PCT

WORLD INTELLECTUAL PROPERTY ORGANIZATION
International Bureau

INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(51) International Patent Classification 5 : E21B 33/127

A1

(11) International Publication Number: WO 94/23177

(43) International Publication Date: 13 October 1994 (13.10.94)

(21) International Application Number: PCT/US94/02713

(22) International Filing Date: 14 March 1994 (14.03.94)

(30) Priority Data:
08/041,123 30 March 1993 (30.03.93) US

(71) Applicant: BAKER HUGHES INCORPORATED [US/US]; 3900 Essex Lane, Suite 1200, Houston, TX 77027 (US).

(72) Inventor: LOUGHLIN, Michael, James; 2523 Droxford, Houston, TX 77008 (US).

(74) Agents: DESAI, Umesh, M. et al.; Baker Hughes Incorporated, Suite 1200, 3900 Essex Lane, Houston, TX 77027 (US).

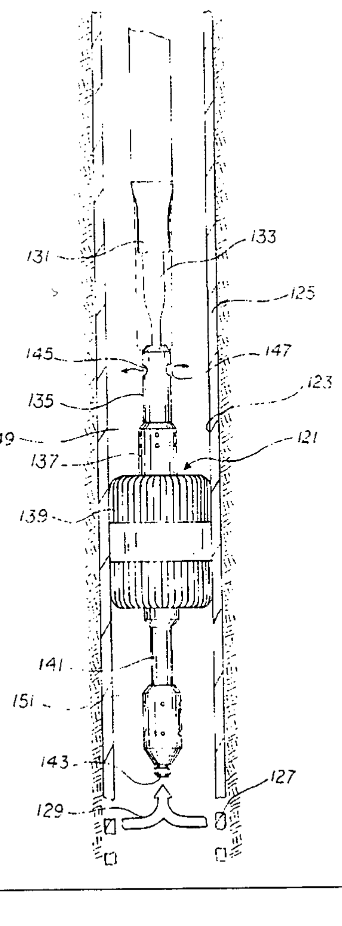
(81) Designated States: AU, CA, DE, DK, GB, NL, NO.

Published
With international search report.

(54) Title: METHOD AND APPARATUS FOR REDUCING PRESSURE DIFFERENTIAL FORCES ON A SETTABLE WELLBORE TOOL IN A FLOWING WELL

(57) Abstract

An apparatus is provided for use in a wellbore (123) for reducing the effects of pressure differential forces which act on settable wellbore tools (121) suspended therein. The apparatus operates to provide a bypass fluid flow path (145, 147) through the settable wellbore tool for directing wellbore fluid through the settable wellbore tool in response to pressure differentials developed across the settable wellbore tool during outward radial expansion of the tool. The apparatus further includes mechanisms (221, 223) for maintaining the bypass fluid flow path in an open condition during at least an expansion mode of operation to diminish the effects of pressure differential developed across the settable wellbore tool. The apparatus also includes mechanisms (193) for closing the bypass fluid flow path once a setting mode of operation is obtained.



FOR THE PURPOSES OF INFORMATION ONLY

Codes used to identify States party to the PCT on the front pages of pamphlets publishing international applications under the PCT.

AT	Austria	GB	United Kingdom	MR	Mauritania
AU	Australia	GE	Georgia	MW	Malawi
BB	Barbados	GN	Guinea	NE	Niger
BE	Belgium	GR	Greece	NL	Netherlands
BF	Burkina Faso	HU	Hungary	NO	Norway
BG	Bulgaria	IE	Ireland	NZ	New Zealand
BJ	Benin	IT	Italy	PL	Poland
BR	Brazil	JP	Japan	PT	Portugal
BY	Belarus	KE	Kenya	RO	Romania
CA	Canada	KG	Kyrgystan	RU	Russian Federation
CF	Central African Republic	KP	Democratic People's Republic of Korea	SD	Sudan
CG	Congo			SE	Sweden
CH	Switzerland	KR	Republic of Korea	SI	Slovenia
CI	Côte d'Ivoire	KZ	Kazakhstan	SK	Slovakia
CM	Cameroon	LI	Liechtenstein	SN	Senegal
CN	China	LK	Sri Lanka	TD	Chad
CS	Czechoslovakia	LU	Luxembourg	TG	Togo
CZ	Czech Republic	LV	Latvia	TJ	Tajikistan
DE	Germany	MC	Monaco	TT	Trinidad and Tobago
DK	Denmark	MD	Republic of Moldova	UA	Ukraine
ES	Spain	MG	Madagascar	US	United States of America
FI	Finland	ML	Mali	UZ	Uzbekistan
FR	France	MN	Mongolia	VN	Viet Nam
GA	Gabon				

METHOD AND APPARATUS FOR REDUCING PRESSURE DIFFERENTIAL FORCES ON A SETTABLE WELLBORE TOOL IN A FLOWING WELL

BACKGROUND OF THE INVENTION

1. Field of the Invention:

This invention relates in general to settable wellbore tools, and in particular to settable wellbore tools which are carried into wellbores on either coiled-tubing strings or wirelines and subjected to pressure differentials during setting.

2. Description of the Prior Art:

Recent advances in the technology relating to the work-over of producing oil and gas wells have greatly enhanced the efficiency and economy of work-over operations. Through the use of either a coiled-tubing string, or a wireline assembly, work-over operations can now be performed through the production tubing string of a flowing oil and gas well. Two extremely significant advantages have been obtained by the through-tubing technology advances. First, the production tubing string does not need to be removed from the oil and gas well in order to perform work-over operations. This is a significant economic advantage, since work-over rigs are expensive, and the process of pulling a production tubing string is complicated and time consuming. The second advantage is that work-over operations can be performed without "killing" the well. As is known by those in the industry, the "killing" of a producing oil and gas well is a risky operation, and can frequently cause irreparably damage the worked-over well. Until the recent advances in the through-tubing work-over technology, work-over operations usually required that the well be killed.

While the through-tubing work-over technologies have significant advantages, some operating problems have been encountered. One problem, which is addressed by the present invention, is that pressure differentials created within the wellbore by the flowing oil and gas well can cause unintended displacement of settable wellbore tools, such as bridge plugs and packers. Flow in either direction can exist in a wellbore if a producing zone is in hydraulic communication through the wellbore with a consuming zone. Such interzonal "cross-flow" may exist in a well irrespective of whether it is flowing to the surface.

Settable wellbore tools are operable in a plurality of operating modes including running modes of operation, expansion modes of operation, and setting modes of operation. The settable wellbore tool is maintained in a running condition during a running mode of operation, with a reduced radial dimension so that the settable wellbore tool may be passed downward into the oil and gas well through the production tubing. Once the settable wellbore tool is passed beyond the lower end of the production tubing string, and placed in a desired location, force is applied to the settable wellbore tool to urge it into an expansion mode of operation in which the wellbore tool is urged radially outward from a reduced radial dimension to an intermediate radial dimension, which at least in-part obstructs the flow of wellbore fluid within the wellbore in the region of the settable wellbore tool.

The obstruction created by the settable wellbore tool frequently creates a pressure differential across the settable wellbore tool. Most commonly, this occurs when a packer or bridge plug is set above a producing zone. Wellbore fluids, such as oil and water, will continue flowing into the well due to the pressure differential between the wellbore fluids in the earth's formation and the wellbore itself, as well as the pressure differential between different zones. Consequently, the wellbore fluids tend to flow within the well. However, the settable wellbore tool at least in-part obstructs the flow of wellbore fluids, and, consequently, a pressure differential is created across the wellbore tool.

The cross flow of fluids may urge the settable wellbore tool upward within the wellbore, away from the desired setting location. This unintended, and harmful, displacement of the settable wellbore tool can occur because the new through-tubing, work-over technologies do not provide suspension means which are as "stiff" as those found in the more conventional work-over technologies. For example, a wireline-suspended, through-tubing work-over tool offers little resistance to pressure differentials which operate to lift the settable wellbore tool in position within the wellbore. Coiled tubing suspension means also do not provide sufficient "stiffness" to upward movement of the settable wellbore tool.

Additionally, if a pressure differential is developed across the settable wellbore tool with a higher pressure level above the settable wellbore tool, the pressure differential may act to disconnect the settable wellbore tool from the suspension means. In a wireline suspended, through-tubing wellbore tool a sufficiently large pressure differential could snap the wellbore tool loose from the wireline cable. Alternately, a high pressure differential could serve to accidentally actuate pressure-sensitive, or tension sensitive, disconnect devices which are used in both wireline-suspended tools and coiled-tubing suspended tools.

SUMMARY OF THE INVENTION

It is one objective of the present invention to provide an apparatus for use in wellbores which reduces the pressure differential forces caused by wellbore fluid flowing into the wellbore, which act on settable wellbore tools which are suspended in the wellbore on suspension members.

It is another objective of the present invention to provide an apparatus for use in a wellbore which reduces the pressure differential forces acting on a suspended, settable wellbore tool, which includes a bypass fluid flow path extending through the settable wellbore tool for directing wellbore fluid through the settable wellbore tool in response to the pressure differential developed across the settable wellbore tool when it partially obstructs the wellbore and fluid flow exists.

It is yet another objective of the present invention to provide an apparatus for use in a wellbore for reducing the pressure differential forces caused by wellbore fluids flowing into the wellbore, which act on settable wellbore tools suspended in the wellbore, wherein the apparatus includes a bypass fluid flow path extending thorough the settable tool for directing wellbore fluid through the settable wellbore tool in response to the pressure differential developed across it, a means for maintaining the bypass fluid flow path in an open condition during at least an expansion mode of operation to diminish the pressure differential developed across the wellbore tool, and a means for closing the bypass fluid flow path once the setting mode of operation is obtained to prevent the flow of fluid through the settable wellbore tool.

