Rudarsko-geološko-naftni zbornik	Vol. 2	str. 151–159	Zagreb, 1990.

UDC 622.323:620.01

Izlaganje sa znanstvenog skupa

ENHANCED RECOVERY FROM WATER-DRIVE GAS RESERVOIRS

Zaki BASSIOUNI

Louisiana State University, Baton Rouge, LA 70803-6417, USA

Key–words: Ultimate rcovery, Gas reservoirs, Water drive mechanism

Ultimate recovery from water–drive gas resorvoirs is governed primarily by the reservoir heterogeneity, residual gas saturation behind the water front, and by relatively high–pressure free gas abandoned updip of the highest perforation. Typical recovery from these reservoirs ranges between 35 and 75% of gas in place.

Gas recovery can be enhanced using the »co–production« technique. In this process, as the downdip wells begin to water out, they are converted to high–rate water producers while the updip gas wells maintain gas production. If enough water is produced, the water influx can be halted or at least slowed down, allowing updip wells to deplete the free gas zone to lower pressure. Also, bypassed gas may regain mobility as pressure is lowered in the water–swept zone.

Material balance calculations and numerical simulation are used to support the technical feasibility of co–production. The technical as well as the economic feasibility is demonstrated using actual reservoirs.

Ključne riječi: Ukupni iserpak, Plinska ležišta, Vodonaporni režim

Ukupni iscrpak iz plinskih ležišta s vodonapornim režimom prvenstveno je uvjetovan heterogenošću ležišta, zasićenjem preostalim plinom iz vodenog fronta i slobodnim plinom razmjerno velikog tlaka koji zaostaje iznad najviše perforacije. Tipični iscrpak iz ovih ležišta iznoi 35 do 75% geoloških rezervi plina.

Iscrpak plina može se povećati primjenom tehnike »koprodukcije«. U tom procesu, čim se uz proizvodnju plina pojavi voda, bušotine se pretvaraju u velike proizvođače vode, dok se održava proizvodnja plina iz ostalih bušotina. Ako se proizvodi dovoljno vode, može se zaustaviti napredovanje vodenog fronta ili barem usporiti, dozvoljavajući tako da se u plinskom dijelu ležišta odvija volumetrički režim. Tako se održava mobilnost mimoilazećeg plina putem smanjenja tlaka u zavodnjenom dijelu ležišta.

Tehnička podobnost koprodukcije provjerava se proračunima materijalnog uravnoteženja i numeričkim simuliranjem. Na primjerima stvarnih ležišta prikazana je tehnička i ekonomska podobnost prikazanog načina proizvodnje plina.

Introduction

Gas reservoirs can be classified, according to drive mechanism, as depletion–drive or water–drive type. Recovery from depletion–drive gas reservoirs is limited only by the minimum reservoir pressure, economically possible. Ultimate recovery from water–drive gas reservoirs is governed primarily by physical properties such as the residual gas saturation behind the water front and by the amount of free gas left updip above the highest perforation. At abandonment, this gas is generally at a much higher pressure than that experienced in a depletion–drive reservoir. The higher the pressure, the greater number of SCF is lost. Depletion–drive reservoirs exhibit recoveries as high as 90% whereas recoveries from water–drive reservoirs typically vary between 35–75% (McKay, 1974).

Recovery from water–drive reservoirs can be increased using the blowdown technique (Lutes et al.,1977., Brinkman, 1981., Chesney et al. 1982). In this technique, higher gas production rates are relied upon to outrun the aquifer advance. Pressure in the gas zone is reduced before the aquifer response is felt. The blowdown technique is limited to systems with a relatively weak water influx. Another shortcoming of the blowdown technique is that gas production cannot be curtailed once the blowdown is implemented without a serious reduction in overall recovery efficiency (Lutes et al. 1977). Also, reservoirs with considerable permeability variations show reduced effectiveness due to uneven water advancement. High production rates could also lead to water coning and sand production.

Another enhanced gas recovery method is the co–production technique (Arcaro et al., 1987). The co–production technique is based on the proposal that recovery in a water–drive gas reservoir can be increased by producing water from downdip wells while producing gas from updip wells. If enough water is produced the water influx can be effectively halted or at least slowed down, allowing updip wells more time to deplete the reservoir. The increased recovery is attributed to a reservoir response much similar to a depletion–drive since the production of water lowers reservoir pressure so more gas is produced due to expansion. Also, water production slows the advance of water front thus tempering the effect of reservoir heterogeneity. In addition, bypassed gas located behind the water front might regain its mobility as the pressure is reduced. Co–production is feasible in all moderate–to–active water–drive gas reservoris. Its application is only limited by economic factors.

This paper presents reservoir calculations supporting the concept of co–productio. These calculations are also used to screen and evaluate reservoirs amenable to this enhanced gas recovery technique. The technical and economic feasibility of co-production is also demonstrated using actual reservoirs.

Co-Production Material Balance Model

The concept of co-production can be demonstrated using a material balance model (Halford, 1985) (MBE). For gas reservoirs the basic balance equation is expressed as (Craft et al., 1950):

$$G_pB_g = G_o (B_g - B_{gi}) + W_e - W_pB_w \quad (1)$$

or

$$\frac{G_o(B_g - B_{gi})}{G_pB_g} + \frac{W_e - W_pB_w}{G_pB_g} = 1 \quad (2)$$

where:

B_g = gas volume factor at time t, RB/scf [res m^3/ Std m^3]
B_{gi} = initial gas volume factor, RB/scf [res m^3/ Std m^3]
B_w = water volume factor, RB/STB [res m^3/ stock-tank m^3]
G_o = original gas in place, scf [Std m^3]
G_p = cumulative gas production at time t, scf [Std m^3]
W_e = cumulative water influx at time t, res bbl [res m^3]
W_p = cumulative water produced at time t, res bbl [res m^3]

The application of the MBE consist of two phases. A »history match« of past performance followed by »prediction« of future performance. The history match phase consists mainly of defining the aquifer's contribution. First, the water influx history is calculated from Eq. 1 using available reservoir data. The water influx history is also calculated using the known pressure data and a selected aquifer model. Different types of aquifer models are available, namely the Schilthuis steady-state model (Craft et al., 1950), the Nabor and Barham solutions for an unsteady-state linear aquifer (Nabor et al., 1964), and the Van Everdingen and Hurst solution for an unsteady-state radial aquifer (Craft et al., 1950). This later model commonly used for edge-water drive is also adapted for the case of bottom-water drive resevoirs (Halford, 1985). The output of the aquifer model is adjusted by varying aquifer compressibility, permeability, and/or area open to flow at the original gas/water contact til a good agreement with the water influx history calculated from Eq. 1 is reached. The aquifer is hence defined, and future behavior of the reservoir can be predicted.

