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Comparison of Different Method for Estimating Average Reservoir Pressure, Using Analytical& Numerical Techniques

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Abstract

A knowledge of the average reservoir pressure ($\bar{p}$) and its changes as a function of time or cumulative production is essential to determine the oil-in-place (OIP) or original gas-in-place (OGIP), to estimate reserves and to track and optimize reservoir performance. The average reservoir pressure is required in many reservoir engineering calculations such as: Material balance studies; Water influx; Pressure maintenance projects; Secondary recovery; Degree of reservoir connectivity. This project aims to calculate of average reservoir pressure for a sample reservoir, with analytical and numerical approaches, by means of Eclipse 100 and Ecrin and will compare the results. For that sample reservoir pressure versus time data are generated from the ECLIPSE 100 and Ecrin will use them to analyze the results of the buildup test and we can get average reservoir pressure. Eclipse 100 also gives us the average reservoir pressure too. our simulation on the reservoir have very good results with error of just 0.56 percent.it shows good similarity between the analytical methods that we use and nemrical methods that we use in simulators , also It is better to getting p-t data from field well testing to generating them from simulator, it can improve our results. For estimating average reservoir pressure, it is better to having single phase because of the multiphase complexities.

Key words: OIP, OGIP, Eclipse 100, Ecrin, Material balance

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1. Introduction

Estimation of oil-in-place, gas-in-place, and reserves is an integral part of reservoir development and management. This requires knowledge of initial reservoir pressure and average reservoir pressure. Initial reservoir pressure should be readily available from newly drilled wells. Unfortunately, a true value of initial reservoir pressure is rarely available. For new wells, initial reservoir pressure is often obtained from pressure buildup tests. The quality of such estimation depends on wellbore storage, the reservoir permeability and the duration of the well test. The same limitations apply to the estimation of average reservoir pressure. The problem is not too serious in case of moderate to high permeability reservoirs but it becomes practically impossible to estimate reservoir pressure in low permeability reservoirs. Moreover, average reservoir pressure values are needed as a function of production time or cumulative production. In the current economic environment, pressure buildup tests are rarely conducted. This poses a challenging situation for reservoir engineers to estimate OIP, OGIP, and reserves

The average reservoir pressure in a reservoir at a given time is an indication of how much fluid (gas, oil, or water) is remaining in the reservoir. It represents the amount of driving force available to drive the remaining fluid out of the reservoir during a production sequence. When dealing with oil the average reservoir pressure is only calculated when it is under saturated (flowing pressure above the bubble point). Average reservoir pressure can be estimated in two different ways:

1.By measuring the long-term buildup pressure in a bounded reservoir. The buildup pressure eventually builds up to the average reservoir pressure over a long enough period of time as shown below. Note that this time depends on the reservoir size and permeability (k) (i.e. hydraulic diffusivity).

2. Calculating it from the material balance equation

Several different methods of interpreting pressure-buildup data to obtain average reservoir pressure have been proposed (Muskat 1937; Horner 1967; Miller et al. 1950; Matthews et al. 1954; Dietz 1965) in the past, and in recent years some new techniques have appeared in the literature (Mead 1981; Hasan and Kabir 1983; Kabir and Hasan 1996; Kuchuk 1999; Chacon et al. 2004). [2]

I will simulate a reservoir with Eclipse 100 and Ecrin. And comparing the results

1.1. Theory

We in the petroleum industry are in the reservoir simulation revolution. As time goes on, simulators will be used more and more, so a basic understanding of reservoir modeling is essential. The engineer! Especially, must become competent in setting up simulation problems, in deciding on appropriate input data, and in evaluating the results if a reservoir is fairly homogeneous, average values of the reservoir properties, such as porosity, are adequate to describe it. The average pressure, time, and production. .behavior of such a reservoir under a solution gas drive, for example, are normally calculated by the familiar methods' of Tamer, Muskat, or Tracy. All of these methods use the material balance equation normally referred to as the MBE. A simple expression for the oil MBE is the following:

(Cumulative net withdrawal in STB) = (original oil in place in STB) — (oil remaining in place in STB)

The cumulative net withdrawal is the difference the cumulative net withdrawal is the difference between the oil that leaves the reservoir and the oil that enters it. In this basic analysis, there is no oil entering the reservoir since the boundaries are considered impermeable to flow. Thus, the MBE reduces to its simplest form. Such a reservoir model is called the tank model (Fig.1.1). It is zero dimensional because rock, fluid properties, and pressure values do not vary from point to point. Instead, they are calculated as average values for the whole reservoir. This tank model is the basic building block of reservoir simulators [1] .

