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Mott

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[45] **July 16, 1974**

[54] **METHOD OF COMPLETING A WELL USING A COMPLETION AND KILL VALVE**

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[73] Assignee: **Hydril Company**

[22] Filed: **Mar. 26, 1973**

[21] Appl. No.: **344,602**

Related U.S. Application Data

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[52] **U.S. Cl.** **166/313,** 166/315

[51] **Int. Cl.** **E21b 41/00**

[58] **Field of Search** .... 166/313, 314, 315, 154, 166/224 R

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Attorney, Agent, or Firm—Pravel, Wilson & Matthews

[57] **ABSTRACT**

A completion and kill valve adapted to be placed immediately above a packer in the well production tubing including a tubular member having an inner bore and a circulation channel therein permitting communication between the inner bore and the well annulus area adjacent the exterior of the tubular member. A movable sleeve closes or opens communication through the circulation channel in response to various pressures and a spring bias acting on the sleeve. Provisions for locking the sleeve in the open position and subsequently unlocking the sleeve in response to inner bore pressure are provided.

24 Claims, 9 Drawing Figures

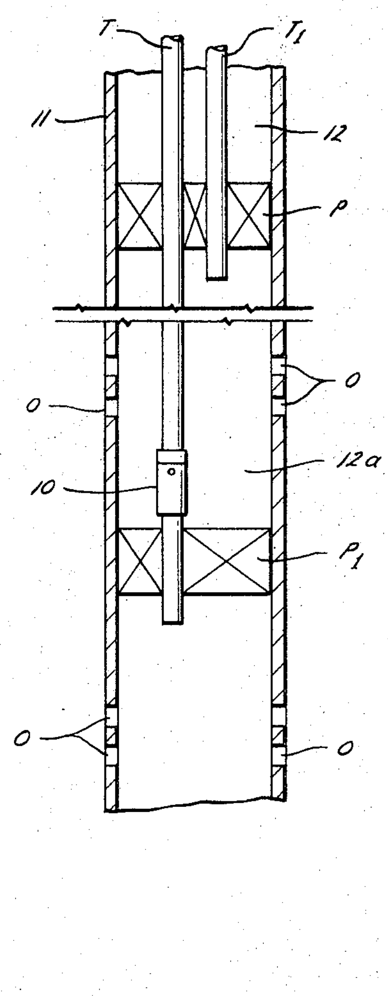


Fig. 1

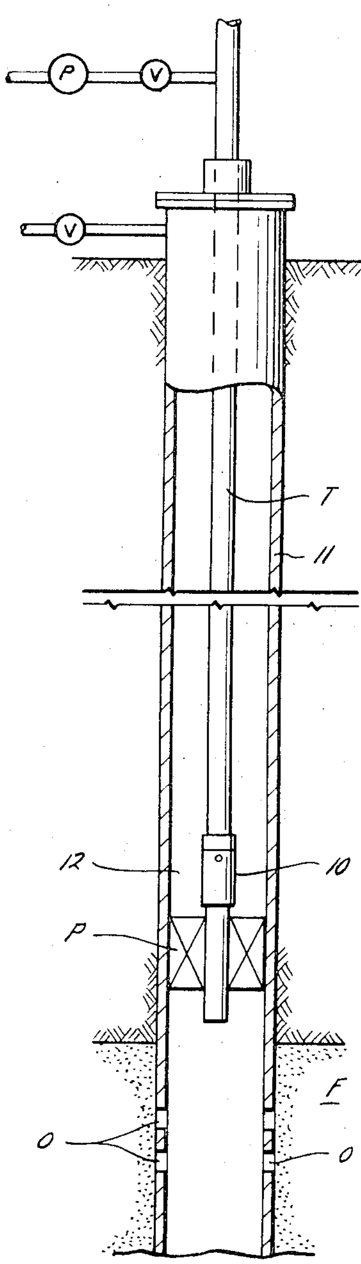


Fig. 2

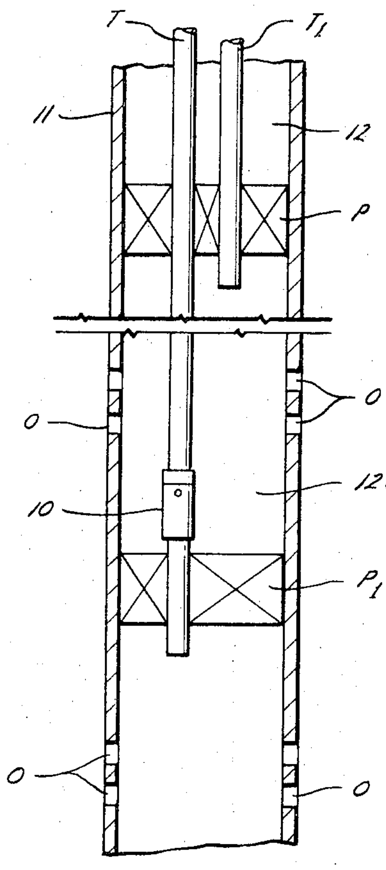
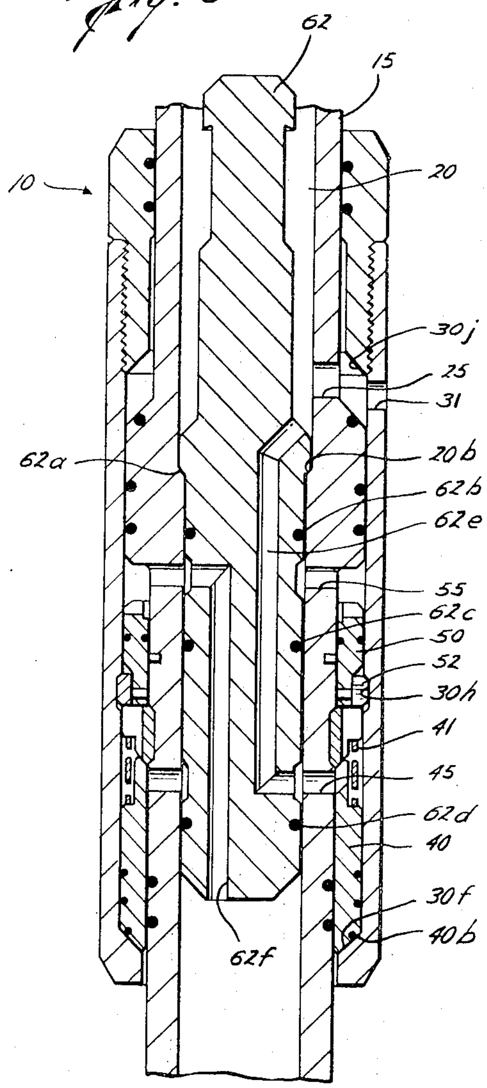


Fig. 8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30j
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31
62a
20b
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62e
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62c
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30h
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45
62d
40
30f
40b
62f

