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Carbonate Reservoir Characterization: An Overview

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Abstract

The primary goal of a carbonate reservoir study is to precisely predict the reservoir rock and fluid properties and their controlling factors in the associated reservoir body from the limited data available from cores and logs (bore-holes). However, carbonate reservoir cannot be characterized using the conventional single-continuum concept like a sandstone reservoir; and it essentially requires a multi-continuum approach due to the associated heterogeneity. Thus, capturing the spatial and temporal distribution of reservoir rock and fluid properties remain to be of prime importance in a carbonate reservoir. Despite such importance, relatively fewer studies have focused on carbonate reservoir characterization. This study has made an attempt to provide the complexities associated with the characterization of carbonate reservoir with reference to their rock and fluid properties, which remain associated with various scales. This study is expected to provide deeper insights on further investigation of carbonate reservoir characterization, which would essentially help to bridge the gap between laboratory-scale observations with that of a real field-scale scenario.

Keywords: *Carbonate reservoir; Rock property; Fluid property; Heterogeneity; Laboratory-scale; Field-scale.*

1. Introduction

Unlike sandstone reservoirs, carbonate reservoirs have to have a fundamentally different geologic and engineering concepts for characterizing and evaluating them using a wide range of scales. Although, sandstone reservoirs too have some kind of heterogeneity, carbonate reservoirs have a distinct heterogeneity and anisotropic nature with reference to the reservoir rock properties (porosity, permeability, rock compressibility, specific surface area); fluid properties (saturation, pressure, density, viscosity, fluid compressibility, irreducible fluid saturation); fluid-fluid interaction properties (relative permeability, capillary pressure, interfacial tension); and rock-fluid interaction properties (wettability, contact-angle). The conventional correlations between porosity and permeability; and other correlations between reservoir rock and fluid properties may not be working well as expected. This is because sandstone reservoirs are fundamentally characterized by primary porosity, while carbonate reservoirs are basically characterized by secondary porosity. Leaving aside, capturing the dynamic nature of fluids in carbonate reservoirs, sometimes becomes challenging, even to characterize the static nature of fluids in carbonate reservoirs. From this perspective, characterization of carbonate reservoirs essentially involves how best the data from VSP/sonic logs (geophysics); MWD/cement bond logs (drilling); and open-hole logs (formation evaluation) along with the data from cased-hole logs; inter-well correlation logs; and geo-chemical signature logs could be integrated by efficiently making use of core analysis and downhole measurements. The reservoir characterization could further be improved by considering the data from advanced well logging tools, special core analysis, closely-spaced drilling tests, digital production, tracer tests and pressure monitoring in order to have a proper conceptualization of fluid flow constraints (such as oil getting confined only to the fractures and dissolution channels; severe channeling of naturally encroaching water or injected fluids- and the presence of fractures or dissolution channels or conductive stylolites leading to discontinuous fluid flow paths, which do not help in increasing the oil recovery); and in turn, the connectivity between static and dynamic reservoir models would remain to be more meaningful and sensible and it would obviously lead to an enhanced predictions on primary, secondary and tertiary recovery operations [1]. Thus, the primary goal of a carbonate reservoir study is to forecast the rock and fluid properties precisely; and their controlling factors in a carbonate reservoir based on limited data [2].

2. Discussion

1. It is known that carbonate sediments have a wide range of particle size and sorting resulting from complex organic processes which gets redistributed with time leading to porosity values ranging between 40 and 75%, while, permeability values ranging between 200 and 30,000 md. If so, how should the fundamental approach of a carbonate reservoir characterization should vary for (a) mud-dominated fabrics (with 70% porosity & 200 md permeability); (b) grain-dominated pack-stones (with 50% porosity & 2000 md permeability); and (c) grain-stones (with 40% porosity and 30,000 md permeability)?
2. Do we also consider the primary environmental factors (affected by physical, chemical & biological conditions of the depositional settings); and the details of the secondary diagenetic processes, while, characterizing a carbonate reservoir?
3. How exactly do we capture the details on the variations of the facies changes (which modify rock properties over tens of meter scale) as against the changes associated with diagenetic processes (which modify rock properties @ smaller scales), associated with a carbonate reservoir?
4. Feasible to couple the factors controlling the quality of a carbonate reservoir with that of the drainage mechanism of a carbonate reservoir, which includes (a) geological-age (depo-time); (b) type of carbonate platform (depo-system); (c) facies belts (depo-zone); three-dimensional geometrical classification (depo-shape); (d) building blocks of the depo-shape (depo-element); and (e) carbonate lithofacies?
5. To what extent, the details (lithology, type and frequency of allochems, microscopic sedimentary features such as bioturbation, presence of opaque materials, laminations, mud cracks, brecciation and fenestral fabric of the samples, type and frequency of various pore types, fractures, cements and compaction features) from a thin section analysis could be converted into its equivalent rock and fluid properties in a carbonate reservoir?
6. Whether computed tomography scanning (CT scan) would be able to identify the presence of fractures @ core-scale? Feasible to capture the details on fracture length, fracture aperture thickness, fracture width and fracture spacing?
7. To what extent, the direct data deduced from cores will precisely reflect geological, petrophysical, geo-mechanical and geo-chemical properties of a carbonate reservoir?
8. Since, indirect measurements have two different spatial scales: (a) wire-line logs @ relatively smaller scales [0.15 m]; and (b) seismic sections @ relatively larger scales; whether, how exactly, these two measurements will be representing a carbonate reservoir, on a common spatial scale?
9. How exactly, will we be able to up-scale the properties associated with microscopic heterogeneities (facies characteristics, diagenetic effects, pore types, pore throat sizes, grain shape, size & packing, and mineralogy), that would remain applicable to a larger (carbonate reservoir) field-scale scenario, measured from thin sections, scanning electron microscope (SEM), mercury injection capillary pressure (MICP), core CT scanning and wireline-logs?
10. Leaving aside, the megascopic heterogeneities, considering, the sensitivity of tectonic activities, structural features and depositional conditions, do we have proper empirical relations or correlations that would take into account macroscopic heterogeneities (stratification, compartmentalization, sequence stratigraphy, reservoir zonation and lateral property trends) also, while characterizing a carbonate reservoir?

