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The Importance of Water Influx in Gas Reservoirs

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ABSTRACT

Although it has long been realized that gas recovery from a water-drive gas reservoir may be poor because of high residual saturations under water drive, it appears that only limited information on the subject has been available until recently. This study was performed to show the quantitative potential importance of water influx. Results indicate that gas recovery may be very low in some cases: perhaps as low as 45 per cent of the initial gas in place. Gas recovery under water drive appears to depend in an important way on: (1) the production rate and manner of production; (2) the residual gas saturation; (3) aquifer properties; and (4) the volumetric displacement efficiency of water invading the gas reservoir.

The manner of estimating water-drive gas reservoir recovery can vary considerably. Examples are: the steady-state method, the Hurst modified steady-state method, and various unsteady-state methods such as those of van Everdingen-Hurst, Hurst, and Carter-Tracy. The Carter-Tracy water influx expression was used in this study.

In certain cases, it appears that gas recovery can be increased significantly by controlling the production rate and manner of production. For this reason, the potential importance of water influx in particular gas reservoirs should be investigated early to permit adequate planning to optimize the gas reserves.

INTRODUCTION

In recent years, the economic importance of natural gas production has become increasingly apparent. This has been evidenced by more intensive exploration efforts aimed at gas production, and exploitation of both deep, as well as low-permeability gas reservoirs. Technical developments such as deep-penetration fracturing have made development of such formations economically feasible. Unfortunately, water influx has forced abandonment of a number of gas reservoirs at extraordinarily high pressures.

Although reservoir engineering methods for estimating water influx have long been available, it appears that application of these methods to the water-drive gas reservoir has been sporadic.[1-3] Available methods for estimating water influx which can be applied to the water-drive gas reservoir problem include the steady-state method,[4] the Hurst modified steady-state method,[5] and various unsteady-state methods such as those of van Everdingen-Hurst,[6] Hurst,[7] and Carter-Tracy.[8] Interesting applications of these solutions to gas reservoir and the aquifer gas-storage problems have appeared recently.[3,12,18]

The experimental study of residual gas saturations under water drive by Geffen *et al.* in 1952 indicated that residual gas saturations could be extremely high.[9] A value of 35 per cent of pore volume is often used in field practice when specific information is not available. The study of Geffen *et al.* showed that residual gas saturation might be much higher in some cases. Naar and Henderson concluded that the residual non-wetting phase saturation under imbibition should be about half of the initial non-wetting phase saturation.[10] The Naar and Henderson result that residual gas saturation under water influx should be about half the original gas saturation is recommended as an estimate if laboratory measurements are not available.

Thus, it is clear that a considerable portion of the initial gas in place might be trapped in a water-drive gas reservoir as residual gas at high pressure. A full water-drive would result in loss of residual gas trapped at *initial reservoir pressure*. Consideration of transient aquifer behavior leads to the conclusion that high-rate production of water-drive gas reservoirs could result in improved gas recovery by reduction of the abandonment pressure. However, there appears to be little quantitative information on this possibility.

One of the few advantages of water-drive gas production appears to be improved deliverability through water-drive support of the reservoir pressure. There may also be an advantage in higher condensate recovery caused by pressure maintenance for gas-condensate water-drive reservoirs.

In view of the preceding, this study was made to assess the potential importance of water-drive in gas reservoir engineering. The Carter-Tracy approximate water-influx expression was used because this equation offers some advantages in hand-calculation which do not appear to have been generally recognized.[8] However, calculations were performed in the main with a high-speed digital computer to permit evaluation of the effect of water-drive under a large variety of conditions.

CALCULATION METHOD

Water-drive gas reservoir performance can be estimated in a manner completely analogous to oil reservoir calculations: a materials balance is written for the reservoir, and a water influx equation is written for the aquifer. Simultaneous solution provides the cumulative water influx and the reservoir pressure. When reservoir performance data (gas produced and reservoir pressures) are available, it is usually possible to match performance data to determine the initial gas in place and the water influx parameters—

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[1]References given at end of paper.

the dimensionless time constant, the water influx constant, and sometimes the size and approximate geometry of the aquifer. Because the purpose of this study is to investigate the potential importance of water-drive, only solutions required to forecast reservoir performance will be used.

