Chapter 32

Potential Tests of Oil Wells

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A potential test is a simple production test under stabilized flowing conditions to determine the ability of a well to produce. Potential or production tests are used to determine the rate of production through a given size of choke. This production rate and GOR then are used to determine if the well is capable of producing the assigned daily allowable production rates.

Production-rate tests are conducted on a well so that its producing capabilities can be determined and a record of its producing abilities maintained. The results of these tests are used in diagnosing and evaluating a producing well. Their importance cannot be overemphasized since they are used in every phase of reservoir and equipment analysis in which a knowledge of the productivity of the reservoir is essential. The test results aid in determining the parameters shown in Table 32.1.

Production tests usually are considered part of routine field operations. Because they are performed on every type of producing well, a standard method of procedure that would cover every well cannot be set forth in detail. In many cases, the method or procedure for obtaining the results desired is left to the engineer's initiative and judgment and, in many cases, ingenuity.

In every production test an initial understanding of the equipment employed and the method of completion, and a general knowledge of the producing reservoir and the results of previous tests on the well or on comparable wells will greatly simplify the testing procedure and aid in obtaining the desired results.

Potential or production rate tests generally are required periodically by most state regulatory bodies in the U.S., such as the Texas Railroad Commission and the Louisiana Dept. of Conservation. The state regulatory bodies, authorized by the various states to control the production of oil and gas, set up a daily allowable or maximum rate at which each individual well may be produced. The well and reservoir conditions are considered in setting up this maximum producing rate. Usually one other condition is involved in setting the producing allowable: *the produced or refined oil and gas storage or market capacity.* These regulatory bodies meet periodically and set a maximum number of producing days for a given period. The allowable is specified in two ways: the maximum amount of oil that can be produced each day and the maximum number of days each set period (usually 1 month) that this maximum daily allowable may be produced.

It is a responsibility of the engineer or person in charge to set up and supervise the proper testing of all producing wells. When the production is controlled by state regulatory bodies, it is also the responsibility of the engineer or person in charge to find out the requirements set up by these regulatory bodies as to the proper method for testing and reporting the tests on producing wells.

The importance of testing and information required to be supplied to the state regulatory agencies cannot be overlooked. Form W-2 of the Texas Railroad Commission's Oil and Gas Div. is an example of the information required (see Fig. 32.1).

As a general rule in Texas and Louisiana, the daily allowable is determined by the producing horizon of the well, but there are exceptions to this rule. The reservoir characteristics, previous reservoir performances, and completion procedures are considered before a definite allowable is set for the well. The general case in Texas is covered by a depth allowable set up in 1947. These allowables are set up for wells completed in proven areas and known reservoirs.

Texas Allowable Rule

The Texas Allowable Rules of 1947 and 1965 were based on producing depth and well spacing. These are normally referred to as "yardsticks." In 1966, another yardstick was established for offshore only (Table 32.2).

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*This author also wrote the original chapter on this topic in the 1962 edition.

TABLE 32.1—DETERMINATIONS FROM TEST RESULTS

1. Optimal or maximum efficient production rates.
2. Correlation and identification of producing horizons.
3. Results of recovery methods.
4. Estimates of oil and gas reserves; for example, gauged rate production decline vs. time.
5. Decline trends and performance productions in the ability of the reservoir to produce.
6. Qualitative determinations of gas and/or liquid contacts.
7. Determinations relative to artificially imposed harmful wellbore or reservoir conditions such as gas or water coning, sanding or bridging action, and paraffin depositions.
8. Analyses and comparisons of well-completion practices and equipment.
9. Performance of and comparison between subsurface well equipment and installation principles.
10. Analyses and comparisons of artificial lifting practices and equipment.
11. Determining the necessity of and evaluating the results of remedial measures.

The allowable given a well completed in a new field or new reservoir is called the "Discovery Allowable." It is usually set up on a producing-depth basis. This allowable is for a certain period of time or until a certain number of wells are completed into the reservoir. For example, in Texas the onshore discovery allowable is for a 24-month period or until the 11th well is completed into the reservoir. The offshore discovery allowable is for an 18-month period or until the sixth well is completed into the reservoir. The discovery allowable in Texas is set up as in Table 32.3.

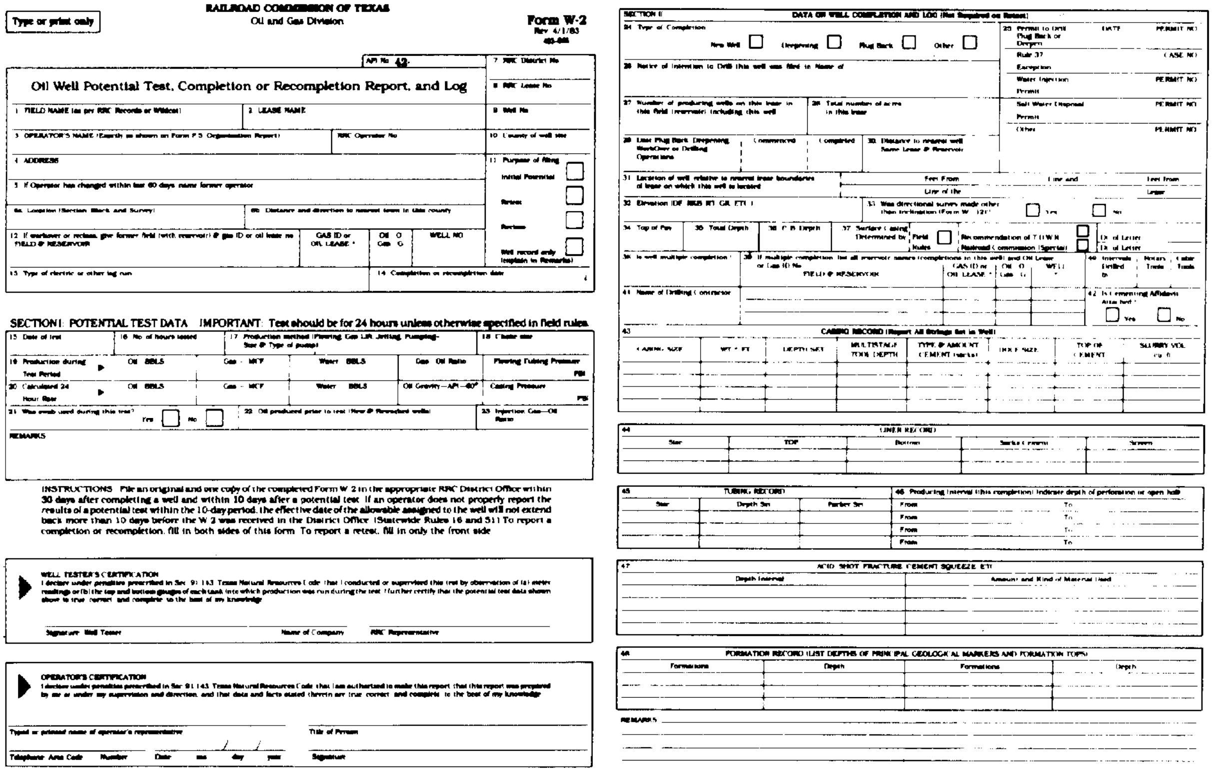
The allowables set up by the state regulatory bodies are not necessarily the proper rate to produce the wells. The producer should work very closely with the reservoir engineers and geologists to see that the test data, along with all other information available, are used to determine the most efficient producing rate of the well or reservoir.

When several companies produce from the same reservoir, it is common procedure to combine their knowledge and arrive at a maximum efficient producing rate (MER).

It is permissible for a company to request a change of allowables to conform more closely to the MER as determined by the company's engineers. Before any change in the allowables is made by the regulatory bodies, a meeting or hearing of all the companies involved in producing from the reservoir is proposed. At this time all the information available is evaluated to determine if a new and different allowable is warranted. This new allowable (to conform more to the MER) usually involves a reduction in the normal allowable set up by the regulatory body.

Productivity Index (PI)

It is desirable to be able to assign to a producing well a quantity that indicates the well's ability to produce. It was once a common occurrence "to open the well up" and measure the amount of production under wide-open flow. Today it is realized that wide-open flow of an oil or gas well can be very harmful to future well conditions.



Type or print only

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division

Form W-2
Rev 4/1/83

API No 42-

Oil Well Potential Test, Completion or Recompletion Report, and Log

7 RRC District No
8 RRC Lease No
9 Well No
1 FIELD NAME (as per RRC Records or Wildcat)
2 LEASE NAME
3 OPERATOR'S NAME (Exactly as shown on Form P-5 Organization Report)
RRC Operator No
10 County of well site
4 ADDRESS
11 Purpose of filing
Initial Potential ☐
Retest ☐
Reclass ☐
Well record only (explain in Remarks) ☐
5 If Operator has changed within last 60 days name former operator
6a Location (Section, Block and Survey)
6b Distance and direction to nearest town in this county
12 If workover or reclass, give former field (with reservoir) & gas ID or oil lease no
FIELD & RESERVOIR
GAS ID or OIL LEASE \#
Oil O Gas G
WELL NO
13 Type of electric or other log run
14 Completion or recompletion date

SECTION I: POTENTIAL TEST DATA IMPORTANT: Test should be for 24 hours unless otherwise specified in field rules.

