JOURNAL OF PETROLEUM GEOMECHANICS
(JPG)

Redeveloping Mature Fractured Carbonate Reservoirs

Maurice B Dusseault
Professor of Geological Engineering, University of Waterloo, Ontario CANADA, mauriced@uwaterloo.ca

Received: 02 Jan 2019; Accepted: 20 Mar 2019

DOI: 10.22107/JPG.2019.88407

Keywords
Redeveloping
Fractured
Carbonate Reservoirs
Persian Gulf Geomechanics
Geomechanical

Abstract

Naturally fractured carbonate reservoirs (NFCRs) comprise the majority of the oil and gas reservoirs around the Persian Gulf. Many of these reservoirs have a long history of exploitation, but vast amounts of oil remain in place. A major redevelopment process for light oil based NFRs will likely be the use of horizontal wells combined with gravity drainage at constant pressure based on voidage replacement with natural gas (top-down) and natural bottom water drive or deliberate bottom water injection (bottom up), or controlled flank water invasion for reservoirs with adequate dip. The excellent recovery factors achieved in Alberta NFCRs depends on appropriate well placement, careful voidage replacement management, and continuous monitoring of pressures, rates and fluid ratios.

Geomechanical aspects of such a redevelopment approach may involve the placing of horizontal wells in orientations conducive to small-scale well stimulation activities revolving around hydraulic fracturing. Such fracturing helps guarantee that sufficient aperture vertical channels are available so that stable gravity drainage can develop and give adequate production rates per well.

The proposed approach and information needs for the proper placement of wells and appropriate stimulation practices are outlined. In particular, good understanding of reservoir permeability distribution, water/oil interfaces, lithology data, and *in situ* stress field data are needed, and this is more challenging in reservoirs that have already gone through some amount of pressure depletion.

1. Naturally Fractured Reservoirs

Carbonate strata are usually naturally fractured because of because of diagenetic processes that are linked to the relatively high solubility of $CaCO_3$ in water (e.g. Nelson 2001). In a geomechanics sense, the high contact stresses that arise in the intergranular matrix during burial under normally pressured conditions leads to dissolution at highly stressed contact points, and precipitation elsewhere in the fabric where the stresses are lesser. For example, a vertical grain-to-grain contact will preferentially dissolve at the physical contact point because of the higher internal energy content arising from the local high effective stresses in the gran mineral. In the vertical direction, this dissolution leads to vertical movement, or compaction, with attendant loss of porosity (Figure 1). The example shown is for quartz grains, but the concept applies to carbonates as well.

In the ground, under a three-dimensional stress state at some depth, suppose that all stresses on the carbonate sediment in a laterally extensive tabular reservoir are equal when dissolution starts, and assume no pore pressure changes. The vertical total stress must remain approximately constant because of the free surface (constant stress boundary condition), but the horizontal (lateral) stress cannot remain constant. Initially, the horizontal grain contacts are under the same contact force as the vertical contacts, and for a typical carbonate bed, any dissolution means that the lateral stress must drop because the boundary condition in the horizontal direction is a no-lateral-displacement of the tabular reservoir. This means that the dissolution, which is driven by diffusion mechanics and effective stresses, in addition to geochemical factors (Zhang & Spiers 2005), will slow down for contacts in the horizontal direction as stresses drop. With continued burial and increase in vertical stresses, vertical fractures will develop at some spacing that is a function of the thickness of the mechanical unit, among other factors (e.g. Wennberg *et al* 2006). Also, the diagenesis and fracture development lead to the condition that the minimum horizontal stress is the lowest, which in turn means that vertical hydraulic fractures are favored during stimulation of wells. Other factors will impact the development of the natural fracture fabric during the course of time, including erosion and uplift, tectonic loading (as in the heavy oil carbonates of the Kuh-i-Mond anticlinal structure, Shafiei & Dusseault 2007), pore pressure generation history, and changing pore fluid geochemistry conditions.

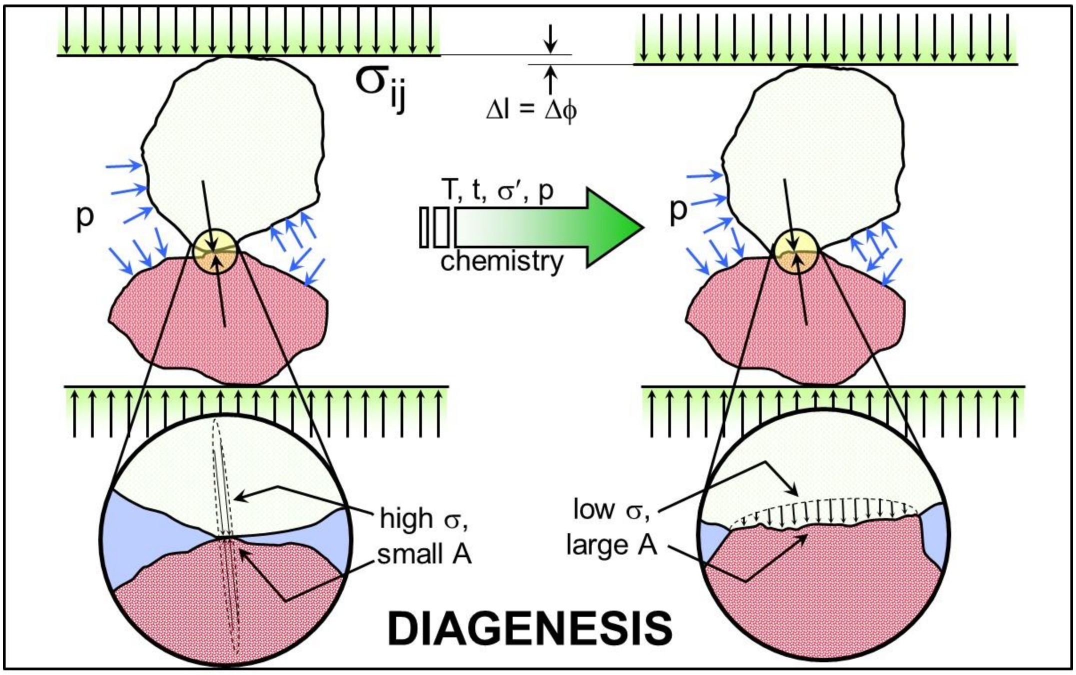

Figure 1. Pressure Solution Triggered by High Contact Stresses Leads to Compaction, Stress Change