For a tuture time and production an initial water influx value is predicted from the aquifer model using the current pressure as first approximation. An iterative process is then initiated to arrive at a better estimate of the pressure. First, a gas volume factor B_g is calculated from Eq. 1. The gas volume factor is converted to its corresponding pressure by the following equation (Craft et al., 1950):

$$P = \frac{P_{sc}\, T\, z}{B_g T_{sc}} \quad (3)$$

where:

P = Average reservoir pressure
P_{sc} = Standard pressure
T = Average reservoir temperature
T_{sc} = Standard temperature
z = Gas law correction factor

Since the z-factor is a funciton of pressure, an iteration is carried out until reasonable convergance is obtained. The pressure calculated from Eq. 3 is compared to the pressure used to determine the water influx. If the two values are not reasonably close, a new water influx is calculated using the new pressure value and the previous calculations are repeated until a desired level of convergence is attained.

The fraction of the reservoir swept by the predicted encroaching water is calculated on volumetric basis by:

$$\text{Fraction Flooded} = \frac{(We - Wp)/(1.0 - S_{wc} - S_{gr})}{(G_o * B_{gi})/(1.0 - S_{wc})} \quad (4)$$

where:

S_{wc} = Connate water saturation, fraction.
S_{gr} = Residual gas saturation, fraction.

The fraction flooded together with a volumetric map similar to that of Fig. 1 slowing well perforations determines the number of water and gas producing wells and in turn the gas and water production rates. Future time cumulative gas and water production can easily be calculated. Calculation is continued until abandonment conditions are reached.

Conceptual Results of the MBE Model

The simulation of Eugene Island reservoir, discussed in detail later, is depicted in Fig. 2 and summarized in Table 1. Conventional production results in 169 BCF out of a total of 274 BCF i place for a recovery factor of 62%. At abandonment, which is reached when the reservoir is watered out, reser-

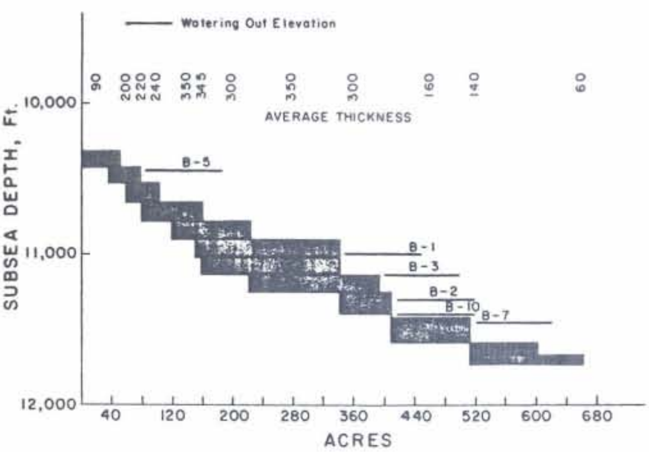

Fig. 1. Example of volumetric maps used to determine watered out wells, case of Eugene Island Reservoir.

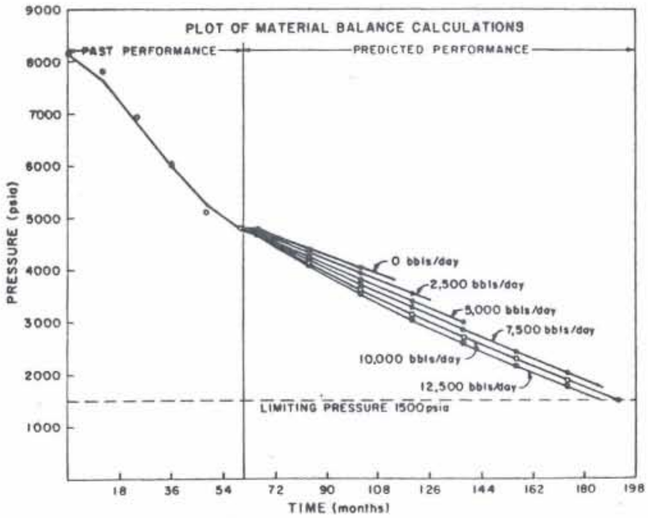

Fig 2. Co–production pressure history for varying amounts of water production, case of Eugene Island reservoir.

TABLE 1

Co-Production MBE Model Result for Eugene Island Reservoir

Water Production BBLs/Day	Cum. Gas Production BCF	Pressure at Abandonment, psia	RF %	Incremental Recovery
0	169.5	3,800	62	–
2,500	178.6	3,400	65	3
5,000	187,7	3,000	69	7
7,000	224.2	1,750	82	20
10,000	228.8	1,500	84	22
12,000	224.2	1,500	82	20

voir pressure is 3,800 psia. Co–production allowed the depletion of reservoir pressure down to the abandonment pressure of 1500 psia. This pressure depletion results, for the optimum case, in 84% recovery which is 22% above the conventional method.

Co–production improved the recovery in all study cases where it was applied. However in cases with an extremely strong water–drive, unreasonably high water production rates would be needed to halt the aquifer. Reasonable water production rates showed an increase in recovery but the incremental returns could not economically justify co–production. Figure 3 shows the limited incremental recovery and pressure depletion realized through co–production in the case of Ship Shoal reservoir characterized by a strong water–drive.