15 Date of test
16 No. of hours tested
17 Production method (Flowing, Gas Lift, Jetting, Pumping—Size & Type of pump)
18 Choke size
19 Production during Test Period ▶ Oil—BBLS | Gas—MCF | Water—BBLS | Gas—Oil Ratio | Flowing Tubing Pressure PSI
20 Calculated 24 Hour Rate ▶ Oil—BBLS | Gas—MCF | Water—BBLS | Oil Gravity—API—60° | Casing Pressure PSI
21 Was swab used during this test? Yes ☐ No ☐
22 Oil produced prior to test (New & Reworked wells)
23 Injection Gas—Oil Ratio
REMARKS

INSTRUCTIONS: File an original and one copy of the completed Form W-2 in the appropriate RRC District Office within 30 days after completing a well and within 10 days after a potential test. If an operator does not properly report the results of a potential test within the 10-day period, the effective date of the allowable assigned to the well will not extend back more than 10 days before the W-2 was received in the District Office (Statewide Rules 16 and 51). To report a completion or recompletion, fill in both sides of this form. To report a retest, fill in only the front side.

▶ WELL TESTER'S CERTIFICATION
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I conducted or supervised this test by observation of (a) meter readings or (b) the top and bottom gauges of each tank into which production was run during the test. I further certify that the potential test data shown above is true, correct, and complete to the best of my knowledge.

Signature: Well Tester
Name of Company
RRC Representative

▶ OPERATOR'S CERTIFICATION
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

Typed or printed name of operator's representative
Title of Person
Telephone: Area Code Number
Date: mo day year
Signature

SECTION II DATA ON WELL COMPLETION AND LOG (Not Required on Retest)

24 Type of Completion
New Well ☐ Deepening ☐ Plug Back ☐ Other ☐
25 Permit to Drill, Plug Back or Deepen DATE PERMIT NO
Rule 37 Exception CASE NO
Water Injection Permit PERMIT NO
Salt Water Disposal Permit PERMIT NO
Other PERMIT NO
26 Notice of Intention to Drill this well was filed in Name of
27 Number of producing wells on this lease in this field (reservoir) including this well
28 Total number of acres in this lease
29 Date Plug Back, Deepening, WorkOver or Drilling Operations: Commenced | Completed
30 Distance to nearest well, Same Lease & Reservoir
31 Location of well, relative to nearest lease boundaries of lease on which this well is located
Feet From Line and Feet from Line of the Lease
32 Elevation (DF, RKB, RT, GR, ETC.)
33 Was directional survey made other than inclination (Form W-12)? ☐ Yes ☐ No
34 Top of Pay
35 Total Depth
36 P.B. Depth
37 Surface Casing Determined by: Field Rules ☐ | Recommendation of T.D.W.R. ☐ | Railroad Commission (Special) ☐ | Dt. of Letter | Dt. of Letter
38 Is well multiple completion?
39 If multiple completion, list all reservoir names (completions in this well) and Oil Lease or Gas ID No
FIELD & RESERVOIR | GAS ID or OIL LEASE \# | Oil—O Gas—G | WELL \#
40 Intervals Drilled by: Rotary Tools | Cable Tools
41 Name of Drilling Contractor
42 Is Cementing Affidavit Attached? ☐ Yes ☐ No

43 CASING RECORD (Report All Strings Set in Well)

CASING SIZE	WT./FT.	DEPTH SET	MULTISTAGE TOOL DEPTH	TYPE & AMOUNT CEMENT (sacks)	HOLE SIZE	TOP OF CEMENT	SLURRY VOL. (cu. ft.)

44 LINER RECORD

Size	TOP	Bottom	Sacks Cement	Screen

45 TUBING RECORD

Size	Depth Set	Packer Set

46 Producing Interval (this completion) Indicate depth of perforation or open hole
From To
From To
From To
From To

47 ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

Depth Interval	Amount and Kind of Material Used

48 FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)

Formations	Depth	Formations	Depth

REMARKS

Fig. 32.1—Sample regulatory agency form.

TABLE 32.2—ALLOWABLE "YARDSTICK" SCHEDULE

	47 Yardstick			65 Yardstick*					66 Offshore**		
Depth (ft)	10	20	40	10	20	40	80	160	40	80	160
0 to 1,000	18	28	—	21	39	74	129	238	200	330	590
1,000 to 1,500	27	37	57	21	39	74	129	238	200	330	590
1,500 to 2,000	36	46	66	21	39	74	129	238	200	330	590
2,000 to 3,000	45	55	75	22	41	78	135	249	245	360	640
3,000 to 4,000	54	64	84	23	44	84	144	265	245	400	705
4,000 to 5,000	63	73	93	24	48	93	158	288	275	445	785
5,000 to 6,000	72	82	102	26	52	102	171	310	305	490	865
6,000 to 7,000	81	91	111	28	57	111	184	331	340	545	950
7,000 to 8,000	91	101	121	31	62	121	198	353	380	605	1,050
8,000 to 8,500	103	113	133	34	68	133	215	380	420	665	1,150
8,500 to 9,000	112	122	142	36	74	142	229	402	420	665	1,150
9,000 to 9,500	127	137	157	40	81	157	250	435	465	730	1,260
9,500 to 10,000	152	162	182	43	88	172	272	471	465	730	1,260
10,000 to 10,500	190	210	230	48	96	192	300	515	515	800	1,380
10,500 to 11,000	—	225	245	—	106	212	329	562	515	800	1,380
11,000 to 11,500	—	225	275	—	119	237	365	621	565	875	1,500
11,500 to 12,000	—	290	310	—	131	262	401	679	565	875	1,500
12,000 to 12,500	—	330	350	—	144	287	436	735	620	950	1,625
12,500 to 13,000	—	375	395	—	156	312	471	789	620	950	1,625
13,000 to 13,500	—	425	445	—	169	337	506	843	675	1,030	1,750
13,500 to 14,000	—	480	500	—	181	362	543	905	675	1,030	1,750
14,000 to 14,500	—	540	560	—	200	400	600	1,000	735	1,115	1,880
14,500 to 15,000	—	—	—	—	—	—	—	—	735	1,115	1,880

*1965 yardstick effective if field discovered after Jan. 1, 1965.

**1966 offshore yardstick effective Jan. 1, 1966.

Wide-open flow may cause water or gas coning, influx of sand into the wellbore, collapse of tubing or casing, and/or many other harmful results.

The ability of a well to produce usually is determined by use of the PI. The use of the PI was first mentioned by Moore in 1930.[1] In a 1936 paper M.L. Harder states that the relative ability of a well to produce shows the PI to be superior.[2]

API states in *Recommended Practice for Determining Productivity Indices*[3] that the PI is calculated from the observed production rates and subsurface pressure measurements obtained. Special applications and modifications by the user to conform to individual requirements and conditions are normally used. The following discussion of PI is not meant to cover all applications but only to show how the PI may be used.

By definition, the PI is equal to the barrels per day of stock-tank oil production per pound force of pressure differential between the wellbore opposite the producing horizon and the static reservoir pressure, which is the average pressure of the well drainage area. Therefore, the PI is, in barrels of oil produced per day per psi decrease in reservoir pressure, the difference between the average pressure in the drainage area of the well and the flowing bottomhole pressure (BHP) of the well. According to the accepted concepts of flow, the rate of flow in a system containing a single fluid under steady-state conditions should be directly proportional to the pressure drop. Using this concept, the PI would be the slope of the line resulting from plotting the rate of flow against pressure drop. On such a plot the wide-open flow quantity or well potential would be measured at the maximum pressure drop available. Such a case is referred to as the "ideal PI." Observed values of production rates vs. pressure differentials do not give straight lines. PI data on nonflowing wells are usually more linear than the data on flowing wells. Experience has shown that the line will be curved. This is because PI is defined to occur under steady or pseudosteady-state flow conditions. The curvature results because μB is not constant if the flow is single phase and/or gas evolution or water coning exists around the wellbore — i.e., relative permeability effects. PI is higher than theoretical when calculated erroneously before pseudosteady-state flow exists. PI is meaningless unless the radius of wellbore damage is fixed — i.e., pseudosteady-state flow is established. The flow of compressible fluids (oil and water) into a wellbore after the drainage area has been established is, strictly speaking, described by a pseudosteady-state flow equation.

TABLE 32.3—DISCOVERY ALLOWABLES

Interval of Depth (ft)	Daily Well Allowable (bbl)
0 to 1,000	20
1,000 to 2,000	40
2,000 to 3,000	60
3,000 to 4,000	80
4,000 to 5,000	100
5,000 to 6,000	120
6,000 to 7,000	140
7,000 to 8,000	160
8,000 to 9,000	180
9,000 to 10,000	200
10,000 to 10,500	210
10,500 to 11,000	225
11,000 to 11,500	255
11,500 to 12,000	290
12,000 to 12,500	330
12,500 to 13,000	375
13,000 to 13,500	425
13,500 to 14,000	480
14,000 to 14,500	540

However, some people in the oil industry describe the flow by a Darcy-type equation, which is referred to as steady-state flow. The difference in the flow rates determined from the two equations is very small. We discuss PI by use of both the steady-state and pseudosteady-state flow equations.

