MECHANICAL EQUIPMENT USED IN THE DRILLING AND PRODUCTION OF OIL AND GAS WELLS IN THE OKLAHOMA CITY FIELD

BY

GUSTAV WADE
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MECHANICAL EQUIPMENT USED IN THE DRILLING AND PRODUCTION OF OIL AND GAS WELLS IN THE OKLAHOMA CITY FIELD

By Gustav Wade

INTRODUCTION

The oil-bearing formations in the Oklahoma City field are at an average depth of 6,500 feet below the surface. Heretofore the oil and gas found in the midcontinent area has been at considerably higher levels. The initial formation pressure in the Oklahoma City field was about 2,600 pounds per square inch, which is much above the usual pressures in other Oklahoma fields. Owing to the greater depth and higher pressure the use of heavier, more powerful drilling machinery and of the most advanced methods of drilling was necessary to drill the wells quickly, at reasonable cost, and with due regard for safety of life and property.

All wells in the Oklahoma City field have been drilled by the rotary method, and a considerable number of wells are provided with all or a part of the cable-tool equipment required for future maintenance of production and repair work. In a few of the first wells the pay horizon was "drilled in" with cable tools in conformance with a regulation of the Oklahoma Corporation Commission, but when this requirement of the regulation was later rescinded wells were completed in the oil sand with rotary tools. Although a great deal of drilling equipment was brought from other fields, some of it had been used for drilling shallow wells and was too light or otherwise inadequate to meet the requirements of deep drilling and high gas pressure; therefore new drilling equipment was purchased in considerable quantity.

This paper presents the results of a study devoted chiefly to new equipment that has been developed to meet the requirements of drilling and producing operations in the Oklahoma City field and that has been accepted by drilling contractors and operators.

SCOPE OF REPORT

The first part of this paper deals with drilling equipment and practices. It includes also such performance data on the drilling equipment as were available to the writer. The second part is devoted to a description of the surface equipment used at wells and on

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1 Work on manuscript completed December 1932.
2 Senior dynamometer engineer, U.S. Bureau of Mines.
leases for production operations and maintenance of the wells. In this section, data are given that pertain to items required on the wells and their costs, from the time the location is staked until the well reaches the pumping stage. A short description of the lay-out of the system for disposing of salt water produced with the oil in this field also is included. Illustrations supplement the description of new or unusual equipment.

The cost figures given are based on 1930 prices. They were obtained from the best possible sources and are thought to be reliable. However, the prices of some pieces of equipment varied with the quantity sold to individual companies or purchasers and therefore may not be representative, for the purpose of reference, of the average prices prevailing in 1930.

ACKNOWLEDGMENTS

The information used in preparing the descriptions of the equipment discussed in this paper was generously furnished by the following companies: The American Iron & Machine Works; the American Tank & Equipment Co.; the American Well & Prospecting Co.; the Baash-Ross Tool Co.; the Badgett Steam Lubricator Co.; the Brauer Machine & Supply Co.; the Carson Machine Works; Continental Supply Co.; the Doheny Stone Drill Co.; the Emco Derrick & Equipment Co.; the Frick-Reid Supply Corporation; the Gardner-Denver Co.; the Hanlon-Waters Co.; the Lucey Products Corporation; the Lee C. Moore & Co., Inc.; the Murray Tool & Supply Co.; the National Supply Co.; the National Tank Co.; the Oil Well Supply Co.; the Parkersburg Rig & Reel Co.; the Reed Roller Bit Co.; the Regan Forge & Engineering Co.; the Republic Supply Co.; the Specialty Oil Tool Co.; and the Star Manufacturing Co.

Many of the data concerning drilling operations and drilling equipment were obtained from the Capitol Drilling Co., the Hubbard Drilling Co., the Mitchell Drilling Co., and the Olson Drilling Co.

The author is indebted to R. J. Donaghoe, engineer for the National Supply Co., for cost data on drilling equipment; to W. H. Stueve, electrical engineer, Oklahoma Gas & Electric Co., for data on energy consumption of electric-driven drilling equipment; and to the American Society of Mechanical Engineers for the use of data in the report on steam-driven rotary drilling equipment prepared by Prof. W. H. Carson, director, School of Mechanical Engineering, University of Oklahoma.


The manuscript was read and criticized by R. J. Donaghoe of the National Supply Co.; K. A. Covell, C. O. Rison, and W. S. Morris
Figure 1.—A, Sinking caisson for a circular cellar.  B, Steel derrick-floor foundation.
of the Indian Territory Illuminating Oil Co.; M. L. Atkinson of
the Phillips Petroleum Co.; and C. P. Bowie, B. E. Lindsly, H. C.
Miller, C. E. Reistle, Jr., Ludwig Schmidt, and G. B. Shea of the
Bureau of Mines.

This report was prepared under the direction of H. C. Fowler,
acting chief petroleum engineer, and H. B. Hill, supervising engi-
near of the Dallas office, of the Bureau of Mines, and was made pos-
sible through the cooperation of the State of Oklahoma.

DRILLING MACHINERY

Most of the wells in the Oklahoma City field were drilled by
steam-driven machinery; others were drilled with electric power.
As is customary in the midcontinent fields, the drilling usually was
done by contractors at a definite price per foot of hole, although a
few operators did their own drilling.

During the early development of the field (1929) the contract
price for drilling was $12.50 per foot; later, as the number of con-
tractors increased and competition became established, the price was
reduced to $11 per foot. This price prevailed until the spring of
1931, when the rate for wells completed with 7-inch casing was
lowered to $8, to remain at that level until it was reduced generally
to $7.50 per foot in the spring of 1932. The operating company
usually furnishes and erects the derrick; digs the slush pits; and
supplies the casing, fuel and water and the sand or drilling line
used for "bailing in" the well.

DERRICK FOUNDATIONS AND CELLARS

Most of the derricks in the Oklahoma City field are bolted to and
rest on concrete foundations or "corners." The corner piers for
well locations where the ground is firm are 3 to 4 feet high, 2½
feet square at the top, about 9 feet square at the base, and conform
with piers for 122-foot steel derricks recommended by the American
Petroleum Institute.  

The cellars are 15 to 20 feet deep and have reinforced-concrete
walls and bottom. Two inclined runways lead into the cellar from
opposite sides, one to be used for a manway and the other for lower-
ing equipment into the cellar. The runways generally have rein-
fored concrete walls and bottom, although some are shored with
2-inch lumber and have wooden cleats nailed to the inclined floor.

Two types of cellars, circular and rectangular, are in general use.
At locations in the old bed of the North Fork of the Canadian River,
which crosses the north part of the field, loose surface sands and
water make necessary the construction of special derrick and cellar
foundations with sheet and pipe piling.

The circular cellar is excavated with the aid of a wooden caisson
about 14 feet in diameter and 16 feet high, which holds back the
sand while excavation is under way and serves as the outside form
for the concrete walls. The cellar walls are 12 inches thick and those
of the runways 8 inches thick; all are reinforced with sucker rods.

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American Petroleum Institute, A.P.I. Code No. 4 of Recommended Field Practice:
Figure 1, A, shows a caisson being sunk with the aid of a water jet at a location where quicksand was encountered. Albright⁴ describes the caissons in detail and methods of using them in the construction of derrick foundations. The cellar walls and runways are poured simultaneously, using a 1-2-4 mix. The cellar floor is usually left unfinished until the surface casing is landed and cemented.

A reinforced-concrete mat 32 feet square and 2 feet thick is laid on the surface, and the corner piers extend about 40 inches above it. Anchor bolts for the derrick legs and dead line are provided, and a 2- by 5-foot opening through the mat is provided for the "rathole." Figure 2 shows the construction details of a derrick foundation on soft ground where piling consisting of used pipe has been driven to bedrock for greater rigidity.

The circular cellar with base slab and corner piers requires about 125 cubic yards of concrete, and where piling is required the cost of construction, ready for the derrick, is about $5,100.

⁴ Albright, J. G., Special Concrete Foundations for Derricks on Quicksand: Oil Weekly, July 17, 1931, p. 27.
Figure 3 shows the construction details of a foundation for a 24-foot-base derrick with a rectangular cellar. The cellar is 10 by 10½ feet in inside dimensions, and the reinforced walls are 8 inches thick; the reinforcing bars are distributed so as to give uniform strength throughout the walls. The runways are 3½ feet wide and have walls 6 inches thick. The corner piers are 9 feet square at the base, 4 feet square at the top, and 5 feet 3 inches high. No sub-floor mat is used, but a concrete pad 2½ feet wide by 7 feet long and 15 inches thick is provided as a footing for the draw works. The cellar requires about 70 cubic yards of concrete, 2,500 pounds of reinforcing steel, and about 6,800 board-feet of lumber for the concrete forms. Forms of sheet steel braced with angle bars are used for the corner piers, and although their first cost is greater than that of wooden forms, they can be quickly set in place; also they can be used repeatedly and therefore are more economical.

Often ready-mixed concrete is purchased and delivered directly into the forms at a cost depending on the length of haul from the mixing plant in Oklahoma City. Some operators find ready-mixed concrete more economical than purchasing cement and aggregates and preparing the concrete by company labor and equipment at the derrick site. Other operators modify the concrete forms so as to include foundations for cable-tool equipment with the foundation for the derrick and rotary equipment. At many locations a concrete slab for mounting the drilling engine is provided and is poured at the same time as the derrick foundation. These slabs are 6 to 8 feet wide, about 10 feet long, and 1½ feet thick, requiring about 3½ cubic yards of concrete.

The derricks are provided with steel base beams, and at most wells the wooden derrick floor is laid on 8- by 10-inch timber sills supported on wooden blocking or underpinning. With this type of construction it was customary to use six or more wooden posts set on the cellar floor as supports for the rotary table. These posts reduced the working space in the cellar, and the master valves could not be screwed onto the casing without first removing the valve bonnet.

A steel derrick-floor foundation, developed by one of the major operators in 1931, overcomes this difficulty and has the additional advantage of being completely salvageable. All parts, except derrick floor and nailing strips, are fireproof. This type of structure for a 122-foot derrick with 24-foot base, as used in conjunction with the rectangular cellar, is shown in figure 3. The rotary table supports are four columns made of pipe. The several steel members are made in pieces convenient to handle and are assembled with bolts. The steel required for its construction consists of 7,220 pounds of structural steel and 2,925 pounds of pipe. Lumber for derrick floor and nailing strips totals 1,550 board-feet. Figure 1, B, is a photograph of this type of floor foundation viewed from the draw-works side, and shows the pad and supports for the draw works, the I-beams across the cellar, and the floor supports made of pipe.

DERRICKS

All derricks used in this field are of steel and are designed for combination rotary and cable-tool drilling. A few 136-foot derricks were used, still fewer of the 156-foot derricks were used, and one 170-foot
derrick was used, but the large majority are 122 feet high with 24-foot square bases. The almost general use of the 122-foot derrick indicates its suitability for drilling operations in the Oklahoma City field. However, with the heavy and powerful drilling equipment employed, the clearance between crown block and traveling equipment in the 122-foot derrick is rather small. The assembly of hoisted equipment (consisting of a “stand” of drill pipe 90 feet long, the elevators which are at least 6 feet long, the casing hook which when in tension is about 9 feet 6 inches long, and the traveling block which is approximately 8 feet 8 inches long) has a total length of slightly over 114 feet. The “break-out” point of the drill pipe is about 4 feet above the derrick floor, and the available working clearance in a 122-foot derrick is thus only about 4 feet. The length of the assembly hoisted is a vertical measurement, whereas the height of the derrick is measured along the neutral axis of the derrick leg from the derrick floor to the base of the water-table beams—an indication that the available clearance is somewhat less than 4 feet. However, the crown block rests on the top of the water-table beams which are 18 to 20 inches high, thereby providing additional clearance. Despite this additional height, the over-all clearance is so small as to necessitate constant vigilance on the part of drillers to avoid overhoisting the blocks.

Most of the derricks are constructed of angle-shaped members throughout, and the remainder have tubular legs and girts and braces of either tubular or angle-shaped cross-section. In general they conform to the American Petroleum Institute standards in dimensions and load-carrying capacity.

One make of derrick introduced into this field in the spring of 1932 departs materially from the A.P.I. specifications in that the water-table opening is 7 feet 6 inches square instead of 5 feet 6 inches. The base is the same size as in other 122-foot derricks, but the wider top results in less taper of the legs and provides more space at the “fourble” board for stacking the drill pipe.

Tubular reinforcing legs are installed on most of the derricks during drilling operations, and at some wells these reinforcing legs are removed when the well has been completed. The derricks are equipped with a ginnpole and a safety platform at the crow’s nest, a guarded working platform outside the legs supported on brackets at the “fourble board” about 90 feet above the derrick floor, and an open ladder.

Although the derricks are designed to withstand wind velocities up to 70 miles per hour, it is general practice to guy all derricks with three or more guy wires on each leg. The guys are anchored to deadmen about 100 feet from the derrick. Where the guy wires cross overhead power or telephone wires, two strain insulators are installed in each guy to prevent accidental grounding of the lines and to protect the derrick and men working in it.

Of the 10 or more makes of derricks used in this field, all are similar in design and differ principally in the method of bracing. Almost all derricks have 10-foot panels at the bottom and 7-foot panels above the first girt. Considerable additional strength has been incorporated in the first and second panels, which sustain maximum loads during drilling, by using starting legs (extending from
FIGURE 3.—Rectangular cellar and steel derrick-floor foundation.
the base of the derrick to the base of the third panel) of greater cross-sectional area than that of the intermediate legs in the upper panels. When made of mild steel the tubular starting legs are of 4-inch, 27½-pound, seamless pipe, and if angle starting legs are used they are 6 by 6 by 7/8 inch in size. On many derricks the starting legs are reinforced with outside trusses or wing braces used in lieu of inner bracings which interfere with drilling operations. This is a convenient and practical method of increasing the strength of the structure, but the effective support of these trusses is greatly diminished if the trusses are displaced from their proper positions. As the trusses project beyond the derrick leg their position is somewhat vulnerable, and while moving in equipment caution must be exercised to avoid striking and distorting these trusses, thereby weakening the derrick.

In most of the derricks the 7-foot panels below the eighth girt have double cross bracing, and the panels above have single cross bracing. In the panels where single cross bracing is used, a vertical member is used between the intersection of the diagonal braces and the adjacent girt below to prevent the girt from sagging. In one make of derrick these vertical members are replaced by a continuous strut which extends from the eighth girt to the intersection of the diagonal braces in the uppermost panel. Although little stress is induced in this strut the advantage gained by its use is that the girts in the single-braced panels can be reduced in size without sacrificing strength of the structure.

The safe load capacities of the derricks range from 398,000 pounds for derricks constructed of mild steel to 596,000 pounds for ones of high-tensile-strength steel. The average load capacity is about 440,000 pounds, and reinforcing legs, where used, increase this by about 300,000 pounds. A few derricks have collapsed during drilling. In all of these derrick failures, however, fishing jobs or attempts to loosen stuck drill pipe were under way when failure occurred, indicating that overloading was the probable cause of failure.

It is general practice in the midcontinent area to drill the hole on the center line of the derrick and "dead end" the hoisting line to the base beam close to the corner pier on the window side of the derrick. The hoisting drum necessarily is set approximately 10 feet from the center of the hole, therefore the horizontal component of the force exerted on the hoisting line is of considerable magnitude. The horizontal components of the forces on the dead line and the line attached to the drum do not compensate, therefore the load imposed on the derrick legs on the draw-works side is considerably greater than that on the other two derrick legs. The rate at which the load is "picked up" is a potent factor which determines the stresses in the primary members of the derrick. The large engines and the high steam pressures make high acceleration possible, and injudicious manipulation of the equipment can easily impose such large dynamic forces on the derrick as to overload one of the legs and collapse the derrick.

The weight of the 122-foot derrick used in this field, including ladder, working platforms, and other accessories, ranges from 32,800 to 34,850 pounds. The average cost of a derrick, including working
platforms, f.o.b. Oklahoma City in 1930, was $2,225; reinforcing legs cost about $730 extra. The derricks are erected by rig-building contractors, and usually the job is completed by a crew of six men in 12 hours. A few derricks have been furnished and erected ready for drilling on lump-sum contracts, locally referred to as “turnkey” jobs.

SLUSH PITS

At each well location are constructed two working slush pits, each 20 by 90 by 6 feet deep, and a reserve pit 90 feet square by 2 feet deep for mud storage and settling. The reserve pit usually is placed close to the working pits so that drill cuttings which settle out in the working pits may be transferred to the reserve pit by means of steam jets. Where ground space is limited a single working pit is used, and wooden baffle dams are employed to divert the mud stream across the pit several times in order to lengthen its path and provide more time for the cuttings to settle out. With teams and scrapers for excavating, slush pits may be constructed at a cost of approximately $600 for each well, although the cost of excavating with clamshell or with steam shovels in some instances is much less.

DRILLING ENGINES

Horizontal, 12- by 12-inch, twin-cylinder, fully enclosed, splash-lubricated steam engines are the most common prime movers used for drilling in the Oklahoma City field. The alloy-steel crank shafts are 5 to 7½ inches in diameter and are mounted on two dustproof roller bearings. One make of engine also has self-alining roller bearings on the crank pins. Steam valves are of the balanced, piston type actuated by eccentrics through conventional link-motion reverse gear. In general, valves and cylinders are lubricated with oil from a hydrostatic lubricator, but many engines also are equipped with force-feed lubricators driven by some part of the valve gear.

In most installations the live steam on its way to the engine passes through a cylindrical, centrifugal-type separator made of boiler plate and set close to the engine. The separator is fitted with a steam trap that automatically discharges the condensate as it accumulates in the bottom of the separator.

One make of engine has an exposed valve gear mounted on the sides of the engine. The valves are actuated by eccentric rods driven by cranks on the overhung ends of the crank shaft and fitted with roller bearings on the crank pins. A fixed link is mounted on the engine frame, and a block moved within this link by the reverse lever forms the pivot point for the radius hanger attached to the eccentric rod. The end of the eccentric rod is connected to a bell crank by a transmission yoke; the oscillating travel of the end of the eccentric rod in the vertical plane is transmitted to the valve by means of the bell crank. On this type of engine there are only two eccentric rods, one on each side; full port opening is attained early in the stroke, and little manual effort is required to reverse the engine because there are no heavy parts to be moved.

The largest prime mover ever used on a drilling well in the mid-continent area had its initial field trial in the Oklahoma City field. This engine is a horizontal, twin-cylinder steam engine of 14-inch
bore and 18-inch stroke. All operating parts are fully enclosed. Figure 4 shows three views of this engine; the upper view is a plan with one-half of the engine shown in cross-section, the center view is a vertical cross-section through the longitudinal center line of one cylinder, and the lower view is an elevation with the side cut away to show the valve and valve gear.

The counterbalanced crank shaft is 6 inches in diameter and is mounted on four babbitted bearings. Crank-pin bearing shells have spherical outer surfaces, making them self-alining, so that any flexing of the shaft under load will not disturb the uniform distribution of pressure on the crank pins. An independent lubricating system supplies each half of the engine. Main and crank-pin bearings are lubricated with oil under pressure; all other operating parts are supplied with oil by either the drip or splash method. The lubricating oil is circulated through the engine by two vane pumps, one mounted on each end of the crank shaft, drawing from a 13-gallon supply in the crank case. The installation of these pumps is somewhat unusual in that the casing and vane revolve with the shaft, whereas the central member remains stationary, being restrained by the suction pipe which is secured to the crank-case housing.

The manufacturers of the engine have directed special attention toward making duplicate parts of the engine interchangeable. The cylinders, for example, can be fitted to either side of the engine frame. Changing a cylinder from the left to the right side of the engine requires merely the rotation of the cylinder 180° about its longitudinal axis. Eccentrics and eccentric rods also can be interchanged by inverting them from their original positions, consequently the number of spare parts that need be carried in stock to guarantee continuous operation of this engine is reduced materially.

The slide valve of the engine is of plate type similar to the Allen valve⁴ except that the passage through the valve is employed only for exhaust steam, whereas in the Allen valve the passage is used only for live steam. There are two openings 5% inches in diameter through the outer wall of the valve that connect the passage through the valve to the exhaust outlet incorporated in the steam chest cover. The circular openings in the outer wall of the valve are fitted with balance rings which prevent leakage of live steam from the steam chest into the exhaust. The steam ports extend the full diameter of the cylinder, and although they are of the conventional reverse-curve form they are relatively short to facilitate rapid elimination of condensate from the cylinder of the engine. The slide valve is of cast iron, alloyed with chromium, manganese, nickel, and silicon and heat-treated to obtain fine-grained texture and to increase the hardness to 360 Brinell. The valve stem is attached to the guide by a floating joint which permits the use of various thicknesses of steam-chest gaskets without cramping the valve-operating mechanism. The link-type reverse gear is manually operated. The link is pivoted at its center, and a counterweight on the reversing shaft balances a part of the combined weight of the link and small ends of the eccentric rods to reduce the force required to reverse the engine.

Figure 4.—14- by 18-inch steam drilling engine.
The engine is of compact construction with smooth exterior surfaces and weighs 12,730 pounds. The mounting base is rectangular, 5 feet wide by 6 feet long, and the over-all length is 8 feet 6 inches. The engine is equipped with a small crane mounted near the center of the engine frame and free to revolve about its mounting to facilitate handling of heavy parts during assembly or inspection. The engine was loaned to a drilling contractor to drill one well and gave satisfactory service.

Another steam engine of special interest is the three-cylinder, vertical, marine-type engine used to drive the Hydril drilling outfit. This engine is described in detail under the heading Hydril Rotary Outfit (see pp. 24 to 26).

The horizontal, twin-cylinder drilling engines used in the Oklahoma City field range in weight from 9,300 to 13,800 pounds, and in 1930 the engines cost approximately $2,500.

![Figure 5.—Steel engine foundation, draw-works braces, and headboards.](image)

**ENGINE ACCESSORIES**

The steam lines usually are of 3½- or 4-inch pipe, and the drilling engines are equipped with 3-inch throttle valves, many of them being of the safety type which, when in the closed position, have an open port that releases all the live steam from steam chest and cylinders to the atmosphere or to a water knock-out trap. This type of valve prevents accumulation of steam or water in the cylinders and accidental starting of the engine because of a leaking throttle valve. The use of 350-pound steam pressure in the Oklahoma City field has subjected the throttle valves to severe service and has brought about difficulties in their operation, consequently few makes of throttle valves have given entirely satisfactory service under that steam pressure.

To obtain a more rigid support than is possible with timber construction, steel is used for engine foundations, headboards, and draw-works braces on many drilling outfits. Figure 5 shows one type of assembly commonly used in the Oklahoma City field. The engine foundation is made of H-beams bolted together to form a framework upon which the engine is mounted. The mudsills are 10-
by 10-inch, 50-pound beams, 18 to 24 feet long, with a \(\frac{3}{8}\)-inch plate
16 inches wide welded to the lower flange of the sill to increase the
bearing area. The several parts are placed in proper position and
alinement and securely fastened together with \(\frac{7}{8}\)-inch bolts.

The steel foundation for a drilling engine weighs approximately
8,000 pounds. It has the advantages over wooden timbers that it is
fireproof and can be assembled more quickly as the labor of framing
is eliminated. It is more rigid, is easily dismantled and moved, and
can be repaired readily when damaged.

The steel foundations were modified from time to time. Figure
6, A, shows a drilling engine installed on a foundation built in the
spring of 1932 which consists of three 20-inch I-beam sills with five
15-inch cross members bolted to them. Pony sills are omitted, and
the engine skids rest directly on the cross members. In some in-
stances these mudsills are imbedded in concrete to a depth of 10
inches for greater rigidity.

The steel headboards are two 15-inch, 40-pound I-beams or chan-
nels clamped to the derrick legs, one on either side of the leg and
provided with plates and eyebolts for anchoring them to the corner
pier of the derrick.

Two types of steel draw-works braces are in general use in the
Oklahoma City field. One type is made of 8- by 8-inch H-beams
with a fixed bearing against the headboard or jack post and a hinged
bearing in a clamp at the foot that grips the upper flange of the mud-
sill and is adjustable. The other type is made of discarded 6\(\frac{1}{2}\)-inch
drill pipe and is provided with fittings for a ball-and-socket joint at
the upper end and a hinged joint at the foot. The ball fitting has
a long thread and locking collar which provide considerable adjust-
ment in length of the brace. The end fittings, adjusting nipple, and
pipe collar are 6 feet 1 inch long, and the drill pipe may be cut to
make up the additional length of the required brace.

At prices prevailing in 1930 the steel engine foundation cost $525;
a set of steel headboards and a complete set of steel braces for engine,
draw works, and rotary table cost $380.

**DRAW WORKS**

Draw works used in the Oklahoma City field are of the 2-post,
3-shaft, 4-speed type with each shaft mounted on two self-alin-
ing roller bearings. (See fig. 7.) The use of roller bearings
eliminates the third post commonly used on plain-bearing draw
works and reduces the length of the shafts; therefore the machines
are more compact. The drum shafts are usually 8 inches in di-
ameter, and the jackshafts are 7\(\frac{1}{2}\) inches in diameter. All are of
forged, heat-treated, chrome-nickel steel. In one make of draw
works the center section of the drum shaft is 9 inches in diameter
to provide greater stiffness. The frame of the draw works is of
structural steel, and the jack posts and knee braces are 10- by 10-inch
H-beams. The jack posts have solid steel rollers on the outside
corner to prevent chafing the jerk line and spinning rope when mak-
ing and breaking joints on the drill pipe and casing.