Intuitively, the more water produced, the better the recovery. The model has indicated, however, that in some cases higher water production rates did not further enhance recovery. Fig. 2 shows that the recovery steadily increases as production rates increase up to 10,000 BBL/day. Beyound that rate the reservoir pressure reaches the chosen limiting value of 1500 psia much faster with no additional recovery.

Technically it is always best to start co–production immediately, but it may have to be delayed until later in the reservoir's life for economic reasons. However, the longer co–production is postponed the higher the daily water production needed to reach a certain recovery level. Such high production rate might not be possible. The optimum water production rate for the reservoir whose past and future performance is presented in Fig. 4 is 10,000 BBL/day. This assumes an implementation date of 1987. If co–production is implemented instead at a later date, perhaps in year 2001, 15,000 BBL/day,

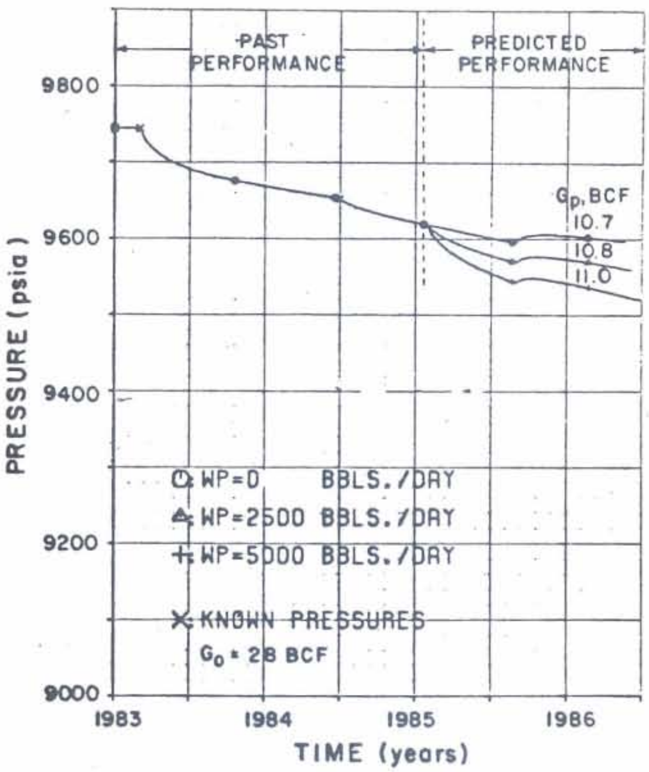

Fig. 3. Predicted pressure history and recovery for Ship Shoal reservoir characterized by a strong aquifer.

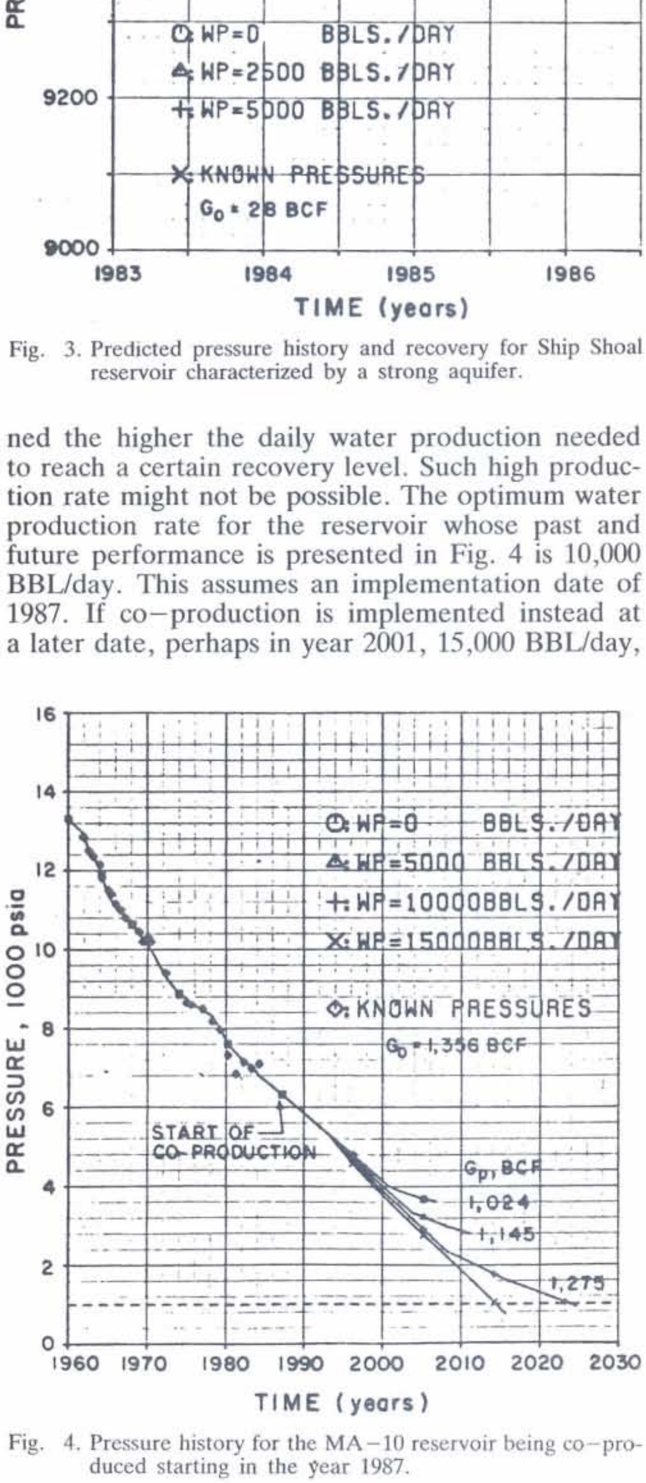

Fig. 4. Pressure history for the MA–10 reservoir being co–produced starting in the year 1987.

as seen in fig. 5, will be needed to realize the maximum possible recovery of 1,275 BCF. Early implementation of co–production reaps additional gains in reservoirs with multiple gas wells by keeping more wells on line and production rates higher until abandonment.