Fig. 3

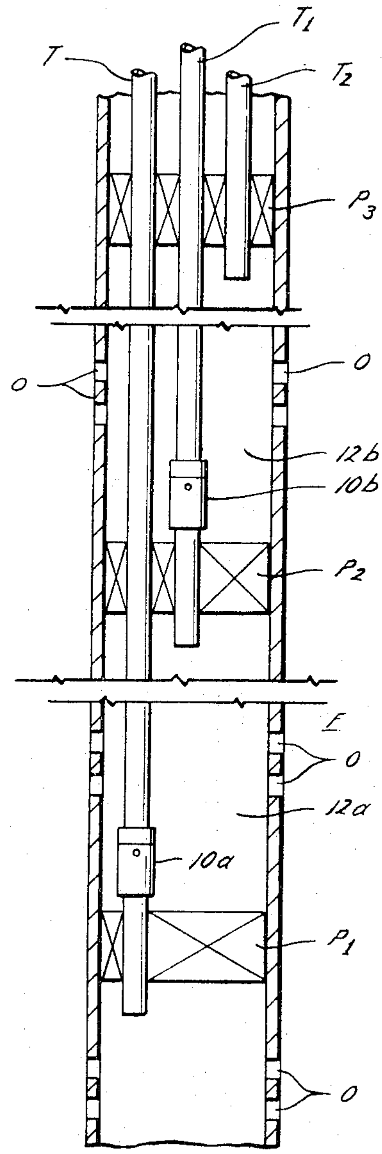

T
T1
T2
P3
O
O
12b
10b
P2
F
O
12a
10a
P1
O

Fig. 4

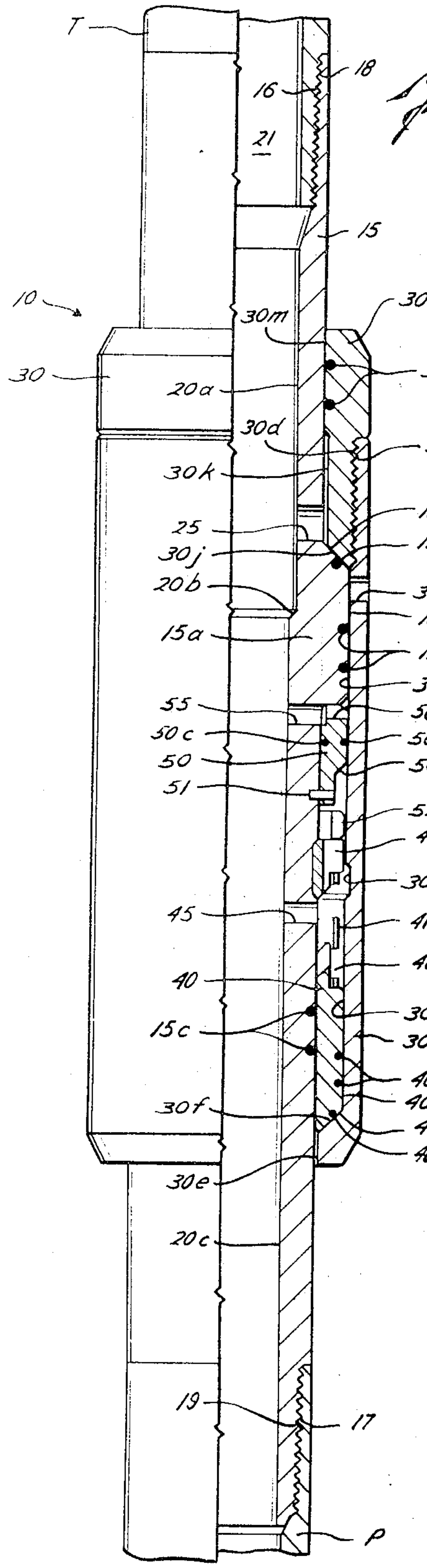
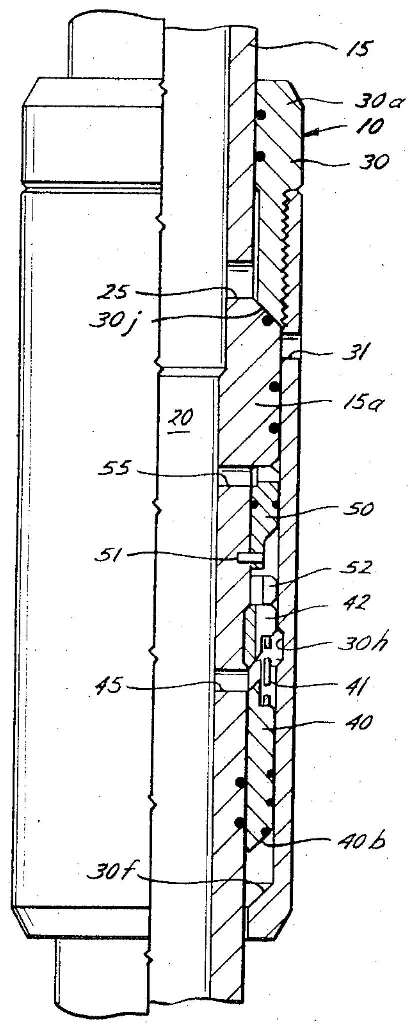

T
16
18
21
15
10
30a
30m
30
20a
30n
30d
30c
30k
15b
25
30j
15e
20b
31
15c
15a
15d
30i
55
50a
50c
50d
50
50b
51
52
42
30h
45
41
40a
40
30g
15c
30b
40e
40d
30f
40b
40f
30e
20c
19
17
P

Fig. 5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30a
10
30
25
30j
31
15a
20
55
50
51
52
42
30h
45
41
40
40b
30f

