Calculated Recoveries by Cycling from a Retrograde Reservoir of Variable Permeability

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ABSTRACT

THE recovery of the heavier components from a gas cap or retrograde pool is shown to be the greatest when the sand is cycled with a dry gas at a low pressure. This conclusion is in direct opposition to the belief that the most efficient production program is pressure maintenance and cycling at or near the dew point.

The results are calculated from: (1) constant volume, variable composition pressure-volumetemperature tests on a mixture of trap gas and liquid from a producing well; (2) published equilibrium constant data and the measured composition of the dew-point material; and (3) the fact that in a sand section of homogeneous permeability, injected gas displaces reservoir gas nearly quantitatively.

The results are based on the simplifying assumption that variable permeability systems may be defined by the ratio of two statistical parameters, and that gas injected into an actual sand will behave as though the sand were composed of many layers, each of constant permeability.

INTRODUCTION

Pressure decline in gas-condensate type reservoirs is accompanied by the formation of a liquid phase throughout the reservoir. Over the past ten years the processing of the material from these types of reservoirs for the heavier hydrocarbon components and the return of the light fractions to the reservoir ("cycling") has

become increasingly popular. It has often been stated that the purpose of such a program is to prevent the loss of the retrograde liquid phase formed in the reservoir.

The purpose of this paper is to present the results of laboratory tests and computations concerned with several possible methods of producing a gas cap or condensate type of reservoir.

The results show that the recovery of heavier hydrocarbons for this type of reservoir is not a maximum under conditions of cycling at or near the dew-point pressure. Instead, variations in permeability and the ability of the dry injected gas to revaporize condensate, point to cycling at a considerably reduced pressure as the optimum production-method. In addition the paper suggests a way of evaluating sands for their permeability variation.

The calculations presented in the following sections of the paper are in terms of the production of the butanes and heavier fraction from the gas cap of a field which had an original pressure of approximately 3000 psi. Specifically, the calculations show:

1. To what extent the condensate formed in the reservoir after pressure decline can be recovered by the cycling of a dry absorber-plant gas through the sands.

2. Whether there would be greater recovery of hydrocarbons if cycling were instigated at the original reservoir pressure.

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In answering the above points, three factors determined the efficiency with which condensate is recovered from a sand. These factors are:

1. The ability of the dry absorber gas to vaporize the condensate in the sand.

2. The effect of bypassing, within a swept out area, due to permeablity variations in the sand.

3. The effect of well pattern on the volume of formation swept out by the injected gas.

Compositional and volumetric changes of reservoir gas and liquid phases during pressure decline and cycling can be calculated from equilibrium constant data and the original composition of the reservoir material. However, in the case of condensate systems, the quantities of liquid phase so calculated are so intimately connected with the equilibrium constant of the heaviest components in the system,³ it is desirable to have the results of PVT and other tests to guide the calculations.

With respect to the effect of bypassing, on a local scale, due to permeability variations, the actual variations are so complex and so largely unknown that attempts are not made to refine the calculating procedure unduly, or to consider whether the flow should be radial or linear or some more complicated form. Rather, the calculations are based on the simple supposition that the flow is linear through variable permeabilities in parallel.

While this paper shows only calculated results, a number of drawdown and cycling tests were conducted in a tube packed with unconsolidated sand originally containing dew-point material. The results of these tests verified the calculated results.

It is believed that the methods used in obtaining the results presented in this paper are of sufficient interest to warrant presenting them in some detail. The results

will be presented in terms of 1000 cu ft of reservoir hydrocarbon space and the term Mcf will be used to designate volumes of gases measured under conditions of 60°F and 14.7 psia.

BEHAVIOR OF THE RESERVOIR FLUIDS DURING PRESSURE DECLINE

Samples of gas and liquid from a high pressure trap were recombined in a PVT cell to give a dew point of 2960 psia at 195°F. The composition of this mixture is given in Table 1.

TABLE 1-Composition of Gas-phase Material at 2960 Psia and 195°F

Component	Mol Fraction	Gal per Mcf
Methane Ethane. Propane. Butanes. Pentanes. Hexanes. Heptanes plus.	$\begin{array}{c} 0.7527 \\ 0.0766 \\ 0.0441 \\ 0.0309 \\ 0.0221 \\ 0.0226 \\ 0.0530 \end{array}$	I.03 0.84 0.99 2.54
	1.0000	5.40

Molecular weight $C_7 + = 114$

Molecular weight $C_7 + = 114$ Density $C_7 + = 0.755$ 60/60Calculated gas gravity (air = 1) = 0.942 Calculated pseudocritical temperature = 449°F Calculated pseudocritical pressure = 658 psia

The PVT behavior of the system was determined by removing successive small quantities of gas from the cell. Thermodynamic equilibrium was established after each removal. Retrograde liquid volumes and the gravity of the effluent gas were measured at each step. Such a procedure is equivalent to assuming the production of only gas-phase material from the reservoir. This is reasonable because oil will not flow from the reservoir at low liquid saturations.

In Fig 1 is shown the retrograde liquid obtained, expressed as a volume percentage. The maximum condensate was 8.25 pct at 1900 psia. Also shown in Fig 1 is the relation between the quantity of gas removed from the cell and the pressure.

The composition of the retrograde

³ References are at the end of the paper.

liquid formed during pressure decline was computed on the basis of equilibrium constant data of Roland, Smith, and Kaveler,⁹ the data presented in Fig 1,

BEHAVIOR OF THE RESERVOIR FLUIDS DURING DRY GAS INJECTION

The initial problem which must be solved is the behavior of the materials in



and apparent density data.¹⁰ The calculation procedure considered the removal of successive small portions of equilibrium gas phase from the system, followed at each point by a new equilibrium between the gas and liquid remaining in the system. This scheme corresponded to the differential removal of gas phase from the PVT cell described above. At every point, however, the equilibrium constant of the Heptanesplus fraction was adjusted until the calculated quantity of liquid in the system agreed with that determined experimentally in the PVT cell as shown in Fig 1. The calculated compositions of the coexisting liquid and gas phases, are shown in Figs 2 and 3.

The data of Figs 1, 2, and 3 in terms of field terminology are shown in Fig 4, which shows a maximum liquid volume at 1900 psia. At this pressure, 31 pct of the liquid is propane and lighter fractions. a constant permeability section into which dry gas is injected. The results obtained will form a basis for estimating the behavior of a variable permeability sand. It is assumed that no mixing takes place between the injected gas and the reservoir gas. The problem then reduces to the calculation of the enrichment of the dry injection gas by contact with the liquid condensate as the dry gas proceeds through the sand.

The process used in this study can be made clear if one visualizes a sand tube of constant cross section, porosity and permeability divided into an arbitrary number of sections along its axis. Retrograde liquid and rich gas in equilibrium with the liquid are originally present in the pores of the sand tube. Dry gas is injected into the tube at one end and at the same time rich gas is produced from the opposite end. Under these conditions the first quantity of injected gas will be progressively enriched by contact with the retrograde liquid as it advances into successive sections of the tube.

compositions obtained from Fig 2 and 3, and the quantity of liquid from Fig 4.