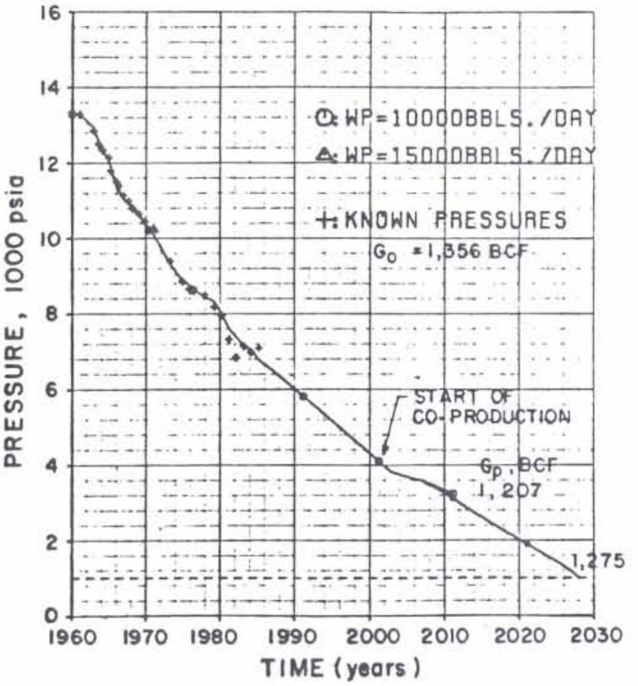

Fig. 5. Pressure history for the MA–10 reservoir being co–produced starting in the year 2001.

The model has also proven usuful for screening reservoirs amenable for co–production and for developing screening criteria. Initial decision as to whether a reservoir is a good canditate for co–production can be made using the cumulative water–drive index, WDI. The WDI is the second term of Eq. 2. From the study of several case histories, listed in Table 2 in descending order of WDI, it can be concluded that if this value is 35% or less, co–production will provide negligible additional benefits. This conclusion is supported by another study showing that for systems with an aquifer twice the reservoir in size, the aquifer effects were negligible (Al. Hashim et al., 1984). At the other end of the spectrum, co–production can be ruled out when the water–drive index is greater than 85%.

Co–Production Stream–tube Model For Strong Water–Drive Resevoirs

When the MBE shows that conversion to a depletion–drive is unlikely due to strong water drive, it might still be possible to show benefit from co–production due to an enhanced areal sweep ot the reservoir. This situation is simulated using a stream–tube plotting model to determine whether or not producing water from one or more wells can force the aquifer to sweep a greater area of the reservoir before reaching abandonment conditions. This model, originally developed for oil reservoirs undergoing water flooding (Martin et al., 1979), is adapted to gas reservoirs with strong water influx (Halford, 1985).

The output of the model consists of plots showing advancement of flood fronts at evenly spaced time steps, Fig. 6. The input requires the location and production rates of gas and water wells. The aquifer is approximated by a given number of equally spaced wells along the original gas/water contact. The strength of each aquifer well is equal to reservoir fluid voidage from gas and water production divided by the number of wells on the contact. The boundary of the reservoir/aquifer system is defined by a series of line segments. Bounding wells are used to remove the physical discontinuity by realizing a no–flow boundary instead. The larger the number of bounding wells used the better boundary definition but the longer computer time needed. Calculation of the image well strengths was approximated using the boundary pair point approach (Lin, 1972).

The efficiency of co–production compared to conventional production can be evaluated by comparing the additional area swept at a specific time. Conventional production from the A–4 gas well of the Ship Shoal reservoir is presented as an example in Fig. 6. Three different co–production scenarios of this reservoir are presented in Figs. 7, 8, and 9 for water production from well A–8 at a rate of 1000, 2500, and 5000 BBL/day respectively. Graphically it can be seen that additional water production

TABLE 2

Results of Several Reservoirs Screened for Co-Production

Field	Gas in Place (BCF)	Average Daily Gas Prod. (MCF/day)	Daily Water Prod. (Bbls/day)	Water Drive Index (%)	Conv. Recovery (%)	Co-prod. Recovery (%)	Incremental Recovery (%)
CNG	28.0	7,000	4,000	92	38	39	1
BM-2A	15.3	2,750	3,500	88	32	37	5
L. Pelto	4.5	3,000	6,000	86	54	55	1
BM-3	189.3	15,000	10,000	85	49	85	36
MA-13	186.3	12.000	10,000	79	57	76	19
MA-7	423.8	10,000	8,000	73	76	92	16
MA-10	1355.6	40,000	10,000	52	77	93	16
EI 295	274.0	15,500	8,000	48	62	83	21
CAM-2	23.7	8,000	1,300	30	94	88	−6
MA-9	331.5	12,000	3,000	22	90	87	−3
CBHAZ	55.5	2,200	400	16	89	85	−4
MA-5	155.8	2.000	550	14	90	88	−2

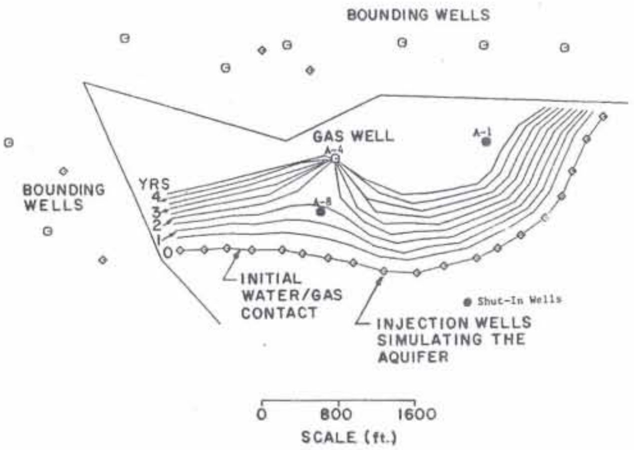

Fig. 6. An example of stream tube model output, case of Ship Shoal reservoir, conventional production.