The hoisting drums are constructed of cast steel with extra-heavy
flanges to resist the side pressure set up by the spooled line and
Figure 6.—A, Drilling engine installed on a steel foundation.  B, Rotary swivel.
range from 22 to 26 inches in diameter. The brake drums are of forged steel, each forged in one piece. The mounting surfaces on the web of the brake drum are machined, and the braking surface on the rim is ground-finished. In two makes of draw works the hoisting drums are of the built-up type in which the drum centers are cast on the shaft, and the brake drums are held between inner and outer flanges by rivets in double shear. Rope grooves are cast in the lateral surface of the drum center or spool to guide the reeling of the hoisting line and to reduce wear on the line caused by false spooling. The grooves are designed for 1½-inch wire line, of which 2,600 feet may be reeled on the drums.

Most of the brakes on the hoisting drum are of the conventional, external, contracting-band type, faced with 1-by 10-inch wire-inserted lining of woven-asbestos fabric fastened to the brake band with brass bolts. One manufacturer uses a molded brake lining applied in 10-inch segments for a more uniform distribution of the braking pressure. Another manufacturer uses the clasmshell or automobile type of brake in which the band is made in two halves joined by a hinged joint to obtain a uniform braking force in both directions of rotation. Brake equalizers of the lever type predominate, although a few differential types are used. Some of the draw works are provided with water-cooled brakes, water being admitted through the drum shaft and piped to each brake drum.

The four speeds of the drum shaft are available through the following arrangement of drives: The engine drives the jackshaft, which in turn drives the line shaft by either of two drives, each selected by a hand lever which engages independent jaw clutches. There are also two drives from the line shaft to the drum shaft, controlled by clutches on the drum shaft operated by pedals. The hand lever may be locked in neutral position so that while driving neither of the clutches controlled by it are engaged. Therefore the line shaft is at rest, and the drum shaft is permitted to rotate in accordance with the "feed" of the bit. Table 1 shows the speed ratios of a draw works in general use in the Oklahoma City field. The ratios given are based on unit speed of the jackshaft, which may be fitted with different drive sprockets (18-tooth, 19-tooth, or others); and in calculations of engine speeds the ratio of drive between the engine and jackshaft must be taken into account.

<table>
<thead>
<tr>
<th>Speed</th>
<th>Clutch combination</th>
<th>Speed ratios, revolutions</th>
<th>Speed of hoisting line, feet per minute</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Jackshaft</td>
<td>Drum shaft</td>
<td>Jackshaft</td>
</tr>
<tr>
<td>1</td>
<td>Low</td>
<td>Low</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>High</td>
<td>do</td>
<td>1</td>
</tr>
<tr>
<td>3</td>
<td>Low</td>
<td>High</td>
<td>1</td>
</tr>
<tr>
<td>4</td>
<td>High</td>
<td>do</td>
<td>1</td>
</tr>
</tbody>
</table>

The complete draw works, without chain guards, range in weight from 22,000 to 24,000 pounds and cost about $6,200 in 1930.
Automatic catheads are in general use on draw works in the Oklahoma City field. These catheads contain an automatic reeling device that operates the jerk line in "breaking out" joints on drill pipe. When the joint is loosened, the cathead releases the jerk line and resets itself for the next joint. Automatic catheads provide a uniform pull on the tongs and permit the use of jerk lines of smaller diameter, thereby affording greater ease of resetting, a saving of time, and safer operation. The engaging clutch is operated by a wire to a pedal at the driller's position. The automatic cathead weighs 473 pounds, and in 1930 the prevailing price was $350.

Draw-works drive chains are of alloy steel with substantial side bars and heat-treated ground pins. Replaceable, hardened, and ground rollers of alloy steel are mounted on the pins to reduce friction. Two sizes of chain are required on every draw works. The no. 3 chain weighs about 8½ pounds per foot and the no. 4 chain, 14 pounds per foot. A total of approximately 160 feet of chain is required per draw works. The cost of the chain is about $720, and under the best conditions one set of chains will drill only two wells in the Oklahoma City field. It is customary to keep about 80 feet of spare chain on hand at each drilling well for replacement purposes.

Sprockets, drive chains, hoisting drum, and brake drums are enclosed with metal guards in compliance with safety regulations of the Oklahoma State Department of Labor. The semienclosed type of guard predominates because of the facility with which chains and clutches may be inspected and lubricated. The guards are ruggedly constructed and equipped with lifting lugs to facilitate handling when it is necessary to remove them in order to replace a broken chain or for inspection. A complete set of chain guards ready for installation cost approximately $590 during 1930.

A device that guides the casing line onto the hoisting drum when hoisting drill pipe or casing out of the hole and prevents whipping of the line when it is unreeling from the drum is used on many of the drilling outfits. Although a few devices are patented the majority are home-made and usually consist of a pair of idlers rigged in a small wire line stretched horizontally between the derrick legs just above the headboards. The casing line runs between the two idlers. The supporting line passes over small pulleys, and the ends of the line are attached to counterweights which resist the horizontal travel of the casing line and cause it to reel properly on the drum. Other home-made, line-guide devices use oil dashpots and levers to attain the same results. Line-guiding devices diminish the wear on casing lines and thereby lessen the number of steel particles that drop from the lines and often cause eye injuries to drilling crews.

**ROTARY TABLES**

Rotary tables are of extra-heavy, all-steel construction. The frames are one-piece castings embodying base, housing, and skids. Lifting lugs or hooks are built into the frame to facilitate handling. The tables revolve on ball or roller bearings running on hardened and ground, alloy-steel races in a bath of oil and are fully enclosed to exclude foreign matter from the working parts and to safeguard
Figure 7.—Four-speed draw works.
Figure 8.—Fully enclosed rotary table.
workmen against injury. (See fig. 8.) Vertical alinement of the table is maintained by angular-contact roller bearings which take both axial and radial loads and are fitted to the skirt of the table. Driving gears are of heat-treated alloy steel with accurately machined teeth enclosed in the housing and lubricated by oil from the bath in which the thrust bearing is immersed. The oil baths hold from 10 to 15 gallons of lubricant. The progress made in the manufacture of gears during the past decade has reduced their cost so that gears with accurately machined teeth have replaced the inferior cast gears formerly used on rotary tables. Rotary-table pinion shafts are mounted on fully enclosed roller bearings which are lubricated by hand-operated grease guns.

The center opening through rotary tables ranges from 25 to 27½ inches in diameter, and this dimension generally is used as a symbol to designate the size of the table. Locking devices which prevent rotation of the table while "making up" joints of drill pipe are incorporated in the pinion-shaft assembly where they are easily accessible yet not likely to be inadvertently engaged. Provisions are made for locking the master bushings into the table to prevent their being lifted out by the tool joints and thus permitting the slips to drop into the drill hole when drill pipe is being hoisted. The over-all height of the table is about 25 inches. Rotary tables range in weight from 9,000 to 11,500 pounds and in 1930 cost approximately $4,200.

Ball and roller bearings have increased the efficiency of rotary tables over tables with plain bearings without proportionately increasing the over-all dimensions. Their use also has resulted in smoother operating machines. With the bearings submerged in oil, ample lubrication of the bearing surfaces is assured, and the circulating oil provides a medium for transmitting heat away from the bearings.

Certain drilling contractors use roller-bearing kelly or drill-stem bushings which contain four units, each fitted with five rollers which bear against the faces of the square drill stem. These roller units assure free vertical movement of the drill stem through the driving bushing and thereby prevent the unnecessary wear on the table bearings which otherwise would be caused by the weight of the string of drilling tools being thrust against the rotary table. The claims made for this device are less wear on the drill stem, uniform control of the feed of the bit, and elimination of "hanging up" of the drill stem in the bushing and its subsequent release, which cause "digging in" of the bit and uneven rotation of the table.

**CROWN BLOCKS**

Crown blocks are of the 5- and 6-sheave, double-deck type from which 4- and 5-sheave traveling blocks are suspended. (See fig. 9.) Crown blocks usually have 4 sheaves 46 to 47½ inches in diameter and 2 smaller ones 27½ to 36 inches in diameter mounted on transverse axes one above the other and supported on steel I-beams. The assembly is compact and provides maximum clearance between lines and derrick water-table beams. A further advantage is that as the ascending traveling block approaches the crown block there is
minimum spreading of the lines, which effect tends to diminish wear on the line and sheave grooves.

The sheaves are cast manganese steel with 1\(\frac{1}{8}\)-inch A.P.I. grooves, and they revolve on roller bearings mounted on alloy-steel shafts which range in diameter from 5\(\frac{3}{8}\) to 8\(\frac{3}{4}\) inches. In one make of crown block the bearings are provided with hardened-steel inner races slipped onto the shaft and held in place by dowels. Lubricant
is supplied to each bearing by a hand-operated pressure gun through ducts that extend to the outside of the block assembly, so that there is little chance of the workman's hands being injured by moving parts when greasing the block. All sheaves are put in static balance so as to rotate smoothly at high speeds.

The make of crown block used most in the Oklahoma City field has the sheaves mounted in staggered relation to each other (see fig. 9, the axis of one sheave being elevated a short distance above that of the adjacent one. Each sheave pin is rigidly attached to and rotates with the sheave on two roller bearings carried on cast-steel supporting members placed transversely across the frame of the block between each pair of sheaves. Each of these cross members supports 2 bearings, 1 for the sheave on each side of the support. This arrangement of the sheaves provides greater bearing area per sheave without increasing the width of the block, and because the bearing area for each sheave is divided between separated bearings there is a broad supporting base for the load on the sheave. Furthermore, the wear is distributed over the entire lateral area of the pin, which gives longer service before replacement. The bearings of the revolving-pin type of sheave are smaller in diameter and cost less than bearings in blocks using the stationary-pin type of construction.

Crown-block frames are of steel I-beams or channels made in units which can easily be hoisted to the top of the derrick and assembled. Crown blocks weigh 5,000 to 7,565 pounds and cost $1,750 to $2,000 at prices prevailing in 1930.

The customary practice in stringing lines in the Oklahoma City field is to anchor the dead end of the hoisting line to a foundation member of the derrick and reeve the line through the blocks so that the stationary line comes closest to the finger board, where it may be grasped safely by the derrickman if necessary to regain his balance. The fast-moving lines are reeved over the large sheaves and the slower lines on the smaller sheaves so as to reduce the bending stresses in the cable to a minimum. (See fig. 10.) When lines are strung in this manner, the beclets of traveling blocks are not used, and the dead lines provide stationary points of attachment for weight indicators which are used at all drilling operations.

TRAVELING BLOCKS

Four-sheave traveling blocks are used most frequently in the Oklahoma City field. The frames of the blocks are forged- or rolled-steel plates—2 side plates and 4 intermediates—held together by alloy-steel pins and separated by spacers to form separate compartments for each sheave. Upper pins are as large as 3\(\text{\frac{1}{16}}\) inches in diameter, lower pins are as large as 6 inches in diameter, and center pins on which the sheaves revolve are as large as 8\(\text{\frac{3}{4}}\) inches in diameter. Center pins may be rotated and fixed in several new positions before they need be replaced. Traveling-block assemblies are enclosed in cast-steel side guards and finger guards to protect workmen's hands and fingers against injury. Furthermore, the guards give the block a smooth outside surface with no projections which might tend to cause "hanging up" on derrick girts or finger board. Guides integral with the guards also prevent the lines from
dropping off the sheaves when the block lies on the derrick floor. The lower clevis of the traveling block is of alloy steel and is hinged on the lower pin.

Traveling-block sheaves are as large as 46 inches in diameter and are cast of an alloy of manganese steel selected to give minimum wear on both the line and the sheave. Large-diameter sheaves facilitate rapid movement of the line. The rope grooves accommodate line 1\(\frac{1}{8}\) inches in diameter and are finished by grinding to the contour recommended by the American Petroleum Institute. The sheaves revolve on replaceable roller bearings which have hardened and ground races pressed into the sheaves. The bearings are lubricated with a pressure gun through alemite fittings; individual ducts extend from the outside to each bearing so that the lubricant may be applied without hazard to the workman.

In one design of traveling block the sheaves are mounted in staggered relation on two axes, one above the other. (See fig. 11.) This arrangement gives a more compact assembly yet provides
more space for bearings. Each pin is fixed in the sheave and rotates with it on two separated roller bearings. This type of construction offers greater resistance to those axial forces at the rim of the sheave that tend to cause unequal wear and consequent tilting of the sheave in single-bearing construction. Moreover, the wear is distributed over the entire lateral area of the pin and one

![Diagram of traveling block](image)

**Figure 11.**—Traveling block.

half the inner surface of the replaceable race; therefore, the bearings give longer service than if the pin was fixed and only its upper surface was subject to wear. The worn race can be replaced at less cost than a worn pin. Since the two axes of the sheaves are separated vertically, any deviation of the suspended block from its normal, upright position sets up a force couple that tends to return the block to the vertical position. This factor is of material ad-
vantage in drilling operations, for the block may be lowered at
c onsiderable speed without entangling the lines and impeding the
work. The sheaves are identical and interchangeable with those
of the crown block made by the same manufacturer; this reduces
the number of spare parts that need be stocked.

Traveling blocks weigh as much as 9,000 pounds, which with
free-running sheaves insures rapid descent of the block with little
chance for the line to become slack and kinked when running the
block down without load. A five-sheave traveling block cost
approximately $3,000 at Oklahoma City during 1930.

**ROTARY HOOK**

Nine-inch rotary hooks with the shank mounted on an enclosed
spring and with roller bearings under the nut to provide easy swivel-
ing are used in the Oklahoma City field. Some hooks have two
springs in tandem because it is believed that two springs will endure
longer than one and still give sufficient travel of the shank through
the crosshead so that the tool-joint pin will jump free of the box
when the joint is unscrewed. The shank and bearing of the rotary
hook are lubricated by a pressure grease gun. The hook is sus-
pended on a forged-steel bail from trunnions integral with the
crosshead and is designed so that the center of gravity is below the
points of suspension to prevent it from overturning. All hooks
are provided with locking pins that may be inserted to prevent
swiveling when not desired and safety latches that close automati-
cally to prevent disengagement of the hook from the bail of the
swivel or the elevators.

The hooks, complete with safety latches, weigh as much as 3,400
pounds, and at prices prevailing in 1930 cost approximately $1,170
each.

**SWIVELS**

The largest available rotary swivels, rated to support safely a work-
ing load of 150 tons rotating at a speed of 100 r.p.m., are used in the
Oklahoma City field. Many of the swivels are designed for 8-inch
drill pipe and equipped with an adapter to fit 6½-inch drill pipe.
The body of the swivel is an alloy-steel casting of large cross-section
which encloses the working parts and forms a reservoir for the oil
in which the working parts operate. In some types of swivels the
body has integral external ribs that increase the strength and the
radiating surface considerably. The trunnions for the bail are as
large as 6 inches in diameter and on most swivels are integral with
the body of the swivel. Bails, which are up to 4½ inches in
diameter in the body and 5 inches in diameter at the point of con-
 tact with the hook, are forged from steel billets.

The load on the swivel is carried on a large thrust bearing which
has tapered rollers traveling on hardened and ground alloy-steel
races. Upthrust is taken by a ball bearing, and two radial ball
bearings maintain the vertical alignment of the rotor. All the bear-
ing operate in a bath of lubricating oil. The oil capacity of the
bath in some swivels is 10½ gallons, and a visible gage indicates
the level of the oil. Besides acting as a lubricant, the oil serves to
transmit the heat generated in the bearings to the outside surface. Ample lubrication lengthens the operating life of swivels and almost eliminates damage such as was formerly caused to rotary hose and derrick members that supported the standpipe when the hose became wound on drill stems.

Rotary-swivel goosenecks are of cast steel with thick walls and fluid passages 3 inches in diameter. The hose end of the goosenecks extends at an angle of 20° from the vertical so that the hose will hang nearly vertical to reduce to a minimum all extraneous bending stresses that might be imposed upon the hose. The end is enlarged to accommodate the hose connection which is usually of the ground-joint union type. In one make of rotary swivel a replaceable threaded ferrule is welded into the gooseneck, and in others the threads on the union are cadmium-plated to prevent seizing and galling. Wash pipes are machined from alloy-steel forgings and are hardened, ground, and polished to reduce wear on the packing to a minimum and to effect a fluid seal with minimum pressure on the packing. Wash pipes usually are made with integral flanges for connection to the gooseneck and are designed for easy replacement, since they are subject to the erosive action of the mud fluid. Figure 6, B, shows the type of rotary swivel used in the Oklahoma City field.

Stuffing boxes are extra long and have as many as 12 packing rings to prevent leakage of mud fluid into the bearings and oil bath without requiring pressure on the packing gland sufficient to impede rotation. Screw-type glands and lock nuts are used on the stuffing boxes.

The weights of rotary swivels range from 2,700 to 4,600 pounds, and the cost of a 6-inch rotary swivel in 1930 was approximately $1,700.

**SLUSH PUMPS**

Slush pumps used in the Oklahoma City field are the direct steam-driven, duplex, reciprocating type of large size and capacity with steam cylinders designed for a steam pressure of 350 pounds per square inch. Mechanical lubricators are used on the steam end of many of the pumps, and the piston rods on the fluid end of all slush pumps are lubricated with streams of water played on them at the stuffing boxes. The steam valves are of the balanced piston type to reduce their weight and the effort required to operate them.

Usually the steam end of the pumps is cast integral with the cradle. For added stiffness one make of pump has the steam and pump ends tied together with four longitudinal tierods. For high volumetric pumping efficiency, provision for large valve area is incorporated in the design of the pumps. This increased volume is obtained by using large valves or by increasing the number of valves, at the same time keeping the valve lift small (in one make of pump the valve lift is three-sixteenths inch) to obtain maximum life from the valves and valve seats. The valves are of forged steel with circular, rubber inserts to seal the ports. Valve seats, which are replaceable, are steel forgings, hardened and ground. The valve guides are integral with the valve seats. One make of slush pump has a small crane mounted on the air chamber to accommodate a chain hoist for lifting the valve-chamber covers.
Pump liners are steel forgings with integral supporting shoulders or flanges. Because of the excessive wear of pump liners, considerable experimentation has been carried on in the Oklahoma City field to improve the wearing qualities of liners. A comparative test, for example, was made in a pump fitted with one ordinary liner and one chromium-plated liner; both liners failed by erosion, the ordinary liner after 5,000 feet and the chromium-plated liner after 5,300 feet of hole had been drilled. The results of this test indicate that the additional service rendered by the chromium-plated liners apparently does not justify their use because of the additional cost of such liners. Erosion of the liners occurs near the ends of the piston stroke and is caused by leakage past the piston of mud fluid carrying abrasives in suspension. Pistons, therefore, are fitted with molded rubber sleeves designed to utilize fluid pressure to effect a seal.

Most of the slush pumps are mounted on steel skids made of I-beams or pipe for rigid support and ease in moving. Slush pumps in common use in the Oklahoma City field are equipped with 14½-by 7½-by 18-inch cylinders, weigh 15,500 pounds, and cost about $2,500 at prices prevailing in 1930. Certain other pumps used in this field are 15 by 7¾ by 20 inches in size, and one pump—the largest slush pump ever built for oil-field use—is 16 by 8 by 24 inches in size and has 16 valves in the pump end. The steam cylinders of this 16-valve pump are cast integral with the frame, each pump cylinder is a separate casting bolted to the frame, and the intake and discharge manifolds are bolted to the pump cylinders to hold them together. The pump is mounted on heavy steel H-beam skids, and the whole assembly weighs 27,500 pounds. The liners of the pump are of forged steel, and the steel piston has two cupped, rubber packers backed by a follower plate.

Annular grooves in the end of the packer or sleeve exposed to the mud-fluid pressure cause it to expand and seal the piston. Liners and pistons are interchangeable between cylinders. The 16 forged-steel valves have inset rubberized-fabric sealing rings, and the replaceable forged-steel valve seats are pressed into place and have central valve guides. When operating at 40 cycles per minute, the pump delivers mud fluid at a pressure of 950 pounds per square inch if supplied with steam at a pressure of 330 pounds per square inch. At this speed the pump delivers 668 gallons of mud fluid per minute. On one occasion when the drilling bit became plugged, the pump pressure rose to 1,550 pounds per square inch. Field trials, however, indicate that some modifications in design probably are necessary to make this pump suitable for oil-field use.

Of the two slush pumps installed at each drilling rig, one is used as a stand-by. The discharge lines of the two pumps, however, are connected in parallel by a manifold which contains a valve that enables sending the discharge of either pump to the standpipe in the derrick. This valve is of the plunger type with rubber molded around a spool-shaped steel core to give a metal-to-metal seat and a rubber seal. Some of the manifold valves used are made so that when one pump is stopped and the other pump is started the manifold valve automatically closes the discharge of the idle pump and diverts the discharge of the active pump to the standpipe. This
valve is provided with a lock to hold it in any desired position. Some pump manifolds are arranged so that mud fluid may be supplied to either of two standpipes in the derrick by either pump; in other installations it is also possible to supply mud fluid for drilling with one pump and to operate the other pump simultaneously to prepare additional mud fluid without disconnecting any part of the piping system.

It is the general practice in the Oklahoma City field, when drilling with 6½-inch drill pipe, to use a 7½-inch pump liner and to operate the slush pump at about 56 strokes per minute under a mean maximum pressure of 650 pounds per square inch. When using 4-inch drill pipe a 7-inch liner is used, the pump speed is about 44 strokes per minute, and the mean maximum pressure is about 900 pounds per square inch. When 3-inch drill pipe and a 7-inch liner are used for drilling, the speed of the pump is about 28 strokes per minute, and the mean maximum pressure is about 1,150 pounds per square inch. It is customary to replace old liners in the slush pumps with new ones just before setting the 9%-inch casing so that the pumps will supply mud fluid at sufficient pressure to remove cavings or settlings from the bottom of the hole, in order that the casing may be lowered to the proper depth, and to prepare the walls of the hole so as to insure a good bond between the cement and the formation.

A piece of suction hose is sometimes installed on the pump inlet to reduce vibration in the suction line and to avoid putting extraneous stresses on the pump when raising or lowering the suction pipe in the pit. The suction hose is 10 inches in inside diameter and 8 feet long and has a wall thickness of 1 inch. Although somewhat expensive, the use of suction hose results in a saving in maintenance expense on the slush pump; however, care must be exercised in jetting the mud fluid with steam not to increase its temperature to the point where the strength of the rubber in the hose will be impaired.

**ROTARY HOSE**

Both fabric and all-steel rotary hoses are used in the Oklahoma City field. The usual sizes of hose are 2½ and 3 inches in inside diameter. The fabric hose has 12 plies of fabric throughout its length and 13 plies in the "cuffs" at the ends to reinforce them for coupling attachment. There are two layers of braided steel-wire reinforcement wound in opposite directions within the walls of the hose and one layer of armor on the outside. The armor consists either of round spring-steel wire, imbedded in rubber or covered with an impregnated-duck, "puttee"-wrapped covering or of several layers of steel strip wound spirally around the outside of the hose. Tension wires are woven into the outer plies at the ends of the hose and are locked into the ferrule of the hose clamp when the coupling is installed. One type of hose coupling has slip rings and slips encircling the hose, which are drawn against an anchor plate by bolts when installed on the hose. The tapered slips which grip the hose have offsets that also grip the armor reinforcement. All fabric rotary hose is subjected to a hydraulic-pressure test of 3,000 pounds per square inch at the factory.

Fabric hose, including couplings, are 45 to 50 feet long, weigh about 720 pounds, and cost about $385 during 1930. Many drilling
contractors have a duel installation of standpipes and hose in the derrick. The second hose is connected to a circulating head, ready to be screwed onto the drill pipe to establish immediate circulation when the kelly joint is disconnected. The second hose serves as a stand-by in case the other bursts and quick resumption of circulation is necessary.

Steel rotary hose is composed of several 5-foot sections of seamless steel tubing jointed together with ball-bearing universal joints of forged steel that permit the hose to be swung in any direction. The joints are fluidtight, and when the hose is under pressure it is slightly less flexible and somewhat heavier than fabric hose. The sections of the steel rotary hose are tied to a cable which extends from a derrick member to the rotary swivel, so that in the event of breakage the ends of the hose will not fall and injure men on the derrick floor. One make of steel rotary hose has loops welded on each pipe section, and adjacent sections are tied together loosely with safety cable.

In an effort to reduce pulsations in the fluid stream and the consequent stresses set up in the rotary hose, a standpipe with an air chamber built into it was given a trial in the Oklahoma City field. Unfortunately the volume of the air chamber was too small to be of appreciable value, and the test was discontinued. Vibration and surging stresses are largely responsible for fatigue failures of machine parts and should be eliminated or reduced to as low magnitude as possible to obtain maximum endurance of the machine. The proper place to dampen (reduce) pulsation in a rotary hose is at the pump where these pulsations originate. Although all slush pumps are equipped with air chambers, those on the larger pumps are so small compared to the displacement of the pump that only small reduction in the pulsations of the fluid stream can be expected. Some drillers are of the opinion that pulsations of the fluid stream are a material aid in the progress of the bit through the formation. Although this may be true at shallow depths it is improbable that the pulsations would be effective at depths of 5,000 or more feet, because of the resistance to flow offered by the drill pipe.