11. To what extent, the assumption of two for saturation exponent (n), would remain to be valid towards estimating water saturation of a carbonate reservoir (S_w) using Archie's equation as a function of resistivity of formation water (R_w), porosity, cementation exponent (m) and true resistivity of the sample (R_t)?
12. Since, there is no known sonic transit time value for samples with different types of porosities such as found in a carbonate reservoir, to what extent, the estimation of porosity using Wyllie's time-averaged equation as a function of sonic transit time in true formation, sonic transit time in rock matrix and sonic transit time in formation fluid – would remain to be meaningful?
13. How exactly the potential storage volume for hydrocarbons in a carbonate reservoir fundamentally differ from that of a sandstone reservoir? What is the implication behind the wide variation of porosity (1-35%) in carbonate reservoirs? Then, why do we have a relative low average porosities (around 10%) in dolomite reservoirs and limestone reservoirs?
14. Carbonate rocks being compressible, and since, porosity decreases with increasing effective stress, whether, porosity measurements are required to be carried out @ in-situ stress conditions? How about the loss of porosity with increasing confining pressure?
15. Unlike the inter-grain porosity associated with sedimentary rocks, whether, the shape of the grains; the presence of intra-grain porosity; and sorting, will have a significant effect on porosity in carbonate sediments? Feasible to capture the details on the presence of pore space within shells and peloids that make up the grains of carbonate sediments?
16. Would it remain feasible to deduce a finite relationship between porosity, grain size and sorting in carbonate rocks?
17. In a typical carbonate reservoir, does the saturation of a non-wetting phase depend on any other function than (a) the interfacial tension between non-wetting and wetting phases; (b) the adhesive forces between the fluids and the minerals that make up the pore walls; (c) the pressure differential between the non-wetting and wetting phases; and (d) pore-throat size?
18. In general, the pressure differential between non-wetting and wetting phases (capillary pressure) is produced by the difference in density between non-wetting and wetting phases resulting from buoyancy effect (produces pressures in hydrocarbon column). If so, in a carbonate reservoir, whether the pressure in the wetting phase will remain to be equal to the difference between (a) the reservoir pressure @ zero capillary pressure; and (b) the height above the zero capillary pressure times water density?
19. Whether the pressure gradient in a carbonate reservoir (measured from repeat formation tester or a wireline formation tester) be used to estimate the distance above the zero capillary pressure level?
20. In a fractured carbonate reservoir, whether, the pressure difference between the oil phase and water phase would remain to be equal to the difference between the specific gravity of the two fluids multiplied by the height of the oil column @ any given height in an oil column?
21. Would it remain feasible to deduce the base of a carbonate reservoir either by using drainage curve or by using imbibition curve?
22. Which of the following geological conditions remain to be very sensitive in generating fractures along with fracture spacing, fracture width and fracture dip: (a) depth of burial; (b) thickness of beds; (c) changes in lithology; (d) local stress field including the amount of differential stress considering mechanical discontinuities; (e) physical/chemical/mechanical properties of rocks and fluids in the pores; (f) rate of over-burden loading/unloading; and (g) gravitational compaction?
23. Permeability being dependent upon both volume of the rock sample and orientation, how do we take into account the influence of fractures and stylolites – present in the core samples - during permeability measurement? How exactly a carbonate reservoir formation needs to be sampled before using it for experimental investigations @ laboratory-scale?
24. Feasible to have a direct relation between porosity and permeability in the absence of having pore-size distribution in a carbonate reservoir?