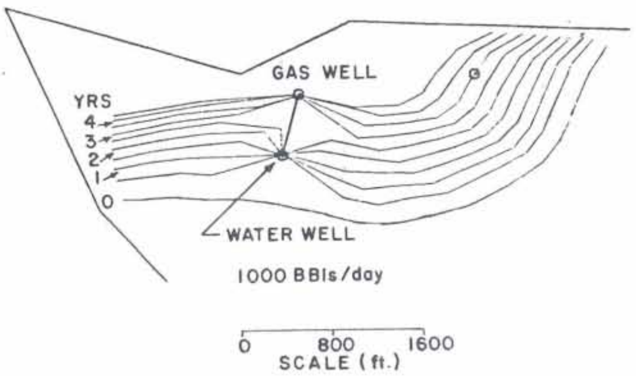

Fig. 7. Co–production of the Ship Shoal reservoir, 1500 BBL of water/day.

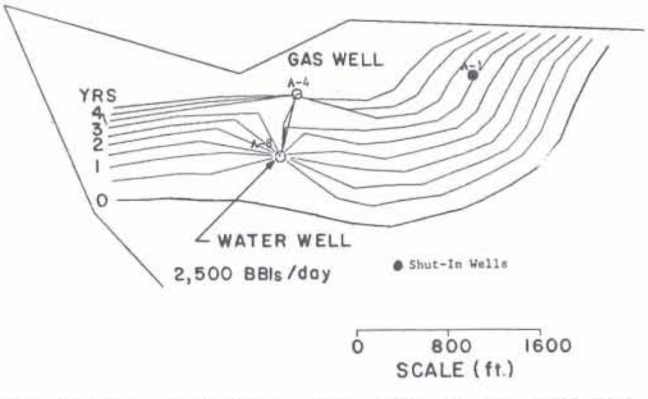

Fig. 8. Co–productionof the Ship Shoal reservoir, 2500 BBL of water/day.

from well A–8 force the aquifer to sweep greater area of the reservoir. The sweep efficiencies and recoveries are listed in Table 3.

Co–Production of Eugene Island Gas Reservoir

This 10,300–ft sand reservoir operated by Chevron is located in Eugene Island Block 305, about 100 miles off the Louisiana shoreline. Volumetric analysis estimated the original gas in place to be 274 BCF. Production data for the last five and a half years has shown that this is a gas–condensate reservoir with a moderate water–drive. Initially, six

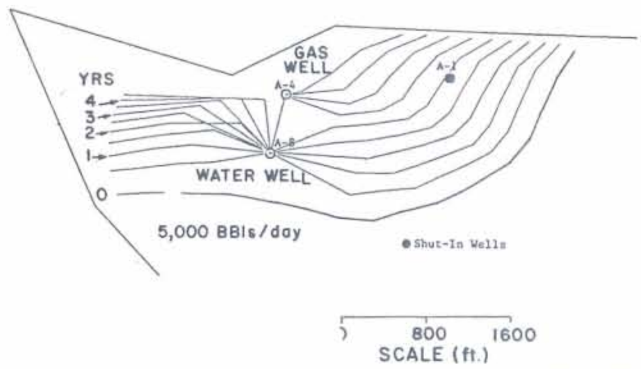

Fig. 9. Co–production fo the Ship Shoal reservoir, 5000 BBL of water/day.

TABLE 3

Displacement and Areal Sweep Efficiency for Each Variance of Well A-8's Water Production Rate

		Breakthrough		4 1/2 year mark	
Water Prod. BBL/day	Time of Breakthrough (yrs.)	Sweep Eff.	Rcovery*	Sweep Eff.	Recovery
0	2.0	32.5%	18.8%	56.0%	32.4%
1,000	3.0	55.7%	32.2%	68.4%	39.5%
2,500	3.5	65.4%	37.8%	74.1%	42.8%
5,000	3.0	63.2%	36.5%	78.7%	45.5%

* Sgr = 0.30, Swc = 0,29

gas wells were drilled. At the time of the study three, B–7, B–10, and B–2, had watered out. A fourth well, B–3, was producing at a high water cut. The top of sand map, Fig. 10, shows the reservoir structure, well locations, and the initial and current gas/water contacts. All wells were tested for gas production rates greater than 20 MMCF/D. For co–production purposes, the water production capacity of the wells is estimated at about 2000 STBW/D using gas lift.

Preliminary studies indicated a water influx index of about 50%. As stated earlier this indicates a water–drive that is strong enough to diminish the reservoirs ultimate recovery if produced in conven-

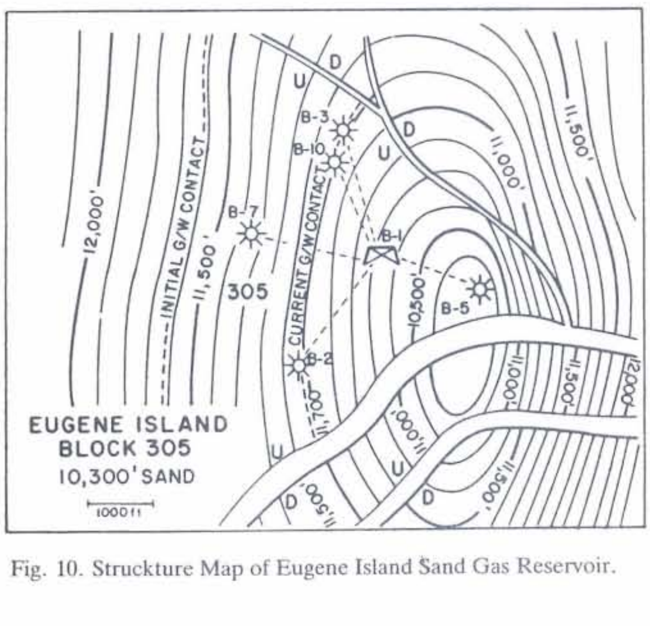

Fig. 10. Struckture Map of Eugene Island Sand Gas Reservoir.