Some drilling contractors change from fabric to all-steel hose when the drill reaches a depth of 6,000 feet. Below that depth high mud-fluid pressure is required to drill the hole successfully.

**HYDRIL ROTARY OUTFIT**

Hydril rotary outfits were used in drilling several wells in the Oklahoma City field. This equipment differs from conventional rotary drilling machinery in that the engine is of the vertical, marine type, and transmits its power to the draw works and rotary table through gears and shafting instead of sprockets and chains. In addition to rotating the drill stem the rotary table lifts and lowers the drill stem by means of hydraulic jacks. This machinery was designed to insure that the drilled hole would be vertical and to enable drilling through "heaving" formations where drilling must be done at pressures considerably higher than the mud-fluid column alone provides.
The engine is a vertical marine-type steam engine with three 10- by 10-inch cylinders equipped with piston-type steam valves. It is rated at 300 hp. at a normal speed of 300 r.p.m. when operating on a steam pressure of 150 pounds. A three-view drawing of the engine is shown in figure 12.

The forged-steel crank shaft, mounted on seven bronze bearings, has journals and crank pins 4 5/8 inches in diameter. The crossheads are fitted with babbitt-lined, cast-iron shoes. The reversing gear is operated by a small steam cylinder mounted on the end of the engine and controlled by a valve actuated by a wire connected to a pedal at the driller's position. Depressing the pedal reverses the engine. The engine is built so that two cut-off points are available: 87 1/2 and 65 percent of the stroke.

Lubrication to the working parts is supplied from a reservoir in the crank case by a plunger pump driven by the engine and is distributed to the bearings through small copper tubes. The cylinders and valves are lubricated by oil fed into the steam by a hydrostatic
lubricator augmented by a force-feed lubricator mounted on the engine.

The controls are a conventional throttle handwheel on an extended stem, a pedal to the reversing gear, and a pedal to open the spring-loaded relief cocks. The engine rests on H-beam skids mounted on a steel-base frame which also supports the draw works. The over-all length of the engine is 101 inches, its width is 45 inches, and its height is 81 inches. Its weight, including the skids, is 11,200 pounds, and its list price in 1930 was $5,000 f.o.b. Los Angeles, Calif.

**DRAW WORKS**

The Hydril draw works consists of a hoisting drum assembly and a cathead shaft supported on two cast-steel pedestals mounted on a rigid cast-steel base frame. The frame is ruggedly constructed and is anchored to the foundation with six large bolts. No jack posts or headboards are required. The drum shaft is 7 inches in diameter and is mounted on self-aligning roller bearings. The cathead shaft, mounted on two plain bronze bearings, is above and clear of the hoisting drum and is driven from the drum shaft by chain and sprockets enclosed in a metal guard. A plain cathead is mounted on the end nearest the driller, and an automatic cathead is mounted on the opposite end of the shaft.

The drum is of built-up construction; the cast-steel spool is 24 inches in diameter by 30½ inches long, and the cast-steel drum flanges are separate, machined, cast-steel pieces 48 inches in diameter by seven eighths inch thick. The two brake rims are of heat-treated pressed steel and are fastened to the drum by 1-inch rivets in double shear. The braking surfaces are 9½ inches wide and ground-finished.

The drum floats on roller bearings on the shaft and is driven by a steel bull-gear and pinion with cut, herringbone teeth, having a gear ratio of 113 : 37. The bull-gear is keyed to the drum shaft, and the pinion floats on its shaft and is engaged with a jaw clutch. A planetary gear train on the other end of the drum provides a speed reduction ratio of 66 : 32. It is engaged with a post-brake friction clutch.

The engine drives the draw works through a flexible coupling, a short connecting shaft, and a three-speed, selective-type transmission mounted on the base of the draw works. The transmission gears are continually in mesh and are engaged by splined clutches. The pinion shaft is driven through bevel gears mounted within the transmission case. The main transmission shaft extends through the case, and a steam-operated clutch to drive the shaft connecting to the rotary table is mounted on the extension.

At an engine speed of 300 r.p.m. the hoisting drum can be operated at 77, 125, and 193 r.p.m. by engaging first, second, and third speed, respectively, of the transmission, and by utilizing the planetary gear drum speeds of 37, 58, and 100 r.p.m. are obtained. At the same engine speed the rotary table may be operated at 50, 81, and 121 r.p.m. The flexibility of the engine increases considerably the speed ranges of the draw works and rotary table.

The draw works is controlled by a system of levers and pedals placed at the driller’s position in one corner of the derrick floor.
Two long hand levers with ratchets control the band brake and planetary gear, a small lever selects the transmission speeds, a pedal controls the master clutch, an adjacent pedal locks it in the engaged position, a third pedal operates the direct-drive clutch, and a fourth pedal controls the automatic cathead.

The draw-works unit weighs 22,625 pounds, and in 1930 the cost, including lever bank, was $15,000 f.o.b. Los Angeles.

**ROTARY TABLE**

The frame of the rotary-table unit consists of a rectangular-base casting and an upper cylinder-head casting between which two hydraulic cylinders are interposed, and the entire assembly is held rigidly together by 16 tiebolts. The table is carried in a cast-steel housing mounted on the upper ends of two piston rods extending from the cylinders and provided with four guides that take care of side thrust. The table has a vertical travel of 42 inches, and the cylinders have a lifting capacity of 65 tons at a water pressure of 350 and of 150 tons at one of 800 pounds per square inch.

The cast-steel table revolves on fully enclosed ball bearings operating in an oil bath and is driven by an internal gear integral with the table and a spur pinion on a splined vertical shaft which is driven by a horizontal shaft extending from the transmission case through a set of miter gears mounted on the frame of the table. The drilling clutch on the horizontal shaft is operated by steam through a four-way valve at the control bank. All pinion and drive shafts are of alloy steel and are mounted on tapered roller bearings.

The table has an opening 20½ inches in diameter and is provided with split-type master bushings and slips for driving a square kelly. A rack-and-pinion-type lock secures the master bushings to the table and locks the kelly bushings and slips to the master bushings. Normally a pair of wedges is inserted between opposite faces of the kelly and the bushing, whereby the weight of the drilling string is supported by the table. By removing the wedges the weight of the drill pipe may be transferred to the hook.

Hydraulic pressure is supplied by a duplex steam pump which draws water from a 100-barrel supply tank and is controlled by throttling the pump. Hydraulic feed to the cylinders is controlled through a manifold made of 2½-inch extra-heavy pipe which interconnects the pump, hydraulic cylinders, and supply tank. Large valves in the manifold provide full admission or discharge of water when rapid up or down movement of the table is desired, and small-diameter bypasses around them provide the finer adjustments required during drilling. A 1,000-pound pressure gage indicates the unit pressure below the pistons, which is proportional to the total load carried by the table. The gage reading affords a means of indicating the weight applied on the bit. As the bit cuts into the formation, weight will automatically be transferred to the table; to compensate for this change, the driller adjusts the bypass valve to release water from the cylinders at such a rate that the table will recede at the same rate as the bit progresses and that the weight on the bit will be kept at the desired value.

The assembly is arranged so that a downward pressure may be exerted on the drill pipe if drilling must be carried on under pres-
sure, as where "heaving" formations are encountered. On such jobs, flush-joint drill pipe operated through a packer is required.

The rotary-table unit is installed on two 20-inch I-beams laid across the cellar and is anchored down to the cellar foundation. It is braced transversely to the derrick corner piers with four tierods provided with turnbuckles for adjustment and with spring cushions to give a slight flexibility.

The rotary-table unit weighs 14,200 pounds, excluding the hydraulic manifold and intershaft; and in 1930 the list price, including master bushings, kelly-drive bushings, and slips for 6-inch drill pipe, was $9,750 f.o.b. Los Angeles, Calif. The water pump, tank, and necessary pipe and fittings comprising the hydraulic system represent an additional investment of about $3,500.

Figure 13 is a typical installation of the Hydri1 and shows in plan and elevation the three units and the drillers' controls in their relative positions.

**PERFORMANCE**

Figure 14 shows a drilling-time curve for a well sunk with a Hydri outfit in the spring of 1931. A graphic log of the formations
penetrated is shown at the left of the curve. This well was completed to a total depth of 6,357 feet in 46 days' net drilling time. The angular deviation of the hole from the vertical was measured at each 500-foot interval of depth; a maximum deviation of 1½° was recorded at a depth of 500 feet; from a depth of 970 to 3,000 feet the deviation ranged from 1½° to 1°, and from a depth of 3,500 feet to the bottom the hole was vertical.

The second string of casing consisting of 176 joints of 9-inch, 40-pound pipe was run into the well in a total working time of 4 hours 15 minutes, or at the rate of about 41 joints per hour. On this job a casing crew of 5 men and a pipe crew of 6 men assisted the regular drilling crew of 6 men. (The drilling crew ordinarily consists of 5 men, but on wells drilling within the corporate limits of Oklahoma
City a crew of 6 men is used because a licensed fireman is required to attend the boilers while they are in service.)

In running casing the rotary table is not disturbed, although the kelly drive and master bushings are removed. An automatic-grip spider with its subbase is mounted on top of the table, and the casing is run through the table opening.

The positive control and flexibility available in drilling operations are the outstanding features of the Hydril outfit, and the ability to drill holes expeditiously and with minimum deviation of the hole from the vertical is attributed to these factors. The Hydril has three distinct advantages over the conventional chain-driven, rotary-drilling outfit: (1) There is more working space on the derrick floor, (2) the driller has an unobstructed view of the derrick floor and engine, and (3) the absence of chain drives from the draw works and rotary table makes the operation of these units much smoother and quieter. All these factors enhance the safety of the drilling crew’s working conditions. On the other hand, the more substantial foundation required for the rotary table increases the cost of the derrick foundation and the rigging-up time.

**BOILERS**

In the Oklahoma City field steam for drilling purposes is generated in gas-fired, locomotive-type boilers ranging from 100 to 125 hp. rated capacity. The usual practice is to use three 125- or four 100-hp. boilers in a battery. A few boilers in the field are less than 100 hp. rated capacity, and one battery of three 135-hp. boilers was delivered to the field but was not used. The boilers are marked with either A.P.I., A.S.M.E., or National Board inspection symbols which show shop-test pressure ratings ranging from 250 to 350 pounds per square inch. Most of the boilers deliver saturated steam, but a large number are equipped with superheaters and are operated at pressures of 230 to 280 pounds per square inch.

Water-tube boilers also were tried in the Oklahoma City field; one battery of two 3-drum-type boilers of 150 hp. capacity and 350 pounds per square inch pressure was used in drilling one well. Although the combustion space in these boilers is much larger than in the locomotive-type boiler, the water capacity is too small to meet successfully the widely fluctuating steam demand of drilling operations as carried on in this field. These boilers were of the stationary type not designed for oil-field service, but they were used merely because they were available when high-pressure locomotive boilers were difficult to obtain.

Most of the locomotive-type boilers used in this field have the steam dome mounted on the barrel of the boiler, although a few have the dome over the firebox. Harris states that the question of whether to locate the steam dome over the firebox or barrel is a point of contention in boiler construction.

The over-all length of boilers ranged from 21 feet 8 inches to 26 feet 7 inches; their weights ranged from 25,000 to 28,000 pounds for 100-hp., 250-pound-pressure boilers and from 32,600 to 40,500 pounds.

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pounds for 125-hp., 350-pound-pressure boilers. The cost of 100-hp., 250-pound-pressure boilers in 1930 ranged from $2,500 to $3,250, and the cost of 125-hp., 350-pound-pressure boilers ranged from $3,850 to $5,000 f.o.b. Oklahoma City.

SUPERHEATERS

Boilers equipped to supply superheated steam have met with much favor in the Oklahoma City field. Figure 15 is a cross-sectional view of this type of boiler and shows a superheater coil in detail. The superheater consists of 10 coils of 1 1/2-inch, seamless steel tubing that terminates in a header mounted in the smoke box. Each coil consists of two hairpin-type loops inserted into two 4 1/2-inch flues in the boiler. Two styles of coils are required for each boiler, one with short connecting risers and the other with long connecting risers. The header is of cast steel and has two compartments, one for saturated and the other for superheated steam. Saturated steam from the dome on the boiler enters at the top of the first compartment, flows through the coils (where it becomes superheated) into the second compartment, and thence goes to the steam mains. The coils connect through ball-and-socket joints to the bottom of the header, one end of each coil terminating in each compartment. The two joints of each coil are secured by a clamp on the coil and a T-headed bolt held in a slot milled in the header; the ball ends of the coil are forced against conical seats in the header by the pressure on the clamp. Figure 15, C, shows this connection in detail.

On the loop of the coil lying in the flue are other clamps or "chairs" that hold the two sides of the loop a fixed distance apart.
and clear of the flue wall in order to give the hot gases access to the entire outer surface of the coil. Figure 15, $B$, is a cross-section of a flue and shows one of the clamps that hold the two arms of the loop of the coil in position.

Some of the regular flues of the boiler are replaced by twenty $4\frac{1}{2}$-inch flues arranged in four horizontal rows. The rows are spaced so that one loop of a superheater coil enters a flue in the top row and the other enters the flue in the third row vertically below it. The adjacent coil projects into flues in the second and fourth rows. By this staggered arrangement the superheater coils are nested close together. The inlet and outlet to the header are fitted with 3-inch nipples that extend vertically upward through the top of the smoke box. The steam outlet terminates in a special $\mathbf{T}$ on which a safety valve and bleeder valve are mounted. The pop or safety valve is set to release at a pressure 3 or 4 pounds lower than the pop valves on the dome so that it will open first to insure a flow of steam through the superheater to prevent overheating and damaging the superheater coils. The bleeder valve is opened to the atmosphere to cause flow through the superheater coils while the boiler is being fired preparatory to being placed in service. The pipe which carries saturated steam from the dome to the inlet of the superheater is arched to eliminate expansion strains and is connected with flanged joints for easy removal when the boiler is prepared for moving.

The changes that are required in a boiler to accommodate this type of superheater must be made in the boiler shop, but the superheater units can be installed in the field in boilers made to accommodate them. The superheater and the additional pipe and fittings required add about 800 pounds of weight and about $1,300 to the cost of a 125-hp. boiler.

No performance tests have been made on superheated-steam boilers in the Oklahoma City field. However, one battery of boilers was equipped with thermometer wells, and a maximum temperature of 574° F. was recorded at a steam pressure of 250 pounds per square inch; this temperature represents 168° of superheat.

All of the advantages to be gained by using superheated steam have not been realized because of the difficulty encountered in removing scale and sediment from boilers equipped with superheaters. The large flues necessary to accommodate the superheater coils have thicker walls than the flues they replace, and since it is necessary to provide at least a 1-inch "bridge" in the flue sheet (for safety the flues must be at least 1 inch apart) the flues are no longer in vertical rows. The circulation of water within the boiler therefore is somewhat retarded, and the difficulty of washing sediment out of the boiler is increased. One contractor partly overcomes this difficulty by drilling holes through the front flue sheet and dislodging scale in the boiler with a scraper on the end of a joint of $\frac{3}{8}$-inch pipe. When cleaning operations are completed these holes are fitted with bull plugs. If the boiler-feed water used in the field was treated to reduce the content of incrusting solids to 12 grains

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1 Smith, V. Weaver. Use of Superheated Steam in Drilling: Oil and Gas Jour., Dec. 18, 1930, p. 83. This article gives the results of a comparative test of saturated steam and superheated steam supplied to drilling operations. The test was conducted in the Gulf coast area and is the first on which data have been published.
or less per gallon before it was delivered into the boiler, all or nearly all boiler trouble caused by sedimentation would be eliminated.

SUPERHEATED STEAM

The principal advantages of using superheated steam in reciprocating engines are as follows:

1. Considerable heat may be abstracted from the steam without condensation, thereby increasing the efficiency of the engines or pumps.

2. A moderate amount of superheat greatly increases the volume of the steam; hence the quantity of water required for a given amount of work, such as drilling a well, is reduced considerably; furthermore, the carrying capacity of the steam lines is increased correspondingly.

3. The thermal conductivity of superheated steam is less than that of saturated steam, therefore less heat is absorbed and lost in the cylinder walls per unit of time.

The use of superheated steam in drilling wells results in a saving in fuel and water. When no condensation occurs in the steam lines there is less pressure drop in the lines and the steam enters the cylinders of the engine and pump in a dry state, thereby increasing the power output of the engine and pump. Not only is the loss of energy contained in the condensate averted when the steam is totally dry, but also the full capacity of the lines is available for transmitting steam. The effect most noticeable to the driller in changing from a well being drilled with saturated steam to one being drilled with superheated steam is the markedly better performance of the slush pumps, even when the boiler pressure is lower.

The use of superheated steam increases the power output and flexibility of the drilling equipment and as a result increases the steam capacity of the boilers so that fewer boilers are required or the same number of boilers need not be fired so heavily to carry the load. Superheated-steam boilers can be operated at a lower steam pressure to do the same amount of work as saturated steam at a given pressure.

The elimination of condensate also improves materially the distribution of lubricant to the steam cylinder walls. It should be remembered, however, that when superheated steam is used the cylinder oil to give satisfactory lubrication must have a higher flash point than the oil used with saturated steam. The temperature of dry, saturated steam at a pressure of 350 pounds per square inch gage is approximately 436° F., whereas that of superheated steam at 280 pounds per square inch gage and 150° of superheat is approximately 566° F. Because the steam delivered from the dome of the boiler is never totally dry and heat losses take place in the lines, condensation occurs, with the result that the temperature of the steam which reaches the engine and pump is lower than that at the boiler.

THERMIC-SIPHON BOILERS

Many boilers used in the Oklahoma City field are equipped with thermic siphons—an auxiliary water passage extending through the firebox from the flue sheet, just below the flues, to the crown sheet.
Thermic siphons have been used in locomotive boilers in railroad service for a number of years, but their adaptation to oil-field use is recent. Figure 16 shows a boiler equipped with a thermic siphon; A is a side view of the thermic siphon alone, and B is a plan of a firebox with the thermic siphon welded into the crown sheet. The lower end of the siphon is circular in cross-section and about 5 inches in diameter. It is welded into the flue sheet and projects into the firebox at an angle of about 30° to the horizontal. About a foot from the flue sheet the siphon assumes a narrow, rectangular shape and extends upward to the crown sheet. The flanged open end is welded into the crown sheet. The upper opening is about 3 inches wide and about 63 inches long, or approximately three fourths the fore and aft length of the firebox. The walls of the siphon are braced with stay
bolts and make a stiff girder that materially aids in supporting the crown sheet.

The primary purpose of the siphon is to increase the rate of circulation of water in the boiler in order to reduce the temperature gradient within the boiler. Sediment in the water is maintained in suspension longer, and formation of scale on the flues is correspondingly retarded. The siphon increases the heating surface of the boiler, makes the boiler more responsive to sudden demand for steam, and improves the quality of the steam—that is, reduces its moisture content. Harris and Eckel⁸ report that the results of field tests conducted in the Gulf coast area show that the thermic siphon increased the quality (dryness) of the steam from 97.1 to 99.1 percent and the boiler efficiency from 51.5 to 56.2 percent. Although no measurements have been made, it is reasonable to assume that similar beneficial results were realized in the Oklahoma City field.

The augmented circulation of water in a siphon-equipped boiler promotes a uniform temperature gradient throughout the vessel and thereby reduces the expansion stresses set up in the boiler seams while the boiler is being brought up to working pressure. The siphon, in addition to bracing the crown sheet against collapse, keeps it covered when the water within the boiler is comparatively low. It is therefore a safety feature of twofold value. Some trouble has been experienced with siphons becoming obstructed with scale and burning. The passage through the siphon is not readily accessible for cleaning, and the stay bolts prevent the use of a “rattler”, the cleaning tool commonly used for this purpose at railroad roundhouses; therefore, the scale must be washed out with a stream of water. Experience has shown that the boiler scale softens if exposed to air for a few hours, so that when the boiler can be out of service long enough to air slack the scale a better cleaning job can be done and overheating of the siphon can be avoided.

The siphon installed in a 125-hp., 350-pound-pressure boiler increases the cost of the boiler approximately $550, but this increase is negligible when the improvement in the boiler’s performance is taken into account.

BOILER ACCESSORIES

Each boiler in the field is equipped with two adjustable safety valves of the pop type installed on the steam dome. A few boiler installations have an automatic-stop check valve, in addition to a shut-off valve, in the steam line from the dome to the steam header. This check valve prevents the flow of steam from the other boilers of the battery into the defective one, in the event of a sudden drop in steam pressure due to failure of a flue or any other cause. This automatic-stop check valve is a 4-inch angle type with cast-steel body and costs $180. The added safety feature more than justifies the initial cost of the valve.

The boiler smokestacks generally used are about 30 feet high and weigh approximately 1,000 pounds each. It is common practice in the Oklahoma City field to use steam-jet blowers in the stacks to increase the draft; no dampers are used in the stacks. On locations

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where available space around the boilers is so limited that guy wires would interfere with buildings, roadways, etc., or where the wires would cross property lines, the smokestacks are usually supported by rigid braces made of pipe. The several stacks of a battery of boilers are tied together with horizontal braces, and sloping braces are run from the end stacks to the boiler. On a few batteries the use of ring steam-jet blowers has made it possible to reduce the height of the stacks to 8 to 10 feet. Figure 19, A, shows a battery of superheated steam boilers with short stacks equipped with ring steam-jet blowers.

FIRE CONTROL

Automatic devices are used to regulate the fires, blowers, and boiler-feed pumps. The fire-control mechanism contains a diaphragm which actuates the feed valve on the gas line through a system of levers. The diaphragm is balanced against the boiler pressure so that a decrease in the pressure causes movement of the diaphragm and admits more gas to the burners. When the boiler pressure is again restored the diaphragm in returning to its original position cuts down the flow of gas, which reduces the intensity of the fire to a predetermined minimum. Where the pressure of the gas supply is subject to fluctuation, a double fire-control mechanism is used. In the second unit the gas diaphragm is balanced against the nominal gas-line pressure, and its communicating levers are interconnected with those of the steam-operated diaphragm. The levers are arranged so that the fires are controlled by the gas-operated diaphragm until the boiler pressure approaches the desired working pressure, whereupon the control is transferred to the steam-operated diaphragm.

BLOWER CONTROL

An automatic control mechanism similar to that used to control the flow of gas to the burner is used to operate the draft in the smokestacks and may be separate from or assembled with the fire control. It is arranged so that a steam-operated diaphragm actuates a valve that admits steam to the steam-jet blowers in the stacks with the opening of the valve that admits gas to the burners; when the fire-control mechanism increases the flow of gas to the burners the blower control increases the draft on the fires. On the other hand, when the fires are reduced the blowers are automatically shut off.

These fire and blower controls are positive in their action and respond rapidly to changes of boiler pressure. When properly adjusted they will hold the steam pressure within 4 pounds of the desired point. Obviously such close control of pressure has met with the unqualified approval of the drilling crew. The controls are installed at the boiler-feed water pumps and require about as much floor space as the ordinary boiler-feed pump. The combined double fire and blower controls cost approximately $280.

WATER-LEVEL REGULATOR

Mechanical devices that automatically maintain the water in boilers at a safe level have been used on stationary boilers in central
power stations for a number of years. Although only a few regulators of the thermostatic type were introduced into the Oklahoma City field, those that were used met with approval because of the added safety feature they provided. Several boiler explosions have occurred in this field which have been attributed either to lack of water in the boilers and subsequent introduction of water into the overheated boiler or to scale-encrusted crown sheets.

One water-level regulator which was used in the Oklahoma City field consists of a thermostatically controlled valve on the feed-water line to the boiler that admits water to the boiler when the water level recedes to a predetermined point and stops the flow when the water level is restored to the desired height. Figure 17 shows a top view of the regulator and a sketch of the connections to the boiler shell. The thermostat is a ½-inch, extra-heavy, brass tube mounted within a perforated 2½-inch-diameter tubular steel housing 6 feet long, installed at the side of the boiler with one end 4 inches lower than the other. The low end is connected to the boiler 2 inches below the low-water level; the high end is connected to the steam space at the top of the boiler near the firebox end, consequently the water in the tube and boiler is at the same level. When the water level in the boiler recedes more of the brass tube is exposed to steam, which is at a higher temperature than the water, and the resulting expansion of the tube is utilized to open a valve which admits more water to the boiler. As the water level rises, the thermostat tube is cooled and in contracting closes the water valve to the boiler. The boiler-feed water pumps are equipped with a diaphragm control device which operates the pump throttle. Boiler pressure is on one side of the diaphragm and pump pressure on the other. Figure 18 shows the pump-control device used in conjunction with the water-level regulator. Normally the pump-control device is adjusted to maintain automatically the feed-water pressure 25 pounds in excess of the boiler pressure. Then the thermostat of the water-level regulator need develop enough force only to open the water valve against a pressure differential of 25 pounds.