25. How exactly to treat a carbonate reservoir system having a distinct fracture permeability and a matrix permeability?
26. To what extent, the concept of total permeability of a coupled fracture-matrix system in a carbonate reservoir would remain to be meaningful?
27. To what extent, the estimation of horizontal permeability in a carbonate reservoir as a function of fracture permeability; matrix permeability; fracture spacing; and fracture dip would remain to be meaningful?
28. If fractures are just acting as a conduit to transport the oil, while, all the oil remains stored in low permeability rock-matrix, then, to what extent, fracture permeability, will be of any use, in estimating the OOIP in a carbonate reservoir?
29. Can we expect the flow to remain to be in laminar regime in high permeable fractures?
30. Whether the withdrawal of oil from low permeable rock-matrix would end up with an increase, or, reduction in fracture aperture width?
31. Given the fact that natural fractures rarely remain to be parallel, then, to what extent, the concept of cubic law, where, the pressure drop remains to be proportional to the cube of the fracture aperture width would remain to be justified in a carbonate reservoir?
32. If the fracture walls or fracture surfaces remain to be rough, then, to what extent, the resulting head loss associated with fracture surfaces would remain to be sensitive?
33. When exactly the concept of absolute roughness and relative roughness on flow through induced fractures would remain to be sensitive? How about the sensitivity of 'head loss due to fraction' with reference to the 'potential head'?
34. Whether cubic law be applied irrespective of the size of the fracture aperture thickness? For example, what exactly controls the fluid flow when the fracture aperture thickness remains to be (a) 0.1 micron; (b) 1 micron; (c) 10 micron; and (d) 100 micron? When exactly, (a) pressure gradient dominates the fluid flow; and (b) capillary forces dominate the fluid flow? Why does even cubic law fail to work at low fracture aperture thicknesses?
35. To what extent, the carbonate reservoir characterization is becoming difficult resulting from the presence of highly directional permeability; and that too, permeability remaining drastically different in one direction from those in another direction – associated with the geologic stresses imposed upon the reservoir rocks?
36. Whether, fracture spacing could be obtained from well-test analysis?
37. To what extent, fault morphology and boundaries of genetic carbonate units really (a) influence the continuity of a carbonate reservoir; and (b) influence the volumetric sweep efficiency?
38. Whether, permeability zonation; and, baffles within and between genetic units really have a significant impact on vertical sweep efficiency?
39. To what extent, the small-scale heterogeneities such as sedimentary structures, interlamination of various rock types, pore-types and non-carbonate minerals would remain to be sensitive in dictating resulting the oil recovery factor in a carbonate reservoir?
40. How easy would it remain to delineate the zones of dolomitization; and in turn, will we be able to quantitatively interpret the concentrations of non-carbonate minerals?
41. To what extent, the presence of fractures in a carbonate reservoir really aid to drain solution gas-drive reservoirs during primary recovery production owing to the gas coming out of solution; and in turn, expelling the crude oil from the pore space into the well-bore?
42. To what extent, the presence of fractures really become avenues for the injected water to bypass huge volumes of oil contained in the low-permeable rock-matrix of a carbonate reservoir, during conventional water-flooding operations?
43. During the displacement of oil by water, whether, imbibition process (where, the wetting-phase saturation gets increased) do not remain to be effective due to the presence of fractures in a carbonate reservoir; and only, drainage (where, wetting-phase saturation gets decreased) remains to be effective?
44. Whether early water-flooding will be a wise idea (before primary production gets over) in a carbonate reservoir?

45. Do we really require a moderate degree of induced fracturing in order to stimulate wells in a low-permeability carbonate reservoir in order to complete a water-flood in a reasonable time period? In such cases, would it remain feasible to have a control over the degree of fracture stimulation using pressure fall-off analyses – by not allowing the fluid injection pressures to exceed the parting pressure of the formation; and by having proper restraints and control over fluid injection, which will not induce the generation of excessively long fractures; and thereby preventing an early water breakthrough that leaves the by-passed oil in the pore space?
46. Whether natural water drives remain to be less effective in carbonate reservoirs than in sandstone reservoirs?
47. What will happen, if, during injectivity tests, if the formation gets fracture parted, while obtaining the estimates of permeability capacity term? Won't it lead to an erroneously larger values of permeability capacity term? To what extent, step-rate injectivity tests will be able to help us in assessing the formation of new fractures? Does this approach take into account the spatial distribution of the flow capacity in a carbonate reservoir?
48. Whether naturally fractured carbonate reservoirs remain to be poor candidates for miscible CO_2-flooding? How about the advantages associated with the gravity effects and the opening of the vertical fracture systems?
49. To what extent, the concept of thermal expansion will be able help in mobilizing the oil from low-permeable rock-matrix into high-permeable fractures, during the operation of steam-flooding in a carbonate reservoir? Whether, steam drive will efficiently heat the low-permeable rock-matrix blocks by heat conduction, where, the viscosity of the stored oil gets reduced by heating (and in turn, thermal expansion moves the oil from matrix into fractures)? Whether carbonates would get dissociated by the steam (release of CO_2) under the reservoir pressure and temperature conditions with favorable effects?
50. To what extent, a pressure cycling steam recovery process (with imbibition and internal gas drive and/or steam flashing) could be used to recover heavy oil from a carbonate reservoir? In such cases, whether, the heating by thermal conduction would remain to be efficient? If so, which of the following processes would remain to be sensitive – that would displace the oil into the fractures: (a) thermal expansion; (b) accelerated imbibition; (c) gravity drainage; (d) expansion by solution gas drive of oil from the rock-matrix during the blow-down phase?
51. To what extent, the presence of sediment-filled and unfilled paleocaves and caverns dictate the resulting porosity and permeability distribution in a karsted reservoir? What will happen, if we have extreme vertical reservoir compartmentalization resulting from the presence of successive levels of cave or cavern systems that remain separated by impermeable host strata (that may serve as barriers to lateral fluid flow); and by having impermeable strata within individual cave or cavern level in the productive section?
52. To what extent, the presence of multi-porosity systems in productive zones (inter-particle pores in cave-filling breccias; matrix porosity in host carbonates; dissolution enlarged fractures and joints; and large, tortuous cavernous pores) – that lead to extreme variations in effective porosity and permeability – lead to the changes in internal pressure gradients (associated with the local fluid flow) and the overall reservoir performance?
53. To what extent, a reservoir engineer will be able to evaluate (a) fluid properties; (b) fractional flow characteristics of rock; (c) formation pressure; and (d) directional permeabilities - in a carbonate reservoir? Feasible to identify the physical processes responsible for the deviation between 'a flood simulator history match' with that of 'the actual field production history'? Feasible to deduce the details of fractional fluid production of each zone, in each well? Feasible to identify, whether, the fluid contacts keep moving in the reservoir? Which of the various zones, exactly, produce water, oil and gas? Feasible to ensure, whether, the pay keeps moving because of water or gas encroachment? Where exactly (which zone), the external fluids are getting injected into the reservoir? Feasible to have a control over the rates at which, various zones in a well, need to be produced? Feasible to make a comparison between the production rates of each zone with that of their

