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Characterization of Primary and Secondary Recovery Processes in an Oil Reservoir: Theoretical Assumptions and Experimental Limitations

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Abstract

Multi-phase fluid flow through an oil reservoir is associated with a complex reservoir drainage mechanism. Prior to drilling, the reservoir pore fluids remain to be in vertical equilibrium between upward capillary and downward gravity effects. However, upon oil production, viscous effects also come into picture, while, inertial effects play a dominant role in highly heterogeneous reservoirs. In addition, capillary effects will also have its influence in horizontal direction upon oil production. Thus, the reservoir drainage mechanism becomes quite complex before any drilling; and following oil production. Further, the drainage mechanism associated with an oil reservoir 'before water breakthrough' remains to be significantly different from that of 'after water breakthrough'. Also, the drainage mechanism associated with an under-saturated oil reservoir remains to be significantly different from that of a saturated oil reservoir. In this context, the present article has made an attempt to provide an overview on primary and secondary oil recovery processes, while highlighting the essential fundamental physics associated with the estimation of reservoir rock and fluid properties at various scales in the discussion section that generally remains to be ignored either at core-scale or at field-scale. The discussion aspect clearly brings out the various assumptions associated with the theoretical approach and the limitations associated with the experimental investigations; and thereby, this study is expected to provide further insights on the improved estimation of reservoir rock and fluid properties associated with primary and secondary oil recovery processes.

Keywords: *Oil reservoir; Multi-phase fluid flow; Primary recovery; Secondary recovery; Drainage mechanism.*

1. Introduction

Petroleum reservoirs are saturated subsurface porous media containing varying amounts of gas, oil and water within the void spaces. Such areally and volumetrically extensive rock intervals were originally formed from sediments deposited as three-dimensional layers of rock (solid grains) fragments with variable sizes physically. Chemically, these solid grains are predominantly composed of either silica-based chemical-compounds (sandstone or clastics); or carbonate-based chemical-compounds (limestone or dolomite). Now, these rock formations at the larger-scale are essentially described by solid-grains, pore-bodies (large portion of the spaces or pores among the solid grains) and pore-throats (the locations, where the spaces between the solid grains narrow) at the pore-scale. In a homogeneous and isotropic porous media, each solid grain will roughly have one associated pore-body and one associated pore-throat; and, there will be a large number of flow paths within each Representative Elementary Volume (REV), which would roughly consist of one-fourth (1/4) of pore-volume; and three-fourth (3/4) of solid-grains volume (the ratio may vary drastically as the reservoir heterogeneity and anisotropicity increases, as the number of solid-grains per cubic meter range from nearly a billion to a trillion per cubic-meter in a typical sandstone reservoir: however, a typical core plug with a couple of inches in diameter and length will consist of tens of thousands to millions of solid-grains; and this core-size remains to be much smaller than a typical reservoir with several square miles of area with oil-bearing intervals tens of feet in thickness). Thus, oil reservoirs typically consist of angular grains with varying grain sizes ranging from well-sorted to poorly-sorted grain formation. And, most oil reservoirs are found in consolidated rocks in which diagenesis has chemically cemented together the loose-sand or carbonate-grains, that were originally deposited, after encountering leaching (the grains remain dissolved to varying extents on their edges and/or internally) and cementation (insoluble chemicals remain precipitated from the pore fluids and reduce the amount of pore space) during early diagenesis. At the beginning of the original deposition, all of the pore spaces (including pore-bodies and pore-throats) remain filled with resident brine. However, in an oil reservoir, the pores remain filled with liquids, with varying proportions of oil and water. Among oil and water fluid phases, a more-continuous connate water-phase and a less-continuous oil-phase is expected to prevail naturally. However, at the end of primary recovery, the continuity of the oil-phase falls to such an extent that we will be looking for water-flooding or gas injection. In the present article, the fundamental physics behind water-flooding has been explained in detail. Then, a detailed list of discussion aspects have been presented with reference to field-scale implementation and finally, critical conclusions have been recommended from this study.

2. Primary recovery

Oil recovery processes in a typical reservoir generally follows primary, secondary and tertiary recovery processes. The primary recovery process during the early stage makes use of the reservoir's natural energy in displacing the resident fluids (water, oil & gas) towards and out of the production well, existing in a reservoir. The primary source of energy forcing the oil out of the reservoir remains to be the elevated reservoir pressure within the reservoir. As the reservoir pressure gets reduced upon hydrocarbon production, the oil and water within the pore spaces expand, and the reservoir rock also gets expanded slightly, and thereby reducing the amount of pore space. As a consequence, the brine in the underlying aquifer and the gas in the overlying gas cap will also expand, and subsequently, these fluids from the top and bottom will flow into the oil-bearing interval and displace the mobile oil.

The volume of primary oil recovery depends on how high the initial reservoir pressure is, while, fluid (water, oil and gas) compressibility, along with the size of the underlying aquifer plays a critical role. The reservoir drainage mechanism associated with the primary production is generally assumed to be of single-phase, until the reservoir pressure reaches the bubble point pressure [1]. The oil production before bubble point pressure is reached is called pressure depletion. Upon reaching bubble point pressure, the dissolved gases in the crude oil starts getting expelled out. The released gases from the crude oil starts accumulating over the oil slowly. Upon reaching the threshold limit, the accumulated gas starts moving towards the production well but at a faster rate than oil, as the gas is relatively less dense than oil. The stage of primary oil recovery during the exsolution of dissolved gases (after reaching bubble point pressure) is called as pressure depletion with dissolved gas drive. Thus, during primary production, the reservoir drainage mechanism remains to be significantly different, once the reservoir pressure falls below the bubble point pressure. Although, delineating the nature of reservoir drive mechanism remains to be challenging during the early stages in the history of a reservoir, it can well be determined by the analysis of production data including reservoir pressure and fluid production ratios.

The nature of the reservoir drive mechanism would significantly enhance the recovery of reserves from the reservoir during its middle and later stages, while, it also helps in deducing proper reservoir management decisions. If the reservoir is completely confined by highly impermeable cap-rock or seal, then, upon hydrocarbon production, when the average reservoir pressure starts depleting, the exsolution and expansion of the dissolved gases in crude oil and resident brine provide reservoir's dominant energy that drives the pore fluids towards and out of the production well. Thus, during solution gas drive, upon reaching bubble point pressure (saturated reservoir), the fundamental mathematical model should include the expansion of this additional gaseous phase emanating from crude oil, along with the expansion of the resident brine and rock, and the exsolution and expansion of the dissolved gases from the resident brine. However, when the reservoir pressure remains greater than the bubble point pressure (under-saturated reservoir), then, bulk expansions of reservoir rock and resident brine provide the dominant drive energy for the mobility of reservoir fluids towards the production well. Most of the oil recovery, in solution gas drive, remains associated with the reservoir pressure that remains greater than the bubble point pressure; and the water-phase can be ignored, as, mostly, there is no production of water associated with this phase.

