United States Patent [19]

Cochran

[11] **3,791,449**

[45] **Feb. 12, 1974**

[54] **TELESCOPING DISPLACEMENT JOINT**

[75] Inventor: **Chudleigh B. Cochran**, Houston, Tex.

[73] Assignee: **Brown Oil Tools, Inc.**, Houston, Tex.

[22] Filed: **Oct. 13, 1971**

[21] Appl. No.: **188,878**

[52] **U.S. Cl.** **166/312,** 166/154, 166/315

[51] **Int. Cl.** **E21b 23/00,** E21b 37/00

[58] **Field of Search** ... 166/150, 153, 154, 156, 312, 166/313, 315

[56] **References Cited**

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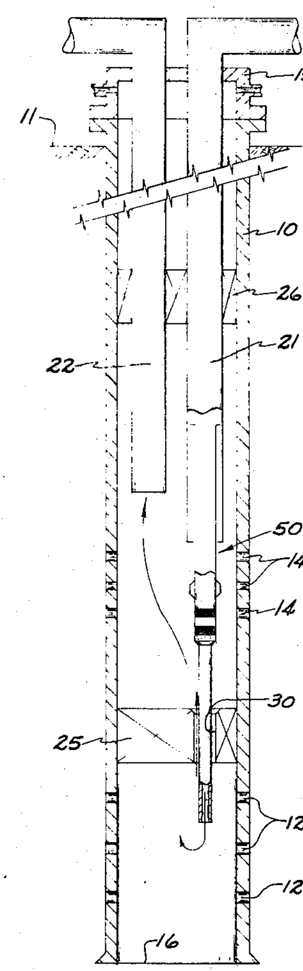
Primary Examiner—Marvin A. Champion
Assistant Examiner—Jack E. Ebel
Attorney, Agent, or Firm—Torres and Berryhill

[57] **ABSTRACT**

Method and apparatus for displacing drilling fluids from between axially spaced well packers in a multiple string well. A telescoping displacement joint may be attached at the lower end of the string which passes through both packers. The joint is initially in a retracted position leaving an annular space btween the joint and the lower packer. After a second string is run, circulating fluid is pumped down the first string, out of the joint, up through the annular space, into the area between packers and out the second string to displace drilling fluids accumulated between packers. Then pressure is applied to the joint, causing a seal carrying portion thereof to extend into sealing engagement with the lower packer. The joint comprises an inner tubular member telescopically engaging an outer tubular member and adapted for limited axial movement from a retracted to an extended position. The joint carries a first seal assembly between the inner and outer tubular members and a second seal assembly on the inner tubular member for sealing engagement with the lower packer.