A general form of the materials balance for a gas reservoir is:

$$G(B_{gn}-B_{gi})+B_w(W_{en}-W_{pn})=G_{pn}B_{gn} \quad . \; . \; . \quad (1)$$

Nomenclature is given at the end of the paper. Note however, that gas formation volume factors for Eq. 1 are expressed in reservoir barrels per standard cubic feet, while water formation volume factors are expressed in reservoir barrels per surface barrel. Often, B_w is assumed to be unity. The gas formation volume factor can be written:

$$B_{gn}=\frac{T\,p_{sc}\,Z_n}{5.615\,T_{sc}\,p_n} \quad . \; . \; . \; . \; . \; . \; . \; . \; . \; . \quad (2)$$

The Carter-Tracy approximate water influx equation is:[5]

$$W_{en}=W_{e(n-1)}+(t_{Dn}-t_{D\,n-1})\left\{\frac{B\Delta p_n-W_{e(n-1)}\,p'_D(t_{Dn})}{p_D(t_{Dn})-t_{D(n-1)}p'_D(t_{Dn})}\right\}, \quad . \; . \; . \; . \quad (3)$$

where

$$t_{Dn}=\frac{2.31\,k_w\,t_n}{\phi\,\mu_w c_t\,r_w^2}, \quad . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \quad (4)$$

$$B=1.1191\,\phi\,c_t\,h\,r_w^2\,F \quad , \; . \; . \; . \; . \; . \; . \quad (5)$$

$$p'_D(t_D)=\frac{d}{dt_D}[p_D(t_D)] \quad . \; . \; . \; . \; . \; . \; . \; . \; . \; . \quad (6)$$

The first derivative of the van Everdingen-Hurst dimensionless pressure drop is not a common function.[6] It is presented in Fig. 1 for an aquifer of infinite extent. Curve-fit equations of high precision have been published by Edwardson *et al.* for the infinite radial aquifer.[11] The Edwardson *et al.* equations are particularly useful for digital computer solution of transient flow problems. If the aquifer is known to be finite in extent, the van Everdingen-Hurst solutions can be differentiated for times when the boundary effect is felt. The derivative will approach a constant value in this case.

Eqs. 1 and 3 can be solved simultaneously to eliminate the water influx term and provide an equation relating the pressure p_n to the gas produced at time n, G_{pn}. The main utility of the Carter-Tracy influx equation, Eq. 3, is that superposition is not necessary. The water influx at any time is related to the water influx at the preceding time analytically. The solution for the pressure p_n obtained

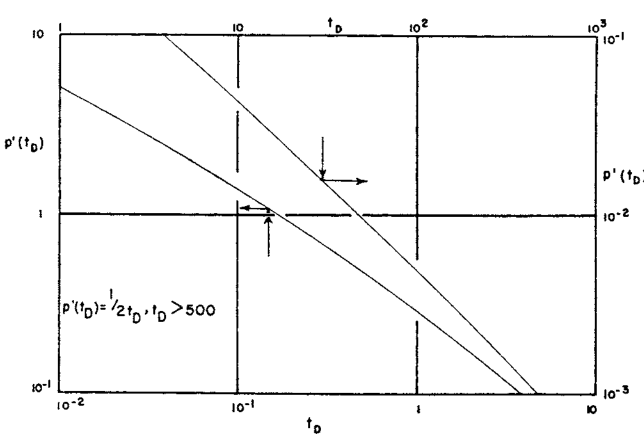

FIG. 1—$p'_D\,(t_D)$ VS t_D FOR AN INDEFINITE RADIAL AQUIFER.

from simultaneous solution of Eqs. 1 and 3 is:

$$p_n=\frac{1}{2C_n\,B\,B_w}\left\{-E_n+\sqrt{E_n^2+4(G-G_{pn})\,K\,Z_n\,C_n\,B}\right\}, \quad . \; . \; . \quad (7)$$

where

$$C_n=\frac{[t_{Dn}-t_{D(n-1)}]}{[p_D(t_{Dn})-t_{D(n-1)}\,p'_D(t_{Dn})]}, \quad . \; . \; . \; . \; . \quad (8)$$

$$K=\frac{T\,p_{sc}}{5.615\,T_{sc}}, \quad . \; . \; . \; . \; . \; . \; . \; . \; . \; . \quad (9)$$

$$E_n=GK\frac{Z_i}{p_i}+B_w\left\{W_{pn}-W_{e(n-1)}\,[1-C_np'_D(t_{Dn})]-C_nB\,p_i\right\} \quad (10)$$

Eq. 3 can be rearranged using the same nomenclature as Eqs. 8 through 10 to yield:

$$W_{en}=W_{e(n-1)}[1-C_np'_D\,(t_{Dn})]+C_nB\Delta p_n, \quad . \; . \quad (11)$$

and

$$\Delta p_n=p_i-p_n \quad . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \quad (12)$$

Eq. 7 can be solved for the pressure at time t_n for gas production G_{pn}, and then the water influx can be computed from Eq. 11. Solution of Eq. 7 is complicated by the fact that the gas-law deviation factor Z_n is a function of p_n. Thus, solving Eq. 7 requires trial-and-error, unless an analytical relationship between p_n and Z_n can be written. In some cases, Z_n can be considered a linear function of p_n over ranges of pressure. An expression similar to Eq. 7 can then be written which does not involve Z_n. However, this usually is not particularly time-saving. The trial solution of Eq. 7 is a simple trial and does not often involve more than two steps.

