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(54) FLUID LOGIC TOOL FOR A SUBTERRANEAN WELL

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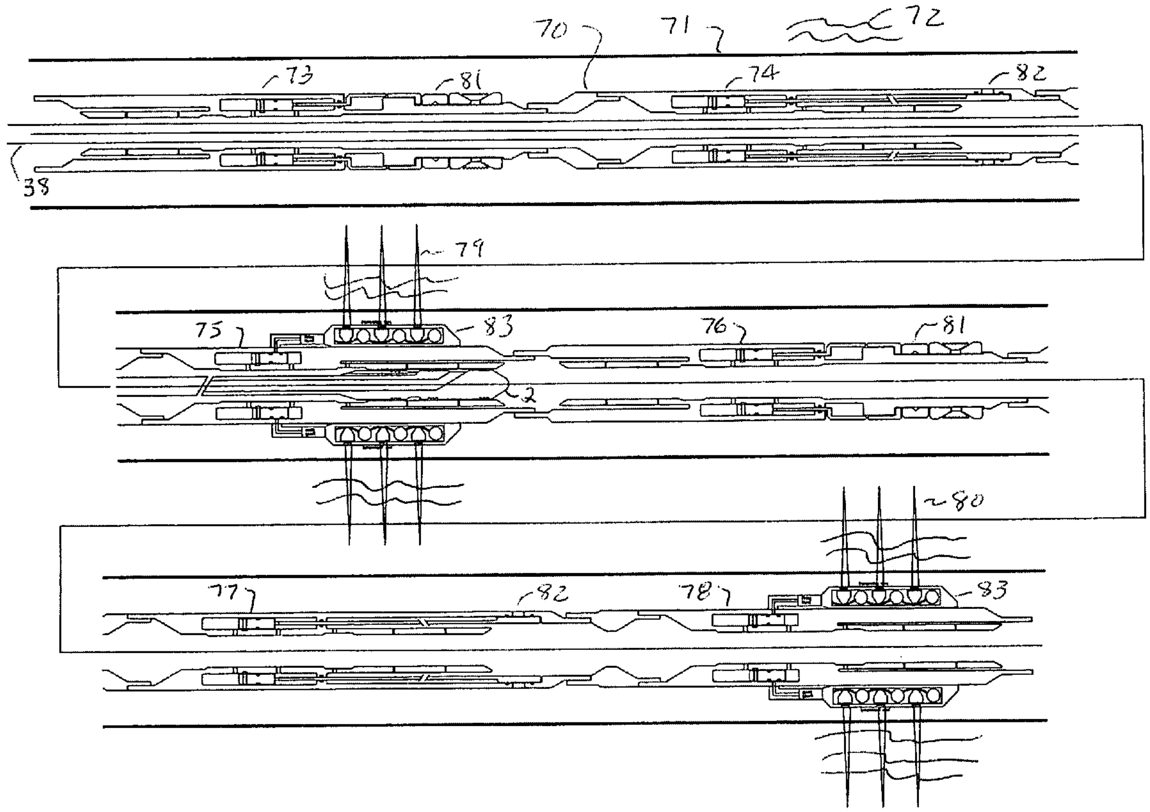
(57) ABSTRACT

An operating tool uses programmed fluid logic provided by use of flow paths including pre-determined spaced ports and varying orifice sizes to provide discreet pressures and fluid flow rates upon pressure differential sensitive devices, such as a membrane or piston, in operative communication with an operative sleeve to manipulate one or more secondary tools, and/or to perform a service, such as, for example, acidzing or stimulation or injecting proppants within the well. The tool remains "immune" to internal well hydraulic or hydrostatic pressures, if desired, until the fluid logic is achieved. The fluid logic is adjustable for activation of tools sequentially by making changes in the port spacing and fluid relief profiles so that all tools can be actuated by a single geometry of fluid flow paths, or each tool can have its own unique fluid flow geometry so it becomes hydraulically coded.



