Practical Natural Gas Engineering

R.V. Smith

Practical Natural Gas Engineering

R. V. Smith

PennWell Books
PennWell Publishing Company
Tulsa, Oklahoma

Dedicated to
*Maxine, Carol,
and Janet*

PennWell Publishing Company
1421 South Sheridan Road/P. O. Box 1260
Tulsa, Oklahoma 74101

Library of Congress Cataloging in Publication Data

Smith, R. V. (Robert Vincent), 1913–
Practical natural gas engineering.

Includes bibliographical references.
1. Gas, Natural. 2. Gas wells. I. Title.
TN880.S63 1983 622'.3382 82-24684
ISBN 0-87814-225-8

Printed in the United States of America

1 2 3 4 5 87 86 85 84 83

ACKNOWLEDGMENTS

Special acknowledgment is due Mr. Elmer E. Templeton for his suggestion that a book such as this was needed and for his encouragement and prodding to complete the book. Mr. M.J. Fetkovich reviewed chapters 6, 7, and 8 and made many helpful suggestions, including the suggestion that type curves be used to analyze pressure drawdown tests. Many others made contributions. Also, the privilege of working many years as a natural gas engineer for Phillips Petroleum Company contributed to the writing of the book.

The following organizations graciously gave permission to use material from their publications.

American Gas Association
American Petroleum Institute
Corporation Commission of the State of Oklahoma
Gas Processors Suppliers Association
Interstate Oil Compact Commission
Pacific Energy Association, formerly
California Natural Gasoline Association
Society of Petroleum Engineers of AIME

CONTENTS

1 Introduction to Natural Gas Engineering

Natural gas engineering is the art of recovering a maximum amount of gas from a reservoir and bringing the gas to the surface at as high a pressure as practical. Both objectives should be accomplished as efficiently and economically as possible. Natural gas engineering also includes forecasting the future performance of reservoirs and the future production from gas wells. The ability to forecast the volumes and the pressures at which the gas is available from wells and reservoirs with an acceptable degree of accuracy is extremely important to the natural gas industry.

Natural gas engineering differs very little from conventional reservoir engineering for oil reservoirs. The principal differences are the units used to describe the production process and the effect of pressure-volume-temperature relationships on the behavior of gas as it flows in porous media and in pipelines. Also, natural gas engineering for the most part is concerned with the single-phase flow of an extremely compressible fluid as compared to oil reservoirs. Nevertheless, it is easy to convert calculations for an all-liquid system to a gaseous system. Progress in natural gas engineering has been hindered to some extent by its preoccupation with the so-called back pressure test and the unavoidable conclusion that gas wells showed evidence of non-Darcy flow.

Although papers published in the 1940s have concluded that gas flow in porous media and gas flow into wells could exhibit non-Darcy behavior, many engineers have taken the position that non-Darcy behavior is a result of the changes in viscosity and compressibility of the gas as it moves to the well. This divergence in views, along with the preoccupation of natural gas engineering with well testing, has proved to be a major stumbling block to natural gas engineering progress. The work of Al-Hussainy, Ramey and Crawford and the work of subsequent investigators have shown that adequately handling changes in viscosity and compressibility still leaves evidence of non-Darcy behavior in the flow of gas to wells.* Further, an understanding of the flow of liquids in porous media has proved that there are no shortcuts to stabilization or magic tests that give the stabilized characteristics of a gas well in a short period of time. Thus, the author believes there is no fundamental difference between the behavior of wells producing liquids and wells producing gas.

The author has attempted to bridge the gap between the results of empirical testing and theory of unsteady-state flow in porous media and thus perhaps to close the gap between conventional reservoir engineering and an understanding of the behavior of gas wells. The latter becomes very important with the recent prices of natural gas and the subsequent push to produce lower-capacity wells at lower-than-ever pressures. The net result has been to increase the importance of natural gas engineering.

Since the author assumes that the reader has some knowledge of reservoir engineering as applied to oil reservoirs and may have had several courses in reservoir engineering, many of the principal subjects in reservoir engineering have not been emphasized. For example, geology has not been mentioned, and the more-technical features of core analysis and results have not been discussed in detail. Instead, the emphasis has been on the behavior of gas wells and gas reservoirs.

RESERVES

The reader will note that the author has avoided the use of the terms *reserves* and *recoverable reserves*. Historically, common practice has been to estimate recoverable gas reserves to be 85% of the gas in place in a dry gas reservoir. Assuming that the West Panhandle and Hugoton fields of Texas had a rock pressure of 435 psig at discovery (shutin pressure at the wellhead), the 85% recovery factor indicates an abandonment pressure at a wellhead shutin pressure of about 65 psig. Many wells in those fields are now approaching the magic pressure of 65 psig, but there has been no movement to abondon the wells. Any sensible observer of practices in the gas industry knows that gas wells are abandoned when current income does not cover current costs of operations.

