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Full Length Research Paper

Factors that affect pressure distribution of horizontal wells in a layered reservoir with simultaneous gas cap and bottom water drive

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Understanding the behaviour of pressure distribution completed in two layered reservoir subject to both active gas cap and bottom water drive mechanisms is very important in reservoir management. To determine the factors that affect pressure distribution of horizontal wells in a layered reservoir subjected simultaneously with a gas-cap at the top and bottom water drives, well completion was carried out in a particular layer and one of the parameters was varied while the others were kept constant. The results show that the following factors: (i) Wellbore radius (ii) Well Length and (iii) Pay thickness affect pressure distribution in two-layered reservoir subject to both active gas cap and bottom water drive which affect pressure distribution.

Key words: Well, pressure, layer, reservoir, well.

INTRODUCTION

A lot of work has been done on pressure distribution for both vertical well and wells (Abbaszadeh and Hegeman, 1990; Kuchuk et al., 1991; Owolabi et al., 2012; Clonts and Ramey Jr., 1986), however, much work has not been done on this subject we are considering in this paper. A good knowledge of effect of well parameters on pressure distribution of horizontal wells in a layered reservoir subject to simultaneous top gas-cap and bottom water drive is an important tool in reservoir management in the production of oil and gas (Ozkan and Raghavan, 1990; Oloro et al., 2013) hence it became an urgent need for this study to be carried out. In this study, the effect of the following factors on pressure distribution on horizontal wells in a two-layered reservoir which is being subjected simultaneously with gas cap and bottom water drive were considered: (i) Wellbore radius (ii) Well Length and (iii) Pay thickness. In determining the effect of these factors, a model that was developed previously in my paper titled "Pressure distribution of horizontal wells in a layered reservoir with simultaneous gas cap and bottom water

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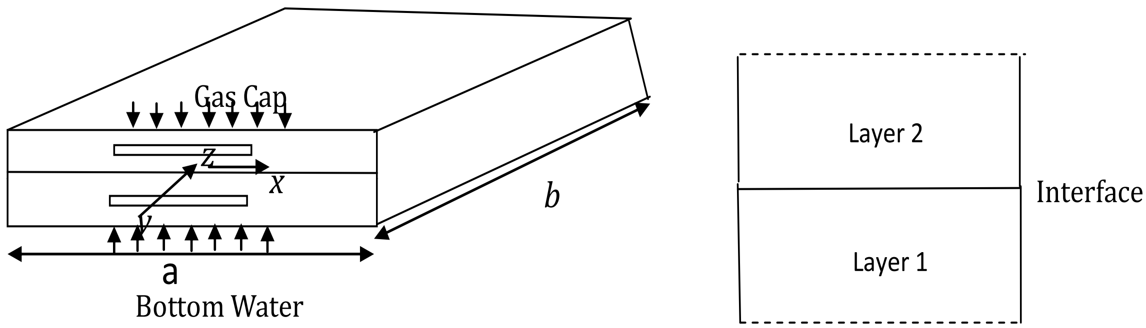

Figure 1. Two-layered reservoir system containing horizontal wells.

Table 1. Reservoir and well properties.

LD1	LD2	ZWD1	ZWD2	ZD1	ZD2	DZ (ft)
0.19764	0.194	0.995	0.788	0.005	0.004	2.5
h_{D1}	**h_{D2}**	**X_{wD1}**	**XwD2**	**YeD1**	**YeD2**	**DX (ft)**
4.785	2.5298	0.99244	0.795	0.0015	0.0215	2.00E+02
XeD2	**XeD1**	**K2 (Md)**	**Kx2 (Md)**	**k1 (mD)**	**kx1 (mD)**	**Dy (ft)**
0.0215	0.14	10	10	8.94427	10	21
Ct_1 (psi-1)	**ct_2 (psi^{-1})**	**L1 (ft)**	**L2 (ft)**	**h1 (ft)**	**h2 (ft)**	
4.00E-06	3.00E-06	250	250	200	100	
YD1	**YD2**	**Ø1**	**Ø2**	**YWD1**	**YWD2**	
8.00E-03	6.00E-03	0.23	0.23	9.92E-01	8.94E-01	
XD1	**XD2**	**µ1 (cp)**	**µ2 (cp)**	**hD2**	**hd1**	
0.00757	0.0065	0.5	0.2	2.5298	4.785	

drive" was used (Oloro et al., 2013).

METHODOLOGY

Pressure distribution of horizontal wells in layered reservoir with active top gas cap and bottom water drives models were used to determine effect of well parameters on pressure distribution (Oloro et al., 2013). This was done by varying a particular parameter which we want to know the effect on the pressure distribution and keeping other parameters constant.

The model diagram is shown in Figure 1 and model equation is given in Oloro et al. (2013). Reservoir and well properties are shown in Table 1. The derivation of Equations 1 and 2 are given in Appendices A and B (Oloro et al., 2013).

Model description and mathematical model for Layer 1

A physical description of the problem illustrated in Figure 1, is two layered reservoir, bounded on top by gas cap at the bottom by bottom water drive. A horizontal well of length L (along the x-axis), width y_w (along the y-axis) and stand-off z_w (along the z-axis) is drilled at the centre. The models used in this work and the derivation are in Oloro et al. (2013).

RESULTS AND DISCUSSION

To determine the effect of wellbore radius on wellbore pressure in Layer 1, P_{wD1} was computed for r_{WD1} values of $1.14x10^{-1}$ and $4x10^{-2}$, while keeping other parameters constant. The results are presented in Table 2 and also illustrated in Figure 2 on log-log axes. It is observed from the figure that at early $t_{D,}$ there is an obvious change in P_{wD1} with change in r_{wD1}. The change in P_{wD1} at later t_D is not obvious as it is shown in Figure 2.

Effect of change in wellbore radius of Layer 1 on pressure distribution for Layer 2 after radial flow period are presented in Table 3 and Figure 3. Results show slightly high productivity when smaller wellbore radius is used.

Effect of change in wellbore radius of Layer 1 on pressure distribution on Layer 2 at wellbore are presented in Table 4 and Figure 4. It is observed that a change in wellbore radius of Layer 1 does not have effect on $P_{wD2.}$ Effect of change in r_{wD1} on P_{wD2} after

Table 2. Effect of change in wellbore radius of Layer 1 on pressure distribution on Layer 1 at wellbore.

t_D	P_{wD1} (rwD1=1.14E-1)	P_{wD1} (rwD1=4E-2)
0.001	3.170692	7.6770781
0.01	20.9151	24.860549
0.1	38.6595	42.04402
1	56.40391	59.227491
10	74.14832	76.410962
100	91.89272	93.59443
1000	109.6371	110.7779

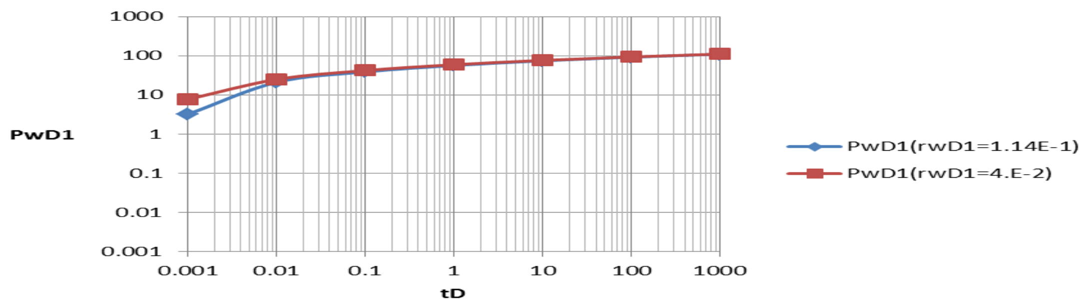

Figure 2. Effect of change in wellbore radius of Layer 1 on pressure distribution on Layer 1 at wellbore.

Table 3. Effect of change in wellbore radius of Layer 1 on pressure distribution for Layer 2 after radial flow period.

t_D	P_{D2} (rwD1=1.14E-1)	P_{D2} (rwD1=4E-2)
0.001	7.79E+00	7.82E+00
0.01	2.49E+01	2.50E+01
0.1	4.22E+01	4.23E+01
1	5.94E+01	5.95E+01
10	7.67E+01	7.70E+01
100	9.41E+01	9.49E+01
1000	1.13E+02	1.13E+02
10000	1.13E+02	1.13E+02

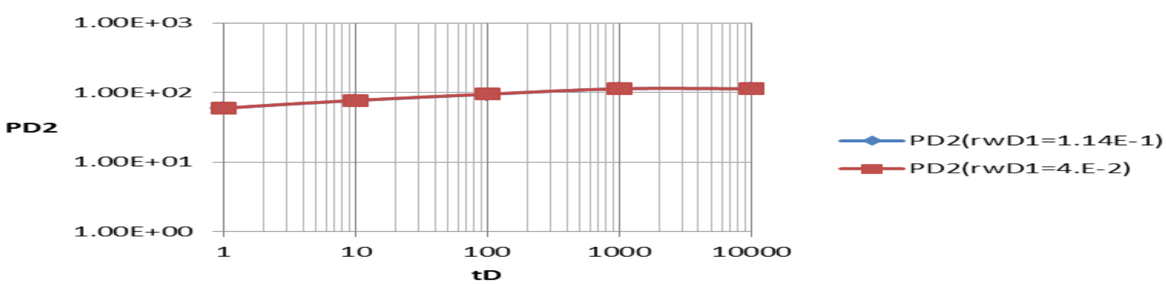

Figure 3. Effect of change in wellbore radius of Layer 1 on pressure distribution for Layer 1 after radial flow period.

radial flow period is shown in Figure 4.