Steady-State Flow

For a radial system under steady-state flow, the equation giving the flow rate is

$$q_o=\frac{7.08\times10^{-3}\ kh(p_e-p_{wf})}{\mu_o B_o[\ln(r_e/r_w)+s]}, \quad \ldots\ldots\ldots\ldots(1)$$

where

q_o = oil production rate, STB/D,
k = permeability of formation, md,
h = thickness of formation, ft,
p_e = pressure at the effective drainage radius r_e normally approximated by $\bar{p}_R$,
$\bar{p}_R$ = average reservoir pressure in drainage area, psi,
p_{wf} = flowing BHP, psi,
μ_o = oil viscosity, cp,
B_o = oil formation volume factor, RB/STB,
r_e = effective drainage radius, ft,
r_w = wellbore radius, ft, and
s = skin effect (zone of reduced or improved permeability), dimensionless

The term equivalent to the PI is

$$J=\frac{q_o}{\Delta p}=\frac{7.08\times10^{-3}kh}{\mu_o B_o[\ln(r_e/r_w)+s]}, \quad \ldots\ldots\ldots\ldots\ldots(2)$$

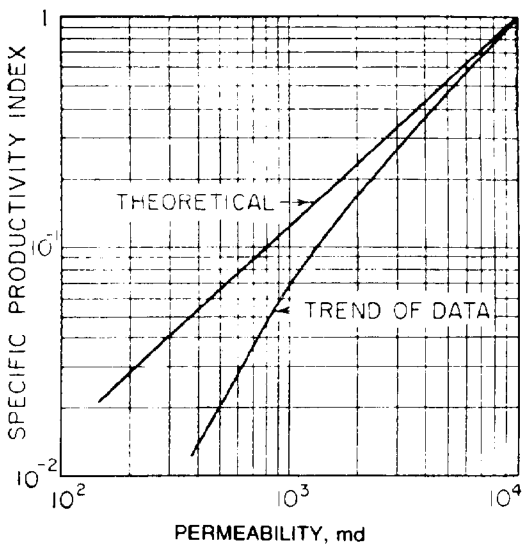


Fig. 32.2—PI—permeability correlation.

where J is the PI, STB/D-psi, and Δp is the pressure difference between p_e and p_{wf}, psi.

In analyzing the PI, it can be seen that it is a function of the formation characteristics, k and h, the fluid characteristics, μ_o and B_o, and the system characteristics, h, r_e, r_w, and s.

Specific PI

The term "specific PI" is frequently used and usually means the PI per foot of pay. When the term "specific" is used, it is necessary to state why. The productivity could just as well have been made specific to any other variable in Eq. 2.

Well systems do not operate at any time under steady-state conditions, but they do under pseudosteady-state conditions. Oil, water, and gas are compressible fluids; therefore, only pseudosteady-state occurs. Thus, we cannot expect Eq. 2 to yield exact correlation. The primary correlation sought has been with permeability so that the PI could be predicted from core analysis. An example of an early correlation is given by Fig. 32.2.[4]

Oil flowing into a wellbore will practically always seem to enter the wellbore from a formation of lower permeability than the homogeneous fluid value determined in the laboratory. In many cases the relative permeability to oil at interstitial water saturation is one. What actually happens is that the permeability measured in the laboratory is too high because the confining pressure is lower than in the reservoir.

Muskat[5] states that the PI should not be used to predict production of high differential pressures by simply multiplying the PI by the pressure drop of interest. He states that it is doubtful that calculated potential tests would agree with actual tests. The relative comparison should reflect the comparative production capacity with fair approximation. The PI times reservoir pressure equals the open flow potential.

Muskat also states that the productivity index is an excellent tool to determine well problems such as:

1. Comparison before and after well treatments to evaluate these treatments. J should increase.
2. Stable GOR, R, with a declining J indicates plugging of wellbore.
3. R increasing markedly without decline in J indicates entry of extraneous gas. This would be the same if R changes with various production rates and J stays constant.
4. Rapid increase in water production should bring a decline in J if water is entering through typical strata within oil pay. If J is maintained, this should indicate the water is not coming through the oil-producing strata.
5. Decline of J should take place during normal reservoir depletion and parallel the normal growth of GOR or water/oil ratio (WOR). If not, plugging of the wellbore should be considered.

These are guidelines for further investigation.

Theoretical PI

Muskat and Evinger[6] first showed that a theoretical PI could be worked out using the steady-state formula as developed for a radial system flowing oil and gas. By such a system it can be shown that the J for a given well system can be expressed in terms of three parameters: (1) the producing GOR, (2) the pressure gradient in the well system, and (3) the absolute reservoir pressure.

It can be shown that for the steady-state flow of oil and gas in a radial system, the following equation expresses the rate of oil flow.

$$q_o=\frac{7.08\times10^{-3}\,kh}{\ln r_e/r_w+s}\int_{p_{wf}}^{\bar{p}_R}\frac{k_o/k}{\mu_oB_o}dp, \quad \ldots\ldots\ldots\ldots (3)$$

where k_o is effective permeability to oil.

The integral

$$\int_{p_{wf}}^{\bar{p}_R}\frac{k_o/k}{\mu_oB_o}dp$$

can be evaluated using Fig. 32.3.

The PI is, therefore,

$$J=\frac{q_o}{p_e-p_{wf}}=\frac{7.08\times10^{-3}\,khA_c}{(p_e-p_{wf})[\ln(r_e/r_w)+s]},$$

$$\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (4)$$

where A_c is the area under the curve.

By using Fig. 32.3 and the definition of the PI, it can be seen that J will not double if (p_e-p_{wf}) is doubled because the area under the curve will not double. Also p_e is determined by reservoir conditions and cannot be varied. Note that for a definite value of (p_e-p_{wf}) taken at a high absolute pressure, J will be greater than for the same (p_e-p_{wf}) taken at a lower pressure because the area under the curve will be greater.

It is not readily apparent, but can be shown, that J depends on the producing GOR, R. A simple explanation is that an increase in R means that the oil saturation is less, thus k_o is smaller. In Fig. 32.3, the curves labeled R_1, R_2, and R_3 are for different GOR's with $R_1 > R_2 > R_3$.

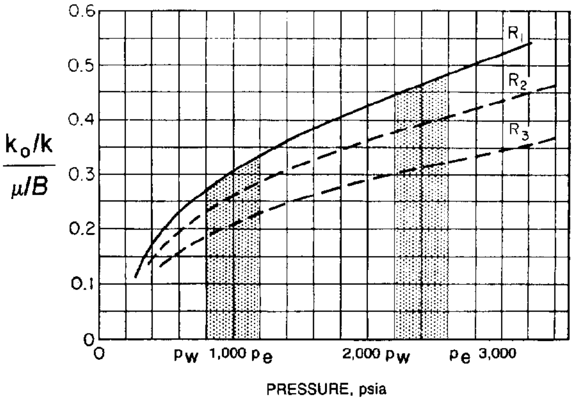


Fig. 32.3—Plot for determining PI for different GOR's.

Pseudosteady-State Flow

The steady-state equation is used frequently; however, this would only apply if the pressure at the outer radius stayed constant, which would only happen if a complete pressure maintenance program were maintained. If the well has a closed boundary or is operating with an established drainage radius, then pseudosteady-state flow occurs. The pseudosteady-state equation is

$$q_o=\frac{7.08\times10^{-3}\,kh\,(\bar{p}_R-p_{wf})}{\mu_oB_o[\ln(r_e/r_w)-0.75+s]} \quad \ldots\ldots\ldots\ldots (5)$$

for a circular drainage area and

$$q_o=\frac{7.08\times10^{-3}\,kh\,(\bar{p}_R-p_{wf})}{\mu_oB_o(\ln x-0.75+s)} \quad \ldots\ldots\ldots\ldots (6)$$

for a non-circular drainage area.[7]

From Eq. 6 the actual PI is

$$J=\frac{7.08\times10^{-3}\,kh}{\mu_oB_o(\ln x-0.75+s)},$$

where x is a factor for noncircular drainage area and well location.

Most reservoir engineering flow equations assume radial geometry. This assumes the drainage area of the well is circular and the well is located in the center. Experience has shown that in many cases the drainage area of the well is rectangular, triangular, or other shapes. As stated previously, the PI, J, is a function of the system characteristics, which can be applied to the productivity index. Shape functions can be determined by reservoir limit tests.[8]

Van Everdingen originally defined the skin effects as the additional resistance concentrated around the wellbore that result from the drilling and completion techniques employed.[9] This skin effect detracts considerably from a well's capacity to produce. More recently the skin effect is also used to indicate improved permeability around the wellbore that results from acidizing and/or fracturing. The skin effect can be defined as

$$s=\ln\frac{r_s}{r_w}\left(\frac{k-k_s}{k_s}\right), \quad \ldots\ldots\ldots\ldots\ldots\ldots (7)$$

where

r_s = radius of area around the wellbore affected by skin effect, ft,
k = formation permeability, md, and
k_s = permeability of area around the wellbore affected by skin effect, md.

The skin effect, s, normally is determined from pressure transient analysis. The reader is referred to Chap. 35, Well Performance Equations, for a detailed treatment of skin effect.

The aim of the production engineer is to make the PI, J, as high as possible; the equation for J indicates this may be done by several ways that include[10]:

1. Remove the skin effect through acid treatment or the use of various completion or drilling fluids, depending on the formation.
2. Increase the effective permeability by fracturing or propping.
3. Reduce the viscosity by formation heating.
4. Reduce formation volume factor, B_o, by production techniques and surface separation system.
5. Increase the well penetration, h, by completing across the entire producing formation. Care should be taken not to complete across a zone of excessive gas or water production.
6. Reduce the ratio r_e/r_w. Since it appears as a logarithmic term, this has little influence. Underreaming is seldom considered as a means of well stimulation.

The above equations should indicate that the most important step in determining and analyzing the performance of any well, especially flowing wells, is to determine the well production rate for any given flowing BHP.

It is now readily apparent that to compare a PI of a well it is necessary to know what is being compared, which includes the permeability, sand thickness, well radius, drainage radius, fluid characteristics, and flow relations. A comparison should also be made on reservoir pressure and pressure drawdown for a similar GOR.