16 Claims, 7 Drawing Figures



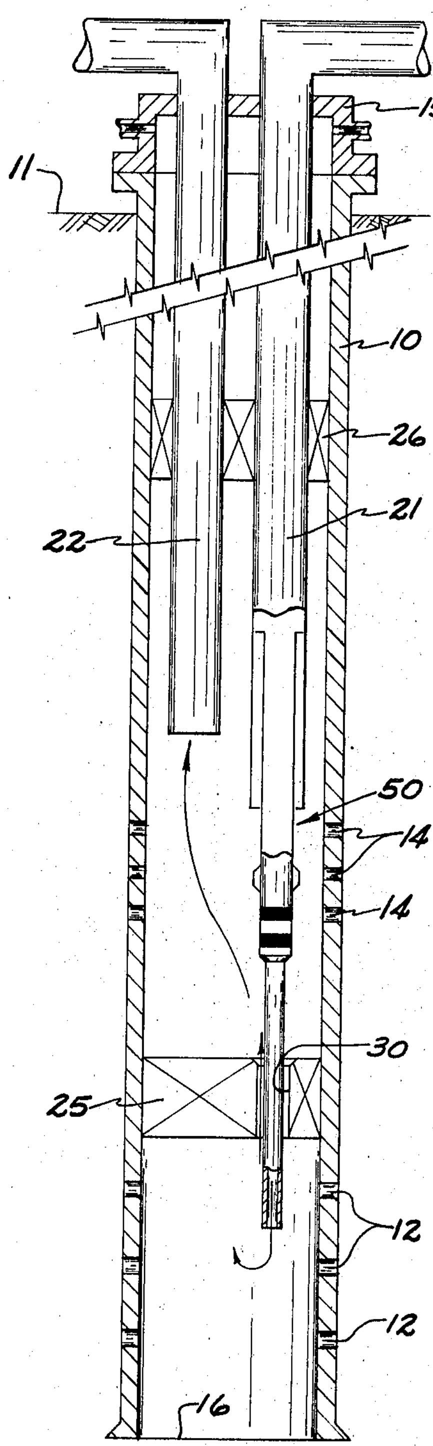


Fig. 1

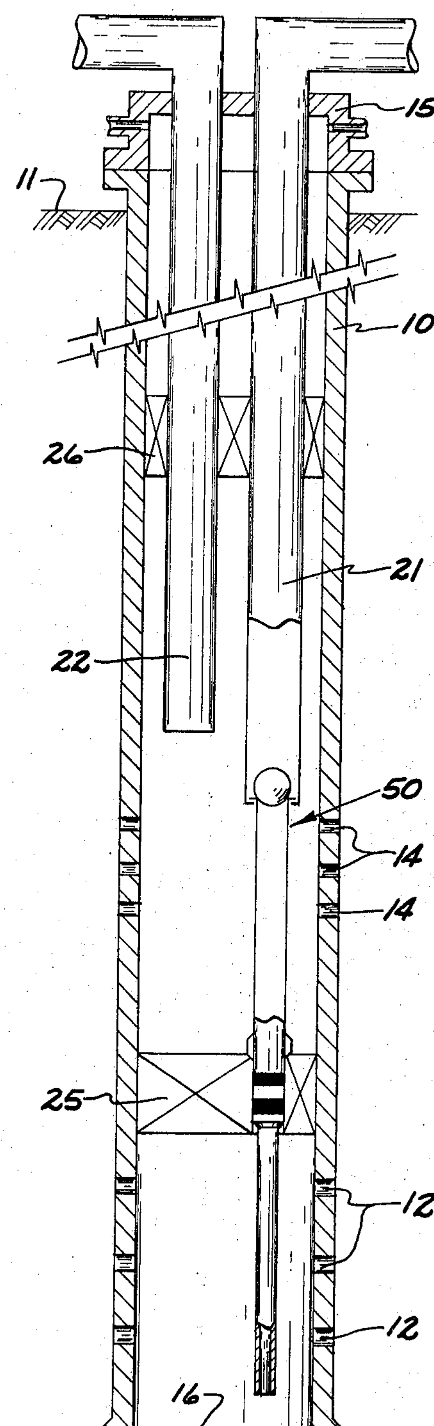


Fig. 2

CHUDLEIGH B. COCHRAN
INVENTOR.