Effect of change in wellbore radius of Layer 1 on pressure distribution for Layer 2 after radial flow period is shown in Table 5 and Figure 5.

It was observed that a change in r_{wD1} after radial flow period does have effect on P_{wD2}. Effect of change in r_{wD2} on P_{wD1} is shown in Table 5. It is observed that at early t_D, P_{wD1} is higher for smaller wellbore radius, but at late

Table 4. Effect of change in wellbore radius of Layer 1 on pressure distribution on Layer 2 at wellbore.

t_D	P_{wD2} (rwD1=1.14E-1)	P_{wD2} (rwD1=4E-2)
0.001	7.6770781	7.6770781
0.01	24.860549	24.860549
0.1	42.04402	42.04402
1	59.227491	59.227491
10	76.410962	76.410962
100	93.59443	93.594432
1000	110.7779	110.7779

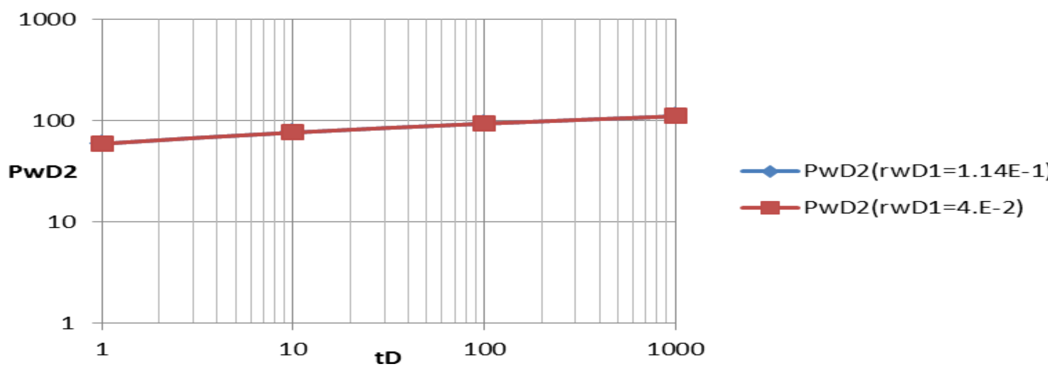

Figure 4. Effect of change in wellbore radius of Layer 1 on pressure distribution on Layer 2 at wellbore.

Table 5. Effect of change in wellbore radius of Layer 1 on pressure distribution for Layer 2 after radial flow period.

t_D	P_{D2} (rwD1=1.14E-1)	P_{D2} (rwD1=4E-2)
0.001	7.79E+00	7.82E+00
0.01	2.49E+01	2.50E+01
0.1	4.22E+01	4.23E+01
1	5.94E+01	5.95E+01
10	7.67E+01	7.70E+01
100	9.41E+01	9.49E+01
1000	1.13E+02	1.13E+02
10000	1.13E+02	1.13E+02

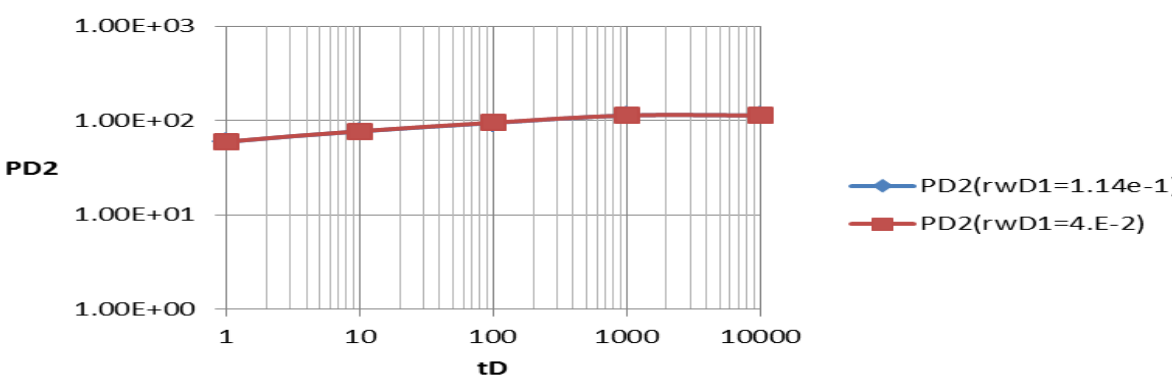

Figure 5. Effect of change in wellbore radius of Layer 1 on pressure distribution for Layer 2 after radial flow period.

Table 6. Effect of change in wellbore radius of Layer 2 on pressure distribution on Layer 1 at wellbore.

t_D	P_{wD1} (rwD2=0.032)	P_{wD1} (rwD2=0.0312)
0.001	3.170692	0.110955
0.01	20.9151	17.85536
0.1	38.6595	35.59977
1	56.40391	53.34417
10	74.14832	71.08858
100	91.89272	88.83298
1000	109.6371	106.5774

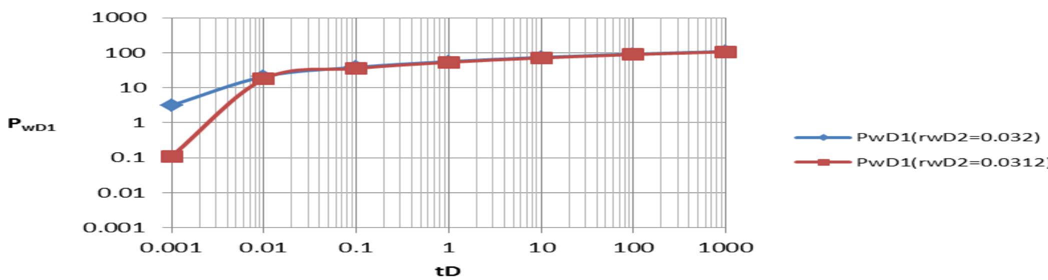

Figure 6. Effect of change in wellbore radius of Layer 2 on pressure distribution on Layer 1 at wellbore.

Table 7. Effect of change in wellbore radius of Layer 2 on pressure distribution on Layer 2 after radial flow period.

t_D	P_{wD2} (rwD2=0.032)	P_{wD2} (rwD2=0.0312)
0.001	7.2992004	7.6770781
0.01	24.482671	24.860549
0.1	41.666142	42.04402
1	58.849613	59.227491
10	76.033084	76.410962
100	93.216555	93.594432
1000	110.40003	110.7779

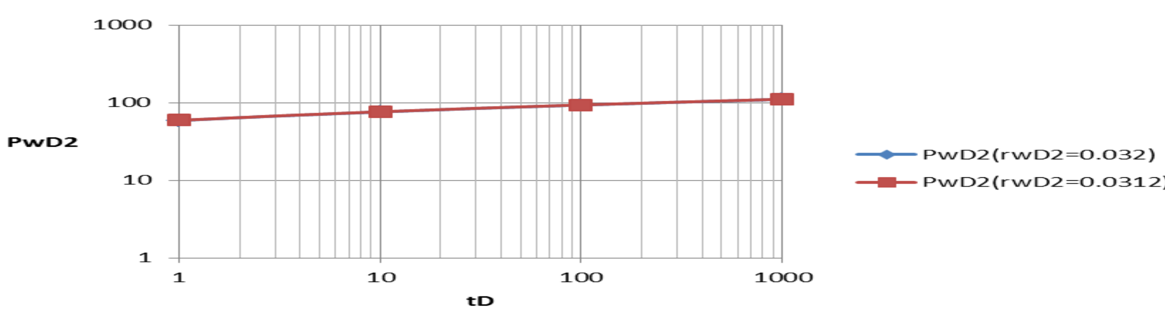

Figure 7. Effect of change in wellbore radius of Layer 2 on pressure distribution on Layer 2 after radial flow period.

t_D the effect of change in r_{wD2} is not much as shown in Figure 5.

Effect of change in wellbore radius of Layer 2 on P_{wD2} after radial flow period is shown in Table 6 and Figure 6. The effect is clearly seen in the table. It is observed that the larger the wellbore radius the higher the productivity in Layer 1.