The standard procedure for conducting PI tests mainly consists of following the directions that have been set forth in the procedures for conducting static and flowing reservoir pressures and gauged-rate production tests. The most popular wireline pressure gauge is the Amerada recording pressure gauge.

In some cases, the use of artificial-lift equipment prevents the passage of subsurface gauges; therefore, other means must be found for determining these pressures. It is possible with the use of sounding devices—i.e., Echometer or Sonolog — to determine the liquid level. Knowing the liquid level, the static or flowing pressures can be approximated by gradient and depth calculations.

Care should be exercised in determining the static and flowing pressures to be sure they are the equilibrium pressures. If there is any doubt regarding the equilibrium conditions, two or more pressure readings should be made several hours apart to be sure they are the same. Some formations stabilize in one hour but most take four to 24 hours. Tight formation could take several days. In determining the actual J, the flowing rates should have wide enough variation to compensate for any errors in measurement.

When artificial-lift equipment is used, the gauged production tests for determining the J must be lower than the production limitations of the lift equipment.

Methods of determining production rates are: (1) stock-tank measurement; (2) portable well testers, including batch-type meters, positive-displacement meters, turbine meters, and flow meters; and (3) stationary test equipment.

Stock-Tank Measurement

The oldest and most widely accepted means of determining the amount of liquid produced by an oil or gas well is the manual gauging of the production in stock tanks. A single well producing into a tank battery presents no testing problems, as it is a simple process to measure the liquid in the stock tanks at the start of the test and the liquid in the stock tanks at the end of the test. Most tank batteries are arranged so that one well may be tested at the battery while the other wells are being produced. This requires, of course, the addition of a test separator in addition to the production separator and also sufficient stock-tank volume so that no commingling of the production is required. A separate gas run and meter would also be required for measurement of the gas produced while the well is on test. If this meter run is not available, a portable orifice well tester could be used.

If testing facilities are not available at the lease, it is necessary to shut in the entire lease while individual wells are being tested into the tank battery. In the latter case, it is usually better to use portable test equipment to determine the production rate.

Before the production test is started, with stock tanks as a means of measurement, it is necessary to determine the amount of basic sediment and water (BS&W) at the bottom of the tank, in addition to the liquid level at the start of the test. If at all possible, stock tanks should be clean, since errors may be introduced in determining BS&W. Dirty stock tanks can cause the tank tables to be in error. If possible, produced water should be produced and gauged in separate stock tanks.

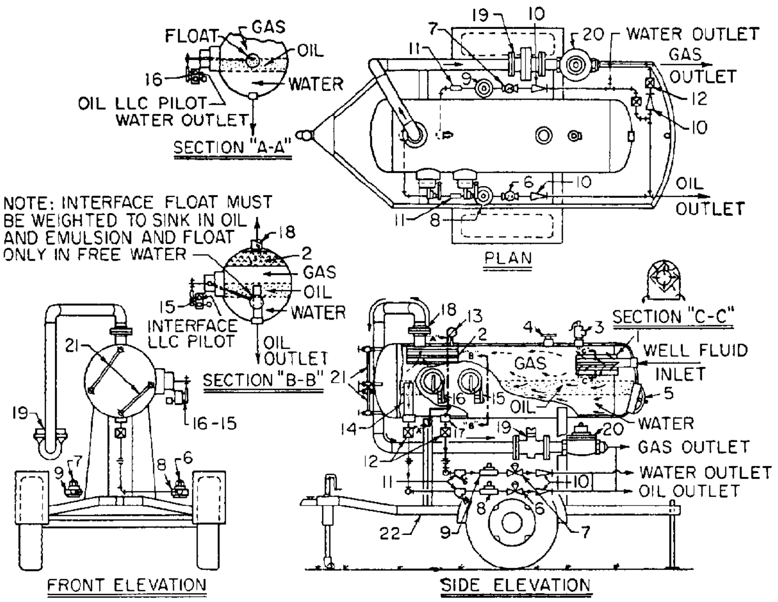
After gauging the test tank or gun barrel, the usual procedure would be to proceed to the separator, check and record the operating pressure, and on large-volume separators, if the well being tested has a low productivity, record the liquid level in the separator. The choke size at the wellhead should be carefully determined and if there is a question, the choke should be checked and calibrated.

If a treater or heater is used, its operating characteristics should be noted so that any conditions not uniform may be considered on the gauged production test. All tests should be made after the production has stabilized and under conditions that are as uniform as possible. No change should be made at the wellhead or tank battery during the duration of the test.

Standard tests should range from 24 to 168 hours in length, depending on the well and reservoir characteristics. All data should be observed and recorded at less frequent intervals. The time between intervals will vary depending on the length of test. In cases where short tests (6 to 8 hours' duration) are necessary, consecutive data recordings should be made hourly.

Tests should be for 24 to 168 hours' duration so that fluctuations in the GOR, as a result of heading tendencies and temperature variations, may be considered and the test results averaged. It is not uncommon to observe a 40 to 50°F temperature variation between night and day atmosphere and to observe a 10 to 20% variation in the gas/liquid ratio. Recognizing these facts, it becomes necessary to measure the temperature of either the liquid or vapor section of the separator.

The preferred location to obtain the temperature would be in the flow line immediately before the separator. This latter temperature would more nearly reflect the ac-



(1) Degassing element
(2) Mist extractor (vane-type)
(3) Relief valve
(4) Safety head (optional)
(5) Elliptical manway
(6) Oil-dump valve
(7) Water-dump valve
(8) Oil meter
(9) Water meter
(10) Check valves
(11) Strainers (optional)
(12) Plug valves
(13) Pressure gauge
(14) Oil outlet-weir nipple (removable)
(15) Interface LLC pilot
(16) Oil LLC pilot
(17) Water outlet (from separator)
(18) Gas outlet (from separator)
(19) Orifice fitting (optional)
(20) Gas back-pressure valve
(21) Liquid-level sight glasses
(22) Trailer assembly

Fig. 32.4—Trailer-mounted three-phase well tester with PD meters.

tual liquid-phase temperature prior to the flash liberation process.

The production should be sampled each time the data are recorded during the production test. This interval sampling is very necessary if storage facilities are such that the water produced must be disposed of as it is produced. Refer to Chap. 17 for sampling information. Wells that produce with a high WOR should always be tested at length because of the usual uneven oil-producing rate.

Depending on the separation pressure and the characteristics of the crude for shrinkage, some consideration should be given to determining the amount of gas produced that is not measured by the gas meter but is vented from the stock tanks.

Points to check to ensure the accuracy of stock-tank gauges include:

1. Correct and accurate strapping table is used with the test tank.
2. No dents or damage has occurred to the stock tank since strapping table was made.
3. Tank is clean with no encrustations or deposits on the walls.
4. If foamy crude is being produced the liquid level will be almost impossible to determine correctly with a gauge tape. Chemical addition or settling time may be required to minimize the foam.
5. BS&W at bottom of tank is determined as accurately as possible before and after the test.
6. Gauge tape must not be kinked and plumb bob must be carefully touched at the bottom of tank.
7. Temperature of oil in the stock tank must be considered.
8. The oil level must be steady and undisturbed while a gauge reading is taken.

Portable Well Testers

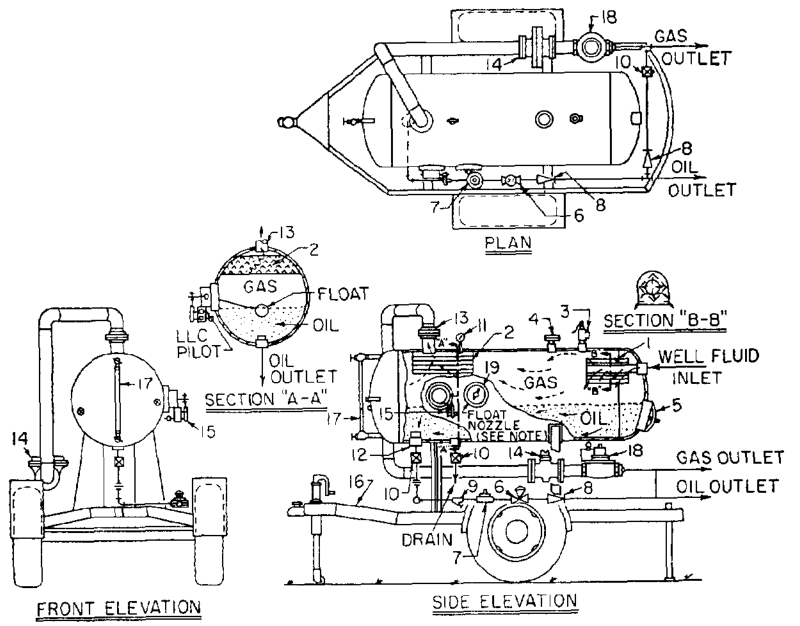
The trend toward unitization and centralization of tank batteries has increased the demand for a means of determining production rates without requiring the installation of additional expensive stock tanks and test separators. The requirements are being solved by the use of well testers.

The well tester is a combination separating and measuring unit for oil, water, and gas. The well tester can be either two or three phase, can be used for permanent installation, or can be skid or trailer mounted for portable operation (see Figs. 32.4 through 32.8). The well tester may utilize several types of meters for both liquid and gas measurement. Note that the two-phase testers (Figs. 32.5 and 32.8) are not fitted with liquid level controllers (LLC's), but are blanked so LLC's can be added in the field for three-phase testing.