In terms of the above description of the method and for a constant permea-



On the other hand, as long as liquid exists in the first section of the tube it will be contacted with fresh dry gas.

Calculations on the basis of the above were carried out for injection pressures of 1310, 860 and 400 psia using the dry injection gas composition shown in Table 2, the retrograde liquid and rich gas bility section, it was found that at 1310 psia the first portion of dry gas introduced into the hypothetical sand tube became saturated with material from the liquid phase after 9 equilibrium steps. Also, at the same time the calculations indicated that all of the liquid would be vaporized by the passage of 3 volumes of dry injection-gas. It is clear that these volumes, necessary to accomplish a particular amount of liquid pickup, are dimensionless. That is, if 3,000 cu ft of gas, under reserthe point and the injection face has been injected into the system. Fig 5 shows the liquid saturation and the gas composition in a linear system of unit pore volume



voir conditions, will vaporize all the liquid in 1,000 cu ft of hydrocarbon space, by the process assumed in the calculations, then 3 cu ft of gas will vaporize the liquid in 1 cu ft of hydrocarbon space. To generalize, then, for the system studied at 1310 psia, a point in a linear system becomes dry when a volume of gas equal to three times the pore volume between

when 0.5, 1.0, 2.0, and 2.8 pore volumes of gas have been injected. An immediate conclusion of these results is that a system, originally containing a liquid phase and a gas in equilibrium, into which a dry gas is injected, is composed of three distinct regions: first a region in which all the liquid has been vaporized, followed by a region of increasing liquid saturation, and finally a region of the original composition. All three regions exist immediately upon gas injection, and only their size changes with increased injection

while region 3 occupies the remainder of the sand. Referring again to Fig 5, after the injection of 0.5 pore volumes, the first 17 pct of the reservoir is dry



FIG 4-LIQUID-VOLUMES VS. PRESSURE.

volum	ıe.	The	sıze	of	reg	gion	s	Ι	and	2	1S
fixed	by	the	qua	inti	ty	of	in	ije	cted	g	as,

Table	2—Composition	of	the	Dry	Injection
	Gas				

Component	Mol Fraction	Gal per Mcf
Methane	0.8814 0.0846 0.0294 0.0018 0.0008 0.0009 0.0011	0.06 0.03 0.04 0.06
	1.0000	0.19

Calculated gas gravity (air = 1) = 0.632Calculated pseudocritical temperature = 372° R Calculated pseudocritical pressure = 672 psia (3 times the pore volume in the first 17 pct has been injected); and 33 pct of the reservoir is region two. The remaining half is region three. When the volume of injected gas has increased to 1.0 pore volumes, the first 33 pct is dry, the remainder of the reservoir is region two and region three has disappeared.*

^{*} An exact analogue of the process may be visualized by picturing a rubber tape, representing composition, lying parallel to a ruler, representing the reservoir. The tape and ruler are each one foot long and are attached at the injection end. For 0.5 pore volumes injected, the first two inches of the tape are painted white for region one and the next four inches are painted red for region two. The fraction of the reservoir occupied by each region for

For a particular cycling test, as shown in Fig 5, the composition of the effluent gas may be calculated as a function of the quantity of injected gas. The liquid content and all the vaporized liquid has been displaced by injected gas (Fig 7).

Fig 7 shows that the ability of the dry gas to become saturated with the liquid

CALCULATED CYCLING PROCESS



of the sand may also be expressed as a function of the quantity of injected gas. Results for these cycling pressures investigated are shown in Figs 6, 7, and 8.

Referring to Fig 6 and specifically to the 1310 psia pressure, the composition of the first gas produced is 3.2 per gallons per Mcf of butanes plus, and corresponds to the composition of the rich gas in the reservoir. The gas produced in the region corresponding to 65 to 196 Mcf injection gas is dry injection gas which has been enriched by "picking up" the retrograde liquid from the sand. Beyond 196 Mcf of injection gas the composition of the injected and produced gases are the same, i.e. no more liquid remains in the sand

different quantities of injected gas may be read directly by stretching or compressing the tape. condensate is approximately the same at the three pressures investigated, i.e. the slopes of the curves are about equal at the ordinate of the chart. However, as there is less condensate initially present at the lower pressures, less injected gas is required to vaporize the liquid.

It should be emphasized here that the calculations so far do not indicate that all of the retrograde liquid can be recovered from a reservoir by cycling dry gas. They do indicate however, that the sand sections in a reservoir which are contacted by sufficient quantities of dry gas can be stripped of the retrograde liquid. The recovery mechanism discussed in succeeding sections will make this point clear.







EFFECT OF VARIABLE PERMEABILITY

The recovery of rich gas from a sand body by the injection of dry gas, and the revaporization of retrograde liquid that has formed during pressure decline are materially influenced by the permeability distribution throughout the sand. Hurst and Van Everdingen,⁶ considering only the displacement of rich gas by dry gas in a sand of variable permeability, have shown that recoveries as low as 35 pct of the rich gas can be expected.

For the purpose of this paper, the term coverage will be used to identify the fraction of the volume of a sand body that is swept out by injected gas. The coverage is always less than unity for two reasons: volumes of sand between injection wells and in other "potential deadspots" are bypassed (macroscopic coverage); and within the swept out area, smaller portions of sand are partially or completely bypassed because of variations in permeability (microscopic coverage).

The microscopic coverage depends not only upon local permeability variations in the sand, but also upon the relative mobility* of the driving and driven phases. However, for the case of a dry gas driving a wet gas, the relative mobility ratio is unity for all practical purposes, so that the problem reduces to that of determining the microscopic coverage as a function of the variation in permeability.

To illustrate the principle of the relationship between microscopic coverage and the variation of permeability, consider the following system: a linear block composed of layers separated from each other by thin impermeable streaks. The layers have permeabilities $k_1, k_2, k_3 \ldots k_n$. Suppose that the block contains a rich gas, r, which is being displaced by an injected gas, i. At any time, the interface between i and r in each layer will be at a distance from the injection face that is proportional to the permeability of the layer.*

If the permeabilities are known, the coverage can then be calculated for particular amounts of injected gas.

In practice, permeability variation is not so simple as described above, and a complete knowledge of the permeability variation over the reservoir is not possible. A simplifying assumption is required. The substitution of the actual variable system with one containing the same amount of variation, but composed of layers, each of constant permeability, is generally recognized as acceptable.

The definition of "the amount of variation" was chosen so that two different sands, with two different permeability profiles, would have the same "variation" if their microscopic coverage were the same for equal amounts of injected gas.

For example, consider two systems, each consisting of two layers. The first system has layer permeabilities of 50 and 100 millidarcys; the second has layer permeabilities of 200 and 400 millidarcys. The coverage by the injection of one pore volume of gas is the same for both systems. The systems have by definition the same permeability variation. Consider now the more general case of a system composed of many layers. The permeabilities are plotted on logarithmic probability paper and the best straight line is drawn through the points.[†] The median permeability is read at the 50 pct line. The permeability above which 84.1 pct of the permeabilities lie is also read from the plot. The difference between these two permeabilities is divided

^{*} The ratio of the relative permeability of a fluid phase to its viscosity is called the mobility; and the ratio of the mobility of the driving fluid to the mobility of the driven fluid is called the relative mobility-ratio.