Historically, recoverable reserves for gas reservoirs have been determined by one or more of the following methods:

1. Volumetric methods with abandonment at an arbitrary shutin pressure

* Reference 7, chapter 7

2. Extrapolation of pressure-cumulative-production curves to an arbitrary abandonment pressure
3. Extrapolation of production rate-time decline curves to an abandonment rate of production
4. Type curve analysis based on theoretical producing rate-time curves

The author contends that recoverable reserves for gas can be determined only by a sensible forecast of production down to a limiting rate of production as determined by economic conditions. Therefore, methods for forecasting production from gas wells have been emphasized.

PRESSURE AND TEMPERATURE BASES FOR GAS MEASUREMENT

The natural gas industry has been plagued by an inability to agree upon a standard pressure base for gas measurement. It is not uncommon to find that production is reported to the regulatory body on one pressure base, reserves are kept on a second pressure base, and heating value is reported on a third pressure base. Further, the pressure base for reporting production varies from state to state. The province of Alberta, which has adopted the SI metric system, uses a measurement pressure base of 101.325 kPa and 15°C, which is equivalent to 14.696 psia and 59°F. Fortunately, the industry in the United States has not been plagued with a multitude of temperature bases for measurement purposes. The author has arbitrarily selected a pressure base of 14.65 psia and a temperature base of 60°F; all gas volumes used herein exist at these standard conditions unless stated otherwise. This has been done in the belief that most readers are required to report test results and production as standard cubic feet at 14.65 psia and 60°F.

NOMENCLATURE*

Symbol	*Description*	*Oil-field Units*
A	constant, equations 5–7 and 5–8	—
A	cross-sectional area	sq ft
A_1–A_8	constants, equation 2–11	—
A_x	availability function, equation 9–23	—

* Standard symbols proposed by SPE-AIME. Exceptions are made where strict conformance with the standard may be confusing.

Symbol	Description	Oil-field Units
b	gas constant for 1 lb of gas	cu ft, psia, $°R^{-1}$, lb^{-1}
B_g	formation volume factor for gas	—
B_1	constant, equation 5–7	—
B_2	constant, equation 5–8	—
cf	volume	cu ft
c'	coefficient, equations 4–4 and 4–5	—
c_g	compressibility of gas	$psia^{-1}$
c_t	total compressibility of a system	$psia^{-1}$
C	orifice-plate coefficient, problem 4–1	—
C	coefficient, equations 7–1, 7–3, 7–7, etc.	—
C (t)	coefficient, equation 7–2	—
d	diameter	in.
d	internal diameter of pipe	in.
d_1	outside diameter of inner pipe, annular space	in.
d_2	inside diameter of outer pipe, annular space	in.
D	internal diameter of pipe	ft
E	internal energy	ft-lb
f	coefficient of friction	—
$\sqrt{1/f}$	transmission factor	—
F	frictional resistance	ft-lb
°F	temperature, degrees Fahrenheit	°F
F_b	basic orifice factor	—
F_g	specific gravity factor	—
F_m	manometer factor	—
F_p	basic orifice prover factor	—
F_{pb}	pressure base factor	—
F_{pv}	supercompressibility factor	—
F_r	Reynolds number factor	—
F_r	factor defined by equation 5–11	—
F_t	flowing temperature factor	—
F_{tb}	temperature base factor	—
F_{tf}	flowing temperature factor	—

Symbol	*Description*	*Oil-field Units*
g	gravitational conversion factor (32.17)	ft/sec^2
G	volume of gas at standard conditions (14.65 psia and 60°F)	cu ft
G_i	gas initially in place	cu ft
G_p	gas produced	cu ft
h	thickness	ft
h_w	differential pressure	in. of water
H	elevation or difference in elevation	ft
I_n	factor used in chapter 5	—
ID	internal diameter	in.
k	permeability (chapter 6 only)	darcy
k	reservoir permeability	md
k	absolute roughness characteristic	in.
K	discharge coefficient	—
K	term in equation 2–1	—
ℓn	logarithm to base e	—
log	logarithm to base 10	—
L	length	ft
m	slope of straight-line, semilog coordinates	psia^2/cycle or psia^2/cp/cycle
m(p)	real gas potential	psia^2/cp
M	thousands	—
M	molecular weight	lb/lb-mole
M_a	average molecular weight air = 28.964	lb/lb-mole
M_i	molecular weight of component i	lb/lb-mole
M_g	molecular weight of gas	lb/lb-mole
Mcf	thousands of cubic feet	10^3 cf
MMcf	millions of cubic feet	10^6 cf
Mcfd	flow rate	10^3 cf/day
MMcfd	flow rate	10^6 cf/day