Each established class of metering equipment has survived and advanced in the petroleum industry today because it fits a definite need in the metering field. Each type has won its place in the petroleum industry by fulfilling the requirements of certain applications better than any other type. Selection of the type of meter used on a well tester may be determined by the user, based on the application of the well tester and the limitations and capabilities of the meters available (see Table 32.4 for various sizes and working pressures of standard well testers). Remember that it is better to have a unit that has the capacity to test (pressure and flow capacity) so that modifications to the test can be minimized.

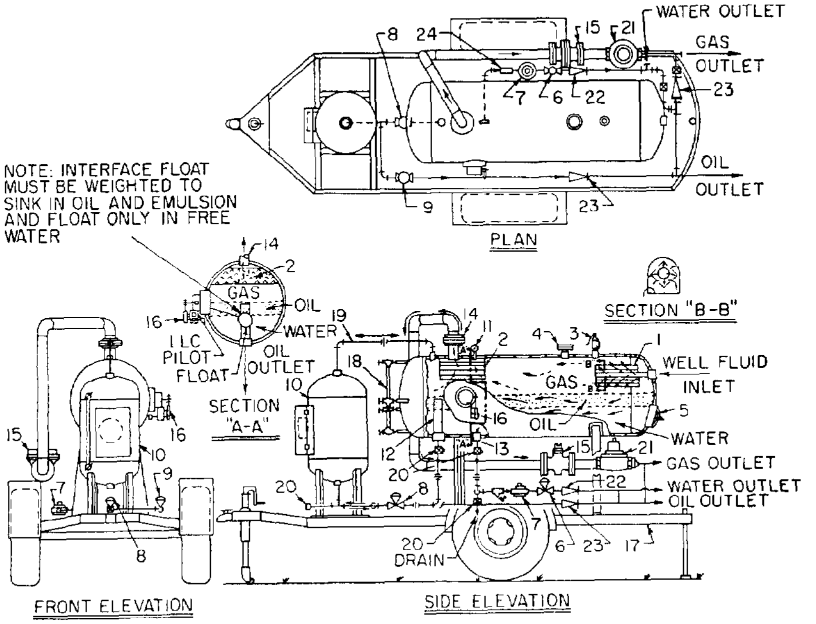
Capacities are based on steady continuous flow for a 24-hour period. Fluid retention time is as follows.

0 to 600 psi = 1 minute.
600 to 1,000 psi = 50 seconds.
More than 1,000 psi = 30 seconds.



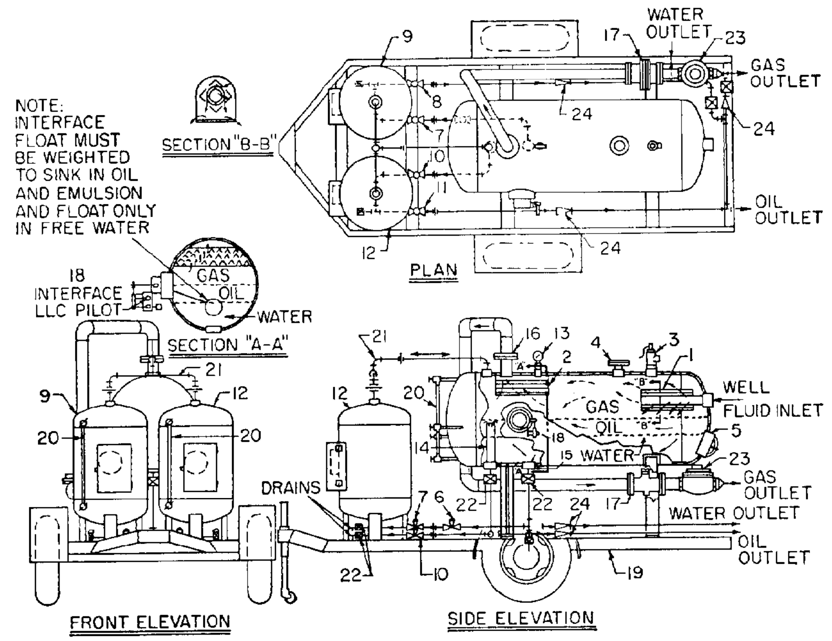
(1) Degassing element
(2) Mist extractor (vane-type)
(3) Relief valve
(4) Safety head (optional)
(5) Elliptical manway
(6) Oil-dump valve
(7) Oil meter
(8) Check valves
(9) Strainer (optional)
(10) Plug valves
(11) Pressure gauge
(12) Oil outlet (from separator)
(13) Gas outlet (from separator)
(14) Orifice fitting (optional)
(15) LLC pilot
(16) Trailer assembly
(17) Liquid-level sight glass
(18) Gas back-pressure valve
(19) Auxiliary float nozzle

Fig. 32.5—Trailer-mounted two-phase well tester with PD meter.



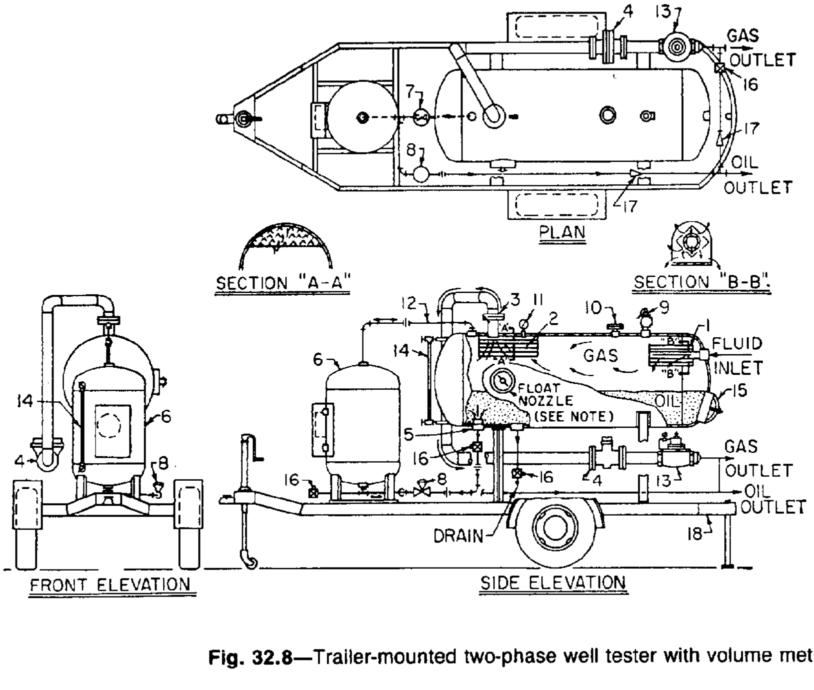
(1) Degassing element
(2) Mist extractor (vane-type)
(3) Relief valve
(4) Safety head (optional)
(5) Elliptical manway
(6) Water-dump valve
(7) Water meter
(8) Oil-inlet motor
(9) Oil-outlet motor valve
(10) Oil meter
(11) Pressure gauge
(12) Oil-outlet wier nipple (removable)
(13) Water outlet (from separator)
(14) Gas outlet (from separator)
(15) Orifice fitting (optional)
(16) Interface LLC pilot
(17) Trailer assembly
(18) Liquid-level sight glasses
(19) Gas-equalizing line
(20) Plug valves
(21) Gas back-pressure valve
(22) Check valve
(23) Check valves
(24) Strainer (optional)

Fig. 32.6—Trailer-mounted three-phase well tester with oil-volume meter and PD meter.



(1) Degassing element
(2) Mist extractor (vane-type)
(3) Relief valve
(4) Safety head (optional)
(5) Elliptical manway
(6) Water-dump valve
(7) Water-inlet motor valve
(8) Water-outlet motor valve
(9) Water meter
(10) Oil-inlet motor valve
(11) Oil-outlet motor valve
(12) Oil meter
(13) Pressure gauge
(14) Oil-outlet weir nipple (removable)
(15) Water outlet (from separator)
(16) Gas outlet (from separator)
(17) Orifice fitting (optional)
(18) Interface LLC pilot
(19) Trailer assembly
(20) Liquid-level sight glasses
(21) Gas-equalizing line
(22) Plug valves
(23) Gas back-pressure valve
(24) Check valves (optional)

Fig. 32.7—Trailer-mounted three-phase well tester with batch-type meters.



(1) Degassing element
(2) Mist extractor (vane-type)
(3) Gas outlet (from separator)
(4) Orifice fitting (optional)
(5) Oil outlet (from separator)
(6) Oil meter
(7) Oil-inlet motor valve
(8) Oil-outlet motor valve
(9) Relief valve
(10) Safety head (optional)
(11) Pressure gauge
(12) Gas-equalizing line
(13) Gas back-pressure valve
(14) Liquid-level sight glass
(15) Elliptical manway
(16) Plug valve
(17) Check valve (optional)
(18) Trailer assembly

Fig. 32.8—Trailer-mounted two-phase well tester with volume meters.

