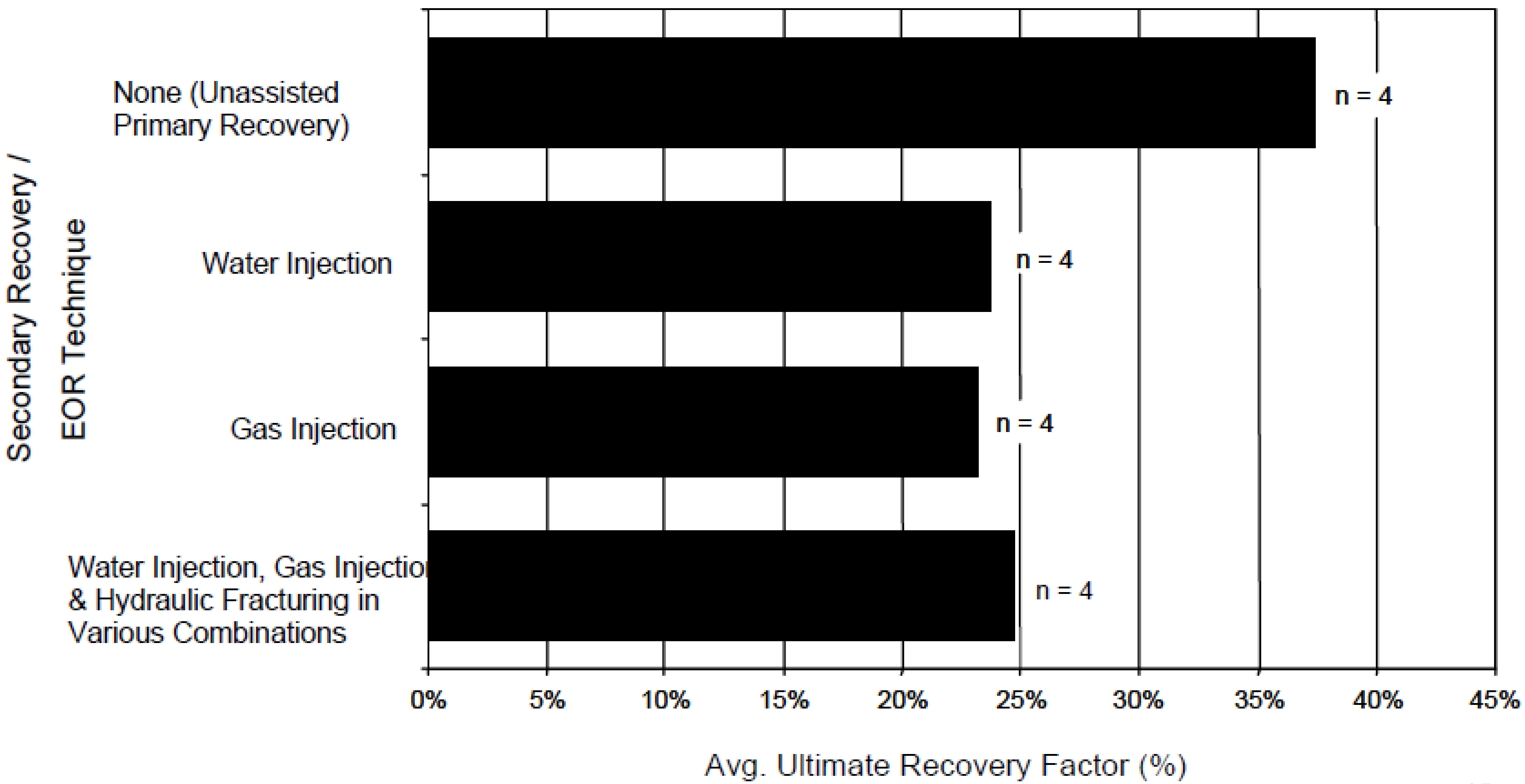
Type II Fractured Oil Reservoirs



Ultimate recovery factor as a function of drive mechanism for Type II fractured oil reservoirs. Sixteen of the 20 Type II reservoirs for which recovery factors are available produce by water drive or by combination drives that include water drive as one of the components.