One further equation is required to set the end point, or abandonment condition—a material balance which states that the maximum gas recovery is equal to the initial gas in place, less gas trapped as residual gas in the watered region, less gas in regions not swept by water, but unavailable to production because of breakthrough of water into all existing producing wells. The end-point equation is:

$$G_{pm}=G\left[1-E_p\left\{\frac{S_{gr}}{S_g}+\frac{(1-E_p)}{E_p}\right\}\frac{p_m\,Z_i}{p_i\,Z_m}\right]. \quad . \quad (13)$$

Eq. 13 can be rearranged to

$$\frac{p_m}{Z_m}=\frac{(p_i/Z_i)}{E_p\left[\frac{S_{gr}}{S_g}+\frac{(1-E_p)}{E_p}\right]}-\frac{(p_i/Z_i)\,G_{pm}}{GE_p\left[\frac{S_{gr}}{S_g}+\frac{(1-E_p)}{E_p}\right]} \quad . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \; . \quad (13a)$$

In this form, it is clear that Eq. 13 expresses the end-point (p_m/Z_m) as a linear function of the ultimate gas recovery, and that the line passes through the point G, initial gas in place, at a zero value of (p_m/Z_m). This suggests a graphical solution of the water influx gas reservoir performance problem. If (p/Z) vs G_p under water drive can be estimated by any appropriate method (e.g., Eqs. 7 through 12 above), the intersection of the performance (p/Z) vs G_p plot and Eq. 13a represents the estimated ultimate gas recovery.

The water-drive gas reservoir performance calculation method presented above by Eqs. 7 through 12 is just one of a number of possible methods. See for example, Bruns *et al.*,[3] Katz *et al.*,[12] and Hubbard and Elenbaas.[18]

The Carter-Tracy form of the water influx equation (Eq. 3) does deserve some comment. It is an approximate expression resulting from solution of a superposition equation by Laplace transform methods. Carter and Tracy present complete details of the derivation in Ref. 8. Their interpretation of the approximate nature of their water influx expression appears to be too restrictive, however. The method is as accurate as any finite-difference superposition method. We have compared results from the Carter-Tracy calculation with the usual finite difference superposition methods for a number of gas reservoir cases (even including gas storage cases reported by Katz *et al.*[12]), and have found excellent agreement in all cases .

Restrictions concerning changes in water influx rate and length of incremental time periods used appear no worse for the Carter-Tracy method than for normal superposition calculations. The Carter-Tracy method does not depend upon the assumption of constant gas production rates. In the event that constant gas production rate is a valid assumption, the water influx solution presented by Hurst[7] can be modified to describe gas reservoir behavior, and is even more convenient to use than the Carter-Tracy equation.

RESULTS

Performance for a water-drive gas reservoir was computed for a reservoir of 5,000 acres in area surrounded by an infinitely-large aquifer. Detailed reservoir and aquifer conditions selected are presented in Table 1. To permit evaluation of the importance of several key parameters, performance was estimated for a range of aquifer permeabilities, reservoir production rates, initial formation pressures, residual gas saturations, and water influx reservoir invasion efficiencies. Although other parameters such as reservoir size, aquifer compressibility, etc., may also be studied, it does not appear necessary at this time to do so to establish the importance of water drive in production of a gas reservoir. Results of this study and that of Bruns *et al.*[3] provide a sufficient range of conditions to indicate the need for specific reservoir studies in particular cases.

In regard to the physical properties of the gas considered in this study, the gas-law deviation factors Z and viscosities were taken from correlations as functions of the pseudo-reduced temperatures and pressures. See Craft and Hawkins, Ref. 1, pages 20, 21 and 265.

TABLE 1—RESERVOIR AND AQUIFER PROPERTIES

Reservoir area	5000 acres
Porosity, ϕ	15% BV
Net thickness, h	100 ft
Initial water saturation, S_w	25% PV
Formation temperature	211F
Pseudo-reduced formation temperature	1.8
Gas gravity (to air)	0.65
Pseudo critical temperature for gas	373°R
Pseudo critical pressure for gas	670 psia
Radius of reservoir, r_w	8340 ft
Formation volume factor for water, B_w	1.02 res bbl/bbl
Total compressibility for aquifer, c_t	6.25×10^{-6} psi^{-1}
Viscosity of water, μ_w	0.35 cp
Base temperature for gas volumes	60F
Base pressure for gas volumes	14.7 psia
Permeability, k	5—500 md*
Initial reservoir pressure, p_i	3000—7000 psia*
Residual gas saturation, S_{gr}	25-45 per cent PV*
Volumetric displacement efficiency, E_p	65-85 per cent*

Gas-law deviation factors:

Pressure (psia)	Z
500	0.963
1000	0.933
1500	0.911
2000	0.897
2500	0.892
3000	0.900
3500	0.920
4000	0.946
5000	1.008
6000	1.083
7000	1.159

*Values varied in study to permit evaluation of importance.