Fig. 6

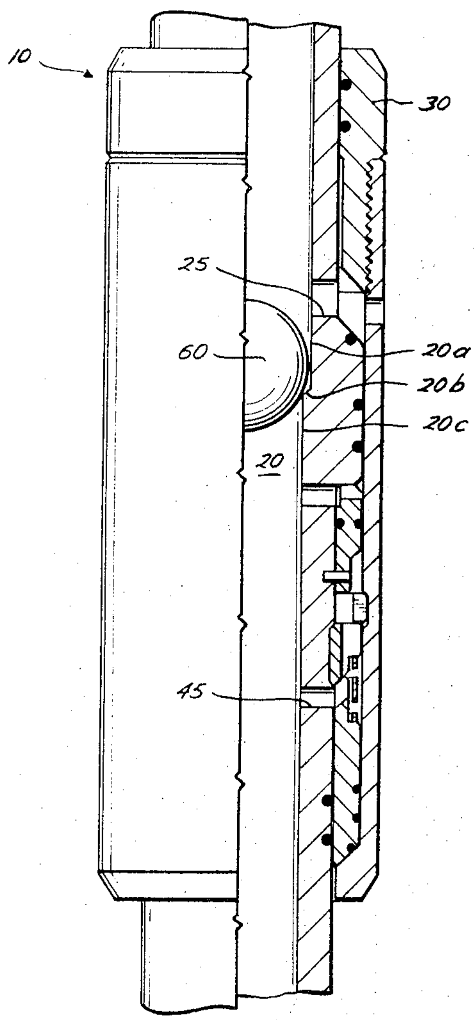

10
30
25
60
20a
20b
20c
20
45

Fig. 7

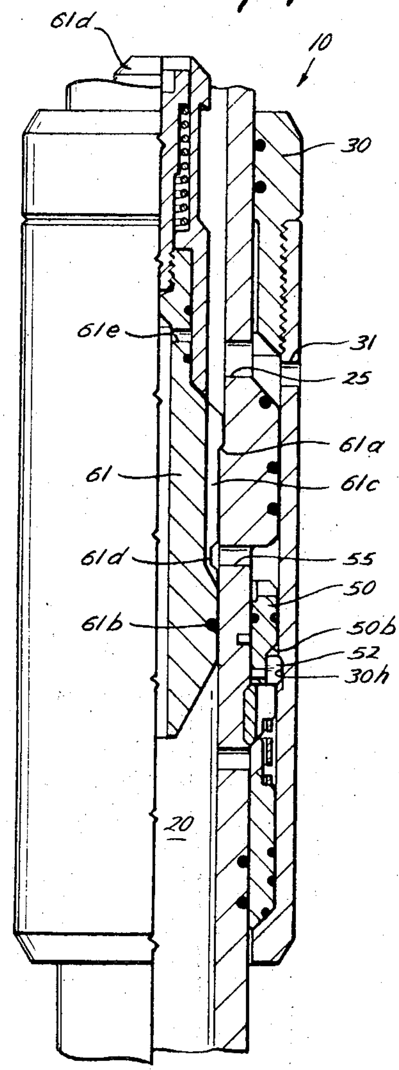
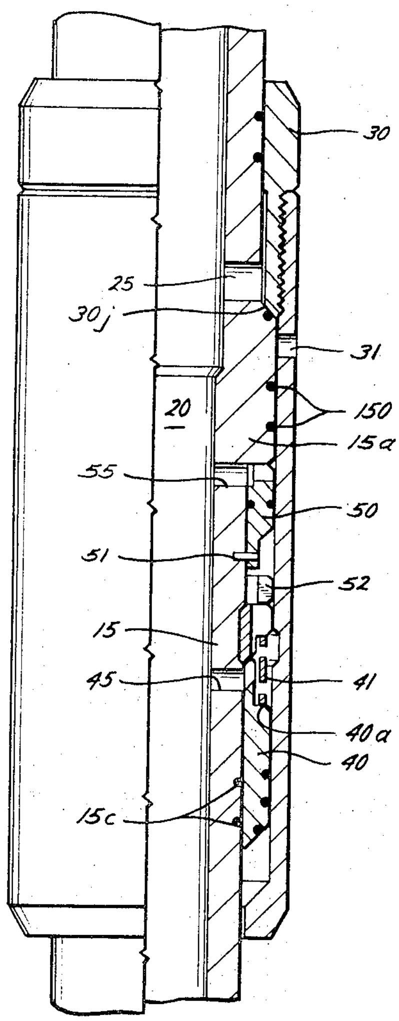

61d
10
30
61e
31
25
61a
61
61c
61d
55
50
61b
50b
52
30h
20

Fig. 9



METHOD OF COMPLETING A WELL USING A COMPLETION AND KILL VALVE

CROSS REFERENCE TO RELATED APPLICATIONS

This is a division of application Ser. No. 138,947, filed Apr. 30, 1971, and now U.S. Pat. No. 3,750,752 issued Apr. 7, 1973.

BACKGROUND OF THE INVENTION

The invention relates to the field of a completion and kill valve.

One of the problems in completing a well has been removing heavy drilling mud from the production tubing to allow hydrocarbons within a formation to flow into the production tubing and on to the surface. A prior approach has been to use a swabbing tool in the production tubing to draw the drilling mud to the surface. Swabbing was costly, time consuming and dangerous. For example the drilling fluid brought to the surface made the working area slippery and unpleasant. Nitrogen injection has also been used to complete a well by lowering the density of the drilling mud in the production tubing and allowing the hydrocarbon pressure to overcome the hydrostatic head of drilling fluid. This method was also costly and time consuming as well as requiring special services and equipment.

Othe devices to complete a well have permitted circulation of a light fluid down the production tubing with the heavy drilling fluid returning up the annulus, but these devices have required that hazardous wire line, packer or tubing work be done under pressure in either opening or closing the device.

Prior art attempts to kill a well by filling the production tubing with drilling fluid back circulated from the annulus into the tubing have also entailed wire line work under pressure or moving the well head or packer with formation pressure on the tubing in either opening or closing the device.

SUMMARY OF THE INVENTION

This invention relates to a new and improved completion and kill valve, including a tubular member adapted to be mounted in a production tubing in a well and having an inner bore communicating with the inner bore of a production string. The tubular member includes a circulation channel therein for permitting communication between the inner bore of the tubular member and the well annulus and a movable member mounted with the exterior of the tubular member which moves in response to a continuous urging means in addition to differential pressures acting on various portions of the movable member to close and open the circulation channel to communication therethrough. A movable, releasable latch member moves to a locking position in response to inner bore pressure communicated through a locking channel for fastening the movable member or sleeve in the open position and moves to a free position in response to inner bore pressure communicated through a sensing channel for releasing the sleeve to thereby enable the sleeve to return to pressure responsive operation.

An object of the present invention is to provide a new and improved completion and kill valve for tubing.

A further object of the present invention is to provide a new and improved completion and kill valve wherein the well may be recompleted after killing.

Yet still a further object of the present invention is to provide a new and improved completion and kill valve which may be locked open in response to surface controlled pressure.

Yet still another object of the present invention is to provide a new and improved completion and kill valve which may be unlocked in response to surface control pressure.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. **1** is a perspective view of the completion and kill valve of the present invention positioned in a single completion well production tubing;

FIG. **2** is a perspective view of the completion and kill valve positioned in a dual completion well production tubing;

FIG. **3** is a perspective view of the employment of a plurality of completion and kill valves in a multiple, for example, triple completion well production tubing;

FIG. **4** is a partial cross-sectional view of the completion and kill valve of the present invention;

FIG. **5** is a view similar to FIG. **2**, illustrating the valve of the present invention maintained closed by outer pressure;

FIG. **6** is a view similar to FIG. **4**, illustrating the valve of the present invention in the open position;

FIG. **7** is a view similar to FIG. **6**, illustrating the valve of the present invention in the locked open position.