^{*} This is not strictly true for a gas because the density varies with the pressure, but it is accurate enough for the purpose and the methods of calculations to be used.

t For some purposes, all the permeabilities are expressed as a per cent of the maximum permeability appearing in the distribution. This has been done in Fig 9. This step is not necessary, however, for computing the "variation,"





by the median permeability, and the ratio is called the variation. The microscopic coverage of two sand bodies will

TABLE 3—PermeabilityVariation of OilSands

Sand	Permea- bility Var.	Ref.
Chapman zone, Richfield field, Calif. Lower Rigoleto zone, Lafitte field, La. Sand well A, South Texas Gulf Coast field Coregraph No. 1, Bradford field, Pa. Coregraph No. 2, Bradford field, Pa. Well No. 220, Neosho County, Kans Well No. 1, Neosho County, Kans Well No. 9, Neosho County, Kans Slaughter field, Permian Basin, Texas Dominquez field, Southern California Shallow depth Deep depth	0.58 0.60 0.60 0.79 0.80 0.79 0.73 0.74 0.85 0.70 0.35 0.59 0.57	I II 2 6 5 5 4 4 4 4 8 7 7 7

be the same if their permeability variation is the same. Table 3 gives the permeability variation for several sands appearing in the literature, and Table 4 gives the

 TABLE 4—Percentage of Reservoir Swept

 over n Times by Injected Gas for

 Different Permeability Variations

 and for Different Amounts

 (Pore Volumes) of

 Injected Gas

Volume of Injected Gas, Pore Volumesª	n								
Gas, Pore Volumesª	0	I	2	3	4	5	6	7	
Variation of 0.30									
0.0 0.2 0.4 0.6 0.8 I 1.5 2	100 80 60 23 11 2 1	0 20 40 60 75 79 55 27	0 0 2 10 35 49	0 0 0 0 7 17	0 0 0 0 0 1 6	0 0 0 0 0 0		0 0 0 0 0 0	
2.5 3	I I	I I I	45 34	25 33	15 23	3 8	0 0	0 0	
4 5 6 8 10	0 0 0 0	00000	17 7 1 0 0	28 18 11 3 0	25 23 17 8 3	18 20 18 12 7	9 14 16 14 9	3 6 11 14 11	
15 20 30 50 100	000000	000000000000000000000000000000000000000	000000000000000000000000000000000000000	00000	00000	0 0 0 0	20000	4 1 0 0	

Volume of Injected				n				
Gas, Pore Volumesª	0	I	2	3	4	5	6	7
Va	riatio	on o	f 0.4	ļo				
0.0 0.2 0.4 0.6 0.8	100 80 60 42 29	0 20 40 57 61	0 0 1 1	0 0 0 0	00000	00000	0 0 0 0	0 0 0 0
I I.5 2 2.5 3	19 8 2 1 1	62 48 34 24 15	18 32 36 32 27	1 10 17 21 24	0 2 10 14 16	0 0 1 7 10	0 0 0 1 6	0 0 0 1
4 5 6 8 10	0 0 0 0	0 0 0 0	20 14 9 0 0	20 17 13 8 4	18 16 14 10 7	13 14 13 10 8	8 10 12 10 8	6 8 10 10 8
15 20 30 50 100	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	1 0 0 0	3 0 0 0 0	5 2 0 0 0	5 3 0 0 0
Va	riati	on o	f 0.5	;0				
0.0 0.2 0.4 0.6 0.8	100 80 60 45 35	0 20 40 51 53	0 0 4 10	0 0 0 0 2	00000	0 0 0 0	0 0 0 0 0	0 0 0 0
1 1.5 2 2.5 3	26 11 4 2 1	53 48 39 31 24	17 26 28 27 25	4 10 15 18 19	0 5 9 11 13	0 0 4 7 9	0 0 1 4 6	0 0 0 4
4 5 6 8. 10	I 0 0 0 0	14 6 0 0	21 16 13 7 3	18 16 14 10 7	14 13 13 10 8	10 11 11 10 8	8 9 9 9	6 7 8 8 7
15 20 30 50 100	0 0 0 0	0 0 0 0	0 0 0 0	2 0 0 0 0	4 2 0 0 0	5 3 0 0 0	6 4 1 0 0	6 4 2 0 0
Va	riati	on o	f 0.6	bo				
0.0 0.2 0.4 0.6 0.8	100 80 60 49 38	0 20 39 43 45	0 0 1 8 15	0 0 0 0 2	0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0
I I.5 2.5 3	30 16 11 7 5	45 44 40 36 32	20 22 22 22 22 22	4 10 12 14 15	1 6 8 10 11	0 2 5 7 8	0 0 2 3 4	0 0 0 1 2
4 5 6 8 10	3 2 1 1 0	25 19 14 5 0	20 18 16 12 9	15 14 13 11 9	11 11 11 10 9	9 9 9 9 8	6 7 7 7 7	4 5 6 6
15 20 30 50 100	0 0 0 0	0 0 0 0	3 0 0 0	6 3 0 0	6 5 2 0 0	6 5 3 0	6 5 3 1	5 4 3 1 0

TABLE 4-(Continued)

Volume of Injected				,	1			
Gas, Pore Volumesª	0	I	2	3	4	5	6	7
Va	riati	on c	f o.	70				
0.0 0.2 0.4 0.6 0.8	100 80 64 53 45	0 20 32 35 35	0 0 4 11 15	0 0 1 5	0 0 0 0	0 0 0 0 0	0 0 0 0 0	0 0 0 0
I I.5 2.5 3	38 27 20 16 12	36 36 35 33 31	16 16 16 16	8 9 10 10 10	2 6 8 8 8	0 3 5 6 7	0 2 3 4 5	0 1 2 3 4
4 5 6 8 10	8 5 4 2 2	27 23 20 14 10	16 15 14 12 10	10 10 10 10 9	8 8 8 8	7 7 7 7 6	5 5 5 5 5	5 5 5 5 5
15 20 30 50 100	I I O O	4 3 1 0 0	7 5 2 0 0	7 5 3 1 0	6 5 3	6 5 4 2 0	5. 4 4 2 0	5 4 4 2 1
Va	riati	on o	f 0.8	80				
0.0 0.2 0.4 0.6 0.8	100 81 69 59 52	0 19 24 27 28	0 0 6 9 11	0 0 1 5 7	0 0 0 0 2	0 0 0 0	0 0 0 0	0 0 0 0
I I · 5 2 · 5 3	46 37 33 30 27	· 29 29 29 28 28	I 2 I 2 I 2 I 2 I 2 I 2	8 8 8 8	4 5 6 6	1 3 4 5 5	0 2 3 4 5	0 2 2 3 3
4 5 6 8 10	22 20 17 14 11	26 24 23 20 18	12 12 12 11 10	8 8 8 8	6 6 6 6	5 5 5 5 5	4 4 4 4 4	3 3 4 4 4
15 20 30 50 100	6 4 3 1 0	14 10 3 1 0	9 8 6 3 0	7 6 5 3 1	6 5 3 1	5 4 4 3 2	4 4 3 3 2	3 3 3 2

 $\phi = \log \frac{k}{\sqrt{2}}$, and k is the permeability in millidarcys.