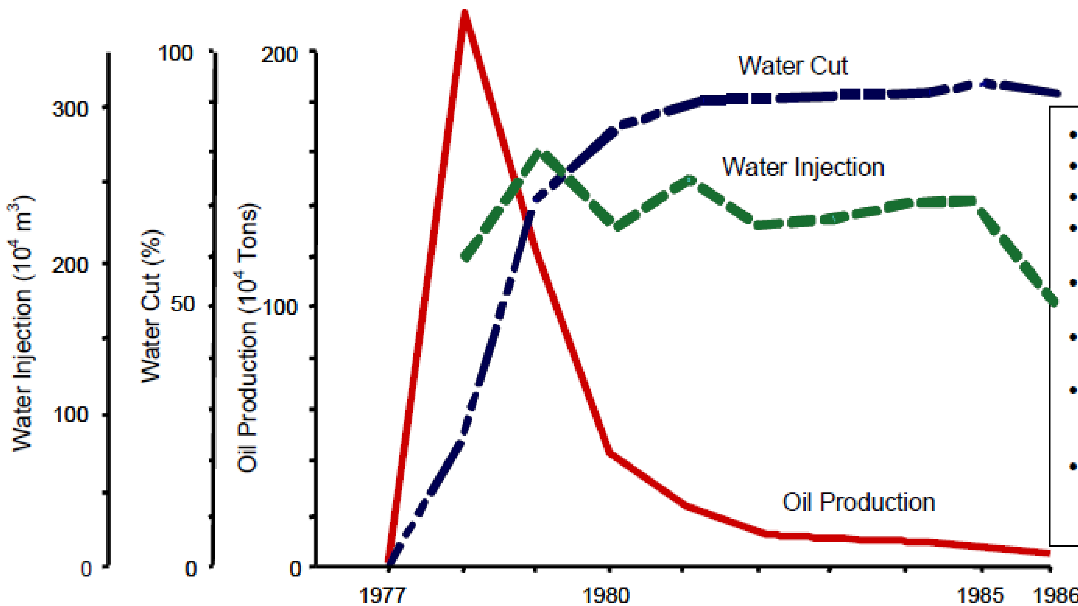
Type II Fractured Oil Reservoirs

Ultimate recovery factor as a function of secondary recovery/EOR technique for Type II fractured oil reservoirs. Reservoirs with strong bottom water drive had excellent recovery without the assistance of any secondary recovery/EOR techniques while reservoirs with weaker water drives or other drive mechanisms have lower recovery factors even when subjected to secondary recovery/EOR techniques



Poor Management of Water Production

Yanling Field, a Type II fractured karstic carbonate oil reservoir in northeastern China, was produced at a very high rate during its first two years onstream. Wells were drilled into the top of the reservoir and completed open hole. The excessively high production rate prevented much matrix oil from draining into the fractures, leading to rapid pressure and production decline in the reservoir. A water injection program undertaken to reverse the pressure decline only served to create a water incursion problem. Yanling field had an abbreviated production life and achieved <20% ultimate recovery

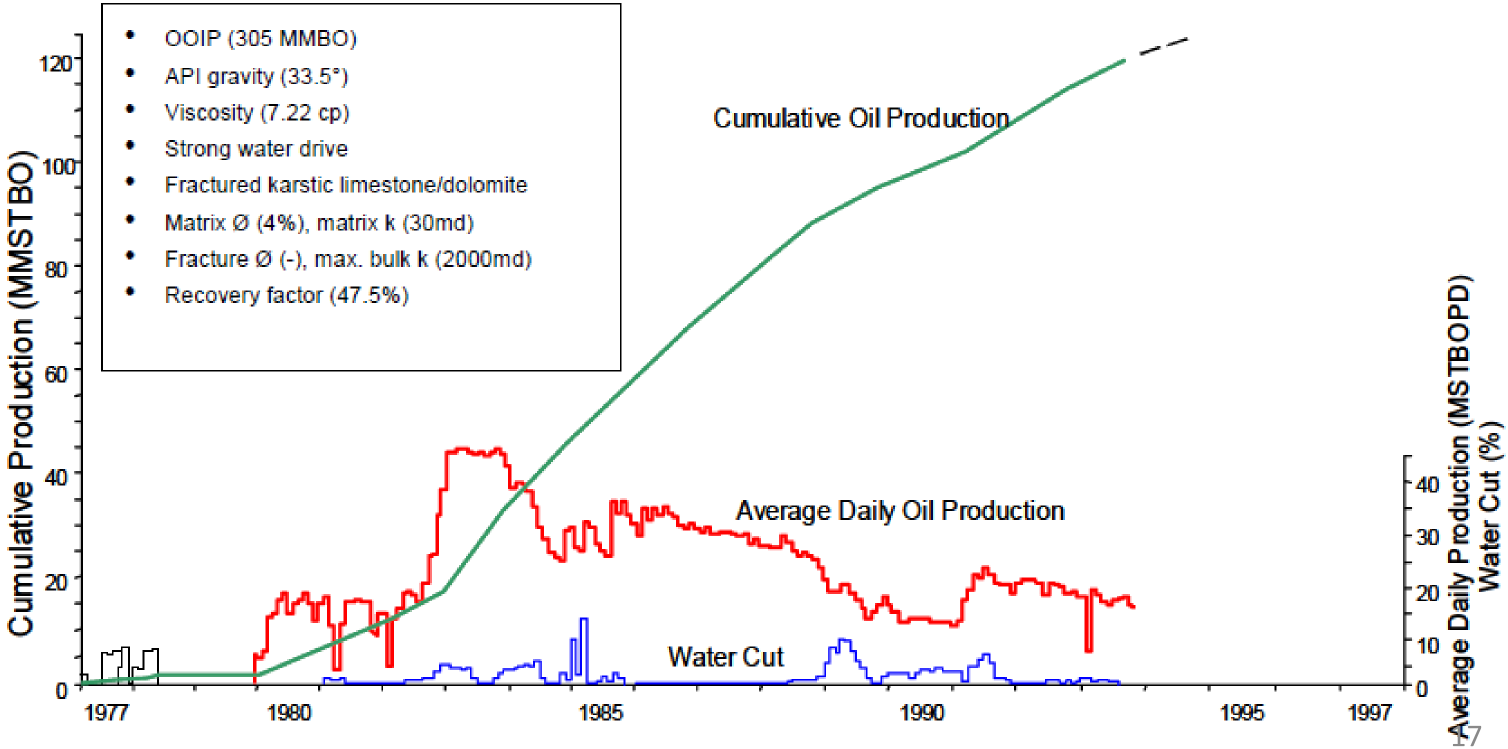


- OOIP (310 MMBO)
- API gravity (27°)
- Viscosity (15.9 cp)
- Active bottom water drive
- Fractured karstic dolomite
- Matrix Ø (1.3%), matrix k (1.2md)
- Fracture Ø (3.4%), max. bulk k (5323md)
- Recovery factor (19.5%)