Regarding gas cap drive, although, to some extent, the gas cap drive benefits from solution gas drive, it derives its dominant source of reservoir energy from the expansion of the already accumulated gas present in the gas cap that drives the pore fluids towards the production well. As the size the initial gas cap increases, the rate at which the gas cap expansion pushes the gas-oil contact (GOC) downwards and the rate at which the reservoir pressure declines upon hydrocarbon production gets reduced. In case of water drive, we have an additional aquifer unit that interfaces with the oil in the reservoir at the oil-water contact (OWC). Since, both reservoir and the aquifer ensures a perfect hydraulic connectivity, as the reservoir pressure depletes in the reservoir upon hydrocarbon production, water in the adjacent connected aquifer gets expanded as the oil from the reservoir gets displaced towards the production well.

Thus, the production rate of oil from the reservoir remains to depend on extent or size of the aquifer and aquifer permeability; and the oil production remains to be nearly a constant until water breakthrough occurs. Viscous fingering may be encountered in bottom water drive than in edge drive reservoirs, resulting from the density difference between oil (on the top) and water (in the bottom), gravity drainage results from the density difference between water, oil and gas in a reservoir with a relatively larger vertical permeability. In order to optimize the performance of a reservoir, the field reservoir engineer should be able to delineate the advantages of various possible drives (mixed drive) associated with a given reservoir. Primary recovery involves the mobility of one phase (oil) in under-saturated reservoir conditions, and it involves two phases (oil and gas) in saturated reservoir conditions in the absence of any mass exchange between oil and gas.

Theoretically speaking, primary recovery will come to an end, only when, the pressure in the reservoir becomes equal to that of atmospheric pressure. In other words, when a petroleum reservoir gets shifted to an unconfined reservoir from its original confined conditions, then, primary recovery will come to an end. However, based on Return on Investment (ROI), the primary recovery will be stopped or the production wells will remain abandoned, well before a petroleum reservoir gets shifted to an unconfined condition. The total recovery obtained at the end of primary recovery hangs around 10 – 15% of OIIP. During the primary production period, the reservoir pore volume required to match the primary depletion pressure history; and also, 'how exactly, a given model's well-by-well performance gets along with the actual production data' are generally investigated, with the application of pore-volume multipliers and permeability modifiers, if required.

3. Secondary recovery

The secondary oil recovery involves the production of water, oil and gas, where water is injected into injection wells in order maintain the field reservoir pressure as wells as to maintain the flow rates, during the oil production from production wells. Unlike primary recovery, in this case, the fluid mass exchange between oil and gas phases must be considered. Secondary recovery produces another 15-20% of OOIP. Thus, even after secondary recovery, more than 50% of the hydrocarbons remain residually trapped in a petroleum reservoir.

The most widely used fluid injection process namely water-flooding has been in practice since 1880 (although, it became popular, only after 1950) in order to improve the oil recovery from an oil bearing formation as enormous amount of oil reserves (more than 50% OOIP) were left behind by inefficient primary recovery mechanisms. Water, being easily available and being relatively cheaper; and since, the enhanced efficiency with which water displaces oil along with the ease with which, water can be injected into a petroleum reservoir makes water-flooding to be a very important oil recovery process. Four critical factors control the recovery of oil by water-flooding technique (N_P), which includes (a) the estimation of oil-in-place in the floodable pore volume at the beginning of the water-flooding (N); (b) the areal sweep efficiency (E_A represents the fraction of the floodable pore volume area swept by the injected water (which essentially on fluid properties of water and oil, the injection and production well pattern design used to flood the reservoir, the spatial and temporal pressure distribution between injection and production wells; and the permeability anisotropy); (c) the vertical sweep efficiency (E_V which essentially represents the fraction of the reservoir formation in the vertical plane, where the injected water will contact); and (d) the pore-scale displacement efficiency (E_D represents the fraction of oil saturation at the beginning of water injection, which remains displaced by water in that portion of the reservoir invaded by the injected water).

Although recovery of oil by water-flooding technique essentially depends on the above four critical factors, it also depends on (a) connate water saturation; (b) oil saturation at the start of water-flooding; (c) free gas saturation at the start of water injection; (d) residual oil saturation to water-flooding; (e) water floodable pore volume; (f) water and oil viscosity; (g) relative permeability to oil and water; (h) effective permeability to oil measured at the immobile connate water saturation; (i) nature and intensity of reservoir heterogeneity; (j) type and nature of water flooding pattern; (k) spatial and temporal pressure distribution between injector and producer; (l) water injection rate; and (m) oil formation volume factor. Water-flooding yields the maximum benefit, when it remains initiated at or near the initial bubble point pressure. When water injection commences at a time in the life of a petroleum reservoir, when the average reservoir pressure remains at a relatively higher level, then, the respective water injection is addresses as 'pressure maintenance' operation. However, if the water injection commences at a time, when the average reservoir pressure has declined to a low level associated with the primary oil recovery, then, the respective water injection process is named as water-flooding. In both cases, the injected water displaces in-situ crude oil and it remains to be a dynamic displacement process [2]. However, it should be clearly noted that the way the injected water displaces the in-situ crude oil at a relatively higher reservoir pressure remains to be significantly different from that of the way the injected water displaces oil at a relatively low average reservoir pressures like in depleted low-pressure reservoirs. In peripheral water-flooding, the water injection wells remain located in the aquifer, where water injectors remain located at a significant distance, away from, any of the oil production wells (more than a couple of km), while, in pattern water-flooding, which happens over an area of the oil reservoir, a network of water injectors and oil producers (like line-drive, five-spot, seven-spot and nine-spot) remain drilled, completed and used for secondary recovery operations [3]. In a water-wet reservoir, water occupies the small pores and contacts the reservoir rock surfaces in the large pores, while oil remains located in the middle of the large pores. However, in an oil-wet reservoir, oil contacts the majority of the reservoir rock surfaces in the large pores, even though, water continues to occupy the smaller pores, even, in oil-wet reservoirs. Further, in oil-wet reservoirs, the water present in larger pores remains located in the middle of the pores in the absence of contacting the large pore throat surface.

Thus, the wettability of a petroleum reservoir remains essentially determined by the presence of large-sized pores, while, the wettability of the small-sized pores mostly remains unchanged as oil never enters the smaller pores associated with the capillary forces. Although, wettability does not have a direct correlation with the resulting water-flood, wettability indirectly influences residual oil saturation, connate water saturation, relative permeability and capillary pressure that directly affects the performance of water-flooding. In addition, a water-flood in a water-wet reservoir is an imbibition process, while water-flood in an oil-wet reservoir pertains to a drainage process. Also, capillary pressure significantly influences the movement of a water-flood front and subsequently impacts the resulting ultimate displacement efficiency. With the reasonable availability of either subsurface brines or offshore seawater, water-flooding plays a crucial role as it not only provides pressure support to aid and enhance oil production, it also displaces oil efficiently as the water-oil viscosity ratio remains to be not too unfavorable. However, sometimes, a stable water-oil emulsions may form, which may require heat and/or chemicals in order to break the emulsions. In essence, water-flooding leaves a sizeable volume of residual oil, remaining in the oil reservoir, at the end of water-flooding operations. In such cases, we may opt for gas injection, as the residual oil saturation to gas generally remains to be lower than the residual oil saturation to water; provided the reservoir pressure remains to be high enough; the oil remains to be a fairly light oil; and/or the reservoir geometry such as dip and structure remains to be appropriate. On the other hand, if the reservoir pressure remains to be high; and if the gas and oil compositions remain to be appropriate, then, miscibility between gas and oil can be achieved and the ideal residual oil saturation to miscible displacement will remain to be zero, indicating the displacement of entire oil (theoretically).