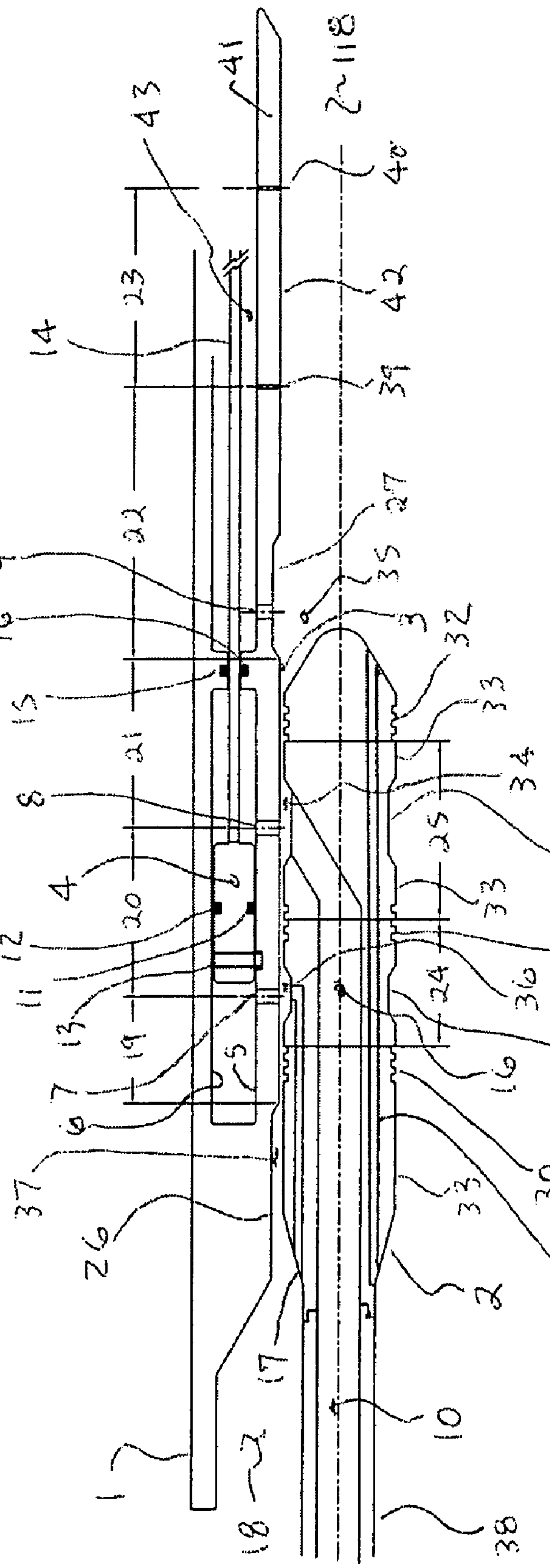

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FIGURE 1

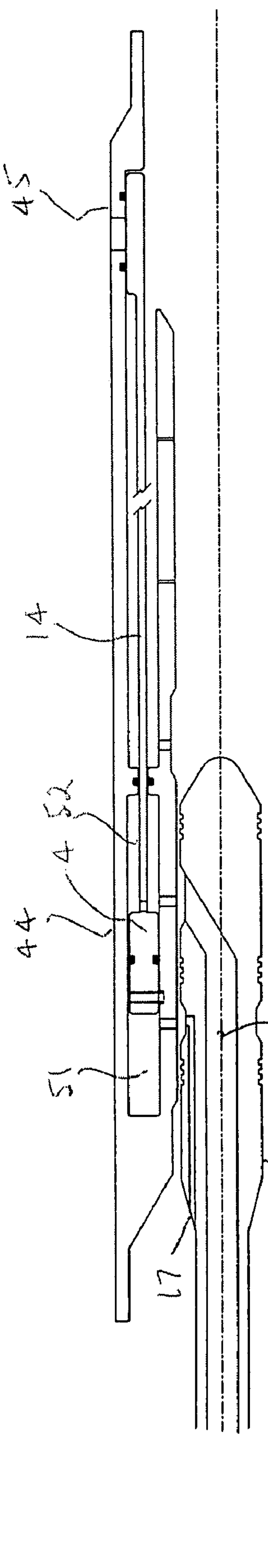
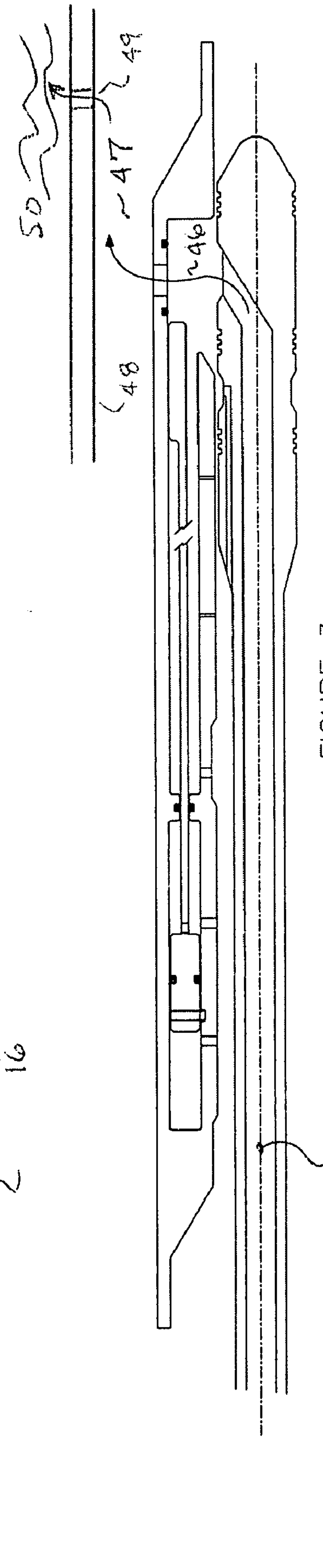



FIGURE 2

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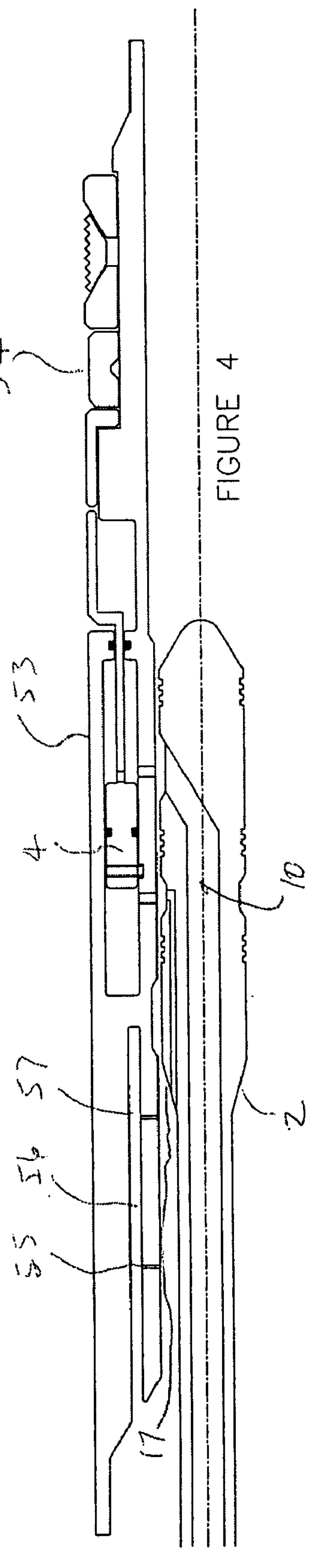


