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Model identification for gas condensate reservoirs by using ANN method based on well test data

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ABSTRACT

The well testing technique has been frequently used in order to identify hydrocarbon reservoir models and estimate the associated parameters such as permeability, skin factor, etc. The analysis of well test data acquired from gas condensate reservoirs is basically different from oil and dry gas reservoirs often exhibiting a complex behavior due to the formation of condensate inside the reservoir. The first step in well test analysis is the detection of reservoir model and its boundaries usually performed through trial-and-error procedures. Previous investigations indicate that the radial composite model is the best feasible model for well test analysis of gas condensate reservoirs. The radial composite model refers to those reservoirs consisting of two separate regions: (1) a circular inner zone with the well at the center, and (2) an infinite outer zone. The best multi-layer perceptron (MLP) configuration is also selected through evaluating the accuracy criteria of various developed MLP networks i.e., measuring the mean relative (MRE) and mean square errors (MSE). The total classification accuracies (TCAs) of two methods used in this study indicate that the coupled MLP clustering model (with a TCA equal to 93.3%) has a better performance than that of the single MLP (with a TCA of 88.65%).

1. Introduction

The introduction of disturbance to oil or gas wells by variation of production flow rate, which is known as well testing, is an important technique for estimating reservoir parameters. Interpretation of well testing data from gas condensate reservoirs is very complex due to the formation of condensate bank near the wellbore where gas pressure falls below dew-point. Laboratory experiments (e.g. CVD) show that, there are 3 zones in the radial composite formations (Elsharkawy and Salah, 1998):

(1) the zone close to wellbore where condensates has a critical saturation accompanied with high mobility while the gas phase shows a very low mobility; (2) The middle zone through which the condensate saturation is increasing but gas has a low mobility and the composition is varying; and (3) The single-phase outer zone far from the wellbore with an initial condensate saturation that can be neglected since the pressure is higher than the dew-point.

These three different regions are depicted in Fig.1 (SadeghiBoogar and Masihi, 2010). Although, fluid properties in a condensate reservoir are strongly pressure dependent and multiphase flow may also occur, the common equations used for modeling these reservoirs exhibit deviations from the linear diffusivity equation. Therefore, for well testing analysis of these reservoirs showing strongly nonlinear behavior, the pseudo pressure method is proposed by Roussennac, 2001.

Three different pseudo pressure techniques are used in gas condensate reservoirs:

(1) Single-phase pseudo pressure; (2) two-phase steady-state pseudo pressure; (3) two-phase three zone pseudo pressure.

The history of all the above mentioned techniques have been briefly reviewed in the present study to select the best one for describing the gas condensate reservoirs used in this work.

Derivation of the single-phase pseudo pressure technique was performed by Al Hussainy and Ramey (1966) and Al Hussainy et al. (1966). This technique assumes only a dry gas exists near the wellbore, and if condensate formation is possible, considers it as immobile fluid. The two-phase steady state model was proposed by O'dell and Miller in 1967, and then examined by Fussel in 1973, assumed two flow regions around the wellbore. In this method, the mobility of condensate in the region which is farther than the wellbore is neglected. After modifications of Chopra and Carter in 1985, and Jones and Raghavan in 1988, the steady-state saturation-pressure relationship was suggested by O'Dell, Miller and Fussel. Derivation of the two-phase three-zone model has been accomplished by Fevang (1995). Gringarten et al. (2000) suggested the existence of a middle zone in the well test data, and also showed the difficulty of detecting this zone. Xu and Lee in 1999 represented a

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Nomenclature

b_j	bias of the *j*th neuron
D	Non-Darcy skin (day/Mscf)
exp	exponential function
f	activation or transfer function
i	point of interest for pressure derivative calculation and normalization.
k	permeability (md)
L_{rad}	Radial distance to discontinuity (ft)
$m(p)$	pseudo pressure
M	flow mobility ratio
max	maximum value of data points
min	minimum value of data points
MRE	mean relative errors
MSE	mean square errors
N	number of inputs to *j*th neuron
n	number of data points
n_j	output of *j*th neuron
Out_{net}	calculated value by ANN corresponded to input data
Out_{real}	real value corresponded to input data
p	pressure data
P	pressure derivative data
X_{max}	maximum value of pressure derivative data in each data set
X_{min}	minimum value of pressure derivative data in each data set
$X_{normalized}$	normalization of interesting pressure derivative data
R	correlation coefficient
s	skin factor
t	time function (ln Δt and modified Horner or superposition times for drawdown and build-up respectively)
x_r	*r*th input to *j*th neuron
w_{jr}	synaptic weight corresponding to *r*th synapse of *j*th neuron
W_{SC}	wellbore storage coefficient (bbl/psi)
Δt	elapsed time (h)
ω	storativity ratio
λ	interporosity flow coefficient