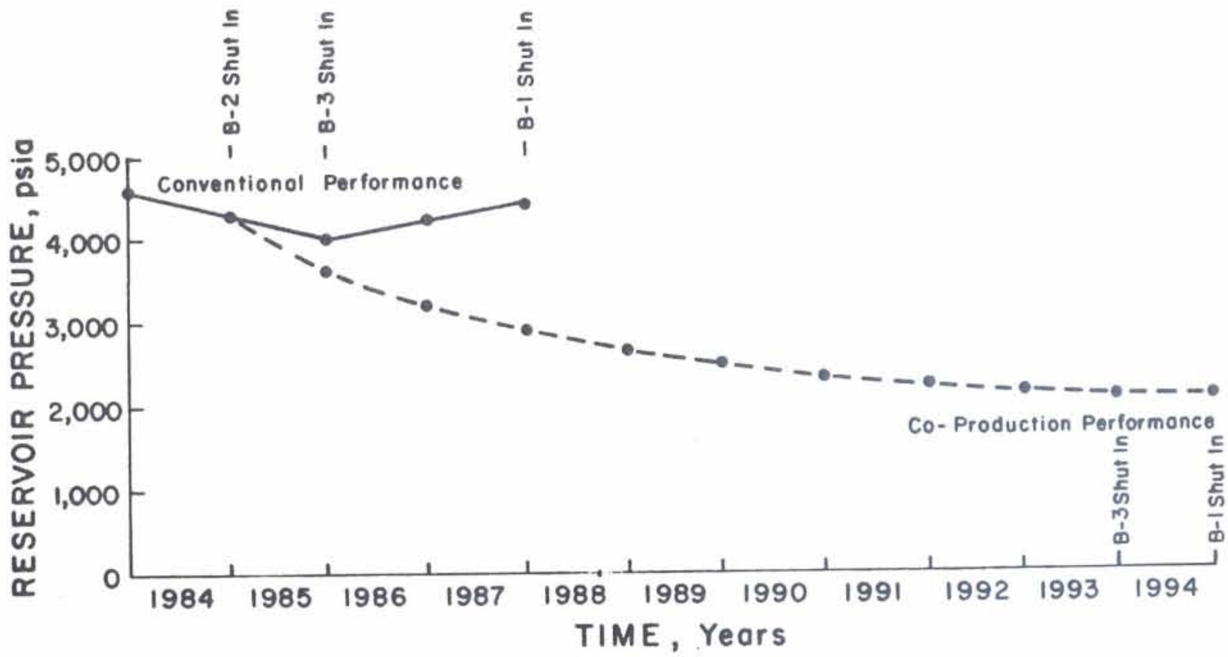

Fig. 11. Pressure History and Reservoir Life Prediction for Conventional and Co–production Cases, Eugene Island Reservoir.

tional fashion. Yet the aquifer is not so strong that co–production cannot economically increase the ultimate recovery.

The first predictions of reservoir performance with and without co–production used the MBE model, figs. 1 and 2. Van Everdingen and Hurst's unsteady–state radial solution was used to describe the aquifer. This first screen of the reservoir assumes an initial flat gas production rate that is varied later in the life of the reservoir with the watering out of wells. The water production rate is held constant for the life of the reservoir as it is co–produced and does not increase as gas wells water out. The results of this preliminary test show that the Chevron reservoir is a good prospect for co–production. Figure 2 shows that the reservoir pressure can be substantially depleted with water production rates from 5000–10,000 BBL/day for incremental gas recovery as high as 22% og original gas in place. The water production rates needed are quite feasible and can be accommodated by three to four water wells.

The reservoir was recommended for co–production and subsequently modeled in greater detail using a simulator developed by Chevron (A r c a r o et al., 1987). Results of this study are shown by figs. 11 and 12. This case is a prime example of successful co–production in both technical and economic terms. Co–production is predicted to yield an additional 55 BCF or a 20% greater cumulative

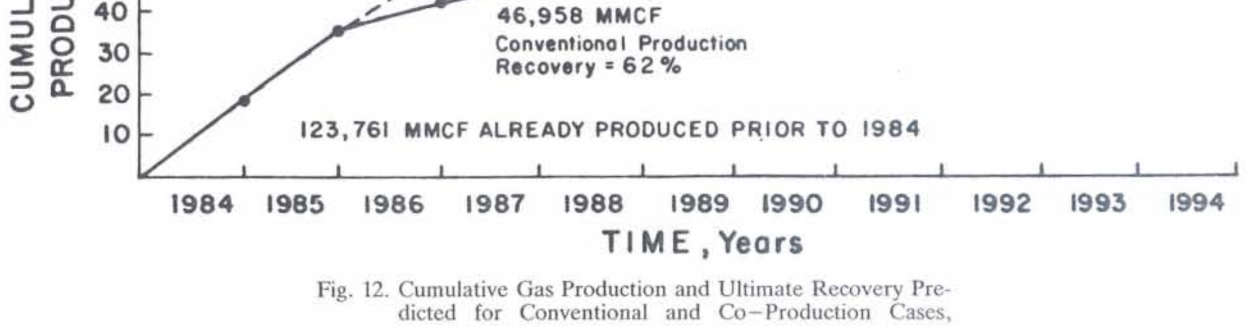

Fig. 12. Cumulative Gas Production and Ultimate Recovery Predicted for Conventional and Co–Production Cases, Eugene Island.

recovery over conventional production. The economic forecasts showed co–production to be twice as profitable as conventional production for gas prices between \$1.50 and \$5.00/MCF. This is graphically depicted in Fig. 13. Economic parameters used in the evaluation are summarized in Table 4.

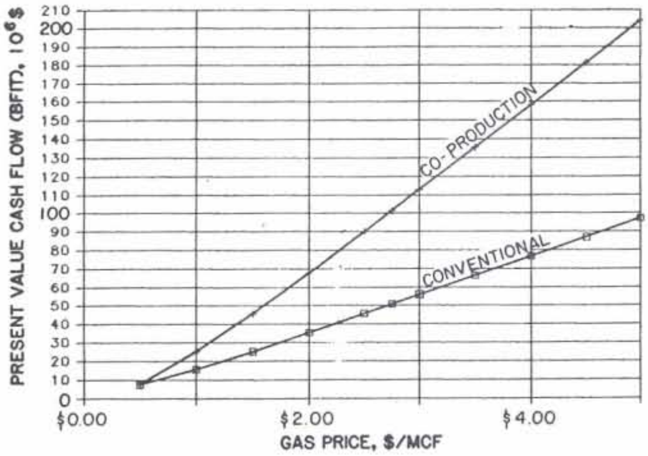

Fig. 13. Present Value Cash Flow Before Federal Income Tax as a Function of the Gas Price for Conventional Production and Co–Production Cases, Eugene Island Reservoir.

