Modeling and analysis of secondary oil recovery with water flooding from a heterogeneous reservoir through advanced wells.

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Abstract

Oil and gas will remain the most important source of energy for the foreseeable future according to DNV's Energy Transition Outlook 2021, and there is an urgent need to improve oil and gas recovery with less carbon footprint to meet the future energy demands. For the extraction of oil from the reservoir, horizontal drilling is being applied due to its higher recovery rate. These horizontal wells are advanced wells equipped with downhole Flow Control Devices (FCDs), sand screens, zonal isolation as well as monitoring and control systems, etc. FCDs are the key elements of advanced wells. The main objective of this paper is to modelling and simulation of secondary oil recovery with water flooding from a heterogeneous reservoir through advanced wells completed by main types of FCDs. In this paper, a computational study of oil recovery from a black oil reservoir is performed through modelling and simulation using the Petrel© software. The modified 'Egg Model' is used which is a synthetic heterogeneous reservoir model consisting of an ensemble of relatively small three-dimensional realizations of a channelized oil reservoir produced under water flooding conditions. A comparative analysis of reservoir models with vertical open hole wells and horizontal open hole wells is presented where it is found that the horizontal well produces 23% more oil. Also, horizontal open-hole wells are further equipped with ICDs which have reduced the water production by 91.4% and have also delayed the water breakthrough in comparison to open-hole horizontal wells.

1. Introduction

The extraction of oil from a reservoir starts by drilling a well into the oil zone. Initially, due to the high pressure, the oil is pushed towards the surface. But as the pressure inside the reservoir drops a recovery method such as water injection is required to maintain a high pressure in the reservoir. This process is called secondary oil recovery.(Lie, n.d.) To achieve cost-effective and efficient oil recovery it is necessary to maximize the well-reservoir contact, and this is achieved using long horizontal wells. However, this method has its challenges. Due to the heel-toe effect and heterogeneity along the horizontal wells, early gas and/or water breakthrough is a big challenge. To tackle this problem, advanced wells are widely used today. Advanced wells are horizontal wells equipped with downhole Flow Control Devices (FCDs), sand screens, zonal isolation as well as monitoring and control systems.(Moradi et al., 2022) FCDs are the key elements of advanced wells. The most widely used flow control device today is passive Inflow Control Devices (ICDs). To achieve a successful design of advanced wells, a suitable dynamic model of oil field and advanced wells must be developed. Generally, it is difficult to observe and understand the dynamics of fluid flow in a porous medium and this is one of the main barriers to developing such dynamic models. Also, it is not possible to measure all the parameters that influence the multiphase flow behavior inside a reservoir. Consequently, predicting how a reservoir will produce over time and respond to different drive and displacement mechanisms is important to understand. This paper aims to provide more insight into the operation of a passive inflow control device (ICD). This is achieved through the reservoir simulation of black oil production from a vertical well and then a horizontal well equipped with ICDs. The reservoir model used for simulation is an enlarged egg model developed in Petrel©.

2. Passive inflow control devices

Since the 1990s, ICDs have been used to reduce the danger of early water and/or gas breakthrough in horizontal wells. ICDs are passive flow restrictor devices that are installed on the production tubing and do not have any moving parts.(Moradi and Moldestad, 2022)

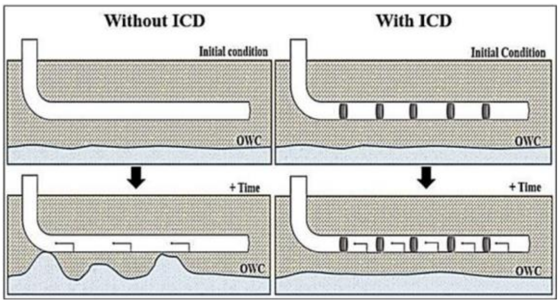

Figure 1: Mitigation of early water breakthrough through the application of ICDs.(Moradi and Moldestad, 2022)

