VIII - THE SECONDARY RECOVERY OF OIL BY WATERFLOODING

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PRIMARY RECOVERY

The Allegany Oil Field in New York is typical of fields whose primary recovery is produced by dissipation of the energy supplied by gas in solution in the oil. Secondary recovery must be obtained by restoring energy to the reservoir.

Discovered in 1879, the field reached its all-time peak production of 20,000 barrels of oil per day in 1882 and its all-time low in 1912 with only 1,550 barrels per day. At this time the 46,500,000 barrels which had been produced, represented less than one third of the total oil produced to date* and about 18% of that estimated to have been in place originally.

Such a decline in production is normal in the solution-gas-drive type of oil field when the natural gas is produced and the energy which forces oil through the pores into the well bore is thus dissipated. This fact is first borne out when the well ceases to flow and must be pumped. Further natural energy dissipation reduces the volume of oil which can be pumped from the well until it becomes uneconomical to operate. Often a vacuum is pulled on the producing well to help increase production and prolong the inevitable natural end. Such a stage had been reached in the Allegany field in 1912 when each well averaged only about 1/8 - 1/10 barrel of oil per day. In other words the primary recovery phase was completed and the stage set for secondary recovery.

RESTORATION OF ENERGY AND SECONDARY RECOVERY

Secondary recovery has been defined as the recovery by any method (natural flow or artificial lift) of those hydrocarbons which enter a well bore as a result of augmentation of the remaining natural reservoir energy after a reservoir has approached its economic limit of production by primary methods. If this rejuvenation takes place earlier it is most often called pressure maintenance and the division between the two is very indistinct. Usually secondary recovery is accomplished by the joint use of two or more well bores.

The first method of secondary recovery used was that of injection of gas and/ or air, into one well, often combined with the use of a vacuum on the oil producing wells in order to further increase the pressure differential between input and producer. This procedure was later found to be more successful than waterflooding in the oil sands of western Pennsylvania, Ohio and West Virginia. Waterflooding was discovered by accident, prior to 1907, by the leaking of fresh water through faulty casing onto the oil sand of a depleted well.

The additional pressure thus put on the sand face caused an increase in oil production on nearby wells and, when recognized, started a flurry of purposely made "leaks" in the casing of other wells. From this random "conversion" of oil wells into water intake wells the process became refined by applying greater control to the amount and condition of water which could get onto the sand face. Coincident with this advance came definite patterns for the injection wells. Through the years this has developed from one injection well surrounded by producers, through the progressive line flood, to the pattern of 4 injection wells on the corners of a square and producer in the center, called the "five-spot". It is this pattern which is used almost exclusively in the Allegany Field and the Bradford Field and which is the most economical and efficient for pattern type waterflooding.

* Total is 150,000,00 barrels to 1/1/57

Of all the factors which affect waterflooding, uniformity is the most important and oil saturation next. Without the required degree of homogeneity, both horizontal and vertical, the oil cannot be removed efficiently or economically. Without sufficient oil content the process cannot make money, even if all oil is removed, so therefore it is useless.

GEOLOGICAL FACTORS

Geological factors play a most important part in determining the success of a waterflood. It is in their application to preliminary estimates and later operation that the geologist can be most helpful to management. The more important geological features which influence a waterflood in its planning and development stage are the thickness, depth, composition, shape and structure of the reservoir.

Thickness of the reservoir is important because the greater thickness means more reservoir volume. No overall minimum can be applied because of varying costs of development and operation and the price of oil. In the Allegany Field 8-10 feet of net pay thickness is the minimum that can be economically flooded at present.

Depth of the reservoir affects the cost of development and the pressures which can be used. Maximum depth at which a flood can be operated depends upon the estimated recoverable oil, the spacing of old wells and the cost and necessity of completing new ones or reworking old ones. Shallow depths limit the amount of pressure which can be used (empirically determined to be equivalent to about one pound per foot of depth) and may expose the formation to the deleterious effects of surface-connected joint planes or other fractures.

Composition of the rock determines whether it is primarily silica or carbonate rock. Sandstones are generally the most efficient waterflood medium, dolomites next and limestones last because of their relative uniformity of texture.