To illustrate the use of Table 4, Fig 9 shows a plot of the permeability profile of a California oil sand.¹ The median permeability is 13.8, and the permeability

 TABLE 5—Percentage of Reservoir Swept

 Over n Times by Injected Gas for Permeability Variation of 0.55 and for

Different Amounts (Pore Volumes) of Injected

100	,	IJ	-	~
	G	as		

Volume of Injected Gas, Pore Volumes	n							
Gas, Pore Volumes	0	I	2	3	4	5	6	7
0.0 0.2 0.4 0.6 0.8 I 1.5 2 2.5 3	100 80 60 47 36 28 13 7 5 3	0 20 40 47 49 49 40 33 28	0 0 13 18 24 25 25 24	0 0 2 4 10 13 16 17	0 0 0 1 6 9 10 12	0 0 0 0 1 5 7 8	0 0 0 0 1 3 5	
4 5 6 8 10 15 20 30 50 100	2 I 0 0 0 0 0 0 0	19 12 7 3 0 0 0 0 0	21 17 14 9 6 2 0 0 0	17 15 13 10 8 4 1 0 0	13 12 12 10 8 5 3 1 0 0	9 10 9 8 5 3 1 0 0	7 8 8 7 6 4 2 1 0	

^a Example: After injection of 1.5 pore volumes, 2 pct remains unswept; 55 pct has been swept over once; 35 pct, twice; 7 pct, 3 times; 1 pct, 4 times; and none 5 times or more.

amount of bypassing as a function of the variation and the amount of injected gas.

The variation is not an accepted statistical definition, but it is easy to compute. If the permeabilities are expressed as sug- $\frac{-\sigma\phi}{\sigma}$

gested by Law,⁷ then $V = I - 2^{-2}$ where V is the variation, $\sigma\phi$ is the standard deviation of the ϕ distribution, at the 84.1 pct line is 5.8. The difference is 8.0, and the variation is $\frac{8.0}{13.8} = 0.58$.

By interpolation from Table 4, after the injection of 2 pore volumes, 9 pct of the reservoir remains unswept; 40 pct has been swept by one pore volume; 23 pct has been swept by 2 pore volumes; 12 pct has been swept by 3 pore volumes; and no part of the reservoir has been swept by 7 or more pore volumes.*

^{*} For injection gas, a pore volume is the volume of the hydrocarbon space within the boundaries of the surface which traces the fartherest advance of the injected gas in all directions. For parts of the reservoir, the statement "40, pct has been swept by one pore volume" means that 40 pct of the volume

Fig 10 shows the producing ratio of injected to original reservoir gas for different quantities of injected gas. This chart is calculated from Table 4. sure maintenance at the dew point of 2960 psia by gas injection, and depletion to 1310, 860, or 400 psia followed by dry gasinjection at those pressures. These cal-





The use of the microscopic coveragedata presented in Table 4 and the thermodynamic data presented in the first section of this paper allows one to compute the hydrocarbon recovery as a function of the quantity of gas injected into the sand. As an example of this, the recovery of gallons of butane-plus fraction from 1000 cu ft of "active" reservoir hydrocarbon space will be calculated under four different production methods: pres-

culations will be made for a sand having a permeability variation of 0.55.

Table 5 presents the behavior of the injection gas in a sand having the permeability variation of 0.55. The data of this table were obtained by interpolation from Table 4. These data are basic for all of the calculations to follow.

PRESSURE MAINTENANCE AT 2960 PSIA BY INJECTION OF DRY ABSORBER-PLANT GAS

The flow behavior of the injected gas is given in Table 5. The C_4+ content calculated from its composition (Table 2) is 0.19 gal per Mcf. The C_4+ content of

described above has had injected gas pass into it once, while the statement "23 pct has been swept by 2 pore volumes" means that 23 pct of the total volume has had injected gas pass into it twice. Thus the total quantity of injected gas is $0.40 \times 1 + 0.23 \times 2 + 0.12 \times 3 + \ldots = 2$ pore volumes.

the rich reservoir gas at 2060 psia is 5.40 gal per Mcf (Table 1). On the unit basis of 1000 cu ft of pore space, the reservoir contains at 2960 psia and 195°F, 1100 gal of C₄+ in 204 Mcf of gas. When filled with dry gas at 2960 psia and 195°F, the reservoir contains 35 gal of C4+ in 182 Mcf.

is necessary to determine the quantity of material existing in the reservoir at the start of the injection process. During the pressure reduction process, the composition of the effluent is independent of the permeability variation.

A summary of these calculations is given in Table 7.

Gallons of C4+					
ected Reservoir Content	Mcf Gal C+ per	Mcf			
(4) (5)	(8) (9)	(8)			
0 I,100 7 887 14 674 21 536 28 418 35 333 52 173 68 109 86 88 104 67 138 56 173 46	$\begin{array}{c ccccc} 0 & 5.40 \\ 41 & 5.40 \\ 82 & 4.90 \\ 121 & 3.50 \\ 160 & 2.70 \\ 198 & 2.20 \\ 385 & 0.68 \\ 476 & 0.45 \\ 568 & 0.31 \\ 750 & 0.24 \\ 932 & 0.21 \\ 0 & 0.11 \\ \end{array}$	0 41 82 121 160 198 293 385 476 568 750 932			
	38 56 I,182 I,080 73 46 I,227 I.090 35 I,100 I,100	38 56 I,182 I,080 73 46 I,227 I,090 35 I,100 I,100			

TABLE 6-Recovery of C4+ by Pressure Maintenance at 2960 Psia

Notes on Calculation Methods

(2)
$$V_i = V_p \cdot \frac{P_2 T_1 Z_1}{P_1 T_1 T_2}$$

 $P_1T_2Z_2$ $= V_p \cdot \frac{2960}{745} \cdot \frac{520}{5} \cdot$ $= V_{p} \cdot \underbrace{\overrightarrow{3}}_{14,7} \cdot \underbrace{\overrightarrow{655}}_{655} \cdot \underbrace{\overrightarrow{0.88}}_{0.88}$ = 181.8 V_{p} (3) From Table 5

(3) From Table 5
(4) Injected gas contains 0.19 gal C4 per Mcf. Item 4 = 0.19 · item 2.
(5) The initial C4+ content, all in the gas phase, is 1100 gal per 1000 cu ft of reservoir space. (See Table 7). The C4+ content of that portion of the reservoir containing injected gas is 35 gal per 1000 cu ft. Therefore, the C4+ content of the reservoir is 1100 · item 3 + 35[1 - item 3].
(6) Gross produced = original + injected - reservoir content. Item 6 = 1100 + item 4 - item 7

item 5.

(7) Net Produced is the amount of the original content produced. Item 7 = 1100[1 - item 3].
(8) Produced gas is part rich gas and part injected gas. The injection of one pore volume of gas produces one pore volume, which is composed of 0.28 pore volumes of injected gas and (1 - 0.28) volumes of rich gas. Item 8 = 181.8[item 1 - [1 - item 3]] + 204 [1 - item 3] = 181.8[item 1 + item 3 - 1] + 204 [1 - item 3].
(9) Slope of the curve obtained by plotting item 6 vs item 8, or better, by performing graphical differentiation of data shown in items 6 and 8 and smoothing results.

differentiation of data shown in items 6 and 8 and smoothing results.