Fig. 2 presents p/Z vs cumulative gas produced for various gas production rates and initial formation pressures. The aquifer permeability was 5 md; residual gas saturation was 35 per cent; and volumetric invasion efficiency was 85 per cent. The characteristic departure of water-drive gas reservoir performance from the straight-line relationship (dashed lines on Fig. 2) between p/Z and G_p for a volumetric reservoir is clearly shown. That is, the dashed lines on Fig. 2 represent zero water influx. An important feature of the curves shown, however, is the effect of production rate on the gas recovery. Each p/Z curve is carried to the cut-off point dictated by the material balance of Eq. 13; the end of the curve represents the estimated ultimate recovery. Clearly, gas recovery for the reservoir conditions used in this case would depend in a very important way upon production practices. A high production rate permits drawing down reservoir pressure before water influx completely engulfs the reservoir.

Fig. 2 also indicates the effect of initial pressure level. This can be seen more clearly in Fig. 3. The gas recovery as a per cent of initial gas in place is presented as a function of rate of production for the 5-md permeability case and pressure levels of 3,000, 5,000 and 7,000 psia. Gas recovery tends to be lower at a given production rate for the high-pressure reservoirs. To cite quantitative gas recov-

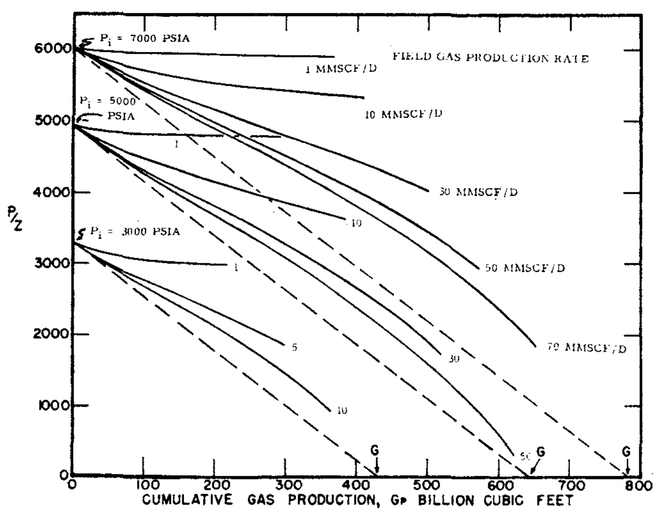

FIG. 2—COMPUTED p/Z VS G_p FOR 5-MD CASE.

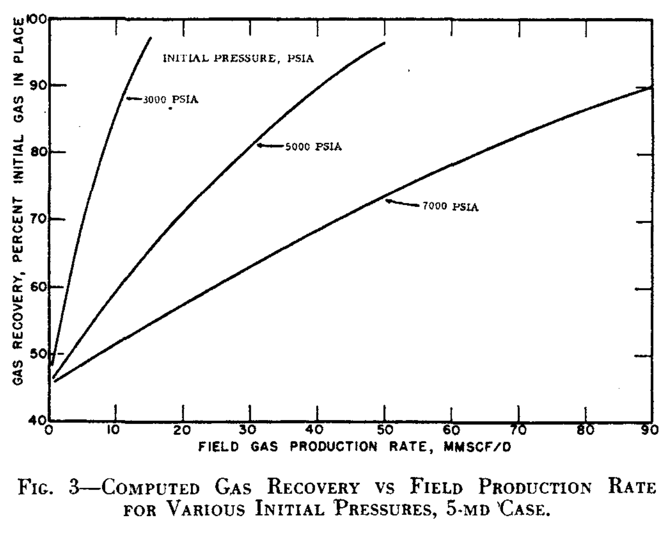

FIG. 3—COMPUTED GAS RECOVERY VS FIELD PRODUCTION RATE FOR VARIOUS INITIAL PRESSURES, 5-MD CASE.

eries, it is necessary to consider practical well deliverabilities and well-spacings so that Fig. 3 can be interpreted reasonably. This will be done in detail later in this paper. However, we can make the following order-of-magnitude estimates at this time. If well spacing is 200 acres per well, 25 wells would be required for the 5,000-acre reservoir used in the example. Thus, field production rates of 10 to 70 MMscf/D would require per-well production rates of 400 Mscf/D to 2.8 MMscf/D. This range of production rates is reasonable for the example, as will be shown later.

Returning to an inspection of estimated gas recoveries, note that gas recoveries on Fig. 3 range from about 45 per cent to in excess of 90 per cent of original gas in place, depending upon the production rate. In regard to pressure level, the calculated gas recovery at a field production rate of 30 MMscf/D ranges from 63.5 per cent for an initial pressure of 7,000 psia to in excess of 99 per cent for an initial pressure of 3,000 psia.