At the time of exploitation of oil and gas, we find that the vast majority of tabular carbonate reservoirs have systems of vertical fractures, giving rise to good vertical permeability in most cases, as in the large and highly productive NFCRs of the Persian Gulf. These fractures do not extend significantly into the cap rock, which may be shale, marl, or a fine-grained siltstone; in other words, the vertical migration seal is intact in these NFCRs because the cap rocks do not exhibit the open fractures of the carbonate reservoir. Their low intrinsic permeability and limited natural fracturing, combined with capillary effects in multiphase fluid flow, generates a barrier to vertical migration of fluids such as natural gas. For example, a fine-grained, water-wet siltstone may have a permeability to water (single phase flow), but the small size of the pore throats serve as a capillary barrier to the upward percolation of free gas or oil (multiphase flow with capillary blockage inhibiting upward migration). The good vertical permeability and intact cap rock of the Persian Gulf NFCRs are positive factors in assessing the potential for redevelopment based on gravity drainage principles.

2. Water Breakthrough in NFCRs

Exploitation of the NFCRs of the Persian Gulf region historically has taken place under pressure drawdown conditions in arrays of vertical wells. Most of these reservoirs have basal or lateral access to active water, and hydrodynamic effects lead to upward coning of basal water (Ahmadi *et al* 2014,) lateral invasion of flank water (Berg *et al* 1994) (Figure 2), and downward coning of gas caps. The coning occurs because the large hydrodynamic forces associated with pressure drawdown overcome the natural tendency to develop a horizontal interface between immiscible fluids of different densities. In other words, aggressive pressure drawdown overwhelms gravity forces.

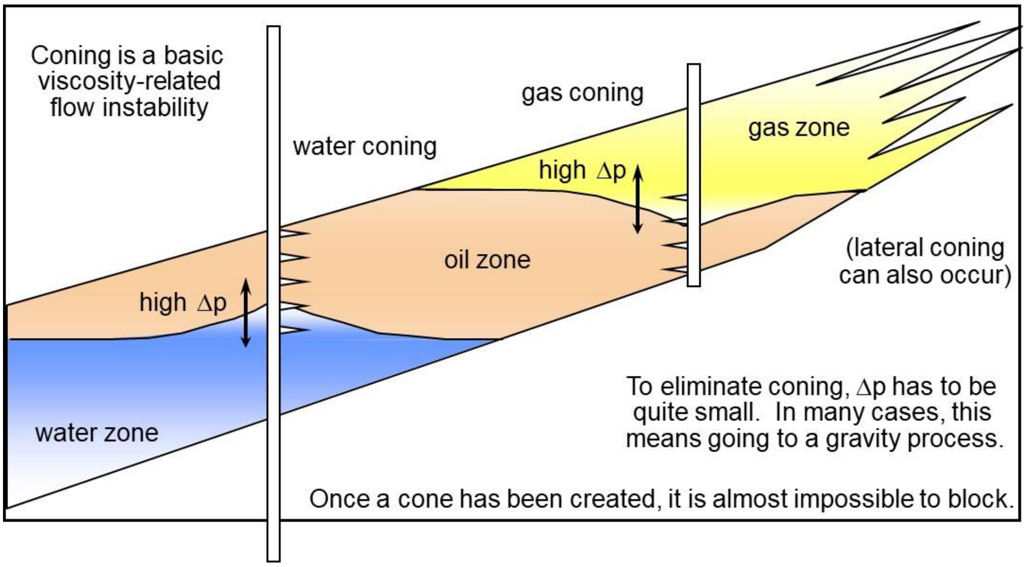

Figure 2. Basal and Flank Water Coning, Gas Coning During Aggressive Drawdown

In some cases, especially in NFCRs, preferential water flow along the higher conductivity natural fractures leads to early water breakthrough, a process called channeling (Figure 3). Once breakthrough has occurred, it is costly and often ineffective to try to block the channel to deflect the displacement flow to other, unswept regions. These two-dimensional diagrams also do not emphasize that in a three-dimensional world, fluids have freedom in all directions to find the most favorable pathway. These are subjects of great interest because of the impacts on oil production. These impacts include reduction of relative permeability to oil as water or gas saturation increases in the coned zone, isolation of oil bodies that are unconnected to any continuous oil flow regime (ganglia – Figure 4), rapid flow along channels, and capillary blockage that develops as phase saturations change. In the case of changes in saturation that lead to large changes in relative permeability, it is generally not possible to reverse the effects, so coning and capillary blockages usually lead to permanent impairment of oil production capacity and generate low ultimate Recovery Factors (R_F).

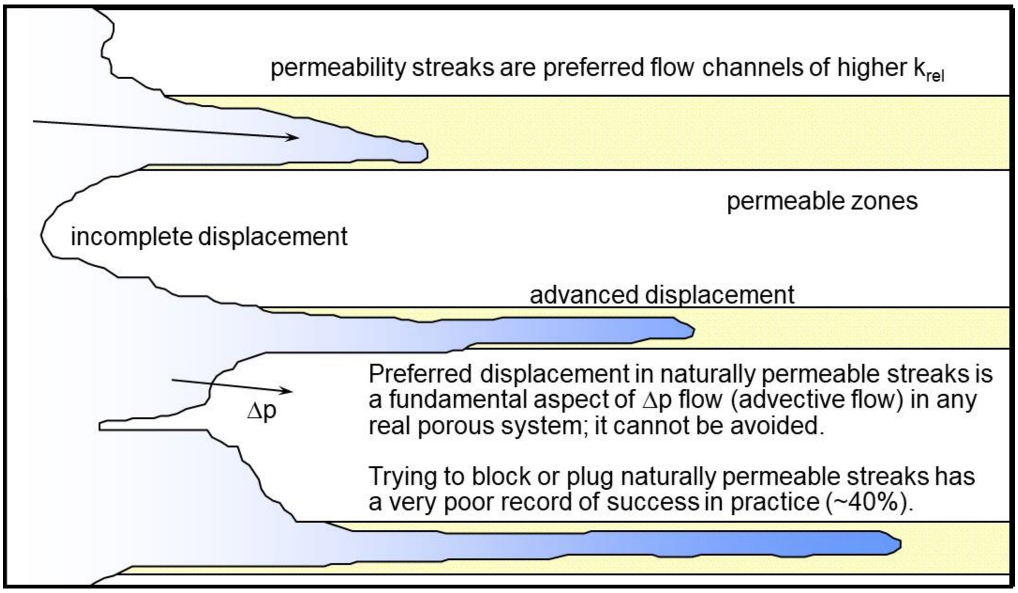

Figure 3. Channeling Arises Because of Permeability Contrasts and Pressure Gradients