During secondary recovery using water flooding, the inter-well connectivity among different injection and production wells remain to play a crucial role (along with 'time-dependent water-oil ratio for entire field, for a specific well pattern, and for a specific well' and 'cumulative oil production' – as a function of pore volume, residual oil saturation, and oil & water relative permeability); and the pressure history during a typical water-flood is of no use for history matching purposes as most of the water-flood is operated based on the concept of voidage replacement, where, injection volume exactly equals the produced fluid volume. There should be sufficient water that must be injected (water injection rate) in order to replace the volumes of produced fluids (total fluid production rate) so that water flood operations may remain to be successful. During water flooding, water must be injected @ large enough rates, and thus, several hydrocarbon pore volumes of water remain to be injected, and eventually, lead to an enhanced water cut with time (mimicking Buckley Leverett leaky-piston oil-water displacement in oil reservoirs).

It is feasible to quantify the water-flood potential as a function of original-oil-in-place, connate water saturation and residual oil saturation, which assumes cent percent sweep efficiency and thereby providing the highest possible oil recovery by water flooding. We then got to delineate the water injection rates as a function of water injection capacity, for which we got to estimate the 'per well' injection rate, which along with the total daily volume of water (that must be injected into the reservoir in order to meet the annual goal) – provide the required number of water injection wells [4]. Then, the number of producing wells required with reference to the number of injection wells is deduced based on (a) ratio between oil and water viscosity; and (b) ratio between water injectivity and well productivity.

For successful water flood operations, we got to grab high quality data including the injection and production rates, and reservoir pressure. In addition, we may also be required to gather data associated with specific well, where, special well tests may be required in order to have a control over fluid mobility within the reservoir by analyzing the inter-well injector-to-producer connectivity so that oil-water displacement can be quantified successfully as the displacement front passes through the complex well patterns. Weekly basis production and injection volumes are required to be calculated for each well. The injected water volumes for each well can be estimated using flow meter and pressure-drop measurements, while the production rates from each well remains to be tested through a test separator in order to determine its total flow rate and the fraction of oil/water/gas production. The temporal evolution of the overall injection and production data requires to be plotted, along with the plots of oil production, water production, gas production, water cut, water-oil ratio and gas-oil ratio for each well - in order to ensure that there are no discontinuities (which may demand changes in field operations). If not, then, we got to execute pressure transient analysis of pressure build-up tests (when a production well is shut in) and pressure fall-off tests (when an injection well is shut in), which essentially determines near-wellbore skin along with the details of reservoir permeability thickness (kh). In addition, we may also use injection tests, which essentially estimate the fracture gradient of the reservoir interval. Thus, for each well, the details on hourly flow-rate and pressure measurements (injection rate vs time; injection pressure vs time; injection rate vs injection pressure; cumulative injection vs time) will be able to provide the information on, whether, a particular well remains performing as expected or not. It should be clearly noted that water flood operations remain controlled by the injection wells, where the injected water drives the oil. In order to evaluate the water-injector performance, we got to have a control over the quantum of water that remains to be injected into each well along with the control on the track of reservoir intervals through which, the injected water remains flowing. It can be noted that the plot between injection rate and injection pressure should indicate a stable performance of an injection well; and the changes in profile shape should not be trending either downward (loss of injectivity resulting from near wellbore formation damage) or upward (injection water getting lost to regions above/below reservoir intervals; or, the exceedance of reservoir fracture gradient). When such changes occur in the slope of the curve, Hall plot can be used, which just require the details on cumulative injection and surface pressures (which can be converted to bottomhole pressures by applying correction for hydrostatic head and friction losses). In addition, Hearn plot can also be used, where the reciprocal of injectivity index and cumulative water injection remains cross plotted, towards determining well skin factor and relative permeability to water. Similarly, we got to analyze the performance of production wells as well by plotting the temporal evolution of oil production rate, water production rate, cumulative oil production, cumulative water production, productivity index and water cut. It will be relatively easier, if we try to segregate the oil production phases into (a) filling up of reservoir by the injected water, where mobile gas gets displaced by the injected water in the absence of water-oil displacement; and (b) oil-water displacement phase – following the primary production by pressure depletion. Thus, with a clarity on inter-well connectivity, water flood performance provides the required details on ‘plumbing’ of the oil reservoir both areally and vertically.

4. Reservoir rock properties

Reservoir rocks form through a sequence of geologic events and processes (deposition, bioturbation, diagenesis, lithification) that occur over the geologic time spans, typically over tens of millions of years. Several changes occur to a sedimentary bed as sedimentation continues: (a) the weight of the younger sediments get compacted and thereby reducing the porosity as well as permeability; (b) temperature and pressure gets increased; (c) lithification occurs as unconsolidated materials get solidified; and (d) a variety of diagenetic processes including leaching and cementation occur. Thus, the reservoir pore network systems, both geometrically and mineralogically, remain to be extremely complex; and thereby, making the reservoir to remain to be heterogeneous almost at all the scales ranging from microscopic to field-scale. The grain-size (fine sand to coarse sand); grain sorting (well sorted to poorly sorted); grain roundness (angular to rounded); and grain sphericity (very angular to well rounded) – all these affect the formation porosity. In addition, secondary porosity results from a variety of diagenetic processes that include dissolution of detrital grains or authigenic cements; shrinkage caused by chemical changes; or by fracturing. Diagenetic processes often result in geometrically more complex pore spaces. Deducing actual values of reservoir rock porosity and permeability remains to be extremely challenging as reservoir discontinuity exists both horizontally and vertically, which eventually impact continuous fluid flow. In general, horizontal core plugs are cut every foot, where, there is an uniform lithology in order to measure porosity and horizontal-permeability values, while, vertical core plugs are cut at larger intervals (5 ft) in order to measure porosity and vertical-permeability values [5]. Thus, (a) delineating the key horizontal and vertical heterogeneities (in the context of permeability variations); (b) identifying the way, the original sediments have been diagenetically getting altered since its deposition, and in turn, the way it influences reservoir porosity and permeability; and (c) capturing the details of the depositional environment and its associated expected pay interval’s continuity therein – would play a critical role before taking critical reservoir management decisions @ field-scale.

5. Reservoir fluid properties

Hydrocarbon saturation along with water and gas saturations, being controlled by capillary pressure essentially defines, whether, how much of the porosity remains occupied by hydrocarbons. The sum of these saturations (water, oi land gas saturations) exactly equals to unity. The fraction of water, oil and gas saturations in a reservoir is predominantly dictated by buoyant forces that tend to segregate the various reservoir fluids as a function of their density;

interfacial forces that act between various pore fluids in pore bodies (fluid-fluid interaction); interfacial forces that act between pore fluids and the solid rock (fluid-solid interaction); and the external hydrodynamic forces resulting from an adjacent water aquifer.