Effect of change in wellbore radius of Layer 2 on pressure distribution in Layer 2 after radial flow period is shown in Table 7 and Figure 7. The effect is clearly

Table 8. Effect of change in well length of Layer 1 on pressure distribution on Layer 1 at wellbore.

t_D	P_{WD1} (L_{D1}=0.129764)	P_{WD1} (L_{D2}=4Xl$_{D1}$)	P_{WD1} (L_{D3}=39.53L_{D1})
0.001	19.29772	4.726915	0.488160695
0.01	37.04212	9.07335	0.937028341
0.1	54.78653	13.41979	1.385895988
1	72.53094	17.76622	1.8347636
10	90.27534	22.11266	2.28363128

Table 9. Effect of change in well length of Layer1 on pressure distribution on Layer 2 at wellbore.

t_D	P_{wD2} (L_{D1}=0.129764)	P_{wD2} (L_{D2}=4XL_{D1})	P_{wD2} (L_{D3}=6.18X L_{D1})
0.001	21.938443	21.93844299	21.93844299
0.01	39.121914	39.12191384	39.12191384
0.1	56.305385	56.3053846	56.30538468
1	73.488856	73.48885552	73.48885552
10	90.672326	90.67232	90.67232637

Table 10. Effect of change in well length of Layer 1 on pressure distribution on Layer 1 after radial flow period.

t_D	P_{D1} (L_{D1}=0.12964)	P_{D1} (L_{D2}=0.52964)	P_{D1} (L_{D1}=0.802964)
0.001	2.26E+01	2.62E+01	2.66E+01
0.01	39.6309	46.4733	47.2315
0.1	56.6558	66.2005	67.2544
1	73.691	85.2431	86.517
10	90.7309	100.82	101.933

Table 11. Effect of change in well length of Layer 1 on pressure distribution on Layer 2 after radial flow period.

t_D	P_{D2} (L_{D1}=0.12964)	P_{D2} (L_{D1}=0.52964)	P_{D2} (L_{D1}=0.802964)
0.001	2.20E+01	2.23E+01	2.23E+01
0.01	3.92E+01	3.98E+01	4.02E+01
0.1	5.64E+01	5.79E+01	5.96E+01
1	7.35E+01	7.62E+01	7.98E+01
10	9.07E+01	9.83E+01	1.08E+02

seen in Table 7. It is observed that the smaller the wellbore radius the higher the productivity.

To determine the effect of change in L_{D1} on P_{wD1}, P_{WD1} was computed at values of L_{D1}, 0.12964, 0.529764 and 5.129764. The results are shown in Table 8. It is observed that the smaller the L_{D1} the larger the P_{wD1}.

Effect of change in L_{D1} on P_{wD2} is as shown in Table 9. The results show that change in L_{D1} does not affect P_{wD2}. Effect of change in L_{D1} on P_{D1} after radial flow period is shown in Table 10. The results show that the larger the L_{D1} the larger the P_{D1}.

Effect of change in L_{D1} on P_{D2} after radial flow period is shown in Table 11. From the table, it is observed that the larger the L_{D1}, the larger P_{D2}.

Effect of change in L_{D2} on P_{wD1} is shown in Table 12. It is observed that change in L_{D2} does have effect on P_{wD1} as shown in Table 12.

Table 13 present the results of effect of change in well length of Layer 2 on pressure distribution on Layer 2 at wellbore. From the results, it was observed that the smaller the well length the higher the productivity of Layer 2 at wellbore and also after radial flow period as

Table 12. Effect of change in well length of Layer 2 on pressure distribution on Layer 1 at wellbore.

t_D	P_{wD1} (L_{D2}=0.134)	P_{wD1} (L_{D2}=0.334)	P_{wD1} (L_{D2}=0.534)
0.001	9.57E+00	1.00E+01	5.70E+00
0.01	26.5751	9.07947	9.07343
0.1	43.531	24.7054	14.2927
1	60.4684	31.9553	18.5834
10	77.1985	38.4888	22.8478
100	93.4722	42.8425	27.0495

Table 13. Effect of change in well length of Layer 2 on pressure distribution on Layer 2 at wellbore.

t_D	P_{wD2} (L_{D2}=0.134)	P_{wD2} (L_{D2}=0.334)	P_{wD2} (L_{D2}=0.534)
0.001	21.93844	8.806508	5.505152361
0.01	39.1219	15.695618	9.817109
0.1	56.30538468	22.589585	14.12906657
1	73.4888555	29.483553	18.44102367
10	90.6723	36.37752	22.75298077
100	107.8557972	43.271488	27.06493

Table 14. Effect of change in well length of Layer 2 on pressure distribution on Layer 2 after radial flow period.

t_D	P_{D2} (L_{D2}=0.134)	P_{D2} (L_{D2}=0.334)	P_{D2} (L_{D2}=0.534)
0.001	7.82E+00	8.88E+00	5.52E+00
0.01	2.50E+01	1.57E+01	9.82E+00
0.1	4.23E+01	2.29E+01	1.42E+01
1	5.95E+01	3.01E+01	1.85E+01
10	7.70E+01	3.64E+01	2.28E+01
100	9.49E+01	4.80E+01	2.72E+01

Table 15. Effect of change in pay thickness of Layer 1 on pressure distribution on Layer 1.

Td	P_{wD1} (h_{D1}=4.785)	P_{wD1} (h_{D1}=8.785)	P_{wD1} (h_{D1}=15.785)
0.001	11.98235	21.9989	39.527
0.01	23	42.227	75.874
0.1	34.02	62.455	112.22
1	45.03596	82.6835	148.5669
10	56.0538	102.9117	184.91
100	67.072	123.14	221.26
1000	78	143.368	257.61
10000	89.107	163.5964	293.95

shown in Table 13.

Effect of change in well length of Layer 2 on pressure distribution on Layer 2 after radial flow period is shown in Table 14. The result shows that the small the well length in Layer 2 higher the productivity in Layer 2.

To determine the effect of change in h_{D1} on P_{D1} and P_{D2}, P_{D1} and P_{D2} were computed with values of h_{D1} of 4.785, 8.785 and 15.785. While h_{D2} remain constant at 6.5298. The results are shown in Tables 15 and 16. From these tables it is observed that a change in h_{D1}

Table 16. Effect of change in pay thickness on of Layer 1 on pressure distribution on Layer 2.

Td	P_{wD2} (h_{D1}=4.785)	P_{wD2} (h_{D1}=8.785)	P_{wD2} (h_{D1}=15.785)
0.001	19.196	19.195988	19.195988
0.01	34.23	34.2314	34.2314
0.1	49.27	49.266828	49.266828
1	64.30224	64.3022	64.3022
10	79.3376	79.337	79.337
100	94.37	94.37	94.37
1000	109.4085	109.4085	109.4085
10000	124.444	124.4439	124.4439

Table 17. Effect of change in pay thickness of Layer 2 on pressure distribution on Layer 2.

Td	P_{wD2} (h_{D1}=4.785)	P_{wD2} (h_{D1}=8.785)	P_{wD2} (h_{D1}=15.785)
0.001	19.196	19.195988	19.195988
0.01	34.23	34.2314	34.2314
0.1	49.27	49.266828	49.266828
1	64.30224	64.3022	64.3022
10	79.3376	79.337	79.337
100	94.37	94.37	94.37
1000	109.4085	109.4085	109.4085
10000	124.444	124.4439	124.4439

Table 18. Effect of change in pay thickness of Layer 2 on pressure distribution on Layer 2.

t_D	P_{wD2} (h_{D2}=6.5298)	P_{wD2} (h_{D2}=8.5298)	P_{wD2} (h_{D2}=10.5298)
0.001	19.195988	19.195988	30.955
0.01	34.2314	44.72	55.2
0.1	49.266828	64.3566	79.45
1	64.3022	83.997	103.69
10	79.337	103.6378	127.938
100	94.37	123.2784	152.184
1000	109.4085	142.92	176.43
10000	124.4439	162.5596	200.675

does affect only P_{D1} and not P_{D2}.

Also to determine effect of h_{D2} on P_{D2}, P_{D2} were computed with values of h_{D2} at 6.5298, 8.5298 and 10.5298, while h_{D1} remain constant at 4.785. The results are shown in Table 18. This implies that to obtain high productivity for a particular layer the well should be positioned at a higher pay thickness.

Conclusions

From the statement of problems, objectives, and the results of study presented in the previous chapters, the following conclusions can be drawn:

(1) It is possible to analyze each layer.
(2) When there is crossflow, pressure transient in the reservoir considered is similar to the behavior of the homogeneous system.
(3) Gas cap drive is more predominant than that of water drive.
(4) Well eccentricity was not found to affect productivities.
(5) Well location further away from the top and bottom boundaries offer delayed in external fluid breakthrough for all well completions.

