Guide to Successful Well Stimulation

By JACK SCHRENKEL
Union Oil Company of California

INTRODUCTION AND PURPOSE

It is important that oil wells be produced at their maximum permissible rate because of the greater income generated, lower lifting costs per barrel, quick return of investment, and the larger oil reserve of a top allowable well.

The rate at which an oil well produces depends upon several factors. These factors are:

1. The difference between the formation pressure and the producing bottom-hole pressure;

2. The flow capacity of the formation expressed in millidarcy feet (KH);

3. Viscosity of the flowing oil with its contained gas;

4. The magnitude or absence of a local resistance to flow around the well, known as "skin effect;"[1,2], and

5. Proper operation of pumping or gas lift equipment.

Excluding skin effect, these factors are described in mathematical terms by an equation known as Darcy's Radial Flow Formula. It is the purpose of this paper to show a determination of the magnitude and cause of skin effect and a consideration of the factors in the Darcy Formula may be used to predict successfully the results of workover operations.

THEORY OF OIL FLOW INTO A WELL

Fig. 1 is a drawing showing the theoretical pressure distribution for radial flow in an undamaged formation, and a fractured formation.

The flow of the oil into the well is described by Darcy's Radial Flow equation, which is as follows:

$$Q = \frac{7.07\ KoH\ (P-Pf)}{u\ B\ \ln Re/Rw}$$

Where:

Q = Production, barrels per day
Ko = Permeability to oil, darcys
H = Effective pay thickness, feet
P = Formation pressure, psi
Pf = Pumping or flowing bottom hole pressure, psi
u = Fluid viscosity, centipoises
B = Formation volume factor, no units
Re = Drainage radius, feet
Rw = Well radius, feet

The equation presented above is the basic form for radial flow. There are variations of this formula to fit special conditions, such as gas wells and wells having non-radial boundaries. This equation is an idealized concept. In actual practice the equation is generally complicated by a factor known as skin effect, which may be defined as a restriction to flow in or near the well bore caused by:

1. improper perforating,
2. reduced permeability from loss of drilling fluids to the formation, and/or
3. scale deposits.

Examination of the Darcy equation reveals there are only a few factors which may be changed to increase oil production. The effective pay thickness (H) may be increased by perforation of additional sections (if all of the pay was not originally perforated). The producing bottom-hole pressure may often be lowered by changing pumping conditions or more efficiently gas lifting a well.

Effective formation permeability (K) may be increased by acid and fracturing treatments. Deeply penetrating fractures in effect increase the effective well diameter (R_W).[3] Other factors in the equation, viscosity (u), formation volume factor (B), and drainage radius (R_e) (function of distance between wells), may not be changed enough to be of any practical use.

METHODS OF SELECTING AND ANALYZING PROSPECTIVE WORKOVER WELLS

Wells which should be considered for possible production improvement are those which will not make the maximum allowable and one or more of the following conditions exist:

1. A well which is not as good a producer as offsetting wells completed in the same formation.

2. A well which is not as good a producer as core analysis or formation test data would indicate.

3. A low P.I. well in a group of high P.I. wells.

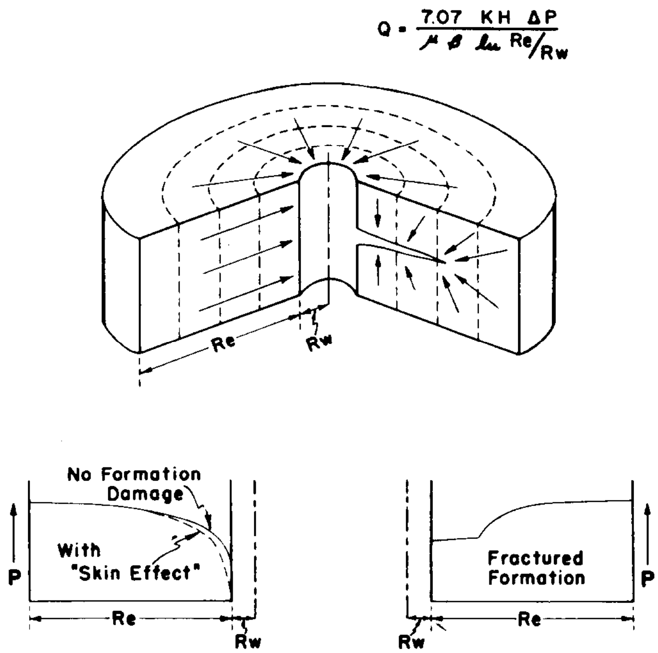
4. A well which has a high gas-oil ratio in a group of low gas-oil ratio wells completed in the same formation.

