June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

Filed July 30, 1959 17 Sheets-Sheet 1

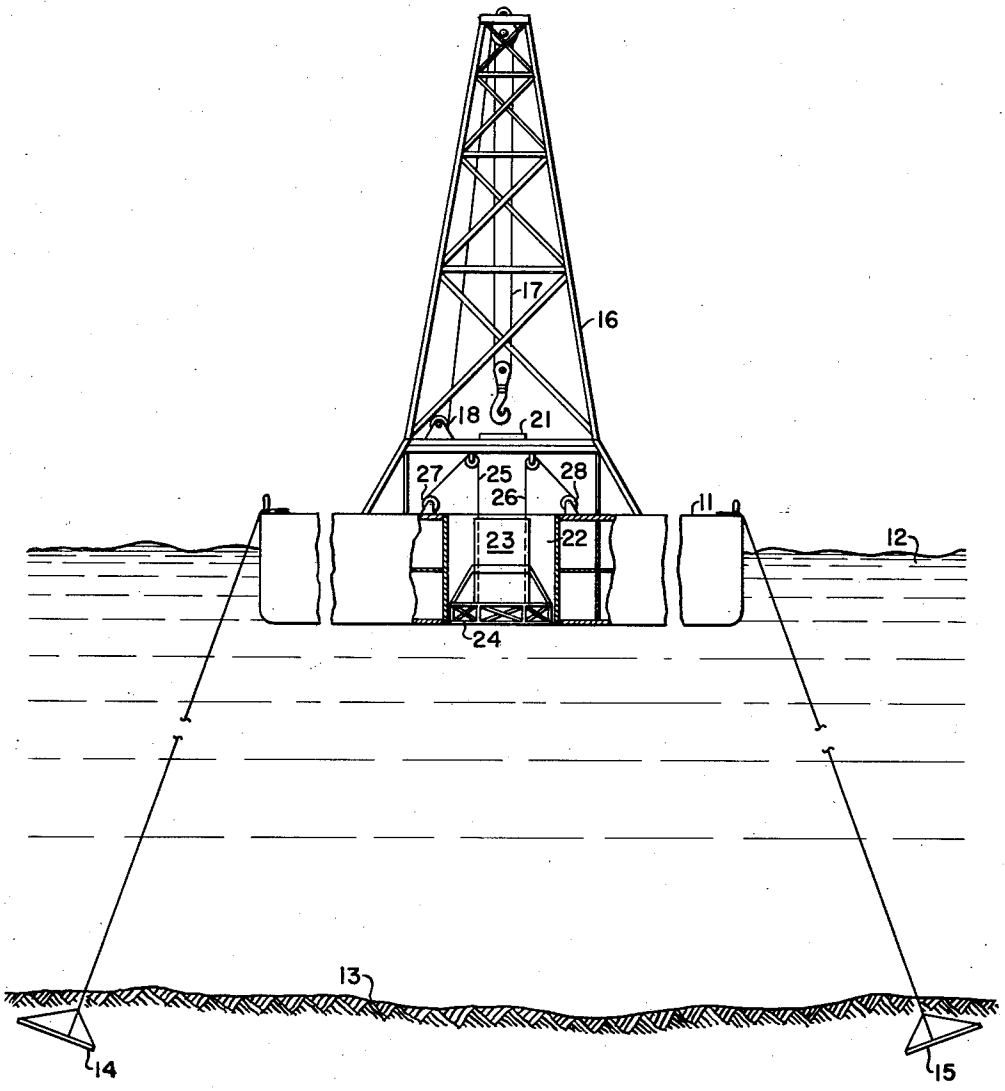


FIG. 1

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BY: J. H. McCarthy
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UNDERWATER WELL COMPLETION METHOD

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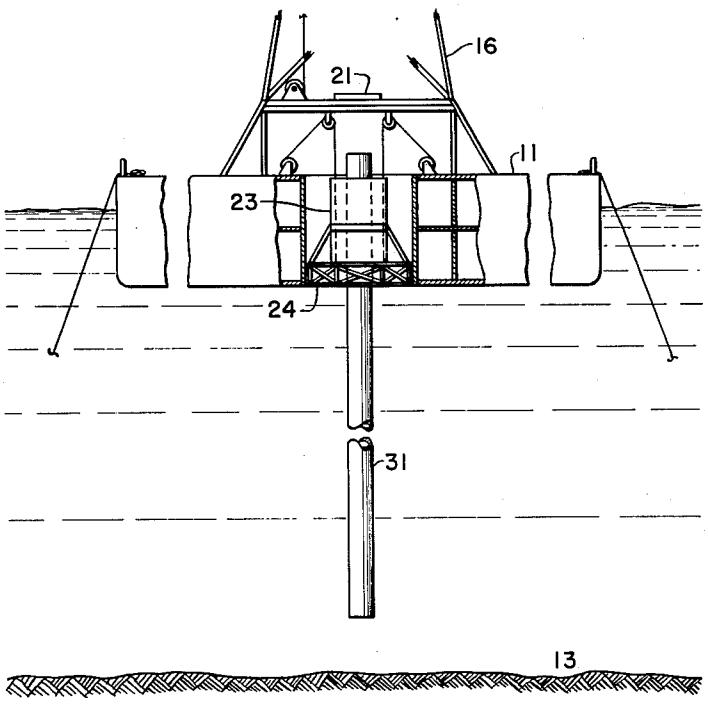


FIG. 2

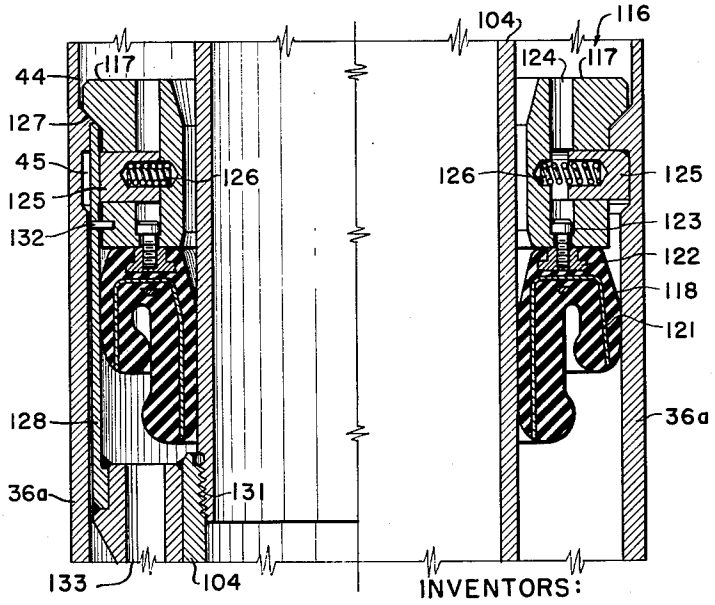


FIG. 19

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BY: J. H. McCarthy
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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

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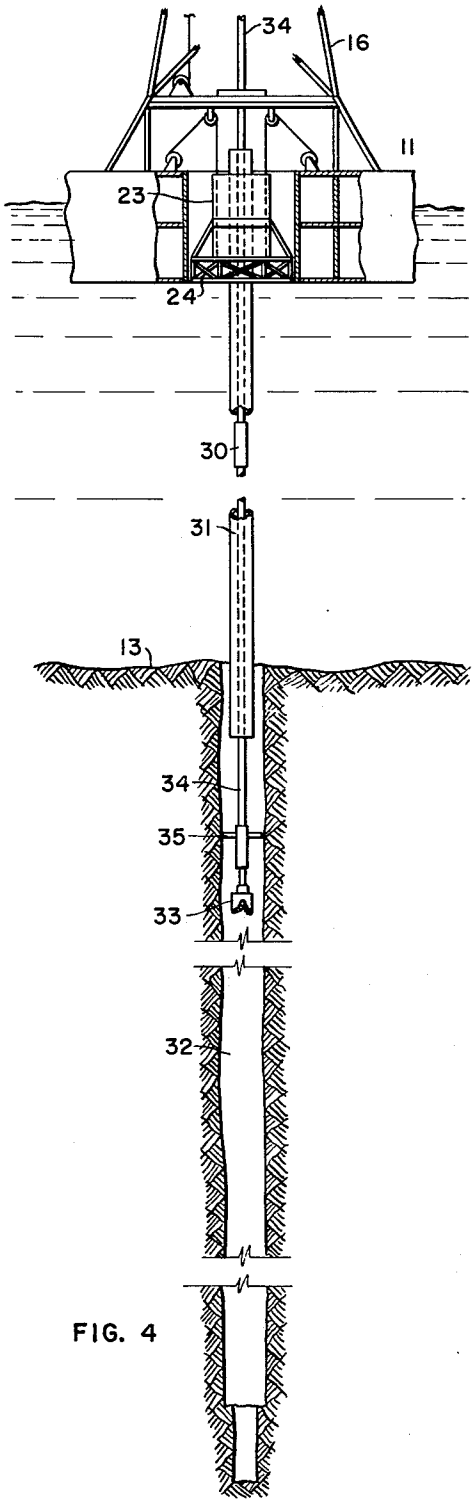


FIG. 4

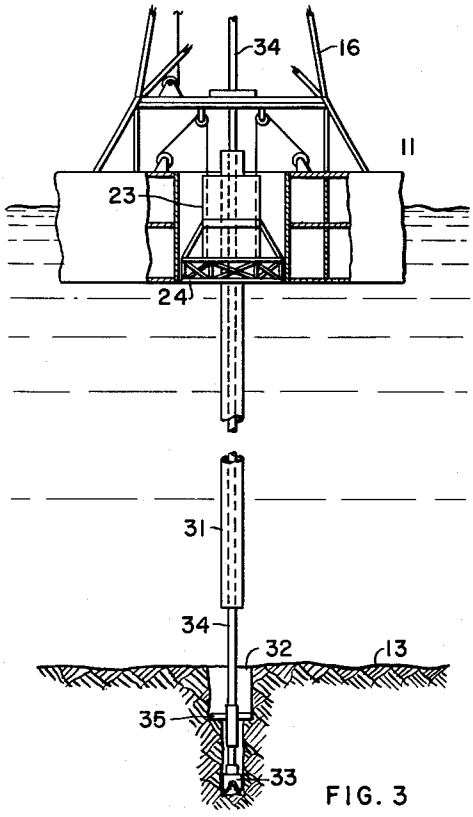


FIG. 3

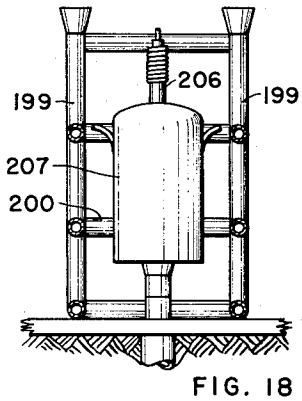


FIG. 18

INVENTORS:
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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

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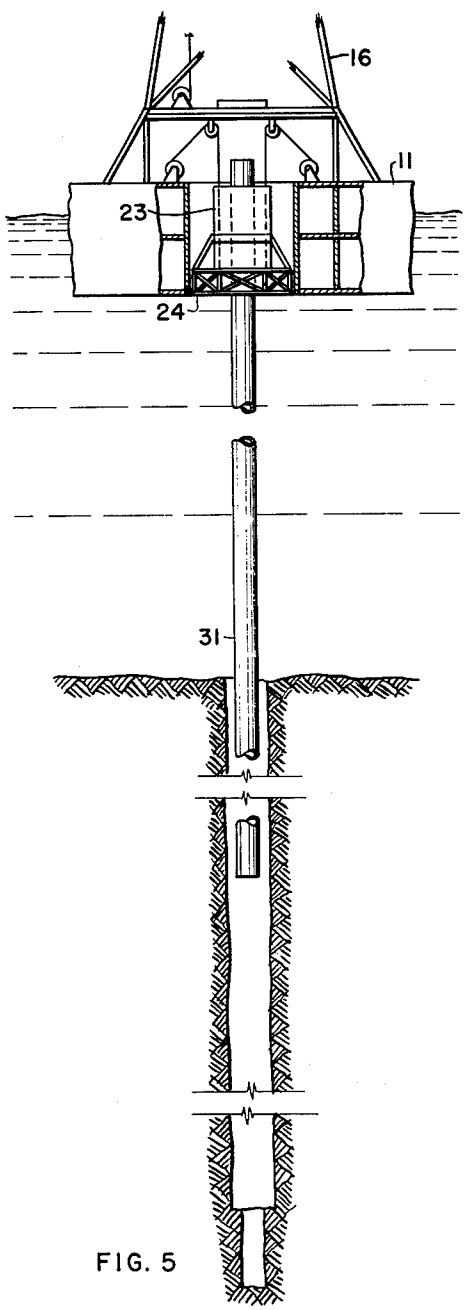


FIG. 5

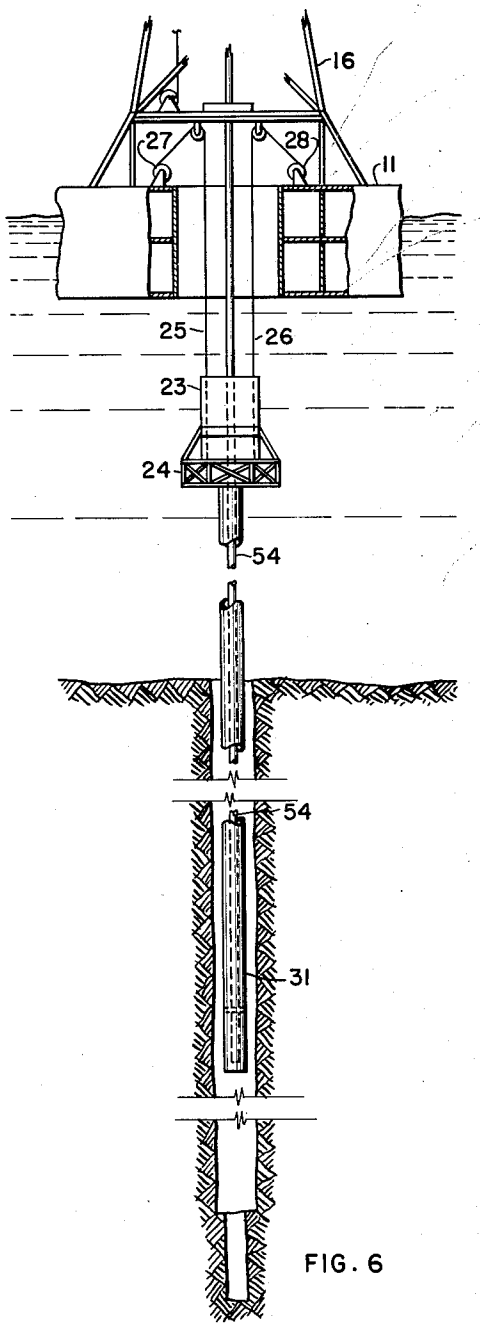


FIG. 6

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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