BY Carlos A. Torres
Bill B Berryhill

ATTORNEYS

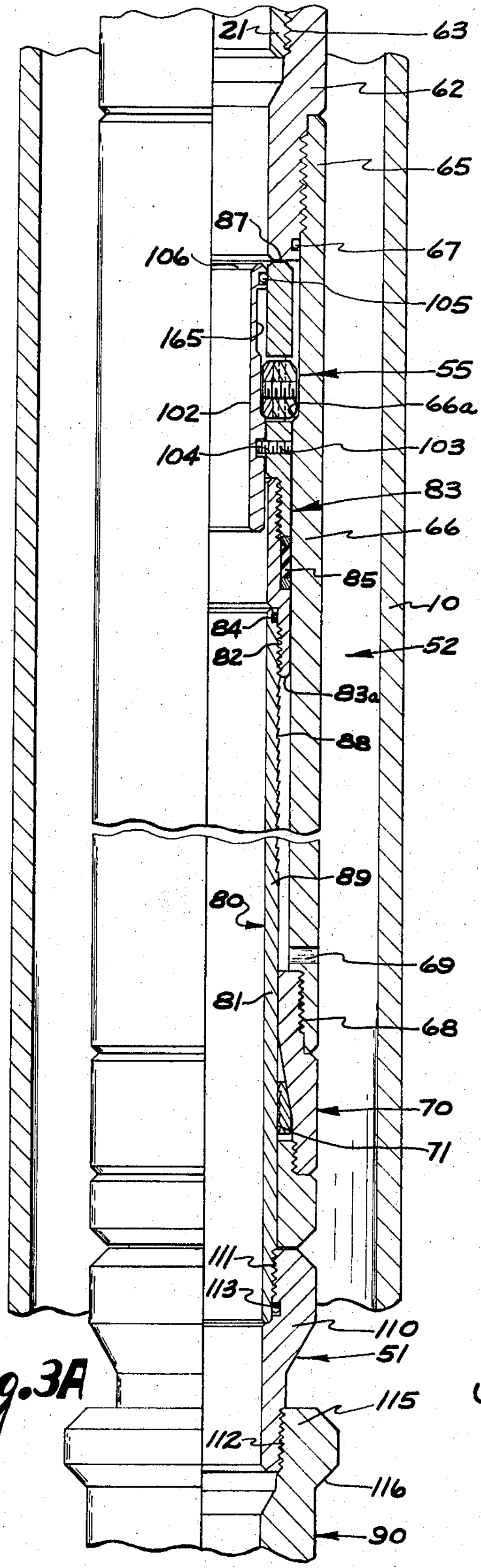


Fig. 3A

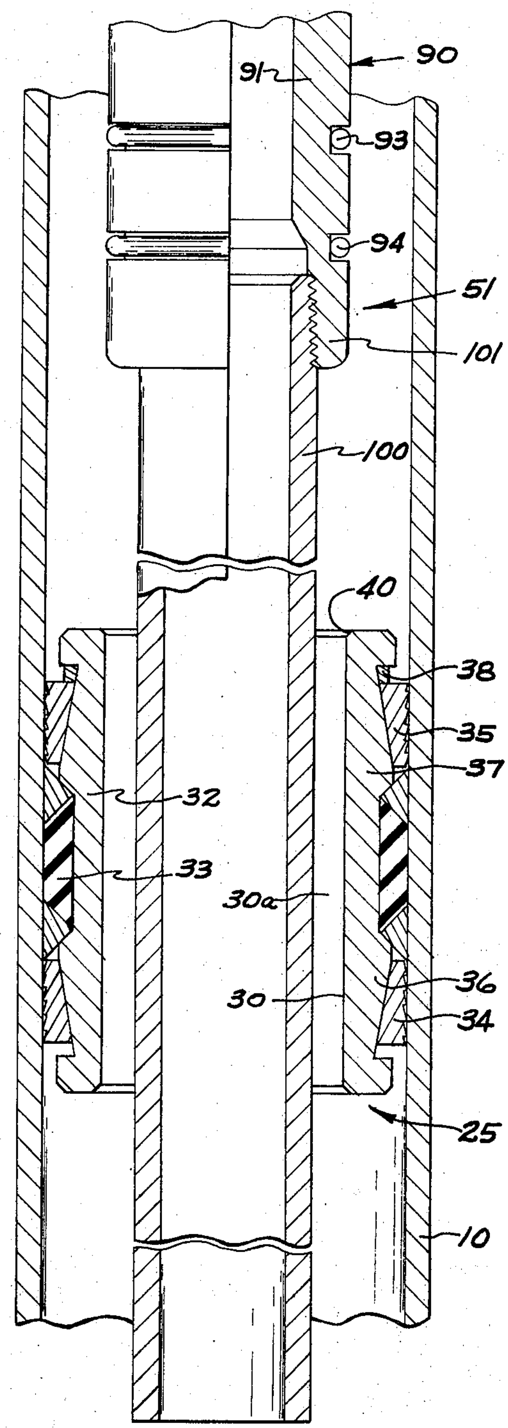


Fig. 3B

CHUDLEIGH B. COCHRAN
INVENTOR.