If an operator has a large number of wells which might respond to workover treatments, workover wells should be selected in order of the greatest forecasted income in relationship to the cost of repair.

In analyzing the performance of a well for a stimulation treatment, it should first be determined whether the pumping or gas lift equipment is functioning properly. Accurate measurements of its oil and water production and gas-oil ratio should be made to see if the reported production tests are representative of the well's ability to produce. In some cases wells have been worked over because of some mistake in reporting actual producing ability. A history of the initial completion, subsequent workovers and their results should be compiled.

The most effective way of detecting skin effect is by use of the pressure buildup test. The rate of bottom-

Figure I Pressure Distribution and Flow Paths for Radial Flow into a Well for Undamaged, Damaged, and Fractured Formation.



hole pressure increase in a closed in well depends upon the rate of production prior to shutin, the natural flow capacity (KH) of the formation, and the viscosity of the formation oil with its dissolved gas. Knowing the viscosity of the fluid and measuring the rate of pressure buildup, formation capacity is readily calculated (see Fig. 2).

The key to the effectiveness of the pressure buildup test in analyzing well completions is that it measures the natural flow capacity of the well when no fluid is flowing and compares this capacity to the overall flow capacity which is measured by a P.I. test immediately before the shutin period. The pressure buildup test, under the proper conditions, is a quantitative measure of the efficiency of a well completion.

In other words, it not only tells us whether or not there is something wrong with the well, but it also tells us the degree to which the well may be damaged and what production increase may be expected if the cause of production impairment is eliminated. The pressure buildup theory is not discussed here. The development and use of this technique has been extensively covered in many articles. 4, 5, 6, 7, 8, 9, 10, 11.

Before the introduction of pressure buildup tests and their growth in popularity, Productivity Indices were the best method to determine the effectiveness of well completions. The Productivity Index (P.I.) is defined as the production in barrels per day divided by the pressure differential between the producing bottom-hole pressure and true static formation pressure.

Generally speaking, a low productivity well is a low P.I. well. It is necessary to have P.I.'s on a good number of wells in the field before their comparison becomes useful. This disadvantage does not apply to the pressure buildup test.

APPLICATION OF ANALYSIS METHODS AND DESIGN OF REMEDIAL PROCEDURE

The analysis methods and remedial procedures outlined in this paper are limited to a stimulation of the zone in which the well is presently completed. It does not cover recompletion to other zones which may be selected by a study of the well logs, formation samples, and the results of drill stem tests and other related information.

Fig. 2 is the result of a pressure buildup test obtained from a well completed in the Morrow Sand in the Texas Panhandle. This well was a new well and had a cumulative production of 2816 barrels at shutin time. It had received a 20,000 gallon sandfrac treatment plus one pound sand per gallon in the perforated interval 7938-84 feet (46 feet).

Presenting the data in the form developed by Arps, the well had a completion factor of 163 per cent. This means the overall capacity of the well to produce was 63 per cent greater than the natural capacity of the formation. One hundred per cent is the standard indicating no impairment, no improvement.

In this well the complete pay section was cored and a summation of the permeabilities showed the well to have a natural formation capacity of 113 millidarcy-feet. The computed formation capacity from the pressure buildup test was 116.7 millidarcy-feet, an agreement between the two methods of 3.3 per cent. This example was selected to illustrate the accuracy of the pressure buildup tests. Good agreement between formation capacities from core analysis and pressure buildup tests are not unusual when all of the factors are known. In vuggy fracture formations, such as the Devonian, pressure buildup tests run in conjunction with drill stem tests are a better measure of formation capacity than core data.

Fig. 3 is the result of a pressure buildup test obtained on a well completed in the Canyon Sand, Nolan County, Texas. The flowing bottom hole pressure was 390 psig at a flow rate of 18 barrels per day, whereas the theoretical perfect completion flowing bottom-hole pressure would have been 690 psig. The Completion Factor of this well was 71 per cent, indicating a formation damage.