These objectives are achieved as is now described. An apparatus is provided for use in a wellbore for reducing the effects of pressure differential forces. The apparatus includes a settable wellbore tool which is suspended in the wellbore on a suspension member, such as a coil-tubing string or a wireline assembly. The settable wellbore tool is operable in a plurality of operating modes including a running mode of operation, an expansion mode of operation, and a setting mode of operation. During a running mode of operation, the settable wellbore tool is maintained in a reduced radial dimension for passage through wellbore tubular conduits such as production tubing. In an expansion mode of operation, the settable wellbore tool is urged radially outward from the reduced radial dimension to an intermediate radial dimension, and at least in-part obstructs the flow of wellbore fluid within the wellbore in the region of the settable wellbore tool, and creates a pressure differential across the settable wellbore tool. In a setting mode of operation, the settable wellbore tool is further radially expanded into a setting radial dimension, and is urged into a fixed position within the wellbore, in gripping engagement with the wellbore surface.

In the present invention, a bypass fluid flow path is provided, which extends through the settable wellbore tool, and operates to direct wellbore fluid through the settable wellbore tool in response to the pressure differential developed across the settable wellbore tool during at least the expansion mode of operation. The present invention further provides for a means for maintaining the bypass fluid flow path in an open condition, during at least the expansion mode of operation to diminish the pressure differential developed across the settable wellbore tool. Finally, the present invention provides a means for closing the bypass fluid flow path once the setting mode of operation is obtained to prevent the passage of fluid therethrough.

Additional objects, features and advantages will be apparent in the written description which follows.

BRIEF DESCRIPTION OF THE DRAWINGS

The novel features believed characteristic of the invention are set forth in the appended claims. The invention itself, however, as well as a preferred mode of use, further objectives and advantages thereof, will best be understood by reference to the following detailed description of an illustrative embodiment when read in conjunction with the accompanying drawings, wherein:

Figure 1 is a schematic view of a prior art inflatable wellbore tool suspended within a wellbore on a wireline assembly;

Figure 2 is a schematic view of a prior art inflatable wellbore tool suspended within a wellbore on a coiled-tubing string;

Figure 3 is a perspective view of one embodiment of the improved settable wellbore tool of the present invention disposed in a cased wellbore;

Figure 4 is a longitudinal section view of an upper fishing-neck subassembly of the preferred settable wellbore tool of the present invention;

Figure 5a is a longitudinal section view of the preferred valving subassembly of the preferred settable wellbore tool of the present invention;

Figure 5b is a cross-section view of the preferred valving subassembly of the preferred settable wellbore tool of the present invention, as seen along lines Va-Va of Figure 5a;

Figures 6a, 6b, and 6c depict, in cross-section, the preferred valve stem of the preferred settable wellbore tool of the present invention;

Figures 6d and 6e are cross-section views of the preferred valve stem of the preferred settable wellbore tool of the present invention, as seen along lines VId-VId, and VIe-VIe, respectively of Figure 6b;

Figure 7 is a one-quarter longitudinal section view of the preferred poppet valve subassembly of the preferred settable wellbore tool of the present invention;

Figures 8a, 8b, and 8c are detailed longitudinal, fragmentary longitudinal, and cross-section views, respectively, of the preferred poppet valve stem of the preferred settable wellbore tool of the present invention;

Figures 9a and 9b are one-quarter longitudinal section views of the guide subassembly of the preferred settable wellbore tool of the present invention, and are read together; and

Figure 10 is a longitudinal section view of the preferred valving subassembly of the preferred settable wellbore tool of the present invention, in a setting mode of operation.

DETAILED DESCRIPTION OF THE INVENTION

Figures 1 and 2 depict in schematic form prior art, through-tubing, work-over systems. Figure 1 is a schematic view of a prior art inflatable wellbore tool 11 suspended within wellbore 13 on a wireline assembly 15. Wellbore 13 includes production tubing string 19 concentrically disposed within casing 17. At the earth's surface 23, a conventional blowout preventer 25 is provided. Wireline assembly 15 includes wireline truck 21 which carries a spool of wireline cable, and an electric power supply 35 which applies electrical energy through electric cable 27 to inflatable wellbore tool 11. Electric cable is directed through guide wheel 29, pulley 31, and lubricator 33, and then fed downward through blowout preventer 25.

As is conventional, production tubing string 19 is packed off at its lower end with inflatable packer 37. Perforations 39, 41 are provided in casing 17 to allow wellbore fluids to pass from formation 43 into wellbore 13.

Inflatable wellbore tool 11 includes a number of components which cooperate together, all of which are prior art devices manufactured, operated, and sold by Baker Service Tools, a division of Baker Hughes Incorporated, having a headquarters in Houston, Texas. Connector 45 is a "rope socket" which serves to connect electric cable 27 to inflatable wellbore tool 11. Collar locator 47 is a device which is used for locating the end of production tubing string 19. Typically, collar locator 47 is an electrical device which detects variation in magnetic flux due to the pressure of casing collars.

Electric motor 48 is connected to the lowermost end of collar locator 47, and includes one or more electric motors which are energized by electricity from power supply 35, which is directed downward into wellbore 13 via electric cable 27. Electric motor 48 provides mechanical power to pump 49, which is connected thereto. Pump 49 is adapted to receive wellbore fluid, and exhausts pressurized wellbore fluid, in small quantities. Typically, pump 49 requires in excess of one hour to completely fill, and set, a standard through-tubing bridge plug. Filter 51 is connected to the output of pump 49, and is adapted to filter debris from the pressurized fluid exhausted from pump 49.

Hydraulic disconnect 43 is connected between bridge plug 55 and hydraulic disconnect 53. Preferably, hydraulic disconnect 53 is adapted to disconnect from bridge plug 55, when a predetermined pressure level is exceeded, which is far in excess of the pressure level required for setting of bridge plug 55. Bridge plug 55 is a standard through-tubing bridge plug manufactured by Baker Hughes Incorporated. Bridge plug 55 includes an annular inflatable wall which is composed of an inner elastomeric sleeve, an array of flexible overlapping slats, and an outer elastomeric sleeve. The annular inflatable wall is disposed over an inflation chamber. Fluid is directed into the inflation chamber through valving (which prevents back flow of fluid) to expand to the annular inflatable wall between a deflated running position and an inflated setting position. Typically, bridge plug 55 is set at approximately 1,500 pounds per square inch of area pressure. In Figure 1, bridge plug 55 is shown in an inflated position, in gripping engagement with casing 17.

As discussed above, when inflatable wellbore tool 11 is lowered within wellbore 13 on wireline assembly 15, through production tubing string 19, the well may be flowing between zones or to the surface from formation 43 into wellbore 13 in response to the pressure differential between formation 43 and wellbore 13. Consequently, a pressure differential may develop between upper region 57 and lower region 59 of wellbore 13 due to the obstruction to flow presented by the inflation of bridge plug 55. As stated above, in an expansion mode of operation, inflatable wellbore tool 11 is urged radially outward from a reduced radial dimension to an intermediate radial dimension which at least in-part obstructs the flow of wellbore fluid within the wellbore in the region of inflatable wellbore tool 11.

This obstruction creates a pressure differential between upper region 57 and lower region 59. If greater pressure is present in upper region 57 than in lower region 59, a downward axial force is exerted on bridge plug 55. In contrast, if a greater pressure exists at lower region 59 than at upper region 57, an upward axial force is applied to bridge plug 55. The pressure differential across bridge plug 55 can be great enough to physically displace bridge plug 55 significant distances within wellbore 13, thus undermining engineering objectives, and perhaps impairing the performance of the oil and gas well. Alternately, the pressure differential across bridge plug 55 can become so great as to accidentally disconnect connector 45 from electric cable 27, causing loss of inflatable wellbore tool 11 within wellbore 13.

A similar problem is present in tubing-conveyed delivery systems, as shown in Figure 2. As shown, coiled tubing truck 71 includes spool 73 for delivering coiled-tubing 75 to wellbore 81. Coiled-tubing 75 is directed downward through injection head 77 and blowout preventer 79. Coiled-tubing 75 is directed into wellbore 81 through production tubing string 85, which is concentrically disposed within casing 83. As is conventional, production tubing string 85 is packed-off against casing 83 at its lower end. Also, perforations 89, 91 are provided for delivering wellbore fluids, such as oil and water, from formation 93 into wellbore 81 in response to the pressure differential between formation 93 and wellbore 81.

As shown in Figure 2, inflatable wellbore tool 95 is suspended within wellbore 81 on coiled-tubing string 75. Preferably, inflatable wellbore tool 95 includes a number of components which cooperate together, such as those components manufactured, operated, and offered for sale by Baker Service Tools, a division of Baker Hughes Incorporated. Coiled-tubing connector 97 operates to connect inflatable wellbore tool 95 to coiled-tubing string 75. High pressure fluid is directed downward into wellbore 81 through coiled-tubing string 75 and is received by inflatable wellbore tool 95. Check valve 99 is connected to the lowermost end of coiled-tubing connector 97, and operates to prevent the back flow of fluid upward into coiled-tubing string 75. Tubing ends locator 101 is coupled to check valve 99, and includes dogs which are movable between open and closed positions, which, when expanded, are larger in radial dimension than the inner diameter production tubing string 85. Once inflatable wellbore tool 11 is passed through production tubing string 19, the dogs may be moved into a radially expanded position, and coiled-tubing string 75 may be withdrawn from wellbore 13, until removable dogs engage the end of production tubing string 85. An increase in the weight carried by coiled tubing string 75 indicates that the dogs are in engagement with the lowermost end of production tubing string 85. Hydraulic disconnect 103 is coupled to tubing end locator 101, and operates to release bridge plug 109 from the rest of inflatable wellbore tool 95 when a preselected pressure threshold is exceeded by the fluid directed downward through coiled-tubing string 75.

