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Chapter

Damage Formation: Equations of water block in oil and water wells

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Abstract

Water block or invasion of water into the pores of reservoir forms during the operations of water-based drilling, injection, many perforations, completion fluids, and some other particular processes in the reservoir (such as fingering and conning). Subsequently, the alteration in the shape or composition of the fine particles such as clay (water-wet solids), as a result of the stress on it, in the flow path of the second phase can lead to the permeability decline of reservoir. Consequently, the solvents such as surfactants (as demulsifiers) to lower the surface tension as a phenomenon associated with intermolecular forces (known as capillary action) during flowback are consumed to avoid the emulsions and sludge mostly in the near-wellbore zone or undertreatment and under-injection radius of the reservoir. However, in addition to surging or swabbing the wells to lower the surface tension, using solvents as the wettability changing agent along with base fluid is a common method in the water block elimination from the wellbore, especially in the low permeability porous media or the reservoirs latter its average pressure declined below bubble point. For more profitability, after using solvents in various reservoir characterizations, the trend of their behavior variations in the different lithologies is required to decide on the removed damage percentage. The investigations on this subject involve many experimental studies and have not been presented any mathematical formulas for the damage of water block in the water, oil, and gas reservoirs. These formulas determine selection criteria for the applied materials and increase variable performance. An integrated set of procedures and guidelines for one or more phases in a porous media is necessary to carry out the step-by-step approach at wellhead. Erroneous decisions and difficult situations can also be addressed in the injection wells or saltwater disposal wells, in which water block is a formation damage type. Misconceptions and difficult situations resulting from these injuries can increase water saturation in borehole and affect the fluid transmissibility power in reaching far and near distances of the wellbore, which results in injection rate loss at the wellhead. Accordingly, for the equations of water block here, a set of variables, of a particular domain, for defining relationships between rock- and fluid-based parameters are required. For these equations, at first, the structural classifications of fracture and grain in the layers (d_1, d_2, and d_3) are defined. Afterward, the equations of overburden pressure (P_{ob}) for a definite sectional area surrounding the wellbore for any lithology (in the three categories relative to porosity) are obtained by these structural classifications and other characteristics of rock and fluid. Naturally, prior to equations of overburden pressure in

a definite layer or a definite sectional area around the wellbore, the overburden pressure of a point in a layer in the first four equations is expressed. In the second, the estimated overburden pressure equations are applied in driving the equations of removed water block (B_k). The equations of removed water block, themselves, are divided into two groups of equations, i.e., equations of oil wells and equations of saltwater disposal wells, and each group of equations is again classified based on the wettability of reservoir rock (oil-wet or water-wet) in the two ranges of porosity. In the third, after describing these equations (i.e., equations of B_k), the other new variable included in the equations of removed water block, that is, the acid expanding ability (I_k) for a definite oil layer around the wellbore, is presented, which is extracted from (1) the full characteristics of reservoir (including experimental and empirical equations of overburden pressure), (2) the history of producing well, (3) core flooding displacement experiments at laboratory, and (4) the acidic and alkaline solvent properties. Finally, the rate of forming water block (q) is calculated using the value calculated for the removed water block, and, additionally, the trend of using solvents is determined for different rocks using these sets of equations. The acceptance criteria are the nature of rock and fluid in the reservoir circumstances. Equations as a quick and cost-efficient method are also introduced, providing computational methods to determine how much and how the blocked fluid in the reservoir layers is removed from the definite strata around the wellbore after injection operation of acids and solvents, with various degrees of acidity, to the types of lithology during acidizing operations. Moreover, these equations can calculate the removed water block (B_k) after injecting solvents to the different acidic properties in the acidizing, for two categories of porosity which cover all lithologies. The equations also ascertain in the current reservoir conditions how much solvent for a type of lithology is to be mixed with other base fluids.

Keywords: defined water and oil layer overburden pressure, overburden pressure of a definite layer point, removed water block equations, injection wells or saltwater disposal wells (SWDW), oil wells, rock and fluid characteristics, chemical solvents

1. Literature review

For avoiding productivity loss in wells, the compatibility of lithology with types of acids, their use percentage, and additive solvents mixed with base fluids are preferred to be handled before acidizing. In the downhole operations, use of solvents such as alcohols and surfactants (as wetting factors for lowering surface tension of the acid and subsequently for better penetration in the matrix of rock) should be carried out in accord with the previously-estimated quantities for any lithology so that the wettbility changes provide the stable conditions for the engaging phases and control losing of oil–based phases toward the formation. The work on water block in the previous literature is in the form of experimental investigations (Holditch, 1999; [1–3]), and an integrated method is necessary for forecasting the outcome of the interactions related to fluid and rock after injecting acids and any fluid mixed with the wetting agents at which our purpose is to dissolve the water blocked in the oil wells. For this, however, finding the exact rock characteristics and the data on injected and in situ fluid behavior in the reservoir is imperative to accurately derive the equations of water block. In other words, the equations of water block are also introduced so as to present computational methods to find out how much and how the blocked fluid is removed from the definite strata with the specific lithology, during injecting solvents.

2. Quantitative structural characteristic classification table in reservoir

Three physical quantities, i.e., intergranular space (IGS), inter-fracture space (IFS), and fracture width (FW), are given in **Table 1**. To find the magnitude of these three variables for mathematical expressions, we consider the effect of fine-grained particles' migration severity on porosity and the affect of carbonate cement or clay in the layer on the damages such as water block, phase trapping and any other obstacle caused by rock and fluid [4]. Generally, too much attention is given to information of porosity and permeability in the qualitative and quantitative situations, including cementing, color, compaction pressure, consolidating and unconsolidating property, particle size in lithology, density, and distances of fracture and grain experimentally and empirically to both the oil layers (oil-wet and water-wet types) and the saltwater disposal wells (mostly water-wet).

2.1 Example

For a reservoir layer containing sand associated with dolomite, the data of intergranular space (d_1), inter-fracture space (d_2), and fracture width (d_3) using **Table 1** is obtained (see a thin section of the whole plug in **Figure 1** which has the φ of 16%).

Solution: The variables d_1 and d_2 are obtained on averaging the values given in their related ranges to each group of rocks in **Table 1** (**Figure 2** illustrates how to figure out d_1, d_2, and d_3 in a sample of reservoir layer). Note: As you know, although

ID	Lithology	IGS, m	ID	Lithology	IGS, m	Symbols
1	CP	5×10^{-2} to 10^{-2}	5	L/D	6.5×10^{-5} to 7.5×10^{-6}	S: sand D: dolomite
2	Fine S	10^{-2} to 2.5×10^{-3}	6	S with SH	7.5×10^{-6} to 10^{-7}	L: limestone SH: shale
3	S with L/D	2.5×10^{-3} to 5.5×10^{-4}	7	SH/clay	$<10^{-7}$	
4	S with L/D/SH	5.5×10^{-4} to 6.5×10^{-5}	Inter-granular space: (IGS) or d_1			

ID	Lithology	IFS, m	ID	Lithology	IFS, m	
1		2.5×10^{-2} to 10^{-2}	5	L/D	10^{-5} to 10^{-6}	-Inter-granular space: (IGS) or d_1
2	Fine S	10^{-2} to 10^{-3}	6	S with SH	10^{-6} to 10^{-7}	-Inter-fracture space: (IFS) or d_2.
3	S with L/D	10^{-3} to 5.5×10^{-4}	7	SH/clay	$<10^{-7}$	-Fracture width: (FW) or d_3,
4	S with L/D/SH	5.5×10^{-4} to 10^{-5}	Inter-fracture space: (IFS) or d_2			

ID	Lithology	FW, m²	ID	Lithology	FW, m	
1	CP	$<10^{-7}$	5	S with L/D	10^{-4} to 10^{-5}	Coarse particles: CP
2	CP	10^{-6} to 10^{-7}	6	S with SH	10^{-3} to 10^{-4}	
3	Fine S	5.5×10^{-5} to 10^{-6}	7	L/D	10^{-2} to 10^{-3}	
4	S with L/D/SH	5.5×10^{-4} to 10^{-5}	8	Sh/clay	$>10^{-2}$	
			Fracture width: (FW) or d_3			

*d_1 and d_2 are the average per range in each ID. For d_3 we have d_3 = 100% (0.1 M), $5 < \varphi \leq 15.5$; d_3 = 30% (0.1 M), $20.5 < \varphi \leq 25$; d_3 = 50% (0.1 M), $15.5 < \varphi \leq 20.5$, M = (d_{max}-d_{mim}/d_{max}).

Table 1.
Quantitative structural characteristic classification table in reservoirs.