respective zone's potential? Feasible to deduce, whether, are there, any portion of the oil field that requires additional well?

54. To what extent, a production engineer will be able to assess (a) pay zone distribution in the vertical direction; (b) the requirement of stimulation; (c) reservoir compatible fluids; (d) the nature of injection profile; (e) the evolution pattern of volumetric production results; (f) required tuning methodologies for history matching; and (g) finding efficient ways to bridge the gaps between pore-scale, core-scale and pilot-scale studies with that of the real field scenario – in a carbonate reservoir? To what extent, the presence of unperforated or incomplete productive zones would hinder the oil recovery factors in a carbonate reservoir? Feasible to delineate the thief zones with ease – that remains to be closed off? Feasible to ensure whether the completion intervals have zonal isolation integrity? Feasible to deduce precisely, whether, how long, will, each wellbore, would remain to be usable efficiently?
55. To what extent, drilling engineer will be able to assess (a) the pressures encountered @ various locations spatially and temporally within the pay zone thickness; (b) the evolution of fracture gradients; (c) the nature of rock integrity during drilling; and (d) the requirement of compatible drilling muds – in a carbonate reservoir?
56. To what extent, facilities engineer will be able to assess (a) whether, the production is going to be oil, gas and/or water; (b) the evolution of production rates; and (c) the nature of produced fluid properties – in a carbonate reservoir?
57. To what extent, petro-physicists will be able to assess (a) log-core relationships; (b) the feasibility of over or under pressures; and (c) the extent of pay – in a carbonate reservoir? Feasible to capture the changes in residual oil saturation and their respective spatial and temporal distribution, upon injection of external fluids during secondary and tertiary recovery; also, how exactly to handle the errors associated with the saturation distribution values? Feasible, to easily delineate, the original and current fluid saturations, in each zone, in each well, in a carbonate reservoir?
58. To what extent, geo-physicists will be able to assess (a) the intensity of acoustic velocities or impedances; (b) acoustic anisotropy; and (c) acoustic impedance trends – in a carbonate reservoir? Whether 4-D seismic or geo-tomography would be able to help in monitoring fluid contacts, or, flood fronts? Any possibility of having deeper potential hydrocarbon zones?
59. To what extent, the geologists will be able to assess (a) the presence of source rock in the geological column; (b) the richness of the source rock; (c) the seal capacity of the upper impermeable seal; and (d) the importance of structure and stratification during secondary and tertiary oil recovery processes?
60. Whether petrophysical models be effectively applied in a carbonate reservoir? Even, if the number of unknowns remain to be lesser than or equal to the number of equations, will it remain feasible, to obtain, all the requires parameters used in the equations – associated with a carbonate reservoir?
61. Can density-neutron cross-plots (density log porosity vs neutron porosity) efficiently be used for the determination of mineralogy and porosity in a carbonate reservoir? Or, density-acoustic cross-plots (density log porosity vs acoustic travel time) should be used? Or, neutron-acoustic cross-plots (neutron log porosity vs acoustic travel time) should be used? Or, density-photoelectric factor cross-plots should be used?
62. Can Hingle plots (where density log function remains substituted for porosity) be used for the determination of mineralogy and water saturation in a carbonate reservoir? How exactly to secure the values of 'm' and 'n'? How exactly to estimate water resistivity?
63. To what extent, the apparent water resistivity estimation would remain to be meaningful in a carbonate reservoir? Should we apply the relation only in water zone? How exactly to deduce 'a' and 'm' for the given carbonate reservoir, towards estimating the formation factor? If we have to make use of water resistivity from spontaneous potential approach, then, how exactly, to deduce the correlation for 'k' as a function of formation temperature, towards deducing water resistivity?