As bridge plug 105 is inflated from a running mode of operation with a reduced radial dimension to a setting mode of operation in gripping engagement with casing 83, the passage of fluid upward or downward within wellbore 81 is at least in-part obstructed by bridge plug 105. Consequently, a pressure differential may develop between upper region 107 and lower region 109. The pressure differential may operate to displace bridge plug 105, and cause it to be set in a fixed position in an undesirable location, or it may cause hydraulic disconnect 103 to fail, and prematurely release bridge plug 105.

Figure 3 is a perspective view of one embodiment of the improved settable wellbore tool 121 of the present invention disposed in wellbore 123, which is cased by casing 125. Casing 125 includes perforations 127 which allow wellbore fluids 129 (including oil and water) to enter wellbore 123. As shown in Figure 3, settable wellbore tool 121 is releasably coupled to releasable connector 131 (which is shown in phantom). Settable wellbore tool 121 includes fishing neck 131 which facilitates retrieval at a later date.

Settable wellbore tool 121 includes a number of subassemblies which couple together and cooperate to achieve the purposes of the present invention. Of course, fishing neck assembly 133 allows for selective coupling with other components. Fishing neck assembly 133 is shown in longitudinal section view in Figure 4. Valving subassembly 135 includes the preferred valving components of the present invention, and is coupled to the lower end of fishing neck assembly 133. Valving subassembly 135 is shown in longitudinal section view in Figure 5a. Poppet valve subassembly 137 is coupled to the lowermost portion of valving subassembly 135, and includes conventional valving which is used to direct high pressure fluid into fluid-actuated wellbore tool 139. Poppet valve assembly 137 is shown in partial longitudinal section view in Figure 7. In Figure 3, fluid-actuated by wellbore tool 139 is shown to be a bridge plug, but could be any other wellbore tool, including wellbore tools which are actuated mechanical force, instead of fluid pressure. A bridge plug is depicted in Figure 3 and discussed in the specification as being representative of other settable wellbore tools including fluid actuated and mechanically actuated wellbore tools, such as conventional packers, and inflatable packers.

Guide subassembly 141 is disposed beneath fluid-actuated wellbore tool 139. Guide assembly is shown in partial longitudinal section view in Figures 9a and 9b. Guide subassembly 141 differs from other, prior art, guide subassemblies in that it includes port 143 at its lowermost end which operates to receive and discharge wellbore fluids. Port 143 is in communication with ports 145, 147 of valving subassembly 135. Ports 143, 145, and 147 are connected together to allow the passage of fluid between upper region 149 and lower region 151.

Therefore, if a pressure differential exists across fluid-actuated wellbore tool 139, fluid will pass between ports 143, 145, 147 to lessen the differential. If upper region 149 has a pressure which is lower than that found at lower region 151, fluid will flow from port 143 to ports 145, 147. Conversely, if pressure at upper region 149 is higher than that found at lower region 151, fluid will flow from ports 145, 147 to port 143. Preferably, in the present invention, the communication of fluid between ports 143, 145, 147 only occurs during specific operating intervals. In particular, communication between ports 143, 145, and 147 is discontinued once fluid-actuated wellbore tool 139 has achieved a setting condition of operation, and is in gripping engagement with casing 125 of wellbore 123.

Figure 4 is a longitudinal section view of fishing neck assembly 133 of the preferred settable wellbore tool of the present invention. As shown, fishing neck assembly 133 includes fishing neck profile 161 which is adapted for receiving a fishing tool. Vent ports 163, 165 are provided in fishing neck assembly 133 to facilitate connection of fishing neck assembly 133 with a fishing tool. Preferably O-ring seal 167 is provided in O-ring seal cavity 169 at the lower end of fishing neck assembly 133, at the interface of outer housing 171 of valve subassembly 135. Central bore 173 is defined within fishing neck assembly 133, and is adapted for directing pressurized fluid downward into valving subassembly 135.

The preferred settable wellbore tool 121 of the present invention continues on Figure 5a, which is a longitudinal section view of the preferred valving subassembly 135 of the preferred settable wellbore tool 121 of the present invention. Figures 4a and 5a can be read together. As shown in Figure 5a, outer housing 171 of valving subassembly 135 includes upper internal threads 175, and lower internal threads 179. Central cavity 177 is disposed within outer housing 177. The material which forms fish neck assembly 133 terminates at end piece 180, which is disposed within central bore 173 of valve subassembly 135. End piece 180 includes external threads 187 which mate with upper internal threads 175 of outer housing 177. Of course, central bore 173 extends through end piece 180.

End piece 180 serves as a stationary ratchet piece 183, which receives movable ratchet piece 185. Internal ratchet teeth 189 are provided in a recessed region of central bore 173, and are adapted for releasably engaging external ratchet teeth 191 of movable valve stem 193.

Figure 6b depicts movable valve stem 193 detached from the remainder of valving subassembly 135. As shown, movable valve stem 193 includes external ratchet teeth 191 which are disposed at thirty degrees from normal, as shown in Figure 6a. External ratchet teeth 191 are disposed on four "finger-like" collets 195, 197, 199, 201. Collets 195, 197 are shown in the view of Figure 6b. Figure 6d is a cross-section view of movable valve stem 193 as seen along lines VId-VId of Figure 6b. In this view, collets 199, 201 are also visible. As shown, the collets are semi-cylindrical in shape, and are separated by gaps 203, 205, 207, 209. Gaps 203, 205, 207, 209 allow collets 195, 197, 199, 201 to flex slightly radially inward in response to downward pressure exerted upon end 211 of movable valve stem 193.

Movable valve stem 193 includes shear pin cavities 213, 215, 217, and 219, which are adapted to receive shear pins 221, 223, 225, and 227. The longitudinal section view of Figure 6b depicts only shear pin cavities 213 and 215. Shear pins 221, 223 are only depicted in Figure 6b. Figure 6e is a cross-section view as seen along lines VIe-VIe of Figure 6b, and depicts all the shear pin cavities 213, 215, 217, 219. Figure 5a shows movable valve stem 193 in full longitudinal section, and thus only depicts shear cavities 213, 215 and shear pins 221, 223.

Returning now to Figure 6b, movable valve stem 193 further includes plug section 229 which is equipped with radial O-ring seal cavities 231, 233, 235, and 237. Figure 6b shows plug section 229 without O-ring seals, but Figure 5a shows plug section 229 equipped with O-ring seals 239, 241, 243, 245, disposed in O-ring seal cavities 231, 233, 235, and 237 respectively. Figure 6c shows the detail of O-ring seal cavity 237.

Returning now to Figure 5a, it can be seen that movable valve stem 193 is allowed to move only in the direction of arrow 247, since the interior ratchet teeth 189 and exterior ratchet 191 are configured geometrically to allow such movement when collets 195, 197, 199, 201 are flexed slightly radially inward. Shear pins 221, 223, 225, 227 (only shear pins 221, 223 are shown in Figure 5a) mechanically couple movable ratchet piece 185 of movable valve stem 193 to retaining ring 249, which mates against shoulder 251, which is disposed along the inner surface of central cavity 277 of outer housing 171. Shear pins 221, 223, 225, 227 cooperate with retaining ring 249 to prevent movement of movable valve stem 193 in the direction of arrow 247, until a predetermined force level is exceeded which operates to shear shear pins 221, 223, 225, 227, and free movable valve stem 293 from the stationary retaining ring 249.

Retaining ring 249 includes fluid flow passages 251, 253. High pressure fluid is directed downward through central bore 173, through gaps 203, 205, 207, 209, and into central cavity 177. Fluid flow passages 251, 253 receive the high pressure fluid from central cavity 177, and direct it past retaining ring 249. High pressure fluid is received by inflation passages 255, 257, which extend axially through valve nipple 181.

Valve nipple 181 includes external threads 259 which are adapted for mating with lower internal threads 179 of outer housing 171. Valve nipple 181 also includes stationary valve seat 261 which includes central bore 263 which is adapted in size and shape to receive plug section 229 of movable valve stem 193. Central bore 263 is adapted for interfacing with O-ring seals 239, 241, 243, and 245, which are carried in O-ring seal cavities 231, 233, 235, 237 of plug section 229 of movable valve stem 193.

Ports 145, 147 (which are also seen in the perspective view of Figure 3) extend radially outward from central bore 263 of valve nipple 181. Ports 145, 147 and inflation passages 255, 257 do not intersect or communicate with one another, contrary to the depiction of Figure 5a. Figure 5a (incorrectly) shows ports 145, 147 intersecting with inflation passages 155, 157 for purposes of exposition only. Figure 5b is a cross-section view as seen along lines Vb-Vb of Figure 5a. As shown, inflation passages 255, 257 are aligned in a single plane which is ninety degrees apart from the plane which includes ports 145, 147. Central bore 163 communicates only with ports 145, 147, and does not communicate with inflation passages 255, 257.

Figure 5a depicts valving subassembly 135 in a running and inflation mode of operation, in which high pressure inflation fluid is directed downward through central bore 173 of stationary ratchet piece 183, and through gaps 203, 205, 207, 209 between collets 195, 197, 199, 201 of movable valve stem 193. Fluid is then directed through fluid flow passages 251, 253 of retaining ring 249, and into inflation passages 255, 257 of valve nipple 181. High pressure fluid is directed to fluid-actuated wellbore tool 139, of Figure 3, and urges it from a deflated running position to an inflated setting position. Figure 3 shows fluid-actuated wellbore tool 139 in an inflated setting position. However, valving subassembly 135 of Figure 5a communicates with port 143 (of Figure 3) and allows high pressure wellbore fluid to be passed through fluid-actuated wellbore tool 139 (without interfering with the inflation thereof) and into central bore 263 of valve nipple 181, for passage into the annular space between valving subassembly 135 and casing 125 of wellbore 123 (of Figure 3). This allows the pressure differential developed across fluid-actuated wellbore tool 139 (of Figure 3) to be lessened. Of course, if the pressure in annular region surrounding valving subassembly 135 exceeds the pressure beneath fluid-actuated wellbore tool 139, fluid may flow downward through ports 145, 147 and exit port 143 (of Figure 3).