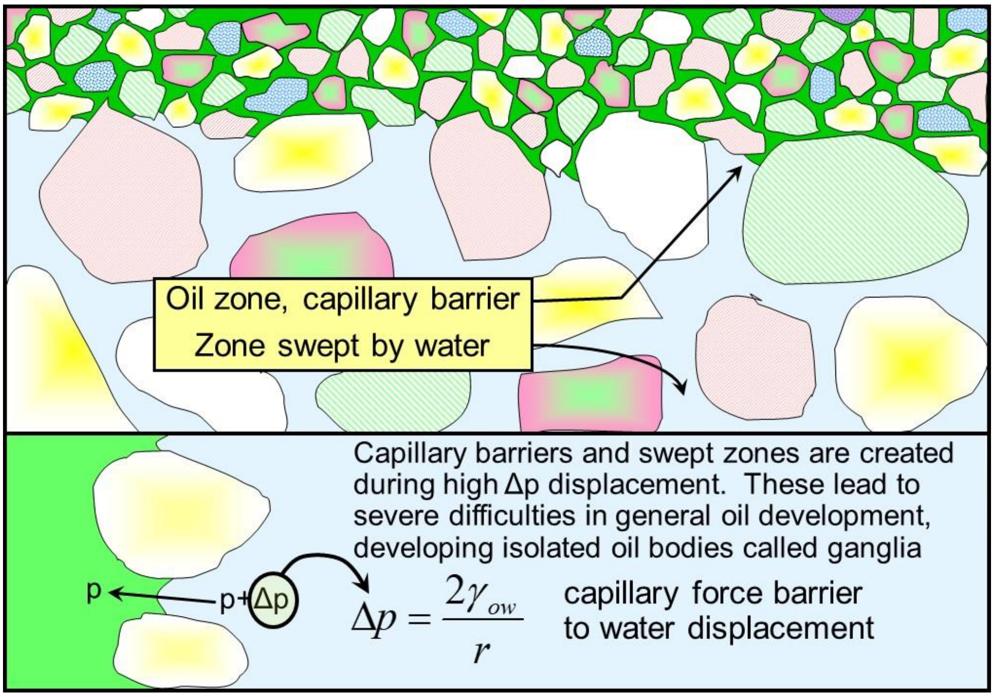

Figure 4. Capillary Isolation of Oil During Pressure-Dominated Flow (γ_{ow} is oil-water surface tension)

Water breakthrough and gas breakthrough because of aggressive pressure drawdown in the oil zone during production, ganglia development, channeling and coning, are all associated with the family of advective instabilities that arise in porous systems with more than one fluid phase. These instabilities have names such as capillary blockage, viscous fingering, water (or gas) coning, channeling, and so on. All of them are explicitly related to simple physical parameters such as permeability, viscosity and surface tension. In practice, many enhanced oil recovery (EOR) methods try to modify these system parameters to increase displacement efficiency and improve R_F values. Modifications might include blocking agents to alter permeability in channels or natural fractures, graded viscosity polymer floods to counteract the viscous fingering effects that arise when there are severe viscosity contrasts, surfactant systems or supercritical carbon dioxide injection to reduce capillary blockage by altering surface tension, and even steam and solvent injection to reduce the viscosity of heavy oils. The magnitude of the pressure drop governs all of these advective instabilities because pressure differences drive advective flow: the higher the pressure gradients, the more severe the problem. However, these instability features are not seen in nature in an undisturbed static virgin reservoir because the accumulation of the oil and gas took place over millions of years with extremely modest head differences so that gravity forces were always dominant.

Examination of natural oil and gas reservoirs before exploitation shows the clear role of density in fluid segregation. The densities of water, oil and gas are typically in the following ranges: Water 1.05-1.20 g/cm^3; Oil 0.80-0.90 g/cm^3; Gas 0.02-0.10 g/cm^3. This density contrast gives rise to buoyancy forces, which in turn lead to sharp stratification of the immiscible phases, separated by stable horizontal surfaces – the gas-oil (G/O) contact and the oil-water (O/W) contact. Whether the reservoir rock is preferentially water-wet (essentially all quartzose reservoirs are water-wet), or of mixed wettability (as in some carbonates or mineralogically more complex arenaceous reservoirs), these differences in phase density lead to a large degree of separation of the immiscible phases. So, a natural hydrocarbon reservoir with a gas cap will have a basal water zone with very little oil and likely no gas whatsoever; the oil zone will have no free gas but with a residual water content because grains are water-wet; and, the superincumbent gas zone will have no oil and only small amounts of water that may be adsorbed on the surfaces and contact points of grains.

This observation is a key to understanding gravity drainage, but a clear understanding of pressure in the ground is needed. In a naturally fractured reservoir under hydrostatic conditions, the pore pressure at 1.0 km depth will be ≈ 10.5-11.5 MPa, depending on the salinity of the water column. The local pressure gradient is ≈10.5 to 12 kPa/m (the density of NaCl-saturated brine is 1.2 g/cm^3, giving a gradient of ≈12 kPa/m), so the pressure 100 m deeper, at 1.1 km depth, will be about 11.6 to 13.2 MPa, clearly higher than at 1 km depth. However, flow is not governed by pressure, but by the differences in hydraulic head. In the example, the hydraulic heads are the same at both points, and this will be the natural (static) condition providing that the points are in full hydraulic connection. This static head condition means that no upward or downward flow can take place because there is no potential (no difference in head), as long as the density of the fluid is roughly the same. But suppose a less dense phase such as gas or oil is included in the bottom of the 100 m interval. Just like a bubble in soda water, there is an additional force, a buoyancy force arising because of density differences, which will cause the lighter fluids to rise and be replaced by downward flow of the dense fluids, until a condition of static equilibrium is reached. This static equilibrium that develops over millions of years during oil migration and accumulation is then disturbed by production at time scales of tens of years.