Figure 1.
A fairly porous typical oil layer drilled from 3572 m and synthetic sandstone with less percentage of fine crystals of anhydrite, dolomite cement, and sub-round/fossil patches. This rock is associated with small ooids in the middle and intraclasts on all sides which have been poorly sorted. The porosity type is fracture and enormous vugs (φ = 16%) containing the oil.
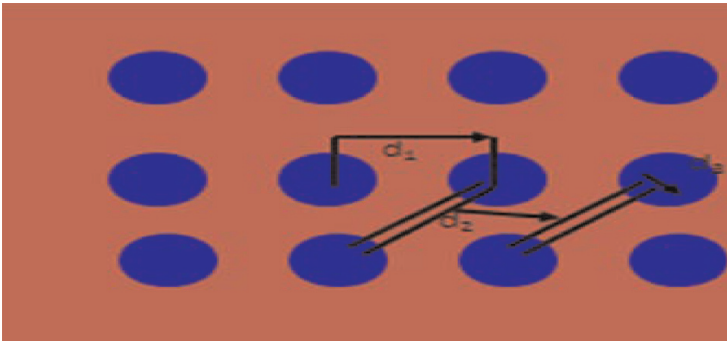

Figure 2.
Situation of grains and fractures to each other in matrix media.

the dolomite and limestone are not the same, all their characteristics, to some extent excluding chemical properties, are mostly similar. Therefore, to calculate d_1, d_2, and d_3 for either dolomite or limestone, we apply a quantity defined for dolomite/limestone in the classification table (**Table 1**):

$$d_1 = \frac{2.5 \times 10^{-3} + 5.5 \times 10^{-4}}{2} = 0.00153 \quad d_2 = \frac{10^{-3} + 5.5 \times 0^{-4}}{2} = 0.0008$$

$$M = \frac{10^{-4} \text{-} 10^{-5}}{10^{-4}} = 0.9 \quad \text{For } 15.5 < \boldsymbol{\varphi} \leq 20.5, \text{ we have } d_3 = 50\%(0.1 \text{ M}) = 0.045.$$

3. Formation damage and overburden pressure

This subsection summary described how overburden pressures, as formulas below, affect the formation damage. The variable can influence the other physical parameters (e.g., porosity and permeability) and underground interactions. Due to its great variability, carbonate rocks are the most onerous to construe and analyze, and their pressure can also range in various levels and change the fluid distribution in the pores. Hence, the overburden pressure influences physical parameters, especially, as the pressure in depths alters the fluid movements and the tectonic displacements. The experimental overburden pressure results on these physical parameters demonstrate a decrease in porosity and permeability while rising overburden pressure in reservoirs [5, 6]. All these variations are observed in the "equation of overburden pressure" [4] in the next sections. In addition, overbalance pressure can affluence a couple of processes in the drilling operations [7].

Overburden pressure can lead to the forming of water block that subsequently will alter the porous media and its fluid, for example, in the reservoirs with dual medium, permeability reduction resulted from overburden pressure of reservoir can prepare the media condition for forming water block [8, 9]. The forces, such as overburden pressure, which changes many physical characteristics in the section of formation adjacent to the wellbore, can relate to the subsurface processes that displace particles while fluids flow through propose media. These forces exerted by fluid and rock on the small drilled or damaged point or on the major underground dimensions could naturally alter the layer pressure and other physical characteristics [10, 11]. Therefore, in small drilled or damaged point or major underground dimensions, the classification of overburden pressure based on porosity is used in the "equations of removed water block."

3.1 Equation of overburden pressure

3.1.1 Equation of overburden pressure in a definite point of a layer

Some methods to calculate overburden pressure are according to Eqs. (1)–(4). Equation (1) is presented by Hubbert and Rubey (1959) for overburden pressure at a depth z that is a function of parameters z, P_0, and g:

$$P(z) = P_0 + g \int_0^z \rho(z) dz \tag{1}$$

where $\rho(z)$ and z are, respectively, the density of the overlying rock and depth and g is the acceleration due to gravity. P_0 is the same datum pressure. Another useful equation for calculating overburden gradient of varying lithology and pore fluid density (this formula can calculate the pressure in every depth) is derived by Matthews and Kelly [12]:

$$\sigma_{ovg} = 0.433 \left[(1-\phi)\rho_{ma} + \left(\rho_f \phi\right) \right] \tag{2}$$

where σ_{ovg} is the overburden gradient, psi/ft., φ is the porosity expressed as a fraction, and ρ_{ma} is the formation fluid density, gr/cc.

Another method presented by Karimi et al. [4, 13, 14] contains six equations summarized in Eqs. (3) and (4), respectively, for oil layers and water layers. In the equations of (3) and (4), the information on petrophysics and geology and the quantitative-structural characteristics classification table the reservoir conditions (**Table 1**), P_{ob} formulated for a point of drilled layer in various porosity ranges. Since reservoir layers have mostly the heterogeneity characterizations, geologists and drillers need to control timely and repeatedly the type of cuttings, drilling mud, and reservoir pressure; the equations can help to effectively accomplish the operations in wellhead and bottom hole through the calculations in which the overburden pressure is important:

$$P_{ob1} = \frac{1}{A} \left| \frac{C_1 \rho_r g h A_w \sqrt{\left(\frac{\mu_o + \mu_w}{\mu_w}\right)} \sqrt{\frac{t_1}{t}}}{d_1^2} \right| + \frac{1}{A} \left| \frac{C_2(W_W + W_o)}{d_3^2} \frac{1}{} \right| = P_{ob1,1} + P_{ob1,2}$$

$$\tag{3}$$

$$C_1 = 2 \times 10^{-5}; C_2 = 0.02; d_3 = 100\% (0.1\,M)\ 5 < \varphi \leq 15.5$$

$$C_1 = 1.75 \times 10^{-5}; \; C_2 = 0.04; \; d_3 = 50\%(0.1\,M) \;\; 15.5 < \varphi \leq 20.5$$

$$C_1 = 1.5 \times 10^{-5}; \; C_2 = 0.06; \; d_3 = 30\%(0.1\,M) \;\; 20.5 < \varphi \leq 25$$

$$P_{ob1} = \frac{1}{A} \left| \frac{C_1 \rho_r g h A_w \sqrt{\left(\dfrac{\mu_w@60°F - \mu_w@T°F}{\mu_w}\right)} \sqrt{\dfrac{t_1}{t}}}{d_1^2} \right| + \frac{1}{A} \left| C_2(W_W) \frac{1}{d_3^2} \right| = P_{ob1,1} + P_{ob1,2}$$

$$(4)$$

$$C_1 = 2 \times 10^{-5}; \; C_2 = 0.25; \; d_3 = 100\%(0.1\,M) \;\; 5 < \varphi \leq 15.5$$

$$C_1 = 1.75 \times 10^{-5}; \; C_2 = 0.3; \; d_3 = 50\%(0.1\,M) \;\; 15.5 < \varphi \leq 20.5$$

$$C_1 = 1.5 \times 10^{-5}; \; C_2 = 0.35; \; d_3 = 30\%(0.1\,M) \;\; 20.5 < \varphi \leq 25$$

3.1.2. Equations of overburden pressure in a definite layer

The equations of overburden pressure of "a definite and delimited sectional area" that contains three equations, summarized in Eq. (5), are included in the equations of the removed water block (B_k) in the oil wells (in the next sections); hence, the removed water block is a function of the overburden pressure of a definite and delimited sectional area. More details on the equation of overburden pressure have been given in references. The variations of overburden pressure for three groups of rocks are given in Eq. (5):

$$P_{ob} = \frac{1}{A} \left| \frac{C_1 \sqrt{W_d} \sqrt{\rho_r g} h \sqrt{\left(\dfrac{\mu_o + \mu_w}{\mu_w}\right)} \sqrt{\dfrac{t_1 + t}{(t_1 - t)}}}{d_1 \sqrt{\dfrac{d_1^2}{d_2}}} \right| + \frac{1}{A} \left| C_2(W_W + W_o) \frac{d_2}{d_1 d_3^2} \right| + \frac{1}{A} \left| \frac{C_3 W_d}{d_3^2} \right|$$

$$(5)$$

where

$$C_1 = 0.2; \;\; C_2 = 1.10; \;\; C_3 = 4.6 \times 10_{+2} \;\; d_3 = 100\%(0.1M); \;\; 5 < \phi \leq 15.5$$

$$C_1 = 0.17; \; C_2 = 1.15; \; C_3 = 4.4 \times 10^{+2} \;\; d_3 = 50\%(0.1M); \;\; 15.5 < \phi \leq 20.5$$

$$C_1 = 0.15; \; C_2 = 1.20; \; C_3 = 4.3 \times 10^{+2} \;\; d_3 = 30\%(0.1M); \;\; 20.5 < \phi \leq 25M = \left(\frac{d_{max} - d_{mim}}{d_{max}}\right)$$

