Effects to Be Considered When Planning Late Stage Depressurisation

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Dag Chun Standnes, Arne Skauge and Øystein Pettersen

Centre for Integrated Petroleum Research (CIPR), University of Bergen, Norway
Allégaten 41, N-5007 Bergen

Abstract

This paper addresses a special effect related to rock compaction which may occur during depressurization (DP) in mature oil fields. Empirical data indicate that reservoirs containing high-permeability channels in a background of more low-permeability soil will experience selective compaction when the fluid pressure is decreasing significantly (such reservoirs are common in the North Sea). Thereby the permeability will be reduced relatively more for weak, high-permeability material than stronger, low-permeability soil (also supported by empirical data) resulting in what we denote permeability homogenization with decreasing fluid pressure (the ratio $k_{channel}/k_{background}$ will decrease). Permeability homogenization has been demonstrated qualitatively by performing numerical simulation of generic reservoirs of Brent type, containing layers with high-permeability channels enclosed in a background of more low-permeability soils. The results show that increased sweep efficiency of oil may occur in certain layers as a result of the permeability homogenization effect). However, improved oil recovery due to permeability homogenization on field scale was difficult to demonstrate due to the simplicity of the model. Improved modeling of the rock compaction process and better understanding of modeling fluid flow in channel systems is required before the effect of permeability homogenization can be quantified more realistically.

Keywords: Rock compaction; Depressurization; Permeability homogenization

E-mail: dag.standnes@cipr.uib.no
arne.skauge@cipr.uib.no
oystein.pettersen@cipr.uib.no

Tel.: +47 55 58 33 74, Fax.: +47 55 58 82 65

Introduction

Many oil fields in the North Sea are produced by waterflooding, resulting in a steadily increasing water-oil-ratio (WOR). A high WOR can be a decisive factor for field abandonment. However, at this stage of the production scheme it has been shown that oil and gas production rates in some cases can be maintained at economical rates or even accelerate if the injection of water is stopped and the reservoir is produced by depletion

(Braithwaite, 1994). Production of oil reservoirs under such conditions is therefore usually referred to as production by depressurisation (DP). Initiating a DP process is expected to induce variation in several different parameters, all which may have strong influence on the oil and gas production rates depending on the rock and fluid properties of the actual reservoir. Variations will usually include changes in:

- Fluid properties. DP will induce larger fluid viscosities due to evaporation and the gas-oil (G/O) interfacial tension (IFT) will increase. The latter effect will have influence on gas and oil relative permeabilities (they will usually decrease with increasing G/O IFT)
- Fluid saturations. Reduced pressure will give shrinkage of oil due to mass exchange and gas expansion. Gas that is initially immobile will be generated and a very important parameter is the critical gas saturation, S_{gc} above which discontinuous immobile gas becomes mobile and can flow towards the production wells
- Phase mobilities. If the gas saturation exceeds S_{gc}; it becomes mobile and will start to flow towards the production wells. Hence, S_{gc} has large consequences for future gas production forecasts when initiating DP, and as reported experimental values (Skauge et al., 1998) have as wide a range as 0.6 – 27 %, reliable measurements of S_{gc} are very important . Additional difficulties also arise when estimating the relative permeability of the mobile liberated gas. Experimental data reported by Egermann et al. (2001) may indicate that discontinuous gas bubbles have approximately two orders of magnitude lower relative permeability than gas originating from ordinary gas flooding
- Rock properties. Compaction of rock will induce reduction in pore volume (PV) and permeability (Braithwaite, 1994; Tehrani et al., 2002)