Shape of the reservoir may have a considerable bearing on the pattern of wells used, the spacing between them and their orientation. In large oil fields this is not so much a factor as it is in the small lense type of field, or in the "shoestring" sand bar field where the permeability is usually greater parallel to the long axis.

Structure of the reservoir is important, but critical only when severe faulting or folding has caused isolated production units or steep and variable dips which would dictate spacing and pattern adjustments.

Uniformity of the above features is certainly to be desired but is not nearly as critical as the uniformity of the geological factors which largely control the efficiency and operation of the flood, namely texture, mineral composition and shale partings.

Texture of the reservoir body is controlled by grain size, shape and arrangement. These in turn affect permeability and porosity and therefore not only the rate at which fluids can move through the reservoir, but also the volume that can be put in, the amount of oil that is left after primary recovery and the percent that can be moved by waterflood. Generally a fine, even textured sand will yield less primary and more secondary oil than a coarse textured reservoir. Grain size and arrangement, plus the amount and type of cementing material, also control pore diameter and distribution which are the most influential factors in determining the rate of fluid flow.

The full effect of mineral composition of the reservoir rock on the operation of a waterflood is not completely determined. We do know that the swelling of certain clay minerals in the presence of fresh water seriously impairs the rate of water throughput. We suspect that changes in mineral content alter the wettability.

While <u>shale partings</u> are in a sense part of mineral composition, they are thought of here in the broader sense of a sedimentary condition which can isolate pay horizons from each other horizontally (lensing) or separate them vertically and thus act as a permeability barrier to any natural gravitational separation of water, oil and gas. While the shale of itself is not a deterrent and many operators prefer to find some shale barriers, the isolation of pay layers vertically and horizontally cannot be too great and still permit fluid movement from injection well to producer.

PHYSICAL AND CHEMICAL FACTORS

We find that many physical and chemical properties of the rock also warrant consideration in planning and conducting a waterflood. <u>Oil, water and gas saturation</u> are most important. Without enough oil no flood can be economical. With the required oil saturation and too high a relative water saturation perhaps only water will move. When gas saturation is too high dangerous by-passing and waste of water may occur. Effective permeability to water will vary as the relative saturation of the rock with water, oil and gas changes, thereby changing water injection rates.

<u>Permeability</u> and <u>porosity</u> of the pay and of the other formations exposed to water injection determine the rate of fluid thruput and the volume of fluid used respectively.

<u>Wettability</u> is actually a physical property of the rock, derived from a combination of geological and chemical factors. It is that property of a rock which renders the rock preferentially oil wet or water wet and determines if the formation will flood successfully.

<u>Character of the natural oil</u> and <u>natural water</u> are important. Each must be compatible with the injected fluid and the viscosity of the oil must not be too high. Allegany crude oil is about 4-6 centipoise at a formation temperature of 68°F and is considered almost ideal.

DEVELOPMENT OF WATERFLOOD OIL PRODUCTION

After acquiring a waterflood prospect there is always information that would be desirable to have which would help determine the best method of operation that will produce the most oil economically, so the first well drilled on the prospect is usually cored and analyzed.

TESTING

There are three types of cores that can be taken. The diamond core, taken with rotary tools operating a diamond bit, cuts a solid section of the formation. It is the most expensive method but also allows a more complete analysis and it usually recovers all the formation.

Next preferred is the Baker core taken with a special bit operated on percussion type tools. The core taken is removed in "biscuits" which are large enough to run most analyses. The drawbacks to this type of coring are frequent loss of core and biscuits not large enough to run a complete analysis.

Chip coring, as the name implies, is a method of recovering fairly large chips of the producing formation. It is easy and inexpensive to take but requires special handling in the laboratory. Not all laboratory tests can be run on chip cores.

After the core is taken it is common practice to obtain an electric log of the well. This log, compared with the core, will give information that is very useful in well completion work and, when compared with electric logs of other wells on the lease will afford a truer evaluation of changes in reservoir characteristics. The interpretation of electric logs is highly specialized work.