64. Can we comfortably apply Archie's second law for estimating water saturation in a carbonate reservoir as a function of water resistivity and porosity?
65. Can we comfortably make use of Pickett plot for estimating water saturation in a carbonate reservoir by establishing unit water saturation trend?
66. To what extent, the conventional porosity/lithology cross-plots used to determine lithology in a carbonate reservoir contains 'gas' also in the pore fluids, in addition, to the presence of mineralogy components including dolomite, limestone, anhydrite, gypsum, salt, and chert?
67. How easy a reservoir management plan in a carbonate reservoir will be – with reference to (a) Whether the reservoir rock and fluid properties are accurately defined? (b) What is the maximum and optimum number of wells to be drilled? (c) Where exactly the wells should be located? (d) how exactly the wells need to be drilled – horizontal/vertical/inclined? (e) how exactly the wells need to be completed? (f) how exactly the recovery factors be optimized? (g) how exactly the reservoir pressure will be maintained as a function of time? (h) when exactly secondary recovery or water-flooding need to be introduced, if required? (i) when exactly tertiary recovery processes need to be introduced? (j) what will be the initial investment?
68. How easy would it remain to characterize a highly undersaturated carbonate oil reservoir (where, the saturation pressure remains to be lower, by an order of magnitude or more, than formation pressure with a low solution GOR)?
69. How easy would it remain to characterize a moderately undersaturated carbonate oil reservoir in the absence of any free gas gap?
70. How easy would it remain to characterize a moderately undersaturated carbonate oil reservoir with initial free gas gap? How lower could the saturation pressure be than the formation pressure – for an efficient oil recovery?
71. How easy would it remain to characterize a saturated carbonate oil reservoir with initial free gas gap (where, initial reservoir pressure equals saturation pressure; and, where, no retrograde condensation occurs in the gas cap with the reduction in reservoir pressure)?
72. How easy would it remain to characterize a saturated carbonate oil reservoir in the absence of free gas gap (where, the reservoir pressure is initially at the bubble point pressure of oil)?
73. Whether the potential energy sources that remain available in a carbonate reservoir, in order to mobilize oil and gas to the wellbore including (a) gravitational energy of oil acting over the vertical distance of the productive column; (b) energy of compression of the free gas in the gas cap or within the oil-producing zone; (c) energy of compression of the solution-gas dissolved in the oil or the water; (d) energy of compression of oil and water in the producing-zone of the reservoir; (e) energy of capillary pressure effects; and (f) energy of the compression of the rock itself; – remain to be significantly different – from that of a sandstone reservoir? How about the relative influence of each energy source on a carbonate reservoir behavior towards producing hydrocarbon? How exactly, the ratio of reservoir oil viscosity to reservoir gas viscosity, solution GOR, formation volume factor, interstitial water saturation, and oil/gas permeability relationships – control the performance of a carbonate reservoir?
74. How exactly will be the evolution of dissolved gas in a carbonate oil reservoir – as the reservoir pressure declines during production – during solution gas drive? Where exactly the free gas phase formed would remain (in the fracture or matrix) – within the oil producing zone? What will happen, if the reservoir is associated with water zones, where, the pressure becomes significant as the pressure declines? Does reservoir pressure depend primarily on cumulative oil recovery in solution gas drive carbonate reservoirs? What will happen, if oil production rate significantly influences the producing GOR? Can we reduce the production rate in a carbonate reservoir in order to enhance the ultimate oil recovery significantly? Would it remain feasible for a carbonate reservoir in order to exhibit significant gravity drainage or water influx, or, to form a secondary gas cap that would essentially make ultimate recovery to remain to be very sensitive to production rate?

75. How exactly, the gas-cap-drive carbonate reservoirs respond to oil production rates? Whether the presence of velocity term in the recovery equation would make the carbonate reservoir to remain to be more rate sensitive? Feasible to prevent gas coning in a carbonate reservoir (even, if it is produced @ low rates), when the wells producing from intervals remain to be closer to the gas gap?
76. Can a carbonate reservoir act as a complete water-drive system, where, essentially, all the fluid withdrawals remain replaced by intruding water? What will happen in a carbonate reservoir, if reservoir withdrawal rates remain greatly to be in excess of the rate of water influx?
77. Whether the combination of low viscosity and high API gravity values – would really emphasize the down-structure oil migration in a carbonate reservoir during gravity drainage?
78. Whether the ultimate oil recovery in a carbonate reservoir would depend on the balance between the capillary and gravity forces – during a gravity drainage? How exactly gravity forces will be able to overcome the capillary resistance to the entrance of water into the fractures? Whether the capillary and gravity forces control the static and dynamic equilibrium of each individual low-permeable rock-matrix block, if the high-permeable fractures remain to act as capillary discontinuities? Feasible to have a precise measurements of capillary pressure curve, particularly, in the very low-pressure change – associated with the field performance predictions for highly fractured carbonate reservoirs?
79. How exactly the oil recovery gets influenced due to the presence of the following diagenetic processes in a carbonate reservoir? (a) dolomitization; (b) cementation; (c) massive dissolution; and (d) grain enhancement.
80. How exactly to have a control over the spatial and temporal distribution of porosity and permeability of a carbonate reservoir, if it is characterized by intermediate porosity (which displays, openings, fissures, dissolution caverns and other openings induced by dissolution and fracturing, in addition to the intergranular openings) as against intergranular porosity (where, carbonate rocks remain composed of calcareous fragments, whose, size, shape and packing determine the pore space geometry)?
81. To what extent, the following data deduced from a pressure transient analysis will remain to be meaningful in a carbonate reservoir? (a) formation conductivity (kh); (b) skin factor; (c) average formation pressure; and (d) formation storage capacity.
82. By what means, the values of flow-rate and pressure – deduced from the following pressure transient and flow tests remain to be different for a carbonate reservoir from that of a sandstone reservoir? (a) pressure drawdown; (b) pressure build-up; (c) variable flow rate test; (d) injection test; (e) fall off test; (g) constant pressure test; (h) deliverability test; (i) vertical testing; (j) drill stem testing; (k) repeat formation test; (l) step rate test; (m) interference test; and (n) pulse testing. Whether the porosity and permeability of the reservoir would remain to be a constant? Whether gravity forces would remain to be negligible? Whether pressure gradients would remain to be small at all locations within a carbonate reservoir?
83. To what extent, the concept of type curves introduced by Ramey [3], which refers to a log-log graph of a specific solution to the flow equation, involving the dimensionless pressure for the vertical axis and the other involving the dimensionless time for the horizontal axis – would be able to help in analyzing the pressure drawdown solution, when the drawdown test remain to be very short for the semi-log straight line to develop – in a carbonate reservoir? Feasible to assume a carbonate reservoir to have a constant porosity, permeability, thickness and a uniform initial pressure? Also, how could we assume a carbonate reservoir to be infinite, isotropic, homogeneous and horizontal reservoir? What will happen, if we fail to capture the correct initial value of pressure?
84. Can we use short-term drawdown tests in order to determine formation permeability and skin effect; and to estimate the reservoir volume in communication with the well, using long-term or reservoir limit tests - in a carbonate reservoir?