Table 6 gives a summary of the calculations for pressure maintenance at 2060 psia together with an explanation of the methods of calculation.

PRESSURE DRAWDOWN FROM 2960 PSIA WITHOUT GAS INJECTION

Prior to determining the effect of injecting gas at the lower pressures it

PRESSURE MAINTENANCE AFTER DRAW-DOWN FROM 2960 PSIA

Again it is necessary to make use of the data presented in Table 5. This calculation differs from that outlined in Table 6 because in addition to displacing the rich reservoir gas, the injected gas revaporizes liquid that has condensed during the pressure decline from 2960 to 1310 psia. Fig 8 shows the C_4 + in the sand as a function of the quantity of injected gas.

the data of Table 5 will give recovery for the section having a 0.55 permeability distribution.

Table 8 gives a summary of the total quantity of C₄+ (expressed as gallons

Table 9 presents the calculations for the recovery of C_4 + at 1310 psia by

	Gas Pr	oduced	Per	Pressure Int	erval		C4+ in Reservoir, Gal			
Pressure, Psia	Pct	Mcf	Gas Pro- duced, Mcf	Avg C ₄ + Content, Gal per Mcf	C ₄ + Pro- duced, Gal	Produced, Gal	Liquid Phase	Vapor Phase		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		
2,960 2,800 2,400 2,200 2,200 1,800 1,600 1,400 1,200	0 5.0 11.6 18.5 25.4 32.6 40.0 47.2 54.4 61.3	0 9.8 22.8 36.2 49.8 63.9 78.4 92.5 106.5 120.0	9.8 13.0 13.4 13.6 14.1 14.5 14.1 14.0 13.5	5.10 4.52 4.08 3.75 3.52 3.37 3.28 3.25 3.22	$50.0 \\ 58.8 \\ 54.7 \\ 51.0 \\ 49.7 \\ 48.9 \\ 46.3 \\ 45.5 \\ 43.5 \\ $	0 50.0 108.8 163.5 214.5 264.2 313.1 359.4 404.9 448.4	0 160 283 358 400 421 428 427 424 418	I, 100 890 708 579 485 415 359 314 271 234		
1,000 800 600 400	68.2 74.9 81.6 88.1	133.5 146.5 160.0 172.5	I3.5 I3.0 I3.5 I2.5	3.23 3.35 3.63 4.20	43.6 43.6 49.0 5 ² .5	492.0 535.6 584.6 637.1	408 397 385 368	200 167 130 95		

TABLE 7--Effect of Pressure Decline on C₁+ Distribution

Notes on Calculation Methods (2) Obtained from constant volume gas phase withdrawal PVT test. See Fig 1

2960 (3) At 2960 psia and 195°F, 1000 cu ft of reservoir hydrocarbon space contains 1000 \cdot

14.7

 $\frac{520}{655} \cdot \frac{1}{0.78} = 204$ Mcf of gas.

At 14.7 psia and 195°F, the total liquid remaining in the reservoir is 4.67 pct, or 46.7 cu ft per 1000 cu ft. From Fig 3 it is estimated that this liquid has a specific gravity of 0.658 at 195°F and a molecular weight of 101. Therefore, the vapor equivalent of the liquid phase is $(62.4 \cdot 0.658)$

$$46.7 \cdot \frac{101}{101} \cdot 379 = 7.35 \text{ Mcf}$$

At 14.7 psia and 195°F the gas phase remaining in the reservoir is

At 14.7 psia and 195°F the gas phase remaining in the reservoir is 1000(1 - 0.0467) · ⁵²⁰/₆₅₅ = 0.76 Mcf. Therefore, the gas produced in going from 2960 psia to 14.7 psia is 204 - (7.35 + 0.76) = 195.9 Mcf. Item 3 = 195.9 · item 2
(4) Obtained by differencing item 3
(5) From Fig 4
(6) Item 6 = item 4 · 5
(7) Summation of item 6
(8) From Fig 4
(9) Original reservoir gas contains 5.4 gal C4+ per Mcf. As shown above, 1000 cu ft of reservoir hydrocarbon space contains 204 Mcf of gas at 2960 psia and 195°F. Therefore, original C4+ content of reservoir is 204.5 · 4 = 1100 gal. Gallons in gas phase at any pressure = original - produced - amount in liquid phase. Item 9 = 1100 - item 7 - item 8.

of liquid) in 1000 cu ft of reservoir space after being contacted with various quantities of dry injection-gas at 1310 psia. These data are for a section of homogeneous permeability and when used with

injecting dry gas. The results of calculations for injection at 860 and 400 psia are included at this point in Tables 10 and 11.

In Fig 11, are plotted the productions

calculated in Tables 6, 9, 10 and 11 as a function of the quantity of gas injected. The intercepts on the ordinate for the

TABLE 8-C₄+ Content of Homogeneous Permeability Section after Being Contacted with Various Quantities of Injection Gas

Volume of In- jected Gas		C₄+ in Liquid	Total C4+ in	
Pore Volume	Mcf	Phase, Gal	Reservoir, Gal	
(1)	(2)	(3) 1310 Psia	(4)	
0	0	422	677	
I	78	230	437	
2	156	55	245	
3	234	Ō	70	
4	312	0	15	
5	390	0	15	
		860 Psia		
0	0	398	577	
I	50	250	408	
2	100	115	260	
3	150	15	125	
4	200	0	25	
5	250	0	10	
6	300	0	10	
		400 Psia		
0	0	368	463	
I	22	282	372	
2	44	180	286	
3	66	76	184	
4	88	34	100	
5	110	0	38	
6	132	0	4	

Notes on Calculation Methods (1310 psia) (2) Injection gas at 1310 psia and 195°F

$$V_{i} = V_{p} = \frac{P_{2}}{P_{1}} \cdot \frac{T_{1}}{T_{2}} \cdot \frac{Z_{1}}{Z_{2}}$$

 $V_{i} = V_{p} \cdot \frac{1310}{14.7} \cdot \frac{520}{655} \cdot \frac{1}{0.91} = 78V_{p} \text{ or } 78 (1)$ (3) From Fig 8.

(3) From Fig 8.
(4) Initial value from items 8 and 9, Table 7 and consists of 255 gal C₄+ in the gas phase and 422 gal in the liquid phase. At one pore volume of injected gas the homogeneous permeability section has lost the 255 gal in the gas phase, added 78 × 0.19 = 15 gal from the injection gas giving a total of 437 which becomes distributed as 230 in the liquid phase and 207 gal in the gas phase. Because the reservoir initially contains about 8 pct liquid, one pore volume is more than sufficient to displace all of the original reservoir gas at this pressure. The error in neglecting the amount of injection gas produced amounts to less than one

injection pressures of 1310, 860, and 400 psia are the quantities of C₄+ obtained by pressure depletion from the original 2960 psia. The recoveries by cycling shown

gallon.

in this figure are only for the portion of the reservoir that has been swept by the injection gas. Fig 12 shows the composition of the produced gas.