The effect of aquifer permeability upon gas recovery under water drive is shown on Figs. 4 and 5 for an initial pressure of 7,000 psia. Gas recovery is less sensitive to production rate for practical production rates as aquifer permeability increases. Water influx responds so rapidly to pressure changes in the high-permeability gas reservoir that it is not possible to benefit much from increased production rate. In the limit, aquifer performance approaches a full water drive as permeability increases. Note that computed gas recovery for the 500-md case shown in Fig. 5 ranges only from about 45 to 46 per cent for field production rates as high as 90 MMscf/D. It can be dangerous to estimate gas recovery for a water-drive gas reservoir from experience with volumetric gas reservoirs. The main factors in the full water-drive gas reservoir are invasion efficiency and residual gas saturation.

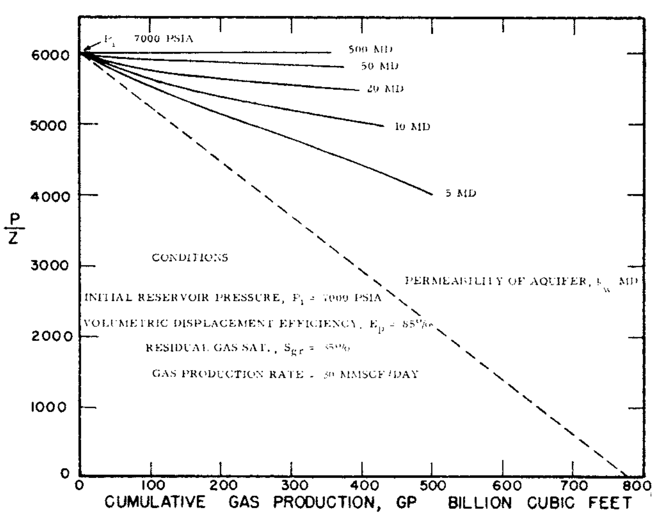

FIG. 4—COMPUTED p/Z VS G_p FOR VARIOUS AQUIFER PERMEABILITIES.

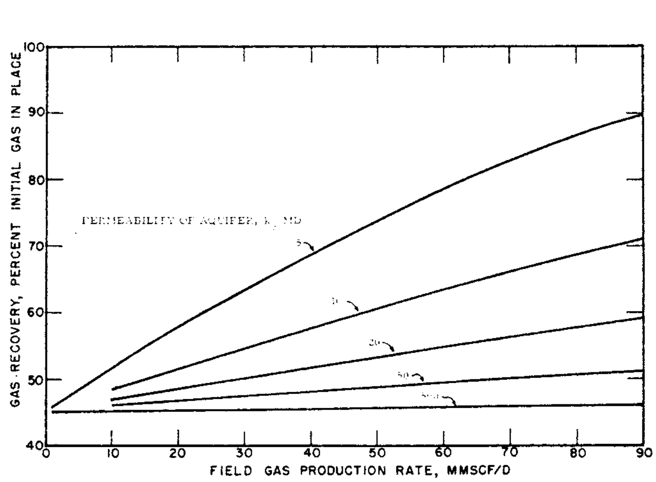

FIG. 5—COMPUTED GAS RECOVERY VS FIELD PRODUCTION RATE FOR VARIOUS PERMEABILITIES, INITIAL PRESSURE OF 7,000 PSIA.

Fig. 6 presents p/Z vs G_p curves for an initial pressure of 5,000 psia and aquifer permeability of 5 md with the volumetric displacement efficiency E_p shown as a parameter. The residual gas saturation is 35 per cent for all cases. This figure shows the effect of variation in volumetric displacement efficiency upon performance. The displacement mobility ratio is low, and thus displacement should be nearly piston-like. This has been shown experimentally by Chierici *et al.*,[13] wherein very little gas recovery was obtained after breakthrough in linear imbibition experiments. It appears the volumetric displacement efficiency should depend largely upon areal displacement efficiency, or well location, as long as it is assumed that the reservoir is homogeneous and water influx is from the edge, not the bottom of the reservoir. Water coning could be a serious problem, and could place an upper limit on permissible well production rates if bottom-water invasion is encountered. Fig. 6 shows that gas recovery should depend somewhat upon invasion efficiency, but the importance of invasion efficiency should not be great if the well density is fairly uniform.

Fig. 7 presents p/Z vs G_p for the 5,000-psia, 5-md case and an invasion efficiency of 85 per cent for various residual gas saturations. Residual gas saturation can have an important effect upon gas recovery at low production rates, as shown by Fig. 7. Clearly, laboratory measurement of imbibition residual gas saturations is desirable for water-drive gas reservoirs.