Returning now to Figure 5a, valve nipple 181 further includes external threads 265, and internal threads 267 for mating with poppet valve subassembly 137. Poppet valve subassembly 137 includes poppet housing 269 and mandrel 271, with annular inflation passage 273 disposed therebetween, and in fluid communication with inflation passages 255, 257. O-ring seal cavity 273 and O-ring seal 275 are provided at the interface of valve nipple 181 and poppet housing 269, to prevent leakage of high pressure inflation fluid from inflation passages 255, 257.

Figure 7 is a one-quarter longitudinal section view of poppet valve subassembly 137 with poppet valve 277 disposed between mandrel 271 and poppet housing 269. Poppet valve 277 is biased to sealingly engage internal shoulder 279 of poppet housing 269 with elastomeric seal elements 279, 281 which are bonded to the body of poppet valve 277. Poppet valve 277 is biased upward by poppet spring 283 which is held in a fixed position by engagement with shoulder 285 of connecting member 287. O-ring seal 289, which is disposed in O-ring seal cavity 291, seals the interface of connector member 287 and poppet housing 269, which are threaded together at internal and external threads 294, 295. Connector member 287 includes external threads 297 which are adapted for mating with internal threads 301 of upper bridge plug collar 303.

Annular inflatable wall 305 is disposed between mandrel 271 and upper bridge plug collar 303. Inflation chamber 299 is disposed between annular inflatable wall 205 and mandrel 271. Annular inflatable wall 305 comprises inner elastomeric sleeve 307 and an array of flexible overlapping slats 309. Slat ring 311 is adapted for welding to the interior surface of upper bridge plug collar 303, and operates to hold the array of flexible overlapping slats 309 in a fixed position relative to upper bridge plug collar 303. Inner elastomeric sleeve 307 is disposed between sleeve ring 313 and upper bridge collar 303. Sleeve ring 313 includes teeth which are in gripping engagement with inner elastomeric sleeve 307 and holds it in a fixed position relative to upper bridge plug collar 303.

In operation, when the fluid pressure above poppet valve 277 exceeds the upward force of poppet spring 283, poppet valve 277 is urged downward relative to mandrel 271 and poppet housing 269, to allow high pressure fluid to pass along the inner surface of poppet housing 269, and flow downward through central passage 315 (in which poppet spring 283 resides), and into inflation chamber 299. The high pressure fluid acts to outwardly radially expand annular inflatable wall 305 and move it between a deflated running position and an inflated setting position.

Figures 8a, 8b and 8c show more detail about poppet valve 277. Figure 8a shows poppet valve 277 in longitudinal section. Figure 8b is an enlarged view of the sealing portion of poppet valve 277 and depicts how elastomeric elements 279, 281 are bonded to the exterior surface of the steel cylinder which forms poppet valve 277. Figure 8c is a cross-section view as seen along lines VIIIc-VIIIc of Figure 8a. As shown, poppet valve 277 includes a plurality of slots 321, 323, 325, and 327 which extend axially along the length of poppet valve 277, and facilitate the passage of fluid around poppet valve 277 when high pressure fluid forces it downward relative to poppet housing 269.

Figures 9a and 9b are one-quarter longitudinal section views, which are read together, which depict lower bridge plug collar 351 (of Figure 3) and the guard assembly 141. As shown, annular inflatable wall 305, which includes inner elastomeric sleeve 307 and an array of flexible overlapping slats 309, is coupled to lower bridge plug collar 351 in a manner similar to that of upper bridge plug collar 303. Specifically, slat ring 353 is welded in place relative to lower bridge plug collar 351, and sleeve ring 355 serves to grippingly engage inner elastomeric sleeve 307 and hold it in position relative to lower bridge plug collar 351.,

Lower bridge plug collar 351 is connected at threads 357 to connector sleeve 359, and is sealed at O-ring seal 361, which resides in O-ring seal cavity 363 of connector sleeve 59. Connector sleeve 359 serves to mechanically interconnect lower bridge plug collar 351 and shear adapter sleeve 365, which it is coupled to by threads 367. Shear adapter sleeve 365 is shearably connected to anchor ring 369 by shearable screw 371 which is coupled by threads 373 in shearable screw cavity 375. A plurality of similar shearable screws are provided circumferentially around shear adapter sleeve 365. The number, cross-sectional area, and structural strength of each shear screw additively combine to determine a force threshold which must be exceeded to shear adapter sleeve 365 loose from anchor ring 369. This shearable connection is provided to allow annular inflatable wall 305 to contract axially relative to mandrel 271. Connector sleeve 269 is sealed at its interface with mandrel 271 by sealing ring 377. At its lowermost end, guard subassembly 141 includes guard 379 which is connected by threads 381 to mandrel 271. Port 143 is provided in guard 379 to allow fluid communication inward along central bore 383 which is in continuous fluid communication through the bridge plug and poppet valve subassembly 137, with central bore 261 of valving subassembly 135.

Therefore, with reference now to Figure 5a, the fluid pressure at port 143 of guard 379 is at one side of movable valve stem 193, while the pressure from the source of pressurized fluid (which serves to inflate the bridge plug) is on the opposite side of movable valve stem 193. Shear pins 221, 223, 225, and 227 provide a predetermined force threshold which must be exceeded by the fluid pressure differential across movable valve stem 193 in order to move movable valve stem 193 downward relative to valve nipple 181 for closure of ports 145, 147. The pressure threshold which is selected for initiation of movable valve stem 193 should be coordinated with the particular fluid-actuated wellbore tool which is selected for use. For example, when a bridge plug is selected, as shown in this embodiment, it is important to keep in mind that the typical bridge plug is in gripping engagement with the casing of the wellbore wall, and thus in a fixed position, in the range of inflation pressures between one 1,000 pounds per square inch and approximately 1,500 pounds per square inch. Therefore, by selecting shear pins 221, 223, 225, 227, of a predetermined strength, flow between ports 143, 145, 147 (of Figure 3) can continue until the bridge plug, or other settable wellbore tool, is in a fixed position relative to the wellbore. Therefore, in the embodiment shown it would be prudent to allow for closure of downward movement of movable valve stem 193, and resulting closure of ports 145, 147 in the range of 1,000-1,500 pounds per square inch of pressure within inflation chamber 299 of the bridge plug.

Figure 10 is a longitudinal section view of valving subassembly 135 with movable valve stem 193 moved into a "closed" position relative to valve nipple 181. As shown, the fluid pressure in region 401 has exceeded the fluid pressure in region 403 by the amount of force required to shear pins 221, 223, 225, and 227, as well as the force required to move movable ratchet piece 185 (which comprise collets 195, 197, 199, and 201) relative to stationary ratchet piece 183. The amount of force required to move movable ratchet piece 185 relative to stationary ratchet piece may be designed to be a small value, so that the total force required to move movable valve stem 193 into a "closed" position relative to valve nipple 188 comprises the force required to shear shear pins 121, 123, 125, 127.

In summary, with reference to Figures 3, 5a, and 10, the present invention allows for fluid flow between upper region 149 and lower region 151 of wellbore 123. Specifically, fluid is allowed to flow between ports 143, 145, and 147, until a predetermined inflation pressure is obtained within the inflation chamber of the fluid-actuated wellbore tool 139. This pressure level corresponds with the pressure differential which must be developed across movable valve stem 193 in order to shear shear pins 121, 123, 125, 127, and move movable ratchet piece 185 relative to stationary ratchet piece 183. Preferably, this pressure level is selected so that fluid-actuated wellbore tool 139 is completely set and fixed in position relative to casing 125. At this point, it is safe to close off communication between ports 143, 145, and 147 to prevent the flow of fluid across fluid-actuated wellbore tool 139.

While the invention has been shown in only one of its forms, it is not thus limited but is susceptible to various changes and modifications without departing from the spirit thereof.

WHAT IS CLAIMED IS:

1. An apparatus for use in a wellbore for reducing pressure differential forces caused by wellbore fluid flowing through said wellbore, which acts on a settable wellbore tool which is suspended in said wellbore on a suspension member, wherein said settable wellbore tool is operable in a plurality of operating modes including a running mode of operation with a reduced radial dimension, an expansion mode of operation in which said settable wellbore tool is urged radially outward from said reduced radial dimension to an intermediate radial dimension which at least in-part obstructs flow of said wellbore fluid within said wellbore in a region of said settable wellbore tool and creates a pressure differential across said settable wellbore tool, and a setting mode of operation in which said settable wellbore tool is further radially expanded into a setting radial dimension and urged into a fixed position within said wellbore in gripping engagement with a wellbore surface, comprising:

a bypass fluid flow path extending through said settable wellbore tool for directing wellbore fluid through said settable wellbore tool in response to said pressure differential developed across said settable wellbore tool during said expansion mode of operation;

means for maintaining said bypass fluid flow path in an open condition during at least said expansion mode of operation to diminish said pressure differential developed across said settable wellbore tool; and

means for closing said bypass fluid flow path once said setting mode of operation is obtained to prevent fluid flow therethrough.