Type II reservoirs tend to have fracture networks that are connected to aquifers, high production rates can lead to rapid water incursion and premature production decline.

Good Water Management of Water Production

Casablanca Field, a Type II fractured karstic carbonate oil reservoir in offshore Spain, <u>has rock and fluid properties similar to those at Yanling</u>. It was developed similarly. Producing wells were drilled into the top 1/3 of the reservoir and completed open hole. However, at Casablanca, the operator <u>carefully controlled production rate</u> by reducing choke size whenever water cut reached 2% of the total liquids production from any given well. No secondary recovery or EOR techniques were applied. By simply controlling production rate and water cut, Casablanca field has achieved an <u>ultimate recovery factor of >45%</u>



The Most Critical Factors for Maximizing Recovery Factor in Type II Fractured Oil Reservoirs

1. Optimization of flow rate
2. Careful management of water production

Factors Controlling RF in Type III Fractured Oil Reservoirs

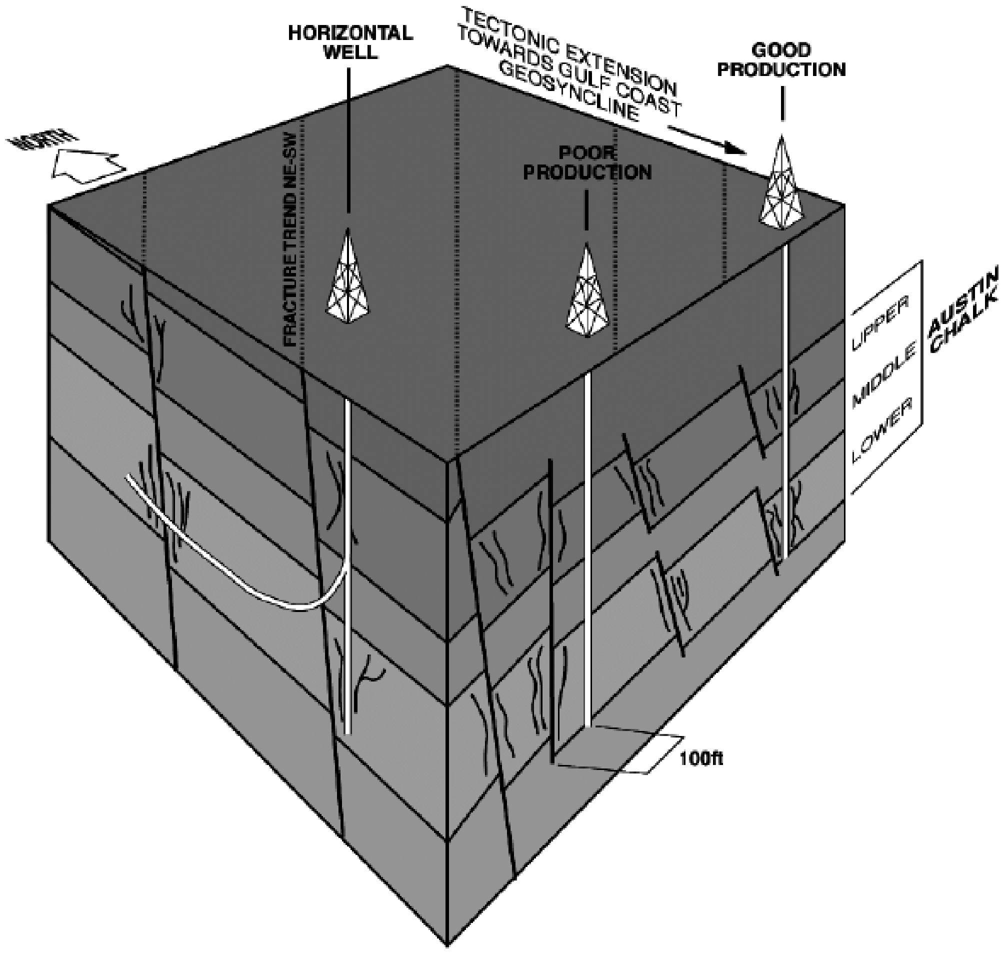
- Type III (microporous) reservoirs have high matrix porosity and low matrix permeability. Matrix provides the storage capacity and fractures provide the fluid-flow pathways.
- Type III fractured oil reservoirs most commonly occur in ductile rocks such as chalk, diatomite and siliceous shale.