In April, 1957, three months after the pressure buildup test was obtained, the well was treated with a 20,000 gallon sandfrac treatment and repotentialed for 118 barrels per day. At the present time (January, 1959) this well is still capable of producing top field allowable of 102 barrels of oil per day, a positive indication that the skin effect due to formation damage was eliminated.

Measured or estimated Productivity Indices are necessary for the good design of gas lift equipment and are useful for the selection of large capacity pumping equipment. Stabilized producing bottom-hole pressures, accurate production rates, and true shutin formation pressures should be used to obtain reliable P.I.'s, otherwise their use will be ineffective.

The P.I. of an individual oil well usually declines with time, due to the greater ease with which gas flows with relation to the flow of oil as reservoir pressure declines. This effect is known as the increased relative permeability of gas to oil, Kg/Ko. The P.I.'s of wells have been observed to decline with decreasing reservoir pressure because natural fractures tended to close up with decreasing reservoir pressure.

If P.I. tests are obtained periodically, sudden decreases in P.I.'s will generally indicate that a well has developed a flow restriction, which is likely caused by scale, salt, or paraffin deposits on the face of the formation. One of the advantages of the P.I. test is that through the use of curves developed by Gilbert and a knowledge of the gas-oil ratio, tubing pressure, and depth of the well, the flowing bottom-hole pressure may be predicted with reasonable accuracy. Using this estimate of producing bottom-hole pressure and the average field pressure, P.I.'s may be estimated with reasonable precision.

In the case of a pumping well, if the well is pumped off, we may assume that the producing bottom-hole pressure is in the order of 0-50 psig. One of the nice features about this method is that by taking the time to obtain accurate well tests, a constant check on the performance of a well may be obtained without losing production.

DESIGN OF REMEDIAL PROCEDURES

Most oil wells completed in recent years have had casing set through the pay zone and have been selectively perforated. Perforating allows selective production of zones and makes workover operations less expensive. A basic consideration is that, when casing is set through a formation, the flow capacity before perforating is zero and increases as the shot density per foot increases. McDowell and Muskat in 1950 showed the flow capacity of systems having various perforation densities, shot penetrations, and well diameters. Their work was based on a series of electrolytic model experiments.

The following tabulations are data selected from their Fig. 2 to represent most nearly an average West Texas completion:

Casing diameter — 6 inches

Shot penetration — 6 inches (1 well diameter)
1/2 inch perforation

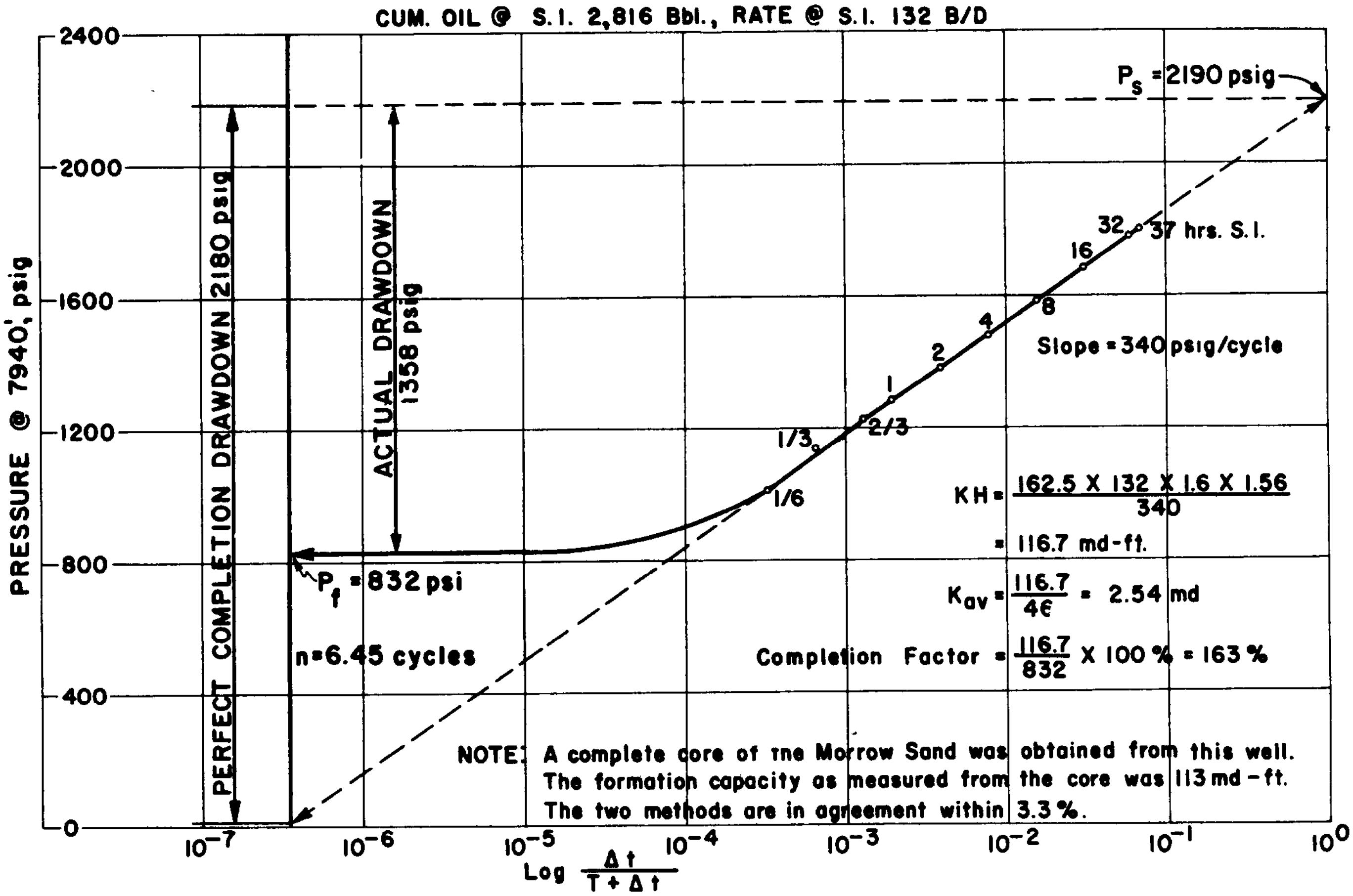
Perforation Density Holes per Foot	Relative Capacity of Perforation Completion to Open Hole Completion, Q/Q
1	.6
2	.83
3	.91
4	.97
5	.99
6	1.01
7	1.03
8	1.04

The above table shows that four 1/2 inch diameter shots per foot having a six inch penetration in a six inch diameter casing will approach 97 per cent of the natural formation capacity. For a system having a perforating density of two shots per foot, it theoretically should have 83 per cent of the natural formation capacity. Therefore, a perforating density of four shots per foot, under the conditions listed above, has a 17 per cent greater theoretical capacity than would a well completed with a perforated density of two shots per foot.

There are several complicating factors that affect the results of this laboratory investigation. In the field, bullets and residue from jet perforating sometimes plug the perforations. Also the penetration generally is greater or smaller than six inches. In the last few years, improved

FIGURE 2

PRESSURE BUILDUP TEST
FARNSWORTH FIELD — OCHILTREE COUNTY, TEXAS
PRODUCING FORMATION: MORROW SAND
JANUARY 7-10, 1956
PERF. 7938'-84' (46'), SF 20,000 GAL.
I.P.F. 194 B/D, 12-16-55, 1/4" CHOKE, TP 675 psig, GOR 1733
CUM. OIL @ S.I. 2,816 Bbl., RATE @ S.I. 132 B/D



design of perforating devices has largely overcome the problem of poor penetration. In older wells the effect of poor penetration may be an important factor in restricting production.

Investigation has shown that there is less chance of formation damage when there is clean oil in the hole and a pressure differential in the well during perforating.

An important point to observe from the above tabulation is that the capacity of a well to produce does increase as the perforation density increases. After about four shots per foot the change is relatively minor. Small acid and fracture treatments will increase the flow capacity above the theoretical flow system.

Many operators are justifiably using perforating densities of two shots per foot in long perforated sections. If long sections are perforated, economies in perforating costs are obtained with two shots per foot. Ball sealers for selective treatment are more easily controlled when there are fewer holes in the casing. If a formation has sufficient permeability to make a natural completion, perforation densities of four shots per foot or greater will probably give superior results.