useful method for analyzing the well testing data, especially for the case that pressure is near or below the dew-point. They suggested a correlation between condensate saturation and pressure assuming the three-zone radial model. Since the three-zone pseudo pressure approach provides a better estimation of relative permeability, initial pressure and skin factor, it could represent the pressure-saturation relationship around the wellbore accurately (Al Ismail and Horne, 2010). In this study, the pressure versus time data is converted to a pseudo pressure using the two-phase three-zone method.

Since 1970, type curves (i.e. Pressure derivative plots) are used as a powerful tool for interpretation of well testing data (Bourdet and Gringarten, 1980; Bourdet et al., 1984; Earlougher and Kersch, 1974). Pressure response does not reveal any information about the reservoir, unless the effects of wellbore storage become insignificant. However, by combining the log–log plot of Δp vs. Δt with the pressure derivative, it becomes possible to summarize the entire analysis in a single plot (Bath, 1998).

Pressure derivative plots are more useful in comparison with the original pressure in analyzing the well testing data. One of the advantages of using the pressure derivative plots is that they provide both a qualitative picture of the well and reservoir type and also a quantitative evaluation of parameters. Before obtaining the quantitative parameters of the reservoir the type or model of the reservoir must be specified according the pattern of the pressure derivative plots. In order to identify the reservoirs model, it is necessary that the actual field derivative plot match the model plot (Amanat, 2004).

Ershaghi et al. (1993) identified a specific reservoir model using ANN. Sung et al. (1996) suggested a MLP network by using Hough transform method to identify reservoir models.

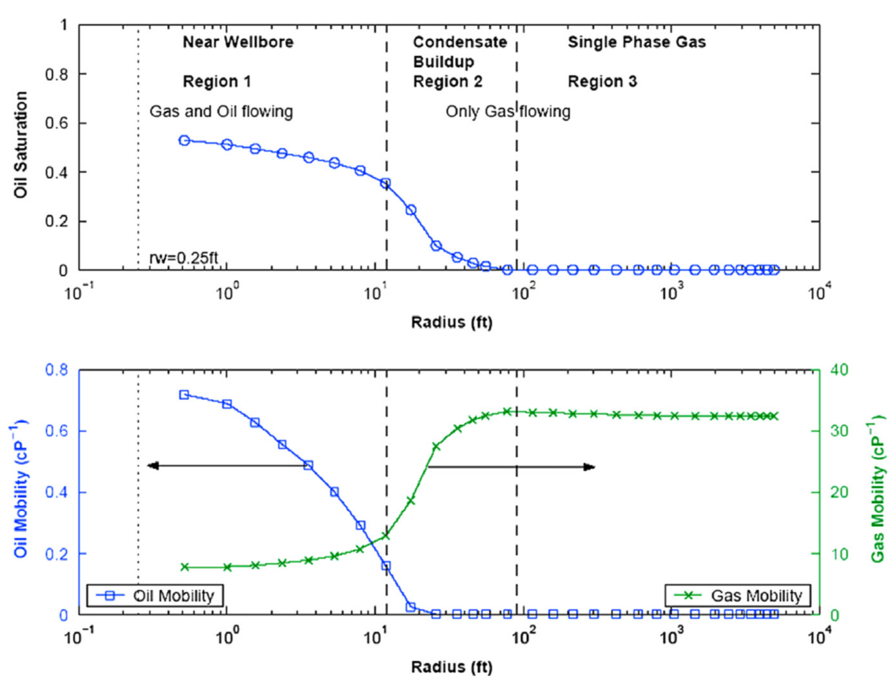

Fig. 1. The change in condensate saturation as well as gas and oil mobility in the reservoir