Core analyses will indicate the formation thickness, pay thickness, permeability, porosity, oil saturation, water saturation, and residual oil saturation after laboratory flooding. From this data accurate estimates of recoverable oil can be made, the most economic well spacing can be determined, the method of completing the wells can be decided and the general economics of the whole operation can be planned.

A typical core in this area would show perhaps eighteen feet of "pay" sand, thirteen percent porosity, five millidarcies permeability, forty-five percent oil saturation that on laboratory tests will waterflood down to a residual oil saturation of twenty-five percent. Connate water can be calculated and usually runs around twenty percent of pore volume.

DRILLING

The drilling of input and producing wells is identical. In this area the accepted practice is to drill a ten inch hole through the unconsolidated formations and set eight inch pipe. This averages 40' of depth. An eight inch hole is then drilled through all the ground water formations (from three to five hundred feet in this area). Six and one-quarter inch casing is set at this point and a six and one-quarter inch hole is then drilled to and through the producing formation to a point forty or fifty feet below it. Average total depth is 1500 feet. The "pay" formation drill cuttings are saved and can be compared with the electric log which is taken as soon as the hole has reached total depth. From the cuttings and electric log the shot is determined. Wells are shot in this area with liquid nitro-glycerin which is lowered into the hole in thin metal containers to a point opposite the producing formation. An average shot would use three quarts of nitro-glycerin per foot of producing formation. The shot is detonated by a "squib" containing two fused sticks of dynamite. The purpose of shooting a well is to break up or fracture the producing formation which greatly increases the effective well bore and therefore increases the rate at which the well can produce fluids or take injected water. Both injection and producing wells are shot. Up to this point both are completed in exactly the same manner.

COMPLETING

The equipping of an injection well consists of running tubing, usually two inch, on a packer which is set immediately above the producing formation. Approximately twenty sacks of cement are placed on top of the packer to hold it securely against the pressure that is to be applied. The tubing is then connected to a line which brings water from a pressure plant. Each well is equipped with a meter so that the amount of water being injected can be determined and controlled. See fig. 3 for diagram of a typical water injection well.

Producing wells, when completed to flow, are equipped in exactly the same manner. If they are to be pumped, a pump barrel is run on tubing to a position near the bottom of the hole. The pump plunger is run into the pump barrel on sucker rods which are used to activate it. These rods in turn are activated by single well jacks, or by jacks connected to a central power by surface rods. Single well jacks are in wide spread use where cheap electric power is available. See fig. 3 for diagram of a typical pumping oil well.

Water lines are buried below frost level to connect each injection well to the pressure plant. Separate oil and gas lines are laid to each producing well to connect them with the fluid gathering system. If oil wells are to be pumped from a central power surface rod lines are run from it to each well jack. If oil wells are pumped individually some form of fuel, electricity or gas, must be lead to each well.