Several papers have been published addressing challenges related to predict oil and gas recovery efficiencies due to DP processes. These papers have mainly focused on the impact of variable critical gas saturation, the shape of the gas relative permeability curve on oil and gas recovery and different experimental methods/techniques to improve the determination of these major parameters (Drummond et al., 2001; Goodfield and Goodyear, 2003). In contrast, this paper addresses a special effect related to the rock compaction process, which will be referred to as *permeability homogenization*. This effect has not to the knowledge of the authors been reported in the literature but may have important impact on oil and gas recovery during DP processes in heterogeneous reservoirs, especially fluvial systems with high-permeability channels in a background of soil with significantly lower permeability, often encountered North Sea sandstone reservoirs. The main purpose of this work is therefore to give empirical evidence of the existence of permeability homogenization by taking into account the rock strength of the different materials in the reservoir. Further evidence will be demonstrated qualitatively by numerical simulation performed on a generic reservoir model of Brent type using the commercial simulator ECLIPSE 100. The numerical model used is rather simple but believed to catch the overall qualitative trends correctly.

This paper is part of an ongoing project where the ultimate purpose is to improve the understanding of modeling of heterogeneous reservoirs under depletion. This includes variations in important quantities typically induced by the DP process like rock compaction, permeability reductions and flow in channel systems. The present work therefore also provides a discussion of the limitations of the present numerical model with respect to these parameters and point at some ways to improve the accuracy of the predictions generated by the simulator. Positive as well as negative consequences of the reservoir homogenization effect may have on oil and gas production are also discussed .

Theory

Rock strength and compaction

Fig. Xx depicts experimental data measured on typical North Sea sandstones showing Young's modulus (E) vs. mean effective stress (σ'). The general trend is that the curves are steeper the higher the initial E-values, i.e. strong rocks become even stronger when loaded. This empirical observation is the underlying principle for the permeability homogenization of sandstone reservoirs having channels with large permeability contrast between channel and background when exposed to loading.

Model for permeability reduction vs. effective stress

Compaction of rock and reduction in pore volume (PV) will induce reduction in permeability. Fig. Xx shows permeability measured vs. effective stress for some typical North Sea sandstone materials. Weak sandstones have in general greater loss of conductivity than strong sands. It therefore seems like a reasonable assumption that the reduction of the rock permeability due to loading is "proportional to the initial value". Rocks having high permeability initially (without loading) will therefore experience a larger negative slope when plotting permeability vs. effective stress than low-permeability rocks. Fig. xx indicates that permeability vs. effective stress in most cases fit the following empirical expression reasonably well:

$$\ln K = -\frac{\ln K_0}{1000} \cdot \sigma' + \ln K_0 \qquad [1]$$

where,

K_0- Permeability in the absence of effective stress (mD)

K- Permeability in mD for effective stress σ' (bars)

Some examples of calculated permeability vs. effective stress from equation 1 are included as dotted lines in Fig. xx for rocks having different initial permeability values. For these examples, it is assumed that the rock permeability vs. effective stress becomes equal to 1 mD at a stress level equal to 1000 bar.

Permeability homogenization

Most fluvial systems are comprised of high permeability channels with significantly higher permeabilities than the background soil. Permeability contrasts between channels and background can typically be in the range from five to several hundred. Decreasing the fluid pressure, p_f, as in a DP process will result in an increase in effective stress (σ'),

$$\sigma' = \sigma - \alpha \cdot p_f \qquad [2]$$

where,

σ – Total stress (Pa)

σ' – Effective stress (Pa)

α- Biot's constant (-)

p_f- Fluid pressure (Pa)

It is generally accepted that rock compaction is determined by effective stress (not the fluid pressure) (Wood 1990). By the preceding assumptions the weak high-permeable sands (channels) will compact more than the stronger low permeable background soil when the fluid pressure (p_f) decreases. Hence, the reservoir will experience a more uniform permeability variation (homogenization of the reservoir) as a consequence of the DP process (reduction in fluid pressure and thereby an increase in effective stress).