FIGURE 4

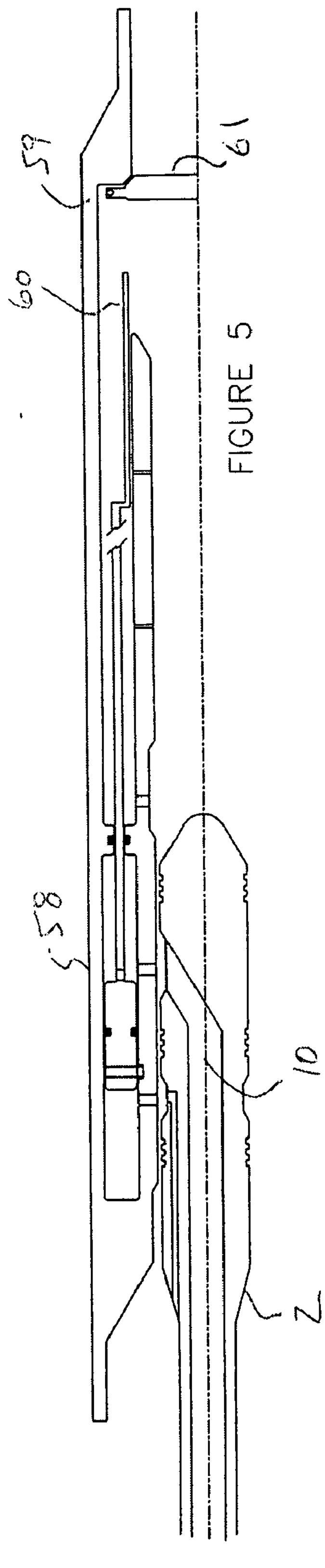


FIGURE 5

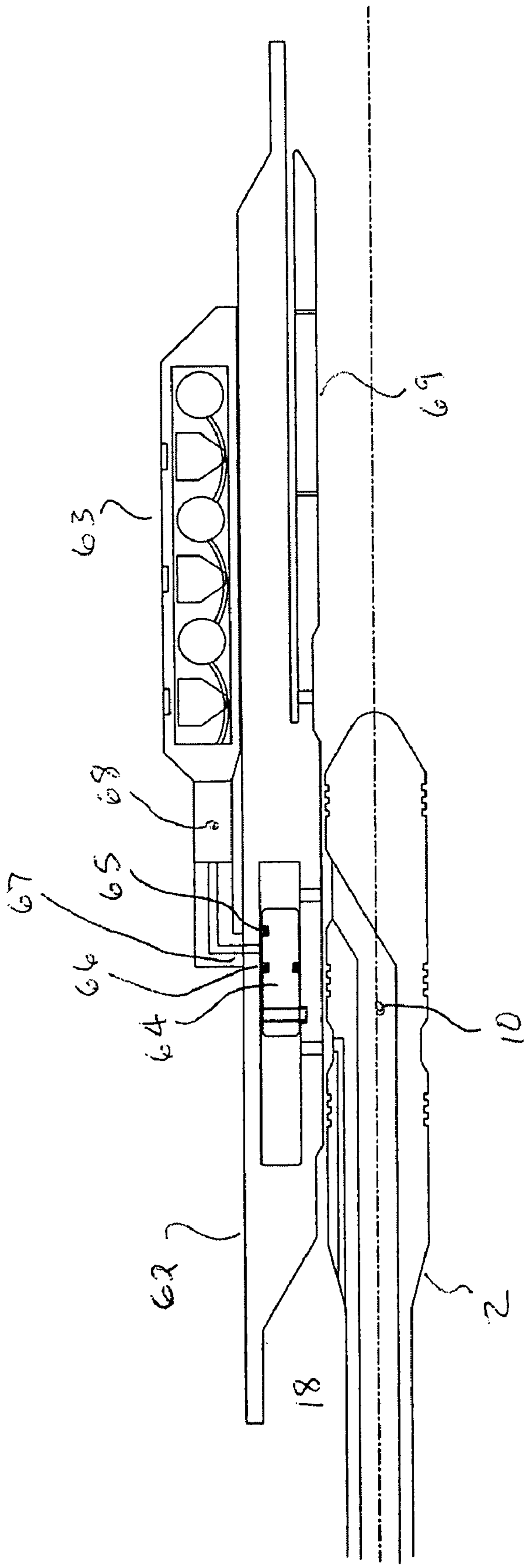


FIGURE 6

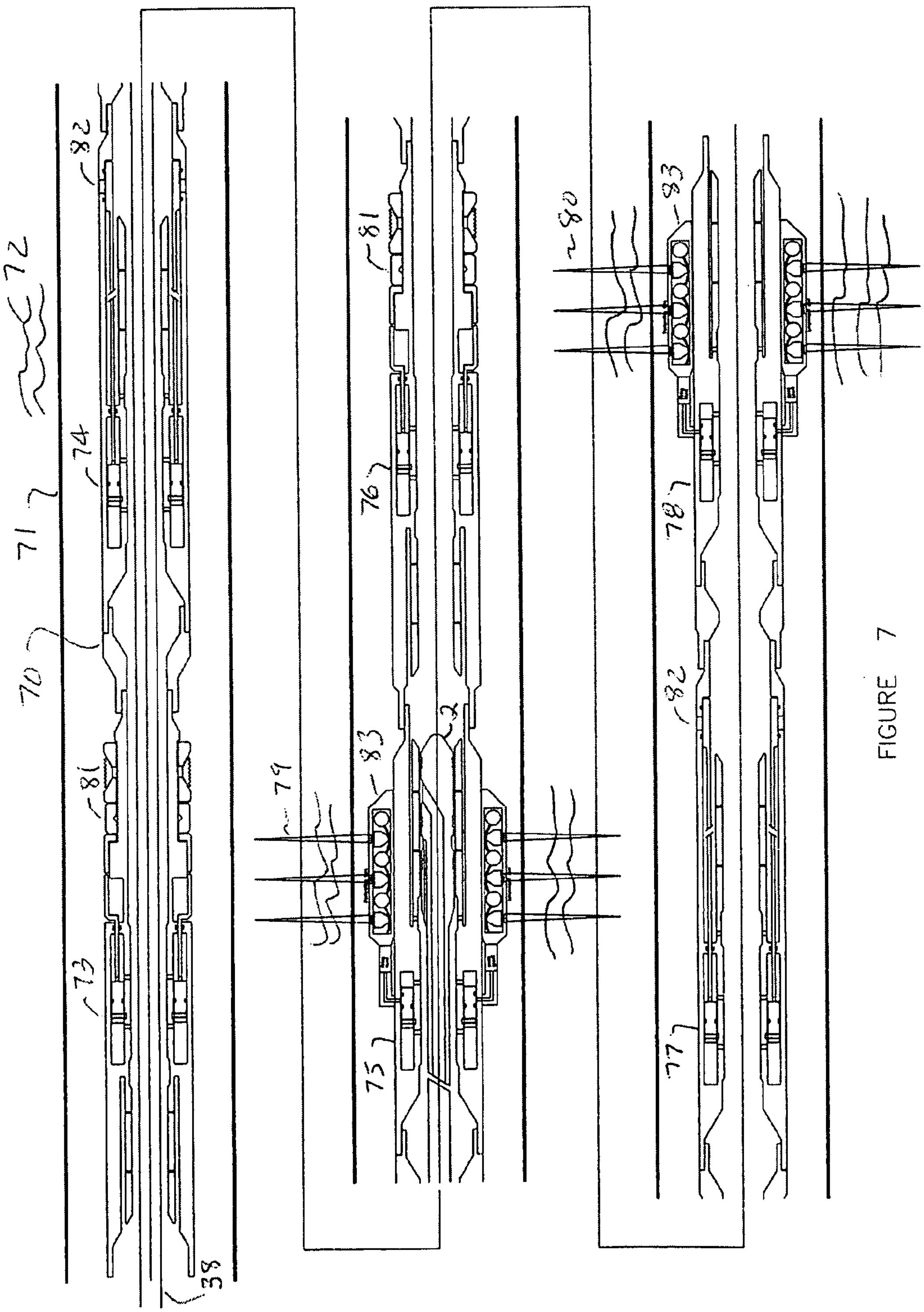


FIGURE 7