Another factor worth consideration in the water-drive gas reservoir is interruption of production. Shutting in gas production will result in reservoir pressure build-up. For the 5,000-psia, 5-md case shown on Fig. 2, producing continuously at 30 MMscf/D or intermittently (on one year, off one year), the computed gas recovery decreased from 81.2 per cent of initial gas in place for continuous production to 66.4 per cent of initial gas in place for intermittent production. This was caused by an increase in abandonment pressure from 1,552 to 2,721 psia.

Some qualification is desirable here. The mechanism of gas entrapment by imbibition of water is not definitely

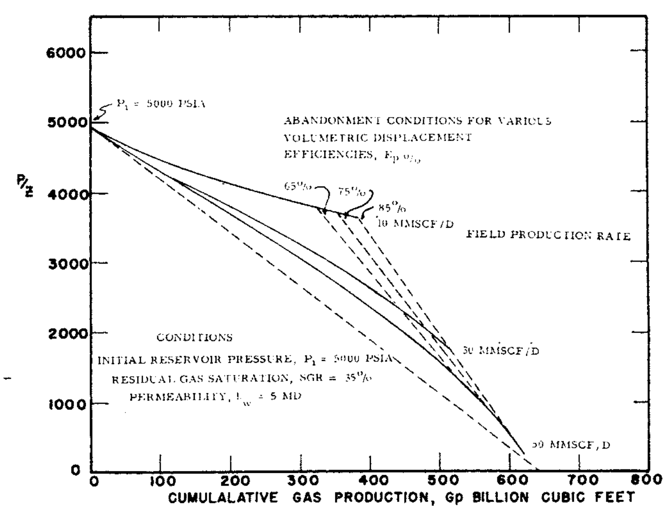

FIG. 6—COMPUTED p/Z VS G_p FOR VARIOUS VOLUMETRIC DISPLACEMENT EFFICIENCIES.

established. There is some evidence that: (1) gravity segregation[13] on interruption of production could lead to a reduced residual gas saturation; and (2) residual gas saturations may be reduced to very low values[10] under extended imbibition. Diffusion of gas through water has been cited, and often discredited for similar phenomena.

DELIVERABILITY

Proper interpretation of the preceding depends strongly upon knowledge of well deliverabilities. That is, any selected field production rate implies a definite number of wells producing a reasonable gas rate. Gas flow can be expressed approximately by the modified Swift and Kiel equation:[14]

$$q_g = \frac{19.87 \times 10^{-6} k_g h \, T_{sc} \, (p_{ws}^2 - p_{wf}^2)}{\bar{\mu}_g \, p_{sc} \, T \, \bar{Z} \left[\ln \dfrac{r_d}{r'_w} + s + D q_g \right]} \quad . \quad . \quad (14)$$

For stabilized (long-time) flow, the transient drainage radius r_d as defined by Aronofsky and Jenkins[15] becomes $(0.472 \, r_e)$. Eq. 14 can be used to produce back-pressure curves for any specific static pressure p_{ws} and well spacing (or r_e). Fig. 8 presents stabilized curves computed from Eq. 14 for a well spacing of 200 acres/well. Formation parameters used are given in Table 2. Using Eq. 14 to produce stabilized back-pressure curves is similar to the method proposed by Carter *et al.*[16] Similar curves can be produced for any well spacing by modifying the value of r_e.

Once deliverability information has been developed from the back-pressure curves as a function of well spacing and static pressure, it is possible to determine the number of wells required to establish any desired field production rate. This information can usually be displayed as a plot of maximum field rate vs well spacing with formation pressure level as a parameter.

One additional piece of information is required. After water influx proceeds during the life of the reservoir, well locations will become flooded out. Thus the producible area is required at each stage of production to permit an estimate of the number of wells which are capable of production. One way to accomplish estimation of producible area is as follows. We assume that a fraction of the total area of the field $(1 - E_p)$ cannot be drained by existing wells at abandonment—although some gas will be recovered by pressure depletion by the time of abandonment. The fraction of the remainder producible at any time can be estimated by a material balance, because the water influx at any time "n" can be calculated by Eq. 11.

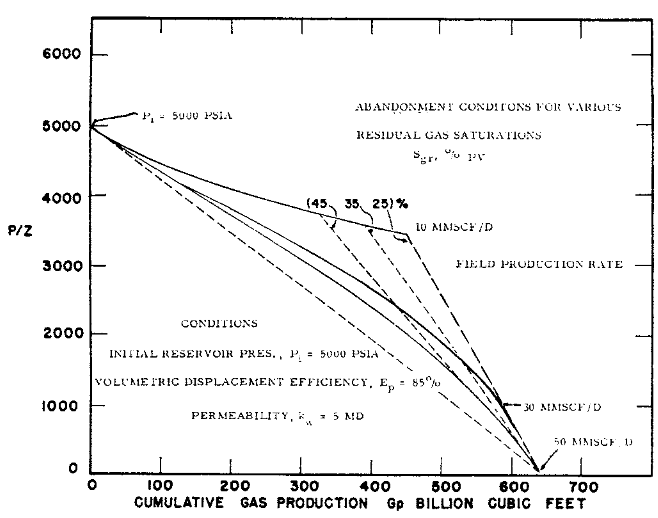

FIG. 7—COMPUTED p/Z VS G_p FOR VARIOUS RESIDUAL GAS SATURATIONS.