Carlos A. Torres

BY Bill B Berryhill

ATTORNEYS

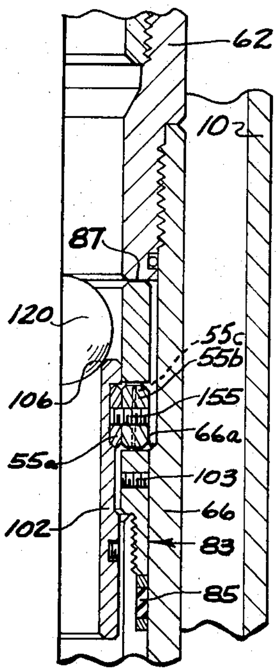


Fig. 4

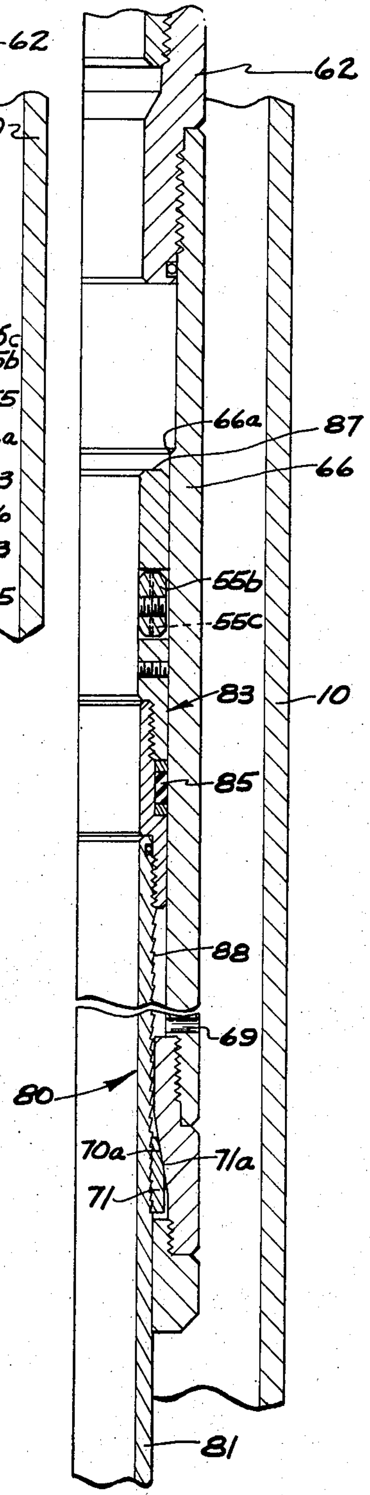


Fig. 5A

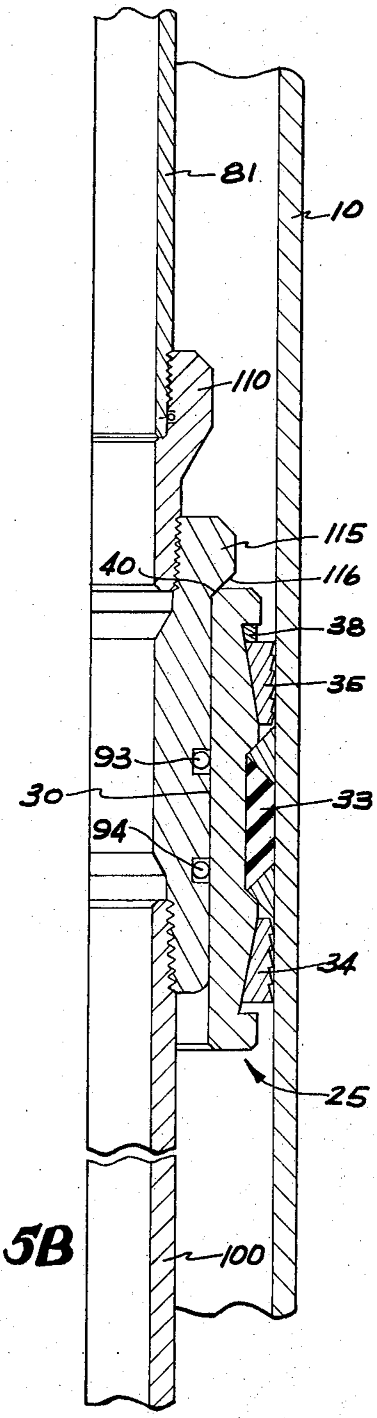


Fig. 5B

CHUDLEIGH B. COCHRAN
INVENTOR.

BY Carlos A. Torres
Bill B. Berryhill

ATTORNEYS

TELESCOPING DISPLACEMENT JOINT

BACKGROUND OF THE INVENTION

1. Field of the Invention

The present invention pertains to drilling and completionof oil and gas wells. In particular, it concerns methods and apparatus for displacing drilling fluids from tubing strings and spaces between packers in a multiple zone well.

2. Description of the Prior Art

When completing a multiple zone well, it is necessary to displace drilling fluids or "mud" which remain standing in the well after drilling operations. In the past, this has been done prior to setting of either the lower or upper packers by circulating fluid down the long string back up around the lower packer into the area between packers and finally out of the well through the short string and/or around the upper packer through the surrounding casing. After the drilling fluid or mud has been removed, both the lower packer and the upper packer are then set. One disadvantage of such a method is the possibility of a blowout of the lower and/or upper zones prior to the setting of packers. In addition, since the drill fluid passes around both packers prior to setting, the distinct possibility exists that the packer seals will be damaged by the erosive passage of drilling fluid around the packers. Of course, if the packers do not properly seal when they are set, an expensive pulling job may be required.

The most popular methods of dual completion employ a permanent packer above the lower production zone and a retrievable hydraulic dual packer above the upper zone. Permanent packers are usually set by electric or other types of wireline devices or on pipe prior to running tubing strings. With permanent packers, the tubing is run and retrieved independently of the packer and without disturbing the packer setting. Since the permanent packer is set prior to running of the long tubing string, the former practice of circulating fluid through the long string and back up around the lower packer can no longer be performed. Several methods have been developed to overcome this problem. In one, the tubing strings are simply run into the well and stopped short of their landing positions while circulating fluid is pumped through the long string into the area between packers and back up the short string. One important disadvantage of such a method is the lack of total pressure protection since the production tree cannot be flanged up until the tubing strings are finally lowered to their landing positions.

In other methods of displacing drilling fluids between packers, a circulating joint is provided in the long string for disposition between packers. The circulating joint is provided with ports which are opened by various means to allow circulation through the long string into the space between packers and back up the short string. After circulation these ports are closed. Many of these circulation joints require wireline tools for opening and closing of the ports. Wireline tools are, of course, susceptible to becoming lodged in the long string due to the heavy drillings muds accumulated therein. Even if they do not become lodged in the tubing string, they may not properly engage the circulating joint operating mechanisms. Other circulating joints have been developed in which the ports are opened and closed by a combination of pressure operation and manipulation of one or both of the tubing strings. Such joints are complex, relatively expensive and require close manufacturing tolerances and precise operational adjustments.

SUMMARY OF THE INVENTION

In the present invention, a method and apparatus for displacing drilling fluids from between a set permanent packer and a hydraulic packer thereabove is disclosed which provides a simpler solution than the methods and apparatus of the prior art. In the present invention, an extensible displacement joint is attached to the end of the long string and lowered into the well penetrating a hole provided therefor in the permanent packer. After tagging the permanent packer with a shoulder on the displacement joint, the string is picked back up a specified distance, is landed in a tubing head at the wellhead and after running and landing of the short string, the production tree is flanged up. In its initial position, the lower portion of the extensible joint penetrates the permanent packer tubing bore. The lower portion of the joint is of a smaller diameter than the packer tubing bore so that an annular space is left therebetween. Therefore, circulating fluid may be pumped down the long string, through the joint and back up through the annular space between the lower portion of the joint and the permanent packer, into the area between the permanent packer and the hydraulic packen, and finally out of the well through the short string.