Co–Production of Ship Shoal Reservoir

CNG operates this reservoir located in the Ship Shoal Block 295. Early volumetric estimates of the reservoir size showed 28 BCF in place. Three wells, A–1, A–4, and A–8, are completed in this reservoir but only two, A–4 and A–8, were being producet at the time of this study. Well locations are shown in Fig. 14 along with the reservoir's structure and the original gas/water contact. At the time of the evaluation, well A–4 was producing 8000 MCF

TABLE 4

Summary of Economic Parameters Used in the Evaluation

Gas price	\$ 0.50 to \$ 5/Mcf range
Oil price	\$20/BBL (gas and oil prices were held constant during the entire life of the project)
Capital investments	none, conventional prediction; \$1,535,220, co-production
Operating expenses	\$2,000/D/well
Royalty	One-sixth (offshore federal lease)
Windfall profit tax	New (Tier III), \$17/STB base price
Discount rate	15%
Federal income tax	46%
Investment tax credit	10% of tangible expenses
Deductible expanses	80% of intangible expenses
Depreciation	Accelerated cost recovery schedule, 20% of intangibles plus 95% of tangibles

of gas/day while well A–8 is producing 2000 MCF of gas and 900 BBL of water daily. At the time of the study the plan was to shut in well A–8 due to water handling cost (GRI Publ. 86/0081).

The water influx history was calculated to be 92%. This strong an aquifer thwarts attempts to deplete the pressure by co–production. When modeled using the MBE, pressures did decline further and more gas was produced in the co–production cases but not greatly as seen in fig. 3. Well locations, however, suggested that perhaps water being produced from well A–8 might divert the aquifer such that a greater area of the reservoir would be flooded or »swept« before A–1 waters out.

The Ship Shoal field was evaluated with the stream–tube model. Four different cases were run with conventional production in the first case and co–production in the later three. The results are shown by Figs. 7 through 9 and Table 3. Well A–4

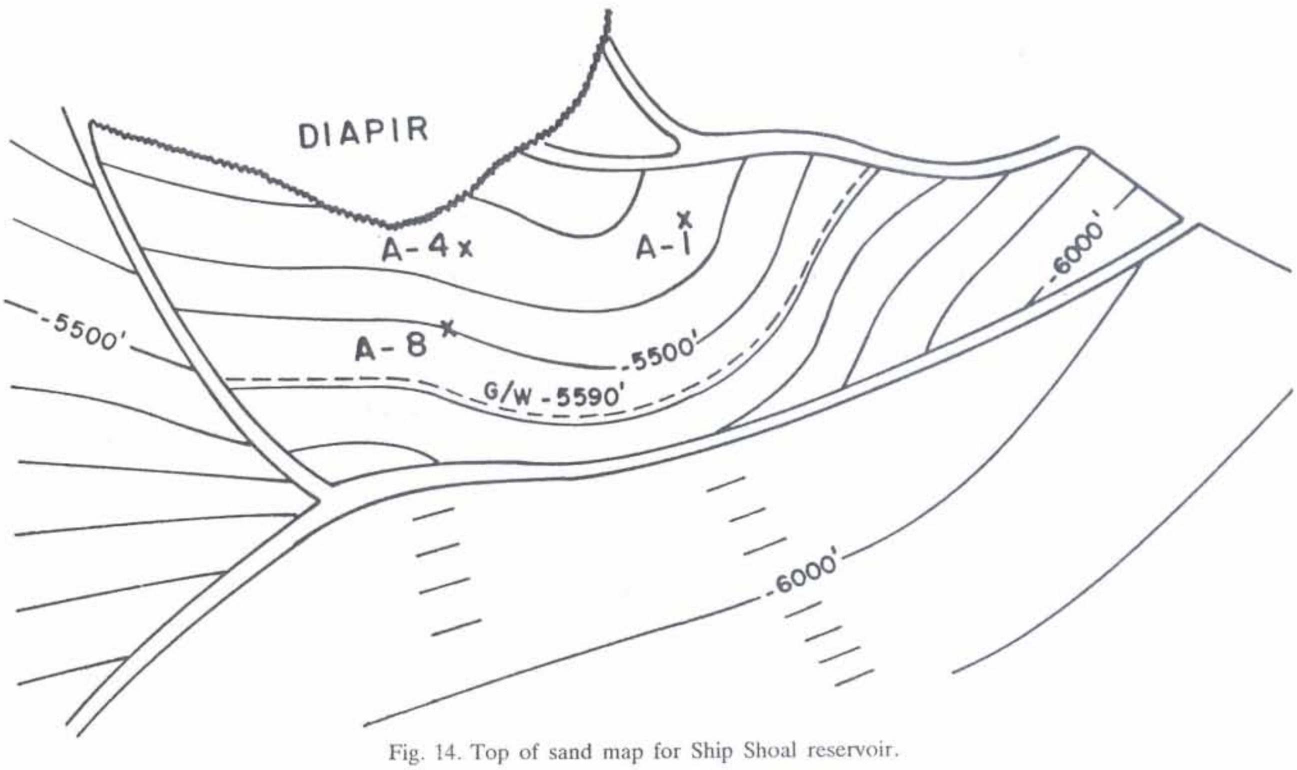

Fig. 14. Top of sand map for Ship Shoal reservoir.

is assumed to produce gas at 7500 MCF/day in all cases while well A−8 produces associated gas at the rate of 2000 MCF/day.

After examining these results, it was decided that added benefits do not warrant the investment and cost of gas−lifting well A−8 to realize higher water production rates. It was recommended, however, that well A−8 be kept on production at its current gas and water rates since it can still enhance the cumulative recovery of the reservoir for reasonable operating cost.