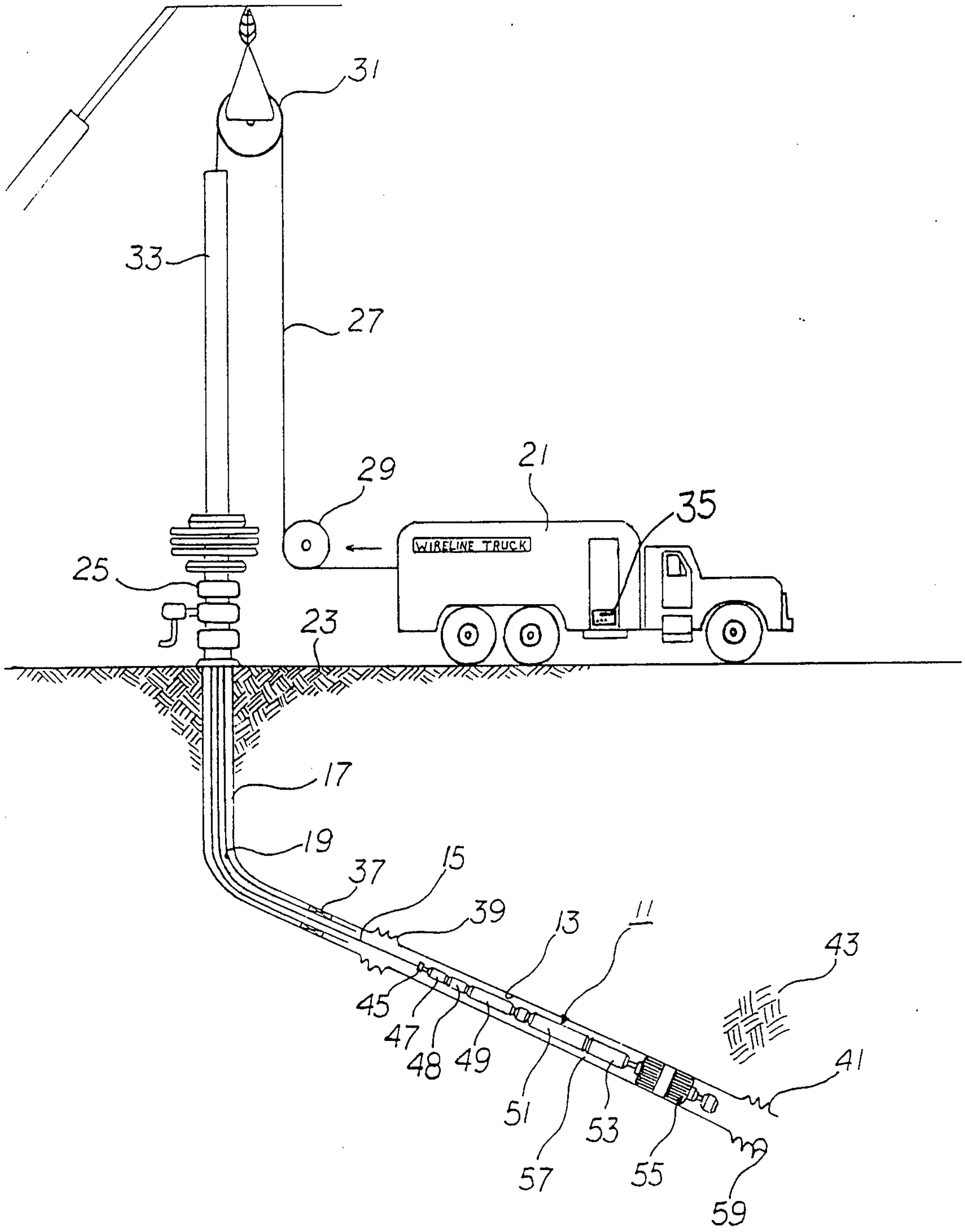


FIGURE 1
PRIOR ART

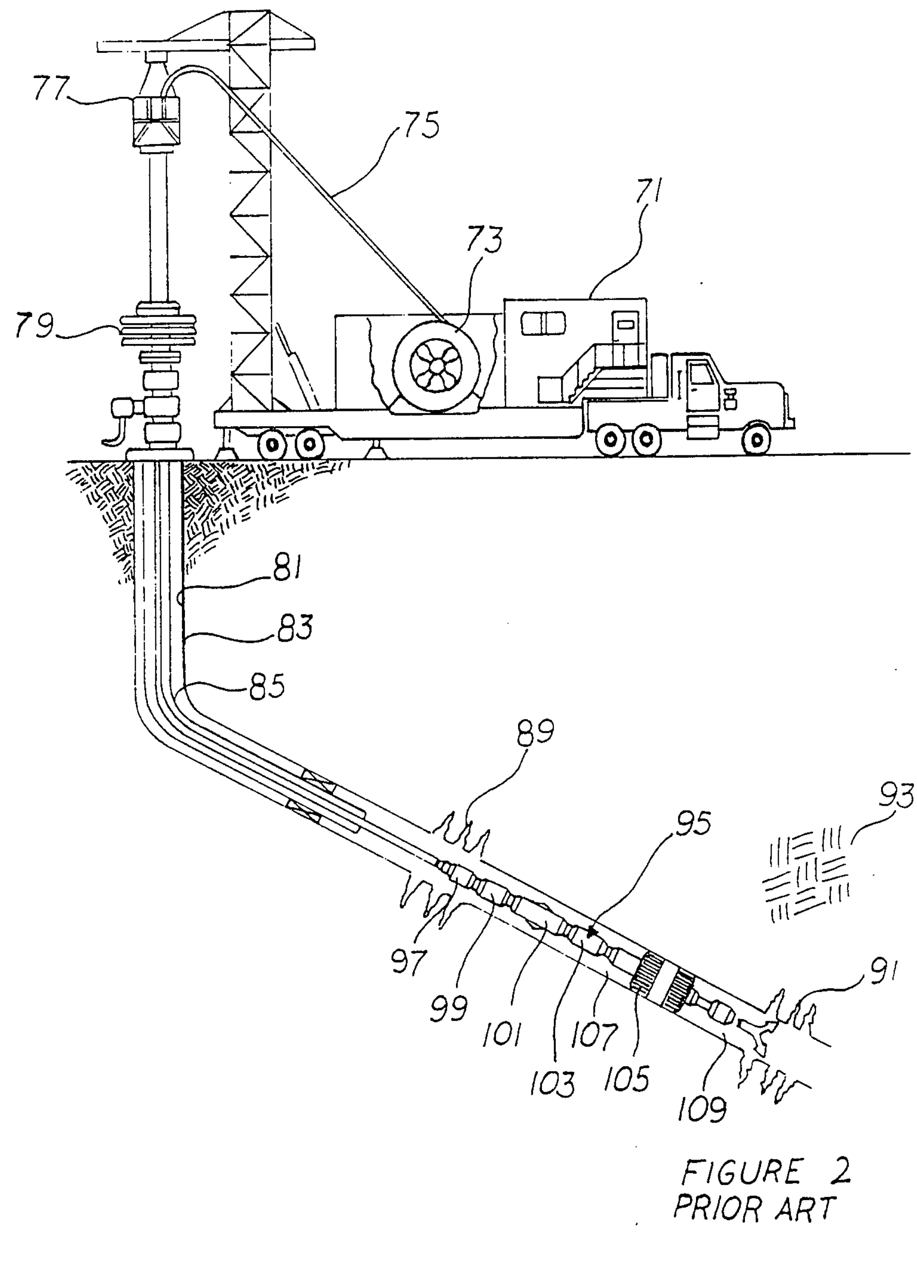


FIGURE 2
PRIOR ART

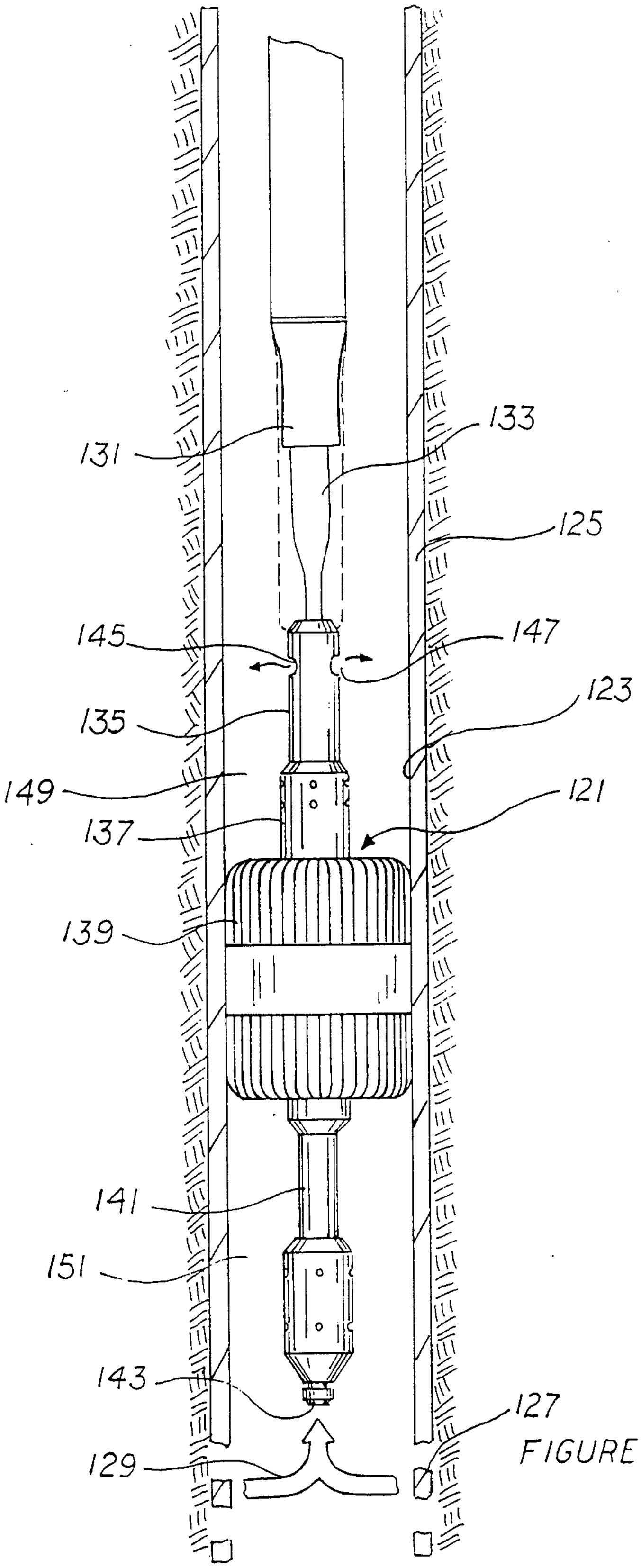


FIGURE 3

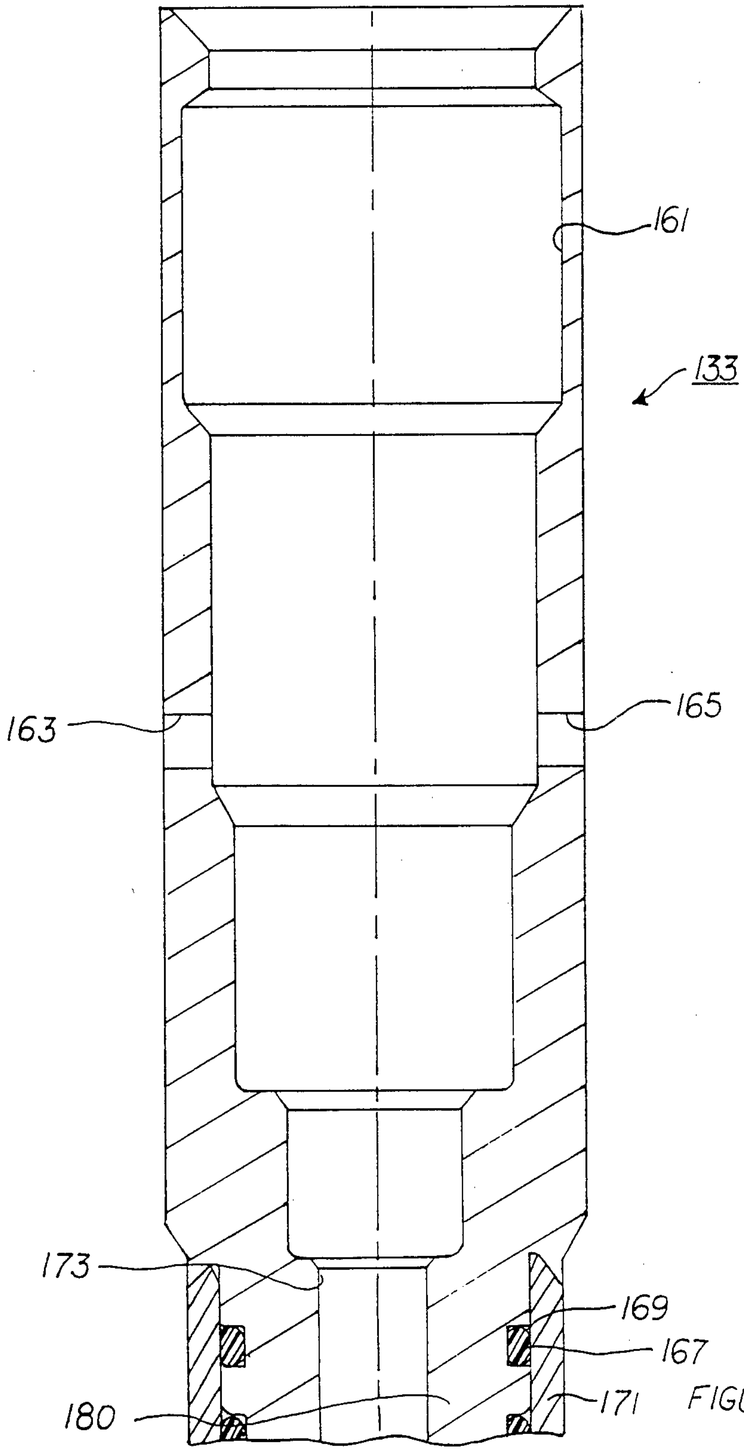