Acid treatments have been used a number of years to treat oil wells successfully. They have been very successful in increasing the production from limestone and dolomite formations in the West Texas—New Mexico area. The development and use of effective mud acids have helped to increase the production of wells completed in sand and limestone reservoirs.

Acid dissolves limestone and dolomite rocks by a chemical reaction which results in water, a soluble gas, CO_2, and soluble residues. One thousand gallons of a 15 per cent concentration hydrochloric acid will dissolve 10.8 cubic feet of pure limestone ($CaCO_3$) in a complete reaction.

The increases in production caused by acid treatments result from the removal of skin effect and the increased permeability of the natural flow channels by dissolving deposits in the natural fractures and the enlargement of flow channels by chemically dissolving the rock, Generally the maximum increase that may be expected from an acid treatment is about 100 per cent greater than the natural formation capacity.

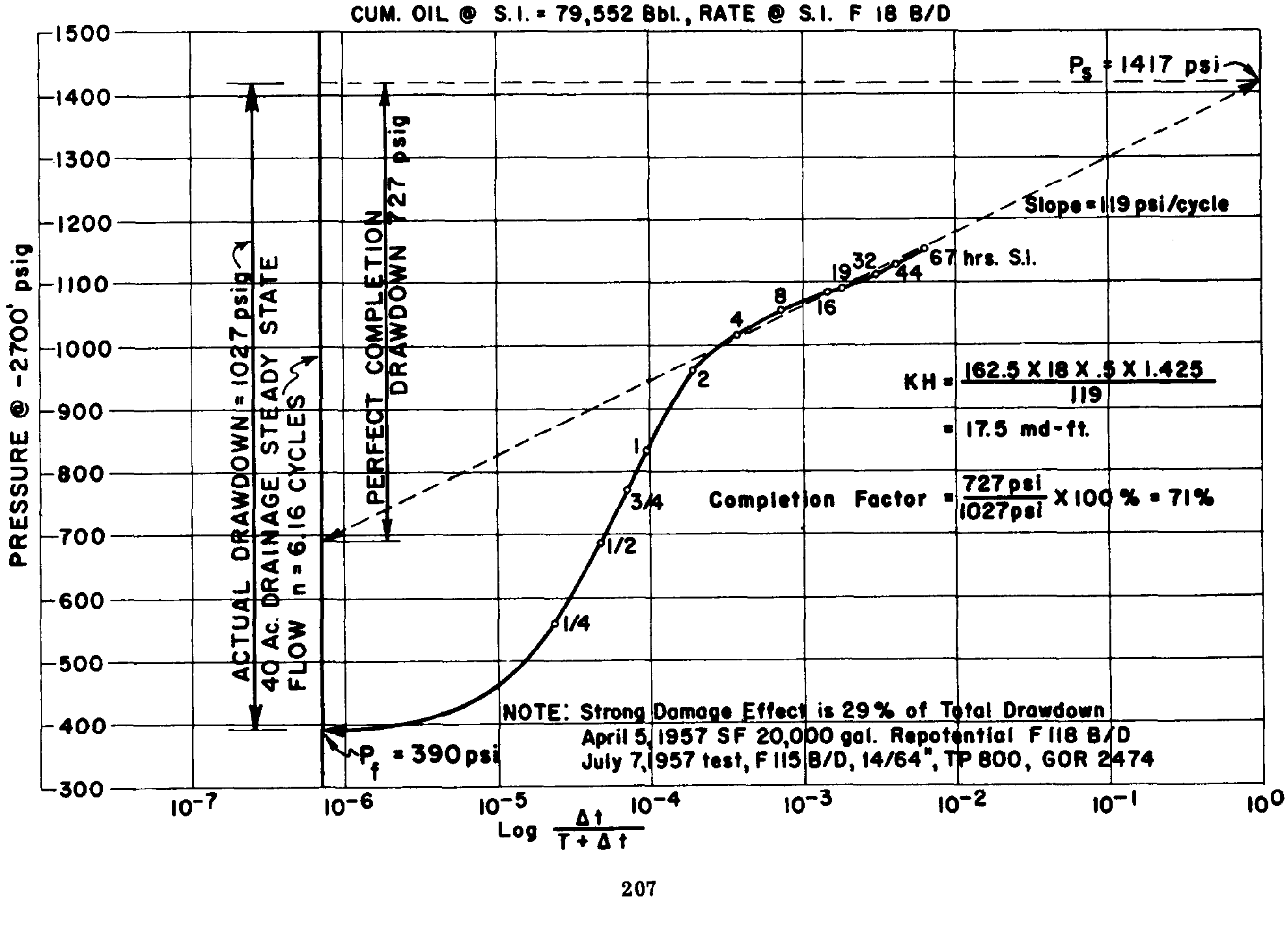
An appreciable number of the large production increases from the use of weak acids (10 per cent concentration or less) has probably been due to dissolving salt in the water phase of the acid mixture in addition to the chemical reaction with the rock. Salt deposition is an important factor in reducing productivity in many West Texas wells.