Reservoir model description, flow functions and production schedules

Reservoir model description

The reservoir considered represents a typical sandstone reservoir of Brent type. The total size of the reservoir is 4000 m in the x-direction (excluding the aquifer), 1500 m in the y-direction and 282 m in the z-direction (positive downwards). The reservoir is modeled by a grid with dimension 46x38x29 (N_x, N_y, N_z), where the active blocks are in cells 1-42, 5-34 and 6-25 in the x, y and z-direction, respectively (N_x = 43-46 and N_y = 1-4 and 35-38 are side-burdens, N_z = 1-5 is overburden and N_z = 26-29 is under-burden, respectively). The reservoir has a dip (≈ 4.9 ° from N_x = 1-12 and ≈ 2.2 ° from N_x = 13-42) and it is produced by 5 wells located up-dip perforated in blocks with N_x = 41. Pressure support is provided by an aquifer (4 first blocks in the x-direction) together with 3 water injection wells places down-dip perforated in blocks with N_x = 4. The reservoir is consisting of 7 different rock types ranging from unconsolidated sandstone to very strong sandstone (Table xx provides the type and properties of each type) and the total number of layers in the reservoir is 20 (dimension of each layer is provided in Table 1). 9 of the 20 layers in the reservoir contain high-permeability channels of different tortuosities. Rock type, permeabilities (horizontal (k_x = k_y) and vertical) and porosities for all channels and backgrounds in every layer are provided in Table 2.

Modeling of pore volume and permeability dependant stress in ECLIPSE

Reduction in PV and permeability due to variation in fluid pressure were implemented using the keyword ROCKTAB. The variation was assumed to be irreversible by applying the IRREVERS option in the ROCKCOMP keyword. Fig. xx shows the PV and permeability-multipliers used in this work for the different rock types. The multipliers were calculated based experimental data and the permeability reduction model presented in the previous section (eq. [1]).

Flow functions used in the simulations

Fig. Xx-xx depicts the relative permeability functions and the G/O capillary function used in the simulations (G/O capillary pressure was included due to its increase with reduced fluid pressure). The relative permeability functions are typical for Brent type sandstone.

Two 2-phase runs (oil and water) were also performed using static permeability values similar to permeability values corresponding to fluid pressure equal to 327 bara (initial pressure) and 100 bara (permability values were corrected by using the transmissibility multipliers in the rocktables). The same relative permeability functions as in the DP were used in these simulations, again neglecting oil-water capillary pressure.

Production schedules

The reservoir is produced for 55 years from 1980 to 2035 at a steadily decreasing oil rate with correspondingly higher WOR. A DP production scheme is evaluated from year 2005 when oil production rate is 4,600 m^3/day, gas production rate 420,000 Sm^3/day and WOR is equal to 0.747. The DP scheme is initiated by shutting off the water injection (initial injection rate was 6,400 m^3/day) and reducing the minimum bottom hole pressure (195 bara initially) by approximately 5 bar/month stepwise over a time period of 3 years until it reaches 40 bara. The initial fluid pressure of 327 bara decreased to 230 and 140 bara in the beginning of 2008 (just after the DP scheme was implemented) for the base case and the DP cases, respectively. To study the impact of decreasing $k_{channe}l/k_{background}$ ratio (permeability homogenization) on the flow pattern, two runs using static permeability values were also performed without any DP. The water injection rate was adjusted so that the water breakthrough occurred almost at the same time in both runs. The purpose of these runs was to avoid any possible interference with variation in gas saturation when interpreting the alteration of flow patterns when decreasing the $k_{channe}l/k_{background}$ ratio.

Results and discussion

The results presented in this section contain several DP runs to demonstrate the effect of reservoir homogenization. Discussion of the limitation of the present model regarding rock compaction and flow simulation in channel systems is discussed.