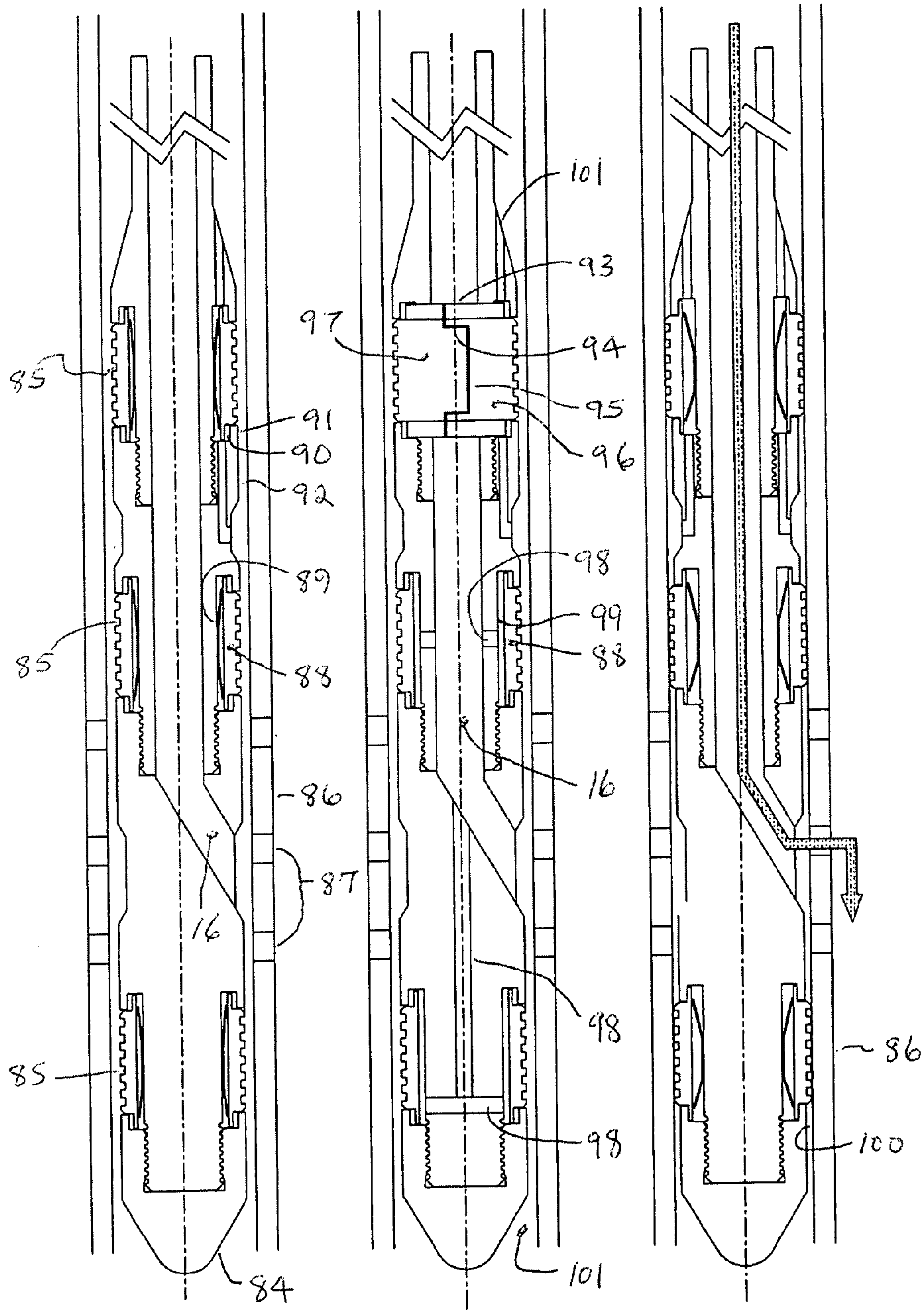


FIGURE 8A FIGURE 8B FIGURE 8C

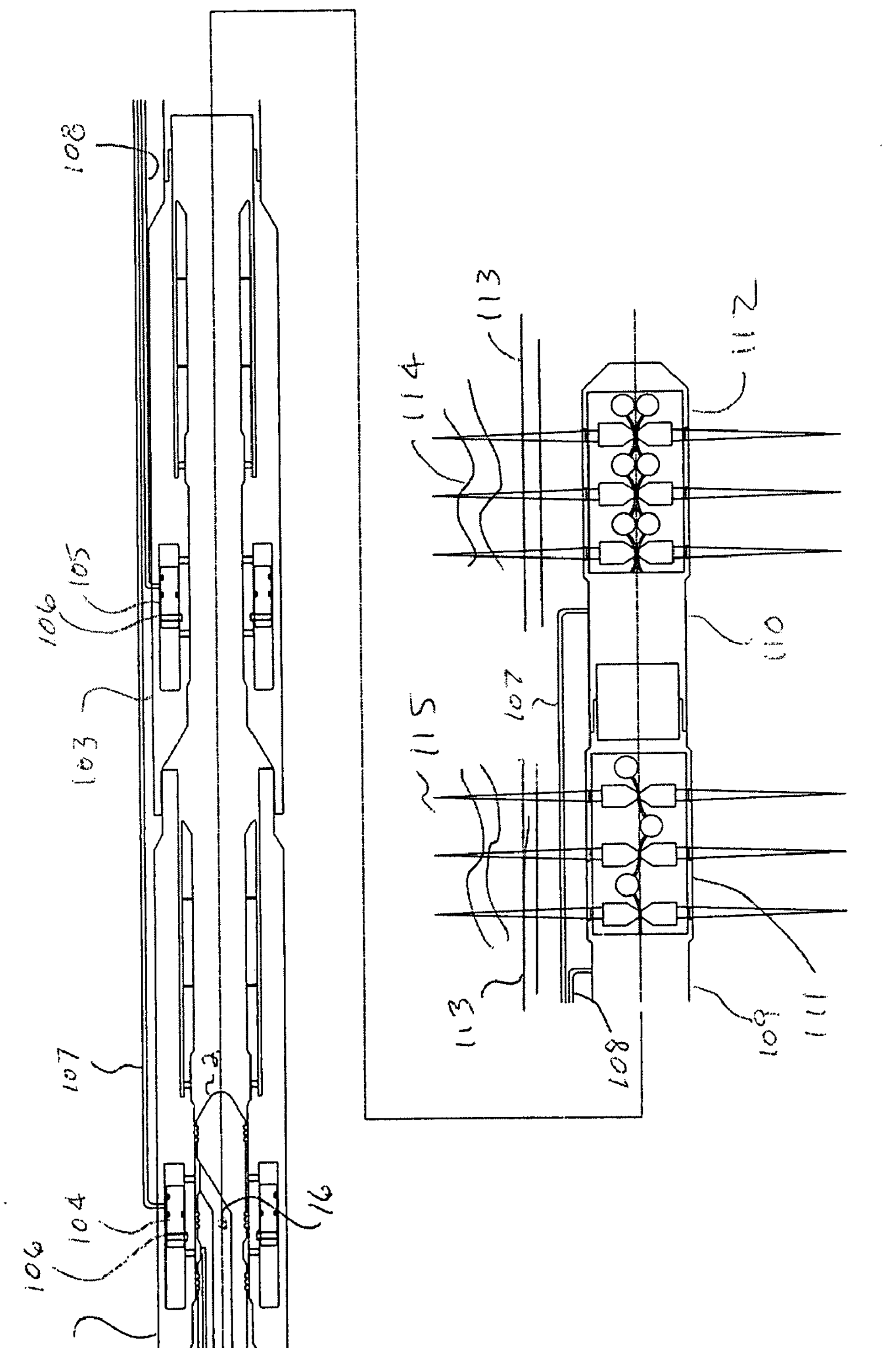
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FIGURE 9