FIG. **8** is a view similar to FIG. **7**, illustrating the valve of the present invention in the locked open position prior to unlocking;

FIG. **9** is a view similar to FIG. **4**, illustrating another embodiment of the present invention.

DESCRIPTION OF THE PREFERRED EMBODIMENT

As illustrated in FIGS. **1, 2** and **3**, the completion and kill valve of the present invention is generally illustrated by the numeral **10** and is connected in a tubular production string or conduit T above a packer P as is well known in the art. The production string T is positioned in a well casing **11** located in a subsurface formation F for recovery of hydrocarbons within the formation F through perforations O, as is well known in the art.

As illustrated in FIG. **4**, the completion and kill valve **10** is illustrated in more detail and includes a tubular member **15** which is connected through the usual box and pin threaded connection **16** and **17**, with the production string T.

The tubular member **15** is provided with an inner bore or channel **20** which communicates with the inner bore or channel **21** of the production tubing T. The inner bore **20** of the tubular member **15** includes a larger diameter upper portion **20*a***, a shoulder **20*b*** and a smaller diamter portion **20*c***.

A circulation channel **25** is formed through the wall of tubular member **15** above the shoulder **20*b*** for permitting communication between the inner bore **20** and the area adjacent the exterior of tubular member **15.**

A movable member **30** is mounted with the tubular member **15** and adapted to be slidably positioned in an open position, illustrated in FIGS. **6, 7** and **8,** permitting flow through the circulation channel 25 and a closed position, illustrated in FIGS. 4 and 5, blocking flow through circulation channel 25. The movable member 30 includes an upper portion 30*a* and a lower portion 30*b* forming a sleeve concentrically mounted with the tubular member 15 exterior adjacent the channel 25. The portions 30*a* and 30*b* are secured together by engagement of thread portions 30*c* and 30*d*, respectively. The inner surface of sleeve 30 forms a chamber defined by a lower small diameter portion 30*e*, a first annular tapered shoulder 30*f*, a lower larger diameter portion 30*g*, a locking recess 30*h*, an upper larger diameter portion 30*i*, a second annular tapered shoulder 30*j*, upper small diameter portion 30*k*, and sealing surface 30*m*.

An enlarged outer portion 15*a* of the tubular member 15 extends into the chamber to serve as a stop and a guide for the sleeve 30. A tapered annular surface 15*b* located adjacent the circulation channel 25 limits the downward movement of the sleeve 30 by engaging shoulder 30*j* of the sleeve 30 in the closed position, as illustrated in FIGS. 4 and 5. Outer surface 15*c* of the enlarged portion 15*a* is located closely adjacent upper surface 30*i* to assist in guiding the sleeve 30 in the sliding movement. The sleeve 30 further includes a flow port 30 therein having a smaller flow area than the channel 25 for permitting communication through the sleeve 30 between the area adjacent the tubular member 15 exterior surface adjacent the circulation channel 25 and the annulus 12 exterior of the sleeve 30 when the sleeve is in the open position. The flow port 31 is sealed from communicating with the circulation channel 25, blocking flow through the circulation channel 25, when the sleeve 30 is in the closed position. The sleeve 30 is slidably sealed to the exterior of tubular member 15 at the upper end by a pair of O-rings 30*n*. The sleeve 30 is also slidably sealed to the tubular member 15 adjacent portion 15*a* by a pair of O-rings 15*d*. The lower small diameter portion 30*e* is slightly larger than the tubular member 15 forming an annular passageway between the tubular member 15 and the portion 30*e* for communicating the annular pressure adjacent tubular member 15 to a slide member 40.

The movable sealing slide 40 is a ring-shaped member mounted with the tubular member 15 exterior surface and concentrically positioned between the sleeve 30 and the tubular member 15. The member 40 is free to slidably move with respect to both the sleeve 30 and the tubular member 15 between a lower or extended position, illustrated in FIG. 4, and an upper or retracted position, illustrated in FIGS. 5, 6, 7 and 8. The member 40 includes a first annular step shoulder 40*a* and a second tapered annular shoulder 40*b* adopted to engage shoulder 30*f* of the sleeve 30 for a purpose to be described more fully hereinafter. The slide 40 moves to the retracted position in response to the annulus pressure adjacent the tubular member communicated through the annular passageway between the tubular member 15 and the portion 30*e* of the member 30 acting on the shoulder 40*b* of the member 40. A pair of O-rings 15*f* seal an inner diameter surface 40*c* of the slide 40 to the tubular member 15. Another pair of O-rings 40*e* seal an outer diameter surface 40*d* of sealing member 40 to the sleeve 30. An O-ring 40*d* also seals the member 40 to the sleeve 30 when the tapered shoulder 40*b* engages shoulder 30*f* limiting the area of shoulder 30*f* communication with the annulus 12 pressure when the shoulders 40*b* and 30*f* are engaged.

As illustrated in FIGS. 4, 5, 6, 7 and 8, a means for biasing movable member 30 to the closed position is provided by spring 41. The spring is positioned within the chamber between the sleeve 30 and the tubular member 15 and is retained in such position by retainer member 41 mounted with tubular member 15 and the shoulder 40*a* of the sealing member 40. The engagement of the sleeve shoulder 30*f* by the sealing member shoulder 40*b* acts as a carrying means carrying the sleeve 30 to the closed position as the closing biasing of the spring 41 moves the slide 40 to the lower position.

A sensing channel 45 is formed through the wall of tubular member 15 below the circulation channel 25 for permitting communication from the inner bore 20 of the member 15 into a portion of the chamber above the shoulder 40*a* of the movable sealing member 40. The sealing member 40 is maintained in the extended position, illustrated in FIG. 4, in response to greater pressure in the inner bore 20 communicated through sensing channel 45 to the shoulder 40*a*. This also maintains the sleeve 30 in the closed position.

As illustrated in FIGS. 4, 5, 6, 7, 8 and 9, a means for locking the sleeve 30 in the open position includes a slidably movable ring shaped latch member 50 positioned between the sleeve 30 and the tubular member 15 and having a locking shoulder 50*a* and a stepped and partially tapered unlocking shoulder 50*b*. The latch member 50 is movably mounted with respect to both the tubular member 15 and the sleeve 30 between a lower or locking position and an upper or free position. The latch member 50 moves downward to the latch or locking position, illustrated in FIGS. 7 and 8 in response to increased inner bore pressure urging on locking shoulder 50*a* and upward to the free position, illustrated in FIGS. 4, 5 and 6, in response to increased inner bore pressure urging on unlocking shoulder 50*b*. A pair of O-rings 50*c* and 50*d* seal the latch member 50 to the tubular member 15 exterior surface and the surface 30*i* of the sleeve 30, respectively. The fastening means further includes a shear pin 51 for maintaining the latch member 50 in the upper position and a split spring radially expansible detent ring 52 positioned below the latch member 50. The detent 52 is adapted to move into the recess 30*h* of the sleeve 30 when the sleeve moves into the open position and is locked in the recess 30*h* by latch member 50 moving downward within the radially expanded ring 52.