Formation Fracturing Treatments

Formation fracturing treatments are among the most effective ways of increasing production. Fracture treatments increase producing capacity by eliminating skin

FIGURE 3

PRESSURE BUILDUP TEST - SHOWING DAMAGED FORMATION
SOUTH LAKE TRAMMELL FIELD - NOLAN COUNTY, TEXAS
JANUARY 28-31, 1957 PRODUCING FORMATION: CANYON SAND
PERFS: 5158'-70', 5174'-82', 5208'-32', 1,500 MA, SF 1,000 GAL.
I.P.F 102 B/D, 2-27-52, TP 265 psi, GOR 619
CUM. OIL @ S.I. = 79,552 Bbl., RATE @ S.I. F 18 B/D



effect and increasing overall permeability in low permeability formations by inducing fractures which deeply penetrate the formation.

The items which determine the effectiveness of a fracture treatment are: 1. the fluid loss characteristic of the fracturing fluid, 2. formation permeability, 3. formation pressure, 4. the rate of injection, and 5. reservoir fluid characteristics.

The lower the bottom-hole pressure, the greater will be the rate at which the formation absorbs the fracturing fluid; and the fluid will not contribute to extending fractures. The greater the rate of injection, other factors being equal, the greater will be the radius of the fracture created.

Other factors being equal, the low permeability formation will fracture to a greater radius than a higher permeability formation. In field practice, fracture treatments are generally not effective in increasing the overall permeability of formations having naturally high permeabilities.

Howard and Fast, through experimental data, have developed a formula which will predict the area and volume of fracture created from a knowledge of the formation and fluid characteristics mentioned above.

The optimum treatment is to include a sufficient amount of sand to pack the fracture which is created. Many of the recent fracture treatments in the West Texas—New Mexico area have been designed by this procedure.

Referring to Fig. 1, and studying the pressure distribution in the fractured formation on the right hand side of the drawing, it is evident that logical reasoning would indicate that the effect of a large amount of overflush is detrimental and tends to defeat the original purpose of sand-frac treatments. The purpose of the sand in a fracturing treatment is to prop open the fractures which have been created.

Fractures packed with sand greatly increase the effective diameter of the well and permit the oil to enter the well through a sand packed conduit of high permeability. If a large amount of overflush is used, it is probable that, while the fractures are held open by pressure, much of the sand will be carried away from the well bore; and the fracture will close up or heal after the fracturing pressures are released.

The overall flow capacity of this area should be maintained at the highest possible rate because the flow capacity in the immediate vicinity of the well has the greatest effect on producing ability. Referring again to Fig. 1, it is evident that, as the oil moves closer and closer to the well, it must move through a progressively smaller area.

Recent experimental work performed by Van Poolen and others has confirmed the detrimental effect of large volumes of overflush. This thinking is contrary to much of the field practice in West Texas where volumes of overflush equal to the size of the fracture treatment are used often.

A paper by Hurst, Rollins and Stewart and a recent one by Crittendon have outlined methods which may be used to predict surface and formation fracturing pressures and to properly design formation fracturing treatments.
An example using the method and nomenclature of Hurst et. al. is presented below.

