OIL-FIELD PRACTICE

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BY

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DEDICATION

To

JAMES F. KEMP,

Professor of Geology in Columbia University,
whose inspiration and guidance have been a
constant aid to me in all my work.

PREFACE

A growing demand for a book dealing with American methods of developing oil properties has led to the writing of the present volume, Oil-Field Practice.

"Practical Oil Geology" was written to set forth the elements of oil geology in simple form. The success of that book, which deals largely with geological and engineering problems, prompted me to supplement that earlier work with Oil-Field Practice. Each book is a complete unit in itself, as the problems discussed are approached from different angles. Several subjects overlap in the two volumes, but taken together such overlapping serves to emphasize the points under discussion.

Some of the material in the present volume was included in my early articles, which dealt largely with operating problems, and which have been used as a nucleus for this book to which much new material has been added. I have also borrowed freely from all books, and other publications on the subject, including Beeby Thompson's excellent work "Oil Field Development;" Bacon and Hamor's "American Petroleum Industry;" Paine and Stroud's "Oil Production Methods," which should be more generally studied; and Andros' "Handbook of Petroleum," a valuable compilation for the oil-man.

I have drawn on the Bulletins of the U. S. Bureau of Mines by C. P. Bowie, Fred Tough, E. W. Wagy, Carl Beal, J. O. Lewis, A. Heggem, Ralph Arnold, and V. R. Garfias. The excellent statistical data of the American Petroleum Institute have been used freely. The "Oil and Gas Journal," the "Oil Weekly," the "Oil Trade Journal," and the "Petroleum World," have been consulted for special articles and statistical data.

The oil-well supply catalogues furnished a wealth of material, especially for cuts and tables. I have always felt that more could be gleaned about operating problems from a thorough study of oil-well supply catalogues than any other way, and have accordingly drawn much from such sources.

The facts and methods set forth in this book are not presented as new matter, but represent a compilation from authoritative sources, supplemented as far as possible by first-hand information.

Perusal of this book will not teach the reader to become an oil-man immediately, but it is my hope that by the aid of this book he can obtain an intelligent insight into the petroleum industry as a whole, and appreciate a few of its many problems.

Acknowledgments are due to the many friends who have given freely of their time, knowledge, and constructive criticism. Mr. Fred Dennett, former Land Commissioner of the United States, has prepared a valuable and timely résumé of the Federal Leasing Bill, which appears in Chapter II. I am indebted to my friends, especially to Chester Narramore of New York, P. A. Gilbert of Warren, Pa., A. A. Aultman of Los Angeles, Norman W. Hendershot of the Oil Well Supply Company of Los Angeles, Alfred A. Smith of Tulsa, T. N. Crawford of New York, Kenneth Cottingham of Columbus, Ohio, W. J. Allen of Denver, Colo., W. M. Dunham, Statistician, George Taber, Jr., of the Sinclair Oil Company, Tulsa, and Walter Miller, Refinery Engineer, Tulsa, for material and suggestions furnished; and to Garda Zoe Farkasch, O. M. Buch and John H. Taber for their valuable assistance in correcting and preparing manuscript.

If anyone has been slighted, and if any material used has not been fully accredited, I shall be glad to acknowledge the omission at a later date.

DORSEY HAGER.

LOS ANGELES, CALIF.,
June, 1921.

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CHAPTER I

GENERAL OBSERVATIONS

With the tremendous development that has taken place in the Petroleum Industry, now one of the largest and most important in the country, it is difficult to realize that it is only two years over three score old. In 1859 Edwin Drake drilled his famous well at Oil Creek and discovered oil in commercial quantity. That strike created the first oil excitement in the Americas. Prior to that time oil was produced in small quantities from the brine wells of western New York and eastern Pennsylvania. Drake was the first man to drill successfully for oil. Since his early discovery the industry has grown by leaps and bounds. Oil has been sought all over the two Continents. Commercial pools have been found in Alaska, in Canada, in sixteen of the United States, in Mexico, in Colombia, Venezuela, Peru, Bolivia and the Argentine.

Thousands of men are engaged in the drilling of oil and gas wells both in new and in proven areas. Thousands of others are engaged in handling the crude product. This must be transported to the refineries which in turn give the finished products of commerce.

In the minds of many people the mining of petroleum is a hazardous gamble. Few indeed have a realization of the magnitude of this great industry or of its highly specialized character. Its development has been so rapid that only those in close touch with the industry fully appreciate its importance and its numerous ramifications which embrace many other industries. Everyone to-day uses petroleum products in some form. They enter into our daily lives in such a fashion that we do not consider their source. Gasoline, kerosene, fuel oil and distillates are all familiarly known and generally used.

But a broader conception may be gained when we consider that the paraffin wax used to seal jars, the fancy sealing waxes, the vaselines, chewing gums, and petroleum jellies are all products derived from crude petroleum. Dyes are manufactured from petroleum. In fact, over a thousand by-products of refined petroleum are in use. (See Plate I, p. 3.) To fill all the demands a tremendous amount of petroleum is required.

Some idea of the growth in the use of petroleum, familiarly called crude oil, may be gathered from the fact that in 1859, the United States supplied 2000 bbl. and in 1920, 443,400,000 bbl.

The demand for oil is increasing. The industry has grown from a very unimportant one to one of our greatest, employing many thousands of men. Over $6,000,000,000 is invested in petroleum properties, in pipe-lines, and in refineries.

The following chart of the working divisions of a complete oil company emphasizes the complexity of the industry.

The *industry* is well organized. Its most important divisions may be subdivided as follows: Producing, Transporting, Refining, and Marketing.

The functions of the producing department are to obtain oil lands, and to find *and develop* the crude petroleum.

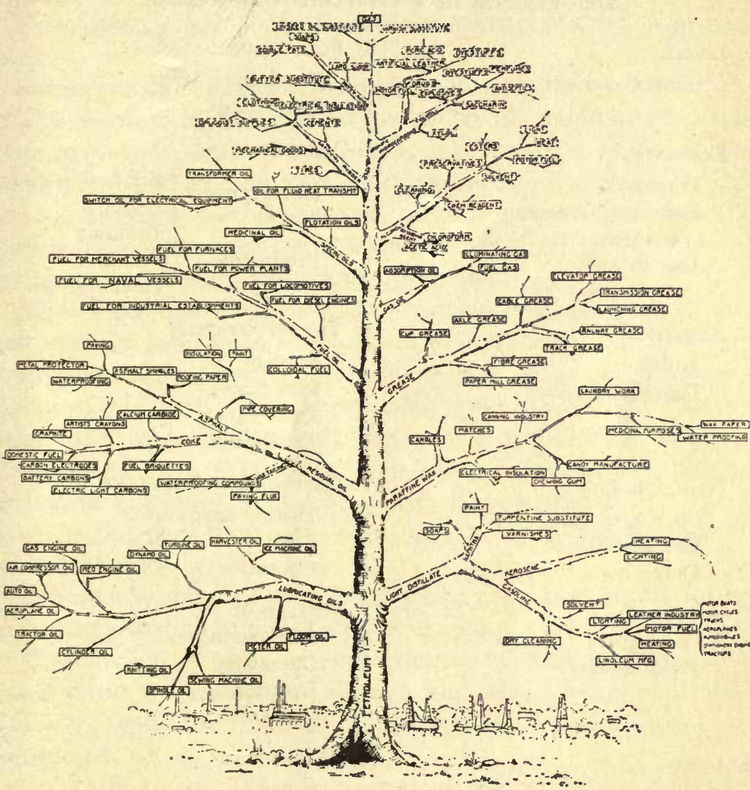
The transportation division carries the oil to the refineries or to the markets.

The refining department takes the raw material and manufactures it into the refined products of common use.

The marketing departments handle the distribution and selling of the products to the ultimate consumer.

The producing of oil falls into natural divisions:

1. Exploration.
2. Development.
3. Storage.



USES OF PETROLEUM PRODUCTS

Dotted Frames Indicate probable future Products

PLATE I.—Courtesy E. Owen and *Oil Trade Journal.*

CHART 1

DEPARTMENTS IN A COMPLETE OIL COMPANY

1. LEGAL:
   - General counsel
2. FINANCIAL:
   - Treasurer
   - Assistant Treasurer
   - Controller
   - Accountant
3. AUDITING:
   - Auditor
   - Traveling auditor
4. GEOLOGICAL:
   - Chief geologist
   - Reconnaissance
   - Detail men
5. SCOUTING:
   - Chief scout
   - Field scouts
6. LAND:
   - Legal
   - Buying
   - Leasing
   - Abstracting
7. ENGINEERING:
   - Surveying
   - Mapping
   - Records
   - Operating engineering
8. PURCHASING:
   - Purchasing agent
   - Storekeeper
9. OPERATING:
   - Development
     - Rig building
     - Drilling
   - Production
     - Teaming
     - Pumping
     - Field storage
10. TRANSPORTATION:
    - Storage
    - Pipe-lines
    - Tank cars
    - Tank ships
11. CASING-HEAD GASOLINE:
    - Testing engineering
    - Erection
    - Operation
12. REFINING:
    - Engineering
    - Chemistry
    - Erection
    - Operation
13. MARKETING:
    - Sales
    - Distribution
    - Wagons
    - Stations
14. STATISTICAL:
    - Statistician
    - Publicity

Exploration includes the search for areas thought favorable for oil accumulation, and the drilling of such areas to prove whether or not they contain oil deposits.

Development covers the field of active exploitation of proven areas.

Storage deals with the care and handling of oil.

The selection of oil lands may be under the guidance of petroleum geologists, trained specialists, who make a study of the accumulation of oil, and who explore areas in advance of the drill and select places for oil tests; or selection may be based on the finding of oil-seepages, or the occurrence of oil in water wells, by gas escapes, or by whim and "hunches."

Many fields have been opened under geological guidance, which has recently become more practical and efficient, but it is safe to say that most of our American fields have been opened without technical guidance. This is especially true in the older Eastern fields, and in early developments in the Mid-Continent fields.

California and Wyoming have given striking examples of geological efficiency, and Oklahoma, Kansas and North Texas have in the past five years seen notable developments due to geological work.

The development of petroleum geology has been rapid, for its use insures the minimum of risk in drilling for oil.

The location of tests without competent geological advice is much more general in the Eastern and Mid-Continent States, however, and the method of haphazard location must be considered.

It is safe to say that competent geological advice will give successful results one in five tests, and that haphazard drilling will more fairly be represented by one in 300.

The study of geological methods will not, however, be treated in this book.

Scope of the Industry.—It is a common belief that all one has to do is to drill a well and then receive dividend checks. This is far from the true condition. The discovery of oil is important, but the proper handling of oil properties, after discovery, requires skilled management and workmen. Oil may be found in quantity but if improperly handled good properties may be total failures.

The storage of oil necessitates great reservoirs or tanks.

Some of the crude oil produced is burned directly, as fuel, some of it is refined by "topping" (a simple distillation process), or by more careful refining methods calling for large and expensive plants and equipment.

The extraction of casing-head gasoline from natural gas has become an important part of the oil industry.

The transportation of oil to the refineries requires expensive equipment, and the investment of many millions of dollars. The pumping of several hundred millions of barrels of oil yearly through pipe-lines is a large business. Consideration of the many thousands of tank cars on our railroads shows that this part of the business has also assumed important proportions.

The marketing and distributing of petroleum products is distinct from other branches and is an important industry.

In any study of an industry, its various branches and ramifications are important. However, there are a number of other subjects that must be given consideration. Investors, or men choosing a life work desire to know about the permanency of the industry they are considering. Has it a long or a short life before it? Will prices continue high? Is it under the control of a monopoly? What are the chances for new capital? Are there any serious labor problems? All these questions are of importance.

Life of the Industry.—The oil industry is 62 years old and more active than ever before. Its future life is difficult to predict but one can figure safely on an active life for at least 50 years. Whether it can maintain an active life for that time in the United States is very questionable. However, there is the world to draw upon, and its resources are very vast.

Future Price of Oil.—The prices in 1921 furnish an interesting study. On Jan. 1, 1921, the quoted price of oil in the main Oklahoma field was $3.50 per bbl. In July, 1921, the price was

$1.00 per bbl. Prices in the Eastern and the Gulf Coast fields were cut in two. Prices in the California fields were cut only 25 cents. This condition is purely temporary, due largely to the business depression during the latter part of 1920 and the first part of 1921. The decrease in the buying power of the public checked the use of motor vehicles with the result that less gasoline was used.

The light oils of the Mid-Continent field felt this decrease in consumption quickly and reacted with lower prices. Another contributing factor to lower prices in the Mid-Continent fields was the very heavy production from deeper sands in the old fields which caused a local glut for the time being.*

Oil prices in 1922 should, however, be higher than in 1921, as the general business depression caused by the reaction to the war period will be largely over by that time. An improvement in general business conditions means increased oil consumption. The supply of oil is limited however and the increased consumption is bound to force prices higher than before. Stocks of oil on hand in storage May 1921 were 155,000,000 bbl., a four months supply only. This is a small margin on which to work.

Future Markets.—In 1921 the United States is facing an actual scarcity of petroleum for the future. During the coal strike in the early winter of 1919–1920 there was an increase in the use of oil for fuel in place of coal. Some of the railroads of the Northwest and the towns and cities now using oil for fuel are facing a return to coal, for the present at least. Conservative marketers are planning to curtail their trade and supply a limited number of customers. California operators in the winter of 1919–1920 purchased 50,000,000 gal. of gasoline in the Mid-Continent oil field and sold it in California practically at cost. California during the summer and the winter of 1920 purchased oil from the Mid-Continent.

Table 1 shows the increase in the use of motor vehicles and the increase in the production of oil for the past 10 years. It will be noted that the increase in motor vehicles for 1920 was

* The importation of Mexican oil is also an important factor in lowering prices temporarily.

Table I.—Adapted from American Petroleum Institute Bulletin 145, 1921

	Number of automobiles end of year	Per cent of increase over previous year	Year's production of crude oil (42-gal. bbl.)	Per cent of increase over previous year	Number of barrels of crude oil each year per car
1911	700,000	..	220,449,391	..	314
1912	1,020,000	45	222,935,044	1	218
1913	1,280,000	25	248,446,230	11	194
1914	1,711,338	34	265,762,535	7	155
1915	2,445,664	42	281,104,104	5	115
1916	3,544,952	45	300,767,158	7	85
1917	5,085,959	43	335,315,601	11	66
1918	5,945,442	17	355,927,716	6	60
1919	7,558,848	27	377,719,000	6	50
1920	9,000,000	19	443,400,000	17	46

Average increase 33 per cent. Average .... 7.1 per cent
Increase 1919 over 1911 in cars................ 979 per cent
Increase 1919 over 1911 in production.......... 71 per cent

19 per cent and for 1919, 27 per cent. This lower rate of increase is directly due to the general business depression starting in 1920. Oil production, however, increased 17 per cent in 1920 as against 7 per cent for 1919.

This is an abnormal condition. Once the business depression is over, increased consumption is bound to result. How high it will go depends entirely upon the available supply of oil. The number of wells drilled in 1919 was 29,072. In 1920 the number was 33,675, an increase of 4,603 or 15.8 per cent. The increase in production was 17 per cent, slightly greater than the percentage increase in new wells.

The estimate for new automobiles is given in Table II. However, oil consumption may be checked due to the fact that oil production cannot maintain its present rate of increase very long. The oil producing areas are limited. That of the United States is 4500 square miles, with a potential reserve of 8,000,000,000* bbl. The amount of new oil land is unknown, but appears to

* Figures of U. S. Geological Survey. They are to my mind too low by 20 per cent.

be of small extent.

Oil consumption will amount to at least 700,000,000 bbl. in 1925 figuring on a 7 per cent annual increase and that United States consumption in 1920 was 443,400,000 bbl. This includes the export trade which was 88,000,000 bbl. in 1920.

Table II.—From American Petroleum Institute Bulletin 145, 1921

Estimate of Future Automotive Vehicles

The following table estimates the number of motor vehicles and engines in use and possible production 1920, 1921, 1922 and 1923 (last three ciphers omitted):

	1920		1921		1922		1923	
	Number in use Jan. 1	Estimated production	Number in use Jan. 1	Estimated production	Number in use Jan. 1	Estimated production	Number in use Jan. 1	Estimated production
Passenger cars	6,500	2,250	7,450	2,500	8,460	2,750	9,518	
Commercial. cars	700	500	1,060	600	1,448	750	1,909	
Farm tractors	300	175	415	250	582	400	866	
Stationary engines	900	350	1,070	350	1,206	350	1,315	
Total using pet. fuel	8,400	.....	9,995	.....	11,696	.....	13,608	

Depreciation Factors

Passenger cars	5 years
Commercial cars	5 years
Tractors	6 years
Stationary engines	6 years

Once the oil production becomes stationary the maximum demand for motor vehicles will be quickly reached. Any increase in the number of machines will be due to improved efficiency in the use of motor fuel. An increase in efficiency of 10 per cent will mean an increase of 10 per cent new cars. Also the increased efficiency will offset a loss in oil production for a short time. Manufacturers of motor vehicles will find their best key to future demands in a study of the oil reserves and in the statistics of oil production and consumption.

The domestic supply of oil in 1919 and 1920 was insufficient to meet the nation's needs. Where then is the nation to find a supply to meet the requirements of the coming years?

Gasoline for motor vehicles is necessary. Better cracking methods will increase the amount of gasoline, and that, of course, means much less fuel oil. In California, the Standard Oil Company claims this will mean 30,000 bbl. per day less of fuel oil, or 10,800,000 bbl. less fuel oil per year from their own plants.

Another fact must be recognized. The old fields decline at an average rate of not less than 15 per cent per year. This decline in production must be offset by new wells.

In 1920 the United States produced 443,000,000 bbl. The decline in old wells for 1921 will be 66,450,000 bbl. which must be overcome by new drilling. This amounts to slightly over 180,000 bbl. per day which, in December, 1920, was equivalent to the production for Louisiana and for all North Texas.

*Mexico as a Reserve.**—Mexico has been considered an area of remarkable promise, but the best advices on Mexico indicate that its potentialities have been greatly over-rated. It is and will remain a remarkable producer, but the fields are small in area, and while producing tremendous quantities of oil for a short time, are flooded out quickly. The history of water flooding of the Chicquchilo, Tepatete, and Juan Casiano oil fields is being repeated by the new Chinampa field which is now going to water rapidly. Wells of 20,000 to 80,000 bbl. per day were brought in, but their life is very short.

Overcoming Scarcity.—The future scarcity of oil may be lessened in several ways.

1. By increased production, which will result from:
   (A) discovering new fields.
      (a) domestic.
      (b) foreign.
   (B) increasing the yield in old fields.

* Mexican reserves are a source of bitter controversy at the present time. It is difficult to obtain true facts as equally good men give widely divergent opinions.

2. By discovery of other fuels and lubricants.
   (A) synthetic fuel.
   (B) development of oil from oil-shales.

Hope of New Fields.—The outlook for increased production from new fields in the United States does not seem encouraging. Some new fields will certainly be found. California may obtain a few new fields, or by deeper drilling on some of the large folds of the Kettleman Hill type may develop a production ranging from 5000 to 6000 ft. in depth. An intensive drilling campaign in California should maintain heavy production several years. In Wyoming and Montana a few new fields can reasonably be expected, as will also be the case in all the older proved areas of the United States. The new fields, however, will not offset the loss in the old fields for any length of time.

For new undeveloped areas, look to Alabama, Arizona, Mississippi, Michigan, New Mexico, Utah, Oregon and Washington. New fields from these states are possible, indeed likely, and the country needs them. Every possible area is now being prospected for oil, and new fields will be brought to light in areas that were ranked as second and third rate, but which to-day are decidedly worth while. A difference of 200 or 300 per cent increase in the price of oil means intense prospecting of poorer producing lands.

There are good chances of finding productive fields in foreign countries—Mexico, Venezuela, Colombia, Peru, Brazil, the Argentine, all have promise of new oil fields of magnitude. Alaska and Canada present some opportunities. Africa, Russia, Roumania, France, Italy and Albania offer oil possibilities. Asia Minor, Persia, Mesopotamia, Arabia and Syria have chances of new fields, as have India and China. The Philippines, New Zealand, Borneo, Madagascar and other Pacific Islands may be reckoned on for future oil.

Developing Old Fields.—Drilling to deeper sands has helped to maintain production in the older fields. There is always, however, the final limit of barren areas, and deeper drilling cannot be continued everywhere, as in many places drilling 5000 to 6000 ft.

would result in no new production, since all the oil-bearing strata were fully proved at depths of 2000 to 3000 ft.

One of the best chances for increased production seems to be not alone in finding new fields, but in finding some means of obtaining higher recovery from sands already producing oil. The results obtained at Bradford by water flooding, and at Marietta, Ohio, by the Smith-Dunn process have been remarkable. Recoveries of 10 to 20 per cent of the oil in the sands are the average under ordinary production methods.* The productions at Bradford, Pennsylvania, and at Marietta, Ohio, have been more than doubled by improved recovery methods.

There is also, of course, the possibility that other fuels may be developed. Synthetic chemistry can do a great deal, and we shall certainly be using benzol, alcohol, and alcohol-benzol combinations for fuel in future years.

The development of the oil-shale industry is only a question of time. It calls for a tremendous outlay of capital. To obtain an oil-shale production equal to our present oil production would require an investment of at least $3,000,000,000, figuring a $2,000,000 investment for each 1000 bbl. of oil produced daily. Our present daily oil production (1922) is a little more than 1,500,000 bbl.

The United States Geological Survey estimated (in 1919) that the potential supply was 8,000,000,000† bbl. or not enough to last us over 15 years at the present rate of consumption. This supply may be increased greatly by better methods of oil recovery, but such methods require careful study.

The growing scarcity of oil means that larger profits will be reaped by the men who make the industry a life work, and there seem to be no better opportunities for a young man today than those presented by the Petroleum Industry.

No Monopoly in the Oil Business.—For many years the Standard Oil Company practically enjoyed a monopoly of the American oil business. That condition has been changed somewhat. A monopoly is not necessarily detrimental. There is no doubt that Standard Oil control resulted in economies

* J. O. Lewis, Bull. 148, U. S. Bureau of Mines.

† Jan. 1, 1922, 9,150,000,000.

in production, transportation, refining, and marketing which lowered the price of all oil products to the consumer. The Standard Oil Company depended on quantity sales and a smaller profit on each sale than was possible for smaller operators. However, a large number of independent producers have sprung up in the past few years and are now competing successfully with the Standard Oil subsidiaries in producing oil. Most of these operators do not have a complete organization for producing, transporting, refining and marketing, but are dependent on the production of oil alone for their profits.

There are several large independent oil companies with complete organizations, notably; The Gulf Production Company, The Texas Company, The Ohio Cities Oil & Gas Co., The Union Oil Company of California, The General Petroleum, The Sun Company, The Empire Oil & Gas Company, The Sinclair Oil Company and the Cosden Oil Company. Besides these large corporations there are independent operators, such as E. L. Doheny, who control big holdings.

Some of the great railroads, notably the Southern Pacific and the Santa Fe systems, have extensive holdings of oil lands, principally in California, Texas, and Louisiana. These companies consume the oil they produce and are also purchasers of oil on the open market. The main foreign companies operating in the United States are the Royal Dutch Shell interests represented by the Roxana in the Midwest, and the Shell Oil Company in California.

Standard Oil Group.—There are 33 large companies comprising the Standard Oil Group. These companies are well managed and properly financed. The dissolution of Standard Oil in 1911 resulted in a rise in the price of stocks of most of the subsidiaries. Those oil men who appreciated real values acquired all the stock available immediately after dissolution and have been well repaid for their foresight.

The dissolution ostensibly left each company as an independent unit and put each concern on a competitive basis. The result has been greater elasticity in management and greater efficiency in operation. The desire of the management of each company to make a showing has proven beneficial. The main companies in this group comprise The Standard of New Jersey, The Standard of New York, The Standard Oil of California, The Standard Oil Company of Indiana, The Carter Oil Company, The Prairie Oil & Gas Company of Kansas, The Magnolia Oil Company, The Standard of Louisiana, The Ohio Oil Company, The Midwest of Wyoming, The Illinois Pipe-line Company, The Prairie Pipe-line Company, The South Penn, and The Atlantic Refining Company. There are numerous others but these concerns are at present the most aggressive of the Standard group in the United States.

The oil industry is no longer a business for men of small means. There are numerous examples of successful operations by men of small capital, but to produce, transport, refine and market oil requires a large outlay of capital. A new concern starting into the field must therefore be prepared with sufficient capital for all emergencies.

Where many men with $10,000 could get a successful start 20 years ago, $100,000 is required today. There is no reason why any group of men with $1,000,000 to spend under good management should not be successful. They must, however, be prepared for failures and discount them in advance. A failure in one place must be offset by gains in another. In the oil business never, "put all your eggs in one basket."

Labor Conditions.—There are no serious labor problems in the oil industry. There are well organized unions in California and in the Gulf Coast fields of Texas but in the Mid-Continent and Eastern oil fields, unions are practically unknown.

The oil-mens' unions have, however, done little to benefit the field worker. There is really no need for unions in the oil industry as the average oil operator takes good care of his men.

The oil business has for many years been the most democratic of our industries. Every man looked forward to the time when he would become an operator on his own initiative. However, as the industry has grown and the large companies have acquired control, there is a tendency on the part of the field workers to unionize. This is perfectly natural as the impersonal relations of corporations are very different from the personal touch of an operator who sees his men often, and can call them all by their first names.

Oil-field workers are principally Americans coming from stock that has been in this country several generations. They are drawn mostly from Pennsylvania, West Virginia, Ohio, Indiana, and Illinois. Texas and California have developed some new men but the main source of supply is from the Eastern oil states. These men are above the average in intelligence, in initiative, and, in general resourcefulness. They have much of the pioneer in their blood.

The industry is highly specialized. There are many classes of workers. Much work is done by contractors, so that there are are drilling contractors, casing-head experts, rig builders, in fact all branches of the industry are represented by specialists.

After studying the divisions of the industry, and the labor divisions, one appreciates more clearly the magnitude of the industry.

Handling Laborers.—Oil-field labor is of two kinds:

(A) Transient.

(B) Resident.

Transient labor travels from field to field, lured on by the excitement of new sights, and new experiences. They are married or single, but if married, their responsibility often sets lightly on them.

The resident workers are of the type that brings their families to the fields and makes their homes on the oil properties or in the nearby towns.

When fields are new and conditions are uncertain, the first type of worker is plentiful, but when the fields grow older, the second type predominates. It is not unusual in traveling over the country, at each new excitement, to meet drillers from all over the country, or the world, for that matter.

Oil fields generally occur in barren, or wild country, often good for nothing else but to produce oil. Men living under such conditions need healthful recreation.

Too often in the past the saloons and the dance halls have been the main sources of amusements, but farsighted operators now make it a point to build comfortable camps for their men. Comfortable bunk houses, club houses, and excellent boarding houses are installed. This keeps the workers contented and in good health.

Food in most oil-field camps is plentiful and of high quality. It is generally quite varied and is well cooked, as oil-field workers demand excellent food, and get it. I do not think I make a mistake in saying, that the cooking is far above what the average man gets at home, or on a farm.

Some idea of the variety of workers and of the wages may be obtained from the wage scale presented below in Table 3, which applies for the present only, and will no doubt be changed this year 1921.

TABLE 3.—CLASSIFICATION AND WAGE SCALE OF OIL-FIELD EMPLOYEES, CALIFORNIA FROM JULY 1, 1920 TO AUGUST 31, 1921*

Classification	Effective wage (8 and 9 hr. day)	Bonus per day
Cable tools		
Driller	$9.75	$0.25
Tool dresser	7.25	0.25
Circulator or third man	6.25	0.25
Rotary tools		
Driller	9.75	0.25
Bit dresser or cat-head man	7.75	0.25
Derrick man	7.25	0.25
Rotary helper	6.75	0.25
Rig builders		
Head rig builder	9.75	0.25
Rig builder	8.75	0.25
Second rig builder	7.75	0.25

* Taken from Los Angeles Chamber of Mines and Oil—*Mining and Oil Bulletin* Sept., 1920.

TABLE 3.—(*Continued*)

Classification	Effective wage (8 and 9 hr. day)	Bonus per day
Well cleaners		
Head well cleaner	8.00	0.25
Well cleaner helper	6.50	0.25
Well pullers		
Head well puller	7.50	0.25
Well puller	6.25	0.25
Engineers and firemen		
First engineer (where fireman is employed)	6.75	0.25
Second engineer (where fireman is not employed)	6.50	0.25
Fireman	6.00	0.25
Pumpers and oilers		
Pumper	6.25	0.25
Oiler	6.25	0.25
Dehydrator operators		
Dehydrator operators (employed continuously in operation of large units)	6.50	0.25
Dehydrator operators (operating in plants in conjunction with other worker classified as pumper)	6.25	0.25
Gasoline extraction plants		
First class plants		
First engineer	6.75	0.25
Second engineer	6.50	0.25
Large booster stations		
Engineer	6.50	0.25
Small booster stations		
Engineer (operating booster station with or without other work)	6.25	0.25
Oilers	6.25	0.25
Pumpers	6.25	0.25
Traptenders	6.25	0.25
Firemen	6.00	0.25
Teamsters and truck drivers		
Teamsters (2 horses) (where teamster does not hitch, unhitch, harness or unharness)	5.75	0.25
Teamsters (2 horse)	6.00	0.25
Teamsters (4 horses)	6.25	0.25
Teamsters (6 or over)	6.50	0.25
Truck drivers (to and including one ton)	6.00	
Truck drivers (to 2 tons)	6.25	0.25
Truck drivers (2 ton when equipped with pneumatic tires all around; and over 2 ton)	6.75	0.25
Head stableman (provided that this classification shall apply only where more than 2 stablemen employed in same barn)	6.25	

2

TABLE 3.—(*Continued*)

Classification	Effective wage (8 and 9 hr. day)	Bonus per day
Stablemen (split time understood, 8 hours work out of 10½)	5.75	0.25
Tractor driver (heavy)	6.75	0.25
Tractor driver (light)	6.25	0.25
Road grading machine operator (operator of any machinery handled behind tractor)	6.25	
Boiler washers		
Boiler washers (no chipping, employed continuously)	5.75	0.25
Boiler washers (where chipping is required; employed continuously)	6.50	0.25
Roustabout crew		
Head roustabout	7.25	0.25
Roustabout	5.75	0.25
Steam, gas engine, and pump repairmen		
Repair man no. 1	6.25	
Repair man no. 2	5.75	
Repair man's helper	5.25	
Warehouse yard men (checkers)	5.00	
Tank car loaders	5.75	
Head garage repair man	6.50	
Garage repair man	6.00	
Garage repair man's helper	5.25	
Electricians (journeymen)	7.00	
Electricians helpers	5.25	

CHAPTER II

LANDS

The acquisition of oil lands is an important branch of the oil business. These lands should first be carefully selected and then obtained either by purchasing outright or by lease. The usual procedure of large companies is to send a geologist or a scout over an area called to their attention. If this man recommends a tract of land a lease man is sent out to obtain the land, either by purchase or on a lease.

Often lands are purchased in the office from land dealers or brokers who buy and sell oil leases or oil properties. In the Mid-Continent fields, such dealers in leases are called "lease-grafters." This name is not used in a derogatory sense, but is applied generally to the men who handle leases irrespective of the honesty or dishonesty of individuals.

A good lease man must have many qualities. He must be resourceful, a good talker, should have a good grounding in law especially in contracts, and have "nerve."

Many people think a lease man is a liar and a cheat but the best lease getters are honest and cleancut men who are convincing in their talk to the rancher, farmer, merchant or banker whom they may meet. There have been some marked cases of sharp practice but on the whole the lease men leave the lessors feeling well treated.

Lands may be classified:

1. Privately owned lands. Obtained: (*a*) By purchase or grant.
   (*b*) Patented lands.
2. State lands.
3. Government lands.
4. Government ward lands.

The titles to privately owned lands are vested in the owners, and comprise the largest portion of the lands of the Eastern United States. These lands may be bought in fee or are leased on a royalty basis.

State controlled lands have the titles vested in the states. Most of the western states own millions of acres of State school lands, granted them by the Federal Government. Generally Sections 2 and 16 are state school lands although in some states, such as New Mexico, 2, 16, 32 and 36 are the state lands.

The State of Texas owns all the public domain, due to its annexation treaty with the United States Government.

United States Government lands are those in which the title is vested in the United States Government. The California oil lands, and Wyoming oil lands were largely of that class. Title was obtained from the Government under the Oil-Placer Act in the early life of the oil industry.

Government ward lands are lands like those in eastern Oklahoma, where the Government considers the Indians as wards, and leases are made with the Indians direct upon approval of the Department of the Interior.

Oil leases generally run for 5 years. Drilling must commence before the expiration of that time, or the lease is cancelled. See Lease, page 21.

The non-payment of annual rentals also gives grounds for cancelling leases.

It is customary to pay rentals for a year in advance. Such rentals range from 5¢ to $2 per acre, and in some rare cases higher.

The advance rental is often spoken of as a bonus. A bonus, properly speaking however, is the amount paid in excess of the rental. Bonuses are generally paid where competition is keen and the land is unusually desirable. Bonuses range from a few cents to as high as $1000 per acre.

Acquiring Oil Lands.—There are four main divisions of oil lands which are defined in another Chapter.

FORM 88—(PRODUCERS)

OIL AND GAS LEASE

AGREEMENT, Made and entered into this..............................day of..............................., 19...... by and

between ....

....

.... party of the first part, hereinafter called lessor(whether one or more)

and ....party of the second part, lessee

WITNESSETH, That the said lessor, for and in consideration of.. DOLLARS cash in hand paid, receipt of which is hereby acknowledged and of the covenants and agreements hereinafter contained on the part of lessee to be paid, kept and performed, has granted, demised, leased and let and by these presents does grant, demise, lease and let unto the said lessee, for the sole and only purpose of mining and operating for oil and gas, and laying pipe lines, and building tanks, power stations and structures thereon to produce, save and take care of said products, all that certain tract of land situate

in the County of..State of New Mexico, described as follows to wit:

....

....

....

....

....

....

....

....

of Section..............Township..............Range..............and containing..............................acres more or less.

It is agreed that this lease shall remain in force for a term of..................................years from this date and as long thereafter as oil and gas, or either of them, is produced from said land by the lessee.

In consideration of the premises the said lessee covenants and agrees:

1st. To deliver to the credit of lessor, free of cost, in the pipe line to which he may connect his wells, the equal one-eighth part of all oil produced and saved from said leased premises.

2nd. To pay the lessor .... DOLLARS each year in advance, for the gas from each well where gas only is found, while the same is being used off the premises, and lessor to have gas free of cost from any such well for all stoves and all inside lights in the principal dwelling house on said land during the same time by making his own connections with the wells as his own risk and expense.

3rd. To pay lessor for gas produced from any well and used off the premises or for the manufacture of casing-head gas,

....DOLLARS per year, for the time during which such gas shall be used, said payments to be made each three months in advance.

If no well be commenced on said land on or before the ....day of......................................19......, this lease shall terminate as to both parties, unless the lessee on or before that date shall pay or tender to the lessor, or to the

lessor's credit in the..Bank at.. or its successors, which shall continue as the depository regardless of changes in the ownership of said land, the sum of......

.... DOLLARS, which shall operate as a rental and cover the privilege of deferring the commencement of a well for..........months from said date. In a like manner and upon like payments or tenders the commencement of a well may be further deferred for like periods of the same number of months successively and it is understood and agreed that the consideration first recited herein, the down payment, covers not only the privileges granted to the date when said first rental is payable as aforesaid, but also the lessee's option of extending that period as aforesaid, and any and all other rights conferred.

Should the first well drilled on the above described land be a dry hole, then, and in that event, if a second well is not commenced on said land within twelve months from the expiration of the last rental period which rental has been paid, this lease shall terminate as to both parties, unless the lessee on or before the expiration of said twelve months shall resume the payment of rentals, in the same amount and in the same manner as hereinbefore provided. And it is agreed that upon the resumption of the payment of rentals as above provided, that the last preceding paragraph hereof, governing the payment of rentals and the effect thereof shall continue in force just as though there had been no interruption in the rental payments.

If said lessor owns a less interest in the above described land than the entire and undivided fee simple estate therein, then the royalties and rentals herein provided shall be paid the lessor only in the proportion which his interest bears to the whole and undivided fee.

Lessee shall have the right to use, free of cost, gas, oil, and water produced on said land for its operation thereon, except water form wells of lessor.

When requested by lessor, lessee shall bury his pipe lines below plow depth.

No well shall be drilled nearer than 200 feet to the house or barn now on said premises, without the written consent of the lessor.

Lessee shall pay for damages caused by his operations to growing crops on said land.

Lessee shall have the right at any time to remove all machinery and fixtures placed on said premises, including the right to draw and remove casing.

If the estate of either party hereto is assigned, and the privilege of assigning in whole or in part is expressly allowed, the covenants hereof shall extend to their heirs, executors, administrators, successors or assigns, but no change in the ownership of the land or assignment of rentals or royalties shall be binding on the lessee until after the lessee has been furnished with a written transfer or assignment or a true copy thereof; and it is hereby agreed in the event this lease shall be assigned as to a part or as to parts of the above described lands and the assignee or assignees of such part or parts shall fail or make default in the payment of the proportionate part of the rents due from him or them, such default shall not operate to defeat or affect this lease in so far as it covers a part or parts of said lands which the said lessee or any assignee thereof shall make due payment of said rental.

Lessor hereby warrants and agrees to defend the title to the lands herein described, and agrees that the lessee shall have the right at any time to redeem for lessor, by payment, any mortgage, taxes or other liens on the above described lands, in the event of default of payment by lessor, and be subrogated to the rights of the holder thereof.

....

....

IN TESTIMONY WHEREOF, We sign, this the..............................day of..............................19......

WITNESS; ....(SEAL)

....(SEAL)

....(SEAL)

ACKNOWLEDGMENT TO THE LEASE

STATE OF NEW MEXICO } ss.
County of .... }

On this .... day of .... A. D., 19......, before me, the undersigned, a Notary Public in and for the County and State aforesaid, personally appeared ....

to me known to be the identical person.... who executed the within and foregoing instrument and acknowledged to me that........ executed the same as .... free and voluntary act and deed for the uses and purposes therein set forth.

Given under my hand and seal of office the day and year last above written.

My commission expires ....

....
Notary Public

ASSIGNMENT

KNOW ALL MEN BY THESE PRESENTS:

That .... of ....
State of .... the within named grant.... in consideration of the sum of ....Dollars to ....
in hand paid, the receipt whereof is hereby acknowledged, do.............. hereby sell, assign, transfer, set over and convey unto ....heirs and assigns, the within grant.

TO HAVE AND TO HOLD THE SAME FOREVER, subject nevertheless, to the conditions therein contained.

IN WITNESS WHEREOF, The said grant.... ha.... hereunto set ....hand.., this....................day of.... ....19.......

....

ACKNOWLEDGMENT TO THE ASSIGNMENT

STATE OF NEW MEXICO } ss.
County of .... }

On this .... day of ...., A. D., 19 ...., before me, the undersigned, a Notary Public, in and for the County and State aforesaid, personally appeared ....

and ....to me known to be the identical person.... who executed the within and foregoing instrument and acknowledged to me that ....executed the same as .... free and voluntary act and deed for the uses and purposes therein set forth.

WITNESS my hand and official seal the day and year first above written.

My commission expires ....

....
Notary Public

OIL AND GAS LEASE

FROM

....

....

TO

....

....

Date....................................., 19.....

Section........, Township........, Range........

No. of Acres ....

..........................County, New Mexico

Term ....

STATE OF NEW MEXICO, } ss.
County of .... }

This instrument was filed for record on the....
..............day of ...., 19....
at ....o'clock....M., and duly recorded
in book................page..............of the
records of this office.

................................County Clerk

By ....Deputy Clerk

HALL-POORBAUGH PRESS, Roswell, N. M.

ACKNOWLEDGMENT WHERE LESSOR SIGNS BY MARK

STATE OF NEW MEXICO } ss.
County of .... }

On this ....day of...............................A. D. 19......, before me, the undersigned, a Notary Public in and for the County and State aforesaid, personally appeared..and..

to me known to be the identical person.....who executed the within and foregoing instrument by........mark.....in my presence and in the presence of..and ....
as witnesses, and acknowledged to me that..............executed the same as..............free and voluntary act and deed for the uses and purposes therein set forth.

Given under my hand and seal of office the day and year last above written.

1. Prospective or wildcat lands.
2. Probable lands.
3. Proven lands.
4. Producing lands.

The acquisition by lease or purchase of these classes of lands falls within the functions of the Land Department of an oil company.

Information about these lands may be obtained by studying the results of geological surveys, from the reports of scouts who keep in touch with new drilling activities, dry-holes, and producting wells, and from the reports of expert appraisers of oil properties.

Wildcat lands are generally acquired by leasing, though in some cases they are purchased outright.

Four systems of acquiring such lands are employed:

1. By checkerboarding, *i.e.* taking pieces here and there over areas thought favorable for oil, regardless of geological conditions.

2. By acquiring large blocks of land for drilling a test well, or wells, regardless of geological conditions.

3. By purchasing offsets to drilling wells regardless of geological conditions.

4. By making systematic surveys of areas to determine whether or not the geological conditions are favorable, and then taking such land under the guidance of the geologist.

This latter system is becoming more generally employed, as the value of applied geology is appreciated, but some companies do not use this system. Many companies, however, employ all four methods.

Royalty.—Leases on prospective oil lands are generally obtained on a royalty basis.

These leases are taken with the understanding that a royalty in oil is given to the owner of the land.

Royalties are regulated largely by custom. In the Eastern and Mid-Continent states the standard royalty is ⅛ of the gross oil obtained. In California ⅛ was long considered the proper royalty, but $\frac{1}{6}$ is now the standard royalty there. Royalties depend upon the risk involved in drilling. In somes case $\frac{1}{10}$ or $\frac{1}{20}$ is a good royalty to pay, or even less, dependent upon the risk involved.

Sliding Royalties.—Sliding royalties are applied in some cases. Under a sliding royalty, the royalty is large for wells above a certain size and decreases as the wells decrease in size. Such a royalty may be as high as $\frac{1}{3}$ for wells over 300 bbls., $\frac{1}{4}$ for wells over 200 up to 300 bbls., $\frac{1}{5}$ for wells over 100 bbls. and up to 200 bbls., $\frac{1}{6}$ for wells over 50 bbls. and up to 100 bbls., $\frac{1}{8}$ for wells of 25 bbls. to 50 bbls., and $\frac{1}{10}$ for wells under 25 bbls. This is merely an example of a sliding royalty.

The Federal Government is putting a sliding-royalty scheme into operation for leases under the Leasing Act of February, 1920. Sliding royalties are not, however, in general use.

Typical Lease.—A typical lease is presented on page 21. This lease, known as Producers 88, is considered one of the fairest used by oil men.

The intent of any good lease is absolute fairness for both sides. If the lessee or lease holder makes money then the owner of the property makes money. If the lessee cannot make a profit the owner makes nothing. On the other hand conditions must not be too onerous for the lessee to fulfill nor too lax so the land owner will suffer neglect.

It is important to realize that oil men spend millions of dollars every year in rentals for leased lands and in drilling dry-holes. These rentals and drilling expenses must be paid from the gross returns on the property.

The acquisition of probable lands generally results in the expenditure of large sums of money for development.

Probable or proven lands are sometimes obtained under drilling contracts with the owners who hold valuable leases and have insufficient funds for development, or have more land than they can develop.

Titles.—The leasing and handling of oil lands demand the most careful scrutiny of titles. It is surprising what seemingly unimportant trifles, overlooked when obtaining lands before oil has been discovered, may lead to serious lawsuits later, and also the consequent loss of a valuable lease. Competent lawyers should pass on all titles. Lease men in obtaining lands should use every diligence to see that proper signatures are obtained and are properly witnessed.

The vicious law suits to wrest possession of valuable Indian lands at Cushing, Oklahoma from the lessees cost the United States Government much time and money. The noted Tommy Atkins case reads like a romance. When it is realized that at least four different Tommy Atkins were produced as the real owner some idea of the complications may be gained.

Contests over the possession of Cimmarron River Bed leases led to a three-cornered fight between the lessors who held that their land extended to the middle of the stream, the State of Oklahoma which held that the River Bed land was State land, and the United States Government which held that the stream was navigable and, therefore, the land was Federal land and under Federal jurisdiction. At Cushing the private owners held that their land boundaries extended to the center of the stream.

The best caution that can be given to anyone in regard to leasing or buying oil lands is to get the best possible lease men and the best possible title lawyers and abstracters money can obtain. If titles are uncertain and the property is worth while, one may take a chance, but it must be done with a full knowledge of the possible consequences.

Size of Acreage.—Lands are acquired in blocks of all shapes and sizes. Some large concerns will not take less than 40 acres of land, others will accept smaller tracts. Most companies desire larger tracts of land. Under the old system of selecting lands without geological or engineering advice tracts of 10,000 to 50,000 acres were essential. However, as knowledge of geological possibilities has become better understood, the large oil companies are looking for quality, not quantity alone, and are discarding hundreds of thousands of acres of lands on which the chances of obtaining oil production are too small to be considered good business hazards.

Public Lands.—The United States lands are obtained on a royalty basis, usually a $\frac{1}{8}$ of all oil or gas obtained from the property. The old procedure was for an oil man or a group of men to file notices or claims upon lands thought favorable for oil. One man could file on as many 20-acre blocks as he could afford to develop, with the understanding that no two blocks were contiguous in the same section of 640 acres. A group of eight men could pool their resources and file upon 160 acres in a unit, and take as many units as possible, with the understanding that no two units were possible in the same section, although four contiguous units might be secured at the intersection of four sections. This system further called for $100 per year per claim expenditure on assessment work to hold the claims. Assessment work meant building roads, building derricks, and preparing for actual drilling operations. The claimant was given a right to his claim for the balance of the calendar year in which he filed, and all of the succeeding year, and had that time in which to do assessment work. Further by drilling a test hole and discovering oil, even a small showing, which would lead him to further expenditures, he was said to have validated his claim and had ample time to develop the property for oil. Discovery of oil gave him his claim and no one but the Federal Government had any rights against the locator or validator.

This system, while leading to much development, was the cause of endless litigation. This was especially true when the Federal Government, in 1909, began a series of withdrawals of possible oil lands. Many men who had started to develop lands in good faith were halted, and had bitter fights with the Federal Government in order to obtain title. Some injustice and hardship was worked, due to the arbitrary stand of some Government officials. However, in many cases there were many fraudulent claims and cases of "dummy locators" and the Government action in such cases was fully justified. The effort of the Government was to conserve our petroleum resources, and to allow the Federal Government some recourse against the wasteful methods often employed.

Federal Leasing Bill.—A new system of administration of Government Federal lands is now in force due to the passage of the Federal Leasing Bill in February, 1920. Under this bill the Government grants a prospecting permit to any reliable company, with certain restrictions. This permit gives a company or individual a right to select 2500 acres for prospecting, which must commence within 6 months after the permit is granted, and drill a hole to a depth of 2000 feet in 2 years. If the company finds oil within the time limit specified, it is given 640 acres on a 5 per cent royalty, and is granted a lease on the balance at a royalty not less than 12½ per cent and graduated based on the size of the wells. This is not liberal treatment, but it is an operating proposition. In cases of Government lands in proven areas, a company obtains a right to prospect 640 acres and obtains 160 acres under a fair royalty, with the understanding that no one individual or company obtains more than one such tract on any one geological structure. This term geological structure is subject to definition at the wishes of the Land Classification Board, and cannot be defined clearly. Every case is a special one.

Leases on Public Lands

FRED DENNETT,
(Former Commissioner General Land office)
ATTORNEY-AT-LAW
WASHINGTON, D. C.

The first recognition of the right to "enter and obtain patent to Federal lands containing petroleum or other mineral oils" was by the Act of February 11, 1897. The method of procedure was in accordance with the provisions of the laws relating to placer mineral claims.

This was manifestly inadequate as under the placer mining laws a discovery had to be made in order to create a valid location. Oil can only be discovered by the costly and lengthy process of drilling. The courts had to devise a method by which to protect the locator while he was engaged in the process of drilling to establish the discovery, and complete the location.

The mining law gives the right to any citizen to explore the public domain to find mineral; hence, the courts have protected a citizen in actual physical possession of a prospective claim on the public domain, while he is engaged in diligent prosecution of work leading to discovery of mineral.

This "diligent" prosecution of work leading to discovery is not satisfied by the doing of assessment work. It calls for the diligent, continuous prosecution of the work leading to discovery, with the expenditure of whatever money may be necessary to that end in view.

A discovery being necessary to complete the location, there could be no assignable right recognized. This hardship was remedied by the terms of the act of March 2, 1911, when the act of that date provided that in "no case shall a patent be denied to or for any lands *heretofore* located or claimed under the mining laws of the United States containing petroleum, mineral oil, or gas, solely because of any transfer or assignment thereof or of any interest or interests therein by the original locator or locators, or any of them, to any qualified persons or person, or corporation, prior to discovery of oil or gas therein."

Owing to the inadequacy of the laws relating to placer oil locations and the growing sentiment in Congress that a policy of leasing should be adopted, large withdrawals were made in 1909, pending the passage of legislation covering the situation. These withdrawals were ultimately sustained by the Supreme Court, but before the decision was rendered Congress passed (act of June 25, 1910) an act directly authorising the President to temporarily withdraw from settlement, location, sale, or entry any of the public lands of the United States and reserve the same for water-power sites, irrigation, classification of lands, or other purposes.

This act contained a specific recognition of the "rights of any person who, at the date of any order of withdrawal heretofore or hereafter made, is a bona fide occupant or claimant of oil or gas bearing lands, and who, at such date, is in diligent prosecution of work leading to discovery of oil or gas" and who remains in such diligent prosecution.

There has and is a strict construction of the word "diligent."

It has been held that the failure of sufficient money to continue the drilling, the cessation thereof pending the attempt to secure additional funds, and the consequent resumption is not a compliance with the rule of diligent prosecution of work.

The agitation for relief on the part of those who had claims within the withdrawn area, and for legislation which would supply some method of securing rights on oil lands, was met by the passage of the act of February 25, 1920, or what is known as the "oil-leasing bill."

This act is divided into 2 parts, the sections granting relief based upon rights claimed to have arisen before the passage of the bill, and those sections which point out the method in which a right may be acquired by proceedings had subsequent to the passage of the act.

Relief applications had to be made on or before August 26, 1920, except in cases which would arise under section 18a, and under section 20. The former section grants 1 year time within which the President may be appealed to to effect a compromise of any claim, the validity of which has been drawn into question, where the land was embraced within the area in the executive withdrawal of September 27, 1909. Under the rules as established and now in force the entryman of lands sought in good faith as agricultural, the lands not being withdrawn or classified as mineral at the time of entry, has 30 days within which to apply for his preference right, after service upon him, the entryman, by a seeker after permit under the general provisions of the act, of notice that he the applicant intends to apply to the Secretary for permit to explore for oil or gas.

It must be remembered that this preference right to entrymen does not apply to claimants under the 640-acre or stock raising homestead law, because the minerals are specifically reserved by the terms of that act; or to cases where the knowledge of the existence of minerals was brought home to the entryman before entry and the claimant made entry under the act of July 17, 1914.

The right to lease lands situated within a known geological structure of an oil or gas producing well can only be secured by competitive bidding under rules and regulations established by the Secretary.

Under the sections providing for the obtaining of a permit to prospect for oil on lands not within a known structure, to be followed upon discovery by a lease, under certain conditions, the applicant should first make location upon the ground by erecting thereon a monument of not less than 4 ft. high, constructed of some durable material, and post on the said monument a notice stating that an application for permit will be made within 30 days from the date of the posting of the notice; he should state thereon his name, the date of the notice, in wich he should state the hour when he affixed the writing to the monuments, and if the land be surveyed, the description by sections or fractions thereof. If the land is unsurveyed, then he should describe it by reference to the courses and distances from such monument and such other natural objects and permanent monuments as will reasonably identify the land, stating the amount thereof in acres.

The land should be in a reasonably compact form. In contiguous tracts within a limited radius may be included in a permit where conditions are such that, because of prior disposals, a reasonable area of contiguous land cannot be procured.

The applicant must be a citizen of the United States. He must so state in his application; he must also set forth the reasons why he thinks the land sought is "oil or gas" land; he must submit a showing of his financial ability to carry out drilling explorations, and must submit a bond in the sum of $1000 by way of undertaking to repair any damage that may result to the oil strata or deposits resulting from improper methods of operation, or failure to comply with the terms of the permit, By following the procedure described above the applicant can secure a permit to prospect for oil on three separate tracts in one State, no one of which is to be greater than 2560 acres in extent, and no two of which can be on the same structure.

The maximum number of permits to a corporation is not limited by permits of individual stockholders, but a corporation may have an interest in not more than three permits in same state, directly or indirectly. Individuals may hold direct interest in not more than three permits and his total interests as permittee and stock holder may not exceed an aggregate of 7680 acres in the same state.

An applicant under section 20, that is an entryman under agricultural land laws, may obtain his preference right, even though the land is situated within a known geolog cal structure in an oil producing field.

The permit grants an exclusive right for a period not to exceed 2 years. The permittee must begin drilling operations within 6 months from the date of the permit, and within 1 year drill one or more wells to a depth of not less than 500 ft., and within 2 years from the date of the permit, not less than 2000 ft., unless valuable deposits of oil or gas shall sooner be discovered. This period may be extended, if the Secretary of the Interior is satisfied that the permittee has been unable with the exercise of due diligence to test the land in the time granted by the permit. The Secretary also has the power to cancel for want of exercise of diligence.

If the land sought is near territory being newly drilled, then every effort should be made to secure an early issue of the permit, because of the danger that oil or gas might be discovered by such drilling, and a known geologic structure of an oil or gas producing well established before issuance of the permit. In that case the applicant would lose his right to secure permit. If, however, the permit is granted, then his right to explore and drill the land has attached and is not defeated by the establishment of the known geologic structure.

An application is not assignable; all intervening rights would fail upon the surrendering of the first application. The permit, or lease, once obtained, may be assigned by, and with the consent of, the Secretary of the Interior.

If a contractor desires to be recognized in connection with a permit, he must file his contract for approval and be charged with the interest covered thereby. It is not necessary for him to do this, so if he desires, he may explore the land under contract with the permittee; then if he wishes to be recognized as interested in the lease, he can bring his contract to the attention of the Department.

Upon the discovery of oil or gas within the time limit, the permittee is entitled to a lease for one-fourth of the land embraced in the permit, a minimum of not less than 160 acres being granted, if there be that amount of acres in the prospecting permit. The area is to be in compact form. If unsurveyed the applicant must secure the survey by the Government, and deposit the fees to cover the expense. This lease is for 20 years, upon a royalty of 5 per cent, and annual payment of one dollar per acre, to be applied on the payment of royalties. There is a preferential right in the lessee to renew the same for successive periods of 10 years upon such reasonable terms and conditions as may be prescribed by the Secretary of the Interior.

The permittee shall also be entitled to a preference right to a lease for the remainder of the land at a royalty of not less than 12½ per cent in amount or value of the production, the royalty to be determined by competitive bidding or fixed by such other method as the Secretary may by regulations prescribe.

After discovery and until the permittee applies for a lease to the one-quarter area he shall pay to the United States 20 per cent of the gross value of all oil or gas secured by him from the lands embraced within his permit and sold or otherwise disposed of or held by him for sale or other disposition.

If the area sought is within the boundaries of a known geological structure the right to a lease is sold to the highest bidder to qualified applicants in tracts not exceeding 640 acres in amount and in tracts which shall not exceed in length two and one-half times their width. If the average daily production of any oil well shall not exceed 10 bbls. per day, the Secretary of the Interior is authorized to reduce the royalty on future production when in his judgment the wells cannot be successfully operated upon the royalty fixed in the lease.

It must be remembered that rules and regulations fixed by the Secretary of the Interior are always subject to change at the discretion of that official.

Before leaving the subject of lands it may be worth while to give a little attention to the descriptions of lands.

PUBLIC DOMAIN

The public lands, or, as generally termed, the public domain, consists of states not included within the boundaries of the thirteen colonies as then constituted, and the areas included within subsequent purchases and cessions. Broadly speaking, all the continental United States and Alaska are public domain except the original thirteen states; the States of Maine, West Virginia, Kentucky, Tennessee, Vermont, and part of Ohio, which were at the close of the Revolutionary War within the confines of other states; and the State of Texas, which as an independent country at the time of its admission, retained control of its unoccupied lands.

The survey, subdivision, and disposal of the public domain was one of the earliest questions of the Government, and the following method of subdivision, was adopted:

TOWNSHIPS

In 1785 the Congress of the Confederacy enacted that the "Western Territory" be divided into "townships six miles square by lines running due north and south and others crossing them at right angles." This is called the rectangular system and with one minor exception has never been departed from since this first enactment. The one exception is a small area in Ohio.

In theory, therefore, the entire public domain is divided into squares called townships, each with their sides running due north and south, and east and west, and each containing 36 sq. mi.

The manner in which townships are located and described is by numbering them north and south and ranging them east and west of control lines called Base Lines and Meridians. The Meridians are lines running due north and south and are known in a few cases by number, but in most cases by name. The Base Lines, which bear the same number or name as the Meridian to which they are attached, are lines crossing the Meridians at right angles and running therefore due east and west. In describing the control of a township the Meridian alone is given; no mention is made, nor need be made, of the Base Line.

The location of these various control lines can be learned only by experience, but no difficulty is presented in this, as they are not very numerous, and since most of them are named either after the states through which they run or some prominent natural feature, their identification in most cases is very simple. There is very great variation in the number of townships controlled by the different meridians, some, such as the Ute, controlling only a few townships, while the Fifth Principal Meridian controls the entire States of Arkansas, Missouri, Iowa, North Dakota, and a great part of Minnesota and South Dakota.

LOCATING TOWNSHIPS

To locate any designated township, first find the intersection of the given base and meridian, then count the indicated number of townships north or south of the base, and then at right angles count the indicated number of ranges east or west.

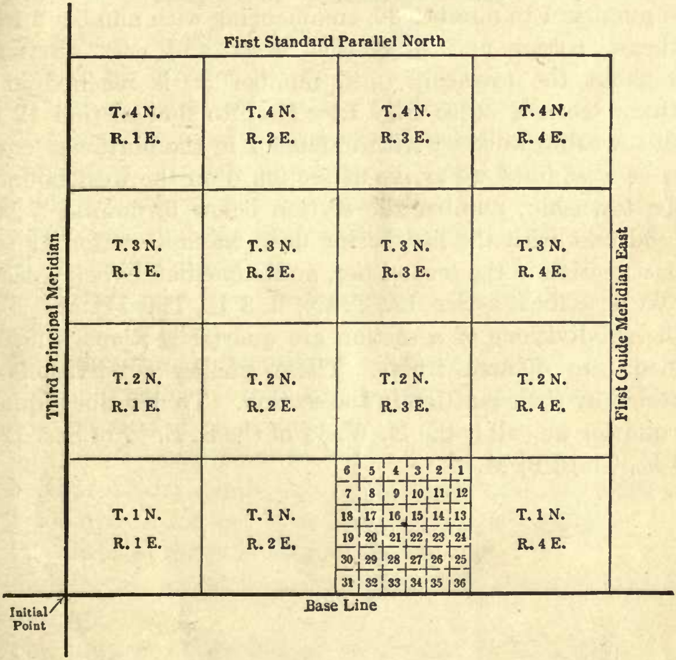


FIG. 1.—Subdivision of land into ranges and townships. T.1N., R. 3E. is shown subdivided into sections.

For example, take Township 3 North, Range 3 East, Third Principal Meridian. (See Fig. 1, page 33.) Then having found the intersection, we count along the meridian 3 townships north of the base, then across this row of townships and at right angles to the meridian, count 3 ranges east and we have our Township

3 North, Range 3 East, Third Principal Meridian, or as ordinarily abbreviated, T. 3 N., R. 3 E., Third P. M.

SECTIONS

It was very early seen that the area embraced within a township was too large for easy disposal, so each township was divided into 36 equal squares called sections, each containing 1 sq. mi., or 640 acres. These sections are identified by numbering them from number 1 to number 36, commencing with number 1 in the northeast corner and proceeding west and east alternately throughout the township until number 36 is reached in the southeast corner. (See Fig. 1.) Thus to find section 12 in a given township we start with number 1 in the northeast corner, number west until we arrive at section 6 on the west boundary of the township, number the section below 6, number 7; then proceed east with the numbering until we find section 12 to be the last section in the second tier, and immediately below section 1. We describe it as Sec. 12., T. IN, R. 3 E., Third P. M.

The subdivisions of a section are quarter sections which are divided into 40-acre tracts. These smaller subdivisions are identified by their position in the section. To describe a quarter of a quarter we call it the N. W. ¼ of the S. E. ¼ of Sec. 12, T. R. 3 E., Third P. M.

CHAPTER III

DEVELOPMENT-DRILLING

CLASSES OF DRILLING WELLS

There are two classes of drilling wells:

(A) Those in "wildcat" or unproven areas.

(B) Those in proven or partially proven areas.

Drilling practice in new areas varies somewhat from practice in proven areas. In the first class of tests, underground conditions are uncertain and one must feel the way slowly. In the second class, underground conditions are known and drilling is largely a matter of routine.

Aims of Drilling.—In oil and gas wells, the following aims are common to all drilling:

1. To find oil or gas deposits of commercial value.
2. To drill a hole of correct size for obtaining and maintaining a good production of oil or gas.
3. To exclude water from the oil or the gas sands.
4. To shut off dry sands that might absorb the oil or the gas.
5. To complete the test in as short a time as possible.
6. To complete the hole at a minimum cost.

Before starting a test in new territory the essential points to be known are

1. The natural or geological conditions of the rocks to be penetrated as nearly as can be determined.
2. The depth to be drilled (See Table 4 page 36).
3. Operating conditions such as labor, fuel, water and transportation.

The natural conditions such as hardness of the rocks, the presence of soft shales and of probable water sands can generally be determined from data furnished by a competent geologist or by the history of drilling in similar areas. Generalized geological sections and drill-logs are valuable guides.

AVERAGE DEPTH OF OIL WELLS

Recent completions tabulated for 1920 show an average depth per well of 1930 ft. In the Mid-Continent field the average is 2100 ft.; in California 2500; Gulf Coast 2100; Kansas 2470 ft. These figures exclude dry holes. The tendency is towards deeper drilling. Many dry holes, not included in several fields, penetrate 3500 ft. and more. The tabulation follows.

TABLE 4

Division	Average daily output	Depth		
		Average	Greatest	Smallest
California	270	2500	3400	1600
Central West	35	500	1300	180
Gulf Coast	570	2100	3400	900
Kansas	140	2470	2700	2400
North Louisiana	700	1700	2800	1300
North Texas	200	2150	3900	260
Oklahoma	230	2090	3500	450
Total	306	1930	3900	180

It will be of interest here to consider the number of wells drilled in the United States. Table 5 below presents some recent data on well completions.

WELL RECORDS FOR THE UNITED STATES, DRILLING 1907–1920

COMPILED BY W. M. DUNHAM

Compiled from the annual reports of the U. S. Geological Survey, except the years 1919, and 1920, which were compiled from the monthly field report of the Oil City Derrick, and Oil & Gas Journal, which the Survey accepts as authoritative:

TABLE 5

Calendar year	Total completions	Total dry	Total gas	Total oil wells	Initial new production	Average initial production per well, barrels
1907	19,601	3,625	450	15,526	618,487	39.80
1908	16,909	3,214	485	13,210	613,260	46.42
1909	18,327	3,404	1,084	13,839	523,567	37.73
1910	14,940	2,422	1,500	11,018	689,163	62.55
1911	13,768	2,363	1,580	9,825	747,220	76.11
1912	17,180	2,855	1,811	12,514	704,253	56.25
1913	25,590	4,282	2,207	19,101	889,914	46.59
1914	23,137	4,142	2,327	16,668	1,568,130	94.36
1915	14,157	2,981	2,022	9,154	1,779,391	194.38
1916	24,619	4,039	1,803	18,777	1,596,358	85.00
1917	23,407	4,851	1,966	16,590	1,482,938	89.39
1918	25,684	5,613	2,229	17,842	1,590,025	89.10
1919	29,229	6,096	2,112	21,021	3,529,118	167.89
1920	33,896	7,429	2,284	24,183	3,653,028	151.06
Total...	300,444	57,316	23,860	219,268	19,984,852	91.14

DETERMINATION OF DRILLING METHOD

The determination of the drilling method is dependent on natural conditions. The two main systems are:

1. The Standard Cable-Tool or percussion system.
2. The Rotary system.

The Circulator system is a modification of the Standard Cable-Tool system. The Combination system is a combination of Standard Cable-Tool and the Rotary systems.

The Standard Cable-Tool system is best employed in hard strata like sandstones, limestones, and hard shales. Holes in these formations "stand up" or do not cave readily, and can be drilled "dry," a preferable system for the proper testing of sands. Such a system is best used in the Carboniferous and earlier rocks of West Virginia, Pennsylvania, Kentucky, Ohio, Illinois, Oklahoma, Kansas, and North-Central Texas. It has also been successfully used in the Cretaceous beds of the Wyoming fields, and in the Sespe region of California, where the rocks of Oligocene and Eocene age are compact and "stand up."

The Rotary system of drilling is best employed in the soft, unconsolidated sediments of the Gulf Coast areas of Louisiana, and Texas, in the soft Miocene beds of California, and in the Permian Red Beds of Oklahoma and Texas.

The Hydraulic Circulating system has had far better success in California than Standard Cable Tools, and with the Rotary system forms the two main systems employed in California at present. Recently the Circulator system has been successfully introduced at Blackwell in western Oklahoma where the handling of gas sands has been a difficult problem.

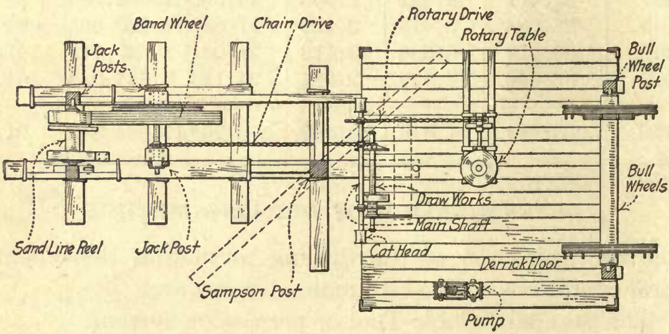


FIG. 2.—Plan for combination rig.

Combination System.—The combination system of drilling is used to good advantage in several fields. Where the upper beds are soft, unconsolidated sediments, say 2500 ft. thick, with hard beds below, the Rotary system may be used to a depth of 2500 ft., after which cable tools are employed. On the other hand, in fields where there is a series of sandstones underlaid by a thick series of caving shales, the cable tools may be used through the hard sandstone beds, and then rotary tools below in the shale.

Figure 2, page 38, shows the arrangement of the derrick for the combination system.

DEPTH

Depth largely governs the type of drilling outfit chosen. Shallow holes up to 1500 ft. in depth can often be tested with a portable drilling outfit at less expense than with heavier equipment. Above 1500 ft. it is customary to use heavy frames or derricks that are usually allowed to remain in place after a paying well is obtained.

Portable Rigs.—Portable drilling rigs of either the rotary or Standard cable-tool type are used in fields where shallow wells of 500 to 1500 ft. are the rule. They are also used in areas of hard, consolidated beds where drilling conditions are simple, and but little casing is needed, as in eastern Oklahoma, eastern Kansas, the Osage and the Greybull fields of Wyoming and in Kentucky, Ohio and Pennsylvania.

However, some deep tests have been made with portable rigs, notably one near Mineral Wells, Texas. This well, called No. 1 Oakes, drilled by Owens and Willis, south of Mineral Wells, Palo, Pinto County, Texas, was carried 4550 ft. with 2200 ft. of 6⅝ in. casing and 2350 ft. of open hole. This is the deepest known test drilled with a portable National rig.

Portable rigs have all the drilling machinery conveniently mounted on a single frame. (See Figs. 3 and 4, pages 40, 41.) The boiler is also portable and mounted on wheels. The advantage of such a system is obvious where a number of shallow wells are to be drilled.

In soft, unconsolidated beds where much casing is used, portable rigs are not desirable, and much heavier outfits are required. Derricks are then installed.

Derricks.—A derrick is the frame structure used in drilling. Its main uses are:

(*a*) To suspend the drilling cables and tools;

(*b*) To house the drilling machinery;

(*c*) To shelter the workers.