EFFECT OF INCOMPLETE COVERAGE OF RESERVOIR BY INJECTION GAS

Having evaluated the recovery from the portion of a reservoir which has been swept by injection gas, it becomes possible to evaluate the recovery from the complete reservoir. The macroscopic coverage can best be determined from electric model studies. For purposes of discussion calculations will be made for a macroscopic coverage of 75 pct.

Fig 13 shows the gross amount of C_4+ produced from a unit reservoir of 1000 cu ft of hydrocarbon space. The macroscopic coverage is 75 pct and the permeability variation is 0.55. The intercepts of the curves and the ordinate are the same as Fig 11. These intercepts represent the recovery obtained during pressure decline, and are independent of the macroscopic coverage and the permeability variation.

To illustrate the derivation of Fig 13 from Fig 11, consider the injection at 1310 psia and 195°F. of 100 Mcf into the unit reservoir. The injected volume will pass into and through 750 cu ft of reservoir hydrocarbon space, and will bypass the remaining 250 cu ft.

As the 100 Mcf of injection gas will effect only 750 cu ft of reservoir hydrocarbon space, the recovery from this volume will be equivalent to that obtained by passing 100 \div 0.75 = 133 Mcf through 1000 cu ft of "active" reservoir space. From Fig 11, the gross production will be 790 gal per 1000 cubic feet. Of this, 425 gal were produced during pressure decline, leaving a net of 365 gal per 1000 cubic feet which were produced due to injection. This is equivalent to 273 gal per 750 cubic feet. The total production for 75 pct macroscopic coverage, as plotted in Fig 13, is 425 gal by pressure decline plus 273 by gas injection, or 698 gal C₄+ per unit reservoir. Fig 13 shows that for a particular amount of injected gas, the gross production of C_1 + is increased maintenance at 2960 psia will recover 71 pct of the C_1 + whereas pressure depletion to 400 psia followed by pressure maintenance at 400 psia will recover 87 pct of the C_4+ .

Vol. of Injected Gas Gallons of C4+ Producing Ratio, Gal C₄+ per Mcf C₄+ Content of Reservoir, Gal Produced Gas, Mcf Gross Prod. Net Prod. Pore Vol Injected Mcf 6 8 2 3 4 5 7 I 0 3.2 3.2 3.2 3.1 677 0 0.2 0.4 0.6 0.8 0 16 0 16 629 581 538 51 102 51 102 3 32 48 63 31 9 12 148 147 192 47 62 495 194 3.0 237 333 397 438 475 78 118 451 356 294 79 120 159 198 Ι.Ο I5 22 241 2.8 342 413 460 I.5 2.0 30 1.60 156 2.5 3.0 195 234 254 217 37 45 1.29 505 238 1.02 4.0 5.0 6.0 8.0 318 59 74 89 532 0.76 312 159 577 632 396 476 635 0.61 0.50 0.32 390 468 624 119 82 573 610 684 119 148 53 34 743 791 639 658 10.0 780 793 0.22 15.0 20.0 22 222 296 877 958 670 1,183 0.20 1,170 1,560 15 15 677 677 1,573 0.10 80 0.10

TABLE 9-Recovery of C4+ by Pressure Maintenance at 1310 Psia

Notes on Calculation Methods

(2) Computed as shown in Table 8

(2) Computed as shown in Table 8.
(3) From item 4, Table 8 and Table 5. For example, at 0.8 pore volume injected item 3 = (0.36 · 677) + (0.49 · 437) + (0.13 · 245) + (0.02 · 70) = 495.
(4) Injected gas contains 0.10 gal C₄+ per Mcf. Item 4 = 0.19 · item 2.
(5) Gross produced = original + injected - present content. Item 5 = 677 + item 4 - item 3.
(6) Net produced is the amount of the original rich gas produced and is equal to the gross produced minus the amount of injected gas that has been produced. The produced injected gas equals the pore volume injected - (1-fraction uneffected). Therefore, item 6 = item 5 - l(1) + (3, Table 6) - 1.
(7) At start of injection, 1000 cu ft of hydrocarbon space contains 38.5 lb-mols of liquid phase + 204 lb-mols of gas, (From Figs 1, 2, 3); total 242.5. After the hydrocarbon space contains only injected gas it will contain 208 lb-mols. Therefore, ultimately 242.5 - 208.0 lb-mols, or 13 Mcf, will be produced than have been injected. These 13 Mcf have been proportioned over the first ten pore volumes of injected gas.

over the first ten por volumes of injected gas. (8) By graphical differentiation of items 6 and 7.

by declining the pressure before gas injection.

CONCLUSIONS

The calculations presented in Figs 11 and 13 are for the gross amount of C4+ produced. Since the production includes some C₄+ originally present in the injection gas, Fig 14 is presented to show the percentage of the C₄+ originally in the reservoir which is produced. For an ultimate producing ratio of one gallon of C₁+ per Mcf of produced gas, pressure

The recovery of the heavier components from a gas cap or retrograde pool under various production methods has been calculated. The results show that the recovery is greatest if the reservoir pressure is allowed to decline prior to cycling dry gas.

Acknowledgments

The authors are grateful to the management of the Standard Oil Company of

Volume of Injected Gas		C4+ Content of	Gallons of C_4+			Produced Gas	Producing Ratio,
Pore Volume	Mcf	Reservoir, Gal	Injected	Gross Prod.	Net Prod.	Mcf	Mcf
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
0 0.2 0.4 0.6 0.8 1.0 1.5	0 20 30 40 50 75	577 543 511 481 446 416 340	0 2 4 6 8 10 14	0 36 70 102 139 171 251	0 36 70 101 137 168 245 245	0 20 31 41 51 76	3 · 4 3 · 4 3 · 4 3 · 4 3 · 4 3 · 4 3 · 2 2 · 5
2.0 2.5 3.0	100 125 150	287 252 220	19 24 28	309 349 385	298 334 365	102 128 153	I.9 I.5 I.35
4.0 5.0 6.0 8.0 10.0	200 250 300 400 500	172 125 95 56 36	38 47 57 76 95	443 499 539 597 636	413 461 491 531 551	204 255 306 408 511	I.10 0.87 0.68 0.40 0.20
15.0 20.0 30.0 ∞	750 1,000 1,500	19 11 10 10	143 190 286	701 756 853	568 575 576 577	761 1,011 1,511	0.19 0.19 0.19 0.19 0.19