Water breakthrough happens when we introduce large forces (large pressure drops) by pumping oil, and these large forces overcome the natural gravity forces that have created the horizontal G/O and O/W contacts. This leads to water or gas coning, fingering and channeling of the more mobile phases, and other effects that often lead to the aggressive injection of water deliberately to try and displace the oil, along with the various EOR approaches mentioned above. or injecting water for oil displacement, which leads to fingering and channeling. For example, if very aggressive gas injection into the gas cap of a reservoir is undertaken to displace the oil downward to production points, the high pressure gradients will overcome the natural stabilizing effect of gravity and phase density, and downward gas fingering or coning will occur, depending on the configuration of the exploitation system. Even if the Δp is then reduced, remnant gas bubbles and ganglia in the gas-invaded zone will impair oil drainage and lead to higher irrecoverable oil amounts.

It appears that the largest technical problem for oil production impairment in the NFCRs of the Persian Gulf is water breakthrough, leading to decrease in oil rates, leading to large and increasing volumes of co-produced water for disposal or re-injection, and leading to recovery factors (R_F) in the range of 20-40%. Various methods have been tried to reduce the impact of the advective instabilities that lead to detrimental water breakthrough (e.g. Allan & Qing Sun 2003), with varying degrees of success, but a general approach to achieve higher R_F values has not fully emerged. Some attempts to use gravity drainage have been implemented, and horizontal redevelopment wells are becoming more common.

3. Gravity Drainage in NFCRs

Gravity drainage means production of fluids dominantly under gravity forces, rather than pressure forces. The concept is not new; it has long been recognized that gravity drainage can be extremely effective (e.g. Hagoort 1980). However, because of the slow flow rates that must be used to avoid instabilities, widespread economical implementation of gravity drainage had to wait till the advent of controlled horizontal well drilling, a technology only perfected in the 1980's, and only widely implemented in the 1990's and thereafter. Long horizontal wells allow the use of gravity drainage while still achieving adequate recovery rates for economic viability. Gravity drainage using low pressure gradients generally means slower production rates, but also higher ultimate R_F values, less water co-production, and fewer problems such as sand production. There is still a strong tendency in the oil industry to maximize early production (driven by discounted cash-flow-models that use a high discount rate), and this means relinquishing later value, or increasing the unit cost of extracting later value by various EOR methods. This is especially the case where there is a high capital investment over many years before oil recovery, as in the case of offshore platforms. In these cases, high-rate early production is needed to return the investment, and gravity dominated approaches are not used. For land-based recovery systems, gravity drainage makes a great deal of sense, especially when interest rates are low and oil prices reasonable. Gravity drainage has achieved a high level of sophistication in the heavy oil and bitumen exploitation activity in Alberta and Saskatchewan, Canada, where the technology of Steam-Assisted Gravity Drainage (SAGD) has revolutionized viscous oil exploitation, resulting in a number of cases in R_F values exceeding 0.75 despite initial (cold) viscosities in excess of 100,000 cP (Figure 5). Is gravity drainage a viable technology under the conditions encountered in most conventional NFCRs in the Persian Gulf region?

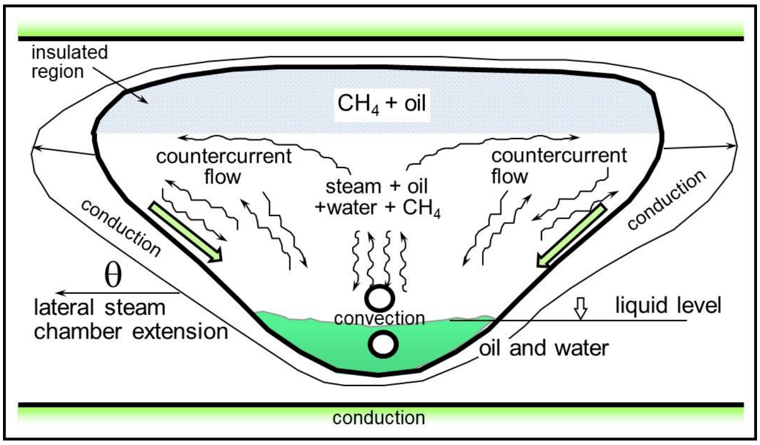

Figure 5. Steam-Assisted Gravity Drainage for High Viscosity Oils

In the SAGD context (Figure 5), steam is injected into one horizontal well and hot liquids produced from another, parallel well that is somewhat lower (3-5 m) and near to the upper well (say within 5-10 m lateral offset). The steam injected in the upper well is low density, so it rises, condenses and heats the viscous oil, which, along with the condensed water, drops because of a much higher density, and is produced at the lower well. It is critically important that the pressure in the injected steam and the pressure of the hot fluid around the lower production well be approximately similar (perhaps within 30-50 kPa, depending on the operator). This prevents short-circuiting of the steam, which might occur if the pressure in the bottom well is too low (Ito *et al*. 2000). To counteract any tendencies for lateral influx of water if there are any small zones that are somewhat permeable and water saturated, it may be necessary to operate the SAGD steam chamber at approximately the same pressure as in the surrounding strata. If there is little to no pressure difference, lateral influx of water, which would have a very negative effect on the thermodynamic efficiency of the process, is inhibited because a significant pressure gradient is needed for water to flow. SAGD has other beneficial effects in the case of unconsolidated sands (dilation and permeability increase, reduction of sand production – Collins 2005), but these effects will not arise in an isothermal process in low viscosity oils in NFCRs. Nevertheless, the development of SAGD clarified many aspects of gravity-dominated fluid segregation and flow in porous (unfractured) media.