ICDs are used to add extra pressure drop to compensate for non-uniform inflow along the length of the horizontal well. Fig. 1 depicts how such devices work to prevent early water breakout by balancing intake along the well. One type of ICD is the Orifice/nozzle-type ICD. Nozzle-type ICDs enable fluid to achieve the desired pressure drop by limiting the fluid flow. To induce flow resistance, fluid is pushed to pass through small openings (orifices) in a pipe. Fig. 2 shows the nozzle ICD where the fluid path is shown by red arrows. The reservoir fluid flows into the well through the annulus via sand screen and then through the nozzle ICD. As stated in Equation 1, when the fluid flows through the small nozzle, the pressure drop is generated as a function of fluid density, velocity squared, and the geometry of the ICD. Also, in the case of nozzle ICD, the pressure drop is not dependent on the fluid viscosity. The nozzle size and the pressure drop for a specific fluid are set for the nozzle ICD before the installation. (Elverhøy et al., 2018)

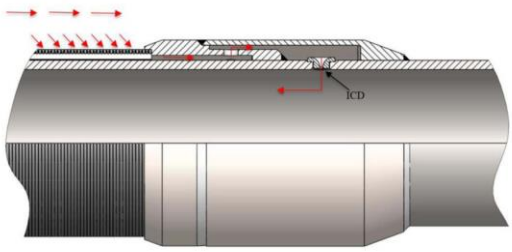

Figure 2: Flow through nozzle ICD. (Elverhøy et al., 2018)

$$\Delta P = C\frac{1}{2}\rho v^2 \quad (1)$$

$$v = \frac{q}{A} \quad (2)$$

Here, q is the volume flow rate of oil, gas, or water depending on the fluid being referred. ΔP is the pressure drop, v is the velocity, C is the geometrical constant, ρ is the density of fluid referred to, and A is the cross-sectional area of the nozzle opening.

Figure 3 shows the performance curve for the ICD which shows ΔP on the y-axis and q on the x-axis.

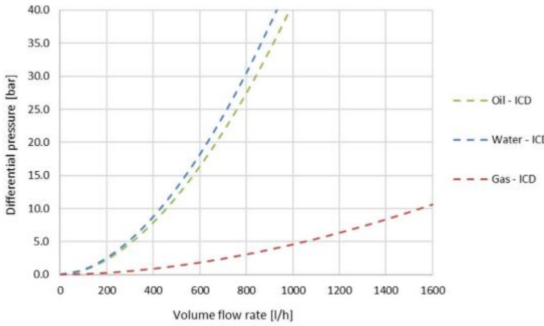

Figure 3: Performance curves for nozzle ICD for oil, water, and gas.

3. Development of Reservoir Model

The reservoir model is developed using the Petrel© 2021 software. The geological model used in this simulation case is the Egg Model. The Egg Model is a synthetic heterogeneous reservoir model consisting of small three-dimensional realizations of an oil reservoir produced under water flooding conditions with eight water injectors and four oil producers. This model has been used to demonstrate a variety of aspects related to water flooding simulations. The model consists of a reservoir with discrete permeability fields modeled with 60×60×7 = 25,200 grid cells of which 18,553 cells are active. The non-active cells are all at the outside of the model, which leaves an egg-shaped model of active cells. (Jansen et al., 2014)

The model is modified in Petrel© and is referred to as Enlarged Egg Model which is used to demonstrate the horizontal well.

3.1. Characteristics of the Enlarged Egg Model.

For simulation of oil production through vertical and then horizontal wells a heterogeneous reservoir model namely the Enlarged Egg Model is created in Petrel©. The datum of the reservoir is at -4000 m. Each grid block has a width and length of 40 m and a height of 8 m. The model expands 2400 m in x and y directions, while the height is 56 m with 7 layers. Fig. 4 shows the Enlarged Egg Model created in Petrel©.

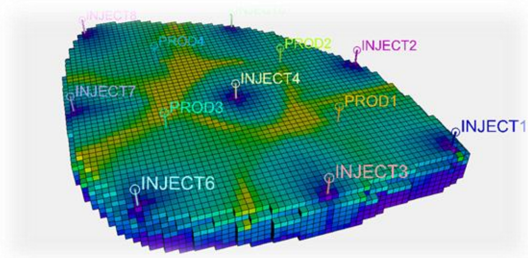

Figure 4: Enlarged Egg Model developed in Petrel©.

The Permeability of the reservoir in the x-direction is equal to the permeability in the y-direction which is equal to 500mD. The permeability in the zdirection is 10 % of the permeability in the x/y direction. Since the reservoir is heterogeneous it has high and low permeability zones which forms the channels as shown in Fig. 5.