(6) The thicker the pay thickness of a particular layer the higher the wellbore pressure.
(7) In order to obtain high productivity, smaller wellbore radius should be used in Layer 1 and larger wellbore radius should be used in Layer 2.
(8) The longer the well length of a particular layer the higher the wellbore pressure.

Nomenclature

C_t: Total reservoir compressibility (Psi $^{-1}$)
h: Formation thickness (ft)
h_D: Dimensionless height
L_D: Dimensionless length
P_D: Dimensionless pressure
P_{wD}: Dimensionless wellbore pressure
p_D: Dimensionless pressure derivative
S: Instantaneous source functions
t: Time (h)
t_D: Dimensionless time
x,y,z: Space coordinates
x_D,y_D: Dimensionless distance in the x and y directions
x_f: Horizontal well half length
z_D: Dimension distance in the z director
k: Horizontal permeability
k_y Permeability in the y – direction (md)
k_z: Permeability in the z direction (md)
l: Horizontal well length (ft)
r_D: Dimensionless radial distance in the horizontal plane
r_{wD}: Dimensionless wellbore radius
x_w: Well location in the x – direction (ft)
x_e: Distance to the boundary or reservoir length (ft)
x_{eD}: Dimensionless distance to the boundary
x_{WD}: Dimensionless well location in the x- direction
Z_w: Well location in the direction (ft)
z_{WD}: Dimensionless well location in the Z direction
Y_w: Well location in the y – direction (ft)
Dimensionless well location in the Y direction.

Conflict of Interest

The author(s) have not declared any conflict of interests.

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Full Length Research Paper

Sensitivity study of low salinity water injection in Zichebashskoe Oilfield

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Presently, low salinity waterflooding is considered one of the most promising and cost-effective EOR methods. Although the recovery mechanisms are still uncertain, decrease of residual oil saturation and alternation of rock wettability are considered to be main mechanisms of the incremental oil recovery. In addition, laboratory and mathematical studies conducted over recent years suggested that mobility control is also a possible mechanism for enhanced oil recovery during low salinity water injection. The mobility control effect is due to induced fines migration and consequent permeability reduction in water invaded areas. The laboratory studies show that the incremental recovery gained from low salinity fines-assisted water flooding strongly depends on end point relative phase permeability for formation and injection waters. Permeability reduction due to fines migration decreases injected water mobility and increases the reservoir sweep. In this study, 24 years of production data from Zichebashskoe field (Russia) including 7 years of low salinity waterflooding are used to study the effect of water relative permeability reduction during low salinity waterflooding on improved oil recovery. The results of 3D reservoir simulations show low incremental oil recovery by low salinity water injection mainly due to two reasons: first a significant amount of water produced before the water injection, that is, a significant mixture between formation and injected waters that decrease the effect of low salinity; and second already high sweep efficiency as a result of water injection into water zone. The sensitivity study shows that the incremental recovery increases for greater relative permeability reduction by low salinity water injection .However, with 20 times decrease of Krwor from formation water to injected water, the incremental oil recovery is still negligible (4%).

Key words: Low salinity waterflood, fines-assisted waterflooding, field case, sensitivity study, fines migration.

INTRODUCTION

Recent studies of low salinity waterflooding have largely focused on the effects of water compositions on wettability, capillary pressure, relative permeability and residual oil saturation (Yildiz and Morrow, 1996; Tang and Morrow,

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1999; Zhang and Morrow, 2006; Jerauld et al., 2008; Pu et al., 2010; Takahashi and Kovcsek, 2010; Berg et al., 2010; Cense et al., 2011; Mahani et al., 2011). The aforementioned studies conclude the effects of low salinity waterflooding to be similar to that for chemical EOR methods (Lake, 1989; Bedrikovetsky, 1993). The detailed analysis of microscopic physics mechanisms of low salinity waterflooding is explained in the reviews by Morrow and Buckley (2011) and Sheng (2014).

Other studies by Bedrikovetsky et al. (2011) and Zeinijahromi et al. (2011, 2013, 2014) propose that the mobility control effect of low salinity water injection that involves mobilization and migration of natural reservoir fines and consequent permeability reduction results in improved recovery. Morrow and Buckley (2011) also suggest that the formation of lamellae and emulsions, stabilized by fines, their migration and straining may result in mobility control and deep reservoir flow diversion. Tang and Morrow (1999) and Fogden et al. (2011), suggest another mechanism of oil-wet and mixed-wet fines detachment by advancing water-oil capillary menisci; the resulting straining may also decrease the water relative permeability and increase oil recovery.

These effects appear to be separate phenomena from the fines migration by low salinity water and plugging of water-filled pores, but may occur simultaneously. Hussain et al. (2013) conducted an experimental study to confirm the above effects of the water phase permeability reduction during formation- and low-salinity waterflooding in oil-saturated rock. It was concluded that the water-wet particles have been removed from the rock by moving low salinity water, resulting in decrease in relative permeability for water and increase in fractional flow for oil. The conclusions agree with the mechanisms proposed by Sarkar and Sharma (1990).

Some low salinity core flood studies have reported the release of significant amounts of fines (Bernard, 1967; Tang and Morrow, 1999; Pu et al., 2010), while others showed no evidence of fines migration (Lager et al., 2008; Jerauld et al., 2008) even though additional oil was recovered. In order to separate these effects, the injections leading to fines lifting and permeability decline are called “the fines-assisted waterflooding” (Kruijsdijk et al., 2011) in the current work. The fines-assisted version of low salinity waterflooding is a mobility control EOR technology. The present paper only considers the effects of fines mobilization and capture to provide mobility control and does not consider changes to the residual oil saturation or relative permeability curves as a result of wettability alternation during injection of low salinity water.

The available literature on laboratory studies and mathematical modelling of low salinity waterflooding highly exceeds that on the field trials. Very limited information on low salinity waterflooding pilot tests have been published in the open literature. Several limited field applications show significant recovery of residual oil (Webb et al., 2004; McGuire et al., 2005; Seccombe et al., 2010). However, the North Sea pilot, where the screening criteria for low salinity waterflood have been met, did not exhibit an incremental recovery (Skrettingland et al., 2010). The lack of information on real field applications of smart waterflooding with alteration of injected water composition as compared with the formation water is a serious restriction for large scale application of the technology in the oil industry.

The current paper presents analysis of a low-salinity water injection in a field case, based on limited available production and injection data from Zachubashskoye field (Russia, Tatarstan). The result of 7 years pressure maintenance by low salinity water injection in Zichebashskoe field is presented and modeled using mathematical modeling of fines-assisted waterflooding (Zeinijahromi et al., 2014).

The results of mathematical modelling of low salinity waterflooding strongly depend on relative phase permeability for formation and injection waters, particularly on Sor and Krwor. Decrease of Sor corresponds to well-known effect of wettability alteration with the salinity decrease, that is, the effect is equivalent to that in chemical EOR. Decrease of Krwor reflects the permeability damage induced by the reservoir fines mobilized by the injected low salinity water, that is, the recovery enhancing mechanism is the same as that in mobility control EOR. In the present study, we concentrate on sweep enhancement, that is, the latter case.

FIELD DESCRIPTION

Figure 1 shows current saturation map of the Zichebashskoe field and wells’ location. The Zichebashskoe field consists of two sandstone reservoirs, Tula and Bobrik (Figure 1a and b). The layers are isolated with no hydrodynamic interaction and are connected to an active aquifer. The Tula (upper) layer has higher horizontal connectivity and permeability compared to that for Bobrik layer.

Production from Zichebashskoe field started in 1989 followed by pressure maintenance with low salinity water injection since 2006. Water production curve on Figure 2 (green line) shows that a significant volume of water has been produced during the period 1989 to 2006, before start of low salinity water injection. The main injectors are located below water-oil contact to inject water in the water zone in order to provide pressure maintenance during 2006 to 2013.