- Cross plots of ultimate recovery factor versus core porosity, air permeability, production-derived permeability, oil viscosity, mobility ratio, API gravity, well spacing, net/gross ratio and residual water saturation **revealed several relationships.**
  - ✓Air permeability of the matrix rock and API gravity of the oil showed a moderate positive correlation
  - ✓Mobility ratio and net/gross ratio showed a weak positive correlation
  - ✓Residual water saturation showed a weak negative correlation

Thus, rock and fluid properties exert a more significant control on ultimate recovery in Type III reservoirs than in Type II reservoirs.

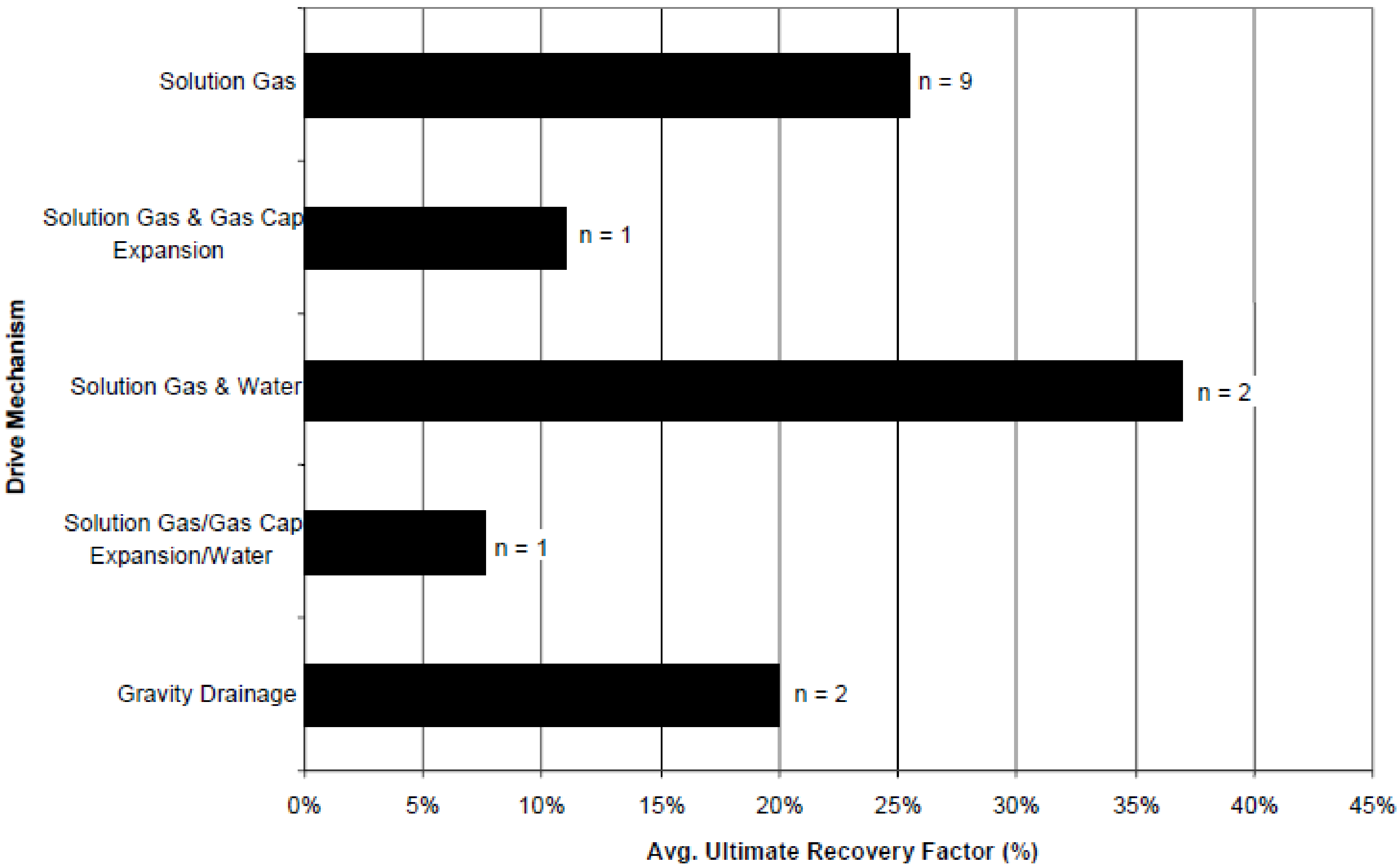
Factors Controlling RF in Type III Fractured Oil Reservoirs

- Because most of the Type III reservoirs are composed of <u>ductile lithologies</u>, fractures tend to be <u>localized</u> around faults and areas of maximum curvature on flexures and generally <u>do not connect to downdip</u> or underlying aquifers.



Type III Fractured Oil Reservoirs

➢All of the reservoirs produce by solution-gas, gascap-expansion and gravity drainage drive or by combination drives in which one of these drive mechanisms dominates.