TABLE 2—CONDITIONS SELECTED FOR EXAMPLE ESTIMATION OF STABILIZED BACKPRESSURE CURVES

k_g	5 md
T_{sc}	520°R
P_{sc}	14.65 psia
s	−3
D	2.5×10^{-4} (Mscf/D)$^{-1}$
r_{w1}	0.3 ft
h	100 ft
T	211F
gas gravity	0.65 (to air)
pTc	373°R
pPc	670 psia

The total reservoir volume which will be invaded by water at abandonment is

$$\text{res bbl} = \frac{1}{5.615} \left[A h \phi \, (1 - S_w - S_{gr}) \, E_p \right] \quad . \quad . \quad . \quad (15)$$

The reservoir volume invaded at time "n" is ($W_{en} B_w$ res bbl). Thus the fraction of the producible reservoir area which can be produced at time "n" is

$$F' = 1 - \frac{5.615 \, W_{en} \, B_w}{[A h \phi \, (1 - S_w - S_{gr}) \, E_p]} \quad . \quad . \quad . \quad . \quad . \quad (16)$$

The fraction F' for any given time "n" can be multiplied by the original number of wells to estimate the number of producible wells remaining at time "n". If well allowables cannot be transferred from wet wells, the field production rate will have to decline as wells become flooded, or more wells will have to be drilled at a reduced spacing. If spacing is maintained constant, the estimation of field performance outlined previously can be used to estimate recovery. The procedure is to use Eq. 16 at the end of each time increment of production to determine

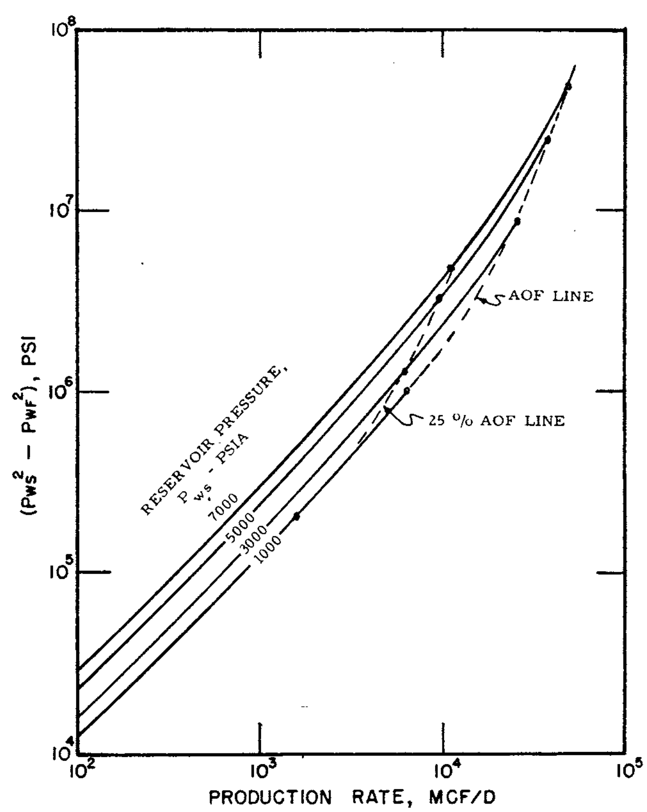

FIG. 8—COMPUTED STABILIZED DELIVERABILITY CURVE FOR WELL SPACING OF 200 ACRES.

the number of wells producing. This number is then used to reduce the field production rate proportionately for the next time step.

Calculations can be made for various well spacings to permit economic evaluation of the effect of well spacing on profitability of development for any given gas field. In the case of volumetric gas reservoirs, gas recovery is usually affected only a few per cent by changes in well spacing. Well spacing studies *can* indicate a maximum in discounted present worth value for a volumetric gas reservoir. However, this represents a type of acceleration project because gas recovery is not increased sufficiently to justify the drilling of wells on closer spacing on the basis of increased recovery. For certain water-drive gas reservoirs, this may not be true. For low-permeability, high-pressure water-drive gas reservoirs, gas recovery can be doubled in some cases by a significant increase in field production rate. Increased field production rate implies closer spacing to provide adequate deliverability. Thus, well-spacing studies for some water-drive gas reservoirs can lead to a maximum in discounted present worth, which is influenced by significant increase in gas recovery as well as an increased income schedule.