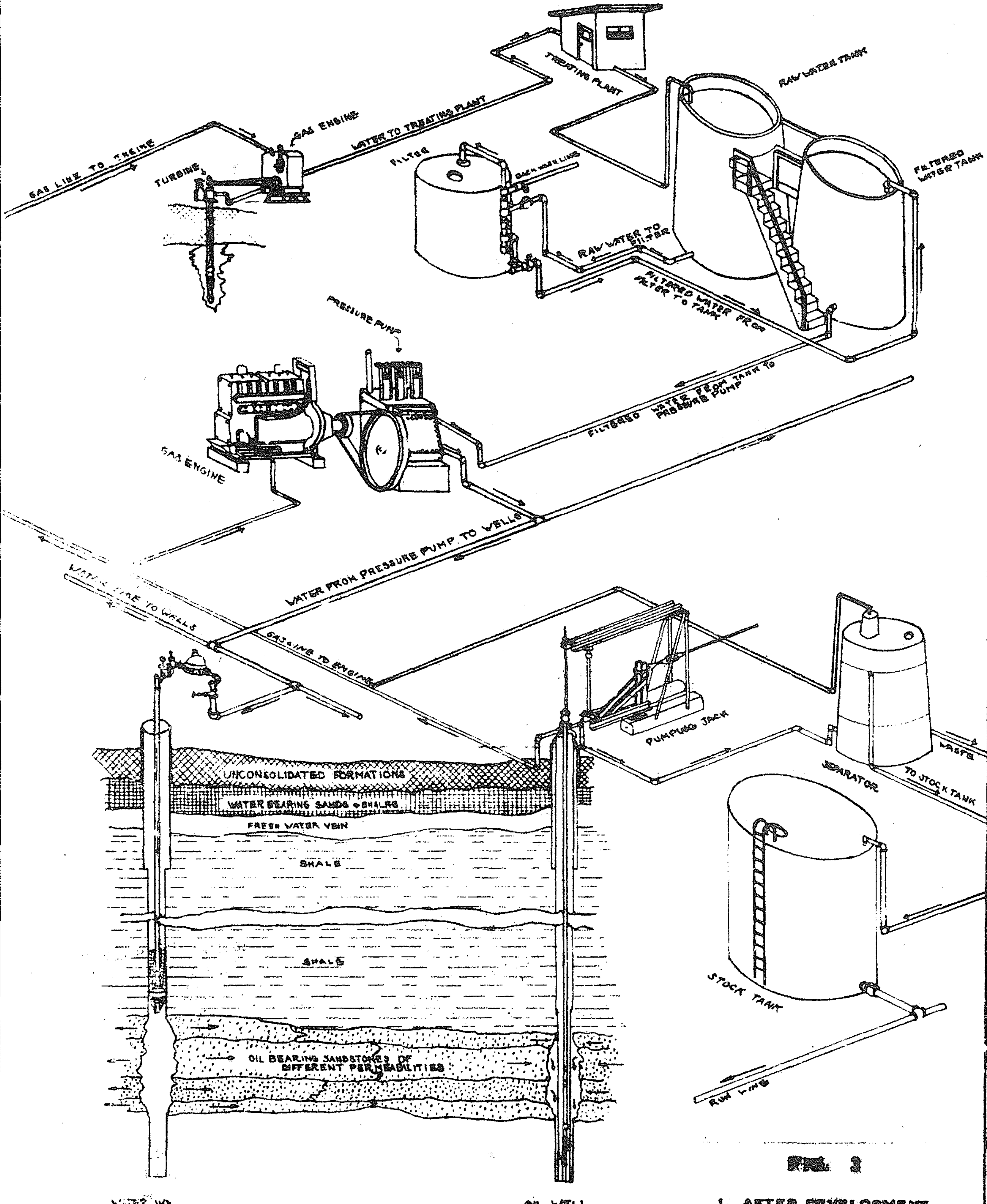


FIG. 3

1. AFTER DEVELOPMENT

COMPLETING

LEGEND

GAS - ▭

OIL - ▭

WATER

RAW - ▭

FILTERED - ▭

THE SLOAN AND ZOOK COMPANY
BRADFORD PA.

METHOD OF OIL RECOVERY BY WATER FLOODING PROCESS IN THE BRADFORD FIELD

M.V. BEAM — MAY 12, 1930

REVISED — BRADLEY PRODUCING CORP. — JUNE 28, 1962

This completes the development of the waterflood property and brings it to the operational stage of injecting water and producing oil. The detailed layout of a complete waterflood system can be seen in fig. 3. Development costs up to this point will average $3000 per acre at the present time in the Allegany field.

PREPARATION AND INJECTION OF WATER

In order to properly waterflood an oil reservoir an adequate source of water must be found and equipment installed to put this water under pressure into the "pay" reservoir.

A good flood water should be clear and free from any foreign particles or bacterial growths. It should be neither corrosive nor scale-forming. The flood water should be compatible with the sand formation to avoid swelling of the clays, and with the formation water to avoid deposition and plugging of the sand.

SOURCE

The water used in this area comes mainly from gravel and rock formations. Gravel wells are found from 20 to 50 feet below the surface, while rock wells are found from 100 to 300 feet below the surface. The gravel water well requires more work in completion and will produce a higher quantity but lower quality water. The amount could range from 50 to 150 gallons per minute. The rock water wells are deeper and as a rule produce less but better water. Rate of production varies from 30 to 85 gallons per minute. Water from rock wells has a better chemical stability with no dissolved oxygen. The gravel water is chemically less stable and more corrosive than rock water.