Water injection into aquifers yields better sweep and displacement than that in the oil zone, since the displacement of oil by water occurs “by the plane surface” moving upwards from water-oil contact during the injection into aquifer (Lake, 1989, Bedrikovetsky, 1993). Slope of the peripheral zones near the initial water-oil contact also increases the recovery during bottom-up waterflooding, since gravity effect decelerates water and accelerates oil. These two simultaneous mechanisms can explain high displacement efficiency during injection in water-oil contact in

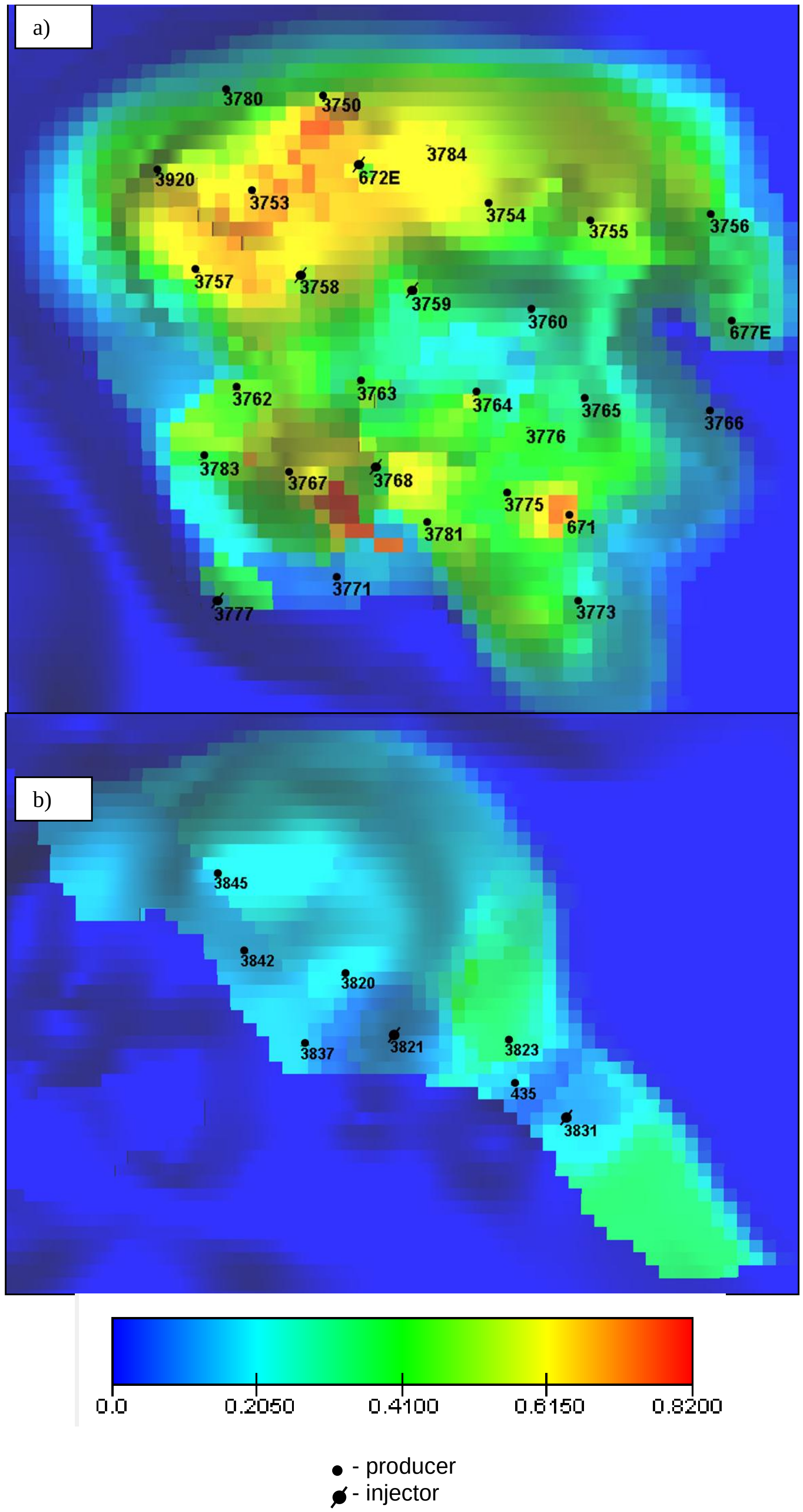

Figure 1. Well placing in Zichebashskoe field; a) Tula layer; b) Bobrik layer.

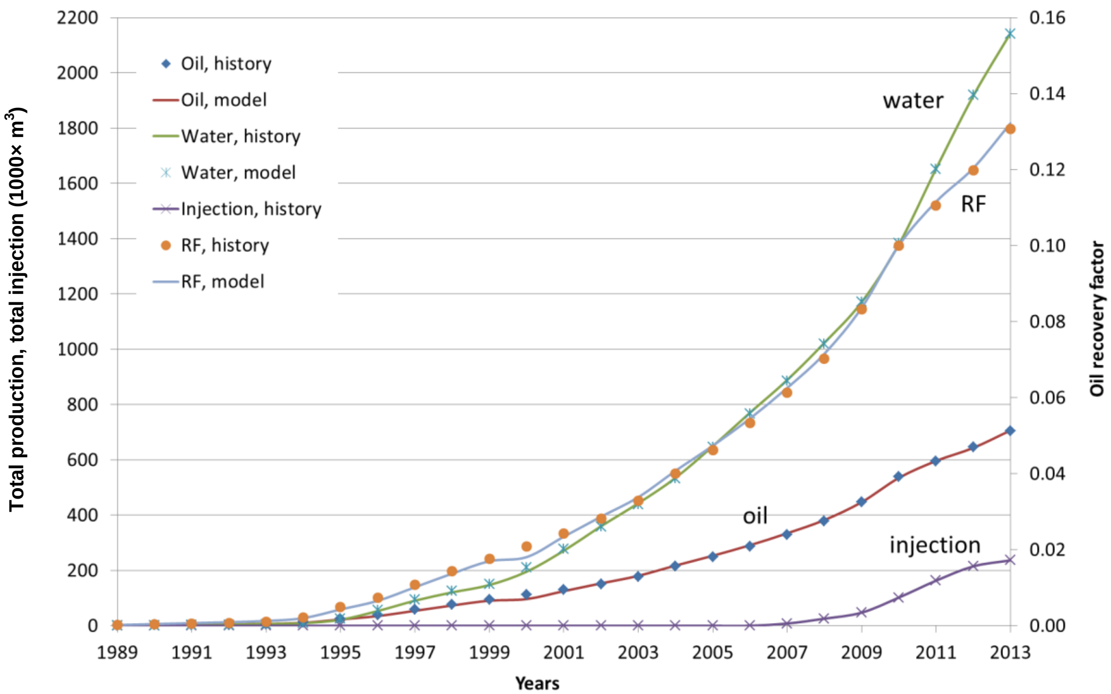

Figure 2. Field history matching.

Zichebashskoe field.

Figure 1 shows oil saturation averaged over the production thickness. Water cut in production wells gradually decreases from the position of initial oil-water contact up to the central part of the anticlinal field. One can also see that oil saturation increases from peripheral areas, where the injectors are located, towards the central part of the field.

The main properties of fluids and rocks are given in Table 1. The initial pressure is above the bubble point pressure; hence there is no initial gas cap and primary energy for the production is provided by adjacent active aquifer.

Tables 2 and 3 show the formation and injected water compositions, respectively. Extremely high formation water salinity is defined by sodium chlorite concentration that highly exceeds those for other salts, while magnesium and calcium salts dominate in injected water. Therefore, intensive ion exchange and consequent fines release is expected to occur during the displacement of formation water by low salinity injected water (Khilar and Fogler, 1998; Bedrikovetsky et al., 2011).

MATHEMATICAL MODELING OF FINES-ASSISTED LOW-SALINITY WATERFLOODING

Let us discuss a system of two-phase flow in porous media with varying water salinity resulting in the fine particles lifting. Following Muecke (1979), it is assumed that the water-wet particles are transported by the water phase. The detached forces mobilize water-wet fines that have been water-wet originally or, according to Berg et al. (2010) and Cense et al. (2011), became water-wet after the arrival of low salinity water; the mobilization occurs if the detaching torque of drag and lifting forces exceeds the attaching torque of electrostatic and gravity forces. It is assumed that the detached fines are inert, that is, they are intact and keep their integrity during detachment. The effects of clay swelling are assumed to be negligible. For simplicity, it is assumed that the volumetric concentrations of attached and retained particles are negligibly small compared to the porous space, that is, the retention of fine particles does not affect the porosity. It is also assumed that the initial salt concentration is the critical salt concentration for the reservoir fines, $\sigma_{a0}=\sigma_{cr}(\gamma_i)$, that is, the reservoir fines start leaving the rock surface with the decrease in salt concentration starting from $\gamma=\gamma_i$. We also assume that the dissipation effects of diffusion and capillary pressure are negligibly smaller than those of fines straining. Alteration of water salinity affects the attached concentration stronger than the velocity alteration; therefore, the velocity dependency of the maximum concentration of attached fines is neglected. The permeability damage by fines straining is significantly higher than that by attachment. Other assumptions include constant temperature, incompressibility of water and oil, constant water and oil viscosities.

Volumetric balance of the overall flux of incompressible water and oil is:

$$\nabla \vec{U} = 0 \tag{1}$$

Volumetric balance for incompressible water is (Lake, 1989)

$$\phi \frac{\partial s}{\partial t} + U \nabla f\left(s, \sigma_s\right) = 0 \tag{2}$$

where the fractional flow function accounts for the reduction of relative phase permeability for water according to Equation 6:

Table 1. Properties of rocks and fluids in Bastrykskoye field.