85. To what extent, line source solution would remain to be meaningful in a carbonate reservoir, where, the pressure behavior of well produces at a constant rate, located in the center of a radial infinite reservoir?
86. To what extent, the information from a drawdown graph will remain to be meaningful in a carbonate reservoir during (a) front-end effects or short time data (pressure behavior being under the influence of wellbore storage, damage, unstable flow conditions in the tubing string); (b) the semi-log straight line portion, applicable to the analysis by the semi-log methods; (c) boundary effects, which include boundaries and interference effects? Feasible to clearly identify the straight-line portion of the semi-log plot in order to precisely estimate the formation conductivity (kh)?
87. To what extent, the concept of skin factor (that relates the pressure drop experienced by the fluid flowing towards the well to the rate of flow) would remain to be useful in a carbonate reservoir? Does this skin factor include all the factors that affect fluid flow towards the well during the various phases? (a) first under radial conditions over the full zone thickness in the region, away from the wellbore; (b) where, it will converge into the completed interval in the region near the wellbore; (c) when, it acts as radial flow through the damaged zone of thickness; and (d) during flow through perforations.
88. How exactly to take into account the inertial effects associated with the high-permeable carbonate reservoirs? Whether, the bottomhole shut-in tool would remain to be effective in eliminating wellbore storage and inertial effects? And, how important are wellbore temperature effects; and the interference of neighboring wells producing pressure changes at the tested well?
89. Do we require to have a two different relative permeability curves (one for the fracture and the other for the matrix) for a fractured carbonate reservoir, as the fracturing plane between two matrix units develops a discontinuity in the multi-phase flowing process? Whether the relative permeability curve for rock-matrix would remain to be representative in relation to the shape of relative permeability curves and the magnitude of their endpoints (irreducible saturation in the wetting and non-wetting phases and the respective relative permeability values at these critical saturations)? Whether the fracture network relative permeability curves would remain to be significantly different from rock-matrix relative permeability curves – due to the very high values of intrinsic permeability associated with the high-permeability fractures? Whether these high permeable fractures would have a dominant control of gravity forces in multi-phase fluid flow in fractures?
90. As it is known, in a sandstone reservoir, the capillary pressure at static conditions is associated with the transition zone, while, at dynamic conditions, the capillary forces remain to play a more limited role as the fluid displacement process essentially remains to be controlled by viscous forces. On the contrary, do we require an enhanced understanding of the displacement process, as the displacement process is critically controlled by gravity and capillary pressure forces, which make the interpretation of capillary pressure curve behavior to remain to be extremely challenging? Whether, capillary pressure behavior with both drainage and imbibition displacement processes, are required to be combined with gravity displacement behavior, which would possibly allow better estimation of fracture-matrix fluid exchange?
91. Whether the displacement of oil from rock-matrix remain to be dependent on fluid saturations, fluid wettability and saturation history in a fractured carbonate reservoir?
92. Whether the shape of a drainage capillary pressure curve would be able to provide the distribution of fracture and fracture aperture thicknesses?
93. How exactly to have a control over gravity drainage displacement in low permeable rock-matrix, where, the oil will move downward by gravity forces, whereas, the capillary forces will oppose fluid exchange because the entrance of gas into the matrix as a non-wetting phase remains opposed by capillary forces, due to the differences in specific weights of gas and oil? Given the fact that capillary forces may remain to be constant with depth, while gravity forces increases with depth, whether the combined effect of gravity-capillary forces

under imbibition displacement would have a significantly different behavior in the displacement history of the drainage or imbibition field process – associated with a fractured carbonate reservoir?