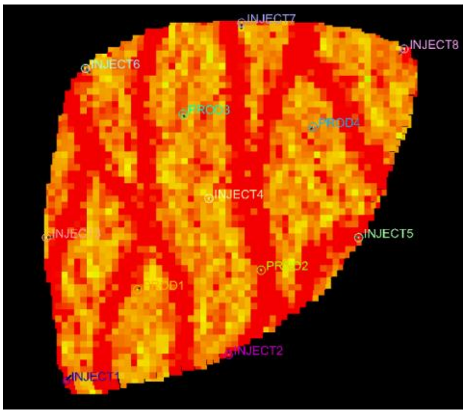

Figure 5: Highly permeable channels.

Tab. 1 shows the characteristics of the reservoir model used for simulation.

Table 1: Reservoir characteristics.

Variable	Value	Unit
Porosity	0.2	-
Oil compressibility	1.1×10^{-10}	Pa^{-1}
Rock compressibility	0	Pa^{-1}
Water compressibility	1.0×10^{-10}	Pa^{-1}
Oil dynamic viscosity	5.0×10^{-3}	Pa s
Water dynamic viscosity	1.0×10^{-3}	Pa s
End-point rel. perm., oil	0.8	-
End-point rel. perm., oil	0.75	-
Corey exponent, oil	4.0	-
Corey exponent, water	3.0	-
Residual-oil satur.	0.1	-
Connate water-satur.	0.2	-
Capillary pressure	0.0	Pa
Ini. Reservoir pressure	40×10^{6}	Pa
Ini. Water satur	0.1	-
Water inj. rate/well	1650	m^3/day
Production well BHP	39.5×10^{6}	Pa
Well-bore radius	0.1	m
Simulation time	7200	day

3.2. Vertical and horizontal well patterns.

Figure 6 shows the 8 injectors (INJECT1 to INJECT8) and 4 vertical producer wells (PROD1 to PROD4) set in a staggered line drive pattern. Each well is 80 m in length vertically with a well-head at -3976 m up to the base of the reservoir at -4056m. The open hole diameter of the well is 8 inches.

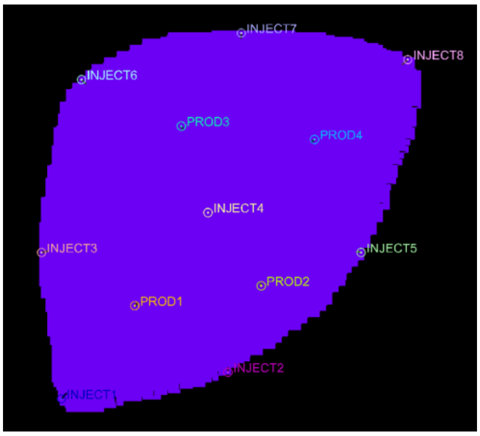

Figure 6: Pattern of producers and Injectors in the reservoir model.

The vertical producer wells are converted to horizontal wells. The horizontal wells rest in the top three layers of the reservoir. The horizontal wells are optimized by trying different positions and directions of the wells before coming to the final will pattern. The length of PROD1 is 533m, PROD2 is 696m, and PROD3 is 660 PROD4 is 634m. The pattern of the horizontal wells is shown in Fig. 7.

Figure 7: Horizontal well pattern.

3.3. Well Completion

For the open hole of 8 inches, the diameter of the casing is 7 inches, and the diameter of the tubing is 5.5 inches which rest inside the casing. The ICDs are implemented inside the compartment. The length of each compartment is 125 m which is the distance between two packers. Each compartment is equipped with 10 ICDs as shown in Fig. 8.

The ICD in this case has a cross-sectional area of 3.3653×10-6 m^2 as calculated from Equations (1) and Equation (2) where the value of ΔP and q are taken from Fig. 3.