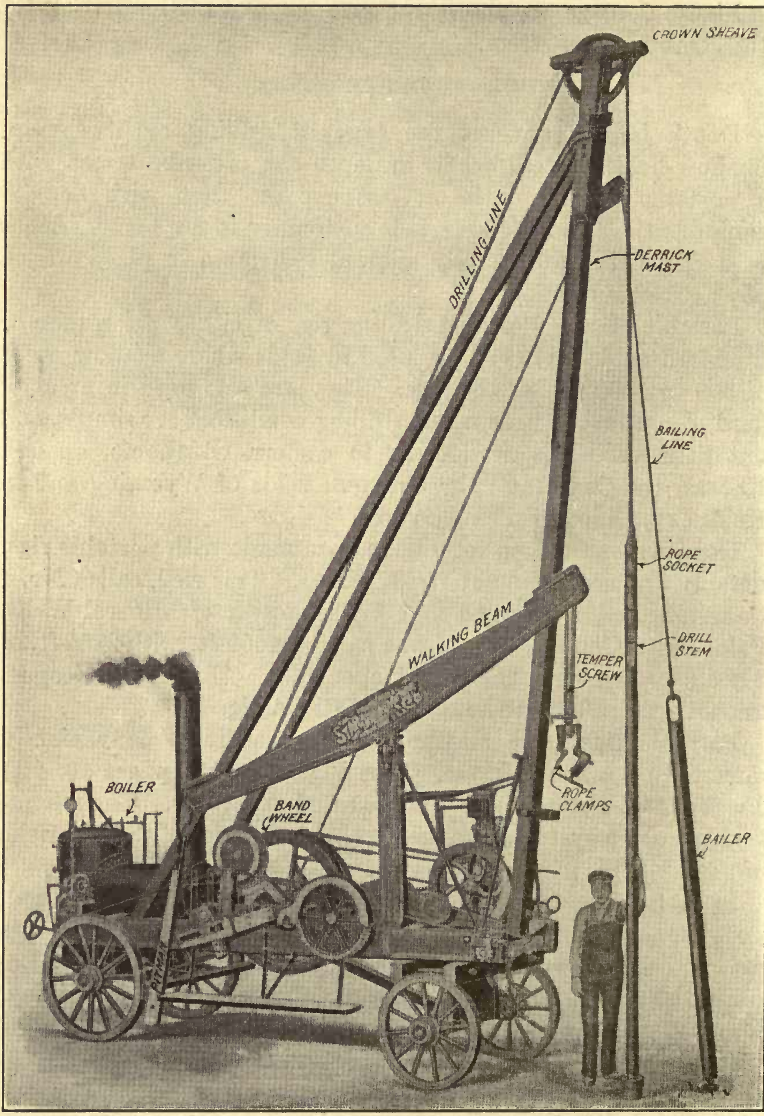


Fig. 3.—Portable cable-tool rig. Pulling tools from hole.

The essential parts of a derrick are:

1. The floor,
2. The crown block,
3. The legs, the girts, and braces supporting the crown block.

The type of derricks employed must be suitable to the drilling systems used. The choice is dependent on the conditions to be met in drilling. Derricks are either of wood or steel.

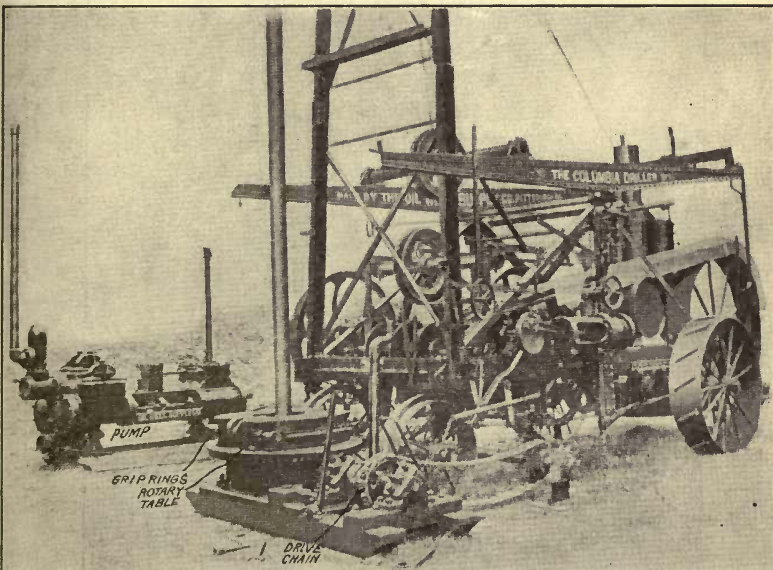


Fig. 4.—Portable rotary-drilling rig.

The wood derricks range in height as follows: 56 ft., 64 ft., 72 ft., 84 ft., 96 ft., 106 ft., 114 ft. and 120 ft. The height varies (1) with the depth to be drilled, and (2) with the amount of casing to be handled.

The highest derricks are generally employed on deep rotary holes. Such high derricks allow the drill pipe or casing to be pulled in sections of four and five joints, thus greatly facilitating the pulling time.

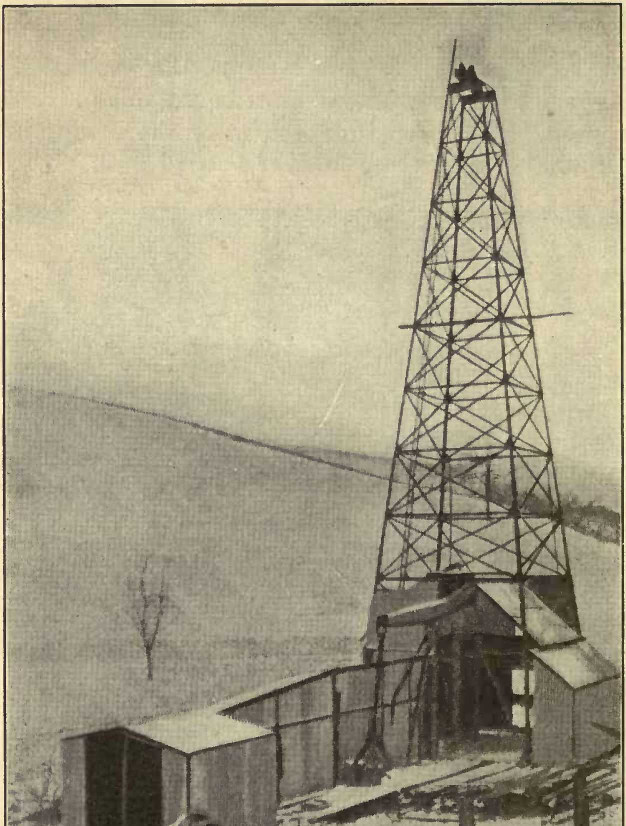


FIG. 5.—Steel derrick for drilling or for pumping wells.

Steel derricks are made of angle irons or hollow tubes. The angle-iron derricks are stiff, but where great strength is required in drilling they can be used.

Hollow, tubular derricks are used in some oil fields for drilling wells. (See Fig. 5, page 42.)

In any area where high wind storms occur, steel derricks are decidedly superior to wooden derricks, as they present a minimum of resistance to the wind, due to the smaller surface exposed.

In a storm (in 1918) in Oklahoma and Kansas several thousand wooden derricks were blown down causing a loss of at least a million dollars.

Wooden derricks, while not so strong, are superior to steel for drilling purposes as there is greater elasticity in the rigs, which is essential where sudden strains and pulls are required. By double bracing the derricks their strength is greatly increased.

Tight guy lines on derricks are of much importance in strengthening derricks. Slack lines assist but little in holding derricks in place.

Rig Building.—In building a rig mud-sills are first laid down as a floor foundation and upon these sills are laid cross sills upon which the derrick floor is built.

The *main* sill supports the Samson-post, which in turn acts as the support for the walking beam. (See Fig. 6, p. 44.)

One of the band wheel or jack posts also rests upon the main sill.

The other supporting post for the band wheel, and one of the posts supporting the calf wheel rest on another sill.

The bull-wheel shaft is supported by two posts called the bull-wheel posts, which rest upon a cross sill called the bull-wheel sill.

The bull wheels are controlled by the band brake.

Steel bull wheels and calf wheels are now being employed for deep wells. The advantage of steel lies in its longer life as 8 or 10 wells may be drilled without relining the wheels.

The band brake consists of a steel band 10 in. wide. One end of the steel band is fastened to the floor of the derrick and the other passes around the brake wheel of the bull wheels, and

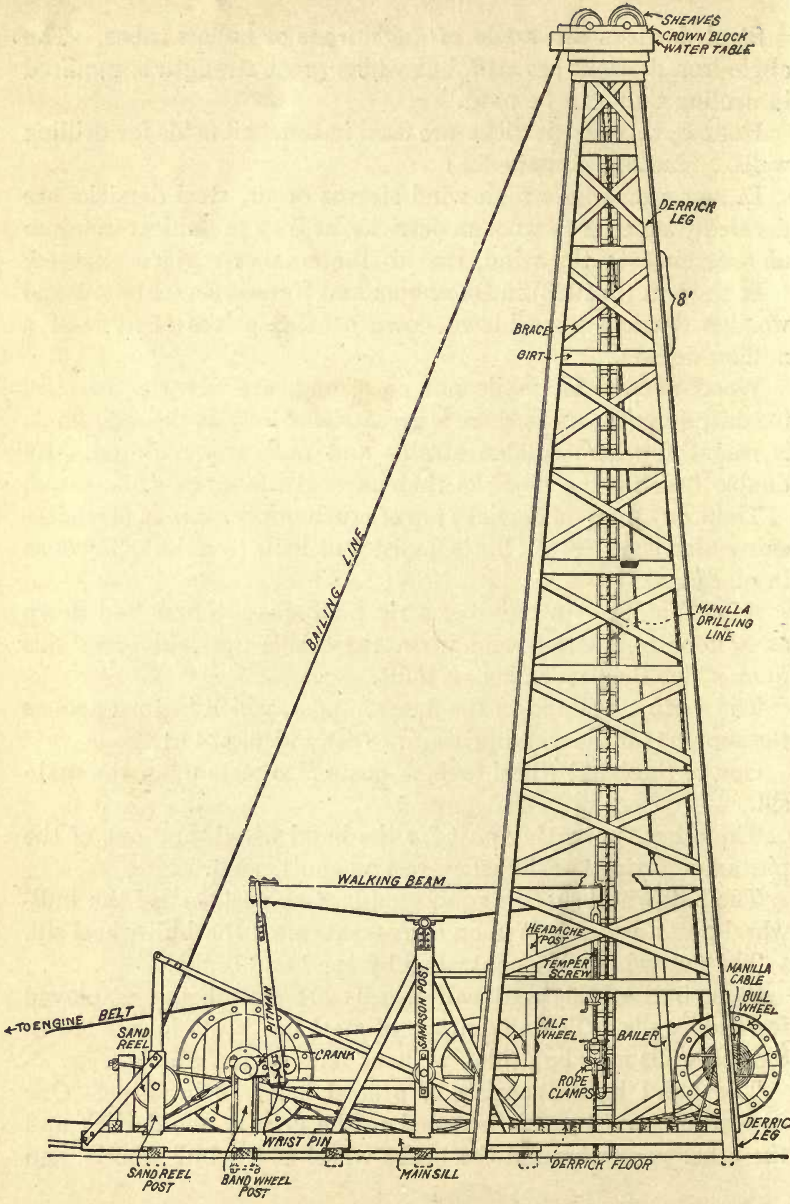


FIG. 6.—California cable-tool outfit. Rigged for drilling.

is attached to the lower arm of the brake lever. This lever controls the band brake. Pushing down on the brake checks or stops the bull wheels and thus controls the speed of the tools when they are let into the hole. If the tools are let into the hole rapidly the band brake may become red hot. To avoid this a water spray plays upon the band brake.

The headache post is a small post which is placed under the walking beam and keeps the walking beam from striking the driller's head if the beam is displaced from its saddle. The headache post rests on the nose sill.

The four legs of the derrick do not rest on the floor but upon blocks of wood or concrete bases sunk in the ground.

Girts are the horizontal pieces that bind the derrick legs together. Braces are the cross pieces extending at an angle of 45 deg. from leg to leg.

Some very heavy rigs have double sets of braces and girts, and heavily reinforced legs.

A hole is cut through the floor, just under the end of the walking beam. This hole is the start of the prospective oil well.

Rig Irons.—All the metal parts used in the construction of a derrick, with the exception of the nails, bolts, sand reel, and guy wire, are known collectively as the "rig irons," and designated by the size of the crank shaft that carries the band wheel.

The crank shafts vary from 3½ to 7½ in. in diameter. The 3½, 4, 4½, and 5-in. rig irons are used on light rigs for drilling from 1000 to 2500 ft. in depth. Heavier rig irons of the 6-in. type and extra heavy 7½ in. are used on deep wells from 2500 ft. and deeper, especially under difficult drilling conditions, as found in California. Six-inch irons are now being used in Texas and in the deeper fields of Oklahoma.

Main Operations in Drilling.—The main operations of oil well drilling are:

1. Cutting the rock material.
2. Removing the cut material.
3. Casing the hole.
4. Fishing out lost tools or casing.

STANDARD CABLE-TOOL SYSTEM

The principle of the cable tool or percussion system is the action of a bit, a heavy mass of sharpened steel, upon the rocks in such a way that impact will cut and crush them. The crushed material is then removed by bailing.

"Drilling Dry" and "Wet."—Where it is necessary to put only enough water into the drill hole to keep the cuttings soft and protect the bit against overheating, the hole is said to be "drilled dry." Where the hole is kept full of water during drilling it is said to be "drilled wet."

A "dry hole" in oil-field parlance is a test that has failed to strike oil. The test may have encountered a flow of water but if no oil were encountered the hole is said to be "dry." A "wet" hole is a hole full of water during drilling and has no relation to whether or not oil has been found.

String of Tools.—A string of standard cable tools (see Fig. 7, page 47) consists of the rope socket, sinker bar, jars, auger or drill stem, and the bit. The cable is attached to the tools by means of the rope socket.

This cable is first'wound on a spool called the bull-wheel shaft and then led over the crownsheave on the top of the derrick and then down to the floor. A special connection called the rope socket joins the drilling tools and the drilling line. The sinker bar is placed between the rope socket and the jars.

The drilling jars have a stroke of 12 to 16 in. They are used in drilling to give play for light up strokes to loosen the bit if it sticks while drilling clay or shales, or becomes frozen by drill cuttings collecting around the tools.

The auger or drill stem is placed between the jars and the bit. The stem gives driving force to the bit. It varies in length from 18 to 36 ft. An average stem is 28 ft. long.

In raising or lowering the tools from the hole it is necessary to connect the bull wheels with the driving machinery. This is accomplished by means of a bull rope (or two ropes on deep wells). The bull rope is a soft manilla cable 2½ in. in diameter which runs from the bull wheels to the band wheel, which in turn is

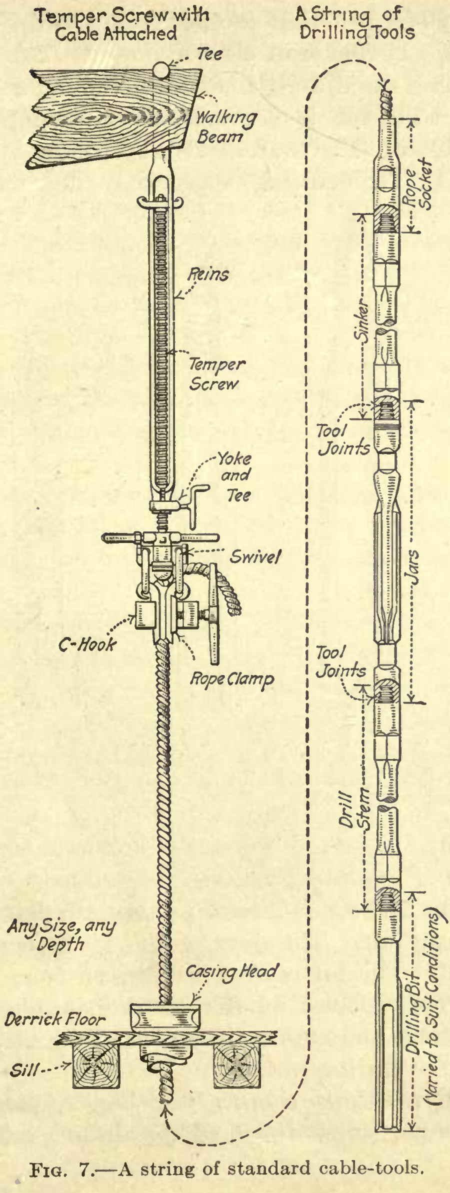


FIG. 7.—A string of standard cable-tools.

driven by a 90-ft. belt that extends from the drive pulley on a steam engine, gas engine or electric motor. This furnishes the means of raising the drilling tools from the hole.

Drill Bits.—The bit, is of course, the most important part of the drilling tools. There are several types of bits. (See Fig. 8, page 48.) The cutting edges only are tempered. The

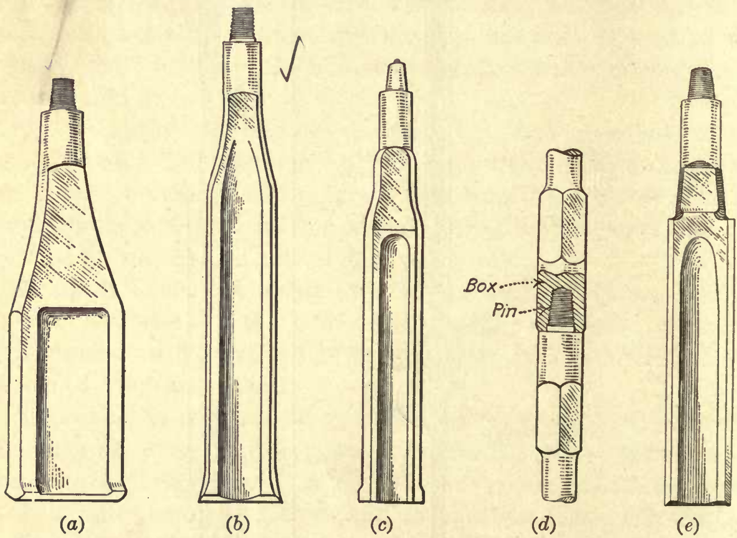


Fig. 8.—Types of drilling bits. (*a*) Spudding bit. (*b*) California pattern. (*c*) Regular pattern, Mother Hubbard. (*d*) Box and pin. (*e*) Mother Hubbard with square shoulders.

face of the bit on the cutting end is hollowed somewhat like a horse's hoof. The cutting edges of the ordinary bit of the California or of the Mother Hubbard pattern are flared out beyond the body of the bit. The flare of the bit wears until the bit tends to bind. The bit is then withdrawn from the hole and sharpened. The hollows in the bit are watercourses which allow the cuttings and mud to pass around the bit, and water to freely follow the cutting surface.

Rope Clamps.—Rope clamps (see Fig. 7, page 47) extend below the temper screw and hold the drilling cable fast while drilling is in progress. The wear and tear of the drilling cable on the clamps wears them out rapidly so that new clamps are required every four or five wells that are drilled. To overcome the expense of throwing the clamps away, liners for the clamps were tried with the result that several new styles of clamps with liners are now in use and all of them save clamp expense.

Tool Joints.—The special joints used for connecting the different parts of the string of tools, such as bit, auger, stem, jars, and rope socket, are called tool joints. These joints consist of male and female parts, or pin and box. The pin is solid and tapered. (See Fig. 7, page 47.) The box is also tapered. The joints are described by giving the diameter of the end of the pin, the base of the pin, its length, thus: a 3 by 4 by 7 joint means 3 in. at the smallest diameter, 4 in. at the base, and 7 in. long.

Tool joints are also used on rotary-drill pipe, but the pin and the box in this case have a hole bored through them, so water can flow through the drill pipe freely and maintain circulation.

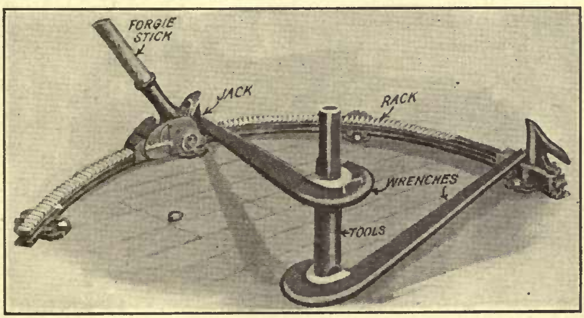


FIG. 9.—Circle, jack, and wrenches for setting up tool joints.

Wrenches.—In putting a string of drilling tools together, heavy wrenches are used. These wrenches weigh from 150 to 300 lb. each, dependent on their size. They come in pairs, one right-hand grip and the other left-hand. (See Fig. 9.) They are usually hung or balanced in the derrick, so that they can be swung on the tools without heavy lifting. Leverage on these heavy wrenches is obtained by a circle and jack. (See Fig. 9, page 49.) This jack works on the rack and pinion plan. The circle is a track with pinions. The jack is operated by a lever called a "forgie" stick. The procedure is to tighten the tools by hand as far as possible, and then use the jack and circle to finish the tightening. Casing is "set up" by using casing-tongs. (See Plate II, page 51) These are manipulated by hand or by machinery, dependent on the amount of tightening desired.

DRILLING OPERATIONS—SPUDDING

"Spudding."—The operation of starting a hole with cable tools is called "spudding." The string of tools is first "set up" and attached by the rope socket to the drilling cable which runs from the bull wheels to the top of the derrick. The tools are lowered through the hole in the derrick floor until they touch the ground at the bottom of the cellar.

The reciprocating, or lifting and dropping motion of the tools, is obtained by means of a jerk-line. One end of this line fits over the crank pin of the driving-shaft crank, and the other end is attached to a spudding shoe which fits over the drilling line near the bull wheel. (See Fig. 10, page 52.) The revolution of the crank pin gives the reciprocating motion.

ANOTHER DESCRIPTION IS AS FOLLOWS

"The well is started by 'spudding.' This is accomplished by attaching a 'jerk line' to the wrist pin of the main driving-shaft crank, the other end of line being connected with a spudding shoe, which works freely on the cable. The motion is thus imparted to the tools, which are lowered as the spudding proceeds, by gradually unreeling cable from the bull-wheel shaft by means of the brake. Pipe is driven in same manner. The illustration shows the drive clamps attached to the auger stem for the purpose of driving pipe."

Spudding is often accomplished for several hundred feet with a manila line, and then a change is made to a steel cable. In

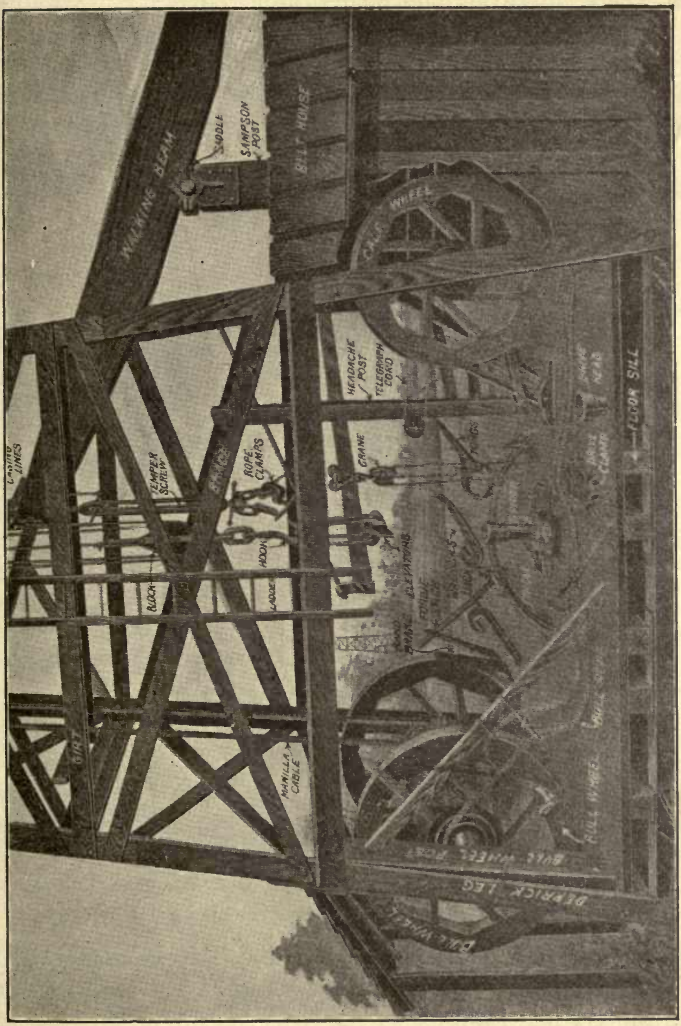


PLATE II.—Tools used on derrick floor, and parts of derrick.

recent years, however, the steel-drilling cable has been found fully as satisfactory for "spudding" as the manila line.

Spudding is continued until the string of tools is below the surface of the ground. Sometimes several hundred feet of hole is made by spudding. It would seem that this operation could be carried on indefinitely, but the leverage of the crank-arm does not give sufficient stroke for hard or for deep drilling. The play in the line is more than the length of the stroke in deep holes.

"HITCHING ON" TOOLS

When spudding has proceeded as far as is thought necessary, the tools are "hitched on" to the walking beam as follows:

The tools are first raised from bottom 3 or 4 ft., and the bull ropes thrown from the bull wheels. The walking beam is then connected to the crank pin by means of the pitman.

The engine is "turned over" until the end of the walking beam in the derrick is at its lowest point. The drilling cable is then fastened in the rope clamps (see Fig. 7), that are suspended from the bottom of the temper screw which hangs from the walking beam. The temper screw allows the gradual lowering of the tools as drilling progresses.

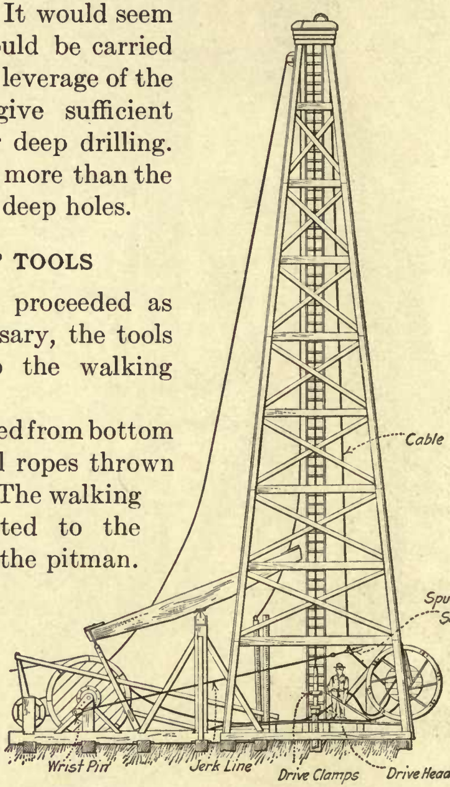


FIG. 10.—Driving casing with jerk line.

As soon as the cable is firmly grasped by the clamps, the walking beam is raised. This throws all the weight of the cable on the walking beam. A little slack in the cable is run off the bull wheels, a weight is attached to keep the slack line from swinging too freely, and drilling is then commenced.

Rapidity of drilling depends largely upon the ability to keep the hole free of cuttings. The drilling sludge must therefore be removed often.

The removal of the material from the hole is performed by a bailer or sand pump. (See Fig. 11, p. 54.) The sides of the hole are kept from caving by using pipe to line the hole.

ACTION OF TOOLS

In drilling, the striking action of the tools must be likened to the lash of a whip. The back lash or snap of the drilling cable drives the bit into the rock and drills the hole. The tools when in the hole must swing free of bottom at their lowest point. As the beam rises and falls there is vibratory action in the elastic cable that causes the line to stretch. The tools will lash out 4 or 5 ft. and strike bottom with terrific force. Experienced drillers tell from the feel of the tools whether or not the bit is striking a solid blow. The "pick up" of the cable is the measure of the blow.

"Pick up" is the feel of the tension on the drilling cable, sand, line or measuring line. If the drilling tools are allowed to rest on the bottom of the hole and then raised there will be a slight jerk perceptible to the eye or to the hand just as the tools are lifted from the bottom of the hole. The same is true of the bailer or the plumb bob on a measuring line. This "pick up" is most important for drillers, not only in measuring hole but in order to know whether or not the tools are striking bottom or swinging free in the hole.

When the screw is "extended" to its full length, which varies from 2 to 6 ft., the bull rope is thrown on the bull wheels and band wheel. The cable is then unclamped from the rope clamps, and pulled from the hole.

Two bull ropes at a time are used in pulling tools from deep holes.

Bailing.—The bailer is next run. The bailer (see Fig. 11*a*) is a long tube much like a joint of casing or pipe. It has a valve in its bottom, and a bail at the top to which is attached the sand line.

The sand line, which is used to lift the bailer, is wound on a spool or drum called the sand-line reel or drum and runs over a pulley on top of the derrick called the sand-line sheave. The sand-line drum is driven from the band wheel by friction drive. On one end of the sand-line shaft is a drive wheel which, when pulled against the revolving band wheel, raises the sand line. A lever operated from the derrick floor pulls the drive wheel against the face of the band wheel.

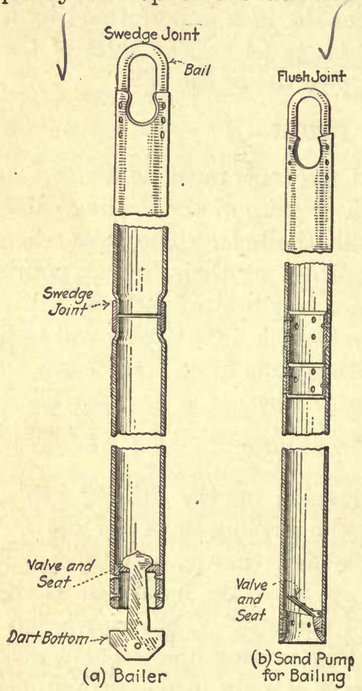


FIG. 11.—(*a*) Bailer; (*b*) Sand pump.

When the brake is neutral or upright the bailer drops of its own weight. The friction drive is only used to brake the bailer or to lift it from the bottom of the hole.

The bailing operation is a simple one. The bailer is first lowered to bottom and fills with fluid. When raised the bottom valve closes. The bailer is raised and dumped and then lowered again. This is repeated several times until the driller is satisfied that the hole is clean, when the drilling tools are again introduced.

Casing the Hole.—When it is desired to insert casing, the tools are withdrawn and tied back in the derrick.

Then the elevators, which are suspended from the top of the derrick by cables called the casing lines, are lowered to the floor. A joint of casing is rolled into the derrick and the elevators are clamped around the casing under a collar. The elevators are now raised to bring the casing over the hole, and the casing is next lowered into it.

A casing spider (see Fig. 12) is set on a pair of sills in the cellar of the derrick. The casing is guided through the hole in the spider. The spider lugs are then placed. The casing is eased down until the lugs grip the pipe. The elevators are then unclamped and raised for another joint. When the second joint is screwed into the top of the first joint the casing is lifted a trifle, the spider is knocked free with a sledge hammer, and the lugs are withdrawn. The two joints are now lowered until the collar of the second joint is near the spider. The casing is then caught in the spider, and the elevator is released. This procedure is repeated until the necessary casing is placed in the hole.

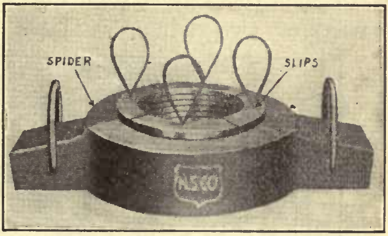


FIG. 12.—Spider and slips for casing.

Cellars.—With the modern cable-tool system of drilling, a good cellar is essential. The floor of the cellar serves as the main rest or support for heavy strings of casing, instead of putting such strains on the derrick floor. The cellar is usually 20 ft. deep and 6 ft. square. Its walls are lined with timber or concrete. A ladder extends from the floor of the derrick into the cellar. A pair of heavy sills is laid in it, and a heavy casing spider rests on them. (See Fig. 33, page 89, Chapter IV.)

When casing is handled one man stays in the cellar and puts in the lugs which grip the casing, and puts on or releases the elevators from the hook.

Lifting Blocks.—The casing lines run through a block which carries the traveling pulleys. The big hook hangs from this block, and upon this hook the bails of the casing elevators are hung. The block may have 3 or 4 pulleys depending upon the size.

Elevators.—Elevators are classed as:

1. Casing,
2. Tubing,
3. Rod.

The working principle is similar for all three types. The tubing and rod elevators are the lightest. A good type of elevator is the Fair. (See Fig. 13.) This elevator consists primarily of two wings or jaws that are latched around the

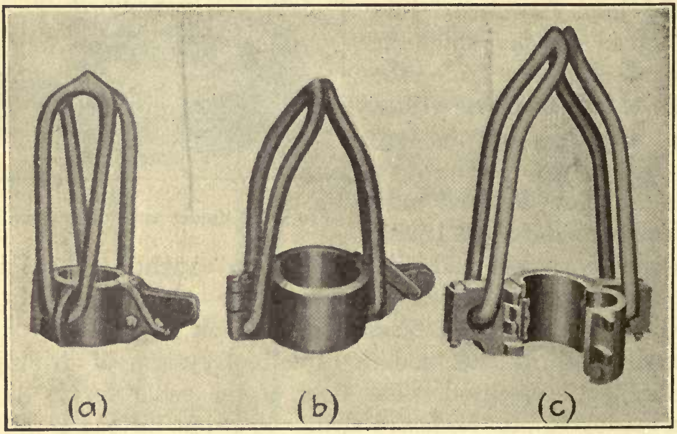


FIG. 13.—Casing elevators.
(*a*) Fair pattern. (*b*) Scott-Mannington pattern. (*c*) Wilson Pattern.*

casing. The inside diameter of these jaws is just a little larger than the casing. Bails are attached to the sides of the jaws and these fit over the casing hook. The elevators when in use are latched around the casing and slide up the joint until they catch under the casing collar, which furnishes a lifting medium.

Several other types of elevators are used, namely the Scott, which has the bail or link locking over the nose of the elevator. (See Fig. 13*b*.) Another type of elevator is used with slips. This elevator has a single bail which carries a solid spider. This spider fits over the top of the casing, and slips are put in to lock the elevator. This is excellent for heavy pulls,

*The Wilson pattern is now in general use in rotary-drilling.

but has little value where it is desirable to handle casing rapidly. The Fair elevator is the simplest and quickest to operate.

Underreamers.—Underreamers are used to enlarge a hole in special cases where the ordinary bit can no longer be used. If for any reason the hole has been cased to a certain depth, and it is necessary to carry the casing deeper, a bit of diameter small enough to go inside the casing must be used. The hole is drilled as far as necessary with a smaller bit, and then the underreamer is used.

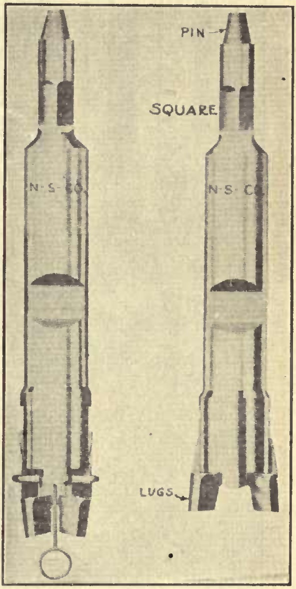


Fig. 14.—Underreamer, (*a*) ready to enter hole; (*b*) expanded.

This underreamer, really an expansion bit (see Fig. 14, page 57) has two lugs, or cutters, that can be contracted to fit the casing. When the tool emerges from the bottom of the casing, the lugs, driven by a powerful spring, expand outward. Drilling with underreamers enlarges the diameter of the hole so the casing may be lowered. A 10-in. underreamer will cut a 13½-in. hole, allowing 10-in. casing, and a casing-shoe, 12 in. over all, to pass freely downward in the hole.

The underreamer lugs when pulled upward are contracted as they hit the inside of the casing-shoe and are then raised to the surface.

ROTARY DRILLING METHOD

The drilling bit with the rotary is attached to the bottom of a column of drill pipe which is given a rotary motion by a special device on the floor of the derrick, called the rotary table. The drill pipe is first grasped by the rotary clamps. These clamps are locked in the rotary table and the table is turned or

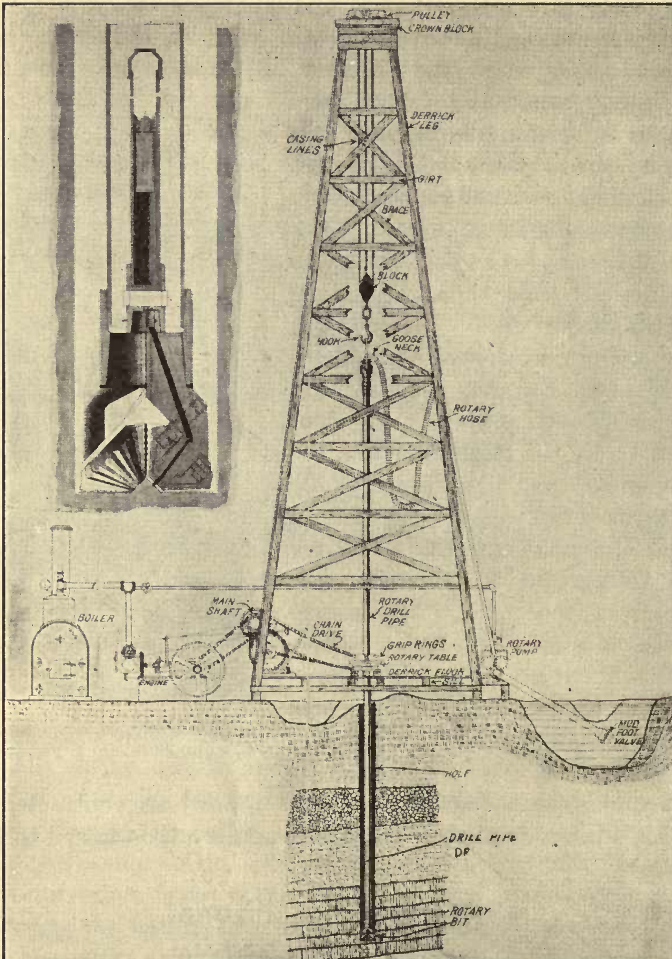


FIG. 15.—Rotary system of drilling. Insert Hughes hard rock bit.

rotated by power transmitted from the engine by the chain drive. (See Fig. 15, Page 58.)

The hollow pipe is suspended from the top of the derrick by drilling lines, similar to the casing lines of the Standard Cable-Tool system. (See Fig. 15.)

The drilling tools with the rotary consist of the bit, generally a fishtail (see Fig. 16), though several other types are used for special cases.

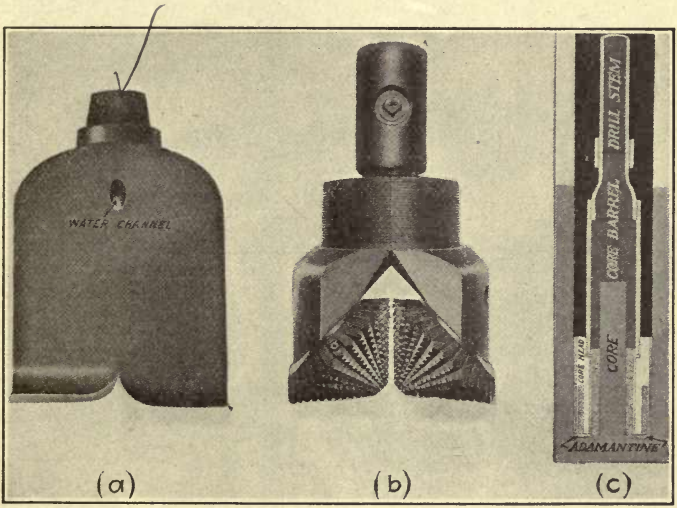


FIG. 16.—Rotary bits. (*a*) Fishtail. (*b*) Hughes cone bit. (*c*) Core barrel.

This bit is attached by a special tool-collar to the end of a string of pipe with upset ends called drill pipe, which is much heavier than casing and made to withstand hard twisting.

An important feature in rotary drilling is the use of water. A constant stream of water is pumped into the drill hole from the sump through the hollow drill pipe. This water leaves the drill pipe through small holes in the end of the bit. (See Fig. 15, page 58.) It tends to keep the bit clear of cuttings, and the steady stream also washes the cuttings from the hole as the water returns to the surface through the annular space between

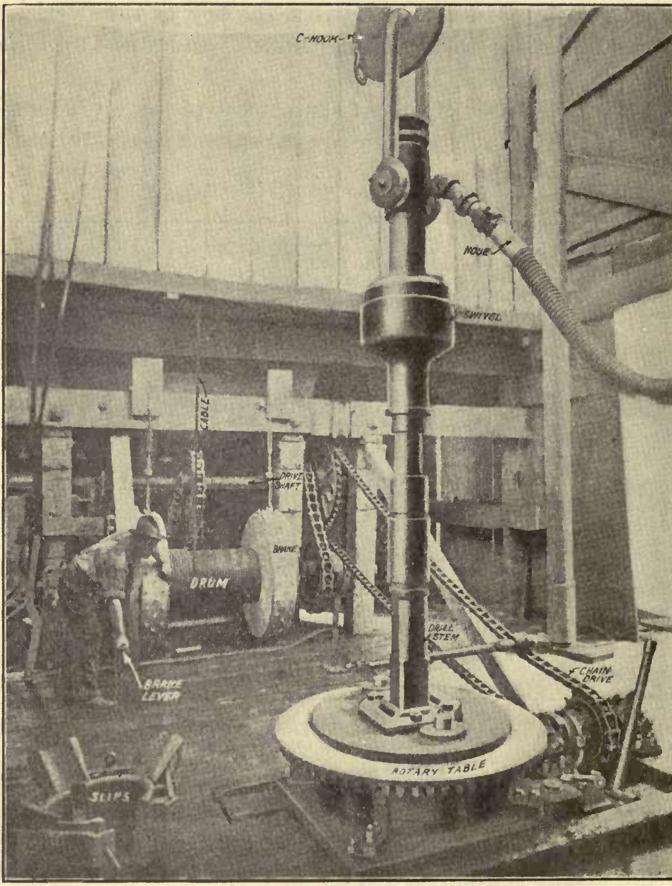


PLATE III.—Rotary-drilling in operation.

the drill pipe and the wall of the hole. The water has another important function. In soft beds the water acts as a jet and washes out the soft sediments. The bit in such cases has practically no cutting to perform, and the hole is washed down as rapidly as the drill pipe can be put in the hole. As high as 500 ft. per 24 hr. has been drilled in that way.

The Rotary method involves some of the same general procedure as with the cable tools.

In rotary drilling, however, the cutting action is obtained by rotating a sharpened steel bit shaped somewhat like a fish-tail. The action is a boring one, somewhat like an auger. The bit is attached to hollow drill pipe, which is turned at the top of the hole by a turning device called the rotary table. See Plate III.

The method of cleaning out the cut material differs also. Water is pumped down the drill pipe and comes up outside the pipe bringing the cut material with it.

Casing is also used, but the head of mud-and-water in the hole is often sufficient to keep the walls intact so that less casing is needed in rotary than in standard test holes.

The drilling tools are suspended from the top of the derrick much the same as casing in the cable-tool method. However the drilling cable instead of being attached to a bull wheel is fastened to a drum (see Fig. 15, page 58) which is driven by a sprocket drive from the line shaft.

The "draw works," as the lifting machinery is designated, is much simpler than with Standard Cable Tools.

The motive power is generally steam. A sprocket and drive chain from the engine connect with a main sprocket on the drive shaft (see Fig. 17). To this main shaft are connected the chain drives for the lifting drum, and for the rotary table (see Fig. 17).

In rotary drilling the various changes in speed and power are obtained by a system of sprockets.

A drive sprocket of small diameter connected to a big sprocket by chain drive gives low speed and high power. A large drive sprocket connected by a chain drive to a small sprocket means higher speed and less power. Figure 17, page 62, shows the relationship.

The middle sprocket M is driven from a sprocket on the engine. This sprocket turns the line shaft on which are two sprockets, D and R, and the cat heads at each end used for lifting material and pulling on the tongs in "tightening" or unscrewing pipe.

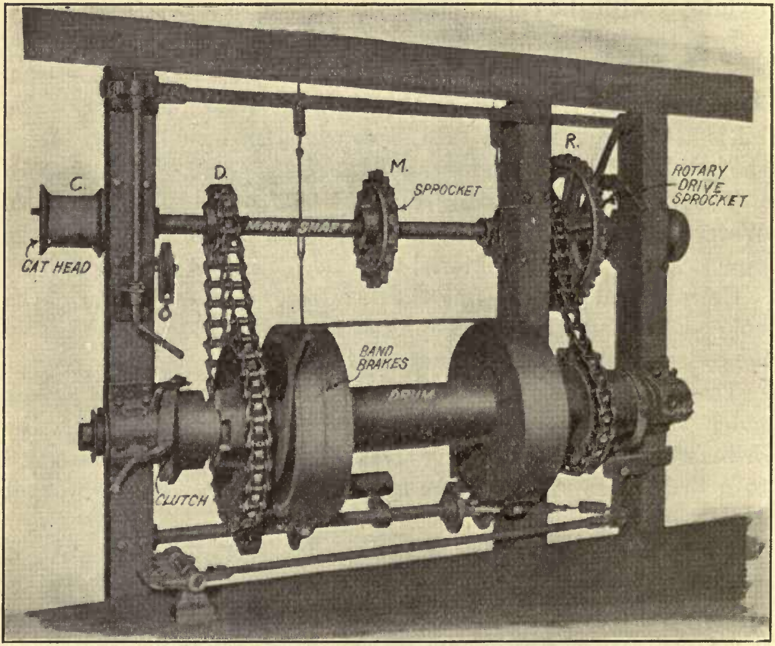


FIG. 17.—Rotary draw works.

The small sprocket D drives the drum when the clutch is engaged.

The rotary drive sprocket R drives a chain which turns the rotary table. (See Plate III, p. 60.) That sprocket in turn drives the rotary table by means of a pinion (see Fig. 18, page 63), which meshes with cogs on the under face of the rotary table.

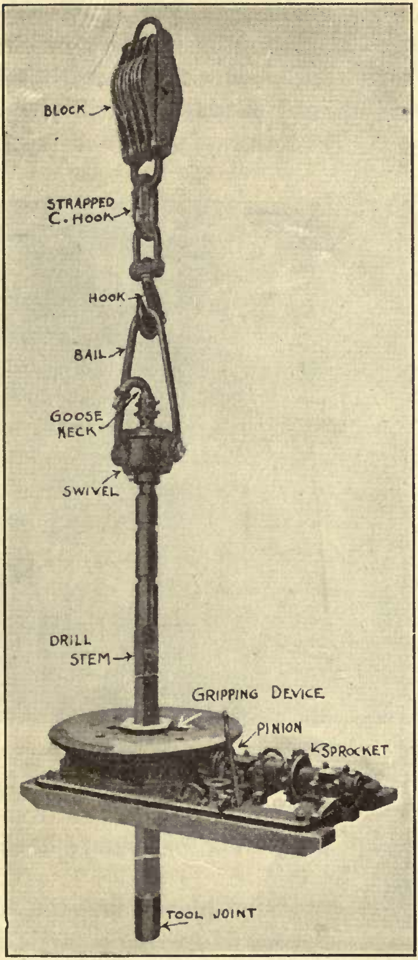


FIG. 18.—Rotary-drilling outfit. Shows driving and gripping devices.

Rotary Mud Pump.—In rotary drilling constant circulation of the water must be maintained.

"*Circulation.*"—Circulation on a rotary or circulator, means that the water pumped downward, through the drill pipe or the casing, passes upward outside the drill pipe or casing to the surface. It literally circulates.

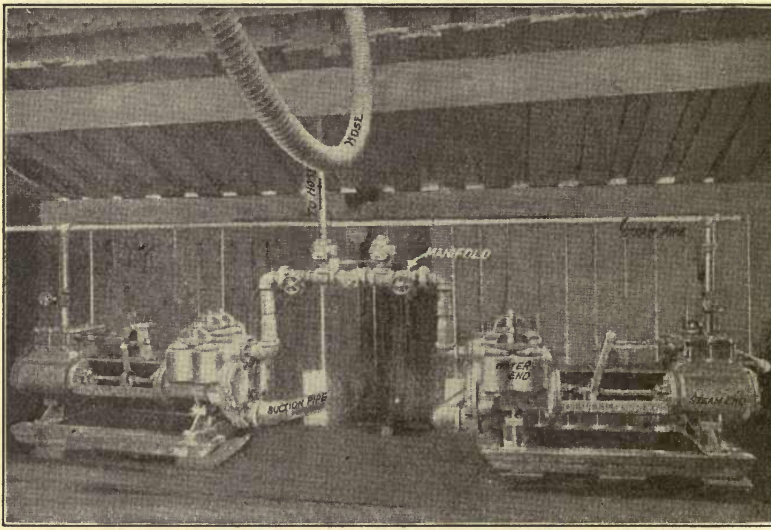


FIG. 19.—Mud pumps for rotary or for circulator systems.

Heavy pumps are used to suck the water from the sump and drive it into the drill pipe. The big pumps have dimensions as follows: $12'' \times 6\frac{3}{4}'' \times 14''$.

Such pumps are generally placed in pairs, connected by a manifold. (See Fig. 19, page 64.) One pump is in constant use. If a pump requires any repairs, it is cut out and the good pump started.

Steel-wire hose is used to connect the lead pipe with the swivel arrangement which is an important factor in rotary drilling.

The hose is attached to the gooseneck of the swivel. (See

Fig. 20, page 65.) The water then enters the drill pipe. The lower part of the swivel turns with the drill pipe, but the whole string of pipe hangs upon the bail which in turn hangs upon the C-hook and block, supported by the drilling lines.

The conical or ball bearings in the swivel permit the rotating of the lower part of the swivel and the string of pipe. A solid, non-rotating swivel would result in twisting of the drilling lines.

"Returns."—The drill cuttings or "returns" of the rotary come up between the drill pipe and the sides of the hole and flow into a ditch or box trough to the sump hole. A series of riffles in the ditch or box trough checks the flow of the returns, and as a result the cuttings deposit in the bottom of the trough, from which they are shoveled out. Some of the cuttings are carried into the sump which is also cleaned out at intervals.

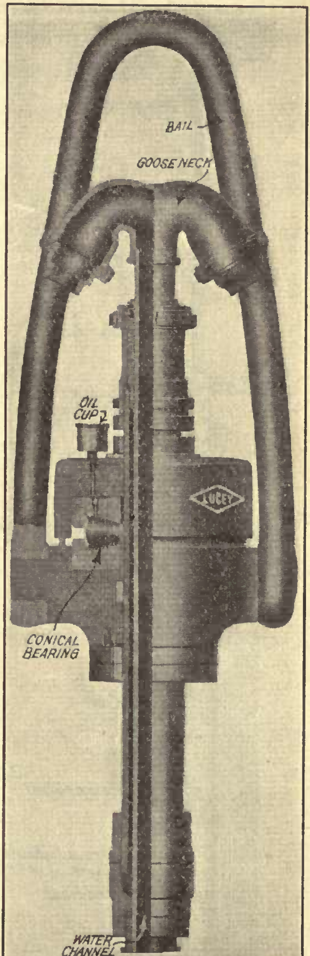


FIG. 20.—Swivel for rotary drilling.

SAMPLES

Samples are best taken from the point nearest the drill hole. A bucket of cuttings is caught and carefully washed and then inspected.

A capable rotary driller can tell from the feel of the drilling tools when a "change in formation" has occurred. He measures the point on his grief stem. He will then watch the ditch carefully and

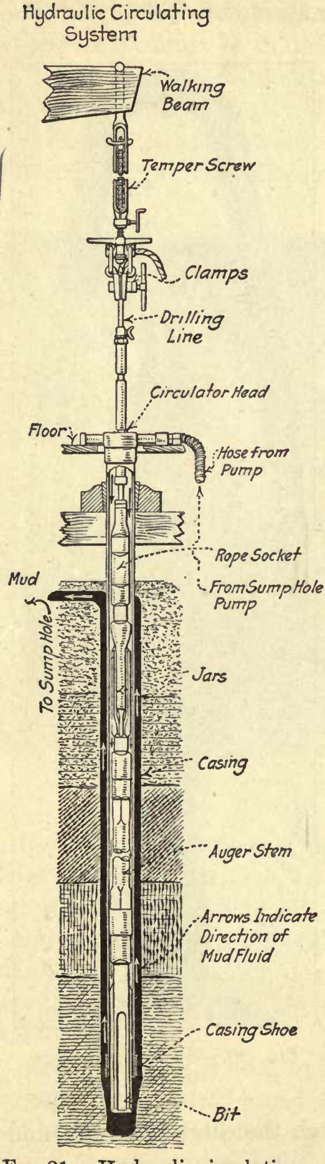


FIG. 21.—Hydraulic circulating system.

take samples. A change in the character of the material is logged.

Oil or gas may also show in the ditch and thus give positive evidence of their presence. In such a case a test of the sand is justified if the showing is a good one.

One danger with the rotary is in mudding-up the beds so that oil or gas does not show at all. Good oil horizons have been passed by in this way.

Careful logs can be kept with the rotary system, but it requires very close inspection to make a good analysis of rotary cuttings.

Core Barrel.—In taking samples in rotary drilling the core barrel provides an excellent method of obtaining good tests of the formation. This core barrel is put on the bottom of the drill pipe, and is rotated into the formation. The core taken from the core-barrel furnishes an excellent sample.

Hydraulic Circulator System.—The Circulator System as used with the cable-tool system calls for the use of heavy mud pumps.

These pumps drive a mixture of clay and water down the casing and up around the outside of the casing to the top of the hole. Constant circulation is maintained (see Fig. 21, page 66).

This method of drilling varies from the Standard Cable-Tool system in that the casing is kept only a short distance above the tools and that the water drives the cuttings from the hole. However, a bailer is employed to get samples as in the Standard Cable-Tool systems. The cable tools work through a circulator head. (See Fig. 21, page 66.)

CHAPTER IV

DEVELOPMENT-DRILLING CONTINUED

Size of the Hole.—The idea in drilling is to start with a large enough hole so that when all reductions are made the completed hole will be large enough, not only to produce oil, but will also give room to manipulate cleaning out tools, bailers and pump tubing.

A completed well or test hole of 6¾ in. in diameter may have a starting diameter of 15½ in. or even more.

Drilling must be conducted so the hole will not be "pointed out" or reduced in size so rapidly that the well must be abandoned before it reaches the depth to which drilling is considered necessary. In areas of Pennsylvanian rocks, or wherever beds stand up readily, the starting diameter can be less than in areas of soft, unconsolidated beds.

Casing Requirements.—Rotary holes require less casing for the same depth than do cable tools. Table 8, page 86, shows that in tests up to 3500 ft. the rotary starts with 12½ in. casing, as against 15½ in. for the cable tools. (Fig. 22, page 69 illustrates this point.)

In rotary drilling casing sizes are reduced on the following plan. After the first casing is introduced, say a 14-in. size for a deep hole, then the next size must be a 10-in. casing. Twelve-inch would go inside the 14-in., but as the diameter of the collar is 13 in., there is small room for circulation; also the friction of the upward-traveling water requires a heavy pump pressure. By allowing two extra inches of clearance good circulation is assured.

Crooked Holes.—The drill hole must be straight. Crooked holes are due generally to rapid drilling in steep dipping formations. If the bailer binds in going into the hole, it is a sign of either a caving or a crooked hole. If the hole is shallow a simple test is to reflect a ray of light from a mirror into the bottom of the hole, and see if it is straight or crooked.

If the casing, when lifted, swings freely, it is a good test of the hole being straight.

Drilling Time.—Drilling time is a factor influenced by the type of drilling method used, and by conditions, such as the hardness of the beds, accidents which cause delay, by the speed with which supplies are obtained, and by the individual efficiency of the drillers. Under favorable conditions 100 ft. per day of hole may be made with cable tools. As high as 150 ft. has been made. Under good conditions, a hole 3500 ft. deep in 60 days would be fast time with cable tools. Under average conditions six months would be considered good time.

With a rotary, drilling time is generally faster than with cable tools. As high as 500 ft. per day has been made with a rotary. Completion of a well 3000 ft. deep in 30 days is fast time. Ninety days for the same depth is good, average time.

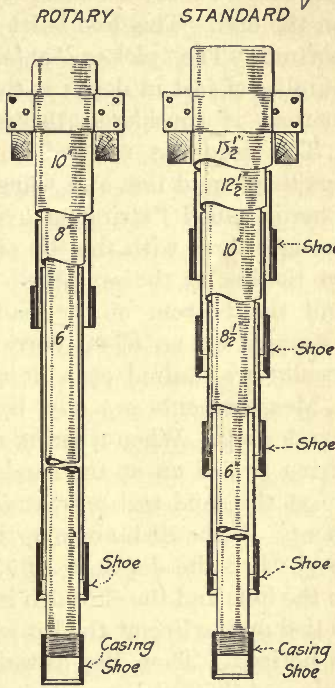


FIG. 22.—Comparative casing strings for rotary and standard systems shows casing saving of rotary over standard system.

MEASUREMENT OF WELL DEPTHS

Accurate depths of oil wells are obtained in five ways, given in the order of their importance.

1. Steel-line measurements.
2. Sand-line measurements.
3. Cable measurements.

4. Casing measurements.
5. (New) Automatic method.

Steel-line measurements are made by a steel tape marked in feet like a surveyor's steel chain, and weighted by a plumb bob on the end. This line is let into the well and allowed to touch bottom. The "pick up" or feel on the line indicates bottom. The number of feet in depth is then read direct from the line. This method is considered the most accurate of those employed.

The sand-line method consists in first measuring a given length of sand line and using that as the unit of measurement. This is called "stringing over." The bottom of the bailer is brought flush with the top of the casing. Then a string is tied on the line at the sand reel. Then the line between the strings and the bottom of the bailer is measured accurately. This measures on an 82-ft. derrick about 170 ft. Where accurate results are desired each derrick must be measured separately.

Measurements are now begun. The first string is run over the derrick. When a string reaches the top of the casing a new string is tied on at the sand reel. The number of strings tied on at the sand reel represents the number of units of measurement. If the distance over is 170 ft. and 10 strings have been used, then the depth is $10 \times 170 = 1700$ ft. If 10 strings are in the hole and the eleventh is part way over the derrick, a string is tied on the line at the top of the casing at the point "pick up" is noticed. Then the distance between the last string in the hole and the "pick up" string is measured and the length added to the amount in the hole. Stringing over with the drilling cable is done much the same way.

Accurate measurements are possible with the sand line. However, the strings may slip. Then, too, unless the first unit over the derrick is carefully measured its error is multiplied every time a string goes into the hole. An error of 6 in. per unit in a 3300-ft. hole would mean 20 times 6 in. or 10 ft. for that depth. Another error is due to the settling of the derrick, which increases with the length of the sand line in the hole. This sag may be as much as 3 ft. with holes 3500 ft. deep.

To overcome this error a measurement should be taken when the line first enters the hole and one on the last length in the hole. Average the two and use that unit as the true measurement.

Casing measurements, especially where the holes are cased to bottom, give accurate measurements of wells. Where each joint has been measured the sum of all the joints gives the actual depths. The measurements are taken from the top of one collar to the top of next collars after the pipe is "set up" in the derrick. In long strings of pipe there is undoubtedly some stretching. A string 3000 ft. long may stretch a foot, but that is negligible. With the rotary system measurements are taken on the drill-pipe as with casing. Accurate results are obtainable in this way.

Automatic Measurements.—C. E. Van Ostrand of the United States Geological Survey has invented a measuring device that he used on the deep wells in West Virginia. It consists of a flat wheel 2 ft. in circumference that is held against the sand line. Two pins in the wheel strike small arms on a meter. This meter registers the number of feet the line travels, and one can read the depth directly in feet from the meter. This method is very accurate and should come into more general use, as the device is simple and inexpensive.

Dressing Bits.—Bits are dressed or sharpened by hand or by steam hammers. Hand-sharpening is used at present on tools drilling far off from machine shops, or in those fields where light bits are used. In the early days of the industry, hand dressing was the rule, but now all large operating companies have the bits sharpened in the machine shop. Dressing large bits by hand is man-killing work.

The bit is heated in a forge that burns oil, gas, or coal. When brought to a cherry-red heat, the bit is pulled from the furnace, and swung on the forge, where the driller and toolie attack the dull end with sledge hammers. The main object in dressing bits is to maintain a flare on the edge of the bit, much like the outer edge of a horse's hoof, and at the same time keep the bottom of the bit slightly concave or hollowed. Figure 23, page 72, shows the dressing of a bit by portable steam hammer.

Standard drilling bits crush and smash as well as dig. For this reason a sharp-pointed bit is not desirable. The bit is used until the flare is worn off and the face of the bit becomes flat.

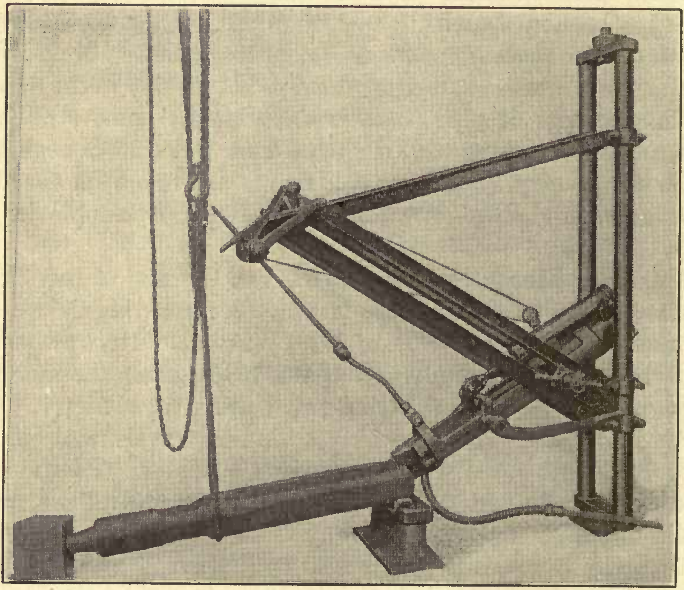


FIG. 23.—Spreading the bit with portable steam hammer.

Rotary drilling bits are used until the flares of the fish-tail are worn down nearly to the point where the bit is split. In dressing a rotary bit the remaining stub is drawn out from the shank so that the steel makes a thin beveled edge. Then the new length is split with a splitting chisel, and the halves are now bent or flared in opposite directions, giving the shape of the typical fish-tail bit. Dressing bits is hard work and calls for skill in proper heating, correct cutting, and shaping.

Types of Engines Employed in Oil-Field Operations.—The steam engines used belong to the horizontal simple reciprocating type. They are set on a heavy wooden block called the engine block. (See Fig. 24, page 73.) A drive belt passes from a pulley on the engine to the band wheel. This pulley wheel is balanced by the fly wheel. Weight is added to the fly wheel by circular balance weights that can be bolted to the fly wheel. The gas engines and electric motors work on the same principle. Drilling engines have dimensions of 10½ by 12 in. to 12 by 12 in.

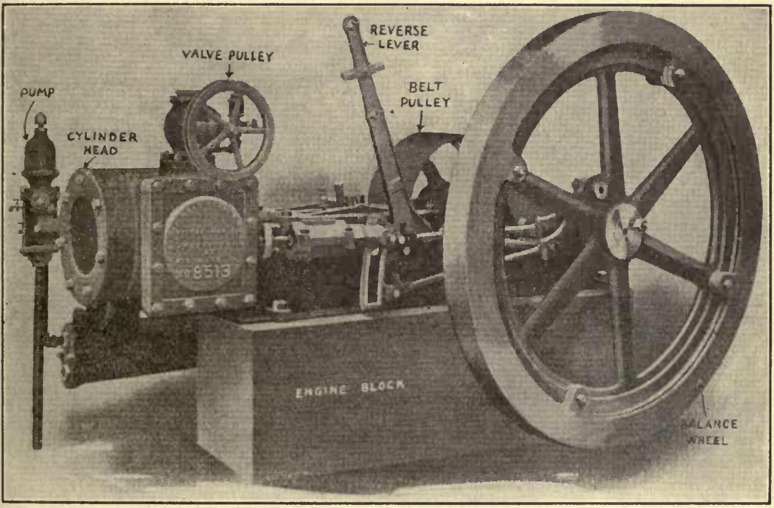


FIG. 24.—Steam engine for drilling.

This means a cylinder diameter of 10½ to 12 in. and a stroke of 12 in.

Pumping-engines range from 9 by 12 to 10 by 12.

These steam engines range from 15 to 60 hp. The deeper the well the greater the power necessary.

Twin Engines.—A recent improvement in oil-field engines is the twin or duplex engine. Two 9 × 10 twin engines are used in place of one heavy 11½ × 12 or 12 × 12 engine. The two engines give a steadier pull than the single engine. In rotary drilling this is less liable to cause "twisting off," which is the result of sudden jerks. Also the engines cannot get "on center." This is a decided advantage in drilling.

Types of Boilers.—The boilers used in drilling are of two general types, namely the locomotive and the plain horizontal tubular. The locomotive type (see Fig. 25) is internally fired, while the simple tubular boiler is externally fired. The latter

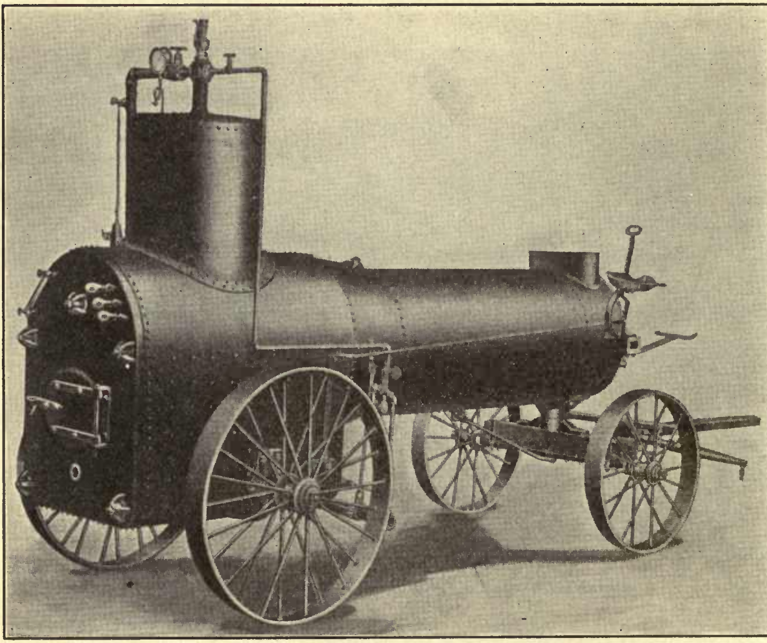


Fig. 25.—Twenty to 25 h.p. oil country boiler. Locomotive type. (Internally fired.)

is hung on a frame and the sides are walled as shown in Fig. 26. This type of boiler is in general use in California. Such boilers develop from 20 to 60 hp. for locomotive types and from 35 to 100 hp. for the horizontal tubular types. They have heating surface roughly 12 sq. ft. per horse power, and use from 15 to 20 bbls. of oil per day, on drilling wells, and 2 to 4 bbls. per day for pumping wells.

On producing leases, batteries of three to six boilers are housed under sheet-iron roofs. These boilers produce steam for pumping the wells and sometimes for drilling operations as well. Such batteries have boilers ranging from 60 to 100 hp. There is not always uniformity in such boiler plants. Some plants have Sterling water-tube boilers, Wilcox boilers, and marine internally-fired water-tube boilers, and also plain horizontal tubular boilers externally fired.

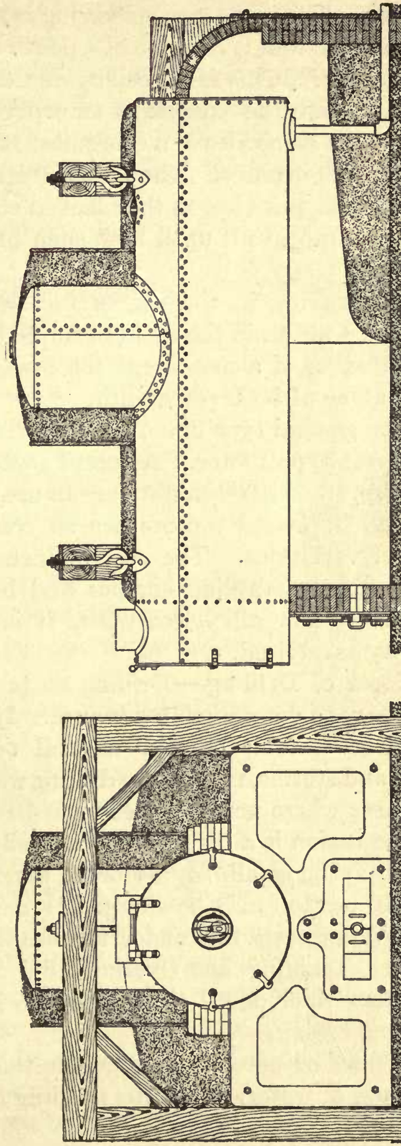


FIG. 26.—Horizontal tubular type boiler. Boilers 35, 40, and 45 hp. are usually set as above.

Fuel.—In drilling wells in new districts the fuel used may be cordwood, coal, fuel oil, and sometimes natural gas, depending upon the relative cheapness of the various types of fuel. In drilling near proven fields, fuel oil or natural gas are the main fuels used.

Use of Electricity for Drilling.—The use of electricity in oil-field operations has made remarkable changes in some places. There is a distinct saving in fuel by the use of electricity. Where the well is in reach of a power line, there is a big advantage in its use. This is especially the case in hilly or mountainous areas, where the expense of transporting fuel oil, or coal, is very high. In some cases, motors also save the hauling of water for steaming purposes. The first motors were not considered suited to oil-field practice, as they lacked elasticity, but they have been greatly improved, until now such motors are well liked by the drillers.

The saving in the use of fuel is marked. On a "wildcat" well in California the fuel bill for oil was $1200 per month. The installation of a motor cut the power cost to $300, a saving in fuel alone of $900 per month.

The general type of motor is rated at 75 hp., 3-phase, 60-cycle, 440-volt type motor. A recent motor in California is rated at 100 hp. Over 200 motors are in use for drilling.

The improved motors are so controlled that they have 80 speed variations. The cost of installing a motor is no greater than that of drilling engines and boilers, and the economy is evident. For all places where it is available, the use of electricity is advised.