A locking channel 55 is formed through the wall of the tubular member 15 at a location between the sensing channel 45 and the circulation channel 25 for permitting communicating from the inner bore 20 of the tubular member 15 through the locking channel 55 into a portion of the chamber above the locking shoulder 50*a* of locking member 50. Shoulder 50*b* of the latch member 50 is positioned in the chamber above the sensing channel 45 for communicating with the inner bore 20 through the sensing channel 45. The locking channel 55 and the sensing channel 45 are blocked from communicating in the chamber by the O-rings 40*d* and 50*d*.

A plug or means for controlling communication of pressure in the inner bore 20 to the desired portion of the valve is positioned in the inner bore 20 by lowereing or pumping the plug down the inner bore 20 of the production string T which will pass through the larger diameter inner bore **20***a* portion but will seat on and be retained by shoulder **20***b* below the circulation channel **25.** The plug controls communication of surface controlled increased inner bore pressure above the plug with the sensing channel **45** and the locking channel **55** as desired. The use of a ball **60** sealing the inner bore below the circulation channel is illustrated in FIG. **6** but a ball or slug sealing to and blocking the inner bore below the circulation channel **25** may be used. The plug **60** embodiment blocks communication of the inner bore above the plug with both the sensing channel **45** and the locking channel **55** and is used in opening the valve as will be described more fully hereinafter.

Another embodiment of the plug or means for controlling communication of pressure in the inner bore is a locking plug **61,** illustrated in FIG. **7,** having a shoulder **61***a* adapted to seat on shoulder **20***b* of the inner bore **20** and positioning the plug **61** in the inner bore **20.** An O-ring **61***b* seals the plug to the inner bore **20***c* at a location between the locking channel **55** and the sensing channel **45** permitting the inner bore **20** above the plug **61** to communicate with the locking channel **55,** but not permitting communication with the sensing channel **45.** An outer groove **61***c* and an annular manifold opening **61***d* adjacent the locking channel **55** permit communication between locking channel **55,** the circulation channel **25** and the inner bore **21** of the production tubing T above the plug **61.** The sensing channel **45** is blocked by the plug **61** from communicating with the locking channel **55** and circulation channel **25** in addition to the inner bore **21** of the production tubing T above the plug. The plug **61** also blocks communication through the inner bore **20.** A port **61***e* and blocking member **61***d* assists in the removal of the plug **61,** as is well known in the art.

An unlocking plug **62,** illustrated in FIG. **8,** is another embodiment of the plug or means for controlling communication of pressure in the inner bore **20** above the plug and is positioned in the inner bore **20** by the shoulder **62***a* seating on the shoulder **20***b* of the inner bore **20** when the plug **62** is lowered in the tubing T. Plug **62** is sealed to the inner bore **20***c* between the circulation channel **25** and the locking channel **55** by O-ring **62***b* and between the locking channel **55** and the sensing channel **45** by O-ring **62***c* and again by O-ring **62***d* below the sensing channel **45.** The unlocking plug **62** permits communication between the inner bore **20** above the plug **62** and the sensing channel **45,** but blocks communication of the inner bore **20** above the plug with the locking channel **55.** Channel **62***e* permits communication between the sensing channel **45,** the circulation channel **25** and the inner bore **20** above the plug **62.** Channel **62***f* permits communication from the locking channel **55** to the inner bore **20** below the sealing ring **62***d* of plug **62.** Communication between the inner bore **20** above the plug **62** to the inner bore **20** below the plug **62** is also blocked.

In the use and operation of the present invention with the single completion well, illustrated in FIG. **1,** tubular member **15** is connected in the production tubing T immediately above the packer P for sealing off the annulus **12** above the production zone and is lowered into the set perforated well casing **12** filled with drilling fluid as is well known in the art. At the desired location the packer P is set sealing the annulus **12** between the casing **11** and the production string T, as is well known in the art.

The valve **10** is assembled in the production tubing **10** in the condition illustrated in FIG. **4.** With equal pressure in the inner bore **20** and the area immediately adjacent the exterior of the tool, the exterior pressure provides equal and offsetting urging on the sleeve **30,** while the inner bore pressure communicated through circulation channel **25** and acting on shoulder **30***j*for moving the sleeve **30** to the open position, is at least balanced by the same inner bore pressure communicated through sensing channel **45** to the shoulder **40***a* of the movable sealing member **40.** This allows the spring **41** to bias the sleeve to the closed position by the slide **40** engaging shoulder **30***f* of the sleeve **30** and moving the sleeve **30** to the closed position as the slide **40** moves to the lower position. This position blocks all communication of the inner bore **20** with the annulus **12** of the well through the valve. Should the pressure in the inner bore **20** become greater than the pressure immediately adjacent the exterior of the tool the greater pressure in the inner bore **20** will act on shoulder **40***a* to maintain the slide **40** in the lower position and thereby the sleeve **30** in the closed position. As illustrated in FIG. **9,** the bore **20** pressure responsive shoulder **40***a* and **30***j* may be provided with different size areas on which the pressure urges. By making the shoulder **40***a* larger than the shoulder **30***j* pressure in the bore **20** will urge the valve closed. In this manner the valve may be pumped closed should the spring **41** malfunction or break.

Lowering the production tubing T into the well casing **11** fills the inner bores **21** and **20** with drilling fluid through the tubing T open lower end and should cause the pressure in the annulus **12** to become greater than the pressure in the inner bore **20** because of the difference in heights of columns of drilling fluid. The greater pressure in the annulus **12** will maintain the sleeve **30** in the closed position, but the slide member **40** will move to the upper position illustrated in FIG. **5.** The movable sealing member **40** has the greater pressure in the annulus **12** acting upwardly on the shoulder **40***b* while the pressure in the inner bore **20** is acting downwardly on shoulder **40***a.* Since the effective surface area of shoulders **40***a* and **40***b* on which these pressures act are equal, the slide member **40** will move upward. The upward movement of the movable sealing member **40** to a position spaced from the shoulder **30***f* permits the greater pressure in the annulus **12** to act on the entire shoulder **30***f* as a means for maintaining the sleeve **30** in the closed position in response to the greater pressure in the annulus **12.** This also occurs in the embodiment illustrate in FIG. **9.**