After displacement of the drilling fluids, it is necessary to seal the annular space between the telescoping joint and the permanent packer. This accomplished by closing the lower end of the long string and applying an internal pressure to the telescoping joint through the long string. An expansion chamber within the joint causes the lower end of the joint to move downwardly with respect to the upper portion thereof until a larger diameter portion of the joint carrying a seal assembly sealingly engages the permanent packer tubing bore. The downward movement is arrested by cooperating stop shoulders on the joint and the permanent packer. This sealing position is maintained by a slip retaining assembly. After the joint has been moved to its final sealing position, the lower end of the long string is again opened and the well is ready for production.

As stated before, the tubing string is anchored at the wellhead and sealing between the permanent packer and the long string is effected without the need for releasing the tubing string or moving the string from the surface. All displacement joint movement is effected by hydraulic pressure without the need for releasing or moving the tubing at the wellhead. In addition to displacing drilling fluids from the long string and between packers, the present invention displaces drilling fluids below the lower packer. These are important features and objectives of the invention. Other objects and advantages of the invention will be apparent from the accompanying drawings and description which follows.

BRIEF DESCRIPTION OF THE DRAWINGS

In the description of a preferred embodiment of the invention which follows, reference will be made to the accompanying drawings in which:

FIG. 1 is a diagrammatic representation of a dual completion well having long and short strings, a lower permanent packer and an upper hydraulic packer and employing an extensible joint, shown in its initial position, for circulating fluid through the long string and back up the short string to displace drilling fluids accumulated in the long string and between the packers, according to a preferred embodiment of the invention;

FIG. 2 is a diagrammatic representation of the dual completion well of FIG. 1 showing the final sealing position of the extensible joint after displacement of drilling fluids from between packers;

FIGS. 3A and 3B are sectional elevation views of the extensible displacement joint and permanent packer of of FIGS. 1 and 2, showing the packer set in the well casing and showing the displacement joint in the initial or retracted position of FIG. 1, FIG. 3B being a lower continuation of FIG. 3A;

FIG. 4 is a sectional view of a portion of the displacement joint showing an intermediate operational position of a retaining mechanism thereof; and

FIGS. 5A and 5B are sectional elevation views of the packer and displacement joint of FIGS. 1–4 shown in the final or extended sealing position of FIG. 2, FIG. 5B being a lower continuation of FIG. 5A.

DESCRIPTION OF A PREFERRED EMBODIMENT

Referring first to FIG. 1, there is shown a well for production of petroleum deposits from upper and lower subterranean formations or zones. An outer conduit or casing string 10 extends from the surface 11 to the bottom of the well hole 16. The casing string 10 is perforated at 12 and 14 to allow flow of petroleum fluids from the lower and upper zones, respectively. A wellhead 15 is attached at the upper end of casing string 10 and provides support for a pair of tubing strings, long string 21 and short string 22. The long string 21 extends downwardly through the casing string 10 past the upper production zone, through a permanent packer 25 and into an area adjacent the lower production. The short string 22 extends from the wellhead 15 through the hydraulic packer 26 to a point in the casing string 10 adjacent the upper production zone.

Normally, the permanent or lower packer 25 completion of run into the well and set by electric or other types of wireline tools or on pipe, and tested. Then the long string 21 is run into the well with the hydraulic or upper dual packer 26 attached thereto. After tagging the permanent packer 25 with a shoulder on joint 50 at the end of string 21, the long string is picked back up several feet and secured at the wellhead. The short string 22 is then run into the well and landed in the hydraulic packer 26. The hydraulic packer 26 can be set and tested at this point. In some cases, it might be left unset until a later time.

Attached at the lower end of the long string 21, so as to form a part of this string, is a telescoping or extensible displacement joint 50, to be more fully described hereafter. In the initial or running in position, as shown in FIG. 1, the lower end of the joint 50 extends through a tubing bore 30 in the permanent packer 25. The diameter of this lower end is such that an annular space, approximately equal in area to the flow area of the tubing string 21, surrounds the joint 50. By pumping a circulating fluid such as water, down through the long string 21, out the end of the joint 50, back up the annular space surrounding the joint through packer 25 into the area between packers, and through the short string 22 to the surface, any drilling fluids (mud) accumulated in long string 21 and between the packers 25 and 26 may be displaced.

After displacement of the drilling fluids, it is necessary to seal the annular space between the joint 50 and packer 25. This is accomplished by closing the lower end of long string 21 or joint 50, as will be described hereafter, and applying pressure to the long string 21. This pressure is applied to an expansion chamber, as will be more clearly understood hereafter, which causes a portion of the telescoping joint 50 to be extended to the position shown in FIG. 2. Downward movement is arrested by cooperating stop shoulders on the joint 50 and packer 25. The joint 50 is provided with seals which, in the extended position, sealingly engage the tubing bore 30 through packer 25. A hold down mechanism is activated to maintain this position. If the upper packer 26 has not been set prior to this point, it is now set and the well is ready for production.