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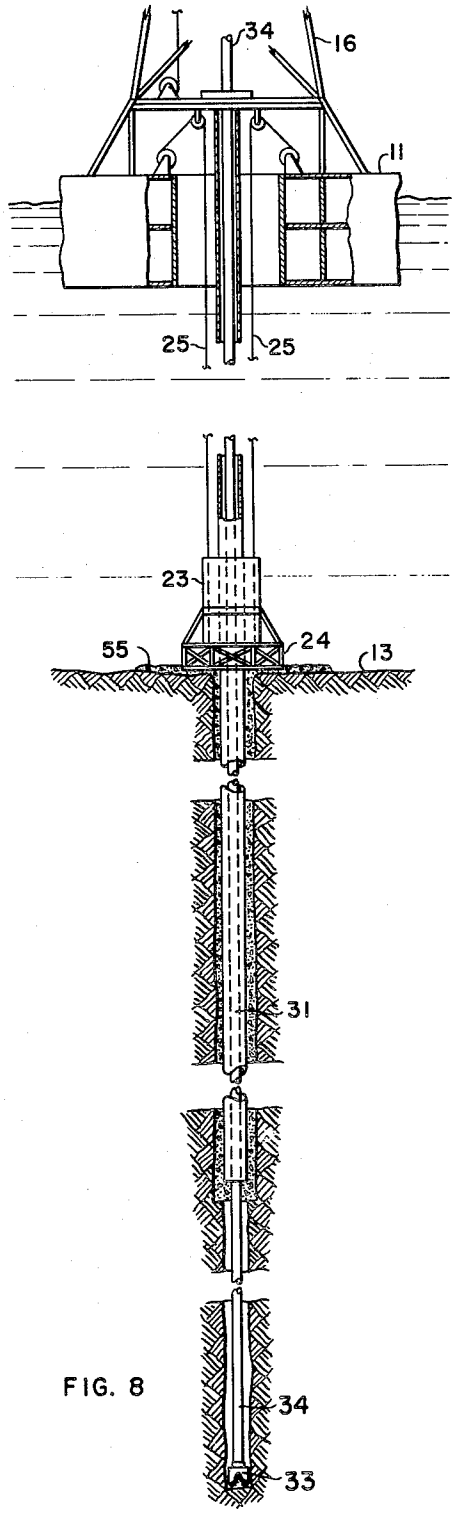


FIG. 8

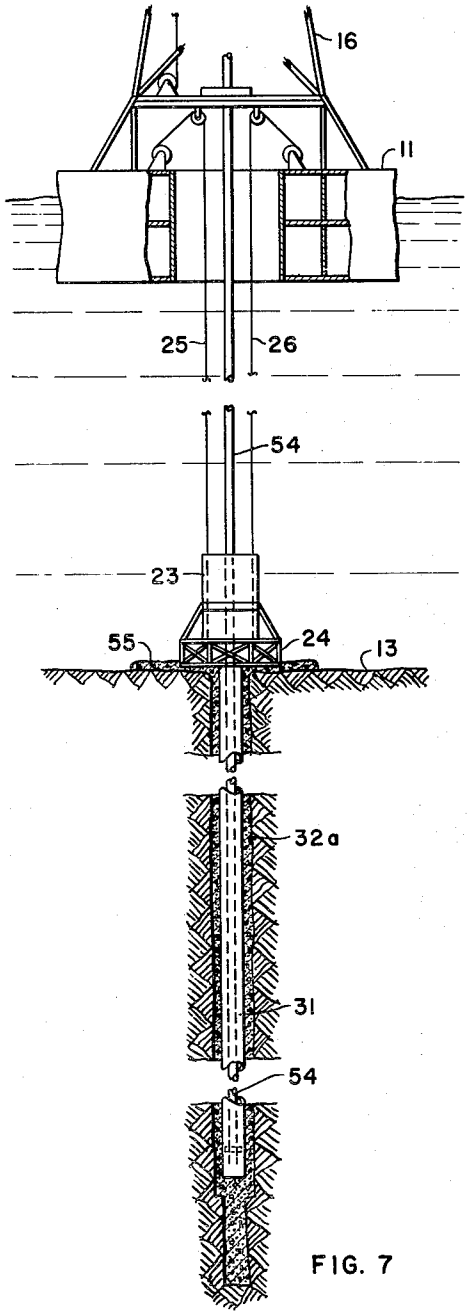


FIG. 7

INVENTORS:
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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

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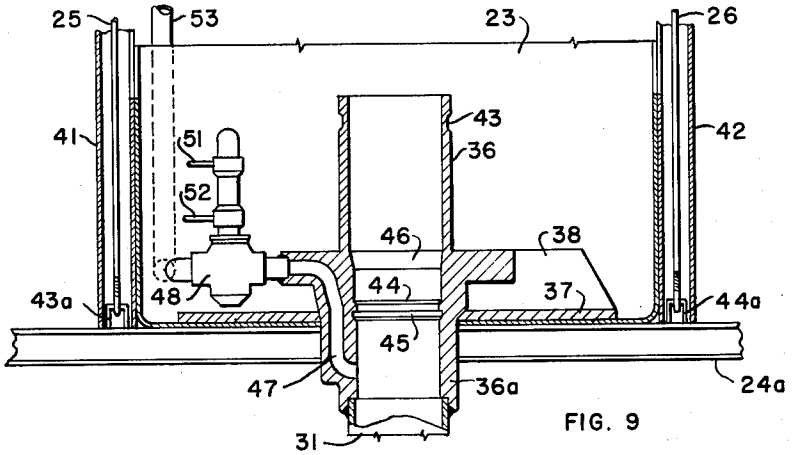


FIG. 9

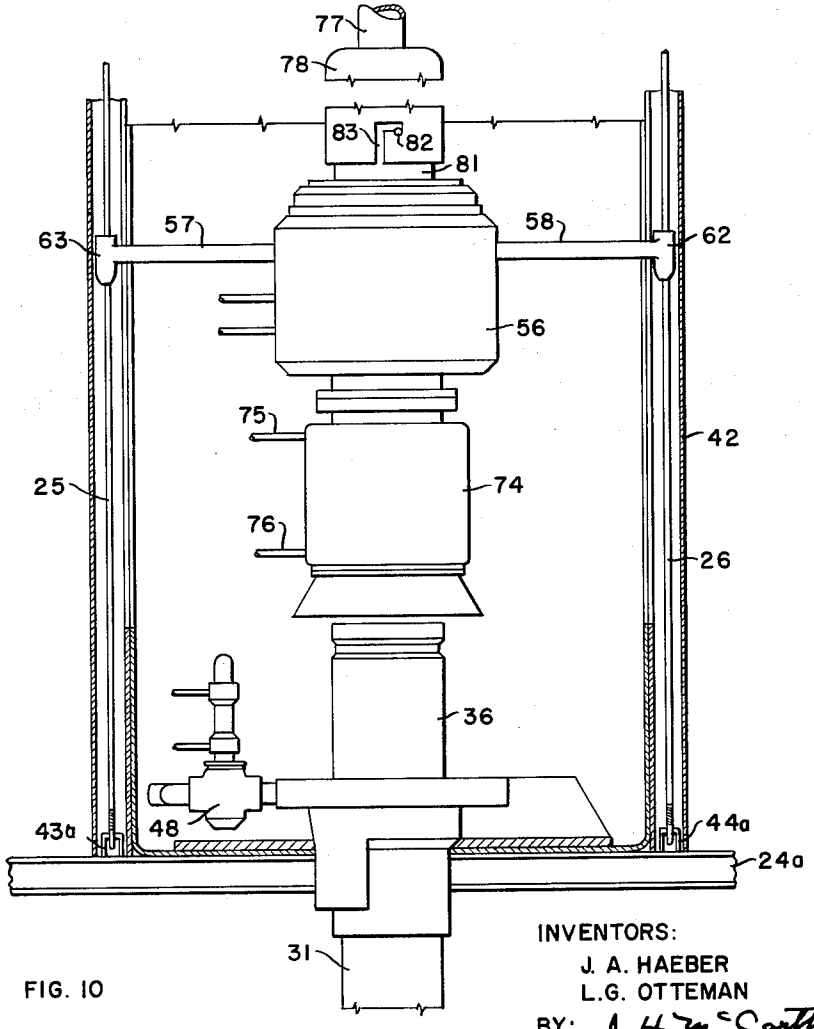


FIG. 10

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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

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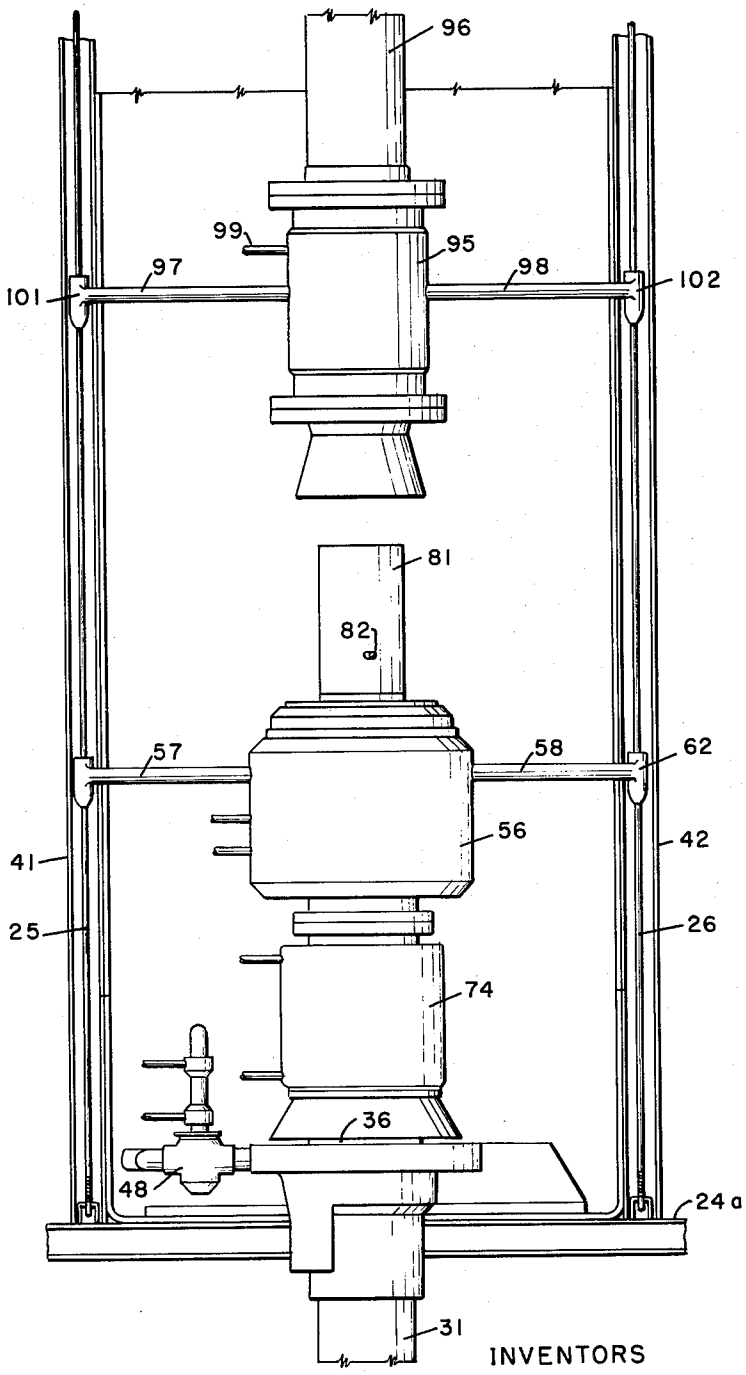


FIG. 11

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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