FIGURE 4

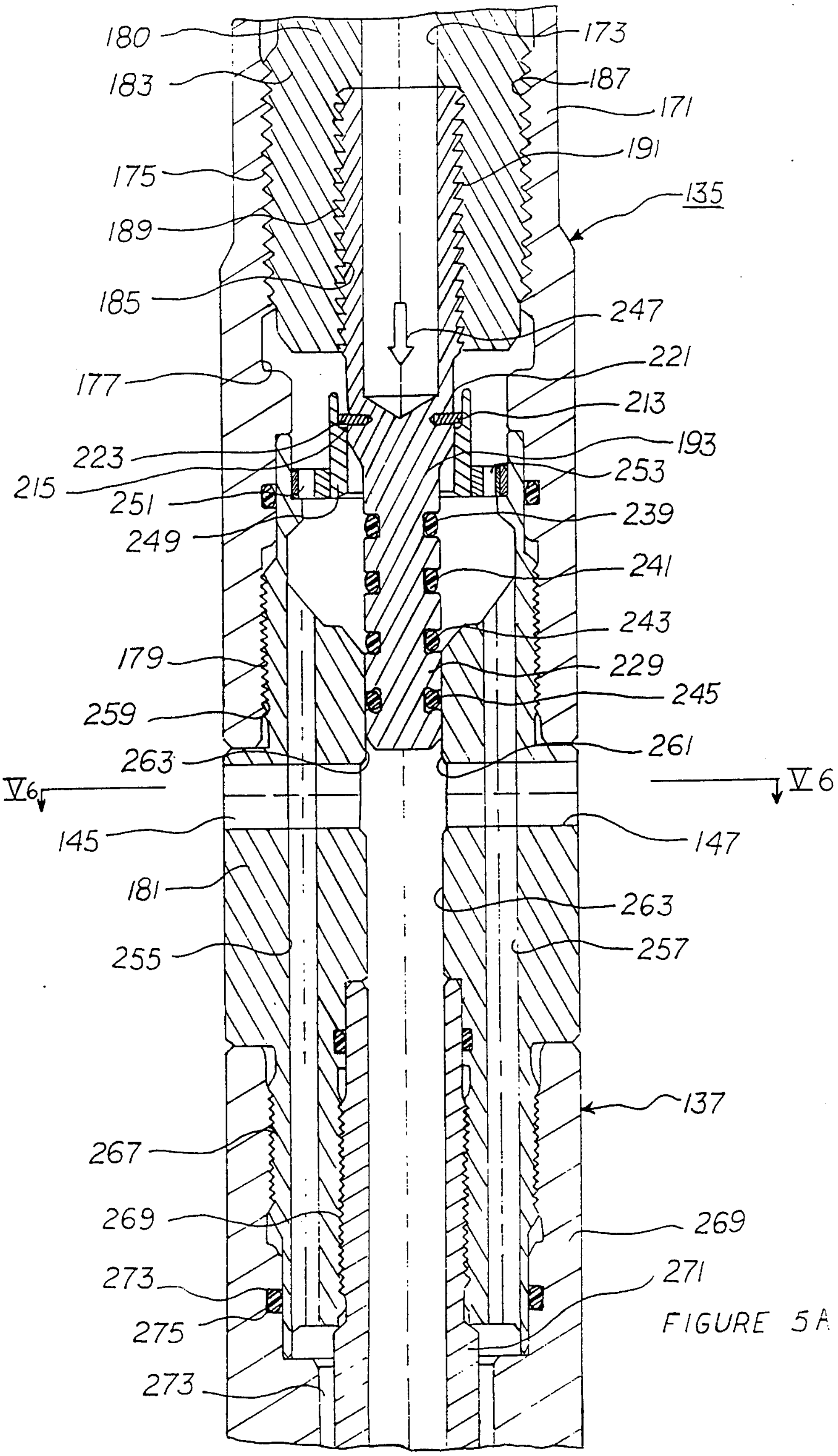

180
173
183
187
171
175
191
135
189
185
247
221
177
213
223
193
215
253
251
239
249
241
243
179
229
259
245
263
261
V6
V6
145
147
181
263
255
257
137
267
269
269
273
271
275
273