TABLE 32.4—WELL-TESTER SPECIFICATIONS

Separator Size			Rated Separator Capacities						
			Two-Phase Separation		Three-Phase Separation				
Shell OD (in.)	Shell Length Seam to Seam (ft)	Maximum Working Pressure (psi)	Oil Plus Water (B/D)	Gas (MMscf/D)	Oil (B/D)	Water (B/D)	Total Liquid Oil Plus Water (B/D)	Gas (MMscf/D)	Approximate Weight (lbm)
16	6	125	500	1.6	500	250	500	1.0	1,200
24	6	125	1,200	3.6	1,200	600	1,200	2.2	1,500
30	6	125	1,800	5.5	1,800	900	1,800	3.5	1,700
36	7	125	2,800	8.0	2,800	1,400	2,800	5.1	2,300
48	7	125	4,800	14.0	4,800	2,400	4,800	8.7	4,600
16	6	300	500	3.5	500	250	500	2.1	1,900
24	6	300	1,200	7.7	1,200	600	1,200	4.9	2,200
30	6	300	1,800	12.5	1,800	900	1,800	7.5	2,400
36	7	300	2,800	17.0	2,800	1,400	2,800	11.0	2,800
16	7	600	500	5.5	500	250	500	3.3	2,600
20	7	600	850	8.3	850	425	850	5.0	2,800
24	7	600	1,200	12.5	1,200	600	1,200	7.5	3,000
30	7	600	1,800	19.0	1,800	900	1,800	12.0	3,200
14	7	1,200	400	6.1	400	200	400	3.8	2,900
16	7	1,200	500	7.7	500	250	500	5.0	3,100
20	7	1,200	850	11.4	850	425	850	6.5	3,400
24	7	1,200	1,200	16.5	1,200	600	1,200	9.1	3,600
12	7	1,800	300	5.5	300	150	300	3.5	3,000
14	7	1,800	400	6.8	400	200	400	4.3	3,400
16	7	1,800	500	8.0	500	250	500	5.5	3,800
20	7	1,800	850	12.2	850	425	850	7.0	4,100
12	7	2,400	300	5.3	300	150	300	3.4	3,500
14	7	2,400	400	6.5	400	200	400	4.2	4,000
16	7	2,400	500	8.0	500	250	500	5.3	4,500
20	7	2,400	850	12.4	850	425	850	7.0	4,800

The type of fluid to be tested must be considered in determining the retention time. If the crude foams, the necessary retention time for the gas to break out of solution may be 5 minutes or longer. For three-phase separation, additional retention time may be required for the oil and water separation depending on the type of emulsion produced. Many times the addition of heat and/or chemicals is required to produce proper separation of the oil and water or gas and oil. Well testers are available in low working pressures that utilize either electric or gas-fired heaters to heat the well fluid and improve the separation processes. The meter used must be of sufficient metering capacity not to limit the capacity of the well tester. Working pressures are available up to 4,000 psi.

The listing in Table 32.4 of sizes and capacities of standard well testers is not complete but may be used as a guide to determine the approximate size and capacity of the unit required for your specific testing purpose.

The types of meter available for use on well testers are (1) batch-type meters, (2) positive-displacement meters, and (3) flow meters, including standard and mass flow meters.

Batch-Type Meters

The batch-type meter works by means of cyclic accumulation, isolation, and discharge of predetermined volumes. Each dump volume is registered on a counter. The counter reading is then multiplied by the dump volume to determine the total measured volume.

When metering vessels such as batch meters are used to measure liquid hydrocarbons, four factors must be obtained and maintained:

1. An unchanging volume in the metering vessel must be maintained consistently. This means that there can be no foreign material deposited in the vessel and that the vessel itself must not change shape or size.
2. Exact upper and lower dumping levels must be obtained and maintained in the metering vessel. These dumping levels must be the same for each cycle.
3. Proper valve arrangement must be maintained so that no liquid may slip through the vessel without being metered. The valve or valves should be arranged so that there is a period of time at the beginning and end of each cycle during which both the inlet and outlet to the metering vessel are closed at the same time. This assures that no unmetered fluid will slip through the metering vessel.
4. An appropriate and accurate "meter factor" must be used to compensate for temperature change of the liquid, shrinkage (volume reduction) of the liquid resulting from pressure reduction, mechanical metering error of the metering vessel, and BS&W content of the liquid.

These various factors are usually combined into one factor known as the "meter factor" or "meter multiplier." These meter factors are usually less than 1.0. In other words, the meter normally reads higher than the net stock-tank volume.

Advantages and Disadvantages of Batch-Type Meters

1. A metering vessel can be used as its own meter proving tank if the vessel is inspected for encrustation, the dumping levels are observed during operations, and valves are checked for leakage.

TABLE 32.5—NOMINAL RATED CAPACITY OF VOLUME-TYPE DUMP METERS

Barrels per discharge	0.25	0.5	1.0	2.0	5.0	10.0	20.0	30.0
Metering capacity, bbl/24-hr day	300	500	720	1,440	2,000	4,000	8,000	15,000

2. A metering vessel will handle more sand and other foreign material without causing trouble than the positive-displacement (PD) meter.

3. A metering vessel will meter from zero flow to maximum rated rate of flow with the same degree of accuracy.

4. Weight-type (hydrostatic-head) metering controls may be used to meter foaming oil.

5. The unit may be adjusted while in operation.

6. Free gas will not register as liquid if the controls should fail to function.

7. Initial and installation cost is slightly higher than with the PD meter.

8. The meter delivers an intermittent discharge of liquid.

9. Gas is required to displace the liquid from the vessel.

10. Paraffin buildup on the vessel wall will cause inaccuracies.

11. The meter requires more space and is heavier than a PD meter.

12. With heavy viscous crudes a larger inlet or differential pressure arrangement between the separator and metering vessel may be required to maintain the rated capacity.

Nominal rated metering capacity of various sizes of volume-type dump meters under normal field conditions is given in Table 32.5. Pressure ratings are up to 3,000 psi. Volume meters are not used for gas measurement.

PD Meters

PD meters are quantitative instruments. They are termed "positive-displacement" because some sensing element is forcibly or positively displaced through a measuring cycle by the hydraulic action of the fluid on the element.[11] For a completed measuring cycle a known quantity is displaced by the sensing element. It is necessary to count the number of cycles and multiply them by the displacement volume to get the total liquid quantity that has passed through the meter. This latter function is carried out by the meter's gear train and register.

Fig. 32.9 shows the basic types of PD meters: nutating disk, oscillating piston, oval gear, rotary vane, reciprocating piston, and bi-rotor.

Probably 80 to 90% of all PD meters in service today are of the nutating-disk type. They are most popular because of the relative simplicity of the construction, ruggedness, accuracy over a wide range, and low cost. The accuracy of the nutating-disk type meter is not as high as that of the PD meters of the other types.

Advantages and Disadvantages of PD Meters

1. Discharge of the metered liquid is continuous.

2. PD meters can be used to meter exceptionally viscous liquids.

3. PD meters do not require gas to displace the fluid through the meters.

4. Initial and installation cost is lower.

5. Temperature compensation can be applied with certain types of PD meters less expensively than with batch-type meters.

6. Paraffin may not reduce metering accuracy.

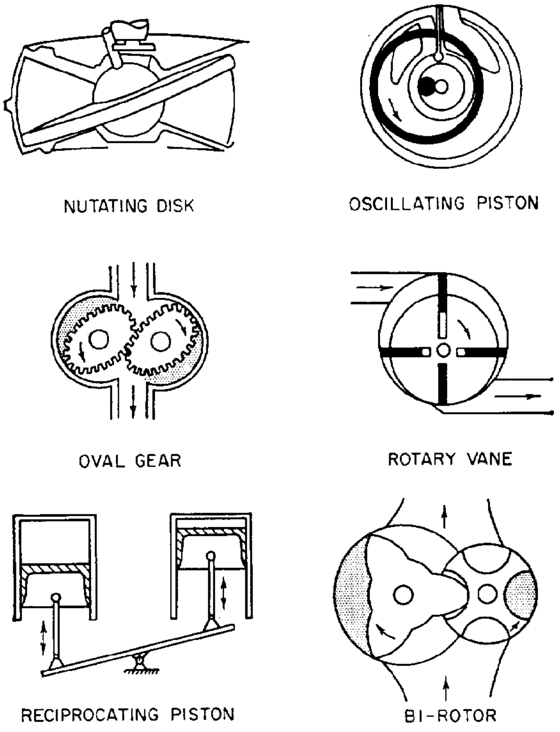
7. Liquids metered must be free of gas, since slugs of gas may damage or wreck the meter. Gas will register as fluid when passing through a PD meter.

8. Sand, mud, salt, or other foreign particles will cause wear on the PD meter and cause inaccurate meter readings.

9. Some type of meter-proving process is required to prove PD meters periodically. Actual stock-tank gauges are used in many cases to determine the accuracy of the meter.

10. Meters must be operated between a minimum and maximum specified rate of flow. High or low rates of flow may affect the accuracy of the PD meter.

PD meters are available in pressure ratings to 5,000 psi. Capacities of PD meters depend on the size and type of meter. If possible the manufacturer of the PD meter should be requested to furnish information regarding the capacity.



NUTATING DISK

OSCILLATING PISTON

OVAL GEAR

ROTARY VANE

RECIPROCATING PISTON

BI-ROTOR

Fig. 32.9—Basic types of PD meters.

TABLE 32.6—AVERAGE CAPACITY FOR NUTATING-DISK-TYPE PD METERS

Size (in.)	Capacity (B/D) Minimum	Capacity (B/D) Maximum
⅝ to ¾	68	340
¾	102	510
1	170	850
1½	342	1,710
2	548	2,740

Average Capacity for Nutating-Disk Type PD Meters. The average rates shown in Table 32.6 are based on oil as the fluid being metered. The manufacturer should always furnish information about recommended capacity. When PD meters are used downstream of separators or vessels that are not continually dumping, it is necessary to size the meter on the maximum "rate" of discharge while the vessel is dumping.