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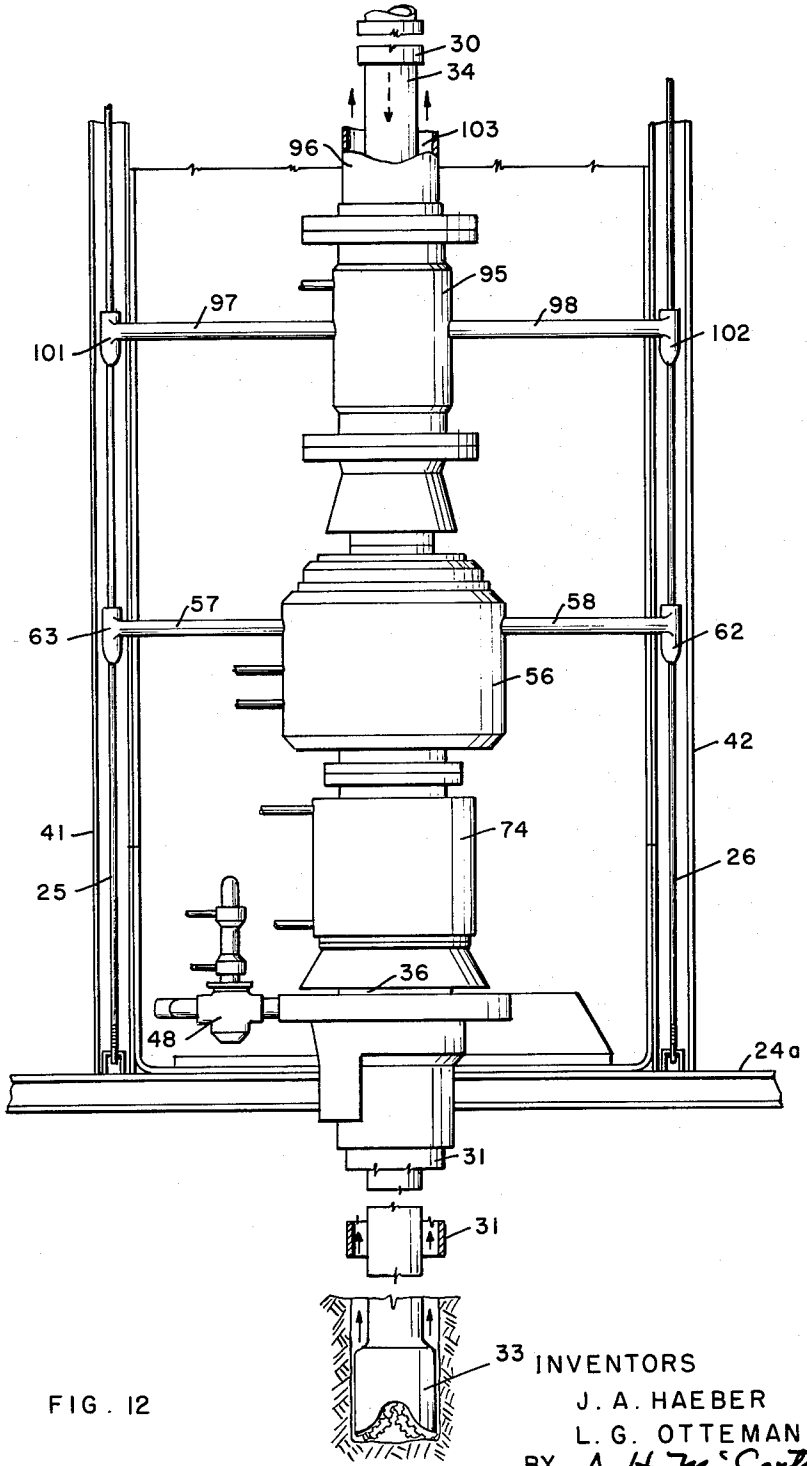


FIG. 12

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UNDERWATER WELL COMPLETION METHOD

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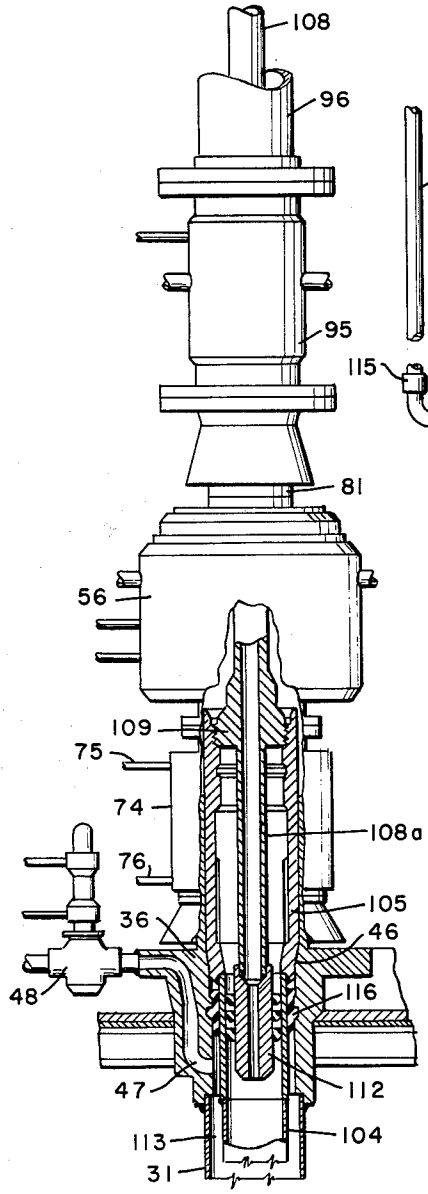


FIG. 13

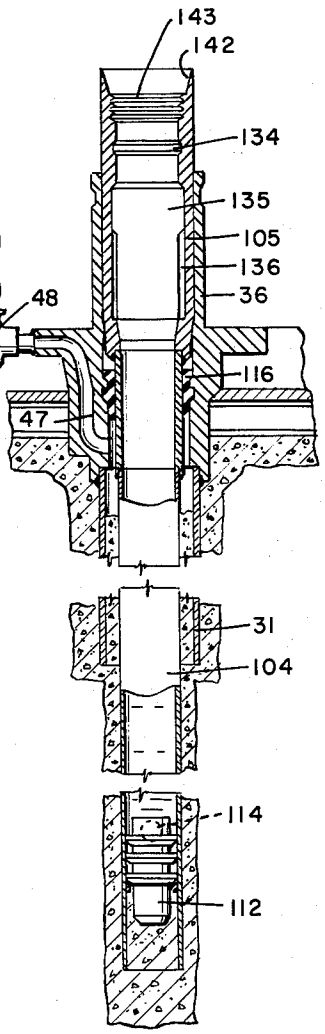


FIG. 15

INVENTORS
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BY J. H. McCarthy
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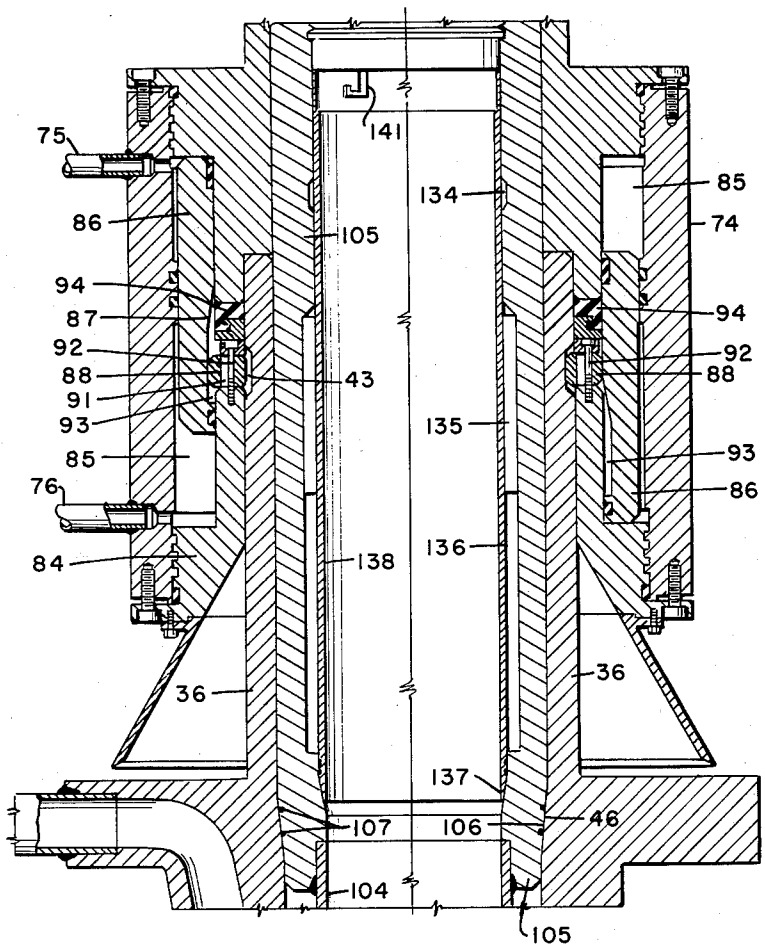


FIG. 14

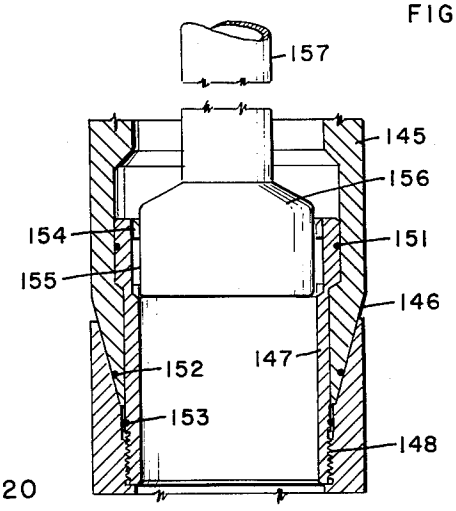


FIG. 20

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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

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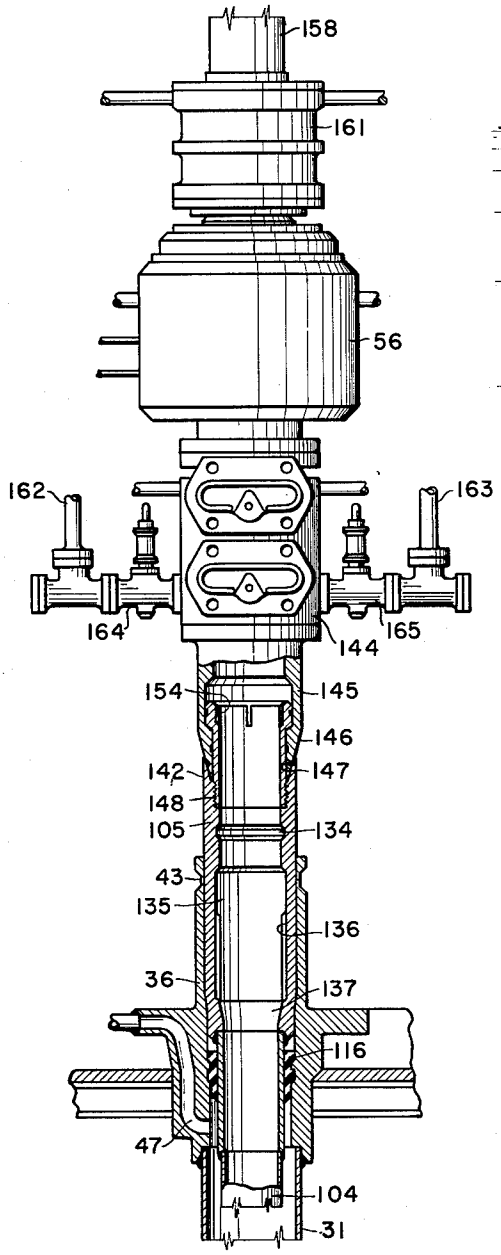


FIG. 16

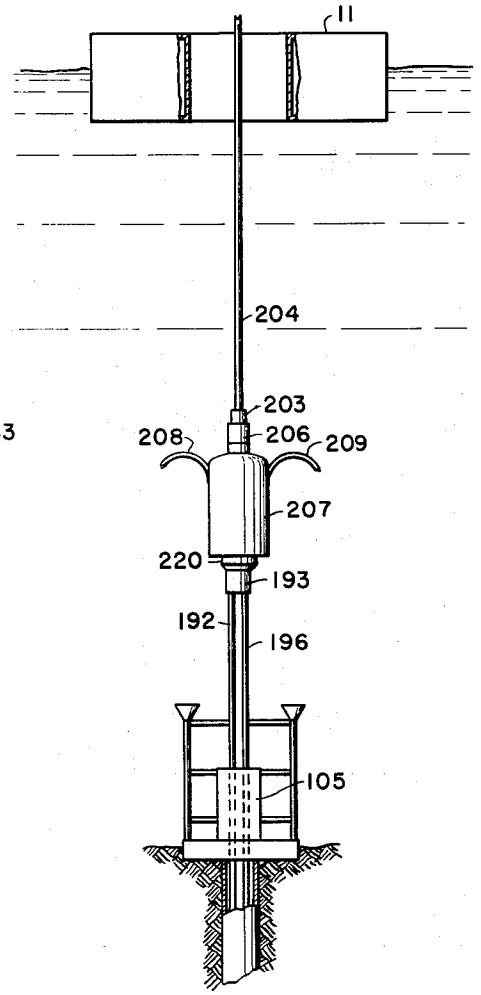


FIG. 17

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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

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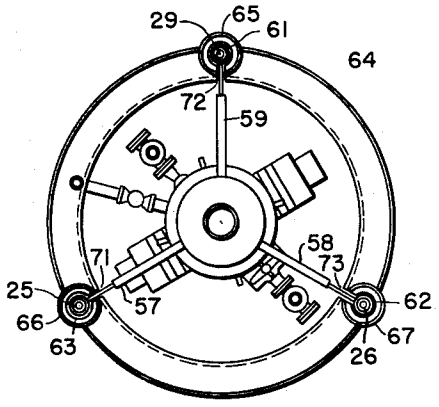


FIG. 22

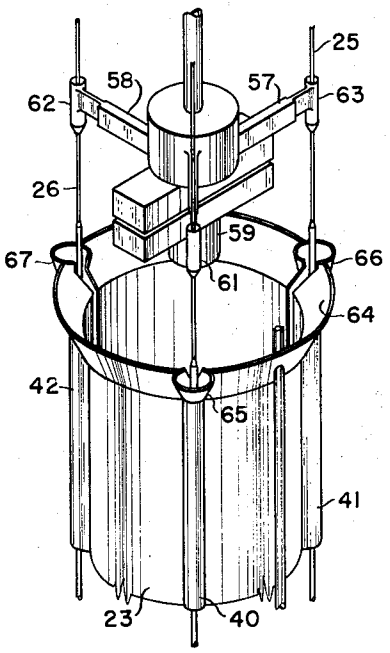


FIG. 21

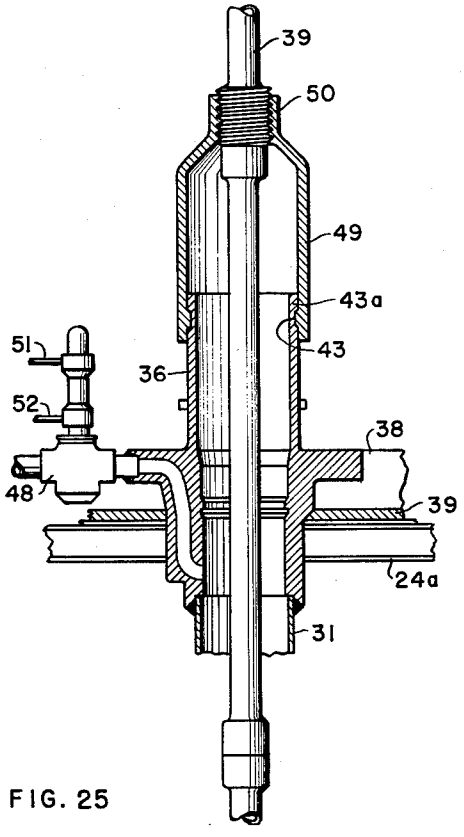


FIG. 25

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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