BOILER-HOUSE UNITS

Drilling contractors have developed methods of grouping the several boiler-house accessories for each battery of boilers into one assembly mounted on a pair of skids for ease of transportation and arranged so that a minimum number of pipe joints need be disturbed in dismantling the equipment for moving. Figure 19, B, shows one of these units disconnected and ready to be loaded on a truck. The assembly (from left to right) consists of 2 turbogenerators, 2 duplex boiler-feed pumps with the valves controlling the feed to 4 boilers mounted between them, a double fire and blower control, and a metal tool box. A fabricated-steel tool house, used by many contractors, is at the extreme right. Figure 19, C, shows a similar boiler-house unit which is unique in that the skids made of drill pipe also serve as pipe manifolds; one is a water manifold and the other a steam manifold. This construction materially reduces the number of connections required.

Water gages of the prismatic-glass type are preferred on 350-pound-pressure boilers because they have greater strength and safety
than tubular-glass gages. Double-spring pressure gages are used on these high-pressure boilers.

Feed water is supplied to the boilers by two 10- by 4½- by 10-inch duplex steam pumps; one serves as a stand-by for boiler washing and emergency use, while the other is in service. Both open and closed feed-water heaters are used, but the closed type is in more general use because it is cheaper and can be made easily in the field shops. Some of the open heaters are quite elaborate in design and have incorporated in them an atmospheric condenser, a filter, and a hot well. In one make of open feed-water heater, provision also is

![Diagram of Boiler-feed pump control.]

made for adding boiler-compound solution to the feed water at a uniform rate by means of a small duplex steam pump which draws the supply from an auxiliary tank and discharges it into the hot well. Although the open type of feed-water heater is more efficient than the closed type, open heaters are not in general use in the Oklahoma City field because of their high initial cost of $1,200 to $2,600. The tests reported by Reistle indicate that with an open-type heater an apparent saving of 9.7 percent in fuel was realized and the total hardness of the feed water was reduced 41.7 percent.

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During the winter months, insulating covers 1 to 2 inches thick, composed of silica, asbestos fiber, and clay, over a reinforcement of chicken wire secured to the boiler by lacing wires and finished with a coating of waterproof cement, sometimes are used on the boilers. This insulation is easily applied and repaired by unskilled labor and can be reclaimed and reapplied when necessary. The average cost of insulating an oil-field boiler by this means is about $225.\textsuperscript{10}

The insulating covers are removed to repair leaking joints on the boilers and often are not replaced when repairs are completed. The boilers usually are exposed to the weather, although sheds are provided for the feed-water pumps and lighting generators. On some exposed locations, windbreaks are erected on the windward side of the boilers. Cold air sometimes is permitted to enter the furnace below the water legs, and its deleterious effect is augmented by the forced draft induced by the blowers. These factors, in conjunction with the scale-forming nature of the water, cause many leaks in boilers. Consequently, the maximum efficiency available from the boilers is not realized.

During the spring of 1932 locomotive-type insulating jackets, made of asbestos or mineral-wool slabs 2 inches thick enclosed in sheet steel, were given a trial. These were well designed and were applied easily to the boiler, but they were too costly to find ready acceptance.

Electric current for lighting derricks usually is supplied by 3-kw., 125-v., direct-current generators, direct-connected to impulse-type steam turbines operated at 3,600 r.p.m. The turbines have three steam-admission valves so that they may be operated on steam pressures ranging from 150 to 350 pounds per square inch; only one valve is opened to develop full load on a steam pressure of 350 pounds. Numerous drilling outfits are equipped with two generator sets.

Many drilling contractors provide themselves with hauling racks into which the various assemblies of pipe required at the boiler plant, such as the steam headers, steam laterals, and feed-water lines, are loaded when moving the drilling outfit. Figure 20 shows one of these racks, $A$, when empty and, $B$, when loaded. The rack is made of discarded pipe welded at the joints and is about 5 feet wide and 24 feet long.

**WATER SUPPLY**

Water for steam generation and drilling in the Oklahoma City field is obtained from the North Canadian River, which crosses the field, and from wells sunk in or near the river bed. During periods of low water the flow of the river is insufficient to supply the demand, and a considerable part of the water required is obtained from wells. Water occurs in two sands of which one is at a depth of 50 feet and the second, or so-called "750-foot sand", is at depths ranging from 700 to 800 feet below the surface. The lower sand has been used as a source of water by the railroads for some time. The hardness of the river water varies, seasonally, from 6 to 27 grains per U.S. gallon;

Figure 19.—A, Superheater boilers equipped with short stacks and jet blowers. B, Boiler-house units on I-beam skids. C, Boiler-house units on pipe skids.
Figure 20.—A, Pipe-hauling rack, empty. B, Loaded. C, Well equipped with needle-valve flow device.
the water from the 50-foot sand has a hardness of about 23 grains, and the water from the 750-foot sand has a hardness of only 2 grains per gallon.

One of the larger companies operating in the Oklahoma City field has a pumping and softening plant at the river with a daily capacity of 200,000 barrels of water. Thirteen electric-driven centrifugal pumps lift the water from pits in the river to the treating plant. During periods of high demand additional water is supplied from 5 shallow wells and 4 wells in the 750-foot sand, all of which are pumped by air lift. The productive capacity of the 9 wells is about 100,000 barrels of water per day.

The water from the river and from the shallow wells is treated with soda ash, hydrated lime, and alum to reduce hardness. Under maximum conditions of treatment, 12 tons of lime, 6 to 7 tons of soda ash, and 1 ton of alum were used daily. Under normal conditions the hardness of the water is reduced to 4 grains per gallon. During the peak of the drilling campaign, however, the water demand was so great that there was insufficient time for the flocculated solids to settle out, even when sodium aluminate was used to accelerate flocculation; consequently the hardness of the water was only slightly less than it was originally. The water from the treating plant is delivered into the distribution system by 11 electrically driven centrifugal pumps at pressures ranging from 300 to 350 pounds per square inch. The distribution system consists of 8-, 6-, and 4-inch pipe lines, with booster stations at strategic points to restore the pressure lost in friction. The operating cost of the plant was approximately $300 per day.

The demand for water at a well drilled with steam-driven rotary equipment ranges from 1,800 to 3,000 barrels per day. At the start of drilling operations approximately 3,000 barrels of water are required to fill the slush pits; subsequently, during drilling, the average daily requirement is approximately 2,000 barrels for boiler feed water and 400 barrels for the slush pits. These quantities represent the water consumed on drilling leases in the Oklahoma City field during 1929 and 1930.

Some operators drilled water wells on their leases and pumped them with steam heads or gasoline-engine-driven pumps. No water-softening treatment was given the water other than the addition of boiler compound to the boiler feed. At some wells drilled within the corporate limits of Oklahoma City water was obtained from the city mains. The average cost for water required to drill a well in the Oklahoma City field was about $600.

The demand for steam usually was so great during drilling that the boilers rarely were "blown down" more than twice in each 12-hour "tour"; consequently scale was deposited rapidly in the boilers, and much trouble was experienced from leaky flues. Usually the rapid deposition of scale in the boilers made it necessary to replace the flues after drilling two wells, and some contractors even made it a practice to replace the flues after drilling only one well. A device for agitating the sediment in the water legs to promote its elimination when "blowing down" was installed in some boilers.

The device was made of 1-inch flexible hose with small holes drilled through the walls at intervals of about 6 inches. One branch was laid in the bottom of the barrel and another at the bottom of the water legs and encircling the fire box; the two branches were joined to a 1-inch outlet that terminated at the boiler blow-off cock. When the boiler was "blown down" the inrush of water through the perforations of the hose was expected to dislodge sediment that had settled in the vicinity of the hose and to carry it out of the boiler. Experience indicated, however, that the hose and its outlet became obstructed rapidly with scale deposits which made it inoperative, so its use was discontinued.

**DRILLING PRACTICE**

Drilling practice in the Oklahoma City field in general is similar to the practice in other fields where rotary equipment is used, although in some instances the practice is altered to meet local conditions.

The diameter of the hole varies with depth, as follows: As it is desirable to carry an opening as large as possible to the producing horizon, the starting hole is 20 to 22 inches in diameter and usually is drilled at this size to a depth of approximately 350 feet to accommodate 15½-inch surface casing; 12½ inches in diameter to a depth of about 5,200 to 5,400 feet where the 9- or 9¾-inch casing is set; 8½ inches in diameter to a depth of about 6,250 to 6,400 feet to accommodate the 7-inch casing; and 6¾ inches in diameter ("open hole") to bottom.

**DRILL PIPE**

The general practice in the Oklahoma City field is to use 6¾-inch O.D. 25.2-pound drill pipe in drilling to the 5,200- to 5,400-foot depth. From this point to about 6,400 feet, 4½-inch, O.D. 16.6-pound drill pipe is used. The well is drilled into the pay horizon, using 3½-inch O.D. 13.3-pound drill pipe.

The drill pipe is handled in stands of three joints each. In accordance with midcontinent practice, the raised platform for stacking the drill pipe when out of the hole is placed between the draw works and rotary table and is supported by the derrick floor. Although this position is convenient for handling the pipe, the available space is limited because of the position of the rotary drive chain and the working space required for the jerk line. The weight of the stacked pipe is concentrated on the derrick floor at a point close to the draw works, and the resultant sagging of the floor tends to interfere with the functioning of the draw-works brakes.

At the outset it is customary to rig up with six lines strung between the traveling blocks and the crown sheaves, which provide sufficient mechanical advantage for hoisting to a depth of 5,000 feet. Eight lines are used with the 9-inch casing.

The drill pipe is of alloy or heat-treated steel in joints 27 to 30 feet long. Standard A.P.I. tool joints are used on the ends of each joint, and when made up in "trebles" the "stands" have an average
length of 90 feet. The average weight of the drill pipe per foot of length, including the tool joints, is:

<table>
<thead>
<tr>
<th>Inches</th>
<th>Pounds per foot</th>
</tr>
</thead>
<tbody>
<tr>
<td>6%</td>
<td>30.1</td>
</tr>
<tr>
<td>4½</td>
<td>18.7</td>
</tr>
<tr>
<td>3½</td>
<td>15.1</td>
</tr>
</tbody>
</table>

The tensile strength of drill pipe listed by two manufacturers whose products have been used generally in this field is given in Table 2.

**Table 2.—Tensile strength of drill pipe**

<table>
<thead>
<tr>
<th>Size (O.D.), inches</th>
<th>Load to part string, pounds</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Manufacturer A</td>
</tr>
<tr>
<td></td>
<td>Grade C</td>
</tr>
<tr>
<td>3½</td>
<td>296,856</td>
</tr>
<tr>
<td>4½</td>
<td>361,385</td>
</tr>
<tr>
<td>6%</td>
<td>535,066</td>
</tr>
</tbody>
</table>

The quantities given in this table are the ultimate strength of the several sizes of pipes and are the limits below which the tension (as determined by the weight indicator) must be held to avoid parting the string on fishing jobs where the maximum strength of the string may be required.

In normal drilling where holes do not deviate more than 3° or 4° from the vertical, a string of 6½-inch drill pipe serves to drill 5 wells in the Oklahoma City field; a few strings of drill pipe have been used for as many as 7 wells.

In the early part of the drilling campaign some trouble was caused by the failure of drill pipe due to erosion of the threaded joints, both where the tool-joint half is screwed on the pipe and where the halves of the tool joint are screwed together. Failures in the joint of the pipe and tool-joint half were largely reduced by assembling the tool joints on the pipe at the mills, using a torque-limit clutch on the jaws of the vise so that the grip on the pipe is released when the applied torque reaches a certain magnitude. This method of making up drill pipe assures a fluidtight joint without overstressing the threads, and these threaded joints are not disturbed until the tool joints have to be replaced. The tool joints are subjected to severe service, for they are unscrewed frequently and made up again; although lubricating compound is applied each time the joint is made up, the joints eventually become worn and consequently are likely to leak. The tool-joint thread is tapered, and the shoulder surfaces of the tool joints alone effect the seal. When the shoulder is worn or damaged, mud fluid leaks through the joint, and eventually the threads become eroded.

Spiral "twist-offs" were experienced soon after the drilling campaign got under way. This difficulty was reduced by modification in the manufacture; the pipe was rotated in one direction through the rolls in sizing the inside diameter and in the opposite direction in sizing the outside diameter of the pipe.
Late in 1931 a number of failures of 6%\text{-}inch drill pipe occurred. The fractures originated at the root of the first engaged thread of the upset end of the pipe. The cause of these failures has not yet been determined. Remedial measures, consisting of arc welding the drill pipe to the tool joint, using a soft welding rod to fill the V, then building up the end of the tool joint 1 or 1\% inches with a harder material, have materially reduced this type of drill-pipe breakage.

Some of the drill-pipe failures which have occurred in the walls of the pipe can be attributed to flaws in the steel that were so minute as to escape notice when the pipe was on the rack. Under the combined stresses in the pipe while drilling, these flaws became enlarged until there was insufficient metal to sustain the internal fluid pressure, and the resultant leakage of mud fluid caused rapid erosion of the metal.

**FLAW DETECTOR**

A device is being developed to detect the flaws in drill pipe by means of an electric current—an application of the same principle embodied in a method used in recent years to detect faulty rails in railroad track. An experimental model of this device was tried on drill pipe in the Oklahoma City field, and several defective pieces were detected by its use. If this promising instrument proves successful, the delays caused by failure of faulty drill pipe will be eliminated, and the cost to contractors of drilling wells will be correspondingly reduced.

This device would be useful to manufacturers for culling out defective material at the mills and would repay its cost in eliminating the expense of subsequent work on faulty pipe as well as the cost of transporting it to the field. Few drilling contractors have enough drilling outfits to justify the purchase of the device for periodically testing their drill pipe.

**DRILLING BITS**

Many types of drilling bits were tried in the early development of the field, and as greater knowledge of the nature of the formations penetrated was gained drillers found that fishtail and drag bits were not so efficient as rock bits in "making hole." Consequently, the general practice adopted in the field was to drill with rock bits, although drag bits sometimes were used in drilling through shale and the sticky formations lying just below the "Checkerboard" limestone.

Disk bits with replaceable, disk-shaped cutters, are used in drilling from the surface down to 2,500 feet and are preferred over other types of bits for loose formations because more rapid progress is made with them.

The cutters have a cutting edge around their entire periphery and revolve on their axes as the bit is rotated in the hole, therefore they have a combined shearing and scraping action. When the cutters are worn they can be removed from the shank and rebuilt several times by adding metal, by autogenous welding, and by facing the cutting edge with tungsten carbide. The cutting edges of the disks are then restored by grinding. It has been found impractical to rebuild the cutters more than three times because of fatigue in the
steel, and the normalizing process necessary to restore the steel to its
original state cannot be carried out satisfactorily in field shops.

In drilling through the hard formations encountered below 2,500
feet a rock bit or cone bit is commonly used. The drilling elements
are two cones having milled teeth on their conical surface. The
cones are mounted on pins. In revolving, the teeth of the cones cut
into the bottom of the hole and advance the bit through the forma-
tion, while two fluted reamers free to revolve on vertical axes ream
the walls and maintain the hole at a uniform diameter. The cones
and reamers are replaceable, and the teeth of the cones can be re-
built and sharpened when worn. Machine-shop facilities, however,
are required to rebuild and sharpen worn cones, and such work is
not attempted in the field shops, although formerly, when the cost
of new cutters was high, some of the machine shops in Oklahoma
City and elsewhere reconditioned large quantities of worn cones. A
subsequent reduction in the price of new cones made this work less
profitable, and the reconditioning of worn cones was greatly reduced.

About 7 gallons of viscous transmission oil ("crater compound")
are contained in a 3-inch pipe, 20 feet long, that extends up into the
drill collar. The upper end of the lubricator pipe is plugged. A
floating plunger inside the lubricator is equipped with two pliable
cups that fit against the inner walls of the pipe, similar to the plunger
in a pump. The lubricator is filled with oil from the bottom before it
is assembled on the shank of the bit. Mud fluid enters at the top
of the lubricator pipe through two small holes in the wall just below
the plug, and the fluid pressure imposed on the plunger forces the
oil through ducts provided in the body of the bit to the bearings
on which the cones revolve. An adjustable valve at the base regu-
lates the rate of flow of oil out of the lubricator. Positive lubrication
promotes rotation of the cones and, because wear is evenly distri-
buted over the cutting teeth, prolongs the serviceable life of the
cutters.

Cone bits are made in halves, parted by a plane through the longi-
tudinal center line; and the two parts are held together by two bolts
through the body of the bit, by the cage of the lubricator, and by
the drill collar which are screwed on the shank of the bit. One cone
is mounted on each half of the bit body, and the reamer shafts are
held in recesses sunk in each half of the body at the parting line.
The cone is mounted on a bushing and held by a ring nut which is
locked in place by a set screw. The bushing screws onto a threaded
stud fixed in the bit half. The oil duct extends through the center
of this threaded stud and registers with an oil hole through the
bushing. A hardened steel plate interposed between the cone and
body of the bit prevents wear on the head of the bit by the rotating
cone and mud fluid. The cone bushing and ring nut are assembled
as a unit at the factory, and to install the cone on the stud the cone
and bushing are locked together and screwed on the stud. The cone
is locked by screwing a pin into a hole in the side of cone; the pro-
longed end of the pin enters a hole in the side of the bushing and
holds the two together.

To install the cones the customary practice is to screw the bushing
on the stud as far as possible by hand and then set it up tight by
striking the locking pin with a sledge. The sledge method also is used to loosen the bushing from the stud when removing worn cones. Obviously this practice is somewhat hazardous because the hammer is deflected easily from the round body of the pin and is likely to strike the cutting teeth of the cone. The teeth are extremely hard and easily broken, therefore they will not withstand a heavy blow from a sledge. The pieces that break off become missiles that may strike nearby workmen and inflict serious injuries. Accordingly, a tool has been developed for removing the cones safely. The tool consists of a cup-shaped casting with projections extending inwardly that mesh with the cutting teeth and grip the cone for either direction of rotation. The tool has annealed lugs on the outer surface on which a hammer may be used without damaging the cones and with little danger of injuring workmen.

"Break-out" blocks for assembling or removing the bit from the drill collar are of various designs. One type of block is a cup-shaped casting that is set in the opening of the rotary table to hold the bit while the drill collar is loosened with tongs. This block bears against the body of the bit, prevents damaging of the cones, and prevents anything from being dropped into the well. A bit vise, consisting of two cradles hinged together and mounted on skids, sometimes is used for servicing rock bits. With the vise open the bit is placed horizontally in the base cradle, and the vise is then closed and locked. With the bit in this convenient position the lubricator and the water cage can be removed from the shank of the bit. The throughbolts are then removed, and by inserting a vise pin through holes in the upper cradle and a hole through the body of the bit the vise may be unlocked and opened. This operation swings the halves of the bit apart, like opening a book, leaving the parting surfaces uppermost, and offers ready access for the replacement of cones, reamers, and wash pipe. The vise is made to fit 12 1/4-inch bits, and special bushings are provided to adapt it to smaller bits of the same type.

Another type of rock bit used in the Oklahoma City field has 5 toothed roller cutters on a transverse horizontal axis and 2 toothed cutters on inclined axes which revolve and cut away the formation as the bit is rotated in the hole. The cutters revolve on roller bearings but are not lubricated. The bit is mounted on a double 3-point reamer which maintains the gage of the hole and tends to prevent deviation of the bit from the vertical. Although this bit usually does not "make hole" as rapidly as the cone-type bit, the cutters can be replaced at less cost and are less likely to become jammed and stop revolving on their axes. Consequently, some contractors consider the roller-type bit as economical for drilling in this field as the cone-type bit. However, all contractors drilling in the Oklahoma City field provided themselves with both types of rock bits.

The roller-type bit has been useful in cutting up pieces of metal lost in the hole. To improve it for this service, a trial was made of a bit with a piece of pipe welded on it to serve as a basket to catch small pieces of metal milled off the "fish" by the cutters. The basket was a piece of 10-inch casing 14 inches long, slipped over the shank of the bit. Its lower end was tack-welded to the head of the bit and the upper end left open, the annular space between the pipe
and shank forming the basket. This method was effective in removing relatively thin and flat metal objects, and the basket did not interfere with the use of the bit for drilling.

WEIGHT INDICATORS

The weight on the drilling bit is an important factor in the progress of the bit into the formation. Experience has shown that excessive weight on the bit will cause it to deviate from a straight line and will result in less service from the cutters. All drilling outfits in the Oklahoma City field are equipped with weight indicators by means of which the tension in the drilling line is translated to a pressure gage visible to the driller. The readings on the gage are proportional to the load on the line; the pressure in pounds per square inch on the gage can be converted to pounds of load on the bit by reference to load tables or curves supplied with each instrument. The complete tables contain the weight equivalent of scale divisions or points on the gage from 5 to 100 for both 1-inch and 1½-inch-diameter drilling lines and for 1, 2, 4, 6, 8, 10, and 12 lines strung between the blocks. By referring to these tables, the driller can determine readily the required reading on the gage for the weight he desires to carry on the bit; the gage reading also will indicate to the driller when the hoisting force exerted in fishing approaches the limits of strength of the drilling string.

CONTROL OF MUD FLUID

As the unconsolidated strata near the surface in the Oklahoma City field contain abrasives, the mud fluid used in drilling the first few hundred feet of hole is discarded as unfit for further use. The other formations, penetrated to the 5,000-foot level, yield a good grade of mud with little abrasive material, so that admixtures are seldom required to improve its properties. The weight of mud fluid is maintained at approximately 9½ pounds per gallon, and the weight and condition of the mud fluid are watched closely when the drill approaches strata known to contain gas under high pressure. Some companies have field engineers check the weight of the mud fluid twice each tour to determine if the driller is keeping the mud fluid in proper condition and to enable him to make any necessary change in the physical condition of the circulating fluid.

The formations encountered in the drill holes below 5,000 feet yield cuttings that are so abrasive that if they were permitted to remain in the mud they would rapidly wear pump liners and other equipment used in the mud-fluid circuit. These abrasive cuttings are eliminated from the mud stream by allowing them to settle out in the pit or by passing them over mechanically operated screens that separate the larger of the solid particles from the mud fluid.

SHEAL SEPARATORS

The shale separator commonly used consists of a series of 30-mesh wire screen-bottomed trays attached to a continuous chain conveyor that moves up an inclined plane. The conveyor is driven through a reduction gear by a small steam turbine or electric motor.
The screen-bottomed trays move up from the bottom of the slush pit, and as they rise above the surface the liquid flows through the wire screen and returns to the pit. The solids which are retained on the screen are carried out of the pit and dropped over the embankment.

The trays are attached to the chains at the leading edges of the trays by hinged joints and slide on guides as they move up the incline to the driving sprockets. In passing over the end sprockets, the trays invert and unload. In returning to the pit on the slack side of the conveyor chains, the trays hang vertically. It is customary to set the shale separator at the far end of the slush pit near the midpoint of the circuit of the mud stream flowing through the slush pit to permit part of the cuttings to settle out by gravity and thus reduce the work of the separator. This separator was developed in the Seminole field, and its efficiency has been improved through experimentation in the Oklahoma City field. The shale separators are subject to a great deal of wear and require considerable attention and repairs to keep them operating. Consequently, most of the drilling contractors discontinued using them.

### MUD SCREENS

Vibrating screens also have been used for removing cuttings from the mud fluid in Oklahoma City. One adjustable vibrating screen is of all-metal construction, mounted in an inclined position on a frame supported on spiral springs. The frame is vibrated rapidly by an eccentric weight on a shaft driven at high speed by a steam turbine. The returns from the drill hole are discharged into a hopper at the upper end of the screen, and as the mud fluid flows down the slope of the screen the liquids pass through the screen to the slush pit and the cuttings are discharged over the foot of the screen into another compartment of the pit. The screen is of 30-mesh wire cloth, 3 feet 7 inches wide by 5 feet long, mounted on a removable frame usually at an angle of 30°. It requires some attention to prevent clogging by the oil from the drilling bit, but otherwise it works well and removes considerable undesirable material from the mud stream. In another make of vibrating screen that was given a trial in the Oklahoma City field vibratory motion was applied to the screen from a unit mounted over it. This screen also tended to become clogged. Drilling contractors in the Oklahoma City field were of the opinion that vibrating screens were too costly to buy and too inefficient for the service required in that field and therefore did not adopt them.

### MUD-WEIGHING DEVICES

Two automatic mud-weighing devices which were developed in the California oil fields have been used to a limited extent in the Oklahoma City field. One of these devices consists of a conical hopper one fourth cubic foot in capacity, into which a continuous stream of mud-fluid returns flows at a rate commensurate with that of the out-going stream from the hopper so that the hopper remains filled to a predetermined level. The influences of fluid inertia and surface tension have been taken into consideration, and their effects have been compensated in the design and calibration of the record-
ing instrument. The hopper is suspended on scales enclosed in a metal case mounted on a tubular pedestal. On one side of the recording instrument an index hand moves over a scale on the dial and indicates the weight of the mud fluid in pounds per cubic foot; on the reverse side a continuous record of the unit weight of the mud fluid used throughout the day is drawn on a clock-driven chart. This record also shows when circulation is interrupted.