Air lift jet pumps were used soon after the beginning of pressure flooding in 1930. Some of these are still in service, but due to the large amount of dissolved oxygen jetted into the water, turbines, submersible pumps and pumping jacks have taken their place. These later pumps produce oxygen free water and reduce pitting and corrosion.

TESTING

Mineral analysis is necessary to tell the characteristics of a water. Dissolved oxygen, pH and free carbon dioxide tests are run at sample location. Tests for the amount of sulfates, iron, manganese, alkalinities, chlorides, hardness, silica, calcium, magnesium and total solids are made in the laboratory. From this analysis can be calculated the amount of settling tankage that will be necessary before filtration and the chemical treatment required.

TREATMENT AND FILTRATION

Inorganic chemical treatment is usually added to the water as it enters the settling tanks or ponds. This treatment is used to coagulate the heavy minerals and prepare the water for filtration. The chemicals used are coagulants, caustic materials, chlorine or chlorine solutions. The caustic material used in this type of treatment will raise the pH to an 8.4 to 8.8 range from the average of 6.5 to 7.5 usually found in natural waters in this area. Chlorine residuals before filtration should be from 1.0 to 0.5 parts per million. After filtration they should range from 0.5 to 0.3 ppm. The chlorine will also act as a bactericide in this treatment.

Filters are used to remove the coagulated minerals, foreign particles and bacterial growths. Anthracite coal is used as the filter bed more often than sand and gravel because the density is lower and it requires lower backwash rates. The filter media is one foot of walnut size on bottom, one foot of hazel-nut size in the middle and one and a half feet of fine grade (similar to sugar grains) on top. The rate of filtering should not exceed 2½ gallons per minute per foot of area. Backwash rates for coal beds should be 6 to 9 gpm, sand and gravel 13 to 16 gpm per square foot. Filtered water storage is provided in order to keep the plant running during backwash of filters and during the shut-downs and repair of low pressure equipment.

Organic treatment is also used usually after filtration to inhibit corrosiveness, sequester heavy minerals and lower the surface tension of the water. Many of the organic compounds also have bactericidal qualities. All of the above mentioned chemicals are fed by a constantly proportioning chemical feeder. The cost of the above treatment ranges from one to two mills per barrel of water.

INJECTING WATER

From the filtered water tank the water gravitates into the suction side of the triplex positive displacement pump. This pump produces the pressure used to inject the water into the tight, fine-grained sands. Leaving the pump the water travels through the distribution system until it reaches each injection well. The distribution system consists of a main line (usually under 4" diameter) with smaller sized laterals ($1\frac{1}{2}$"-2") running to the intake wells. The entire system is buried below the frost line. At the injection well a barrel-registering meter is used, similar to the home water meter. Typical water well surface connections and equipment can be seen in fig. 3.

When water is started into a new injection well pressure is gradually raised for a few weeks before full line pressure is used. The rate of injection may be high at first until partial fill-up of the reservoir is obtained. The steadied rate of an injection well will average one-half to one barrel of water per day per foot of sand. If pressures are raised too rapidly at the start of injection, or are carried too high at any time, a condition of "break-through" or "pressure-parting" may occur. This critical pressure seems to average about one pound of sand face pressure per foot of depth. We feel this could be caused by the lifting of layers of shale which may be above, below, or within the sand formation. It may also be vertical fracture along the zones of joint plane weakness. If a well is shut off immediately and left idle for several days this may correct the "break-through". Otherwise selective plugging agents can be injected into the formation break to plug off the flow rate in this section.

Over the 15 year life of an average Allegany field waterflood an injection well will take about 75,000 bbls. of water. This amount of water has gone into an area of $2\frac{1}{2}$ acres (330' square in an average five-spot). If we assume that the recoverable oil from the average five-spot will be 7,500 bbls., there will be 10 bbls. of water injected for each bbl. of oil produced. As the cost of treating and pressuring the water for injection will average $1\frac{1}{2}$ cents per barrel we thus have a total water cost of about 15 cents for every barrel of oil produced.