If $T < 176°F$ then $\mu_o@T° = \mu_o\text{-}22pH_0@60°F \times \dfrac{(176°F - T°)}{60°F} [(\rho_o@60°\text{-}\rho_o@T°)/\rho_o@60°]$ and

$$\mu_0 = \mu_o@60°F, \qquad\qquad (6)$$

If $T \geq 176°F$ then $\mu_o@T° = \mu_o\text{-}17pH_0@60°F \times \dfrac{(T° - 176°F)}{60°F} [(\rho_o@60°\text{-}\rho_o@T°)/\rho_o@60°]$ and

$$\mu_0 = \mu_o@176°F, \qquad\qquad (7)$$

where P_{ob} is the formula of overburden pressure (bar) and the constant A is a unit conversion factor from k_{gf} to bar and equals to 10197.162. φ indicates porosity (%). ρ_r is the rock density (kg/m^3), and the ρ_o and ρ_w are the oil and water densities (kg/m^3), respectively. $\rho_r = W_d/(V_b\text{-}V_p)$ at which V_b is the bulk volume (m^3), V_p is

the empty space volume (m^3), and W_d is the dry weight for sectional area without any fluid (k_{gf}). g is the acceleration of gravity(kg/m^3), h is the layer depth from earth surface (m), and t is the geological age of favorite layer on million years (my), at which t_1 denotes the lower layer age. d_1 and d_2 denote, respectively, intergranular space and inter-fracture space (it refers to matrix media or distance between fractures) (m), while d_3 denotes fracture width (m). d_{max} and d_{mim} in Eq. (5) determine the maximum and minimum fracture width in each lithology which is calculated from **Table 1**. C_1, C_2, and C_3 are defined as the constants in which C_1 and C_3 are associated with W_d (dry layer weight) and their values, and also their effect on P_{ob} is maximum in the oil layers with low porosity, but C_2 is associated with the fluid weight ($W_w + W_o$), i.e., oil and water, and its volume, and also its effect on P_{ob} becomes minimum in the low-porosity oil layers. In general, the values of constants change for different layers in the determined porosities, depending on the composition of layer. μ_o is obtained by Eqs. (6) and (7), which indicates the viscosity of oil (kg/m-sec) in an oil layer at reservoir temperature (°F), and pH is oil acidity which usually does not change in the reservoir media.

3.1.3. Exercise

In this exercise you will be familiarized with the method of obtaining overburden pressure in "a definite point of an oil layer with length of 80 m in depth 3593 m." This layer is composed of sand with a little dolomite and anhydrite, and the geological period is pre-Miocene (25 my ago), which is located on a layer with geological age of Eocene period (50 my ago). The geological and petrophysical characteristics of layer (φ = 18.86%) are given below. (A) Use Eqs. (2) and (3) to solve the problem. (B) If, instead of a definite point, the goal is to treat a definite layer or delimited sectional area (i.e., whole sectional area with l = 80 m and A = $1.13 \times 10^{+3}$ m^2), then use Eq. (5) to solve the problem. (C) Assume that there is a definite layer or delimited sectional area (φ = 11% and with lithology of sand associated with less percentage of shale in depth of 3605 m) with geological age of Eocene period (50 my ago) with the same size exactly beneath the layer with geological period of pre-Miocene (25 my ago). (D) The lowest sectional area with geological age of 65 my with the same size is exactly beneath Eocene period. (Note on C: use **Table 1** (sand with shale) to calculate d (d_1, d_2, and d_3) and then P_{ob}, assuming that the other data is identical with other sectional areas). The sectional areas are depicted with A, B, C, and D in **Figure 3**.
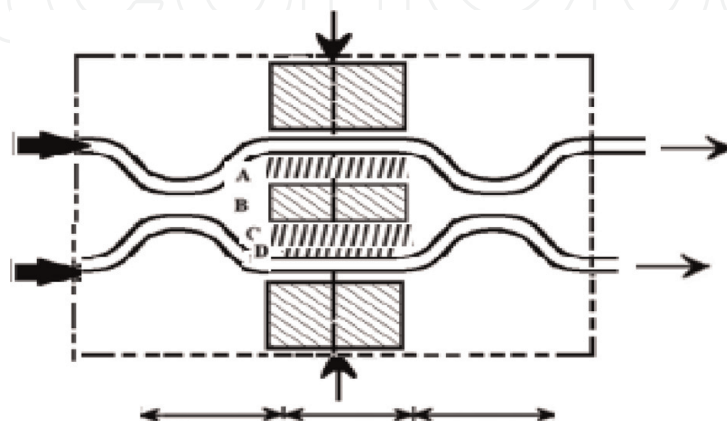

Figure 3.
A schematic of four reservoir layers with various geological ages.

Characteristics of the sub-layer 2 of formation A: Cylindrical area section n of layer A (m^2) = 1.13 × 10^{+3}; A_{we} = 0.05 m^2; W_d (k$_{gf}$) = 2,038,984; h (m) = 3593; ρ_w at 60°F = 1.145 × 10^{+3}; ρ_w at 191°F = 1.135 × 10^{+3}; ρ_o at 60°F = 851.9; ρ_o at 191°F = 821.9; ρ_r (kg/m^3) = 2.82 × 10^{+3}; K (md) = 23; t (my) = 25; t_1 (my) = 50; L (m) = 80; μ_o at 60°F = 11.3; μ_o at 176°F = 3.3; μ_o at 191°F = 2.43; pH$_o$ at 60°F = 6.8; μ_w at176°F = 0.72; μ_w at 60°F = 1.73; μ_w at 191°F = 0.65 cp; d_1 = 7.75 × 10^4; d_2 = 5.5 × 10^4; V_w (m^3) = 3.37; V_o (m^3) = 13.49; V_d (m^3) = 73.78; T (°F) = 191. Due to the patches of anhydrite in containing of rock, d_1 may be close to d_2 (density unit is kg/m^3).

4. Water block and formation

In this section the characteristics of layer such as rock transmissibility, effect of pathways on the fluid conductivity and particles, and the other physical variables in underground conditions are studied. The previously carried out studies discern the water block subject matter from the other damages, like the phase trapping index (APTi). In the studies investigators researched on the role of oil-based fluids, surface tension, injection of dry gas, drawdown pressure, and outputs of displacement and evaporation processes on the trend of blocking fluid around the wellbore within the fracture and matrix. For example, see [15–21]. But many studies are carried out on the solvents and water block, and their results determined the role of solvents and other fluids injected on injection type and fingering and coning water in water, oil, and gas reservoirs around the wellbore as well as their destructive effect on reservoir through water block [20–22]. However, the water block as a major issue in water injection wells can damage permeability more in sandy layers, and clay minerals become sensitive to the salinity degree and pH of water injected [23]. In low-permeability reservoirs, the containing of reservoir can displace the clay minerals [24]. The changes in wettability can improve the water block depending on the reservoir conditions [25]; in this case some experimental works are designed and carried out to the wettability alterations on the liquids [26]. Moreover, to discern the interactions of rock and fluid, other important researches are carried out for the dense and loose reservoirs by [1, 2]. The modeling results on the fractured and unfractured systems by Parekh [27] and their production times by Lake [28] highlighted the considerable water block in fractures due to the less pressure difference between the capillary and drawdown states. Consequently, in the case of the difference between static and flowing bottom-hole pressures, the fracture effect has an important role in decision-making on the overburden pressure as well as the type and the percentage use of solvent used in any lithology [13, 14].

5. Selection criteria

In driving the "Equations of Water block" and "Equation of Overburden Pressure" it is necessary to determine whether the heterogeneity alterations widely studied and monitored in certain periods through reports during our equations have any positive effect on product performance in defining main thresholds for each variable. However, the criteria should be set based on (1) the rock and fluid nature at the reservoir conditions, (2) the intended use of the wellhead product history, and (3) most importantly the previously delimited area around the wellbore that injection in a great deal time slowly will improve it [4, 29–36].

5.1. General methodology for novel equations

the discussions below composed of (1) the use of **Table 1**, (2) the use of equation of overburden pressure, and (3) the introduction of equations of water block for the oil-wet and water-wet layers of oil reservoirs for removing the damage.