Costs of Drilling.—Drilling costs in new untested areas are not easy to determine in advance. If all goes well, the costs may be low. Accidents and natural occurrences such as floods, fires and storms, may tie up drilling wells for weeks or even months in cases where new supplies must be ordered. The accessibility of the region is a big factor. If easily reached, the cost of haulage may be small, say $4 or $5 per ton, but in some areas $30 to $40 per ton may be charged.

Drilling costs fall under the headings Labor, Material, Fuel, Water, Teaming, and Overhead.

Labor includes "rigging up." Drilling material includes rig and casing.

It may be necessary to include the cost of a pipe line, pump, and use of water, under the heading Water.

Teaming is always an item of expense. Teaming may be by horse, by ox teams, or by truck.

Overhead includes superintendence and camp supplies.

Drilling costs vary greatly. To purchase a complete new outfit and drill a hole 3500 ft. deep in California will cost not less than $100,000. In Wyoming a hole of the same depth can be drilled for $80,000.

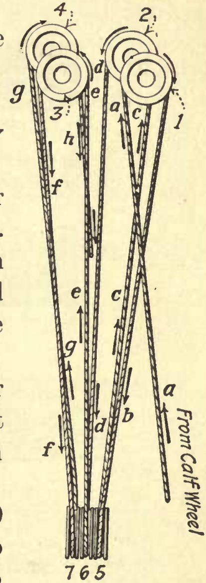


FIG. 27.—Method of stringing casing blocks for use of seven lines.

In Oklahoma a test 3500 ft. deep can be drilled for $80,000.

In Texas a 3500-ft. test will cost $80,000.

In Ohio a 3500-ft. test will cost under ordinary conditions $35,000.

It must be understood that a "dry" hole or failure will not cost as much by any means. The tools, casing and rig can be salvaged. In some deep holes the value of tools, casing, and rig amounts roughly to 50 per cent of the value of the hole.

If the holes were drilled by a contractor who furnishes tools and everything except casing, the costs would be about as given below.

Shallow wells drilled with portables 250 to 500 ft. may be completed at a cost of $1000 to $1500. Wells 900 to 1000 ft. cost $3500 to $5000. Wells of 2000 to 2500 ft. cost in California $50,000 to $60,000. In Wyoming such wells cost $25,000 to $35,000. In Oklahoma $15,000 to $20,000. In Texas $15,000 to 25,000.

The first hole is generally the most expensive. Once a field has been discovered later drilling costs are much lower.

Casing Lines.—The casing line extends from the calf wheel and over the derrick. One end of the casing line is attached to the pulley block or may be attached to a bar on top of the derrick, depending on the number of lines used.

The deeper the hole and the heavier the casing, the more lines are used. A single pulley block for 3 lines may be used at first, but as many as 11 lines may be necessary for deep holes.

The casing lines are strung over the casing sheaves so that the pulley block and hook center directly over the drill hole. This is essential to avoid binding. The number of lines required

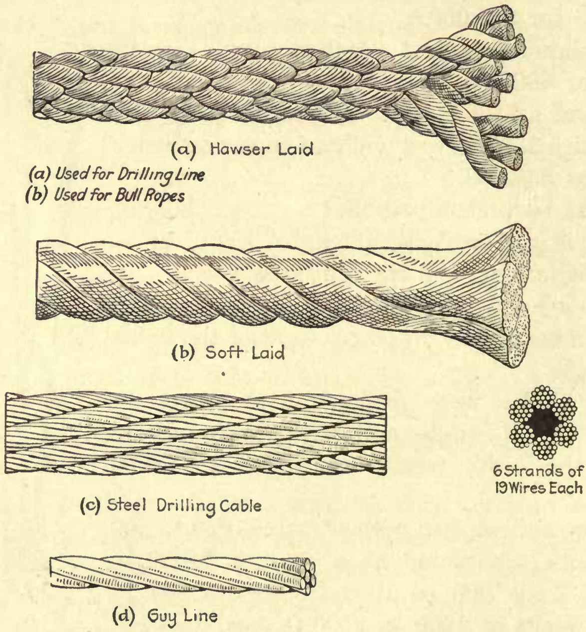


FIG. 28.—Type of cordage used in oil fields.

depends of course upon the weight of the casing to be handled. A sketch of the way casing lines are strung is shown in Fig. 27, p. 77.

The calf wheel is driven either by rope drive from a wheel on the end of the band wheel or by a sprocket-chain drive from a drive wheel on the end of the band-wheel shaft.

It is important here to speak of the cordage used in oil-field operations.

Cordage.—Two kinds of cordage are used in the oil fields.

(A) Rope
- Sisal hemp — Ordinary purposes
- Manila hemp — Drilling cables; Bull ropes

(B) Wire
- Drilling lines — Drilling
- Casing lines — Casing
- Sand lines — Bailing
- Guy wires — Support derrick

See Table 6

Manila drilling cables (see Fig. 28) were used exclusively for many years, but the steel-drilling cables (see Fig. 28, page 78) are preferable to manila cables. In a few places manila cables are used to drill shallow wells, or are used for "spudding" operations. Steel lines, however, can be used for all such purposes and are now cheaper.

Manila-drilling rope is sold by weight. It has diameters of 1½ to 2½ in. and weighs from ¾ to 2⅛ lb. per foot.

Bull-ropes have diameters of 2 to 2½ in., and weigh 1³⁄₁₀ to 2⅛ lb. per foot.

Steel-drilling cables are of the common, 7-ply type with 19 strands and a hemp center. (See Fig. 28.) They have a left-hand lay and will stand the following strains. See Table 6.

TABLE 6

Diameter	6–19 Drilling lines			6–19 Casing lines			6–7 Sand lines			Guy or dead line	
Inches	Weight per foot	Tons test	Safe load	Weight per foot	Tons	Safe load	Weight per foot	Tons	Safe load	Weight per foot	Tons
1¼	2.45	50.0	10.00	....	....	...	....	..	...	2.45	1½
1	1.58	34.0	6.80	1.58	45.0	9.0	....	..	...	2.00	1⅛
⅞	1.20	26.0	5.20	1.20	35.0	7.0	....	..	...	1.58	1
¾	0.89	20.5	4.04	0.89	26.3	5.3	....	..	...	1.20	⅞
⅝	....	....	.....	0.62	12.5	2.5	0.62	13	2.6		
9/16	....	....	.....	....	....	...	0.50	10	2.0		

Sheaves.—The main or crown sheave (see Fig. 29, page 80) over which the drilling cable passes, the casing sheave, and the sand-line sheave over which the sand line passes differ to correspond with the demands on them. The crown sheave is a heavy pulley of a diameter which permits rapid revolving with a large surface exposed to cooling and a minimum of flexing strains. A crown pulley with a diameter of 26 in. must stand a speed of over 1000 ft. per minute. This means for a 6.8 ft. circumference nearly 150 r.p.m.

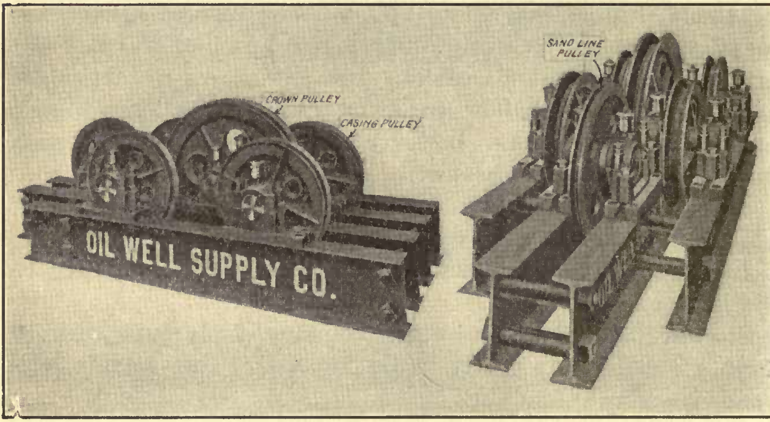


Fig. 29.—Steel crown block and pulleys.

The casing sheaves are of smaller diameter as they revolve at a slower rate of speed. The casing sheaves are seldom used for speeds over 50 r.p.m.

Sand-line sheaves must stand high speeds of 150 to 200 r.p.m. The weight on them is light, however, and the line used is 5/8 in. in diameter, so that the sheave is of light construction.

The main problem with pulleys is the lubrication of the pulley grooves. The sheaves are set in hardwood grooves which are kept well greased with a good heavy axle grease. Where steel-crown blocks are used the metal seats are kept well greased. Many fires in derricks have started from ungreased pulleys on wooden-pulley grooves. It is one of the toolies' duties to see that the pulleys are greased.

Casing.—Casing is used primarily as a lining for producing oil and gas wells and as an auxiliary in drilling. Casing consists principally of heavy steel tubes, though occasionally some iron tubes and in rare instances wooden tubes are employed. It must be clearly borne in mind that the amount of casing is governed by the number of caving shales and sands encountered, by the water sands, and also by accidents in drilling.

The exclusion of water from oil and gas sands and the "shutting off" of dry sands that might absorb the oil or gas are made possible by the use of casing, and also by the use of mud-fluid. The casing acts as a lining for the hole and keeps back the cavings and the water, and also serves to keep the oil and gas within proper bounds.

Casing serves:

1. To exclude water, mud, or sand from the drill hole while drilling is progressing;

2. To exclude water or mud from oil and gas sands;

3. To separate the various oil and gas producing horizons from one another;

4. To confine oil or gas to its immediate producing horizon.

Casing to meet these requirements should be both gas- and water-tight. It should have sufficient resistance to external water pressure so that the casing will not collapse, and it must have sufficient tensile strength in the threads, so when suspended it will hold together.

Casing sizes must be selected to suit the varying diameters of holes.

The deeper the hole, the greater the water and the rock pressures encountered. Casing must then be correspondingly heavy, not only to withstand greater collapsing pressures, but also greater tensile strains, for as the casing is lowered and raised, greater strains are put upon it. In the past the use of light "hen skin" pipe has caused more lost holes than any other one cause.

Table 29 in the Appendix gives some idea as to the sizes, weights and strengths of casing used.

Casing is of four types.

1. Riveted.
2. Lap weld.
3. Butt weld.
4. Seamless.

Riveted or stove-pipe casing (see Fig. 30, p. 82) was formerly quite widely used for large-sized pipe at the top of the hole. The

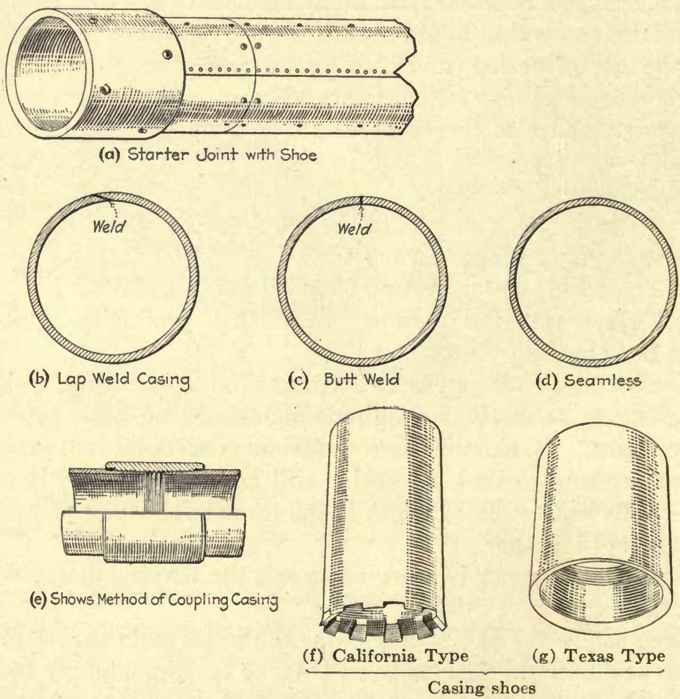


Fig. 30.—Types of casing, couplings, and casing shoes.

pipe came in flat sheets about 2 ft. long that were rolled to form cylinders which were then riveted at the well. Short sections were put in a hole until the desired length was secured, usually from 10 to 15 sections. Such pipe is used to hold back gravel and surface alluvium or to shut off surface water. The diameter of this riveted casing ranges from 12½ to 20 in. Good practice now calls for real screw casing. Dimensions of 15½, 18 and 20 in. are available.

Lap-weld casing (see Fig. 30, p. 82) is made by welding the beveled edges of the steel or iron sheet which overlap. This is the type of casing most generally used.

Butt-weld tubes (see Fig. 30, p. 82) are made by welding the two sides of the sheet by direct contact. One-inch, two-inch and three-inch sizes are the general sizes for butt-weld pipe.

Seamless casing is made without any seams at all by pulling the metal through dies. Seamless casing is used principally for drill pipe with the rotary system.

The strength of welded pipe depends, of course, upon clean welding. The weakest points will be in the seams. If the weld has not been clean the pipe is weak. Seamless pipe does away that danger, of course.

Couplings.—Casing is threaded at both ends. Collars are used to couple the joints (see Fig. 30). The casing and the collars have beveled threads, which gives the greatest resistance to stripping.

Casing Shoe.—It was found that the bottom of the casing was liable to be bent or crushed when passing through hard beds, and also that where the casing was driven, the bottom would collapse. To overcome this difficulty, the casing shoe was invented. This is nothing more than an extra heavy and long steel collar, which is screwed on the bottom joint of a string of casing. It is beveled on the lower end. (See Fig. 30, p. 82.)

With rotary pipe the shoe sometimes has a notched edge, with cutting teeth, so that, if desired, it may have a cutting action when the pipe is rotated.

Handling of Casing.—Skillful manipulation of a heavy string of casing requires careful attention.

A string of 10 in. casing 3000 ft. in length weighs 73 tons. The weight of such a heavy string sometimes causes the derrick to collapse. It requires at least nine to eleven casing lines to handle such a weight readily. The force required to move such a weight applied to the cable is roughly 7 to 8 tons.

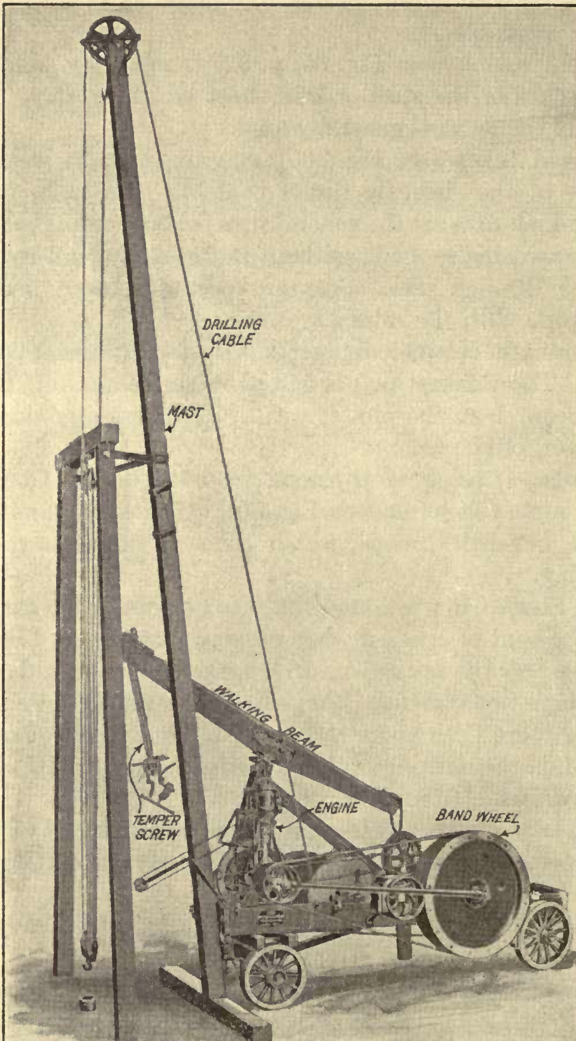
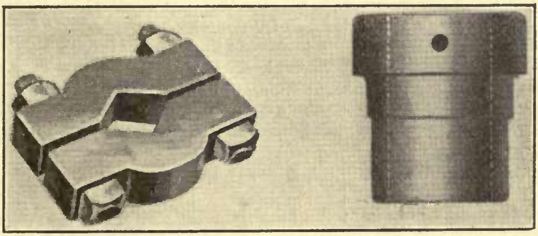


FIG. 31.—Method of handling casing with portable rig.

The casing is handled in units or joints about 20 to 21 ft. in length. This casing is put in the hole a joint at a time.

Procedure.—A joint of casing is pulled into the derrick by a rope sling attached to the end of the big hook on which the elevators are also hung. The elevators are then set on the joint and it is lowered into the cellar.

The first joint of casing is held in a spider by four slips. The spider rests on a pair of sills (see Fig. 33, page 89) which are laid on the floor of the cellar. As each new joint is added the slips are pulled free and the upper joints are lowered into the hole until the top joint of casing is flush with the derrick floor. The slips are then put in again and the casing lowered on them.



(*a*) (*b*)

Fig. 32.—(*a*) Drive clamps; (*b*) Drive head.

One man of the crew stands on the roof of the derrick or on a cross board and balances each new joint of casing so that it will not bind while being coupled together.

This process is repeated until the complete string of casing is in the hole. Then other operations are resumed.

Care must be exercised that casing of proper diameter is used. In one case in Wyoming 6¼-in. casing was used when 6⅝-in, was needed. The next string ordered was 5⅝-in., which would not pass through a 6¼-in. casing as the outer diameter of the collars is 6½-in. Such mistakes are expensive.

Driving Casing.—Sometimes it becomes necessary to drive casing. When that is done a pair of drive clamps is fastened to the auger stem. These clamps (see Fig. 32*a*) are grooved pieces of iron bolted together around the stem. The tools are dropped upon the drive head (see Fig. 32*b*) which fits over the top collar of the casing, and protects the threads. There is a grooved slot in the drive head into which the collar of the casing fits. The driving is done by means of the jerk line as in the "spudding" operation described on page 50 and shown in Fig. 10, page 52.

Amount of Casing.—Some idea of the amount of casing used in deep wells may be obtained from the following tables.

TABLE 7.—CASING STRINGS
Cable Tools

Texas-Ranger	California	Lance Creek, Wyoming	Cushing, Okla.	Bradford, Pennsylvania
200–15½–70 lb.	1000–15½–70 lb.	60–15½–70 lb.	40–15½–52½ lb.	290–10–35 lb.
900–12½–50 lb.	2000–12½–50 lb.	750–12½–50 lb.	800–12½–50 lb.	1450–8¼–24 lb.
1800–10 –40 lb.	2500–10in.–50 lb.	2200–10in.–40 lb.	1650–10in.–45 lb.	2100–6⅝–17 lb.
2200– 8¼–28 lb.	3500– 8¼–36 lb.	2800– 8¼–32 lb.	2150– 8¼–32 lb.	2150–8¼–32 lb.
3000– 6⅝–24 lb.	.... lb.	3400– 6⅝–26 lb.	3500– 6⅝–26 lb.	
3500–5$\frac{3}{16}$–17 lb.				
3500–2 –4½ lb.	2½–6¼ lb. tubing	2 –4½ lb. tubing	2 –4½ lb. tubing	2 –4½ lb. tubing

TABLE 8.—CASING STRINGS
Rotary

California Montebello	Gulf Coast Goose Creek	Louisiana Caddo	California Midway
2000–12½ in.–50 lb.	125–12 in.–45	200′–10″–32½lb.	1600–12½ in.–45 lb.
2500–10 –50	2100– 8 in.–29 Line pipe	2300 6″–195″	8¼ –36
3500– 8¼ –36	3100– 6 –19.50lb. Rotary		3500
2500– 6	Liner or screen pipe	200 4½″–125″	6
3200– 3 – 9 lb.	3400 to	2500 2″ 4½″ Tubing	3500– 2½ –6¼ or
	3500–2½ –6¼ lb. tubing	....	3 –7.69 lb. tubing

Pulling Excess Casing.—After an oil well is finished it is found in many instances that some of the casing in the hole can be withdrawn to advantage. For instance, if there are 12½-in. 10-in., 8¼-in. and 6⅝-in. strings and the 10-in. merely prevents caving of the formations during drilling operations, it is advisable to pull the 10-in. string and in some cases pull the 12½-in., leaving the 8¼-in. to shut off water, and the 6⅝-in. casing as the oil-string.

"Freezing Pipe."—Where casing is stuck tight by mud or shale settling around the pipe it is said to be "frozen." Where a pipe is frozen it may be very difficult to free it. Freezing is avoided by maintaining circulation with the rotary or the circulator systems. Where the mud pumps are not used the pipe must be lifted from time to time to keep it free.

Shooting off Casing.—It is sometimes found that a string of casing cannot be pulled from the hole, as the casing is "frozen" tight. Shooting is employed to save part of the casing.

A torpedo is prepared and lowered on a sand line to a depth just above the frozen part, preferably at the last collar, which is located by a collar finder. The casing is now put under strain by being pulled taut. The shot is fired; the collar expands a trifle, and the tension on the casing is sufficient to free it. Shooting this way is very satisfactory. Firing is generally done by a battery although a jack squib may be used.

Fishing Methods.—The subject of fishing is directly connected with the drilling of oil wells, and also with the handling of production.

Accidents may happen to drilling tools, to casing, or to tubing in a hole which may result in the loss of the tools or of the casing. If the tools are dropped or lost they must be "fished out" if possible.

Fishing methods are by no means simple. Different methods and tools must be employed for varying conditions.

The underlying principle of all fishing tools is to furnish a grab or hold on the broken or lost parts. This hold may be obtained by tools which take a direct hold or grab or by a friction hold, or by both combined.

Auxiliary tools are used to prepare the way for the grabbing operation.

Fishing troubles are due mainly to the following causes:

On drilling (Standard Cable-Tools) wells

1. Cable breaks
2. Breaking of pins at tool joints (jumped pins)
3. Unscrewing of pins
4. Casing troubles
   (1) Collapsing
   (2) Slipping of threads
   (3) Corkscrewing due to dropping
   (4) Freezing of casing

Rotary—drilling wells

1. Loss of bits
2. Twisting off of drill pipe
3. Freezing of drill pipe or casing

Finding the Trouble.—When an accident has occurred the first consideration is to determine the trouble, and then to plan the remedy.

The best procedure is first to run an impression block in the hole to determine the position of the lost part.

The impression block is made by putting a covering of asphalt or tightly packed soap upon the bottom of a block of wood which is fastened on the end of a joint of pipe, or of tubing. The block is made just small enough in diameter to enter the hole.

Photographic devices have been tried, but their use is expensive and questionable.

The impression block is let into the hole on the sand line. It is lowered firmly on the top of the lost tool, or the top of the lost casing. This leaves an impression in the gum on the block.

When the block is withdrawn the impression shows the relative position of the lost tool or the casing to the sides of the hole and the impression of the broken parts. This furnishes a guide for later procedure.

Where the threads in the box of a tool joint or where the threads of a casing collar are stripped, it may be possible to screw on a new box or to put in a fresh joint of casing. Such cases are simple. However, if the tops of the tools are battered other methods must be tried.

Fishing.—Fishing "jobs" are of two types:

(A) Fishing for lost drilling tools or parts of tools

(B) Fishing for lost casing, rotary-drill pipe or tubing

The most general cases of Class *A* are (1) lost bits, lost strings of tools, lost bailers, lost cable and tools.

Fishing for lost tools is difficult work. A lost tool may be recovered quickly by fishing or may require months of hard work. The procedures followed in disposing of lost tools are:

(*a*) Fishing tools out,

(*b*) Sidetracking tools, and

(*c*) Drilling them up.

Fishing String.—When fishing for a string of tools, fishing jars are used. These jars are much longer than ordinary drilling jars so that a long upstroke may be obtained. The arrangement of the string is also different (see Fig. 33). The stem is placed above the jars to give a heavy upstroke and the fishing tool is, of course, below the jars which is the opposite arrangement to the drilling string. When a grip has been secured and a good pull on the lost tool fails to budge it, an upstroke is attempted, and a series of these strokes may "jar loose" the lost casing or lost tools.

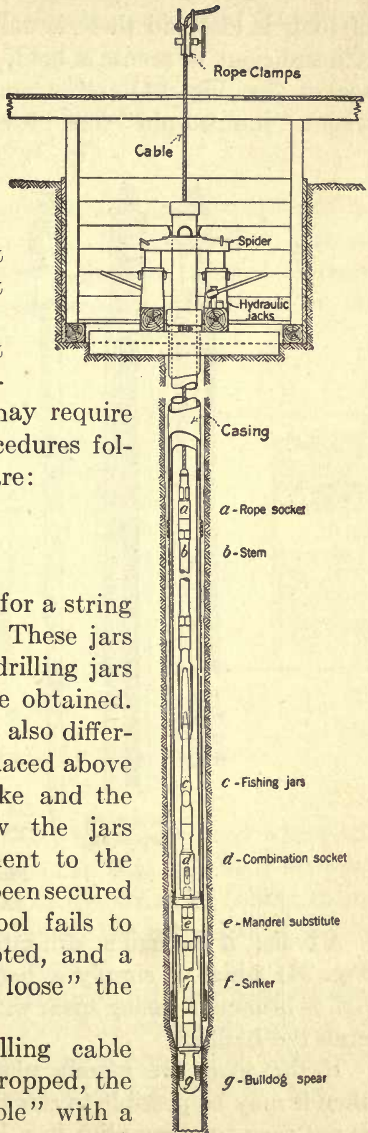


FIG. 33.—String of fishing tools. After U. S. B. M.

Fishing Procedure.—If a drilling cable has parted and the tools have dropped, the procedure is to "run into the hole" with a rope-spear, or grab (see Fig. 34, page 90) and pull out the cable and tools. If a string of tools is lost and there is only a small amount of cable above it insufficient to secure a hold, then it is necessary to use a slip socket (see Fig. 34) and attempt a hold. The same will apply with a "jumped pin" (one broken off at the joint).

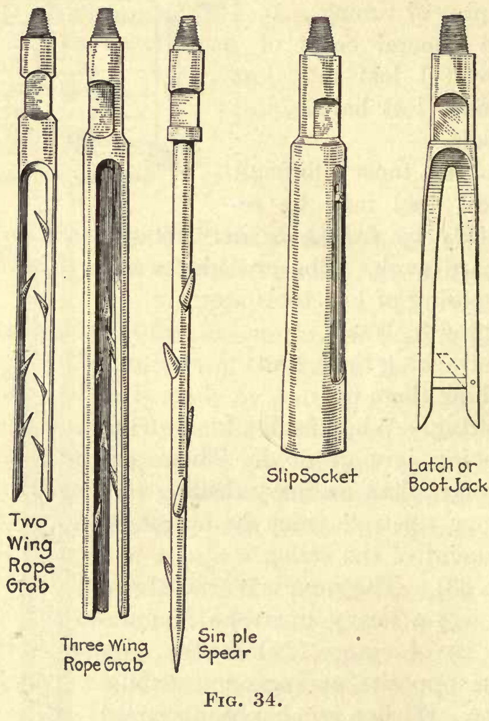


FIG. 34.

A bailer, if the bail is still intact, is caught by a latch jack (see Fig. 34) which is simply a hook that catches the bail. If the bail is broken, a casing spear with slips may be run into the hole to grab the bailer.

If the tools are merely unscrewed and a pin is sticking up, then it may be possible to screw on again and pull out, but this is not easy to accomplish in a large hole.

Fishing for casing, tubing or drill pipe requires one of three types of tools:

(A) Die Couplings. { steel die nipples.
(B) Casing Spears. { steel die collars.
(C) Overshot.

If the casing or tubing has unscrewed and has not dropped far it may be possible to screw it on again. This procedure is possible with casing or tubing more often than with the tools. However, if the loss is due to stripped threads a new collar on the casing or a new joint of pipe may secure results.

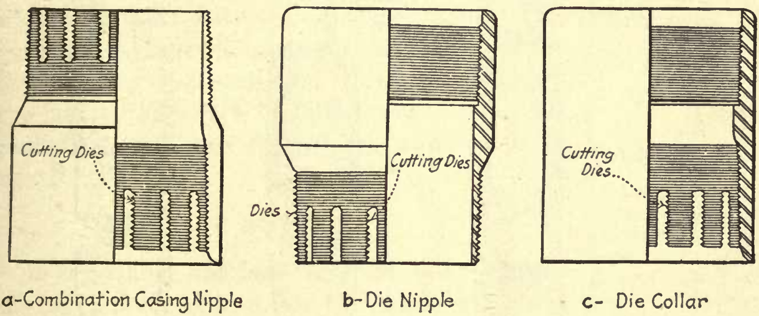


FIG. 35.—Nipples and die collar for fishing out casing.

Die Nipple.—The die nipple (see Fig. 35), is used where it is possible to cut new threads in a collar that has been stripped. The nipple is used on the bottom of the string of fishing casing. The die collar is used on a casing where the collar has been stripped and it is possible to cut new threads.

If die nipples fail and the casing is open at the top a casing spear (see Fig. 36, page 92) is used. This tool enters the casing and when pulled upward the slips take a good grip. The casing may be readily pulled if no cavings have settled around the pipe. If so jarring may be necessary.

CASING SPEARS

The best types of spear or slips are those that can be released readily if the casing does not pull out freely.

One of the best methods of fishing for casing on difficult jobs

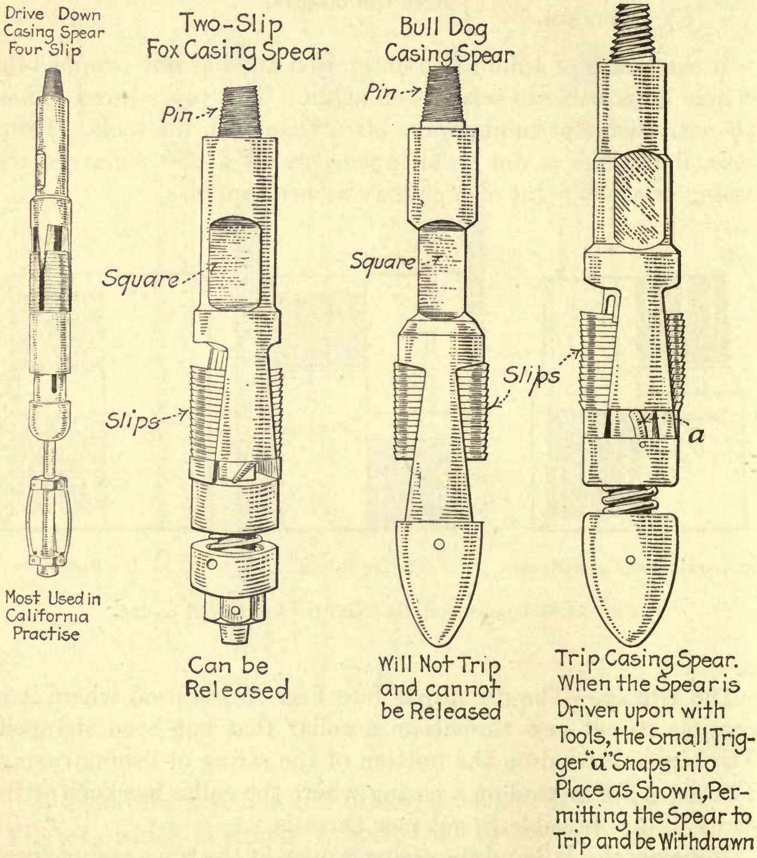


Fig. 36.

is to use a casing spear and a bowl socket with slips. The casing spear is attached to the cable. The spear grips inside the casing and the bowl while the slips grip the outside of the casing. If the casing does not pull easily, jarring may be resorted to. Hydraulic jacks may also be used. The elevators used to lift the fishing-string with the jacks give this method terrific lifting power. If casing does not respond to this method the hole is abandoned, or, where the beds are soft and unconsolidated, all the pipe possible is withdrawn and "drilling by" is attempted.

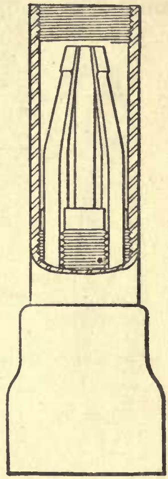


FIG. 37.—Overshot. The springs pass down over pipe and couplings but catch under a coupling when pulled up.

OVERSHOT

In some cases "overshots" are used, particularly when the top of the casing has been badly battered and a spear will not enter. An overshot (see Fig. 37) is a belled pipe or nipple which contains flat steel springs inside. This overshot is "run on" casing or drill pipe and fits over the top of the casing. In going downward the springs slip over the pipe collars but when pulled upward, the springs grip the casing beneath a collar.

SWAGE

If the casing has been crushed and its inside diameter reduced to a size that tools or a bailer will not enter readily, a swage (see Fig. 38) is generally employed. The swage is put on the bottom of a string of tools in place of a bit, and is driven through the collapsed place in the pipe. This brings the casing back to its normal diameter. Jars are used with the swage so if the swage sticks it can be jarred loose.

A small swage may be used at the start, and as the inside of the casing is opened a larger swage may be employed.

Sidetracking Tools or Casing.—It has been found in drilling operations in areas of soft unconsolidated formations, like those occurring in California and Louisiana, that a whole string of lost tools, or several hundred feet of lost casing may be drilled by or "sidetracked." This is done only after every effort has been made to recover the lost tools or casing. Sidetracking appears strange to those operators trained in hard rock areas where the hard formations do not permit the passing of a string of tools and the pushing of the lost string into the soft wall of the hole. In some drilling operations it is not unusual to sidetrack as much as 400 ft. of casing and proceed with operations as if no loss had occurred.

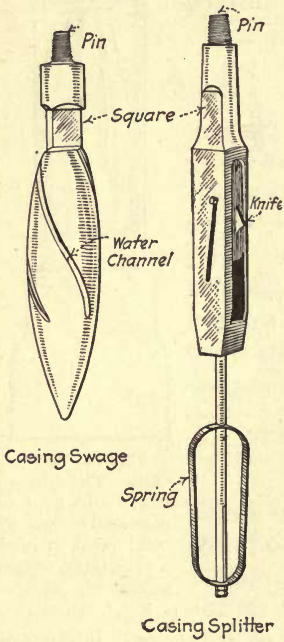


FIG. 38.—(*a* and *b*) Swage-casing splitter; (*c*) Casing cutter.

This method cannot be employed with hard rocks like those in the Eastern States.

"Drilling Up" Bits, Casing or Other Lost Material.—In cases where lost parts cannot be recovered it may be possible to "drill up" the parts. Cast-iron breaks up readily. Iron and steel pipe cannot withstand the drilling action of a hard-steel bit, but tempered tools and parts cannot be "drilled up" readily.

In rotary drilling, milling tools have been used to drill a hole through the bit left on the bottom of a string of drill pipe.

Lee Hager, of Houston, Texas, drilled such a hole which was reduced to a 4-in. diameter. The 4-in. drill pipe was "frozen tight" at a depth of 2000-ft. The oil sand was expected within 20 ft. The case appeared a hopeless one. The difficulty was overcome by using 2-in. drill pipe and a milling tool that was rotated through the rotary bit. A flowing well making several hundred barrels was successfully obtained in this way.

The casing splitter (see Fig. 38) is used when a hole is about to be abandoned. The casing is ripped at a joint and the weakened threads will not hold against a strong pull on the pipe.

TABLE 9.—ROCK CLASSIFICATION SUMMARY

General Class	Rotary-drillers' Term	Use in Rotary System	Cable-drillers' Term	Use in Cable-tool System	Technical Equivalent
Sands	Sand	Any uncemented sand.	Sand	Any uncemented sand; also many slightly cemented sands or very porous formations.	Sand
	Water sand	Sands, the samples of which appear clean and bright. Sands tested and found to produce water.	Water sand	Sands producing water.	Sand
	Quicksand	Sands that cave and settle rapidly.	Quicksand	Sands that cave and settle rapidly.	Sand
	Heaving sand	Sands that cave and are forced up the hole.	Heaving sand	Sands that cave and are forced up the hole.	Sand
	Oil sand	Sands or other porous formations containing oil.	Oil sand	Sand or other porous formation containing oil.	Oil sand
	Gas sand	Sands or other porous formations containing oil.	Gas sand	Sand or other porous formation containing gas.	Gas sand
Gravel, boulders	Gravel	Any formation having the feel of gravel while drilling.	Gravel	Correctly used.	Gravel
	Boulders	Large loose pieces of any formation.	Boulders	Correctly used.	Boulders
Clay, shale	Clay	Clay or soft shale; usually not sticky.	Clay	Correctly used.	Clay, or sandy clay
	Gumbo	Soft sticky clay.	Gumbo	Soft sticky clay.	Clay
	Shale	Formations having parallel bedding.	Shale	Consolidated clays.	Shale
Consolidated formations	Rock	Any consolidated formation.	Rock	Term not used.	Rock
	Gas rock	Any rock formation containing gas.	Gas rock	Term not used.	Rock
	Chalk rock	Applied to light-colored chalk only.	Chalk rock	Correctly used.	Chalk
	Sand rock sandstone	Terms used interchangeably for all cemented formation.	Sandstone	Correctly used.	Sandstone
	Packed sand	Loosely cemented sand.	Packed sand	Correctly used.	Sandstone
	Shell	Thin layer of hard material.	Shell	Thin layer of hard material.	Rock
	Shell rock	Any consolidated formation containing fossil shells.	Rock with shells	Formation containing shells.	Rock with shells
	Flint or flinty rock	Any very brittle rock.	Flint or flinty rock	Correctly used.	Flint
	Limestone	Limestone, also hard shale.	Limestone	Correctly used.	Limestone
	Lignite	All fossil wood.	Lignite	Correctly used.	Lgimite or fossil wood
	Gypsum	Correctly used when recognized; also reported as limestone or shale or sticky gumbo.	Gypsum	Correctly used.	Gypsum
Miscellaneous	Shells	Fossil shells	Shells	Fossil shells.	Fossil shells

Rock Classification.—The importance of keeping good logs of wells cannot be over-estimated. Rocks are given various names by different drillers. Table 9, after Arthur Knapp, taken from his interesting paper "*Rock Classification from the Oil Driller's Standpoint,*" presented at the New York Meeting of the A. M. M. E., February, 1920, summarizes the various names and gives their usages. This is a valuable table for the interpretation of formation names used in drilling.

LABOR ON DRILLING WELLS

In no industry is the workingman so intelligent as in the oil business. Most of the men are of American descent. They come from all parts of the United States.

The out-of-door life has developed a rugged type of men peculiar to the industry. Oil-field workers have much of the pioneer in them, especially the drillers and their helpers. Where these men are drilling on "wildcat" wells in sparsely settled areas they are often called upon to use all their resourcefulness in overcoming natural difficulties. They must use their initiative. This develops a set of very independent workers.

The rotary drillers were early developed in South Texas and in California. The early cable-tool men were from Pennsylvania and West Virginia. California developed the circulator men. However the influence of the Pennsylvania and West Virginia methods have dominated Kentucky, Ohio, Indiana and the Mid-Continent fields. The influence of the Texas drillers was early felt in California, Louisiana and now in North Texas and Southern Oklahoma.

Standard Drilling Crew.—The crew of a Standard Cable-Tool outfit consists of two men known as the driller and the tool dresser or "toolie."

On most outfits two sets of men are employed. The working time is divided into two tours (pronounced like tower) of 12 hr. each. The practice of using three sets of men working 8 hr. each is now being tried in California with fair success.

The duties of driller and toolie are much the same. The driller, however, is the responsible head of the drilling crew. The "toolie" attends to the boiler, oils all machinery, prepares the bits for dressing, does most of the climbing to the top of the derrick and greases the sheaves and crown pulley.

On circulator outfits a third man is employed. His special duties are to watch the mud-pumps, clean out the slush boxes, and assist generally around the derrick.

When it is necessary to fish for tools or pull casing additional men are furnished as required.

Rotary Drilling Crew.—The rotary crew consists of a driller, and from three to four helpers.

The helpers are divided into derrick man, pump man, boiler man, and tool dresser on wildcat wells.

A five-man crew can do faster work than four, and money is saved by their employment.

Each man has his special duties to perform. A well trained rotary crew works with a mechanical precision and speed that is best likened to the work of a finely trained gun crew. Every man knows exactly what to do and how to perform his duties with the least waste of time and effort.

Derrick Men.—The derrick man must be a nervy chap who can stay aloft in the derrick without getting dizzy. He must be agile, quick, and know what is wanted. His function on a rotary rig is to see that the pulleys are greased, to attend to the pumps when on the floor, and to clamp the elevators on the casing when going into the hole, or unclamp them when coming out. He stands balanced, one foot on the finger board and one on the plank platform which is generally placed about 25 ft. below the top of the derrick. He should have about 5 ft. of play on the casing on which to hitch or unhitch the elevators.

The free elevators are carried upwards at the rate of 4 ft. per second. The elevator man must hitch on the elevators and have them locked before the elevator picks up the casing or drill pipe. It takes a sure hand and quick eye, but a good derrick man accomplishes the trick easily with a foot or so to spare. Unhitching is a little slower as the elevators are not dropped so readily.

The derrick man also balances the drill pipe, casing or tubing as the case may be, so that it is screwed together easily.

Accidents occasionally happen. The derrick man may fail to lock the elevator, in which case the pipe may be picked up and then fall, or the elevators in unhitching may hit the platform and drop from the hook. The men on the floor are, however, on the watch for such accidents and seek shelter quickly. They are seldom injured.

The derrick man is really in a dangerous place. Recent laws in California make it compulsory for a company to furnish life belts for the derrick man, and it is customary to allow him to build a shelter against inclement weather when he stays aloft. Many men scorn the belt, but in rainy weather or when the boards are slippery, such protection is advisable. A railing is now put around the top of the derrick. The old idea was to work on top of a derrick without any protection from slipping. A man would lift the sheaves around, or would stand with sledge hammer and work without any protection. That, however, is now becoming a thing of the past.

It is surprising that more men are not killed around derricks, but the men are active, hardy and fearless, which saves them from many accidents which softer men would suffer.

Responsibility of Drillers.—Too much emphasis cannot be laid on the responsibility of drillers. Drilling an oil well means an expenditure of from $10,000 to $100,000 or even more.

Any man in ordinary business would be very careful about the men whom he would entrust with the expenditure of such a sum of money. If the driller fails to make good he is "let go," but in the meantime he may have wrecked a hole and caused a loss of many thousands of dollars.

Good drillers are skilled workmen and are usually men far above the average worker in intelligence. However, before entrusting the drilling of a hole to a driller look up his record and determine what he has done. Don't wait until he wrecks a hole and then investigate. That is a costly method.

Drillers in "boom" times are scarce and a good operator may feel he must take what he can get, but that is an expensive system. Go slow and employ good men, even if their pay may be double what one wants to pay. A business man would not entrust a green clerk to manage his business for him, nor should an oil man take a green driller.

Drilling by Contract.—Many oil companies prefer contract drilling to company drilling. Contracting has many advantages, especially for small companies, and even for large concerns. Drilling contracts are usually based on the price per foot for drilling. Underreaming is paid for at a day rate. Fishing time is paid for by the contractor except where fishing is due to underreaming or other special work. The operator furnishes rig, fuel, water and casing and the contractor furnishes the drilling equipment, which includes boilers, cables, drilling engines and drilling tools. The price per foot must be high enough to enable the contractor to pay his drillers and obtain a profit for his work, barring poor work or extra difficulties. Drillers working for a contractor usually work harder than for a company. They realize that a contractor must make his money from their efforts and do their best to get results for him. The personal element enters into the work quite largely in this case. Good contractors get results from their men that average companies cannot get at all. Contractors, as a rule, finish holes ahead of company men.

The main disadvantage of contracting holes lies in the fact that the quicker a contractor finishes a hole the larger his profit. This leads many times to efforts to "make hole" which may result in crooked holes, and in missing possible oil sands. However, contract drilling is generally cheaper and fully as efficient as a company doing its own work. Many companies, however, prefer their own organizations and, when operating on a large scale with good superintendents, obtain excellent results. Some large companies employ contractors besides having their own drilling organizations. This system tends to speed up the company drillers. If the company men fail to make a good hole the contractor will get the new work.

CHAPTER V

DEVELOPMENT—PRODUCTION METHODS

The development of an oil property after the discovery well has been obtained calls for a systematic plan of action. The mere drilling of additional wells is not enough.

A study of the number of wells necessary to drain the acreage properly and the questions of offensive or defensive measures against the neighbors, must all be taken into account.

The care of the wells and the proper selection of pumping systems all call for an exact as well as a broad knowledge of operating methods.

OIL-WELL SPACING AND SITES

Oil-well sites are made arbitrarily, but certain customs have been followed for years. There are at present two systems of selecting sites.

1. Straight line system.
2. Contour system.

The first system is by far the most general and is employed by most oil operators. The second system is being followed somewhat by companies that employ geologists to make their inside locations.

In many cases there is little choice in spacing wells. If the tracts are held by various owners there is no choice but to drill the property in conformity with the development of the neighboring properties. It is customary in most oil fields to place wells 300 ft. each way from a corner. In some places the custom is 250 ft. If one operator spaces his wells that distance from the line his neighbor is expected to follow the same procedure on his tract. If, however, the neighbor disregards this custom a line fight may take place, and each operator will crowd his wells as close to the line as possible. Fig. 39, page 101, shows some average well spacings.

Line fights are great wastes and are seldom indulged in by reputable companies.

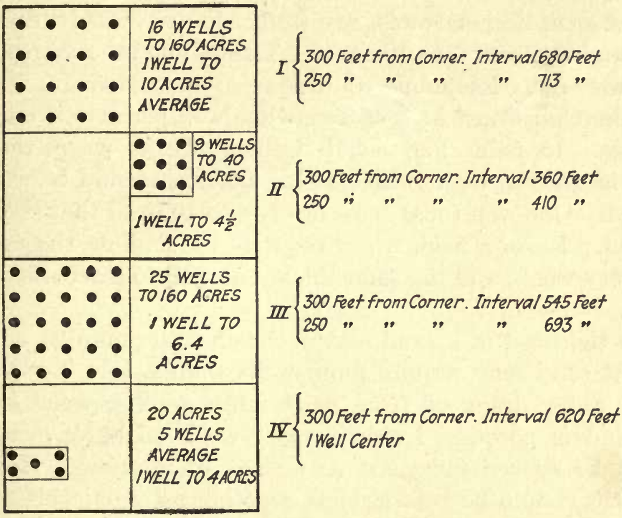


Fig. 39.—Examples of well spacing.

Offsetting.—Whenever a producing well has been drilled on a property within 300 ft. of the line dividing the adjoining property, it is customary, and in some states is made legal, to start a well on "*B*" opposite the well, as an offset to keep the first well on "*A*" from draining the oil from "*B.*" The well on "*B*" is generally placed the same distance from the line as the first well on "*A.*"

PROBLEMS IN WELL SPACING

Well spacing offers a number of problems. The number of wells needed to develop a tract of land depends not only upon the local geological conditions but upon the way the land is subdivided. If one company controls a pool or a large acreage the well spacing is planned to meet the geological conditions.

It is well known that shallow tracts with low gas pressure 100 to 200 lbs. per square inch will require more wells than deep tracts with large pressures of 800 to 1000 lbs. of pressure. Shallow tracts 200 to 500 ft. deep will require one well to every 2 or 3 acres. On deeper tracts, say from 2000 to 3000 ft. each well will be given from 6 to 10 acres. There is no set rule regarding this, however. Economic conditions govern spacing.

In the Gulf Coast area of Texas one well per acre is the usual practice. In fields like North Central Texas where the wells come in with a high initial yield, spacing should be carefully studied. One well to 20 acres or even to 40 is all that should be allowed. In some fields where the wells are shallow, the gas pressure very weak, and the sand thick, one well to 2 acres is not too many.

The tightness of a sand also determines the number of wells. A tight sand may require more wells than a very porous one. Some wells drain oil from neighboring wells especially where the sand is porous. In such cases wells on one's own lands should be spaced far apart so as not to interfere. However, line wells should be kept as close together as practicable to keep the neighbors from draining one's holdings.

In some fields like the Gulf Coast fields, wells have been placed on $\frac{1}{16}$ of an acre tracts. This was especially true at Spindle Top during "boom" times, and resulted in great loss. The derricks in some places were so close that the derrick floors overlapped.

Town-lot drilling in shallow areas means close spacing. In such excitements one well to a 50 by 150-ft. lot is not unusual. Such close spacing means a tremendous waste of money as one well would obtain all the oil that a dozen or more would. The history of Spindle Top, of Burkburnett, of Paola, Kansas, of Cleveland, Oklahoma, and of Los Angeles, California, all bear this out.

Wherever possible well sites should be made as the result of engineering advice. If the geologic structure can be determined the sites should be made to conform to the structure. To put such a plan into effect one or two companies should control the structure. This plan must of course be varied to suit the local conditions but is an excellent one to obtain all the oil with a minimum number of wells. One decided advantage of such a plan is the maintenance of a gas reservoir at the top of the dome. As long as this reservoir remains untapped it will act like the air chamber on a force pump. The gas in the top of the reservoir tends to drive the oil downward to the wells on the side of the dome. Such a plan will only be successful where one or two companies control a field.

Natural Factors Affecting Oil Wells.—The natural factors in the handling of wells are:

1. Gas pressure.
2. Character of the oil sands, porosity, saturation.
3. Character of the oil, specific gravity, viscosity.
4. Effect of one well upon another.
5. Water conditions.
6. Number of oil strata.

Gas Pressure.—Gas pressures vary in every field. In the Mid-Continent and North Texas areas, in Louisiana and in West Virginia, initial gas pressures roughly run 40 to 43 lbs. per each 100 ft. of depth. In California, however, the pressures do not have this regularity.

The importance of conserving gas pressures must be fully appreciated. Gas is the natural expulsive force for oil and the dissipation of this pressure must be guarded against. The waste of natural gas due to allowing wells to flow into the air with the hope of bringing in oil is not only a national waste of valuable fuel but a loss of good lifting power as well. It is a known fact that as the gas pressure decreases the oil production also decreases.

This intimate relation between the pressure of gas and the production of oil must be emphasized. Instead of allowing the gas to escape, shut it in, and drill another well lower on the dip for the oil, if oil is expected in the same sand.

Wells making millions of feet of gas which will later be of value must not be sacrificed for momentary considerations. Even where wells are pumped and the pressure is not high enough to cause oil to flow the gas may act as an aerating agent, *i.e.* make pumping easier. Also the presence of gas tends to bring in the oil from the area around the well. The value of gas has best been appreciated where air has later been introduced into the wells to form conditions approximating natural conditions. Production has been increased as much as 500 per cent in some of the pools where such methods have been employed. (See Marietta or Smith-Dunn process, page 195.)

A marked example of the efficiency of gas operation may be obtained by a study of the Salt Creek Field, Wyoming. In that field, wells have been flowing for 11 years. The field contains few derricks, only casing-heads and flow-lines show, yet the wells have maintained productions of 100 to 300 bbl. per day at practically no expense. These wells are 800 to 1000 ft. deep.

A knowledge of the texture and the specific gravities of the sands guides the production man in the handling of oil. A free open-textured sand will allow oil to flow rapidly into the drill hole. The life of such wells will be shorter than wells with closer-grained sands. Coarse-grained sands have less pore space than close-grained sands.

The specific gravity of oils is an excellent guide in operating. It is well recognized that a heavy asphaltic oil will flow less freely through sands than light oils so that pumping rapidly will drain the sands less quickly.

The effect of offset wells must be fully appreciated. Nearby wells draw production from others. By keeping wells continually pumping the channels in the sand are kept open. If one well stops it is often found that neighboring wells increase in production. If the nearby wells belong to competing companies there is a direct loss, so the careful operator must watch his wells closely, and repair any damages to pumps, or tubing, in his well; or clean out at once, if sand troubles or other troubles occur.

Water conditions bear an important relation to production.

Much water in oil sands reduces the oil production, decreases the quality of casing-head gas, and increases lifting expenses.

Elimination of water trouble causes a material saving, and often a material increase of production.

Methods of combatting water are well understood. Ordinary plugging of oil wells has not been successful. The best methods are careful cementing, proper casing, and mudding-off of sands.

The time to eliminate water troubles is when drilling the wells. If careful drilling and casing methods had been followed in the past most of the water troubles would not have occurred.

Where the oil sand is saturated with water, the oil and gas are driven back into the well and the production declines. This water may be the result of having drilled too deep originally, or be due to water entering the sands from above.

Where water is found in the same sand with oil there is the problem of pumping both together. There may be only 10 bbl. of oil and 90 bbl. of water. Such an amount of water calls for some method of separating oil and water. If the oil separates freely this can be done by simple heating or by standing but if an emulsion of oil and water has been formed other treatment is required. The handling of such water in oil wells taxes the ingenuity of oil operators. The suggested remedies are treated in Chap. VII.

Operating Wells.—After production has once been obtained the problem of handling the wells must be taken into consideration. The problems are of two kinds:

1. Mechanical.
2. Natural.

The mechanical factors are more easily recognized than the natural.

There are three types of wells in oil fields:

1. Flowing oil wells.
2. Pumping oil wells.
3. Wells making oil and gas.

The mechanical equipment and the handling of flowing wells are simple. If the well is a large one and comes in under control the oil will be ejected by pressure through the casing and conducted to the reservoirs by lead lines or flow lines (see Fig. 40, page 106). Where the well is a small producer and will not flow through the casing it may be induced to flow by putting in tubing

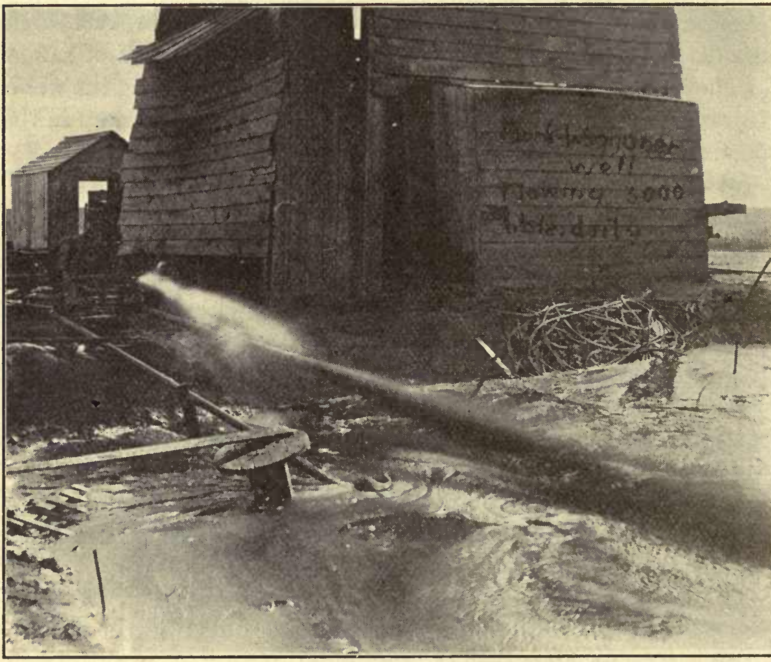


Fig. 40.—Burkwaggoner well at Burkburnett, Texas, flowing 3000 bbls. per day through flow line. (*Courtesy Los Angeles Chamber Mines and Oil.*)

and a packer, thus reducing the size of the hole. The reduction in size of the hole creates greater pressure within a smaller space and consequently will force out the oil.

CONTROLLING WELLS

The test of a good oil man is his ability "to bring in a well" under control. Gushers (see Fig. 41, page 107) sound interesting to the general public, but are the bane of an oil man. The loss of production resulting from an uncontrolled flow of oil means a serious monetary loss, not only of oil, but sometimes loss due to damages to crops nearby, such as orange and lemon trees in California, corn fields and cotton fields in Oklahoma, and cotton fields in Louisiana and Texas. Such damage is generally unnecessary.

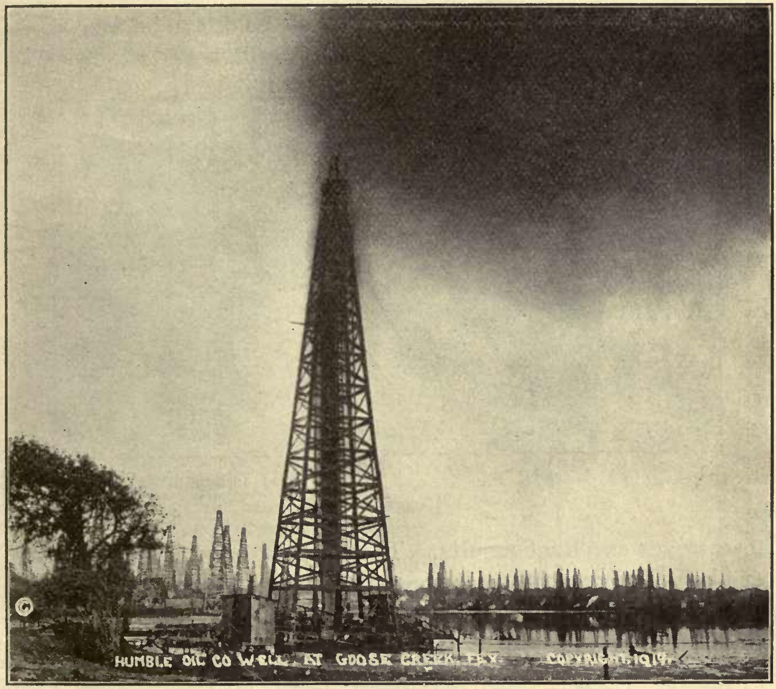


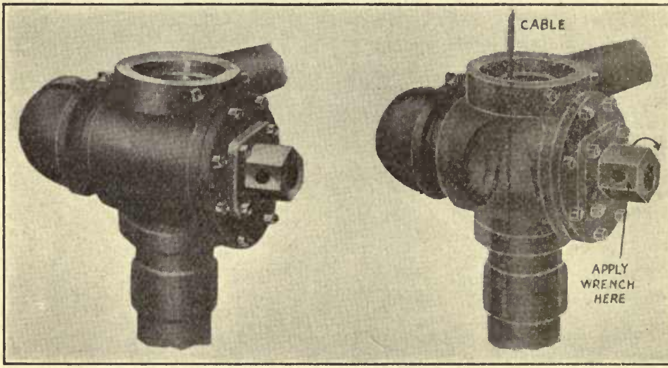
Fig. 41.—Flowing well of Humble Oil Co. at Goose Creek. (*Courtesy Los Angeles Chamber Mines and Oil.*)

The careful operator prides himself on "bringing in a well" without getting a drop of oil on the derrick floor. This can be done by good operators.

The uncontrolled flow of the Spindletop gushers resulted in the loss of millions of barrels of oil. The famous Lake View No. 1, near Maricopa, California, was the cause of a tremendous expense and but little profit for the men who owned it. Much of its 60,000 bbls. per day went to waste in the early stages of production.

Sometimes a driller may penetrate an oil sand without expecting it, but if the proper safeguards are used on a drilling well there is no excuse for a wild flow of oil.

On a standard cable rig the old-style oil saver can be used when drilling into an oil sand. A new control head, called the Heggem



(*a*) Actual. (*b*) Diagrammatic.

FIG. 42.—Heggem control head.

head, gives excellent results. This control head is quite simple (see Fig. 42, page 108). It consists of a revolving valve that can be closed quickly if the well starts to flow.

With the rotary or circulator systems of drilling, a gusher can be readily brought in under control.

If oil is struck and the well tends to flow, the hole can be quickly pumped full of mud fluid, and the flow checked. The column of mud will hold back the oil until arrangements can be made to complete the well properly.

FINISHING OIL WELLS (CALIFORNIA PRACTICE)

When the drillers have carried the hole into the oil sand their main work is done. The hole is now in the hands of the production men, who are experts at handling wells.

In California two practices are common. The driller in one case sets the casing through the sand a few feet, and then drives a heavy wooden plug in the bottom of the casing. This latter is called a heaving plug and keeps the underlying soft beds of sand or shale from entering and clogging the casing. The oil sand is completely cased off by the oil string. To obtain the oil it is necessary to perforate this string at the points where the oil sand is reported. This is done in the hole.

Perforating Casing.—It is accomplished by lowering a cutting tool called a perforator in the hole. There are several types of perforators but the best type consists of a rolling knife which is a star-shaped, toothed wheel with five cutting points (see Fig. 43, page 109).

After the casing is perforated the well is bailed to remove the sand, sludge, and the drilling water. Such bailing may require several hours or several days. If the well flows, the control casing head regulates the flow, but if no flowing follows, bailing and pumping is necessary. Then a pump is placed in the well.

One grave danger of casing perforated in the hole is the poor results often obtained. Clean-cut perfora-

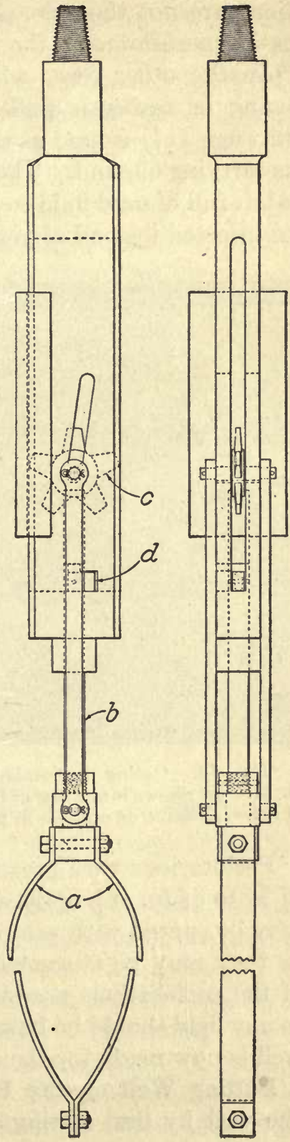


FIG. 43.—Star perforator. (*a*) spring; (*b*) mandrel; (*c*) rolling knife; (*d*) lug.

tions are not the rule. Figure 44 shows a photograph of some casing perforated in the hole.

In the other cases where a rotary or circulator is used the string of casing is pulled and shop-perforated casing (see Fig. 45, page 111) is used at those points indicated by the well record as carrying oil sand. The perforated casing is inserted and the well is left full of mud fluid to keep back any oil. Oil-well screen may be inserted instead of perforated pipe.

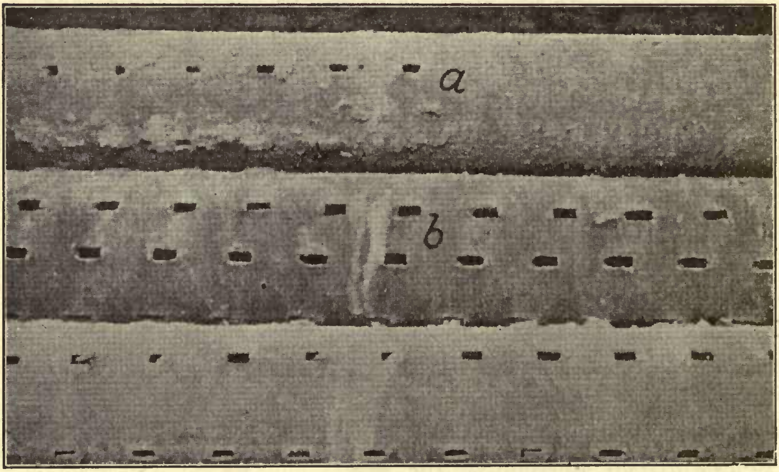


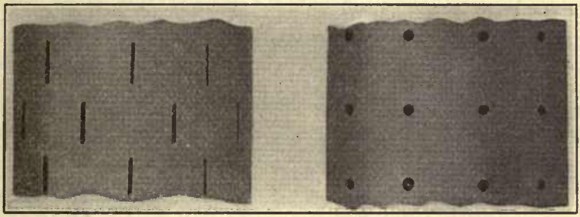
FIG. 44.—Casing perforated in the well (after *Technical Paper* 247, U. S. B. M. (*a*) Shows lower row of holes only partly cut; (*b*) Shows poor arrangement of holes, all being on one side of the casing.

Perforations vary greatly in size. They may have diameters of ⅜ to ¾ in. or lengths of 2 to 3 in. and ½ in. wide. The holes may be spaced with centers 4 to 6 in. apart and the rows regular or they may be staggered. Each operator has a different idea of the perforations necessary. No rule can be given. Practice in any field should be based on the best results in that field. The well is now ready for the pump.

Putting Well on the Pump.—The well gang starts work at the well by first setting on a casing head (see Fig. 46, page 112).

The drillers leave the casing a foot or two below the level of the floor. If the casing is 8¼ in. in size a bell nipple 8¼ in. in diameter at one end and 6⅝ in. in diameter at the other is screwed into the 8¼ in. and a Tee or a 4-way casing head screwed to that.

The 4-way head is useful where a heavy flow of oil is expected. However, for most wells a Tee head is sufficient. This head furnishes a means of controlling the oil. Lead lines to carry off the oil are screwed into one of the bushed openings of the 4-way head or the Tee and the well is ready for installing the pump.



(a) (b)

FIG. 45.—Shop perforated casing. (a) slots; (b) holes.

Tubing with a working barrel for the pump at the bottom is next put in. This operation is much the same as was used with casing, only tubing is lighter and more readily handled. The well-crew in this case uses a light 4-line block for wells 3000 ft. deep and pulls from the calf wheel. A 2-line block may be sufficient for wells up to 1000 ft. in depth.

Heavy 3 in. tubing weighs 9 lb. per foot, or 180 lb. per joint of 20-ft. length. Two thousand feet would weigh 18,000 lb. or 9 tons.

Just before the last joint of casing is inserted a cast-iron tubing ring is placed under the top joint. The top collar of the tubing rests on this. Packing is placed between the tubing ring and its seat in the casing head. A gunny sack is sometimes used for packing and is wrapped under the collar of the tubing.

A nipple is next screwed into the top of the tubing and upon this nipple is a 3-way Tee (see Fig. 46). The side opening of the Tee is for the lead line which allows the fluid to flow off as it is

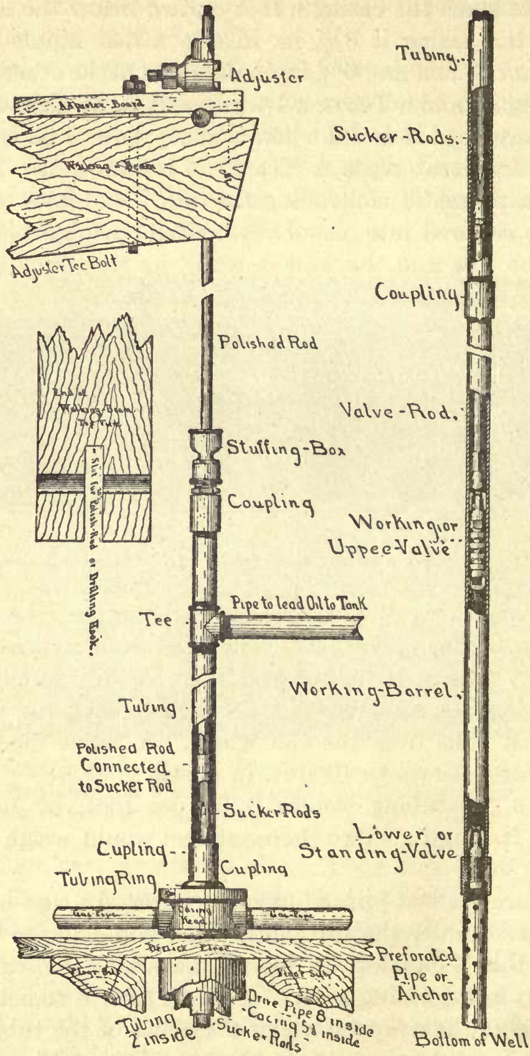


FIG. 46.—Equipment for a pumping well of Mid-Continent or Eastern type.

pumped to the top. The upper opening is for the stuffing box which packs off the oil, and through which the polished rod works.

Putting in Rods.—The next operation is to put in the pump plunger and pump rods. The first stand of sucker rods is connected to the pump parts consisting of standing-valve, garbut-rod, steel-plunger and top-valve.

This length is then put in the hole. Other joints are screwed on until the plunger and valves touch the bottom of the tubing.

The polished rod connects the sucker rods and the lifting power. The iron-pump rods or sucker rods are ¾ or ⅞ in. in diameter. These rods come in 30-ft. lengths joined by box and pin couplings. Three or four such rods may be welded together to form one long rod. They are attached at the bottom to the top valve of the pump, and are fastened to the walking beam or jack by a connecting rod called the polished rod.

A special box with threads for a sucker-rod pin on one end and threads for the polished rod on the other is screwed upon the top sucker rod and the polished rod is screwed into this. The well is now ready to put on the beam.

The walking beam is set on the wrist pin which is adjusted for the stroke desired. The beam carries a pair of reins suspended from the slot in the end of the beam much as the temper screw is suspended.

These reins carry a yoke which fits under a clamp held by U-bolts to the polished rod. When the clamps are fastened the stroke is adjusted after several trials. The adjustment is so timed that the top valve or plunger has the proper stroke and does not touch the lower valve. This can be assured by allowing for the same when the polishing rod is screwed on, and the foot or standing valve is seated. This seating is done in the case of the California wells, by letting the weight of the rods force down the standing valve. In the Eastern fields the valve is seated in the foot of the pump cylinder when put in the well or, in a few cases, is dropped in the tubing. This latter course is followed when the hole is full of fluid.

The well is now on the beam and ready to start pumping. The engine is started and in 15 to 30 min. of pumping is pushing out the oil.

Handling of Mid-Continent and Eastern Wells.—The finishing of wells in areas of hard rock is quite different from those of California or the Louisiana and south Texas areas. In the hard-rock areas it is customary to drill a well into the oil sand as far as the driller considers prudent, to avoid water.

The perforated oil string as known in California is not used. The hole around the sand is left open (not cased). The last string of casing is set just above the oil sand. The hole is then shot.