# FLUID LOGIC TOOL FOR A SUBTERRANEAN WELL

## CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application is a utility application based upon: (1) Provisional application Ser. No. 61196326, filed Oct. 15, 2008, entitled "Fluid Logic Tool for a Subterranean Well", Gregg W. Stout, inventor; and (2) Provisional application Ser. No. 61207131, filed Feb. 9, 2009, entitled "Fluid Logic Tool", Gregg W. Stout, inventor.

## BACKGROUND OF THE INVENTION

[0002] 1. Field of the Invention

[0003] This invention relates to downhole tools for oil and gas wells and similar applications and more particularly to servicing or completing wells.

[0004] 2. Brief Description of Prior Art

[0005] Many types of downhole tools are conveyed into the well for various types of applications in order to produce oil and gas from underground formations. As an example, typical downhole tools are packers, sliding sleeves, ball valves, flapper valves, and perforating guns, and gravel pack screens, to mention a few. Well formations may have one or more producing zones where each zone may need a series of tools such as a packer and a sliding sleeve and a gravel pack screen. When screens are run and positioned in a zone, this is commonly called a gravel pack completion or a frac pack completion and many varieties of downhole tool hookups exist.

[0006] Packers are typically used to create a seal between the I.D. of the casing to the O.D. of a production or completion string thus isolating producing formations. Typically, completion packers are set in the well bore by application of tubing pressure through the inside of a work string and setting tool. A ball may be dropped from the surface and it seats at a point below the setting tool, workstring pressure is applied, and the setting tool strokes to set the packer. A ball or ball seat can obstruct access the tools below the packer. Often it is attempted to recirculate the ball out of the hole. Sometimes a plug is set in a nipple below the packer so setting pressure can be applied to set the packer. In this case, the plug may have to be removed.

[0007] The current invention provides a means to maintain a full open I.D. through the completion. Packers are also set on wireline or electric line where a Baker E-4 generates sufficient pressure and force to set a packer, but this method is usually limited to setting sump packers or setting a single completion packer with minimal weight hanging on the bottom of the packer.

[0008] Intelligent well completions use some form of control line that is strapped to the O.D. of a completion string that hydraulically or electrically can generate force to set packers. This process can be very expensive and control lines are always subject to some type failure.

[0009] The present invention provides a new alternative to hydraulically set single or multiple packers in a single run without dropping balls or setting plugs. Additionally the same tool that sets the packers can be configured to unset packers or actuate other tools during a single trip into the hole.

[0010] Sliding sleeves are used to control the flow of fluid or slurry to or from a formation into the pipe string. Sliding sleeves, or frac sleeves, typically have profiles on the inside of the sleeves that allow mechanical shifting tools to engage the inside of the sleeves so they can be shifted open or closed. Sliding sleeves may be selectively shifted with different shifting tool key profiles such as the Otis standard and selective profiles for the Model "B" shifting tool. Other companies have varying key profiles for shifting sleeves and shifting tools.

[0011] The present invention allows one tool configuration to shift all sliding sleeves selectively or only shift, or actuate, one type of tool and not the other tools.

[0012] The problem with shifting keys is that the shifting tools tend to jump out of the mating profiles for various reasons and shifting force is limited as a result. Sliding sleeves that have been downhole for extended periods of time tend to collect scale and can become difficult to shift. The present invention provides a means to apply a higher force to shift sliding sleeves where conventional methods tend to fail, especially in highly deviated wells. It is sometimes impossible to shift sliding sleeves in a deviated well with wireline because the deviation prevents the wireline shifting tool to reach the sliding sleeve. Also, it may be possible to reach sliding sleeves in a deviated well with coiled tubing and a shifting tool, but when the shifting tool engages the sliding sleeve; the drag forces on the coiled tubing through the bend limit the ability to shift the sliding sleeves.

[0013] The present invention does not create additional drag force on the coiled tubing, so the ease of moving coiled tubing through the bend is increased.

[0014] Also, the number of shifting tool key profiles and mating sliding sleeve profiles is limited, so shifting selectivity in multiple zones is also limited. Furthermore, shifting tool collets or keys sometimes break leaving unwanted debris in the hole.

[0015] The present invention provides a means, without collets or keys, to selectively shift an unlimited number of sliding sleeves, opened and closed, in combination with the force generated by hydraulics.

[0016] Sliding sleeves also are shifted open and closed by the use of control lines that hydraulically, electrically or mechanically stroke a sleeve up or down. It would be advantageous to have a backup means to shift sliding sleeves either open or closed if the control lines fail. It would also be very convenient, from an operations standpoint, to shift all the sliding sleeves in the hole either opened or closed by one continue sweep of an actuating tool through the inside of the sliding sleeves.