Evidence of the reservoir homogenization effect

Reservoir homogenization should most probably occur in layers of the reservoir where there is a significant difference in rock strength between the material in the high-permeability channel and the background, i.e. the homogenization effect is most likely to be observed in grid layers 10, 13, 17 or 18. Fig. xx shows oil saturation in layer 13 as a function of time for the base case (no DP) and the DP scheme (initiated from 2005). Layer 13 is comprised of weak soil channels (k_x = k_y = 5,000 mD initially) in a background of strong soil (k_x = k_y = 10 mD initially). It can clearly be seen in Fig. xx that the oil saturation is rediced more uniformly (better sweep efficiency) in the pictures were DP has taken place as the fluid pressure in the reservoir is reduced and the $k_{channel}/k_{background}$ ratio decreases due to different compaction in the channel and background. However, the pictures are disturbed due to the fact that gas evolves out of the oil phase as the pressure starts to drop. To avoid any interference from the gas phase when interpreting the results, two runs were performed using non-pressure depending permeabilities. These “static” permeabilities were derived using the permeability-multipliers in the rocktable corresponding to fluid pressures equal to 327 (multipliers equal to 1 for both layers) and 100 bara (multipliers equal to 0.1475 for the channel material and 0.60256 for the background), respectively. Fig. Xx shows the results comparing the flow patterns in layer 17 generated by these two runs 5 and 10 years after water breakthrough. The water injection rates in these runs were tuned so that water breakthrough occurred almost at the same time. It can be seen that decreasing the $k_{channel}/k_{background}$ ratio increases the sweep effect in the layer considerably. Hence, decreasing $k_{channel}/k_{background}$ ratio will increase the area sweep within a layer as expected.

These results confirm that increased sweep of oil to some degree will take place as a consequence of the permeability homogenization process. However, to demonstrate the pure effect of permeability homogenization on oil and gas recovery on field basis for a 3-phase system is a much harder task to fulfill. Fig. xx shows field oil efficiency for the generic Brent model as a function of time for the base case and the base case with DP from 2005 using both low and base case gas relative permeability curves. It can be seen that oil recovery immediately increased when initiating the DP process (oil recovery was a little bit higher for the case with low gas relative permeability as expected due to..) but the effect was rather small and a closer investigation showed that the jump could be attributed mainly to the decrease in the bottom hole pressure in the DP schedule. At this stage of the project, further analysis of the DP process calls for an improved method for simulating rock compaction and fluid flow in channel systems.

As stated previously; parameters as rock compaction and permeability reduction may not be treated sufficiently accurate by the simulator, and flow in channel systems as such is insufficiently handled by flow simulators. Rock compaction (PV-reduction) and permeability variations are accounted for in ECLIPSE using the ROCKTAB keyword to define PV and permeability-multipliers as a function of *fluid pressure*. However, PV and permeability reductions due to rock compaction seem to be better represented if they are specified as a function of effective stress (see eq. Xx). Using fluid pressure instead of effective stress is based on the assumption that the total stress is constant, which is usually not the case. A better and more realistic way to model reduction in PV and permeability is by using an external rock compaction simulator to calculate the effective stress values and use these values to create more physically correct tables for PV and permeability reductions. Hence, detailed knowledge of channel width, tortousity and permeability together with reliable rock strength parameters is therefore of great importance when evaluation the impact permeability homogenization may have on local flow properties due to DP processes.

Another challenge related to the permeability homogenization effect is to improve the understanding of simulation of flow in channel systems, i.e. the fluid exchange rate between channel and background. There is a tendency for the flow simulator to overestimate the oil production from the low-permeability background areas increasing the sweep efficiency considerably compared to what is observed in the field. How to represent or tune the transmissibility multipliers for the channel boundary grid-blocks in such a way that flow patterns in layers with channels behave more like what is observed in the field needs further investigations.

The effect of permeability homogenization may improve sweep efficiency in layers with high permeability contrast between channel and background and thereby reduce water cycling through the high permeability channels. However, increased loading of high-permeability rock channels (weak rocks) may induce pore collapse and thereby production of solid material (sand production). This aspect may also be investigated for each several case if it is believed to be of critical importance.