Conclusions

The co−production technique presents a viable technical method of enhanced gas recovery from water−drive gas reservoirs. This is especially true in cases where the water−drive index exceeds 35%. The earlier co−production is implemented, the higher the recovery.

In the case of strong aquifers where co−production cannot greatly lower the reservoir pressure, it was shown that continuing to produce gas wells at high water cuts could shield updip gas wells and force the aquifer to displace more of the gas in place. However, low incremental recovery should be expected.

The feasibility of the co−production technique in an actual case is demonstrated by the technical analyses of the Eugene Island reservoir. The predicted revcouvery for the co−production case is 83%, compared with only 62% for the conventional−production approach, which represents an increase of 56 BCF (1.59×10^9 m^3). The economic analysis shows the co−production technique to be a very attractive option for producing this reservoir. Co−production is undoubtedly feasible in many other water−drive gas reservoirs that meet the water−drive index screening criteria. An economic study of each possible reservoir would be necessary, however, to determine its profitability.

Received: 16. I. 1990.

Accepted: 4. VI. 1990.

REFERENCES

Al−Hashim, H. W. and Bass, D.M. (1984): »The Effect of Aquifer Size on the Performance of Partial Water−Drive Gas Reservoirs,« *SPE* 13233

Arcaro, D. P. and Bassiouni, Z. (1987): »The Technical and Economic Feasibility of Enhanced Gas Recovery in the Eugene Island Field by Use of the Co−production Technique«, *JPT* 585−590.

Brinkman, F. P. (1981): »Increased Gas Recovery from a Moderate Water−Drive Reservoir«, *JPT* 2475−80.

Chesney, T. P., Lewis, R. C., and Trice, M. L. (1982): »Secondary Gas Recovery From a Moderately Strong Water−Drive Reservoir: A Case History«, *JPT* 2149−57.

Craft, B. C. and Hawkins, M. F. (1956): *Applied Petroleum Reservoir Engineering,* Prentice Hall Inc., Englewood Cliffs, NJ, 36.

»Economic, Engineering and Geological Technical Support for Co−production Activities in Louisiana,« GRI publication 86/0081.

Halford, K. J. (1985): »Screening of Co−production Prospects,« M. S. Thesis, Louisiana State University,

Lin, J. (1972): »An Image Well Method for Bounding Arbitary Reservoir Shapes in the Streamline Model,« Doctorate Dissertation, University of Texas at Austin

Lutes, J. L. et al (1977): »Accelerated Blowdown of a Strong Water−Drive Gas Reservoir,« *JPT* 1533−38.

Martin, J.C. and Wegner, R.E. (1979): »Numerical Solution of Multiphase Two−Dimensional Incompressible Flow Using Stream−Tube Relationships,« paper *SPE* 7140

McKay, B. A. (1974): »Laboratory Studies of Gas Displacement from Sandstone Reservoirs Having a Strong Water Drive,« *APEA Journal,* p. 189−194.

Nabor, G. W. and Barham, R. H. (1964): »Linear Aquifer Behavior,« *JPT,* 561−563.

Povećani iscrpak iz plinskih ležišta s vodonapornim režimom

Z. Bassiouni

Napuštanje ležišta plina s vodonapornim režimom potiskivanja redovito je pri znatno većim tlakovima u ležištu nego pri volumetrijskom režimu, pa su pridobive rezrve plina znatno manje pri vodonapornom režimu.

Zaustavljanja ili usporavanja fronte vode pri zavodnjavanju plinskog ležišta mogu se postići intenzivnim crpenjem vode iz aquifera, po mogućnosti bušotinama što bližim toj fronti. Takvo istovremeno crpenje plina iz ležišta i vode iz aquifere (koprodukcija) može se upravljati primjenom modela materijalnog uravnoteženja:

$$G_pB_g = G_o(B_g - B_{gi}) + W_e - W_pB_w$$

ili

$$\frac{G_o(B_g - B_{gi})}{G_pB_g} + \frac{W_e - W_pB_w}{G_pB_g} = 1$$

gdje su:

B_g = obujamski faktor plina nakon vremena t, [ležišni barel/scf ili ležišni m^3/m^3]

B_{gi} = početni obujamski faktor plina [ležišni barel/scf ili ležišni m^3/m^3]

B_w = obujamski faktor vode [ležišni barel/scf ili ležišni m^3/m^3]

G_o = početni obujam plina u ležištu [scf ili m^3]

G_p = ukupna proizvodnja plina nakon vremena t [scf ili m^3]

W_e = ukupni utok vode nakon vremena t [ležišni barel ili ležišni m^3]

W_p = ukupna proizvodnja vode nakon vremena t [ležišni barel ili ležišni m^3]

Primjena jednadžbe materijalnog uravnoteženja obavlja se u dvije faze: snimanje »povijesti proizvodnje« i predviđanje »budućnosti proizvodnje«. U povijesti proizvodnje treba utvrditi dotadašnji udio aquifera. Za budućnost se iteriranjem utvrđuje najpovoljnije kretanje fronte vode.

Postupak je ilustriran primjerom ležišta Eugene Island koje je prikazano tabelom 1 i slikom 2. Konvencionalnim načinom mogao se očekivati iscrpak plina od 62% u odnosu na geološke rezerve, a koprodukcijom postignuto je 22% više, odnosno 84%. Najpovoljnije je da koprodukcija počne od početka crpenja plinskog ležišta. Međutim, slika 4 prikazuje pokazatelje ležišta kod kojeg je crpenje počelo 1960. godine a koprodukcija 1987. godine.

U slučaju vrlo velikog vodonapornog tlaka i dotoka u ležišta, bolja rješenja dobiju se modelom cijevnog protoka (Stream–tube model). Rezultat tog modela prikazan je na primjeru ležišta Ship Shoal i to na slikama 6, 7, 8 i 9, te u tabeli 3.

Ekonomska analiza prikazana u tekstu i u tabeli 4 ukazuje da se koprodukcijom, osim povećanih iscrpaka plina, postižu i rezultati konkurentni ostalim ležištima uz klasično crpenje. Potrebne su dopunske ekonomske studije da bi se sagledala profitabilnost izloženih načina proizvodnje plina.