Water saturation varies throughout the oil reservoir primarily depending on the height above the oil-water contact (OWC) and on reservoir rock quality. A highly-porous and a highly-permeable reservoir rock contains a relatively lesser water saturation. The first few feet (10 – 50 ft) of the oil column above OWC represents a transition zone, where, a relatively larger fraction of mobile water saturations generally result in water production, if well completions are made in this portion of the reservoir. Connate water generally represents the water saturation above the oil-water transition zone, where, the water saturation remains to be immobile and production from that portion of the oil column remains to be water-free. When the mobile water becomes immobile, then, the respective water saturation is referred to as irreducible water saturation. The salinity of connate water associated with an oil reservoir ranges between 5000 ppm – 250,000 ppm salt. Oil and water saturations are obtained from core plugs using the Dean-stark extraction procedure or on smaller rock samples using the 'sum-of-fluids' retort method.

Permeability, pertaining to a single-phase fluid flow represents the ease with which the fluid can flow through a saturated porous medium. In a petroleum reservoir, we use the concept of 'relative permeability', where, the concept of single-phase absolute permeability remains replaced by multi-phase effective permeability in extended form of Darcy's law. Relative permeability is dimensionless as the individual phase permeabilities are referenced, as a ratio, typically to the single-phase permeability value. Further, when, two immiscible fluids remain simultaneously flowing through a petroleum reservoir, each impacts the other's movement. The fluid with a relatively denser phase tries to pull the fluid with a relatively lighter phase by exerting drag forces. Hence, the relative permeability will always remain to be lesser than unity, when both fluid phases remain flowing, irrespective of the saturation of the fluid phases. However, the relative permeability of each fluid phase remains to be strong non-linear function of that phase's saturation. Thus, in a typical petroleum reservoir, oil-water relative permeability remains to be independent on the fluid's viscosities, while, it primarily depends on the saturations of the two fluid phases. The shape of a given relative permeability curve essentially depends on reservoir rock properties (porosity and permeability), capillary pressure at the pore-scale and the applied pressure gradient at the larger field-scale. Both oil and water relative permeability curves start at the assumed connate water saturation value. The relative permeability to oil (k_{ro}) starts from a value of unity as k_{ro} calculations have been referenced to the oil permeability measured at the connate water saturation value. However, the relative permeability to water(k_{rw}) curve starts from a value of zero as water becomes immobile below connate water saturation (S_{wc}). At the end of the relative permeability curves, the (k_{ro}) value decreases to zero at the residual oil saturation to water-flood (S_{orw}). Thus, oil remains trapped in the reservoir as isolated globules or ganglia at relatively higher water saturation values as the oil phase becomes discontinuous. It is to be noted that k_{rw} at S_{orw} remains to be considerably lesser than k_{ro} @ S_{wc}. This is because the residual oil remains to be located in the larger pore spaces, while the connate water remains to be located in the smaller pore spaces. Hence, the maximum value of k_{rw} remains to be strongly affected by S_{orw}, however, k_{ro} remains to be weakly affected by $S_{wc.}$ The water-oil relative permeability curves remain to be critical input to calculations of water-flood behavior, either for predicting the future water-flood performance, or, during actual field-scale water-flooding performance.

Viscosity ratio (equal to the oil viscosity divided by the water viscosity) and mobility ratio are the two terms that are used to define, whether, how exactly, in a two-phase fluid flow, the displaced and displacing fluids interact. If the displacing fluid has a higher viscosity than the displaced fluid, then, the displacement is referred to as being at a "favorable" viscosity ratio. On the other hand, if the displacing fluid has a lower viscosity than the displaced fluid, then, the displacement is referred to as being at an "unfavorable" viscosity ratio. For example, at an oil-water viscosity ratio of unity, the displacement would remain to be stable and the water will not finger through the oil as the displacement proceeds. However, at oil-viscosity ratio of around 100, the displacement would remain to be more unstable and a number of "viscous fingers" develop and advance rapidly.

Mobility ratio remains to be the extended version of viscosity-ratio, in order to include water and oil relative permeability values. The mobility ($M = k_i/\mu_i$) of a fluid represents the ratio between relative-permeability (rock property) and viscosity (fluid property). The mobility relates to the amount of resistance to flow – that a fluid has – at a given saturation of that fluid - within a petroleum reservoir. From the definition of mobility ratio, it remains clear that a low viscosity fluid will have an enhanced mobility, while, a high viscous fluid will have a reduced mobility. Mobility ratio is generally defined as the mobility of the displacing phase divided by the mobility of the displaced phase. A favorable mobility ratio has a low value (unity or less), where the displaced fluid phase has a higher mobility than the displacing fluid phase. The mobility ratio applied during a typical water-flooding scenario assumes a plug-like displacement between the oil-phase, in front of the flood front @ connate water saturation; and the water-phase @ residual oil saturation, behind the flood front. Although, relative permeability to oil remains to be unity @ irreducible water saturation, water will not finger as rapidly through higher-viscosity oil as expected, with the reduction in the values of end point relative permeability to water pertaining to residual oil saturation.

6. Reservoir fluid-fluid interaction property

In a petroleum reservoir, apart from the basic reservoir rock and fluid properties, the concept of fluid-fluid and fluid-solid interaction properties play a very crucial role as fluid flow through a petroleum reservoir remains characterized by multi-phase fluid flow. With reference to fluid-fluid interaction property, interfacial tension (IFT) between the fluid pair remains to be the critical parameter that essentially quantifies IFT as a measure of immiscibility. The immiscible fluids of interest in a petroleum reservoir will be the resident-brine and crude-oil (hydrocarbon consists of variety of molecules with a wide range of molecular weights). There will be cohesion of similar molecules within each fluid phase, while, there will be repulsion of dissimilar molecules at the oil-water interface; and IFT can be measured using a pendent-drop device; and the value of IFT between oil and brine (10 – 50 dynes/cm) varies depending on the composition of both phases.

Capillary pressure reflects the pressure difference between wetting and non-wetting phase fluids. It is an interfacial phenomenon, unlike the reservoir pressure, where a finite, normal compressive stress acts over a finite area.

7. Reservoir fluid-solid interaction property

The interaction of a pair of fluids with a solid surface is described in terms of the forces acting on a droplet associated with a solid surface and it is defined by Young's equation. The contact angle defines the intersection of the two fluids, where they meet at the horizontal solid interface, for a simple system of a droplet on a smooth flat surface. The contact angle is used to define which of the fluid pair remains to be more wetting: for low contact angles, the droplet fluid is the more-wetting phase, while, for high contact angles, the droplet fluid is the more non-wetting phase. The contact angle remains to depend on the chemical composition of the smooth flat solid surface and the liquid pair being tested (the composition of oil including the amount of gas in solution; the salinity and pH of connate water and resident brine; the mineralogy of the rock surfaces; and reservoir pressure and temperature).

Wetting describes the tendency of a fluid in order to spread over the surface of a solid; or, the affinity of the solid surface towards a particular fluid. If a fluid easily spreads over a solid surface, then, it is referred to as wetting that solid surface. On the other hand, if a fluid forms droplets that do not spread but attempt to minimize their contact area with the solid, then, that fluid is addressed as being strongly non-wetting. At the laboratory-scale, a reservoir's wettability state can be deduced by using surface-active chemicals, either to ensure that the surface is strongly water-wet (hydrophilic) or to make it oil-wet (oleophilic and hydrophobic).