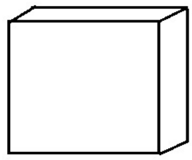


Fig 1: tank model (A.S.Odeh,SPE 2790)

Average reservoir pressure calculation can be done with two approaches; analytical and numerical approaches. Analytical is the well testing approach and numerical is the simulation approach. They have differences in methods and of course in the results. [3]

1.2 Material and methods

There are several types of reservoir simulators. Choice of the proper simulator to represent a particular reservoir requires an understanding of the reservoir and a *careful examination of the data available.* A model that fits Reservoir A may not be appropriate for Reservoir B, in spite of apparent similarities between Reservoirs A and B. A reservoir model is useful only when it fits the field case. One basis for classifying models, as discussed earlier, is the number of dimensions. The two-dimensional

Model is the most commonly used. There are several two-dimensional geometries, the most popular of which is the horizontal (x-y) geometry; but the vertical (x-z) and the radial (r-z) geometries are also used quite often.

Simulators can be classified also according to the type of reservoir or process they are intended to simulate.

There are, for example, gas, black oil, gas condensate, end miscible displacement reservoir simulators. Moreover, there are one-, two- and three-phase reservoir models. Furthermore, any of these simulators may or may not account for gravitational or capillary forces. It is not enough to choose the proper simulator with respect to dimensionality; the simulator must represent the type of hydrocarbon and the fluid phases present [1].

To find out the similarity between well testing approach and simulation approach. I would like to find out the differences between analytical and numerical approach results for a same reservoir with simulation by Eclipse 100 and Ecrin for estimating average reservoir pressure.

2. Data and Simulation

reservoir has conditions as below;

Has a gridding of:

80 1 1

Has a radial shape, and has a top of 7000ft.

it has a porosity of 0.15, permeability of 80 md, thickness of 180 ft.

the radii are;

table 1: radii of the grids of the model

0.26	0.290458561	0.337464702	0.392078046
0.4555297	0.529250004	0.614900778	0.71441278
0.830029231	0.964356383	1.120422268	1.301744957
1.512411866	1.757171895	2.041542478	2.371933959
2.755794095	3.201775946	3.719932931	4.32194546
5.021384231	5.834016145	6.77815973	7.875098077
9.149558611	10.6302705	12.35061228	14.34936426
16.67158276	19.36961573	22.50428283	26.14624639
30.37760438	35.29374098	41.00547682	47.641567

55.35160405	64.30938898	74.71685024	86.80859512
100.8571984	117.1793467	136.1429775	158.1755732
183.7737973	213.5146906	248.0686789	288.2146857
334.8576911	389.049132	452.0106036	525.1613974
610.1504944	708.8937376	823.6170188	956.9064554
1111.766687	1291.688607	1500.728054	1743.597243
1800	1800	1800	1800
1800	2000	2000	2000
2000	2000	2000	2000
2000	2000	2000	2000
2000	2000	2000	2000