[0017] The present invention also allows the option of setting packers, or actuating other devices, during the same trip used to shift the sliding sleeves.

[0018] Ball valves and flapper valves may be run in a completion to control flow of well fluid through the pipe either to stop well production or to prevent fluid loss to the formation. These devices may be operated by application of tubing or annulus pressure or by shifting tools stroked up or down to open or close the valves. Ball valves can be actuated by pressuring either on the annulus side or the tubing side. In many cases annulus pressure is not possible due to the completion configuration. Also, if a single pressure to actuate the ball valve is only available to open a close the valve, then a so called "J" mechanism is used. "J' mechanisms sometimes jam up and don't work or the operator gets confused and doesn't know where he is at in the "J".

[0019] The present invention provides a means to open and close a Ball Valve from the tubing pressure side without a "J" mechanism to cause problems and no pressure needs to be applied to the annulus side of the valve.

**[0020]** It would be desirable to selectively hydraulically operate, open and close, ball valves or flapper valves or other types of valves with the same tool that is used to set packers and operate sliding sleeves all in the same trip.

**[0021]** It would also be desirable to have a tool system where tools such as packers, sliding sleeves, and valves would not be actuated from application of tubing or annulus pressure anywhere in the hole. The current invention only actuates tools when the correct fluid geometries are present, so inadvertent or unexpected application of pressures to the tools does not affect the tools.

**[0022]** Perforating guns are used to generate holes in casing or tubing to provide flow paths for producing oil or gas. These holes also provide flow paths to place proppant into formations from the surface. Perforating guns are detonated a number of different ways, i.e., electric line, jarring with wireline, impacting firing heads with drop bars, or application of tubing or annulus pressure to actuate a firing head that in turn detonates the perforating gun or guns. A problem exists when it is desired to fire multiple guns at different times in multiple zones, especially with single trip TCP (tubing conveyed perforating) guns. The TCP guns are the more desirable gun because of the perforating performance, i.e., large charges with good charge stand-off, and the ability to perforated long zones either vertical or horizontal. Methods are lacking to selectively fire these guns in multiple zones without coming out of the hole.

**[0023]** The present invention offers a means to selectively hydraulically detonate perforating guns with the same tool that is used to open and close ball valves or flapper valves, or other types of valves, set packers, and operate sliding sleeves all in the same trip whether the well is vertical or horizontal. Furthermore, the present invention offers a solution to preventing the pressure generated from the detonation of one gun, to inadvertently apply pressure to a second or third gun that could detonate the gun. The invention fires only one guns at a time only when fluid geometry between an inner tool and an outer tool matches.

**[0024]** It would be advantageous to operate many types of tools other than those described above in a single trip into the well. A single trip in the well equates to reduced rig time due to fewer pipe runs in and out of the well. The simplicity of the inner tool of the present invention and the use of hydraulics to generate higher forces offer increased reliability downhole. It would also be desirable to operate many tools downhole, multiple times, and still be able to place cement, place fluids, acidize, frac multiple formations, reverse out, and operate the above tools all in the same trip. It would also be beneficial to be able to re-enter the well and operate all of the above tools in one trip, while being able to "identify" each tool to assure the correct tool is being actuated.

## SUMMARY OF THE INVENTION

**[0025]** An operating tool is provided using programmed fluid logic applied through an operating fluid for use in a subterranean well. The tool is activatable by use of an operating conduit having first and second flow paths communicating with a source for the operating fluid, preferably at the top of the well, to perform a service operation within the well.

**[0026]** The operating tool comprises an outer member carried into the well on a first tubular conduit including an outer cylindrical housing and an inner cylindrical housing, and defining a fluid chamber between the housings. The inner member is positionable within the outer member and is carried into the well on a second tubular conduit.

**[0027]** The operating tool also includes an activation means, such as a sleeve, disposed within the outer member and is selectively manipulatable, or moveable therein in at least one direction to initiate the service operation within the well. Pressure differential sensitive means, such as a piston head, a thin metal flexible membrane, or the like, is in selective operative communication with the activation means, such as a sleeve.

**[0028]** The tool further includes a plurality of orifice means, each of said orifice means being in communication with the pressure differential sensitive means. Each of the orifice means includes at least one orifice profile defined on at lest one of the outer and inner members. The orifice means provide sufficient operating fluid flow at a pressure at the pressure differential sensitive means to selectively initiate the service operation, such as setting a packer, opening or closing a valve, initiating activation of a perforating gun, transmitting proppant into the well, transmitting acidizing fluid into a zone or zones within the well, or delivering a stimulation fluid into the well.

**[0029]** The operating tool also includes a plurality of fluid transmitting ports disposed through the inner cylindrical housing for transmitting the programmed fluid logic in the operating fluid at a flow rate and pressure delivered by the operating conduit within one of the operating tool flow paths, through the orifice means into one of the ports and upon the pressure differential sensitive means, to selectively and operatively communicate the pressure differential sensitive means with the activation means to move the activation means in one direction and, during such movement, to direct fluid in the chamber adjacent the pressure differential sensitive means out of the chamber through another of the fluid transmitting ports, thence into the second flow path of the operating conduit, as the service operation is performed.

**[0030]** The "operating fluid" contemplated for use in the present invention may be any of a number of fluids conventionally used in drilling, workover, or completion operations in subterranean wells. Such fluids may also include proppants, gravel and other additives for various known uses in the wells.

**[0031]** The well may be acidized or any other operation requiring a fluid to be transmitted, may be performed in the well using either the operating fluid or a second or treatment fluid introduced into the well after the service operation is performed.

**[0032]** The "first tubular conduit" may be casing, or a conventional work string or production string.

**[0033]** The "operating conduit" or operating conduit, may be casing (in the event that the well is uncased or "open hole", drilling, production or workover tubing, coiled tubing, or the like.

**[0034]** The "pressure differential sensitive means" may be a piston head, a thin membrane, a component which dissolves or operatively deteriorates upon certain exposure to a particular chemical, such as an acid solution (i.e. a fluid having a pH below 7.0).

**[0035]** By "programmed fluid logic" and/or "fluid flow path logic", I mean to refer to the resultant anticipated fluid flow rate at a given pressure resulting from the use of the orifice means and the fluid transmitting ports at the given depth of the well upon the pressure differential sensitive means sufficient to initiate and complete the manipulation of an auxiliary tool or remedial or other service operation(s) in the well.