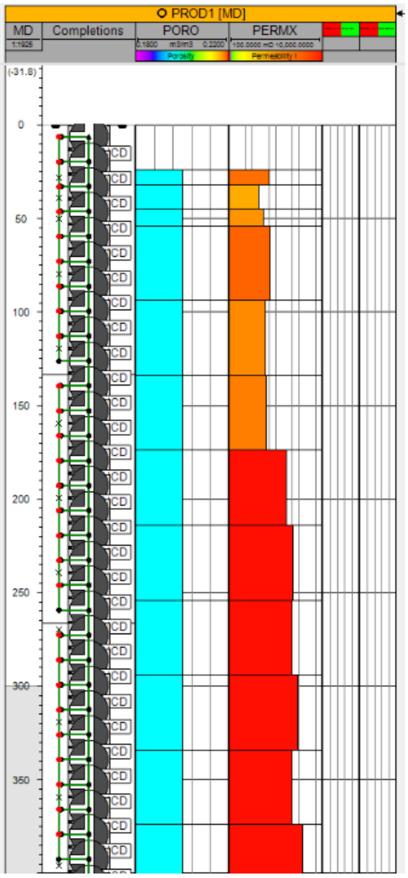

Figure 8: ICD completion developed in Petrel©.

3.4. Well segmentation.

The standard well model cannot be used to model the frictional pressure losses, acceleration pressure loss, and pressure drop across the flow control device. To overcome the shortcomings of the standard well model in the case of horizontal wells, a more rigorous well model is used which is a multi-segment well model. Muti-segment well analysis breaks the well into a series of continuous segments with 0, 1, or more connections to the reservoir grid blocks as shown in Fig. 9. Each segment will consist of four equations three material balance equations and one pressure drop equation. These equations contain the elements that define hydrostatic, acceleration, and friction effects. The equations are solving the pressure, flow rate, and fluid composition in each segment. (Youngs et al., 2010)

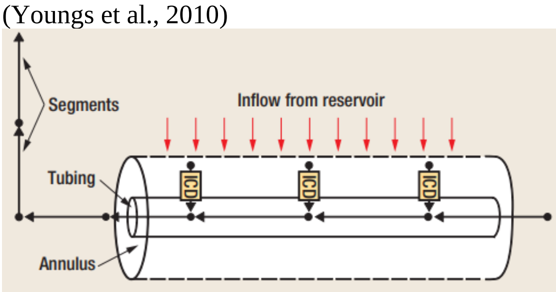

Figure 9: ICDs implemented in multisegmented model as individual segments. .(Youngs et al., 2010)

The four producers are segmented in Petrel©. A separate segment is created for each grid block. Each segment is shown by a cross sign (×) in Fig 8. The components of pressure drop in the segmentation are phase slip, friction, and acceleration.

4. Result and discussion

In this chapter results obtained from different simulation cases run in Petrel© are presented and discussed. The reservoir production is controlled by the rate of water injection which is 1650 m3/day and bottom-hole pressure (BHP) which is 395 bar. The different simulation cases compared in this chapter are the production of vertical open holes vs the production of the horizontal open hole. The other case is where all the horizontal open hole production well are equipped with the well completions like casing, tubing, packers, and ICDs. Also, all the producers are provided with segmentation so that the effect of phase slip, friction, and acceleration are taken into consideration while the production. Then the horizontal open hole is compared with the multi-segmented horizontal well equipped with ICD.

3.1. Vertical open hole vs horizontal open hole.

The result for the horizontal well is given by the solid line while the result for the vertical open hole is given by the dashed line, the green color shows the result for oil and the blue is for water.

Field production rate

From the results plotted in Fig. 10, the rate of production of oil for the horizontal well is significantly higher than the vertical producer which at its peak gives the production rate of 6000 m^3/day in the case of horizontal and 3600 m^3/day in case of vertical producers. After day 2400 the production rate in horizontal cases drops just below vertical production. This is because in the initial 2000 days most of the oil is produced. Also, the production rate of water is very high in the case of a horizontal well. The reason for the higher production rate in the horizontal well is because the horizontal well provides a larger surface area compared to the vertical well given the difference in their lengths. Also, the simulation results of all the production wells show that there is a rapid increase in oil production before the water breakthrough. This is caused because the viscosity of water is 5 times lower than that of the oil and hence water is 5 times more mobile than oil. This highly mobile water tends to push oil rapidly towards the production well which leads to a sudden increment. After the water breakthrough, the rate of production of oil starts dropping.