Unfortunately, it is not often that an operator has the option to exercise control over well spacing or production rate. Nevertheless, the preceding is presented for the sake of completeness, and to sound a warning for planning development of newly-discovered gas reserves which appear likely to be under water-drive. In the latter event, care should be taken to perform complete tests on the discovery well to permit a study of potential effects of production rate and well spacing on economics.

It should be emphasized that the information on the effect of gas production rate on reserves, and the abandonment point presented in this paper depends on the assumption that water coning is not the controlling factor. We recognize that water-coning and reservoir heterogeneities often are controlling.

CONCLUSIONS

As a result of this study, the following conclusions appear warranted. Assuming that the reservoir is reasonably homogeneous, and that water influx will be from the edge of the formation, it appears that gas recovery from certain water-drive gas reservoirs may be very sensitive to gas production rate. If practical, the field should be produced at as high a rate as possible, and field curtailment should be avoided. This may result in a significant increase in gas reserves by lowering the abandonment pressure.

The sensitivity to field production rate appears to increase as permeability decreases, and as initial pressure decreases. The information presented in this paper and that of Bruns *et al.*[3] should provide an indication as to when detailed studies might be worthwhile for particular reservoirs.

Computations indicate that gas recovery should depend somewhat upon water invasion efficiency, but the effect should not be great if the well density is uniform.

Residual gas saturation can have an important effect upon gas recovery, particularly at low production rates. Laboratory measurement of imbibition residual gas saturation is desirable for water-drive gas reservoir estimations.

Sufficient technology on gas production exists to write reasonable expressions for stabilized gas well deliverability. These expressions, coupled with proper well testing can provide information needed to determine field deliverability as a function of well spacing and pressure level. Economic analysis may indicate a maximum in discounted present worth of production from a water-drive gas reservoir at a given well spacing. This fact and the preceding conclusions indicate the desirability of early investigation of the potential effects of production rate and well spacing upon development of new gas reserves likely to be under water drive.

Finally, the Carter-Tracy[8] water influx expression offers a simple method to estimate performance of water-drive gas reservoirs. The method is suitable for hand calculation.

NOMENCLATURE

A = area of reservoir, sq ft
B = water influx constant (see Eq. 5)
B_{gi} = gas formation volume factor at pressure p_i, res bbl/scf
B_{gn} = gas formation volume factor at pressure p_n, res bbl/scf
B_w = water formation volume factor, res bbl/surface bbl
C_n = function of t_{Dn} (see Eq. 8)
c_t = total compressibility for the aquifer, psi^{-1}
D = non-Darcy flow constant, (Mscf/D)$^{-1}$
d = differential operator
E_n = function of t_{Dn} (see Eq. 10)
E_p = volumetric invasion efficiency, fraction
F = fraction, correction for limited portion of reservoir perimeter open to water influx
F' = fraction (see Eq. 16)
G = original gas in place, scf
G_{pm} = cumulative gas produced at abandonment, scf
G_{pn} = cumulative gas produced at time t_n, scf
h = net thickness, ft
K = constant (see Eq. 9)
k_g = effective permeability to gas in the reservoir, md
k_w = effective permeability to water in the aquifer, md
$p_D(t_{Dn})$ = van Everdingen-Hurst dimensionless pressure drop
$p'_D(t_{Dn})$ = first derivative with respect to t_{Dn} of $p_D(t_{Dn})$
p_i = initial formation pressure, psia
p_m = pressure at abandonment, psia
p_n = pressure at time t_n, psia
pP_c = pseudo critical pressure, psia
pT_c = pseudo critical temperature, °R
p_{wf} = bottom-hole flowing pressure, psia
p_{ws} = static reservoir pressure, psia
q_g = gas production rate, Mscf/D
R = gas law constant, 10.73 psia-cu ft/lb mol − °R
r_d = transient drainage radius of Aronofsky and Jenkins, ft
r_w = reservoir radius, ft (radius of circle of area A)
r_w' = well radius, ft
s = skin effect, dimensionless
S_g = initial gas saturation, fraction
S_{gr} = residual gas saturation, fraction
S_w = initial water saturation in gas reservoir, fraction
T = reservoir temperature, °R
t_{Dn} = dimensionless time at time t_n (See Eq. 4)
t_n = time, years
T_{sc} = standard condition temperature, °R
W_{en} = cumulative water influx at time t_n, surface bbl

W_{pn} = cumulative water produced at time t_n, surface bbl

$\bar{Z}$ = real gas law deviation factor at average pressure (evaluated as per Ref. 17)

Z_n = deviation factor at pressure p_n

ϕ = fractional porosity

μ_w = viscosity of water, cp

$\bar{\mu}_g$ = average gas viscosity, cp (evaluated as per Ref. 17).

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