FIGURE 5A

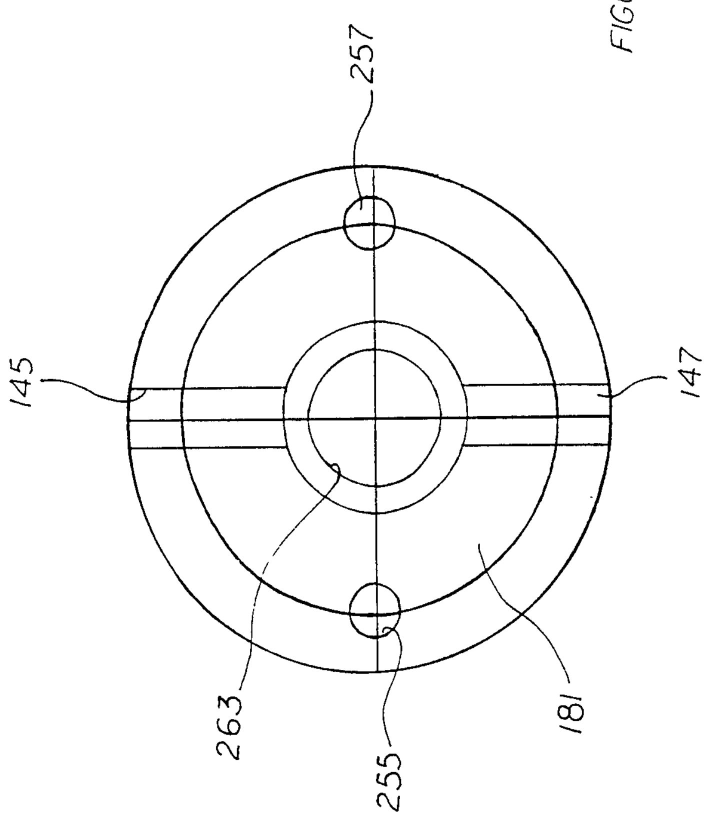


FIGURE 5 B

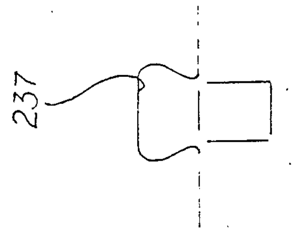


FIGURE 6C

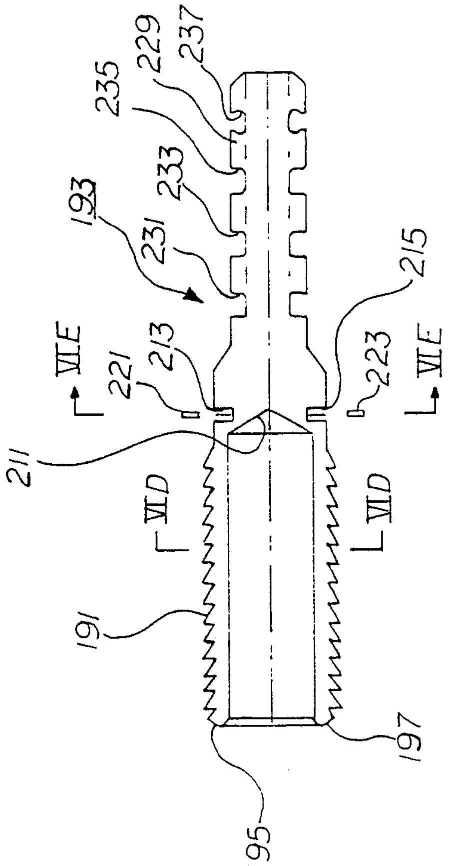


FIGURE 6B

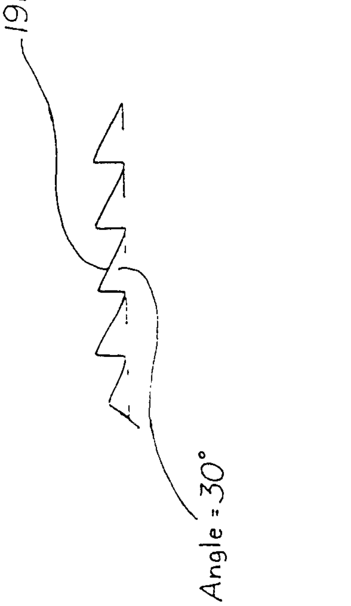


FIGURE 6A

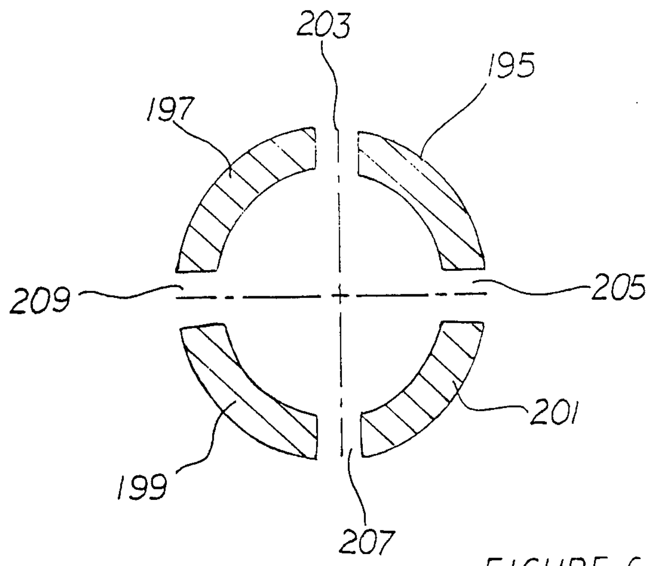


FIGURE 6 D

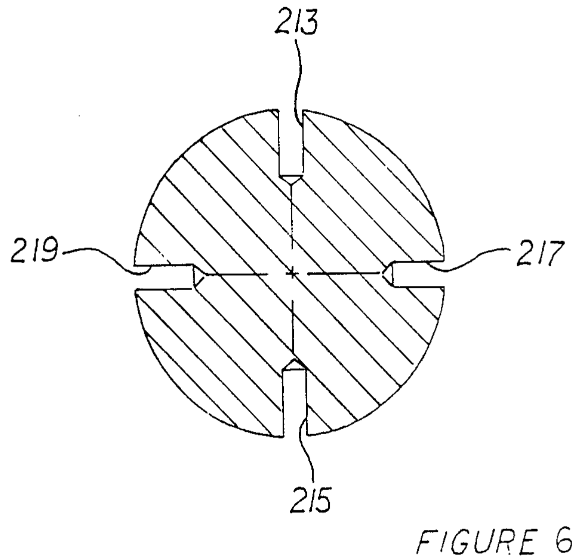


FIGURE 6 E

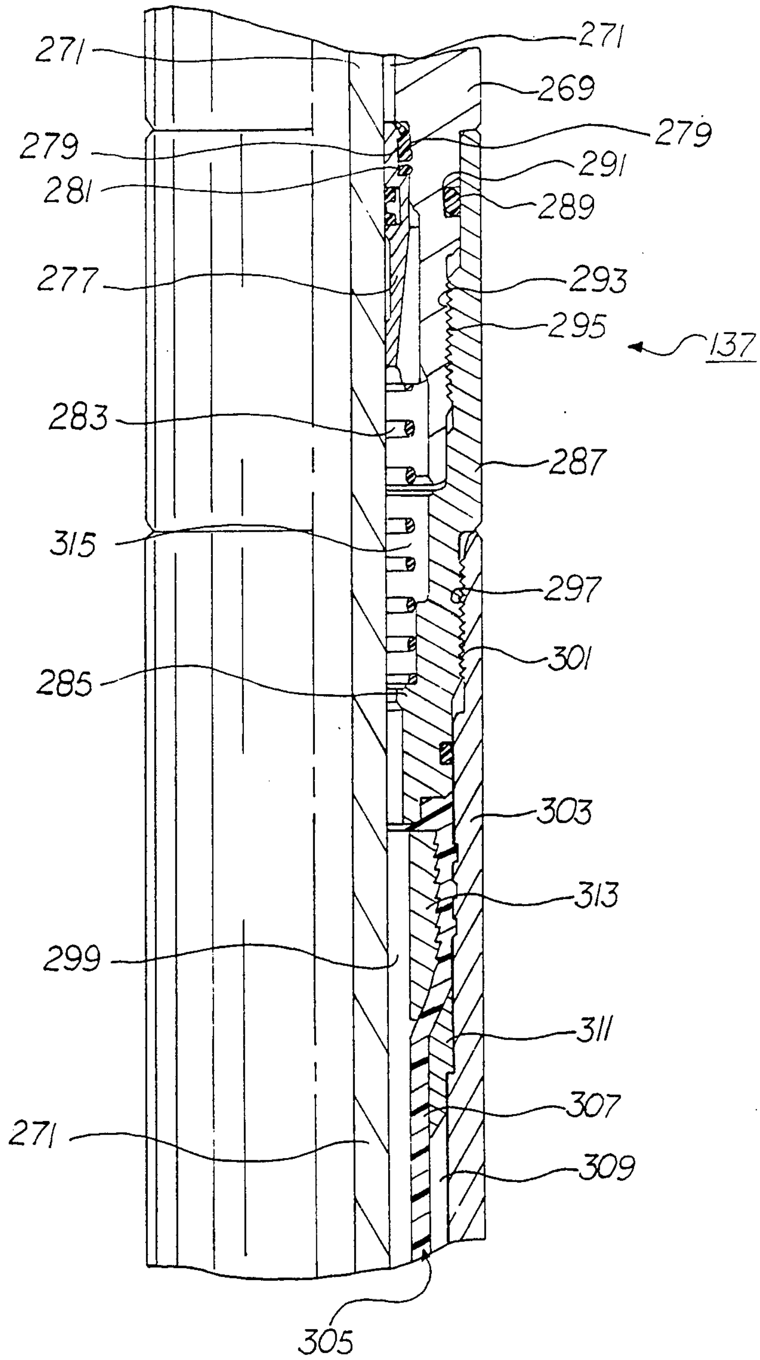

271
271
269
279
279
291
281
289
277
293
295
137
283
287
315
297
301
285
303
313
299
311
307
271
309
305