Filed July 30, 1959 17 Sheets-Sheet 13

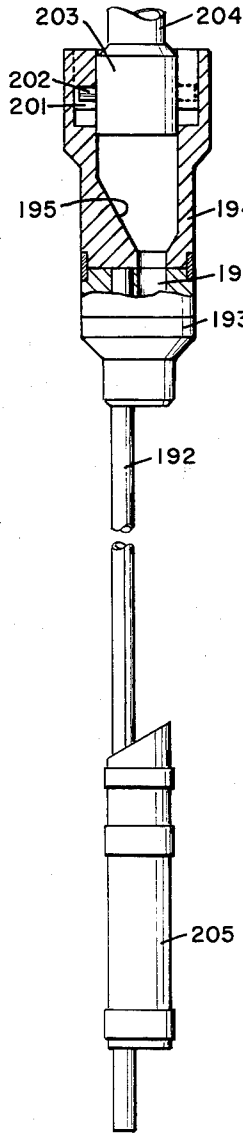


FIG. 23

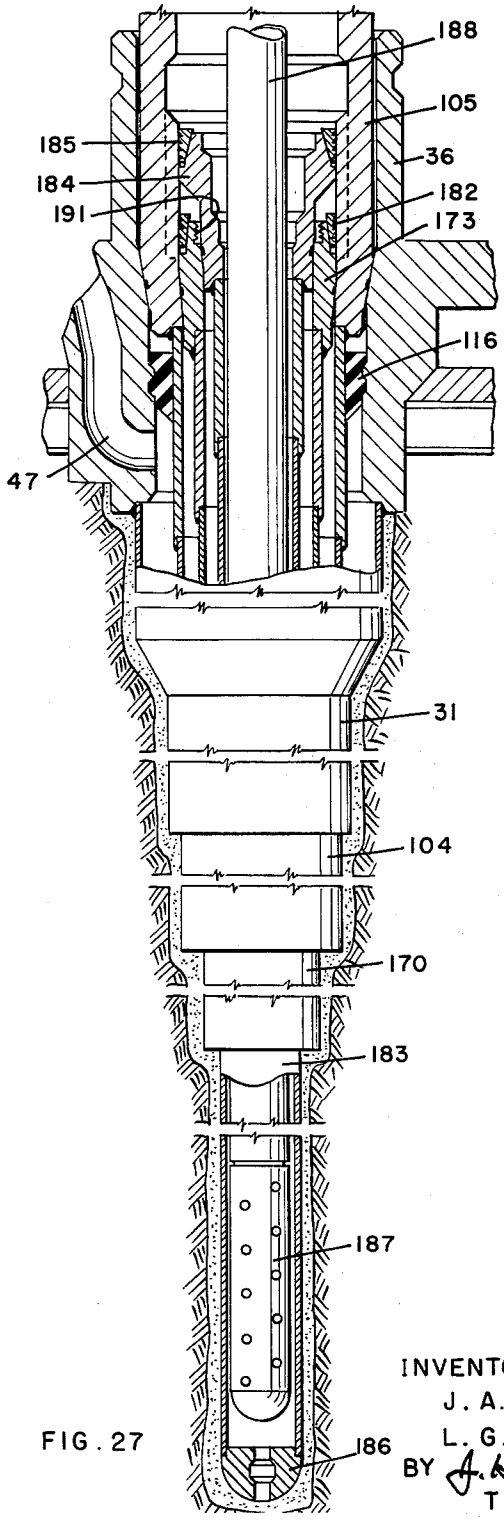


FIG. 27

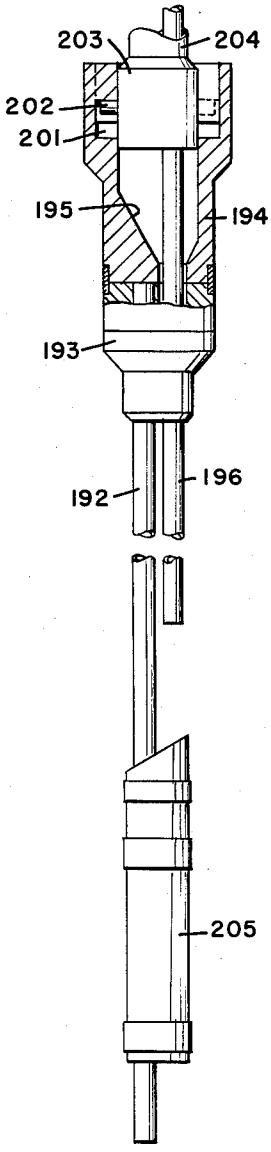


FIG. 24

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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

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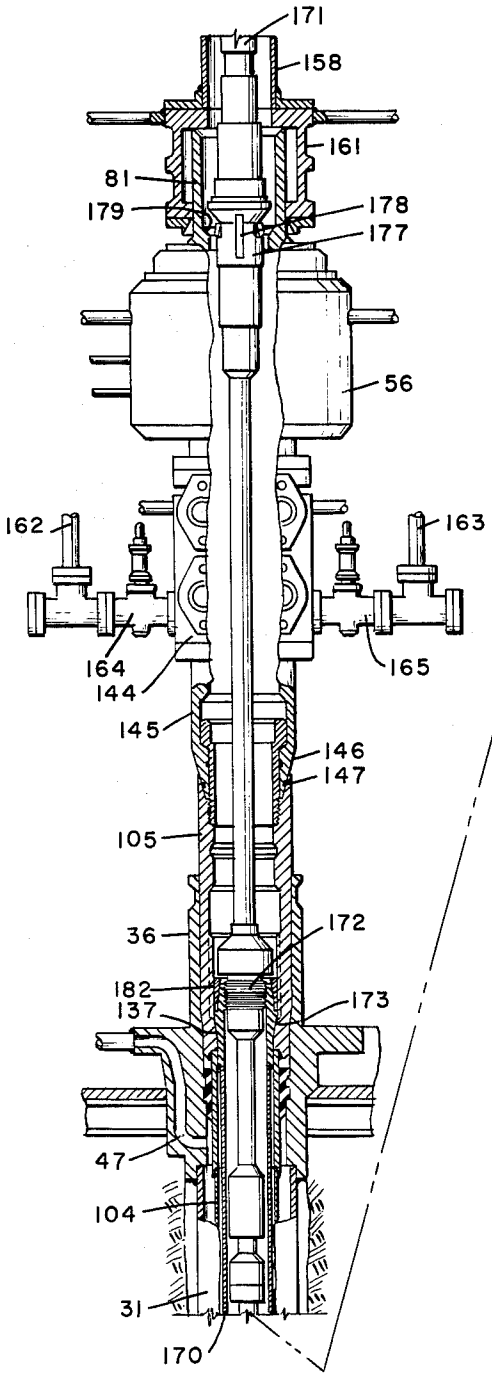


FIG. 26 a

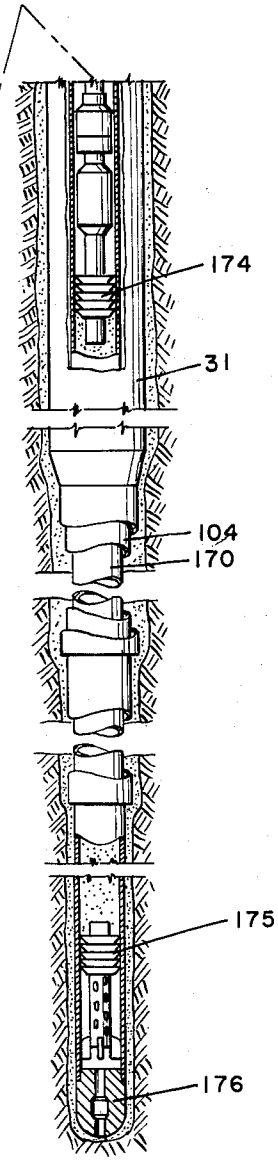


FIG. 26 b

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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

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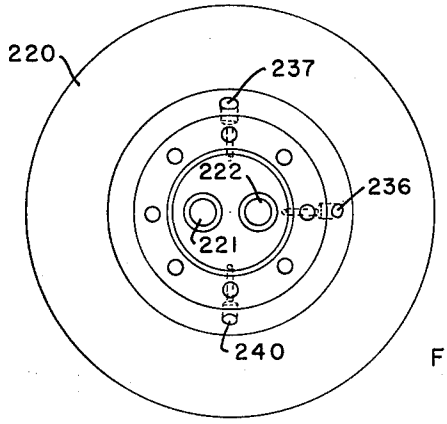


FIG. 35

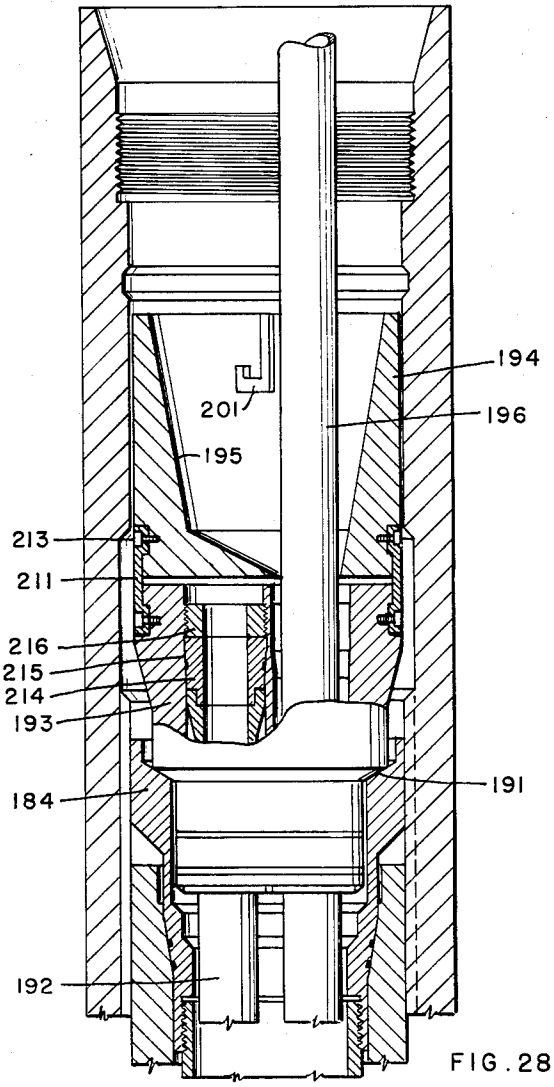
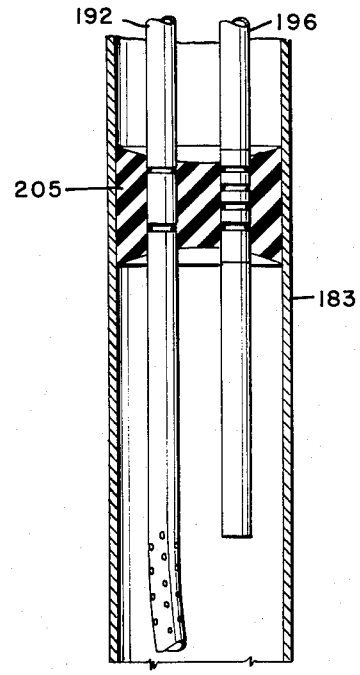


FIG. 28



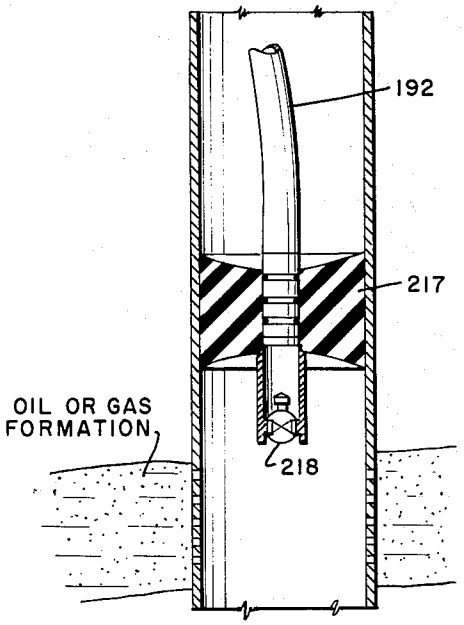


FIG. 30

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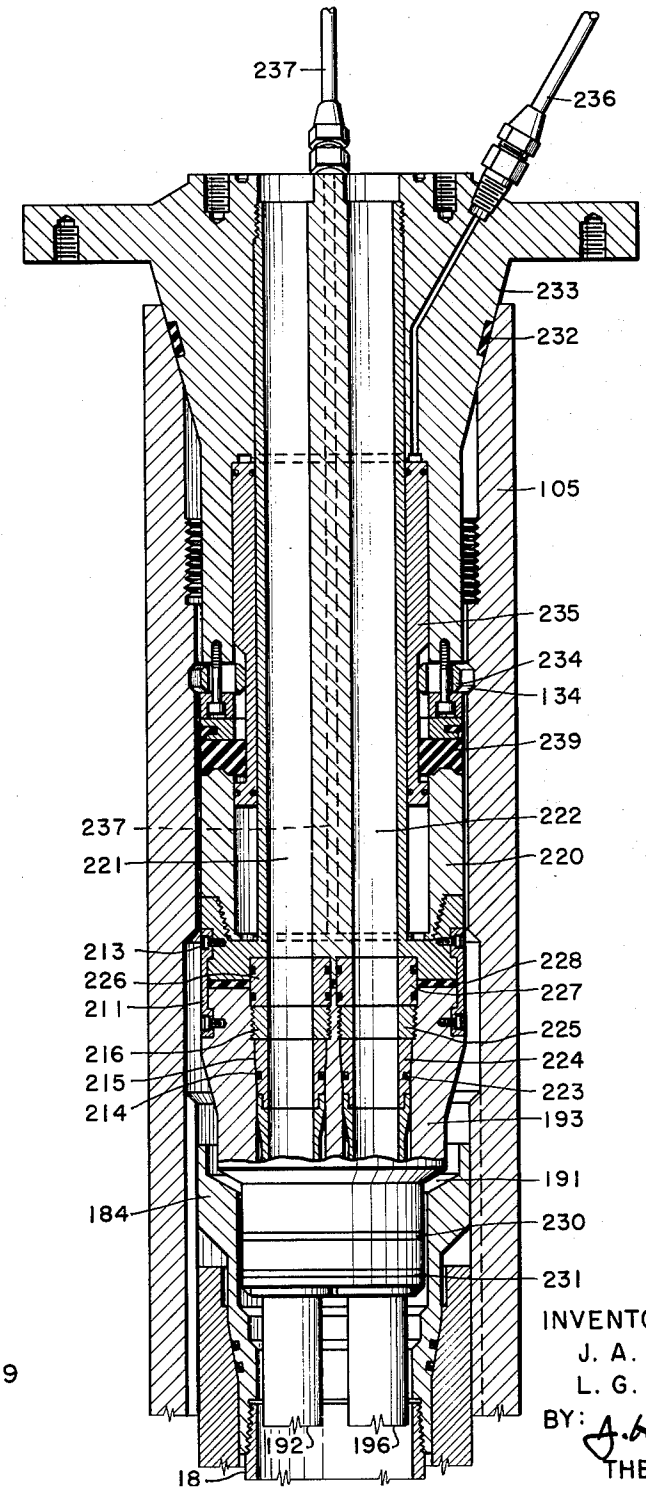