Referring also now to the remaining drawing figures the extensible joint 50 will be described in detail. In FIGS. 3A and 3B the joint is shown with packer 25 in the initial or circulating relationships of FIG. 1. The permanent packer 25 is shown in its set position within casing 10. The packer 25 may be any type of packer which presents a bore 30 suitable for sealing engagement with the tubing string. Those skilled in the art are familiar with the construction and operation of the various types of packers. However, for purposes of illustration, the type of packer 25 shown in the drawings will be briefly and generally described. The packer comprises a tubular body 32 on which is carried an annular seal 33, a set of two-way slips 34, 35, and corresponding setting cones 36, 37. By manipulation of the body 32 and setting sleeve 38, the setting slips 34, 35 are brought together to compress the seal 33 for sealing engagement with casing 10 and body 32. The seal compression and the position of the packer within casing 10 is maintained by the engagement of the teeth of slips 34 and 35 with the inner wall of casing 10. This position may be maintained by a set of internal locking slips (not shown) between tubular body 32 and setting sleeve 38. As previously pointed out the tubular body 32 is provided with a smooth cylindrical bore 30 for sealing with the tubular string, as will be more clearly understood hereafter. The upper end of the packer is provided with a frustoconical stop shoulder 40, which in this case is carried by the upper end of tubular body member 32. The purpose of this stip shoulder will be more clearly understood hereafter.

This displacement joint of the present invention comprises a tubular male assembly, designated generally by the numeral 51, and a tubular female assembly, designated generally by the numeral 52, adapted to telescopically receive a portion of the male assembly 51 for limited relative longitudinal movement therein, where it not for the latching dogs 55 between the two assemblies. The outer female assembly 52 comprises a collar or adaptor 62 having a threaded box 63 for connection to an adjacent section of tubing string 21. Connected to the lower end of adapter 62 by a pin and box connection 65 is an elongated tubular housing 66. An annular seal ring 67 assures a fluid-tight connection therebetween. Connected to the lower end of tubular housing 66 by another pin and box connection 68 is locking and retaining section 70 which carries a set of locking slips 71. The function and operation of slips 71 will be described hereafter.

The tubular male assembly 51 comprises an upper sliding connection section 80, an intermediate seal and landing section 90 and a lower flow-tube section 100. Upper section 80 comprises a tubular member 81 connected to its upper end by a pin and box connection 82 to a head section 83. This connection is made fluid-tight by a seal ring 84. The head section 83 is provided with a seal member 85 so that the head section 83 slidingly and sealingly engages the internal walls of female assembly housing section 66. The upper end of the head section 83 is provided with an upwardly facing surface 87 which would be exposed to whatever pressure might exist in the tubing string 21. The exterior of cylindrical section 81 is provided with upwardly facing teeth 88, the purpose of which will be more clearly understood hereafter. The lower end of tubular section 81 slidingly engages the interior of the locking and retaining section 70 of female assembly 52. Since the outside diameter of tubular section 81 is less than the inside diameter of housing 66 and annular space 89 exists therebetween. A pressure equalization port 69 through the walls of housing 66 assures that the pressure in annular chamber 89 is the same as the pressure surrounding housing 66. Thus, this pressure acts on the downwardly facing surface area 83*a* of head 83 while the internal tubing pressures act on the upwardly facing surface 87.

Mounted on the interior of the male assembly 51, adjacent head section 83, is a cylindrical seat member 102 which is held in place by the engagement of shear screws 103 with an annular groove 104. Seal 105 assures sealing engagement with the interior of head section 83. The seat member 102 is provided with an upwardly facing frustoconical seating surface 106, the purpose of which will be more fully understood hereafter. An annular section or groove 165, the function of which will be seen hereafter, is also provided.

The locking dogs 55 are initially held between the exterior of seal member 102 and the upper interior of housing 66. In this position, the locking dogs 55 engage an upwardly facing shoulder 66*a* in housing 66 to maintain the entire male assembly 51 in the retracted position of FIGS. 1, 3A and 3B.

The intermediate seal and landing section 90 of male assembly 51 is connected to the lower end of upper section 80 by an adapter member 110 and pin and box connections 111, 112. Seals 113, 114 assure that these are fluid-tight connections. The seal and landing section 90 comprises a tubular body 91 on which is carried a seal assembly, a pair of axially spaced seals 93, 94. Except for the landing shoulder 115 the outside diameter of the body 91 is slightly less than the internal diameter of the tubing bore 30 of the packer 25 therebelow. The landing shoulder 115 provides a downwardly facing frustoconical surface 116 which corresponds with the upwardly facing frustoconical surface 40 in the packer 25. On initially running in of the long string 21, the shoulder 115 is tagged up with packer surface 40 so that the long string may be picked back up the proper distance for landing.