Shooting Oil Wells.—The shooting of oil sands is a subject about which little is known. It is recognized that shooting hard sands or limestones generally increases the production if the well is producing, or in many cases where only a showing of oil occurred it has caused the bringing in of big wells.

Many operators can tell stories of wells that showed scarcely a rainbow of oil, which when shot, made big wells.

In shooting wells the oil operators determine from the character of the sand how much nitroglycerin to use. There is no set rule for the amount; experience is the only real gauge. Coarse, porous sandstones or conglomerate do not need shooting, nor do soft flowing sands. Hard, fine-grained sandstones, and porous limestones must be shot.

Shooting accomplishes several things:

(*a*) Breaks up the sand causing channels to form.

(*b*) Allows connection with fracture zones or joint planes.

(*c*) Makes a larger collecting area.

(*d*) Creates more seepage space in the hole.

Liquid nitroglycerin and solid gelatin have both been used successfully.

Liquid nitroglycerin is more generally used than solid gelatin. The difficulty with solid gelatin has been in obtaining proper detonators. The Allison detonator, however, has been very successful in California. There is no doubt at all but that a general use of solid gelatin would be safer if it were employed as efficiently as the liquid form. Nitroglycerin is made by stirring glycerin oil into a mixture of nitric and sulphuric acids.

The operator usually informs the torpedo or shooting company what is needed in the way of a shot, and the "shooters" do the rest.

Determining Size of Shot.—A hole 6½ in. in diameter in a fine grained sandstone 25 ft. thick would require four shells 5 in. in diameter and 5 ft. 2 in. long, each containing 20 qts. of nitroglycerine. A shot for a hole which has a diameter of 4½ in. and has a sand body 45 ft. thick consists of six shells 3 in. in diameter and 6 ft. 11.3 in. long of 10 qts. capacity or 60 qts. in all.

Shells are in general made in 3, 5 and 7 in. sizes holding 10, 20 and 30 qts. respectively. The following table gives some idea of the size of shells used:

Table 10.—Lengths and Diameters of Various Tubes of 10 and 20 Quart Capacity

Diameter inches	Lengths			
	Ten-quart		Twenty-quart	
	Feet	Inches	Feet	Inches
2	15	5.4		
2½	9	10.7	20	1
3	6	11.3	13	9
3½	5	1.8	10	2
4	3	11.5	7	11
4½	3	2.0	6	4
5	2	7.5	5	2
5¼	2	5.0	4	9
5½	2	2.5	4	5
5¾	..	....	4	0
6	..	....	3	7
6¼	..	....	3	4½
6½	..	....	3	2
6¾	..	....	2	11½
7	..	....	2	9

Firing Charge.—In firing shots two methods are used. One method is to use a "go devil" or jack squib which is a small shell containing nitroglycerin. This shell is dropped from the top of the hole upon the charge and is guided by the wire line with which the charge has been placed. It may be necessary to drop several "go devils" before the charge is detonated.

The second method of detonating is to use an electrical firing device. Successful results are obtained by this method but it fails sometimes through broken wires which allow contact with the casing, thus "short circuiting" the current.

Squibbing.—Squibbing is the practice of using small charges of 2 to 4 qts. of nitroglycerin for occasional shots. These shots are used particularly to stir up sluggish wells several months after the first shooting.

Many wells respond to squibbing and show a marked increase in production afterward. It is thought that squibbing burns the paraffine coatings from the walls of the hole and allows the oil to enter again freely. Some operators squib every few months.

"Shooters."—"Shooters" are the men who put the charges in the wells and fire them. These men become very reckless in the handling of nitroglycerin. They transport the glycerin in lead-lined cans, and drive their "glycerine wagons" over rough, bumpy roads with an abandon that is foolhardy. Shooters take great chances and every once in a while the papers report "shooters" blown to atoms. It is likely such explosions are due to high heat engendered by the heat of chemical action where the glycerin still contains some free acid.

Spontaneous Shooting.—The practice of placing charges of nitroglycerin in a hole and letting the charge explode itself is being used in North Central Texas. This was started by accidentally leaving a shot in a hole some hours. The charge exploded spontaneously. Experiments were then tried and it was found that shots would explode in from 24 to 96 hr.

This method is not efficient as there must be some disintegration of the charge due to chemical reaction. It is also dangerous.

Action of Well after Shooting.—A well when shot may flow freely. In this case the control-casing head regulates the flow. However, if a steady flow does not follow the shot, the well must be pumped. Preparatory to pumping, the hole is bailed clean to get out the drilling sludge remaining, and to clean the residue from the shot. The well is then put on the pump as described before.

PUMPING METHODS

The main methods of lifting oil are:

1. By the walking beam.
2. By pumping-jacks.
3. By individual motors at well.
4. By compressed air lift.

"Walking-beam" System.—Under the walking-beam system the walking-beam and engine used in drilling may be employed as power to lift the pump rods. However, the drilling well may be replaced by a smaller steam engine; or a gas engine or an electric motor may be installed. Gas engines are more economical than steam, and it is now found that electricity is even cheaper than gas.

The walking-beam system is used more especially for wells over 1500 ft. in depth, and where it is desirable to keep heavy engines for pulling rods and cleaning wells.

Jack System.—Under 1500 ft. the jack system is generally used. In this system power is furnished from a central station. A "power" is located in this station. It usually consists in an eccentric which is fastened to a vertical shaft (see Figs. 47 and 48). The shaft is driven by a belt connecting with a pulley driven by a steam engine, gas engine, or electric motor. This eccentric (or eccentrics) has connections to which shackle rods are attached. These shackle rods in turn are connected to the pump rods by a pumping device styled a jack (see Fig. 49a and 49b). Such a jack is in reality a simple lever. The point of application of power is at A, the fulcrum at B and the weight

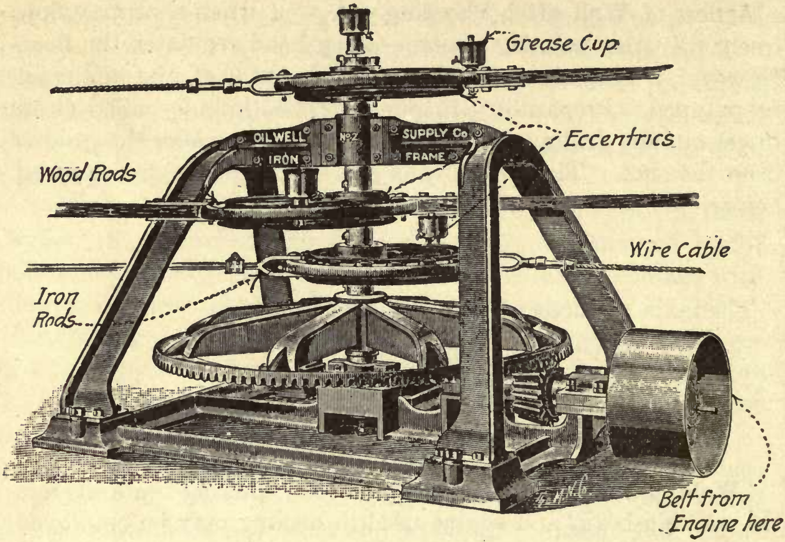
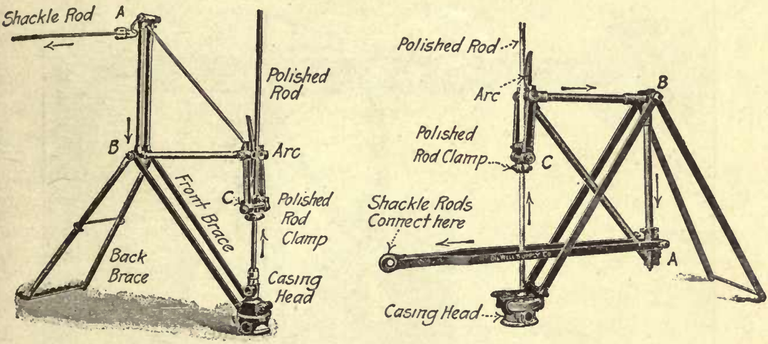


FIG. 47.—Pumping power. Note eccentrics and shackle rods.

FIG. 48.—Pumping power using wire cables, Newhall, Calif.

lifted at C. The frame supports the fulcrum. The pull may be over as in Fig. 49a or under as in Fig. 49b. Jacks are used where the stroke is regular and slow, and for efficiency one well must be balanced against the other, so that the rods falling in well #1 will lift the rods in well #2 with a minimum of energy from the power plant. Several wells may be pumped from one jack-plant so long as each well is counterbalanced by weights equal to the weight of the string of rods to be lifted.



(*a*) Overhand pull. (*b*) Underhand pull.

Fig. 49.—Types of pumping jacks.

Individual pumping motors for wells (see Fig. 50) are used where electric wires can be readily installed. These motors are useful in wells that are placed in river beds or in lakes, where it is difficult to operate steam or gasoline engines.

Electric Pumping.—Electric drive practically eliminates most of the shut-downs chargeable to engines due to rod breakage; water clogged steam lines or trouble with the engine itself. Rod breakage is greatly reduced since the motor during the pumping stroke does not pick up the rods with a jerk as is the case with steam or gas engines, the speed of the band wheel being practically constant during the entire revolution. The rods are therefore less liable to crystallize.

In pulling and cleaning a well, a motor will pull the first stand of tubing as fast as the last one, practically regardless of the load to be lifted, while with engines the speed is considerably reduced on the heavier work. Quicker work can be done with motors in spotting rods and tubing when screwing up, since no delay is caused by overtravel when hoisting and lowering. On the lease of the Birch Oil Company, near Fullerton, the cleaning gang using a standard 15/30 pumping and cleaning motor equipment, pulled sixty 60-ft. stands of ¾-in. rods in 55 minutes.

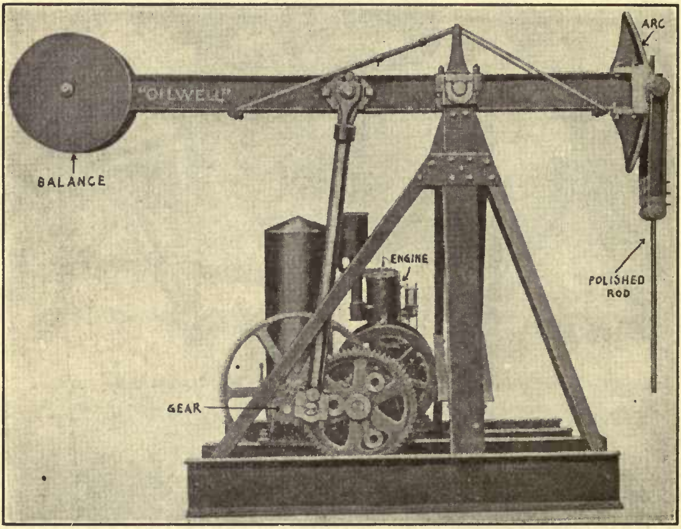


Fig. 50.—Individual structural steel unit power for pumping with gear driven by engine or by electric motor. Engine in illustration.

One of the most noticeable savings effected by the use of electric pumping equipment is in the item of labor or attendance charges. Because a motor can always be depended upon to pump the well at a given constant speed on the same point of the controller, thus obviating the possibility of speed fluctuations encountered with steam or gas engines, and because the motor is provided with protective devices to guard against possibility of damage in emergencies, one pumper can look after a greater number of wells, with the assurance that the possibility of the engine running away and its constant damage, due to parting of the rods or breaking of the band wheel belt, is absolutely eliminated.

Balances.—Many times it is found advantageous to weigh or balance the walking beam. One arm of the balance weight is swung on the Samson post, the other is attached near the end of the beam on the pitman side. In other cases the weight is hung on the end of the walking beam and fastened to the brace between the engine block and the sand reel. Such weights counterbalance the weight of the rods and make pumping easier. There is a decided saving, as less power is needed to lift the oil. Vibration is also less, which eliminates the wear and tear on all the pumping machinery.

Lifting Costs.—The actual expense of lifting oil varies greatly. The smaller the production of a well the greater the cost. With new wells of large production, say 50 to 100 bbls. each per day, the actual lifting cost plus overhead may be as low as 5¢ per barrel, or as high as 20¢. Ten cents is a fair average for wells of such a size. Wells making 1 bbl. may cost as high as $1.50 per barrel. No rule can be laid down for such costs.

However, on one Mid-Continent lease 200 wells are handled by five pumpers and one roustabout. These wells average ½ bbl. each or 3000 bbl. a month. The total cost of labor, lease expense and overhead is $1500 or 50¢ per barrel, a very low cost.

In California an average 2500-ft. property with 10 wells making 30 bbls. each per day would cost as follows: 300 bbl. per day, 9000 per month—30 days. Two pumpers, one well crew, three men, a teamster and two firemen made up the crew. The total cost would run (including superintendence, wear and tear and all overhead) $3000 per month, or roughly, 33⅓¢ per barrel. This is by no means a high figure.

Capacity of Pumps.—The speed of the pumps ranges from 10 strokes per minute for very heavy oil to as high as 20 strokes per minute for lighter oil. With the walking beam the second hole is used, which gives a 16-in. stroke although an 18-in. stroke is sometimes used.

For a 3-in. pump with a stroke of 16 in. the pumping capacity for 20 strokes per minute would be:

$$\frac{49\times20\times1440}{42} = 336 \text{ bbl. per day.}$$

A 2-in. pump with a stroke of 16-in. would give, in the ratio of $2^2 : 3^2 = 4 : 9 = 149.4$ bbl. per day.

Where a pumping power is used the stroke is usually less and the number of strokes per minute is less.

A stroke of 12-in. and 15 strokes per minute will raise with a 2-in. pump

$$\frac{.163\times15\times}{42} = \frac{58680}{7} = 83.828 \text{ bbl. per day.}$$

A 3-in. pump will raise 9/4 of a 2-in. or 188.6 bbl. per day.

Pumps, however, seldom pump their full capacity. For some old wells the fluid is exhausted in an hour or two. The pumping is then stopped, the well unshackled and allowed to stand for several days until it has obtained more oil. Continued pumping does little or no good in such cases. Where a well makes enough oil to fill the casing, and responds steadily to pumping, continuous operation is necessary to obtain the oil.

Placing the Pump.—It is advisable in wells making little sand, to place the pump just above the top of the pay. Pumping the oil to a lower level than the pay sand may result in paraffining of the sands with oils of paraffine base.

In wells making much sand, or when the fluid stands high in the well, place the pump several hundred feet in the fluid.

For example, if a well is 3000 ft. deep and the fluid rises 1500 ft., place the pump at 2000 ft. As the fluid level falls after continued pumping, lower the tubing, always keeping the pump as high as possible.

Pumping near the bottom of the hole is practiced by some oil operators who desire to keep the sand moving, but the practice is a questionable one. Such wells experience great trouble with worn out pumps and with wells "off the beam" a large part of the time.

TYPES OF PUMPS

There is a difference in the pumps used in the Western and in the Eastern hard-rock fields.

The loose sand of California necessitates a plunger pump (see Fig. 51, page 123). The pump used in the Eastern hard-rock fields consists of a plain bored cylinder with a simple bottom or stationary valve and top or traveling valve which has leather packers or rings like the standing valve. In the California pumps there is a garbut rod which is attached to the bottom valve so it can be readily pulled if the well sands up or gives trouble. With the Eastern pumps, however, there is little need for pulling rods often, so that the garbut rod is eliminated as is also the hollow steel plunger.

California Pump.—The type of pump used in California consists essentially of a cast-iron cylinder highly polished inside called the working barrel. (See Fig. 51, page 123). A hollow steel plunger fits the working barrel very snugly. A traveling valve fits on top of the steel plunger. This valve is of the ball and seat type. A square nut with a hole bored through it is screwed on the lower end of the plunger. The garbut rod extending from the bottom or standing valve (see Fig. 51, page 123) passes through the hole in the nut into the plunger cylinder. On the top end of the garbut rod is a wing nut. The garbut rod is extremely useful where it is necessary to replace parts of the standing valve. Also

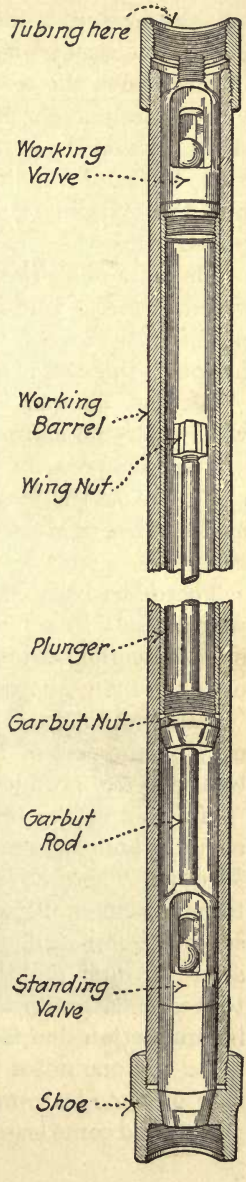


Fig. 51.—Plunger pump for wells in California.

when the valves sand-up they can often be pulled loose from their seats, and washed by being raised and lowered in the oil in the tubing above the working barrel. As the plunger is raised the nut on the plunger engages the wing nut on the garbut rod. A slight jerk on the garbut rod will free the standing valve. However, the sand sometimes packs so tight that it is not possible to pull the standing valve. When such is the case the tubing is pulled.

The cost of California pumps is a large item. Wells are pulled several times a month and new pumps placed in the well. Such pumps cost $35. If three pumps a month are used, as frequently happens, the cost is $105 per well.

Vacuum Pumps.—Vacuum pumps in oil fields are used on old wells after the gas pressure is nearly exhausted.

They temporarily increase the yield of oil from old wells, and also increase the yield of casing-head gasoline. Vacuums as low as 25 inches of Mercury are obtained, but 15 to 16 inches is more general.

There has been considerable question over the use of vacuum pumps, and in some states there are laws against them. Undoubtedly the operator who uses such pumps has an advantage over the man who does not.

Pulling Wells.—The cost of pulling oil wells is measured not only by the cost of the labor, and of the material used, but also by the loss of production due to pulling the wells.

If a well makes 150 bbls. per day and it requires a day to pull a pump and replace it, then the production lost is 75 bbls. for ½ day. There is, however, a relationship, that does not occur to many men, between the wear of a pump and the time it should be replaced. A careful lease man will note that a new well after the first month's run declines slowly as the pump begins to wear. A pump that handles 150 bbls. of oil will drop slowly in production due to wearing of the pump and consequent slippage. If one notes that the well is off 5 bbls. from normal the rule of some lease-men is to pull at once and replace. On the other hand some lease men say, "Do not disturb a pumping well."

Of the two, the first is preferable. If the trouble is merely due to a defective valve, a few hours will remedy the fault and

Fig. 52.—Tubing fished from a well, after having dropped several hundred feet.

only part of a day's production will be lost. The best policy is to pull the valves and see what the trouble may be. If the valves are defective change them, if not, let the well pump awhile longer.

Tubing Catcher.—In all oil fields more or less trouble results from difficulty with breaking or parting of tubing. This may rip a hole in the casing, or may punch a hole through the bottom water plug and thus cause nasty fishing jobs. This results in the expense of a "shut down" well, of fishing operations, and in some cases abandonment. Figure 52, page 125, shows some tubing fished from a well. Such troubles can be prevented by either putting an anchor of tubing below the pump which will rest on bottom and support the tubing string if it breaks, or by means of a tubing catcher, like that in Fig. 53, page 126. The tubing *B* runs clear through the catcher; the head *C* holds the slips *D* which are free to slide upward. The string of tubing is placed above *A*, and the pump below *A′*. If the tubing parts, the weight of the tubing causes the tubing to drop so rapidly that the striker *H* which is held on the spring *I* due to its inertia will not obtain any acceleration due to the drop. As a result the lower controlling ring of the slips will strike the top of the striker *H* and be forced outward. The slips at once engage the casing and check the fall of the tubing. The device is very efficient as well as ingenious.

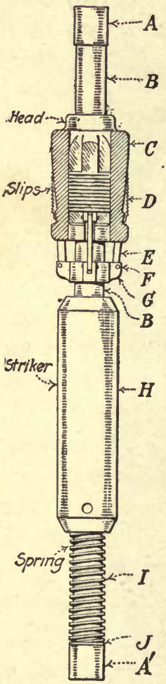


FIG. 53.—Tubing catcher.

Tubing Packer.—In wells like those of Oklahoma and Kansas and in the Eastern oil fields or pools there is often gas with the wells. It may be desirous to force the gas out of the tubing with the oil; a gas packer is then inserted. One of the latest types is the gas packer shown in Fig. 54. This spiral packer is set in shale. The oakum packing is laid around the spiral which is then compressed by letting the weight of the tubing upon it. This makes a tight joint with the shale wall and keeps the gas from working upward and forces it through the gas cage and into the tubing. This is also used on gas wells.

Operating Difficulties.—Operating difficulties are better appreciated when California practice is studied. In California, when

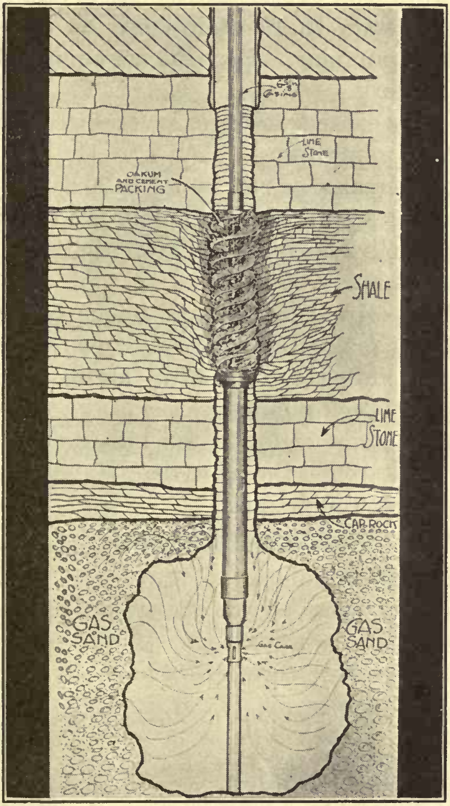


FIG. 54.—Screw packer on tubing for use in oil or gas wells.

a test has reached the oil sand and production is assured the hole is turned over to the well gang composed of four men.

These men proceed to put in the pump and tubing and other accessories. Once a new well is put on the pump the troubles just commence.

Each well must be treated differently. Some start pumping and give little trouble, others give a great deal. In many California wells it is not unusual to have new pumps worn out within 12 hr. when pumping where great quantities of sand enter the hole.

It is often necessary to maintain crews on the well night and day to keep them pumping. Derricks are equipped with electric lights for night work.

Sometimes wells cause trouble for several weeks before settling down into steady pumpers.

Wells without screen pipe run from 7 to 20 days without renewing pumps. After settling down, 15 days is a fair life for a pump on an average well 2 years old. After that time pumps must be renewed about every 30 days.

Sand Troubles.—In California and in the Gulf Coast area of Texas and Louisiana soft, unconsolidated sands are found. These sands flow into the wells with the oil and often fill the casing and clog the well pumps.

It is no uncommon sight to see hundreds of thousands of cubic feet of sand around the oil wells. Handling of this sand is expensive and very troublesome.

Sand causes decreased production due to:

1. Wearing out of pumps.
2. Clogging of wells.
3. Cleaning out operations.
4. Handling sand on surface.

Elimination of sand troubles means a great saving to the oil producer.

This can be accomplished largely.

1. By using a pump system that can handle the sand,
2. By using strainers or screens to prevent the inflow of sand,
3. By "cleaning-out" systems.

A pumping system for handling sand has been worked out along the following lines:

1. Use of steel plungers instead of leather cups in a working barrel.
2. Place the pump a hundred feet or more above the oil sand. Where wells are a few months old this system may work.

Cleaning out systems involve periodic "washing out" or "drilling out" of the sands that accumulate in a well. This may call for several days' or several weeks' work and is expensive in that the well is "off" for that period and that after wells are "on the beam" the trouble commences again.

Strainers or oil-well screens have eliminated a large percentage of sand troubles. The principle is merely to use perforations so screened that fine sand can enter the well but larger particles cannot.

Some oil producers claim that it is essential "to get the sand to obtain the oil." This idea is difficult to dislodge from some minds.

Certainly in those new fields where wells are flowing freely any form of perforation that would check the flow of oil sand would check the production of oil.

The question is still an open one and only a careful study of the whole question will determine the relative value of the systems.

Several types of screens are on the market.

Figure 55, page 130, shows a number of different types of screens. Figure 56 shows the setting of screen in the Gulf-Coastal area of Texas with the rotary system.

The treatment of wells varies in a marked degree in various fields. In the Mid-Continent and Eastern fields the handling of wells is simple compared to the Gulf Coast, and to California conditions. The softer unconsolidated sediments of the latter regions present a set of operating problems that must be solved in a different manner from the hard rocks of the East.

In the Mid-Continent and Eastern areas there is little or no sand with the oil. The presence of large quantities of free sand in the California wells makes it necessary to clean the wells oftener, requires a different pump plunger, and calls for closer watching of wells.

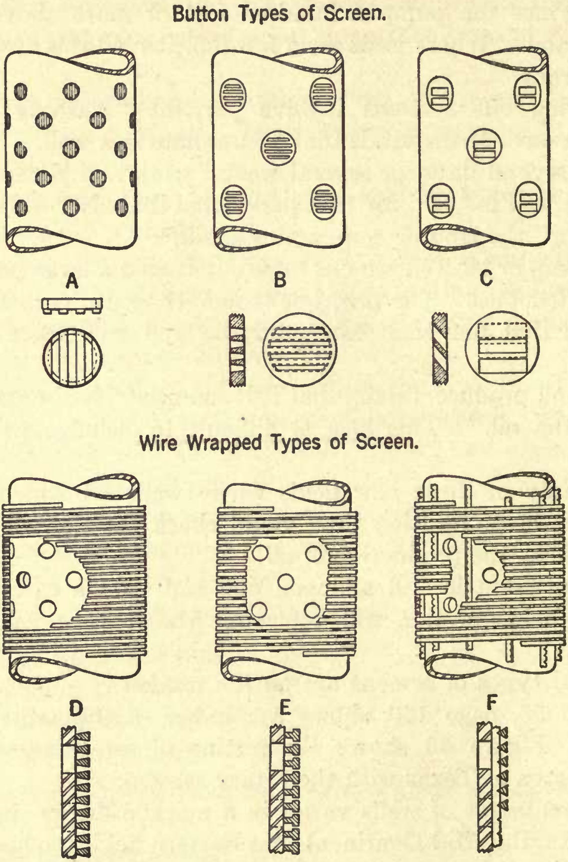


FIG. 55.—Types of screen pipe. *A*, McEvoy screen; *B*, Layne & Bowler button screen, keystone openings; *C*, Layne & Bowler button screen, shutter openings; *D*, Layne & Bowler keystone wire-wrapped screen; *E*, Getty screen; *F*, Stancliff screen. (*After Technical Paper* 247, *U. S. B. M.*)

Gauging Oil Wells.—A careful gauge of each well is essential as a guide in estimating the proper time to repair the pump, or to clean out the well. In Eastern practice

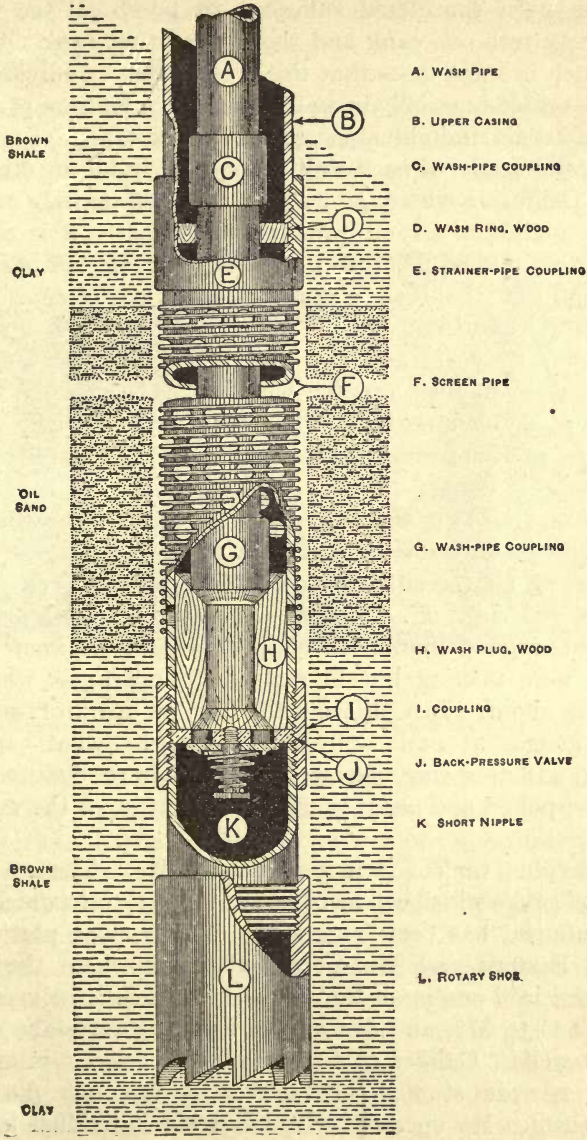


FIG. 56.—Diagram showing method of setting screen pipe when mud-laden fluid has been used in drilling the well. Is particularly adaptable to wells drilled by the rotary drill. (*After Technical Paper* 247, *U. S. B. M.*)

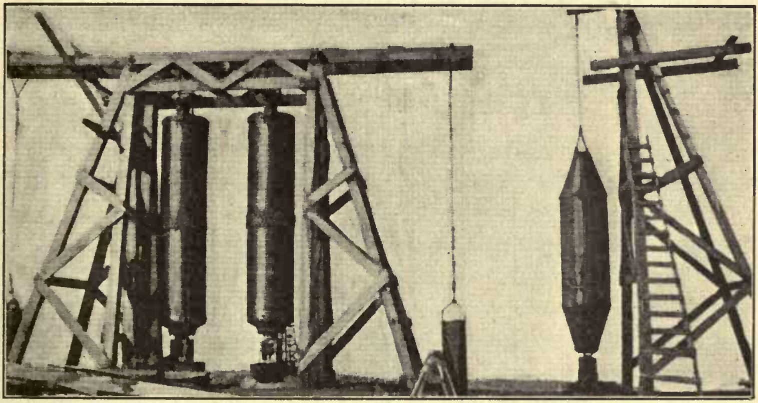
it has been considered sufficient to pump all the wells on a property into one tank and then gauge that tank. Conditions are such in some cases that this is sufficient. Individual gauges are desirable especially in making careful valuations of properties. In California, individual gauges have been taken for many years. A careful study of each well is most desirable in other regions than California where the wells may fall off entirely over night.

To maintain an oil production efficiently it is essential to obtain individual records of each well. Many oil operators will contend that this is sheer nonsense and waste of effort. "We've pumped wells from West Virginia to Oklahoma and handled wells for 40 years and never needed individual well gauges." "Any good pumper can tell what a well is making," are stock answers to this question. This would be fine if true. It would surprise many operators to test out their wells and find just what each one is doing.

On one lease it was found that wells considered as oil wells were really water wells and that a few wells on the lease were producing all the oil. The others should have been plugged or the water shut off. Yet the pumper on that lease was considered a good man. He simply thought he knew what the wells were making but in reality did not know what he was talking about. In California the best oil operators secure separate gauges at each well, and know just what each well is doing. In this way, if a well decreases in production unduly it will be pulled and needed pump parts put in, or the well cleaned out.

Individual tanks now in use are expensive. The use of a water and oil gauge which can be placed at the tank into which the wells are pumped has been suggested. This applies particularly to those Eastern and Mid-Continent leases where the wells are pumped into one main tank. Such a gauge is inexpensive, say from $25 to $75, and one or two gauges would take care of 15 or 20 wells. Gauges could be taken at regular intervals, and their records studied. If the wells are not normal then pull them. No operator who has tried individual gauges will go back to the old "guess" system of obtaining his production. Under that system the total production is pro-rated among the various wells.

Tail Pumps.—Tail pumps are used on many wells to pump the oil from sump holes to the storage tanks. Such pumps are attached to the pitman end of the walking beam. A board is extended beyond the walking beam and a Tee, to which the



(*a*) (*b*)

Fig. 57.—McLaughlin gas traps.

(*a*) Compound type. (*b*) Single chamber type.

pump rod is welded, fits into a slot in this board. An old well-pump working barrel is used. A bottom valve is dropped into this working barrel. The top valve is of the ordinary type used in well pumps.

An improved pump of this kind has guides which eliminate vibration and play in the tail pump.

Gas Traps.—The rich vapors coming from the well with the oil were wasted for many years. However, when the value of those vapors was realized the oil operator devised gas traps to catch these vapors as they came from the well. The gas trap was originally designed by A. C. McLaughlin to catch gas from the lead lines and use such gas for fuel on the lease.

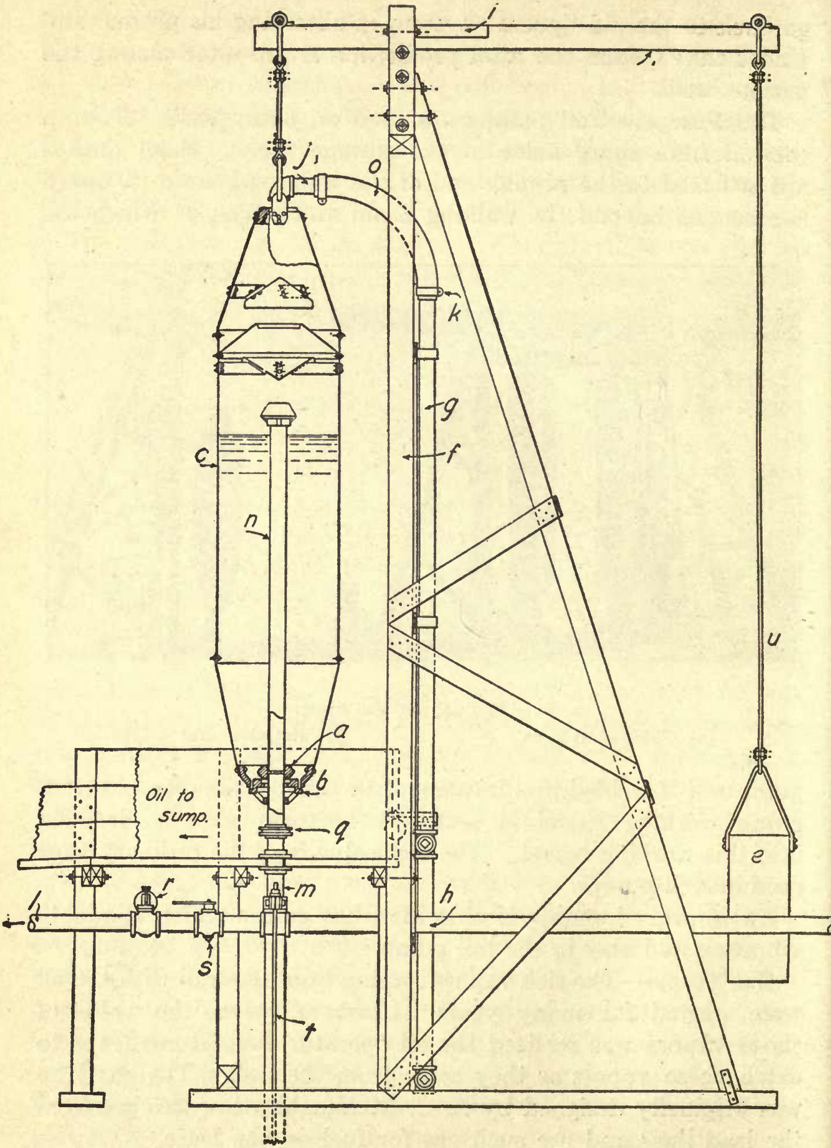


FIG. 58.

This trap (see Figs. 57 *a* and *b*, and Fig. 58) consists of a tank with an oil and gas inlet at the bottom of the tank, and an oil *outlet* at the bottom. At the top of the tank is a gas outlet.

Operation.—The oil and gas enter the tank through *n*. The sand settles on the bottom. The gas rises and is piped off at *j*. The cylinder *C* hangs on the lever arm *d* and is balanced by the counter weight *e*. At the bottom of this cylinder is an opening for the oil inlet *n* which is a 3-in. nipple 4 ft. long connecting to the lead line *h* from the well. A cast-iron valve *a* is fitted over the end of this nipple. At the bottom of the cylinder is also a valve *a*. The weight *e* keeps the cylindrical valve seat *b* tight against the cast-iron valve *a*.

Oil and gas enter the cylinder. The gas flows out through the 2-in. gas outlet *j* in the top of the cylinder. The oil and sand settle in the bottom of the cylinder. When the weight of the oil and sand in the cylinder are sufficient to offset the balance weights *e* hanging from the lever arm the cylinder slides downward. The oil and sand then flow from the cylinder into the box below. Where the oil and gas enter steadily the valve is kept open and constant streams of oil flow from the trap at the same time as the gas is separated.

TREATMENT OF OIL AFTER LEAVING WELLS

The handling of oil after it leaves the well deserves special consideration.

Such oil contains sediment and water, usually called B. S. (basic sediment). This basic sediment may comprise 4 or 5 per cent of sand. This is true in California and the Gulf Coast areas where great quantities of sand make up the sediment.

Fig. 58.—McLaughlin low-pressure trap. *a*, Valve; *b*, valve seat; *c*, trap shell; *d*, beam; *e*, counterweight, made of old casing filled with scrap iron; *f*, support; *g*, pipe from gas line; *h*, oil line from well; *i*, iron guide for beam; *j*, gas outlet; *k*, hose clamp; *l*, discharge to sump; *m*, nipple; *n*, oil inlet; *o*, hose; *q*, flanged union; *r*, safety valve; *s*, emergency stop valve; *t*, hold-down rods; *u*, old ½-inch sand line; *v*, vacuum attachment; *L*, length of attachment. Gas trap patented.

The oil in those fields is first run into settling reservoirs or sump-holes at the well. The sand settles to the bottom of the hole and the oil is pumped off. Such a method is costly, as a portion of the volatile hydrocarbons escapes and leaves a heavier oil. Recent California practice consists in running the oil through a sand box which has a riffle-like arrangement. Most of the sand settles in the box and is shoveled out from time to time by the pumper. The oil runs into a small tank where the remaining sand settles. The oil is pumped from this tank into a storage tank. Every few weeks the small tank is cleaned.

Gauging of Oil in Tanks.—Oil is bought and sold on the basis of price per barrel. The price is roughly based on the specific gravity of the oil: the light oils bring the highest prices, generally speaking, though the refining values are the final factors in determining price. However, the measurement of the oil in the field or in the storage tanks is made for the purpose of determining the quality and the quantity of the oil bought or sold.

The big pipe line or purchasing companies maintain gaugers at monthly salaries ranging from $150 to $300. It is the duty of these men to gauge the storage tanks on properties where the company has purchased oil, before running the oil into the pipe line. The gauger takes his measurements using a steel tape with with a plumb bob on the bottom.

The tanks are gauged both before the oil is pumped, and immediately afterward. The difference between the two readings gives the total amount of oil run. The tanks have previously been strapped or standardized, and each inch is given a value in barrels for that tank. Once the number of inches is known the amount of oil is readily computed. However, the temperature at which the oil is gauged causes some variation in quantity. Oil contracts with cold and expands with heat, so a standard gauging temperature of 60 ° is accepted. All readings must then be corrected for that temperature.

Again oil often contains basic sediment and water, so allowance must be made for that. This is ascertained by taking samples of the oil and making tests with a centrifugal machine.

Samples of oil are obtained by means of an oil-thief. Samples are taken, one near the bottom, one halfway up, and one at the top.

Specific gravity tests are made with the ordinary Baumé spindles. Fifty c.c. of the oil is poured into test tubes filled with 50 c.c. of gasoline, then put in the centrifugal machine and whirled vigorously for several minutes. This whirling causes a separation of the particles of oil and water in the sediment.

One can read the amount of water and sediment on the graduated test tube, and, dividing this by 2, obtain the full percentage of each constituent.

After accepting a tank, if not run at once, the gauger padlocks the valve gates, for cases of robbing oil tanks are known. Also unscrupulous operators might divert part of their oil to other smaller tanks, and then pump it back into the larger tanks and sell it again.

Dehydration—Separation of Oil and Water.—Where oil and water are together, as often happens, the water may, or may not, form an emulsion with the oil.

An emulsion of oil and water is an intimate mixture of oil and water in such a manner that the oil and water will not separate when allowed to settle, but form a liver-colored mixture that has the properties of neither oil nor water.

Where the water and oil do not mix, simple settling may suffice to separate the oil and the water. However, where an emulsified condition exists, heating may cause separation, or it may be necessary to use electricity, or centrifuge, or both.

Where heating alone is used, steam coils are placed in the bottom of the gauge tanks. The steam heats the oil as high as 120° and causes its separation from the water. The danger in heating is the loss of volatile constituents, and for that reason care must be exercised in not raising the oil to too high a temperature.

Electrical System of Dehydration.—The electrical dehydrating system is quite simple. The electrical process of dehydration is based upon the principle that oil is practically a non-conductor of electricity while water is a good conductor.

Mechanical processes have not met with much success in treating with emulsions. Where the oil comes from a well and is whipped by the gas it may form a liver colored mixture that cannot be separated by standing in a tank, by heating, or by centrifugal methods.

An emulsion of oil and water is an intimate mixture in which minute globules of water are coated by a film of oil, producing a mixture unfit for use.

An electric current can be used successfully to break up an emulsion and thus dehydrate the oil.

Temperature plays an important part in successful dehydration. The temperature may range from 140° to 180°F. In practice the thicker the emulsion the higher the temperature needed.

The oil treated in the above mentioned process ranges from 15 to 65 per cent water and the average amount of oil net after treating is approximately 18 bbls. per kilowatt hour or one-ninth of one cent per barrel for electricity at the rate of 2¢ per kilowatt hour. Electrical dehydration causes practically no loss of gasoline and the records show that after treatment the gravity of the oil has been raised from 1° to 2° and has in consequence an increased market value. This increase in market value in some cases is enough to pay the cost of dehydrating. The opposite is true in the heating process because crude oil containing any appreciable gasoline will suffer evaporation under the temperature necessary to break down the emulsion and naturally the loss of gasoline means less dehydrates, less gravity and less market value.

The heating process necessitates close watching; the electric practically none. The heating process discolors the oil, impairing its market value; the electric dehydrator clarifies the oil leaving its natural color. The low fire hazard with electricity is important.

A record run of 7,000 bbls. of the same grade of crude oil was made, first by the heating process, then by the electrical. Eighteen hours was required with heat and only 7.5 hours with electricity, the net amount of oil being 5150 bbls. with the former process and 5160 bbls. with the latter. The total cost by the heat process for this run was $387 or 7½¢ per barrel, while the entire expense with electricity, even including a royalty of ½¢ per barrel, was $102 or slight by less than 2¢ per barrel.

The electric dehydrator effectively treats oils of different grades at the same time without in any way impairing their efficiency. On a test, 28 gravity crude oil containing 25 per cent emulsion at a temperature of 70° was cleaned simultaneously and separately with 13 gravity oil containing 30 per cent emulsion at a temperature of 180°, by the same electric dehydrator, and the dehydrates showed only 1.3 per cent water and foreign matter in suspension, a limit of 2 per cent being permissible.

The electric dehydrating plant is made up of units called treaters and the usual size is a four-treater plant. The cost installed is about $2000 per treater. The cost of installation is generally borne by the oil companies and the ownership of the dehydrate is retained by the manufacturers, who also exact a royalty from the oil companies on each barrel of dehydrate produced.

In general, the electric dehydrator operates on a single phase alternating current at a pressure of 11,000 volts, the voltage being stepped up from the regular service of 440 or 2200 volts. The emulsion is passed between high charged electrodes and in this electrostatic field the small globules and particles of oil, by static attraction for each other, form in chains which in turn coalesce into free water which readily settles to the bottom of the treater and is drawn off. In certain leases where water is very scarce, the water electrically removed from the oil is of considerable value.

Due to the condenser effect caused by the highly charged electrodes, the electric dehydrator operates at about 98 per cent loading power factor. The average maximum demand is 4 kw., the average load factor 50 per cent and the average gross income approximately $25 per month.

Centrifugal System.—The lastest development in separating oil and water in storage tanks is the centrifugal cream separator adapted to separating emulsified oil. The oil is heated and then run into centrifugal machines. (Fig. 59.) The whirling of the centrifuges breaks up the molecular cohesion. The water drops to the bottom of the centrifuge, the oil rises to the top. These centrifugal machines revolve at speeds of 6,000 r.p.m.

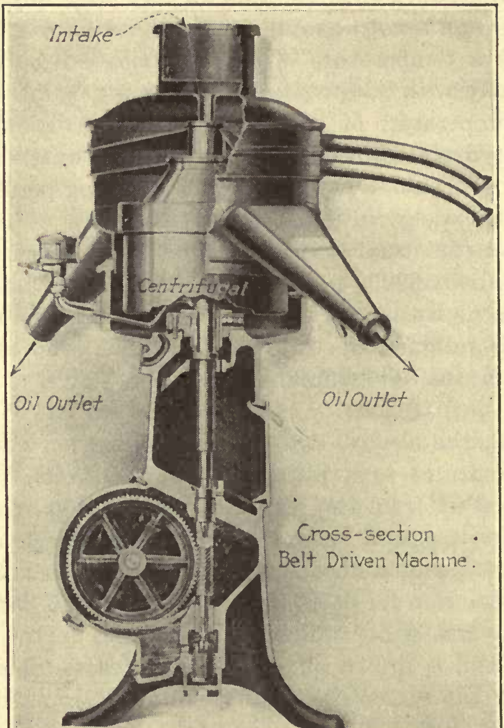


FIG. 59.

LEASE MEN

In all oil fields the workmen have special duties. The well crew works on the wells that give trouble. These men pull rods and pumps, start gas engines, and do some of the general roustabout work around a lease. They are usually daylight workers.

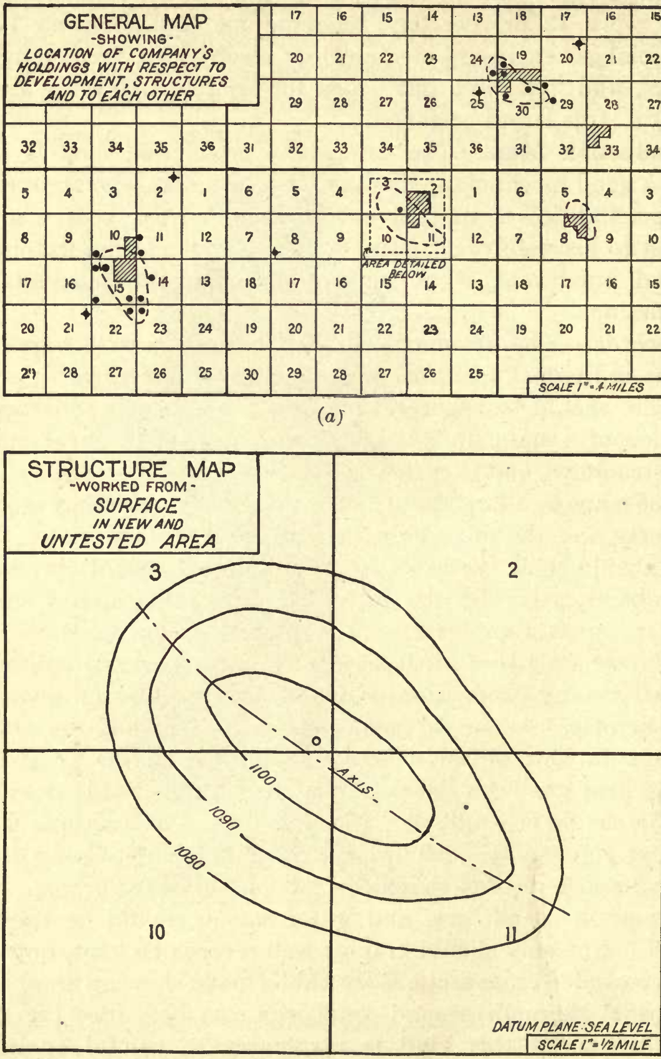
The pumpers watch the pumping wells and oil the machinery. They work 12 hr. per day, relieving one another every 12 hr.

Special gas engineers, steam fitters, electricians, firemen for the boilers, and "cleaning out" men for troublesome wells, are all used on large leases or farms.

Production Man.—The competent production man is more than a good mechanic. He must also be a man who appreciates the possibilities of natural conditions. A lease boss who can attend to his wells obediently, but has no idea of natural underground conditions, is at sea in obtaining the maximum of production.

Records.—The keeping of oil-field records is most important to any individual operator, or producing oil company.

There should be a general map on a small scale showing the location of a company's holdings with respect to development, new structures, and to each other. (See Fig. 60*a*.) There should also be maps on a larger scale, made in orderly units showing each property and the ownership thereof, both fee and lease. This map should show the exact location of development (producing and abandoned wells, dry holes, and gas wells) and of storage and transportation facilities. A plat of producing leases on a still larger scale is of great assistance in working out subsurface conditions and production problems, and in showing inventory and invoice. A careful geological map showing the surface geology in new untested areas, should be on file (Fig. 60*b*). If the field has been developed, a careful map made from well records should be available. (See Fig. 61*a*). Well records should be kept graphically. All formations should be noted and depths given; casing records should be put on the same graph. Such information as oil, gas, and water sands, should be carefully noted. Not only should graphic well records be kept, but carefully compiled cross-sections should be made showing graphically just what the underground conditions may be. (See Fig. 61*b*.) Information of this kind is invaluable to careful operators. Graphic charts showing the production of individual wells, of groups of wells, of all the wells in a single field, and then of the



(b)

FIG. 60.—(a) General map. (b) Geological map showing surface geology.

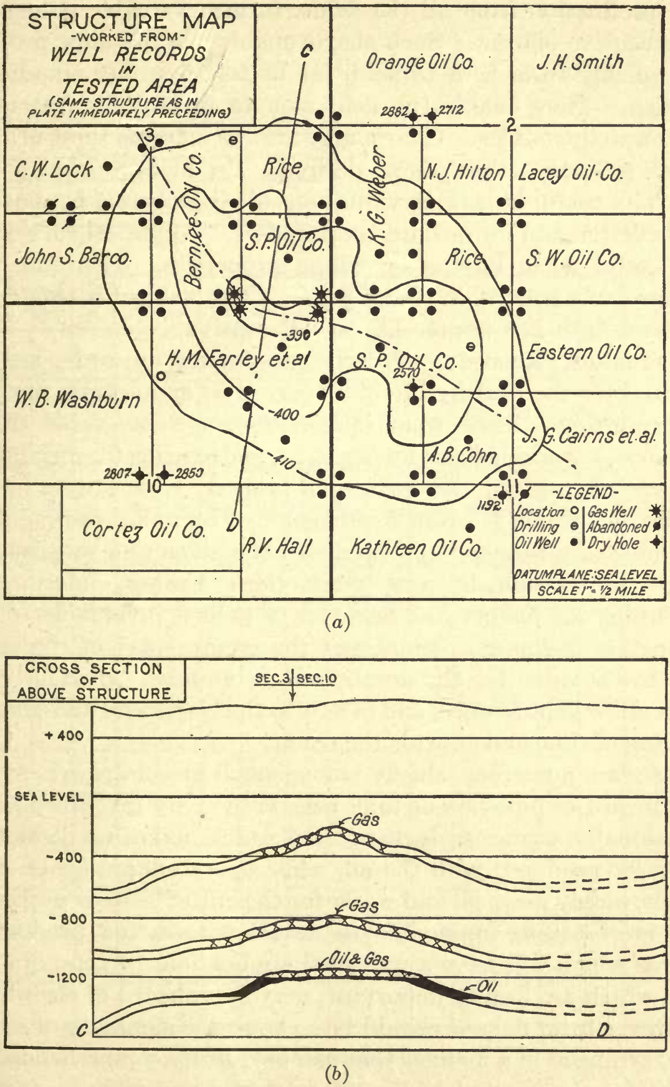


Fig. 61.—(a) Contour map from well records. (b) Cross-section from well records.

total production from all the fields, furnish valuable guides for the executive officers. Such charts enable one to follow production quickly from field to field, far better than any amount of printing. They enable the field men to place their fingers at once on well troubles. Charts may also be made to show drilling costs, or any other data desired. Production charts are especially useful in making valuations of oil property, in allowing for depletion and for income tax purposes. Appraisal curves are also useful when buying or selling properties. Their use has become quite general in recent years. This subject is treated at greater length in Chapter IX on "Valuation."

Production Records.—Orderly production records are as essential for the healthy life of a concern as an accurate method of accounting. Aside from information, such as value of oil produced, a working basis for taxation, and figuring the retirement of invested capital, the records, if properly kept, have a future application which is often overlooked. From the viewpoint of the value of a property, oil produced at a given time means little except in relation to past production. Certain information concerning the history and behavior of wells is invaluable to the production engineer. Oftentimes the greater part of the same data has a value for the accountant or auditor. Obviously, if it can all be kept at once, and in a form that is concise and simple, a saving of time and effort is the result.

Cases are numerous, chiefly among small producers, where the bare record of pipe-line or tank runs is the only inventory kept. Occasionally a concern is discovered which makes no deduction for water produced with the oil, while operators are legion who can show only gross oil and water for the entire lease or property.

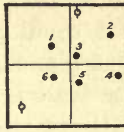
It is of course impossible to devise a form for production records which will have a universal application. Factors in one field, which are locally important, may be unheard of elsewhere. Whatever form is used should be a condensed summary of essentials, arranged in a manner that can be quickly comprehended.

The form suggested in Fig. 62 is elastic and includes factors which are regarded as having an importance in most areas.

State .... Co. ....

Tp .... R .... Sec. ....

Sands	Depth	Thickness	Porosity	Spacing
1	820′	20′		
2	855′	6′		
3	900′	8′		



Well No.	Comp'd	Initial 24 Hrs.	Sands	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
1	3/6/10	450	1 2	500	480	501	475	470	465	462	420	415	415	425	413	
2	5/15/16	200	1	300	302	280	270	275	260	262	255	260	250	250	240	
3	11/2/16	300	1	325	318	300	310	280	280	285	275	270	275	265	260	
4	3/3/17	200	1 2	160	160	140	130	60 C 5/20	220	210	208	200	205	180	175	
5	3/30/17	220	1 2	200	180	185	170	160	165	280 D Z-16	300	280	270	270	255	
6	9/8/18	350	1	190	185 5	170 10	150 10	135 30	120 50	125 60	100 80	Shut	down		Oil Water	

FIG. 62.—Production record.

The blank form can be drafted as a tracing, from which prints are taken and entries made on the latter under their respective heads. Some data will vary with time as the property is drilled. Such, notably, is Spacing.

A small graphic representation of the section or lease will give at a glance the locations and relative positions of wells. While the scale is necessarily small, it will show the well arrangement without referring to the larger lease or property maps. Where production is obtained from several sands, the average depth, thickness, porosity, and spacing should be recorded. The per cent of porosity may not be obtained from every well unless a special effort is made to do so at the time the well is drilled. Such determinations can be made from fragments of the sand which are drilled out or shot out while the well is being completed.

For the sake of comparison, the initial 24-hr. production of new wells is entered. While the determination of the future value of a well is erratic when judged from its initial production alone, it may sometimes be desired for that purpose. The extent to which initials maintain the level of production for the field, and the decline of initials as the property is drilled, may be of value also.

Where water is made with the oil, the amount of each should be entered as separate monthly production. Aside from the economic angle of the amount of water lifted by a certain well, it serves as a check to determine how rapidly one decreases as the other grows in volume. Steps may be taken to remedy defects in a single well before conditions have reached a critical stage. Where several wells begin to produce water with the oil, it is possible to determine the cause by noting the sequence of wells making water and the rate of increase for each. The measures necessary to preserve other wells from the casing leak of one of their number and the problem of encroaching bottom water are, clearly, widely different.

When a well is deepened to lower producing horizons it is advisable to indicate that fact in the production records. Allowance must be made in such instances for the sudden change in the rate of decline. The new sand, for all practical purposes, will perform like a new well, adding its high initial to the settled yield of the older sand. Where a well is deepened, some symbol, such as initial letters can be employed to indicate its deepening and the sand reached. This symbol can then be entered under the month when the deepening was completed.

Wells often show an abnormal decline until they are cleaned. If the increased production following cleaning is entered without making note of the cause of the increase, it may lead to false conclusions later. Where neither deepening nor cleaning are recorded, any one following the production figures is at a loss. A sudden flare-up in production due to cleaning and a similar increase as a result of deepening may be due to either, but there should be no room for conjecture.

The production record, containing all essentials, can be kept on a form of convenient size. Sheets 10 by 12 in. are large enough for most purposes. Total production for each well and for the lease or section may be entered as a summary. The leaves can then be bound to form a production record book.

Casing Records.—Production records will have a value to both auditor and engineer, while casing records fall in the province of the latter only. The two have nothing in common, the casing records being confined entirely to the mechanical end of individual wells. The necessity for preserving such information is apparent. Almost any operator knows of instances where a change was undertaken on the mechanical equipment of a well when it was discovered too late that some important detail was not as anticipated.

The casing record can be made either as a graphic representation or in the form of a table. For the purposes of record, it is felt that the latter is better since less time is consumed in filling in the desired information. In case of trouble with one of the wells, it is often advantageous then to make the graphic from the table. Remedial measures can be more easily planned when casing, tubing, shut-offs, and the like are visualized.

Where the drilling methods are standardized a form may be drawn up as a tracing, from which entry blanks are taken. Horizontal spaces can be used for casing sizes—conductor at the extreme left, followed by the largest casing used, that in turn by the next largest, and so on in succession until the smallest size is reached. Vertical spaces are reserved for wells, each of which is entered by name or number. Following the description of the well, the surface elevation is given as so many feet above the sea level. In the space under conductor, enter the depth in feet to which the latter was carried.

The same is done in succession for each of the casing strings, showing the depth in feet at which each size was landed. Points at which casing was cut or perforated, water shut-offs and type of same, liners, adapters, depth of working barrel and valves are additional items. Suitable space is reserved for the date of completing each well, whether shot or natural—with a shot record, if the former—and the dates of pulling and cleaning out.

Much of the bulk of such a record can be reduced by employing symbols to represent such details as shut-offs, perforations and the like. No set form can be followed, however, because methods and equipment are so variable. See form in Appendix, page 272.

CHAPTER VI

TRANSPORTATION—STORAGE—FIRES

The transportation of oil has become a large industry in itself. Once the oil is brought above the ground, it must be carried to the consumer, which may be by a railroad using fuel oil, a refiner who distills the crude, or an exporter who sells to foreign markets.

Oil is transported in four ways:

1. Wagons or trucks.
2. Railroads.
3. Barges.
4. Pipe lines.

Wagon or truck transportation is used in a few instances where wells are not large enough to justify a pipe line to a railroad point. Oil is sometimes taken to a railroad by wagon or trucks, and then shipped in tank cars to the refinery or other destination.

In the sixties and seventies wagons pulled by two-horse teams were one of the main reliances for oil transportation. It has been estimated that 6000 teams were used to haul oil in the early days. If all the tales about them are true, those teamsters were tougher than the teamsters of the present day.

The development of tank cars has been rapid. There are at present (1920) 72,000 tank cars in operation. Such cars are merely small horizontal steel tanks (see Fig. 63, page 150) with a capacity of 200 to 300 bbls., mounted on car trucks. They are filled at loading racks, which in turn connect with pipe lines leading from storage tanks. Tank cars are used to transport both crude oil and the refined products. Such cars are built by the railroads and leased to the various oil companies.

Comparatively little crude oil is carried by railroad. The refined products, however, are largely carried that way. In new fields where pipe lines have not been installed, or where the fields are too limited to justify the heavy expenditure necessary for a pipe line, tank cars furnish a convenient means of transportation.

Oil is generally run to railroad points through short pipe lines. The tank cars are filled at the loading rack. At that point the oil from the pipe line is distributed by a system of pipes to the

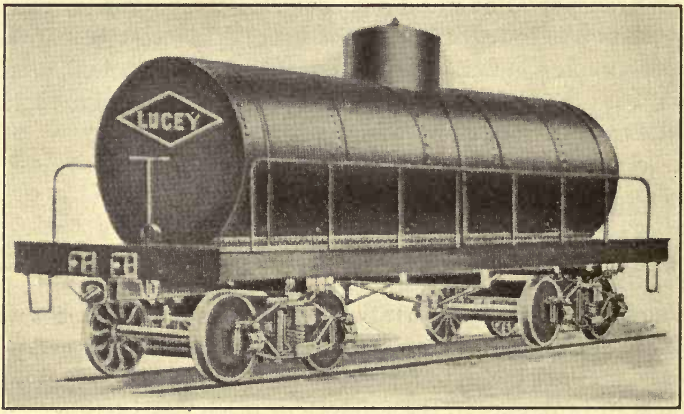


Fig. 63.—Tank car.

various outlets which are controlled by valves. A tank car is run up to the rack, and filled by opening a valve at a convenient point.

Barges—Tank Ships.—In the early days of the industry in Pennsylvania, oil in barrels was floated down the Allegheny River in barges. On some of the early barges barrels were not used but the oil was pumped direct into the bottom of the barge. Barge transportation was very cheap. This method of transportation can be used in a few places, where the fields are small and the entire production is readily handled, but it is not applicable for handling the production from large fields.

Tank ships have been in use since 1863. Such ships are generally oil burners, but they may be steam, gas, or sailing vessels. Their capacities range from 2,000,000 to 5,500,000 gal. of oil, which means an equivalent of from 50,000 to 107,000 bbl. of oil, or nearly as much as two big 55,000-bbl. tanks. Such vessels are sometimes 500 ft. long. Figure 64, page 151, shows a photograph of some oil tankers. These ships are so

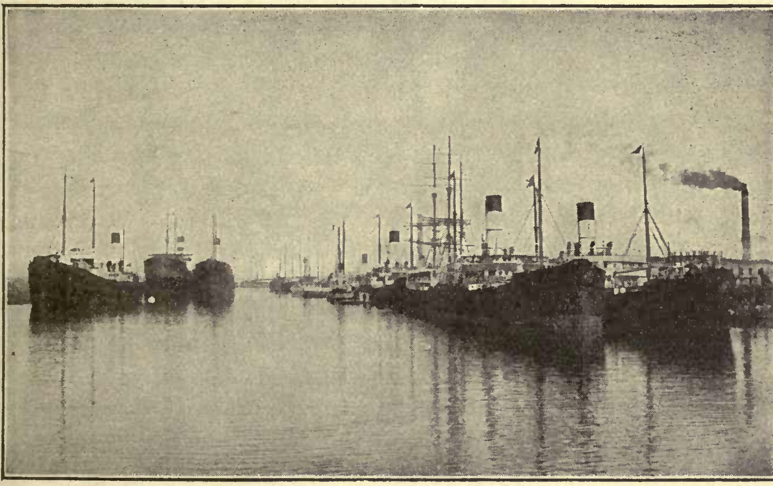


Fig. 64.—Fleet of tankers.

constructed that fire loss is at a minimum. The number of tankers in operation in 1920 was 328, with a combined capacity of 710,785,000 gal.

Pipe Lines.—Pipe lines furnish the most important oil transportation system. The first successful pipe line was laid in 1865, by Samuel Van Syckel, of Titusville, Pennsylvania. This line, 4 miles long, extended from Pithole, Pennsylvania, to Miller Farm, the nearest railroad point. Previous attempts of Hutchins and Harley had met with failure, due to the vicious attacks of teamsters, who feared destruction of wagon transportation. In 1875

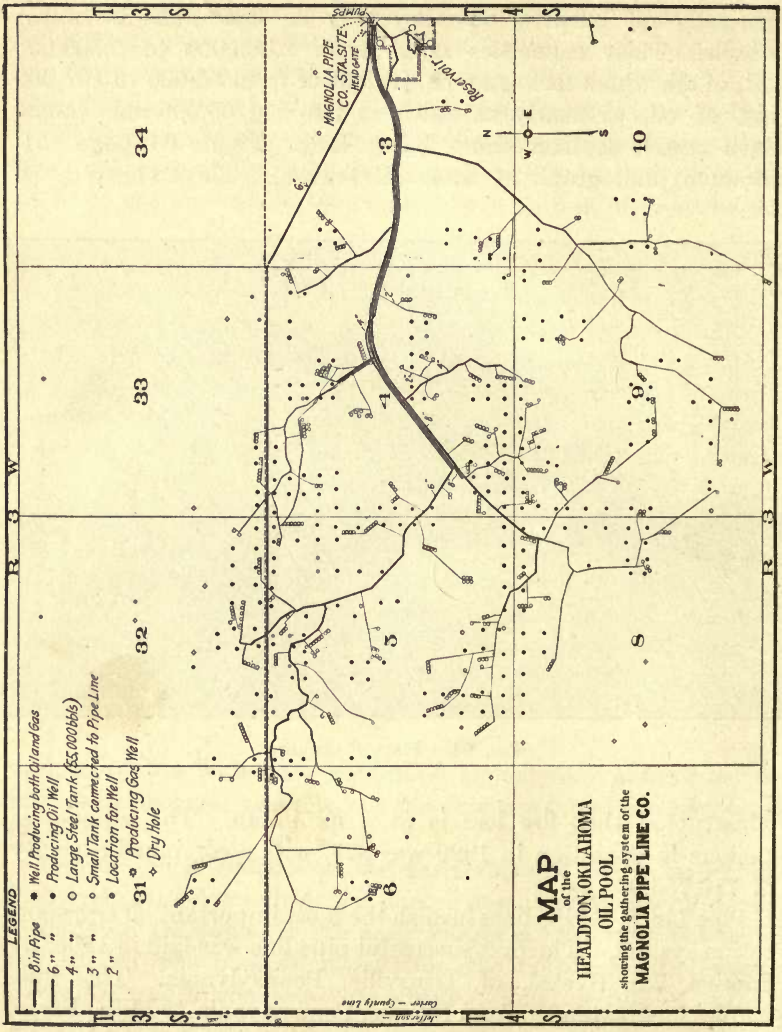


FIG. 65.—Pipe line gathering system.

a 4-in. line, 60 miles long, was carried to Pittsburgh. To-day great trunk lines extend from Oklahoma to the Atlantic seaboard, to the Great Lakes and to the Gulf of Mexico, through which more than 500,000,000 bbl. of oil a year are pumped.

It is of course necessary to be assured of a large supply of oil before undertaking the construction of extensive pipe lines, and for that reason such lines are built only after fields have been sufficiently developed to show a big production.

A pipe-line system consists of

1. Gathering lines.
2. Lateral and main trunk lines.
3. Gathering-line and trunk-line pumping stations.

The oil collected at the farm or lease storage tanks is run by gravity or forced by small pumps to the main gathering lines which connect a number of properties. Such gathering lines, are steel pipes, of from 2 to 6 in. in diameter. These gathering lines in turn connect with the lateral lines which run from a field to the main trunk line. The lateral and trunk lines have diameters of from 6 to 8 in. Such lines are generally buried from 12 to 18 in. below the ground. New trunk lines may be added as the fields or pools increase in production.

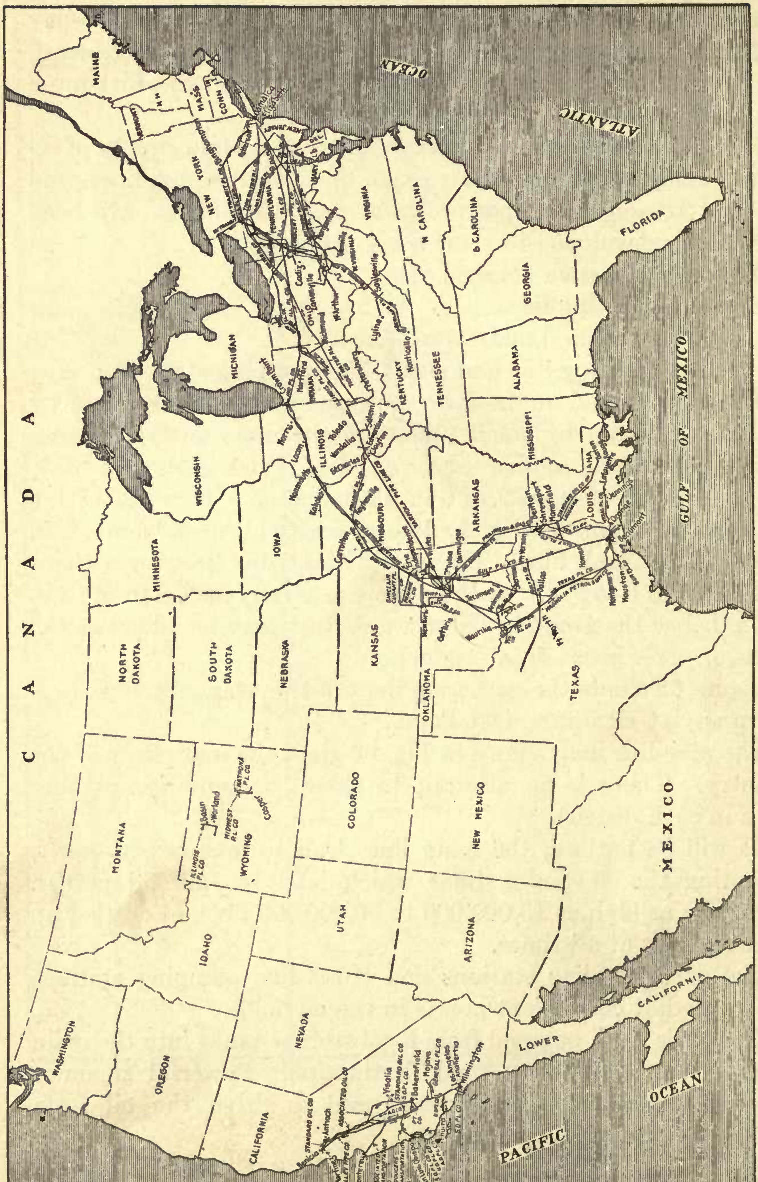
Figure 65 shows the gathering lines of the Magnolia Pipe Line Company at Healdton, Oklahoma.