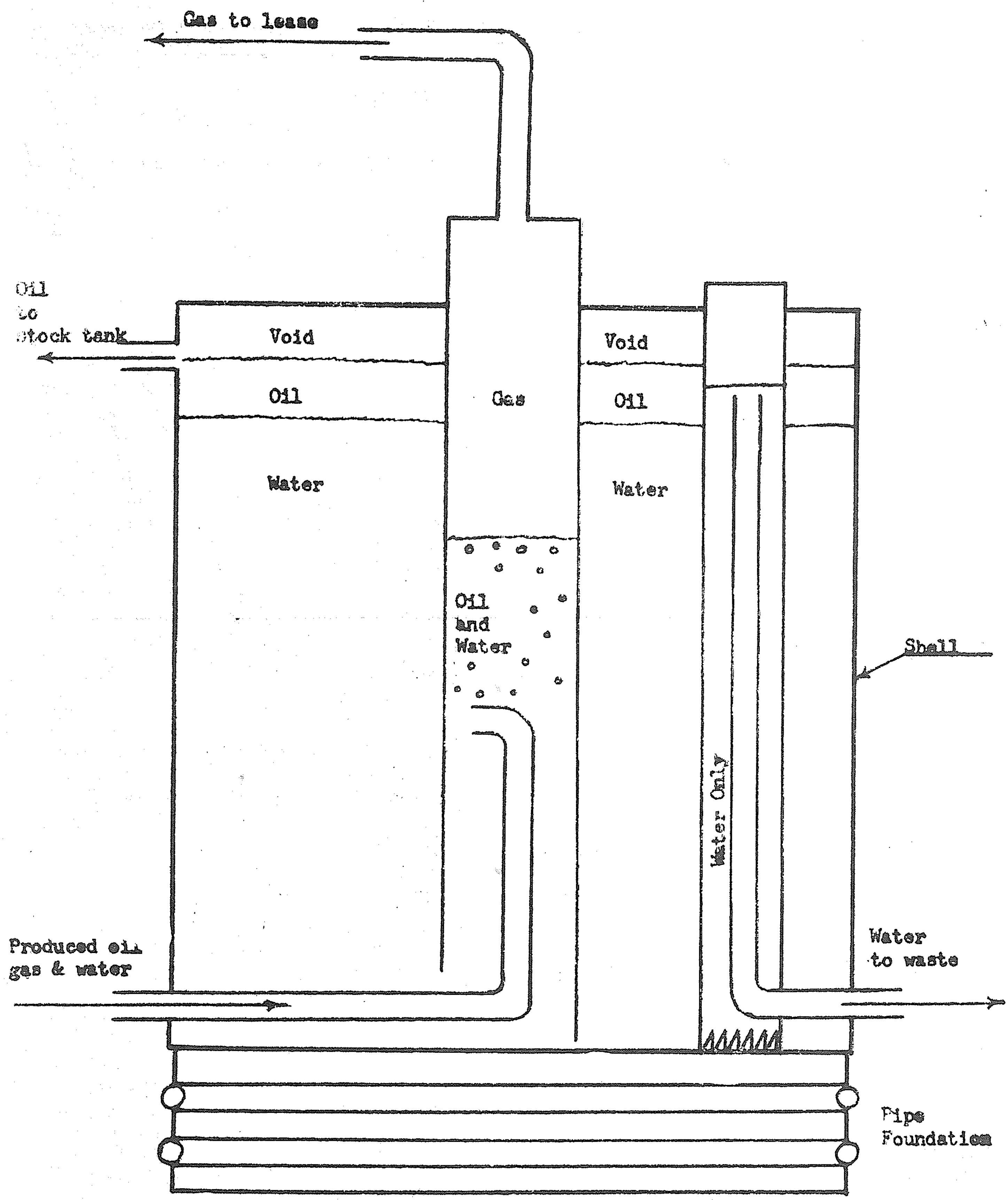
PRODUCTION OF OIL

The production of crude oil in the Allegany field involves lifting the fluid from the producing sand in the well bore to the surface of the ground. This lifting is accomplished either by flowing or pumping the well. Sand characteristics, time and economics involved determine which method shall be used in producing the oil well.