FIGURE 7

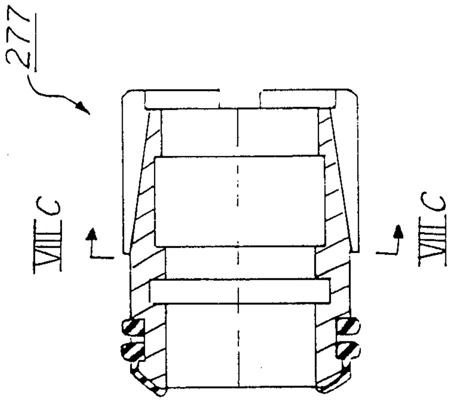


FIGURE 8A

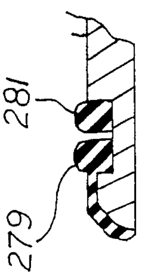


FIGURE 8B

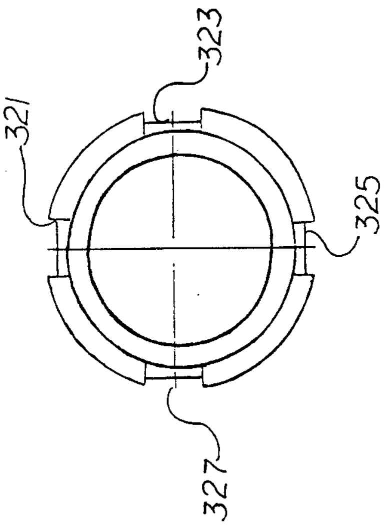


FIGURE 8C

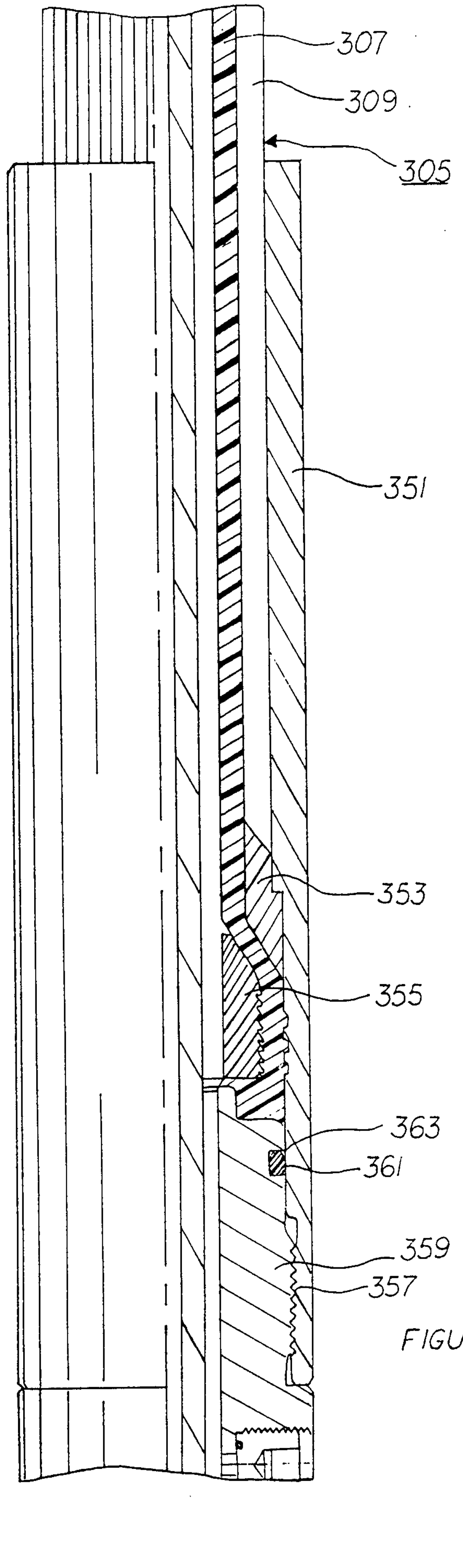


FIGURE 9A

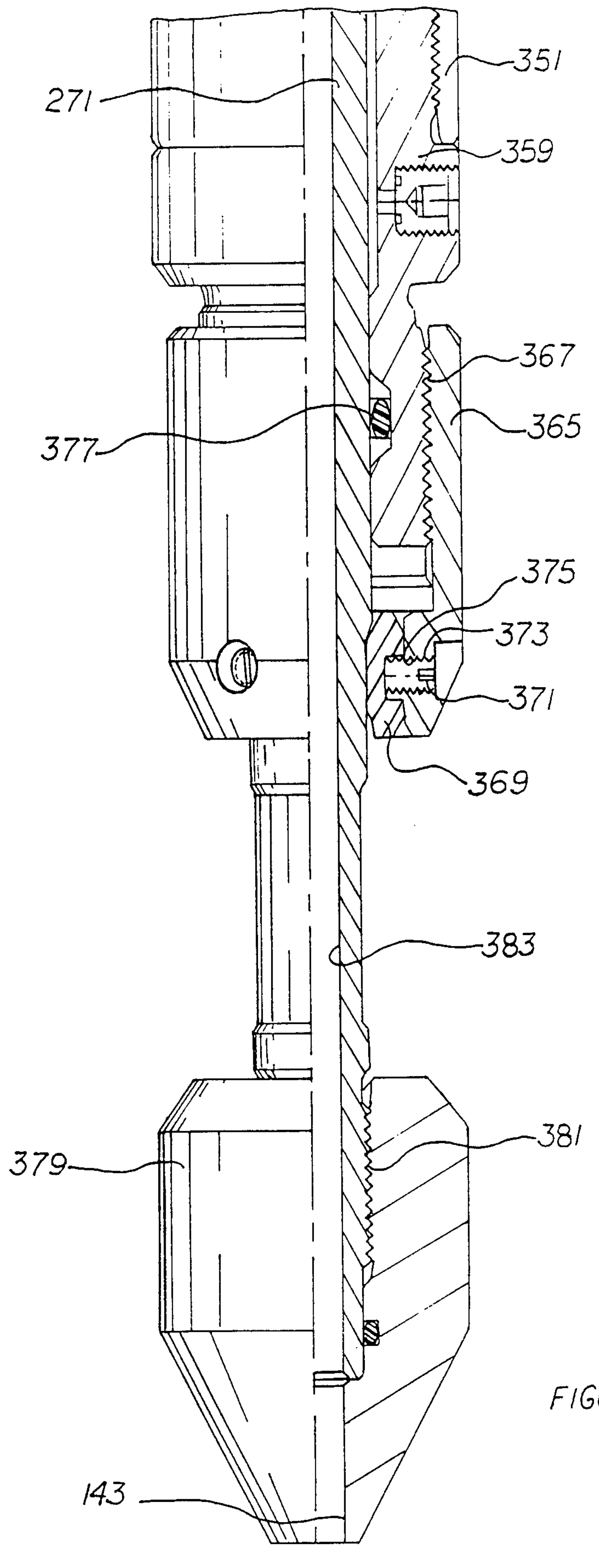


FIGURE 9B

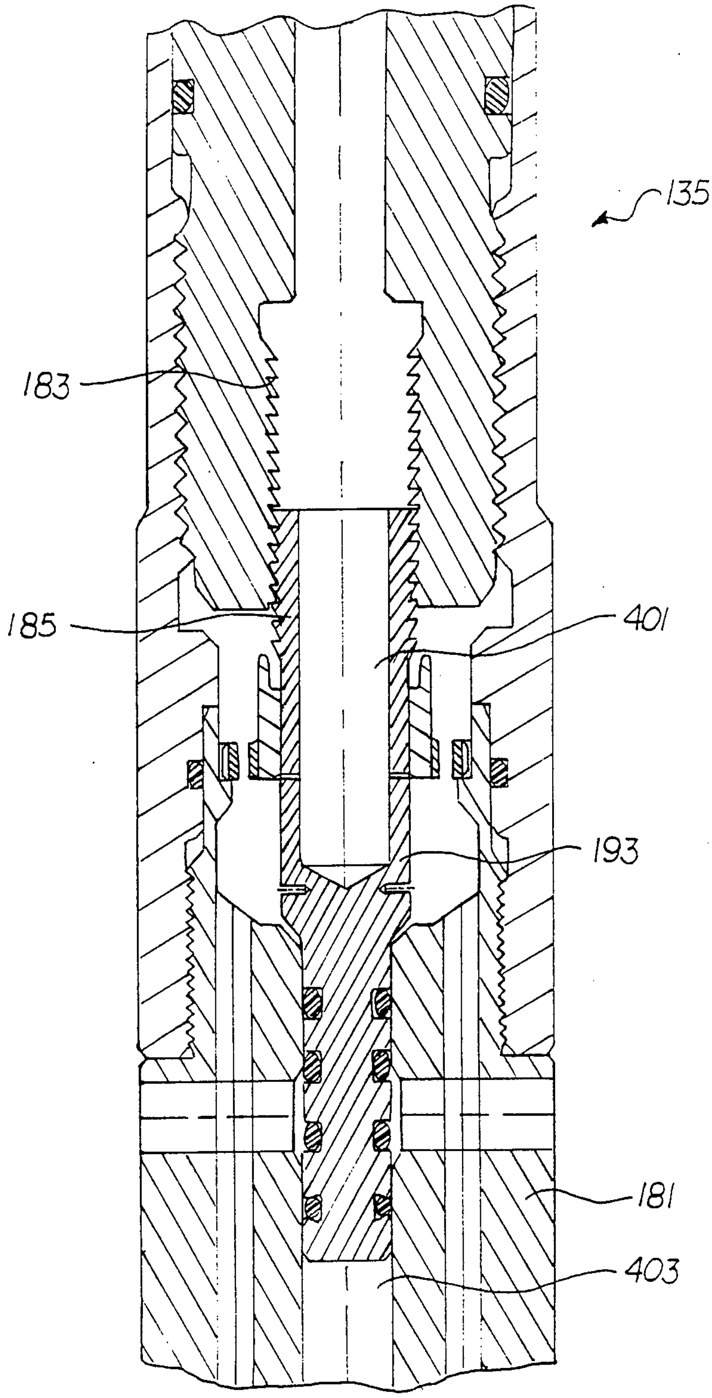


FIGURE 10

INTERNATIONAL SEARCH REPORT

International Application No
PCT/US 94/02713

A. CLASSIFICATION OF SUBJECT MATTER
IPC 5 E21B33/127

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 5 E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category °	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	EP,A,0 518 371 (BAKER HUGHES INCORPORATED) 16 December 1992 see claim 40 -----	1

☐ Further documents are listed in the continuation of box C.

☒ Patent family members are listed in annex.

° Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier document but published on or after the international filing date
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
1 July 1994	14. 07. 94

Name and mailing address of the ISA	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+ 31-70) 340-2040, Tx. 31 651 epo nl, Fax: (+ 31-70) 340-3016	Sogno, M

INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No
PCT/US 94/02713

Patent document cited in search report	Publication date	Patent family member(s)		Publication date
EP-A-0518371	16-12-92	US-A-	5133412	28-07-92
		US-A-	5228519	20-07-93
		US-A-	5265679	30-11-93
		US-A-	5297634	29-03-94