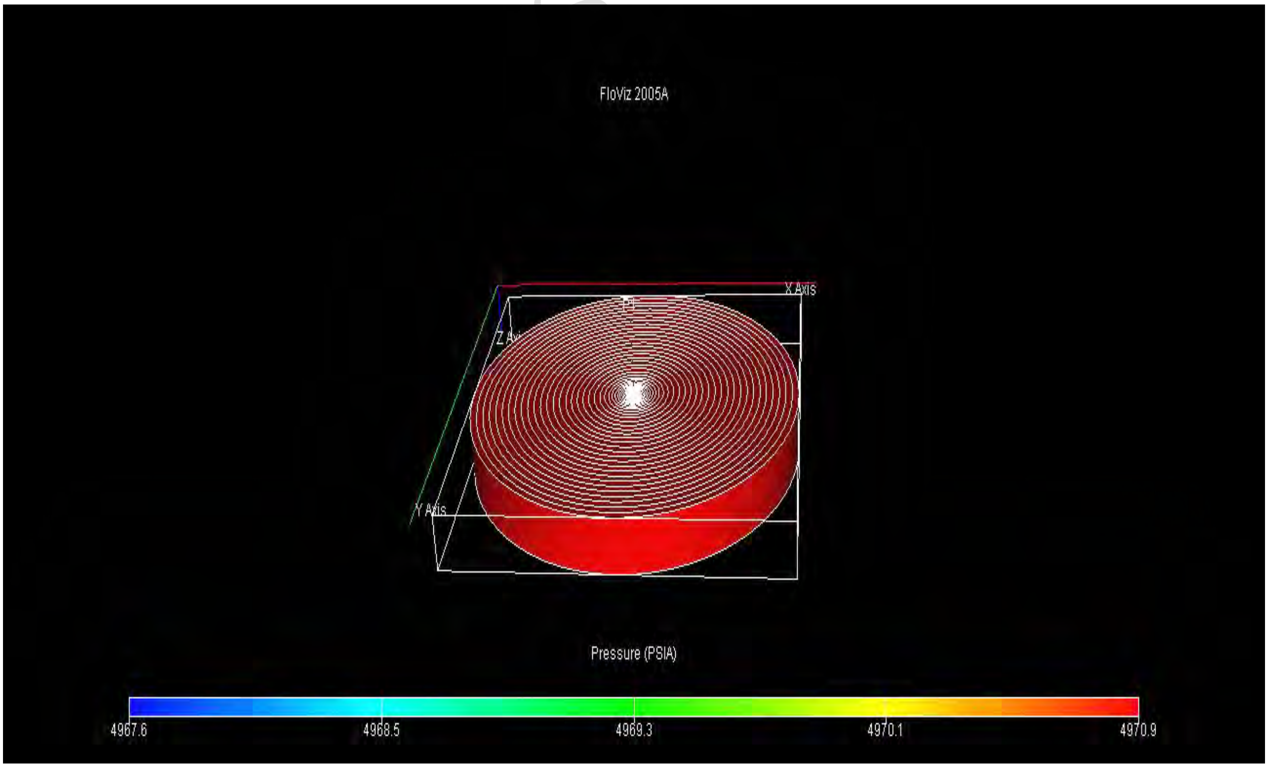


Fig 2 :model gridding image

The wellbore has a radius of .25ft.

The well was perforated in 1 1 1 grid.

Reservoir is single phase, oil.

Oil has this PVT data as following;

table 2: oil PVT data

The oil phase pressure	The corresponding oil formation volume factor	The corresponding oil viscosity
400	1.012	1.16
1200	1.0040	1.164
2000	0.9960	1.167
2800	0.9880	1.172
3600	0.9802	1.177
4400	0.9724	1.181
5200	0.9646	1.185
5600	0.9607	1.19 /
800	1.0255	1.14
1600	1.0172	1.14
2400	1.0091	1.14
3200	1.0011	1.14
4000	0.9931	1.14
4800	0.9852	1.14
5600	0.9774	1.14 /

Rock compressibility in the pressure of 3600 psi is 1E-6.

Oil has a density of 44.98 lb/ft^3.

Datum is at 7180ft and has a pressure of 5000psi. water oil contact is at 8000 ft and gas oil contact is at 2000ft.

Reference depth for bottom hole pressure of well is 7180ft. oil rate is 100 STB.

The bottom hole pressure limit is 800 psi.

I got time steps different. I got the well producing for 1.047169 days then shut-in the well for 1.0471068 days.

table 3: oil rate-time data

Time(Day)	Oil rate(STB/D)
1.0471069	100
2.0942137	0

3. Results

The graph of the oil rate is as follow:

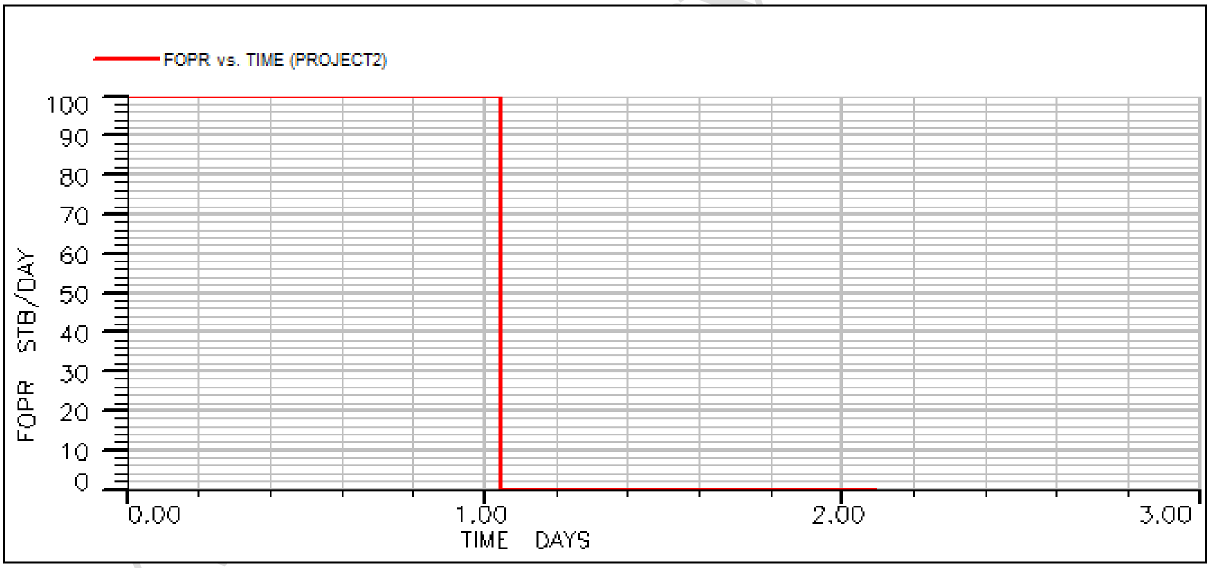


Fig 3: rate vs. time diagram in model

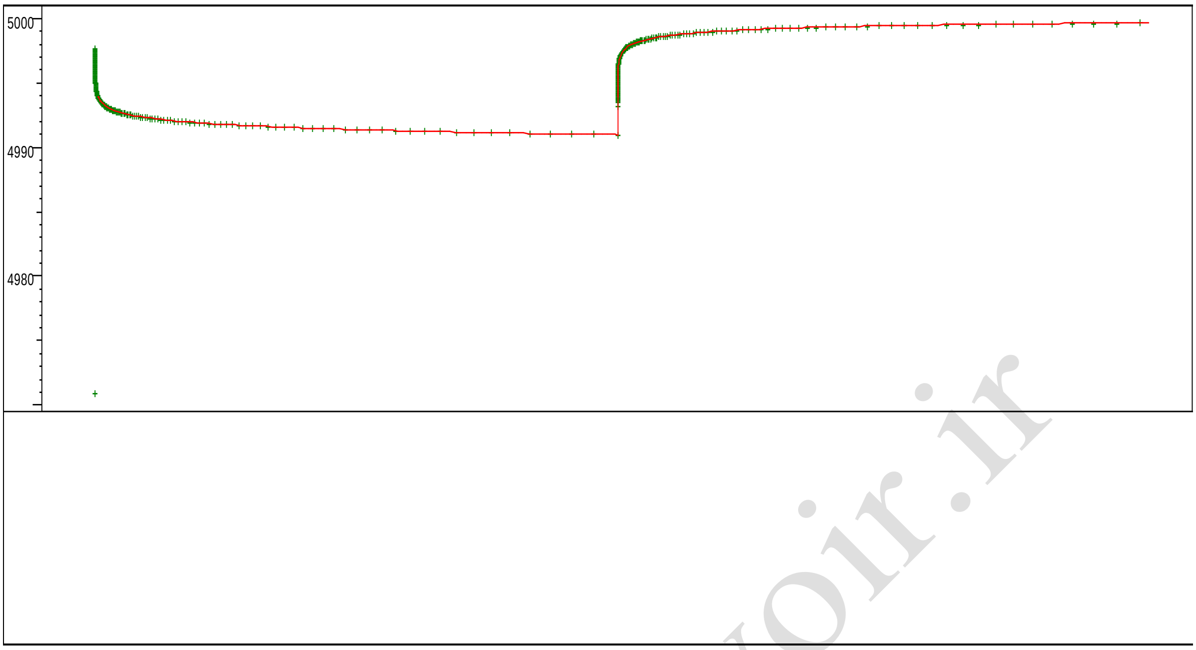
I should earn the bottom hole pressure of well versus time from Eclipse 100 and use it as data for the Ecrin.