The lower or flow-tube section 100 of the male assembly 51 is connected to the seal and landing section 90 by pin and box connection 101. In the initial or retracted positions shown in FIGS. 1, 3A and 3B the flow tube 100 penetrates or extends through packer 25. However, its outside diameter is less than the diameter of bore 30 so that an annular space 30*a*, approximately equal in area to the flow area of flow-tube 100, exists around the flow-tube within packer 25.

As stated earlier with reference to FIG. 1, the long tubing string 21 is run into the well with the displacement joint 50 in the position shown in FIGS. 3A and 3B. After tagging the permanent packer 25, the tubing string is picked back up a few feet and landed and secured at the wellhead. As the tubing string 21 is run into the well, drilling fluid or mud is accumulated in the string 21 and between packers 25 and 26. (See FIG. 1). Next, the short string 22 is run into the well, landed and secured at the wellhead. The upper or hydraulic packer 26 may be set at this time.

To displace the drilling fluid accmulated in the long string 21, under packer 25 and between packers 25 and 26, a circulating fluid, such as water, is pumped downwardly through the long string 21 and back up the annular space 30*a*, surrounding flow tube 100, into the area between packers 25 and 26. Continued circulation forces the drilling fluid upwardly through the short string 22 for removal from the well. This circulating operation is illustrated by the arrows in FIG. 1.

After the drilling fluids have been displaced, the annular space 30a must be closed off to isolate the lower production zone from the upper production zone. This is accomplished by first dropping a closure member such as a rubber ball 120 (see FIG. 4) down the tubing string 21 into the displacement joint 50 for sealing engagement with seating surface 106 of seat member 102. Thus, the lower end of the tubing string 21 is now closed. See FIGS. 2 and 4. Increased pressure acting on the ball 120 first causes the shear screw 103 to fail allowing the seat member 120 to drop to the position shown in FIG. 4, where the inwardly biased latching dogs 55 spring into engagement with groove 165. Since the dogs 55 no longer engage shoulder 66a and pressure is exerted on the upwardly facing surface 87 of head 83 a downwardly directed force causes the entire male assembly 51 to be displaced axially downwardly until the frustoconical surface 116 of landing shoulder 115 engages cooperating frustoconical surface 40 on packer 25, as shown in FIG. 5B. In this position the seal assembly 93, 94 sealingly engages the tubing bore 30 of the packer 25, blocking the pre-existing annular passage 30*a* therebetween. As the upper section 80 of the male assembly 51 moves downwardly, the upwardly facing teeth 88 on tubular member 81 engage the downwardly facing teeth on the locking slips 71. The downwardly facing frustoconical surface 70*a* cooperates with upwardly facing frustoconical surface 71*a* on the back of slips 71 to wedge the slips 71 into tighter engagement with the teeth 88, in the event forces are applied which tend to force the male assembly 51 in an upward direction. Thus, the male assembly 51 is locked in the sealing and landed position shown in FIGS. 2, 5A and 5B. The direction of the teeth on upper section 80 and slip 71 and cooperating surfaces 70*a* and 71*a* do not, however, prevent the aforementioned downward movement of male assembly 51.

Except for the fact that the lower end of the tubing string is closed by ball 120 and seat 102, the well is now ready for production. To open the string, enough pressure is applied to the string to shear the connection 155 between inner and outer portions 55*a*, 55*b* of dogs 55. When this connection is broken the inner portion 55*a* of latch dogs 55, seat 102 and ball 120 drop out of the string into the bottom of the well, leaving the string 21 clear for production, as shown in FIGS. 5A and 5B. The outer portion 55*b* of dogs 55 are provided with wings

55*c* which engage lips (not shown) on head **83** to prevent obstruction of full bore opening through the joint.

Displacing drilling fluids from between the packers, according to the present invention, is much preferred over prior methods. It allows setting of packers, running and landing of tubing strings and flanging up of the production tree prior to displacement. It requires no wireline tools for opening or closing of circulating joint ports and requires only two simple pressure steps to complete. The displacement joint of the present invention is simple both to manufacture and operate and eliminates complex circulating joints.

Although only one method and one embodiment of the apparatus of the invention have been described herein, mamy changes and modifications of both the method and apparatus may be made by those skilled in the art without departing from the spirit of the invention. It is therefore intended that the scope of the invention be limited only by the claims which follow.

I claim:

1. A method of displacing drilling fluids from a multiple zone well having upper and lower packer means therein comprising the steps of:

a. running and landing a first string of tubing in said well with displacement joint means on the lower end thereof for disposition between said upper and lower packer means, a portion of said displacement joint means extending through a bore in said lower packer means leaving an annular passage therebetween;

b. running and landing a second string of tubing in said well extending through said upper packer means into the space between said packer means; and

c. circulating fluid through said first and second strings, said annular passage and said space between said packer means to remove drilling fluid accumulated between said packer means and below said lower packer means.

2. The method of claim **1** and the further steps of closing the end of said first string of tubing by pumping a closure member into said displacement joint and applying pressure to said displacement joint means through said first string of tubing to axially move at least a portion of said displacement joint means into sealing engagement with said bore through said lower packer means.