Canyon Sand Well — South Lake Trammell Field

Casing 5-1/2 inch, 15.5#/Ft., J-55 casing
perforated four shots per foot at

5230-48 feet	(18 feet)
5260-74 feet	(14 feet)
5300-10 feet	(10 feet)
	(42 feet)

Two previous treatments consisted of:

	Size and Type of Treatment	Injection Rate	Tubing Pressure
Initial completion 11-20-52	1,000 gallons refined oil + 3/4# sand/gallon	2.66 BPM	3900 psig
Workover 3-7-53	Reperforated the initial interval; 1000 gallons refined oil + 3/4# sand/gallon	2.5 BPM	2400 psig

Analyzing a number of treating reports in the field, it was found the rock rupture pressure, Pr, was equal to .65 psi/feet. The predicted surface pressure, Ps, is equal to:

$$P_s = (P_r - P_h + P_f) \times D$$

where:

P_s = surface pressure (psi)
P_r = formation resistance pressure (psi/feet)
P_h = hydrostatic pressure (psi/feet)
P_f = pressure losses due to friction (psi/feet)
D = depth (feet)

The surface pressures to part the formation at various pump rates prior to the treatment were then calculated as follows:

P_r = .65 psi/feet (study of treatment reports)
P_h = .393 frac-oil (no sand)

At 10 BPM, P_f = .04 psi/feet - through 5-1/2 inch casing
P_s = (.65 - .393 + .04) (5200 ft.) = 1544 psig

At 20 BPM, P_f = .135 psi/feet - through 5-1/2 in. casing
P_s = (.65 - .393 + .135) (5200 ft.) = 2038 psig

At 30 BPM, P_f = .24 psi/feet - through 5-1/2 in. casing
P_s = (.65 - .393 + .24) (5200 ft.) = 2584 psig

During the formation breakdown with refined oil prior to starting the sand-oil mixture, the well head pressure was 2400 psig at an injection rate down the casing of 29-1/2 barrels per minute. This pressure was within 7 per cent of the predicted pressure and showed the accuracy with which surface pressures may be predicted when other factors are known.

Using charts to predict the volume of fracture, based on data developed by Howard and Fast, it was calculated that the volume of fracture created would be 500 cubic feet, by a 25,000 gallon treatment, at an injection rate of 35 barrels per minute. The weight of sand to pack this volume would be 58,850 pounds. The well was fractured with 25,000 gallons at 29-1/2 barrels per minute with 60,000 pounds of sand.

Only five barrels of overflush were used at the end of the treatment. A check with wire line indicated that there was no sand fillup. In this particular example the predictions from the equation did work or were, at least, on the safe side.

DISCUSSION

The methods presented here are only a few of the more important techniques. Supplementary types of analyses would be a comparison of core analyses' permeabilities with the completion permeabilities obtained from P.I. or pressure buildup tests, and a comparison of formation capacity obtained from pressure buildup on drill stem tests with the effective flow capacity after completion.

In certain special cases, estimates of permeability may be obtained from resistivity gradients on electric logs. Other factors to consider would be analyzing the oil for salt content to see if the formation might be hindered by salt accumulation on the face of the well bore. The Stiff Method of graphically presenting water analyses may be very useful in determining the source of water production.

If the basic idea of fluid flow into a well, as presented by Fig. 1, is kept in mind and tests obtained to determine if there is a skin effect, predictions of the outcome of workover operations may be made with reasonable accuracy. The workover of existing wells offers an economical way of increasing income from oil properties.

The well in Fig. 3 in a 20 month period (to 1-1-59) has recovered 25,000 barrels in excess of the amount it would have recovered had it not been successfully stimulated. The net value of this additional oil is $55,000 and was obtained at a workover cost of $6,000.

Better results will be obtained from well stimulations when the bottom-hole pressure is high. Fracture treatments will be more effective and greater pressure is available to force the oil into the well. This fact is evident from an examination of the Darcy equation as the flow rate of oil is directly proportional to the pressure differential of the formation and the producing bottom-hole pressure.

If a workover procedure has been carefully planned, the cost of workover may be estimated with reasonable precision. Workover costs may greatly exceed the predicted cost when we have a "let's try this" frame of mind and one product is tried, it doesn't work, and another product is used to try again. The general outcome of this is that an operator ends up "grasping at straws" at considerable expense. Usually a successful well stimulation treatment will have a very quick pay-out period.

Appended is a check list consisting of 12 general questions which a person should answer concerning any prospective workover treatment. It is not necessary that an individual be expert in the analysis of pressure buildup or P.I. tests to realize their utility. Field men should cooperate with the engineers to condition wells properly before obtaining pressure buildup or P.I. tests and to obtain accurate well tests constantly. Also, simple things such as the possibility of fresh water removing salt deposits should not be overlooked.