6. Equations of removed water block (B_k) in oil reservoirs

6.1. Equations of B_k in the oil-wet oil reservoirs with dimensions defined

The equations of removed water block have been obtained through the experimental data and empirical information to answer to many fundamental questions on anisotropic and isotropic reservoirs that their composition includes multi mineral with various pores geometry and varied relative proportions. The equations proposed solutions to contrast the various oil layers and presented the alternatives to treat their damage while confronting to the damage in the porous media. The equations of oil-wet oil reservoirs for two porosity ranges are expressed in Eqs. (8) and (9):

$$B_k = \sqrt{k}q_i \sqrt{-\frac{I_k A_w \Delta P}{\frac{\rho_f V}{t}(q_{max} - q_{min})}} \sqrt{(pH_f/pH_{ac2\%})\text{-}1} \sqrt{(1 - \frac{D_s}{H_{Mg}})^2} \; I_k = 6.5 \times 10^2 (T°) \; (h)\left(1\text{-}\frac{\mu_f}{\mu_{ac2\%}}\right)^4 \left(\frac{P_p}{P_{ob}{}^{C_1}}\right)^{-2}$$

$$C_1 = 0.10 - C_{mu}; \; 0.05 < C_{mu} \leq 0.10 \; ; 5 < \phi \leq 15.5 \tag{8}$$

$$(B_k)_{o.w} = \sqrt{k}q_p \sqrt{-\frac{I_k A_w \Delta P}{\frac{\rho_f V}{t}(q_{max} - q_{min})}} \sqrt{\left(\frac{pH_f}{pH_{ac4\%}}\right)\text{-}1} \sqrt{\left(1 - \frac{D_s}{H_{Mg}}\right)^2} \; I_k = 7.1 \times 10^2 (T°)(h)\left(1\text{-}\frac{\mu_f}{\mu_{ac4\%}}\right)^4 \left(\frac{P_p}{P_{ob}{}^{C_1}}\right)^{-2}$$

$$C_1 = 0.10\text{-}C_{mu}; \; 0.05 < C_{mu} \leq 0.10 \; ; 15.5 < \varphi \leq 25 \tag{9}$$

6.2. Equations of B_k in the water-wet oil reservoirs with dimensions defined

The variables mentioned above for oil-wet reservoirs are applied here for the water-wet oil reservoir equations. These equations for two ranges of the porosity are expressed in Eqs. (10) and (11) as follows:

$$(B_k)_{w.w} = \sqrt{k}q_p \sqrt{-\frac{I_k A_w \Delta P}{\frac{\rho_f V}{t}(q_{max} - q_{min})}} \sqrt{\left(\frac{pH_f}{pH_{ac2\%}}\right)\text{-}1} \sqrt{\left(1 - \frac{D_s}{H_{Mg}}\right)^2}$$

where

$$I_k = 5.4 \times 10^2 (T°)(h)\left(1\text{-}\mu_f/\mu_{ac2\%}\right)^4 \left(\frac{P_p}{P_{ob}{}^{C_1}}\right)^{-2} C_1 = 0.10 - C_{mu}; \; 0.05 < C_{mu} \leq 0.10; 5 < \varphi \leq 15.5$$

$$\tag{10}$$

$$(B_k)_{w.w} = \sqrt{k}q_p \sqrt{-\frac{I_k A_w \Delta P}{\frac{\rho_f V}{t}(q_{max} - q_{min})}} \sqrt{\left(\frac{pH_f}{pH_{ac4\%}}\right)\text{-}1} \sqrt{\left(1 - \frac{D_s}{H_{Mg}}\right)^2}$$

where

$$I_k = 5.9 \times 10^2 (\text{T}°)(h)\left(1 - \frac{\mu_f}{\mu_{\text{ac4\%}}}\right)^4 \left(\frac{P_p}{P_{ob}^{C_1}}\right)^{-2} \quad \text{C}_1 = 0.10 - \text{C}_{\text{mu}}; \ 0.05 < \text{C}_{\text{mu}} \le 0.10; \ 15.5 < \varphi \le 25$$

(11)

where removed water block or B_k is the power of chemical in the damage removal and proves the relationship between the expanding of chemicals and the damage made. B_k is proportional to the rate of blocking the fluid (q_B) and reversely to the square root of the acid expanding ability ($\sqrt{I_k}$) in which q_B is calculated from $q = \frac{Bk}{\sqrt{I_k}}$. In the B_k the volume of water block that per minute endured the temperature $T°$ in depth of h after injecting acid and solvents with diverse acidity properties, is estimated, and its unit is $\frac{m^3}{\min\sqrt{T°m}}$. I_k is the acid expending ability, in which its unit becomes mK or T°m, where 1 K = 1000 mK. One K denotes the expending of an acid sample of 28% injected to a well with the previously predicted pressure and rate of injection and production. And the well is located in a layer L of centimeter long (a length of zone around the wellbore which the front of the fluid injected covers which zone and causes the damage) with a cylindrical cross section at depth h from the earth surface which endures an overburden pressure of its upper layer column. Depending on the favorite layer lithology, the acid injected with base fluids is converted to acids 2–4% (ac2% to ac4% in Eqs. (10) and (11)) at reservoir circumstances. In these conditions, the viscosity of base fluid mixed with solvent and the expended acid viscosity are assessed for reservoir fluid displacement behavior. Practically, 1 K measures the capacity of the gradual expending of an acid in which its variable is indicated with I_k and is applied where the sectional areas with large horizontal scales of the reservoir layers programmed to treat, stimulate, fracture, complete, and/or drill. In the expending acid, the media with a more ability can push the previously blocked fluid with rate of q_B, in which the underground chemical expending is measured and assessed with I_k. C_{mu} determines the percent solvent used associated with base fluid that in oil reservoirs is mainly gasoil, and the constant of C_1 is calculated by which. The percent of C_m is commonly being used at wellhead and in relationship of C_1 is subtracted from the maximum allowable amount delimited by factory's product. At equations, this maximum amount becomes 0.10 for mutual solvents. Accordingly, the superscript C_1 varies in value for the solvent types that subsequently will change the variable of I_k. P_{ob}, overburden pressure (bar), is obtained from Eqs. (1)–(3). K is the permeability (md), and SI has unit of K which is equal to about 0.98692×10^{-12} or 10^{-12} m^2. q_p is the last oil rate (m^3/min) in production well before injecting fluids. P_p is the last oil pressure (bar) in production well before injecting fluids. ΔP is the pressure loss of acid 28% and retarder acid with gasoil mixed in solvent (bar), and A_w is considered the sectional area of wellbore (m^2). V equals the entire volume of fluids injected into the well (m^3), excluding the volume of fluid mixed with solvent. t is the injection time of the entire volume of fluids injected into the well (min). ρ_f is the density of base fluid (kg/m^3) in which mutual solvent is mixed with it at wellhead. μ_f is the μ of base fluid mixed with solvent that is equal to the average of viscosity of the base fluid (in here is gasoil) and viscosity of the solvent (kg/m-s) under reservoir conditions. $\mu_{\text{ac4\%}}$ is the viscosity of acid 27% and retarder acid (kg/m-s) that have endured the conditions of reservoir. pH of the base fluid mixed with solvent is the average of the acidity percent of the base fluid and mutual solvent under reservoir conditions. pH$_{\text{ac4\%}}$ is the acidity of acid 27% and retarder acid, which have endured the reservoir conditions in a sandy layer and have been converted to acid 4%, as in most of the limestone layers this amount is 2–3% (this value in its related equations

averagely based with ac2%). D_s and $(H)_{Mg}$ are, respectively, salinity degree (ppm) and Mg hardness of formation water (ppm), and according to the procedure of oil industry to obtain the Mg hardness, we apply the Ca^{+2} to 0.4 ratio. The sensitivity and alteration range of variables in equations depends on the reservoir nature.

6.3. Expending ability or I_k

I_k denotes acid expending ability based on mK, which generally demonstrates the viscosity for acids expended to 2 and 4% under reservoir conditions for the two groups of the limestone/dolomite layers and the sandstone layers, as the other groups change between these percentages. For example, a chemical in a limestone media with high temperature and permeability can better be expended than a sandy media usually with low porosity; instead, in the same sandy media, the (B_k) volume is more. The I_k represents not only the property of the acid, but also it describes the various rocks that could alter in form and structure by natural agents. See **Figure 4** which is only to indicate the trend of alterations in the variables of the correlation of I_k for the different layers. Also, **Figure 4** illustrates the acid expending ability versus overburden pressure in the reservoir layers which have directly been analyzed from the field and lab information. The exact I_k is obtained from the correlation of I_k for types of the reservoir lithology; thus, we cannot extrapolate the curves to obtain a special variable so that the intercept is read as an exact value. In general, as the φ increases, C_m or the same percentage solvent used also increases. Subsequently, $C_1 = 1 - C_m$ in the $P_{ob}{}^{C1}$ declines and the I_k also declines. Under these conditions, q_B or the rate of blocking is high and B_k (or $q_B \sqrt{I_k}$) also increases. As was discussed, the B_k, power of damage removal by chemical, is directly proportional to the product of the square root of expending in the rate of blocking; in other words, q_B is the expending square root of the removed water block.