To complete the well permitting flow of hydrocarbons from the formation F, it is necessary to displace the heavy drilling fluid from the bore **21** of the production string T with a lower density fluid, as is well known in the art. As illustrated in FIG. **6,** the plug or ball **60** for controlling communication in the inner bore **20** is placed in the production string inner bore **21** and is pumped or lowered until it seats on shoulder **20***b* positioning the ball **60** between the circulation channel **25** and the sensing channel **45.** The pressure in the inner bore **20** above the plug or ball **60** is then increased by injecting the lower density fluid into the inner bore **21** of the production tubing T at the surface by a pump or other fluid pressure generating means, as is well known in the art. The increased pressure above the plug **60** is communicated through the circulation channel **25** to the shoulder **30***e* where it urges on the shoulder **30***e* to overcome the pressure in the annulus **12** urging on shoulder **30***f* or the urging of the movable slide **40** and moves the sleeve **30** to the open position. This allows the heavy drilling fluid within the inner bore **20** of the production string T above the plug **60** to flow through the circulation channel **25** and the flow port **31** into the annulus **12** of the well above the packer P. The drilling fluid in the annulus **12** is removed from the well casing **11** at the surface permitting the production string to fill with lighter fluid. When the production string T above the plug **60** is filled with lower density fluid above the blocking means **60,** the pumps are stopped decreasing the pressure in the inner bore **20** above the ball or plug **60.** When the pressure in the inner bore **20** decreases sufficiently to be substantially equal to the pressure in the annulus **12,** the spring **41** closes the valve blocking flow from the inner bore **20** into the annulus **12.** With the valve now closed, formation F pressure greater than the hydrostatic pressure within the well casing **11** at the perforations O allows the hydrocarbons to flow into the casing **11** through the perforations O and on to the surface through the inner bore **21** of the production tubing T, as is well known in the art. Normally the blocking means **60** is retrieved by the formation pressure flowing the ball **60** to the surface where it is removed from the bore **21** completing the well. The ball **60** may be removed by smashing the ball **60** or by retrieving with a wire line, but the removal by formation pressure with retrieval at the surface is preferred.

To kill the single production zone well by filling the inner bore **21** of the production tubing T with a heavy fluid, the locking plug **61** is lowered down the production tubing inner bore **21** until it seats on shoulder **20***b* of the tubular member **10.** The plug **61** communicates the inner bore **20** above the plug **61** with the circulation channel **25** and the locking channel **55** while blocking communication past the plug **61.** Surface pumps are then used to increase the pressure in the inner bore **21** of the production string T above the plug **61.** This increased pressure is communicated to the inner bore **20** above the plug **61** and communicated through the circulation channel **25** to the shoulder **30***e* for moving the sleeve **30** to the open position. The pressure in the inner bore **20** above the plug **61** is also communicated by the plug **61** through locking channel **55** to the locking shoulder **50***a* of the latch member **50.** The increased pressure acting on shoulder **50***a* moves the latch member **50** downward, shearing pin **51,** and moving the latch member **50** to the lower position, illustrated in FIGS. **7** and **8.** In this position, the step shoulder **50***b* moves within the detent **52** locking it in the recess **30***h* of the sleeve **30** and thereby mechanically locking the sleeve **30** in the open position. The latch member **50***b* prevents the detent **52** from moving out of the recess **30***h* which would allow the valve to close. With the valve now mechanically locked open, the pumps are stopped. The surface pumps are then connected to the well casing **11** and are used to inject or introduce the heavier drilling fluid into the annulus **12** above the packer P. The heavier drilling fluid in the annulus **12** then back circulates from the annulus **12** above the packer P through flow port **31** and circulation channel **25** into the inner bore **20** above the plug **61** filling the inner bore **21** of the production tubing T. The lighter fluids displaced by the heavier drilling fluid are removed from the inner bore **21** of the production tubing T at the surface. The heavier drilling fluid in the inner bore **21** establishes a greater hydrostatic head preventing flow of hydrocarbons from the formation through the perforations O in the casing **11** killing the well. Plug **61** may be removed at the surface when the tubing is pulled or retrieved by a wire line when the back circulation is complete and formation pressure is no longer within the tubing T inner bore **21.**

To recomplete a single production zone killed well having a locked open sleeve valve, the locking plug **61** is removed and the cross over plug **62** is lowered down the inner bore **21** of production tubing T until it seats on shoulder **20***b*. The crossover plug **62** positioned in the inner bore **20** by shoulder **20***b* permits communications of the inner bore above the plug **62** with sensing channel **45** and the circulation channel **25.** The locking channel **55** communicates with the inner bore **20** below the blocking plug **62,** but is blocked from communicating with the inner bore above the plug **62.** The plug **62** also blocks communication through the inner bore **20.** The surface pumps are used to inject the light fluid into the inner bore **21** of the production tubing T. This increases the inner bore **20** pressure above the plug **62** in the open valve **10** and displaces the heavy drilling fluid below the lighter fluid through the circulation channel **25** and the flow port **31** into the annulus **12** of the well above the packer P and back to the surface where it is removed from the casing **11.** The increased pressure in the inner bore **20** is also communicated through plug channel **62***e* and the sensing channel **45** to shoulder **50***b* of the latch member **50** for moving the latch **50** upward away from the detent **52** unlocking the sleeve **30** and freeing sleeve **30** to be moved to the closed position by the spring **41.** Fluid on the upper side **50***a* of latch member **50** is vented into the inner bore **20** below the plug **62** by channel **62***f* preventing any trapped fluid from blocking movement of the latch member **50** to the upper position. Light fluid is pumped into the inner bore **21** until it fills all of the inner bore **21** above the plug **62.** The pressure in the inner bore **21** is then decreased closing the valve **10.** When the plug **62** is retrieved the hydrocarbons are free to flow into the casing **12** through the perforation O and on to the surface through the inner bore **21** of production tubing T as is well known in the art.

FIG. **2** illustrates use of the present invention in a dual completion well. The completion and kill valve **10** is placed in the lower zone production tubing T immediately above the packer **P-1** separating the upper and lower production zones. To complete the dual completion well, the plug **60** is lowered down the inner bore **21** of the lower production zone tubing string T until it seats on the shoulder **20***b* in the inner bore **20** of the valve **10.** Surface pumps are then used to inject or introduce a lighter density fluid into the production tubing inner bore **21** above the ball **60** while also increasing the pressure in the inner bore **20** above the ball **60** to open the valve **10.** The displaced heavier drilling fluid is removed from the well at the surface through the inner bore **21** of the upper zone production tubing **T-1.** The lighter fluid is circulated from the inner bore **21** of the production tubing T through the circulation channel **25** into the upper production zone **12***a*, and through the inner bore **21** of the upper zone production tubing T-1 to the surface. The pumps continue to introduce the light fluid until the inner bore 21 of the upper zone production tubing T is filled with lighter density fluid from the lower zone production tubing inner bore. When the inner bore 21 of both tubings T and T-1 are filled with the light fluid, the pumps are shut down, lowereing the pressure in the inner bore 20 above the plug 60 and allowing the spring 41 to move the sleeve 30 to the closed position. The pressure in the upper formation is then free to flow hydrocarbons through perforations O in casing 11 into the area 12*a* and on to the surface through the inner bore of production tubing T-1. The plug or ball 60 must be removed from the valve 10 before the production tubing T can flow the lower formation hydrocarbons to the surface.