Characteristic	Layer	
	Tulsky	Bobrikovsky
Reservoir top depth (m)	1180	1200
Formation thickness (m)	2.3	11.5
Net pay thickness (m)	1.8	4.3
Relative thickness of sandstone layers	0.98	0.93
Initial oil saturation	0.78	0.82
Reservoir temperature (°C)	25	25
Initial reservoir pressure (MPa)	11.8	12
Bubble point pressure (MPa)	1.3	2.1
GOR (m^3/ton)	1.7	1.4
Oil density under reservoir conditions (kg/m^3)	875	870
Oil density under surface conditions (kg/m^3)	880	883
Oil viscosity under reservoir conditions (mPa·s)	26.6	21.5
Formation volume factor	1.039	1.023
Water density under reservoir conditions (kg/m^3)	1170	1170
Water viscosity under reservoir conditions (mPa·s)	1.7	1.7
Specific-productivity index [m^3/(day·MPa·m)]	2.1	2.4
Displacement efficiency obtained from corefloods	0.572	0.600

Table 2. Composition of formation water in Zichebashskoe field.

Composition	MW (g/mol)	Conc. (mol/L)	Conc. (mg/L)	Conc. (g/L)	Conc. % (w/w)
NaCl	58.439	3.26534	190823.3	190.8233	79.71
$MgCl_2$	95.205	0.12336	11744.2	11.7442	4.91
$MgSO_4$	120.367	0.00625	751.8	0.7518	0.31
$CaCl_2$	110.978	0.32437	35997.7	35.9977	15.04
$NaHCO_3$	84.006	0.00090	75.7	0.0757	0.03

Table 3. Composition of fresh lake water injected in Zichebashskoe field.

Composition	MW (g/mol)	Conc. (mol/L)	Conc. (mg/L)	Conc. (g/L)	Conc. % (w/w)
NaCl	58.439	0.00034	20.1	0.0201	2.37
$MgCl_2$	95.205	0.00029	28.1	0.0281	3.31
$MgSO_4$	120.367	0.00115	137.8	0.1378	16.25
$CaCl_2$	110.978	0.00250	276.9	0.2769	32.64
$NaHCO_3$	84.006	0.00459	385.5	0.3855	45.44

$$f(s,\sigma_s)=\left[1+\frac{k_{ro}(s)\mu_w(1+\beta\sigma_s)}{k_{rw}(s)\mu_o}\right]^{-1} \quad (3)$$

and $\vec{U}$ is a three dimensional vector of the overall water-oil flux:

$$\vec{U}=(u_x,u_y,u_z)$$

The mass balance of suspended, attached and retained particles is:

$$\frac{\partial}{\partial t}[\phi sc+\sigma_a+\sigma_s]+U\vec{\nabla}(cf)=0 \quad (4)$$

Here it is assumed that no fine particle attachment occurs in the reservoir during the injection of water without fines. Particle detachment occurs during injection of low salinity water into oilfield, where the attached fines with maximum concentration are in contact with water with continuously decreasing salinity, where drag and lifting forces are determined by interstitial velocity of water (Yuan and Shapiro, 2011). Equation (4) means an instant particle release governed by the torque balance.

Size exclusion capture of mobilized fine particles in small pores is described by the equation of linear kinetics (Bedrikovetsky, 2008)

$$\frac{\partial \sigma_s}{\partial t} = \lambda_s cUf \tag{5}$$

Here, the straining rate is proportional to water flux f(s)U since the mobilized fine particles are transported by the water phase.

The mass balance of salt in the aqueous phase assumes low salt concentration not affecting the aqueous phase density ρ_w:

$$\frac{\partial}{\partial t}[\phi\gamma] + \vec{\nabla}\left(\gamma\vec{U}\right) = 0 \tag{6}$$

The modified Darcy's law for two-phase flow accounting for permeability damage to water is:

$$U = -k\left[\frac{k_{rw}(s)}{\mu_w(1+\beta\sigma_s)} + \frac{k_{ro}(s)}{\mu_o}\right]\nabla p \tag{7}$$

Finally, the system of governing equations for two-phase oil-water flow with fines mobilization, due to the decrease in water salinity and consequent reduction of relative permeability for water, consists of 7 equations:

i) Volumetric balance for incompressible flux of carrier water and oil,
ii) Volumetric balance for incompressible water,
iii) Mass balance for suspended, attached and strained particles,
iv) The maximum concentration of attached fine particles as a function of interstitial water velocity, salinity and saturation,
v) Size exclusion retention rate,
vi) Advective mass transfer of salt in porous space with retained fines and
vii) Modified Darcy's law accounting for permeability reduction due to fines straining.

This system determines 7 unknowns σ_a, s, p, c, γ, σ_s and U.

The initial conditions corresponding to injection of low salinity water into oil bearing formation include initial water saturation and initial concentrations of salt and of attached particles, zero values of suspended and strained fines. Boundary conditions on the injection wells include rate, unit fractional flow for water, salt concentration and zero concentration of suspended fines. Well bottomhole pressure is a boundary condition at the production wells.

The above system describes fines assisted waterflooding for all length scales, from core to a reservoir. Zeinijahromi et al. (2013) provides detailed derivation.

Mechanism for improved sweep efficiency due to fines migration

The observations, that fines migration can cause permeability decline because of changes in water composition and are sufficient to warrant the consideration of the effects of induced fines migration on waterflooding. During a waterflood, the rapid breakthrough of water can be a significant problem, leading to high water cut at producing wells and lower volumetric sweep efficiency. The problem is particularly pronounced for a mobility ratio significantly greater than unity or where the variation of permeability across the reservoir is significant. Fines release, due to the alteration of the chemistry of the injected water, and the consequent decrease in permeability, may be able to provide the mobility control and hence the ability to improve waterflood performance (Lemon et al., 2011; Zeinijahromi et al., 2011). Since the mobilization of fines by changing the chemistry of the injected water can only take place in the water-swept zone, only the effective permeability to water of the reservoir is decreased, reducing the mobility ratio. However, the main disadvantage of mobility control is that, for a given injection rate, the induced formation damage results in an increased injection pressure.

In displacement of oil by water in a heterogeneous reservoir, water propagates preferentially in highly permeable zones, with slow displacement of the oil in low permeability zones. A further displacement front in the low permeability zone occurs after water breakthrough in highly permeable zones and the creation of an injector/producer channel filled by high mobility water. The formation damage induced by mobilized fines in the swept zone homogenizes the permeability distribution across the reservoir and diverts the injected water into unswept areas. Hence, the induced formation damage causes the delayed breakthrough period and improved sweep efficiency for a given volume of injected water.

HISTORY MATCHING

Injection of low salinity water results in detachment of reservoir fines, their migration and straining in thin pore throats. The mathematical model for fines assisted water flooding is similar to those of mobility control EOR. Hence, in this study, the mathematical model for low salinity waterflood with changing relative phase permeability and accounting for fines mobilization and consequent permeability reduction in water swept areas, is used (Zeinijahromi et al., 2014). The system of equations for fines assisted waterflood is mapped on the system of equations for polymer flooding, allowing low salinity water injection with fines migration to be modeled using chemical option of black-oil model. Reservoir simulation software Tempest (Roxar, 2014) is used for modelling of low salinity and "normal (formation)" waterflooding in this study. The tracer option in Tempest is equivalent to polymer option without adsorption, where relative permeability can be made dependent on tracer (salt) concentration. The tuning parameters are pseudo (at the reservoir scale) phase permeability for oil and formation water, and the reduction factor to obtain the phase permeability for low salinity water from the phase permeability for formation water.

The Corey parameters are obtained by tuning the curves of cumulative oil and water production. The form of tuned pseudo relative permeability is shown in Table 4 for Tula and Bobrik layer. The Corey powers smaller than unity determine the convex forms of pseudo phase permeability, which is typical for those as obtained at the reservoir scale.

The result of history matching is presented in Figure 2 and exhibits a good match between the field history and the modelling data after the history matching. This model is later used to simulate normal (formation) water and low salinity water injection scenarios in Zichebashskoe field.

SENSITIVITY STUDY OF WATER RELATIVE PERMEABILITY REDUCTION

The mobility control effect of low salinity water injection is due to

Table 4. Pseudo relative permeability.

Layer	Swi	Sor	Krowi	Krwor	n_w	n_o
Tula	0.22	0.36	0.65	0.100	0.65	0.9
Bobrik	0.18	0.35	0.69	0.080	0.65	0.9

reduction of water relative permeability caused by fines migration. The coreflood results presented in laboratory studies by Zeinijahromi et al. (2014) and Hussain et al. (2013) show that changing from injection of formation water to fresh water causes a significant decrease in relative permeability for water under residual oil saturation Krwor; while residual oil saturation, connate water saturation and relative permeability for oil under connate water are almost the same.