94. When exactly a counter-flow (where, the production of a non-wetting phase has an opposite direction of flow to that of the imbibing wetting phase) gets developed in a fractured carbonate reservoir? Whether the role of oil buoyancy would remain to be very critical in dictating the counter-flow?
95. Given the fact that when a non-wetting phase fluid (oil) enters a wetting phase (water) porous system, then, the oil gets filled up at the centers of the largest, well connected pores, while, the wetting phase (water) is found lining the pore walls and filling the smallest pores; and, thereby essentially reducing the pore space available for flow of either wetting-phase or not-wetting phase. If so, do we require a correction for permeability values (resulting from the varying saturations of water, oil and gas) in a carbonate reservoir as well?
96. Whether the concept of end point method (which assumes that a reasonable estimate of the curvature could be made) be used to measure effective permeabilities @ irreducible water saturation and residual oil saturation in a carbonate reservoir?
97. Since, restoring core samples @ laboratory scales to the actual field carbonate reservoir conditions remain to be challenging; and, since, the pore surfaces remain to be reactive to changes in fluids, and in turn, these reactions could alter the wettability state in a carbonate reservoir, to what extent, the measurement of relative permeability for a carbonate reservoir @ laboratory-scale would remain to be justified?
98. As it is known, oil becomes mobile only after attaining a saturation defined by the relative permeability curve that equates to a reservoir height defined by the capillary pressure curve. Does this level exactly define the oil-water contact in a real field (carbonate reservoir) scenario? How easy would it remain to delineate a transition zone in a carbonate reservoir?
99. Does permeability in a carbonate reservoir depend only on porosity and pore-size?
100. Does fluid saturation in a carbonate reservoir depend only on porosity, pore-size and capillary pressure (which remains to be directly linked to reservoir height through the density difference of the fluids involved)?
101. Does relative permeability in a carbonate reservoir depend only on absolute permeability and fluid saturation?
102. In a carbonate reservoir, how easy would it remain to distinguish between inter-particle porosity (pore space located between grains) and vuggy porosity (pore space not located between grains/crystals? How exactly to capture the details of separate vugs (vugs that remain inter-connected only through the inter-particle pore network: moldic, intra-particle [intra-crystal, intra-grain, intra-fossil], intra-grain micro-porosity, shelter) and touching vugs (vugs that form an inter-connected pore system: fracture, solution-enlarged fracture, cavernous, breccia, fenestral)?
103. To what extent, Leverett J function, which relates water saturation to capillary pressure (which is a function of reservoir height) and 'square root of permeability over porosity' (which is a function of pore size) – would remain to be justified in a carbonate reservoir, which has larger volumes of vuggy porosity, with extensive intra-grain micro-porosity? Whether permeability and fluid saturations are controlled only by pore-size distribution (which are described by rock fabric descriptions and porosity in carbonate reservoirs with no vuggy porosity)?
104. In a carbonate reservoir, when we make a plot of reservoir height (y-axis) vs fractional water saturation (x-axis), under what circumstances, the profile (a) intersects the x-axis; and (b) remains parallel to x-axis, when the reservoir porosity remains to be high (say, 15 – 20%)? Also, under what circumstances, the profile intersects the x-axis at the minimal fractional water saturation (when the porosity remains to be high)?
105. In a carbonate reservoir, whether a plot between porosity (x-axis) and water saturation (y-axis: logarithmic) always remain to be linear?

106. In a carbonate reservoir, when we plot, relative permeability (y-axis) vs fractional water saturation (which can be correlated with reservoir height vs fractional water saturation), what exactly dictates the reservoir height pertaining to (a) only water production; (b) both oil and water production; and (c) only oil production?
107. How exactly to determine the displacement pressure as a function of average particle size for a vuggy carbonate reservoir? Will it still follow the exponential profile?
108. In a vuggy carbonate reservoir, when we plot, permeability (y-axis: logarithmic) against inter-particle porosity, will it still follow a linear relation for various particle-size groups?
109. In a carbonate reservoir, what exactly dictates the slope of the profile between logarithmic permeability and porosity?
110. Whether characterization of a carbonate reservoir will remain to be significantly different for reservoirs composed of (a) grain-stones; (b) dolo-grain-stones; (c) grain dominated pack-stones; (d) grain dominated dolo-pack-stones; (e) mud dominated dolo-stones; (f) mud-dominated limestones; and (g) mud-dominated dolo-stones? Whether, permeability (as a function of fractional inter-particle porosity) and initial water saturation (as a function of reservoir height and porosity) in a carbonate reservoir is going to be highly reservoir specific?
111. How easy would it remain to estimate the permeability of a carbonate reservoir as a function of inter-particle porosity (total porosity – separate vug porosity) only, which eliminates separate-vug porosity? How do we capture the effects of separate vugs on permeability and initial water saturation? Feasible to have a control over the pore sizes that connects the intra-particle and inter-particle pore space?
112. How easy would it remain to relate the rock fabrics of a carbonate reservoir with that of the petro-physical properties, secured from core and wireline log data, in multiple dimensions, using geologic processes and stratigraphic principles?
113. How easy would it remain to distinguish between inter-particle pore-size and intra-particle pore size (separate vugs) – in a carbonate reservoir?
114. To what extent, in a carbonate reservoir, the concept of variography (which uses variograms to statistically characterize spatial variability) be used successfully in order to quantify the spatial continuity from the secured data through geological interpretation? To what extent, geostatistical approach (where, mean and covariance or variogram are the basic measures) remain to be distinct and better from that of a classical statistical approach (where, mean and variance are the basic measures)?
115. Can conditional simulation (which is not used to estimate reality but just to deduce realizations that have the similar degree of spatial variability and complexity as reality) be used to characterize a complex carbonate reservoir?
116. How easy would it remain (a) to describe the vertical succession of depositional facies in core slabs identifying depositional cycles; and (b) to identify sequence boundaries and high frequency cycles – from a vuggy carbonate reservoir?
117. How easy would it remain to distinguish between compaction effect (which is both a physical and chemical process from the increased over-burden pressure due to burial; and which remains to be a function of texture only) from that of cementation effect, as both tend to reduce pore-size and porosity, in a limestone reservoir?
118. Dissolution being a diagenetic process by which carbonate and evaporate minerals are dissolved and removed; and eventually, lead to the creation and modification of pore spaces in reservoir rocks; would it remain feasible to distinguish fabric selective dissolution from that of non-fabric selective dissolution, associated with a limestone reservoir?
119. Having known that carbonate facies remain to be more difficult to image seismically than clastic facies; and since, porosity remains to be affected by the stratigraphic setting and the depositional facies, to what extent, any inaccurate estimation of porosity would tend to enhance the risk and cost associated with the exploration and development of a carbonate oil field? To what extent, transgression (long-term sea rise) and regression (long-term sea fall) of sea level would have influenced the carbonate porosity? And, to what extent, the