The q_B obtains through the ratio of the B_k obtained from the equation to $\sqrt{I_k}$. Most often, as the h increases, then φ also decreases. Subsequently, the C_m or the same percentage solvent decreases, and the superscript C_1 in both $P_{ob}{}^{C1}$ and I_k

ID	Lithology	ID	Lithology
1	Coarse particles	5	Sand with limestone /dolomite
2	Coarse sands	6	Shale sands
3	Fine sands	7	Limestone/dolomite
4	Sand with limestone /dolomite/shale	8	Shale/clay

ac% in 2 as 3 and ac% in 7 as 8 (although in 8 a little less, including $P_{ob}{}^{C1}$ in I_k is ignored); To estimate T^o and h using $P_{ob}{}^{C1}$ and I_k obtained of formulas, don't use of this curves.
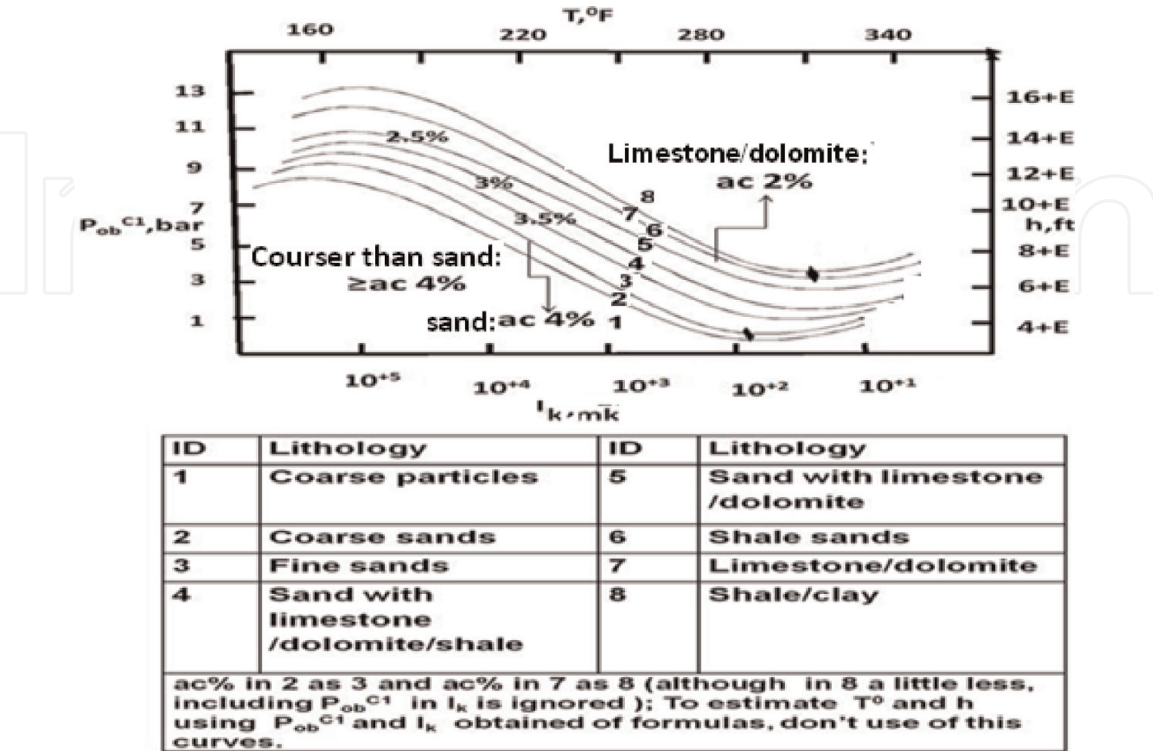
Figure 4.
Acid expending ability versus overburden pressure in reservoir layers [33, 36, 37].

increases. Under this condition in which the acid expending (I_k) is more, up to 2%, q_B or rate of blocking in such a low-porosity media with relatively usual permeability is low, and the amount of (B_k) is less. If the I_k is estimated for a horizontal layer to a length larger than 100 m, then we can estimate the I_k together with other layers as a multiple of 100 m (e.g., for the pure sandy layer in length of 152 m, the entire I_k is multiple of 1.52. If we assume that 52 m of this layer is limestone and 100 m is sand, then the entire I_k is the sum of 0.52 I_k and 1 I_k in which the data are substituted in the related correlations to I_k). For additional detailed information on the index of I_k, the reader is referred to the section of units.

6.3.1. Exercise

An oil well with pressure of 600 psi is produced from the oil-wet sandy layer (containing a little dolomite) with porosity 18.86%, temperature 191°F, and length 80 m, located in depth 3593 m. The acid 28% injected to increase the production, after 204.83 min using sampling from backflow at wellhead, determined the acid in the reservoir conditions expanded to an acid 4% and its viscosity is 0.55. In the next step, the percent solvent used with base fluid to reduce surface tension during operations is 4.5% whole base fluid (nearly less than 5 bbl), and allowable percent delimited for solvent by factory is in the range of $0.05 < C_{mu} \leq 0.09$. In the laboratory at 191°F, the fluid viscosity (μ_f) is measured and calculated from the average viscosities of solvent and water (nearly 1.21 cp). Estimate I_k using Eq. (8) for this reservoir if P_{ob} obtained through Eqs. (5)–(7) for this definite sectional area is 880,224,837 bar.

6.3.1.1. Challenges in equations

The equations presented in this capture have not been interpreted for the gas-bearing layers. In the gas reservoirs, the pore spaces are quite smaller relative to spaces saturated to the water and oil in the oil and water reservoirs. As writing these equations for gas-bearing layers, the following should be noted: (1) the diversity and size of porous in gas-bearing layers is less than that in oil-bearing layers or as such in water-bearing type. For this, formulating of related equations for overburden pressure does not need that they be categorized into the three groups of porosity as conducted above for the oil layers or the water layers. Instead, devising an equation for any porosity less or equal to 5 is sufficient. (2) Since the gas compressibility varies considerable as compared to the density in the liquids, thus only the property of gas compressibility relative to its density caused the gas molecules to occupy the less space that consequently will increase the effects of adhesion and cohesion. As a result, the measure of "high viscosity" for the liquids will be modified for the gas viscosity when the compressibility of gas as a significant variable is included in its related "single equation" for the viscosity. And (3) a combination of porosity and compressibility in the modified equation of gas viscosity proves the equation of overburden pressure for gas layers in a range of porosity (1–5%) that then can correct the equations of (B_k) to the gas reservoirs. Accordingly, in the equation of viscosity that has been corrected through compressibility for a gas layer's overburden pressure, the variation range of porosity in Eq. (5) in the set equations on overburden pressure ranges from 1 to 5% instead of 5 to 10%, and the term d or d_1, d_2, and d_3, from **Table 1**, can distinguish the type of lithology for any gas reservoir in which the equation is modified.

Now, if a researcher intends to demonstrate the equations of water block (B_k) for the gas well, it needs to derive only one equation according to the corrections on compressibility at the abovementioned discussions. In a single equation, afterward,

the porosity would be modified and applied to calculate the overburden pressure of a defined layer around the wellbore. However, only two equations, ultimately, can predict the (B_k) in the gas wells to the two wettability types of water-wet and oil-wet (although the gaseous layers become mostly water-wet). As a final note, I must say that if there is no any water or oil in a gas reservoir, then we can assume the value of "viscosity" in the equation of overburden pressure is zero.

7. Example

The goal in this example is to obtain the rate of removed water block (B_k) formed in a definite layer or sectional area (cylindrical type) around an oil well with oil-wet wettability. The lithology of delimited layer is sandy containing dolomite, which is located in the depth 3593 m at 191°F (φ,% = 18.83). To treat the damage, at first the gasoil mixed with solvent (mutual type) is consumed in the acidizing. Using the given date below, calculate P_{ob} and B_k. The salinity degree, Ca ion of formation, and viscosity of fluids are obtained from **Tables 2** and **3**.

Solution problem:

Geology data of layer (L = 80 m): {A (m^2) = 1.13 × 10^{+3}; W_d (k_{gf}) = 203,8984; L (m) = 80; h (m) = 3593}, {ρ_w at 60°F = 1.145 × 10^{+3}; ρ_w at 191°F = 1.135 × 10^{+3}; ρ_o at 60°F = 0.8519; ρ_o at 191°F = 0.8219; ρ_r (kg/m^3) = 2.82 × 10^{+3}}, {φ (%) = 18.86; k (md) = 23; t (my) = 25; t_1 (my) = 50}, {μ_o at 60°F = 11.3; μ_o at 176°F = 3.3; μ_o at 191°F = 2.43; μ_w at 176°F = 0.72; μ_w at 60°F = 1.73; μ_w at 191°F = 0.65 cp; pH_o at 60°F = 6.8}, {d_1 = 7.7 × 10^{+4}; d_2 = 5.5 × 10^{+4}; d_3 = ?}, {V_w (m^3) = 3.37; V_o (m^3) = 13.49; V_d (m^3) = 73.78; T (°F) = 191}. Because the patches of anhydrite in containing of rock, the d_1 equals to d_2.