The other mud-fluid weight recorder consists of a weight element submerged in the slush pit and connected by a flexible copper tube to a recording pressure gage placed at a convenient point on the derrick floor. The weight element is a cylindrical chamber, one end of which is closed by a sensitive, flexible diaphragm. The diaphragm encloses a column of air which extends to the pressure gage, and the outer surface of the diaphragm is exposed to the mud-fluid pressure. The fixed relation between the specific gravity of liquids and their hydrostatic pressure is employed to actuate the pressure gage. The weight element is attached to a float by a brass pipe of definite length to form an assembly that floats in the mud fluid with the flexible diaphragm always submerged at an almost constant depth. The float is made so that a change in the buoyancy of the mud fluid will have only a negligible effect on the depth the weight is submerged. The flexible tube is attached to the top of the float which is free to rise and fall with the mud-fluid level in the pit. A change in the specific gravity of the mud fluid results in an equivalent change in the hydrostatic pressure imposed on the diaphragm. The diaphragm yields under the pressure differential, the enclosed column of air is correspondingly compressed or expanded, and the pressure change is transmitted directly to the pressure gage through the enclosed air column. Compensations have been made for the effects of temperature changes on the enclosed air columns over mud-fluid temperatures ranging from 35° to 185° F. and air temperatures ranging from 60° to 120° F. Errors caused by stiffness of the diaphragm and lag in the gage amount to less than 1 pound per cubic foot at the most and usually are reduced considerably by vibration while drilling operations are under way. The weight element and float are confined in a cage set on the bottom of the slush pit near the intake of the pumps. The cage limits the lateral movement of the float but permits it to rise and fall freely with a change in the mud-fluid level in the pit. The recording chart on the pressure gage gives the driller a continuous record of the unit weight of the mud fluid used throughout the day.

**CASING PROGRAMS**

It is general practice to set three strings of screwed casing in the wells—a string of surface pipe, a water string, and an oil or producing string. All the strings are bradhead. The surface string is lap-welded pipe, usually 15½ inches in diameter. A large part of the surface casing used in this field is salvaged pipe brought in from nearby oil fields.

A local factory makes 20-inch, 80-pound pipe from 3½-inch steel plate rolled into cylindrical form and arc-welded in one longitudinal seam. Three sections of this pipe are welded together, end to end, to form 40-foot joints, the maximum length that can be handled.
conveniently in the derrick. The 40-foot lengths are provided with "bell and spigot" joints which also are welded before the casing is lowered into the hole. This casing is made at a cost comparable with the price of reconditioned screwed casing of equivalent size and has been used in a few wells.

The water and producing strings are seamless, screwed joint casing. The five casing programs followed in the Oklahoma City field are listed in table 3. The A.P.I. grade of the casing, the depth at which it is set, the sizes of hole drilled, the quantity of cement used, and the time allowed for the cement to set and harden before drilling is resumed also are given in the table. The first three programs are the chief ones followed and are typical for the field. Less than 3 percent of the wells in the field are cased according to either the fourth or fifth program listed.

**Table 3.—Casing programs—Oklahoma City field**

<table>
<thead>
<tr>
<th>Program</th>
<th>Diameter, inches</th>
<th>Weight, pounds per foot</th>
<th>A.P.I. grade</th>
<th>Depth set, feet</th>
<th>Diameter of hole, inches</th>
<th>Quantity used, sacks</th>
<th>Time to set, days</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>13.5</td>
<td>30</td>
<td>Lap weld</td>
<td>300</td>
<td>20-22</td>
<td>400</td>
<td>3</td>
</tr>
<tr>
<td>B</td>
<td>15.5</td>
<td>30</td>
<td>Lap weld</td>
<td>300</td>
<td>20-22</td>
<td>400</td>
<td>3</td>
</tr>
<tr>
<td>C</td>
<td>12.4</td>
<td>24</td>
<td>D</td>
<td>5,500</td>
<td>12</td>
<td>1,500</td>
<td>3.5</td>
</tr>
<tr>
<td>D</td>
<td>20</td>
<td>60</td>
<td>D</td>
<td>2,000-2,200</td>
<td>12</td>
<td>2,000</td>
<td>5</td>
</tr>
<tr>
<td>E</td>
<td>15.4</td>
<td>30</td>
<td>Lap weld</td>
<td>300</td>
<td>24</td>
<td>500</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>13.4</td>
<td>24</td>
<td>D</td>
<td>2,000-2,200</td>
<td>12</td>
<td>2,000</td>
<td>5</td>
</tr>
</tbody>
</table>

1 After Spang Chalfant & Co., Inc.; data sheet no. 101.
2 8½-inch bits are too large for full-weight, 9-inch, 40-pound casing; 8- or 7½-inch bits are often used.
3 Some operators require only 3 days when the well is not bailed.

**SETTING CASING**

The conductor pipe usually is set and cemented at a depth of 300 feet. The top coupling is flush with the top of the cellar floor. Below this coupling a pipe clamp provided with anchor bolts is mounted on the pipe and provides the means for anchoring the bradenheads and well-head connections.

The longer strings of casing are cleaned with steam, thread protectors are removed, and the pipe is carefully inspected before it is run into the hole. It is customary to lay aside the joints of casing made up of short sections ("pup joints") and use them in the upper end of the string so as to terminate the casing at the proper landing point without a special nipple having to be cut to complete the string.

A guide shoe is screwed and arc-welded to the bottom of the first joint on the water and oil strings. At least two float valves also are included in these strings of casing. Usually they are installed above the second and third joints of casing from the bottom, and it is gen-
eral practice to arc-weld both threaded joints of the float valve to the casing after the joints are made up.

The 9- or 9½-inch casing usually is landed so that the bottom of the top collar is 12 to 14 inches above the uppermost collar on the surface pipe to provide space for the heavy, forged, split-spider casing support. Where a blow-out preventer is included in the connections, slightly greater space is allowed to accommodate it. The casing spider is installed either when the casing is run or after the cement has set 3 to 7 days. In either event the work usually is done during daylight hours to avoid accident and to insure that the connections are properly made. Before the spider is clamped to the casing the same tension is applied to the casing as was registered by the weight indicator when the casing was cemented to avoid imposing excess stresses on the pipe which might cause it to pull apart.

The 6¾- or 7-inch oil string is set at a casing point usually designated by the operator’s geological department. This casing is landed with the bottom of its upper coupling about 15 inches above the top of the slips in the spider supporting it. The support usually is installed after the cement has hardened for 5 to 7 days, and care is taken to keep the tension in the string of casing the same as when the casing was cemented.

PRESSURE-CONTROL EQUIPMENT

To keep the well always under control cellar assemblies are used while drilling below 3,000 feet. Figure 21 shows the cellar assembly used when drilling inside the surface casing. The open end of the conductor pipe is flared, and a 3,000-pound-test gate valve is installed on the 8-inch mud overflow line. The valve is anchored to the conductor pipe by means of discarded sprocket chain, cable, or rods, tightened with turnbuckles. The valve is installed at a point outside the cellar where it is accessible and can be operated safely.

The operator furnishes a 15½- by 6¾-inch hinged wooden plug or a suitable rubber packer at each drilling well to plug the open end of the conductor pipe. If a blow-out threatens while drilling with 6¾-inch drill pipe in the hole, the drilling string is lifted a few feet and the packer is clamped onto the drill pipe and lowered into the belled end of the conductor pipe. The weight of the drill pipe will hold the packer in place against considerable pressure. The valve on the overflow line is then pinched, and mud fluid is pumped into the hole as rapidly as possible until the flow of gas from the formation ceases and equilibrium is established.

If high-pressure gas is encountered before the 9-inch casing is set, the gas may enter low-pressure surface formations, escape around the outside of the surface casing, and form a crater at the surface. Therefore, a drilling valve is never used in the cellar assembly installed on the surface casing. To increase the hydrostatic head on high-pressure gas sands quickly, finely ground minerals, containing salts of the heavy metals, usually barite, are added to the mud fluid. Operators keep a supply of weighting material on hand for an emergency. The hole is always kept full of 9½-pound mud fluid when drilling below 3,000 feet, and while the drill pipe is being withdrawn
the hole is refilled with mud fluid after each 10 or 11 stands are removed, or mud fluid is pumped continually into the hole between the casing and drill pipe to maintain the hydrostatic head on the sands. The mud is pumped into the casing through a pipe which is lowered into the casing to prevent air bubbles from becoming entrained in the mud fluid and lightening the column.

The cellar assembly used when drilling inside the 95/8-inch casing is shown in Figure 22 and consists of the following parts installed on the top of casing upward in the order named: A 95/8- by 10-inch nipple; a 95/8-inch, 3,000-pound-test drilling valve; a 95/8- by 38-inch nipple; a 5,000-pound-test, ram-type, manual- or steam-operated, blow-out preventer, and a 95/8-inch belled nipple. An 8- or 9-inch flanged side connection is provided between the drilling valve and blow-out preventer to serve the mud-fluid overflow line. The overflow line beyond the flange is the same as in the drilling assembly used previously (described on p. 51) and is similarly anchored. The drilling valve has an extension stem provided with universal joints, so that it may be operated from outside the derrick and thus

Figure 21.—Cellar assembly for drilling inside surface casing.
obviate the necessity for men to enter the cellar. The blow-out preventer has rams actuated by steam that can be closed upon the drill pipe to shut off flow through the annular space between the drill pipe and casing. It is provided with 1-inch water connections by which mud can be washed out of the operating mechanism. Water is applied at least once daily while drilling, to keep the mechanism clear and to insure that the rams will function properly. The blow-out preventer also can be fitted with rams that close in on 7-inch casing in order to close the annular space, if necessary, when running casing.

The drill pipe is equipped with a float valve to prevent backflow through the drill pipe when drilling at depths where formations containing fluids at high pressure may be encountered. The float valve consists of a tool joint with a back-pressure valve fitted within it. This assembly is installed in the drilling string, usually a short distance above the drill collar but always above a point where a pressure beyond the collapsing strength of the drill pipe would occur.
This arrangement of equipment provides the means for keeping the well under control while drilling.

When the depths where the casing is to be seated are reached, it is customary to prepare the hole for the casing by rotating a rock bit, "dressed" with a new set of cutters and reamers, in the hole to remove any projections from the walls that might interfere with the free passage of the casing into place. Meanwhile mud fluid is circulated for at least 6 hours to remove all the cuttings from the hole that otherwise would settle to the bottom and prevent the casing from being lowered to the desired point.

The cellar assembly used for drilling inside 7-inch casing is shown in figure 23. This consists of the following parts, listed in order from bottom to top: 7- by 17-inch nipple; 7-inch 3,000-pound-test drilling valve; 7- by 7-inch nipple; and 7- by 9%/8-inch swaged nipple. The 9%/8-inch nipple, mud-overflow line, blow-out preventer, and belled nipple from the cellar assembly previously used
while drilling inside 9 1/2-inch casing are installed above the swaged nipple.

After casing has been set and cemented and the cement has hardened 5 to 7 days, drilling may be resumed. While drilling the cement plug the mud returns from the drill hole are bypassed into the auxiliary slush pit to provide ample time for the cement cuttings to settle out of the mud. When the cement plug has been penetrated the drill pipe is lifted a few feet off bottom and mud fluid circulated until all cement cuttings have been removed from the hole. Drilling is not resumed until the mud fluid is free of cement and of the proper density.

Special care is exercised in controlling the condition of the circulating mud fluid when drilling below 5,000 feet. The amount of sand in the mud fluid is watched closely because sand in sufficient quantity causes the drill pipe to stick in the hole, and when more than 10 percent of solids is in the mud fluid the wall of the hole will cave. Such caving frequently results in drill-pipe twist-offs and expensive fishing jobs.

The sand content of the mud fluid frequently is determined roughly by filling a glass jar one fifth full of a sample of the mud and adding water to fill the jar completely. The desirable constituents of the mud will remain in suspension in the liquid, and the sand will settle to the bottom. If the settlements from a sample of 10-pound mud represent 10 percent or more of the volume, the mud is considered unsafe for use in drilling below 5,000 feet, and more time must be allowed for the sand to settle out before the mud fluid is recirculated.

OPERATORS’ RECOMMENDATIONS

The hazards associated with drilling into the high-pressure gas- and oil-bearing formations in the Oklahoma City field were recognized early in the drilling campaign. The major operating companies realized that the density and other physical properties of the mud fluid were of primary importance in preventing blow-outs and in making drilling operations reasonably safe. Accordingly, these operators formulated a set of recommendations for the guidance of their contractors in carrying on drilling operations. These recommendations are as follows:

1. Boilers are to be set at least 75 feet from the derrick and on the windward side where possible.

2. The rotary table must be lined up with particular care to avoid starting the hole off center. Any engineering assistance required for this job will be furnished by the company.

3. When drilling from 3,000 feet depth to the 9%-inch casing seat (5,200 to 5,500 feet), the hole shall be kept full of mud fluid weighing at least 9 1/2 pounds per gallon, and when drilling below this depth the weight shall be increased to 10 pounds per gallon. The company’s “sample grabber” will sample and weigh the mud fluid once every 6 hours while drilling is in progress.

4. Before running each string of casing two pits filled with good mud fluid should be at hand for immediate use in preventing a blow-out.

5. Before running casing the hole should be conditioned to receive it by rotating a rock bit with a new set of cutters and reamers and circulating mud fluid for at least 6 hours until all cuttings have been removed from the hole.

6. The hole shall be cased with three strings of casing. (See table 3.)

7. Cementing casing.—The surface casing is to be cemented with at least 400 sacks of cement and allowed to set for 3 days before drilling is resumed. The
water string is to be cemented with at least 1,500 sacks of cement and allowed to set for 5 days. The oil string is to be cemented with at least 600 sacks of cement and allowed to set for 7 days.

8. Upon removal from the hole, each joint of drill pipe should be measured in the presence of a company representative, whenever an oil- or gas-bearing formation has been encountered.

9. A float valve must be used in the drill pipe when drilling below 3,000 feet depth. Care must be taken to fill the drill pipe with mud fluid to displace all air in the pipe above the valve.

10. The drill pipe must be equipped with rubber casing protectors to prevent damage to the casing while drilling inside casing other than the surface pipe.

The value of these recommendations was fully recognized, and the reputable drilling contractors operating in this field followed them closely in their drilling operations. The chance of gas blow-outs while drilling operations were under way was great, and every known precaution was taken to prevent them.

**COMPLETING THE WELL**

When the depth to which the well is to be completed is reached and all drill cuttings have been removed from the hole it is customary to thin the mud by adding water to reduce its weight to about 9 pounds per gallon and to continue circulation until the fluid is free of sand. When the drill pipe has been removed from the hole the drilling assembly is removed from the cellar, and permanent wellhead connections are installed in its place. At least two 7-inch 4,000-pound-test gate valves are installed on the 7-inch casing to serve as master valves for the well, the casing is extended above the derrick floor, and a Christmas tree or flow connection is installed on top of the casing. Some operators include a blow-out preventer on the casing, usually installed just below the derrick floor. The master valves and Christmas tree usually are anchored down separately to the clamps installed on the surface pipe and to the bradenheads. The 7-inch casing and Christmas tree or flow connections also are braced to the derrick corner piers to reduce vibration while the well is flowing. Figure 24 shows one type of cellar connection and Christmas tree in which screw-type valves are used. The method of anchoring shown in this figure is used on the smaller wells. Sometimes a lead ring and packing gland are fitted on the threaded connections of the master valves to seal leaks that might develop through the threaded joint to the casing. When flow-line connections to the separators and lease tanks and connections to the gas lines and vent lines are completed the well is ready to “bail in.”

The Christmas-tree assembly usually consists of the following fittings, which are listed in the order in which they are installed, from the top of the casing to the top of the Christmas tree:

- One 7-inch seamless nipple.
- One 7-inch, 4,000-pound-test, screwed gate valve (lower master).
- One 7-inch seamless nipple.
- One 7-inch, 4,000-pound-test, screwed gate valve (upper master).
- One set of 1½- by 9- by 45-inch casing clamps with 1½-inch turnbuckles.
- One 7-inch seamless nipple.
- One 7-inch seamless nipple.
- One 7-inch, 3,000- or 4,000-pound-test, screwed gate valve with 1½-inch turnbuckles.
- One 7- by 18-inch standard nipple.
- One 1½- by 9- by 45-inch standard 7-inch casing clamp.
The flow-line connections leading from the side of the cross on the Christmas tree are made up of the following fittings:

One 4- or 6-inch hydraulic nipple.
One 4- or 6-inch, 3,000-pound-test, manifold gate valve.
One 4- or 6-inch hydraulic nipple.
One 4- or 6-inch adjustable flow bean.

In the Christmas tree shown in figure 24 the body of the upper 7-inch gate valve and the cross are forged into one piece.

A number of the wells that penetrate the Wilcox formation produce large quantities of gas with the oil, and, in many, considerable sand is entrained in the oil, so that the valves are often damaged and subject to leaks. To reduce leakage troubles and to facilitate repairs to damaged master valves, some of the operators in the Oklahoma City field use wellhead connections of the type shown in
figure 25. In this type of wellhead connection flanged valves are
used in place of screwed valves, and interposed between the valves
are special tie-down flanges provided with lugs for anchor rods
which tie down to the casing supports. The anchor rods are 1\(\frac{1}{2}\) or
2 inches in diameter with hand-forged eyes to fit the companion
flange lugs and are tightened with turnbuckles. The assembly shown
in figure 25 has three master gates on the 7-inch casing and a special
packing gland on the flange to which the lower master gate is bolted
to prevent leakage through the threaded joint on the casing. It will
be noted that a 9\%\(\frac{3}{8}\) -inch gate valve is installed on the forged-steel
swaged nipple which encloses the slips on the 7-inch casinghead.
This valve is intended for emergency use if the 7-inch master valves
become damaged and cannot be closed. The 7-inch nipple may be
unscrewed from the collar above the slips in the casing support, the
nipple removed, and the 9\%\(\frac{3}{8}\) -inch valve closed to stop the flow from
the well.

BLOW-OUTS

Blow-outs were likely to occur during three stages in the drilling
operations; namely, when drill pipe was in the hole, when drill pipe
was out of the hole, and while running casing. Consequently, dif-
ferent procedure was necessary to overcome the blow-out and again
bring the well under control.

DRILL PIPE IN HOLE

1. If a blow-out starts when drill pipe is in the hole, the drilling
string is lifted a short distance, a packer is clamped on the drill pipe
and lowered into the belled end of the drilling assembly, and mud
fluid is pumped into the hole as rapidly as possible to restore the
static head of the column of mud in the hole.

2. When the drilling assembly is equipped with a blow-out pre-
venter the rams are immediately closed upon the drill pipe, and mud
fluid is pumped into the hole as rapidly as possible.

DRILL PIPE OUT OF HOLE

If a blow-out starts when the drill pipe is out of the hole, drill
pipe is run into the hole “open ended” to as great a depth as condi-
tions will permit, a packer clamped on the drill pipe is lowered into
the belled nipple on the conductor, the valve on the return line is
pinched, and mud fluid is pumped into the hole as rapidly as possible
to seal off the formation producing the gas.

Where a blow-out preventer is installed the rams are closed and
mud fluid is pumped into the hole against pressure until a mud
column is again established.

RUNNING CASING

When casing is being run the blow-out preventer is equipped with
rams to fit the casing, and, if a blow-out threatens, the rams are
closed on the casing to shut off flow through the annular space. If
the drilling assembly is not provided with a blow-out preventer a
slip-type packer is kept on hand ready for immediate use. If a
Figure 25.—Wellhead connections with flowhead.
blow-out starts, the packer is clamped onto the casing and lowered into the belled end of the drilling nipple. This method will control moderate pressures only.

**EQUIPMENT FOR CONTROLLING "WILD" WELLS**

The potential hazards presented when a well blows "wild" in the Oklahoma City field have caused the public as well as the operators a great deal of concern. From the beginning of the development of the field until the end of 1931 eight wells have gotten out of control.

The most notable of these "wild" wells was Mary Sudoku no. 1 which blew out while being drilled into the pay horizon. Twenty joints of 3½-inch drill pipe were blown out of the hole, and the well came in as a gas well. After blowing gas for about 24 hours, the well sprayed oil which gradually increased until after the second day when the flow was estimated at 1,000 barrels of oil per hour with gas estimated at 100,000,000 cubic feet per day. Not only is every effort made to prevent blow-outs, but also a great deal of study has been devoted to the development of devices and methods for bringing wild wells under control. The development of equipment and successful methods for controlling wild wells is noteworthy evidence of the ingenuity of engineers and production men in charge of development work in the field.

Many of the operators have equipment on hand, ready for immediate use, for controlling wild wells. This equipment usually consists of the following:

Two 4,000-pound-test, swaged nipples with 13¾-inch female thread on one end and 9¾-inch male threads on the other end of each nipple. This type of nipple is used when necessary to screw onto the outside of the 9¾-inch casing head and casing support.

Two combination steel die nipples (also called die couplings) with packing flanges on the bottom, packing glands, extra packing rings, and a wing guide. One of these die nipples is for 6¾-inch and the other for 7-inch casing.

Two ball-bearing guide rings or pull-down swivels for 9¾-inch casing.

One set of eight 2-ton chain hoists for pulling the Christmas-tree and die-nipple assembly down onto the casinghead.

One inverted bradenhead made to fit over a 9¾-inch casing head and casing support.

The die nipple has 1 inch of fluted threads that cut new threads on the end of the casing and 3½ inches of full threads that complete the joint to the casing.

The wing guide consists of 14 radial vanes welded to end rings which hold the vanes apart at fixed angles. The assembly is divided longitudinally and is clamped over the flanged end of the die nipple so that the vanes are parallel to the longitudinal axis of the die nipple.

The pull-down swivel is a sleeve that slides over 9¾-inch casing, and in a counterbored recess in its lower end a ball bearing rests on the 9¾-inch collar. Four equally spaced eyes welded into the outside surface of the swivel serve as lugs for the attachment of chain hoists.

These parts are assembled on a joint of 9¾-inch casing with the die nipple on the lower end and a complete Christmas-tree assembly on the top. (See fig. 26.) The assembly is hoisted into the derrick with the Christmas tree uppermost and with all the master valves open by means of a temporary hoisting gear. Four of the chain
hoists are anchored to the four derrick legs about 20 feet above the derrick floor, and four chain hoists are anchored to the bases of the derrick legs. The upper chain hoists are hooked into the eyes in the upper swivel, and the lower chain hoists are hooked into the lower swivel; by these means the die-nipple assembly is drawn into the stream blowing from the well. When the assembly intercepts the stream the reaction of the wing guide to the stream causes the die-nipple assembly to center over the well and tends to keep the assembly in vertical alinement. The eight chain hoists are then operated in unison and draw the die nipple down onto the end of the casing in the well. The wing guide is removed, and the packing flange and gland are loosened and lowered over the well casing out of the way. At this stage in the operation the stream blowing from the well is flowing through the die-nipple assembly. With the chain hoists kept taut the die nipple is held in engagement with the end of the casing, and the die-nipple assembly is revolved by means of chain tongs until new threads are cut on the casing, and the assembly is screwed securely to the casing. The packing ring is then inserted in the recess between the casing and the lower end of the die nipple, and the packing gland is drawn up to prevent leakage through the newly made, threaded joint. After the newly installed equipment has been anchored down securely to the casing supports in the cellar, the master valves are closed to shut in the well.

Figure 26 shows the wellhead connections on a "wild" well brought under control with the use of a die nipple. The detail view shows a cross-section of one guide ring and the die nipple with the wing guide in the positions these parts occupy when the assembly is drawn down onto the well casing.

On this well the swaged nipple was not required. The upper guide ring which was above the uppermost valve was removed after the well was shut in and is not shown.

PERFORMANCE OF DRILLING MACHINERY

STEAM-DRIVEN, ROTARY-DRILLING MACHINERY

To determine the actual performance of steam-driven machinery the energy supplied and the water required must both be measured accurately. Where fuel and water are furnished to the drilling contractor free of cost, as in the Oklahoma City field, there is no particular inducement for the contractor to measure either of them or economize in their use. Consequently performance data of drilling operations in the Oklahoma City field, other than the drilling time for the wells, were not available.

The need for precise information on the energy requirement and its utilization in steam-driven, rotary-drilling equipment has long been recognized, and to obtain such information the American Society of Mechanical Engineers sponsored a series of field tests, of which the first was made in 1930 on a drilling well in the Oklahoma City field. This test was conducted by Prof. W. H. Carson, of the University of Oklahoma, and the results were published in 1932.\textsuperscript{12}

\textsuperscript{12} American Society of Mechanical Engineers, Reports of Tests on Steam Equipment for Drilling Rotary-Drilled Oil Wells: Research Pub., 1932, New York, N. Y.
Figure 26.—Connections on "wild" well brought under control with a die nipple.
This is the first report of its kind ever published and contains a fund of data of great value to the petroleum industry. The equipment tested was typical of the heavy-type drilling machinery used in this field and consisted of the following:

Four 125-hp, saturated steam boilers,
One 12- by 12-inch, twin drilling engine,
One 2-post, 4-speed draw works.
One 25½-inch rotary table.
Two 14- by 7½- by 18-inch duplex slush pumps,
One 5-sheave crown block.
One 4-sheave traveling block.