**[0036]** The present invention provides a downhole tool system and method that allows for completing or servicing a well with single or multiple zones of production. Stated one way, an outer tool, or series of outer tools, are run in a completion or other tubular string positioned inside of a casing or other tubular conduit string, or mounted in the casing, are selectively initiated to manipulation hydraulically by an inner tool that is positioned in close proximity to the inside of the outer tool or tools. Fluid flow path logic between the inner and outer tools allows actuation or manipulation of the outer tool with application or reduction of surface pressure. The outer tools remain "immune" to internal hydraulic or hydrostatic pressures, if desired, until the pre-selected fluid logic is achieved by use of the inner tool. The fluid logic between the tools is adjustable by making changes in the port spacing and fluid relief profiles so that all tools can be actuated by a single geometry of fluid flow paths, or each tool can have its own unique fluid flow geometry so it becomes hydraulically coded, so to speak. Many hydraulic codes can be used to selectively actuate a variety of tools in single zones or multiple zones. The inner tool also offers a well "location finder" option. The "location finder" hydraulically identifies an outer tool and verifies inner tool position in the well to assure the proper outer tool is being actuated.

**[0037]** A large number of downhole functions can be performed in a single trip into the well, for example, set and release packers, open and close sliding sleeves, detonate perforating guns, open and close flappers or ball valves. All of these procedures can be done with significant forces generated by hydraulics. The inner tool is very versatile in that it can be conveyed by several means, and not only serves as an actuation tool, but can also be used for various types of well services, such as cementing, acidizing or fracturing.

**[0038]** The invention provides a tool system where an inner through-tubing tool mates with an outer tool that can be made up in a completion positioned inside of casing or in the casing itself, or other tubular conduit. The inner tool actuates the outer tool by application of hydraulic pressure through a pre-designed flow path. The flow paths between the inner and outer tools must properly match in order to actuate the outer tool. The inner tool also has a large I.D. flow path that allows pumping of fluids or slurries to/from the formation.

**[0039]** The inner tool can be run on work string (jointed pipe), coiled tubing, as part of a completion or service tool hookup, with wireline or electric-line tools with hydraulic capability, with tractors with hydraulic capability or any other method that can deliver hydraulic pressure the inner tool.

**[0040]** Many "fluid logic codes" can be generated between the inner and outer tools by adjusting; 1) port size and spacing, 2) the number of ports, 3) the length fluid reliefs, 4) the relative position of the fluid reliefs to the ports, and 5) any other related geometry. Theses adjustments can be made on both the inner and outer tools to create unique fluid flow geometries and each geometry can be coded as A, B, C, D, E, and on, for example.

**[0041]** If more than one outer tool is positioned downhole, this one tool can be given its own fluid code so that only a pre-planned geometry can activate it. If many tools are downhole, a single fluid code can be used to selectively actuate all tools in a single trip.

**[0042]** The outer tools are hydraulically designed, with a "balanced piston", so that advertent or inadvertent application or existence of hydraulic or hydrostatic pressure does not have an effect on the tool. The outer tool stays inactive until the inner tool fluid code matches the outer tool fluid code and pressure is applied through or around the inner tool in order to shift the "balanced piston". Once the "balanced piston" shifts, pressure from hydraulic fluid acts as a trigger to begin actuating the outer tool. As an alternative, the outer tool (CLT) can be used without the "balanced piston" feature, if desired, and substituted with a non-balanced piston or no piston at all. With the absence of a piston, fluid pressure can communicate with any type of device that would actuate a downhole tool.

**[0043]** The "fluid logic codes" (FLC) are analogous to a variety of wireline locating or shifting profiles, i.e., only certain key profiles engage and shift certain sleeve profiles. Or they (FLC) could be analogous to the multitude of codes available with the new technology called "RFID" HERE actuated tools. The Fluid Logic Tool can route pressure against outer tool piston area to create adequate force to reliably cause outer tool actuation. In contrast to the RFID actuated tools, FLC is a non-electric approach with the reliability of simply applying hydraulic pressure to the tool. Of course, FLC technology could be used in conjunction with wireline or RFID technology or other technologies for redundancy purposes.

**[0044]** The outer tool has a hydraulic piston, device, or mechanism that can supply a force needed to set or release packers, shift sliding sleeves or frac sleeves both open and closed, open or close flapper valves or ball valves or any type of motion actuated valve, initiate the firing sequence of tubing conveyed (TCP) or casing conveyed perforating guns (CCP) or perforating guns mounted in a completion string, or other types of downhole tools.

**[0045]** The outer tool has a hydraulic piston that can move mechanical devices, interface with hydraulic devices, interface with electrical devices, optical devices, magnetic devices, pneumatic devices, or others.

**[0046]** The outer tool can include a downhole positioning device or locating device. This device is a tube attached to either the top or bottom of the outer tool. The tube has one or more orifice spaced lengthwise along the tube. As the inner tool moves through the orifice while applying pump pressure from the surface, the orifice cause changes in pressure and flow rate to create "Pressure Blips". The orifice are sized and placed in the tube to develop a preplanned pressure profile at the surface to tell the operator where the tool is located. The orifice can be substituted with changing diameters or other geometry to create pressure fluxuations while pumping down the work string. The "orifice" creates a calibration point from which to move the inner tool in order to actuate an outer tool. Of course, the "orifice" is optional or any number of orifice and orifice longitudinal spacing can be used in the outer tool to help identify the outer tool and its position in the well. Pressure and flow signatures of the "orifice" are pre-determined by surface tests before the tools are run into the well.

**[0047]** The inner tool can be used to "sweep" through the outer tools to actuate the outer tools. In other words, the inner tool can be moved, at a selected speed while accompanied by a selected pump rate, through an outer tool to actuate the outer tool. In this case, precise positioning of the inner tool to the outer tool is not required. For example, if the inner tool is positioned below a series of closed sliding sleeves, the inner tool may sweep upward through the sliding sleeves to open all the sliding sleeves.

**[0048]** The inner tool may use any type of seal that engages pressure wise, with the I.D. of the outer tool. For example, each set of seals that are adjacent to the fluid flow ports may be Labyrinth type seals, elastomer seals, non-elastomeric seals, or any type of seal that directs fluid flow into the ports. The seal can be as simple as two metal surfaces, the O.D. of the inner tool and the I.D. of the outer tool, i.e., the clearance between the two surfaces is sufficient to direct fluid into the outer tool. The seal does not have to be a prefect seal to actuate the outer tool, but must seal sufficiently to cause a reliable pressure differential across the "balanced piston" in the outer tool to actuate the outer tool. The Labyrinth seal, a series of metal grooves, is the preferred seal due to its clearance with the I.D. of the outer tool, its ability to restrict flow past it, and its robustness.