TABLE 10-Recovery of C₄+ by Pressure Maintenance at 860 Psia

See Table 9 for notes on calculation methods

TABLE 11—Recovery of C₄+ by Pressure Maintenance at 400 Psia

Vol. of I Ga	njected s	C ₄ + Content of	Gallons of C++			Produced Gas,	Producing Ratio,
Pore Vol.	Mcf	Reservoir, Gal	Injected	Gross Prod.	Net Prod.	Mcf	Gal C ₄ + per Mcf
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
0	0	463	0	0	0	0	4.6
0.2	4.4	445	0.8	18.8	18.8	4.8	4.6
0.4	8.8	427	1.7	37.7	37.7	9.7	4.6
0.6	13.2	410	2.5	55.5	55.5	14.6	4.5
0.8	17.6	390	3.3	76.3	76.0	19.5	4.4
I.0	22	371	4.2	96	95	24	4. I
I.5	33	329	6.2	140	138	36	3.5
2.0	44	287	8.4	184	180	49	3.0
2.5	55	259	10.5	214	208	61	2.6
3.0	66	234	12.5	242	233	73	2.4
4.0	88	187	17	293	280	96	1.9
5.0	110	143	21	341	324	122	1.6
6.0	132	110	25	378	357	146	1.4
8.0	176	68	33	428	399	195	1.0
10.0	220	43	42	462	425	243	0.80
15.0	330	23	62	502	443	353	0.40
20.0	440	10	84	537	457	463	0.25
30.0	660	5	125	583	462	683	0.20
50.0	1,100	4	208	667	462	1,123	0.19
100.0	2,200	4	418	867	463	2,223	0.19
80		4			463		0.19

See Table 9 for notes on calculation methods













California, and particularly to Mr. E. G. Gaylord, for permission to publish this paper. They are also grateful to Mr. G. L. Powell for suggesting the problem.

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DISCUSSION

N. VAN WINGEN*-The paper by Standing, Lindblad and Parsons is an important contribution toward a better understanding of the behavior of retrograde condensate-type reservoirs. The first essential prerequisite for an adequate prognostication of the behavior of such pools is the availability of variable composition (constant volume) PVT data such as presented here by the authors. This type of information has to date been very scarce as the majority of published research

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has dealt with systems of constant composition (variable volume). To the best of my knowledge only two variable composition papers have previously been published, one by E. W. McAllister¹² and the other by F. H. Dotterweich and E. O. Bennett.¹³ Results obtained for constant as compared to variablecomposition systems generally differ to a sufficient extent to be of significant economic importance. Thus, it is to be hoped that emphasis will be given in future research to this type of approach, rather than to additional work involving systems of constant composition which do not duplicate the behavior of actual reservoirs.

The authors' method of combining reservoir fluid thermodynamics with a consideration of the dynamic characteristics of the reservoir rock offers a unique approach to a difficult problem. It should be taken into account, however, that any calculations involving a consideration of permeability variation will be subject to a material potential hazards factor as data to adequately describe the permeability characteristics of a reservoir are seldom available. Jan Law14 adequately demonstrated this point and concluded that current knowledge of fluid characteristics far outdistances knowledge of the interstitial characteristics of the sand phase. Thus, while the results of an analysis as here presented by Standing and co-authors is of considerable theoretical interest, the actual behavior of any field to which it may be applied may well differ markedly from that as indicated by the calculations. It is true that the authors point out an agreement between computations and results as obtained in a laboratory sand column, but this agreement resulted from the fact that, contrary to an actual reservoir, the permeable variation of the laboratory column was subject to accurate analysis. The authors' simplifying assumption of substituting for the actual variable permeability system one which is composed of layers each

¹² E. W. McAllister: Application of Laboratory Data on Phase Behavior to Evaluation of Condensate Reservoirs. California Oil World,

²nd issue Oct. 1945. ¹³ F. H. Dotterweich and E. O. Bennett: Trends in Processing Gas Condensate Reservoirs. *The Oil Weekly* (May 6, 1946).

¹⁴ J. Law: A Statistical Approach to the Interstitial Characteristics of Sand Reservoirs. Trans. AIME (1944) 155, 202.

of a constant permeability neglects the very important phenomenon of oblique flow. The combined effect of the above factors may be such that the coverage or recovery efficiency as actually obtained in a reservoir may, under certain adverse conditions, not even approximate that as here computed theoretically.

The above statements are not meant to detract in any sense from the value of this excellent paper, but rather to point out the extreme complexity and difficulty involved when field permeability data are to be used quantitatively. In this regard this paper again serves to bring out the desirability and ultimate economic value of conducting extensive coring and core analysis operations during the early stages of a field's development.

The authors' conclusion that for a variable permeability retrograde pool the recovery of heavier hydrocarbon fractions is greatest when the reservoir pressure is allowed to decline prior to cycling is of extreme interest. I do feel, however, that for any actual field certain other basic factors in addition to permeability variation should also be carefully considered before proceeding to deliberately reduce the initial reservoir pressure. Thus for example, all California condensate pools discovered to date have been found to be underlain by black oil production. For the majority of such reservoirs the increased black oil recovery obtainable from a maintenance of gas cap pressure should in general far outweigh economically the value of the decreased butane plus recovery for the gas cap. Also irregular by-passing can probably be controlled more effectively at the higher pressures.

I would like to ask the authors the following questions:

I. To what extent would a 50 pct error in the concept of a field's permeability variation (which is well conceivable) effect the theoretically computed butane plus recovery.

2. The authors have varied nearly all the parameters except composition. What would be the effect on the analysis if the gas were either very much richer or leaner than the one here considered.

3. The authors cite a recovery of butane plus of 71 pct for pressure maintenance at 2960 psi as compared to 87 pct for depletion to 400 psi followed by cycling at the latter pressure. Rather than merely considering the respective quantities of butane plus, what would be the respective values of the total products recovered for the two methods of operation.

4. Is it possible that errors in the calculation due to lack of adequate basic data may effect the final result to an extent greater than the theoretically computed increased recovery. In other words, what is the probable degree of certainty of the theoretically computed increased recovery at the lower pressure.

J. C. YOUNG^{*}—In Figs 13 and 14, which show the relationship of the recovery of C_4 + versus the amount of gas injected, did you include in your calculation the C_4 + which can be produced after each method of cycling is completed and the reservoir is being depleted down to a minimum pressure without gas injection?

If not, it appears to me that a considerably higher ultimate recovery of C_4+ can be expected from the 2960 psia-cycling system than shown. After cycling at 2960 psia, according to your calculation for an ultimate producing ratio of one gallon of C_4+ per Mcf of produced gas, there is left in the formation 29 pct of the original C_4+ . Table 7 shows that there is 58 pct of C_4+ produced by pressure decline from the dew point to 400 psia. If this is so, with the remaining C_4+ in the formation, then the ultimate C_4+ recovered can be expected to be in the neighborhood of 88 pct when the reservoir is totally depleted.

Can you give me the recovery of C_4 + expected by pressure decline to 400 psia after each method of cycling to a producing ratio of one gallon of C_4 + per Mcf of produced gas?

In regard to the behavior of the reservoir fluids during dry gas-injection, you assume that no mixing takes place between the injected gas and the reservoir gas. Will you please give me some of your reasons for this assumption? Undoubtedly, you have laboratory data to verify it.

I wish to take this opportunity to compliment you and the co-authors of this excellent paper. It is a great contribution to the industry. It has introduced invaluable data which

^{*} Conservation Committee of California Oil Producers, Los Angeles, California.

engineers can use in the determination of the most economical method of producing condensate or large gas-cap fields.