Perhaps the best example of the positive impact that gravity-dominated flow in conventional oils can have in NFCRs is the development of the low-viscosity oil in the Devonian pinnacle reefs of Alberta.[1] These are naturally fractured reservoirs of limited areal extent but with a tall HC column. Most of them have excellent vertical and lateral seals but have active bottom water, and often with gas caps (Irwin and Batycky 1997), or at least gas caps that develop from exsolution as pressure depletion takes place. They have overall excellent vertical permeability because of the vertical attitude and high conductivities of the natural fractures, and the matrix permeabilities are reasonable but spatially inhomogeneous. This excellent vertical permeability, combined with a low oil viscosity and the lack of lateral (flank) water, leads to a natural stabilization from gravity effects because it means good well productivity is achieved without huge local drawdowns and high gradients. Perturbations in the horizontal G/O and O/W contacts are rapidly rectified if drawdown is stopped during Δp-dominated production. When these conditions are combined with careful well re-completions and control of basal water rate and gas cap growth, a gravity-dominated production takes place, even with vertical wells. In the original Leduc reef itself, as well as many others in the reef trend (including Zama Lake, Rainbow Lake and other nests of pinnacle reefs) R_F values exceeding 60% were common. The NFCR reefs in Alberta during primary exploitation mostly showed very high R_F values, achieved through the positive impact of natural gravity stabilization and drainage.

With the advent of controllable horizontal well placement, redevelopment of a number of these pinnacle reefs took place to foster gravity drainage and phase interface stabilization (e.g. McIntyre *et al*. 1996). New horizontal wells were placed in the appropriate location in the reservoir (Figure 6), in the remaining oil zone; then, production rate control, gas cap re-injection, and controlled basal water influx (or basal water injection) took place to "pinch" the remnant oil bank onto the horizontal well location. The pre-existing vertical wells were re-purposed to help control the vertical displacement, with the O/W interface moving upward and the G/O interface moving downward at velocities slow enough so that gravity forces remained dominant. This was done with voidage balance (1.0 m^3 in = 1.0 m^3 out) to maintain constant average pressures, thereby eliminating significant pressure gradients. This was possible because there was a strong stabilization effect arising from the good vertical permeability and the density contrasts among the immiscible fluids. This redevelopment led to R_F

[1] The most comprehensive publicly available data set and geological study of any large basin in the world is the *Atlas of the Western Canada Sedimentary Basin*. It is published by the Alberta Geological Survey, a branch of the Alberta Energy Regulator (AER), and comprises 35 Chapters with more than 50 Gigabytes of information. It can be downloaded for free from the following website: https://ags.aer.ca/publications/chapter-pdfs

values generally in excess of 0.85, the highest values in the world.

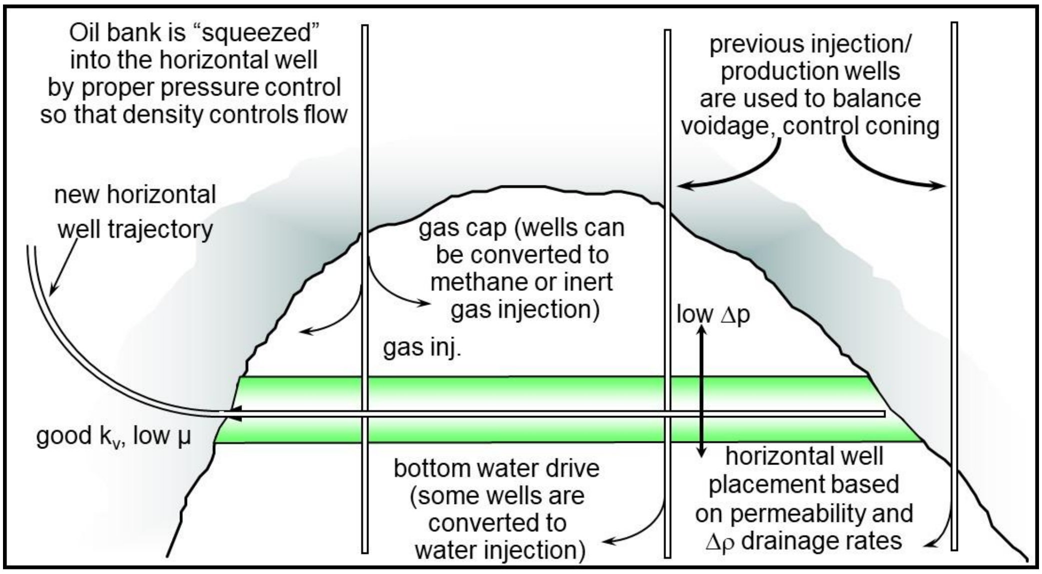

Figure 6. NFCR Pinnacle Reefs Redevelopment using Gravity Drainage Principles

Is gravity drainage effective in NFCRs where there are highly conductive fractures and a matrix of modest permeability? The cases above, and other similar cases, indicate that it can be highly effective. Extensive research at the University of Waterloo in the period 1985-2005 (e.g. Kantzas *et al* 1988) showed that as long as gravity forces are allowed to dominate, the mechanisms of slow gravity-dominated vertical displacement of oil by gas can lead to remarkably high R_F values. A series of seminal articles (Zendehboudi *et al* 2011, 2012, 2013) involving laboratory simulation and mathematical modeling in NFCRs show that, with careful control, R_F values in NFCRs subjected to gravity drainage can be high, and even the matrix oil can be produced and replaced with the inert gas phase. These works to a degree confirm what was already known empirically from field implementation, but with a rigorous scientific framework allowing for the development of a quantitative assessment scheme.

To clarify why high R_F values are noted in experiments and in the field, Figure 7 shows the physical principles behind top-down inert gas injection gravity drainage (called by various names, including GOGD – Gas-Oil Gravity Drainage – by Shell Oil – Ikwumonu *et al* 2007). As long as large pressure gradients are not used, the thin oil film that resides stably between the water and the gas phase (this is the thermodynamically favored configuration) remains intact, so the denser oil above continues to drain downward along the thin films as it is replaced by gas. If the gas is injected too quickly, not only does it lead to fingering and reduction of the relative permeability to oil, it can snap off the oil film and isolate some of the upper oil as unconnected ganglia. Clearly, it is necessary to understand the mechanisms and to determine the rate of gas injection that is commensurate with reasonable rates of oil flow that will achieve high values of R_F, yet without destabilization of the oil films and other aspects of advective instabilities. There is an optimum rate for inert gas gravity drainage, and seeking to exceed that rate may lead to temporary increases in oil recovery rate, but significant losses of oil in the long term as the R_F values are impaired.