FIG. 29

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June 21, 1966 J. A. HAEBER ETAL 3,256,937

UNDERWATER WELL COMPLETION METHOD

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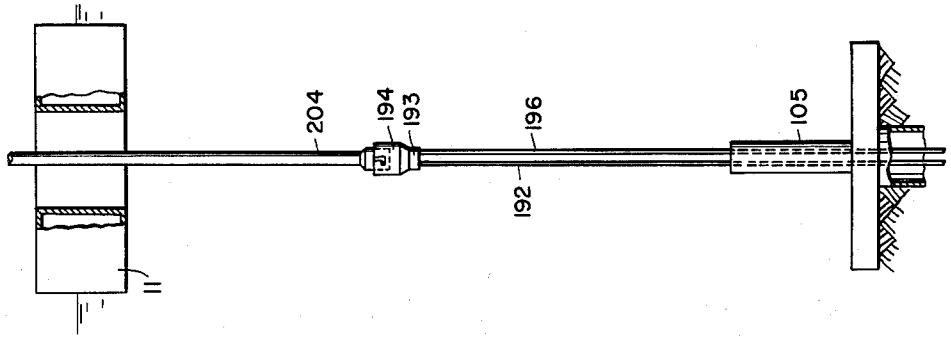


FIG. 34

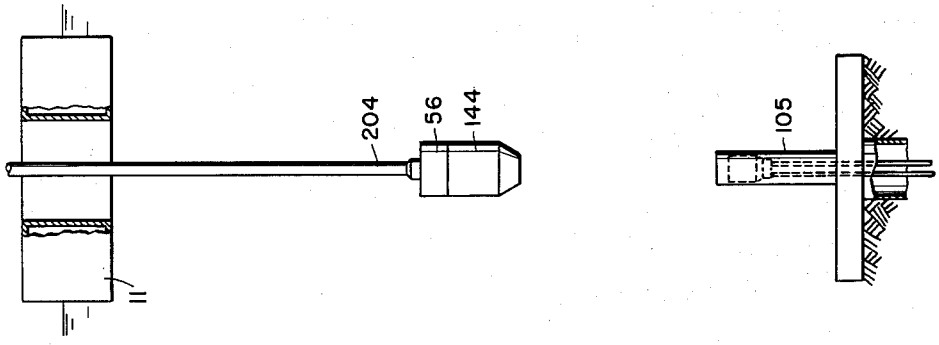


FIG. 33

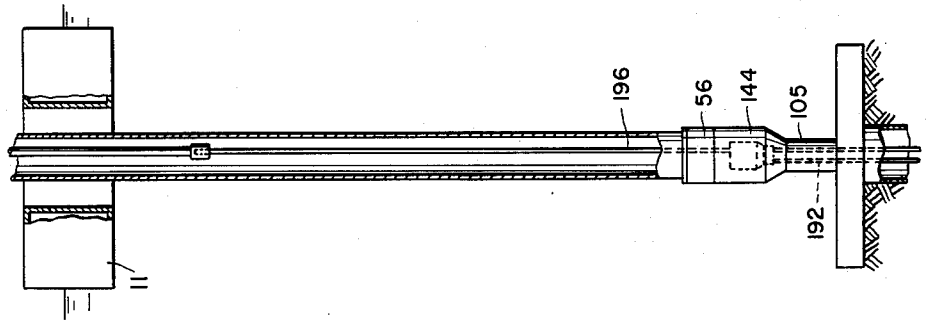


FIG. 32

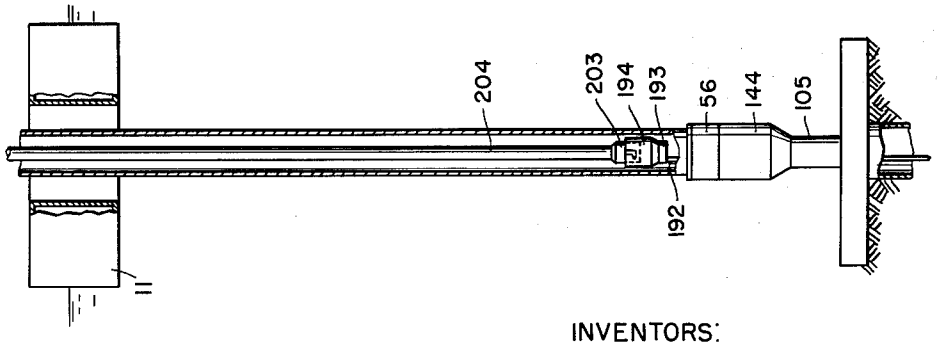


FIG. 31

INVENTORS:
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L. G. OTTEMAN
BY: A. H. McCarthy
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United States Patent Office 3,256,937 Patented June 21, 1966

3,256,937

UNDERWATER WELL COMPLETION METHOD

John A. Haeber and Lloyd G. Otteman, Houston, Tex., assignors to Shell Oil Company, a corporation of Delaware

Filed July 30, 1959, Ser. No. 830,538
6 Claims. (Cl. 166—46)

This invention relates to the drilling of offshore wells and pertains more particularly to a method and apparatus for completing wells drilled in offshore waters which may be anywhere from 100 to 1,500 or more feet deep.

At present offshore wells are drilled either from stationary platforms anchored to the ocean floor, movable barges temporarily positioned on the ocean floor or from movable barges floating on the body of water on which drilling operations are being carried out. Regardless of the manner in which the wells are drilled, most wells are completed in a manner such that the outermost tubular member of the well extends upwardly from the ocean floor to above the surface of the water where a wellhead or Christmas tree is mounted thereon for controlling the production of the well.

Wellheads extending above the surface of the water constitute a hazard to navigation of vessels in the area as well as constituting a structure which is readily attacked by the wave-action, it being well known that the corrosive action of seawater and the air readily attack the normal steel platforms unless they are protected in a suitable manner by corrosive-resistant material.

It is therefore an object of the present invention to provide a method and apparatus for drilling and completing offshore wells in a manner such that the entire wellhead assembly is submerged to minimize corrosion of equipment.

A further object of the present invention is to provide a method for drilling and completing an offshore well in a manner such that the wellhead is located below the surface of a body of water, for example, near the ocean floor, so that deep draft vessels can safely pass overhead, thus eliminating the blow-out hazard presented by the possibility of ships hitting the wellhead or a supporting platform therefor.

Another object of the present invention is to provide a method for drilling and completing of offshore wells from a remote location without the aid of divers or without employing a rigid structure extending from the well to a point above the surface of the water.

Still another object of the present invention is to provide a method for re-entering, either with wire line or rotary equipment, an offshore well whose wellhead assembly is located well below the surface of the body of water.

Another object of the present invention is to provide a method for maintaining control of an offshore well at all times during drilling, completion and production operations.

A still further object of this invention is to provide a method of running and cementing multiple strings of pipe within a well drilled at an offshore location.

It is also an object of the present invention to provide a method for connecting a Christmas tree to a well tubing at a point above the surface of the water before running the Christmas tree to its position near the ocean floor.

A further object of this invention is to provide well drilling and completion apparatus utilizing self-energizing seals.

These and other objects of this invention will be understood from the following description taken with reference to the drawing, wherein:

FIGURE 1 is a diagrammatic view illustrating the floatable drilling barge anchored to the ocean floor over a drilling location and supporting a wellhead support frame and container;

FIGURE 2 is a partial diagrammatic view of the equipment of FIGURE 1 with a conductor pipe extending through the wellhead container to a position close to the ocean floor;

FIGURE 3 is a diagrammatic view showing the equipment of FIGURE 2 with a drill string extending through the conductor pipe and starting a hole in the ocean floor;

FIGURE 4 is a diagrammatic view illustrating the withdrawal of a bit and drill string from the hole that has been drilled for the conductor pipe;

FIGURES 5 and 6 are diagrammatic views illustrating the lowering of the conductor pipe and the wellhead container and support frame to the ocean floor with a cementing string being run in FIGURE 6 while the conductor pipe is still positioned above the bottom of the hole;

FIGURE 7 is a schematic drawing illustrating the cementing of the conductor pipe in the borehole with the wellhead support frame positioned on the ocean floor;

FIGURE 8 is a schematic drawing illustrating continuation of the drilling operations through the conductor pipe;

FIGURE 9 is a view taken in longitudinal cross-section of a casinghead supported in the wellhead container;

FIGURE 10 is a view illustrating the operation of lowering a landing head and blow-out preventer on top of the casinghead;

FIGURE 11 is a view showing the lowering of a marine conductor with its landing head about to be set down on a mandrel on the top of a blow-out preventer;

FIGURE 12 is a view of the equipment within the wellhead container while carrying out the drilling operation illustrated in FIGURE 8;

FIGURE 13 is a view taken in longitudinal cross-section of the wellhead equipment prior to carrying out a cementing operation;

FIGURE 14 is a view taken in longitudinal cross-section of the seal and lock hold-down head in its inoperative and operative positions;

FIGURE 15 is a schematic view of a portion of the wellhead equipment taken in longitudinal cros-section after a cementing operation is carried out;

FIGURE 16 illustrates the wellhead after blow-out preventers have been mounted thereon;

FIGURE 17 is a diagrammatic view of a production control unit being lowered to an underwater wellhead;

FIGURE 18 is a view of another form of a wellhead support structure;

FIGURE 19 is a view taken in longitudinal cross-section of an annular sealing device illustrating its operative and inoperative positions;

FIGURE 20 is a view taken in longitudinal cross-section of a tool for locking equipment into place;

FIGURE 21 is an isometric view showing the tool guide assembly mounted on the wellhead container;

FIGURE 22 is a plan view of the equipment shown in FIGURE 21;

FIGURES 23 and 24 are longitudinal views of single and dual tubing strings suspended from a running tool;

FIGURE 25 is a view illustrating another apparatus for lowering the casinghead to the ocean floor;

FIGURES 26*a* and 26*b* are views taken partly in longitudinal cross-section of the equipment in the well after cementing a second string of casing;

FIGURE 27 is a view taken partly in longitudinal cross-section of a well being perforated;

FIGURE 28 is a longitudinal view taken in cross-section of a running tool for dual tubing strings;

FIGURE 29 is a longitudinal view taken in cross-sec-

tion of the lower end of the wellhead assembly connected to dual tubing strings;

FIGURE 30 is a diagrammatic view illustrating an arrangement of packers and tubings within a well;

FIGURES 31 to 34 are schematic views showing installation of dual tubing strings within an underwater well casinghead; and,

FIGURE 35 is a plan view of the tubing lock-down assembly of FIGURE 29.

Referring to FIGURE 1 of the drawing, a drilling barge **11**, of any suitable floatable type is illustrated as floating on the surface of the water **12** and fixedly positioned over a preselected drilling location by being anchored to the ocean floor **13** by anchors **14** and **15**. Equipment of this type may be used when carrying on well drilling operations in water varying from about 100 feet to 1,500 feet or more. The drilling barge is equipped with a suitable derrick **16** containing fall line **17** and a hoist **18** and rotary table **21** as well as other auxiliary equipment needed during the drilling of a well. The derrick **16** is positioned over a drilling slot or well **22** which extends vertically through the barge in a conventional manner. When using the equipment of the present invention the slot **22** in the barge **11** may be either centrally located or extend in from one edge. However, drilling operations may be carried out over the side of the barge without use of a slot.

A wellhead support structure, such as a container **23**, which is preferably in the form of an open top tank, and its horizontally extending support frame **24** is shown as being suspended in the well **22** of the barge **11** by means of two or more cables **25** and **26** which run to individual hoists **27** and **28**, or other suitable means. This arrangement provides means for subsequently lowering the wellhead container and its support frame to the ocean floor. In some circumstances the container **23** and its support frame **24** may comprise a unitary structure of interconnected girders **199** and crossbracing members **200** as shown in FIGURE 18.