A summary of the results obtained from the tests on this drilling well is given in table 4. Column 1 shows the several items considered; 2 gives the daily average data for a period of 33 days while drilling with 6½-inch drill pipe from the surface to a depth of 5,570 feet; 3 shows the same data as 2, expressed on the basis of each foot of hole drilled; 4 contains the daily average data for a period of 10 days while drilling from a depth of 5,570 to 6,329 feet with 4½-inch drill pipe; and 5 shows the same data as 4, expressed on the basis of each foot of hole drilled.

<table>
<thead>
<tr>
<th>Item</th>
<th>Drilling to 5,570-foot depth with 6½-inch drill pipe</th>
<th>Drilling from 5,570 to 6,329 feet with 4½-inch drill pipe</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Daily average for 33 days</td>
<td>Average per foot of hole drilled</td>
</tr>
<tr>
<td>------</td>
<td>--------------------------</td>
<td>-----------------------------</td>
</tr>
<tr>
<td>Water to location...</td>
<td>664,000</td>
<td>3,584</td>
</tr>
<tr>
<td></td>
<td>lbs.</td>
<td></td>
</tr>
<tr>
<td>Gas to boilers...</td>
<td>1,688</td>
<td>11.22</td>
</tr>
<tr>
<td></td>
<td>hrs.</td>
<td></td>
</tr>
<tr>
<td>Water in boiler blow-down</td>
<td>421,000</td>
<td>2,404</td>
</tr>
<tr>
<td></td>
<td>lbs.</td>
<td></td>
</tr>
<tr>
<td>Water evaporated...</td>
<td>1,202</td>
<td>7.13</td>
</tr>
<tr>
<td></td>
<td>hrs.</td>
<td></td>
</tr>
<tr>
<td>Steam to drilling engine</td>
<td>51,906</td>
<td>936</td>
</tr>
<tr>
<td></td>
<td>lbs.</td>
<td></td>
</tr>
<tr>
<td>Steam to slush pump...</td>
<td>147.5</td>
<td>87</td>
</tr>
<tr>
<td></td>
<td>hrs.</td>
<td></td>
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<tr>
<td>Steam to turbine-generator</td>
<td>366,994</td>
<td>2,188</td>
</tr>
<tr>
<td></td>
<td>lbs.</td>
<td></td>
</tr>
<tr>
<td>Steam lost in leakage, washout, etc.</td>
<td>1,604.5</td>
<td>6.26</td>
</tr>
<tr>
<td></td>
<td>hrs.</td>
<td></td>
</tr>
<tr>
<td>Steam for settling mud...</td>
<td>80,775</td>
<td>478</td>
</tr>
<tr>
<td></td>
<td>lbs.</td>
<td></td>
</tr>
<tr>
<td>Steam for cleaning floor, bit, etc.</td>
<td>244</td>
<td>13.25</td>
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<tr>
<td></td>
<td>hrs.</td>
<td></td>
</tr>
<tr>
<td>Boiler pressure...</td>
<td>225.6</td>
<td>227</td>
</tr>
<tr>
<td></td>
<td>lbs. per sq. in. gage.</td>
<td></td>
</tr>
<tr>
<td>Steam quality at boilers</td>
<td>98.4</td>
<td>98.3</td>
</tr>
<tr>
<td></td>
<td>percent</td>
<td></td>
</tr>
<tr>
<td>Gas to boilers (1,217 B.t.u. per cu. ft.)</td>
<td>91</td>
<td>8.83</td>
</tr>
<tr>
<td></td>
<td>cu. ft.</td>
<td></td>
</tr>
<tr>
<td>Boiler efficiency including heat to blow-down...</td>
<td>56.4</td>
<td>56.6</td>
</tr>
<tr>
<td></td>
<td>percent</td>
<td></td>
</tr>
<tr>
<td>Boiler efficiency, based on water evaporated...</td>
<td>54.4</td>
<td>52.0</td>
</tr>
<tr>
<td></td>
<td>percent</td>
<td></td>
</tr>
<tr>
<td>Boiler horsepower, including heat to blow-down (4 boilers)...</td>
<td>533</td>
<td>373</td>
</tr>
<tr>
<td></td>
<td>horsepower</td>
<td></td>
</tr>
<tr>
<td>Drilling engine, thermal efficiency...</td>
<td>125.2</td>
<td>85.2</td>
</tr>
<tr>
<td></td>
<td>percent</td>
<td></td>
</tr>
<tr>
<td>Over-all thermal efficiency of drilling engine and boiler...</td>
<td>6.13</td>
<td>5.64</td>
</tr>
<tr>
<td></td>
<td>percent</td>
<td></td>
</tr>
<tr>
<td>Slush pump, thermal efficiency...</td>
<td>4.48</td>
<td>4.00</td>
</tr>
<tr>
<td></td>
<td>percent</td>
<td></td>
</tr>
<tr>
<td>Over-all thermal efficiency of slush pump and boiler...</td>
<td>2.44</td>
<td>2.07</td>
</tr>
</tbody>
</table>
The results show clearly the enormous expenditure of energy required to drill a well with steam-driven, rotary-drilling equipment and are representative of drilling practice in the Oklahoma City field during 1930. Outstanding points are that the over-all thermal efficiency of the slush pump is below 2.5 percent and that of the drilling engine is less than 3.5 percent. Where fuel is scarce or could be marketed at commercial rates, deep drilling by this method would be almost prohibitive.

Another interesting point brought out in the report is that the engine, while drilling at a depth of 4,800 feet, developed 127 indicated horsepower, whereas while rotating at the same depth and speed but with no weight on the bit it developed 120 indicated horsepower. This small difference shows that only 7 horsepower did useful work and that over 94 percent of the power was absorbed in friction. A large part of the losses can definitely be attributed to friction on the drill pipe caused by the crookedness of the hole. A subsequent survey of this well showed the following deviations from the vertical: $2^\circ$ at 500 feet; $1\frac{1}{2}^\circ$ at 1,000 feet; $3\frac{1}{2}^\circ$ at 2,000 feet; $2\frac{1}{2}^\circ$ at 2,500 feet; $1^\circ$ at 3,000 feet; $3^\circ$ at 3,500 feet; $5^\circ$ at 4,000 feet; and $3\frac{1}{2}^\circ$ at 4,500 feet.

To determine the friction losses in the drilling machinery alone it would be necessary to incorporate a dynamometer or torque-measuring device in the rotary table to measure the turning force and power applied to the drill stem; then if it were possible to measure simultaneously the torque applied to the bit the power absorbed by friction of the drill pipe rotating in the hole could be calculated. When such measuring devices are available it will be possible to segregate the various power losses in drilling, and the modifications to drilling machinery most likely to increase efficiency will be evident.

Drilling-time data were collected on a number of wells drilled in the Oklahoma City field during 1929 and 1930, and the results are shown in table 5.

**Table 5. — Progress made in drilling wells**

<table>
<thead>
<tr>
<th></th>
<th>1929</th>
<th>1930</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of wells considered</td>
<td>128</td>
<td>180</td>
</tr>
<tr>
<td>Average total drilling time per well, days</td>
<td>131.8</td>
<td>92.37</td>
</tr>
<tr>
<td>Average delays for fuel, water, fishin, waiting on cement, etc., do</td>
<td>19.1</td>
<td>14.07</td>
</tr>
<tr>
<td>Average net drilling time per well, do</td>
<td>112.7</td>
<td>78.3</td>
</tr>
<tr>
<td>Average depth of wells, feet</td>
<td>6,469</td>
<td>6,533</td>
</tr>
<tr>
<td>Average drilling rate per day, do</td>
<td>57.4</td>
<td>83.4</td>
</tr>
</tbody>
</table>

1 Includes wells spudded in during 1929 and completed in 1930.

Table 5 summarizes the experience of 45 contractors, and, although the quantities given are not based on all wells drilled in the field during the respective periods, they are probably representative for the whole field. The increase in drilling rate for 1930 over that for 1929 is partly accounted for by improvements in the drilling machinery but mostly by the experience gained during the preceding year and greater knowledge of the underlying structural conditions.

Figure 27 gives a composite drilling-time curve for 30 wells included in the above table which were drilled in June and July 1930.
and is typical of the progress made in drilling a well during that period.

**DRILLING WITH ELECTRIC POWER**

Approximately 25 wells were drilled in the Oklahoma City field with electric-driven rotary outfits up to the spring of 1932. This type of load is not particularly attractive to the power company, and probably no more wells will be drilled in this field with electric power. The field is well supplied with electric distribution lines, and temporary transformer stations were installed to furnish 440-volt, 3-phase, 60-cycle current to the motors. The motive power of the draw works ranged from two 65-hp. motors to one 250-hp. motor, and slush-pump motors ranged in size from 150 to 250 hp.

Performance data for individual drilling operations are not available, but power-company records indicate that the connected load ranged from 280 to 500 hp. for individual drilling outfits and that

![Composite drilling-time curve for 20 wells.](image)

*Figure 27.—Composite drilling-time curve for 20 wells.*

the period during which power was served to each drilling well ranged from 79 to 248 days and averaged 124.7 days for 21 wells drilled. The total energy consumed in drilling a well ranged from 215,000 to 566,080 kw.-hr. and averaged 352,377 kw.-hr. for 21 wells whose average depth was 6,484 feet. Therefore, the average energy consumption was 54.35 kw.-hr. per foot drilled, and the average energy cost was $0.944 per foot of hole drilled. Delays occurred on seven wells due to fishing jobs and other causes which resulted in abnormal consumption of energy and length of drilling time. Drilling progressed at normal rates on the other 14 wells, and the records for these wells, which were drilled to an average depth of 6,505 feet, show that the average energy consumed was 298,663 kw.-hr. per well. The specific energy consumption was, therefore, 45.91 kw.-hr., costing $0.768 per foot of hole drilled. These 14 wells were served with power for an average period of 99 days.
Periodic readings were taken of energy consumed on 10 wells while drilling at several depths. Computations were made of the energy required per foot of hole drilled, and the results were plotted on coordinate paper using kilowatt-hours as abscissas and drilling depth as ordinates. A curve of average results for the 10 wells and the points applying to 5 of them are shown in figure 28. The curve is representative of the existing conditions but does not necessarily indicate energy requirements where drilling progresses at normal rates. The great divergence of the points beyond the 3,000-foot depth was caused largely by manual control of the drilling outfits which made it possible to overload the motors for short periods. Fishing jobs were necessary in several of the wells and had a marked influence on the positions of the plotted points because the energy
consumption increased greatly during the fishing operations although drilling progress was nil. The 10 wells were served with power for an average period of 138 days. The anticipated energy requirement for normal drilling would therefore be considerably less than that indicated by the curve shown in figure 28 if due consideration was given to the choice of motors and if in their operation ordinary care was exercised in keeping the load factor at a high value.

SURFACE EQUIPMENT AT PRODUCING WELLS

FLOWHEADS

In producing wells in which the formation gas pressure is high, oil and gas flow from the wells at high velocities when the master valves are opened. The flow is turbulent, and in wells producing from unconsolidated formations large quantities of sand are brought to the surface with the oil and gas when the wells are opened. This condition obtains in many of the wells in the Oklahoma City field which produce from the Simpson and Wilcox formations. One well, for example, which flowed through a 4-inch choke during its initial production test, was reported to have produced 4,200 barrels of oil, 600 barrels of sand, and 8,300,000 cubic feet of gas in 2 hours. The wellhead connections were so badly damaged by the cutting action of the sand in the stream during this period that the well had to be shut in to prevent their destruction before the usual 4-hour test was completed.

Many other wells have had their connections destroyed by sand cutting in even shorter periods, and in a few wells the wellhead connections and master valves have been destroyed repeatedly.

According to Knowlton, Charles, and McGee.13

Large volumes of sand have been produced from many of the wells in the Wilcox area. As much as 700 barrels per hour, or a total of from 4,000 to 5,000 barrels per well is not uncommon. In one well which was producing from 95 feet of Wilcox sand, the volume of sand removed would leave a hole in the producing formation, if the hole is assumed to be cylindrical, slightly over 21 feet in diameter and 95 feet in length.

One of the first steps taken to prevent sand cutting of the wellhead connections was to install flowheads on the wells. These flowheads are made in several forms of which the essential features are an expansion chamber to diminish the velocity of efflux and a shock-absorbing device upon which the stream impinges. The simplest form of flowhead is made of a 6-foot section of 15½-inch, 70-pound casing which has a 7-inch nipple about 2½ feet long welded into one end that projects about 2 feet into the flowhead and serves as a nozzle. The other end of the section of casing is closed with an “orange-peel” weld and has a short piece of 6-inch pipe welded to the top and extended upward to serve as a guide for the anchoring clamps. A 12½-inch pipe coupling welded into the side wall of the flowhead opposite the end of the nozzle forms the outlet to the flow lines. This flowhead is inexpensive to construct and can be made in the ordinary field shop.

Figure 29 shows two modified forms of this type of flowhead. The form shown in A is made in two parts joined with a Victaulic coupling above the outlet to the flow line. The domed, upper end usually is about 3 feet long and partly filled with lead. A 6-inch nipple is welded on the top for attachment of anchoring clamps. The flowhead shown in B is made of two sizes of casing (either 20 and 12½ inches or 15½ and 10 inches in diameter) placed one

within the other and with the annular space between them filled with neat cement. A replaceable, "solid" choke in the inlet retards the flow.

Although these flowheads have given satisfactory service, wells equipped with them are never left unattended when flowing for fear of failure of the head. Flowheads must be inspected periodically for wear, as there is no way of being forewarned of their failure in service.
Another type of flowhead used in the Oklahoma City field is similar in design to the body of an angle globe valve with walls about 3 inches thick. This flowhead has a twin outlet for flanged connections to the flow lines and an opening in the top for bailing. When the bailing operation is completed this opening is closed with a bull plug which serves also as a support for the anchoring clamps. Another flowhead is cast in the form of a T threaded for 6½"- or 7-inch casing. A special 6½"- or 7-inch by 12-inch swaged nipple is screwed into the side outlet. This special nipple has internal threads into which a choke is screwed. A bull plug into which an oak plug has been driven is screwed into the top opening after bailing is completed. The wooden plug serves as a target or buffer which takes the impact of the stream and prevents the sand from cutting through the metal of the bull plug. Ten or twelve wells were equipped with cast flowheads of this type. Although these flowheads are reported to be satisfactory, many engineers question the use of castings for this service because the rapid changes of temperature to which they are subjected, caused by the refrigerating effect of the expanding gas when the well is opened, set up stresses that may cause castings to crack.

Two types of large cylindrical vessels called “sand hogs” of welded-plate construction also are used as flowheads in the Oklahoma City field. One type is 3 feet in diameter, 15 feet high, designed for a working pressure of 500 pounds, and tested for a hydrostatic pressure to 800 pounds per square inch. (See fig. 31, p. 76.) The shell is made of 25-pound, steel boiler plate, the heads are of 30-pound boiler plate, and the seams are arc-welded with buttstraps welded on the outside. The inlet through the bottom head is a collar into which is screwed either a nipple extending inward or a “solid” choke to restrict the flow. The stream is directed upward against a wearing plate tack-welded to the interior surface of the shell. The resulting expansion and the cushion of gas and oil in the upper part of the chamber tend to reduce the abrasive effect of the sand.

Two opposed outlets ranging in size from 8¼ to 15¼ inches are placed near the bottom of the chamber, and a 10-inch opening is provided in the upper head through which the bailer is admitted. When this type of chamber was first used in the field the top opening was closed with a bull plug after bailing operations were completed. In later models a special plug was screwed into place from inside the chamber by means of a short section of 5-inch pipe welded to the top of the plug; this section of pipe extended to the outside of the chamber. A section of 12½-inch pipe, 13 inches long and filled with lead, was screwed on the head of the plug with the lead face exposed to the stream from the well. Connections were provided in the top head for two 4-inch safety valves, and a manhole gave access to the interior of the chamber for cleaning. The inlet and outlet connections to the chamber are replaceable. The inward extension of the outlet nipples protects the shell from abrasion by preventing concentrated movement of the stream at the points of outlet. The flowhead usually is anchored to the bradhead of the well and the derrick corner piers by anchor bolts or cables. This type of flowhead was used on 48 wells. One of these flowheads failed while
the well was being opened for production, and two men operating the master valve were killed. The upper head was sheared, the shell was badly shattered, and some pieces were thrown over 600 feet from the well. The failure was attributed to internal combustion of an explosive mixture of gas and air, because the shut-in pressure of the well was known to be insufficient to rupture the vessel.

Another shell-type flowhead which was introduced into the field later differs from the one just described in that it has a removable top and an internal shock-absorbing cushion. This flowhead (fig. 30) is 30 inches in diameter and 9 feet 9 inches long. The domed bottom head is welded to the shell, and the top of the chamber has a flanged open end. The shell is of 7/8-inch steel plate rolled into cylindrical shape and arc-welded in one longitudinal seam. The bottom head is of steel 1 inch thick, and the top cover, which is a square steel plate 2 1/4 to 2 5/8 inches thick and slightly domed at the center, is fastened to the flange of the shell with twenty-four 1-inch bolts. The corners of the plate are bent up slightly and drilled to serve as lugs for diagonal anchor bolts, which are fastened to the corners of the derrick. Four vertical anchor rods from the bradenhead pass through steadying brackets welded to the outside of the shell near the bottom head and extend through the flange, serving as bolts to hold the cover plate. A removable steel working platform, supported by brackets which hook into lugs welded on the shell, is provided for the man who guides the bailer. The flowhead is set vertically over the wellhead, and the stream from the well enters through the 6 5/8-inch inlet at the bottom head. A collar, into which is screwed a "solid" choke, is welded inside the bottom head. The inlet has a replaceable liner faced with tungsten carbide. The choke is a forged-steel tube 3 feet long and has lugs welded on near the upper end to accommodate a wrench.

A floating head inside the chamber rests on four lugs welded to inner wall of the shell. A pillow made of scrap packing and belting sewed into a burlap bag acts as a cushion between the floating

**Figure 30.**—Installation of cushion-type flowhead and cone-bottom separators.
head and the top cover. The floating head is a cylindrical cup 2 feet in diameter and about 1 1/2 feet deep, made of steel plate welded at the joints. The base of the floating head is 2 1/4-inch steel billet, the walls are 3/8-inch steel plate, and the top is 3/8-inch steel plate with a central opening 16 inches in diameter. The floating head is installed in an inverted position opening downward. The stream is directed into the opening, and liquid is retained within the cup to absorb the shock, prevent abrasion, and eliminate the cutting action of the stream on the walls of the chamber. The only parts of the flowhead subject to the cutting action of the stream are the liner of the inlet nipple, the choke, and the floating head, all of which are replaceable.

The procedure followed in "bringing-in" a well equipped with this kind of flowhead is to bail until the static head of the mud fluid in the well is overcome by the gas pressure at the bottom of the hole. The bailer is then withdrawn from the well, and the master valve is closed. The choke, floating head, and pillow are installed, and the cover is bolted on and anchored down. The master valves are then opened, and the well is permitted to flow. Discharge from the flowhead is through two 12 1/2-inch opposed outlets, so that the reactions of the two streams are compensating.

This flowhead is designed for working pressures up to 750 pounds per square inch with a safety factor of 3 and is given a hydrostatic test of 1,000 pounds per square inch at the factory. Two smaller sizes of this type also are made; one, 24 inches in diameter by 9 feet 9 inches long, is tested to a pressure of 600 pounds per square inch, and the other, 15 inches in diameter by 60 inches long, to a pressure of 400 pounds per square inch.

Holding back the sand in the formation at the bottom of the hole with screen pipe perhaps would obviate the need for flowheads on the wells and eliminate the hazards of sand-cut wellhead connections, but the use of screen pipe has not been accepted generally in the Oklahoma City field because the restriction offered by the small opening of the screen tends to retard the rate of flow. The allowable production of the wells under the current proration program is based upon their potential rate of flow; therefore the operators are reluctant to use equipment that would restrict flow during periodic potential-production tests. However, after the potential rate of flow for the well has been established, the application of screen pipe or tubing to the well would be of ultimate advantage under conditions of curtailed production, because the increased back pressure on the formation would tend to prevent sand from being dislodged.

On regular production the wells are opened for short periods to produce their allowable flow, which necessitates a greater number of manipulations of the valves than if the wells produced continuously. Usually the connections and chokes are changed when the well is to be subjected to a potential test so as to obtain the greatest possible rate of flow. To reduce wear on the master valves and obviate changes to the wellhead connections, a flow nipple which bypasses the upper master valve is used. This flow nipple can be adjusted to any size of opening up to 3/8 inch in diameter, and on one well which had a wellhead pressure of 1,800 pounds per square inch the flow was varied from 6 to 1,200 barrels per day. The flow nipple permits flowing the well continuously without producing oil
in excess of the total allowable under proration restrictions; furthermore, potential rate of flow of the well can be taken at any time without changing the wellhead connections. Some of these flow nipples are installed in bypass connections provided on the master valves, and others are installed in the companion flanges above and below the upper master valve.

Many large wells that produce from the Wilcox sand have a forged-steel cross installed on top of the oil string with an adjustable needle valve for controlling flow. Figure 20, C, shows this type of flow device. The needle and valve seat are replaceable. The valve seat is from 2½ to 6 inches in inside diameter, and the flow line to the separators is 12½ inches or more in diameter. No attempt was made to prevent sand from cutting the fittings, but experience showed that the flow passage should be proportioned so that cutting would be confined largely to parts that could be replaced quickly and at little expense. When potential test of the well is taken the valve seat is removed and a straight sleeve substituted.

**WELLHEAD CONNECTIONS**

The several strings of casing are united in two bradenheads in the cellar; one holds 9½- to 15½-inch casing and the other 7-inch flow string to 9½-inch casing. The bradenheads are designed to withstand a pressure of 3,000 to 5,000 pounds per square inch. The flow string in the well is usually 7-inch A.P.I. casing with two or three master valves below the derrick floor and extension stems about 50 feet long. Both flange- and screw-type master valves are used, but most operators prefer the screwed valves. Some operators provide a packing gland on the threaded master valves and use a lead packing ring to prevent leakage through the threaded joint of the valve and casing. The master valves and fittings are designed for a working pressure of 3,000 to 5,000 pounds per square inch and are anchored to both the cellar foundation and to clamps on the outer string of casing, usually by steel rods 1½ or 2 inches in diameter. Although discarded cable and rotary chain also are used extensively for anchoring wellhead connections, rods are preferred by most operators. All tie-downs are provided with turnbuckles so that they may be tightened whenever necessary.

Flowheads are not required on wells producing from limestone and other consolidated formations, because they do not produce sand. Consequently, a Christmas tree is used on these wells. On many wells a heavy steel cross is installed in the Christmas-tree hook-up between the upper and middle master valves, and the flow from the well is through the side outlets of the cross and thence through adjustable flow beans or "solid" chokes to the oil-and-gas separators. Some wells are provided with large-diameter lines connected to the top valve above the cross on the Christmas tree. One line leads to the slush pits for disposal of mud fluid or mixtures of mud, water, and oil which, if delivered into the separators, would interfere with their operation. Other lines provide for the delivery of wet gas into the separators.
The separation of the large volume of gas produced with the oil in the Oklahoma City field necessitates separators of large capacity. On small wells one separator is sufficient, but on wells making large quantities of gas as many as four separators are sometimes required.

Two-stage separation is employed on wells producing relatively small quantities of high-gravity oil and large quantities of gas. In two-stage separation the flow from the well is delivered into 4 or 5 high-pressure separators, connected in parallel, where initial separation takes place. These separators are designed for working pressures up to 500 pounds and usually are operated at a pressure ranging from 240 to 375 pounds per square inch. The gas from these separators is "dry" and usually is discharged directly into gathering lines for lease requirements or into gas-company pipe lines. The oil discharged from the high-pressure separators contains considerable gas in solution and is delivered into a low-pressure separator, operated at a pressure ranging from 40 to 75 pounds per square inch, where final separation of gas from the oil takes place. The low-pressure separator is large enough to accommodate the total flow of oil from the well. From the low-pressure separator the oil flows to the gage tanks, and the gas goes through gathering lines to the gasoline plant. With 2-stage separation "wet" gas only is delivered to the gasoline plant, consequently the compressors can be operated economically and the output capacity of the gasoline plant is proportionately increased.

Four makes of oil-and-gas separators are generally used in the Oklahoma City field, and their sizes range from 3 feet in diameter by 10 feet high to 7 feet in diameter by 29 feet high. Working pressures of the high-pressure separators range from 300 to 500 pounds per square inch with a safety factor of 5. Shell seams of the separators are buttstrap-riveted, buttstrap-welded, or both. The following specification is typical of the high-pressure separators used in the field.