8. Reservoir drainage mechanism

The fundamental drainage mechanism of an oil reservoir essentially depends on the distribution between viscous effects (resulting from pressure gradient @ macroscopic-scale; and it is associated with the absolute permeability and the fluid mobility); gravity effects (resulting from density gradient @ micro/macroscopic gradient; and, it is associated with 'force of gravity' [g] and 'the vertical interval over which the oil and water are both present' [h]); and capillary effects (resulting from saturation gradients @ pore- or microscopic-scale; and it is associated with capillary pressure [p_c] values @ various fluid saturations) – in the absence of inertial effects. Prior to drilling, there exists a vertical equilibrium between the capillary and gravity effects in an oil reservoir in the presence of crude oil and connate water. In a homogeneous and isotropic oil reservoir, this vertical equilibrium means that the lowest water saturations and highest oil saturations would remain to be at the top of the oil column, while, the highest water saturations would remain to be at the bottom portion of the oil column (or leg); and finally, there will be no oil and 100% water at Free Water Level (FWL). The capillary pressure at FWL is zero, while the capillary pressure at Oil-Water Contact (OWC) has a finite value in the presence of both oil and water. In addition, within the oil column, there can be a range of oil compositional variations resulting in a high-density oil @ oil-water contact (at the bottom of the oil column), while, light-dense oil finding its place at the top of the oil column. And, viscous effects (in comparison with capillary and gravity effects) are generally found to be insignificant prior to drilling. However, following discovery and during the production operations, large pressure gradients are applied in order to extract the oil. During primary production, all wells are operated @ low pressures (pressure sinks) in order for the pore fluids to flow towards the production well. However, during water-flooding operations, the water injection wells are operated @ high pressures, while the production wells continue to be operated @ low pressures.

9. Discussion

1. If capillary and gravity forces dictate the vertical equilibrium of pore fluid distribution in an oil reservoir, before drilling, then, how come these two fundamental forces can be assumed to be ignored (during oil production), while developing mathematical models in order to characterize fluid flow through an oil reservoir by considering only viscous effects (in the absence of inertial effects)? Won't we have both horizontal as well as vertical components of capillary forces upon oil production?
2. If only viscous effects are considered to be responsible for fluid flow towards production well in an oil reservoir (following production operations), using original Darcy's law, then, only pressure-gradient and mobility (k/μ) plays a role – towards characterizing fluid flow - in the absence of any scope for the capillary pressure (saturation gradient) and gravity effects (density gradient). Can such simplified Darcy's law be used for characterizing two-phase fluid flow in an oil reservoir by just introducing the concept of 'relative permeability'; and by having an individual flow equation for oil and water phases?
3. What is the physical significance of the endpoints of oil and water relative permeability curves observed at the laboratory-scale? Whether the immobile water saturation of the core plug at the start of the water-oil relative permeability experiments @ laboratory-scale – would remain to be exactly equal to the connate water saturation of an oil reservoir, located above the oil-water transition zone @ field-scale? Feasible to retain original reservoir wettability conditions @ laboratory-scale? Won't it require a significantly longer time in order to capture the true value of residual oil saturation @ laboratory-scale? Apart from the value of initial water saturation, to what extent, the laboratory-scale values of (a) residual oil saturation; (b) oil relative permeability @ initial water saturation; and (c) water relative permeability @ residual oil saturation – remain meaningful at larger field-scale? Feasible to conduct the above experiments using core plugs that exactly reflects the values of 'field-scale' 'reservoir porosity' and 'reservoir permeability'?

4. In an oil-water petroleum reservoir system, when the summation of oil and water relative permeability does not amount to unity (in fact, less than unity), then, how would the assumption associated with the fractional flow equation (“the sum of the oil flow rate and the water flow rate remaining equal to total flow rate”) would remain to be valid?
5. Unlike the case with a favorable mobility ratio, would it remain feasible to prevent the abrupt increase of ‘fractional flow of water’ almost, right from the position of initial water saturation itself, when the mobility ratio remains to be highly unfavorable?
6. How exactly to capture the displacement of oil by water in a heterogeneous oil reservoir (non-linear system) in the presence of gas saturation, for a transient fluid flow, where, fluid saturations varies both spatially as well as temporally, which in turn, causes, spatial and temporal variation of relative permeability and pressure? Can the fluid be assumed to remain incompressible? Could the porosity remain as a constant? Whether the fractional flow of water will remain to depend only on water saturation? Won’t there be any mass transfer between oil and water phases? Whether the velocity with which the water saturation moves through the reservoir would still linearly remain to be a function of the derivative of the fractional flow with respect to water saturation?
7. If compressibility of both oil and water taken into account, then, to what extent, in a real field scenario, ‘volume of oil production’ and ‘rate of oil production’ remain to be different from that of ‘volume of water injection’ and ‘rate of water injection’ – before water breakthrough occurs, where no water is produced? Whether the way, the oil and water production rates changes, following water breakthrough is going to be a complex function of reservoir rock and fluid properties?
8. Given that the nature of capillary pressure remains to be path dependent; and it remains to be a strong function of, whether the wetting-phase saturation remains to be increasing (imbibition) or decreasing (drainage), what does the difference between drainage and imbibition curves indicate (hysteresis), when they remain smaller and larger (as they do not over-lap)?
9. Whether the core samples used for experimental investigations @ laboratory-scale (for estimating reservoir rock and fluid properties) really remain representative of the real field-scale oil reservoir, including reflecting in-situ wettability?
10. Whether the nature and type of fluids used during experimental investigations @ laboratory-scale, for estimating reservoir rock and fluid properties, really reflect the field-scale oil-water interactions and field-scale oil/water displacements?
11. Given the complexity of variation in reservoir rock and fluid properties; and the complexities associated with fluid-fluid interaction and fluid-solid interaction, whether, will we be getting only one value of ‘connate water saturation’ or ‘residual oil saturation’; or, only ‘one curve for relative permeability to oil’ and ‘one curve relative permeability to water’ – for a given oil reservoir, associated with a real field scenario? If not, to what extent, using average or median values of reservoir rock and fluid parameters will remain to be representative of a real field scenario?
12. Given the fact that reservoir permeability values remains to be log-normally distributed (unlike porosity values, which remain to be normally distributed), how would it remain feasible to deduce one single average value of permeability for an entire oil reservoir? What should be the apt depth of vertical interval (vertically) at which the porosity and permeability values needs to be measured? Similarly, what should be the apt spatial locations (areally) at which porosity and permeability values need to be estimated? Won’t it become essentially biased, if we measure the porosity and permeability values, only from the locations, where, the wells have already been drilled, while leaving aside the locations of the reservoir which remain not drilled?
13. Following Terzhagi’s one dimensional consolidation principle in vertical direction and Biot’s inclusion of lateral stresses, the resultant over-burden stresses will keep varying upon oil production as the pore-pressure gets depleted, and subsequently, effective stress gets modified too with space and time. If so, how would it remain feasible to have a single value of ‘space and time independent average porosity’, associated with an oil reservoir?