Prior to commencing drilling operations a large diameter conductor pipe **31**, which may be from 20–48 inches in diameter, is lowered through the bottom of the wellhead container **23** and suspended therein in any suitable manner, as by slips. As shown in FIGURES 2 and 3, drilling operations commence with the conductor pipe **31** being positioned with its lower end a short distance above the ocean floor **13** to permit circulation of drilling fluid (sea water) upwardly from the hole **32** being drilled. Alternatively the hole may be drilled and the conductor pipe slipped over the drill string and down into the hole afterwards. As shown in FIGURE 3, the drilling of a borehole **32** for a 20-inch conductor pipe **31** may be accomplished by mounting a 17½-inch drill bit **33** at the lower end of a drill string or stem **34** with, for example, a 24-inch collapsible under-reamer bit **35** mounted above bit **33**. An example of an under-reamer bit **35** is a Baker Model "D" Rotary Hydraulic Expansion Wall Scraper. The borehole **32** to accommodate the conductor **31** may be drilled from the ocean floor to a distance of from 200 to 600 feet or more below the mudline. Drilling operations are carried out while preferably circulating sea water down through the drill stem **34** without any return of the drilling fluid to the drilling barge **11**, i.e., the drilling fluid is lost into the ocean. Since the drilling barge **11** is anchored in place by anchors **14** and **15** as shown in FIGURE 1, there is little rise and fall of the drilling barge **11** on the surface of the water **12** with respect to its position above the ocean floor **13**, but preferably a conventional telescoping bumper sub is employed in the drill string to allow some vertical extension of the string. Since there is the possibility of slight horizontal movement of the drilling barge on the surface of the water, at some locations it is necessary to use a conductor pipe larger than 20 inches in diameter at the mudline to provide enough strength to resist the lateral loads, in addition to the normal vertical loads, which would result from the vessel being displaced slightly off the hole during drilling operations. Thus, a 36- or 48-inch conductor pipe or foundation pile may be necessary near the mudline. However, for purposes of illustration, the present invention will be described hereinbelow with a 24-inch diameter conductor pipe being employed that was swaged down to 20 inches.

Boring of the hole **32** for the conductor pipe has been accomplished in FIGURE 4 and the drill bits **33** and **35** are being withdrawn on the drill stem upwardly to the drilling barge. Just prior to withdrawing the bit from the hole **32** the conductor pipe **31** is lowered slightly into the hole **32** as it would otherwise be difficult to stab the conductor **31** accurately into the hole **32** after the drill string and bit have been withdrawn therefrom.

In FIGURE 5 the conductor pipe **31** is shown being lowered into the borehole **32**. In drilling in some formations, it is often advantageous to switch from sea water as a drilling fluid to a clay-containing drilling mud before running the 20-inch conductor pipe into the hole in order to facilitate running of the pipe and to control the hole against caving.

Prior to lowering the conductor pipe **31** and the wellhead container **23**, a casinghead **36** which is fixedly secured to a base plate **37** and radial reinforcing ribs **38** is positioned in the hole in the bottom of the wellhead container **23**, as shown in FIGURE 9, with the lower end of the casinghead **36***a* extending downwardly a distance sufficient so that the top of the conductor pipe **31** can be fixedly secured thereto in any suitable manner as by screw threads or welding. The wellhead container **23** in turn is fixedly secured to one or more girders **24***a* of the support frame **24** in any suitable manner as by welding. Positioned along the vertical wall of the wellhead container **23**, either inside thereof, are two or more guide tubes **41** and **42** which are provided with guide line anchoring means **43***a* and **44***a* at the bottom thereof, respectively, to which the hoist lines **25** and **26**, which will later be utilized as guide lines for installing other equipment, may be securely anchored.

A circumferential groove **43** is provided in at least a portion of the outer wall of the casinghead **36** (FIG. 9), preferably near the top thereof, to provide means for temporarily locking other equipment to the casinghead. Additionally, one or more internal grooves **44** and **45** are provided for seating and locking an annular seal (not shown) below a tapered shoulder **46** which is formed on the inside wall of the casinghead for seating a casing and tubing suspension body or mandrel thereon. A conduit **47** is provided through the casinghead **36** which is in communication with the interior of the casinghead below grooves **44** and **45** and with the exterior. The conduit **47** is normally closed by a remotely operated valve **48** which may be of any suitable type, either electrically, pneumatic, or hydraulically operated. For purposes of illustration, this application will be described with regard to using hydraulically-operated valves. Thus, valve **48** may be energized by hydraulic fluids entering or returning through pressure lines **51** and **52** which extend to the drilling barge on the surface. The conduit **47** communicates through valve **48** with a service line **53**, used as a cement return line, which allows cement or mud to be pumped at a later time from the interior of the casinghead **36** upwardly to the drilling barge **11** in order to determine when sufficient cement has been pumped into the well. This service line **53** may be also used as a choke, fill-up or kill line.

With the wellhead container **23** suitably connected to the casinghead **36** which is in turn connected to the top of the conductor pipe **31**, the entire assembly is lowered on a drill pipe running string or on hoist lines **25** and **26** by unreeling hoists **27** and **28**. At the time the wellhead container is lowered, a cementing string of pipe **54** is run down through the wellhead container and into the conductor pipe **31**, until its lower end is just above the bottom of the pipe **31**, as shown in FIGURE 6.

The wellhead container and its support frame **24** are then lowered to the ocean floor **13** as shown in FIGURE 7 and cement is pumped down through a cementing string **54** and up the annular space between the conductor pipe **31** and the borehole wall **32***a* in a quantity sufficient to fill the annular space causing it to overflow and form a cement pad in and around the wellhead support frame **24**. The amount of cement needed is generally determined by calculating the volume of the hole to be cemented and the size of the cement pad **55** wanted at the top of the hole on the ocean floor. It is realized that instead of employing hoist cables **25** and **26** to lower the wellhead container **23** and its support frame **24**, the entire apparatus may be lowered in place on the ocean floor by employing a running string **39** (FIG. 25) which is essentially a pipe string similar to the cementing string **54** of FIGURE 6 with suitable coupling means, such as a "jay" tool **49**, attached to the lower end thereof for connecting below lugs **43***a* or into groove **43** of the casinghead **36** during the lowering of the assembly into position.

Prior to continuing the drilling operations through the conductor pipe **31**, it is necessary to mount a conventional blow-out preventer **56** (see FIG. 10) over the casinghead **36**. The blow-out preventer **56** is of a conventional type except that it is provided with two or more guide arms **57** and **58** with guide cones **62** and **63** attached to the outer ends thereof, preferably by swivel joints to facilitate aligning. The guide cones are of a diameter slightly less than the inner diameter of the guide tubes **41** and **42** and have a lower portion that tapers downwardly, as illustrated in FIGURE 10.

As shown in FIGURES 21 and 22, the wellhead container **23** is provided at the top thereof with an upwardly and outwardly sloping flange **64** while guide tubes **40**, **41** and **42** are attached to the outside of the container **23**, as by welding, in order to give greater clearance within the container itself. Preferably, each of the guide tubes **40**, **41** and **42** has a cone-shaped flange **65**, **66** and **67** attached to its upper end which serves to align guide cones **61**, **62** and **63** as they move downwardly into the guide tubes. Each of the guide cones **61**, **62** and **63** is provided with a vertical hole therethrough of a diameter slightly larger than the guide cables **25**, **26** and **29** thus allowing the guide cones to pass freely down the cable and rest within their respective guide tubes **40**, **41** and **42**. The wellhead container **23** as well as the adjacent walls of the fixedly secured guide tubes **40**, **41** and **42** are provided with slots **71**, **72** and **73** therein in order to enable the arms **57**, **58** and **59** to pass therethrough. The slots are preferably smaller than the diameter of the guide cables to hold the cables in the tubes.

Returning to FIGURE 10 of the drawing, the blow-out preventer is shown as being connected to the top of a hydraulically-operated seal and lock hold-down head **74** which is actuated by hydraulic pressure through pressure lines **75** and **76**. The seal and lock hold-down head **74** was previously flanged to the bottom of the blow-out preventer **56** on the drilling vessel after which the guide wires **25** and **26** were threaded through the guide cones **63** and **62**. For purposes of clarity of description, the operation of the equipment of the present invention will be described with regard to only two of the guide lines. The combined blow-out preventer **56** and hold-down head **74** were lowered into position by means of a running string **77** which was connected to the top of the blow-out preventer **56** by means of a running or lowering head **78**. It is realized that the running string, which is essentially a long string of pipe extending from the drilling vessel down to the ocean floor, may be provided at its lower end with any suitable connecting means for connecting it to the blow-out preventer **56** or its associated movable equipment. In the particular arrangement shown the running head **78** comprises a tubular member adapted to fit over a mandrel **81** extending upwardly from the blow-out preventer **56**. The mandrel **81** is provided with a pin **82** which is adapted to seat in a J-slot in the running head. This is a well known means of connecting elements in the field of well drilling although it is to be realized that the threaded joint could be employed equally as well. Additionally, instead of using a running string **77** the equipment could be lowered into place by means of a wire line having a quick disconnect socket attached to its lower end.

In FIGURE 10 a seal and lock-down head **74**, known as a wellhead connector, manufactured by Hydril Co., Los Angeles, California, is illustrated just prior to lowering it into position on the casinghead **36**. In FIGURE 14, the seal and lock-down head is shown in greater detail after it has been lowered into position on the casinghead **36**. As shown in FIGURE 14, the seal and lock-down head comprises an annular housing **84** whose inner diameter is just slightly larger than the outer diameter of the casinghead **36**. The annular housing **84** is provided with an annular chamber **85** in which there is movably mounted an annular sleeve **86** having a tapered face or shoulder **87** on the inside thereof. The annular chamber **85** is also provided with a plurality of locking blocks or dogs **88**, each of which is provided with a vertical slot **91** which is substantially wider than a pin **92** passing therethrough thus permitting movement of the dogs **88** so that they extend, in an operative position, into the bore of the hold-down head, as shown in the right-hand half of FIGURE 14. In their inoperative position the dogs **88** normally extend into a recessed portion **93** of the annular sleeve **86**, being forced to this position when the hold-down head was originally forced over the casinghead **36**. By applying hydraulic pressure through pressure conduit **75**, the annular sleeve **86** is forced downwardly so that its tapered shoulder **87** contacts the locking dog **88** forcing it out of the recess **93**, from the position shown on the left-hand side of FIGURE 14 to the position shown in the right-hand side of FIGURE 14. At this time the hold-down head **74** is fixedly locked on the casinghead **36**. At the same time an annular seal **94** carried by the housing **84** forms a fluidtight seal between the hold-down head **74** and the casinghead **36**.

After the blow-out preventer **56** and the hold-down head **74** of FIGURE 10 have been secured to the casinghead **36**, the running string **77** (FIGURE 10) is disconnected from the mandrel **81** at the top of the blow-out preventer **56** by lowering the running string slightly, rotating it counterclockwise a short distance and then lifting up on it to disconnect pin **82** from the J-slot **83**, in a manner well known to the art. As shown in FIGURE 11, a landing head **95** which was previously flanged to the bottom of a 22-inch marine conductor **96** on the drilling vessel is then lowered down into place over the mandrel **81** extending upwardly from the blow-out preventer **56**. To lock the landing head securely on top of the blow-out preventer **56**, pressure is applied to port **99**. The landing head is a unit known to the oil well art as a modified Regan Forge and Engineering Co., California, type K blow-out preventer which is provided with an annular packer which cooperates with the mandrel **81** to form a fluidtight connection therewith. Since this element is well known to the art it will not be further described at this point.

As shown in FIGURE 11 the landing head **95** is provided with a pair of guide arms **97** and **98** to which a pair of guide cones **101** and **102** are attached and adapted to slide downwardly on the guide wires **25** and **26**. It is realized that the 20-inch blow-out preventer could be provided as an integral part of the **20**-inch casinghead **36** thus obviating this temporary connection to the casinghead by means of seal and lock-down head **74**. However, this procedure would require leaving the 20-inch blow-out preventer **56** in the wellhead container to become part of the permanent wellhead installation.

After the equipment of FIGURE 11 has been lowered into place as shown in FIGURE 12, a drill string **34** in-

cluding preferably a bumper sub **30**, and drill bit **33** are inserted into the top of the marine conductor **96** at the drill vessel and lowered down through the marine conductor **96**, landing head **95**, blow-out preventer **56**, hold-down head **74** and conductor pipe **31** to the bottom of the borehole as shown in FIGURE 12. Well drilling operations are then resumed in a conventional manner with a drilling fluid being circulated down through the drill string **34** and upwardly through the annular space **103** between the drill string **34** and the marine conductor **96** to the drilling vessel. While only one blow-out preventer has been shown it is obvious that a plurality of blow-out preventers could be landed individually, or connected together at the surface and lowered together into place in a manner described hereinabove with regard to the single blow-out preventer. Both the Regan type-K blow-out preventer or landing head **95** and the blow-out preventer **56** are hydraulically operated with control lines running from these elements to the drilling vessel at the surface. It is quite apparent that since the marine conductor has a diameter of 22 inches that additional drilling of the well must be carried out with a drill bit of a smaller diameter such, for example, as a 17½-inch bit. Drilling of the well is continued by rotating drill string **34** and drill bit **33** from the drilling vessel **11** as shown in FIGURE 8 until the well has been drilled at the diameter of the bit to the desired depth. The drill string and drill bit are then withdrawn from the hole to the drilling vessel.

The 17-inch borehole is then cased with a casing string **104** (FIGURE 13) which is made on the drilling vessel **11** and lowered through the marine conductor **96**, landing head **95**, blow-out preventer **56**, hold-down head **74**, and conductor pipe **31**.

As shown in FIGURES 13 and 14, prior to lowering the top of the 13-inch well casing into place, a casing and tubing suspension body **105** is fixedly secured to the top of the casing **104**, as by screw threads or welding in the drilling vessel. In some installations, however, the casing and tubing suspension body **105** may be previously secured to or integrally formed with the casinghead **36** when the latter is lowered to the ocean floor. Casing **104** could then be hung from within the lower end of suspension body **105**. As shown in FIGURE 14, the casing and tubing suspension body is provided near its lower end with a tapered ledge **106** which is adapted to seat on the tapered shoulder **46** of the casinghead **36**. O-ring seals **107** may be provided to give a fluidlight connection. With the casing suspension body **105** seated in the casinghead **36** the entire casing will be suspended from the casinghead. The casing suspension body **105** and casing string **104** is lowered into place by means of a combination running and cementing string **108** (FIGURE 13) which has at its lower end a coupling **109** temporarily securing it to the top of the suspension body **105**. A stinger section **108***a* of the cementing string **108** extends downwardly past the coupling **109** to the lower part of the suspension body **105** and has a ball-operated wiper plug attached to it by means of shear pins; however the wiper plug could also be attached to the casing with shear pins in the same manner.

