Journal of Natural Gas Science and Engineering 22 (2015) 150–162

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

journal homepage: www.elsevier.com/locate/jngse

Gas/condensate variable rate reservoir limits testing

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ARTICLE INFO

Article history:
Received 23 August 2014
Received in revised form
18 November 2014
Accepted 19 November 2014
Available online 28 November 2014

Keywords:
Two-phase pseudo-function
Gas/condensate
Shape factor
Boundary dominated flow

ABSTRACT

Production analysis models incorporating appropriate transport mechanisms in porous media are helpful elements in the estimation of reservoir parameters (e.g. hydrocarbon in place, average reservoir pressure, skin, and permeability) using usual and inexpensive production data. Due to different thermodynamic and flow behavior of gas/condensate reservoir, the multi-phase production data of such reservoir cannot be accurately analyzed using single-phase dry gas models.

This study presents a novel analytical model to estimate initial gas-in-place, average reservoir pressure, drainage area size and shape from boundary dominated multi-phase production data in gas/condensate reservoirs. For this purpose, the governing flow equation of multi-phase gas/condensate reservoirs was derived and linearized using new two-phase pseudo-functions and the boundary dominated flow solution was developed for variable bottom-hole pressure/rate conditions in any bounded gas/condensate reservoirs. The new equation was coupled with a material balance equation and formed a new gas/condensate production analysis model. An important feature of the proposed method is that it forms a linear plot so that by using its slope and intercept, the desired estimates of reservoir properties could be determined.

The proposed model is validated by different fine-grid compositional simulation models by changing different reservoir and fluid properties including different reservoir fluid types, relative permeability data, reservoir geometry, and production history mode. Results of this study are compared with the results of numerical simulation models and error analyses are performed. Results show that the proposed method estimates the reservoir properties quite well for all models and all errors are within engineering practices.

1. Introduction

Production analysis models incorporating appropriate transport mechanisms in porous media are helpful elements in efficient development and operation of any natural gas reservoir. Analysis of long-term variable production data could estimate reservoir parameters like hydrocarbon in place, average reservoir pressure, and drainage area size and shape using usual and inexpensive production data. Estimation of drainage area size and shape from production data (bottom-hole pressure and flow rate) has been reported for single phase flow of liquid and gas in various literature. Blasingame and Lee (1986) was the first who presented a new method of estimating drainage area size and shape from variable rate production data for single phase flow of a liquid with small and constant compressibility. Although, previous works like Earlougher (1972) work had already dealt with the problem for particular rate scheme, Blasingame and Lee developed a general variable rate approximation. They also presented a similar methodology for analyzing variable rate production data for single phase gas flow by introducing the new adjusted time and pressure functions to account for the pressure dependent changes in gas properties (Blasingame and Lee, 1988).

The concept of material balance time for analysis of variable well rate data was first introduced by Blasingame and Lee (1986) for boundary dominated oil reservoirs. For dry gas reservoirs, Al-Hussainy et al. (1966) defined pseudo-pressure and Agarwal (1979) and Fraim and Wattenbarger (1987) defined pseudo-time to linearize the gas flow equation considering pressure

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http://dx.doi.org/10.1016/j.jngse.2014.11.023
1875-5100/

List of symbols

A	area, m^2
b_{pss}	intercept defined in Eqns. (4) & (9)
B	formation volume factor, Sm^3/Sm^3
C	a conversion factor
C_A	shape factor
G	initial gas-in-place, Sm^3
G_p	produced gas, Sm^3
h	reservoir thickness, m
J	productivity index, m^3.cp/bar.day
k	permeability, mD
k_r	relative permeability
m	intercept defined in Eq. 10
n	moles
n_p	produced moles
p	pressure, bar
P^*	pressure at outer boundary of Region 1, bar
P_{dew}	dewpoint pressure, bar
$P_{p,tp}$	two-phase pseudo-pressure, bar/cp
q	flow rate, Sm^3/day
q'	total flow rate defined in Eq. (5), Sm^3/day
r	radial distance, m
r_e	reservoir external radius, m
r_w	wellbore radius, m
r_{ws}	effective wellbore radius, m
R_p	producing gas oil ratio, Sm^3/Sm^3
R_s	solution gas in oil phase, Sm^3/Sm^3
R_v	vaporized oil in gas phase, Sm^3/Sm^3
S	skin
S_g	gas saturation
S_o	oil saturation
Sw	water saturation
t	time, day
$t_{a,tp}$	two-phase pseudo-time, day
$t_{acr,tp}$	two-phase material balance pseudo-time, day
u	darcy velocity, m/day
z	deviation factor
φ	porosity
μ	viscosity, cp
ρ	density, kg/m^3
ρ'	molar density, $mole/m^3$