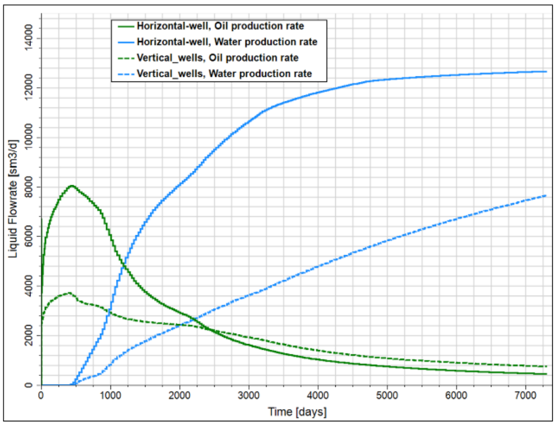

Figure 10: Production rate of oil and water for the horizontal wells vs vertical wells.

Cumulative field production.

The total production of oil and water over time of 7300 days (20 years) is shown in Fig. 11. The production of the horizontal well is higher than that of the vertical. Over time of 20 years, the horizontal well has produced a little over 7×10^7 m^3 of water and 1.6×10^7 m^3 of oil. While the vertical open hole wells have produced 3×10^7 m^3 of water and 1.3×10^7 m^3 of oil. So, the horizontal well has produced a higher quantity of fluid from the reservoir. Although the production of water is notably high in the horizontal case. This is because the horizontal wells, in this case, are not equipped with any kind of FCDs and hence these wells are prone to heterogeneity effect, and the water breakthrough is observed quite early.

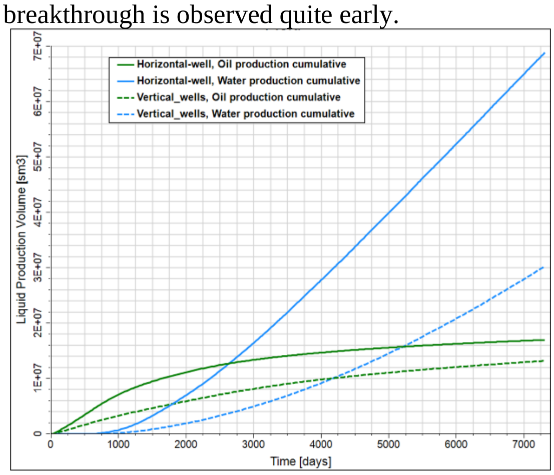

Figure 11: Cumulative production of oil and water for the horizontal well and vertical well vs time.

Tab. 2 shows the total oil and water production of the field in the case of vertical open holes and horizontal open holes.

Table 2: Cumulative production after 7300 days

Well	Oil m^3	Water m^3
Vertical	1.3×10^7	3×10^7 m^3
Horizontal	1.6×10^7	7×10^7 m^3

Dynamic results

The dynamic results in Fig. 12. show that in the case of vertical open hole lot of oil is trapped in the upper layers of the reservoir. Since the result of cumulative oil production shows no further increment. In the case of horizontal open hole more oil recovery is observed.

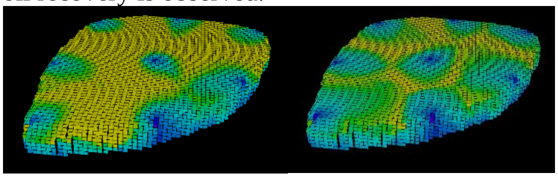

Figure 12: Dynamic simulation result of vertical (left) producer and horizontal producers (right)

3.2. Horizontal open hole well vs horizontal well with ICDs.

In this case, all the horizontal wells are equipped with ICDs, and the production and production rate of the whole reservoir field are analyzed. The result of the production rate of horizontal open hole wells is compared with the horizontal wells with ICD

Field production rate

The result of production rate over time shown in Fig. 13 shows that the rate of production after implementing the ICDs has dropped significantly in the first 2000 days. Also, the initial hype of oil production is flattened. This is because ICDs help to reduce the pressure in horizontal wells by restricting the flow of fluid through a small passage. This also helps to obtain a smoother flow profile over the length of a horizontal well. Implementation of ICD also helped to delay the water breakthrough significantly. Without ICDs the water breakthrough was seen on day 450 while after implementation of ICD the water breakthrough is obtained on day 1700. ICDs have also been helpful to reduce water production as the water production rate at its peak without ICDs is 12800 m^3/day and with ICDs is just 2000 m^3/day.