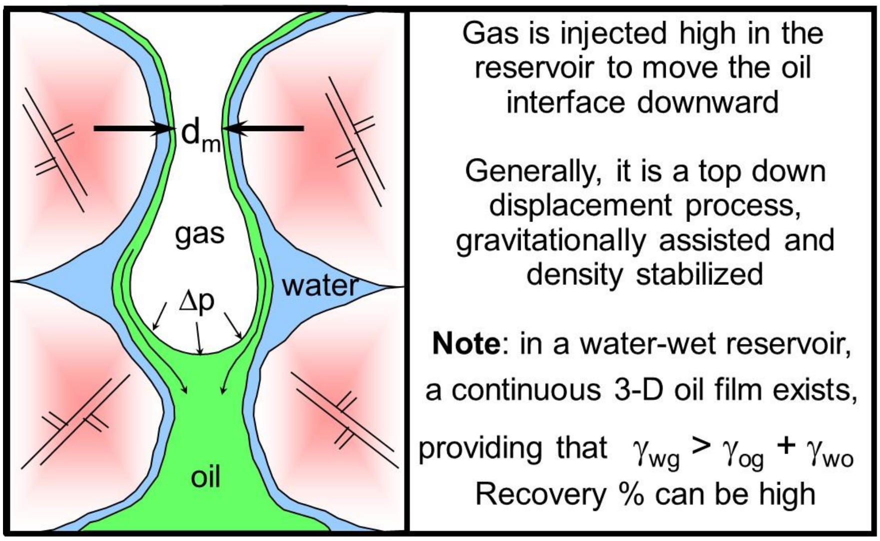

Figure 7. Inert Gas Injection Gravity Drainage, a Top-Down Stabilized Displacement Process

4. A Redevelopment Approach for NFCRs

Redevelopment of appropriate Persian Gulf NFCRs with gravity drainage approaches can substantially increase R_F values. There are many issues that have to be addressed, including the geometry of the reservoir, the petrophysical nature of the various zones, the properties of the fluids, and so on. Here, the discussion will be limited to the major actions in a redevelopment program that focuses on conversion of existing partially depleted assets that have suffered from excessive water ingress. The general steps in a workflow for candidate selection, design, implementation and operation would involve the following:

- Assess potential candidates using first-order parameters (geological suitability, vertical permeability…).
- Refine the Earth Model to include geomechanics parameters, particularly stress data.
- Evaluate the magnitude of bottom-water drive and other related factors such as natural gas availability for top gas injection.
- Determine the rates of drainage of oil from the carbonate rock matrix that will be achievable under gravity drainage with very small gradients to avoid fingering or coning.
- Carry out mathematical simulations to decide on the best locations within the oil column for the horizontal production wells.
- Drill the production wells in the direction parallel to the smallest horizontal stress and complete the wells with slotted liners for maximum unimpeded inflow, and install pressure sensors at the heel for production pressure management. Mathematicalmodeling and careful assessment will be required to place the horizontal wells optimally in the oil zone so as to achieve the best production rate and R_F results.
- Use hydraulic fracturing along the axis of the production wells to create vertical fractures or to open existing natural fractures to enhance average vertical permeability of the reservoir.
- Convert existing vertical wells to inert gas injection wells and bottom-water injection wells, either in a co-injection mode or by choosing different wells for different purposes. In general, downhole pressure gauges are desirable to allow fine control of injection pressures.
- If the field is somewhat depleted it may be necessary to carry out water and gas injection until the pressure is appropriate to just balance any tendency for lateral water influx. On the other hand, if the

lateral water is regionally active, it will recharge the pressures, but gravity drainage will have to take place at the same pressure to avoid influx.

- Carry out gravity drainage while following the principle of voidage replacement so that nowhere in the field do significant destabilizing pressure gradients develop.
- Monitor pressures in the oil, gas and water zones continuously to avoid inhomogeneous distributions of pressure laterally that could be locally destabilizing (e.g. leading to too much coning or channeling in certain locations).
- Monitor all the inflow parameters carefully during production so that changes in the ingress rate of water and gas can be noted quickly, allowing adjustment of the injection and production rates and pressures needed to sustain a uniform stable pressure and flow system.