Calculation P_{ob}: In **Table 1** in ID of 4, we have d_3 = 50% (0.1 M) = (d_{max}–d_{mim})/d_{max}; d_3^2 = [0.05(5.5 × 10^{-5} _10^{-5}) /(5.5 × 10^{-5})]^2 = 0.002 m. μ_w at T = 191°F using its related equations equals to 2.43 cp. If we substitute the data in equation of overburden, then P_{ob} in a layer with length of 80 m in depth of 3593 m equals to 834,678,036 + 409 + 455,466,392 = 8 80,224,837 bar.

Fluid and well data: ρ_{water} at 191°F = 8620 kg/m^3; $\rho_{ac4\%}$ at 60°F = 1180; $\rho_{solvent}$ at 191°F = 910; $\mu_{ac4\%}$ at 176°F = 0.57; $\mu_{ac4\%}$ at 191°F = 0.55; μ_{water} at 60°F = 1.43; $\mu_{solvent}$ at 191°F = 0.99; $\mu_{water + solvent}$ at 191°F = 1.21; $pH_{ac4\%}$ at 191°F = 0.67; pH_{water} at 191°F = 5.7; $pH_{solvent}$ at 60°F = 4.99; $pH_{solvent}$ at 191°F = 7.83; $pH_{water + solvent}$ at 191°F = 6.77; P_{water} = P_1 = 1700 psi = 115.6 bar; $P_{water + solvent}$ P_2 = 950 psi = 64.5 bar; P_p = 600 psi = 41 bar; q_{mim} = $q_{water + solvent}$ = 4.5 bbl/min = (0.72 m^3); q_{mam} = q_{water} = 9.5 bbl/min = (1.51 m^3); q_p = q_i = 1.4 bbl/min; {r_w = 0.42 ft. = 0.128 m; A_{we} = 0.05 m^2; V_{we} = 1187.25 bbl}, {V_{water} = 775 bbl; $V_{solvent}$ = 5.5 bbl; $V_{water + solvent}$ = 100 bbl; V_p = 105,090 bbl; V = V_{inj} = V_{water} = 775 bbl = 123.22 m^3};

Hardness, ppm		Salinity		Ions, ppm					
Total	Ca	220,000	Cl	Mg	Ca	Fe	Co_3	So_4	
54,000	45,000		150,875	2187	18,000	74	854	425	

pH of Water	pH of low-viscosity solvent (LVS)	pH of high-viscosity solvent (HVS)
5.4	4.99	9.52

For the filtration of water, the filter 0.45 μm was used. The pH of water is before boiling.

Table 2.
Formation water ionic specifications.

Fluid type	T (°F)	μ (cp)	Type and constant of tube used
Oil	60	11.93	s.2, 0.006
	176	3.3	
	191	2.43	
	220	2.35	
	225	2.09	
Gasoil	60	5.06	Cannon-Fenske
	176	1.59	
	191	1.43	
	220	1.24	
	225	1.20	
Water	60	1.73	s.50, 0.004247
	176	0.75	
	191	0.62	
	220	0.52	
	225	0.51	
LVS	60	4.47	s.1.c, 0.03102
	176	1.39	
	191	0.99	
	220	0.81	
	225	0.76	
HVS	60	7.09	s.1, 0.01345
	176	1.73	
	191	1.04	
	220	0.76	
	225	0.71	

ρ_w = 1.145, ρ_o = 0.8519, ρ_{gasoil} = ρ_{go} = 0.8620, ρ_{LVS} = 0.91, ρ_{HVS} = 0.8910, oil salt = 14; ρ is g/cm^3; LVS, low-viscosity solvent; HVS, high-viscosity solvent.

Table 3.
Typical fluid viscosity specifications used/compared in various temperatures.

D_s = 220,000 ppm; H_{Mg} = 9000 ppm; ρ_{water} at 191°F = 8620; C_{mu} = 5.5%; t_{inj} = 204.83 min.

Calculation $(B_k)_{O.W}$: C = 0.10-C_{mu} = 0.1–0.055 = 0.045; P_{ob}^C = 2.52 bar; (P_p/P_{ob}^C) = 16.27; $(1-\mu_f/\mu_{ac4\%})^2$ = 1-$(1.2/0.55)^2$ = 1.44; $[(pH_f/pH_{ac4\%})-1]^{0.5}$ = 3.02. Using ρ_{go}, V_{inj} in loose oil-wet rock and Δp = −65.6 bar, we have $[(A_w\Delta P)/((\rho_f V/t) \times (q_{max}-q_{mim}))]^{0.5}$ = 0.03$(1/m^2)^{0.5}$ = 0.03$(1/mmDarcy)^{0.5}$, and using equation of I_k at 191°F, now I_k equals 3705 mK. If we substitute the data in equation of B_k for loose oil-wet rocks, then we have $(B_k)_{O.W}$ = 52.53$(m^3/min) \times [(T°m)^{-0.5}]$.

In the wells produced from a layer with silt compositions, the high salinity and calcium ion concentration have a considerable role in the increase of calcium deposits around the wellbore and formation of water block, as these percentages are higher in saltwater disposal wells. With this method of calculation, we can measure the damage for the other wells with the various characteristics of formation that have been previously producing a constant flowing bottom-hole pressure (BHP) and now have confronted to the damaging or unloading conditions and or the production rate loss.

8. Equations of water block in saltwater disposal wells: a chemical injection process for removing damage in saltwater disposal wells

The acids diluted with water, due to the membrane of water on the rock and the penetration of water into the pores, prevent the immediate contact of the acid

against rock as well as high diluting cannot also strength against dense minerals. Therefore, the solvents (as demulsifiers) especially mutual solvents as a mediocre fluid are injected associated with the various percentages of acids to control the reactions formed by the water block on the rock at a smaller scale. In practice, the application of these investigation is based on the used solvents in acidizing to help (1) provide an integrated solution of removing the water block in a definite sectional area around the SWDW's wellbore using the properties of the rock and the injected and in situ fluids (e.g., solution type, rock composition, solids size, pressure, concentration, etc.), (2) control the parameters of rock and fluid at the wellhead and reservoir as well as predict how and where these parameters are able to be controlled, (3) provide the computational methods with most measures in which these methods determine how much of water block is removed in the reservoir layers with various lithologies in the course of injecting solvents with the various acidity properties in the acidizing operations, (4) provide the methods that enable the designer to match and manipulate the occurrences inside the reservoir rock before starting the injection operations and as such enable them for recognition of its treatment, and (5) facilitate the software applications at the time of access to the state-of-the-art facilities and various producing chemicals to the disciplined and methodical approach that for this aim: (a) these equations associated with the equations related to oil layers in other references without any onerous technique are easy to code up, (b) this paper and similar it to the oil wells in other references that would help in writing the software and/or sub-equations of these equations in the calculations of above-mentioned underground processes (stimulation, fracturing, recovery, capturing, etc.).

Before anything, for this aim and better understanding of the effect of the chemical on damage, a process of forming and removing the water block in the water-wet oil-bearing rocks is shown in **Figure 5a–c**, and then the theory of water block in the formation is presented. This schematic indicated the trend of forming and removing damage before and after using water, interfacial tension (IFT), and mutual solvent (MUS).

As discussed above in the introduction, in the methodology, first, the structural layer characteristics (IGS, IFS, and FW) are obtained from the experiments on the oil-and water-wet layers and the wellhead information mentioned (**Table 1** in previous pages); second, the equation of overburden pressure as a function of the physical parameters resulted from previous information indicates its own role in
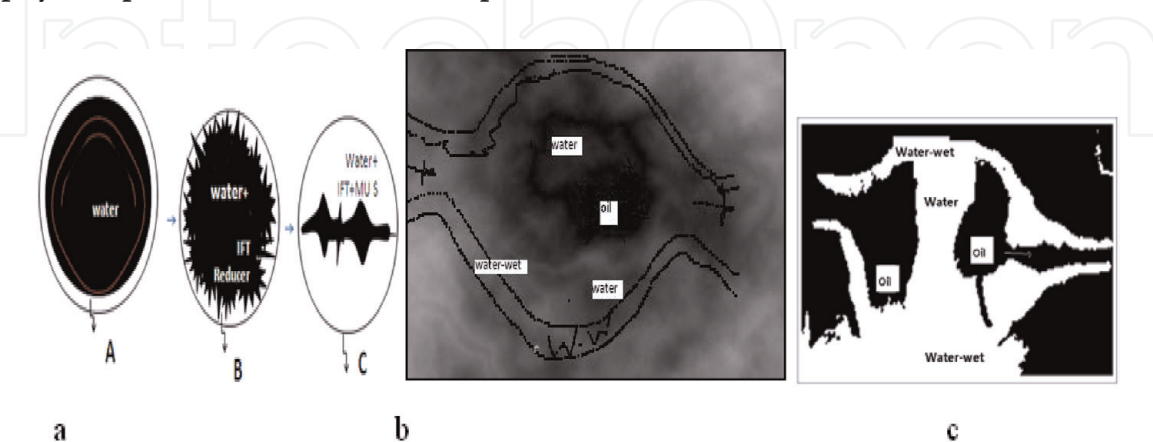
Figure 5.
(a) Schematic of the mutual solvents treatment process under reservoir conditions: (A), primary situation of water-wet reservoir contains water; (B) injection of the IFT reducer, dash link area added to oil-wet part; (C) injection of mutual solvent through conductivity and miscibility caused the mixture of chemical and water to flow outward the matrix, and then the replacing fluid should be injected with low speed to prevent the damage of matrix. (b) An image of forming water block. (c) A schematic of the water block after developing in the path of the residual oil flow [13, 14].

revealing parameters effecting on the water block (Eqs. (8)–(10)); and finally, the novel equations of water block are introduced for the water-wet layers of injection wells.