Subscripts

cr	constant rate
D	dimensionless
g	gas
gg	gas component in gas phase
go	gas component in oil phase
i	initial conditions
o	oil
og	oil component in gas phase
oo	oil component in oil phase
sc	standard conditions
tp	two-phase
w	water
wf	well flow

Superscripts

—	average

dependency of gas properties. For variable gas rate conditions, material balance pseudo-time was introduced by Palacio and Blasingame (1993).

Gas/condensate reservoirs exhibit different thermodynamic and flow behavior in porous media and cannot be modeled as simple as dry gas reservoirs. In these reservoirs, when the wellbore pressure falls below dew point pressure, condensate drops around the well and based on the Fevang and Whitson study (1996), three regions are developed. In the first region near the wellbore, both the gas and oil phase are flowing, but in the second region, the oil phase saturation is below critical saturation and only the gas phase is flowing. In the third region, only the gas phase is present. The amount of liquid phase present depends not only on the pressure and temperature, but also on the composition of the fluid. A lean gas/condensate has low amounts of heavy components and could produce a small volume of the liquid phase, less than 100 bbl per million ft^3 (561 m^3 per million m^3), in the reservoir when pressure is reduced below the dew point pressure. A gas/condensate comprising significant amounts of heavy hydrocarbon products is rich and can produce relatively large volumes of condensate, generally more than 150 bbl per million ft^3 (842 m^3 per million m^3) (Fan et al., 2005). The lower limit of the initial producing gas-oil ratio for a gas/condensate is approximately 3300 scf/STB. The upper limit is not well defined and values of over 150,000 scf/STB have been observed. There are no established boundaries in the definitions of lean and rich and these figures should be taken merely as indicators of a range. An initial producing gas-oil ratio of 3300–5000 scf/STB indicates very rich gas/condensate, one which will condense sufficient liquid to fill 35% or more of the reservoir volume. Moreover, an initial producing gas-oil ratio of 150,000 scf/STB indicates very lean gas/condensate. A very rich gas/condensate generates more than 300 bbl per million ft^3 liquid (1683 m^3 per million m^3) and a very lean gas/condensate generates less than 7 bbl per million ft^3 liquid (39 m^3 per million m^3) (McCain, 1990).

Due to presence of two phases in gas/condensate reservoirs, estimating drainage area size and shape from multi-phase production data analysis using dry gas techniques will introduce enormous errors. The only published study on production data analysis of gas/condensate reservoirs is by Sureshjani and Gerami (2011). In their study, a new analytical model based on the concepts of modern production decline analysis techniques was developed to estimate the average reservoir pressure and initial gas-in-place from production data. They assumed the retrograde fluid is composed of two components, which are surface dry gas and surface dead oil and the formulations of their study were only developed for gas component. In the current study, a new analytical model to analyze the multi-phase gas/condensate production data considering gas and oil phases simultaneously is developed to estimate drainage area size and shape. Rather than focusing on a particular rate scheme, in this study a general variable rate solution was developed that yields accurate results for typical production situations. There is no published study about reservoir limits testing in multi-phase reservoir. As was described, Blasingame and Lee (1986) presented the results of their study about reservoir limits testing of oil reservoir and in 1988, presented the results of similar study about gas reservoir. Unfortunately, there is no study about reservoir limits testing of gas/condensate reservoirs. In current work, reservoir limits testing of gas/condensate reservoir was studied while the effect of oil phase was included in the developed model as well.