3. The method of claim **2** and the further step of opening the end of said first string of tubing for production of well fluids therethrough by increasing the pressure therein causing said closure member to exit said joint below said lower packer means.

4. The method of claim **1** in which both of said packer means are set prior to said circulating of fluid.

5. The method of claim **1** in which said lower packer means is set prior to said circulating of fluid.

6. An extensible joint for well pipe strings, comprising:

a. an outer tubular means having means thereon for connecting said joint to an adjacent section of pipe string;

b. inner tubular means telescopically engaging said outer tubular means for limited axial movement from a retracted position to an extended position relative to said outer tubular means;

c. first seal means between said outer and inner tubular means carried by head means on the upper end of said inner tubular means, said head means having an upwardly facing annular surface area exposed to the pressure within said tubing string and a downwardly facing annular surface area exposed to the pressure within said tubing string and a downwardly facing annular surface area exposed to the pressure existing around said outer tubular means;

d. second seal means carried by said inner tubular means for sealing engagement with an opening through apparatus in said well, when said inner tubular means is in said extended position.

7. A displacement joint as set forth in claim **6** in which said inner tubular means is connected to said outer tubular means, in said retracted position, by retainer means, said retainer means being releasable to permit said axial movement.

8. The displacement joint of claim **7** in which said inner tubular means is provided with closable valve means whereby a releasing force may be applied to said retainer means by applying pressure to said displacement joint through said pipe string.

9. An extensible joint for well pipe strings comprising:

a. an outer tubular means having means thereon for connecting said joint to an adjacent section of pipe string;

b. inner tubular means telescopically engaging said outer tubular means for limited axial movement from a retracted position to an extended position relative to said outer tubular means;

c. first seal means between said outer and inner tubular means;

d. second seal means carried by said inner tubular means for sealing engagement with an opening through apparatus in said well, when said inner tubular means is in said extended position;

e. retainer means connecting said inner tubular means to said outer tubular means, in said retracted position, said retainer means being releasable to permit said axial movement; and

f. valve means provided on said inner tubular member by which a releasing force mey be applied to said retainer means by applying pressure to said displacement joint through said pipe string, said valve means comprising a seat member, attached to said inner tubular means by connection means, and a closure member engageable with said seat member, said connection means being releasable at a predetermined pressure level in said pipe string when said closure member engages said seat member to allow axial displacement of said seat member relative to said inner tubular member.

10. The displacement joint of claim **9** in which said retainer means comprises a radially contractable latch member engageable with an annular groove in said seat member on said axial displacement to permit said axial movement of said inner tubular means.

11. The displacement joint of claim **10** in which said latch member comprises a first portion engaging said seat member and a second portion engaging said inner tubular member, said first and second portions being connected by attachment means which is frangible upon the existence of a predetermined pressure differential across said valve means from said inner tubular means.

12. A displacement joint as set forth in claim **6** in which said inner and outer tubular means are provided with cooperable locking means engageable in said extended position to prevent retraction of said inner tubular means from said extended position.

13. An extensible joint for well pipe strings comprising:

a. an outer tubular means having means thereon for connecting said joint to an adjacent section of pipe string;

b. inner tubular means telescopically engaging said outer tubular means for limited axial movement from a retracted position to an extended position relative to said outer tubular means;

c. first seal means between said outer and inner tubular means;

d. second seal means carried by said inner tubular means for sealing engagement with an opening through apparatus in said well, when said inner tubular means is in said extended position; and

e. cooperable locking means provided on said inner and outer tubular means engageable in said extended position to prevent retraction of said inner tubular means from said extended position, said cooperable locking means including a roughened surface on said inner tubular means and slip means carried by said outer tubular means for engagement with said roughened surface.

14. The displacement of claim **13** in which said slip means and said roughened surface comprise oppositely facing teeth permitting movement of said inner tubular means toward said extending position but preventing movement in the opposite direction.

15. The displacement joint of claim **6** in which said inner tubular means is provided with shoulder means engageable with said apparatus, in said extended position, to limit said axial movement and to support said inner tubular means.

16. The displacement joint of claim **15** in which said second seal means is carried below said shoulder means.

* * * * *

UNITED STATES PATENT OFFICE
CERTIFICATE OF CORRECTION

Patent No. 3,791,449 Dated February 12, 1974

Inventor(s) Chudleigh B. Cochran

It is certified that error appears in the above-identified patent and that said Letters Patent are hereby corrected as shown below:

Abstract, line 6: change "btween" to --between--.

Column 1, line 7: change "completionof" to --completion of--.

Column 2, line 28: change "packen" to --packer--.

Column 4, line 46: change "stip" to --stop--.

Column 4, line 53: change "where" to --were--.

Column 7, line 15: change "mamy" to --many--.

In the Claims:

Column 10, line 8: after "displacement" insert --joint--.

Signed and sealed this 25th day of June 1974.

(SEAL)
Attest:

EDWARD M.FLETCHER,JR.
Attesting Officer

C. MARSHALL DANN
Commissioner of Patents