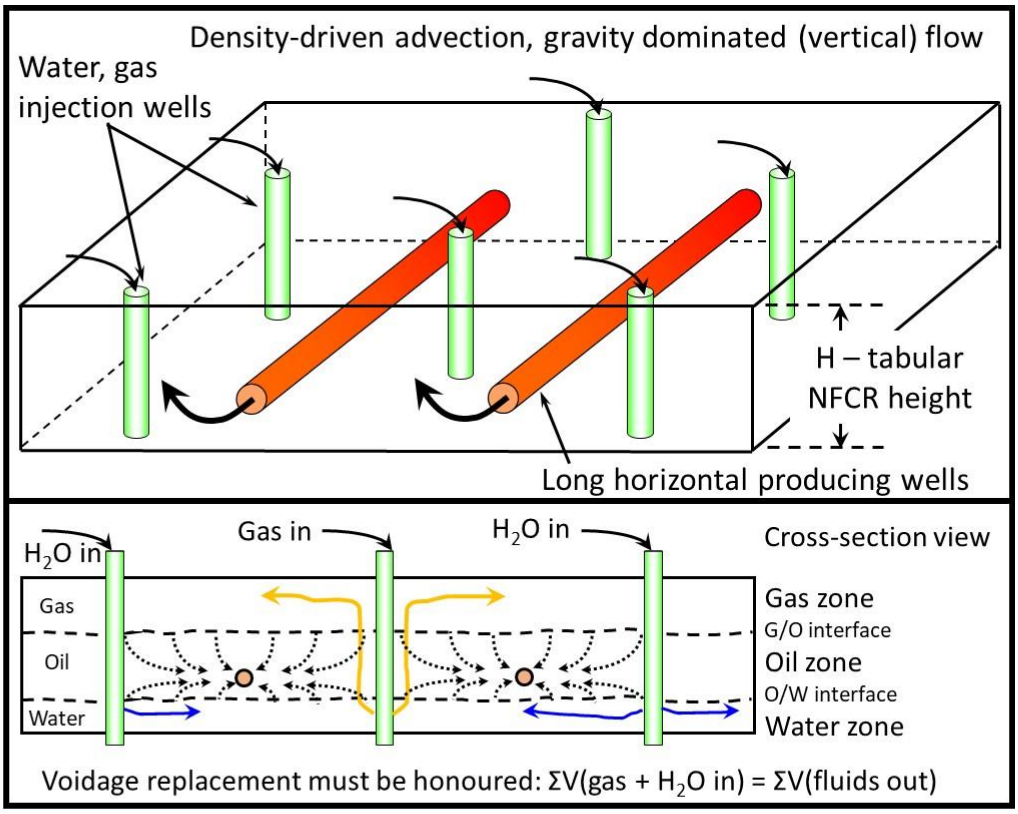

Figure 8. An Array of Wells for Gravity Drainage in a Flat-Lying Reservoir

During operations, monitoring changes in production phases (O, W, G cuts), rates, and pressures in the region of the well will help to manage the wells. For example, if the water cut is beginning to rise, it may be necessary to slightly increase the backpressure on the production well to reduce the instability. If a gas cut starts to develop, the rate of injection of inert gas may have to be reduced locally to reduce gradients. Other operational decisions will be guided by the data trends.

The inert gas to be used can be methane, flue gas or even pure carbon dioxide if the CO_2 sequestration potential is of interest and is economical. In the case of CO_2, phase changes and solubility in oil will have to be assessed. The CO_2 may be a substantial aid to oil displacement as it dissolves into the oil (viscosity reduction, swelling of oil, etc.), but the density contrast in the supercritical state is less than for methane or flue gas, and CO_2 is clearly more costly. The viscosity reduction effect of methane or flue gas is small, and the rate of dissolution into the oil phase is limited. Once methane is in a free phase, it dissolves back into the oil phase only slowly (surface area of the interface is modest), so it acts as a lower solubility inert gas phase that is functionally immiscible, and if it is available in bulk locally it serves as an excellent top-down displacement fluid for the G/O contact. Note that once the gravity drainage phase is complete, it is likely that the R_F will be high enough that the methane can be simply recovered by reservoir blow-down, using the vertical wells to product he methane.

It may be useful to inject the inert gas deep in the formation, allowing the gas to rise to the upper part through buoyancy. This may help reconnect ganglia and isolated oil zones to the production system through spontaneous reconnection of thin films because of surface tensions and thermodynamic effects. Referring back to Figure 7, if the inequality expressed at the bottom of the figure is satisfied, then the stable thermodynamic state (lowest energy) is to have the oil film residing between the water phase and the gas phase (de Gennes 1985).

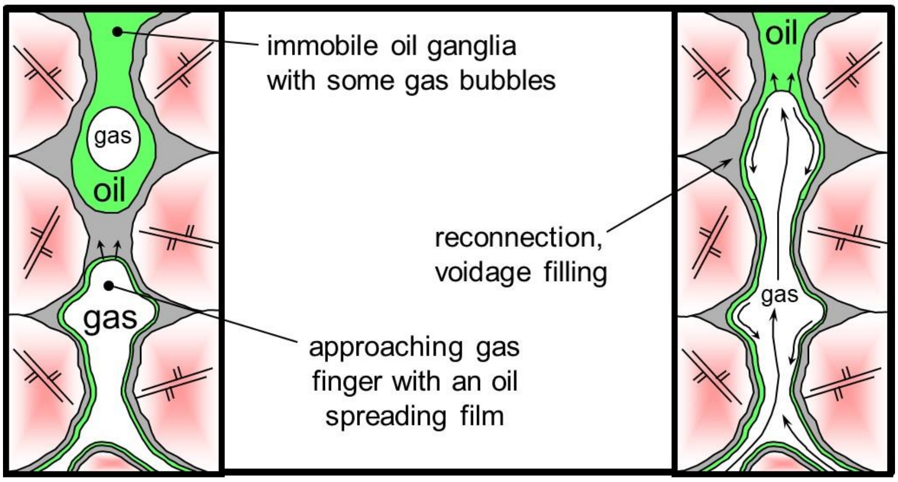

Figure 9. Reconnection of Phases in Three-Phase Gravity Drainage

This diagram reveals an important point: reconnection of ganglia may be possible in practice, even though they cannot be "mobilized" by conventional pressure methods. If phase reconnection is achieved, a continuous three-dimensional thin oil film will develop and allow the slow production of oil from the carbonate matrix.

An important design element is to provide horizontal wells in the appropriate location in the reservoirs so that the low-viscosity oil displaces toward the well most effectively. Core tests and modeling (see Zendehboudi et al articles) will be needed to make decisions on locations for horizontal wells.

A gravity drainage system is operated with the minimum pressure gradients that can be sustained under stable conditions so that effective gravity segregation of phases will occur. This means that channeling will be minimized, but perhaps not equal to zero. Attempts to overdrive the system to achieve greater production rates may give short term oil rate increased, but these will be followed by a significant drop in production rates as advective instabilities re-emerge.

Horizontal wells are used to redevelop the field and a key factor in gravity drainage is to guarantee excellent vertical permeability to help stabilize the G/O and O/W interfaces. The conductivity of the natural fractures over the oil drainage height may not be adequate, so that the horizontal well can be stimulated and the induced fractures are approximately oriented at 90° to the well axis. If it proves necessary to promote upward fracture growth and minimize downward fracture growth, it is possible to use less dense agents such as gelled propane, giving a stronger buoyancy and hence a stronger upward growth component.

For stable gravity displacement, minimizing advective instabilities is vital. This means, first of all, that as much as possible the G/O and W/O interfaces are maintained in a horizontal attitude, avoiding coning and lateral water breakthrough, and avoiding downward gas coning. This means that the pressure gradients associated with drawdown of the horizontal well must be kept close to zero. Now that the array of re-purposed vertical injection wells (top gas, bottom water) is available for injection control, the three-dimensional well array can be operated in an optimal manner to avoid generating excessive vertical or horizontal pressure gradients. This optimization scheme uses pressures, rates and compositions as inputs, and can be developed as a mathematical routine.