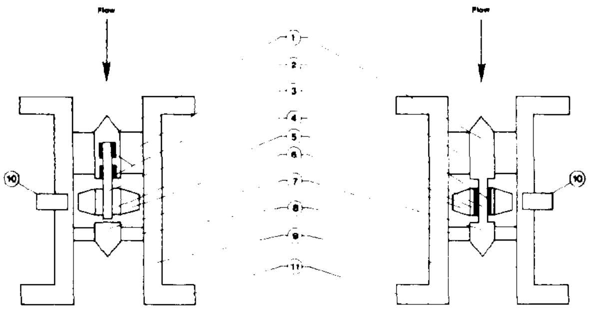
PD meters are used in some cases for gas measurement. The types used are the bellows and birotor. High cost and size have held the use of PD meters for gas measurement to a minimum.

Turbine Meter

Today most liquid measurement is done by the use of turbine meters. A turbine meter is a flow rate measuring device which has a rotating element that senses the velocity of the flowing liquid.[12] This liquid causes the rotating device to rotate at a velocity proportional to the volumetric flow. The movement of the rotating device is sensed either mechanically or electrically and is registered. The actual volume is then compared to the registered readout to arrive at a meter or register factor (see Figs. 32.10 and 32.11).

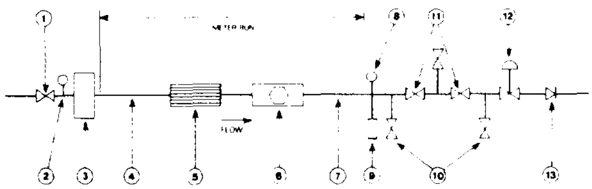
The turbine meter is used because of its simplicity and costs. Each meter application will require different meter or register factors.

Considerations in the selection of turbine meters include (1) properties of the liquid to be metered—viscosity, density, vapor pressure, corrosiveness, and lubricating ability; (2) operating conditions, including pressure, flow rates and whether continuous or intermittent, temperatures (some meters have temperature compensators), and quantity and size of abrasive particles in the fluid; and (3) space availability (see Fig. 32.12). Items or conditions that normally affect the meter factor are shown in Table 32.7. Both turbine and PD meters should be connected so that meter factors may be periodically determined.



(1) Upstream stator
(2) Upstream stator supports
(3) Bearings
(4) Shaft
(5) Rotor hub
(6) Rotor blade
(7) Downstream stator
(8) Downstream stator supports
(9) Meter housing
(10) Pickup
(11) End connections

Fig. 32.10—Names of typical turbine meter parts.



(1) Block valve
(2) Pressure gauge (optional)
(3) Filter, air eliminator and/or strainer as required
(4) Straight pipe
(5) Straightening vane (as required)
(6) Turbine meter
(7) Straight pipe (with straightening vane as required)
(8) Pressure gauge
(9) Thermometer
(10) Proving connections (should be downstream of meter run)
(11) Valve with double-block and bleed or valves with a telltale bleed
(12) Control valve (as required)
(13) Check valve (as required)

Fig. 32.11—Turbine meter system schematic.

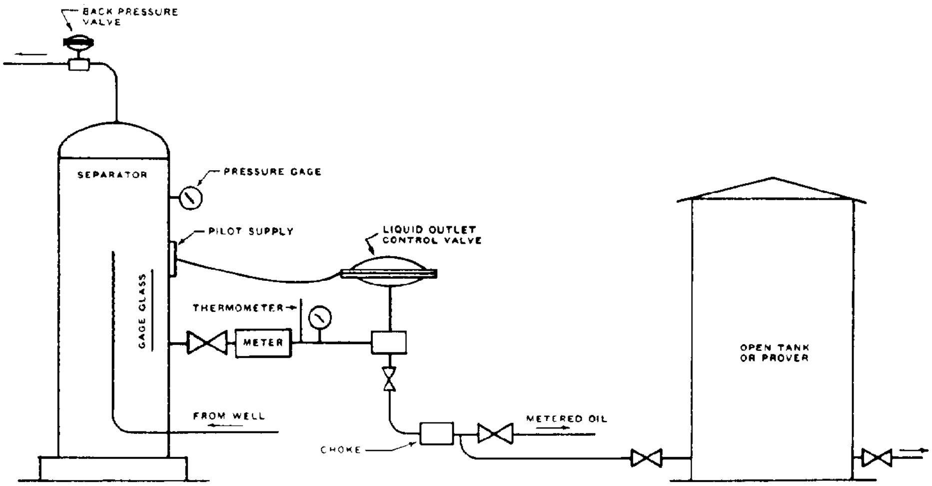


Fig. 32.12—Schematic operation diagram of oilwell production meter installation with stock tank or open prover.

Flowmeters

The standard-type flowmeters are: orifice plate, Venturi tubes, flow nozzle, Pitot tube, drag body, and lift surface. These meters or devices are used to create a flowing differential pressure. This flowing differential pressure is used to solve the flow equation for the rate of flow.

Orifice plate, Venturi tube, flow nozzle, and Pitot tube are commonly used. Drag body and lift surface are not as familiar. The net force resulting from a pressure difference is measured. This pressure difference is used to solve the flow equation. If the force is parallel to the flow direction, the force is called "drag body." If the force is perpendicular to the flow direction, the force is called a "lifting surface."

In addition to differential pressure drop, six other factors must be considered and included in the integration to determine a basic flow rate or quantity. They are (1) static pressure, (2) flowing temperature, (3) specific gravity of the flowing quantity, (4) size of orifice run, (5) size of the orifice plate if orifice plate is used to create the differential pressure, and (6) supercompressibility, if applicable.

These factors may be considered by the solving of the flow equation or they may be applied as a multiplying factor applied to the meter reading.

Mass Flowmeter. In about 1942, W.J.D. VanDijik of The Netherlands constructed and evaluated the first mass flowmeter, as such. The mass flowmeter measures the quantity of matter passed through the meter. This mass is independent of all ambient conditions, which is not true of volumetric meters discussed previously. If any type of flowmeter mentioned above is compensated in any way (electrically, mechanically, or a combination of both) for fluid density, it is a mass flowmeter. As early as 1930, pressure and temperature compensators could be attached to a standard orifice meter. They were mass flowmeters, in a true definition of mass flowmetering, although they were not called by that name.

On well testers, and for measurement of produced water, oil, and gas, it is most common to use turbine, PD, and batch meters for liquid measurement and the standard orifice meter for gas measurement. Mass flowmeters may be used for both gas and liquid measurement. Because of the cost and special requirements for technicians to operate and maintain these meters, they are seldom used in field operations.

Automation and remote readout requirements can be accomplished with the use of well testers in much the same way as with automatic custody units. The liquid measurement may be relayed by pneumatic or electrical impulses to a transmitter. These impulses in turn may actuate some type of recording unit at a central location. The gas measurement would require some type of pressure transducer to convert the differential pressure to an electrical signal. More often, when remote recording of gas flow is required, an integrating flowmeter is used and the transmitted signal will read in volumetric units.

Fig. 32.13 shows a well tester installed at a tank battery for permanent test or lease automation.

Stationary Metering Installation

Stationary metering installations are those that include metering separators, metering treaters, and any other

TABLE 32.7—CONDITIONS AFFECTING THE METER FACTOR

1. Mechanics of meter as to tolerances.
2. Change in clearance due to wear or damage.
3. Flow rates and variations in flow.
4. Temperatures of liquids.
5. Viscosity of liquids.
6. Pressure of liquids.
7. Pressure drop across the meter as a resistance to flow.
8. Foreign material lodged or deposited in the meter or connecting piping.
9. Inlet condition changes, such as changes in the entrance to the meter, which change the flowing fluid profile.
10. Lubricating properties of the liquid.
11. Accuracy and conditions of meter-proving system and meter-factor test.

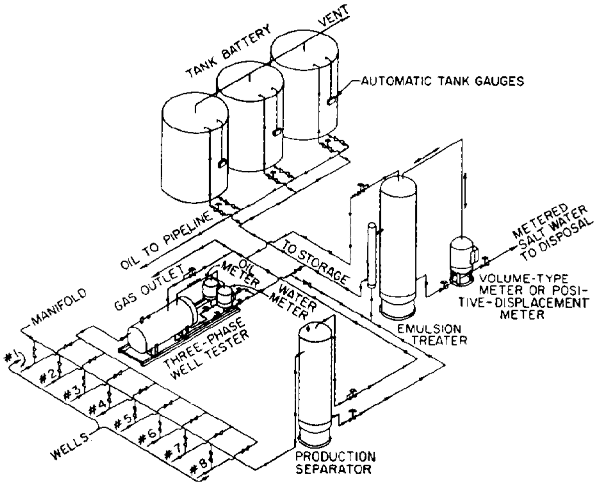


Fig. 32.13—Unitized or automatic tank battery.

type of meter used in conjunction with test separators or emulsion treaters. These units are installed as an integral part of the tank battery.

The metering separator combines two functions of separating and metering the produced fluid (see Figs. 32.14 and 32.15). The metering separation is divided into one compartment for separating the liquid and the gas and into one or two other compartments for metering the oil and water. PD meters may be used for metering all produced fluids.

Pressure ratings range to 3,000 psi. Capacities will be the same as shown for standard oil and gas separators in Chapter 12. The metering capacity will be as shown for the type of meter used.

GOR

The GOR may be defined as the rate of gas production divided by the rate of oil production. It is usually expressed as standard cubic feet of gas per barrel of stock-tank oil produced under stabilized flowing conditions for a 24-hour period.

The term "cubic feet of gas" or "standard cubic feet of gas" means the volume of gas contained in one cubic foot of space at a standard pressure base and standard temperature base. This standard base is normally 14.65 psia and 60°F. Most tables published for orifice well testers, Pitot tubes, flow provers, and other gas measurement means are referred to a base pressure of 14.65 psia and 60°F temperature. Whenever the conditions of pressure and temperature vary they may be converted to a standard or base condition by the use of the real gas law.