The casing **104** may now be cemented in place by pumping cement down the cementing string **108** from the drilling vessel so that it is circulated down the full length of the casing **104** around the bottom thereof and up the annular space **113** between the conductor pipe **31** and the casing **104** out of the discharge conduit **47** through valve **48** and up the service or return line **53** (FIGURE 9) to the drilling vessel again. Near the end of the cementing operation a ball **114** (FIGURE 15) is dropped down the cementing string **108** of FIGURE 13 where it seats at the top of the wiper plug **112**. Build-up of pressure within the line causes the shear pins holding the plug **112** at the lower end of the stinger **108***a* to shear and follow the cement down to the bottom of the hole. Both the ball **114** and plug **112**, being of drillable material, will be drilled out when well drilling operations are resumed.

After the cementing operations have been completed, as shown in FIGURE 15, valve **48** in the service or cement line is closed hydraulically from the operating vessel at the surface and the service line **53** will be disconnected from the valve **48** in any suitable manner from the surface as by pulling it free from a shear connection **115** near the valve or any other suitable quick disconnect means. In addition the hydraulic lines which operate the casinghead valve **48** may also be retrieved after pulling them free with the valve in the closed position. After the cementing operations have been completed the cementing string **108** is withdrawn to the drilling vessel after first unscrewing it at coupling **109**.

While the O-ring seals **107** (FIGURE 14) form a fluidtight seal between the casinghead **36** and the casing suspension body **105**, it may be desirable to provide additional sealing means in the form of an annular packer which is secured to the 13-inch casing string **104** and run into the well to a point just below the suspension body **105**. An annular seal **116** (FIGURE 13) may take the form shown in FIGURE 19. The annular seal **116** comprises an annular ring element **117** mounted in sliding engagement with the casing string **104** and being fixedly secured in any suitable manner to an annular packer or sealing ring **118** which is made of some resilient material such as rubber, synthetic rubber, or a suitable plastic material. The annular packer **118** may be of any suitable cross-section with the cross-sectional dimension being of sufficient size so that a fluidtight seal is formed between the outer wall of the casing string **104** and the inner wall of the lower portion of the casinghead **36***a* when the seal is in its operative position, as shown in the right-hand side of FIGURE 19. The annular packer seal **118** is preferably of the cross-sectional form shown which is that of a double lip packer with a plurality of spring elements molded in the packer **118** and tending to force the two lips of the packer away from each other and against the adjacent walls of the casing string **104** and the casinghead **36***a*. A base ring **122** is molded in the top of the packer ring **118** so that it may be connected by means of bolts **123** to the annular ring element **117**. A series of vertical holes **124** shown in the ring element **117** are merely for the purpose of securing the bolts **123** to the base ring **122**. Mounted for radial sliding movement in an outwardly direction from the ring element **117** are a plurality of locking lugs or dogs **125** which are normally urged outwardly by compression springs **126**.

The locking lugs **125** are of a size sufficient to fit within the groove **45** on the inner surface of the casinghead **36***a* while the ring element **117** is provided with a downwardly sloping shoulder **127** adapted to seat on the lower portion of the groove **44** in the casinghead. In order to retain the expansible packer ring **118** in its retracted position, as shown in the left-hand side of FIGURE 19, while the casing string **104** is being run into a well, a retainer housing **128** is fixedly secured as by screw threads **131** to the outer surface of the casing string **104** at a predetermined point thereon. The retainer housing **128** is of a diameter slightly less than the internal diameter of the casinghead **36** and its lower portion **36***a* so that the container can pass readily therethrough.

During the installation of the annular packer **116** shown in FIGURE 19, the packer ring **118** and the locking lugs **125** are in their retracted position as shown in the left-hand side of FIGURE 19 being held in that position by the retainer housing **128** which is in turn secured to the ring element **117** by one or more shear pins **132**. When the ring element **117** has seated on shoulder **127**, continued downward movement of casing string **104** and the retainer housing **128** fixedly secured thereto causes pin **132** to shear thus allowing continued downward movement of the retainer housing **128** with the well casing **104**. As the retainer housing **128** moves downward the compression springs **126** urge the locking lugs **125** out-

wardly into groove **45**, thus locking the entire packer or sealing assembly against both upward and downward movements. As the retainer housing **128** continues its downward movement past the packer ring **118**, the spring elements **121** urge the outer lip of the sealing ring **118** against the casinghead forming a fluidtight seal thereagainst. Preferably, the retainer housing **128** is provided with a plurality of fluid ports **133**, as shown, to allow circulation of fluid or cement past the retainer housing **128**. An annular seal **116** of the type described provides an annular packer at all times between the casing string **104** and the casinghead **36** even though the casing string **104** might be moved upwardly during the life of the well so as to cause the casing suspension body **105** (FIGURES 13 and 14) to be lifted off the seating shoulder **46** of the casinghead **36** (FIGURE 14).

After the casing string **104** has been cemented in place and the cementing string **108** (FIGURE 13) has been unscrewed from the casing and tubing suspension body **105** and pulled upwardly to the drilling vessel, the marine conductor **96** together with the landing head **95** flanged to the bottom thereof are withdrawn upwardly to the drilling vessel in an operation that is the reverse of that described with regard to FIGURE 11. The landing head **95** is disconnected from the mandrel **81** on the top of the blow-out preventer **56** by releasing the pressure fluid to its pressure lines. The running head **78** described with regard to FIGURE 10 is then lowered on its running string **77** into contact with mandrel **81** of the blow-out preventer **56**. The pin **82** of the mandrel **81** is aligned in the J-slot **83** of the running head **78** and locked therein by rotation. Hydraulic pressure fluid is then applied through pressure line **76** leading to the seal and hold-down head **74** so that the annular sleeve **86** therein is forced upwardly and allowing the locking blocks **88** to move radially into the recessed portion of the annular sleeve **86** when the hold-down head **74** is pulled upwardly of the casinghead **36** together with the blow-out preventer **56** to which it is flanged. These elements are pulled upwardly to the drilling vessel by means of the pipe string **77**. After this operation the wellhead is in the form shown in FIGURE 15.

As illustrated in FIGURE 14, the casing and tubing suspension **105** has an inner wall that is irregular in that annular grooves **134** and **135** are formed therein as well as a splined section **136** and a seating shoulder **137**. In order to protect the grooves **134** and **135**, section **136** and shoulder **137** during drilling operations, a temporary sleeve **138** may have been installed in the suspension body **105** at the time it was originally lowered into the casinghead **36**, or may be installed after attaching the blow-out preventer **144**. After drilling operations have been completed the sleeve **138** can be removed by lowering a suitable running head similar to **78** (FIGURE 10) except that it would have a pin on the outer surface thereof to engage one or more J-slots **141** in the top of the sleeve **138** in order to withdraw it from the well. It is realized that instead of using a running head with a pin on it that the head could be in the form of coupling **109** shown in FIGURE 13 which engage the top of the sleeve **138** in a screw-threaded manner if threads were provided therein. From FIGURE 15 it may be seen that the top of the casing and tubing suspension body **105** is provided with a seating bowl **142** with suitable coupling means such as screw threads **143** located therebelow.

Prior to continuing drilling operations, one or more blow-out preventers **56** and **144** for example of the conventional ram-type which are flanged or welded together (FIGURE 16) are lowered down to the wellhead. While this particular operation is described with regard to two blow-out preventers, in many cases only one blow-out preventer is necessary. Since drilling operations will be continued with a small size bit, blow-out preventers of a smaller size are generally employed. The present arrangement of equipment also facilitates the removal of a low pressure blow-out preventer, which may be used in the early stages of drilling, and substituting therefor a high pressure blow-out preventer for use when drilling has progressed to deeper formation where the possibility of encountering high pressures is greater. To the bottom of the lowermost blow-out preventer **144** is secured, in a fluidtight manner, a seal and lock-down head which comprises a tubular element **145** having its lower end tapered, as at **146**, to meet with the tapered seating bowl **142** in the top of the suspension body **105**. Slidably and rotatably mounted within the tubular element **145** is a locking sleeve **147** having a threaded lower end **148**.

As shown in greater detail in FIGURE 20, the seal and lock-down head is preferably provided with O-ring seals **151**, **152** and **153**, or other suitable sealing means for making the joints fluidtight. One or more keyways **154** are formed in the inner surface of the lock sleeve **147** at the top thereof which will be engaged by the keys **155** of a locking tool **156** which is lowered through the blow-out preventers **56** and **144** and rotated after the keys **155** engage the keyways **154** so that the threaded lower end **148** of the locking sleeve **147** engages the threads **143** in the top of the suspension body **105**. After this operation, the running string **157** and locking tool **156** are withdrawn to the surface. The seal and lock-down head connection described hereinabove with regard to FIGURES 16 and 20 is preferably used. However, it is understood that if desired the blow-out preventer **144** could be flanged directly to the seal and lock-down head similar to the one described with regard to element **74** in FIGURE 10 which can then be fixedly secured to the casinghead **36**.

Conduits such as a choke line **162** (FIGURE 16) and a kill line **163** running down from the drilling vessel, are preferably connected to the blow-out preventer **144** and are in communication therethrough, that is below the rams or sealing elements thereof, with the well. The choke line **162** and its control valve **164** allows fluid under pressure to be bled from the well with the blow-out preventer **144** closed. The kill line **163** and its control valve **165** allows fluid to be pumped from the drilling vessel into the well to kill the well, when necessary. Both valves **164** and **165** are hydraulically operated and controlled from the drill barge on the surface.

After the blow-out preventers **56** and **144** (FIGURE 16) have been connected to the suspension body **105**, a marine conductor **158** is made up on the drilling vessel at the surface and is provided at its lower end with a landing head **161** which is identical to landing head **95** illustrated in FIGURE 13. Since continued drilling of the well will be done with a smaller size bit, the diameter of the marine conductor **158** may be smaller than that of marine conductor **96** shown in FIGURE 13. For example, a 16-inch conductor may be employed rather than a 21½-inch conductor. The marine conductor **158** and its landing head **161** are lowered down to and secured to the blow-out preventer **56** in the same manner as described with regard to marine conductor **96** and landing head **95** in FIGURE 13. With the wellhead and elements arranged in a manner shown in FIGURE 16, a drill string is lowered together with a drill bit down through these elements from the drilling vessel at the surface and drilling operations are continued.

When the well has been deepened to the desired depth, the drill string and drill bit are withdrawn from the well to the drilling barge above and a second string of casing **170** is lowered through casing **104** into the hole in much the same manner as that described with regard to FIGURE 13. A running string **171** (FIGURE 26*a*), which also serves as a cementing string, is provided with a threaded portion **172** which is adapted to engage a similarly threaded portion of a casing hanger **173** which is fixedly secured to the top of the casing **170**. Positioned below the threaded portion **172**, the cementing

string **171** is provided with wiper plugs **174** and **175**, the last named plug **175** being shown at the bottom of the casing string **170** after cementing operations have been started. The bottom of the casing **170** is provided with a float shoe **176**, if desired.

The cementing of the second casing string **170** in the well differs from the operation carried out with regard to cementing the first string **104** in place in that the cement return conduit **47** is no longer available to permit the return of cement to the surface. If the casing hanger **173** at the top of the casing string **170** was to be seated on the shoulder **137** of the casing and tubing suspension body **105**, it would be impossible to pump cement down the well as there would be no opening through which the fluid in the well could be displaced. Thus, during cementing operations it is necessary to pump the cement into place before the hanger **173** of the second casing string **170** is seated on its seating shoulder **137**. Due to the rise and fall of the drilling barge on the surface of the water, it would be impossible to support the casing hanger **173** a short distance, say 6 inches, off the seating shoulder **137** as the constant rise and fall of the drilling barge would cause the casing hanger **173** to pound on its seat **137**, or possible damage other portions of the interior of the casing and tubing suspension body **105**.

To obviate this difficulty, the running or cementing string **171** is provided with a standoff cementing tool **177** at a predetermined distance above the threaded portions **172** of the casing hanger **173**. The standoff cementing tool **177** may be described as being a temporary casing hanger means of any suitable type, such for example one having retractable wedges **178** which, when extended, seat on shoulders **179** within the landing mandrel **81** so that the casing hanger **173** is suspended a predetermined distance, say 6 inches off its seat **137** during cementing operations, thus allowing well fluid to pass up the annulus between the first and second casing strings **104** and **170**, respectively. The standoff cementing tool **177** may be similar to and operates on the principle of rotatable releasing spears such as those manufactured by S. R. Bowen Company, Santa Fe Springs, California as shown in the Composite Catalog of Oil Field Equipment, page 744, 1957 edition. Upon rotation of the running or cementing string **171** from the surface, i.e., from the drilling barge, the wedges **178** are retracted so that the casing hanger **173** can be lowered to its seat **137** within the casing and tubing suspension body **105**. Instead of employing retractable wedges **178**, the standoff cementing tool may have an arrangement of screw-threaded members as described in the above-identified patent application.

During cementing operations the fluid in the well borehole is forced up the annular space between the running string **171** and the marine conductor pipe **158**. If desired, the casing hanger **173** may be provided with a set of hold-down slips **182** which are set when the casing hanger **173** is lowered to its seat. In the event that the casinghead **36** was not provided with a cement return conduit **47**, the standoff method of cementing a casing string could also be employed when cementing the first casing string **104** in place.

With the second casing string **170** (FIGURES 26*a* and 26*b*) cemented in place, drilling of the well may be continued to any desired depth at which time a third casing string **183** having a hanger **184** and slips **185** would be installed in a manner similar to that described with regard to FIGURES 26*a* and 26*b*. The hanger **184** (FIGURE 27) would seat in hanger **173**. The third casing string **183** would be preferably provided with a cementing shoe **186**.