Use of the valve 10 in the killing of a dual completed well by filling the inner bore 21 of both production tubings T and T-1 with a heavier fluid may be accomplished by two methods. In the first method, the step of the method of completing the dual zone well are repeated with two exceptions. The plug 60 lowered in the inner bore 21 of the production tubing T need not be removed to kill the well. The other change is that a heavy fluid is injected into the inner bore 21 of the lower zone tubing above the plug 60 and allowed to circulate through the valve 10 into the inner bore 21 of the upper zone production tubing T-1 and filling both inner bores 21 with the heavy fluid while the lighter fluid is removed from the inner bore 21 of the upper zone production tubing.

In the second method to kill a dual completion well, the locking plug 61 is lowered down the inner bore 21 of the lower zone production tubing T to seat in the valve 10. The pressure in the inner bore 21 above the plug 62 is then increased to open and mechanically lock open the valve 10. Heavy drilling fluid is then injected into the inner bore 21 of the upper zone production tubing T-1 while removing the displaced lighter fluid from the inner bore 21 of the lower zone production tubing above the sleeve valve 10. The injection of the heavy drilling fluid is continued until the inner bores of both the upper and lower zone production tubings are filled with heavy drilling fluid thereby killing the well.

FIG. 3 illustrates the use of the present invention in completing a three zone production well by displacing the heavy fluid in the inner bores of the production tubings. A packer P-1 separates the lower zone from the middle zone while a packer P-2 separates the middle zone and the upper zone. The packer P-3 seals the annulus 12 above the upper zone. The bottom two zones are first completed by lowering the plug 60 in the inner bore 21 of the lower zone production tubing to seat in the inner bore of valve 10a and then injecting lighter fluid in the inner bore 21 of the lower zone production tubing T to increase the pressure above the plug 60 to thereby open the valve 10*a*. The displaced heavy drilling fluid is removed from the well through the inner bore 21 of the middle zone production tubing T-1. The injection of the lighter fluid above the plug 60 continues until the inner bore 21 of the middle zone production tubing T-1 is filled with the lighter fluid. The pumps are shut down decreasing the pressure in the inner bore 21 of the lower zone production tubing closing valve 10*a*. A plug 60 is then lowered down the inner bore 21 of the middle zone production tubing T-1 until it seats in the valve 10*b*. Lighter fluid is then injected at increased pressure into the inner bore 21 of the middle zone production tubing T-1 above the plug 60. This opens the valve 10*b* and permits flow of fluid from the inner bore 21 of the middle zone production tubing T-1 into the annulus 12*b* between packers P-2 and P-3 and up the inner bore 21 of the upper zone production string T-2 to the surface. The heavy fluid within the well is removed through the inner bore 21 of the upper zone production tubing T-2. When the lighter fluid is circulating back to the surface through the upper zone production tubing T-2, the pumps are shut down decreasing the pressure in the inner bore of the middle zone production tubing T-1, closing the valve 10*b*. When the plugs 60 are removed, all three zones are ready to produce and the well is completed.

To kill the triple producing zone well, a plug 60 is lowered down the inner bore 21 of the lower zone production tubing T until it seats on the shoulder 20*b* within the inner bore of valve 10*a*. The surface pumps are then used to introduce heavy drilling fluid at increased pressure into the inner bore 21 of the production tubing T to open the valve 10*a* and circulate the heavy drilling fluid through the annulus 12*a* into the inner bore of middle zone production tubing T-1 and back to the surface. The lighter fluid is removed from the well through the inner bore 21 of the middle zone production tubing T-1. This circulation fills the inner bore of the two lower production zones tubing T and T-1 with heavy drilling fluid. To kill the upper production zone, the plug 60 is lowered down the production tubing T-1 until it seats on the shoulder 20*b* of valve 10*b*. Surface pumps are then used to introduce heavy drilling fluid into the inner bore 21 of the production tubing T-1 at increased pressure. The increased pressure in the inner bore 20 of the middle zone production tubing T-1 above the plug 60 opens the valve 10*b* circulating the heavier drilling fluid into the annulus 12*b* and back to the surface through the inner bore 21 of the upper zone production tubing T-2. The displaced lighter fluid is removed from the well through the inner bore 21 of the upper zone production tubing T-2. Filling the inner bore 21 of the upper zone production tubing T-2 with the heavy fluid kills the upper zone and completes the killing of the well.

From the multiple zone methods set out above it si apparent that a plurality of the valves 10 connected in the production tubings may be used to complete and kill a well having any number of production strings. If a plurality of N completion and kill valves 10 are employed, a well having a plurality of $N + 1$ production strings, may be completed and killed by circulating different density fluids in the well through the valves 10.

The foregoing disclosure and description of the invention are illustrative and explanatory thereof, and various changes in the size, shape and materials as well as in the details of the illustrated construction may be made without departing from the spirit of the invention.

What is claimed is:

1. A process for completing a single production zone in a well having a set well casing and production tubing inner bore filled with heavy drilling fluid by displacing the heavy drilling fluid from the production tubing inner bore through a pressure responsive sleeve valve located in the production tubing above a packer with a lighter density fluid comprising:

a. lowering a plug down the inner bore of the production string;
b. seating the plug in the sleeve valve;
c. injecting a lighter density fluid into the inner bore of the production tubing above the plug;
d. increasing the pressure of the fluid in the production tubing inner bore above the plug for opening the sleeve valve;
e. removing the displaced heavier drilling fluid from the well casing;
f. substantially filling the inner bore of the production tubing above the plug with the lighter density fluid;
g. decreasing the pressure of the fluid in the inner bore of the production tubing above the plug for closing the sleeve valve;
h. removing the plug from the sleeve valve wherein the well is completed.

2. A process for completing two production zones in a well having a set well casing, an upper zone and a lower zone production tubing having inner bores filled with heavy drilling fluid by displacing the heavy drilling fluid from the upper zone and lower zone production tubing inner bores with a lighter density fluid through the use of a pressure responsive sleeve valve located in the lower zone production tubing above a packer separating the production zones comprising:
a. lowering a plug down the inner bore of the lower zone production string;
b. seating the plug in the sleeve valve;
c. injecting a lighter density fluid into the inner bore of the lower zone production tubing above the plug;
d. increasing the pressure of the fluid in the lower zone production tubing inner bore above the plug for opening the sleeve valve;
e. removing the displaced heavier drilling fluid from the well through the upper zone production tubing inner bore;
f. substantially filling the upper zone production tubing inner bore with lighter density fluid from the lower zone production tubing inner bore;
g. decreasing the pressure of the fluid in the inner bore of the lower zone production tubing above the plug for closing the sleeve valves; and
h. removing the plug from the sleeve valve wherein both zones of the well are completed.