<table>
<thead>
<tr>
<th>Diameter</th>
<th>feet</th>
<th>3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Height</td>
<td></td>
<td>15</td>
</tr>
<tr>
<td>Steel in shell, boiler-plate</td>
<td></td>
<td>25-pound</td>
</tr>
<tr>
<td>Steel in heads, boiler-plate</td>
<td></td>
<td>30-pound</td>
</tr>
<tr>
<td>Working pressure</td>
<td>pounds per square inch</td>
<td>500</td>
</tr>
<tr>
<td>Test pressure (cold water)</td>
<td></td>
<td>800</td>
</tr>
<tr>
<td>Factor of safety</td>
<td></td>
<td>5</td>
</tr>
<tr>
<td>Oil capacity</td>
<td>barrels per day</td>
<td>3,000</td>
</tr>
<tr>
<td>Gas capacity</td>
<td>million cubic feet per day</td>
<td>30</td>
</tr>
<tr>
<td>Inlets (2)</td>
<td>inches</td>
<td>6%</td>
</tr>
<tr>
<td>Oil outlet (1)</td>
<td>do</td>
<td>4</td>
</tr>
<tr>
<td>Safety valve (1)</td>
<td>do</td>
<td>3</td>
</tr>
<tr>
<td>Weight</td>
<td>pounds</td>
<td>6,300</td>
</tr>
<tr>
<td>Price</td>
<td></td>
<td>$1,950</td>
</tr>
</tbody>
</table>

The low-pressure oil-and-gas separators used most commonly in the Oklahoma City field are 5 feet in diameter by 16 feet high and 7 feet in diameter by 23½ feet high. These separators are designed for working pressures of 125 to 150 pounds per square inch and a safety factor of 3. Separation of oil from gas is effected by expansion of the gas, by the centrifugal scrubbing action of the fluid against the enclosing chamber walls, and by circuitous flow around
baffles. Expansion of the gas usually occurs in three steps, and centri
tugal force of the incoming fluid throws the liquid out of the gas
stream. The finely divided oil which remains as "fog" in the gas
subsequent to scrubbing is separated from the gas by mist extractors
in which nozzles impart a whirling motion to the stream or by a
labyrinth system of baffles which changes the direction of flow of
the gas frequently before it reaches the discharge outlet. The mist
extractors are installed in the upper part of the separators.

The following specification is typical of the large, low-pressure
oil-and-gas separators used in the Oklahoma City field:

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diameter</td>
<td>7 feet</td>
</tr>
<tr>
<td>Height</td>
<td>23½ inches</td>
</tr>
<tr>
<td>Steel in shell, boiler-plate</td>
<td>½ inch</td>
</tr>
<tr>
<td>Steel in heads, boiler-plate</td>
<td>½ inch</td>
</tr>
<tr>
<td>Working pressure</td>
<td>125 pounds per square inch</td>
</tr>
<tr>
<td>Test pressure (cold water)</td>
<td>200 pounds per square inch</td>
</tr>
<tr>
<td>Safety factor</td>
<td>3</td>
</tr>
<tr>
<td>Oil capacity</td>
<td>55,000 barrels per day</td>
</tr>
<tr>
<td>Gas capacity</td>
<td>150 million cubic feet per day</td>
</tr>
<tr>
<td>Inlets (4)</td>
<td>6½ inches</td>
</tr>
<tr>
<td>Oil outlets (2)</td>
<td>6½ inches</td>
</tr>
<tr>
<td>Gas outlets (3)</td>
<td>5½ inches</td>
</tr>
<tr>
<td>Float valves (2)</td>
<td>10 pounds</td>
</tr>
<tr>
<td>Weight</td>
<td>16,176 pounds</td>
</tr>
<tr>
<td>Price</td>
<td>$2,525</td>
</tr>
</tbody>
</table>

The oil is released from the separator to the gage tanks through a
discharge valve controlled by a float, which causes the discharge
valve to open when the level of the liquid in the separator rises above
a predetermined point and to close when the level falls below, so as
to prevent flow of gas into the gage tanks. The float usually is in a
chamber outside the separator to prevent the agitation and surging
within the separator from interfering with the action of the float,
and the float chamber is connected to the separator by two 1½-inch
pipe connections. The float operates the oil valve either mechani-
cally, through a system of levers and links, or pneumatically, by gas
pressure applied to a diaphragm which actuates the oil valve and is
controlled by a pilot valve operated by the float. The gas discharges
at the top of the separator into a line brought down to the ground,
where connection is made to the gathering system. Branch lines are
run from the separator discharge line to points 75 feet or more from
the well and their ends extended upward 40 to 60 feet. These gas-
relief or vent lines are equipped with semibalanced back-pressure
valves, and the vertical risers are provided with Pitot-tube connec-
tions for measuring the volume of gas flowing to the air. The
pressure in the separator is regulated by weights on the back-
pressure valves. During the initial test of the well it is customary
to release all of the gas through the vent lines direct to the
atmosphere in order to measure the flow by means of Pitot tubes.

On regular production of the well the gas from the separators is
delivered into the gas gathering lines and goes to the gasoline plant,
and the back-pressure valves on the vent lines release gas to the
atmosphere only when pressure in the separators becomes excessive.

Every oil and gas separator is equipped with a pressure gage, a
gage glass indicating the position of the oil level, and one or more
safety valves installed in the top head. Although both lever- and
pop-type safety valves are in common use for this purpose, some sep-
Separators are equipped with a hemispherical copper diaphragm which covers a flanged opening in the upper head of the separator. The diaphragm ruptures at a pressure below the safe working pressure of the vessel and leaves an unobstructed opening 10 inches in diameter through which gas rapidly escapes. A new diaphragm must be installed before operations can proceed. This safety device is available in several sizes and for various pressures and has been used on electric-driven slush pumps to protect the pump from excessive pressure.

At different times sand carried by the oil has rendered separators inoperative. Sometimes the volume of sand which accumulated in the separator was so great that separation of oil and gas could not take place, and at other times the cutting action of the sand destroyed the shell of the separator. Modifications in the design of separators have been made to overcome the effects of sand. For example, in one make of separator the shell has been extended in height, and the bottom has been made conical with a large-diameter opening at the apex of the cone. A discharge line, normally closed by a valve, is connected into the opening, and sand which accumulates in the separator is discharged at intervals to the slush pits or flow lines. The interior of the shell is protected against the cutting action of the sand by a steel wearing plate bolted to the shell at the point of entry of the stream, the flow being tangential to the wall of the shell. This wearing plate is made in four sections placed side by side, each held securely to the shell by three bolts. The central bolt holding each section in place is provided with a telltale hole, a small hole drilled from the end of the bolt to the base of the head similar to stay bolts in boilers. When the head of the bolt is worn off, leakage through the telltale hole indicates that fact, and replacement of the wearing plate is necessary.

**MUD SEPARATORS**

The wells completed during 1929 and the first half of 1930 were located in outlying districts and at considerable distances from residences. In these areas the customary method of "bringing in" a well was to bail down the mud fluid until the static head was reduced below the pressure of oil and gas entering the well; the well was then permitted to "clean itself" of mud and water by blowing to atmosphere. When clean oil appeared at the wellhead the flow lines to the separators were opened and the valve on top the Christmas tree was closed, thus shutting off the flow to the atmosphere. The period of blowing necessary to clean the well ranged from 20 minutes to 1 hour or more, during which time considerable oil and gas were wasted and a serious fire hazard existed. As the field was developed, the oil-bearing formations were found to underlie a part of the city, and the wells located close to dwellings had to be completed by less dangerous methods.

Two methods which are considered relatively safe were used in completing wells in the town-lot areas of the field. In one method a mud separator was used, and in the other, the "washing-in" method, the mud fluid in the hole was displaced with clear water instead of bailing out the fluid to reduce the static pressure on the
producing sands. Open flow of gas, oil, and mud fluid to the atmosphere is avoided in both methods.

In the first method a 12½-inch pipe carried the flow in a straight line from the wellhead to a mud separator or trap in which mud, shale, sand, and water were separated from the gas. The mud and water were discharged to the slush pits, and the gas was passed into the oil-and-gas separators. The 12½-inch delivery line was equipped with a valve, and between this valve and the wellhead 8-inch flow lines branched off at obtuse angles to the separators. After the well had cleaned itself of mud and water the lines to the separators were opened, and the valve on the delivery line was closed to cut the mud trap out of the circuit. Then the mud trap was no longer required and was removed if needed at another well.

The mud separator is a cylindrical vessel 5 feet in diameter and 15 feet high. In construction it is similar to an oil-and-gas separator, differing principally in that it has larger outlets at the bottom and float and valve mechanism designed for mud instead of oil. The float operates a pilot valve that feeds gas to a diaphragm which opens the mud discharge valve when the float rises and closes it when the float recedes to a predetermined level. The discharge valve is 10 inches in diameter and is designed to permit the passage of large solid particles. The gas outlet, which is 12½ inches in diameter, is connected to the separators by 8-inch branch lines. The mud trap has a 6-inch pop valve in the upper head and a 6-inch drain at the bottom. It is designed for a working pressure of 200 pounds and is shop-tested to a pressure of 300 pounds per square inch. Some of the traps are lined with sheet lead to protect the shell against sand abrasion. This lining increases the weight of a trap about 2,300 pounds.

Figure 31 shows an installation of separators, mud trap, and connecting lines. In this method of bringing in wells the operators used various arrangements of connections but, in general, made provision for removing the mud trap and part of the delivery line without disturbing the separators or the permanent flow lines after the well was free of mud.
The "washing-in" method of completing wells has been used to some extent in the Gulf coast area of Texas and consists essentially of reducing the static pressure of the fluid column in the well by displacing some of the drilling fluid with clear water. Ordinarily a string of tubing is run into the hole almost to the bottom, water is pumped in through the tubing, and the displaced mud fluid flows out of the top of the casing into the slush pits leaving the hole full of water. The well is induced to flow by introducing gas to displace part of the water and "rocking" the well to aerate the column in the tubing in order to lighten it until its static pressure is less than that of the formation gas. In the Oklahoma City field, however, tubing is not used, but the customary method of "washing in" the well is to displace the drilling fluid by clear water pumped in through the 3½-inch drill pipe. At a depth of 6,500 feet the formation pressure is approximately 2,470 pounds per square inch, whereas the static pressure of a column of water of this height is 2,817 pounds per square inch—a difference of 347 pounds per square inch. When all the mud fluid has been removed from the hole the drill pipe is withdrawn and the water column bailed down until the gas pressure overcomes the pressure of the water column. The well is then permitted to clean itself through the usual oil-and-gas separators into flow tanks or pits.

**GAGE TANKS**

The gage tanks used in the Oklahoma City field are of the bolted, sheet-steel type, with a capacity of 500 to 2,000 barrels. The customary tank setting consists of 6 to 12 tanks in a battery, arranged in two parallel rows. Each tank has a vaportight roof provided with a vapor vent. The 1,500-barrel tank, the size mostly commonly used, costs about $1,000 erected. Where sand accompanies the oil, settling tanks often are used between the oil-and-gas separators and the tank batteries. Settling tanks are set on elevated platforms at the tank-battery setting and have a 10-inch flanged opening in the bottom through which the accumulated sand is removed. A few settling tanks of special design have baffles at the inlets to cause the sand to accumulate along the tank walls. These tanks have conical bottoms and a system of water jets which are directed down on the apex of the cone to facilitate the removal of sand.

**FIRE PROTECTION**

Within the limits of Oklahoma City regulations require the operators to comply with certain specific measures for protection against fire. Oil tanks larger than 2,000 barrels in capacity, for example, are not permitted, and the tank battery is limited to 15,000 barrels in capacity and must be enclosed by a woven-wire fence 6 feet high supported on steel posts. The tank battery must be surrounded by an earthen dike at least 3 feet high and 3 feet wide at the top, and on the crest of the dike there must be a coping made of sheet steel one eighth inch thick and 2 feet wide welded together to form a continuous band. The coping must slope inward and upward at an angle of approximately 30° to the vertical and be supported by steel stakes. This coping is designed to prevent or retard burning oil from over-flowing the dike and to facilitate fighting such a fire. The capacity
inside the dike must be at least one and one-half times the capacity of the tank battery. Each tank must be provided with one 3-inch steam or foam connection for each 400 square feet of surface area of the contents, and the connections must be arranged so that steam or frothy mixtures can be introduced into the tank either separately or together. At each tank battery there must be one foam generator, with a capacity of not less than 1,000 gallons of foam per minute, and 1 pound of chemical for each square foot of surface area of oil contents in the tanks must be kept on hand, stored so as to protect it from deterioration by the elements. Each tank battery also must be provided with at least one water connection with an available water supply of 300 or more gallons per minute at a pressure of 75 pounds per square inch.

These regulations usually are met by providing a steam boiler, set not less than 75 feet from the well or tanks, a pump, and a foam generator. The generator is installed in a small fireproof building which also serves for storage of chemicals. The piping system includes a manifold with branch lines to the several tanks and with outlets to which chemical fire engines can be connected to assist in combating fires that are too large for the installed equipment to extinguish.

For further protection against fires some operators ground the derrick legs with copper wires attached to permanent grounds in the event the derrick should become electrically charged or struck by lightning. At a few wells water lines are provided which supply water to snuffer lines or sprinklers installed in the cellars to extinguish fires there and to keep the master valves and other cellar connections cool in the event of a fire above. The larger operators have water systems on all their leases and maintain water pressure at about 350 pounds per square inch. One company also protected tanks located in the river bed against floods by fitting each tank with a check valve on one outlet so that water would enter the tanks during a flood and prevent them from floating off their foundations. During a flood in June 1932 none of these tanks was moved by the water, whereas a large number of other tanks not equipped with these valves were displaced and damaged.

WALKWAYS

Steel walkways and stairways are used at many tank batteries, and one type consisting of plates, angles, and shapes that are punched with a series of holes and assembled with bolts, much like toy building sets for small boys, is of special interest because the great number of holes available for the bolts facilitates erection and makes it possible to adapt the structure readily to various tank installations and surface irregularities. The stairs and walkways are provided with handrails, and all walkways have toe rails. Holes are punched in the walkway plates and stair treads to safeguard against slipping. Where conditions permit, the walkways are supported on brackets bolted to the tank walls; elsewhere they are supported on angle-iron legs set on concrete footings. These walkways have distinct advantages over the wooden structures which they supplant in that they are fireproof and more durable and can be assembled and dismantled more readily. Furthermore, they can be salvaged and installed at
another location with no waste of material other than a few bolts and nuts that may be damaged in removal. If the structural members are bent or distorted, they can be straightened without difficulty. Steel walkways similar to those used at tank batteries also are used for loading racks.

Steel walkways are made in three sizes for tanks, 8, 16, and 24 feet high. The walkway for 8-foot tanks costs, erected, $2.65 per foot for 16-foot tanks, $8.20 per foot; and for 24-foot tanks, $4.60 per foot. The 8-foot stairway with handrails costs, erected, $24.80, the 16-foot stairway $47.50, and the 24-foot stairway $71.

COST OF WELLS

COST OF ROTARY-DRILLING OUTFIT

The following table gives the items which comprise the conventional steam-driven, rotary-drilling outfit and the materials required to drill a rotary hole in the Oklahoma City field after the derrick has been erected. The prices quoted represent the cost to the drilling contractor during 1930. The weight of the individual items is given in the right-hand column:

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
<th>Weight, pounds</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boiler plant:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Three 125-hp., 325-pound-working-pressure, A.S.M.E. code, boilers</td>
<td>$11,549</td>
<td>88,217</td>
</tr>
<tr>
<td>Three low-pressure gas burners</td>
<td>729</td>
<td></td>
</tr>
<tr>
<td>Firebrick</td>
<td>45</td>
<td></td>
</tr>
<tr>
<td>Two 10- by 4½- by 10-inch boiler-feed pumps</td>
<td>1,082</td>
<td>10,000</td>
</tr>
<tr>
<td>Two 8-inch steam lubricators</td>
<td>270</td>
<td></td>
</tr>
<tr>
<td>One 8-inch steam lubricator</td>
<td>95</td>
<td></td>
</tr>
<tr>
<td>One 3-kw turbogenerator</td>
<td>465</td>
<td>375</td>
</tr>
<tr>
<td>Lighting equipment</td>
<td>50</td>
<td>100</td>
</tr>
<tr>
<td>Pipe (steam, water, and gas)</td>
<td>400</td>
<td>18,000</td>
</tr>
<tr>
<td>Pipe fittings</td>
<td>1,325</td>
<td>6,900</td>
</tr>
<tr>
<td>Valves</td>
<td>1,450</td>
<td>8,416</td>
</tr>
<tr>
<td>Hand tools</td>
<td>530</td>
<td></td>
</tr>
<tr>
<td>Two steel tool boxes (1 at boilerhouse and 1 at derrick)</td>
<td>230</td>
<td>0</td>
</tr>
<tr>
<td>Subtotal</td>
<td>18,249</td>
<td></td>
</tr>
</tbody>
</table>

Drilling machinery:

One 12 by 12 horizontal, twin-cylinder, roller-bearing, steam-drilling engine, with separator and 3-inch throttle and relief valve | 2,547 | 13,800 |
One steel engine foundation | 535 | 8,000 |
One 3-shaft, 4-speed draw works, all steel, grooved drum, steel posts, roller bearings, and 4½- by 10-inch rolled-steel brake drums | 6,212 | 22,125 |
One set 15-inch steel headboards with bolts and plates | 175 | |
One set (7) steel engine and draw-works braces | 380 | |
One set steel chain guards | 550 | |
80-foot, no. 4, alloy-steel sprocket chain | 400 | 1,120 |
40-foot, no. 3, alloy-steel sprocket chain | 160 | 336 |
One 6-inch automatic caldron | 350 | 473 |
1,350 feet of 3½-inch, 6 by 19, Right-lay, steel wire line | 608 | 2,740 |
One weight indicator with 12-inch face, 100-ton gage | 335 | 122 |
One 2½-inch, fully enclosed rotary machine, complete with 14-tooth sprocket and split table bushings | 4,118 | 9,400 |
One set split drill-stem bushings, manganese steel for 6-inch drill-stem attachment | 80 | 184 |
One set split drill-stem bushings, manganese steel for 4½-inch square drill stem | 80 | 200 |
One set split drill-stem bushings, manganese steel for 3½-inch square drill stem | 80 | 213 |
One set 6½-inch drill-pipe slips | 138 | 166 |
One set 4½-inch drill-pipe slips | 138 | 159 |
One set 3½-inch drill-pipe slips | 138 | 159 |
One 6-sheave crown block | 2,000 | 7,565 |
One 76-inch, 5-sheave traveling block | 3,075 | 9,638 |

1 This is enough drilling line for 122-foot derricks; 1,750 feet of line is required for a 156-foot derrick.
### Table 6.—Cost of rotary-drilling outfit—Continued

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
<th>Weight, pounds</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling machinery—Continued.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>One 4-inch, spring rotary hook with safety latch.</td>
<td>$1,170</td>
<td>3,470</td>
</tr>
<tr>
<td>One 6-inch, rotary swivel with 6-inch by 6-foot 4-inch L.H. pin coupling</td>
<td>1,075</td>
<td>2,700</td>
</tr>
<tr>
<td>One 2½-inch by 47-foot, 12- by 13-ply, rotary hose complete with couplings</td>
<td>380</td>
<td>700</td>
</tr>
<tr>
<td>Two 14½- by 7½- by 18-inch, duplex, steam-driven, double pump on steel skids</td>
<td>5,000</td>
<td>30,000</td>
</tr>
<tr>
<td>One 6-inch, double-entry pump manifold.</td>
<td>120</td>
<td>50</td>
</tr>
<tr>
<td>One 6-inch swivel circulating head.</td>
<td>125</td>
<td>200</td>
</tr>
<tr>
<td>Subtotal</td>
<td>29,997</td>
<td></td>
</tr>
<tr>
<td>Drilling string:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>One 4-inch by 38-foot, California-type, square drill stem with full 3-inch openings</td>
<td>558</td>
<td>3,680</td>
</tr>
<tr>
<td>One upper coupling, 6-inch drill stem to 6-inch by 6-foot 4-inch L.H. box</td>
<td>60</td>
<td>100</td>
</tr>
<tr>
<td>One lower coupling, 6-inch drill stem to 6-inch by 6-foot 4-inch R.H. pin</td>
<td>52</td>
<td>88</td>
</tr>
<tr>
<td>One lower coupling, 5 by 6 R.H. box and pin</td>
<td>57</td>
<td>100</td>
</tr>
<tr>
<td>One 4½-inch by 38-foot, California-type, square drill stem.</td>
<td>342</td>
<td>1,900</td>
</tr>
<tr>
<td>One upper coupling, 6-inch by 6-foot 4-inch L.H. box to 2½-inch by 3½-inch L.H. pin</td>
<td>65</td>
<td>100</td>
</tr>
<tr>
<td>One upper coupling, 3½-inch by 4-inch by 5½-inch L.H. box.</td>
<td>42</td>
<td>88</td>
</tr>
<tr>
<td>One lower coupling, 3½-inch by 4½-inch by 5½-inch R.H. box.</td>
<td>46</td>
<td>80</td>
</tr>
<tr>
<td>One 3½-inch by 28-foot, California-type, square drill stem.</td>
<td>272</td>
<td>1,100</td>
</tr>
<tr>
<td>One upper coupling, 5-inch by 6-foot 4-inch L.H. box to 2½-inch by 3½-inch L.H. pin</td>
<td>64</td>
<td>80</td>
</tr>
<tr>
<td>One upper coupling, 3½-inch by 4-inch by 5½-inch R.H. box.</td>
<td>42</td>
<td>80</td>
</tr>
<tr>
<td>One lower coupling, 3½-inch by 4½-inch by 5½-inch R.H. pin.</td>
<td>40</td>
<td>80</td>
</tr>
<tr>
<td>Seven feet of 6-inch O.D., 25-pound, alloy-steel, seamless drill pipe</td>
<td>9,194</td>
<td>138,600</td>
</tr>
<tr>
<td>Two hundred and forty 6½- by 24-inch, alloy-steel tool joints (mounted on drill pipe at mill)</td>
<td>9,618</td>
<td>35,088</td>
</tr>
<tr>
<td>Six feet of 8-inch O.D., 16-gauge, alloy-steel seamless drill pipe</td>
<td>7,113</td>
<td>107,900</td>
</tr>
<tr>
<td>Two hundred and forty 4½- by 20-inch, alloy-steel tool joints (mounted on pipe at mill)</td>
<td>6,787</td>
<td>38,960</td>
</tr>
<tr>
<td>Seven feet of 10-inch O.D., 13.50-pound, alloy-steel seamless drill pipe</td>
<td>6,187</td>
<td>93,100</td>
</tr>
<tr>
<td>Two hundred and sixty 3½- by 20-inch, alloy-steel tool joints (mounted on pipe at mill)</td>
<td>6,019</td>
<td>11,700</td>
</tr>
<tr>
<td>Two 10½-inch rock bits, complete with lubricator.</td>
<td>572</td>
<td>2,245</td>
</tr>
<tr>
<td>Two 8½-inch rock bits, complete with lubricator.</td>
<td>573</td>
<td>985</td>
</tr>
<tr>
<td>Two 5½-inch rock bits, complete with lubricator.</td>
<td>462</td>
<td>470</td>
</tr>
<tr>
<td>One 12-inch disk bit with extra set of cutters and reamers.</td>
<td>565</td>
<td>680</td>
</tr>
<tr>
<td>One 3-inch roller bit with double, three-point reamer.</td>
<td>980</td>
<td></td>
</tr>
<tr>
<td>One overshot drill collar for 12¾-inch rock bit.</td>
<td>198</td>
<td>584</td>
</tr>
<tr>
<td>One overshot drill collar for 10¾-inch rock bit.</td>
<td>104</td>
<td>278</td>
</tr>
<tr>
<td>One overshot drill collar for 8¾-inch rock bit.</td>
<td>76</td>
<td>140</td>
</tr>
<tr>
<td>One 6-inch by 12-foot, alloy-steel drill collar.</td>
<td>234</td>
<td>1,600</td>
</tr>
<tr>
<td>One 6½- by 24-inch, drill-reamer float valve.</td>
<td>112</td>
<td>170</td>
</tr>
<tr>
<td>One 4½- by 24-inch, pipe float valve.</td>
<td>85</td>
<td>150</td>
</tr>
<tr>
<td>One 3½- by 24-inch, pipe float valve.</td>
<td>67</td>
<td>65</td>
</tr>
<tr>
<td>One 8- by 10½-inch O.D., relaying and circulating overshot.</td>
<td>325</td>
<td>360</td>
</tr>
<tr>
<td>One 4- by 7½-inch O.D., relaying and circulating overshot, complete</td>
<td>765</td>
<td>195</td>
</tr>
<tr>
<td>Two hundred and forty 4-inch rubber casing protectors for 4½-inch drill pipe</td>
<td>2,160</td>
<td>480</td>
</tr>
<tr>
<td>Two hundred and forty 3-inch rubber casing protectors for 3½-inch drill pipe</td>
<td>1,830</td>
<td>260</td>
</tr>
<tr>
<td>One 3-inch expander and core for protectors.</td>
<td>65</td>
<td>90</td>
</tr>
<tr>
<td>One 3-inch expander and core for protectors.</td>
<td>65</td>
<td>80</td>
</tr>
<tr>
<td>One 6½-inch, triple, extra-heavy, rotary elevators, less links.</td>
<td>440</td>
<td>760</td>
</tr>
<tr>
<td>One 4½-inch, triple, extra-heavy, rotary elevators, less links.</td>
<td>235</td>
<td>450</td>
</tr>
<tr>
<td>One 3½-inch, triple, extra-heavy, rotary elevators, less links.</td>
<td>280</td>
<td>370</td>
</tr>
<tr>
<td>One set 2½- by 72-inch, weldless elevator links.</td>
<td>315</td>
<td>612</td>
</tr>
<tr>
<td>Two 6-inch, two-step, spring-latch, rotary tongs, complete.</td>
<td>475</td>
<td>590</td>
</tr>
<tr>
<td>Two 3½-inch heads for above tongs.</td>
<td>218</td>
<td>300</td>
</tr>
<tr>
<td>Two 4½-inch heads for above tongs.</td>
<td>385</td>
<td>336</td>
</tr>
<tr>
<td>One 16-inch by 275-foot manila cap line.</td>
<td>48</td>
<td>165</td>
</tr>
<tr>
<td>45 feet of 2¼-inch manila cable.</td>
<td>47</td>
<td>90</td>
</tr>
<tr>
<td>500 feet of 1-inch, plain-laid, manila rope.</td>
<td>33</td>
<td>142</td>
</tr>
<tr>
<td>300 feet of 1½-inch, 6- by 19-strand, left-lay, wire line.</td>
<td>37</td>
<td>80</td>
</tr>
<tr>
<td>100 feet of 1½-inch, 6- by 19-strand, left-lay, wire line.</td>
<td>12</td>
<td>40</td>
</tr>
<tr>
<td>160 feet of ¼-inch, 6- by 19-strand, left-lay, wire line.</td>
<td>28</td>
<td>100</td>
</tr>
<tr>
<td>Wire rope clips.</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>3-inch, 8-inch, and 10-inch blocks.</td>
<td>31</td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td>58,696</td>
<td></td>
</tr>
<tr>
<td>Casing equipment:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>One 1½-inch, O.D., automatic-grip elevator.</td>
<td>1,368</td>
<td>2,450</td>
</tr>
<tr>
<td>One set 4½-inch O.D., automatic-grip elevator.</td>
<td>360</td>
<td>230</td>
</tr>
<tr>
<td>One 7-inch O.D., automatic-grip elevator.</td>
<td>986</td>
<td>1,425</td>
</tr>
<tr>
<td>One set 7-inch O.D., slips for above.</td>
<td>229</td>
<td>100</td>
</tr>
<tr>
<td>One 8½-inch O.D., automatic-grip.</td>
<td>720</td>
<td>2,050</td>
</tr>
<tr>
<td>One set 9½-inch O.D., slips for above.</td>
<td>360</td>
<td>230</td>
</tr>
<tr>
<td>One 7-inch O.D., automatic-grip.</td>
<td>631</td>
<td>1,260</td>
</tr>
</tbody>
</table>

1 This cable is unraveled and makes 3 spinning ropes.
The table does not include a bailer or a bailing line. The bailers usually are 5 inches in outside diameter and range in length from 50 to 60 feet. The contractors usually purchase the valve and bail. The bailers are made from discarded casing by a field shop. Reliable cost figures are not available; and since one bailer will serve several drilling outfits, this item has been omitted purposely from the list. The bailing line is usually a 5/8-inch-diameter, 6- by 19-strand wire line about 7,000 feet long; in the Oklahoma City field it is general practice for the operators to provide these lines to bail in the wells, therefore this item is not included in the table.