5. Final Comments

Gravity drainage can yield high recovery factors, even in naturally fractured carbonate reservoirs. Implementation must pay attention to many factors, but in a field redevelopment the availability of vertical wells in combination with the horizontal wells to be installed to achieve economically interesting gravity drainage is an advantage. Vertical wells will serve as the voidage replacement control injectors to displace the O/W contact upward, and the G/O contact downward, without destabilization arising from the triggering of advective instabilities. Proper understanding of the stress fields and orientation of the horizontal wells to allow effective hydraulic fracture stimulation to enhance vertical permeability may be a necessary step to achieve good productivity.

6. Acknowledgements

Through contact with them as colleagues and students, I learned a great deal about the physics of gravity flow from Professors Francis Dullien, Ioannidis Chatzis, Sohrab Zendehboudi and Ali Shafiei.

7. References

Ahmadi, MA; Ebadi, M; Hosseini, S-M. 2014. Prediction breakthrough time of water coning in the fractured reservoirs by implementing low parameter support vector machine approach. *Fuel* **117**, 579–589.

Allan, J; Qing Sun, S. 2003. Controls on Recovery Factor in Fractured Reservoirs: Lessons Learned from 100 Fractured Fields. *Proc. 2003 SPE Annual Technical Conf. and Exhibition*, Denver CO. SPE 84590, 18 p.

Berg, RR; DeMis, WD; Mitsdarffer, AR. 1994. Hydrodynamic Effects on Mission Canyon (Mississippian) Oil Accumulations, Billings Nose Area, North Dakota. *AAPG Bulletin* **78(4)**, 501-518.

Clemens, T; Wit, K. 2001. The Effect of Fracture Spacing on Gas/Oil Gravity Drainage in Naturally Fractured Reservoirs. *Proceedings 2001 SPE Annual Technical Conference and Exhibition*, New Orleans, Paper SPE-71507-MS, 7 p.

Collins, PM. 2005. Geomechanical Effects on the SAGD Process. *Proc. 2005 SPE International Thermal Operations and Heavy Oil Symposium*, Calgary Alberta, SPE 97905, 12 p.

de Gennes, PG. 1985. Wetting: statics and dynamics. *Reviews in Modern Physics* **57**, 827 ff.

Hagoort, J. 1980. Oil Recovery by Gravity Drainage. *Society of Petroleum Engineers Journal* **20(03)**. Paper SPE-7424-PA 12 p. DOI https://doi.org/10.2118/7424-PA .

Ikwumonu, A; Rawnsley, KD; Al-Habsi, M; Penney, RK. 2007. Key Learnings from History Matching a Thermally Assisted Gas Oil Gravity Drainage Pilot in Fractured Reservoirs. *Proc. International Petroleum Technology Conference*, Dubai UAE. Paper IPTC-11411, 10 p. DOI https://doi.org/10.2523/IPTC-11411-MS .

Irwin, DD; Batycky, JP. 1997. The Successive Displacement Process: Oil Recovery During Blowdown. *SPE Reservoir Engineering Journal* (November Issue), 240-245.

Ito, Y; Ichikawa, M; Hirata, T. 2000. The growth of the steam chamber during the early period of the UTF Phase B and Hangingstone Phase I projects, *Proceedings Canadian International Petroleum Conference,* Calgary Alberta, Paper 2000-05 of the Petroleum Society of CIM, 16 p.

Kantzas, A; Chatzis, I; Dullien, FAL. 1988. Enhanced Oil Recovery by Inert Gas Injection. *Proc. SPE Enhanced Oil Recovery Symposium*, Tulsa OK. Paper SPE 17379, 10 p. DOI https://doi.org/10.2118/17379-MS .

Lacy, S; Ding, W; Joshi, SD. 1992. Horizontal Well Applications and Parameters for Economic Success. *Proc. Second Latin America Petroleum Engineering Conference,* Caracas, Venezuela, SPE 23676, 12 p.

McIntyre, FJ; Hunter, B; See, D; Wong, F.; Fong, D; Adamache, I. 1996. Redeveloping Mature Miscible Flood Reservoirs with Horizontal Wells: A Summary of Six Years of Experience. *Journal of Canadian Petroleum Technology* **35(3)**, 46-62.

Nelson RA. 2001. *Geological Analysis of Naturally Fractured Reservoirs*, 2nd edition. Gulf Professional Publishing (Elsevier), 332 p.

Shafiei, A; Dusseault, MB. 2007. Development Options for Kuh-e-Mond Heavy Oil Field in Iran. *Proc World Energy and Chemicals Exhibition and Conference*, Kuwait, 22-25.

Wennberg, OP; Svånå, T; Azizzadeh, M; Aqrawi, AMM; Brockbank, P; Lyslo, KB; Ogilvie, S. 2006. Fracture intensity vs. mechanical stratigraphy in platform top carbonates: the Aquitanian of the Asmari Formation, Khaviz Anticline, Zagros, SW Iran. *Petroleum Geoscience* **12**, 235–245.

Zendehboudi, S; Chatzis, I; Dusseault, MB; Shafiei, A. 2011. Empirical Modeling of Gravity Drainage in Fractured Porous Media. *Energy Fuels* **25(3)**, 1229-1241.

Zendehboudi, S; Rajabzadeh, AR; Bahadori, AR; Chatzis, I; Dusseault, MB; Elkamel, A; Lohi, A; Fowler, M. 2013. Connectionist Model to Estimate Performance of Steam-Assisted Gravity Drainage in Fractured and Unfractured Petroleum Reservoirs: Enhanced Oil Recovery Implications. *Industrial and Engineering Chemistry Research*, **53**, 1645−1662.

Zendehboudi, S; Shafiei, A; Chatzis, I; Dusseault, MB. 2012. Numerical Simulation of Freefall and Controlled Gravity Drainage Processes in Porous Media. *Journal of Porous Media*, **15(3)**, 211-232.

Zhang, X; Spiers, CJ. 2005. Compaction of granular calcite by pressure solution at room temperature and effects of pore fluid chemistry. *International Journal of Rock Mechanics & Mining Sciences* **42**, 950–960