E. C. BABSON*—Messrs. Standing, Lindblad and Parsons have presented a radical departure from the conventional concept of the mechanics of cycling. In the past, most writers on the subject have assumed, either implicitly or explicitly, that the principal gain in recovery

 TABLE 12—Permeability Variation in Calitornia Oil Sands

Field	Zone	Phi Standard Devi- ation	Per- meabil- ity Vari- ation
Dominguez	Second Third Fifth Second	1.9 2.4 2.3	0.48 0.57 0.55
East Coyote	Second and Third	3.2 3.1	0.66
Olinda	Stern Miocene Miocene Miocene	5.4 1.9 4.2	0.85
	Miocene Miocene Miocene	3.5 3.7 3.0	0.72
Richfield	Miocene Chapman	2.3 4.4 2.1	0.55 0.73 0.52
Rio Bravo	Rio Bravo Rio Bravo Lower Zins	1.0 1.1 1.8	0.30 0.32 0.47
	Lower Zins Lower Zins O'Dea O'Dea	2.6 2.3 2.7	0.60 0.55 0.61
	O'Dea O'Dea O'Dea	2.0 2.8 3.2	0.50 0.62 0.67
Santa Fe Springs.	O'Dea Bell (Com- posite)	2.0 2.4	0.50 0.57
	Meyer Nordstrom Nordstrom	2.I 2.2 I.0	0.52 0.54 0.30
	Buckbee Buckbee O'Connell	I.7 2.1 I.2	0.45 0.52 0.34

resulting from cycling is due to the production of a considerable portion of the hydrocarbons from the reservoir before the pressure has declined to a level which would permit appreciable retrograde condensation. It has been considered that for practical purposes no important portion of the hydrocarbons which have condensed in the reservoir can be recovered by revaporization. Mr. Standing and his collaborators present quite a convincing case that this point of view is in error and that the vaporization of hydro-

* Union Oil Co., Santa Fe Springs, California. carbons condensed in the formation can be of great importance.

There is one weakness in the authors' approach which could possibly modify their results significantly. The authors' calculations are all based upon equilibrium conditions and their conclusions would certainly be applicable to an operation in which sufficient time were permitted for the injected gas to come to equilibrium with the condensed liquid in the formation. The question arises, however, whether the speed of vaporization is rapid enough to permit a close approach to equilibrium during an actual cycling operation.

The author's Table 3 is of interest, particularly in the light of recently published statements regarding the extreme variation in permeability in California oil sands. In order to amplify the information given by the author, some additional data on permeability variation in California oil sands are shown in Table 12.

W. T. LIETZ*—The authors calculate, under the circumstances outlined in the report, pressure maintenance at 2960 psi will lead to an ultimate recovery of 71 pct of the C_4 + originally present in the sand; whereas, depletion to 400 psi, followed by pressure maintenance at that reduced pressure, will bring this recovery up to 87 pct.

In the first case, however, after hoving recovered the 71 pct, the reservoir has still the original pressure and with the subsequent depletion, additional liquid products will be recovered. In the second case, this final depletion will yield a substantially smaller amount of additional oil because, firstly, more C_4 + has already been recovered and, secondly less gas is available to carry off the C_4 + fractions.

It would be interesting to see the calculations carried on beyond the end of pressure maintenance and obtain a recovery efficiency for a final pressure of, say 200 psi for the two operating schemes discussed in the paper.

Finally, a comparison of costs for the two methods would add to the value of this paper.

M. B. STANDING, E. N. LINDBLAD and R. L. PARSONS (authors' reply)—Much of the

* Shell Oil Co., Los Angeles, California.

comment on the paper has been focused on the possibility of obtaining recovery by pressure decline after cycling to economic depletion at the dew point. The following discussion The production by pressure depletion from this reservoir will be a mixture of the production from the two regional volumes. As an approximation, the rates of production from



FIG 15—CHART SHOWING RATE OF PRODUCTION OF BUTANES PLUS DURING PRESSURE DECLINE AFTER

CYCLING TO DEPLETION AT DEW POINT.

Permeability variation = 0.55 Macroscopic coverage = 75 pct

Curves are for systems of constant original composition: 1. Original producing ratio of 10 times economic limit; 2. Ratio of 5.4; 3. Ratio of 3; 4. Ratio of 1.5.

covers this point, and answers in a general way the comments of Messrs. W. Tempelaar Lietz, N. van Wingen, and J. C. Young.

After cycling to depletion at the dew point, the reservoir may be divided into two regional volumes: a volume containing essentially original dew-point material and a larger volume containing a mixture of original dewpoint material and dry injected gas. In the larger volume, the dew-point material may be thought of as being in the lower permeability parts, although a considerable amount of mixing will probably have taken place. the two regional volumes will be in proportion to their volume. By further assuming normal retrograde behavior in the region containing original reservoir gas, and no retrograde behavior in the region containing predominantly dry injected-gas, the curves of Fig 15 may be calculated. The results show that if the butanes-plus content of production from the original reservoir gas is more than four times the butanes-plus content of gas that may be processed economically, additional butanes-plus may be economically recovered by declining the pressure after cycling to







FIG 17-EXPERIMENTAL DATA SHOWING EFFICIENCY WITH WHICH ONE GAS IS DISPLACED BY SECOND GAS IN SAND SECTION OF CONSTANT PERMEABILITY.

depletion at the dew point. Additional results, not shown graphically, indicate that the recovery of the butanes-plus for the richer mixtures (more than a ratio of 4) is the same for cycling at the dew point followed by pressure decline to a low pressure as for initial pressure decline to a low pressure followed by cycling to depletion. In both cases, the heavier fractions remaining in the reservoir at depletion are very nearly equal to the heavier fractions existing in the macroscopically by-passed region after straight pressure decline. All of the above conclusions have been based on the experimental results obtained with the particular retrograde mixture used in this study. However, it appears likely that the conclusions are broad enough to be applicable to any retrograde mixture, and this is the justification for presenting the results in dimensionless form.

To summarize, additional recovery may be had by pressure decline after cycling to depletion, providing the original retrograde mixture is sufficiently rich. For rich mixtures the recovery is independent of the cycling pressure and the problem reduces to that of determining the most economical pressure at which to cycle. For lean mixtures, the maximum recovery is obtained if cycling is preceded by pressure depletion.

With respect to the question by Mr. Van Wingen on the effect of an incorrect evaluation of the permeability variation, the effect may be determined by calculating the recovery for several different permeability variations. This has not been done. However, as an indication of the results which would be expected, the recovery for cycling at the dew point has been calculated for several different permeability variations. The results are shown in Fig 16. These results indicate that if the permeability variation is low, say less than 0.60, the percentage of recovery is relatively independent of the variation.

Mr. Young's questioning of the flooding efficiency in a section of uniform permeability is in order. The displacement efficiency of one gas by another in a section of constant permeability was assumed in the calculations to be 100 pct. This assumption was based on an experimental test in which air was displaced by a dry hydrocarbon gas from a tube packed with unconsolidated sand. The results of the test are shown in Fig 17. The results show that after the injection of one pore volume of gas, 94 pct of the air has been displaced.

Mr. Babson's data on the permeability variation of several California sands are appreciated. The data show that for the sands considered, the permeability variation in California is certainly no greater than in other parts of the country. The permeability variation of the Chapman zone as determined by Mr. Babson (0.52) and by us (0.58) indicates the extent to which two computers might differ in estimating the variation in a sand.