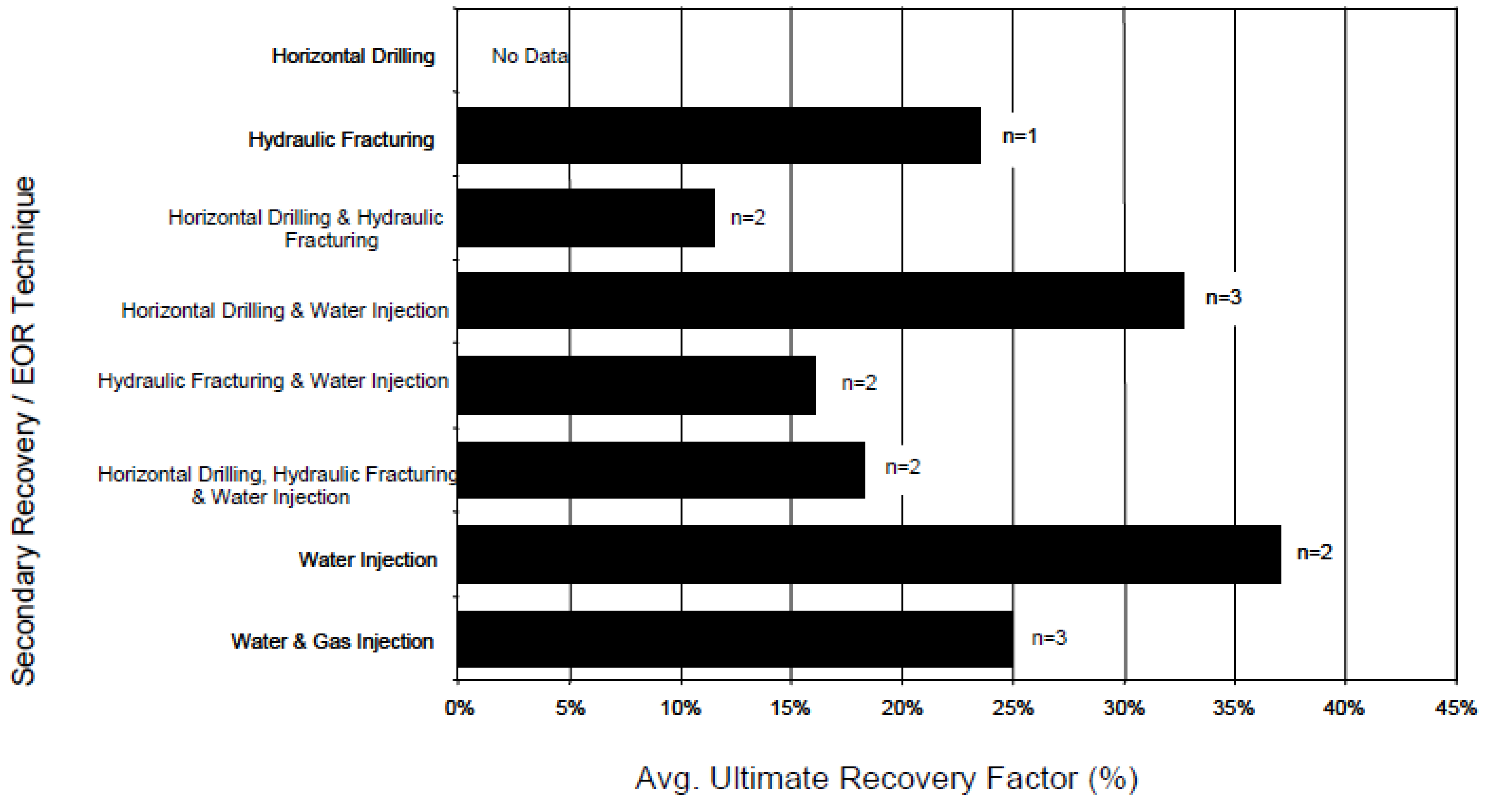


Type III Fractured Oil Reservoirs

Field	Country	Basin	Hydrocarbon Type	Reservoir Lithology	Drive Mechanism	Secondary Recovery/EOR Technique	Ultimate Recovery Factor (%)
Dan	Denmark	North Sea Central Graben	Light oil	Primary Chalk	Solution gas/ gas cap expansion	Horizontal drilling/ hydraulic fracturing	11.0%
Ekofisk	Norway	North Sea Central Graben	Light oil	Primary Chalk	Solution gas	Water injection/ gas injection	35.0%
Eldfisk	Norway	North Sea Central Graben	Light oil	Primary Chalk	Solution gas	Hydraulic fracturing	23.5%
Fahud	Oman	Oman Foredeep	Light oil	Chalky limestone	Gravity drainage	Water injection (poor efficiency)/ gas injection	18.0%
Giddings	USA	Gulf of Mexico	Medium & light oil	Primary Chalk	Solution gas	Horizontal drilling/ hydraulic fracturing	-
Idd El Shargi	Qatar	Arabian Gulf	Medium oil	Chalky limestone	Gravity drainage	Horizontal drilling	-
Kraka	Denmark	North Sea Central Graben	Light oil	Primary Chalk	Solution gas/ gas cap expansion	Horizontal drilling	-
Lisburne	USA	North Slope	Medium oil	Limestone/dolomit	Solution gas/ gas cap	Horizontal drilling/ hydraulic	7.6%
Lost Hills	USA	San Joaquin	Heavy & medium oil	Chert/diatomite	Solution gas	Hydraulic fracturing/ water injection	17.0%
Midale	Canada	Williston	Light oil	Dolomite	Solution gas	Horizontal drilling/ water injection (poor efficiency)	31.0%
Natih	Oman	Oman Foredeep	Light oil	Chalky limestone	Gravity drainage	Water injection (poor efficiency)/ gas injection	22.0%
Norman Wells	Canada	Western Canada	Light oil	Chalky limestone	Solution gas	Horizontal drilling/ water injection	37.0%
Pearsall	USA	Gulf of Mexico	Medium oil	Primary Chalk	Solution gas	Horizontal drilling/ hydraulic fracturing	12.0%
Salym	Russia	Western Siberia	Light oil	Chert/shale	Solution gas	Hydraulic fracturing/ water injection	-
Skjold	Denmark	North Sea Central Graben	Light oil	Primary Chalk	Solution gas/ water (weak)	Water injection	30.0%
South Belridge	USA	San Joaquin	Heavy & light oil	Chert/diatomite	Solution gas	Hydraulic fracturing/ water injection	15.0%
Three Bar	USA	Tobosa	Light oil	Chert	Solution gas	CO2 injection/ water injection	-
Valhall	Norway	North Sea Central Graben	Light oil	Primary Chalk	Solution gas	Horizontal drilling/ hydraulic fracturing/ water injection	29.0%
Weyburn	Canada	Williston	Light oil	Dolomite	Solution gas	Horizontal drilling/ water injection (poor efficiency)	30.0%
Yibal-A	Oman	South Oman	Light oil	Primary Chalk	Solution gas/ water	Water injection	44.0%