Conclusions

The following conclusions can be drawn from this work:

- Empirical data indicate that rock strength increases more with larger initial value of Young's modulus. This observation implies that weak rocks will compact relatively more than stronger rocks when loaded
- Empirical data for permeability vs. stress show that permeability reduction increases with increasing initial permeability value (without load). High-permeability rocks will therefore experience significantly larger permeability reduction than low-permeability rock when exposed to loading according to equation [2]
- Selective permeability reduction referred to as permeability homogenization can occur in reservoirs containing layers of high-permeability channels in backgrounds of more low-permeability rocks. This effect may increase the sweep efficiency in such layers
- Simulations performed on a generic reservoir model show evidence of the permeability homogenization effect in certain layers. However, improved effect due to permeability homogenization on field oil recovery was not easy to quantify with the generic Brent model applied
- Improved modeling of rock compaction and increased knowledge of how to model fluid flow in channel systems is required in order to investigate the effect of permeability homogenization further

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Table 1. Reservoir grid dimensions for active blocks.

Layer	DZ (m)	Grid block in y-direction	DY (m)	Grid block in x-direction	DX (m)
6	9	5	50	1	2000
7	5	6	50	2	1500
8	6	7	50	3	1100
9	6	8	50	4	600
10	7	9	50	5	300
11	5	10	50	6	150
12	20	11	50	7	150
13	4	12	50	8	140
14	3	13	50	9	140
15	20	14	50	10	140
16	20	15	50	11	140
17	4	16	50	12	140
18	5	.	50	13	100
19	23	.	50	.	100
20	5	.	50	.	100
21	20	.	50	.	100
22	22	.	50	.	100
23	30	32	50	40	100
24	30	33	50	41	100
25	38	34	50	42	100

Table 2. Initial petrophysical data for the different layers in the reservoir with no load.

Layer	Channel	Rock type	$k_{channel}$	$k_{background}$ (k_x, k_y) .	k_z	$\phi_{channel}$	$\phi_{background}$
6	No	Unconsolidated sand	15000	-	500	0.35	0.35
7	Yes	Unconsolidated sand	15000	1250	125	0.35	0.29
8	Yes	Unconsolidated sand	15000	1250	125	0.35	0.29
9	Yes	Weak sandstone	6000	250	25	0.31	0.26
10	Yes	Weak sandstone	6000	50	5	0.31	0.24
11	Yes	Relative weak sandstone	1250	50	5	0.29	0.24
12	No	Moderate sandstone	250	250	25	0.26	0.26
13	Yes	Weak sandstone	5000	10	2	0.29	0.21
14	No	Shale	0	0	1	0.1	0.1
15	No	Weak sandstone	6000	6000	500	0.31	0.31
16	No	Relative weak sandstone	1250	1250	125	0.29	0.29
17	Yes	Unconsolidated sand	15000	250	25	0.35	0.26
18	Yes	Weak sandstone	6000	50	5	0.31	0.24
19	No	Relative weak sandstone	1250	1250	125	0.29	0.29
20	Yes	Relative weak sandstone	1250	10	2	0.29	0.21
21	No	Moderate sandstone	250	250	25	0.26	0.26
22	No	Moderate sandstone	250	250	25	0.26	0.26
23	No	Strong sandstone	50	50	5	0.24	0.24
24	No	Strong sandstone	50	50	5	0.24	0.24
25	No	Very strong sandstone	10	10	2	0.21	0.21

Table 3. Overview over different runs performed.

Run #	DP	k_{rg}	S_{gc}	
1 (Base case)	No	N	2 %	
2	Yes	N	2 %	
3	Yes	Low	2 %	
4	Yes	Low	0 %	
5	Yes	Low	5 %	
6	Yes	Low	10 %	
7	Yes	Low	20 %	
8	No	2-phase	Na	
9	No	2-phase	Na	
10				
11				
12				
13				