The pipe-line map shown in Fig. 66 gives the main lines of the country. There is no attempt to show the numerous smaller lines in each district.

As will be noticed, the main lines lead to lake or sea ports, excepting the Wyoming lines which lead to railroad points. There are as high as 15,000,000 to 20,000,000 bbls. of oil tied up in these lines at all times.

The gathering-line stations and trunk-line pumping stations are located at convenient points in the oil fields.

The oil is then pumped from local storage tanks into the main line or lines and to its final destination. Powerful steam or internal-combustion engines are used to drive the oil from station to station along the line.



PIPE LINES IN THE UNITED STATES (1916) LEADING FROM OIL FIELDS TO REFINERIES
(From Map Prepared for United States Geological Survey under the Supervision of John D Northrop)

FIG. 66.—Pipe lines of the U. S.

PIPE-LINE CONSTRUCTION

In pipe-line construction, as in railroad construction, the topography must be studied and lines of least resistance followed. Curves are avoided wherever possible.

The friction factor is an important one. If the friction due to curves is greater than that due to climbing grades then, if practicable, the pipe line must go upgrade.

Pipe lines are built to run in as nearly straight lines as possible. This may necessitate crossing numerous hills. Pumps are required to make the first lift to carry the oil to the top of a hill, but once up the hill gravity carries the oil down. Only sufficient pressure to overcome friction in the line is necessary after the first lift.

Main gathering lines should be located in valleys so that "feeders" will flow into the valley by gravity. Short curves should be avoided wherever possible as greater friction results.

The laying of pipe lines across streams calls for no great engineering skill, but for common-sense methods based on practice.

In some cases derricks are erected and pipe lines are suspended across a stream. In other cases pipe lines are laid on river bottoms. This is done in deep streams by floating a pontoon across the stream with the pipe line upon it, and then lowering the pipe overboard; or sometimes, simply by connecting the pipe together, and then pulling it across the stream by barge.

In Mexico the Pearson interests laid their offshore lines by building tracks into the Gulf, running the pipe out on trucks and then dropping it off the trucks.

The quality of oil determines largely the rapidity of flow and also the question of pump pressure needed. Heavy viscous oils, like those of California, flow slowly through a pipe line and require greater pressures to drive them through the line than are required by light oils, like those of Pennsylvania and the Mid-Continent.

Heavy oils must sometimes be heated to facilitate the flow. Light oils flow quite freely in warm weather but require heating in the winter.

Steepness of Grade.—The steepness of grade is a factor to be considered. If the pipe line is down hill all the way, a gravity flow may be possible. If on the level, comparatively long breaks between relay stations may be permissible. However, in an area of high hills considerable pressure may be necessary to lift the oil up the grades.

Pipe Specifications.—Pipe-lines are built of hydraulic steel pipe. Such pipe is light, as the pump pressures rarely exceed 600 to 800 lbs. It is tested at from 1000 to 1200 lbs.

Pipe weighs as follows;

6 in. — 19.37 lbs.
8 in. — 29.20 lbs.
10 in. — 41.60 lbs.
12 in. — 50.90 lbs.

Pump Stations.—Pumping stations (see Fig. 67) 12 to 25 miles apart are designed to deliver on a 6-in. line 600 bbls. per hour with 600 lbs. line pressure. An 8-in. line would carry 1200 bbls. per hour against a 1200-line pressure.

Pumping stations are placed at intervals of 1½ to 90 miles apart. A heavy oil of high viscosity, like the heavy California crude oil requires stations 14 miles apart. The oil must be heated to reduce viscosity and will retain sufficient heat at this interval. The oil is heated at the pump stations to 130 to 150°F. in heater drums 5 ft. in diameter, 21 ft. long. These drums are much like a water-tube boiler and the oil circulates through them. Heat is supplied by exhaust steam from the pumps. With light oils of 40°Bé., and low viscosity it is not necessary to heat the oil in the lines. With such oils, stations are placed 25 to 40 miles apart, depending upon local conditions.

Different grades of oil are often pumped through a pipe line at the same time. A light oil is started through the line. Later a hundred thousand barrels of heavy oil may be pumped through the line. Then a hundred thousand barrels of light oil may be pumped through the line following the heavy oil. The two different oils mix slightly at their junction but the amount of mixing is not great—say a few hundred barrels or a thousand barrels of oil may be affected. Where the two oils are very different in character it may be necessary to put through a small batch of "buffer" oil or oil of a grade intermediate between the two main batches.

Pipe lines are generally buried 18 in. deep. This depends upon the depth to which freezing will affect the ground.

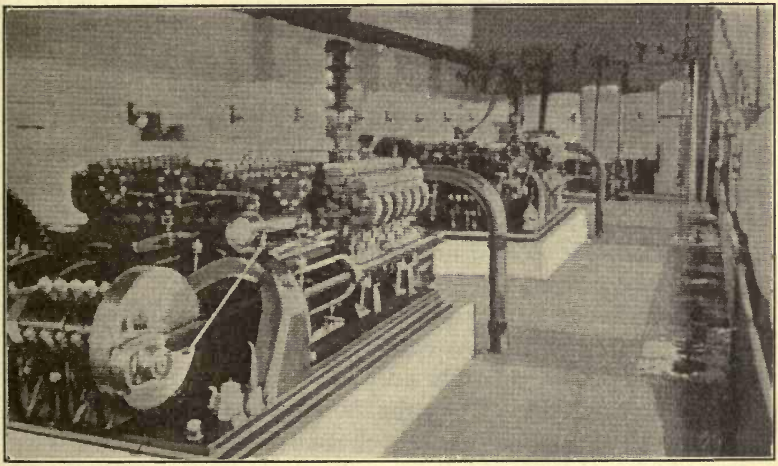


FIG. 67.—Pipe line pumping station. (*After Stratford.*)

Typical pumping station of pipe line between oil fields and refineries. As an example of capacity: Distance between stations, 50 mi. Line, 6 in. Pressure at sending station, 660 lb. per sq. in. Horsepower required, 182. Total oil pumped in 24 hr., 13,128 forty-two-gallon barrels, or about 3 bbl. per horsepower per hour. The viscosity of petroleum pumped and topography of country over which pipe line passes determines distance between pumping stations; minimum about 15 mi. and maximum about 100 mi. (*After Stratford.*)

Cost of Building Pipe Lines.—The cost of pipe lines in 1921 may be indicated roughly:

4 in.—$6,500 per mile
6 in.— 9,000 per mile
8 in.—12,000 per mile
10 in.—15,000 per mile

Pipe-line Construction.—Pipe-line construction may be subdivided into three phases:

1. Selection of line. Engineering surveys.
2. Securing right-of-way for pipe lines, telephones and telegraph lines.
3. Building line:
    (*a*) Right-of-way men.
    (*b*) Stringing gang.
    (*c*) Laying gang.
    (*d*) Ditching gang.
    (*e*) Covering-up gang.

The selection of a line depends upon a number of factors which must be weighed by the men in charge of the work. The engineers desire to avoid rivers and rough country as far as possible, and water supply for the pumping stations must be taken into consideration. It is also important that the line be accessible from railroad points.

Careful surveys are made and maps showing all grades prepared. Men are then sent out to obtain rights of way for the line, and these are generally purchased outright. This applies not only to the rights of way for the pipe line itself, but also to those for telephone and telegraph lines.

The "right-of-way gang" goes ahead along the right of way and clears the line of all obstructions. Trees are cut down, stumps pulled and the line made ready for ditching.

The "stringing gang" then brings the pipe and lays it along the right of way. The pipe is hauled by wagon or truck and dropped where wanted.

The "laying gang" is next in order. This gang consists of "stabbers," whose duty it is to see that the joints of pipe are in line for "screwing up;" the "tong men" who put on the "back up" tongs, which are put on the pipe into which a new joint is being screwed; the "rope men," who hold the joint of pipe, while the stabber centers it; the "barmen" who move the pipe, and the "jack men" who screw up the pipe. Such crews consist of 40 men, and where pipe machines are used, 28 men form a crew.

As much as 8700 ft. of 8-in. pipe has been laid in 9 hr. With ordinary gangs, the average performance is from 2500 to 4000 ft. per day.

The ditching gang follows the pipe or laying gang. This gang digs the ditch, by hand or by machine where possible. Plowing is necessary and where hard rock is encountered blasting is employed. When the ditch is completed, the pipe is laid in it and covered.

Where the pipe must be laid in alkaline soil, the line is laid on the surface, and is coated with asphaltum and tar paper.

STORAGE OF OIL

When the oil is above ground, it is usually carried direct from the well to the refiner or other consumer by the pipe-line company. However, the pipe-line company may store the oil for future use; or the producer may store his own oil for a future market.

The refiner who uses large quantities of oil must keep a sufficient reserve in storage to take care of his needs.

Oil storage is of two main types:

1. Earthern reservoirs, either lined or unlined with concrete.
2. Tanks, steel or wooden.

The most natural reservoirs are the sump holes or temporary earthen reservoirs that have served to store oil around a flowing well. They are, however, makeshifts, serving only to hold the oil until better storage facilities can be furnished. Such reservoirs are generally constructed hastily. A few hours' work with a scraper creates an embankment across a gully behind which the oil collects.

In California, in Mexico, in Texas, and in fact in all the fields where the oils are largely of fuel grades, say from 14 to 22°Bé., sump holes have played an important part.

The losses by evaporation and seepage in reservoirs are large. A loss of 15 to 25 per cent is not unusual where the oil stands for 5 to 6 months. The loss in gravity alone ranges from 4 to

6°Bé. However, such losses must be expected where flowing wells of 25,000 to 60,000 bbl. per day break loose and adequate storage is not available.

Losses.—The most natural improvement in earthen reservoirs was putting roofs over them, which largely prevented evaporation losses. The next step in progress in reservoirs was the cement-lined reservoir. Large earthen reservoirs capable of holding 500,000 to 1,000,000 bbl. are constructed and these are carefully lined with cement. The losses in such reservoirs are very low, being in some cases less than one-half of 1 per cent per year.

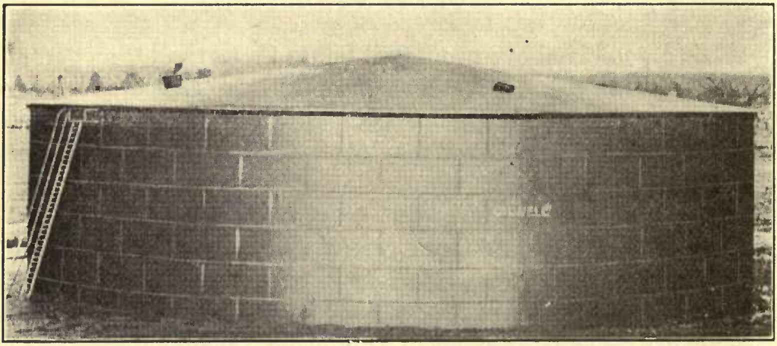


FIG. 68.—Steel storage tank of 37,500 to 50,000 bbl. type.

When the Lake View gusher was brought in, several narrow canyons were converted into reservoirs across which concrete dams were built and the oil pumped into those reservoirs. These canyons were deeper and much narrower than the ordinary sump hole and evaporation losses were necessarily smaller since evaporation losses depend directly on the surface of the oil exposed to the atmosphere.

Tanks.—Steel and wooden-tank storage has been used almost entirely in the Eastern, the Mid-Continent, and the Wyoming oil fields. The light oils of those fields are so susceptible to loss that wooden and steel-tank storage was accepted at once.

Steel storage is by far the most efficient. Some wood tanks are used as receiving tanks on the leases, but oil is not stored in them for more than a few weeks at most.

Tanks vary in size anywhere from 50 to 55,000 bbl. Fifty to two-hundred-barrel tanks are used on leases for storage of oil.

The big storage tanks range from 37,500 to 55,000 bbl. in capacity. A tank of 37,500 bbl. capacity has a diameter of 94 ft. and a height of 30 ft. A 55,000-bbl. tank has a diameter of 114½ ft. and a height of 30 ft. (See Fig. 68, page 160.)

Some tank dimensions are given in the Table 11 after Bacon and Hamor, page 69 of *American Petroleum Industry:*

TABLE 11

Capacity, barrels	Diameter		Height, feet
	Feet	Inches	
55,000	114	6	30
37,500	94	0	30
30,000	86	0	30
20,000	70	0	30
20,000	77	0	25
10,000	49	7	30
10,000	54	0	25
5,000	43	0	20

Such tanks are made of six rings of thin steel plates. The lowest ring of plates is the heaviest—23 lbs.; the top the lightest —8 lbs. in weight.

Wooden tanks are in general use on leases for water and also for storing oil. They are shaped like a conical frustrum and have steel hoops or straps binding them.

Tanks are gauged or "strapped." Allowance is made for all beams and supports inside the tanks. The value of each ¼ in. of height of the tank is carefully determined and tables constructed for tanks of given diameters. When gauges are taken it is a simple matter to consult these tables and determine from them the amount of oil in a tank.

Steel tanks have lives varying from 15 to 35 years. Twenty years may be considered a fair average life. Tankage costs vary greatly. A 250-bbl. tank costs $300, or $1.20 per barrel. A 55,000-bbl. tank would range from 30 to 35¢ a barrel. Wooden tanks cost from 35 to 40¢ a barrel.

Concrete-lined reservoir costs vary greatly. A large 750,000-bbl. reservoir should cost in the neighborhood of 15¢ per bbl.

LOSSES IN STORAGE

In the storage of petroleum there are large losses. Long exposure of petroleum to the air means an escape of the lighter hydrocarbons. This wastage or loss is the main problem to be met and solved in any storage plan. Losses in storage are due to:

(*a*) Seepage.

(*b*) Losses of evaporation.

(*c*) Increase in specific gravity.

Seepage losses are found particularly in unlined earthen reservoirs.

In California, losses of 7 to 10 per cent with oil of 12 to16°Bé. can be attributed to seepage losses. In areas like the Mid-Continent oil field the loss by seepage of the light oils is so great as to preclude any idea of using anything but steel or wooden storage.

With good concrete-lined reservoirs seepage losses showed from 1 to 2 per cent per year.

Evaporation Losses.—The greatest loss in storage is due to the escape of the light volatiles from the crude oil and the increase in the specific gravity of the oil. Unroofed reservoirs show large losses.

The losses of light volatiles from open sump holes under a blazing sun are high. Were such oil allowed to stand long there would be only a tarry residue remaining.

It has been found that losses from wooden and steel covered tanks vary greatly. Losses as high as 25 per cent a year have been obtained from wood-roof tanks. Steel-tank storage of light oils in Oklahoma shows losses ranging from 0.5 to 2.5 per cent per year.

In California, wooden-covered steel tanks showed losses of 0.1 per cent to 2.5 per cent per month.

Loss in Specific Gravity.—It has been found that oils lose very little in gravity in the Baumé scale under good storage conditions. Cushing crude stored 2 years and 5 months showed a change from 40° to 38°Bé. or a loss of 2°. Some Glenn pool crude showed a change after 7 years and 3 months of 32.9 to 32.7 or 0.2°, a remarkable showing. A loss in specific gravity of 0.5° per year would be a high average for good steel storage.

Tank Farms.—The large pipe-line companies group their storage tanks together into "tank farms." One may count 40 or 50 large 55,000-bbl. tanks assembled on one tract of ground. Such tanks are usually spaced 200 to 300 ft. apart. Each tank is surrounded by an earthen reservoir. In case of fire and the bursting of an oil tank the burning oil is confined to the reservoir or sump.

Oil-Tank Fires.—Oil tank fires (see Fig. 69) result largely from ignition of the gases from the tank during electrical storms. The escaping vapors are ignited by the lightning. Such storms are rare in California. In Oklahoma and Kansas the loss has been as high as twenty 55,000-bbl. tanks in a year or over 1,000,000 bbl. of oil. In Oklahoma and Kansas oil tank fires are numerous. Occasionally, careless handling of matches or smoking causes fires, but such cases are rare.

Cunningham Protector.—There are several methods of fire fighting. Prevention is, of course, most desirable. Along the line of prevention from electrical storms there is the Cunningham Fire Protector. (See Fig. 70, page 164.) This consists of a device through which the gases and vapors from the stored oil must pass. The roof of the tank is sealed tight by a treated canvas cover. Then the trap, or device for escaping gases, is placed at the highest point on the roof.

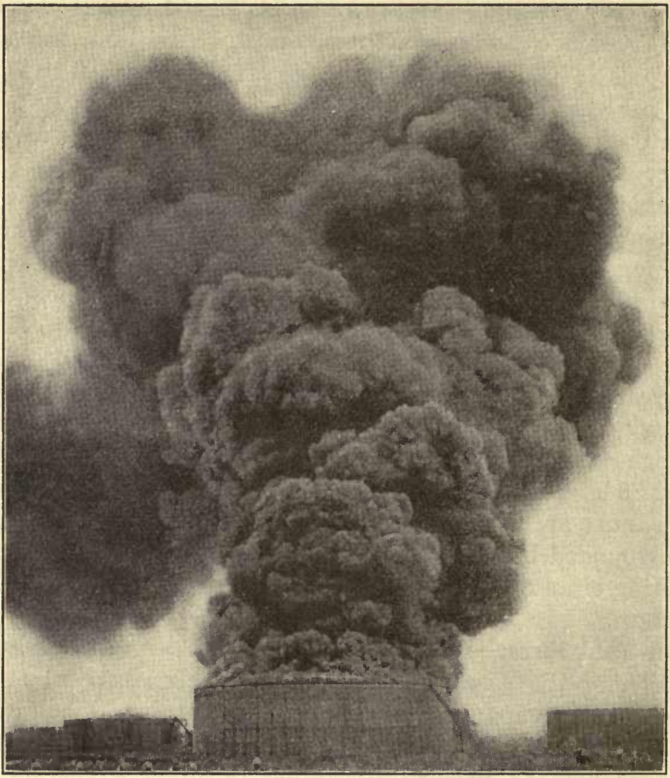


FIG. 69.—Oil-tank on fire at Cushing, Oklahoma.

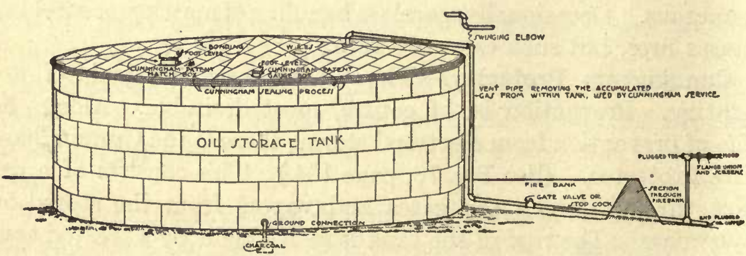


FIG. 70.—Indicates in a general manner the installation of the Cunningham Tank Protector System. (*Courtesy Cunningham Tank Protector Co.*)

The gases are carried to a point beyond the dyke or fire bank around the reservoir, and are there allowed to escape through

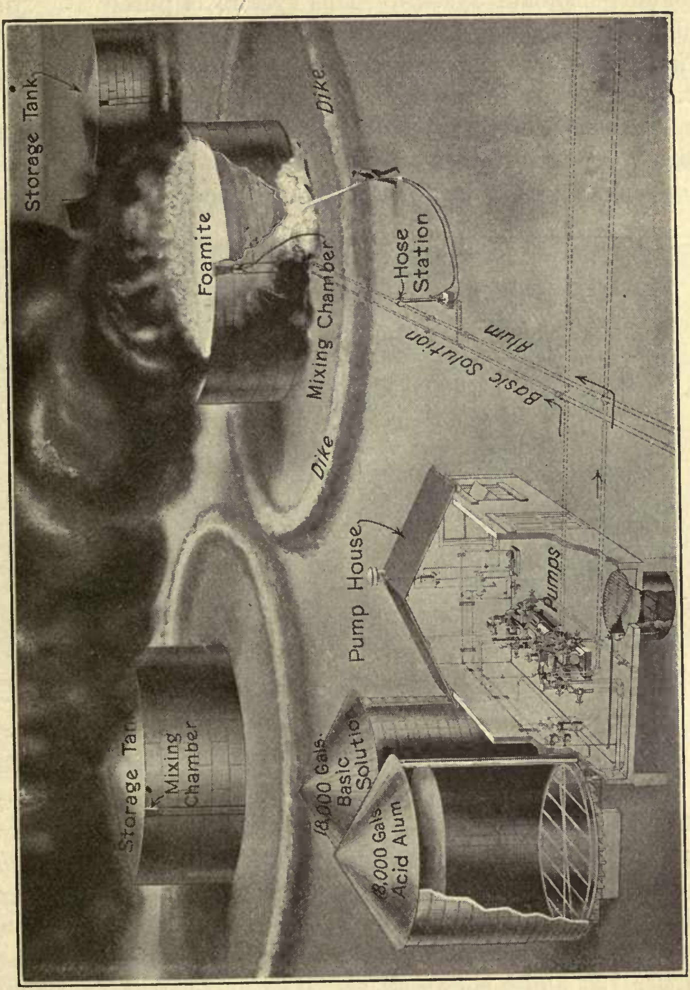


FIG. 71.—Foamite fire-fighting system in operation.

a screened hood. The claims made for this system are that the sealing of all the vents in the tank prevents the fires and also prevents large evaporation losses. Fire fighting and preventive measures also reduce insurance rates.

Foamite-firefoam System.—This system is purely an extinguishing one after a fire has started.

Figure 71 shows the system working. Alum is in *A*, the acid tank, and licorice in the *B* tank, each holding 18,000 gal.

In case of fire, these solutions are pumped to the mixing chamber on the storage tanks. As soon as mixed, chemical action commences and a thick foam is formed. This foam flows

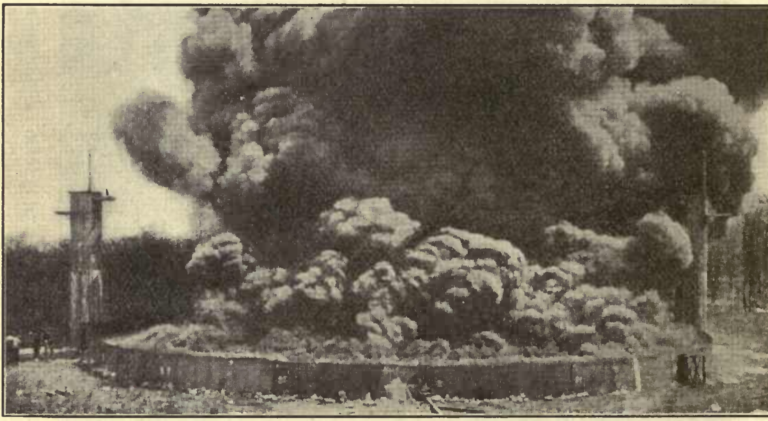


FIG. 72*a*.—Huge 55,000 tank fire at its height. Note strong wind blowing.

from the mixing chamber over the surface of the burning oil. The chemicals generate carbonic acid gas which chokes the fire and at the same time the foam excludes the air. In a few minutes the fire is extinguished.

It is important to keep the solutions in tanks *A* and *B* separate until they meet in the mixing chamber.

Figure 71 also shows a hose extinguisher for small fires, which may occur on the outside of a tank, on the tank farm.

Figure 72*a* and *b* shows an actual example of the system at work.

Steam.—Another extinguishing system, not so desirable as Foamite, consists of turning steam into the top of the tank to snuff out the flame. Steam lines are run from the boiler plant. These open into the tanks and, in case of fire, the steam is turned in. If used early this method is effective, but in big tank farms such a system is impractical, as the boiler plant is far away from some of the tanks and could not deliver steam enough to snuff out the flames.

Sump holes are built around storage tanks. In case of fire it is often necessary to turn the water from the bottom of the tank into the sump, as the fierce heat of the burning oil generated

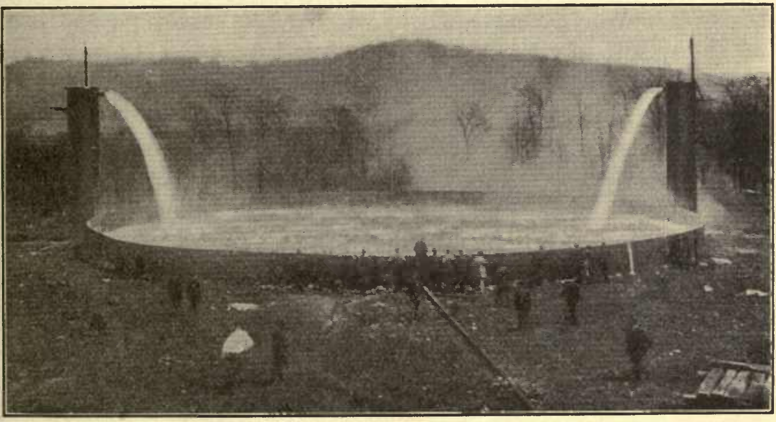


FIG. 72*b*.—Illustration 48 seconds later than 72*a*, showing how effectively the blanket of foam smothered the blaze.

steam from the water in the bottom of the tank and might cause an explosion that would spread the fire. Clearance of at least 200 ft. should be maintained between tanks on tank farms.

Fires in Oil Fields.—Fires in oil fields are due to a number of sources. Derricks catch on fire because of friction of the crown pulley from bailing. Cigarettes, cigars or matches cause fires around the oil rigs. Crossed wires may cause sparks. Spontaneous combustion of waste or rags, grass fires, or leaking gas lines all cause fire. These causes can be removed readily by a little care and vigilance.

Once a derrick starts burning it is only a few minutes (10 to 15) before it will fall over. It may be desirable to control the fall of a derrick to save buildings, and this can be done by pulling on the guy wires in the desired direction.

Friction of the flowing oil may heat the top of the casing and cause combustion, or a fire may start because of the carelessness of some workman, through a lighted match, cigarette or cigar. Once on fire, a flowing well is a difficult problem to fight. Control valves should always be placed on drilling or producing wells where flowing oil or gas wells are expected. If the fire starts it can be extinguished by closing the valve and shutting off the supply of oil or gas.

When a well is not equipped with such appliances the first method used is to try to smother or snuff the flame with steam. A battery of boilers is quickly assembled and steam lines laid near the burning well. Then the steam from the battery is turned on all at once and the fire may be smothered; or a gust of wind may carry the flame above the oil or gas for an instant, and the steam will snuff the flame.

Where the fire is too vicious for the ordinary steam method, tunnelling to the casing has been tried, and control has been gained by crushing in the casing by means of jacks until the flow is reduced sufficiently so that the steam could snuff out the flame. In other cases a stream of mud has been played into the crater formed by the burning well until the mud finally extinguished the flame.

In November, 1914, a 30,000-million gasser in the bottom of the Cimmaron River Bed in the Dropright Pool of the Cushing Field was extinguished by an ingenious method. Steam had been tried without success. Then a wire cable was suspended from a derrick on one bank to one on the other. A heavy boiler smokestack, open at the top, was hung on this cable and pulled over to the burning gas well. The idea was to drop the smokestack over the gas well and control the flame so that it could be snuffed out by steam. A number of attempts were made to swing the stack into place, but the gas pressure and the volume were so great that the plan was abandoned the first day. Later efforts succeeded, however, and the flame was snuffed out and the well controlled.

No rules for fire fighting can be laid down, but rigid rules regarding smoking around wells can be enforced and other preventive measures employed. Boilers should be placed far enough away so that gas from an unexpected sand cannot be ignited from the boiler fire.

Also, the bits should be dressed outside of the derrick floor, especially in areas where the depth to gas or oil-sands is unknown. Where such depths are known the bits may be dressed, and fires can be maintained until the sands are nearly reached. Even in such cases, however, great care must be exercised.

Grass fires sometimes cause the burning of derricks, and all grass should be cut from around derricks, tanks, and oil sumps. Moreover, the habit of looking for leaks in gas lines with an open flame should be discouraged, as grass fires are sometimes caused that way.

CHAPTER VII

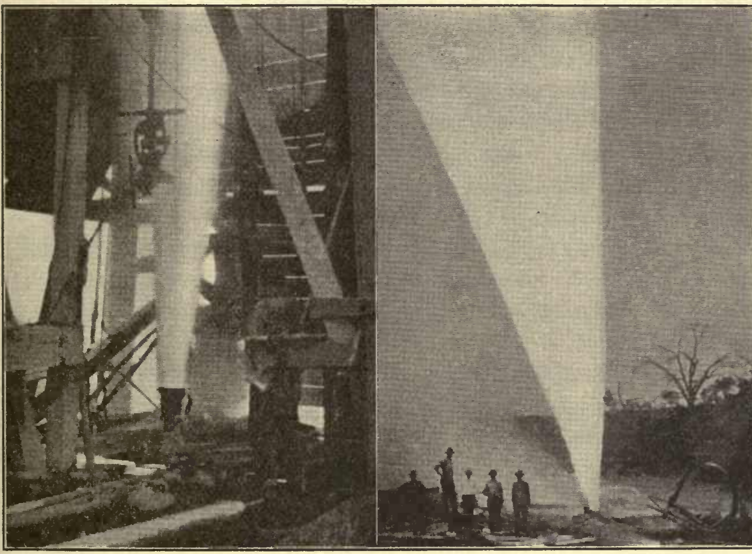
AVOIDABLE OIL-FIELD WASTES AND LOSSES

In no industry perhaps has there been greater waste than in the production of oil. The transportation, refining and marketing departments of the industry are highly standardized, but in seeking for oil and in handling the oil after it has been found, there is admittedly waste, although it is doubtful if much of it could be avoided, considering the methods employed in the past.

There has recently been much discussion regarding better operating methods in the oil business. For a number of years the United States Bureau of Mines and the United States Geological Survey have been making studies and experiments with a view to the conservation of our oil resources. The efforts of these Bureaus are to-day better understood than they were formerly, because of a policy of publicity and educational campaigns that were greatly needed.

In the past the petroleum industry was unorganized; each operator was out for himself and the "devil take the hindmost." To-day the American producers, refiners, and distributors are doing good work in coöperating to overcome wasteful production methods. Money was made so quickly in some fields that economies seemed petty, but in many instances willful ignorance of what constituted true economy produced almost criminal results. A few barrels of oil flowing down a creek is not a great waste, but a 50,000,000 cu. ft. daily gas well allowed to flow wild for months is a shameful waste, not only of fuel, but of lifting force in an oil field. Perhaps the gas has no immediate value, and in some areas may not have for some 20 years, but nevertheless its loss is a national waste. Its more immediate loss, however, is the fact that a decrease in the supply of gas means decreased oil production. Figure 73 shows some escaping as well.

In some cases such losses seem unavoidable. The question always is "Do the present demand and necessity for oil warrant the loss of a product like gas, which may not be economically valuable in a new area for many years, although a generation from to-day its value will be unquestioned?" In concrete form it may be stated; "Is it more important to conserve gas wells



A B

FIG. 73.—*A*. Gas wasting from a well being drilled. *B*. A burning gas well.

against future needs, or to develop an oil field which is of value immediately?" The immediate need, as against a future one, generally governs our actions. It does, however, seem a great national waste to see so much natural gas escaping. Legislation has to some extent checked such waste, but not by any means completely.

The employment of oil for fuel on the lease under boilers to generate steam for drilling or pumping is often a great waste. On some properties as much as 100 bbls. of oil per day may be used to generate steam. As high as 35,000 bbl. per year were so employed on one lease. At a value of $1.50 per bbl. this would mean $52,500.00.

The installation of gas engines using waste gas on a lease would save all the oil and pump the wells just as efficiently.

In the past one of the greatest losses was that of the casing-head gasoline which was allowed to escape with the flowing gas, and the light vapors coming off the oil as it flowed from the well. Great savings have been effected along such lines by the casing-head gasoline industry, which now obtains gasoline from the vapors in gas wells, from the vapors in flow lines of oil wells, and from the vapors escaping from the oil-storage tanks. The magnitude of this former waste can be appreciated by a study of the rapid growth of the casing-head gasoline industry.

The old forms of oil storage have given way to new. The earthen reservoir cannot compare with the steel tank. The escape of waste oil from flowing wells is now seldom allowed. Small streams of oil trickling down rills is a sight now rarely seen. In some of the early California excitement, however, a few such streams were dammed up and from 200 to 300 bbl. of oil per day were pumped from dams by people who appreciated the value of this waste product. In one instance—at Coalinga—this waste continued unchecked for over 3 years.

Losses like these, however, should be apparent to everyone. The great losses in the oil industry, which have not yet been remedied and which are a constant cause of unnecessary expense, may be summarized as:

(A) Unnecessary drilling due to
- (*a*) Poor locations,
- (*b*) Too many wells to acreage.

(B) Improper drilling methods due to
- (*a*) Poor drillers,
- (*b*) Inexperienced operators,
- (*c*) Dishonest operators.

(C) Low oil recovery due to
- (*a*) Allowing premature escape of gas,
- (*b*) Water troubles,
- (*c*) Inefficient operating methods.

Inexperienced operators often lose heavily by going into areas where there is little or no chance of success, and then expending large sums on unnecessary drilling equipment or on long hauls, with the result that they use up their money before they are fairly started.

Thousands of wells are drilled in the United States every year of which 80 per cent are successful. The balance, or 20 per cent, are unsuccessful wild cat or prospect holes in new areas, and dry holes drilled in the proven areas. (See Table 5, page 36.)

The greatest waste in such drilling operations is due to locating the test wells in areas that have so little chance for oil that the risk is not justified.

Geology reduces risk, and while geological tests are not always successful, it is safe to say that 1 success in 5 is a fair average. This is more efficient than 1 in 300, which is the proportion of success without geology.

Again, tests may be so located that they do not prove anything worth while. One hears the statement that the drill proves only 6 in. around the hole. This, however, is a sophistry. One properly located test may prove the entire absence of oil in an area, although under certain conditions several wells may be desirable. There are cases where dry holes occur in the hearts of oil fields, but this is exceptional. Also, some holes are drilled in granite or in igneous rock.

Wherever dry holes or abandoned wells are found, one stock story is current explanation for the failure. It is told from the Atlantic to the Pacific Coast. "They struck oil, but the Standard Oil Company bought them off, and plugged the well." I can say that in my experience and active travel in oil fields I have not found a single instance that would check up that stock story. In a few instances holes had been abandoned by oil men on lands that later were developed into oil property. It was the misfortune of the earlier operators to lose. Whenever this stock story is told, smile at it and admire the nerve of the oil man who spent his money on a failure and gave up only because his funds were exhausted or his drill would go no further.

Everyone who drills wells knows the discouragement of "dry holes," and can laugh grimly at tales of "being bought off." Fraud may occasionally be practised, but very seldom.

An accurate history of the oil fields would recount numerous instances of men who have drilled 40 or 50 dry holes before making a successful strike. One operator drilled 150 dry holes before success crowned his efforts. This drilling was carried on in areas of shallow and medium depth in the Eastern and Mid-Continent areas at a time when wells cost from $5,000, to $10,000. The persistency and bull-dog tenacity of the old-time oil man is well illustrated by these pioneers. It can be truthfully said that a true oil man must be an optimist of optimists.

The human side of the history of the oil industry is full of stories of nerve and courage—of strong men who blazed the way for the rest of us. We should thrill with pride and admiration for the pioneers who forged ahead of the crowd and opened new fields under the most discouraging conditions. Many of them failed to reap the fruits of their efforts, and in numerous cases the only monuments such men have left behind them are the oil fields that have been developed because of their earlier efforts.

The courageous spirit of our American oil pioneers has been handed down to their sons, and now that Americans are invading foreign fields, this spirit will win out. Englishmen may boast of their control of foreign fields due to the diplomatic assistance of their government, but when the future history of the world's oil fields is written, we shall find American names and American companies playing a big part in foreign fields, despite our late start. Anyone who knows Americans, their courage, and tenacity, can feel only confidence in the final outcome of America's place in the struggle for control of the oil supplies of the world.

Saving Dry Holes.—At least 95 per cent of the dry holes now drilled could be avoided. Some dry holes must be drilled. Operators, however, in outlining a proven oil pool now start a score or more holes where three or four would limit the pool just as well.

After oil has been found the system of close off-setting is sometimes followed. Unnecessary line fights which are wasteful may develop. In some areas town lot drilling is resorted to, which means that four to five wells per acre are drilled where one well to 4 acres would be ample. Such excitements are not rarities. They have been experienced in pools like Burkburnett, Texas; Paola, Kansas; and Cleveland, Oklahoma. In some places, as at Spindletop, Texas, the acreage is parceled out into lots as small as $\frac{1}{16}$ acre. Such wasteful drilling should be avoided or regulated by law.

Even good operators, however, often put too many wells in a given area. In the Ranger and Stephens County areas of North Central Texas one well to 20 acres would be sufficient to obtain all the production, but one well to 5 acres was considered good practice.

Escape of Gas.—Allowing natural gas to escape is one of the greatest sources of loss in the oil industry. Natural gas is the cheapest lifting power available.

Inexperienced Drillers.—Other wastes are due to poor or inefficient drillers, or drillers unfamiliar with the areas in which they are drilling. It may also be the tendency of drillers to loaf on the job. Hundreds of thousands, if not millions, of dollars are lost every year by inefficient drillers. Such men either do not know their business or deliberately make work last longer than is necessary. The latter can be done only too readily. Drilling troubles can be innumerable, and every trouble possible and plausible.

Inexperienced Oil Operators.—Many oil companies are managed by men who know nothing at all of the oil business, and who undertake important operations like drilling oil wells without any idea of the risks and difficulties to be encountered. Such men will raise $25,000 for drilling a well when $50,000 is needed. As a result they run out of money quickly and must re-finance, if possible. Thousands of holes have been suspended due to the lack of the funds necessary to complete them to the depth necessary for a thorough test. Such holes not only cause financial losses but do not test the area drilled.

Dishonest Operators.—Dishonest operators are not plentiful.

They are the parasites of the oil business. This applies especially to the cheap operator or promoter who makes his money by organizing a company and selling stock to the public on the basis of "blue sky" alone. Such a man may personally get a lease for $1000 and turn around and sell it to his company for $50,000, knowing that it is not worth 50¢. Yet he has taken his profit legally.

Waste of Gas.—The greatest loss in efficiency is in wasting the natural gas. In oil fields it is not an uncommon thing to have the drill touch the oil sand, and where heavy gas is encountered allow the gas to flow until the well "drills itself in." Wells making 10,000,000 cu. ft. per day have flowed wide open for 3 months. In actual heat units that meant a waste of 10,000,000,000 B.t.u. In terms of coal of 12,000 B.t.u. per pound, that meant 833,333 lb. or 416 tons of coal per day, or 526,315 lb. of oil, equivalent to 1571 bbl. of 335 lb. each. And this waste went unheeded. It is not alone the waste, although that is most serious and is important, but the fact that we have thrown away the cheapest and best lifting force for oil that can be found.

The best example of common-sense handling of flowing wells with gas is the Salt Creek Field in Wyoming, and it furnishes undisputed evidence of the value of gas as a lifting agent.

The big flowing wells in the Maricopa Flats, California, were controlled wells. The same wells were capable of flowing from 5000 to 20,000 bbl. per day if turned loose, but they were held down to a flow of 500 to 1000 bbl. per day, with the result that they flowed several years without resorting to pumping, some even as long as 5 years. Flow plugs of extra hard steel from ½ to ⅝ in. in diameter were inserted in the flow lines, and the oil passed through these plugs which acted as reducers. Such well control means ultimately more oil, and lower operating costs. Oil recovery is higher, as the gas both drives and sucks the oil out of the pores.

Water Menace.—Water is a constant menace in the oil fields. Many operators do not understand water conditions. They all agree that water in large quantities is a bad thing, but do not take the time to study the reasons for its presence. "If we've got water, what more can be said?" is the attitude of many of them.

Pennsylvania and West Virginia "old-timers" did not understand the new conditions obtaining in the California or in the Mid-Continent oil fields. "Flooding," in the sense of killing the oil sands by the infiltration of waters from top or bottom, was not well understood by eastern operators. The fact that water from holes several locations away from producing wells might destroy good wells was not brought home to the oil men until careful engineering tests were made. To-day, however, there is no excuse for careless or slip-shod methods of handling water problems. Sooner or later most of our oil fields will be flooded with water, but premature flooding is inexcusable.

SOURCES OF WATER

There are two main sources of water in all oil fields: water confined in the oil-bearing strata and water occurring separate from the oil zones. In the first case water is sealed in the oil sand and normally it underlies the oil and gas. It may be sulphur or salt water, or, in fact, may contain many minerals. Originally it was meteoric or rain water that percolated through the earth until it reached the oil strata, where it was sealed or held in by the shaley or clayey beds that are generally found above and below the oil sands. In some cases, however, this water is the sea water contained in the shales and sands before folding occurred. This water is generally under pressure, and as it is already in the oil zone, there is no way of eliminating it as a source of trouble. However, where there are two or more oil zones and but one is troubled with water, there may be great economy in shutting off one of the troublesome zones.

On the whole, water confined to the oil zone is less dangerous to the industry than water occurring separate from the oil zone. The latter may occur above, below, or between the oil strata. Generally occurring under head and in large quantity, it becomes a source of great danger to an oil field when it enters the oil zones. Indeed it is the water most to be feared and most to be guarded

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against. Obviously, such water enters the oil zones only as the result of artificial or man-made causes, as the oil zones and water-bearing strata are separate and distinct. Earthquakes or volcanic upheavals may cause faulting and shattering of the formation to such an extent that water enters the oil zones from the separate water sands, but for all practical purposes the latter causes will not be considered.

Two sources of water have been discussed. For the sake of clearness all those waters originally confined in the oil zone will

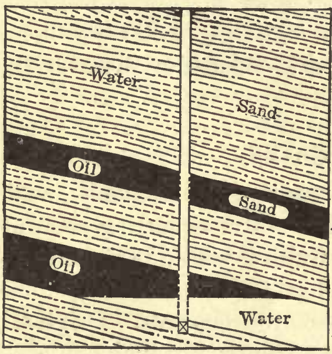


FIG. 74.—Bottom water encroaching on horizon B.

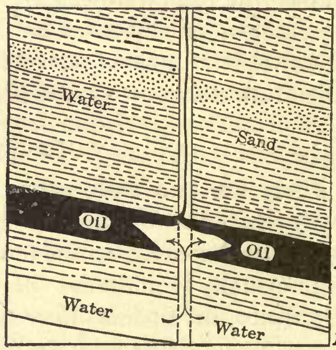


FIG. 75.—Water from B. flooding A.

be called *primary* waters, and all waters occurring in strata separate from the oil zones and entering the oil zones from artificial causes will be called *secondary* waters. These definitions refer to the original sources of the water. The terms "top water," "bottom water," "intermediate water," "surface water," and "edge water" are in constant use by oil men to express the occurrence of water in oil wells, especially those newly drilled. These terms do not take into account the sources of the water, whether or not it was originally confined in the oil zone by natural processes or introduced by artificial means.

Primary Water Troubles.—Primary water, as above mentioned, lies at the bottom of the oil sand under pressure. As the gas and oil are withdrawn from the sand, the water rises to replace them.

In time nearly all the oil is drawn from the sand and only the water is left. The field must then be abandoned. This is the result of natural exhaustion and is expected in most fields. Where there is but one oil zone, little avoidable danger or trouble occurs. Assuming, however, two strata (Fig. 74), as is commonly the case, water will rise from the lower stratum, *B*, into the upper stratum, *A*, unless proper precautions are taken to avoid this condition. Where the gas pressure is strong the water in *B* will be driven into *A*. Especially is this true when zone *B* becomes all or nearly all water (see Fig. 75). By properly confining the water to the bottom zone, water troubles would be averted for a time. Again, there is an extreme condition as shown in Fig. 76, page 179, in which the water takes possession of *A* and then enters *B*. This requires that the water in *A* be kept from *B* by methods differing from those used in the two previous cases.

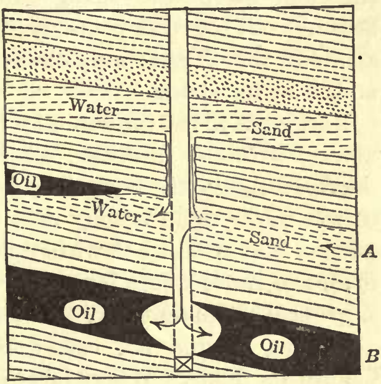


Fig. 76.—Water from horizon A. flooding horizon B.

These cuts illustrate the extremes of water flooding. Such conditions are theoretical, but are closely approximated in the oil fields. Generally all the oil is not driven from the well, but exists as an emulsion of finely divided oil and water which is very difficult to treat. However, the two cases given act as the limits within which all primary water troubles of the flooding type may be placed.

Secondary Water Troubles.—Secondary water enters the oil zones due to five causes, namely:

1. Accidents to the casing used in shutting off the water sand.
2. Faulty cementing of the water sand.
3. Cave-ins, due to the withdrawal of a large quantity of sand from the oil stratum, thus allowing water to enter the oil zone from above.

4. Cases where no effort has been made to shut off the water formation, especially in prospect holes.

5. Water from neighboring wells.

Accidents to the casing that shuts off the water may result from the dropping of sharp-pointed tools, bailers or sand pumps into the hole, or from falling tubing. The casing may be eaten, due to the corroding action of the minerals in the water, and later collapse. The cutting action of sand in a flowing well is often sufficient to cut the casing. Sometimes the casing is defective or is not put together properly. Again, the sudden shifting of the sands in the oil zone may cause the casing to pull apart or break at the water string.

Accidents to the cement may result from the causes enumerated above, without, however, affecting the casing to any marked degree. Again the cement may be improperly mixed, the action of the water upon it may destroy its efficiency, or it may be so porous that it will not withstand the water which seeps through it and in times wears large channels. Where the water pressure is great, the cement may be ineffective.

Caving around the casing is of common occurrence in the California fields. Where large quantities of sand, often 50,000 to 100,000 cu. ft., are taken from the oil zones, there must of necessity be left some form of cavity underground. This cavity leaves the roof above it unsupported. Where the roof consists of soft shale or clay, caving is inevitable. If the distance between the oil zone and the water stratum is slight, such a caving would assuredly admit water to the oil sand.

In cases where no effort is made to shut off water, the consequences are often very dangerous to the life of the field. Then the water has free scope and soon floods the near-by portion of the field and later may spread over a large extent of good territory. "Wild-cat" drillers are especially prone to neglect the proper precautions to shut off water. When he strikes oil the speculator sells his property and leaves the purchaser to shoulder the burden of responsibility. Sometimes these properties stand idle a long time and in consequence become worthless.

One well may make water and later flood other adjacent wells. Such water introduced into other wells may also be classed as secondary water, as improper casing methods allow this infiltration of water from one well to another.

Correcting Water Troubles.—The fact that should be emphasized is that in most cases water troubles can be to a great extent eliminated, and in others entirely overcome. The methods employed are largely those of common sense and practical engineering. The beneficial results of such treatment are quite apparent. Wells that have made as much as 100 bbl. of water and only 4 or 5 bbl. of oil have, when the water was shut off, produced 10 to 20 bbl. of oil and no water.

The shutting off of water also decreased the lifting expense to a very marked degree. Wells that once pumped in the third hole were later pumped in the second, and instead of pumping 24 hr. were pumped only 4 or 5 hr. per day, which makes a large saving in expense and also in the wear and tear of rods and tubing.

Shutting off the water increased the production of casing-head gasoline on one lease from 400 gal. per day to an average of 1400 gal., and only three wells were treated.

In starting to correct water troubles, it is essential to know:

1. Whether the water is primary or secondary.
2. Whether or not natural flooding has taken place.
3. Whether or not the well has been drilled too deep.
4. Whether or not casing trouble in the well is letting in water.
5. Whether or not water is coming from a neighboring well.

To ascertain these facts a careful survey of the property and its neighbors must be made. Natural conditions must be studied and maps and cross sections made.

After carefully studying conditions, a plan of procedure is outlined. In some wells cementing may be necessary, new casing points in others, or total abandonment may be advocated for some wells.

Once the trouble has been ascertained the practical field man steps in and proceeds to doctor the wells in accordance with the general remedial plan.

The various methods of combating water troubles are:

1. To put the walking beam in the third hole, thus gaining a longer pump stroke, and speeding up the wells to pump as fast as possible.
2. To install air compressors and use air lifts for handling the water.
3. To abandon the hole.
4. To shut off the water:
   (*a*) by wooden or lead plugs;
   (*b*) by packers;
   (*c*) by cementing;
   (*d*) by mudding off the water.

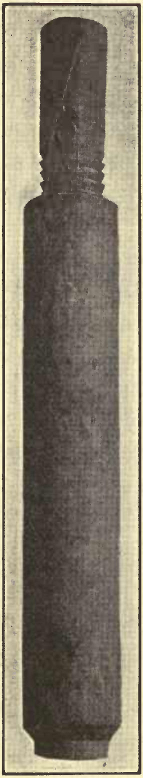


Fig. 77.—Expansion type of lead plug.

1. Where wells are pumped rapidly, rod and tubing troubles follow quickly. "Crystallized" rods result from the fast pumping and breakages are more frequent. Shutdowns due to such causes sometimes average as high as 40 per cent of the pumping time. When wells are shut down production is lost, due to loss of time. When again on the beam it is noticed that the wells may pump water for several days before making any oil.

Another loss is that of the casing-head gasoline content. Vacuum pumps will not work with any efficiency on water-flooded wells, especially when the oil sand is submerged.

The high cost of pumping small wells increased so rapidly that in the North Cushing, Oklahoma, pool wells were abandoned when making a few barrels of oil because the lifting expense was greater than the value of the oil.

2. The pumping of water by compressed air is an expensive system, with the other remedies available. The compressed air system of pumping water will not be described here as its use is unnecessary with present methods of handling water troubles.

3. There are occasions when water has flooded the sands completely; when knowledge of the sands in the well is so incom-

plete; when the hole is full of tools which cannot be fished out, that abandonment of the hole is justified.

Wooden and Lead Plugs.—"Bottom water"—that in the bottom of a sand—may be shut off by using wooden or lead plugs (see Fig. 77, page 182).

These plugs are let down to the bottom of the hole. A hole drilled into the middle of the plug holds a mandrel or round wedge. When this is driven down the wood, or lead as the case may be, is expanded and fills the drill hole. Some fine mud placed on top of this may assist in shutting off the water. This method fills a temporary need, but is not the most efficient.

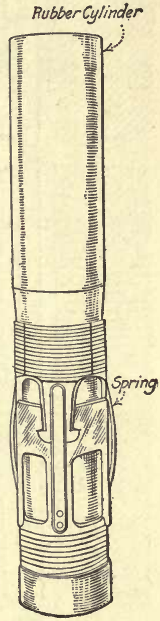


FIG. 78.
Wall-packer.

Packers.—Before cementing methods were so well developed, packers were much used to shut off water. In the Mid-Continent and Eastern fields, where cementing methods are not so well recognized, they are still greatly in favor. In hard formations, where limestone or hard shale beds are found, packers may be used to advantage.

Packers are placed on the tubing or on the casing, and shut off the water. They are of two main types:

(*A*) Wall packers.

(*B*) Bottom packers.

Wall packers are of several types. The device shown in Fig. 78, page 183, is placed between joints of casing and let down on the casing string to a point above the oil sand where a hard limestone or shale bed is found. This packer consists of two cylinders, which partly telescope. A rubber cylinder is placed on the outside of the upper cylinder. When the casing is turned a catch is released and the upper cylinder, forced downward by the weight of the casing, tends to telescope into the lower cylinder. This expands the rubber against the wall of the hole and makes a tight joint. The casing is then turned which sets the packer tight against the wall of the hole. Any water above the packer is excluded from the hole. Where much open hole is left, the packer may be set on a string of tubing instead of casing.

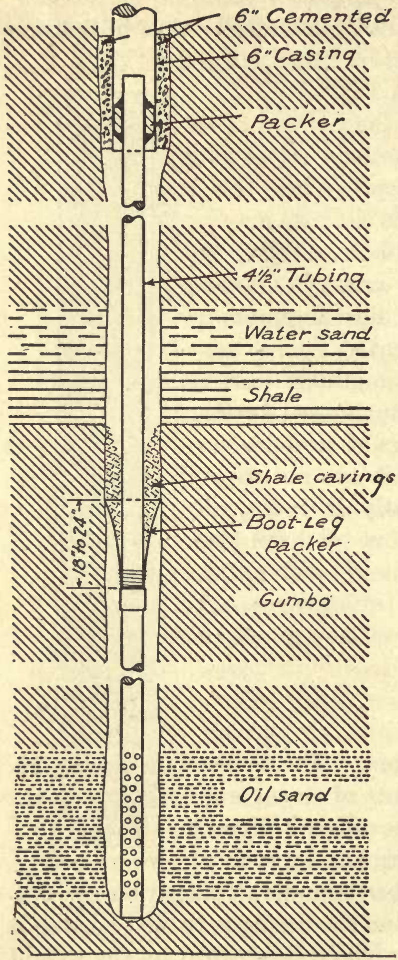


Fig. 79.—Bootleg-packer and its use. (*After U. S. B. M.*)

Another type of packer, called the "boot-leg," shown in Fig. 79, has much the same action. The "boot-leg," however, is a homemade affair, of canvas or leather riveted together, and is conical in shape. The upper part flares out. This packer is set below the water sand. Mud or soft shale cuttings are put in the hole above the packer and settle in the "boot-leg." This causes the "boot-leg" to expand, and makes a tight joint with the wall of the hole.

Seed bags filled with flaxseed are sometimes wrapped around the casing. When soaked with water the seeds swell and form a tight joint.

Bottom Packers.—Bottom packers are used in place of plugs. They are of several types. The screw packer, shown in Fig. 80, is a new packer. It is placed in the bottom of the hole, above the water horizon. The screw is turned and the packing is set tight against the wall of the hole. This forms a tight seal. Other types of bottom packers are used.

Sod has sometimes been used in place of a packer. The bottom of the hole is filled up to the oil sand with sod, which is tamped tight. This may make an effectual shut-off.

However, cementing is superior to all other methods.

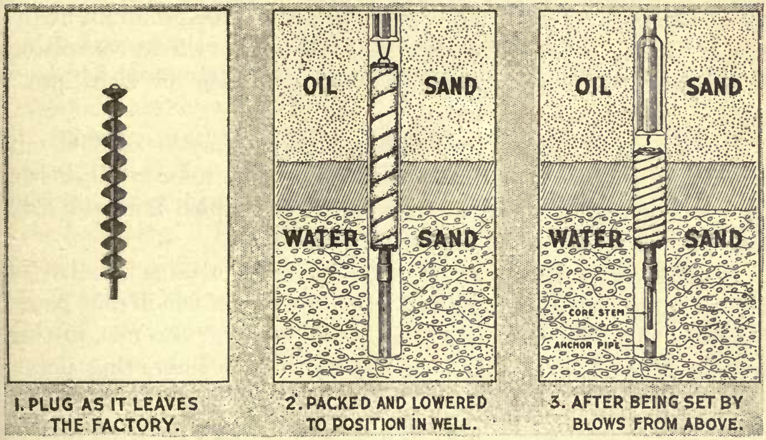


FIG. 80.—Screw packer for bottom water.

Note the illustrations. The spirals as shown in 1 are made of boiler plate steel. They are fastened to the core stem by means of the top plate, stretched into position with powerful tension, and held so stretched by a fragible dowel driven through the anchor-socket on the bottom.

To seal the well the plug is packed with oakum, and an anchor pipe is screwed on the bottom of a length to strike the bottom of the hole when the plug has reached the proper depth. The plug is then lowered into the well until this anchor strikes bottom. (See 2.)

The top of the plug is then tapped a few blows from above. This breaks the dowel pin, allowing the spirals to collapse and pushing the core down into the anchor pipe. As the spirals collapse they expand laterally, their edges taking a biting hold in the walls of the well. At the same time the packing is compressed and forced into every chink, crack and cranny. The slips in the anchor socket prevent the core from slipping back, so that the plug, once set, is locked in place. (See 3.)

Cementing Methods.—The use of cement in shutting off water is not a simple matter. Care must be taken not to cement off the oil sands, as has often been done. Delays in shutting down the wells must be cut down to a minimum. All these points must be borne in mind.

Cement should be used as an auxiliary in controlling water. Anyone can put cement in a hole and shut off water. This is not the problem involved. The idea is to put in the minimum quantity of cement to secure the best possible results where cementing is necessary. One may shut off water and also the rich "pay" sand. That must be avoided.

It may seem that a hole full of cement may be drilled out readily, but experience has shown that a hole may be drilled in the cement and a cylinder of cement is left which lines the drill hole and may effectually seal off the oil sand.

In following scientific cementing methods, a large number of factors must be considered, neglect of any one of which may cause failures. Too much cement, too little cement, too fast setting cement, too slow setting cement, the wrong cementing point, cementing when unnecessary, all may cause failures. Neglect of details in operations may cause failures, and it is because of such neglect and of failure on the part of oil men to appreciate the delicate nature of their wells that so little has heretofore been done to shut off water and check a menace of constantly growing importance.

Cementing is not a difficult process. The essential points in any cementing process are:

(*a*) Using proper cement.
(*b*) The proper quantity of cement.
(*c*) Method of introducing cement.

A number of excellent portland cements are used. Some set quickly; others are slow setting. A cement that hardens in 24 hr. may be used in some cases, or a cement that requires a week or two weeks to set may be employed. Cement may be dumped in a well with a bailer, or it may be pumped into a well with a string of tubing, or through casing. In cases of rotary drilling, it is pumped through the drill pipe.

Circulation is first obtained. By "obtaining circulation" it is understood that the water that is pumped into the well returns on the outside of the string of casing that is to be cemented. Circulation is carried on until the hole is free from drilling sludge. Good circulation insures the proper introduction of the cement.

One of the objects in cementing is to have all the cement possible between the wall of the hole and the casing. To insure this several methods have been employed. Two of the principal methods are described briefly.

Perkins Method.—With the Perkins method two plugs are used. (see *B*, Fig. 81). A wooden plug is dropped into the casing. Cement is pumped above this plug, which is driven to the bottom of the casing. The bottom of the casing is a few inches off bottom. A special shoe is used on the bottom of the casing.

When all the cement is in the casing, a second plug is dropped inside, and water is pumped in above this plug. The pressure of the water drives the second plug downward upon plug 1. When plug 2 reaches plug 1, all the cement is out of the hole. Also the back-pressure on the pump shows that the second plug has reached bottom, so the pump is stopped and the casing is lowered to bottom. Later the soft wood plugs are readily drilled up by the bit when drilling is commenced.

Tubing Method.—A second method of cementing commonly used is the tubing method. In this case tubing is put in the hole inside the casing. This string of tubing extends to within 5 or 6 ft. of bottom. A top packer is placed between the tubing and casing, so that when water or cement is pumped into the hole, circulation of water takes place outside the casing.

Cement is pumped through the tubing (see Fig. 82). When all the cement has been put in the hole, water is pumped in above the cement. A sufficient time for all the cement to reach bottom and collect outside the casing is allowed for.

The casing is next lowered to bottom, the tubing withdrawn, and the cement allowed to set.

Cementing methods consistently followed will give good results and insure safety from water. Cement not only acts as a

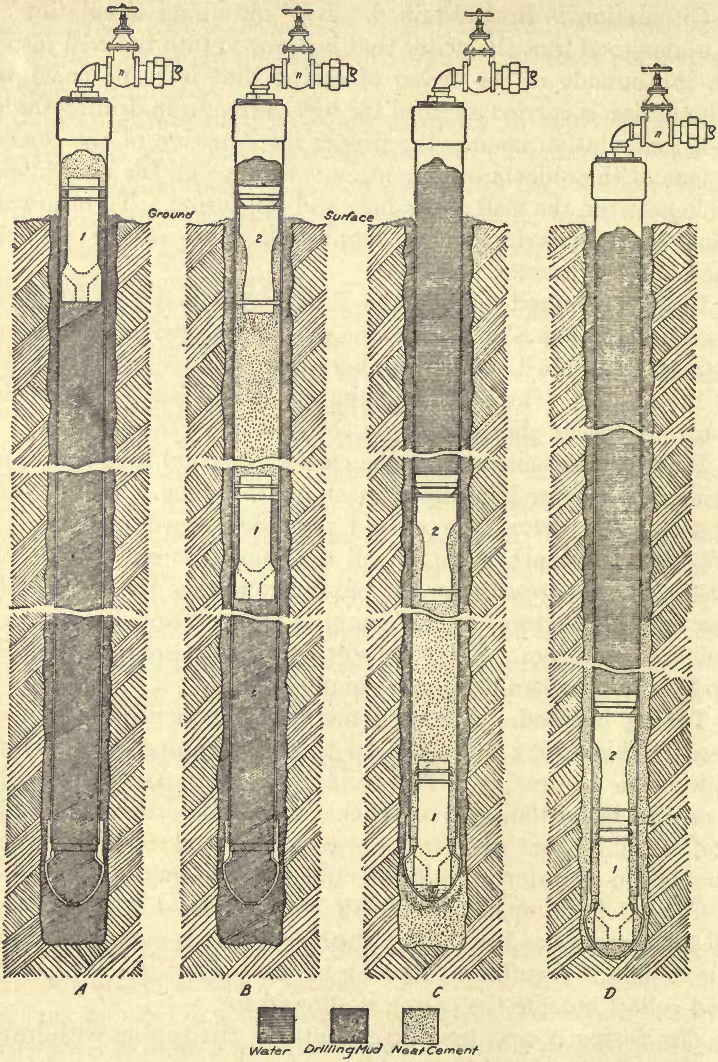


FIG. 81.—Cross-section showing different stages of the "Perkins Process" for cementing oil and gas wells. (*After U. S. B. M.*)

plug to shut off water, but also protects the casing somewhat from direct contact with acid waters that eat it up.

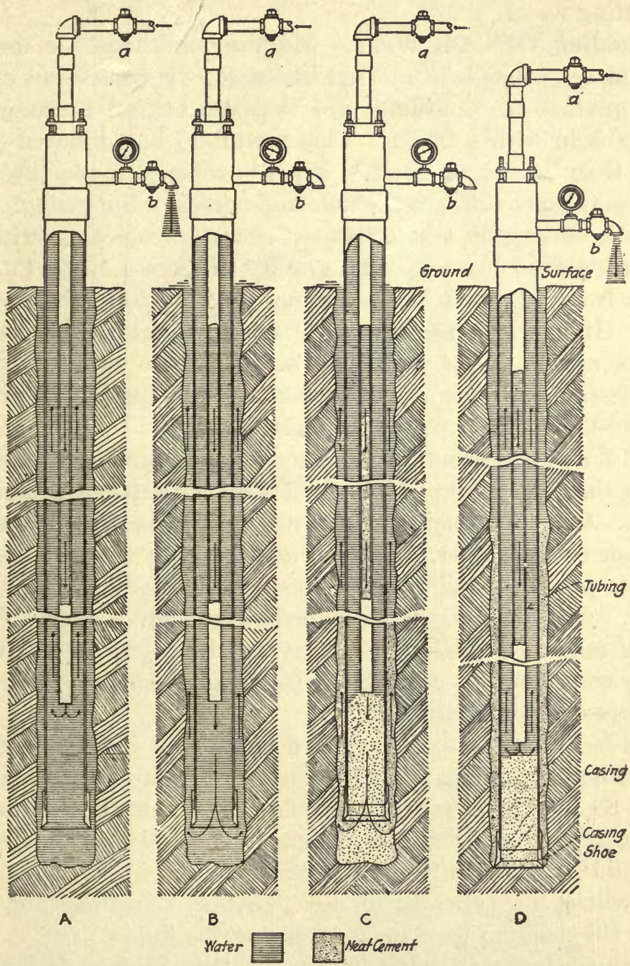


FIG. 82.—Different stages of cementing oil and gas wells by tubing method.

In some California oil fields the casing is badly eaten by the waters in the wells. In some fields casing will not last over

3 years, due to the corroding action of the water. This means either expensive replacement of casing or the flooding of a well by infiltrating water.

"Mudding Off" Oil Wells.—Mudding methods are used in many places where cement might be used. It consists of pumping a mixture of mud-fluid into the hole behind the casing, or putting it in with a bailer. This mud-fluid has different properties than water or mud.[1] When properly made the mud particles will not settle in the hole and "freeze" the casing. The fluid will effectually seal off water, as water cannot penetrate it. Mud-laden fluid has a specific gravity of from 1.15 to 1.3, and weighs from 72 to 81 lb. as against 62.5 lb. per cubic foot of water. It exerts a pressure of 0.499 to 0.564 lb. per square inch as against 0.434 for pure water. Some oil-field waters have specific gravities of 0.4 to 0.50, so the specific gravity of the mud-fluid must vary accordingly.

Mud-fluid may even take the place of casing and has the advantage in that when properly made it does not settle and bind the casing. As a consequence, casing may readily be pulled from the well 5 or 6 years later. Another advantage is the fact that the mixture protects casing from the corrosive action of oil-field waters. Also drilling may be carried on through the fluid. Mud-fluid is made by mixing pure clay or shale with water until a creamy consistency is obtained. Tests can be made to determine the proper specific gravity.

Mud-laden fluid may be pumped into a well just like cement, using either the tubing method, or it may be placed with a bailer. Figure 83 illustrates the use of mud-fluid in shutting off sands.

In rotary or in circulator drilling it is simpler to handle the mud-fluid than with the cable-tool system, as the pipe mixing facilities are already in use. Instead of tubing the drill pipe is the medium used for introducing the fluid.

Another use for the mud-fluid is in overcoming a flow of gas during drilling. In numerous cases high-gas flows check drilling

[1] Mud-fluid is a mixture of fine clay or shale and water to make a mud-fluid.

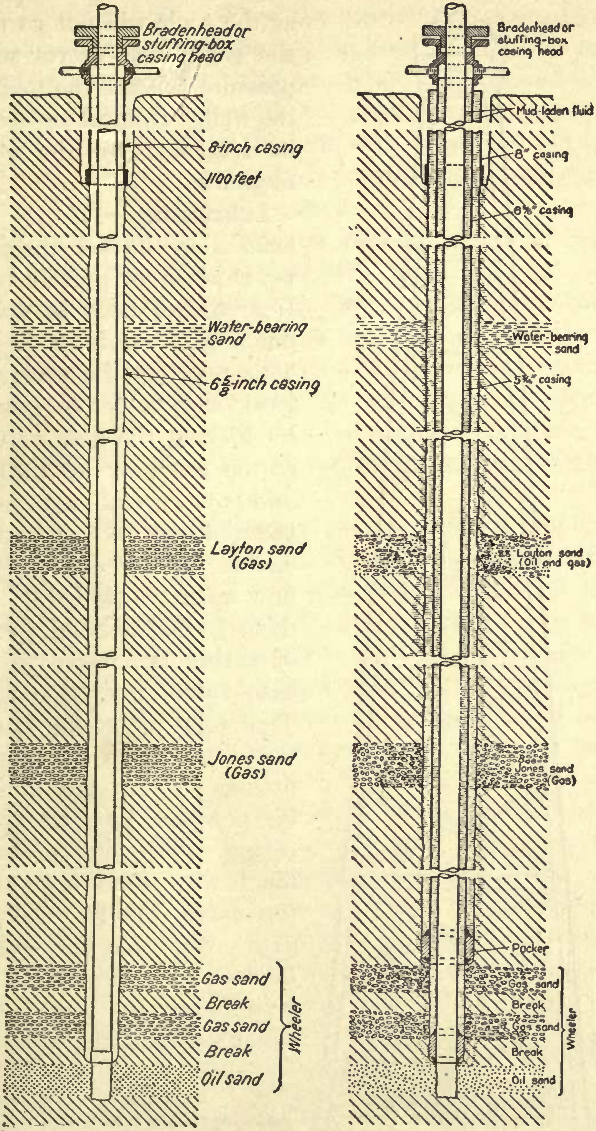
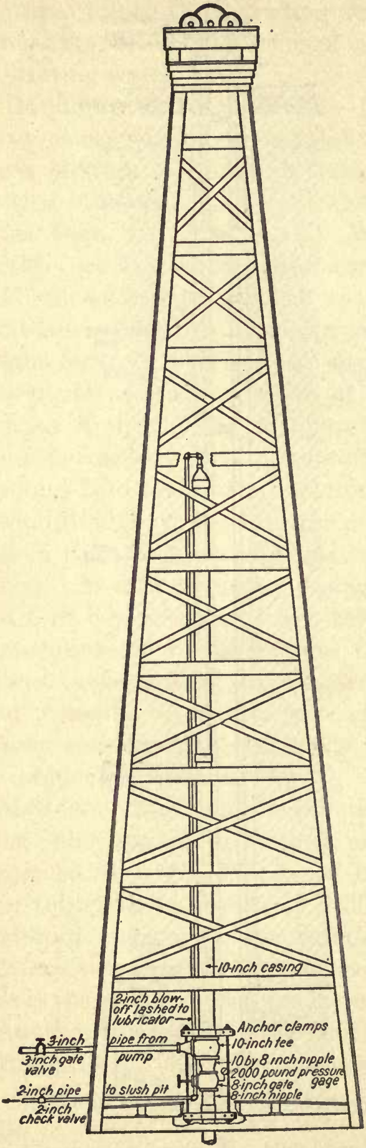


Fig. 83.—Shutting off sands by means of mud-fluid. *A*, Shows open passages about casing. *B*, Shows well finished with mud-fluid.



as the tools will not go through the gas which exerts sufficient pressure to force the tools out of the well. In most cases this can be remedied by the following methods:

Lubricating.—If a control head is on the well the gas may be shut in or greatly reduced. If a control head is not used, put a gate valve on the casing. This may call for several days' work with a heavy gasser but by leaving the gate valve open so the gas may go through it, and by careful manipulation, the well may be "capped." To enable further drilling, the gas flow must be "killed." This is done by lubricating. A joint of casing is screwed on top the gate valve (Fig. 84, page 192). This joint of casing has a top valve to which are connected fittings so that mud-fluid may be pumped into the joint of casing. The joint of casing is filled with mud-fluid and the top valve closed. The bottom gate valve on the casing is then opened slowly. The gas pressure on the mud is quickly equalized, and the mud falls to

FIG. 84.—Device for introducing mud-laden fluid into a well under heavy gas pressure.

the bottom of the hole. When the top joint of casing is empty, the bottom valve is closed, the top opened, and another batch of mud-fluid is pumped in. This procedure is continued until the gas is killed, which is not until the pressure is overcome by the mud. In some cases filling the hole with water will kill the gas, but at times the water pressure is insufficient to offset the gas pressure and mud-fluid must be used.