The modeling results show that the incremental recovery as a result of fines migration is highly dependent on degree of damage to water relative permeability. The purpose of this section is to study the effect of the degree of water permeability reduction on recovered oil. This is done by back calculating the recovery from the reservoir if formation water had been injected and comparing it with different low salinity water injection scenarios. Experimental results from different studies showed that during the injection of formation water, no ionic exchange or fines migration due to alteration of electrostatic force occur. Therefore, we define formation water injection as a basic waterflood option, which is referred to as “normal” waterflooding.

Four cases of low salinity water injection are modeled and compared with normal waterflooding using tracer option of Tempest reservoir simulator. All reservoir, well and injection parameters are similar for four scenarios except the degree of damage caused by fines migration. Low salinity water injection is modeled for a case with negligible damage (3 folds decrease of water relative permeability as compared with normal waterflood), a normal damage case (6 folds decrease) and two extreme damage cases (10 and 20 folds decrease) (Figure 3). The pseudo relative permeability Kr depends on saturation and salinity γ (or tracer concentration in Tempest C). Following the coreflood study by Hussain et al. (2013), it is assumed that pseudo relative permeability for oil, Krowi, residual oil saturation, Sor and power for oil, n_o are independent of salinity or tracer concentration. The value of end point relative permeability Krwor for injected salinity (γ=0 or in Tempest: $C=C^{max}$) is decreased 3, 6, 10 and 20 times if compared with that for formation water (γ^0=1 or in Tempest: C=0).

In all cases, the well pressure is maintained below the fracturing pressure to avoid unrealistic prediction. In order to study the production improvement from the field, cumulative oil and water production are compared with normal water flooding (formation water injection) as the base case.

RESULTS AND DISCUSSION

Figure 4 shows the comparison for recovery factor and cumulative oil and water production between the normal and low salinity waterflooding. One can see that fines assisted water flooding resulted in production improvement in Zichebashskoe field by increasing the oil production and decreasing produced water. However, the results show that the improved recovery benefits are highly sensitive to the degree of reduction of water relative permeability during low salinity water injection (Figure 4a, b, c and d).

Figure 3a shows that with the three times decrease of water relative permeability due to low salinity, the incremental recovery is insignificant (~0.7%) and a reduction of produced water volumes is also small. The gained incremental recovery increases if the relative permeability of water decreases 6 times during low salinity water injection (Figure 3b); however it is much smaller than the 11% reported in Zeinijahromi et al. (2014) for a homogeneous 5 spot pattern. It can be explained by significant amount of water that has been produced before the start of low salinity water injection in Zichebashskoe field, that is, the injected water displaces the oil under already high water saturation. Another reason is injection of low salinity water into the aquifer in Zichebashskoe field. Oil is directly displaced by high salinity formation water and injected water lags significantly behind. The above are the main reasons why the incremental recovery factor with low salinity waterflooding is not significant.

The model for low salinity waterflood only accounts for fines migration and consequent decrease of relative permeability for water, that is, the effects of wettability change and residual oil saturation decreasing are ignored. Accounting for decrease in relative permeability for water and decrease in oil residual can bring additional incremental recovery if compared with the normal waterflooding.

Figure 4c and d present modeling results for severe water relative permeability reduction. It can be observed that the higher damage caused by fines migration results in more oil production improvement (Table 5). The cumulative volume of produced water also decreases with increase in damage. Since the mobilization of fines by changing the salinity of the injected water only takes place in the water-swept zones, only the effective permeability to water is decreased that reduces the water mobility. The formation damage induced by mobilized fines in the swept zone tends to homogenize the permeability distribution across the reservoir and diverts the injected water into unswept areas. Hence, higher induced formation damage causes more homogenized water front and improved sweep efficiency for a given volume of injected water in the case under study. It must be mentioned that the incremental recovery caused by

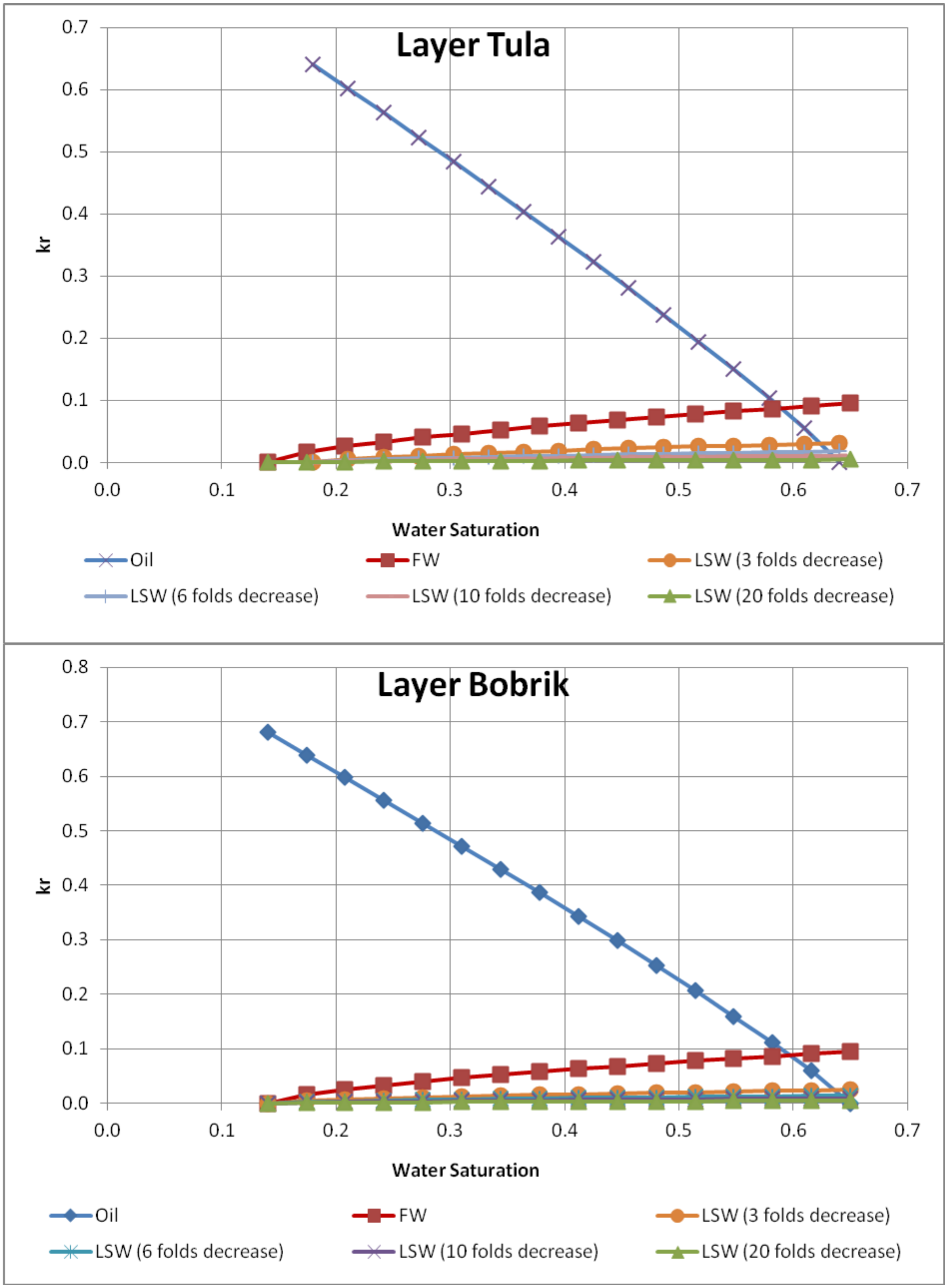

Figure 3. Relative permeability for water and oil for the case studies with the sensitivity analysis curves.