Also, given the heterogeneous nature of stress distributions with space and time; and heterogeneous nature of the reservoir itself (stratified layers with non-communicating layers), how would it remain feasible for us to have a single average value of permeability for an entire oil reservoir? In addition, whether, Dykstra-Parsons approach will be able to quantify its coefficient of permeability variation or its dispersion measure (based on relatively low values of k_{50} and $k_{84.1}$), for a relatively low permeable stratified reservoir, in the absence of providing the nature of the reservoir heterogeneities, while ignoring both the higher values of reservoir permeability (through which most drainage happens like thief zones) and lower values of reservoir permeability (where, most impermeable pathways remain associated with like obstacles to fluid flow); and mostly, considering permeability values between 15% and 85%? Whether the concept of Lorenz coefficient, where, the fraction of total flow capacity and total storage remain related – really take into account the scale-dependent nature of reservoir heterogeneity? Or, how exactly, to take into account, the Lorenz coefficient, if we end up with, the same value of Lorenz coefficient, for varying permeability distributions, associated with an oil reservoir?

14. While estimating capillary pressure for an oil-water petroleum reservoir system @ laboratory-scale, would it remain feasible in order to ensure that (i) the displacing fluid will not flow through the selected semi-permeable membrane's uniform pore-size; and (ii) the capillary continuity of the displaced fluid phase remains ensured from the core plug through the porous-plate membrane (as losing capillary continuity would reflect that the core plug has reached its irreducible saturation, which is incorrect); (a) when applied pressure exceeds 100 psi by using standard porous plate method; and (b) when applied pressure exceeds 500 psi by using high pressure porous plate method? Also, can we afford to increase the sample size to have a diameter greater than 1.5 inches in high pressure porous plate method? Also, whether both these approaches can be used for the cases of elevated reservoir temperatures (when temperature exceeds 90^{O} C)? With the effective permeability to the displaced fluid getting reduced with decreasing saturation, how about the length of the time required to reach equilibrium (to complete the sequence of measurements on a single core plug) @ higher displacement pressures? To what extent, porous plate method can efficiently be modified in order to deduce the capillary pressure data pertaining to an imbibition process (as against the conventional drainage capillary pressure measurements)? Whether the core plug in porous plate methods can be considered to be @ uniform saturation (in the absence of any fluid saturation distribution across the core plug), upon reaching equilibrium, @ each pressure level?
15. To what extent, the component of gravitational force (by varying the rotation speed of the centrifuge; and by varying the distance between the center of the core sample and the rotation point of the centrifuge: measured in terms of 'centrifugal acceleration' as a function of 'centrifuge speed' and 'radius to center of core') plays a crucial role in estimating the capillary pressure @ laboratory-scale using 'low-speed centrifuge' method (with a maximum pressure of 80 psi); and by using 'high-speed centrifuge' method (with a maximum pressure of 800 psi) – for an oil-water petroleum reservoir system – with a sample size pertaining to 1.5 inches diameter? Can the centrifuge speeds be easily converted into an equivalent capillary pressure value, based only on, (a) centrifuge and core-plug dimensions; and based on (b) the fluid pair used for the test? Whether the volumes of liquid collected – from core plug's pore volume - be directly used to calculate average saturation of the core sample; or, how exactly Hassler-Brunner [6] or Forbes methods [7-9] remain justified? If the permeability of core sample becomes significantly lower, then, whether the centrifuge can be rotated at a predetermined constant speed, or, the centrifuge requires to be rotated at varying speeds, which remains intended to desaturate the core sample over a specific period of time? Towards determining entry pressure (the pressure at which the non-wetting phase first enters any pore of the rock sample) using MICP method, what is the lowest value of porosity and permeability that can be used? Also, when the penetrometer containing the rock sample gets shifted from low-pressure side of the instrument (where sample's bulk volume is determined) to the high-pressure side of

the instrument, doesn't it amount to exposure of core samples to varying stresses (due to extreme pressure variations), which is not reflective of a real field scenario? Towards estimating connate water saturation using MICP method, how could we determine minimum water saturation value pertaining to 'the maximum hydrocarbon column thickness and its associated capillary pressure value pertaining to reservoir conditions' @ laboratory-scale?

16. When estimating relative permeability by transient method, what is the consequence of having an enhanced flow rate through the core plug (which is used to minimize the capillary end effects)? Also, how will we ensure, whether or not, the saturation distribution of the fluid remained stabilized; and also remained uniform, during the flow tests?
17. When IFT measurements are made using pendant-drop interfacial tensiometer, and if the reservoir's solution gas contains significant amount of carbon-di-oxide (CO_2 getting ionized/dissolved into the resident-brine phase; and thereby, changing its pH), then, to what extent, the resulting IFT values would get influenced? To what extent, the IFT values (between oil and water) vary for a light crude and a heavy crude oil? Also, how exactly, IFT values get influenced as a function of (a) temperature, (b) brine salinity and (c) density difference between oil and brine?
18. While measuring contact angles @ laboratory-scale, to what extent, the polished mineral surfaces influence the degree of resulting contact angle? Also, to what extent, water-receding angles remain to be reliable associated with an oil-water reservoir system? And, how about the time required to attain a constant value of contact angle, where wetting equilibrium is obtained in cleaned cores with crude oil? Really feasible to identify the wettability of core samples from mild oil-wet reservoirs with significant heterogeneity? To what extent, laboratory-scale contact angle measurements remain to be significantly different from in-situ reservoir wettability?
19. If the same core material can be influenced differently by different crudes; and if the same crude oil can cause different wettability effects in various cores (some kind of interaction between core and crude oil being inevitable); then, whether laboratory measurements remain to be representative of the wettability characteristics of real field reservoir rocks? Feasible to capture @ laboratory-scale, (a) the systematic changes in flow behavior as the wettability gets changed; and (b) whether, how exactly, the contact angle and the oil-water relative permeability curves get shifted (associated with a real field scenario)?
20. Would it remain feasible to produce a stable and reproducible 'mixed-wet reservoir condition' @ laboratory-scale? If so, how easy would it remain to maintain (a) the surfaces of large pores to become strongly oil-wet; and (b) the surfaces of smaller pores and near grain contacts (pendular grains) to remain in water-wet @ laboratory-scale? Also, if the pore-structure and the mineral composition of core samples influence the surface drainage of oil from mixed-wettability @ laboratory-scale, then, how would laboratory-scale core samples reflect the actual surfaces and wetting nature of real field complex three-dimensional solid-grain network? Also, at the laboratory-scale, would it remain feasible to achieve very low residual oil saturations, following surface drainage (as depletion times remain to be very high @ field-scale resulting either from gravity drainage or from segregation)? Also, when estimating residual oil saturation in a mixed-wet reservoir, @ laboratory-scale, whether, the measured value using experiments pertain to 'immobile oil saturation corresponding to zero relative permeability'; or, does it pertain to 'an oil saturation corresponding to a finite, negative capillary pressure'? In addition, would it remain feasible to distinguish between (a) the counter-current imbibition fluid exchange that may occur through entire core-sample; and (b) the water-oil displacement related to the viscous fluid-flow phenomenon caused by the pressure gradient; @ laboratory-scale?
21. Since, the length of the oil-water transition zone varies roughly between 10 ft (in good quality rocks) and 100 ft (in poor quality rocks) above OWC, how can we deduce a single average value of 'connate water saturation' instead of distributed values (such as between 1% and 50%)? Similarly, how could we have a single value of 'residual oil saturation' in a

given oil reservoir, when it actually depends on rock lithology, rock quality, reservoir wettability, pore-size distribution and connate water saturation (and, which generally varies between 4% and 40%)?