The flowing method uses the energy of the water drive to force the oil and water to the surface through the tubing.

In the Allegany field primarily two different means are used in pumping wells, that is the individual well jack and the Oklahoma style jack pumped by a central power. The main difference in these two methods is that the individual well jack is a unit complete in itself with a motor to supply power to the jack for lifting the rods and bottom hole equipment. The power to the Oklahoma style jack is supplied by a cable or rod line from the eccentric of the central power.

TYPICAL SEPARATOR AS USED
IN ALLEGANY OIL FIELD
Fig. 4



Two different types of central powers are in use today, the gear power and the bandwheel power. The gear power uses a gear and pinion powered from the engine by a belt to motivate the eccentric whereas the bandwheel power uses a horizontal band wheel powered by a belt running from the engine to motivate the eccentric.

Generally about 25 wells are pumped off of one central power. About four barrels of fluid per hour can be pumped from each well. Since this is normally more than will flow into the well bore it is not necessary to pump all the wells simultaneously, and the pumping times of the individual wells may be staggered throughout the pumping period.

At the beginning of production in a waterflood only oil and gas are produced. At peak oil production water will generally appear in the producing well. After peak oil production the same amount of fluid is produced but the oil keeps decreasing and water increasing until the water-oil ratio becomes excessive. When this condition exists the lease becomes unprofitable to operate and is abandoned.

The gas which collects in the annular space between the casing and tubing is taken off at the casing head of the well and piped around the lease where it is used to run engines and furnish heat. The oil and water is pumped into pipe lines generally of 2" diameter which connect several wells to a separator. Since there is little emulsion in the fluids produced they can be separated by gravity at the separator as shown in fig. 4. From the separator the oil is piped into stock tanks and the water is run to waste. Gas from the separator is returned into the gas line system supplying engines and heat.

The standard stock tank in this field will hold about 140 barrels, being 10' high with a diameter of 10'. After a tank is full a gauger from the refinery measures the amount of oil in the tank and allows it to enter the pipe line leading to the refinery. Oil in the stock tanks must be at a minimum of 75°F, or must be heated to that temperature before the gauger will run the oil out to the refinery.

Operating costs vary depending on the size of the lease, the terrain, the characteristics of the fluid produced, the depth of the oil sand and the method by which the oil is produced. Generally we assume that over the producing life of a lease it costs $1.50 per barrel to pump the oil and $1.00 per barrel to flow it.

ECONOMICS OF WATERFLOOD OIL PRODUCTION

The oil producer has only two basic problems. One is the acquisition of reserves. Since the production of oil is a "wasting" operation, the only way a producer can stay in business is to acquire at least as much oil as he produces. He may acquire reserves in several ways. He can explore and develop primary reserves. He can purchase known reserves, or he can acquire reserves that can be recovered by special techniques such as waterflooding is practiced in the oil fields of New York.

The other problem the producer must solve if he is to remain in business is to produce his oil at a profit. This requires the use of efficient development and operating practices.

In acquiring waterflood reserves, a producer may purchase the "Fee" interests, all of the rights to the land and minerals. He may acquire only the mineral rights plus the right to use the surface for the development of the minerals. He may acquire a lease which gives him the exclusive right to prospect for and produce minerals from a property.

In acquiring fee interests or mineral rights the producer owns all the oil and gas he produces, but has the cost of acquisition in obtaining these rights. Where he acquires a lease (working interest), the producer bears the entire cost of producing all of the oil and the basic mineral owner usually reserves one-eighth of the gross oil produced (basic royalty), saved and marketed for himself at no cost of production. This type of acquisition has the advantage to the producer of requiring relatively small amounts of initial cash, and it also reduces his risk capital.

Most secondary reserves are held by producers who have produced, or are in the process of producing, the primary reserves. Usually there is a considerable amount of information available which enables the waterflood producer to more accurately evaluate the property as a secondary prospect. This information decreases to some extent the risk he must take.