Drilling can now be carried on through the mud-fluid, and if desired casing can be set to case off the gas sand.

There are, of course, cases where "gas blow-outs" are so serious that the casing may be blown from the hole and, as in the case at White Point, just opposite Corpus Christi, Texas, craters large enough to hold sky scrapers may be formed. Under such conditions mudding might be successful, but such large craters demand a great supply of mud and water and equipment sufficient to fill them.

There have been a few cases where the gas pressure has been so high that it was impossible to drill after lubricating. At Sand Draw, Wyoming, the Producers and Refiners, in their drilling, encountered a pressure of 1550 lb. per cubic inch at a depth of 2300 ft. The company lubricated the well, but when it was opened and drilling with a rotary was commenced the mud-fluid was blown from the hole and no headway in drilling could be made. As yet no method of drilling through the gas has been successful.

Increased Oil Recovery.—One of the greatest single problems facing the oil industry is the problem of increasing the oil recovery. From all the data available average recovery on oil properties will not exceed 20 per cent of the oil in the sand. It has been proven by experimental tests on sands that from 40 to 50 per cent of the oil always remains in the oil sand, but the other 50 per cent should all be recovered. One and one-half times the amount at present recovered is left in the ground. Such conditions do not speak well for our methods of handling producing wells. That it is possible to obtain more oil than has been done so far was demonstrated at Bradford, Pennsylvania, and at Marietta,

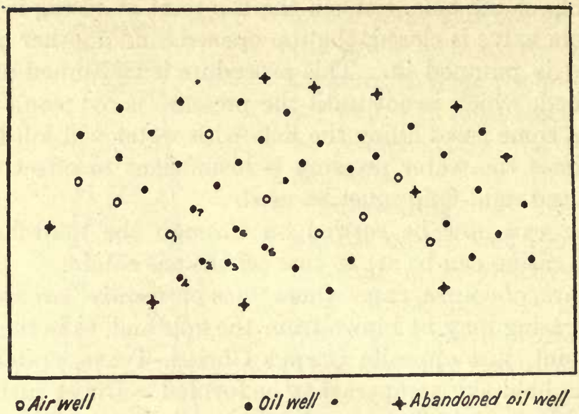


FIG. 85*a*.—Plat of oil property on "Chesterhill streak" near Pennsville, Ohio, showing irregular distribution of air wells caused by irregularities in the oil sand. Making well No. 1 an air well greatly increased the yields from wells 2 and 3 for a time; then the air "blew through" and made "by-pass" channels. No. 4 was a tight well and was not affected. Nos. 2 and 3 were then shut in and this increased the yields from Nos. 5 and 6. No. 7 and the other wells above were also benefited. (*After Bull.* 148, *U. S. B. M.*)

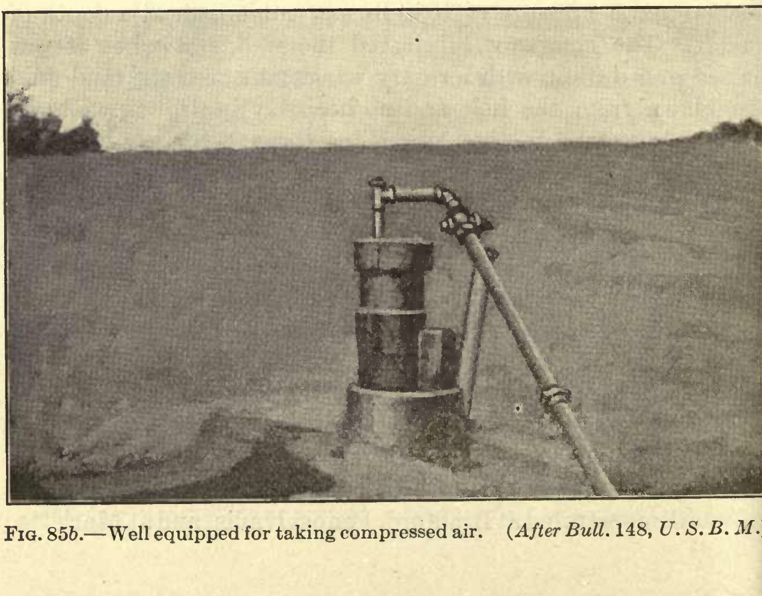


FIG. 85*b*.—Well equipped for taking compressed air. (*After Bull.* 148, *U. S. B. M.*)

Ohio. At the former place a water-flooding system is employed, and at Marietta the Smith-Dunn compressed air system is used. The success of those systems should encourage further study along the lines of increased recovery.

Smith-Dunn Process.—The Smith-Dunn or Marietta process consists in forcing compressed air into the oil sands to take the place of the gas that was drawn from the sands. The air is introduced in central wells (see Fig. 85*a*) and forces the oil to the surrounding wells. The air well must, of course, be sealed tight so that the air cannot escape (see Fig. 86). Production has been increased several hundred per cent due to this use of compressed air.

This method can be used to advantage in areas where there are thick shale bodies which overlie the oil horizon and form practically impervious covers which will not allow the air to escape.

The low dip of 10 to 20 ft. per mile and the ideal conditions at Marietta, Ohio, do not exist in all places, but experiments with this method may prove successful in other fields.

Bradford Flooding System.—The water-flooding system employed at Bradford, Pennsylvania, has given excellent results for that field. At Bradford the main oil producing sand is 40 to 50 ft. thick, is coarse-grained and very uniform in size of grain.

Procedure.—One central well is selected from a group of four or five wells. This well is filled with water to its full depth, which is 1100 ft. The hydrostatic head is 477.4 lb. (1100×434). The water spreads away from the hole in all directions and drives the oil outward from the water hole. The rate of travel is slow, 150 ft. per year, or less. Where the producing wells are 500 ft. apart a ring of new wells may be drilled inside to catch the oil. Old wells have gained from 100 to 1000 per cent by this method. Wells making ½ bbl. have, when flooded, made 2 to 5 bbl. Wells making 2 bbl. have increased to 10 bbl.

The same principle of flooding may be applied in other cases. The uniform, coarse-textured sand, the very low dip of the sand, 10 ft. per mile, give ideal conditions for the application of such a method. Modifications may apply in other places.

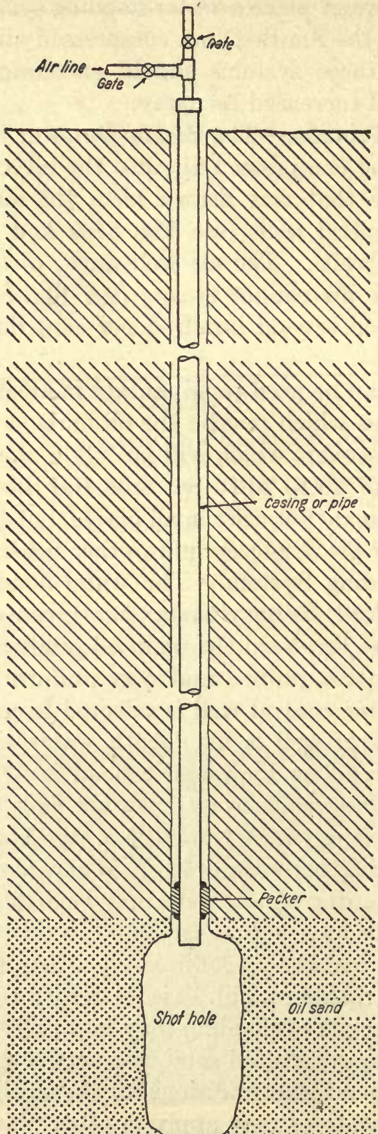


FIG. 86.—Diagram of a shallow well equipped for taking compressed air. (*After Bull.* 148, *U. S. B. M.*)

CHAPTER VIII

REFINING METHODS—CASING-HEAD GASOLINE

REFINING

Crude oil, as it comes from the wells, can rarely be used directly except for fuel purposes. The heavy California and Gulf Coast oils can be burned directly under boilers to generate steam, and are so used to a large extent. The lighter Eastern oils are rarely so used.

The value of crude oil depends upon the products that can be obtained from it by refining. Crude oil is a mixture of a large number of hydrocarbon compounds. When the crude oil is heated vapors are given off which when condensed give products such as gasoline, kerosene, fuel distillates, and wax, all having different physical properties.

Kinds of Crude Oils.—Oils in a refining sense are said to have paraffin, asphalt, or mixed bases. A paraffin base oil is one that has a waxy paraffin residue in the still. An asphalt base leaves an asphaltic residue in the still. A mixed crude is one that has both paraffin and asphaltic residues.

Examples of oil of paraffin base are the light oils of Pennsylvania and West Virginia; oils of asphaltic base are the heavy oils of California and the Gulf Coast area of Texas and Louisiana. Mixed base oils comprise the light oils of Upper Louisiana, of Oklahoma, Kansas and Wyoming. There is, of course, not only a physical but a chemical difference in such oils. The paraffin base oils belong to the chemical series $C_n\ H_{2n} + 2$; the asphaltic oils belong to the series $C_n\ H_{2n}$, and the mixed bases have elements of both series. Refining methods vary for each kind of oil.

The light Eastern and the Mid-Continent oils carry larger quantities of gasoline, and the lighter naphthas, than do the heavier oils of California and the Gulf Coast fields. Some idea of the products obtained and their per cents from 100 gal. of crude oil are given below in Tables 12, 13, and 14.

TABLE 12.—PENNSYLVANIA OIL, 100 GAL.

	Specific gravity, Bé,	Gallons	Gallons per barrel (42 gal.)
Gasoline	66.2	25	10.50
Turpentine substitute (naphtha)	51.9	15	6.30
Kerosene	45.7	15	6.30
300° oil	40.3	15	6.30
Non-viscous neutral oil	35.5	12	5.04
Viscous neutral oil	31.0	8	3.36
Steam refined cylinder stock	25.0	8	3.36
Refined paraffin wax	....	2	0.84

TABLE 13.—MIXED CRUDE: CUSHING OIL SHOWS 100 GAL. CRUDE

	Specific gravity, Bé,	Gallons	Gallons per barrel (42 gal.)
Gasoline	65.7	30	12.60
Turpentine substitute (naphtha)	48.2	20	8.40
Kerosene	40.1	15	6.30
Gas oil	34.6	15	6.30
Viscous neutral oil	28.0	10	4.20
Steam refined cylinder stock	24.0	6	2.52
Refined paraffin wax	....	½	0.20
Asphalt	....	3½	1.47
5 per cent loss in manufacture			

TABLE 14.—CALIFORNIA CRUDE (17.6°BÉ.)

	100 gal. crude, gallons	Gallons per barrel (42 gal.)
Gasoline, 61°Bé	2	0.84
Distillate, 52°Bé	6	2.52
Kerosene, 42°Bé	8	3.36
Stove oil, 34°Bé	6	2.52
Fuel oil, 28°Bé	30	12.60
Lubricating stock, 205°Bé	20	8.40
Asphalt grade *D*	25	10.50
Losses	3	1.26

Principles of Oil Refining.—The principles of oil refining are simple, but actual practice is quite complicated. It was early found that by heating petroleum it gave off hydrocarbon vapors which, when condensed or cooled, formed products having properties different from crude petroleum. If the temperature were raised to a very high point, all but a small per cent of the crude oil evaporated; the residue was a coke. It was found too that within certain ranges of temperature for the same oil a uniform product was formed. By using higher temperatures, other products were obtained.

The next move was merely the application of these simple facts to the making of various products in commercial quantities.

Instead of laboratory apparatus, steel stills similar to boilers were used. They are heated by fire from below or by steam coils inside, or by a combination of fire below and steam inside. Cooling and collecting tanks are necessary. The early apparatus was simple, but as the demands for various grades of products have developed many and various types of stills and coolers have resulted.

In present practice a refinery consists essentially of stills, condensers (coolers), agitators, for treatment of the condensed product, to take out bad odors and to give good color. Filters are also used to take out impurities and to give good color to the oil. Tanks to store the refined products are also necessary.

Boiler houses, laboratories and offices are all a part of the general plan of operation.

Refining Operations.—In refining, the scheme of operation centers upon the end-products and the by-products desired. If gasoline is the main object, the scheme will be to turn all products as far as possible into gasoline. If kerosene is the main object, gasoline must be secondary. Gasoline is, however, in such demand that at present it is the chief product of the refineries.

Before a comprehensive refining scheme for an oil is determined the quality of the crude oil must be known, and its peculiarities studied. A careful physical analysis is made and a laboratory refining test carried out. Actual commercial runs should be made where a large amount of oil is to be refined. The evaluation of crude oil will not, however, be treated here.

The scheme of a refinery is simple. It consists of:

(*a*) Crude oil storage tanks, to hold oil preparatory to refining.

(*b*) Stills in which to distil the oil.

(*c*) Condensers in which to cool the product as it comes off the stills.

(*d*) Agitators for the treatment of the condensed product to remove bad odors and impurities.

(*e*) Tanks in which to store the final products after treatment in the agitators or to hold the products left in the still.

(*f*) Filters to filter the oils.

(*g*) Wax presses and wax machine.

Once the character of the oil and knowledge obtained as to its best use has been determined, refining operations are commenced in earnest.

Refining Practice.—The refining of crude oil is divided into two stages:

(A) The separation into groups or "cuts" by distillation.

(B) The separation and finishing of the groups or "cuts."

The first stage is well illustrated in Figs. 87 and 88. The crude oil is run into the crude still and heated. The products are separated in the aerial condenser tower and then cooled in the water condenser box.

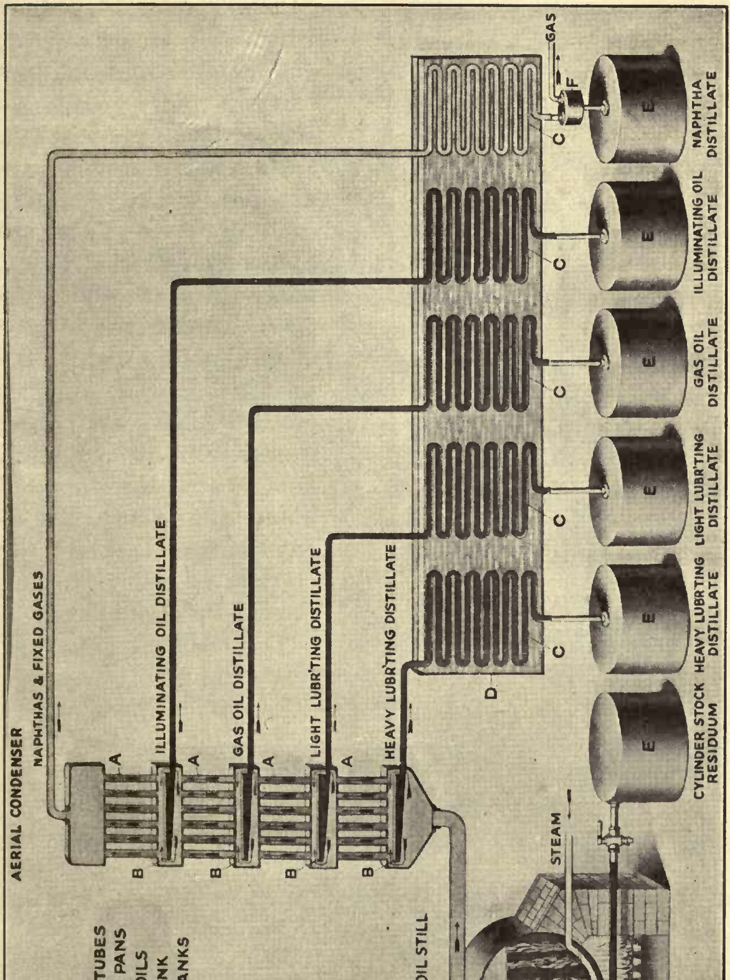


FIG. 87.—First separation of crude petroleum into groups by distillation. (*Courtesy Veedol.*)

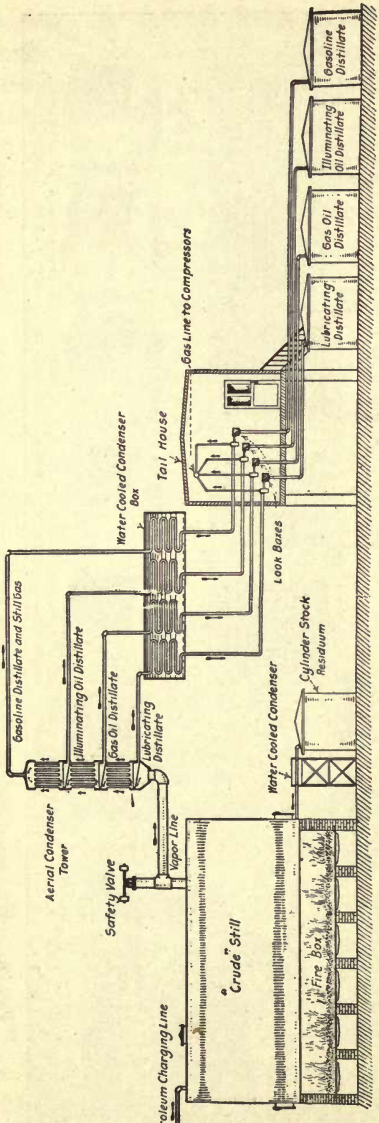


FIG. 88.—Illustrating first stage in the refining of petroleum by steam. (Courtesy Veedol.)

The products as they leave the condensers or coolers are conducted by carrying pipes to the receiving house (see Fig. 88). In this house the pipes are exposed, and at points in each of them there are glass-covered "look" boxes, through which the operative can see the color of the liquid, by which the quality is gauged. Samples are also taken here. There is a system of mainfolds here so that the stream of liquid can be switched to any desired tank by the opening of one valve and the closing of another.

The resulting groups or fractions are:

1. Gasoline distillate.
2. Illuminating-oil distillate.
3. Gas-oil distillate.
4. Crude lubricating distillate.
5. Crude cylinder stock residuum.

Each of these groups contains some of the product of the group above it. Illuminating-oil distillate contains some gasoline distillate. Gas-oil distillate contains some illuminating-oils distillate, and so on through each group. Further distillation called reducing is necessary. These products must not only be separated but all impurities must be removed.

SEPARATION OF CRUDE OIL INTO CUTS OR FRACTIONS

Paraffin Base Oils.—With paraffin base oils where lubricating stock is desired the cuts are not made on temperatures, but upon a specific gravity basis.

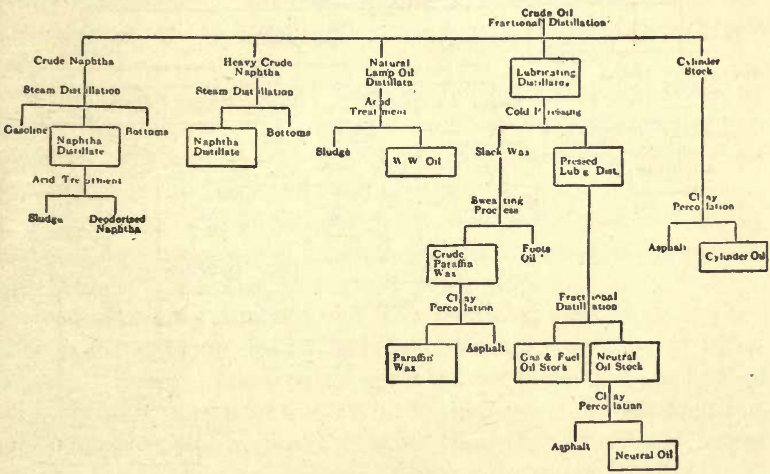


FIG. 89.—Chart of paraffin-base distillation. (*After Robinson*).

The first cut is completed when the product reaches a gravity of 54°Bé.

The distillate secured is crude naphtha, which is run to a separate tank and then re-run to give gasoline, naphtha distillate, and other products.

The next cut is at 41°Bé. This product is natural lamp distillate (kerosene distillate) which is refined.

When the stream reaches 38°Bé. the receiver is changed. This distillate is the mineral seal stock, which is later re-run and refined. At 36.5°Bé. the cut is gas and fuel-oil stock. The next cut at 33°Bé. is the last. This fraction is the lubricating distillate which is cold pressed to obtain the slack wax. The residue is cylinder stock which is filtered and treated as shown in the scheme.

The first flow sheet (see Fig. 89) presented above gives the product obtained from the fractional distillation of a paraffin base petroleum. This sheet shows both the various groups, and their product.

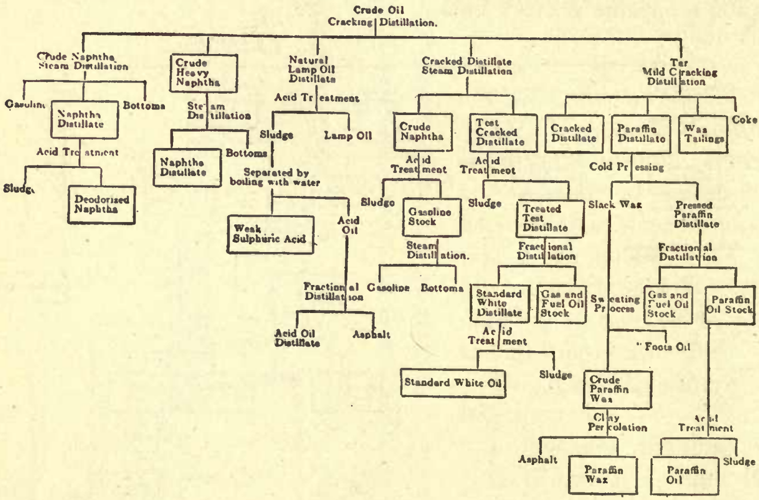


FIG. 90.—Chart of Mid-continent cracking distillation (mixed base crude). (*After Robinson.*)

Mixed Base Crude.—With mixed base crude, and using destructive or dry distillation, the oil is distilled in direct heated stills fired by coal, gas, or oil. The first cut is at 200° to 325°F. The product is crude naphtha. The second cut is at 325 to 475°F. This is the crude heavy naphtha.

The third cut, the natural lamp distillate, is obtained at 475 to 625°F.

After 650° F. up to 700° "cracking" takes place. The fires are slowed down and the distillation takes place slowly.

All the lighter fractions are first taken off without "cracking." Cracking does not take place until after 625°F. All the "cuts" to that point are normal. From 625° on the temperature is raised very slowly to 675 to 700°F. A distillate is produced. This distillate contains gasoline, some lamp oil and much heavier oil, and consists of about 20 per cent of the crude.

The residue in the still is a heavy back tar about 42 per cent of the crude. This tar is further distilled rapidly and gives off about 22 per cent of paraffin distillate and about 15 per cent of cracked distillate. The residue consists of wax tailings and coke. The flow sheet (see Fig. 90) gives the products of mixed base crude.

Definition.—"Cracking" in its simple analysis means breaking up or disassociating by heat and pressure the molecules of the heavier hydrocarbons of crude oil, and combining them into molecules of the higher elements.

"Cracking" has been considered a dangerous process as the early attempts resulted in some serious explosions. Also, the products obtained had very unpleasant odors.

New Cracking Process.—A new cracking process called the Bacon Process is in use by the Gulf Refining Company of Pittsburgh. This process depends upon the use of vertical steel tubes or stills 20 ft. long and 6 to 19 in. in diameter. The strength of tubes of this size is much greater than that of stills of larger diameter and they will withstand heavy pressures.

This system is claimed to be safer and cheaper than any other. The process is continuous, the still being kept full of oil from the bottom to the top of the heat chamber.

Fire and Steam Distillation on Mixed Base Crude.—With fire and steam distillation where cylinder stock is desired the first cut is the crude naphtha at 280°F. Open steam is introduced at a temperature of 212°. The second cut, the crude heavy naphtha, is at 330°F. The third cut, lamp-oil distillate from which kerosene is obtained, is made at 500°. The last cut is at 620°F., at which temperature the wax distillate is over, leaving the cylinder stock in the still.

This cylinder stock is then treated further. The use of bottom steam in the stills produces a larger quantity of cylinder stock of good quality.

Asphalt Base Crude.—Asphalt base crude is refined very much as the paraffin and mixed crudes. The residue is asphalt instead of cylinder or tar stock. No wax is obtained.

Distilling Processes.—Two general distilling processes are employed: (*a*) the intermittent, (*b*) the continuous.

Intermittent System.—With the intermittent system, the oil is heated in one tank to varying ranges of temperature. The product of the first range of temperature, say from 175 to 325°F., is called the first cut. The product from the second range of temperature, 325 to 475°, is called the second cut.

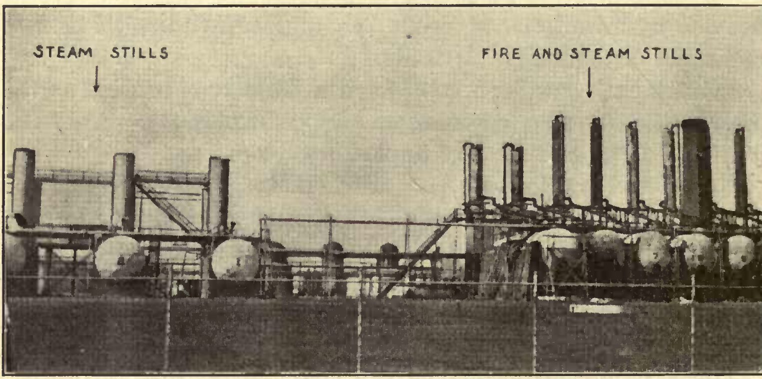


Fig. 91.—Photograph of stills at Cosden refinery, West Tulsa, Okla.

The temperature is then raised from 475 to 625°; higher temperatures will result in "cracking." The number of cuts depends upon the quality of the oil, and varies for different oils. The final cut leaves a residue of coke or asphalt in the still. Such a system is called the intermittent system of refining.

Continuous System.—With the continuous system of refining, a battery of stills (see Fig. 91, page 206) is used. These stills are heated independently of one another, but are so connected that the oil flows from the first still into the second still by gravity flow, and is there subjected to a higher range of temperature. It then flows to the third still and finally to the last still in the series. In each still the temperature is higher than in the preceding one, and different products are obtained. The vapors from the oil are taken from the domes at the top of each still and are run through condensers and then into the agitators (see Fig. 92, page 207) for treatment.

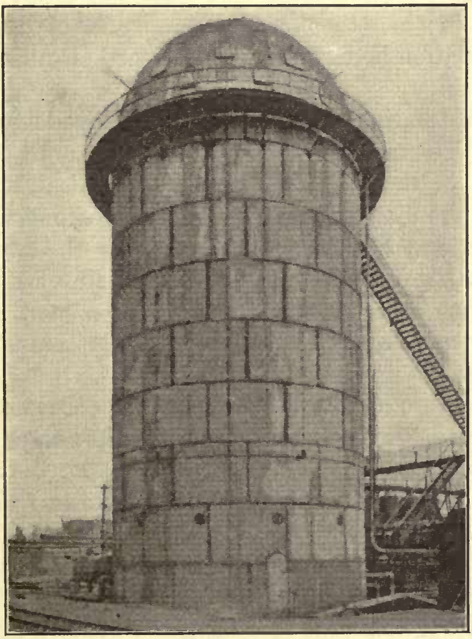


FIG. 92.—Five thousand bbl. illuminating oil agitator in which the crude kerosene is chemically treated and washed with water, air being used to agitate the oil during treatment. (*After C. W. Stratford.*)

The oil is, of course, first pumped into the first still but no pumping is necessary until the last stills are reached.

Continuous distillation is widely employed.

Types of Distillation.—Stills vary with the several different types of distillation, which are:

1. Destructive distillation, in which the stills are heated directly by coal, gas, or oil fires alone.

2. Vacuum, in which the heat is applied to the still by a direct fire while a vacuum of 15 in. of mercury is maintained on the contents of the still and within the entire condenser system.

3. Fire and steam (reduced pressure), in which fire is applied to the still and open steam is continuously bubbled through the boiling oil.

4. Steam, in which there is no direct fire, all of the heat required for the distillation being supplied by closed steam coils arranged within the still.

Vacuum distillation is not generally employed except for lubricating oils. The main system used is the fire and steam method. Open steam in the oil minimizes the chemical decomposition occurring in the distillation of heavy hydrocarbons.

Separation and Finishing of the Groups or Cuts.—After the separation into groups is carried out the groups are then reduced or broken into other products which are refined as shown in Fig. 93, Scheme I and Chart 1, and Figs. 94, and 95, Scheme II, Charts 1 and 2.

The various products from each cut are collected in separate tanks. The first cut may carry not only the lighter benzines and gasolines, but also have a small percentage of kerosene. A second distillation will separate the gasolines from the lower hydrocarbons. Similarly the next cut may carry some lubricating stock and a second distillation will separate this. All the gasoline is finally run into one tank, all the fuel distillates into another, and the kerosenes into another as shown in Fig. 93.

Treating Crude Gasoline Distillate—Scheme I, Chart 1.—The crude gasoline is drawn from tank (1), Fig. 93. It is run to the agitator (2). This first product has a bad odor and dark color. This odor is due principally to unsaturated hydrocarbon compounds which are treated with sulphuric acid and agitated with air. The acid reacts on impurities. It is then washed with a steam jet which dilutes the sulphuric acid and carries off the sludge. To neutralize the acid, soda ash is mixed with the product and

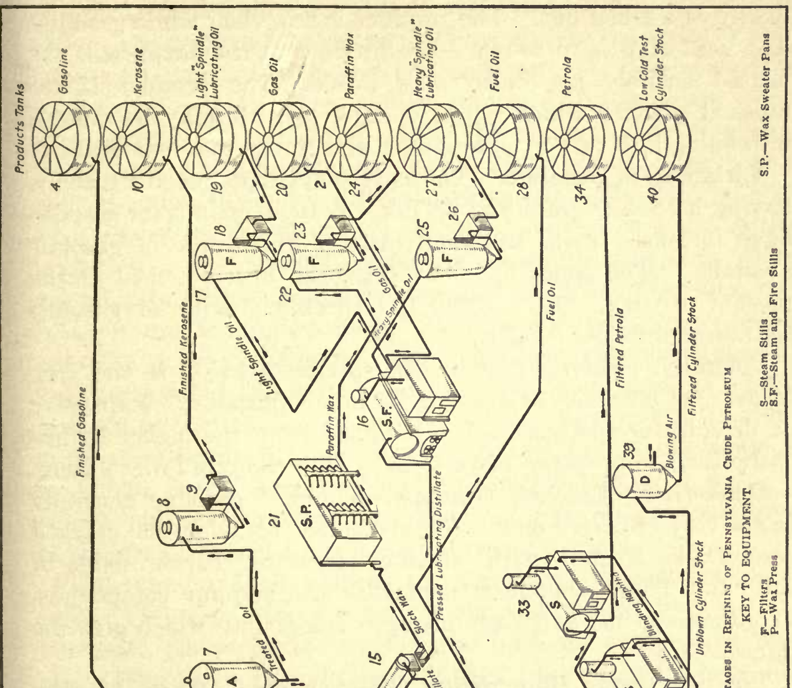


Fig. 93.—Final stages in refining, Pennsylvania crude petroleum. Chart I. Scheme 1. (*Courtesy Veedol.*)

finally is washed out. The product is now clear white gasoline. The next step is to re-refine the product in the steam still (3), heated entirely by steam coils inside. The product is the finished gasoline which is put in tank (4). It may be divided in refining into two or more grades and run to different tanks.

Variations in Gasoline.—The early refiners produced a gasoline having a specific gravity of 62°Bé. As the demands for gasoline have increased there has been little of this grade of gasoline available. The specific gravity has been lowered until at the present writing, May, 1921, the specific gravity of gasoline for automobile use is 52°Bé.

Volatility.—Volatility and not specific gravity is the true measure of efficiency of gasoline for motor purposes. Expansive or driving force of gasoline is obtained from the higher hydrocarbons when properly mixed with hydrocarbons of lower nature.

Deodorizing Cracked Gasoline.—Cracked gasoline generally has a very offensive odor. To overcome this odor, the cracked product is treated with alkaine plumbite, cupric oxide or sodium. These chemicals neutralize the sulphur compounds, naphthenic acids, and basic nitrogen compounds which give the offensive odor.

Treating Crude Illuminating Oil—Scheme I, Chart 1.—The crude illuminating oil is run from tank (5) to the steam still (6). The gasoline distillate is carried over to the gasoline distillate tank (1) or to the agitator (2). The illuminating oil is carried to the agitator (7), is treated with acid and alkali to remove impurities and is then filtered at (8), then a filter of Fuller's earth. This filtering gives it the water-white color.

The next step is to carry this product to a settling tank (9) where any of the fuller's earth in the oil settles to the bottom. The product, now the kerosene of commerce, is put in tank (10).

The crude lubricating distillate (11) passes to a combined steam and fire still (12) where its temperature is raised high enough to "crack" the paraffin wax in the distillate.

Wax is of two kinds, amorphous and crystalline. Only crystalline wax can be separated from oil by pressing. Some fuel oil is separated from the distillate and this goes directly to tank (28). The cracked lubricating distillate goes to the agitator (13) where it is treated with acid and soda ash. It is next carried to the chiller (14). The chilled wax and distillate are then pumped into the wax press (15). The pressed lubricating distillate from which lubricating oils are made is run to the steam and fire stills (16) and is distilled or reduced. The light spindle oil is carried to the filter (17) and then allowed to settle in the tank (18). The clarified product is carried to tank (19). The gas oil from (16) is carried directly to tank (20). The slack wax is taken from the filter press (15), and carried to the wax-sweater pans (20) in the sweat house. The paraffin wax is then filtered at (22) and settled and carried to tank (24), from which it is later pumped to the molding house and is there prepared for market.

Treating Crude Cylinder Stock.—The crude cylinder stock in tank (29) is fed into the blending tank (3) where it is mixed with naphtha to thin it down sufficiently to permit the separation of petrola (vaseline) from it, and of easy filtration.

The cylinder stock naphtha solution passes through the chiller (36). This separates the amorphous wax which drops to the bottom. The separated petrola goes back to the blending tank and is then drawn off and filtered at (31). It is settled in tank (32) and is distilled in the steam still (33) to separate the naphtha. The filtered petrola goes to tank (34) and the blending naphtha back to the blending tank (30). The cylinder stock solution which passes through the chiller (35) is carried to the filter (36) and filtered separates from the cylinder stock naphtha solution when run through Fuller's earth. It is settled in tank (33) and is then run into the steam still (38). The blending naphtha runs back to the blending tank, and the unblown cylinder stock is carried to the dehydration tank where it is blown with air to remove all traces of water. When this is done it is pumped to the tank (40).

Making Gasoline—Scheme II, Chart 1.—A still further example of refining gasoline and kerosene is illustrated in Chart 1, Scheme II. (See Fig. 94.) The crude oil from the crude oil tank is run into the crude oil still (1) and treated The dis-

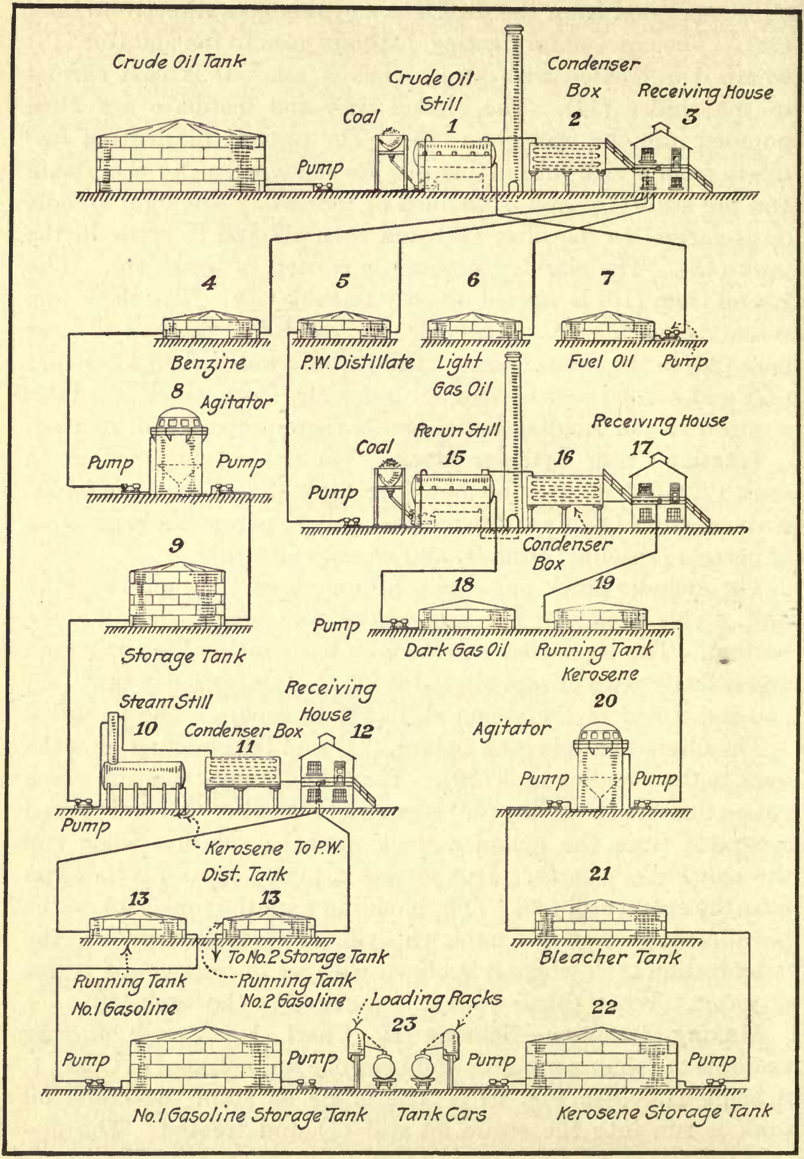


FIG. 94.—Chart 1. Scheme II. Shows making gasoline and kerosene. (*Courtesy Sinclair Oils.*)

tilled product passes through the condenser box (2) in which the pipes pass through circulating cold water to the receiving house (3) where the look boxes are located. These boxes have glass faces through which the color of the condensate can be seen. The boxes are connected with manifolds having valves which allow oil to be switched to any desired tank. The first condensate (benzine) is run into tank (4). Tank (5) carries the F.W. distillate. Tank (6) carries the light gas oil cut. Fuel oil is run into tank (7).

The benzine from (4) is run into the agitator (8) where it is treated with sulphuric acid. The benzine is agitated by air blasts to give good mixing. The sulphuric acid eats the impurities and imparts a white color to the benzine. The next procedure is to neutralize the acid with soda ash and wash it with water. The neutralized oil is next pumped into storage tank (9) from where it is pumped into the steam still (10). It passes from the steam still to the condenser box and then into the receiving house (12). The first cut from the benzine is high-grade gasoline which goes to the gasoline tank No. 1 (13). The second cut is low-grade gasoline which is run to tank No. 2 (13).

The kerosene cut is carried to another tank. The gasoline is then run to the storage tank (14) from which it is carried to the tank cars (23).

Kerosene—Scheme II, Chart 1.—In following the F. W. distillate cut in tank (5), the condensate is run to the re-run still (15) and goes through the condenser box (16) to the receiving house (17). The first product is run to the running tank (19), and from there is carried to agitator (20) where it is purified much like the gasoline cut. It is next run to the bleacher tank (21) where it is allowed to settle, and is then pumped to the kerosene storage tank (22) from which it is run to the tank cars (23). This completes the operation.

Refining of Wax and Lubricating Oil—Scheme II, Chart 2.—The general procedure for refining wax and lubricating oil is illustrated in Chart 2. (Fig. 95.) The procedure follows that in Chart 1, up to the treatment of the wax distillate.

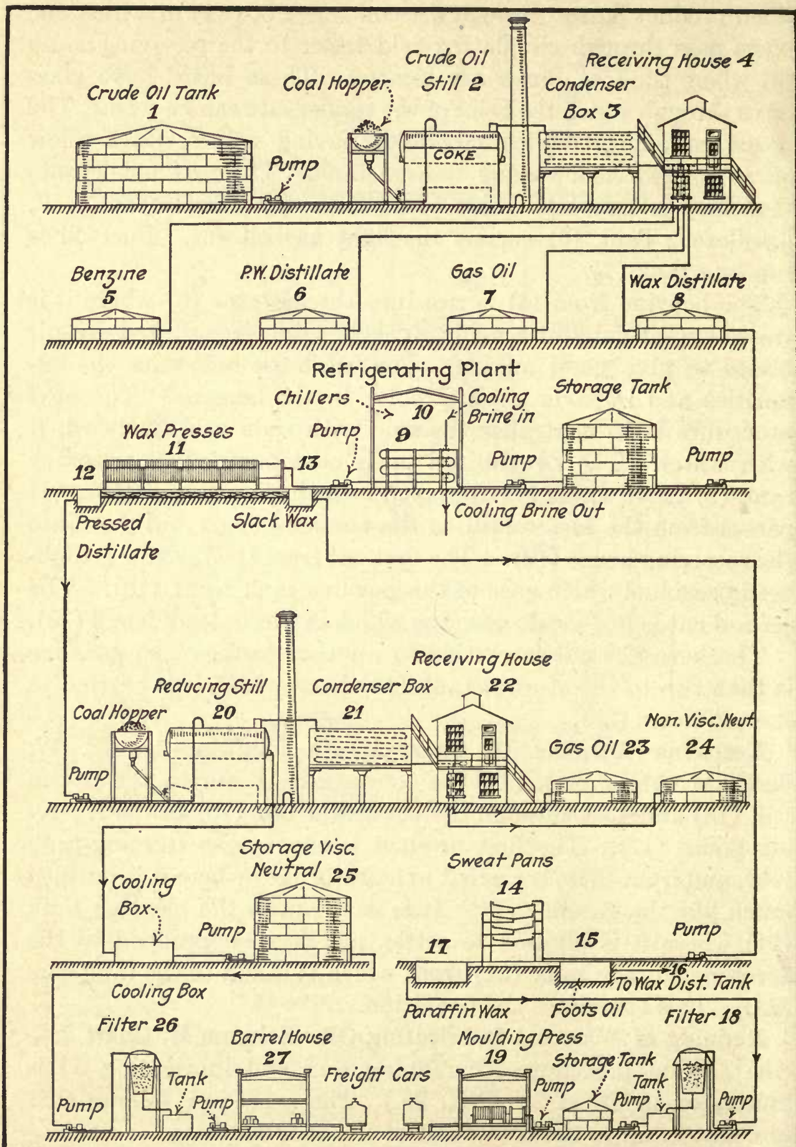


FIG. 95.—Chart 2. Scheme II. Showing making lubricating oils and paraffin wax. (*Courtesy Sinclair Oils.*)

The wax distillate is shown coming off from the receiving house and going into tank (8). It is pumped into the storage tank and from there through the refrigerating tank (9) and (10), where it is chilled. The chilled wax goes to the wax filter press (11) where it is forced under heavy pressure (300 lb. per square inch) through canvas filters that catch the wax. The pressed distillate (12) includes the lubricating stock and is treated as described later. The slack wax which contains considerable oil is freed from the filter press and is carried off to the sweat pans (14). The sweating takes place in a square brick building filled with pans, placed one above the other with some space between. These pans have frames swung in the upper part. The pans are first partly filled with water. The slack wax from the filter press is melted and then pumped into the pans where it settles on the frames above the water. The water chills the wax, and also leaves it suspended on the frame. The water is next drawn off from the pans, the sweating room is then closed tight and steam is turned into the steam coils under the pans. The wax becomes soft and melts very slowly. The oil with the wax runs into the pans, carrying a little wax with it.

The sweated wax cakes are then melted and filtered through Fuller's earth at (17) to take out impurities. It is then pumped to the storage tank and from there is carried to the molding press (19) or is caused to drop on revolving chilled plates. As the wax chills it is removed by a set of stationary knives which cut the wax from the revolving plate. This is the wax of commerce which is then barreled and sent out to market.

Pressed Distillate—Scheme II, Chart 2.—The pressed distillate (12), which comprises the principal lubricating stock for cylinder oil, is carried to the reducing still (20) and is redistilled there. Part of the oil goes off as gas oil and non-viscous neutral oil, and is run into tanks (23) and (24).

The remaining residue in the still is the lubricating stock. This is cooled and then stored in tank (25). It is next filtered (26) and then barreled in the barrel house (27). This is the lubricating oil of commerce.

The schemes just outlined are modified with oils of different character, but the elementary principles hold good for oil of any kind. The types of stills, of agitators, of condensers, of filters, and of wax presses may all vary, but the simple refining scheme follows those outlined above.

Steam stills equipped with closed steam coils are used only for the distillation of the lighter volatile products. They are used particularly for distilling gasoline. The highest temperature attained is 212°F.

Capacity of Stills.—Stills range in size from 75 to 1300 bbl. capacity. Large stills have diameters of 14 to 15 ft. and lengths of 42 to 45 ft.

Many small companies prefer four small stills of 250 bbl. capacity each to one large 1000–bbl. still, as they can use the continuous system with four smaller stills. Large concerns use batteries of stills of the 14 by 42 ft. size, or even larger.

Topping or Skimming.—The practice of only separating into their groups the light constituents from the heavy in a continuous operation or by intermittent distillation is called topping or skimming.

Topping is generally used with oils to separate the lighter fractions containing the gasoline and naphtha contents from the heavier fuel oil. Three or four cuts are made. The lighter products are then shipped to a refinery where they go through the operations outlined before. The residue of lower fractions is sold as fuel oil.

Topping is often employed by oil companies that do not care to build a complete refining system. By separating the lighter parts of the oil from the heavier they can obtain a higher price for the light products, and generally sell their fuel oil at a good figure. Topping or skimming will, in this way, give a larger profit than selling the crude alone.

Refinery Capacities.—Capacities of refineries vary greatly. Topping plants may treat 1000 to 10,000 bbl. of oil per day. Some of the big refineries have capacities of 20,000 to 60,000 bbl.

Refinery Profits.—The idea is quite general that refineries make tremendous profits. On the contrary many refineries are failures. In good periods the profit on refined products obtained from a barrel of crude oil may range as high as $2 per barrel and as low as 30 to 50¢ per barrel. One dollar per barrel is a fair profit.

However, the fair way to determine profits is on the amount of capital invested in a refinery. A refinery having an investment of a million dollars and on a good market may pay 20 to 30 per cent per year on the investment, or even higher. Refinery profits, however, vary with the market and with the different products obtained from the crude oil, which vary in every field. No set scale of profits can be announced as conditions are so different in every part of the country.

CASING-HEAD GASOLINE

The extraction of gasoline from the vapors from oil wells has developed into an important business. It is so intimately related to the oil industry that a general treatise on the petroleum industry would not be complete without some mention of the casing-head gasoline business.

Definition of Casing-head Gasoline.—Natural gas is classed as "dry" gas or "wet" gas. Dry gas is defined as gas that fails to show any of the light hydrocarbon vapors that emanate from oil. However, recent experiments have shown that gases once considered dry do carry small quantities of light vapors.

"Wet" gas is defined as gas that carries light hydrocarbon vapors that emanate from oil. These vapors when obtained by the condensation and refrigeration or the absorption systems give light products of the benzine series.

Casing-head gasoline is gasoline obtained by catching the "wet" gas from the flow lines leading from the casing head of an oil well, and condensing or absorbing the vapors. These vapors emanate from the oil and are obtained from gas traps at the wells and from traps placed on the storage tanks for crude oil.

Three important methods of obtaining the gasoline from the vapors are in use: (1) The compression and refrigeration system; (2) the absorption; (3) combinations of 1 and 2.

Compression and Refrigeration Process.—The compression and refrigeration process consists primarily in compressing the "wet" gas under high pressure to a small volume, and then condensing the volatile vapors by using low temperatures.

This process calls for a compressor to compress the gas, and cooling or condensing coils to condense the vapor after it leaves the compressor. Collecting tanks for the condensate are also necessary. The general procedure is described on page 225.

Absorption Process.—The absorption process consists in compressing the gas under low pressure to a small volume, and then passing it through an absorbing medium, generally mineral seal oil. The mineral seal oil, which has absorbed the light petroleum vapors, is then collected in a still, and distilled. The vapors given off are then condensed and collected in proper storage tanks.

The two processes are employed as follows: The compression and refrigeration processes are used for rich gases running from 1 to 12 gal. per 1000 cubic feet and the absorption system is used for gases having from 1/10 to 1 gal. per 1000 cubic feet. The latter system is best applied where there are large volumes of low-grade "wet" gas, such as are found in the gas lines running from gas fields to the large cities. Indeed, some of the early gases once classed as "dry" gases are now successfully treated by the absorption system.

The big gas wells of high volume generally carry small proportions of casing-head gasoline. Wells of 10,000,000 to 80,000,000 cu. ft. have very small quantities of gasoline, but with such large volumes even a small amount of gasoline, say 1/10 gal. per 1000 cubic feet, will be profitable.

The older an oil well the richer the gasoline contents. Some old wells at Glenn Pool, Oklahoma, run as high as 12 gal. per 1000 cubic feet.

Vacuum pumps on wells increase the richness of the gasoline contents.

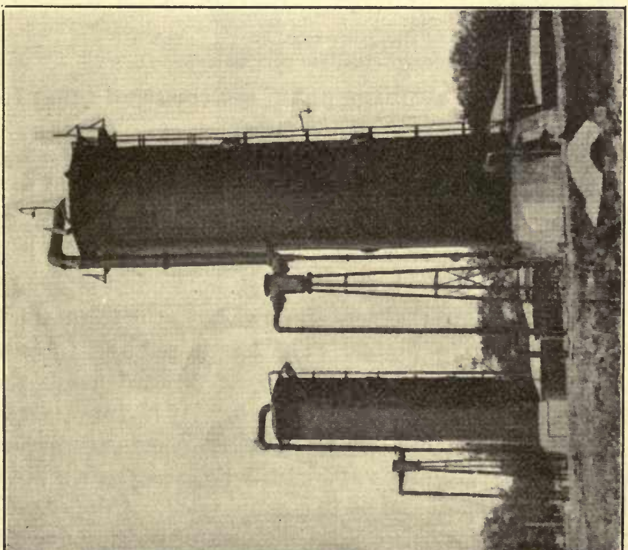


FIG. 96*a*.—Towers 12 by 48 ft.; work at zero to 10 lb. pressure. Average capacity 2,500,000 cu. ft. each. Note trap on gas-discharge line. (*After U. S. B. M.*)

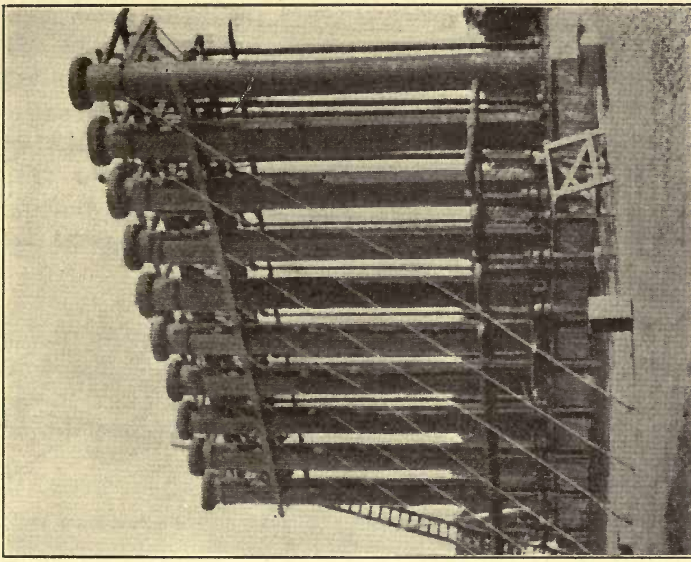


FIG. 96*b*.—Gas intake side of high pressure absorption towers. (*After U. S. B. M.*)

Absorption Methods.—There are two classes of absorption methods: one for large volumes of rich gases at low pressures—40 to 50 lbs., and one for lean gases at high pressures—100 to 300 lbs. In the first type the absorber has a diameter of 12 ft. and a height of 48 ft. (See Fig. 96A.) In the second type the absorber has a diameter of 20 to 30 in. and heights of 30 to 50 ft. (See Fig. 96B.) The system of baffle boards in the absorbers is in each case much the same as shown in Fig. 97, which gives the details of an absorber.

The first type can treat 2,500,000 cu. ft. per day.

The second type can treat from 5,000,000 to 6,000,000 cu. ft. per day for each absorber. The absorbers are usually placed in batteries.

The extraction of casing-head gasoline by the absorption method demands:

(*a*) Gathering lines.

(*b*) A flow tower in which the gas and absorbing medium can meet and mix.

(*c*) Receptacles for the absorbate.

(*d*) Stills for distillation of the mineral seal oil.

(*e*) Condenser coils or refrigerator system.

(*f*) Tanks for the condensed gasoline product.

There are, of course, auxiliary pump systems, and tanks for the mineral seal oil.

The mineral seal oil, however, is used over and over again. There is some loss, say 5 per cent, occasioned each time by leakage and some vaporization, but the loss is negligible.

The mixing towers or absorbers are generally vertical cylindrical towers 30 to 50 ft. high, although horizontal absorbers are in use. The liquid mineral seal oil flows from the top of the tower downward over baffle plates. The gas is allowed to enter at the bottom of the tower and in passing upward meets the oil. The light vapors in the gas are absorbed. At high pressures 7 to 10 gal. of mineral seal oil per 1000 cu. ft. of gas are necessary.

Separation of the gasoline vapors from the absorbate is obtained by distilling the mineral seal oil in a simple still. Condensation is obtained through air-cooled pipes with water passing over them.

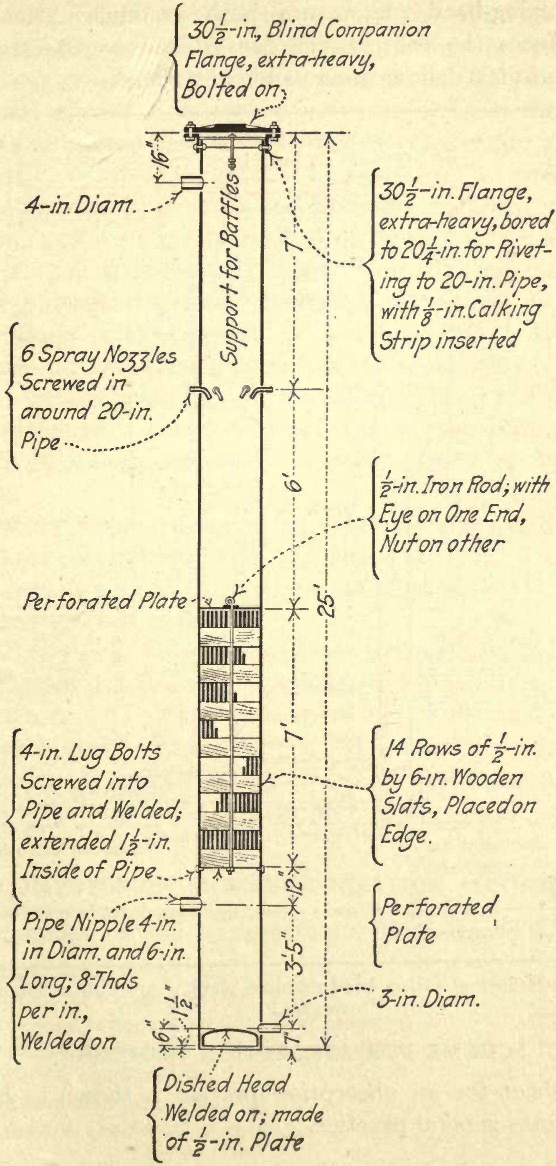


FIG. 97.—Details of high pressure tower 20 inches by 25 feet in size.

Some casing-head plants use both systems. The "lean" products from the compression are treated by the absorption system, and may deliver good yields of gasoline.

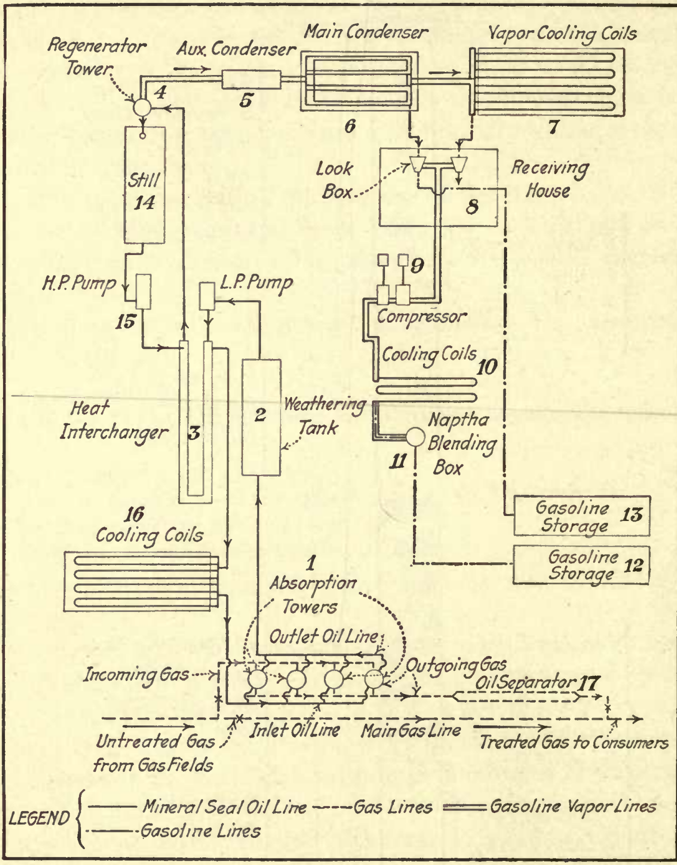


FIG. 98.—Flow sheet of casing head gasoline plant. Absorption type. (*After Snyder.*)

SCHEME FOR ABSORPTION PROCESS

A flow sheet for an absorption process is shown in Fig. 98. This illustrates general practice.

The gas is passed into the lower part of the absorbers (1). It there meets the mineral seal oil which flows downward. The outgoing gas passes to the oil separator (17). The absorbate or mineral seal oil with the absorbed vapors is carried to the weathering tank (2) where some of the lightest vapors are allowed to escape.

The absorbate is next passed through the heat exchanger (3) where it passes the mineral seal oil flowing to the absorption tower. The absorbate receives heat from the mineral seal oil. The absorbate next passes to the regenerator tower (4) which is over the still. The absorbate is heated to 212°. All the light vapors pass off and are condensed in the condensers (5) and (6). The light vapors pass through the vapor-cooling coils (7). The heavier condensate passes through the receiving house (8) in which the look boxes are located, and is carried to the gasoline tank (13).

The lightest vapors cooled in (7) pass to the receiving house (8) and then are compressed at (9) and cooled at (10). This product is then blended with naphtha in the blending tower (11) and from there carried to the tank (12).

The mineral seal oil obtained from the regenerator tower (4) blows into the still and the vapors left in it are carried over into the condenser (5). This oil is quite hot, and must be cooled before reaching the absorbers (1). It passes through the heat interchanger (3) and is further cooled at (16) from where it is carried to the absorbing towers (1). This completes the full cycle.

COMPRESSION AND REFRIGERATION METHODS

The compression and refrigeration system demands.

(*a*) Gathering lines.
(*b*) Scrubber or intake receiver.
(*c*) Two-stage compressors. (1) Low pressure.
(*d*) Condensers—coolers. (2) High pressure.
(*e*) Tanks for condensate.
(*f*) Auxiliary pumps.
(*g*) Expansion engine.

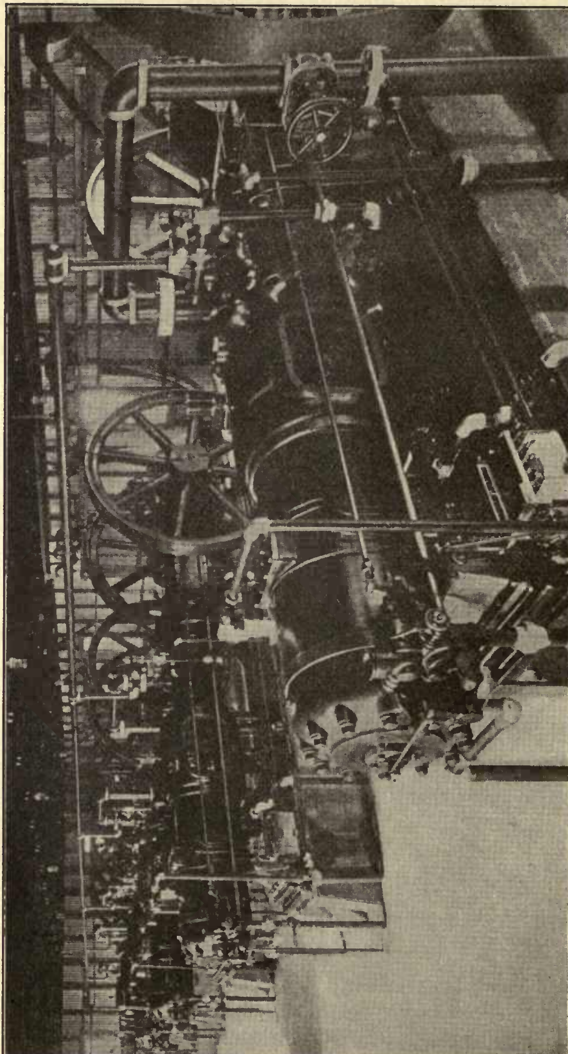


FIG. 99.—Interior of a gasoline plant equipped with six 50-horsepower direct-connected compressors.

The gathering lines are generally 4-in. lines leading from the wells.

In constructing gasoline plants the points to be observed first are the richness of the gas, the supply, the price, and the cost of obtaining the finished product.

The greatest cost of a casing-head gasoline plant is the cost of the gathering lines necessary to bring the gas to the plant. This is especially true of the compression system. To save cost of lines the plants are generally located in a producing oil field. Pipe lines must be run to the various wells to gather gas. If the wells produce each 50,000 ft. of gas per day, a plant capable of handling 5,000,000 cu. ft. will require 100 wells.

With the absorption system the same principle holds true. In case of plants that treat the gas from gas lines the plant can be built in or near the city to which the gas is delivered. There is no expense for gathering lines in this case.

The compressors are of the two-stage direct driven type. Gas engines or electricity is used. The low-stage compressors give pressures of 40 to 50 lb. The high-stage from 200 to 300 lb. per square inch. Figure 99 shows a compressor.

SCHEME FOR COMPRESSION AND REFRIGERATION PROCESS

The flow sheet shown in Fig. 100 gives the compression and refrigeration system.

The gas from the field mains enters the intake receiver at (1). The gas is taken into the low-stage compressors at (2) and is compressed to pressures of 40 to 80 lb. per square inch. The gas passes through the trap (3) where any lubricating oil or other low-grade condensate is caught.

The product then passes into the low-pressure cooling coils (4). In these coils part of the vapors having the lowest range of specific gravity are condensed and drawn off into the tanks at (5). The uncondensed vapors pass off as the arrows indicate and are carried to the high pressure cylinders (compressors) (10). The condensate in (5) is carried off into the "make tank" (7) where

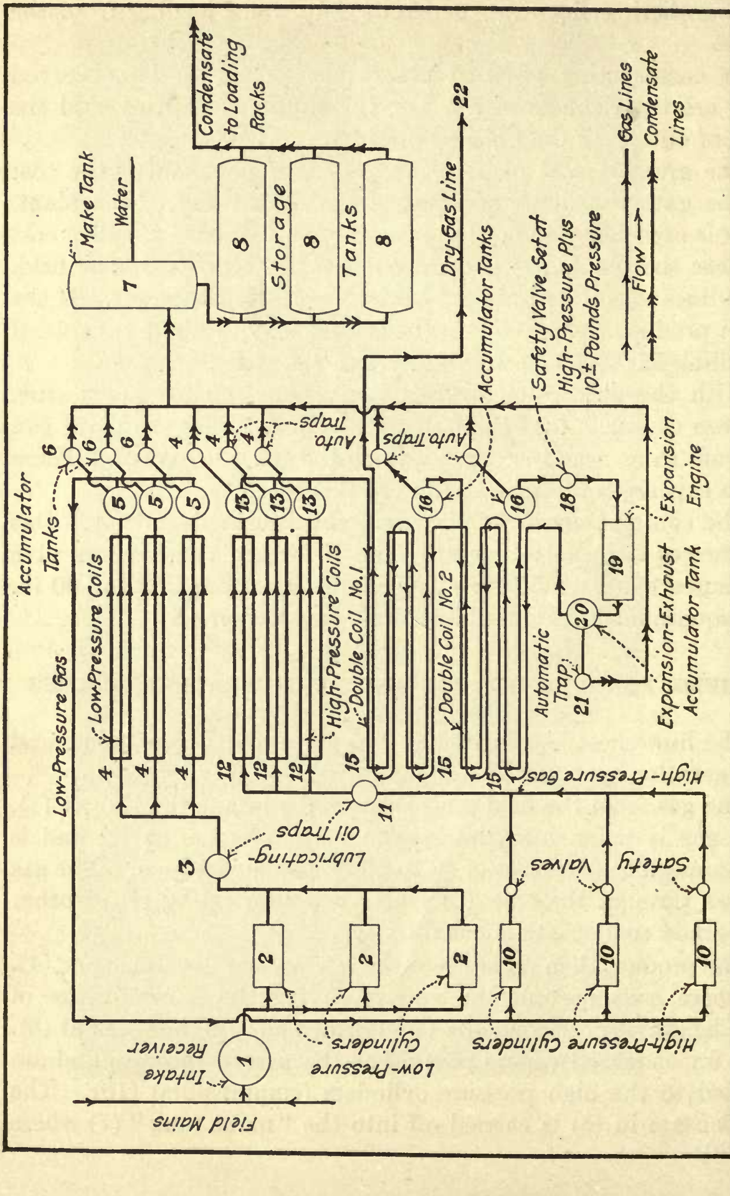


FIG. 100.—Flow sheet of compression plant using 2 stage compression and single stage expansion. (*After U. S. B. M.*)

any water in it is drawn off and blending is also carried on. From there the product goes to the storage tanks (8) and from there to the loading racks (9).

The condensed gas run to (10) is compressed at high pressures of from 200 to 300 lb. per square inch and from there goes to the high-pressure cooling coils (12) and into the accumulator tanks (13). The condensed product is taken off through (14) and into the "make tank" (7).

The uncondensed gas coming from the tanks (13) is carried to the double cooling coils, and into the accumulation tank (16). Part of the product is condensed here and is run into tank (7). The residual gas is carried through the coils (15) and through the tank (16) where more of the condensed product is obtained and carried to tank (7).

The final residue of gas and vapor, the most difficult condensable portions, are carried through the expansion engine (19). From (19) the condensed portions accumulate in the tank (20) and are drawn off through the automatic trap (21) and from there to the "make tank" (7). This is the last stage of separation. The residual gas passes from (20) and is allowed to expand rapidly through the coils (15) so that it cools the vapors coming off from (13). The final gas passes off from (15) to the gas line (22). This completes the scheme.

It must be realized that the schemes presented merely give the general outline. No two plants are exactly alike and changes are made as improvements take place, but the flow sheets outlined give a fair idea cf both systems.

Blending.—The product obtained from the compression and refrigeration system, or from the absorption system, ranges from 85 to 100°Bé. It is very "wild" or volatile. It evaporates much more rapidly than gasoline and, accordingly, the raw product must be very carefully sealed. Also this product requires careful handling and is subject to many restrictions in trasportation. To overcome some of these difficulties the product is blended with naphtha of lower specific gravity. The naphtha of 50 to 54° is blended with this higher condensate to form a product of about

68°Bé. This is accomplished by filling a tank half full with casing-head and then pumping in naphtha which settles toward the bottom, and mixes with the condensate.

The blended product is then "weathered" or exposed to the air until the product has a vapor tension of 10 lb. per square inch. This product has a specific gravity of 60 to 65°Bé. and can be transported without difficulty.

This blended gasoline is fully as good for internal-combination engines as the straight gasoline obtained from refining crude oil.

Reduction of Heating Values.—It is interesting to note that treatment of gas from gas lines reduces the heating value of the resultant gas. A natural gas consisting of methane, ethane, propane, butane and pentane will have a much higher heating content than pure methane. It is not unusual to have such a mixture of gases and vapors give 1700 B.t.u. per 1000 cubic feet as against 950 B.t.u. for methane gas. After treating the "wet" gas the B.t.u. of the resultant lean gas may register 1000 or 1100 B.t.u. cu. ft.