22. If an oil field remains to be greater than 100 ft thick, then, how could we estimate the value of oil density, by ignoring the vertical variation in oil density, resulting from lighter hydrocarbon molecules preferring to float upward, while heavier hydrocarbon molecules preferring to sink downward?
23. How exactly to define the areal and vertical distribution of residual oil saturation values for an oil reservoir, taken from cores? Whether, the application of bleeding and shrinkage factors would be able to reflect the actual reservoir conditions? Also, if the variation of oil saturations from cores vary by an order of magnitude (say, 5 – 50%), then, what exactly we mean by an average value? Whether, such average values will be able to correlate well with reservoir porosity, or, permeability, or depth above FWL? Further, whether, the estimate of residual oil saturation would vary with volumes of investigation of the formation?
24. While measuring the steady-state oil and water relative permeability values, would it remain feasible to get rid-off the capillary end-effect errors, observed at the outlet of the core samples, by maintaining a relatively larger pressure gradient across the core sample? By having a relatively larger pressure gradient with reference to the capillary pressure difference between oil and water, would it remain feasible to ensure a stabilized displacement (by maintaining a relatively larger flow velocity) @ laboratory-scale using cores towards determining relative permeability curves? Further, with slight miscibility between oil and water; and with slight compressibility for oil, would it remain feasible to maintain the flow velocity to remain as a constant at all cross sections of core sample, while determining oil and water relative permeability curves?
25. Whether the number of core samples used in the laboratory; and the number of core measurements remain to be representative of real field conditions? How do we ensure application of proper mud formulation (by mitigating mud filtrate flushing of core minerals); the proper recovery procedure for retrieval of core samples from friable and unconsolidated formations (by ensuring an optimal rate of penetration during coring, towards reducing the quantum of filtrate entry into the cores); and the proper coring procedures following the retrieval of the cores from special core barrels (the critical core handling approaches that remain necessary before moving cores from rig-site to laboratory in order to prevent the grain rearrangement during transport of cores) – in order to secure good quality of cores from the field? Even, if we manage to secure relatively good quality of cores from field, to what extent, 'oil production rate' and 'water rate' as a function of time; and its associated 'field-scale ultimate oil recovery forecast' would remain to be justified based on laboratory core-scale measurements?
26. Whether the usage of average values for saturation and capillary pressure for a given core sample towards plotting capillary pressure against saturation would serve the intended purpose? Also, if the core plugs remain collected from various wells associated with multiple commercial laboratories, then, to what extent, the concept of such average values would really reflect the real field scenario?
27. Since, the values of relative permeabilities remain to be a function of 'direction of saturation change', whether all the core flooding experiments @ laboratory-scale are carried out corresponding to 'the direction of saturation changes' associated with the real field reservoir?
28. At the laboratory-scale, with a relatively small core sample geometry, would it remain feasible to get an improved understanding on the mobility ratio that determines, whether, how exactly, the water-oil displacement front remains stable (or unstable) – from the details of (a) viscosity ratio; and (b) the relative permeability values of oil and water?
29. At the laboratory-scale, with a relatively small core sample geometry, would it remain feasible to capture, whether, what exactly determines, how swift and the degree to which, any injected fluid (that remains heavier than oil) would remain to segregate downwards

(leading to slump) and eventually, would try to under-run the oil as the injected fluid tries to move towards production well from the injection well – resulting from 'the density difference between oil and water' in combination with 'the force of gravity' and 'the vertical permeability'?

30. Since, at a given reservoir temperature, the volume of gas that could dissolve in the crude oil remains to be strongly correlated with the reservoir pressure (along with the variation of volume of natural gas dissolved in the crude oil with depth), how could we estimate (particularly @ saturated reservoir conditions), 'the density of oil (the mass of hydrocarbon liquid per unit volume @ reservoir P & T; and which strongly depends on volume of gas dissolved in the oil @ reservoir conditions); and viscosity of oil (a measure of crude oil's resistance to flow)' 'pertaining to reservoir conditions with a thick oil column' @ laboratory-scale – as they depend not only on pressure and temperature of the reservoir, but also depend on 'the volume of gas in solution' (GOR); 'the density of stock-tank-oil' (STO density); and gas specific gravity?
31. During a typical PVT (or compositional) analysis @ laboratory-scale (using constant composition expansion; differential-liberation expansion; or, constant volume depletion), if the separated oil and gas (collected from an oil-field's test separator) are allowed to recombine @ laboratory, as a function of test separator's GOR, under isothermal conditions but with varying pressure (ranging from initial reservoir pressure to stock-tank/atmospheric pressure), then, would these laboratory test results be able to replicate (a) the way, the oil and gas phases remain interacting in a reservoir (with varying areal and vertical compositions of fluid density and viscosity); and (b) the way, the pore fluids gets mobilized as a function of pressure depletion, upon oil production (given the possibility that reservoir oil bubble point pressure may also vary with increasing depth, along with vertical variation in reservoir pressure – that involves a combination of gas and water displacements along with the oil recovery)?
32. Although, water has a relatively low compressibility, how about the sensitivity of 'the volume of gas dissolved in the brine' (in the presence of an underlying aquifer) – along with the conventional factors (including reservoir pressure, temperature and salinity) - @ laboratory-scale? Whether, laboratory conditions will be able to accommodate the in-situ salinity variations of brine density, along with the application of a proper compressibility correction factor caused by the gas dissolved in the brine? Also, whether @ laboratory-scale, do we really bother about the compatibility (of ionic composition) between injected water and in-situ brine (which would otherwise might lead to scale formation resulting from insoluble precipitates)? Whether the lower residual saturation achieved at the laboratory-scale, by designing the specific salinity composition of the injected water (low salinity water flooding), can be successfully up-scaled to a larger field-scale implementation? In addition, to what extent, we would be able to replicate the real field scenario (water-oil displacement scenario in a communicating stratified reservoir), where, reservoirs with sufficient vertical permeability and with the displacement advancing very slowly so that gravity effects dominates and in turn, water and oil vertically segregates as they flow from injection to production wells, @ laboratory-scale using experimental investigations? Whether experimental investigations would be able to quantify the effects of adverse mobility ratios; strong capillary effects; gravity differences of oil and water; water under-running (caused by density difference between oil and water); the interplay between gravity & stratification (when, low-permeability layer is on top; and, when high permeability layer is on the top); and, local geologic variations – towards forecasting water-oil displacement in multiple dimensions? Further, how exactly, to replicate the scenario @ laboratory-scale investigations, where, in a real field scenario, if various layers are required to be operated at varying bottom-hole-pressures at the wellbores, in the presence of cross flow between various layers within the wellbore? Also, at the laboratory-scale, would it remain feasible to maintain a relatively higher injection rates of fluids, where, viscous forces 'significantly' influence the water-oil displacement front? Further, would it remain feasible to quantify (a) time to initial water-flood response; (b) time to peak oil rate; (c)

peak oil rate; and (d) ultimate water-flood reserves – associated with a typical water-flooding, @ laboratory-scale, using experimental investigations – in order to estimate the minimum, average and maximum oil recovery?