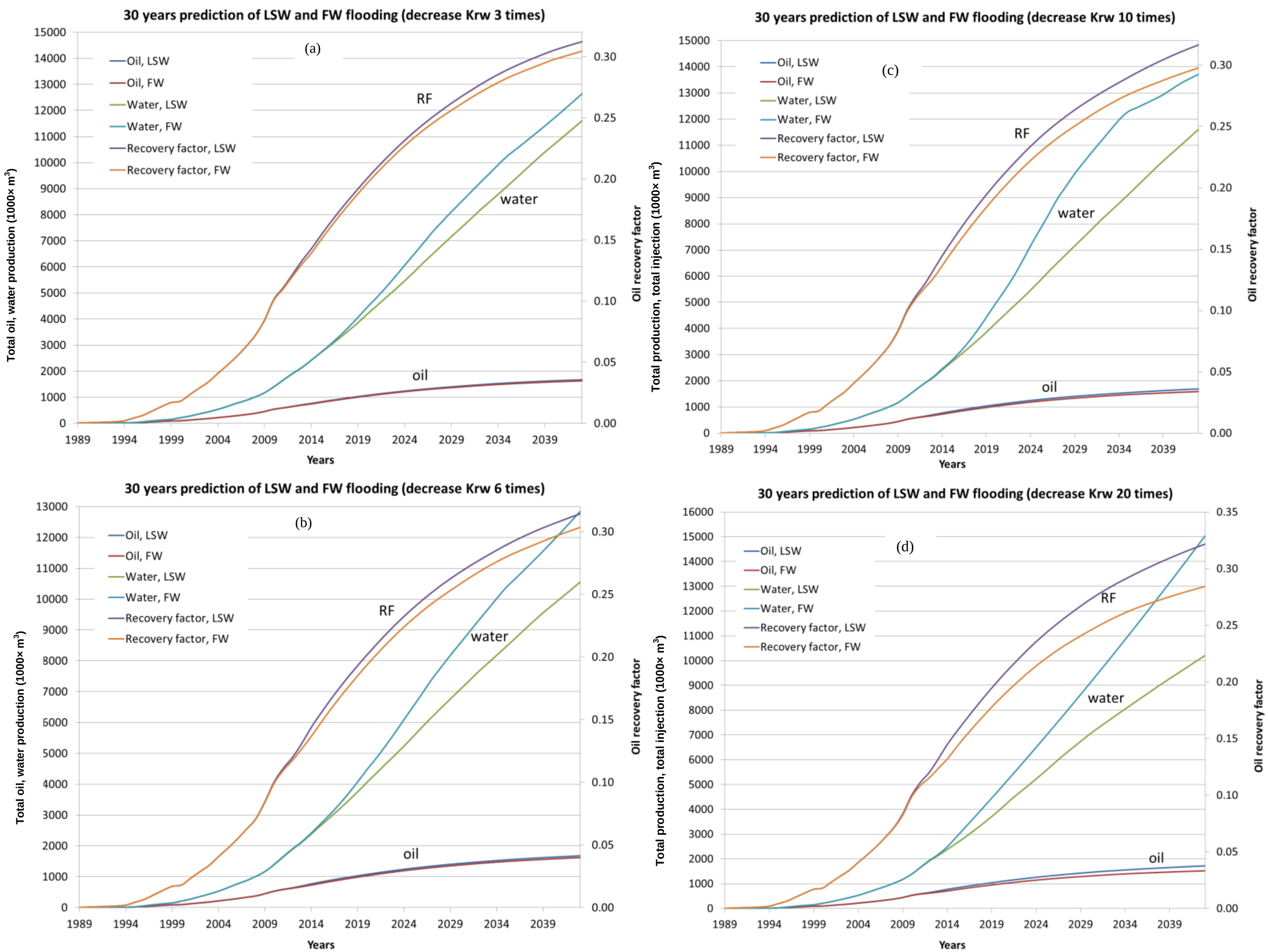

Figure 4. Comparison between formation and low salinity waterflood for 30 years prediction a) 3 time decrease of Krwor b) 6 times decrease c) 10 times decrease d) 20 times decrease.

Table 5. Pseudo relative permeability.

Folds	Oil Incremental RF
20 folds decrease	0.038
10 folds decrease	0.019
6 folds decrease	0.011
3 folds decrease	0.007

induced fines migration also depends on reservoir heterogeneity; thus there is an optimum permeability reduction above which no extra incremental recovery can be obtained (Zeinijahromi and Bedrikovetsky, 2014). Experimental studies show that the degree of permeability reduction with injection of low salinity water is a function of the difference between formation and injection water salinity as well as type, size and concentration of initial reservoir fines (Khilar and Fogler, 1998; Bedrikovetsky et al., 2011; Zeinijahromi and Bedrikovetsky, 2013). A great difference between salinity of formation and injected water and also high concentration of movable fines can result in large release of fines from reservoir rock and consequently sever permeability damage. However, in high permeable reservoir with small volume of in-situ fines, change of injected water salinity may not result in a significant damage to rock permeability to be used as mobility control method. To further validate the method, the amount of coreflood studies with double-salinity waterflood must be enhanced.

Low salinity water injected in Zichebashskoe field aimed to maintain reservoir pressure above the bubble point pressure (1.3 to 2.1 MPa). The pressure maintenance above the bubble point pressure by the waterflooding yields the commingled flow of oil with water that has significantly higher viscosity than the associated gas. In addition, oil viscosity increases during gas liberation during pressure depletion; thus, pressure maintenance during water injection is applied to avoid decrease of the oil flux due to gas evaporation and flow (Dake, 1998). Despite salinity of the injected water does not affect the pressure maintenance; the main shortcoming of waterflooding is water breakthrough to producers and cutting-off oil flux by lower viscosity water. Low salinity water can highly affect water flux and oil production. Decrease of the contact angle between oil and water results in decrease of residual oil saturation and improving water and oil relative permeability yielding some decrease in water flux, increase in the oil rates and the recovery factor. Moreover, lifting of the reservoir fines during low salinity waterflooding and the consequent fines migration result in significant decrease in relative permeability for water (Zeinijahromi et al., 2014; Hussain et al., 2013).

It should be mentioned that the current study does not emphasize the fines migration as the primary mechanism for low salinity effects in the field under investigation. The present paper concludes low efficiency of tertiary fines-assisted low-salinity waterflooding. In the case where the reservoir rock contains a lot of kaolinite, tertiary low-salinity water injection into water zone yields some minimum incremental oil recovery.

The mathematical model for low salinity water injection with increase of the rock wettability by water accounts for reduction in residual oil saturation, some increase in relative permeability for oil and some decrease in water relative permeability at the core scale. Despite ion exchange is the essential part of the mathematical model and residual oil alteration is triggered by change of the multi-component vector of ion concentrations, the above effects of chemical EOR is the main mechanism of incremental recovery due to salinity reduction (Pires et al., 2006). The mathematical model for so-called fines-assisted low-salinity waterflood accounts for permeability damage to water due to migration of mobilized fines (Zeinijahromi et al., 2013). So, relative permeability for water decreases at the reservoir scale and the model for fines migration representing the mobility-control EOR also feature the variation of relative permeability. Finally, the salinity-dependence of relative permeability is the main EOR mechanism in the mathematical modeling of low salinity waterflooding.

The coreflood data are unavailable for the presented study. The forms of relative permeability as extracted from the coreflood would reveal whether chemical or mobility-control EOR effects dominate. In the present study, we concentrate on decrease in relative permeability for water.

Conclusions

Oil and water production data for low salinity waterflooding in Zichebashskoe oilfield are history matched by the fines-assisted-waterflood model (tracer model in Tempest) with high accuracy. The modeling show that injection of low salinity water results in improved oil production and reduction in produced water volume. However, the improved recovery with fines assisted waterflooding depends on degree of the permeability damage during low salinity water injection. The higher the water relative permeability reduction due to fines release, the greater is the incremental recovery; however, obtained improved recovery is limited by heterogeneity of the reservoir.

Low salinity water injection under the conditions of Zichebashskoe field results in negligible incremental recovery and small decrease in the produced water if compared with the waterflooding by formation water. The phenomenon is explained by high flooding of the reservoir before commencement of low salinity water injection, by high salinity aquifer water. Another explanation is that low salinity water injection into aquifer causes lower incremental recovery than that with the injection into oil-zone due to usual high sweep efficiency of water injection into aquifers.

NOMENCLATURE

Latin letters

c	= *concentration of suspended particles*
f	= *fractional flow of water*
k	= *absolute permeability*, L^2, *mD*
k_o	= *initial absolute permeability*, L^2 , *mD*
k_{ro}	= *oil relative permeability*
k_{rw}	= *water relative permeability*
p	= *pressure*, $ML^{-1}T^{-2}$, *Pa*
q	= *volumetric flow rate*, L^3T^{-1}, m^3/s
s	= *water saturation*
t	= *time*, T, *s*
u	= *dimensionless velocity of the overall two-phase flux*
x_D	= *dimensionless length.*

Greek letters

γ	= *brine ionic strength*, $molL^{-3}$, *mol/lit*
ϕ	= *porosity*
γ^0	= *ionic strength of the injected brine*, $molL^{-3}$, *mol/lit*
γ_i	= *reservoir initial brine ionic strength*, $molL^{-3}$, *mol/lit*
μ_o	= *oil dynamic viscosity*, $ML^{-1}T^{-1}$, *cp*
μ_w	= *water dynamic viscosity*, $ML^{-1}T^{-1}$, *cp*
β	= *formation damage coefficient*
λ_s	= *filtration coefficient for straining*, L^{-1}, *1/m*
σ	= *volumetric concentration of captured particles*
σ_a	= *volumetric concentration of attached particles*
σ_{ao}	= *initial volumetric concentration of attached particles*
σ_{cr}	= *maximum volumetric concentration of captured particles*
σ_s	= *volumetric concentration of strained particles.*

Conflict of Interest

The authors have not declared any conflict of interests.

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