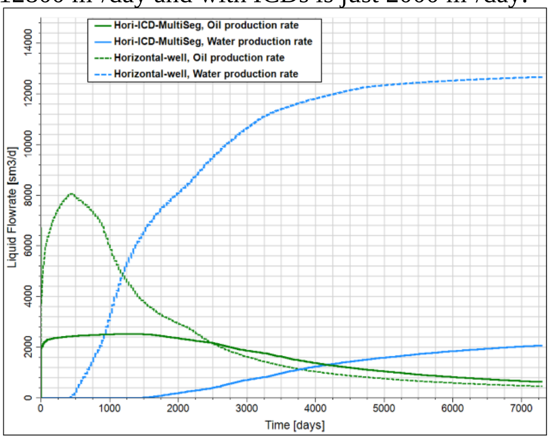

Figure 13: Production rate of oil and water for the horizontal well and horizontal well with ICDs vs time.

Cumulative field production

The simulation results for the total production of the field show that the field with open-hole horizontal wells has produced more oil and water over 20 years (7300 days). However, the lower production of oil is not a bad sign at all. Fig. 14 shows that after 7300 days the oil produced is almost 1.7 times that of oil which stands at 1×10^7 m^3 of oil in the case of horizontal wells with ICD. Whereas, in the open hole the water produced is 4 times more than the oil being produced.

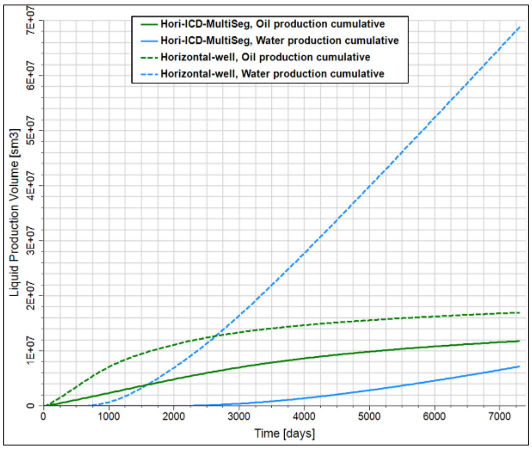

Figure 14: Cumulative production of oil and water for the horizontal well and horizontal well with ICDs.

Tab. 3 shows the total oil and water production of the field in the case of horizontal open hole and horizontal well with ICD.

Table 3: Cumulative production after 7300 days

Well	Oil m^3	Water m^3
Vertical	1.6×10^7	7×10^7 m^3
Horizontal	1×10^7	0.6×10^7 m^3

Dynamic results

The dynamic results in Fig. 15. show that in the case of horizontal open hole producers most of the oil is produced. While in case of the horizontal wells with ICD large amount of oil is still to be produced and the water is in most of the lower layers.

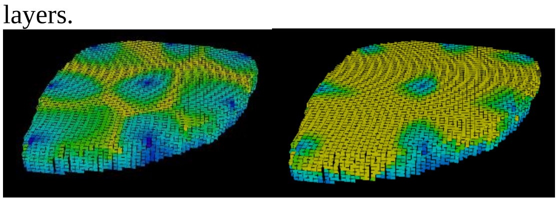

Figure 12: Dynamic simulation result of horizontal open h. (left) producer and horizontal with ICD (right)

5. Conclusion

The simulation results show that the horizontal wells help to improve the production from the reservoir by increasing the surface area in contact with the reservoir. However, they do not necessarily improve the quality of production. Replacing the open hole vertical wells with open-hole horizontal wells increased the oil production by 23% but it will also increase the production of water by 133%. This is because horizontal wells are prone to heterogeneity effect, especially in the heterogeneous reservoir which may lead to the early water breakthrough which further leads to the drop in oil production.

This effect of early water breakthrough in the open hole horizontal well can be mitigated using the FCDs such as ICD. The comparative analysis of production from horizontal wells equipped with ICDs and the horizontal well with open hole shows that the use of ICDs helps to avoid the early water breakthrough. Results show that the production of water is reduced by 91.4% in wells with ICD. Although there is also a reduction in oil production which is about 37%, the results show that more oil and less water will be produced over time which makes it more economical and environmentally friendly since the amount of water produced is reduced remarkably. Hence, it can be concluded that applying the advanced wells with ICD can improve the quality of production.

Acknowledgment

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