CONCLUSION

In conclusion, it is believed that careful study of the existing situations and use of the analysis methods outlined here will permit the prediction of the outcome of workover operations with reasonable tolerance. Well stimulations are a fertile source in increased revenues at a nominal cost.

ACKNOWLEDGMENT

Appreciation is extended to the management of Union Oil Company of California for permission to publish this paper.

REFERENCES

1. Van Everdingen, A. F.: The Skin Effect and its Influence on the Productive Capacity of a Well, Trans. Am. Inst. Mining Met. Engrs. (Petroleum Development and Technology) 198, 171 (1953).

2. Hurst, William: Establishment of the Skin Effect and its Impediment to Fluid Flow into a Well Bore, Pet. Engr. 25 (11) B6(1953).

3. Bearden, W. G. and Wilsey, L. E.: Reservoir Fracturing — A Method of Oil Recovery from Extremely Low Permeability Formations, Trans. Am. Inst. Mining Met. Engrs. 201, pp. 169-175, (1954).

4. Van Everdingen, A F., Ibid.

5. Hurst, William, Ibid.

6. Thomas, G. B.: Analysis of Pressure Buildup Data, Trans. Am. Inst. Mining Met. Engrs. (Petroleum Development and Technology), 198, 125 (1953).

7. Miller, C. C.; Dyes, A. B.; and Hutchinson, C. A. Jr.: The Estimation of Permeability and Reservoir Pressure Buildup Characteristics, Trans. Am. Inst. Mining Met. Engrs. (Petroleum Development and Technology), 189, 91 (1950).

8. Horner, D. R.: Pressure Buildup in Wells, Proc. Third World Pet. Congress (II), 503, The Hague (1951).

9. Arps, J. J.: How Well Completion Damage Can Be Determined Graphically, World Oil, 140 (5) 225 (1955).

10. Perrine, R. L.: Analysis of Pressure Buildup Curves, API Drilling and Production Practice (1956) 482-509.

11. Gladfelter, R. E.; Tracy, G. W.; and Wilsey: Selecting Wells Which Will Respond to Production-Stimulation Treatment, API Drilling and Production Practice (1955), 117-129.

12. Arps, J. J., Ibid.

13. Gilbert, W. E.: Flowing and Gas-Lift Wells Performance, API Drilling and Production Practice, 126-157 (1954).

14. McDowell, James M. and Muskat, Morris: The Effect on Well Productivity of Formation Penetration Beyond Perforated Casing, Petroleum Trans. Am. Inst. Mining Met. Engrs, 189 (Nov. 1950) No. 11.

15. Krueger, R. F.: Joint Bullet and Jet Perforation Tests (Progress Report), API Drilling and Production Practice, 126-140 (1956).

16. Howard, G. C. and Fast, C. R.: Optimum Fluid Characteristics for Fracture Extension, API Drilling and Production Practice, 261-270 (1957).

17. Van Poolen, H. K.; Tinsley, J. M.; Saunders, C. D.: Hydraulic Fracturing — Fracture Flow Capacity vs. Well Productivity, Pet. Trans. Am. Inst. Mining

Engrs., 213 (1958) 91-95.

18. Hurst, R. E.; Franks, J. E.; and Rollins, J. T.: Horsepower Requirements for Well Stimulation, presented at the Spring meeting of the Southwestern District API Division of Production, Fort Worth, Texas, March 12-14, 1958.

19. Crittenden, B. C.: The Mechanics of Design and Interpretation of Hydraulic Fracture Treatments, Am. Inst. Mining Met. Engrs. Paper 1106-G presented at the Fall meeting of the SPE of AIME, Houston, Texas, 1958.

20. Howard, G. C. and Fast, C. R., Ibid.

21. Stiff, H. A., Jr.: The Interpretation of Chemical Water Analysis by Means of Patterns, Tech. Note 84, Petrol. Techn. Trans. Am. Inst. Mining Met. Engrs. Vol. 192 (1951) 376-379.

22. Hurst, R. E.; Rollins, J. T.; and Stewart, H. A.: Fresh Water Fracturing in Oil Reservoirs, Am. Inst. Mining Met. Engrs. Paper Number 821-G Permian Basin Oil Recovery Conference, Midland, Texas, April 18-19, 1957.