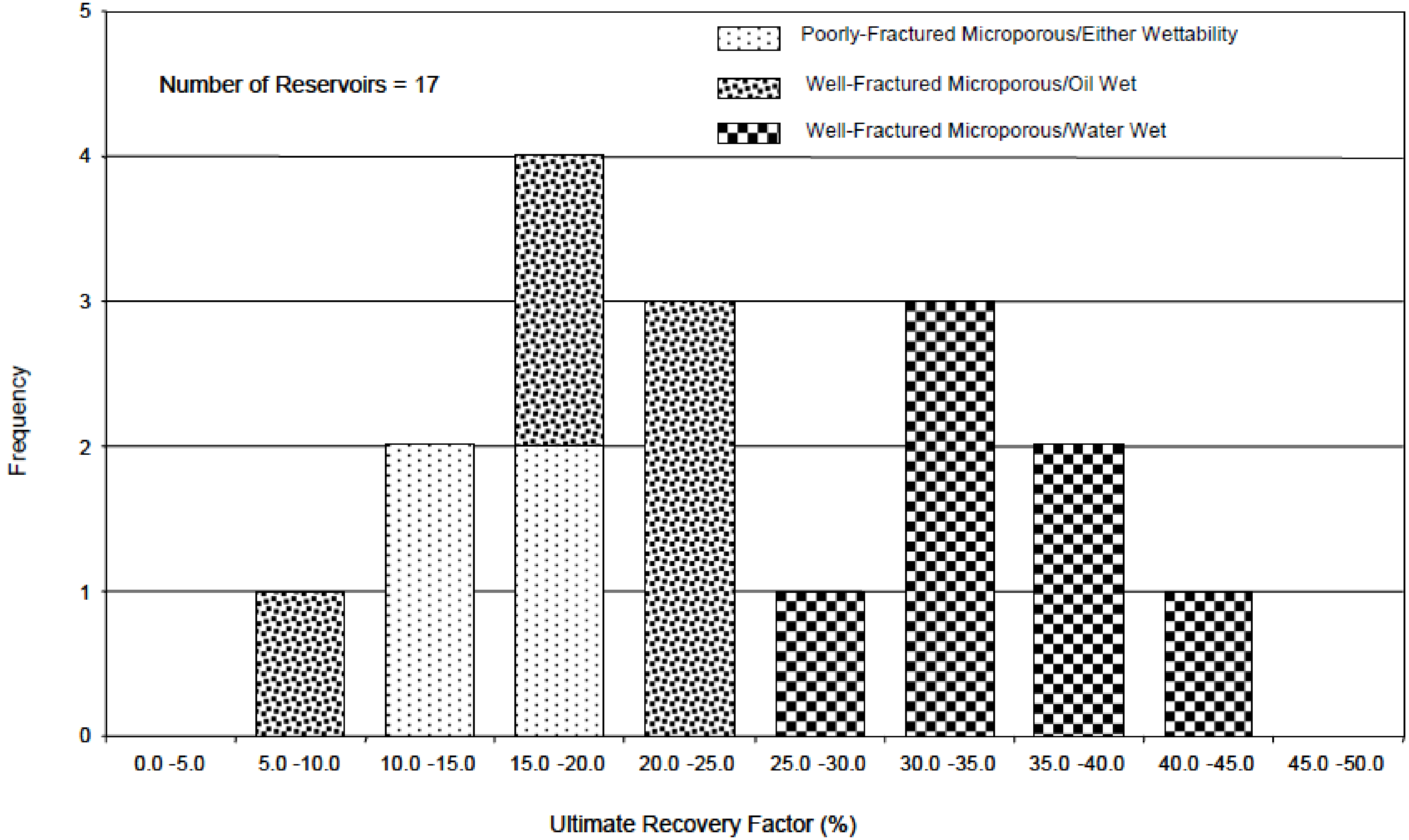
Type III Fractured Oil Reservoirs

➢In contrast to Type II reservoirs, the application of secondary recovery and EOR techniques is essential for maximizing recovery.