For this purpose, I run the data file of Eclipse with such a data in problem section and earned the results of the bottom hole pressure versus time.

These are tabulated as following:

The graph of the p vs. t is as following:

The upper graph is pressure graph, and the lower is rate graph.

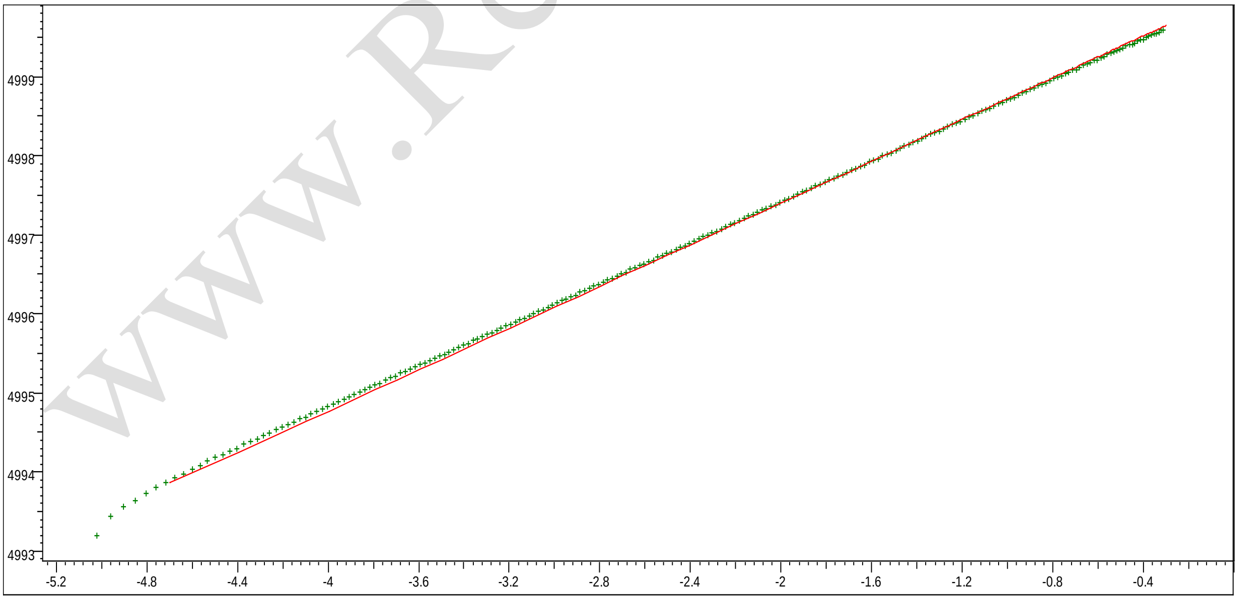


History plot (Pressure [psia], Liquid Rate [STB/D] vs Time [Day])

Fig 4: History plot, liquid rate vs. time

Know I analyzed the case with the data.

Case is vertical well, no wellbore storage, homogenous with infinite boundary.The semilog graph is as following:

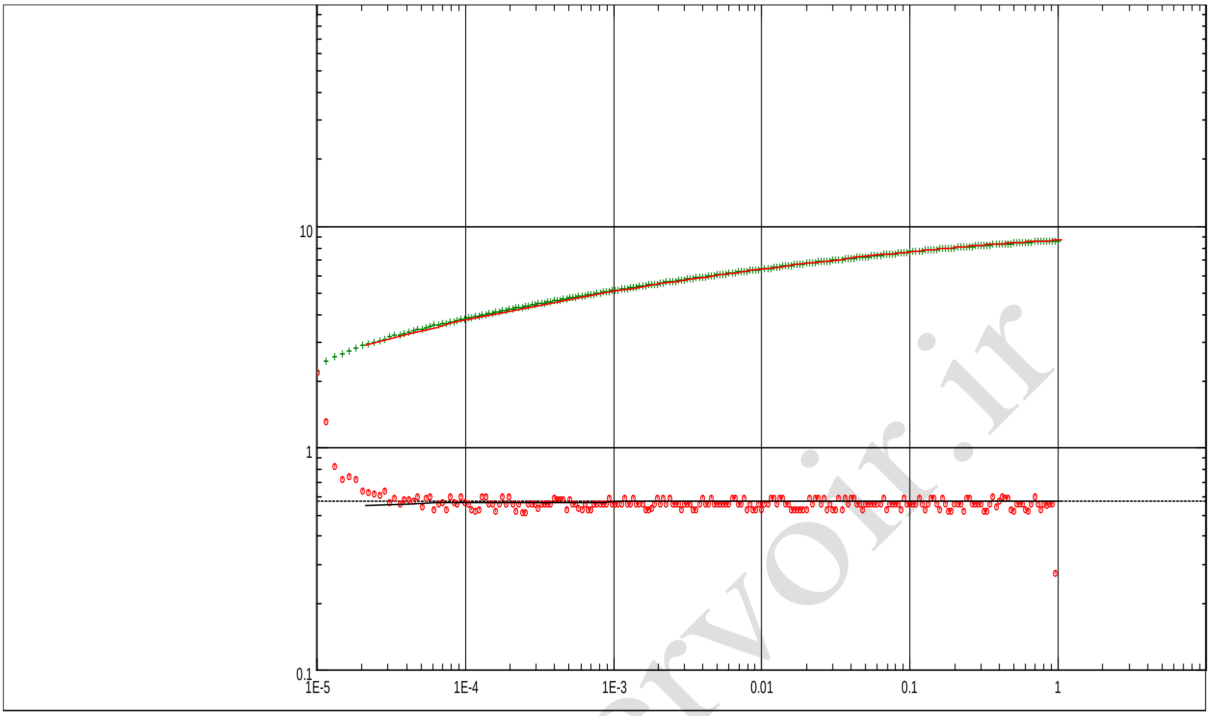


Semi-Log plot: p [psia] vs Superposition time

Fig 5: semilog plot: p vs. superposition time

straight line is the Fitting line among the data.

And the log-log graph is as following:



Log-Log plot: dp and dp' [psi] vs dt [Day]

Fig 6: log-log plot of dp and dp' vs. dt

And the lines are fitted.

The results from the Ecrin with the data have earned from Eclipse 100 and case definition have good similarity.

Results as following:

table 4: results of Ecrin

Skin	-0.783
Average permeability	78.9 md
p_i	5000.04 psi
R_{inv}	1730 ft
Test.vol.	0.25494 bcf
Δp(total)	-0.898328 psi
Δp ratio	-0.103521

Average reservoir pressure	4998.91psi
p_{wf}	4990.97psi

The results from ECLIPSE100 or the case definition data are:

table 5: results of Eclipse 100

Skin	0
Average permeability	80 md
Average reservoir pressure	4970.9psi

The results have a good similarity and the difference is about **0.56%**.

4. Conclusion

The average reservoir pressure in a reservoir at a given time is an indication of how much fluid (gas, oil, or water) is remaining in the reservoir. It represents the amount of driving force available to drive the remaining fluid out of the reservoir during a production sequence. When dealing with oil the average reservoir pressure is only calculated when it is under saturated (flowing pressure above the bubble point). Average reservoir pressure can be estimated in different ways. In this thesis have shown by an example reservoir that the results from Ecrin are reasonably equal to the results from Eclipse 100. For oil systems, the difference between the initial reservoir pressure and the average reservoir pressure vs. cumulative production or real time should have a linear relationship, if plotted on a Cartesian graph. For gas, the pseudo time should be used instead of real time. The difference between the results can be constituted from differences between analytical solution and numerical solution. Some algorithms are presented to compute $\bar{p}$ from buildup test in an objective fashion. A knowledge of the average reservoir pressure (p) and its changes as a function of time or cumulative production is essential to determine the oil-in-place (OIP) or original gas-in-place (OGIP), to estimate reserves and to track and optimize reservoir performance For estimating average reservoir pressure, it's better to having single phase because of the multiphase complexities Simulation will give a good approximation to us for estimating reservoir pressure.It's better to getting p-t data from field well testing to generating them from simulator, it can improve our results.

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