3. A process for completing three production zones in a well having a set well casing, an upper, a middle and a lower production zone tubing inner bore filled with heavy drilling fluid by displacing the heavy drilling fluid with a lighter density fluid from the production tubing inner bores through the use of a pressure responsive sleeve valve located in the lower zone production tubing above a packer separating the lower zone and the middle zone and a second pressure responsive sleeve valve located in the middle zone production tubing above a packer separating the lower zone and the middle zone comprising:
a. lowering a plug down the inner bore of the lower zone production string;
b. seating the plug in the lower zone production string sleeve valve;
c. injecting a lighter density fluid into the inner bore of the lower zone production tubing above the plug;
d. increasing the pressure of the fluid in the lower zone production tubing inner bore above the plug for opening the sleeve valve located in the lower zone production tubing;
e. removing the displaced heavier drilling fluid from the well through the middle zone production tubing inner bore;
f. partially filling the middle zone production tubing inner bore above the middle zone production tubing sleeve valve with lighter density fluid from the lower zone production tubing inner bore;
g. decreasing the pressure of the fluid in the lower zone production tubing inner bore above the plug for closing the sleeve valve in the lower zone production tubing;
h. lowering a plug down the inner bore of the middle zone production string;
i. seating the plug in the middle zone production string sleeve valve;
j. injecting a lighter density fluid into the inner bore of the middle zone production tubing above the plug;
k. increasing the pressure of the fluid in the middle zone production tubing above the plug for opening the sleeve valve;
l. removing the displaced heavier drilling fluid from the well through the upper zone production tubing inner bore;
m. substantially filling the upper zone production tubing inner bore with lighter density fluid from the middle zone production tubing inner bore;
n. decreasing the pressure of the fluid in the middle zone production tubing inner bore above the plug for closing the valve; and
o. removing the plugs from the middle zone and lower zone production tubing inner bores wherein the well is completed.

4. A process for recompleting a production zone of a well previously killed by locking open a pressure responsive sleeve valve located in a production tubing above a packer and back circulating heavy fluid down a well casing, through the locked open sleeve valve to fill the production tubing inner bore by displacing the heavy fluid in the production tubing inner bore with a lighter density fluid and unlocking the locked open sleeve valve permitting it to close comprising:
a. lowering a plug down the inner bore of the production string;
b. seating the plug in the sleeve valve;
c. injecting a lighter density fluid into the inner bore of the production tubing above the plug;
d. increasing the pressure of the fluid in the production tubing inner bore above the plug for unlocking the valve and maintaining the valve open;
e. removing the displaced heavier fluid from the well casing;
f. substantially filling the inner bore of the production tubing with the lighter density fluid;
g. decreasing the pressure of the fluid in the inner bore of the production tubing above the plug for closing the valve; and
h. removing the plug from the sleeve wherein the well is recompleted.

5. A process of completing a well by displacing a heavy fluid within a bore of a production tubing with a lighter fluid using a controllable valve mounted with the production tubing for forming a flow enabling cir-

culation channel through the production tubing, including the steps of:

a. positioning a plug in the bore of the production tubing;

b. controlling the application to the valve of fluid pressure in the bore of the production tubing with the plug to establish the circulation channel for communicating through the production tubing; and

c. injecting the lighter fluid into the well to displace the heavy fluid with the lighter fluid wherein the well is completed.

6. The invention as set forth in claim **5**, including the step of:

removing the displaced heavier fluid from the bore of the production tubing through the circulation channel to complete the well.

7. The method as set forth in claim **5**, including the step of:

substantially filling the bore of the production tubing with the lighter fluid to complete the well.

8. The method as set forth in claim **5**, including the step of:

decreasing the pressure of the fluid in the bore of the production tubing after injecting the lighter fluid for closing the circulation channel wherein the well is completed.

9. The method as set forth in claim **5**, including the step of:

injecting the lighter fluid into the bore of the production tubing to displace the heavier fluid.

10. The method as set forth in claim **5**, including the step of:

locking open the circulation channel to enable communication through the production tubing when the controlled fluid pressure is reduced.

11. The method as set forth in claim **10**, including the step of:

injecting the lighter fluid into the bore of the production tubing through the circulation channel wherein the well is completed.

12. The method as set forth in claim **11**, including the step of:

flowing the lighter fluid through a well casing to a location adjacent the circulation channel for injecting into the bore of the production tubing through the circulation channel.

13. The method as set forth in claim **11**, including the step of:

flowing the lighter fluid through a bore of a second production tubing positioned in the well to a location adjacent the circulation channel for injecting into the bore of the production tubing through the circulation channel.

14. The method as set forth in claim **10**, including the step of:

unlocking the circulation channel to thereafter block communication through the circulation channel when the controlled fluid pressure is reduced.

15. A process for completing a well having a production tubing with a bore filled with heavy fluid by displacing the heavy fluid from the production tubing bore with a lighter density fluid by using a pressure responsive valve connected in the production tubing above a packer for providing a circulation flow channel through the production tubing when fluid pressure is applied in a controlled manner to the valve comprising:

a. seating a plug in the valve by lowering the plug down the bore of the production string to control the application of fluid pressure to the valve.

b. increasing the pressure of the fluid in the production tubing bore above the plug for controlled application to the valve for opening the valve to provide the circulation flow channel;

c. displacing substantially the heavier fluid from the bore of the production tubing with the lighter fluid; and

d. removing the plug from the valve wherein the well is completed.

16. The method as set forth in claim **15**, including the step of:

removing the displaced heavier fluid from the bore of the production tubing by flowing through the circulation channel provided by the valve to complete the well.

17. The method as set forth in claim **15**, including the step of:

substantially filling the bore of the production tubing with the lighter fluid to complete the well.

18. The method as set forth in claim **15**, including the step of:

decreasing the pressure of the fluid in the bore of the production tubing after injecting the lighter fluid for closing the valve to block flow through the circulation channel wherein the well is completed.

19. The method as set forth in claim **15**, including the step of:

injecting the lighter fluid into the bore of the production tubing to displace the heavier fluid.

20. The method as set forth in claim **15**, including the step of:

locking the valve in the open condition providing the circulation channel by applying controlled fluid pressure to the valve to enable communication through the production tubing when the controlled fluid pressure is reduced.

21. The method as set forth in claim **15**, including the step of:

injecting the lighter fluid into the bore of the production tubing through the circulation channel wherein the well is completed.

22. The method as set forth in claim **21**, including the step of:

flowing the lighter fluid through a well casing to a location adjacent the valve for injecting into the bore of the production tubing through the circulation channel.

23. The method as set forth in claim **21**, including the step of:

flowing the lighter fluid through a bore of a second production tubing positioned in the well to a location adjacent the valve for injecting into the bore of the first production tubing through the circulation channel.

24. The method as set forth in claim **20**, including the step of:

unlocking the valve by applying controlled fluid pressure to the valve to thereafter block communication through the circulation channel when the applied controlled fluid pressure is reduced.

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