Type III Fractured Oil Reservoirs

➢Recovery factors were compared for 17 Type III fractured oil reservoirs for which the wettability and fracture intensity had been determined. All of the well-fractured, water-wet Type III reservoirs have ultimate recovery factors >25%, while all of the well-fractured, oil-wet Type III reservoirs have ultimate recovery factors <25%



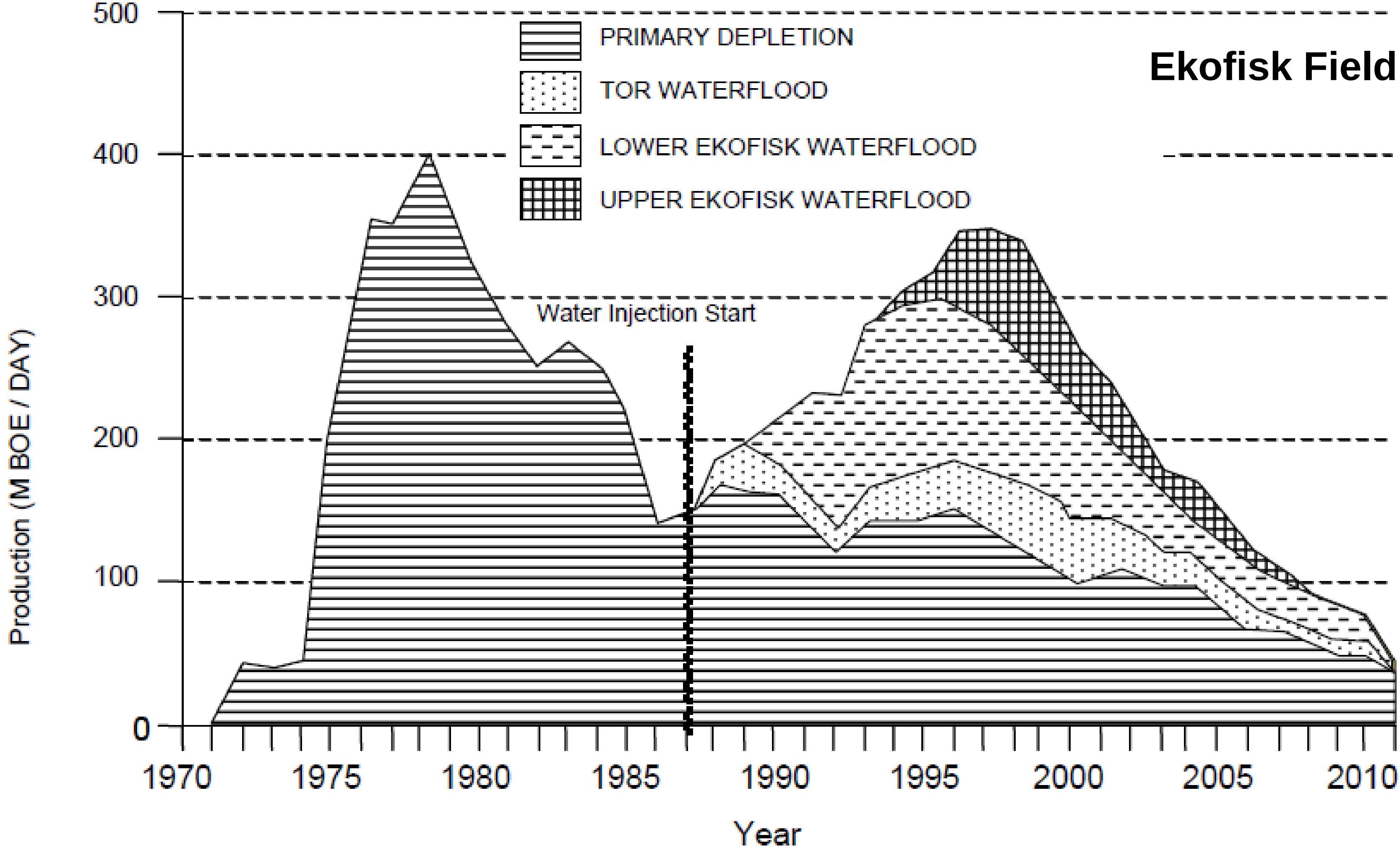
Type III Fractured Oil Reservoirs

- In poorly fractured reservoirs, in which bypassed oil is commonly left behind in matrix blocks, ultimate recovery factors are <20% regardless of wettability.

- The reason for the large disparity in recovery factor between water-wet and oil-wet Type III reservoirs is that:
    - water can penetrate microporosity in water-wet reservoirs by capillary imbibation, thus providing an efficient primary recovery mechanism, while it cannot do so in an oil-wet reservoir.
    - For the same reason, water injection into a water-wet reservoir is far more efficient than water injection into an oil-wet reservoir. Therefore, secondary water flooding of a water-wet reservoir further increases its ultimate recovery factor, but often has little effect on an oil-wet reservoir.