In this field 3⅛-inch drill pipe is used only 4 or 5 days on each well while drilling into the pay horizon after the flow string has been landed. For contractors who operated only 1 or 2 drilling outfits the investment in this size drill pipe was not justified, and they rented strings of 3⅛-inch drill pipe complete with tool joints and casing protectors from supply companies at $125 per day plus replacement costs for any damage sustained by the pipe during use. The drill pipe was rented with the provision that it was not to be used for fishing jobs. This rental arrangement was of mutual advantage to both parties, as the contractor's investment was reduced by about $14,000, and under the conditions prevailing the supply company received payment for the pipe in rental fees sooner than if the pipe had been sold on the basis of time payment. In the end the supply company still owned the pipe, and the value as scrap steel represented clear profit.

**COST OF WELLS EQUIPPED FOR NATURAL FLOW THROUGH CASING**

Table 7 is an estimate of the cost of an average well in the Oklahoma City field producing from the Wilcox sand and is based on prices of material and cost of labor as of November 1930. The assumption was made that the well would first produce by natural flow through the casing, then by gas lift, and finally by pumping, and the cost of changes in equipment to meet the different producing conditions was taken into account. The cost of the drilling machinery is not included, as it is usually the property of the drilling contractor. The drilling cost to the well owner is largely covered by the fourth item in the table.
The table was compiled at a time when it appeared that such a program would be the logical order of operating the field. Subsequent decline in market demand for oil has prolonged the first stage of operation indefinitely, and very few wells producing from the Wilcox sand had reached the second or gas-lift stage in November 1932. Commodity prices also have declined, so that the cost of new equipment required, as well as the salvage value of equipment released in the change-over, will probably differ from the figures given in table 7 when the time for the change-over arrives.

**Table 7.** Cost or average well in the Oklahoma field producing from the Wilcox sand

### COST OF WELL EQUIPPED FOR NATURAL FLOW THROUGH CASING (First stage)

<table>
<thead>
<tr>
<th>Item</th>
<th>Gross cost</th>
<th>Salvage</th>
<th>Net cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>122-foot derrick with reinforcing legs</td>
<td>$4,675</td>
<td>$520</td>
<td>$4,155</td>
</tr>
<tr>
<td>Labor on derrick</td>
<td>825</td>
<td>825</td>
<td></td>
</tr>
<tr>
<td>Labor on cellar and pits</td>
<td>675</td>
<td>675</td>
<td></td>
</tr>
<tr>
<td>Drilling labor</td>
<td>65,853</td>
<td>65,853</td>
<td></td>
</tr>
<tr>
<td>Casing</td>
<td>20,755</td>
<td>20,755</td>
<td></td>
</tr>
<tr>
<td>Heavy wellhead connections, clamps, valves, casing shoe, etc.</td>
<td>3,482</td>
<td>3,482</td>
<td></td>
</tr>
<tr>
<td>Cement</td>
<td>1,788</td>
<td>1,788</td>
<td></td>
</tr>
<tr>
<td>Labor, cementing casing</td>
<td>800</td>
<td>800</td>
<td></td>
</tr>
<tr>
<td>Company labor</td>
<td>1,500</td>
<td>1,500</td>
<td></td>
</tr>
<tr>
<td>Fuel, for drilling well</td>
<td>6,000</td>
<td>6,000</td>
<td></td>
</tr>
<tr>
<td>Water</td>
<td>860</td>
<td>860</td>
<td></td>
</tr>
<tr>
<td>Hauling</td>
<td>2,500</td>
<td>2,500</td>
<td></td>
</tr>
<tr>
<td>Incidental expense</td>
<td>1,000</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td><strong>Total, natural-flow well</strong></td>
<td>118,693</td>
<td>620</td>
<td>118,073</td>
</tr>
</tbody>
</table>

### COST OF WELL EQUIPPED FOR GAS LIFT (Second stage)

<table>
<thead>
<tr>
<th>Item</th>
<th>Gross cost</th>
<th>Salvage</th>
<th>Net cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tubing</td>
<td>$2,160</td>
<td>$2,500</td>
<td>$2,160</td>
</tr>
<tr>
<td>Heavy wellhead connections reclaimed</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Light wellhead connections installed</td>
<td>250</td>
<td></td>
<td>250</td>
</tr>
<tr>
<td>Labor and hauling</td>
<td>350</td>
<td></td>
<td>350</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2,760</td>
<td>2,500</td>
<td>260</td>
</tr>
<tr>
<td><strong>Total, gas-lift well</strong></td>
<td>121,453</td>
<td>3,120</td>
<td>118,333</td>
</tr>
</tbody>
</table>

### COST OF WELL EQUIPPED FOR PUMPING (Third stage)

<table>
<thead>
<tr>
<th>Item</th>
<th>Gross cost</th>
<th>Salvage</th>
<th>Net cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Additional tubing</td>
<td>$198</td>
<td></td>
<td>$198</td>
</tr>
<tr>
<td>Sucker rods</td>
<td>1,506</td>
<td>1,506</td>
<td></td>
</tr>
<tr>
<td>Gas engine</td>
<td>2,500</td>
<td>2,500</td>
<td></td>
</tr>
<tr>
<td>Rig front</td>
<td>2,300</td>
<td>2,300</td>
<td></td>
</tr>
<tr>
<td>Rig irons, etc.</td>
<td>2,500</td>
<td>2,500</td>
<td></td>
</tr>
<tr>
<td>Enginehouse and bethouse</td>
<td>800</td>
<td>800</td>
<td></td>
</tr>
<tr>
<td>Tubing and rod fittings</td>
<td>400</td>
<td>400</td>
<td></td>
</tr>
<tr>
<td>Belt</td>
<td>325</td>
<td>325</td>
<td></td>
</tr>
<tr>
<td>Circulating tank</td>
<td>200</td>
<td>200</td>
<td></td>
</tr>
<tr>
<td>Labor and hauling</td>
<td>725</td>
<td>725</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>11,454</td>
<td></td>
<td>11,454</td>
</tr>
<tr>
<td><strong>Total, pumping well</strong></td>
<td>132,907</td>
<td>$3,120</td>
<td>129,787</td>
</tr>
</tbody>
</table>

### COST OF LEASE EQUIPMENT (Excluding main service systems)

<table>
<thead>
<tr>
<th>Item</th>
<th>Gross cost</th>
<th>Salvage</th>
<th>Net cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Separators, tanks, etc.</td>
<td>$15,746</td>
<td>$9,445</td>
<td>$6,301</td>
</tr>
<tr>
<td>Water system</td>
<td>1,983</td>
<td></td>
<td>1,983</td>
</tr>
<tr>
<td>Gas system</td>
<td>651</td>
<td></td>
<td>651</td>
</tr>
<tr>
<td>Boilers, for field pump, etc.</td>
<td>1,948</td>
<td></td>
<td>1,948</td>
</tr>
<tr>
<td>Lease roads</td>
<td>117</td>
<td></td>
<td>117</td>
</tr>
<tr>
<td>Gas-lift plant equipment</td>
<td>10,500</td>
<td>8,925</td>
<td>1,575</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>30,045</td>
<td>18,370</td>
<td>11,675</td>
</tr>
<tr>
<td><strong>Grand total</strong></td>
<td>162,952</td>
<td>21,490</td>
<td>141,462</td>
</tr>
</tbody>
</table>
General conversion of the wells to the gas-lift stage of operation will not be made until the market demand and the price of oil justify the additional investment.

A number of the operators have moved serviceable producing equipment from Seminole and other nearby oil fields where it was no longer needed. These items as well as gas for fuel do not represent a cash outlay, but their value is included in the estimate. The average cost of an oil well in the Oklahoma City field, covering the three stages of its productive life, is therefore about $141,500.

The casings are cemented on contract by well-cementing companies, but the owners of the well furnish the cement and the labor necessary to dump the cement into the mixer. The cementing company charges $75 to $100 for cementing the surface pipe, $290 to $415 for cementing the 9%-inch casing (depending on whether one or two cementing trucks are required), and $215 to $225 for cementing the 7-inch flow string. The cement costs about $0.75 per 100-pound sack in carload lots, and an additional cost for hauling the cement to the well location makes the total cost for cement about $1,788 per well. Usually 28 to 40 men are required to dump the cement into the hopper of the mixer, and the cost of this labor for the three cementing jobs amounts to about $800 per well.

TRANSPORTATION FACILITIES

Transportation arteries are of primary importance in developing any oil field, as well as in marketing its production. The Oklahoma City field is particularly well-favored with respect to railroads and highways. Five steam railroads and one electric road serve the city; also one paved highway, US 77, skirts the western edge of the field, while another paved road, Oklahoma highway 3, the main route between Oklahoma City and Shawnee, Okla., crosses the field from west to east. On this artery 12 or more of the supply companies which serve the midcontinent area with oil-field equipment have established branch stores so that necessary supplies are available immediately. Well-graded roads, of which some are hard-surfaced traverse the field along the section lines. The topography is favorable for easy road construction, and lease roads to well locations were built at comparatively low cost.

Suitable major highways and lease roads have contributed greatly to the expeditious movement of drilling equipment in the field. Most of the hauling is done with 5-, 7-, and 10-ton trucks equipped with trailers, and most of the well locations in the field are accessible to these vehicles. The roads in the north end of the field in the bed of the river, however, are impassible during part of the rainy season because of soft soil and poor drainage, and heavy equipment has to be moved over them with tractors and “crawler” wagons equipped with track-laying devices in place of wheels.

The trucks used by the drilling contractors have demonstrated the adaptability of the modern automobile truck to oil-field service. They are equipped with hoisting winches and removable A-frame cranes, which materially increase their usefulness for loading the heavy pieces of equipment. The winch is mounted on the bed of the truck adjacent to the driver's cab and is driven by the truck engine
through a power take-off controlled by the driver. The hoisting drum is provided with a rack and pawls which engage the teeth of the rack, permitting the load lifted to be held suspended on the winch line. A cathead mounted on the end of the drumshaft provides an auxiliary lifting or pulling means. The winch and crane are powerful enough to lift a slush pump weighing approximately 15,000 pounds and place it on its foundation.

The winch truck is especially convenient in loading casing and drill pipe. The truck to be loaded is “spotted” lengthwise with the pipe rack, and a winch truck is backed up to the other side of the first truck so that the crane extends over it. For this service the winch line is fitted with a bridle with hooks in the two cable ends which engage the ends of the pipe. The pipe is lifted by the winch, swung over the hauling truck, and placed in position on the load. The operation of loading a 125-hp. boiler on a 6-wheel truck and 2-wheel trailer with one of these winch trucks was witnessed, and the facility with which the hoisting winch performed was well demonstrated. The hauling truck and trailer were “spotted” alongside the boiler with the trailer at the smoke-box end of the boiler. Timbers and blocks were laid between the boiler and truck to form a ramp. From a winch truck backed up to the other side of the loading truck a winch line was passed over the first truck and made fast to the boiler, so that when power was applied the boiler rolled up the ramp onto the hauling truck. Three stops were made to change the hitch of the line in order to continue the rolling motion of the boiler until it landed on the truck. The boiler was loaded and lashed onto the truck ready to start on its journey in 45 minutes; only six men were engaged in the work.

Winch trucks also are used to level and align the boilers in a battery when rigging up to drill. After the boiler is in an upright position with one end resting on the firebox the firebox end is raised into position by tilting it to either side and blocking up the elevated corner of the firebox. The tilting is done by means of the winch line attached to the steam dome. The smokebox end of the boiler is lifted by means of the winch line, passed over the rear end of the truck backed up to the end of the boiler, and made fast to the rim of the boiler shell at the lowest point. Applying power to the winch lifts the end of the boiler, and it is held on the line until the blocks on which it is to rest are placed.

Teams are used only for hauling equipment to “wild” wells or through areas where gas is known to exist and internal-combustion engines cannot be used because of the fire hazard attending their operation.

SALT-WATER DISPOSAL

Salt water is produced with the oil by some of the wells in the Oklahoma City field, especially in the eastern part of the field where the oil occurs in silicious limestone formations which contain large quantities of salt water. It appeared early in the producing life of wells drilled into the silicious limestone and rapidly increased in volume as the wells continued to produce.

Purchasers of crude require that the oil must not contain B.S. or water in excess of 1 percent to be acceptable to the refiner.
Chemicals to accelerate the separation of salt water from the oil are introduced into the flow lines between the wellhead and separators by means of hydrostatic "lubricators" of about 5-gallon capacity. The agitation within the separators causes intimate mixing of the chemicals with the fluids produced from the well. The liquid mixture from the separators flows to a treating tank equipped with steam-heating coils, and gravity separation of water from the oil is effected through the application of heat. The water drawn off the bottom of the treating tanks flows to gathering ponds and the water-free oil is pumped to gage tanks.

Some of the major operating companies have cooperated in building a water-disposal system whereby salt water in the gathering ponds on the leases is pumped to an outfall line, the intake of which is at the point of greatest elevation in the field. From this point the water flows by gravity about 8 miles to a pond having an area of 25 acres and is disposed of by evaporation. Figure 32 shows the salt-water gathering system.

The trunk gathering line, which begins near the center of sec. 13, T. 11 N., R. 3 W., runs eastward to the range line and then south along the section line about 2 3/4 miles. It then runs southwest to the intake end of the outfall line at the center of sec. 36, T. 11 N., R. 3 W. The first three quarters mile of the line is of 10-inch pipe, the next one quarter mile of 12-inch pipe, and the remainder of 16-inch pipe. The size of the trunk line is increased at each point where a lateral line joins it. At the center of sec. 36 the trunk line terminates in a system of headers and a metering station. A 6-inch lateral line from leases in the southeastern part of the field also connects at this point.

The meter station consists of two installations of orifice meters, one in the trunk gathering line and the other in the 6-inch lateral line. The meter setting on the trunk line consists of two parallel horizontal "runs" of 12-inch pipe about 40 feet long, connected at both ends to 16-inch headers. Each "run" or branch has a gate valve at both ends, an orifice flange union at the center, and a check valve adjacent to the valve on the outlet end. The outlet header is welded to an inverted U-trap or siphon which connects to the buried header on the outfall line. The top of the siphon has a bleeder valve and vent for discharging air. The meter setting on the lateral line is of 8-inch pipe and differs from the meter setting on the trunk line in that the check valves are omitted and the two branches do not connect to headers. The quantity of water flowing through the lines is determined from 24-hour charts recorded by the meters, and these records serve as the basis for calculating what part of the operating costs of the disposal system is chargeable against the several leases served.

The outfall line is 20 inches in diameter and extends from the center of sec. 36, T. 11 N., R. 3 W., to the evaporating pond in sec. 31, T. 10 N., R. 3 W., a distance of about 8 miles. The outlet end is about 175 feet lower than the intake, giving an average fall of 22 feet per mile, which is enough to give the line ample capacity for the present rate of water production from the leases served. Later, if it becomes necessary, the capacity of the line can be more than doubled by installing pumps and pumping the water at a pressure
Figure 32.—Salt-water gathering system.
of 125 pounds per square inch—the safe operating pressure for which the line was built.

All the lines in the salt-water disposal system are of spiral-welded pipe, a comparatively recent development in pipe manufacture. The strength and light weight of spiral-welded pipe make it suitable for many uses where seamless or lap-welded pipe would be too expensive to buy and lay. Spiral-welded pipe is made of sheet-metal strip wound in helical form over a mandrel with the edges of the sheet joined by a lock seam, arc-welded on the outside. The finished pipe has a helical, outside rib, and a smooth interior, except for a slight groove at the joint. The material of which this patented pipe is made is an alloy of iron, copper, and molybdenum which is easily worked and readily welded. The light weight of this pipe makes 40-foot joints as easily handled as 20-foot joints of standard pipe of the same diameter. Since it is made of sheet stock, shop inspection is facilitated, closer tolerances in wall thickness are possible, and economical distribution of material throughout the cross-section of the pipe is attained.

Consequently, there is a saving in weight of material used in this special pipe over that of ordinary butt-welded, lap-welded, or seamless pipe of equivalent size and strength, and this saving correspondingly reduces the cost of transporting and distributing the pipe in rough country. The flexibility inherent in the seam of the spiral-welded pipe enables the pipe to absorb the longitudinal forces set up by temperature changes without overstressing the material. The helical rib formed by the seam also stiffens the pipe and increases its resistance to bursting and collapse. Each joint of 20-inch pipe was given an internal hydrostatic test of 325 pounds pressure per square inch at the mill, and the tests indicate that the ultimate bursting pressure of the 20-inch pipe is greater than 700 pounds per square inch. Other tests show also that the 20-inch pipe will withstand a collapsing pressure of 80 pounds per square inch. Both of these test results exceed calculated values obtained from the formulas ordinarily used for determining the strength of thin tubes. The pipe is made in 40-foot joints with pipe ends of standard weight and thickness, grooved for Victaulic couplings. A joint of 20-inch pipe, for example, weighs about 1,400 pounds.

A thin coating of paint was applied to the pipe at the mill, and a heavy coating of enamel was applied in the field. The pipe was first cleaned of dirt, then dipped one joint at a time into a vat of hot primer, and then into a vat of hot enamel. The coating is about three thirty-seconds inch thick; has a smooth, glassy surface; and increases the weight of each joint of 20-inch pipe about 280 pounds.

The outfall line of the water-disposal system crosses under the tracks of the direct-current electric railway running from Oklahoma City to Norman, Okla., and considerable trouble from leakage has been experienced in this section of the line. Investigations of the cause of leakage indicated that the trouble was caused by electrolysis due to return current leaking from the track circuit. The salt water has high electric conductivity which materially aggravated the destructive effects of electrolysis. The thickness of the coating of paint on the pipe was not always uniform, nor was it entirely homogeneous, as air bubbles were sometimes included in the enamel coating; at such points the coating broke down and permitted the
stray electric current to concentrate, and penetration of the wall of the pipe rapidly followed. Remedial measures, which consisted of installing buried copper conductors in parallel with the railway tracks and bonding them to the pipe, greatly reduced the deleterious action of stray currents and practically eliminated leakage from this source. The poor condition of the track circuit of the railway was attributed to the fact that many of the copper rail bonds had been stolen while the railway was not in service.

CONCLUDING STATEMENT

Every oil field during its development stage brings out new pieces of equipment (or new methods of procedure) designed to meet special requirements. When they have proved their efficacy in solving peculiar difficulties, reducing costs, and increasing efficiencies, usually these devices become part of the "working tools" of the industry, replacing the worn-out equipment, sometimes less efficient and at other times made obsolete by the newer equipment. On the other hand, some pieces of equipment and methods of operation are so "standard" in design or basic in principle that they are subject to few, if any, radical changes.

In general, good design has been identified with the development of mechanical equipment used in the Oklahoma City field and the demands of the field have been met by the equipment manufacturers. Refinement in design and the use of high-strength alloy materials which have improved the qualities of other industrial machinery are apparent in the new equipment used in this field. Examples of this trend to apply to the oil field developments in other industrial lines are the roller bearings and alloy-steel shafts of the new types of draw works and drilling engines.

Naturally a few errors were made, but these resulted in improvement; and the industry now has heavier, more rugged equipment than was previously used east of the Rocky Mountains to meet the problems of penetrating the earth's crust to still greater depths. Higher pressures can now be met successfully in more efficient ways, and flows of oil and gas from deep-lying formations can be controlled more satisfactorily.

The effect of the next development of a major oil- and gas-producing area, if and when it may occur, upon the design and construction of "tools" and methods described in this paper, can only be determined in retrospect from a future time-reference point. Based upon observation and study in the Oklahoma City field, the following items of construction and operation are germane to the subject of future development of mechanical equipment in the oil industry, both from safety and efficiency standpoints.

(1) The limiting capacity of the draw works depends upon the brakes on the hoist. The brakes are of the friction band type and although the best lining material obtainable is used, their service life is short and the maintenance expense considerable. Water cooling to expedite dissipation of heat and thus prolong the life of the brakes has been resorted to, but this method cannot be expected to be adequate for much increase in drilling depth. Clouds of vapor from the cooling water evaporated often engulf the derrick floor in cold weather, creating a potential accident hazard.
(2) There is need for stronger and more durable rotary hose that will still be flexible enough and have an ample factor of safety if it becomes necessary to increase mud pressure much above the magnitude used in this field. Unless pump pulsations are reduced, the mud pressure cannot be increased materially without danger of rupturing the armored-fabric rotary hose now used. Sectional all-steel rotary hose can be made amply strong but has the disadvantage of not being as flexible as is desirable when under pressure.

(3) The large size of steam boilers used in drilling in this field is perhaps more the result of the drilling contractors' ideas of what was required than of the boiler manufacturers' judgment in design. Some boilers are so large and heavy that they cannot be moved over the highways by truck without violating State regulations on weight limitations and load distribution.

Although the high boiler pressure used in this field probably will not become general practice in other oil fields for some time, indications are that the trend is toward the use of higher steam pressures.

The adoption of superheated steam in oil-well drilling is a logical step of advance. The type of superheater boiler used in this field is somewhat difficult to clean internally. This is a matter of considerable importance, for it is almost axiomatic in boiler practice generally that any point of design that increases the difficulty of cleaning will result in a boiler that will not be kept clean.

Field experience obtained with the separate, individually fired superheater that has been used in California oil fields, together with that gained from the use of superheater boilers in the Oklahoma City field, undoubtedly will indicate the form of superheated-steam generator that will be most practical for oil-field service.

(4) Although more a matter of planning than of mechanical design, the orientation of derricks directly influences the placement of equipment so that workmen can get utmost service out of it without exposing themselves to unnecessary hazards. In the Oklahoma City field, in common with many other fields, there is no general practice followed of orienting the derrick so that on tubing and rod-pulling jobs the hoist operator will not be obliged to face the sun in observing equipment hoisted into the derrick. Where terrain permits orienting the derrick in any direction, this point should be considered, rather than arbitrarily setting up either parallel or perpendicular to property lines.