Amount of Gasoline Obtained Lower in Summer.—There is a difference in the amount of casing-head gasoline obtainable in summer and winter from plants. In the hot summer days the yield is as much as 30 per cent lower than in the winter months. The amount of refined product depends greatly on the differences in temperature. When the outside air is 30° the vapors in the compressors will have a temperature of say 180°F. This means that in the summer the compressor has a temperature of 180° and the cooling atmosphere temperature is 80 to 90°. The chilling effect is, therefore, much less in summer than winter and, as a result, the amount of casing-head gasoline obtained is less.

CHAPTER IX

ELEMENTS OF VALUATION—BUYING OIL PROPERTIES

It is an evident fact that the measure of success of any oil-producing operation is the profit obtained. A large producing company in making profits must possess:

1. An assured supply of crude oil.
2. A refining capacity.
3. Transportation facilities.
4. An assured market.
5. Good management.

Oil operators who are planning for the future realize fully the importance of all these elements in their business. Large concerns continually seek new properties, both proven and unproven. It is likewise essential for any large concern to know as nearly as possible the potential reserves of its properties, if an intelligent operating plan is to be followed.

At present the United States Treasury requires estimates for depreciation and oil depletion in making out income tax reports. This forces many oil operators to a study and estimation of their underground reserves that otherwise would not be undertaken. For these reasons any method that will give a minimum estimate or a fair average of future production is well worth while.

The valuation of the oil properties of any company, whether for its own information, to guide in operating campaigns, for purchase, sale, or for taxation purposes falls into two divisions:

1. The valuation of the physical property.
2. The estimate and valuation of the future recoverable oil.

Estimates of Oil Reserves.—Estimates of underground reserves have become more systematic in the past few years. There is less of the guessing element involved than in the past, due to better methods of estimation. The careful compilation of data on producing areas, the thoughtful study of the histories of producing properties and their rates of decline, have furnished oil men with a fund of information that makes for simpler and more accurate estimates.

The history of oil properties can be shown graphically by production curves, or by decline curves. Such curves are constructed from accurate records of past performance of the producing properties examined. Graphs furnish a convenient method of assembling data. There is a tendency, however, for the geologist or the petroleum engineer, who are the men largely instrumental in guiding the systematic study of oil properties, to over-emphasize the value of their methods and use refinements that are unnecessary. Good approximations are useful, and that is all that an estimate can furnish. There are uncertain factors such as flooding of properties by water, exhaustion of gas, cementation of sands, or drainage by neighboring properties that must be allowed for. Careful students will take these factors into account, but no rule can be set for them.

On the other hand, the introduction of improved operating conditions may completely change estimates of the amount of oil recovered from a property. This will notably be the case in the future as improved methods are employed. The Bradford water-flooding system, the Smith-Dunn compressed air system, or other similar systems may alter estimates very materially.

Scientific studies are valuable, but often the scientific man places too much reliance on his methods and not enough on experience nor on that elusive factor, judgment. There are oil men experienced in operating producing properties who can in several visits to a property understand its possibilities better than many technical men who spend weeks of work on an appraisal.

Valuation of oil reserves on producing properties with past history as guidance is much simpler than on new producing properties, but even on new properties certain minimum conditions can be determined—based, of course, on the past history of other properties.

The main methods employed in obtaining figures for future production are:

1. The saturation method, which includes the barrels per acre and the barrels per acre-foot methods.
2. The historical method which is
   (*a*) Mathematical,
   (*b*) Graphic.

Saturation Method.—Sands, sandstones and limestones are porous. The pore space may be as high as 35 per cent by volume, or as low as 5 per cent. A fair average is 20 per cent volume. A cubic foot equals 7.5 gal. If a cubic foot of sand or sandstone contains 20 per cent voids it will hold by volume 7.5 gal. × 20 per cent = 1.5 gal. per cubic foot. For an acre-foot this will be

$$\frac{43{,}560 \text{ cu. ft. per acre} \times 1.5 \text{ gal.}}{42 \text{ gal. per barrel}} = 1555.6 \text{ bbl. per acre-foot for}$$

a sand 1 ft. thick covering an acre.

Another way to figure is the following: The total gallons per acre-foot equal $\frac{43{,}560 \times 7.5}{42} = 7778$ bbl. in an acre-foot.

This last is a constant figure and in estimating by the saturation method is useful. The amount of oil a sand having 20 per cent voids would be 7778 × .20 = 1555.6 as obtained above. It is sometimes worth remembering that 5.6 cu. ft. equal 1 bbl.

Experience has shown in some fields that a recovery of 15 per cent is a fair average. The total recoverable oil in sand having 20 per cent voids would then be 1555.6 × .15 = 233.3 bbl. per acre-foot. Using the factor 7778, 10 per cent voids, and a recovery of 25 per cent, the figures would be 7778 × .10 × .25 = 7778 × .025 = 194.4 bbl. per acre-foot.

A sand 50 ft. thick would, if all "pay," carry in the first case 233 × 50 = 11,650 bbl. per acre; in the second case 194.4 × 50 = 9720 bbl. per acre.

If there were one well per 8 acres the yield per well would be 93,200 bbl. and 77,760 bbl. respectively.

The saturation method may be used as a rough check for the amount of recoverable oil expected, and it will be found fairly satisfactory for present operating conditions. Where, however, improved methods are used this figure gives little index except as a minimum. Some yields per acre-foot are presented in Table 15.

The recovery per acre for known areas where sand conditions are uniform gives a good idea of the amount of oil expected under known conditions. If one property with a sand 50 ft. thick actually produces 5000 bbl. per acre, other undrilled properties in the same field should give similar results *if as well located.* Recovery per acre is, of course, based on the knowledge of past performance of properties. A few records of production per acre are presented in Table 15, page 233.

It is interesting to note the very high average recovery per acre in the Gulf Coast fields of Texas and in California. Such yields are average and the only comparable average figure is the production at Cushing, Oklahoma, which is 12,000. This is an extremely high average for the production in hard-rock fields and is due to the thickness of 50 ft. of pay sand. The California sands and the Gulf Coast sands range from 40 to 100 ft. in thickness.

Yields of as high as 65,000 bbl. per acre were obtained at Robinson, Illinois, and at Cushing, Oklahoma, but on 160 acre tracts only. The California estimates are for fields ranging in size from 1000 to 15,000 acres. The Gulf Coast fields range from 300 to 4000 acres.

Geological conditions largely control the production of a tract of oil land. A piece of land high on a dome or anticline may produce three or four times the amount of oil that wells lower on a fold will produce. The gas pressure is greater near the top of a fold, and as gas is the main expulsive force for oil, the greatest recovery is near the gas. This does not always follow, but the relationship is very close. Also, properties located down the dip on the flanks of a dome, anticline, or other type of fold are subject to water flooding earlier than properties on the top. All

TABLE 15.—COMPILED RECOVERY TABLE

State	Sand	Total yield, acres	Productivity: Per acre	Productivity: Acre-foot	Depth	Acres per well
Average United States		......	2,500			
Pennsylvania	Bradford	80,000	2,700			
West Virginia						
Roane Company	Big Injun 10′	......	2,372	237	2,000	8–10
Lincoln Company	Berea 12′	......	1,693	141	2,000–2,600	8
Illinois		......	2,750			
Casey		......	4,000	...	300–2,000	
Crawford Company	Robinson 7′	......	1,695	242	300–1,000	6
			65,000 high			
Kansas	Augusta 30′	......	4,800	160	2,500–2,600	
			45,000 high			
Oklahoma	All	......	3,400			
	Bartlesville 15′	......	1,800	120	500–1,700	6
	Glenn Pool 40′	19,000	8,000	200	1,100–1,900	7
	Cushing Pool 50′	19,000	12,000			
			65,000	240	1,200–2,520	8
Average high	Osage 20′	30,000	3,000	150	1,500–2,500	11
North Central Texas			3,000			
		......	20,000	...	2,500–3,300	
California average		......	12,000 present			
			20,000 ultimate			
Coalinga	...	15,000	13,32 present	...	1,000–4,500	14
McKittrick	...	1,700	35,000 present	...	800–2,000	3.3
Midway-Sunset	...	41,000	7,259 present	...	800–3,500	
			20,000 ultimate			
Kern River	...	7,800	33,000	100	300–2,000	
Ventura Company	...	5,000	6,000	...	500–3,000	
Lompoc and Santa Maria	...	8,500	10,000	...	2,500–3,500	
Wyoming						
Salt Creek	...	4,000	20,000	200	800–1,500	10
			ranges from 4,000–63,500			
Gulf Coast						
Spindle Top		330	141,600			
Batson		710	42,100			1.8
Sour Lake (After J. R. Suman)	...	1,120	50,500			good
Humble		4,050	20,000	...	800–3,500	spacing
Goose Creek		840	28,700			1 avg.
Saratoga		640	31,000			
Louisiana						
Caddo-high figures	...	......	12,000–44,000	200	2,300	5–10

these factors must be taken into consideration and roughly weighed in figuring values of oil lands.

Historical Methods.—Historical methods, based on past performances of wells, are now in general use. In the absence of good historical data, however, the saturation method has its value when used intelligently, especially when the nature of a sand as regards porosity and thickness is known. With the historical method, actual performance is the measuring standard.

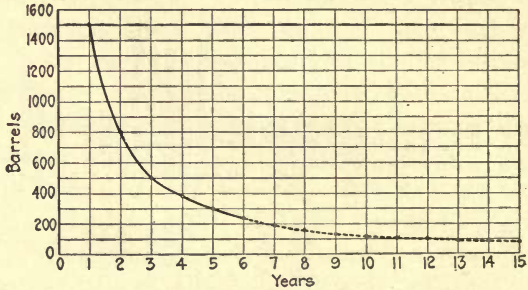


FIG. 101.—Curve showing in bbls. history to sixth year, and future extension to fifteenth year. Same values in Table 18.

In valuing producing properties fully drilled up the object to be determined is the future decline of the wells as based on past performance. Past history is decidedly of value in such cases. A curve is constructed to the point of recent production as in Fig. 101 and the curve is then projected from the known years to the future. The future production taken from the graph is shown in Table 16. The ratio percentage factors for this well are presented in Fig. 102, and Table 17.

The information needed to obtain figures for the production for properties partly drilled is gleaned from the life history of the wells adjoining the property. This information should be gathered from the earliest history to the present time. The performance of the average well should be selected.

Detailed methods of determining the average well will not be fully discussed here. Average wells can be ascertained by comparing curves for a number of properties or by mathematical

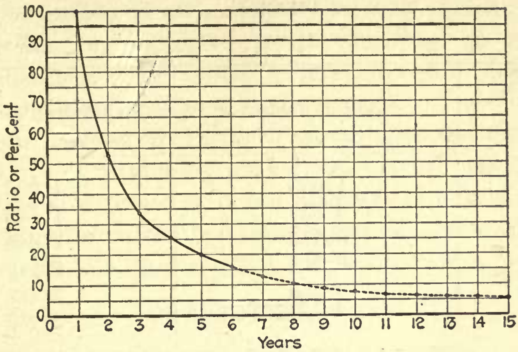


FIG. 102.—Curve showing history in percentage ratios of first years production to 6th year; and future extension to the 15th year. Same values in Table 19.

TABLE 16

I	II	III
Age Years	Production per years Bbl.	Cumulative Production Bbl.
1	15,000	15,000
2	8,000	23,000
3	5,000	28,000
4	3,800	31,800
5	3,000	34,800
6	2,400	37,200
	Future	
7	1,900	39,100
8	1,550	40,650
9	1,300	41,950
10	1,150	43,100
11	1,025	44,125
12	975	45,100
13	900	46, 00
14	850	46,850
15	820	47,670

TABLE 17

I	II	III
Age Years	Decline factor	Cumulative factor
1	1.000	1.000
2	0.533	1.533
3	0.333	1.866
4	0.253	2.119
5	0.200	2.319
6	0.160	2.479
	Future	
7	0.126	2.605
8	0.103	2.708
9	0.086	2.794
10	0.076	2.870
11	0.068	2.938
12	0.065	3.003
13	0.060	3.063
14	0.056	3.119
15	0.054	3.173

weighing and averaging. Such studies are best made by assembling production figures and averaging them, or by putting the information in graphic form by constructing curves on coördinate paper. The latter method is preferable as it clearly shows the history in an easily remembered form. Curves of this sort are no more accurate than the data from which they are drawn.

Curves showing the relationship of initial production to the total first year's production are especially valuable in making estimates of flush production or appraising new properties with no definite history of their own. These curves can be constructed showing the initial daily production of individual wells in relation to total production of each of those wells for the first year.

Curves or graphs of other conditions such as acreage per well to production or depth to production can be made. The present discussion is based principally on the composite decline curves obtained from average wells.

There are several methods of assembling the data obtained from a study of producing properties. In all cases, the future performance of a property is the ultimate object of the studies made. The information regarding a well can be assembled as in Table 16, page 235, and a curve constructed from this data.

PRODUCTION CURVE

If the yearly production in barrels of a well is plotted on the left side of the sheet as shown in Fig. 101, page 234, and the time in years on the bottom line, and the points are linked together, the resultant curve graphically reproduces the actual history of the well. Such a curve is called a production curve. The well in this case is an average well.

Suppose, however, the first year's production is called 1.00 see Table 17—and each succeeding year's production is given in terms of the first year, the ratios measure the decline per year in terms of the first year's production. The total ratios can then be added to obtain the total cumulative factor of production.

RATIO DECLINE CURVE

If the ratios are plotted and a curve made it is called a percentage or ratio decline curve. This curve has the advantage of being general in its application. In the same field wells of similar initial yields follow the same general decline. The productions of other wells in the same field follow curves of the same general character.

If the future production of the well is desired, the curves from the known points may be extended and each future year's percentage or ratio obtained graphically, as shown in Fig. 102. The percentage or ratios for the curve are given in Column 2, Table 17. Ratios may be used instead of per cent and are preferable for calculations.

Another method giving similar figures would be to figure the average production of each year compared to the last year and use those figures for estimating future production. In Column 2, Table 20, page 253, the average yearly production is shown in ratios. The ratio of the following year to each past year is shown in Column 9, Table 20.

It has been found in plotting a large number of production curves, and of percentage or ratio decline curves, that each shows the same general trend. A composite curve derived from a number of curves or average production figures furnishes a good working curve, which is a guide for an approximate study of general conditions.

These composite curves may be too high for some properties or too low for others, but they at least furnish index curves that are of value. If anything, such curves tend to minimum rather than to maximum error.

Suppose the actual production of the first year of a well is 15,000 bbl., the second year 8000 bbl., the third year 5600 bbl., the fourth year 4200 bbl., the fifth year 3400 bbl., the sixth year 2600 bbl. Plot these figures and extend the curve to obtain future production. The results are shown in Table 17. If the ratios or percentages are plotted, the results for the next four years after the sixth as read from the curve are 0.126, 0.103, 0.086, 0.076. The property shows a cumulative percentage or ratio for the next four years of 0.391 of the first year's production.

The total cumulative ratio for 15 years is the sum of the yearly ratios, which in this case is 3.173. In barrels this reduces to $3.173 \times 15{,}000 = 74{,}670$.

If other wells follow the same general history as shown in Fig. 102, and Table 17, then this cumulative percentage can be used as a factor for other wells. One well may make 70 bbl. per day average for the first year, another 50 bbl., but the total ultimate factor is the same for each well.

The 70 bbl. well makes 21,000 bbl. the first year. The ultimate cumulative production for 15 years will be $3.173 \times 21{,}000$

= 66,633 bbl. The 50-bbl. well will make 15,000 bbl. per year. Its cumulative production will be 3.173 × 15,000 = 47,595 bbl.

RATIO OF DAILY YIELD TO ANNUAL

The relationship of initial yields of wells to their average daily yield for the first year varies in each field for wells of various sizes, but follows a general relationship for each field. The proportion that the initial production bears in the Oklahoma field is roughly 1 : 4. A well making 100 bbl. per day initial will average 25 bbl. per day for the first year. In California a well with an initial production of 100 bbl. will give an average of 50 bbl. per day for the year, or produces twice as much in the first year as will a well in the Oklahoma field.

The ultimate production bears somewhat the same general relationship.

The comparative ratios of initial daily production to the average production per well for the first year are approximately:

Oklahoma 4 or 5 : 1.

California 2 or 3 : 1.

Such generalizations must be used most carefully. The relationship in each field should be established before using such figures.

Such comparative declines must be compared with wells of the same class.

Wells making initial yields of 1000 bbl. act differently from wells making 100 bbl. initial. A well making 1000 bbl. initial production may produce 90 per cent of its total cumulative production the first year, where a well making 100 bbl. initial produces from 30 to 40 per cent of its total production the first year. Wells making 10 bbl. initial will make from 15 to 25 per cent of their total production the first year.

For this reason in studying wells in any field a generalized curve for wells of different classes must be used. A curve for a 500-bbl. well will not apply for a 100-bbl. well. However, it has been found that the 100-bbl. well will follow the decline of the 500-bbl.

well after the 500-bbl. well has declined to the 100-bbl. basis. A new 100-bbl. well in the same field will, in other words, conform to the decline curve or decline table of the 500-bbl. well.

Table 18.—Comparison of the Ultimate and the Second Year's Percentages of Average Wells in Different Fields

Field 1	Average daily production first year, barrels 2	Second year's percentage of first year's production, per cent 3	Approximate ultimate cumulative percentage, per cent 4
Oklahoma:			
Bartlesville	17	49	310
Osage (eastern)	35	63	330
Bird Creek-Flat Rock	30	60	300
Nowata	19	50	270
Glenn pool	45	51	240
Okmulgee-Morris	38	52	320
Hamilton Switch	56	55	320
Muskogee pool	24	44	210
Ponca City	32	61	320
Cushing:			
Layton sand	34	32	235
Wheeler sand	53	23	175
Bartlesville sand	208	30	220
Healdton	67	62	420
Kansas (shallow)	4	75	750
North Texas: Electra	75	51	330
North Louisiana:			
Caddo	66	54	290
Red River	475	23	
De Soto	190	35	
Crichton	85	28	
Gulf Coast:			
Humble pool (cap rock)	47	51	
Humble pool (deep sand)	289	38	
Sour Lake pool	84	39	
Spindletop pool	92	45	
Saratoga pool	23	53	
Illinois:			
Crawford County	11	52	280
Clark County	3	65	350
Lawrence County	100	61	370
Southeastern Ohio: New Straitsville pool	22	37	210
West Virginia:			
Blue Creek	17	27	170
Duvall district (Lincoln County)	17	69	280
Rock Creek	8	65	470
Spencer	22	70	350
Wyoming: Salt Creek	100	69	460
California:			
Coalinga (East Side)	180	76	480
Coalinga (West Side)	...	79	574
Kern River	...	78	550
Midway	189	70	520
Maricopa	...	59	445
Japan: Kurokawa	89	49	300

This will hold true with limitations and is sometimes a valuable guide. Knowing the history of a 500-bbl. well one could figure the performance of a 100-bbl. well from such a history. However, the history of a 100-bbl. well would not furnish the index for the performance of a 500-bbl. well.

Declines vary in different fields as does the total ultimate production. Table 18 after Carl Beal gives the estimated cumulative percentages for a number of different areas. These figures are general, but are useful in fixing in mind the relative productions of wells in various parts of the country.

VALUATION AND BUYING

As noted before, any valuation of oil properties is divided into an estimate of the values of the physical property and of the oil reserves.

The estimate of the value of the physical property will not be considered to any extent here, except to define depreciation, which must be taken into account in allowing for values of property.

Depreciation.—The term depreciation is used to cover the waste of assets due to exhaustion, wear and tear and obsolescence of property (Arnold & Darnell—*Manual for the Oil and Gas Industry*, p. 13).

The valuation of any physical property is based on a knowledge of replacement cost. Estimates of the life of the machinery may be obtained from Table 19 which shows depreciation.

Factors in Valuation.—The recoverable oil includes a number of problems of extreme interest. It is necessary to know:

(A) The amount of recoverable oil;

(B) The cost of obtaining the oil;

(C) The profit from that recoverable oil.

To determine the amount of recoverable oil, a detailed study of the oil properties is necessary. The properties are first classified into producing, proven, probable, prospective, and worthless land.

TABLE 19.—TABLE USEFUL LIFE AND DEPRECIATION

Class	No.	Reference, page	Summary taken from page 62 *Manual Oil and Gas Industry*	Useful life, years	Annual depreciation, per cent
A..........	1	57	Drilling equipment....................	4	40–25–15–10
	2	57	Wells..................................		
	3	57	Dehydrators:		
			Electric............................	5	20
			Pipe and tanks....................	2	50
	4	58	Tanks:		
			Steel 5000–55,000 bbls..............	20	5
			2500–5000..........................	12	8⅓
			Galvanized-iron 500–2500...........	12	8⅓
			Less than 500.....................	8	12½
			Wood..............................	5	20
			For movable tanks:		
			Galvanized-iron 500–2500...........	9	11½
			Less than 500.....................	6	16⅔
			For water tanks:		
			500–2500..........................	8	12½
			Less than 500.....................	5	20
	5	58	Tools..................................	3	33⅓
	6	58	Transportation equipment.............	3	33⅓
	7	58	Water plants..........................	10	10
	8	58	Electric equipment....................	10	10
	9	59	Machine shops.........................	7	14
A..........	10	59	Buildings:		
			Small wood........................	10	10
			Frame structure...................	15	6⅔
			Corrugated-iron siding............	6	16⅔
			Concrete..........................	25	4
			Brick.............................	25	4
			Steel.............................	25	4
B..........	1	59	Pipe lines:		
			Mains over 6 in. diameter...........	20	4½
			Mains under 6 in. diameter..........	16	5⅝
			Gathering lines...................	10	9
			Less 10 per cent salvage.		
			Pump stations.........................	10	10
C..........	.....	60	Tank cars.............................	20	5
	1	60	Refineries:		
			Class 1.—Located at point assuring a long supply of crude oil; or well-constructed plants....	20	5
			Class 2.—Located at points assuring supply of crude oil for several years.............	10	10
			Class 3.—Skimming plants and small refineries of poor construction, or located at points where supply of crude oil is not assured for a long period of time............	6	16⅔

TABLE 19 (*Continued*)

Class	No.	Reference, page	Summary taken from page 62 *Manual Oil and Gas Industry*	Useful life, years	Annual depreciation, per cent
D..........	1	62	Sales or marketing equipment:		
			Tankers..........................	20	5
			Barges..........................	5	20
			Filling stations—		
			Class A.—Ordinary wood or corrugated steel construction.	5	20
			Class B.—Brick and concrete or extraordinary construction.	10	10
			Distributing stations................	10	10
			Tank wagons—		
			Motor..........................	4	25
			Horse..........................	6	16⅔
			Steel barrels......................	7	14² ⁄ ₇
			Track and switches................	8	12½
E..........	.....	63	Natural gas (utility companies):		
	1		Drilling equipment. (See A–1.)		
	2		Wells. (See A–2.)		
	3		Gas pipe lines—		
			Mains..........................	12	8½
			Gathering lines..................	10	10
			City lines......................	10	10
	4		Compressor stations................	7	14² ⁄ ₇
	5		Gathering stations................	6	16⅔
	6		Field stations....................	4	25
	7		Meters and regulators..............	5	20
			Considered as a whole plant.........	10	20
F..........	1	64	Natural gas gasoline:		
			Plant—Compression, with 20 per cent salvage value..................	4	35–20–15–10
			Absorption plants, with 20 per cent salvage........................	4	35–20–15–10

Definitions.—*Producing oil land* is land on which there are producing oil wells.

Proven oil land is that which "has shown by finished wells, supplemented by geologic data, to be such that other wells drilled thereon are practically certain to be commercial producers." (Arnold & Darnell—*Manual for the Oil and Gas Industry*, p. 91.)

Probable land lies close to producing tracts and from all geological data, though not proven, should show a continuation of the producing area.

Prospective oil lands "include those areas, classified entirely by geologic observations, on which all available evidence indicates the possible presence of oil in commercial quantities." (Carl H. Beal—Decline and Ultimate Production of Oil Wells. Bureau of Mines, Bulletin No. 177.)

Worthless lands are those which from geologic evidence or from the results of drilling operations are considered of no value as regards oil production.

The amount of oil under a prospective tract is absolutely an unknown proposition; but some idea of relative values may be gained from very careful study of neighboring fields.

In estimating the amount of oil obtainable follow one of the methods outlined earlier. The size of the tract and the number of wells to properly drain it must be known.

The cost of obtaining the oil is generally a factor that can be allowed for in advance. It varies from year to year, and in different fields. Profit depends upon the life of the well and upon the market price of oil. All reliable estimates of lives of wells and the price of oil are important to consider. When those factors are once determined the rest is largely mathematical.

In buying properties the desired amount of profit, in per cent, and the rate of interest are essential factors for the buyer to keep in mind. In valuations of properties, and in buying, the present value of a future expected profit is essential.

Buyers and sellers have their problems well defined. Unless the buyer sees a good profit he will not buy, and unless the seller sees a fair return he will not sell. Bargaining comes in here, and prices are fixed by a compromise which is satisfactory to both. However, intelligent ideas of value may be obtained from good estimates.

The writer is presenting methods in the following cases, not detailed appraisals. He has accepted a basis of 10 years for his calculations, but this period might be 5 years or any other time that suits the needs of each case.

In the cases following, royalty will not be considered. The oil recoveries will be treated as if the company owned all its lands in fee. Where royalties are considered the deductions for royalty oil must of course be taken out of the gross production. Drilling and lifting costs on the royalty oil are, however, borne by the lessee.

Royalty.—A production of 100 bbl. per day gross at a royalty of 1/8 would in terms of net production, be, 100 bbl. less 1/8 or 12½ = 87.5 bbl. The pipe-line deductions for basic sediment and water would measure from 1 to 3 per cent. If 1.5 per cent is deducted the gross net production would be 86 bbl.

Average per Well.—For any property, the amount of oil can be reduced to the expected amount per acre or per well. If it is a producing property, the number of wells, present production and future production per well are points to be determined. If proven, probable, or prospective properties, the number of well locations left is essential. The number of locations depends directly upon the number of acres allowed per well, which is governed by local practice, and the different conditions encountered in each field. No inflexible rule can be laid down for the number of acres per well. In some fields 2 acres per well would be proper, in others one well to 5 acres or to 10 acres would seem good practice. The general system of well spacing shows an average of one well to 8 acres as standard.

The number of acres necessary to drain a given tract most efficiently depends upon so many variable factors that as yet a scientific system of ascertaining the proper number of wells has not been developed. It is necessary, however, to base calculations on average wells and the average number of acres per well as shown by good practice in a field. Such figures must be obtained to intelligently measure the future recovery of a property.

Determining Number of New Wells.—The annual decline of wells as shown in the tables and in the curves varies from year to year and finally reaches a figure which is fairly constant. The decline as shown in Column 9, Table 20, page 253, is large at first and very small later. Such declines vary in different fields, but the rate can be established for one field and it will be found fairly constant.

If it be desirable to lay out a prolonged drilling campaign it is important to know that the initial yields of new wells drilled in a field which has been producing for several years are less than in the earlier years. If the general yearly decline of the field as a whole is 15 per cent per year over the preceding year, it is found the decline in the new wells will also show that average. A new well this year shows an initial production of 200 bbl. Next year the initial production of new wells will be 15 per cent less or 170 barrels. The succeeding year the initial yield will be 15 per cent less than 170 bbl. or 144.5 bbl. The average decline in production per year will show the same relationship. This principle holds in general and is valuable in determining the number of new wells needed each year to maintain the production at a constant figure. This is of interest to a large company with large tracts of proven acreage.

The method of determining the number of new wells necessary to maintain a given level of production is as follows:

Last year's total production for a property was 3,000,000 bbl. The average decline in the field for all wells is shown to be 15 per cent. Next year's production will also be 15 per cent less if no new wells are drilled. This is a decline of 450,000 bbl. The average new well last year produced 35,000 bbl. per year. However, the production of new wells this year will be 15 per cent less, or 21,250 bbl. The number of new wells required to maintain production will be $\frac{450,000}{21,250} = 21 +$. To maintain last year's level of production, 21 new wells are required.

For the succeeding year the decline will still be 450,000, but the new wells will show a yield of 15 per cent less than 21,250 or 18,063, bbl. The new wells needed will be $\frac{450,000}{18,063} = 24.9$, or 25 wells.

Life of Oil Wells.—The life of an oil well is governed by several factors. Water flooding may destroy the wells as in Mexico, or it may affect local areas, as in a few American fields, but this is exceptional. The rate of decline, the price of oil, and the production costs are the real measurements of longevity.

Oil wells may produce oil indefinitely in small quantities, as shown in the Pennsylvania field. The measure of their life is the amount of profit obtained above the actual pumping or lifting cost. As long as the oil obtained from a well pays a profit above its lifting and overhead expense, the well will be allowed to produce. In times of low prices small wells will be abandoned or shut down. In times of high prices these small wells will produce. In other words, the final limit to the productive life of a well is the economic level, where the cost of operating is equal to the market value of the oil produced. This holds for any class of well. Column 3, Table 20, page 253, shows the ratio of the cost per barrel at a set market price. The market price is \$3.50; the lifting cost varies as shown in Column 3. Column 4 shows the profit. When the quantity of oil equals 42 per cent of a barrel the profit is 0. This is shown in Table 20 at the twenty-sixth year, and in Table 21 is not in sight, though it will be at the fortieth year. Costs of production fluctuate and the price of oil fluctuates, and in making estimates allowances must be made for both cost and price.

Early estimates of the lives of oil wells have generally proven low. Six or seven years was considered the average life of wells in the California, Gulf Coast and Mid-Continent fields, 10 years ago. All these estimates have been revised. The high price of oil and the proved life of wells have shown the fallacy of the early estimates, which were based on low market prices.

Pennsylvania, Ohio, and West Virginia show numerous records of wells pumping 30 to 40 years. The old Drake well which was drilled in 1859 is still producing oil. Illinois shows a steady life in its wells, as numerous properties are over 15 years old. In the Mid-Continent fields, wells 12 to 15 years old are good producers to-day, and have some years ahead of them. In the Gulf Coast area, Spindletop is producing oil from the early wells, now 18 to 19 years old. The Caddo, Louisiana, field is still producing, though wells there are 15 years old.

In California, the Coalinga, Maricopa, and McKittrick oil fields show numerous wells 12 to 15 years old. In the Midway field wells from 10 to 14 years old are plentiful and good for 10 years additional life. The Kern River field near Bakersfield has numerous wells 15 years old, and should produce at least 10 years more. The Old Salt Lake field in California has produced oil for 20 years. The Olinda field is over 22 years old, and still has a long life ahead of it.

The Salt Creek oil field in Wyoming was drilled in 1908, and its wells are good producers after 12 years. Other fields in Wyoming 10 years old or over are the Grass Creek and the Lander fields.

It would seem that a safe estimate of the life of wells is certainly 10 years, and one is safe in assuming that length of time in making estimates for new wells, with the possibility of even longer life. In many producing fields 10 years of added life can be safely assumed, but such assumptions must be made with all due respect to local conditions.

Present Value of a Future Profit.—The present value of a future profit is the sum of money which, invested at a given rate of interest in good securities, will equal the full amount at the date the profit is realized.

A dollar profit received 10 years from to-day is worth to-day at simple interest at 6 per cent $\frac{100}{160} = .62.5¢$.

In other words $0.625 placed at simple interest of 6 per cent for 10 years would equal $1 at the end of that period. Similarly, the per cent value of any amount running for 5 years at 6 per cent $\frac{100}{130} = 0.769$.

At compound interest the principal amount would be less. For 10 years it would be 0.558, and for 5 years 0.747.

Column 5, Table 20, page 253, gives the factors by which to divide the future profit to obtain its present value.

As shown in Table 20 the largest profits would be paid in the early years. If the returns on the investment were returned on such a basis the amount of interest would be paid in proportion.

The amount received the second year would not be so large as the first year and the amount of interest less.

Interest.—In buying property, interest on the investment must be considered. The interest would be automatically cared for by retiring the investment on the basis of the decline curve. If a definite amount of money were paid back each year to retire the capital, a large amount at first and a smaller amount in later years in proportion to an average curve, then that money could be invested in good securities.

The difference between the present and the future value of the profit compensates for the interest. This could be carried out in more detail, but it is thought sufficient to illustrate the principle. No hard and fast rule of procedure can be set down as the terms of each transaction vary, but if the general plan of buying is based on the procedure outlined, estimates can be made that will be good guides in purchasing properties.

Dividends.—If an oil concern owns only one property it should declare its largest dividends in the earlier years according to the ratio of annual decline. If, however, the company has a large reserve of proven and of prospective land it can plan a drilling campaign which will maintain a steady production.

An oil company, using its funds for development, could put aside an amortization fund which would pay interest and retire the initial capital within a few years. The amount set aside each year to return the capital would be made on the basis of the method described on page 248.

A large, well organized operating company should pay dividends of not less than 10 per cent a year, and upward. Good stocks of old companies pay as high as 50 per cent per year on the original capitalization.

Expectations of Ordinary Stock Companies.—The general public has a mistaken idea of the value of oil companies. During the past five years many millions of dollars have been invested in oil companies without rhyme or reason. The country seems to have gone oil mad. Many big promotions that will never pay have been "put across." Also thousands of small companies have been formed that will never pay profits to their stock holders.

A few figures may prove of interest. In Texas, out of 1050 new stock companies formed in 1918 and 1919 only seven paid profits. In Oklahoma, in 1918, the State Corporation Bureau figured that out of every $550 invested in stock companies only $1 was returned. In Kansas out of 1500 new companies in 1916 and 1917 only 12 had paid profits.

These figures are fair examples of the risks undertaken by novices. The early excitement in North Central Texas caused a reaction that hurt the whole oil industry.

However, it is only fair to state that not one well organized and financed oil company under good management has failed in the oil business. This is remarkable when the hazards of the business are understood.

Future Price.—In making valuations the future price is important. The elements affecting the market are

1. The future supply of oil:
   (A) Domestic,
   (B) Foreign countries.
2. The consumption of oil:
   (A) Domestic,
   (B) Foreign.

I. The future supply depends upon
   (A) The maintenance of present production,
   (B) The development of old fields,
   (C) The opening of new fields,
   (D) The improvements in recovery methods.

II. The consumption of oil depends upon
   (A) The maintenance of the present markets,
   (B) Finding new markets,
   (C) Increased demand in the present market,
   (D) Check on present demand,
   (E) Actual decrease in present demands.

To answer intelligently the various points brought out specific knowledge of future possibilities must be obtainable. Such information is at present fragmentary so far as foreign possibilities are concerned. More is known in a qualitative rather than a quantitative way about such possibilities.

Domestic (United States) future supply is easier to analyse. The records of the United States Geological Survey, of State and private surveys furnish some ground for a general answer to the future supply in the United States. This information checked by actual drilling operations and development gives some good indices that cannot be disregarded.

It is a self-evident fact that to maintain present production requires a great deal of new drilling. The old fields fall off at an average rate of 15 to 20 per cent year. This loss in production must be maintained by new drilling.

The increase in demand for all the past ten years has shown an average of 7 per cent per year. There seems no reason to doubt that this general rate of increase of demand will hold or even increase if the supply of oil holds out. The price of oil will increase unless checked. Such a check must come from

(A) excess of production over demand,
(B) stabilization of demand,
(C) cost of oil so high that substitutes will compete.

In making valuations future price and market should be taken into consideration. Much of the information given in pages 6 and 7, Chap. I, is directly applicable to the discussion of price.

Barrel-Production Method.—Oil land in the Eastern fields is purchased on the barrel basis. In buying a producing property, the average daily production for a stated period, usually ten days, or a study of the pipe-line returns for a steady producer, is taken as a starting point. The price is quoted at so much per barrel, for the daily production. The price asked varies for the age of the wells, and the character of the oil. Originally the Standard Oil system of buying regulated the price, and the present system is largely the result of this.

The owner asks $4000 per barrel and $100 more for each 10¢ increase in market price of oil. If an owner sells 100 bbl. of production and asks $4000 per barrel and overnight the market price per bbl. increases 10¢, he will ask $4100 the next day, if the original deal was not closed. These methods of purchasing oil property are based on experience.

Values of this kind often bear little relation to the amount of oil under a property. In general such methods give prices that are too high for safe investment, unless there is undeveloped acreage or a much higher market price in mind.

A general formula of value used by the Standard Oil Company is to multiply the average daily production into the present market price of the property by 1000. For example, suppose the price of light oil in Oklahoma is $3.50 per barrel. If the settled net production on a lease is 100 barrels, the value of the production will be 100 × $3.50 × 1000 = $350,000.

Valuing—Flush or New Production.—Production when "flush" or new is harder to value than "settled" production with a known decline.

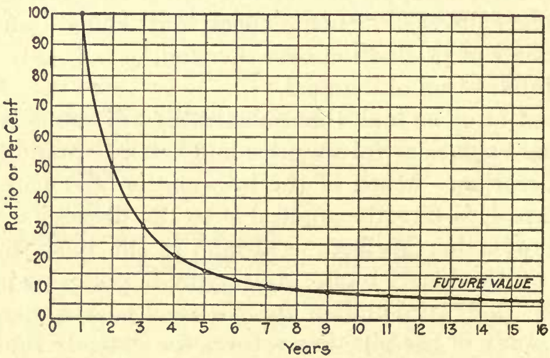


FIG. 103.—Decline curve for new well. Same values in Table 20.

Example: A well comes in making 100 bbls. flush. Such a well will average 25 bbls. per day per year of 300 days. What is it worth per barrel? To obtain its value the history of neighboring wells or fields must be worked out. To simplify the method the decline curve shown in Fig. 103, page 252, is employed as a typical average for wells of 100 bbls. size in this field. Table 20 presents the history in ratios of an average well.

TABLE 20

1 Age of Production yrs.	2 Factor yearly production	3 Factor Operation costs	4 Factor Profit	5 Factor for present value	6 Factor Present value of profit	7 Factor Cumulative value of profit	8 Factor Cumulative production	9 Ratio production of preceding year
1	1.000	0.024	0.976	1.06	0.920	0.920	1.000	
2	0.500	0.025	0.475	1.12	0.424	1.344	1.500	.500
3	0.305	0.027	0.278	1.18	0.235	1.579	1.805	.610
4	0.213	0.029	0.184	1.24	0.148	1.727	2.018	.700
5	0.162	0.030	0.132	1.30	0.101	1.828	2.180	.765
6	0.131	0.031	0.100	1.36	0.073	1.901	2.311	.808
7	0.112	0.031	0.081	1.42	0.057	1.958	2.423	.855
8	0.100	0.032	0.068	1.48	0.045	2.003	2.523	.893
9	0.092	0.033	0.059	1.54	0.038	2.041	2.615	.920
10	0.085	0.034	0.051	1.60	0.031	2.070	2.700	.930
11	0.080	0.034	0.046	1.66	0.027	2.099	2.780	.940
12	0.076	0.034	0.042	1.72	0.024	2.123	2.856	.950
13	0.073	0.035	0.038	1.78	0.021	2.144	2.929	.950
14	0.070	0.036	0.034	1.84	0.018	2.162	2.999	.950
15	0.067	0.036	0.031	1.90	0.016	2.178	3.066	.950
16	0.064	0.037	0.027	1.96	0.013	2.191	3.130	.950
17	0.061	0.037	0.024	2.02	0.011	2.202	3.191	.950
18	0.059	0.037	0.022	2.08	0.010	2.212	3.250	.950
19	0.056	0.037	0.019	2.14	0.008	2.220	3.306	.950
20	0.054	0.038	0.016	2.20	0.007	2.227	3.360	.950
21	0.052	0.039	0.013	2.26	0.005	2.232	3.142	.950
22	0.050	0.040	0.010	2.32	0.004	2.236	3.462	.950
23	0.048	0.040	0.008	2.38	0.003	2.239	3.510	.950
24	0.046	0.041	0.005	2.44	0.002	2.241	3.556	.950
25	0.044	0.041	0.003	2.50	0.001	2.242	3.600	.950
26	0.042	0.042	0.000	....	.....	.....	3.642	.950

Explanation of Table 20.—Column 1 gives the age. The production in ratios of the first years is presented in Column 2. This table is for an average well making 100 bbls. flush for a typical field; and other production of new wells in the field should follow the same general history. Column 9 shows the production of each year compared to the preceding year. Column 4 shows the relation which the operating cost bears to the market price which is $3.50. This cost varies with the age of the well. Column 4 shows the future profit after deducting operating cost. This is obtained by subtracting the figures in 3 from those in 2. Column 5 shows the factor which divided into the future profit in Column 5 will give the present value of a profit as shown in Column 6. Column 7 shows the cumulative profit which is obtained by adding the figures in Column 6. Column 8 gives the cumulative production.

Such a table can be readily made for any field. The decline figures can be obtained in the usual manner from the decline chart, and then extended. The factor of operating cost, Column 3, is found by taking average costs for wells of various sizes and determining the cost per barrel, allowing for overhead, taxes, etc. For new wells the cost is low and increases as the well grows older. The proportion for a new well may be 0.024 of the production, say 10¢ a barrel for a 25-bbl. well on a lease.

For a well 10 years old making 2 bbl. the cost per barrel will be as high as $1.25 to $1.75 per barrel. These figures have been averaged and based on the ratio of the first year's production to bring out the principle more clearly. To find the proportion the cost in later years bears to the production, divide the figures in Column 3 by those in Column 2. For the first year the proportion is 0.024, the fifth year 0.18, the tenth year 0.40, the fifteenth year 0.51, the twentieth year 0.70, the twenty-fifth year 0.93. Such figures vary from field to field, and the relative costs in each field must be studied, but the comparisons are valuable.

The value of reducing all future profits to a present value basis furnishes means of discounting the future as far as possible. One can allow factors of safety later. It is too often forgotten that a dollar running for 20 to 25 years at 6 per cent amounts to a large sum at the end of that period.

Production is often bought at figures that leave a very small margin of profit. The buyer usually pays too much for his production. He will make a profit but unless the market price increases he will many times get less than 6 per cent on his money when he should get 15 per cent or 20 per cent.

Table 20 brings out some interesting points. It will be noticed that in the twenty-sixth year the production has decreased to factor 0.042. At that point the lifting cost is 0.042

and equals the amount of oil received so that the profit is 0, and the well would be abandoned. If, however, the market price of oil is increased, the profit will increase, and the production will not be abandoned.

Discussion of Example 1.—From Column 7, Table 20, the total present value of the cumulative profit is 2.242 for a 25-year life. The average pumping time on a property is 300 days per year. If a barrel of production averages 1 bbl. per day for 300 days, the first year's production is 300 bbl. The price of oil is \$3.50. The total present value of the cumulative profit is

$$300 \times \$3.50 \times 2.242 = \$2354.10$$

The total present value of a barrel of new production is then \$2354.10. If the well's production averages 25 bbl. per day at present the production will be worth $2354.10 \times 25 = \$58{,}852.50$ for a 25-year life.

In buying a barrel of this production one would want to figure at least a 100 per cent return on the investment in 10 years with interest. A different set of figures would be used in this case.

The total present value of cumulative profits for the first 10 years would be the sum of the profits or 2.07. The present value in dollars would be $300 \times 350 \times 2.07 = \$2173.50$. An operator in buying would want 100 per cent profit, and would pay $\frac{2173.50}{2} = \$1086.75$ per barrel, for the new production.

It is interesting to note that the cumulative present value of the profit for 25 years is 2.242 and for 10 years is 2.07. The total residual profit for the remaining 15 years is 0.172 or a little over 1 per cent average per year. However, the well will be pumped no matter how small the profit especially if there area number of wells on one unit. An increase in the price of oil may continue the life of a well far beyond the point indicated.

It will be noted in these discussions that the factor of cumulative profit was sought mainly instead of the factor of cumulative production. Profit is the ultimate aim in valuing a property.

The production in barrels could have been obtained and then reduced to dollars. Instead, however, the profit factor for each year has been determined and then reduced to dollars at the very end. This plan will vary with each engineer.

The main factors in valuing oil land have been considered. To apply these methods to a more general case, consider a new 100-bbl. well on a property of 160 acres with 19 drilling locations remaining. This well of 100-bbl. flush will average 25 bbl. per year as determined from past history of similar wells. Such a well will follow the general decline curve for the field.

As shown in Table 20, Column 7, the present value of profit for a barrel of new production is 2.07 for 10 years, or in dollars \$2173.50 as shown above. The value of a new well making 25 bbl. average for the year will then be $25 \times \$2173.50 = \$54,337.50$ for 10 years.

The buyer must also figure on drilling 19 additional wells which would cost an average of \$20,000 each, or \$380,000 for the 19 wells. The drilling cost must be deducted:

The profit for one well is shown to be \$54,337.50. The amount for 19 wells will be $\$54,337.50 \times 20 = \$1,086,750.00$.

The total present value of profits above drilling costs will then be \$1,086,750 less \$380,000 or \$707,750.

At 100 per cent profit the buyer would pay $\dfrac{707,750}{2} = \$353,875.$

This means \$2211 per acre for the 160 acre tract.

Valuing Settled Production.—"Settled" production is a term of indefinite meaning. To some oil operators a well is considered settled when the production is 6 months old. To others, production is settled when 12 months old. Settled production is really not a specific term but a relative one.

When the decline in production becomes constant a well may be considered really settled. The decline as shown in Column 3, Table 21 is not really constant until the thirteenth year. However, for all practical purposes production is considered settled when the decline in production is not marked. A well may have an initial production of 100 bbl. and at the end of the year produce 20 bbl. per day. The drop is 80 bbl. and is very large. At the end of the next year the well makes 12 bbl. or a drop of only 8 bbl. which is not so marked. A buyer will generally consider production well "settled" at the end of the first 12 months. Actually this is not the case.

TABLE 21.—SETTLED PRODUCTION

1 Age of production yrs.	2 Calendar years	3 Factor decline yearly production	4 Factor operating costs, per cent	5 Factor Future profit,	6 Factor for present value	7 Factor present value of profit	8 Factor cumulative value of profit	9 Factor for cumulative production
5	0	1.000	0.023	In buying, the 5th year's figures are used as basis Factor 1.00				
6	1	0.808	0.023	0.785	1.06	0.740	0.740	0.808
7	2	0.690	0.024	0.666	1.12	0.590	1.330	1.498
8	3	0.617	0.025	0.592	1.18	0.501	1.831	2.115
9	4	0.555	0.026	0.529	1.24	0.426	2.257	2.670
10	5	0.524	0.027	0.497	1.30	0.382	2.639	3.194
11	6	0.493	0.028	0.465	1.36	0.334	2.973	3.687
12	7	0.468	0.029	0.439	1.42	0.309	3.282	4.155
13	8	0.450	0.030	0.420	1.48	0.283	3.565	4.605
14	9	0.431	0.031	0.400	1.54	0.259	3.824	5.036
15	10	0.413	0.032	0.381	1.60	0.238	4.062	5.449
16	11	0.394	0.033	0.361	1.66	0.217	4.297	5.843
17	12	0.376	0.034	0.342	1.72	0.198	4.477	6.219
18	13	0.364	0.035	0.329	1.78	0.183	4.660	6.583
19	14	0.345	0.036	0.309	1.84	0.167	4.827	6.928
20	15	0.333	0.037	0.296	1.90	0.155	4.982	7.261
21	16	0.320	0.038	0.282	1.96	0.143	5.125	7.581
22	17	0.308	0.039	0.269	2.02	0.133	5.258	7.889
23	18	0.296	0.040	0.256	2.08	0.123	5.381	8.185
24	19	0.283	0.041	0.242	2.14	0.113	5.494	8.468
25	20	0.271	0.042	0.229	2.20	0.104	5.598	8.739

The term "settled production" is, however, so generally employed in oil circles that it is difficult to avoid using it.

Table 21 and Fig. 104 present data on old production. The age of the production in this case was chosen at the end of the fifth year of the life of a well.

A barrel of production 5 years old will settle in this case as shown in Table 21. The production at the end of the sixth year would be only .808 of the preceding or fifth year, or .808 of a barrel. The production for the next year, the seventh, would be 85.5 of 0.81 or – 0.69. The factors are shown in Table 21 for each year.

Table 20 shows production from its flush to its later stages for a barrel of new production. Table 21 and Fig. 101 show the performance of a barrel of production bought at the end of the fifth year. The two tables, while related, show values for two different ages of a barrel of production.

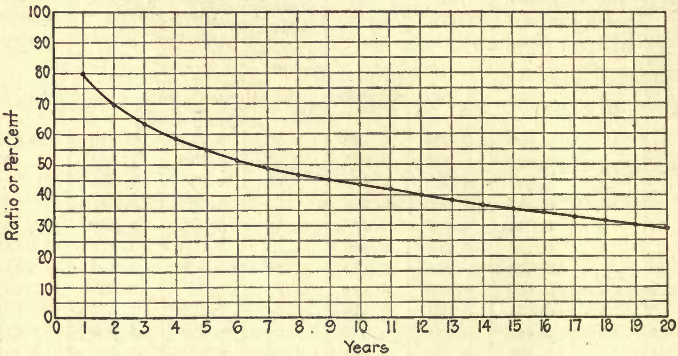


FIG. 104.—Decline curve for production starting end of the 5th year. Same values in Table 21.

As shown in Table 21 the yearly decline in time becomes very small. A barrel of production bought at the end of the fifth year will for the cost figures given and a market price of $3.50 produce many years before the factor of oil produced and the factor for operating cost are equal. In fact, at the end of the twentieth year a well which when purchased make 2 bbls. daily would yield 2 × 0.27 or 0.54 of a barrel, and its life would continue for many more years.

For 20 years the total cumulative factor of production from Column 9, is 8.74. The total cumulative present value of the profit, see Column 8, is 5.598.

Application of Method.—To apply the above method. An operator desires to know the present value of 1 bbl. of such production in dollars. The producing time per year averages 300 pumping days. The present value for each year is, Market price of oil, $3.50 × 300 × 5.598 factor present cumulative profit per barrel for 20 years = $5878.00. This represents the present value of a barrel of production, if the well produces for 20 years.

A buyer, however, would consider this from another angle. He would probably figure only 10 years life. In buying such production he would require 100 per cent initial capital returned, interest, and at least 50 per cent profit on his money. He would want the capital returned in at least 5 years, and his profit in the next 5 years. The balance of the profit above 10 years would be a gamble.

He would figure as follows: The total amount desired is 150 per cent above interest in 10 years. Divide the present value of the future profit as of 10 years by 150. This would give the total amount he could afford to pay. The present value for 10 years is

$$\$3.50 \times 300 \times 4.065 = \$4263$$

The highest price he could pay to meet the conditions would be $\frac{4263}{150} = \$2840.$

It is well to bear in mind that the 20-year figures show a present value of $5878. The figures of present value for 10 years show a value of $4263. The difference, $1615, represents the present value of the profit after 10 years and up to 20 years. Anyone buying the production at $2810 would receive a return of the money invested in 5 years, interest at 6 per cent and 50 per cent profit on the investment in 10 years, and the gamble for a future profit of $1615 or 59 per cent on the amount invested for the second 10 years.

Flush and Settled Production.—In buying settled or aged production with proven undrilled acreage, one has a combination of two problems. The settled production and the proven acreage should be treated as two separate units, and a price for each determined. Then the sum of the two prices would fix the amount paid for the property. If purely prospective acreage were in view its value should also be added.

TOTAL VALUE OF A PROPERTY

The sum of the oil and land values plus the value of the physical property such as tools, casing, machine shops, tankage, and improvements, and salvage make up the total value of the property.

In these discussions the value of the oil alone has been considered. The value of the natural gas and of the casing-head gas must be taken into account. The natural gas from a property might pay all operating expenses and a handsome return on the investment. Likewise, the value of the casing-head gasoline possibilities enters into the price paid for a property. Such possibilities must, however, be studied as separate units although they later appear in the value of the property.

Another element to be considered is the fact that a company which can buy the oil for its refineries can afford to pay a higher price for oil property than a company which has no refinery. An assured supply of oil is essential to a refinery. The profit derived from the refined products will largely affect the higher price a company might pay to obtain an assured supply of oil.

Valuation Where a New Field of One Producing Well Only Has Been Opened.—One is often faced with the problem of valuing a new field of a single producing well. This presents some difficulties. However, some idea of value may be gained if a well-defined geological structure has been determined. Figure 105, page 261, shows a dome. The discovery well on the 1000-ft. contour line is making 200 bbl. at a depth of 2500 ft. The pay sand is 50 ft. thick and *carries no water.* From this latter fact one can safely assume that the oil will carry down to the 950 contour line. There will be an area within that contour limit of at least 400 acres. Assume that this 400 acres has a sand body at least 25 ft. thick and a recovery of 200 bbl. per acre feet of sand, the following computations will determine the amount of oil that is likely to be recovered in 10 years.

400 (acres) by 25 ft. (thickness) by 200 bbl. (recovery per acre-foot) = 2,000,000 bbl. of recoverable oil. Two hundred bbl. per acre-foot holds only in areas that average that amount. For California some areas show 300 bbl.; for some Eastern fields the recovery is as low as 75 to 100 bbl. per acre-foot. Assume that all this oil will be recovered in 10 years at an average cost of \$1 per barrel. Assume the average price received is \$3.50 per barrel. The maximum income in 10 years would then be 2,000,000 × 3.50 = \$7,000,000.

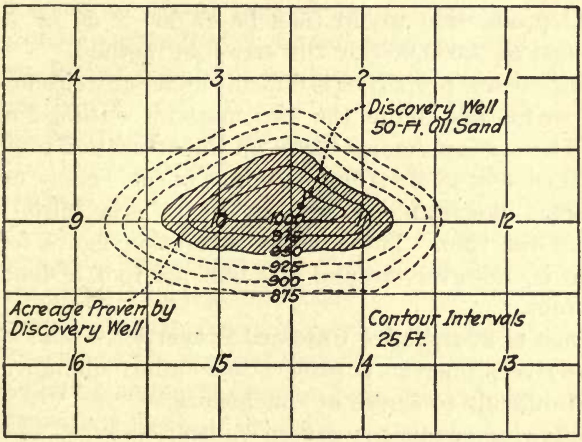


FIG. 105.—Sketch showing dome and discovery well.

The cost of operating at \$1 would then be 2,000,000 × \$1 or \$2,000,000. The total value of the oil at \$3.50 would be 2,000,000 × \$3.50 or \$7,000,000. The total income would be \$7,000,000 less \$2,000,000 or \$5,000,000. The present value would be 0.77[1] × 5,000,000 = \$3,850,000. The highest price an operator could afford to pay with a 100 per cent profit would then be $\frac{\$3{,}850{,}000}{2}$ = \$1,925,000 in round numbers. The price one

[1] The figure 0.77 represents a rough average for 10 years. Refinements are not employed.

could pay per acre would be $\frac{\$1,925,000}{400} = \$4,812.50$ per acre. Such figures are rough approximations only, but furnish some bases for calculations.

Compare this method with the appraisal curve method below. Suppose a well makes 200 bbl. per day initial. In another field of the same general character other wells show approximately 15,000 bbl. the first year. If the total ultimate factor of such a well were 2.87 the total production in 10 years would be 43,050.

There is room on this 400 acres for 50 wells at 8 acres to a well. The total production would then be $43,000 \times 50$ or 2,150,000 bbl.; as against 2,000,000 by the acre-foot method.

Figuring on new properties is difficult under any circumstances, but the writer has found the two methods outlined above of value. The per foot figures based on the saturation method and on sand thickness would seem preferable in some cases, especially in new areas like Homer, Louisiana, where large initial productions were the rule. The average saturation figure for North Louisiana is, however, around 400 bbl. per foot instead of 200 bbl. per foot.

Valuation of Prospective Untested Properties.—The valuation of prospective properties is subject to so many unknown factors that it is difficult to arrive at conclusions.

The following conditions govern values:

(*a*) structural condition;
(*b*) depth of oil sands;
(*c*) number of oil sands expected;
(*d*) thickness of sands;
(*e*) porosity of sands;
(*f*) character of oil expected;
(*g*) geographic relation to other oil fields;
(*h*) area of property;
(*i*) accessibility,
  (1) roads,
  (2) railroads;
(*j*) pipe-line facilities;
(*k*) refining facilities;
(*l*) market conditions.

No one has yet discovered any method but actual drilling by which to determine absolutely the presence or absence of commercial production in any area.

A careful study of the geological conditions, *i.e.*, seepages of oil, sands favorable for oil reservoirs, domes, anticlines or terraces favorable for oil accumulation, of thick bodies of carbonaceous or petroliferous shales is desirable and may throw some light on the presence or absence of oil in the area.

It is worth while to know that 95 per cent of all the oil fields of the world are on domes, anticlines, or terraces, or that 19 out of 20 oil fields are found under such conditions. It has been found in certain areas that such folds produce as follows: Osage, Oklahoma, 90 per cent folds productive, Wyoming, 50 per cent, California, 75 per cent, and out of all known tested folds the proportion producing is 20 per cent.

It is also recognized that drilling haphazard without geological selection means one test in 300 to bring in a field. The geologist may reduce the hazard to 1 in 5. With a known selected fold in a general area the chances are then about sixty times better than those without careful selection.

The amount of acreage within reach of the drill is important. If but 500 acres can be reached with the drill, the property, other conditions being equal, is one-tenth as valuable as one having 5000 acres within reach of the drill.

There is, however, a limit regarding size. If too small the operating units are hardly worth while, and if too large the area will not likely be a rich producer. Medium-sized units of from 1000 to 5000 acres are most desirable.

It is, of course, well understood that a two-sand country is more valuable than one; three more valuable than two and so on. Often, however, one sand is the main productive sand of a district, and that one sand may produce more oil than all the others combined. The well-known Bradford sand of Pennsylvania, the Bartlesville sand of Oklahoma, the Woodbine sand of Louisiana, the Frontier sands of Wyoming are the main sands sought in those particular fields, and if these or any other well-known sands are thought to underlie an area, greater value is attached to it than if average sands exist.

A thick sand if fully saturated, will produce more oil than a thin one of the same character. One 100 ft. thick should produce 10 times the oil of a sand 10 ft. thick under the same conditions of saturation.

Porosity is also a factor. The more porous sands range from 15 to 25 per cent voids, and the tighter sands 5 to 10 per cent. Given a porous condition, a porous sand is worth more than one less porous. The character of the oil expected, of course, influences the desirability of the land. Heavy fuel-oil land with oil at $1.50 per barrel will be worth only one-half as much as land under which $3 oil is expected.

Accessibility means, of course, the ease with which the acreage could be developed. If in a difficult country and 100 miles from railways the cost of a pipe line would be $15,000 per mile for 8-in. line. Consequently there would be little or no profit left.

The above factors all determine the value of land and in part are all factors of the size of wells and their longevity. The true measure is really the value of oil to be expected, and the chances of obtaining the same. There are, however, so many unknown factors that it would be foolhardy to make estimates of future recovery. One could assume definite conditions to exist and then base returns on those conditions, but the whole pyramid would tumble if one of the conditions was not met.

With a dome of known size and with known sands underlying a district, a scheme like the following might be constructed, but it is highly speculative. Royalty and pipe-line deductions have not been included.

(1). Area within reach of drill on dome—1000 acres;

(2) Number of sands—2;

(3) Total thickness of sands—50 ft.

History of sand of same character shows production averaging 5000 bbls. per acre for 10 years.

Total recoverable oil for 10 years normal expectation 1000 × 5000 at present market price, $3 = $15,000,000.

Expenses of obtaining oil.

Cost of 125 wells. @ $30,000 per well.

125 × $30,000 =	$3,750,000
Operating expenses @ 50¢ per barrel =	$2,500,000
Total	$6,250,000

Total expected profit = $15,000,000 − $6,250,000 = $8,750,000.
Present value of this profit at 77¢ = $6,737,500.

Chances in area are 1 in 5 for obtaining oil. Value per acre then is:

$$\frac{\$6,737,500}{1000\text{ (acres)} \times 5} = \frac{\$6,737,500}{5000} = \$1347.50 \text{ per acre.}$$

Allowing for a profit of 100 per cent, the highest amount an operator could afford to pay would be $\frac{\$1347.50}{2} = \$673.75$ per acre.

This and higher prices have been paid for land near or adjoining a well; but to go into a district 5, 10, or 20 miles from a producing field and offer such a figure would be unwarranted. Even where conditions governing production can be reasonably assumed such methods are speculative.

At present, land around drilling wells without geological selection brings from $5 to $100 per acre depending on how close a well is to the land purchased. Considering the ordinary chances of 1:300, land on a good dome or anticline selected by geologists where the chances are 1:5 is worth 60 times more than ordinary acreage, or $350 to $6000. Of course one will not pay it, but logically the land is worth that much. In actual practice, however, the price ratio is approximately 2:1 for wells on favorable folds over those off such folds. In every case the buyer should determine an index formula for any area, and then buy accordingly.

Most estimates of values of undrilled lands, away from productive areas are arbitrary, unscientific, and little understood. They too often represent a mere opinion or guess, but in light of good index figures they furnish the best known method.

SIZING UP AN OIL COMPANY

Since the signing of the Armistice in 1918, there has been an unprecedented period of wild speculation in the petroleum industry, accompanied by all manner of reckless spending and big promotions. Thousands of new companies have been formed, a large majority of them selling stock, and 99 per cent of them doomed to failure. Even large corporations have had no easy time.

In analyzing an oil company, use common sense. Oil companies are in no way different from other industrial organizations. Unfortunately the public thinks of the oil business as a wild speculation and plays it as they would a game of cards. That idea is all wrong. The elements of value in any oil stock may be quickly analyzed. Everything depends upon the personnel of the company. The word "personnel" covers a wide field. Given an individual or group of men, and he or they will make or break an oil company. The man or men at its head must be good executives and command capital. With this combination success is assured and it is important to know that there has been no failure of a company headed by a good executive.

In investigating any company, ascertain who is the individual or the group responsible for its major policy and decisions, and you can rest your judgment on that man or men.

A study of the failures of oil companies shows many causes, varying from extravagance, theft, poor judgment and lack of capital to failure in drilling or in operating. In the last analysis, however, they all fall back to faulty management. The personal equation predominates largely, here as in every business. System, routine—all—are merely aids to the free activities of the men who are running the enterprise.

Analyze the men at the top. The only recommendation for many oil companies is a list of the stockholders and the officers who are ostensibly at their head. Often such a list means very little. Men may command millions, but if there is not a man of proven ability who is also vitally interested in the success of the venture in active charge failure is unavoidable, unless by some freak of fortune the Gods relent and allow it to succeed.

APPENDIX

ORIGIN OF THE 42-GAL. BARREL

By W. M. Dunham

The men who buy, sell, produce, transport, refine and market petroleum never give a thought why the American oil barrel of commerce contains 42 gal., when the laws of the United States decree that a barrel, particularly the wine barrel, shall have a capacity of 31½ gal. The origin of the 42-gal. oil barrel is an interesting story, and should have a place in your book. I challenge you to find anyone, geologist, producer or refiner among your acquaintances who can relate its origin. It follows:

One of the difficulties at the outset of the petroleum industry in the United States was the scarcity of packages to serve as containers for the crude product in transportation from the well to the refinery. The demand for barrels outgrew the supply, and any cask fit to retain fluid was impressed into the service of the producer. The unit of measure at the outset being the gallon, sales were made on that basis, therefore the size of the package was not a necessary condition of trade. But later on, when the barrel became the unit, discrepancy in the size of barrel became a matter of embarrassment to the producer. The resources of the seaport towns were drawn upon for coopers, and as a consequence men from the Eastern States were among the first to recognize the importance of establishing barrel works in the oil fields.

The whaling industry, at the time unprofitable, owing to the extended voyage and hardships of the chase, had a fully developed cooperage industry, and mechanics drawn from this trade found employment in the oil-producing country. The capacity of the barrel became a matter of comment among producers about the time of the advent of the whale-oil men, who brought casks of enormous size with them, which in periods of surplus production, were offered and accepted as ordinary barrels. Therefore, the necessity for a uniform barrel was clearly apparent. As a result of these discussions, 40 gal. became the trade-custom barrel for crude oil, and this continued from 1860 to 1866, when representative producers got together and issued the following:

"Whereas, it is conceded by all producers of crude petroleum on Oil Creek that the present system of selling crude oil by barrel without regard to size is injurious to the oil trade, alike to the buyer and seller, as buyers with the ordinary size barrels cannot compete with those with large ones, we therefore mutually agree and bind ourselves that from this date we shall sell no crude oil by barrel or package, but by the gallon only. An allowance of 2 gal. will be made on the gauge of each and every 40 gal. in favor of the buyer."

It will be seen that the barrel by resolution differs from the barrel of adoption only in the addition of 2 gal. for tare or waste. Later on, after the establishment of pipe lines, buyers began to demand 42 gal. net with the addition of 2 per cent for tare, which is the accepted barrel of to-day, plus 1 per cent, although the construction placed upon the barrel by the Government during the period of excise—April 1, 1865, to March 1, 1866—was: "Any vessel containing not more than 45 gal. and not less than 28 gal." This amount was subject to a duty of $1.

STANDARDS OF MEASURE

Sec. 1. Standards of measure shall be those authorized by the United States Government for the following:

A gallon shall be 231 cu. in., which is known as the American or wine gallon.

A half barrel, when not otherwise specified, shall be considered as contained in wood and shall be from 28 to 35 gal.

A half barrel when contained in metal, shall be 30 gal.

A barrel contained in wood shall be from 47 to 53 gal.

A barrel when contained in metal, shall be 54 gal.

A barrel in bulk, other than crude oil, shall be 50 gal.

A barrel in bulk, for crude oil, shall be 42 gal.

A tank car, when not otherwise specified, shall be 8000 gal.

A tank car may be known as a "tank" when reference is obviously had to shipping.

Shipments may be made in other size tank cars, but the total gallonage, being the number of tank cars given in the order multiplied by 8000, shall be delivered and accepted.

The Imperial 35-gal. barrel—Canadian—Great Britain. Difference between the American 42-gal. oil barrel of commerce, and the Imperial 35-gal. oil barrel, three-tenths of 1 per cent. Figure it out, satisfy yourself.

The Imperial gallon contains 277 cu. in., or six-fifths of an American gallon. To reduce American gallons to Imperial gallons, divide the number of American gallons by six, and subtract the quotient from the number of American gallons.

DRILLING SUPERINTENDENT

ROTARY DRILLERS

ROTARY HELPERS

FIRST OIL SAND FROM FEET TO FEET

SECOND

THIRD

CASING RECORD	SIZE AND WEIGHT	LANDED AT	CUT AT	KIND OR MAKE
SIDETRACKED				
CEMENTED	SIZE AND WEIGHT	NO. SACKS USED	BRAND	NO. DAYS SET
PERFORATIONS	FROM	TO	SIZE HOLE	NO ROWS
SHOT FROM	TO	QUANTITY USED	PER CENT	SHOT BY
BRIDGES	FROM	TO	MATERIAL USED	MATERIAL USED
HEAVING PLUGS	SIZE	LENGTH	DEPTH	MATERIAL

Record for well history.

HISTORY

LEASE

WELL NO.

STANDARD DRILLERS

PROPERTY

LEASE

SEC

STANDARD HELPERS

WELL LOCATED

ELEVATION

FIRST IMPORTANT WATER SAND FROM FEET TO FEET

SECOND

THIRD

DRILLING STARTED

DRILLING FINISHED

TOTAL DEPTH DRILLED FEET

INITIAL PRODUCTION BBLS.

30 DAYS AFTER COMPLETION

PRODUCTION BBLS

GRAVITY DEG. B

WATER CONTENT PER CENT

ROTARY

FROM TO FEET

CABLE TOOLS

FROM TO FEET

THREADS	KIND OF SHOE	CEMENTED	PRICE PER FOOT	TOTAL PRICE

COSTS

DERRICK

METHOD USED	FLUID LEVEL	BAILED TO	LEVEL AFTER 12 HOURS	SHUT OFF YES OR NO

CASING

DRILLING (F. R.)

OTHER

HOLES PER FT	SHOP DRILLED	MACHINE METHOD	OPERATOR

TOTAL WELL COST

DEEPENED

DATE STARTED

SHOT FROM	TO	QUANTITY USED	PER CENT	SHOT BY

DATE FINISHED

REDRILLED

DATE STARTED

CEMENT PLUG	FROM	TO	NO SACKS USED	BRAND

DATE FINISHED

ABANDONMENT

DATE STARTED

DATE FINISHED

ADAPTERS	FROM	TO	LENGTH	MATERIAL USED

Record for well history (Con.)

Form 3

Blank Oil Company

DRILLER'S REPORT

Date.......................................192.....

Section...............................

Well No...........................

Tour......................M. to......................M.

Began tour at...............ft. made.............ft. Total.............ft.

Formation changes

From..................ft. to..................ft...

From..................ft. to..................ft...

From..................ft. to..................ft...

From..................ft. to..................ft...

From..................ft. to..................ft...

From..................ft. to..................ft...

Work done ....

....

Remarks ....

....

....

....

....

Repairs made...

....

Men employed...

....

.... Driller

.... Driller

Be Sure and Note all Changes in Formation and Depth at which same occur.

Form for drillers report.

FORM 51

ORIGINAL
MAIL TO LOS ANGELES OFFICE

DAILY WELL REPORT
BLANK OIL COMPANY

LEASE ____________________

WELL No. ____________________ ____________________ 19____

MAKE SEPARATE REPORT FOR EACH WELL

CONDITION OF WELL ____________________

WORK DONE ____________________

REPAIRS MADE ____________________

CONDITION OF TUBING ____________________

CONDITION OF RODS ____________________

CONDITION OF PUMP ____________________

NEW OR USED WORKING BARREL INSTALLED ____________________

DEPTH OF PUMP ____________________

REMARKS ____________________

NAMES OF MEN EMPLOYED ____________________

____
SIGNATURE HEAD WELL PULLER

REPORT EACH WELL WHEN COMPLETED

Form for daily well report.