ACQUISITION OF RESERVES

The oil producer deals in calculated risks. His success or failure is determined by his accuracy in determining what his risks are. If the risks are high, as in primary exploration, he must have the possibility of getting his investment back several times before he can justify a "wildcat" well.

He may wish to spread his risk. This he does in many ways, by selling part of his working interest, by selling an overriding royalty on his share of the production or by a deal with a drilling contractor who will drill a well for an interest in the property. He may get "dry-hole" money from people who have interests in nearby properties and who are willing to pay some part of the well costs, if it is "dry", for a test in the area. These are only a few of the myriad types of deals used in the industry to spread the risk.

Royalties themselves are dealt frequently. Royalties are sold by people who prefer a known amount of cash in hand to an indefinite amount to be produced at an indefinite rate in the future. The three significant factors governing royalty values are the reserves attributed to the royalty, the price of the oil and the rate of production.

The producer acquiring secondary reserves attempts to accurately estimate the number of barrels a property will produce. From this he subtracts the amount that he must produce to the royalty or other interests. The balance is the production he will have left to generate his income. He must then estimate the price he is going to receive for his production. From this information he can determine what his gross income will be. He then estimates the time it will take him to produce this income and the costs of developing and operating the property.

The sum of these costs subtracted from working interest income gives him a balance. From this balance he must determine how much he can pay for the property, and still leave him a reasonable return on his investment for profit.

As an example let us use the costs and figures mentioned in the foregoing pages and assume the present price for crude oil in the Allegany field of $4.88 per barrel. It will cost $1.00 to develop the property, 15 cents to inject the required water and $1.50 to pump it for every barrel produced. The royalty owner will get 61 cents for every barrel (1/8 royalty). If we assume 50 cents per barrel is paid to purchase the property, the operator will have only $1.12 per barrel for a return on his investment over a 15 year period.

This is a very brief summary of the industry economics. There are hundreds of variations in the types of deals the producer can make. The prime considerations are always the risk involved, the return he can expect on his investment, and the time it will take him to produce his income.

EXTENT OF WATERFLOODING IN THE U. S.

From the small increases in oil production which were first noticed around "leaking casing" or "purposely dumped" wells in Pennsylvania about 1907, waterflooding has grown to be a scientifically engineered, production practice accounting for over 5% of the nation's 7,800,000 barrels of oil produced per day.

From Pennsylvania the method spread to New York in 1912. Increased production from waterfloods was noted in Kansas as early as 1916, Illinois in 1924, North Texas in 1930 and Oklahoma in 1931. California started waterflooding in 1946 and experimental tests were initiated in four fields in Michigan in 1956.

At the present time 19 states of the 27 which produce oil have recognized waterflood production and in 7 of these it is of major value. Ninety percent of all the oil produced in the Pennsylvania Grade oil fields of New York and Pennsylvania (including parts of Ohio, West Virginia and Kentucky) in the last 30 years has been by waterflood. It accounts for approximately 30% of the oil presently produced in Illinois and Indiana, 14% of Oklahoma's production and 13% of Kansas'. In Texas waterflood production is only 3% of the state's total, but is the highest of any of the states at about 90,000 barrels per day.

Where waterflooding is feasibile it will generally produce, as a secondary recovery process, as much oil as was produced by primary means. When it is initiated before the end of the primary recovery stage it can more than double the expected primary recovery. A fine example of this is the well known East Texas field from which initially the recovery was estimated to be about 40%. The field is presently producing about 200,000 barrels per day, and is estimated to yield an ultimate total of 6 billion barrels, 90% of the oil originally in place, because of water injection since 1938.

There has accordingly been an increasing amount of application of injected water to the newer oil fields before they are primarily depleted, thus accomplishing a higher efficiency of production and shortening the time required to produce it.

It has been predicted that 25% of the country's oil production will come from waterflooding by 1980.*

*This and other statistical data above are taken primarily from articles by Albert E. Sweeney, Jr. of the Interstate Oil Compact Commission, and published in the Oil and Gas Journal of 3/26/56, p. 73; the Petroleum Engineer of May 1956, p. B-120. Also from "Secondary Recovery of Oil in the U. S." (See bibliography)