The volume of gas used should be the total gas produced from the reservoir through either the casing or tubing. Any gas that is injected back into the reservoir for artificial lifting purposes such as gas lift should be subtracted from this total gas produced.

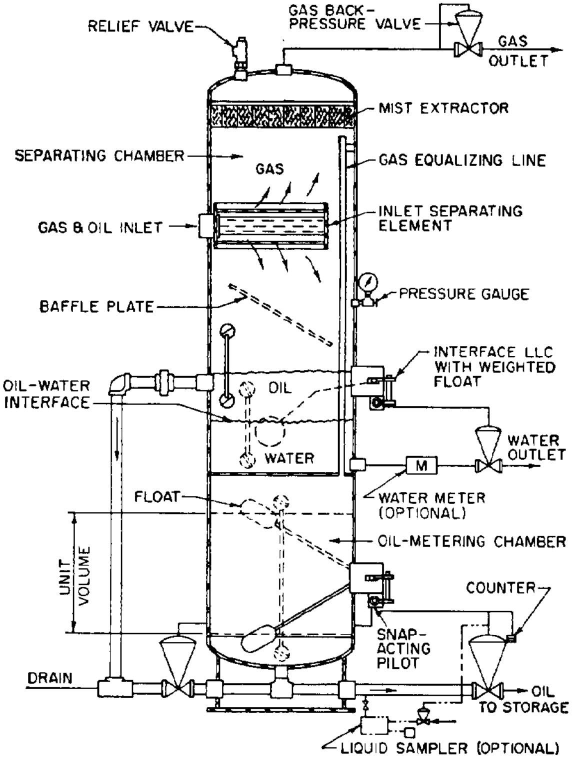


Fig. 32.14—Metering separator with free water knockout.

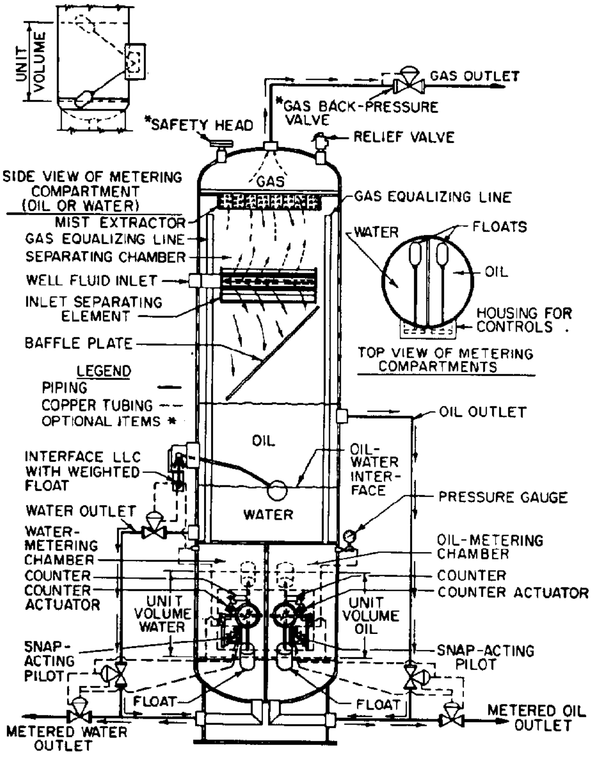


Fig. 32.15—Three-phase metering separator with integral metering compartments. Gauge glasses and valves are furnished for separating chamber and both metering chambers. Automatic BS&W samples can be furnished as an option.

The volume of oil produced should be determined by any of the means discussed in the first part of this chapter.

Procedures for Well Testing

Flowing Wells. The oil flow should be stabilized during the 24-hour period immediately preceding the test. This stabilized flow should be very close to the assigned allowable or the daily producing rate. If the well being tested is a discovery well, the producing rate should be as close to the assigned discovery allowable as possible. Any adjustments should be made during the first 12 hours of the stabilization period and no adjustment made during the last 12 hours or during the time the well is on test. All gas withdrawn from the reservoir must be included as produced gas. If the oil has a great deal of shrinkage after it is placed in the stock tanks, some means should be considered for measurement of the gas that breaks out of solution. Any gas used for operation of machinery or for any other purpose must be considered as produced gas. Tests should range from 24 to 168 hours' duration to consider any uneven flow.

Intermittent Flowing Wells (Stopcocked). The procedure for testing should be as outlined for flowing wells, except the shut-in casing and tubing pressures should be approximately equal to the pressures recorded at the beginning of the test. The Texas Railroad Commission states, "The closed-in casing pressure at the end of the 24-hour test period shall not exceed the closed-in casing pressure at the beginning of the test by more than six-tenths (0.6) pounds per square inch per barrel of oil produced during the test." This rule also applies to flowing wells. This is true because of the "loading" characteristic of some wells while shut-in. Before an accurate test can be made the flow must be stabilized and stabilization cannot occur while producing from a loaded annulus or tubing.

Gas-Lift or Jetting Wells. The volume of gas used should be the net produced gas or formation gas. Formation gas will be equal to the total gas produced minus the injection gas.

Pumping Wells. In computing the GOR for pumping wells, the total volume of gas produced during the 24-hour period, ending with the closing in of the well at the conclusion of the tests, and the total barrels of oil that are produced in order to obtain the daily allowable must be used regardless of the actual pumping time in the 24-hour period. If the gas produced is not enough to measure accurately, this should be indicated on the test report as gas "too low to measure."

In some states the regulatory agencies will lower the assigned allowable of the well if the daily or producing allowable is not produced while making GOR tests.

Average GOR

To obtain an average GOR for several wells or for all the wells in a field, one cannot take the arithmetic average value of the ratios. For example, two wells with GOR's of 2,000 and 4,000 would not necessarily have an average ratio of 3,000. For the average ratio to be 3,000 the wells would have to produce the same amounts of oil. The average GOR of several wells must be obtained by dividing the total gas production of all wells involved. For example, if the 2,000-ratio well produced 50 B/D oil and the 4,000-ratio well produced 200 B/D oil, the average GOR for the two wells would be

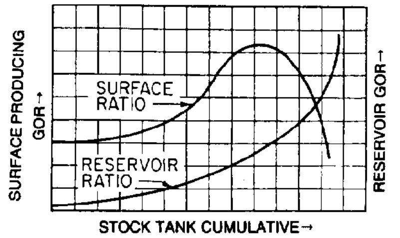


Fig. 32.16—Typical performance curve for an internal gas-driven reservoir.

$$\bar{R}=\frac{(2{,}000\times 50)+(4{,}000\times 200)}{50+200}=3{,}600 \text{ cu ft/bbl.}$$

For a large number of wells, the average ratio can be figured as

$$\bar{R}=\frac{\Sigma(R_{iw}\times q_{iw})}{\Sigma q_{iw}} \quad \text{..........................} \quad (8)$$

where

$\bar{R}$ = average GOR, cu ft/bbl,
R_{iw} = individual well GOR, cu ft/bbl, and
q_{iw} = individual well daily production, STB/D.

Cumulative GOR

The cumulative GOR is defined as the total amount of gas produced and kept from the reservoir up to a certain time divided by the cumulative oil produced up to the same time. Therefore,

$$R_p=\frac{G_p-G}{N_p}, \quad \text{..............................} (9)$$

where

R_p = cumulative GOR, cu ft/bbl,
G_p = total gas produced, cu ft,
G = gas reinjected, cu ft, and
N_p = total oil produced, bbl.

GOR as a Criterion of Reservoir Performance

The producing GOR is often used as an indication of the efficiency of a producing well, and the increase in the ratio is looked on as a danger signal in the control of the reservoir performance. The GOR should be kept as low as possible (see Fig. 32.16). The area under the curve, shown as the surface ratio, will be the total amount of produced gas. This is by the previous definition of

GOR. This shows that maintaining the GOR as low as possible will increase the cumulative production for the same amount of produced gas.

Consider the internal-gas-drive reservoir. As oil is produced from the reservoir the space is taken over by gas volume. The presence of gas within the reservoir decreases the ability of oil to flow and increases the ability of gas to flow. After a certain minimum gas saturation (about 5 to 10%) is exceeded, the ease with which gas flows increases to such an extent that it flows concurrently with the oil. This process continues until finally the only flow is almost all gas. This allows the reservoir energy to escape and causes the reservoir to cease production by natural means. Fig. 32.16 shows how the stock-tank cumulative production almost ceases as the reservoir/GOR increases.

Key Equations in SI Metric Units

$$q_o=\frac{5.427\times10^{-4}kh(p_e-p_{wf})}{\mu_o B_o[\ln(r_e/r_w)+s]}, \quad \ldots\ldots\ldots\ldots\ldots (1)$$

$$J=\frac{q_o}{\Delta p}=\frac{5.427\times10^{-4}kh}{\mu_o B_o[\ln(r_e/r_w)+s]}, \quad \ldots\ldots\ldots\ldots\ldots (2)$$

where

q_o = oil production rate, m^3/d
k = permeability of formation, m^2
h = thickness of formation, m
p_e = pressure at the effective drainage radius r_e, normally approximated by p_R, kPa
p_{wf} = flowing bottomhole pressure, kPa
μ_o = oil viscosity, Pa·s
B_o = oil formation volume factor, res m^3/STm^3
r_e = effective drainage radius, m
r_w = wellbore radius, m
s = skin effect (zone of reduced or improved permeability), dimensionless
J = productivity index (PI), m^3/(d·kPa)

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