ORIGINAL
MAIL TO LOS ANGELES OFFICE

FORM 37

Nº 2498

FUEL OIL REPORT

BLANK OIL COMPANY

________________ 19____

THE FOLLOWING________________OIL, FOR FUEL USE ONLY BY THIS COMPANY, HAS BEEN DELIVERED THIS DATE TO

LEASE________________

SECTION ________________

WELL NO.________________

TANK NO.________________

BOILER PLANT NO.________________

____

DELIVERED FROM TANK NO.________________

LOCATED AT________________

	FEET	INCHES	BARRELS	
MEASUREMENT OF DEPTH OF OIL IN TANK AT BEGINNING OF RUN				
LIKE MEASUREMENT AT END OF RUN				
GROSS AMOUNT OF RUN				

REMARKS________________

____

____

BLANK OIL COMPANY

BY________________

MAIL ON DAY OF OIL DELIVERY

Fuel oil report.

ORIGINAL
MAIL TO LOS ANGELES OFFICE

FORM 52

RUN TICKET REPORT BLANK OIL COMPANY № 2498

____________________ 19___

THE FOLLOWING ____________ OIL IN BULK OF 42 U. S. GALLONS PER BARREL

DELIVERED TO ____________ IN { TANK NO. ______ RESERVOIR ______ CAR INITIAL AND NO. ______ PIPE LINE OF ______ }

FROM ______ LEASE, SECTION ____ T ____ R ____

TANK NO. ______ WELL NO. ______ TEMPERATURE ____ DEG. F.

AT TEMPERATURE ____ ° F., DEDUCTIONS AS SHOWN BELOW:

ORIGINAL GRAVITY ____ ° BAUME GRAVITY CORRECTED TO 60° F. ____ ° BAUME

	FEET	INCHES	BARRELS	
MEASUREMENT OF DEPTH OF OIL IN TANK AT BEGINNING OF RUN				
LIKE MEASURE AT END OF RUN				
GROSS AMOUNT OF RUN				
DEDUCTION TO CORRECT TEMPERATURE TO 60° F.		%		
GROSS QUANTITY DELIVERED AT 60°				
DEDUCTION FOR WATER, SAND, AND OTHER FOREIGN SUBSTANCES		%		
NET AMOUNT DELIVERED				

BUYER'S RUN TICKET NO. ______ DATED ______ 19___

BUYER'S RUN TICKET SIGNED BY ______

BLANK OIL COMPANY

BY ____________

ATTACH THIS FORM TO BUYER'S RUN TICKET AND MAIL ON DAY OF OIL DELIVERY

Run ticket form.

TABLE 22.—WORLD'S PRODUCTION OF CRUDE PETROLEUM SINCE 1857, BY YEARS AND COUNTRIES, IN BARRELS OF 42 GAL.

Year	Rumania	United States*	Italy	Canada	Russia	Galicia	Japan and Formosa	Germany	India
1857	1,977								
1858	3,560								
1859	4,349	2,000							
1860	8,542	500,000	36						
1861	17,279	2,113,609	29						
1862	23,198	3,056,690	29	11,775					
1863	27,943	2,611,309	58	82,814	40,816				
1864	33,013	2,116,109	72	90,000	64,686				
1865	39,017	2,497,700	2,265	110,000	66,542				
1866	42,534	3,597,700	992	175,000	83,052				
1867	50,838	3,347,300	791	190,000	119,917				
1868	55,369	3,646,117	367	200,000	88,327				
1869	58,533	4,215,000	144	220,000	202,308				
1870	83,765	5,260,745	86	250,000	204,618				
1871	90,030	5,205,234	273	269,397	165,129				
1872	91,251	6,293,194	331	308,100	184,391				
1873	104,036	9,893,786	467	365,052	474,379				
1874	103,177	10,926,945	604	168,807	583,751	149,837			
1875	108,569	8,787,514	813	220,000	697,364	158,522	4,566		
1876	111,314	9,132,669	2,891	312,000	1,320,528	164,157	7,708		
1877	108,569	13,350,363	2,934	312,000	1,800,720	169,792	9,560		
1878	109,300	15,396,868	4,329	312,000	2,400,960	175,420	17,884		
1879	110,007	19,914,146	2,891	575,000	2,761,104	214,800	23,457		
1880	114,321	26,286,123	2,035	350,000	3,001,200	229,120	25,497	9,310	
1881	121,511	27,661,238	1,237	275,000	3,601,441	286,400	16,751	29,219	
1882	136,610	30,349,897	1,316	275,000	4,537,815	330,076	15,549	58,025	
1883	139,486	23,449,633	1,618	250,000	6,002,401	365,160	20,473	26,708	
1884	210,667	24,218,438	2,855	250,000	10,804,577	408,120	27,923	46,161	
1885	193,411	21,858,785	1,941	250,000	13,924,596	465,400	29,237	41,360	
1886	168,606	28,064,841	1,575	584,061	18,006,407	305,884	37,916	73,864	
1887	181,907	28,283,483	1,496	525,655	18,367,781	343,832	28,645	74,284	
1888	218,576	27,612,025	1,251	695,203	23,048,787	466,537	37,436	84,782	
1889	297,666	35,163,513	1,273	704,690	24,609,407	515,268	52,811	68,217	94,250
1890	383,227	45,823,572	2,998	795,030	28,691,218	659,012	51,420	108,296	118,065

1891	488,201	54,292,655	8,305	755,298	34,573,181	630,730	52,917	108,929	190,131
1892	593,175	50,514,657	18,321	779,753	35,774,504	646,220	68,901	101,404	242,284
1893	535,655	48,431,066	19,069	798,406	40,456,519	692,669	106,384	99,390	298,969
1894	507,255	49,344,516	20,552	829,104	36,375,428	949,146	171,144	122,564	327,218
1895	575,200	52,892,276	25,843	726,138	46,140,174	1,452,999	141,310	121,277	371,536
1896	543,348	60,960,361	18,149	726,822	47,220,633	2,443,080	197,082	145,061	429,979
1897	570,886	60,475,516	13,892	709,857	54,399,568	2,226,368	218,559	165,745	545,704
1898	776,238	55,364,233	14,489	758,391	61,609,357	2,376,108	265,389	183,427	542,110
1899	1,425,777	57,070,850	16,121	808,570	65,954,968	2,313,047	536,079	192,232	940,971
1900	1,628,535	63,620,529	12,102	913,498	75,779,417	2,346,505	866,814	358,297	1,078,264
1901	1,678,320	69,389,194	16,150	756,679	85,168,556	3,251,544	1,110,790	313,630	1,430,716
1902	2,059,935	88,766,916	18,933	530,624	80,540,044	4,142,159	1,193,038	353,674	1,617,363
1903	2,763,117	100,461,337	17,876	486,637	75,591,256	5,234,475	1,209,371	445,818	2,510,259
1904	3,599,026	117,080,960	25,476	552,575	78,536,655	5,947,383	1,419,473	637,431	3,385,468
1905	4,420,987	134,717,580	44,027	634,095	54,960,270	5,765,317	1,472,804	560,963	4,137,098
1906	6,378,184	126,493,936	53,577	569,753	58,897,311	5,467,967	1,710,768	578,610	4,015,803
1907	8,118,207	166,095,335	59,875	788,872	61,850,734	8,455,841	2,001,838	756,631	4,344,162
1908	8,252,157	178,527,355	50,966	527,987	62,186,447	12,612,295	2,070,145	1,009,278	5,047,038
1909	9,327,278	183,170,874	42,388	420,755	65,970,350	14,932,799	1,889,563	1,018,837	6,676,517
1910	9,723,806	209,557,248	50,830	315,985	70,336,574	12,673,688	1,930,661	1,032,522	6,137,990
1911	11,107,450	220,449,391	74,709	291,096	66,183,691	10,519,270	1,658,903	1,017,045	6,451,203
1912	12,976,232	222,935,044	53,778	243,336	68,019,208	8,535,174	1,671,405	1,031,050	7,116,672
1913	13,554,768	248,446,230	47,198	228,080	62,834,356	7,818,130	1,942,009	†995,764	7,930,149
1914	12,826,579	265,762,535	39,849	214,805	67,020,522	†5,033,350	2,738,378	†995,764	7,409,792
1915	12,029,913	281,104,104	43,898	215,464	68,548,062	4,158,899	3,118,464	†995,764	8,202,674
1916	¶10,298,208	300,767,158	50,585	198,123	¶72,801,110	6,461,706	2,997,178	†995,764	8,491,137
1917	†2,681,870	335,315,601	†50,334	205,332	†69,000,000	¶5,965,447	2,898,654	†995,764	8,078,843
1918	8,730,235	355,927,716	35,953	304,741	40,456,182	5,591,620	2,449,069	711,260	8,000,000
1919	....	377,719,000							
Total....	151,722,700	4,986,290,719	983,242	24,417,270	1,873,039,199	154,051,273	38,514,523	16,664,121	106,162,365

TABLE 22 (*Continued*)

Year	Dutch East Indies	Peru	Mexico	Argentina	Trinidad	Egypt	Other Countries	Total	Per cent produced by U. S.
1857								1,977	
1858								3,560	
1859								6,349	31.5
1860								508,578	98.3
1861								2,130,917	99.1
1862								3,091,692	98.8
1863								2,762,940	94.5
1864								2,303,780	90.5
1865								2,715,524	91.9
1865								3,899,278	92.3
1867								3,708,846	90.2
1868								3,990,180	91.2
1869								4,695,985	89.9
1870								5,799,214	90.7
1871								5,730,063	90.8
1872								6,877,267	91.5
1873								10,837,720	91.3
1874								11,933,121	91.5
1875								9,977.348	88.1
1876								11,051,267	82.6
1877								15,753,938	85.4
1878								18,416,761	84.7
1879								23,601,405	84.3
1880								30,017,606	87.6
1881								31,992,797	86.4
1882								35,704,288	85.0
1883								30,255,479	77.5
1884								35,968,741	67.3
1885								36,764,730	59.4
1886								47,243,154	59.4
1887								47,807,083	59.2
1888								52,164,597	52.9
1889								61,507,995	57.9
1890								76,632,838	59.9

1891								91,100,347	59.6
1892								88,739,219	56.9
1893	600,000	...	...	...	...	...	...	92,038,127	52.6
1894	688,170	...	...	...	...	...	...	89,335,697	55.2
1895	1,215,757	...	...	...	...	...	...	103,662,510	51.0
1896	1,427,132	47,536	...	...	...	...	...	114,159,183	53.4
1897	2,551,649	70,831	...	...	...	...	...	121,948,575	49.5
1898	2,964,035	70,905	...	...	...	...	...	124,924,682	44.4
1899	1,795,961	89,166	...	...	...	...	...	131,143,742	43.5
1900	2,253,355	274,800	...	...	...	...	...	149,132,116	42.5
1901	4,013,710	274,800	10,345	...	...	...	†20,000	167,434,434	41.4
1902	2,430,465	286,725	40,200	...	...	...	†26,000	182,006,076	48.8
1903	5,770,056	278,092	75,375	...	...	...	†36,000	194,879,669	51.5
1904	6,508,485	345,834	125,625	...	...	...	†40,000	218,204,391	53.7
1905	7,849,896	447,880	251,250	...	...	...	†30,000	215,292,167	62.6
1906	8,180,657	536,294	502,500	...	...	...	†30,000	213,415,360	59.2
1907	9,982,597	756,226	1,005,000	101	...	...	†30,000	264,245,419	63.2
1908	10,283,357	1,011,180	3,932,000	11,472	169	...	†30,000	285,552,746	62.5
1909	11,041,852	1,316,118	2,713,500	18,431	57,143	...	†20,000	298,616,405	61.3
1910	11,030,620	1,330,105	3,634,080	20,753	142,857	...	†20,000	327,937,629	64.0
1911	12,172,949	1,368,274	12,552,798	13,119	285,307	9,150	†20,000	344,174,355	64.0
1912	10,845,624	1,751,143	16,558,215	47,007	436,805	205,905	†20,000	352,446,598	68.9
1913	11,172,294	2,133,261	25,696,291	130,618	503,616	94,635	†20,000	383,547,399	64.7
1914	‡11,834,802	1,917,802	26,235,403	275,500	643,533	777,038	†20,000	403,745,342	65.8
1915	‡12,386,800	2,487,251	32,910,508	516,120	†750,000	262,208	†10,000	427,740,129	65.7
1916	‡13,174,399	2,550,645	40,545,712	796,920	928,681	411,000	†25,000	461,493,226	65.2
1917	‡12,928,955	2,533,417	55,292,770	1,144,737	1,599,455	1,008,750	§7,004,973	506,702,902	66.2
1918	13,284,936	2,536,102	63,828,327	1,321,315	2,082,068	2,079,750	§7,390,080	514,729,354	69.1
1919			87,359,533						
Total	188,388,203	24,414,387	373,270,332	4,296,093	7,429,534	4,848,436	21,990,053	7,976,482,450	

* Quantity marketed. † Estimated. ‡ Includes British Borneo. ¶ Estimated in part. § Includes Cuba, 19,167 bbls.; Venezuela, 127,743 bbls.; Persia, 6,856,063. Figures from United States Geological Survey, Department of Interior. No. 1919 production figures available except for United States and Mexico.

TABLE 23.—PETROLEUM MARKETED IN THE UNITED STATES, 1859–1919, IN BARRELS OF 42 GAL.

Year	Pennsylvania and New York	Ohio	West Virginia	California	Kentucky and Tennessee	Colorado	Indiana	Illinois
1859	2,000							
1860	500,000							
1861	2,113,609							
1862	3,056,690							
1863	2,611,309							
1864	2,116,109							
1865	2,497,700							
1866	3,597,700							
1867	3,347,300							
1868	3,646,117							
1869	4,215,000							
1870	5,260,745							
1871	5,205,234							
1872	6,293,194							
1873	9,893,786							
1874	10,926,945							
1875	8,787,514							
1876	8,968,906	31,763	120,000	12,000				
1877	13,135,475	29,888	172,000	13,000				
1878	15,163,462	38,179	180,000	15,227				
1879	19,685,176	29,112	180,000	19,858				
1880	26,027,631	38,940	179,000	40,552				
1881	27,376,509	33,867	151,000	99,862				
1882	30,053,500	39,761	128,000	128,636				
1883	23,128,389	47,632	126,000	142,857	4,755			
1884	23,772,209	90,081	90,000	262,000	4,148			
1885	20,776,041	661,580	91,000	325,000	5,164			
1886	25,798,000	1,782,970	102,000	377,145	4,726			
1887	22,356,193	5,022,632	145,000	678,572	4,791	76,295		
1888	16,488,668	10,010,868	119,448	690,333	5,096	297,612		
1889	21,487,435	12,471,466	544,113	303,220	5,400	316,476	33,375	1,460
1890	28,458,208	16,124,656	492,578	307,360	6,000	368,842	63,496	900

1891	33,009,236	17,740,301	2,406,218	323,600	9,000	655,482	136,634	675
1892	28,422,377	16,362,921	3,810,086	385,049	6,500	824,000	136,634	521
1893	20,314,513	16,249,769	8,445,412	470,179	3,000	594,390	2,335,293	400
1894	19,019,900	16,792,154	8,577,624	705,969	2,500	515,746	3,688,666	300
1895	19,144,390	19,545,233	8,120,125	1,208,482	1,500	438,232	4,386,132	200
1896	20,584,421	23,941,169	10,019,770	1,252,777	1,680	361,450	4,680,732	250
1898	15,948,464	18,738,708	13,615,101	2,257,207	5,568	444,383	3,730,907	360
1897	19,262,066	21,560,515	13,090,045	1,903,411	322	384,934	4,122,356	500
1899	14,374,512	21,142,108	13,910,630	2,642,095	18,280	390,278	3,848,182	360
1900	14,559,127	22,362,730	16,195,675	4,324,484	62,259	317,385	4,874,392	200
1901	13,831,996	21,648,083	14,177,126	8,786,330	137,259	460,520	5,757,086	250
1902	13,183,610	21,014,231	13,513,345	13,984,268	185,331	396,901	7,480,896	200
1903	12,518,134	20,480,286	12,899,395	24,382,372	554,286	483,925	9,186,411	
1904	12,239,026	18,876,631	12,644,686	29,649,434	998,284	501,763	11,339,124	
1905	11,554,777	16,346,660	11,578,110	33,427,473	1,217,337	376,238	10,964,247	181,084
1906	11,500,410	14,787,763	10,120,935	33,098,598	1,213,548	327,582	7,673,477	4,397,050
1907	11,211,606	12,207,448	9,095,296	39,748,375	830,844	331,851	5,128,037	24,281,973
1908	10,584,453	10,858,797	9,523,176	44,854,737	[6]727,767	379,653	3,283,629	33,686,238
1909	10,434,300	10,632,793	10,745,092	55,471,601	[6]639,016	310,861	2,296,086	30,898,339
1910	9,848,500	9,916,370	11,753,071	73,010,560	[6]468,774	239,794	2,159,725	33,143,362
1911	9,200,673	8,817,112	9,795,464	81,134,391	[6]472,458	226,926	1,695,289	31,317,038
1912	8,712,076	[1]8,969,007	12,128,962	[7]87,272,593	[6]848,368	206,052	970,009	28,601,308
1913	8,865,493	8,781,468	11,567,299	97,788,525	[6]524,568	188,568	956,095	23,893,899
1914	9,109,309	8,536,352	9,680,033	99,775,327	[6]502,441	222,773	1,335,456	21,919,749
1915	8,726,483	7,825,326	9,264,798	86,591,535	[6]437,274	208,475	875,758	19,041,695
1916	8,466,481	7,744,511	8,731,184	90,951,936	1,203,246	197,235	769,036	17,714,235
1917	8,612,885	7,750,540	8,379,285	93,877,549	3,100,356	121,231	759,432	15,776,860
1918	8,216,655	7,285,005	7,866,628	97,531,997	4,376,342	143,286	877,558	13,365,974
1919	9,441,936	8,243,592	9,032,688	101,221,784	5,027,904	241,680	929,780	12,436,000
Total. .	797,644,653	471,610,978	303,507,398	1,211,448,360	23,241,092	11,561,050	107,035,364	310,661,380

TABLE 23 (*Continued*)

Year	Kansas	Texas	Missouri	Oklahoma	Wyoming	Louisiana	United States	Total value
1859							2,000	$ 32,000
1860							500,000	4,000,000
1861							2,113,609	1,035,668
1862							3,056,690	3,209,525
1863							2,611,309	8,225,663
1864							2,116,109	20,896,576
1865							2,497,700	16,459,853
1866							3,597,700	30,455,398
1867							3,347,300	8,066,993
1868							3,646,117	13,217,174
1869							4,215,000	23,730,450
1870							5,260,745	20,503,754
1871							5,205,234	22,591,180
1872							6,293,194	21,440,503
1873							9,983,786	18,100,464
1874							10,926,945	12,647,527
1875							8,787,514	7,368,133
1876							9,132,669	22,982,822
1877							13,350,363	31,788,566
1878							15,396,868	18,944,620
1879							19,914,146	17,210,708
1880							26,286,123	24,600,638
1881							27,661,238	25,448,339
1882							30,349,897	23,631,165
1883							23,449,663	25,790,252
1884							24,218,438	20,595,966
1885							21,858,785	19,198,243
1886							28,064,841	19,996,313
1887							28,283,483	18,877,094
1888							27,612,025	17,947,620
1889	500	48	20	....	....	....	35,163,513	26,963,340
1890	1,200	54	278	....	....	....	45,823,572	35,865,105

1891	1,400	54	25	30	....	....	54,292,655	30,529,553
1892	5,000	45	10	80	....	....	50,514,657	25,906,463
1893	18,000	50	50	10	....	....	48,431,066	28,950,326
1894	40,000	60	8	130	2,369	....	49,344,516	35,522,095
1895	44,430	50	10	37	3,455	....	52,892,276	57,632,296
1896	113,571	1,450	43	170	2,878	....	60,960,361	58,518,709
1897	81,098	65,975	19	625	3,650	....	60,475,516	40,874,072
1898	71,980	546,070	10	....	5,475	....	55,364,233	44,693,359
1899	69,700	669,013	132	....	5,560	....	57,070,850	64,603,904
1900	74,714	836,039	[1]1,602	6,472	5,450	....	63,620,529	75,989,313
1901	179,151	4,393,658	[1]2,335	10,000	5,400	....	69,389,194	66,417,335
1902	331,749	18,083,658	[1]757	37,100	6,253	548,617	88,766,916	71,178,910
1903	932,214	17,955,572	[1]3,000	138,911	8,960	917,771	100,461,337	94,694,050
1904	4,250,779	22,241,413	[1]2,572	1,366,748	11,542	2,958,958	117,080,960	101,175,455
1905	[2]12,013,495	28,136,189	[1]3,100	(3)	8,454	8,910,416	134,717,580	34,157,399
1906	[2]21,718,648	12,567,897	[1]3,500	(3)	[4]7,000	9,077,528	126,493,936	92,444,735
1907	2,409,521	12,322,696	[1]4,000	43,524,128	[5]9,339	5,000,221	166,095,335	120,106,749
1908	1,801,781	11,206,464	[1]15,246	45,798,765	[5]17,775	5,788,874	178,527,355	129,079,184
1909	1,263,764	9,534,467	[1]5,750	47,859,218	[5]20,056	3,059,531	183,179,874	128,828,487
1910	1,128,668	8,899,266	[1]3,615	52,028,718	[5]115,430	6,841,395	209,557,248	127,899,688
1911	1,278,819	9,526,474	[1]7,995	56,069,637	[5]186,695	10,720,420	220,449,391	134,044,752
1912	1,592,796	11,735,057	(8)	51,427,071	1,572,306	9,263,439	222,935,044	164,213,247
1913	2,375,029	15,009,478	[9]10,843	63,579,384	2,406,522	12,498,828	248,446,230	237,121,388
1914	3,103,585	20,068,184	[10]7,792	73,631,724	3,560,375	14,309,435	265,762,535	214,125,215
1915	2,823,487	24,942,701	[10]14,265	97,915,243	4,245,525	18,191,539	281,104,104	179,462,890
1916	8,738,077	27,644,605	......	107,071,715	6,234,137	15,248,138	300,767,158	330,899,868
1917	36,536,125	32,413,287	......	107,507,471	8,978,680	11,392,201	*335,315,601	522,635,213
1918	45,451,017	38,750,031	......	103,347,070	12,596,287	16,042,600	*355,927,716	703,943,961
1919	34,769,100	85,312,000	......	81,127,900	13,342,320	16,250,000	377,719,000	867,753,379
Total	183,219,398	412,862,005	86,977	932,448,357	53,361,893	167,019,911	4,986,290,719	5,396,620,547

* Includes Alaska, Michigan and Missouri production, estimated at 10,300 bbls. in 1917 and 7,943 bbls. in 1918. [1] Includes production of Michigan. [2]Include production of Oklahoma. [3] Included with Kansas. [4] Estimated. [5]Includes production of Utah. [6] No production in Tennessee recorded. [7] Includes small production in Alasia. [8] No production in Missouri; Michigan included in Ohio. [9] Includes production of Alaska, Michigan and New Mexico. [10] Includes production of Alaska and Michigan. Figures of the United States Geological Survey, Department of Interior.

TABLE 24.—CASING WEIGHTS, DIAMETERS, COLLAPSING PRESSURES, CEMENT CAPACITY

Size	Weight per foot	O/D	I/D	Collapsing press., sq. in.	Water col. Factor Safety 2	Cap. 1 ft. gal.	Cap. 1 ft. cu. ft.	Linear ft. 1 gal.	Lin. ft. 1 sack cement
1½	2.748	1.900	1.610	11,839	13,649	0.10575	0.0141	9.480	78.01
2	4.000	2.375	2.040	10,851	12,489	0.1698	0.0227	5.893	48.45
2	4.50	2.375	1.995	12,524	14,415	0.1624	0.0217	6.160	50.73
2½	5.897	2.875	2.469	10,869	12,510	0.2487	0.033	4.025	33.35
2½	6.25	2.875	2.441	11,692	13,457	0.243	0.0325	4.120	33.85
3	7.694	3.500	3.068	9,317	10,723	0.384	0.0513	2.608	21.41
3	8.50	3.500	3.018	10,557	12,151	0.3716	0.0497	2.695	22.13
3	10.00	3.500	2.922	13,183	15,173	0.3483	0.04657	2.871	23.79
3½	9.26	4.000	3.548	8,667	9,975	0.5136	0.06866	1.950	16.50
4	10.98	4.500	4.026	7,740	8,908	0.6613	0.0884	1.515	12.44
4	11.75	4.500	3.990	8,451	9,727	0.6495	0.0868	1.541	12.69
4¼	16.00	4.750	4.082	4,710	5,425	0.6792	0.0908	1.475	12.13
4½	12.85	5.000	4.506	2,900	3,340	0.8281	0.1107	1.209	9.950
4½	15.00	5.000	4.424	3,610	4,160	0.7982	0.1067	1.255	10.32
5⅝	20.00	6.000	5.352	3,290	3,790	1.1677	0.1561	0.859	7.045
6¼	20.00	6.625	6.049	2,380	2,740	1.4916	0.1994	0.671	5.518
6¼	24.00	6.625	5.921	3,220	3,710	1.4295	0.1911	0.701	5.760
6¼	26.00	6.625	5.855	3,650	4,205	1.3974	0.1868	0.716	5.895
6¼	28.00	6.625	5.791	4,070	4,690	1.3667	0.1827	0.7325	6.025
6⅝	20.00	7.000	6.456	1,980	2,280	1.6988	0.2271	0.590	4.845
6⅝	26.00	7.000	6.276	3,100	3,570	1.6061	0.2147	0.624	5.125
6⅝	28.00	7.000	6.214	3,480	4,010	1.5739	0.2104	0.636	5.220
6⅝	30.00	7.000	6.154	3,850	4,435	1.5440	0.2064	0.647	5.325
7⅝	26.00	8.000	7.386	1,940	2,235	2.2240	0.2973	0.449	3.701
8¼	28.00	8.625	8.017	1,670	1,925	2.6204	0.3503	0.379	3.140
8¼	32.00	8.625	7.921	2,150	2,475	2.5583	0.3420	0.392	3.218
8¼	36.00	8.625	7.825	2,630	3,030	2.4962	0.3337	0.4015	3.300
8¼	38.00	8.625	7.775	2,880	3,320	2.4648	0.3295	0.406	3.338
8¼	43.00	8.625	7.651	3,510	4,045	2.3863	0.3190	0.419	3.450
9⅝	33.00	10.000	9.384	1,280	1,475	3.5899	0.4799	0.279	2.295
10	40.00	10.750	10.054	1,420	1,635	4.1210	0.5509	0.2434	1.969
10	45.00	10.750	9.960	1,800	2,075	4.0440	0.5406	0.2475	2.037
10	48.00	10.750	9.902	2,030	2,340	3.9976	0.5344	0.251	2.060
10	54.00	10.750	9.784	2,510	2,890	3.9026	0.5217	0.2562	2.101
11	47.00	11.750	11.000	1,380	1,590	4.9334	0.6595	0.2032	1.678
11	60.00	11.750	10.772	2,220	2,560	4.7307	0.6324	0.2119	1.739
11⅝	40.00	12.000	11.384	840	970	5.2827	0.7062	0.1895	1.558
12½	40.00	13.000	12.438	500	575	6.3083	0.8433	0.1589	1.306
12½	45.00	13.000	12.360	750	865	6.2298	0.8328	0.1609	1.322
12½	50.00	13.000	12.282	1,010	1,165	6.1497	0.8221	0.1629	1.338
12½	54.00	13.000	12.220	1,210	1,395	6.0869	0.8137	0.1645	1.354
13½	50.00	14.000	13.344	640	735	7.2598	0.9705	0.1379	1.131
15½	70.00	16.000	15.198	790	910	9.4150	1.2586	0.1064	0.876

AMOUNT OF CEMENT NECESSARY

The amount of cement required to fill certain spaces in an oil well should be approximately known when a job is commenced and the following table, where the space is exactly stated, can be used for such a purpose. In actual practice the exact cavity may not be known. The tables is based on the fact that a sack of cement, weighing about 100 lbs., will occupy about 1.1 cu. ft. after being mixed with water and allowed to set.

Table 25.—Lineal Feet Filled by One Sack of Portland Cement Alongside of Oil-well Casings

(One sack equals 1.1 cu. ft. neat cement when set)

Size of casing		Diameter of well (excess over casing diameter)					
Normal, inches	Actual outside diameter, inches	One inch, feet	Two inches, feet	Three inches, feet	Four inches, feet	Five inches, feet	Six inches, feet
4¼	4.75	19.2	8.8	5.4	3.7	2.8	2.2
4½	5.00	18.3	8.4	5.2	3.6	2.7	2.1
5⅝	6.00	15.5	7.1	4.4	3.2	2.4	1.9
6¼	6.625	14.2	6.6	4.2	2.9	2.2	1.7
6½	7.00	13.5	6.3	4.0	2.8	2.1	1.7
7⅝	8.00	11.9	5.6	3.5	2.5	1.9	1.5
8½	8.625	11.2	5.2	3.3	2.4	1.8	1.4
9⅝	10.00	9.7	4.6	2.9	2.1	1.6	1.3
10	10.75	9.0	4.3	2.8	2.0	1.5	1.2
11⅝	12.00	8.1	3.9	2.5	1.8	1.4	1.1
12½	13.00	7.5	3.6	2.3	1.7	1.3	1.0
13½	14.00	7.0	3.4	2.2	1.6	1.2	1.0
15½	16.00	6.1	3.0	1.9	1.4	1.1	0.9

Table 26.—Weight of Water in Pipe of Different Diameters in Lengths of One Foot

The following table will be found useful in computing the weight of water in a string of pipe or casing in a well:

Diameter, inches	Water, pounds	Diameter, inches	Water, pounds	Diameter, inches	Water, pounds	Diameter, inches	Water, pounds
1	0.3405	3¾	4.7879	7¾	20.450	13½	62.052
1⅛	0.4309	4	5.4476	8	21.790	14	66.733
1¼	0.5320	4¼	6.1498	8¼	23.174	15	76.607
1⅜	0.6437	4½	6.8946	8½	24.599	16	87.162
1½	0.7661	4¾	7.6820	8¾	26.068	17	98.397
1⅝	0.8991	5	8.5119	9	27.579	18	110.310
1¾	1.0427	5¼	9.3844	9¼	29.132	19	122.910
1⅞	1.1970	5½	10.2990	9½	30.728	20	136.190
2	1.3619	5¾	11.2570	9¾	32.366	21	150.150
2⅛	1.5375	6	12.2570	10	34.048	22	164.790
2¼	1.7237	6¼	13.3000	10½	37.537	23	180.110
2½	2.1280	6½	14.3850	11	41.198	24	196.110
2¾	2.5748	6¾	15.5130	11½	45.028	25	212.800
3	3.0643	7	16.6830	12	49.028	26	230.160
3¼	3.5963	7¼	17.8960	12½	53.199	27	248.210
3½	4.1708	7½	19.1520	13	57.540	28	266.930

A cubic foot of water weighs 62.425 pounds, and contains 1,728 cubic inches, or 7.481 gallons.

A gallon of fresh water weighs 8.35 pounds, and contains 231 cubic inches. To find the number of gallons of water in a foot of pipe, divide the weight of water by 8.35.

WATER PRESSURE

The pressure of still water in pounds per square inch against the sides of any pipe or vessel of any shape is due alone to the head or height of the surface of the water above the point pressed upon, and is equal to 0.434 pounds per square inch for every foot of head, the fluid pressure being equal in all directions. For example: the pressure in pounds per square inch at the bottom of well tubing 1,000 feet deep and filled with water would be $0.434 \times 1000 = 434$ pounds pressure.

TABLE 27.—THEORETICAL POWER REQUIRED TO LIFT WATER

The values in this table represent theoretical horse-power. If actual values are required the values given in the table must be divided by the mechanical efficiency of the pump and driving unit, also the means of transmission.

Gallons of water raised per minute	Miners' inches	Height in feet to which water is raised											
		5	10	15	20	25	30	40	50	60	70	80	100
20	1.78	0.025	0.051	0.076	0.101	0.127	0.152	0.203	0.253	0.304	0.355	0.405	0.506
30	2.67	0.038	0.076	0.114	0.152	0.190	0.228	0.304	0.380	0.456	0.532	0.608	0.760
40	3.56	0.051	0.101	0.152	0.203	0.253	0.304	0.405	0.506	0.608	0.709	0.811	1.01
50	4.46	0.063	0.127	0.190	0.253	0.316	0.380	0.506	0.633	0.760	0.886	1.01	1.27
75	6.68	0.095	0.190	0.276	0.380	0.475	0.569	0.760	1.01	1.14	1.33	1.52	1.90
100	8.91	0.127	0.253	0.380	0.506	0.633	0.760	1.01	1.27	1.52	1.77	2.03	2.53
150	13.4	0.190	0.380	0.569	0.760	1.01	1.14	1.52	1.90	2.28	2.66	3.04	3.80
200	17.8	0.253	0.506	0.760	1.01	1.27	1.52	2.03	2.53	3.04	3.55	4.05	5.06
250	22.3	0.316	0.633	0.949	1.27	1.58	1.90	2.53	3.16	3.80	4.43	5.06	6.33
300	26.7	0.380	0.760	1.14	1.52	1.90	2.28	3.04	3.80	4.56	5.32	6.08	7.60
350	31.2	0.443	0.887	1.33	1.78	2.22	2.66	3.54	4.43	5.32	6.21	7.09	8.87
400	35.6	0.506	1.01	1.52	2.03	2.53	3.04	4.05	5.06	6.08	7.09	8.11	10.1
500	44.6	0.633	1.27	1.90	2.53	3.16	3.80	5.06	6.33	7.60	8.86	10.1	12.7
600	53.5	0.760	1.52	2.28	3.04	3.80	4.56	6.08	7.60	9.12	10.6	12.2	15.2
800	71.3	1.01	2.03	3.08	4.05	5.06	6.08	8.11	10.1	12.2	14.2	16.2	20.3
1000	89.1	1.27	2.53	3.80	5.06	6.33	7.60	10.1	12.7	15.2	17.7	20.3	25.3
1200	107	1.52	3.04	4.56	6.08	7.60	9.12	12.2	15.2	18.2	21.3	24.3	30.4
1500	134	1.90	3.80	5.69	7.60	10.1	11.4	15.2	19.0	22.8	26.6	30.4	38.0
2000	178	2.53	5.06	7.60	10.1	12.7	15.2	20.3	25.3	30.4	35.5	40.5	50.6
2500	223	3.16	6.33	9.49	12.7	15.8	19.0	25.3	31.6	38.0	44.3	50.6	63.3
3000	267	3.80	7.60	11.4	15.2	19.0	22.8	30.4	37.9	45.6	53.2	60.8	76.0
3500	312	4.43	8.87	13.3	17.7	22.2	26.6	35.4	44.2	53.2	62.1	70.9	88.7
4000	356	5.06	10.1	15.2	20.3	25.3	30.4	40.5	50.6	60.8	70.9	81.1	101
4500	401	5.70	11.4	17.1	22.8	28.4	34.2	45.6	56.9	68.4	74.8	91.2	114
5000	446	6.33	12.7	19.0	25.3	31.6	38.0	50.6	63.2	76.0	88.6	101	127

TABLE 28.—CASING

All Weights and Dimensions are Nominal

Size	Diameters		Thickness	Weight per foot		Threads per inch	Couplings		
	External	Internal		Plain ends	Threads and couplings		Diameter	Length	Weight
2	2.250	2.050	0.100	2.296	2.340	14	2.714	2⅝	1.361
2¼	2.500	2.284	0.108	2.759	2.820	14	2.964	2⅝	1.499
2½	2.750	2.524	0.113	3.182	3.250	14	3.214	2⅞	1.804
2¾	3.000	2.768	0.116	3.572	3.650	14	3.464	2⅞	1.957
3	3.250	3.010	0.120	4.011	4.100	14	3.771	3⅛	2.612
3¼	3.500	3.250	0.125	4.505	4.600	14	4.021	3⅛	2.799
3½	3.750	3.492	0.129	4.988	5.100	14	4.271	3⅛	2.987
3¾	4.000	3.732	0.134	5.532	5.650	14	4.521	3⅛	3.174
4	4.250	3.974	0.138	6.060	6.200	14	4.771	3⅝	3.923
4¼	4.500	4.216	0.142	6.609	6.750	14	5.021	3⅝	4.141
4¼	4.500	4.090	0.205	9.403	9.500	14	5.021	3⅝	4.141
4½	4.750	4.460	0.145	7.131	7.250	14	5.271	3⅝	4.360
4½	4.750	4.364	0.193	9.393	9.500	14	5.271	3⅝	4.360
4¾	5.000	4.696	0.152	7.870	8.000	14	5.521	3⅝	4.578
5	5.250	4.944	0.153	8.328	8.500	14	5.828	4⅛	5.929
5	5.250	4.886	0.182	9.851	10.000	14	5.828	4⅛	5.929
5	5.250	4.886	0.182	9.851	10.000	11½	5.800	4⅛	5.742
5	5.250	4.768	0.241	12.892	13.000	11½	5.800	4⅛	5.472
5	5.250	4.648	0.301	15.909	16.000	11½	5.800	4⅛	5.742
5³⁄₁₆	5.500	5.192	0.154	8.792	9.000	14	6.078	4⅛	6.200
5³⁄₁₆	5.500	5.044	0.228	12.837	13.000	11½	6.050	4⅝	6.759
5³⁄₁₆	5.500	4.892	0.304	16.870	17.000	11½	6.155	5⅛	8.849
5⅝	6.000	5.672	0.164	10.222	10.500	14	6.664	4⅛	7.729
5⅝	6.000	5.620	0.190	11.789	12.000	11½	6.636	4⅛	7.516
5⅝	6.000	5.552	0.224	13.818	14.000	11½	6.636	4⅛	7.516
5⅝	6.000	5.450	0.275	16.814	17.000	11½	6.636	4⅛	7.516
6¼	6.625	6.287	0.169	11.652	12.000	14	7.308	4⅝	9.825
6¼	6.625	6.255	0.185	12.724	13.000	14	7.308	4⅝	9.825
6¼	6.625	6.257	0.184	12.657	13.000	11½	7.280	5⅛	10.630
6¼	6.625	6.135	0.245	16.694	17.000	11½	7.280	5⅛	10.630
6¼	6.625	5.913	0.356	23.835	24.000	11½	7.280	5⅛	10.630
6⅝	7.000	6.652	0.174	12.685	13.000	14	7.692	4⅝	10.497
6⅝	7.000	6.538	0.231	16.699	17.000	11½	7.664	4⅝	10.225
6⅝	7.000	6.538	0.231	16.699	17.000	10	7.642	5⅛	11.133
6⅝	7.000	6.450	0.275	19.751	20.000	10	7.699	6⅛	14.458
6⅝	7.000	6.334	0.333	23.711	24.000	10	7.699	6⅛	14.458

CASING

All Weights and Dimensions are Nominal (*Continued*)

Size	Diameters		Thickness	Weight per foot		Threads per inch	Couplings		
	External	Internal		Plain ends	Threads and couplings		Diameter	Length	Weight
7¼	7.625	7.263	0.181	14.390	14.750	14	8.317	4⅝	11.401
7⅝	8.000	7.628	0.186	15.522	16.000	11½	8.788	5⅛	15.308
7⅝	8.000	7.528	0.236	19.569	20.000	11½	8.788	5⅛	15.308
8¼	8.625	8.249	0.188	16.940	17.500	11½	9.413	5⅛	16.461
8¼	8.625	8.191	0.217	19.486	20.000	11½	9.413	5⅛	16.461
8¼	8.625	8.097	0.264	23.574	24.000	11½	9.413	5⅛	16.461
8¼	8.625	8.097	0.264	23.574	24.000	8	9.358	6⅛	18.577
8¼	8.625	8.003	0.311	27.615	28.000	8	9.358	6⅛	18.577
8⅝	9.000	8.608	0.196	18.429	19.000	11½	9.788	5⅛	17.153
9⅝	10.000	9.582	0.209	21.855	22.750	11½	10.911	6⅛	26.136
10	10.750	10.192	0.279	31.201	32.515	8	11.958	6⅝	39.772
10	10.750	10.146	0.302	33.699	35.000	8	11.958	6⅝	39.772
10⅝	11.000	10.552	0.224	25.780	26.750	11½	11.911	6⅛	28.536
11⅝	12.000	11.514	0.243	30.512	31.500	11½	12.911	6⅛	31.051
12½	13.000	12.482	0.259	35.243	36.500	11½	14.025	6⅛	37.499
12½	13.000	12.278	0.361	48.730	50.000	8	14.085	7⅛	46.464
13½	14.000	13.448	0.276	40.454	42.000	11½	15.139	6⅛	44.495
14½	15.000	14.418	0.291	45.714	47.500	11½	16.263	6⅛	52.401
15½	16.000	15.396	0.302	50.632	52.500	11½	17.263	6⅛	55.779

Table 29.—California Casing

All Weights and Dimensions are Nominal

Size	Diameters		Thickness	Weight per foot		Threads per inch	Couplings		Weight
	External	Internal		Plain ends	Threads and couplings		Diameter	Length	
4½	4.750	4.082	0.334	15.752	16.000	10	5.364	6⅝	9.963
4¾	5.000	4.500	0.250	12.682	12.850	10	5.491	6⅝	8.533
4¾	5.000	4.408	0.296	14.870	15.000	10	5.491	6⅝	8.533
5⅝	6.000	5.352	0.324	19.641	20.000	10	6.765	7⅛	15.748
6¼	6.625	6.049	0.288	19.491	20.000	10	7.390	7⅝	18.559
6¼	6.625	5.921	0.352	23.582	24.000	10	7.390	7⅝	18.559
6¼	6.625	5.855	0.385	25.658	26.000	10	7.390	7⅝	18.559
6¼	6.625	5.791	0.417	27.648	28.000	10	7.390	7⅝	18.559
6⅝	7.000	6.456	0.272	19.544	20.000	10	7.698	7⅝	17.943
6⅝	7.000	6.276	0.362	25.663	26.000	10	7.698	7⅝	17.943
6⅝	7.000	6.214	0.393	27.731	28.000	10	7.698	7⅝	17.943
6⅝	7.000	6.154	0.423	29.712	30.000	10	7.698	7⅝	17.943
7⅝	8.000	7.386	0.307	25.223	26.000	10	8.888	8⅛	27.410
8¼	8.625	8.017	0.304	27.016	28.000	10	9.627	8⅛	33.096
8¼	8.625	7.921	0.352	31.101	32.000	10	9.627	8⅛	33.096
8¼	8.625	7.825	0.400	35.137	36.000	10	9.627	8⅛	33.096
8¼	8.625	7.775	0.425	37.220	38.000	10	9.627	8⅛	33.096
8¼	8.625	7.651	0.487	42.327	43.000	10	9.627	8⅛	33.096
9⅝	10.000	9.384	0.308	31.881	33.000	10	11.002	8⅛	38.162
10	10.750	10.054	0.348	38.661	40.000	10	11.866	8⅛	45.365
10	10.750	9.960	0.395	43.684	45.000	10	11.866	8⅛	45.365
10	10.750	9.902	0.424	46.760	48.000	10	11.866	8⅛	45.365
10	10.750	9.784	0.483	52.962	54.000	10	11.866	8⅛	45.365
11⅝	12.000	11.384	0.308	38.460	40.000	10	13.116	8⅛	50.445
12½	13.000	12.438	0.281	38.171	40.000	10	14.116	8⅛	54.508
12½	13.000	12.360	0.320	43.335	45.000	10	14.116	8⅛	54.508
12½	13.000	12.282	0.359	48.467	50.000	10	14.116	8⅛	54.508
12½	13.000	12.220	0.390	52.523	54.000	10	14.116	8⅛	54.508
13½	14.000	13.344	0.328	47.894	50.000	10	15.151	9⅛	67.912
15½	16.000	15.198	0.401	66.806	70.000	10	17.477	9⅛	98.140

TABLE 30.—DRIVE PIPE

All Weights and Dimensions are Nominal

Size	Diameters		Thickness	Weight per foot		Threads per inch	Couplings		
	External	Internal		Plain ends	Threads and couplings		Diameter	Length	Weight
2	2.375	2.067	0.154	3.652	3.730	11½	2.923	3⅝	2.380
2½	2.875	2.469	0.203	5.793	5.906	8	3.486	4⅛	3.748
3	3.500	3.068	0.216	7.575	7.705	8	4.111	4⅛	4.493
3½	4.000	3.548	0.226	9.109	9.294	8	4.723	4⅛	5.973
4	4.500	4.026	0.237	10.790	10.995	8	5.223	4⅛	6.740
4½	5.000	4.506	0.247	12.538	12.758	8	5.723	4⅛	7.439
5	5.563	5.047	0.258	14.617	14.989	8	6.410	5⅛	11.871
6	6.625	6.065	0.280	18.974	19.408	8	7.473	5⅛	13.956
7	7.625	7.023	0.301	23.544	24.021	8	8.474	5⅛	15.955
8	8.625	8.071	0.277	24.696	25.495	8	9.588	6⅛	24.343
8	8.625	7.981	0.322	28.554	29.303	8	9.588	6⅛	24.343
8	8.625	7.917	0.354	31.270	32.334	8	9.882	6⅛	31.320
9	9.625	8.941	0.342	33.907	34.711	8	10.588	6⅛	27.035
10	10.750	10.192	0.279	31.201	32.631	8	11.950	6⅝	40.108
10	10.750	10.136	0.307	34.240	35.628	8	11.950	6⅝	40.108
10	10.750	10.020	0.365	40.483	41.785	8	11.950	6⅝	40.108
11	11.750	11.000	0.375	45.557	46.953	8	12.950	6⅝	43.664
12	12.750	12.090	0.330	43.773	45.358	8	13.950	6⅝	47.220
12	12.750	12.000	0.375	49.562	51.067	8	13.950	6⅝	47.220
13	14.000	13.250	0.375	54.568	56.849	8	15.438	7⅛	66.024
14	15.000	14.250	0.375	58.573	61.005	8	16.438	7⅛	70.533
15	16.000	15.250	0.375	62.579	65.161	8	17.438	7⅛	75.043
17 O.D.	17.000	16.214	0.393	69.704	73.000	8	18.675	7⅛	91.746
18 O.D.	18.000	17.182	0.409	76.840	81.000	8	19.913	7⅛	109.669
20 O.D.	20.000	19.182	0.409	85.577	90.000	8	21.913	7⅛	121.298

Table 31.—Oil Well Tubing

All Weights and Dimensions are Nominal

Size	Diameters		Thickness	Weight per foot		Threads per inch	Couplings		
	External	Internal		Plain ends	Threads and couplings		Diameter	Length	Weight
1¼	1.660	1.380	0.140	2.272	2.300	11½	2.054	2⅞	0.974
1½	1.900	1.610	0.145	2.717	2.748	11½	2.294	2⅞	1.103
2	2.375	2.041	0.167	3.938	4.000	11½	2.841	3⅝	2.146
2	2.375	1.995	0.190	4.433	4.500	11½	2.841	3⅝	2.146
2½	2.875	2.469	0.203	5.793	5.897	11½	3.449	4⅛	3.636
2½	2.875	2.441	0.217	6.160	6.250	11½	3.449	4⅛	3.636
3	3.500	3.068	0.216	7.575	7.694	11½	4.074	4⅛	4.366
3	3.500	3.018	0.241	8.388	8.500	11½	4.074	4⅛	4.366
3	3.500	2.922	0.289	9.910	10.000	11½	4.074	4⅛	4.366
3½	4.000	3.548	0.226	9.109	9.261	8	4.628	4⅛	5.510
4	4.500	4.026	0.237	10.790	10.980	8	5.233	4⅛	6.673
4	4.500	3.990	0.255	11.561	11.750	8	5.233	4⅛	6.673

TABLE 32.—LINE PIPE

All Weights and Dimensions are Nominal

Size	List price per foot	Diameters		Thickness	Weight per foot		Threads per inch	Couplings		
		External	Internal		Plain ends	Threads and couplings		Diameter	Length	Weight
1/8	$0.06	0.405	0.269	0.068	0.244	0.246	27	0.582	1 1/8	0.043
1/4	0.06 1/2	0.540	0.364	0.088	0.424	0.426	18	0.724	1 3/8	0.069
3/8	0.06 1/2	0.675	0.493	0.091	0.567	0.571	18	0.898	1 5/8	0.126
1/2	0.09	0.840	0.622	0.109	0.850	0.856	14	1.085	1 7/8	0.205
3/4	0.12	1.050	0.824	0.113	1.130	1.138	14	1.316	2 1/8	0.316
1	0.17 1/2	1.315	1.049	0.133	1.678	1.688	11 1/2	1.575	2 3/8	0.445
1 1/4	0.23 1/2	1.660	1.380	0.140	2.272	2.300	11 1/2	2.054	2 7/8	0.974
1 1/2	0.28	1.900	1.610	0.145	2.717	2.748	11 1/2	2.294	2 7/8	1.103
2	0.37 1/2	2.375	2.067	0.154	3.652	3.716	11 1/2	2.841	3 5/8	2.146
2 1/2	0.59	2.875	2.469	0.203	5.793	5.881	8	3.389	4 1/8	3.387
3	0.77	3.500	3.068	0.216	7.575	7.675	8	4.014	4 1/8	4.076
3 1/2	0.93	4.000	3.548	0.226	9.109	9.261	8	4.628	4 1/8	5.510
4	1.10	4.500	4.026	0.237	10.790	10.980	8	5.233	4 1/8	6.673
4 1/2	1.28	5.000	4.506	0.247	12.538	12.742	8	5.733	4 1/8	7.379
5	1.50	5.563	5.047	0.258	14.617	14.966	8	6.420	5 1/8	11.730
6	1.94	6.625	6.065	0.280	18.974	19.367	8	7.482	5 1/8	13.869
7	2.40	7.625	7.023	0.301	23.544	23.975	8	8.482	5 1/8	15.883
8	2.54	8.625	8.071	0.277	24.696	25.414	8	9.596	6 1/8	24.130
8	2.92	8.625	7.981	0.322	28.554	29.213	8	9.596	6 1/8	24.130
9	3.47	9.625	8.941	0.342	33.907	34.612	8	10.596	6 1/8	26.838
10	3.25	10.750	10.192	0.279	31.201	32.515	8	11.958	6 5/8	39.772
10	3.55	10.750	10.136	0.307	34.240	35.504	8	11.958	6 5/8	39.772
10	4.17	10.750	10.020	0.365	40.483	41.644	8	11.958	6 5/8	39.772
11	4.68	11.750	11.000	0.375	45.557	46.805	8	12.958	6 5/8	43.326
12	4.55	12.750	12.090	0.330	43.773	45.217	8	13.958	6 5/8	46.898
12	5.12	12.750	12.000	0.375	49.562	50.916	8	13.958	6 5/8	46.898
13	5.68	14.000	13.250	0.375	54.568	56.649	8	15.446	7 1/8	65.506
14	6.18	15.000	14.250	0.375	58.573	60.802	8	16.446	7 1/8	70.031
15	6.60	16.000	15.250	0.375	62.579	64.955	8	17.446	7 1/8	74.555

SPECIFIC GRAVITY OF CRUDE OIL AND METHOD OF FINDING IT

The instruments used are a hydrometer and a standard thermometer. The hydrometer, which is a glass column marked with graduations from 10° to 100°, was invented by Antoine Béaume, a French chemist, and the scale on the instrument has always borne his name. The hydrometer, when placed in a jar or a bottle of oil, sinks to the point on the scale which indicates the gravity in degrees Béaume. The basis of temperature for testing oil is 60 degrees Fahrenheit and for oil at a greater or less temperature, variations must be calculated. Hydrometers are usually provided with a special scale for figuring temperature variations. The specific gravity is found by dividing 140 by 130 plus the Béaume degrees; for example, if the hydrometer registers 30°, this added to 130 equals 160, which divided into 140 shows specific gravity .875°.

Following is a table showing Béaume degrees, specific gravity and weight per gallon of oil.

TABLE 33

Degrees, Béaume	Degrees, specific gravity	Weight per gallon, pounds	Degrees, Béaume	Degrees, specific gravity	Weight per gallon, pounds	Degrees, Béaume	Degrees, specific gravity	Weight per gallon, pounds
10.0	1.000	8.33	34.0	0.855	7.12	62.0	0.731	6.09
10.7	0.995	8.29	34.9	0.850	7.08	62.3	0.730	6.08
11.0	0.993	8.27	35.0	0.850	7.08	63.0	0.728	6.06
11.4	0.990	8.25	35.9	0.845	7.04	63.6	0.725	6.04
12.0	0.986	8.21	36.0	0.845	7.04	64.0	0.724	6.03
12.1	0.985	8.21	36.9	0.840	7.00	65.0	0.720	6.00
12.9	0.980	8.16	37.0	0.840	7.00	66.0	0.717	5.97
13.0	0.979	8.16	37.9	0.835	6.96	66.4	0.715	5.96
13.6	0.975	8.12	38.0	0.835	6.95	67.0	0.713	5.94
14.0	0.973	8.10	38.9	0.830	6.91	67.8	0.710	5.91
14.3	0.970	8.08	39.0	0.830	6.91	68.0	0.709	5.91
15.0	0.966	8.05	40.0	0.825	6.87	69.0	0.706	5.88
15.1	0.965	8.04	41.0	0.820	6.83	69.2	0.705	5.87
15.9	0.960	8.00	42.0	0.816	6.79	70.0	0.702	5.85
16.0	0.959	7.99	42.1	0.815	6.79	70.6	0.700	5.83
16.6	0.955	7.96	43.0	0.811	6.76	71.0	0.699	5.82
17.0	0.953	7.94	43.2	0.810	6.75	72.0	0.695	5.79
17.4	0.950	7.91	44.0	0.806	6.72	72.1	0.695	5.79
18.0	0.947	7.88	44.2	0.805	6.71	73.0	0.692	5.76
18.2	0.945	7.87	45.0	0.802	6.68	73.5	0.690	5.75
19.0	0.940	7.83	45.3	0.800	6.66	74.0	0.689	5.74
19.8	0.935	7.79	46.0	0.797	6.64	75.0	0.685	5.71
20.0	0.934	7.78	46.4	0.795	6.62	76.0	0.682	5.68
20.6	0.930	7.75	47.0	0.793	6.60	76.6	0.680	5.66
21.0	0.928	7.73	47.6	0.790	6.58	77.0	0.679	5.65
21.4	0.925	7.71	48.0	0.788	6.57	78.0	0.675	5.63
22.0	0.922	7.68	48.7	0.785	6.54	78.1	0.675	5.62
22.3	0.920	7.66	49.0	0.784	6.53	79.0	0.672	5.60
23.0	0.916	7.63	49.9	0.780	6.50	79.7	0.670	5.58
23.1	0.915	7.62	50.0	0.780	6.49	80.0	0.669	5.57
24.0	0.910	7.58	51.0	0.775	6.46	81.0	0.666	5.55
24.8	0.905	7.54	52.0	0.771	6.42	81.2	0.665	5.54
25.0	0.904	7.53	52.2	0.770	6.41	82.0	0.663	5.52
25.7	0.900	7.50	53.0	0.767	6.39	82.9	0.660	5.50
26.0	0.898	7.48	53.4	0.765	6.37	83.0	0.660	5.50
26.6	0.895	7.46	54.0	0.763	6.35	84.0	0.657	5.47
27.0	0.893	7.44	54.6	0.760	6.33	84.5	0.655	5.46
27.4	0.890	7.41	55.0	0.759	6.32	85.0	0.654	5.44
28.0	0.887	7.39	55.9	0.755	6.29	86.0	0.651	5.42
28.3	0.885	7.37	56.0	0.755	6.29	86.2	0.650	5.41
29.0	0.882	7.34	57.0	0.751	6.25	87.0	0.648	5.39
29.3	0.880	7.33	57.1	0.750	6.25	87.8	0.645	5.37
30.0	0.876	7.30	58.0	0.747	6.22	88.0	0.645	5.37
30.2	0.875	7.29	58.4	0.745	6.21	89.0	0.642	5.35
31.0	0.871	7.25	59.0	0.743	6.19	89.6	0.640	5.33
31.1	0.870	7.25	59.7	0.740	6.16	90.0	0.639	5.32
32.0	0.865	7.21	60.0	0.739	6.16			
33.0	0.860	7.17	61.0	0.735	6.12			

Table 34.—Conversion Tables, Inches to Millimeters

Inches	0	1/16	1/8	3/16	1/4	5/16	3/8	7/16	1/2	9/16	5/8	11/16	3/4	13/16	7/8	15/16	Inches
0	0.0	1.6	3.2	4.8	6.4	7.9	9.5	11.1	12.7	14.3	15.9	17.5	19.1	20.6	22.2	23.8	0
1	25.4	27.0	28.6	30.2	31.7	33.3	34.9	36.5	38.1	39.7	41.3	42.9	44.4	46.0	47.6	49.2	1
2	50.8	52.4	54.0	55.6	57.1	58.7	60.3	61.9	63.5	65.1	66.7	68.3	69.8	71.4	73.0	74.6	2
3	76.2	77.8	79.4	81.0	82.5	84.1	85.7	87.3	88.9	90.5	92.1	93.7	95.2	96.8	98.4	100.0	3
4	101.6	103.2	104.8	106.4	107.9	109.5	111.1	112.7	114.3	115.9	117.5	119.1	120.6	122.2	123.8	125.4	4
5	127.0	128.6	130.2	131.8	133.3	134.9	136.5	138.1	139.7	141.3	142.9	144.5	146.0	147.6	149.2	150.8	5
6	152.4	154.0	155.6	157.2	158.7	160.3	161.9	163.5	165.1	166.7	168.3	169.9	171.4	173.0	174.6	176.2	6
7	177.8	179.4	181.0	182.6	184.2	185.7	187.3	188.9	190.5	192.1	193.7	195.3	196.8	198.4	200.0	201.6	7
8	203.2	204.8	206.4	208.0	209.5	211.1	212.7	214.3	215.9	217.5	219.1	220.7	222.2	223.8	225.4	227.0	8
9	228.6	230.2	231.8	233.4	234.9	236.5	238.1	239.7	241.3	242.9	244.5	246.1	247.6	249.2	250.8	252.4	9
10	254.0	255.6	257.2	258.8	260.3	261.9	263.5	265.1	266.7	268.3	269.9	271.5	273.0	274.6	276.2	277.8	10
11	279.4	281.0	282.6	284.2	285.7	287.3	288.9	290.5	292.1	293.7	295.3	296.9	298.4	300.0	301.6	303.2	11
12	304.8	306.4	308.0	309.6	311.1	312.7	314.3	315.9	317.5	319.1	320.7	322.3	323.8	325.4	327.0	328.6	12
13	330.2	331.8	333.4	335.0	336.5	338.1	339.7	341.3	342.9	344.5	346.1	347.7	349.2	350.8	352.4	354.0	13
14	355.6	357.2	358.8	360.4	361.9	363.5	365.1	366.7	368.3	369.9	371.5	373.1	374.6	376.2	377.8	379.4	14
15	381.0	382.6	384.2	385.8	387.3	388.9	390.5	392.1	393.7	395.3	396.9	398.5	400.0	401.6	403.2	404.8	15
16	406.4	408.0	409.6	411.2	412.7	414.3	415.9	417.5	419.1	420.7	422.3	423.9	425.4	427.0	428.6	430.2	16
17	431.8	433.4	435.0	436.6	438.1	439.7	441.3	442.9	444.5	446.1	447.7	449.3	450.8	452.4	454.0	455.6	17
18	457.2	458.8	460.4	462.0	463.5	465.1	466.7	468.3	469.9	471.5	473.1	474.7	476.2	477.8	479.4	481.0	18
19	482.6	484.2	485.8	487.4	488.9	490.5	492.1	493.7	495.3	496.9	498.5	500.1	501.6	503.2	504.8	506.4	19
20	508.0	509.6	511.2	512.8	514.3	515.9	517.5	519.1	520.7	522.3	523.9	525.5	527.0	528.6	530.2	531.8	20
21	533.4	535.0	536.6	538.2	539.7	541.3	542.9	544.5	546.1	547.7	549.3	550.9	552.4	554.0	555.6	557.2	21
22	558.8	560.4	562.0	563.6	565.1	566.7	568.3	569.9	571.5	573.1	574.7	576.3	577.8	579.4	581.0	582.6	22
23	584.2	585.8	587.4	589.0	590.5	592.1	593.7	595.3	596.9	598.5	600.1	601.7	603.2	604.8	606.4	608.0	23
24	611.2	609.6	612.8	614.4	615.9	617.5	619.1	620.7	622.3	623.9	625.5	627.1	628.6	630.2	631.8	633.4	24
25	636.6	635.0	638.2	639.8	641.3	642.9	644.5	646.1	647.7	649.3	650.9	652.5	654.0	655.6	657.2	658.8	25
26	662.0	660.4	663.6	665.2	666.7	668.3	669.9	671.5	673.1	674.7	676.3	677.9	679.4	681.0	682.6	684.2	26
27	687.4	685.8	689.0	690.6	692.1	693.7	695.3	696.9	698.5	700.1	701.7	703.3	704.8	706.4	708.0	709.6	27
28	712.8	711.2	714.4	716.0	717.5	719.1	720.7	722.3	723.9	725.5	727.1	728.7	730.2	731.8	733.4	735.0	28
29	738.2	736.6	739.8	741.4	742.9	744.5	746.1	747.7	749.3	750.9	752.5	754.1	755.6	757.2	758.8	760.4	29
30	763.6	762.0	765.2	766.8	768.3	769.9	771.5	773.1	744.7	776.3	777.9	779.5	781.0	782.6	784.2	785.8	30
31	789.0	787.4	790.6	792.2	793.7	795.3	796.9	798.5	800.1	801.7	803.3	804.9	806.4	808.0	809.6	811.2	31
32	814.4	812.8	816.0	817.6	819.1	820.7	822.3	823.9	825.5	827.1	828.7	830.3	831.8	833.4	835.0	836.6	32
33	839.8	838.2	841.4	843.0	844.5	846.1	847.7	849.3	850.9	852.5	854.1	855.7	857.2	858.8	860.4	862.0	33
34	865.2	863.6	866.8	868.4	869.9	871.5	873.1	874.7	876.3	877.9	879.5	881.1	882.6	884.2	885.8	887.4	34
35	890.6	889.0	892.2	893.8	895.3	896.9	898.5	900.1	901.7	903.3	904.9	906.5	908.0	909.6	911.2	912.8	35
36	916.0	914.4	917.6	919.2	920.7	922.3	923.9	925.5	927.1	928.7	930.3	931.9	933.4	935.0	936.6	938.2	36
37	941.4	939.8	943.0	944.6	946.1	947.7	949.3	950.9	952.5	954.1	955.7	957.3	958.8	960.4	962.0	963.6	37
38	966.8	965.2	968.4	970.0	971.5	973.1	974.7	976.3	977.9	979.5	981.1	982.7	984.2	985.8	987.4	989.0	38
39	992.2	990.6	993.8	995.4	996.9	998.5	1000.1	1001.7	1003.3	1004.9	1006.5	1008.1	1009.6	1011.2	1012.8	1014.4	39

GLOSSARY OF TERMS USED IN DRILLING. AFTER U. S. B. M.

Adapter.—Tool that adapts one size of casing to another size and permits unobstructed passage of tools.

Bushing.—A pipe fitting that permits the connecting of two different sizes of pipe.

Ball-bearing Race.—A steel receptacle containing steel balls that permit easy turning under weight.

Belled Out.—Spread until bell-shaped.

Bull Ropes.—Driving ropes used in hoisting the tools.

Cable "Reach" and "Take-up."—Stretch and shrinkage of cables.

Collar.—Coupling.

Collar-bound Pipe.—Pipe held in hole by sediment packing between collars.

Calf Line.—Wire cable to hoist pipe.

Circulating.—Forcing fluid down the inside and up the outside of a string of casing.

Crank Shaft.—Shaft with "handlelike" crank attached; extends through center of band wheel.

Collapsed Pipe.—Pipe crushed by outside pressures.

Drilled Off.—When drillings have accumulated in the hole until the drilling tools barely touch bottom, the tools are said to have "drilled off."

Drive Clamps.—Steel blocks to be attached to drilling stem to strike pipe.

Drivehead.—Circular, steel, "coupling-like" tool. Used to protect pipe coupling from damage from drive clamps.

Engine Balance.—Iron rim to weight flywheel of engine.

Engine "Off Its Feet."—Engine out of control.

Formation.—Material penetrated by the hole, whether hard rock, clay, or running sand.

Frozen Pipe.—Pipe fast in hole from cavings settling around it.

Flush.—Flush with hole. Nearly the same size as the hole.

Gas Pockets.—Small accumulations of gas confined by formation.

Hitch.—Usually refers to the grasping of the wire line or manila cable by means of the clamps hung from the temper screw. In a "*tight hitch*" the tools are held up so as to take advantage of the elasticity of the cable in "switching" loose tools that have become fast, or, in ordinary drilling, in allowing the tools, when properly spaced, to hit bottom by increasing the engine speed. A "*loose hitch*" is usually not good practice in ordinary drilling and is used more often in fishing jobs when enough slack is allowed the cable to permit the "jars" to strike up in order to loosen tools that have become fast in the hole.

Hitch String.—String used as marker to determine correct spacing of tools.

Hitch On.—To connect cable to walking beam by means of the clamps on the temper screw.

"Hold."—When a fishing tool grasps an object in the hole it has taken "hold."

Jar.—The surface evidence of the blow struck by drilling tools in motion.

Jars.—A linked tool. When the links strike together the blow is proportional to the weight of stem or tool above them.

Jar Stroke.—When the jars are inactive, refers to the maximum stroke of which the jars are capable; when active, refers to the length of stroke being used as governed by the wrist pin in the crank.

Jerk Line.—Short cable about 21 feet long. By connecting this cable to the crank shaft and to the drilling cable, the tools may be operated without the use of the walking beam.

Jump a Pin.—To break off the threaded end of a drilling or fishing tool.

Mud Country.—Localities where the caving of the formation causes much mud in drilling.

Pipestretch.—The distance that pipe will pull or stretch before leaving the bottom of the hole.

Pipe Friction.—Friction on that part of the pipe that is exposed to the formation.

Pull Out.—To hoist the tools from the hole.

Rock Engine.—A forward and backward movement of the engine, but not a complete revolution.

Spudding.—Drilling with the tools on a jerk line in starting the hole.

Spider.—Tool that encircles and holds the pipe by means of steel wedges.

Screen Pipe.—A perforated pipe with protected perforations to keep out sand.

Stroke of Tools.—Distance tools travel when operated as in drilling.

Switching.—Loosening tools that are fast in the hole with cable tension, but without using jars.

String of Tools.—Tools used in drilling.

String Up Tools.—To connect drilling tools.

Tongs.—Large pipe wrenches.

Sidetrack.—To drill past an obstacle in the hole.

Wristpin.—The steel pin in the crank shaft to which the walking beam is attached by means of the pitman.

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Blown.—A common expression for a well that is being pumped by means of the release of compressed air at a considerable distance below the normal level of the fluid. Such wells are commonly known as "air wells."

Break.—This is a very loose term commonly used in the oil fields to denote a line along which a change of underground conditions is noticed in the development of an oil field.

Bridge.—This is a term used to describe either the material with which a well is plugged at a distance from bottom or the operation of first starting a plug in such a position. Bridges are placed as a foundation on which to land casing or to build a solid plug.

Brought In.—A well is "brought in" or "comes in" when it commences to produce.

Cased Off.—Excluded from a well by means of metal casing.

Contour Lines.—These represent level lines along the surface contoured. They are spaced at regular intervals of distance from a level datum plane such as sea level. Those used in this paper are actually "underground contours," as the surface contoured is the surface of one of the beds of the formation composing the "Kern River oil series." This use of the contour should not be confused with that in a topographic map, in which the surface contoured is the ground surface. There is, however, a certain similarity. If all the formations above the surface represented by an underground contour map were removed, the underground contour map would then become a topographic map.

Correlate.—To determine the stratigraphic relation of formations logged in two or more wells.

Correlation.—An interpretation of the relation existing between formations logged in two or more wells.

Edge Water.—Water native to the lower portions of an oil sand.

Diatomaceous.—Composed partially of the silicious skeletons of diatoms.

Infiltration.—Commonly used to denote percolation of water from water bearing strata to oil sands.

Landed.—When a string of casing has been permanently placed in a well and allowed to support its own weight, it is said to have been landed.

Logged.—Recorded in the log of a well.

Oil String.—A string of casing used to keep a well open from the point of shut-off to and through the formations from which oil is entering the well.

Oil Zone.—A series of oil bearing beds between arbitrarily chosen limits, but usually limited by persistent water sands or zones.

Plugged Off.—This describes the condition existing when fluid, encountered in the lower part of a well, has been excluded from a higher part by placing an effective plug in the formation between these two places.

Shell.—A term used by drillers to denote a hard stratum.

Shut-off.—This term is used in the usual oil field manner. Ordinarily it refers to the exclusion of water, encountered in a well, from deeper portions of the well by effecting a watertight bond between the metal casing and the walls of the hole. It is, however, sometimes used in describing the effectiveness of jobs of plugging to exclude lower waters from upper portions of a well.

Sidetracked.—Whenever a portion of a well is redrilled, causing a new hole to be made alongside of casing, or other metal, this casing, or material, is said to be sidetracked.

Skimmed.—The manner in which a well is pumped when the pump is above the level at which water stands in the well.

String of Casing.—Any number of joints of casing screwed or driven together and hung or landed in a well.

Water String.—A special case of a string of casing applying to one with which a water "shut-off" has been effected.

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