8.1 Equations of overburden pressure in the water layers

As mentioned above, the main subject matter is related to a definite stratum in which its dimensions are specified, and we aim to break/diminish the blocked water. Thus, first, the overburden pressure determined in a definite sectional area [13, 14, 37] through six equations (summarized here in Eqs. (10)–(12)), is applied to include all structural and non-structural characteristics of rock mass, lithology at various times and dynamic fluid distribution in the removed water block equations.

$$
P_{ob} = \frac{1}{A} \left| \frac{C_1 \sqrt{w_d} \sqrt{\rho_r g} h \sqrt{\frac{\mu_w @60° - \mu_w @T°}{\mu_w @T°}} \sqrt{\frac{t + t_1}{(t_1 - t)}}}{d_1{}^2 \sqrt{\frac{1}{d_2}}} \right| + \frac{1}{A} \left| C_2 \times W_w \times \frac{1}{d_1 \times d_3{}^2} \times d_2 \right|
$$
$$
+ \frac{1}{A} \left| \frac{C_3 \times W_d}{d_3{}^2} \right|
$$

$$(12)$$

$C_1 = 1.11; C_2 = 1.1; C_3 = 9 \times 10_{+2} \; d_3 = 100\%(0.1M) \quad 5 < \varphi \leq 15.5$

$C_1 = 0.99; \; C_2 = 1.15; \; C_3 = 8.7 \times 10^{+2} \; d_3 = 50\%(0.1M) \quad 15.5 < \varphi \leq 20.5$

$C_1 = 0.90; \; C_2 = 1.20; \; C_3 = 8.6 \times 10^{+2} \; d_3 = 30\%(0.1M) \quad 20.5 < \phi \leq 25 \; M = \dfrac{d_{max} - d_{mim}}{d_{max}}$

Water velocity in the reservoir is determined using.

If $T < 176°F$, $\mu_w @T° = \mu_0 - 0.12 pH_w @60°F \times \dfrac{(176°F - T°)}{60°F} [(\rho_w @60° - \rho_w @T°)/\rho_w @60°]$

where

$$\mu_0 = \mu_w @60°F \qquad (13)$$

If $T \geq 176°F$, $\mu_w @T° = \mu_0 - 0.09 pH_w @60°F \times \dfrac{(T° - 176°F)}{60°F} [(\rho_w @60° - \rho_w @T°)/\rho_w @60°]$

where

$$\mu_0 = \mu_w @176°F \qquad (14)$$

8.1.1. Units in P_{ob}

P_{ob} is overburden pressure (bar) in which the constant of A is to convert the unit of k_{gf} to the bar and equals to 10197.162. h is the depth of layer from earth surface (m), φ is porosity (%), and g is the acceleration of gravity (kg/m^3). ρ_r is rock density, kg/m^3, and ρ_w is water density, kg/m^3. ρ_r = $W_d/(V_b-V_p)$ at which V_b = bulk volume (m), V_p is pore volume (m^3) and W_d is dry weight (k$_{gf}$). t is geological age of favorite layer on the million years (my) at which t_1 is the lower layer age. μ_w is viscosity of water contact in water layer under reservoir temperature (kg/m-s), and

the pH is water acidity. T is the reservoir or experiment condition temperature (°F). C_1, C_2, and C_3 are dimensionless constants at which the C_1 and C_3 relate the W_d (dry layer weight) in which their value and also their effect on P_{ob} in the layer with low porosity are maximum, whereas C_2 relates the fluid weight ($W_w + W_o$) in which its value and also its effect on P_{ob} in low porosity layers are minimum. Therefore, the constant values would change with different sets of rocks in the determined porosities. d_1 and d_2 are, respectively, intergranular space and inter-fracture space (matrix media or distance between fractures) on meters. d_3 is fracture width on meters. d_{max} and d_{mim} are maximum and minimum fracture width in each lithology which is obtained from **Table 1**.

8.2 Equations of removed water block in saltwater disposal wells (B_k in SWDW)

The damage of water block is one of the formation damages caused by the increase of water saturation in the near or very far distances from wellbore and can occur either in the oil wells or saltwater disposal/depleted oil wells [13, 14, 33, 36]. To remove the damage, the solvents are usually used (especially mutual solvents) associated to other base fluids such as water and gasoil in the treatment processes of the water and oil wells [38–43]. In this investigation the equations are presented to estimate the removed water block in the salt water disposal wells according to Eqs. (15) and (16):

$$B_k = \sqrt{k}q_i \sqrt{-\frac{I_k A_w \Delta P}{\frac{\rho_f V}{t}(q_{max} - q_{min})}} \sqrt{(pH_f/pH_{ac2\%})\text{-}1} \sqrt{(1 - \frac{D_s}{H_{Mg}})^2}$$

$$I_k = 1.7 \times 10(T°)(h)\left(1\text{-}\frac{\mu_f}{\mu_{ac2\%}}\right)^4 \left(\frac{P_i}{P_{ob}C_1}\right)^{-2}$$

$$C_1 = 0.10 - C_{mu}; 0.03 < C_{mu} \leq 0.10; 5 < \varphi \leq 15.5 \tag{15}$$

$$B_k = \sqrt{k}q_i \sqrt{-\frac{I_k A_w \Delta P}{\frac{\rho_f V}{t}(q_{max} - q_{min})}} \sqrt{(pH_f/pH_{ac4\%})\text{-}1} \sqrt{\left(1 - \frac{D_s}{H_{Mg}}\right)^2}$$

$$I_k = 1.8 \times 10(T°)(h)\left(1\text{-}\frac{\mu_f}{\mu_{ac4\%}}\right)^4 \left(\frac{P_i}{P_{ob}C_1}\right)^{-2}$$

$$C_1 = 0.10 - C_{mu}; 0.03 < C_{mu} \leq 0.10; 15.5 < \varphi \leq 25 \tag{16}$$

The unmentioned units of variables here for Eqs. (15) and (16) are the same as in Eqs. (8)–(11). The most percent of solvents removing damage, for example mutual solvents (C_{mu}), is commonly used in gas wells and at least in water wells. If chemical mixed to base fluid is alcohol, surfactant, and/or any other reaction controller, then the changes of C_{mu} depend upon well conditions and usage range in the chemical catalog. P_{ob} (on the bar), in Eqs. (15) and (16), is the overburden pressure that is obtained from Eqs. (12)–(14). q_i, m^3/min, is the last water rate in the SWDW before injecting fluids, and P_i, bar, is the last injection pressure before injecting fluids. ΔP, bar, is the pressure difference of acid 28% and retarder acid with water mixed in the solvent. V, m^3, is the entire volume of fluids injected to the well, excluding the volume of fluid mixed with solvent. t, min, is the injection time of entire volume of fluids injected to the well. μ_f is the density of base fluid mixed with

solvent. μ_f, kg/m-s, is the average of viscosity of base fluid (in here is water) and solvent mixed with it under reservoir conditions obtained at laboratory. $\mu_{ac4\%}$, kg/m-s, is the viscosity of acid 27% and retarder acid that have endured conditions of reservoir. pH_f is the average of acidity for base fluid mixed with solvent under reservoir conditions obtained at laboratory.