After cementing and hanging in the same manner as previously described for casing **170**, the lowermost casing **183** (FIGURE 27) is perforated in any manner well known in the art, as by running a perforating gun on a wire line or pipe string **188** to the desired level within the well, at which level the perforating gun is discharged. Subsequently, the well may be gravel-packed if necessary. If gravel packing is not required, the perforating operation may be accomplished by lowering a perforating gun through a well tubing after it has been installed. After the perforating operation, the gun **187** is withdrawn from the well.

The well is now ready to have a string of tubing run down into the well through the equipment shown in FIGURE 26*a* which comprises the marine conductor pipe **158**, the landing head **161** and the blow-out preventers **56** and **144**, all of which are locked securely together in a fluidtight manner and to the casing and tubing suspension body **105**. If a single tubing string is to be run into the well it is provided with a temporary or permanent tubing hanger at its upper end which is seated within the hanging shoulder **191** of FIGURE 27. Preferably, the well is provided with a pair of tubing strings so that tools, instruments, or other devices may be circulated down through the tubing to the bottom of the well and returned by reverse circulation. Due to the difficulty of simultaneously installing multiple strings of parallel tubing in an offshore well which may be thousands of feet deep, the tubings are preferably installed one at a time.

As shown in FIGURE 23, a tubing string **192** is fixedly secured at its upper end to a tubing hanger **193** which in turn is temporarily secured in any suitable manner to a tubing guide member **194** and run into the well as shown in FIGURE 31. The interior of the tubing guide tool **194** (FIGURE 23) is provided with a sloping surface **195** by which a second tubing string **196** (FIGURE 24) is guided into a bore **198** (FIGURE 23) which is parallel to the tubing string **192**. The upper end of the tubing guide tool **194** is provided with one or more J-slots **201** adapted to engage the pin **202** of a J-tool **203** secured to the lower end of a running pipe string **204**. After the first tubing string **192** has been lowered into position, the running string **204** is withdrawn to the surface. In FIGURES 24 and 32 the second tubing string **196** is shown as being run into place through the tubing hanger **193**, it being understood that at the time this operation is carried out the tubing hanger **193** is seated on the hanger shoulder **191** of the innermost casing string, as shown in FIGURE 28.

The tubing guide tool **194** is shown in FIGURE 28 as being secured by means of a split-ring connector **211** to a tubing hanger **193**. The split-ring connector **211** may be secured by set screws **213**, or any other suitable means. The upper end of the tubing string **192** is preferably connected to a slope-shouldered donut hanger **214** adapted to seat on shoulder **215** within the tubing hanger **193**. If desired, a threaded collar **216** may be installed above the hanger **214** to hold it down in place as the tubing is run into the well. The upper end of the second tubing string **196** is lowered from the barge into the guide tool by a wire line or J-tool and running string similar to elements **203** and **204**.

Prior to running the tubing strings **192** and **196**, a Baker Oil Tool, Inc., Model "D" wire-line-set single bore production packer **217** is installed in the inner casing string **183** (FIGURE 30) to close it above the production interval to control the well pressure after removal of blow-out preventers and prior to setting the wellhead assembly. Additionally, a Brown Oil Tool Co. dual bore hydraulic-set packer **205** may be run into the well on the first tubing string **192** to seat the bottom of the second tubing string **196** after it has been run. The wire line set packer **217** in the bottom of the casing is provided with a wire line retrievable plug **218** in a manner well known to the art, which plug is subsequently removed after the wellhead assembly is installed. The lower packer **217** and its plug **218** provide a temporary closure means for containing the well pressure during completion of the well, while the dual production packer **205** prevents casing pressures and corrosive fluids from going up the well during production.

In a preferred embodiment of the present invention, the lower portion of the tubing string **192** below the dual packer **205** is perforated, or provided with adjustable slide valve means therein, to permit circulation of a fluid down one tubing **192** and up the other tubing **196** at a point above packer **217**.

With the tubing strings installed within the well, the marine conductor pipe **158** and its landing head **161** (FIGURE 26) are disconnected in a manner which is the reverse of the operation in which they were originally connected, and are then withdrawn upwardly to the drilling barge. The locking tool **156** of FIGURE 20 is then attached to the lower end of a running string and run down through the blow-out preventers **56** and **144** (FIGURE 16) to unlock the locking sleeve **147** in a manner which is the reverse of the operation by which the element was locked. A running string **204** (FIGURE 33) is then used to raise the disconnected blow-out preventers **144** and **56** and their associated equipment upwardly to the drilling barge. At this time the wellhead equipment comprises that shown in FIGURE 27 of the drawing with the equipment of FIGURE 24 replacing the string **188** and perforating gun **187** in FIGURE 27.

A running string similar to that shown as element **204** in FIGURE 24, having a J-tool **203** attached to the lower end thereof, is run into the casing and tubing suspension body **105** (FIGURE 27) to engage the tubing guide tool **194** (FIGURE 24). By means of the running string **204**, the tubing guide tool **194**, together with the two tubing strings **192** and **196** connected thereto, are withdrawn upwardly from the seating position on the shoulder **191** (FIGURE 28) of the casing hanger **184** and pulled upwardly (FIGURE 34) to a barge **11** where the tubing hanger **193** (FIGURE 28) is disconnected from the guide tool **194**, is connected to the lower end of the production control unit or wellhead assembly **207**, as shown in FIGURE 17.

The guide tool **194** (FIGURE 28) is removed by unscrewing set screws **213** of split-ring connector **211** and substituting for guide tool **194** the lower end of the tubing hanger lock-down device **220** (FIGURE 29), which is in turn secured to the bottom of the wellhead assembly or production control unit **207** (FIGURE 17). The tubing hanger lock-down body **220** is provided with a pair of vertical conduits **221** and **222** in register at their lower ends with the tubing strings **192** and **196**. At their upper ends the conduits **221** and **222** of the lock-down body **220** are in fluid communication with the flow lines **208** and **209** within the production control unit **207**.

Prior to connecting the split-ring connector **211** to the tubing hanger lock-down body **220**, the second tubing string **196** is suspended by means of a donut hanger **223** seated on shoulder **24**. A threaded hold-down collar **225** is installed with sealing subs **226** and **227** positioned above the collars **216** and **225**. A sealing ring **228** is positioned between elements **193** and **220**. Primary packing O-ring seals **230** and **231** contain the annulus pressures while a seal **232** is provided in the sloping face of the top of the lock-down body **220** to keep sea water out of the installation. As illustrated, the weight of the tubing strings **192** and **196** are supported by the sloping face **233** of the body **220** bearing against the mating face on the upper end of the tubing and casing suspension body **105**. However, if desired, a portion of the weight may be put on shoulder **191** by having tubing hanger **193** rest thereon.

The lock-down body **220** (FIGURE 29) is provided with a series of hydraulically-operable and radially-slidable locking dogs **234** adapted to move outwardly from the body **220** and seat in the annular groove **134** of the casing and tubing suspension body **105**. A piston **235** is adapted to move vertically, under fluid pressure from conduit **236**, forcing the dogs outwardly. When fluid pressure is applied through conduit **237** to move the piston in the opposite direction, the locking dogs **234** become unlatched so that an upward pull on the body **220** will retract them. An annular seal **239** is preferably employed also. A third pressure conduit **240** may be provided in the head of the lock-down body **220** (FIGURE 35) in order to obtain the tubing annulus well pressure.

Since in this well installation a pair of tubing strings **192** and **196** are employed, the production control unit **207** is provided with two flexible flow lines **208** and **209** which are adapted to lay on the ocean floor after the production control unit **207** has been lowered into the casing and tubing suspension body **105** and locked therein. The production control unit contains the necessary piping, valves, chokes and other equipment normally connected together and mounted on the top of a well, and known as a "Christmas tree," together with the necessary hydraulic or electrical systems including pumps, reservoirs, motors, etc., to operate the valves at the head of the well from a remote location. While the present invention has been described with regard to installing dual parallel tubing strings, the method and apparatus may also be used to install single strings, dual concentric strings and three or more parallel strings.

With the production control unit **207** seated and locked in place on the casing and tubing suspension body **105**, the running head **203** is disconnected from the top of the production control unit **207**, or from its lubricator **206**, and the running string **204** is then pulled upwardly to the surface, with the production control unit **207** left on the ocean floor (FIGURE 18). The lubricator or wellhead closure **206** may be of any desired type suitable for use in offshore underwater wellhead assemblies. A typical lubricator or wellhead closure of this type is shown and described in copending patent application Serial No. 830,587, filed July 30, 1959, now abandoned. A lubricator of this type permits re-entry into the well for well control or work-over purposes. With all of the wellhead equipment placed on the ocean floor, the cables **25**, **26** and **29** of FIGURES 8 and 21, by which the various pieces of equipment were lowered to the ocean floor, are disconnected from the barge and allowed to either drop to the ocean floor, or are connected to a float at their upper end so they may be easily recovered when it is desired to go back into the well for servicing work. If the cables are dropped to the ocean floor they may be first connected together at their upper ends so as to facilitate retrieving them by a grappling hook or any other suitable means. Preferably, however, the cables are anchored to the ocean floor at 120 degrees to each other in order to prevent entanglement.

While the present invention has been described with regard to the drilling of underwater wells wherein the operations are carried out while employing a rotating drill stem, it will be quite apparent that the operations of the present invention can be employed in the drilling of underwater wells while using a turbo-drill or an electrically operated forwardly-advancing drilling machine positioned at the bottom of a well.

The present method of drilling and completing wells may also be employed when the wellhead support structure or container **23** is positioned at any level above the ocean floor as long as the final wellhead assembly is located beneath the surface of the water at a depth so that it is not subject to damage by collision with moving vessels. Also, if desired, the well may be spudded with the hole for the conductor pipe **31** being drilled with a large diameter cutting tool without the wellhead support structure or container **23** being suspended in place from the vessel together with the conductor pipe **31**. Alternatively, the conductor pipe **31** and container **23** could be slipped or threaded over the top of the drill stem **34** and lowered so that at least the lower end of the conductor pipe **31** was in the drilled hole before pulling the drill stem back onto the drilling vessel.

We claim as our invention:

1. A method of well completion from a floating vessel in communication through a marine conductor pipe with an underwater well positioned beneath said vessel and having guide means extending therebetween and having

a blowout preventer secured to a casinghead positioned above the ocean floor with casing extending into the well and cemented therein, said method comprising

(a) closing the well below the casinghead to prevent the escape of a formation fluid under pressure,

(b) remotely disconnecting the blowout preventer and marine conductor pipe and withdrawing them to the vessel,

(c) guiding a string of tubing on a running string from the vessel down into the well casing,

(d) hanging the string of tubing in the casinghead and

(e) withdrawing said running string to said vessel.

2. A method of completing from a floating vessel an underwater well positioned beneath said vessel and having guide means extending therebetween and having a blowout preventer secured to a casinghead positioned above the ocean floor with casing extending into the well and cemented therein, said method comprising

(a) closing the well casing to prevent the escape of a formation fluid under pressure,

(b) remotely disconnecting the blowout preventer and withdrawing it to the vessel,

(c) guiding a string of tubing on a running string from the vessel down into the well casing with the upper end of the tubing string at a point above the surface of the water adjacent the vessel,

(d) attaching a production wellhead assembly to the top of said tubing string,

(e) lowering the upper portion of said tubing string into said well casing, and at the end of this step

(f) lowering the production wellhead assembly on the top of the casinghead to close said casinghead.

3. A method of well completion from a floating vessel in communication through a marine conductor pipe with an underwater well positioned beneath said vessel and having guide means extending therebetween and having a blowout preventer secured to a casinghead positioned above the ocean floor with casing extending into the well and cemented therein, said method comprising

(a) lowering a perforating device from the vessel and perforating the casing opposite a producing formation,

(b) closing the well casing below the casinghead to prevent the escape of a formation fluid under pressure,

(c) remotely disconnecting the blowout preventer and marine conductor pipe and withdrawing them to the vessel,

(d) guiding a string of tubing on a running string from the vessel down into the well casing with the upper end of the tubing string at a point above the surface of the water adjacent the vessel,

(e) attaching a production wellhead assembly to the top of said tubing string,

(f) lowering the upper portion of said tubing string back into said well casing, at the end of this step

(g) lowering the production wellhead assembly on the top of the casinghead to close said casinghead, and

(h) remotely releasably locking said production wellhead on said casinghead and sealing it thereto in a fluidtight manner.

4. A method of completing from a floating vessel an underwater well positioned beneath said vessel and having guide means extending therebetween and having a casinghead positioned above the ocean floor with casing extending into the well and cemented therein, said method comprising

(a) positioning a string of tubing in the well casing with the upper portion of said tubing string extending upwardly to a point above the surface of a body of water adjacent said vessel,

(b) attaching a valved production wellhead assembly to the top of said tubing string,

(c) lowering the upper portion of said tubing string into said well casing while guiding the production wellhead assembly into register with the top of said casinghead,

(d) lowering the production wellhead assembly on the top of the casinghead to close said casinghead, and

(e) remotely connecting said production wellhead assembly to said casinghead and sealing it thereto in a fluidtight manner.

5. The method of claim **4** including the steps of

(a) closing the well casing to prevent the escape of a formation fluid under pressure prior to positioning the tubing string in the well casing, and

(b) bringing the bottom of the tubing string in fluid communication with the producing formation of said well after the production wellhead assembly has been connected to the casinghead.

6. A method of completing from a floating vessel in communication through a marine conductor pipe with an underwater well positioned beneath said vessel and having guide means extending therebetween and having a casinghead positioned above the ocean floor with casing extending into the well and cemented therein, said method comprising

(a) closing the well casing to prevent the escape of a formation fluid under pressure,

(b) guiding a string of tubing on a running string from the vessel down into the well casing,

(c) hanging the string of tubing in the casinghead and withdrawing said running string to said vessel,

(d) disconnecting from said casinghead said marine conductor pipe and withdrawing it to the vessel,

(e) lowering a running string from said vessel into said casinghead to connect to the upper end of said tubing string,

(f) withdrawing the upper end of the tubing string to a point above the surface of the water adjacent the vessel,

(g) attaching a production wellhead assembly to the top of said tubing string,

(h) lowering the upper portion of said tubing string back into said well casing, and at the end of this step

(i) lowering the production wellhead assembly on the top of the casinghead to close said casinghead.

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