33. Since, the concept of a 'general' solution using modeling approaches remain to be virtually meaningless, would it remain feasible to analyze the reservoir by incorporating the specific and well-defined reservoir non-uniformity @ laboratory-scale using experimental investigations? Feasible to have a control over the pressure gradient that occurs normal to the flow direction (when the invading and displaced fluids have differing mobility) during core analysis? Feasible to analyze multi-layer core samples having variable rock and fluid properties in each layer (not with an idealized stratification, which just provides a statistical equivalence to the actual non-uniformity in reservoir rock properties); in the presence of cross-flow among these multiple layers (not with cent percent areal or pattern sweep efficiency, while cross flow becomes inevitable @ pore-scale), while including oil stripping in the flooded part of the formation and behind the advancing oil-water interface? Under such circumstances, whether the penetration of an injected fluid front (which will follow the individual layer's permeability variations) – would remain to be continuous from core-inlet (injection well) to core-outlet (producing well)?
34. While validating Dykstra-Parson's semi-empirical correlation for quantifying stratification effects on oil recovery (despite having a good control over mobility ratio and initial water saturation), would it remain feasible to have a control over (a) vertical permeability variation; and (b) the fractional recovery of oil in place at a given producing water-oil ratio @ laboratory-scale?
35. Can we try to validate the 'laboratory results' with that of 'results from a streamline simulator' (although, streamline simulators have a relatively 'lesser numerical dispersion and grid orientation effects' with computationally less intensive), if the oil-water displacement flow patterns remain not associated with the dominant viscous forces, while capillary effects and gravity effects (water slumping) play a crucial role? Also, how will we accommodate the significant material balance errors emanating from various streamline numerical solution techniques? Further, to what extent, the stream-line numerical solution techniques will be able to provide reasonable results, when the rate of fluid flow in the well gets altered significantly; or, when a new well remains added; or, when an older well remains shut-in (that leads to shifting of streamlines; and in turn, causing a significant departure of flow rates directed to each injector; and in turn, leading to an unbalanced injection from well to well, which will eventually attempt to sweep the oil in the reservoir non-uniformly)?
36. Would it remain feasible to increase the oil recovery by secondary recovery, in the absence of a natural water flood, where brine flux from a relatively larger adjacent aquifer would be driving the oil? What happens if the reservoir is of poor quality (with low porosity and permeability values); with strongly oil-wet nature; and having a low quality & high viscosity oil? In addition, how exactly, the performance of secondary recovery will get affected, if the number of producing wells are drilled with a relatively larger well spacing, while producing at higher flow rates? Towards a successful secondary recovery, would it remain feasible to drill around 10,000 wells in the second six month period, even though, the number of wells drilled during the first six month, following the discovery, hangs around only 100 wells?
37. If a reservoir remains to be highly heterogeneous, characterized by highly stratified carbonate, having significant variations in porosity and permeability, both areally and vertically, then, to what extent, the application of water-flooding with various pattern layouts and well-spacing would remain to be successful?
38. Would it remain feasible to have the following details at the earliest in a field-scale scenario, following primary production and during the commencement of secondary oil recovery? (a) major producing zone, where oil keeps flowing with ease; (b) a producing oil-water contact, below which, only brine was produced during primary and secondary recovery operations; (c) a residual oil zone, where oil saturation remains to be immobile;

and (d) a free water level, below which, we have 100% water saturation. Based on these details, would it remain feasible: (a) To assess the remaining hydrocarbon reserves under current operations? (b) To delineate the possible changes in order to enhance secondary recovery under current operations? (c) To determine the feasibility of infill drilling – by carrying out surveillance programs; areal flood balancing; injection, production, vertical conformance & pattern performance monitoring; and optimization? Further, would it remain practically feasible in order to maintain a relatively higher water-oil ratio in order to achieve higher oil recovery by producing, separating, reinjecting and recycling large volumes of water on a daily basis @ field-scale?

39. Feasible to investigate the fundamental physics associated with a water-flooding mechanism of a large, high-porosity, fractured chalk oil reservoirs containing a low-viscosity, high formation volume factor light oil, where both imbibition and viscous displacement dominates @ laboratory-scale using experimental investigations (that impacts the reservoir behavior and its associated oil recovery efficiency)?
40. Does water injection induce shear in a carbonate reservoir? Whether the coupled effect of shear failure and water weakening of the rock matrix result in additional deformation of the carbonates, even under conditions of constant or decreasing stress levels?
41. To what extent, the performance of water flood will get impacted resulting from (a) the quantum of natural gas that remains dissolved in reservoir oil (GOR)? (b) the ratio between viscosity of oil and the volume of dissolved gas; and (c) the number of hydrocarbon pore volumes injected water that remains flowing through the reservoir?
42. To what extent, oil recovery by spontaneous imbibition gets increased with reference to the oil recovery by water flooding – upon decreasing salinity of the injected fluid (low salinity water flooding)? To what extent, the brine salinity is required to be decreased from its original value (say, from 30,000 ppm)? How exactly, to quantify the physics of wettability alteration to an enhanced water wettability state – upon reducing the salinity of the injected brine – that essentially improves the oil recovery?
43. Can we successfully apply four-dimensional seismic data analysis (which aids to monitor reservoir production processes in a volumetric sense – towards optimal reservoir management), (a) if the reservoir rock remains to be only slightly compressible having low porosity? (b) if the reservoir fluid properties fail to exhibit a significant compressibility contrast in the absence of having only insignificant saturation changes over time between the monitor surveys? and (c) if the results include significant false anomalies resulting from time-lapse seismic acquisition and processing?

10. Conclusions

The present article has provided an overview on primary and secondary oil recovery processes along with the reservoir rock and fluid properties. A detailed discussion on the assumptions associated with the theoretical approach and the limitations associated with the experimental as well as filed works have been presented. The following conclusions have been drawn from the present study.

1. Following oil production, upon drilling, not only the vertical equilibrium between capillary and gravity effects gets disturbed, while the additional viscous effects resulting from mobility of oil (and water) comes into picture. In addition, the horizontal component of capillary pressure also plays a crucial role upon oil production. Further, inertial effects may also play a crucial role. Thus, the nature and intensity of forces driving fluid flow following drilling has new additional forces that appears both at pore-scale as well as at macroscopic-scale.
2. Unlike the reservoir pressure, where a finite, normal compressive stress acts over a finite area, capillary pressure reflects the pressure difference between wetting and non-wetting phase fluids only at the interface. Hence, updating capillary pressure from the pore-scale to a larger field scale average reservoir pressure requires further understanding.
3. The concepts of capillary pressure, relative-permeability and wettability are strongly related with pore-scale reservoir physics (along with hysteresis); and merging such associated sub-pore-scale properties namely interfacial tension, relative permeability to oil and water, and

contact angles respectively, along with the relatively larger microscopic-properties (viscosity, density, compressibility); and macroscopic properties (porosity and scale-dependent permeability) remain not convincing and requires further investigation.
4. Since the laboratory investigations using coring studies involve only a small number of core samples that actually do not represent the variability in reservoir rock and fluid properties over various scales; and since, it remains extremely challenging to retain the in-situ reservoir fluid content and in-situ reservoir wettability, the reservoir rock and fluid properties measured at the laboratory-scale may not be representative of real field conditions always.

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