prediction of lateral facies changes in a carbonate reservoir remain to be challenging? And, how exactly will we be able to delineate the reservoir boundaries?

120. How exactly the origin and deposition of carbonate sediments remain controlled by tectonism, climate, eustatic and sedimentation changes, which essentially condition the architecture of the carbonate deposits, the discontinuities and the resulting distribution of petrophysical properties?
121. How exactly the chemical reactivity of carbonate rocks dictate the resulting reservoir heterogeneity?
122. Why do we end up with a relatively lower producing GOR in fractured carbonate reservoirs? When could we expect a relatively high vertical communication in fractured carbonate reservoirs, which would probably cause the liberated gas to get segregated towards the top of the reservoir?
123. What are the favorable circumstances in a carbonate reservoir that would cause a relatively larger supply of fluids into high permeable fracture from low permeable rock-matrix, resulting from gravity and imbibition (combined with fluid expansion), segregation and advection? Will it always lead to a relatively lower rate of pressure decline (per barrel of oil produced)?
124. Why do we have a relatively smaller transition zone with sharp, horizontal fluid contacts in a fractured carbonate reservoir? How do we ensure that the changes in the fluid contacts tend to rapidly get re-equilibrated even during production, while, promoting low pressure drops around producing wells even @ high producing rates, resulting from the presence of high permeable fractures, in a fractured carbonate reservoir?
125. How exactly the details from the experimental investigations on examining the elastic behavior of carbonates carried out under unconfined compression test or tri-axial test @ laboratory-scale help us to understand the actual field-scale behavior? What exactly do we understand by characterizing the carbonate failure mode as a function of various confining pressure?
126. How sensitive will the role of bulk modulus be in a carbonate reservoir, which will significantly influence the resistance of carbonate to an overall gain or loss of volume, in conditions of hydrostatic pressure? Similarly, how exactly, the shear modulus of carbonate (modulus of rigidity that examines how stiff a carbonate reservoir rock is subjected to shearing deformation with no change in the volume) would dictate the rigidity of the rock?

3. Conclusions

Carbonate reservoirs being rich in oil and gas resources and widely distributed across the globe, carbonate reservoirs have the characteristics of large reserves and high production. However, the presence of dissolved vugs, pores and fractures generate a complex heterogeneity, which remain to be a huge obstacle in the research and exploitation of carbonate reservoirs. From this perspective, this article has tried to bring out the varieties of complexities associated with the characterization of a carbonate reservoir. The following conclusions have been drawn from the present study.

1. Mere evaluation of porosity and permeability will not be sufficient towards characterizing a carbonate reservoir; and it not only requires the details of rock fabrics that define the exact rock type, but also, the details on the critical pore-throat radius needs to be deduced which dictates the connectivity of the resultant pore spaces through which fluid flow occurs.
2. It is extremely critical to monitor and to have a control over the evolution of secondary porosity and secondary permeability (generation of secondary and tertiary fractures) resulting from the presence of various types of porosity.
3. Determination of initial reservoir rock and fluid properties including bulk porosity, matrix porosity, fracture porosity, bulk permeability, rock permeability, fracture permeability, rock compressibility, fluid compressibility and water/oil/gas saturations remain to be very sensitive in determining original oil in place.

4. The deduction of relative permeability to water, oil and gas remain to be very challenging in a carbonate reservoir, while the inferences on capillary pressure and contact angle (wettability) requires a lot of further investigation associated with a carbonate reservoir as the existing correlations may not work well.
5. Deducing both pore-scale (microscopic) displacement efficiency and the larger volumetric-scale sweep efficiency (areal sweep efficiency and vertical sweep efficiency) associated with a carbonate reservoir remains to be extremely challenging and requires further investigation.

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