8.3. Layer thickness in equations

Thickness determines the pressure in the lowest layer in which depth h is treated and endures the weight of the reservoir column. The real value of thickness is its impact on the lowest reservoir layer. Strictly speaking, this is a complementary application of h that is used to calculate the overburden pressure and/or any other quantity such as formation damage (e.g., it is the type of water block), mud optimum pressure, and petrophysical and geological parameters of the reservoir in the processes of stimulation, acidizing, micro-fracturing, and recovery in domain of the definition of reservoir layers. It has been observed in equations that a depth (h) at the large size for overburden pressure could not become the same depth (h) at the small size as defined for the lowest treating layer, so long as the layer is evaluated in the non-perpendicular zones. See **Figure 6** in which "h" is illustrated to the equation (equation with all porosities, including three equations) of overburden pressure and water block, and it does figure out that the h's have a relationship with the type of application. Therefore, in the first layer, it requires to determine the whole overlying column which exerts a pressure on the lowest layer we are about to treat in the processes before or while producing. In calculations, the h is considered the thickness of the layer which has a cylinder-shaped geometric figure so as to cover a fully horizontal zone. This horizontal zone, in which the fluid pressure and the sudden gravitational forces emerged in the entire area of desired treating/drilling layer associated to the thickness of h through which movements and slips are made, could be led to compacting pores and displacing particles in the layers. These compacting and replacing occurrences can increase in the salty layers, and eventually unsteady the overburden pressure of the large contact area of the same layer and the boundary layers that slow the fluid moving forward or moving tools toward the boundary reservoir. Approaching these pressures to each other, it might damage to any moving tools in horizontal zone. Generally, in calculations of the
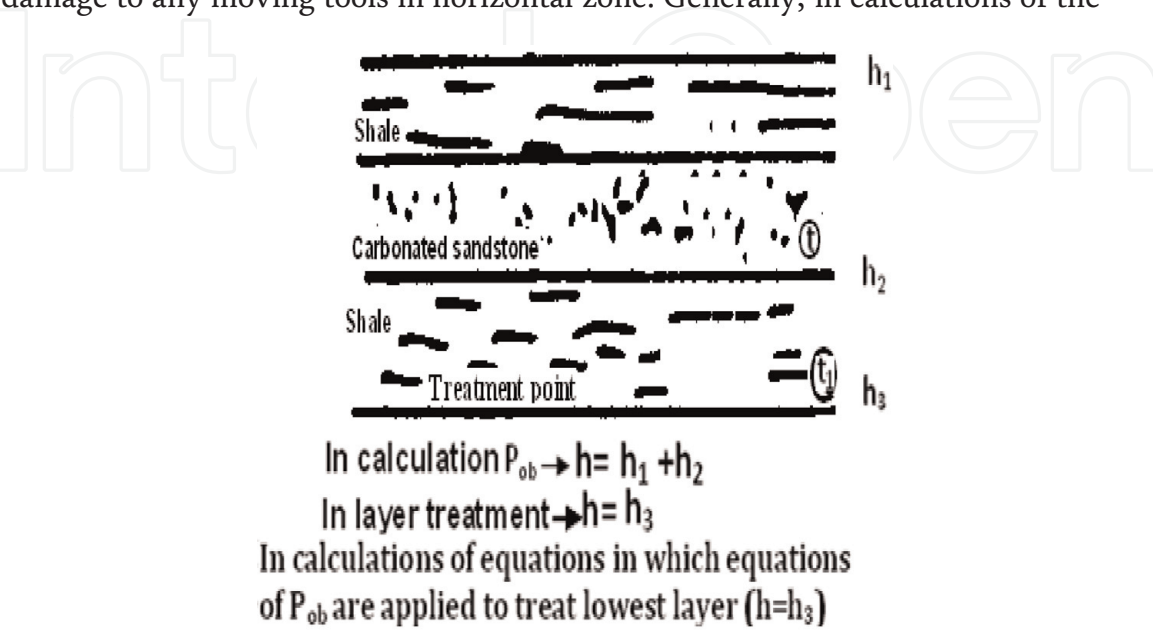
In calculation $P_{ob} \rightarrow h = h_1 + h_2$
In layer treatment $\rightarrow h = h_3$
In calculations of equations in which equations
of P_{ob} are applied to treat lowest layer ($h = h_3$)

Figure 6.
The total trend of h in P_{ob} and B_k [33, 36].

underground operations such as water block in horizontal operations, we consider the whole thickness of the lowest layer as h. The decision to design a geometric section for the area of the well (A_w) in equations of B_k depends on the desirable selected area around the wellbore. For this aim, as the part of the well/layer design, it is worthwhile determining the definite layer area using the integral techniques or other practical ways in industry and how A_w is defined which should also be related to h. Even though an integral method provides the additional assurances to an effective area of layers without geometric shape, it may require a lot of time, and as such it may sometimes not practical. If we consider a well in which the zone to the length of L and the thickness of h_2 is treated to propel the fluid onward and or take away the obstacles around the wellbore for flowing the water injection issues (issues emanated from the scale, water block and phase trap, or any other arbitrary and tentative process of fluids and rocks that are caused to mechanical anisotropy and completion skins), then the addition of length has a relative relationship with the overburden pressure and consequently with damage caused by water block. And, the damages of rock and fluid are more in these long zones; thus, these high-angle wells have their own complexities while treating them to lessen the damages. Drawdown caused by these damages in the more consolidated formations is usually higher and against the plugged debris is more in the pore throats.

For more discussion on the variable L in equation of overburden pressure that is out of scope of this investigation, we suppose the damage is made in well to a large extent while drilling, and then the first L at the beginning of drilling is bit-length. After that the drill string length is added to the length of bit, this length is corresponding to the L in the overburden pressure equation that further affects on the mud, pressure drop near the wellbore, reservoir pressure, and any other treatment process in which open or casing-completed horizon is appropriate in increasing vertical permeability. Of course, these permeability increments decrease as the ratio of thickness to horizon length increases (see h in the I_k and L in the P_{ob} that have a direct and reverse relation with damage removed, respectively). For instance, in a slant well, usually more than 20°, this length is calculable using well angle and thickness drilled.

A summary of the main points on these equations in this capture of book is expressed, and it requires for an engineering to take some kind of action:

- The flow rate increases in permeable rocks which has a significant role in pushing the damage like water block, and performance of low-viscosity solvents is at a maximum amount in loose water-wet rocks. The efficiency of high-viscosity solvents and low viscous solvents in loose rocks is averagely more than that in dense rocks.

- As the pores of the rock saturate with water owing to the water-based fluid invasion, therefore, the residual oil phase would be pushed along with fractures because of the rate, pressure drop, and high capillary pressures. Furthermore, since the aperture size in faults is wide (mostly FW > 0.35 m), in equations of B_k for salt water disposal wells (SWDW) is assumed the front of fluid injected into well during flowing through the area around the wellbore are not encountered to the fault.

- The decrease of porosity (φ) with depth (h) in the reservoirs is mostly true. But the C_m or the same percentage solvent used according to the factors indicated in equations reduces over these variations. In such a situation, which the acid expending (I_k) estimated high, the rate of blocking (q_B) in such a low porosity media with relatively usual permeability becomes low, and subsequently the

amount of the (B_k) is less. For this reason, the certainty of (I_k) as a measure to ascertain water block in equations of the (B_k) could help to effectively decide for treating the damage raised of water block in the zone around the wellbore that is surrounded by the other layers.

Nomenclature

Physical quantities

K = absolute permeability, md
ρ = density, kg/m^3
V = volume, m^3
W = weight, kg
L = length, m
T = temperature, °F
μ = viscosity, kg/m-s
A_w = sectional area, m^2
P = pressure, bar or psi
φ = porosity, %
ΔP = pressure loss, psi
q = rate, m^3/s
q_{mam} = maximum rate, m^3/s
q_{mim} = minimum rate, m^3/s
q_B = rate of blocking the fluid, m^3/min
C_{mu} = mutual solvent concentration
D_s = salinity degree, ppm
H_{Mg} = hardness of Mg, ppm
pH = potential of hydrogen
d_1 = intergranular space, m
d_2 = inter-fracture space, m
d_3 = width fracture, m
I_k = coefficient of Karimi (acid expending ability), mK or T°m
mk = a unit of measure of acid expending ability
B_k = removed water block or power of damage removal by chemical, m^3/min $\times$ (T°m)$^{-0.5}$

Subscripts

f = fluid
B = blocking of water
W = weight
B = symbol of blocking of water
r = rock
b = bulk
d = dry
w = water
w.w = water-wet
o = oil
o.w = oil-wet
ac = acid
mu = mutual
p = pore
ob = overburden pressure

HVMS = high-viscosity mutual solvent
LVMS = low-viscosity mutual solvent
HVSs = high-viscosity solvents
LVSs = low-viscosity solvents

Superscripts

C_1 = solvent percent numbers
A = convert coefficient for k_{gf} to bar functions, etc.
μ_O = equation of oil viscosity
P_{ob} = equation of overburden pressure
B_k = removed water block equation, $\frac{m^3}{\min\sqrt{T^0 m}}$
$(B_k)_{o.w}$ = equation of removed water block in oil-wet oil wells
$(B_k)_{w.w}$ = equation of removed water block in water-wet oil wells

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