Effect of Wettability on Ultimate Recovery Factor in Type III Fracture Oil Reservoirs- Ekofisk Field

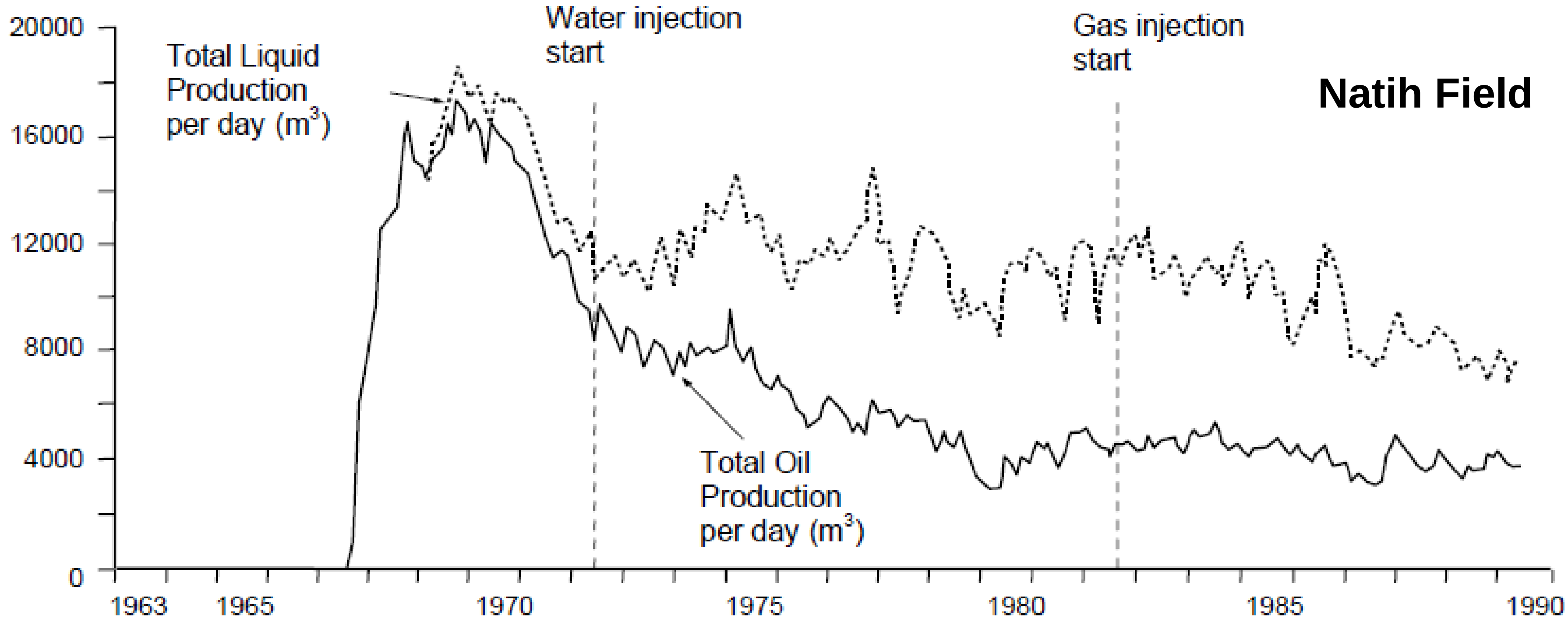
Ekofisk Field, in the Norwegian sector of the North Sea, produces from several water-wet, Type III primary chalk reservoirs. The field came on stream in the early 1970s, ramped up to full production in about 5 years, and almost immediately went into steep decline. Water injection was begun in the late 1980s. The reservoirs were very responsive to water flooding, the production decline was reversed, a secondary production peak that was almost as high as the primary production peak was reached in the late 1990s, and the field achieved a recovery factor under water flood of >35% .



- OOIP (6,400 MMBO)
- Solution gas drive
- Naturally fractured, water-wet over-pressured chalk
- Water injection since 1987 (successful)
- Recovery factor (35%; primary = 18%, secondary = 17%)

Effect of Wettability on Ultimate Recovery Factor in Type III Fracture Oil Reservoirs- Natih Field in Oman

Natih Field in Oman produces from an oil-wet, Type III diagenetic chalk reservoir. The field was ramped up to full production within a few years of coming on stream, and quickly went into steep pressure and production decline. The primary production profile is almost identical to that at Ekofisk. Pressure-maintenance water injection did not arrest the production decline. After the failure of the water-injection program, crestal gas injection was begun to induce gravity drainage. Gas injection arrested, but did not reverse, the production decline. In part because of the poor response water injection, this oil-wet reservoir achieved an ultimate recovery factor of only 22%



- OOIP (3,000 MMBO)
- Initially solution gas drive, followed by gravity drainage
- Naturally fractured, oil-wet chalky limestone reservoir
- Water injection began in 1972 (failed)
- Crestal gas injection since 1982 (successful)
- Recovery factor (22%)

Natih Field might have achieved a greater ultimate recovery if a different secondary recovery program had been chosen (e.g., crestal gas injection only).