Symbol	*Description*	*Oil-field Units*
n	quantity of gas	lb-mole
n	coefficient in equations 7–1, 7–2, 7–3, etc.	—
N	mass rate of flow	lb/sec
N_{Re}	Reynolds number	—
OD	outside diameter	in.
p	pressure	psia
(p)	indicates preceding variable is a function of pressure	—
Δp^2	difference in pressures squared	$psia^2$
p_b	base pressure for gas measurement	psia
p_{cf}	pressure on casing at surface—no packer with flow-through tubing	psia
$\bar{p}_{cs}$	stabilized shutin pressure at surface on casing—no packer	psia
p_m	low base pressure for real gas potential	psia
p_m	measurement pressure	psia
p_{pc}	pseudocritical pressure	psia
p_{pr}	pseudoreduced pressure	—
$\bar{p}_R$	stabilized shutin reservoir pressure	psia
p_{tf}	surface pressure on tubing, flow through tubing	psia
p_{tfd}	deliverability pressure	psia
$\bar{p}_{ts}$	stabilized shutin pressure at surface on tubing, equation 7–7	psia
p_{wf}	bottom-hole flowing pressure	psia
p_{ws}	bottom-hole shutin pressure	psia
q	energy lost to surroundings	ft-lb
q	volumetric rate of flow	cfd
q_d	deliverability	Mcfd
q_D	dimensionless rate of flow	—
q_h	rate of flow	cf/hr
q_k	rate of flow	Mcfd
q_m	rate of flow	MMcfd
q_o	rate of flow for oil	bbl/day
q_{of}	open flow potential, equation 7–8	Mcfd

Symbol	*Description*	*Oil-field Units*
r	radius	in.
r	internal radius of pipe	in.
r_w	wellbore radius	ft
r'_w	effective wellbore radius	ft
R	gas constant	cu ft, psia, °R^{-1}, lb $mole^{-1}$
°R	°F + 460, degrees Rankine	°F + 460
R_g	gas to hydrocarbon liquid ratio	cu ft/bbl
s	factor in equations 5–19 and 5–20	—
s	van Everdingen skin effect, equation 8–23	—
S_w	water saturation	fraction
t	time (check usage)	days, years
(t)	preceding variable is function of time	—
t_D	dimensionless time	—
T	absolute temperature, °F + 460 = °R	°R
T_b	base temperature for gas measurement 60°F or (°F + 460) depending on usage	°F, °R
T_{pc}	pseudocritical temperature	°F + 460
T_{pr}	pseudoreduced temperature	—
u	velocity	ft/sec
$\bar{u}$	average velocity	ft/sec
v	specific volume	cu ft/lb
V	volume (chapter 6, cc)	cu ft
V_g	volume containing gas	cu ft
V_L	vapor volume equivalent of hydrocarbon liquid	cu ft/bbl
W	weight (chapter 6)	gm
W	energy supplied to system	ft-lb
W_f	energy loss caused by friction or irreversible energy loss	ft-lb
x	ratio of pressures $\bar{p}_R/p_{wf}$	—
x_f	fracture length	ft

Symbol	*Description*	*Oil-field Units*
X	see equation 2–21	—
X	length of pipe	miles
y_i	mole fraction of component i in gas mixture	—
Y	see equation 2–21	—
Y	expansion factor in gas measurement	—
z	compressibility factor	—
$\bar{z}$	compressibility factor at average conditions	—
γ_g	gas specific gravity (air = 1.000)	—
γ_{gf}	gas gravity of flowing fluid in a well	—
γ_o	specific gravity of oil referred to water	—
Δ	increment of the following variable	—
Δp^2	difference in pressures squared	psia^2
μ	viscosity	cp
$\bar{\mu}$	viscosity at average conditions	cp
ρ_a	density of dry air	lb/cu ft
ρ_g	density of gas	lb/cu ft
ρ_{pr}	pseudoreduced density, equation 2–10	—
ρ_L	density of liquid	lb/cu ft
ρ_1	density (chapter 2)	gm/cc
ϕ	porosity	fraction

Subscripts

a	air	—
b	standard or base conditions for gas measurement	—
b	bulk (chapter 6)	—

Symbol	*Description*	*Oil-field Units*
cs	casing, shutin (with pressure)	—
cf	casing, flowing (with pressure)	—
d	deliverability (with pressure)	—
e	external boundary	—
f	flowing	—
f	friction	—
f	fracture	—
g	gas	—
i	initial	—
i	i^{th} component	—
k	thousands	—
L	liquid	—
m	millions	—
m	measurement (with pressure)	—
ma	matrix	—
n	n^{th} term	—
o	oil	—
of	open flow	—
p	pore, see equation 6–1	—
p	prover	—
pc	pseudocritical	—
pr	pseudoreduced	—
r	related to radius, equation 5–11	—
R	reservoir	—
t	total system	—
tfd	deliverability (with pressure)	—
tfp	pipeline pressure	—

Symbol	*Description*	*Oil-field Units*
w	water	—
w	wellbore	—
wf	bottom-hole flowing (with pressure)	—
ws	bottom-hole shut in, (with pressure)	—
x	indicates a function of *x*, equation 9–23	—
1,2,3, etc.	indicates time or position	—