**[0049]** The inner tool is a very versatile multi-purpose device since it can be used to actuate single or multiple tools in single or multiple zones without coming out of the hole. It provides feedback to the surface as to its position in the well. It can be used as a wash tool to clear debris away ahead of the tool while fluid is circulated down the workstring. It can be used to place fluids downhole or condition well fluids. It can be used to acidize, place sand, place cement, or fracture formations. It can be used to simply open or close a valve or it can be used in a more complicated scheme of events such as setting a packer, opening a sleeve, detonating a perforating gun, and closing a sleeve or any variety of operations in any sequence. It can be used on coiled tubing to service a live well. Other tools can be run with it, i.e., it can be used with a pressure actuated positioning device to hold it in place while fracing, pressure recording devices can be attached, jarring devices can be attached, and so on.

## BRIEF DESCRIPTION OF THE DRAWINGS

**[0050]** FIG. **1** is a longitudinal cross-sectional schematic view of the present invention with the inner tool positioned inside of the outer tool.

**[0051]** FIG. **2** is a view similar to that of FIG. **1** showing the present invention with the inner tool in position to actuate a sliding sleeve.

**[0052]** FIG. **3** is a view similar to that of FIGS. **1** and **2** with the inner tool positioned in the outer tool for the purpose of injecting fluid or slurry through the outer tool.

**[0053]** FIG. **4** is a similar view of the present invention with the inner tool positioned to set or release a packer.

**[0054]** FIG. **5** is a similar schematic view of the present invention with the inner tool positioned to actuate a flapper valve.

**[0055]** FIG. **6** is a similar schematic view of the present invention with the inner tool positioned to actuate a perforating gun.

**[0056]** FIGS. **7***a*, **7***b*, and **7***c* is a similar schematic view of a two zone completion hookup with multiple outer tools. The inner tool is in close proximity so it can be moved to actuate each outer tool.

**[0057]** FIGS. **8***a*, **8***b*, and **8***c* are similar schematic views of the present invention with the inner tool positioned in a perforated pipe and the inner tool is dressed with expandable metal pads that have labyrinth seal grooves machined on the O.D. of the pads. The pads are shown to be biased outward by either springs or hydraulic pressure differential across the pads.

**[0058]** FIG. **9** is a similar schematic view of the present invention with the inner tool positioned to actuate a series of TCP ("tubing conveyed perforating") guns. The TCP guns are fired one at a time by moving the inner tool relative to the outer tool. The outer tool has a balanced piston that is secured sufficiently enough to withstand shock or hydraulic forces of a detonating perforating gun.

## DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

**[0059]** FIG. **1** consists of a "Completion Fluid Logic Tool" (CLT, also referred to as the outer tool) **1** with a "Service Fluid Logic Tool" (SLT, also referred to as the inner tool) **2** positioned in the inside bore **3** of the CLT **1**. The SLT **2** and CLT **1** may take on several forms as described later in the description. A Piston **4** is located between an inner housing **5** and outer housing **6** with ports **7** and **8** and **9** adjacent to the piston **4**. Based on the type or form of the CLT, different porting arrangements may be used.

**[0060]** The objective of the porting arrangements, for example port **7** and port **8**, is to allow tubing (internal) pressure **10** to act on each side of the piston **4**, on both sides of seals **11** and **12**, in order to keep the piston **4** in a pressure balanced, or near pressure balanced, condition so that any increase in tubing pressure **10**, for any reason, does not cause the piston **4** to move. If the piston **4** does not move, the CLT **1** remains in a dormant state and does not function. The piston **4** may be shear pinned **13**, or locked in another manner, until sufficient force, due to intentionally applied pressure **10** with the SLT **2**, causes the piston **4** to shear or unlock.

**[0061]** Movement of the CLT **1** piston **4**, via pressure **10** application from the SLT **2**, initiates activation of the CLT **1**. The piston **4** may be mechanically attached, via an activation sleeve **14** for example, to a device to perform some downhole function, such as, opening and closing a sliding sleeve, initiating the setting of a packer, initiating a perforating gun, etc. Also, the piston **4** can be attached to a device hydraulically, electrically, magnetically, optically, pneumatically, etc., so when the piston **4** moves, the CLT **1** is activated.

**[0062]** If a configuration utilizing the activation sleeve **14** is used, it may be necessary to have seals **15** and **16** that remains pressure balanced, or near pressure balanced, through ports **8** and **9**. If it is necessary to keep the piston closely pressure balanced, then the SLT **2** could have an additional port, not shown, to communicate with ports **8** and **9** simultaneously. It should also be apparent that the piston could have the option of not being pressure balanced in certain applications.

**[0063]** FIG. **1** also shows the SLT **2** with an internal flow path **16** and an adjacent flow path **17**. Pressure **10** or **18** can be applied to either of the flow paths **16** or **17**. If pressure **10** is applied to flow path **16**, then fluid would enter port **8** and pressure would act below the piston **4** biasing it upward and port **7** and flow path **17** would accept fluid from above the piston **4** to allow the piston to move upward. Furthermore, if pressure **18** is applied to flow path **17**, then fluid would enter port **7** and pressure **18** would act above the piston **4** biasing it downward and port **8** and flow path **16** would accept fluid from below the piston **4** to allow the piston to move downward. Therefore, the up and down movement of piston **4** will cause the activation sleeve **14** to simultaneously move up or down to function a completion tool such as a sliding sleeve.

**[0064]** The longitudinal spacing, i.e. distances **19**, **20**, **21**, **22**, **23**, **24**, **25** but not limited to the number of distances, in conjunction with diametric changes i.e. recesses **26**, **27**, **28**, and **29** but not limited to the number of diameters, can be altered or adjusted to achieve different flow paths around the piston **4** or multiple pistons, through flow paths **16**, **17** or other flow paths, to actuate one or more tools. Tools like packers or sliding sleeves can be actuated selectively if desired. A single flow path geometry can be used to actuate all tools. A flow path geometry can be selected so only one tool can be actuated and any others can not be actuated.

**[0065]** It should be understood that one SLT **2** can be built to activate all CLT **1** devices located downhole, or one configuration SLT **2**, say configuration geometry "CS1", can be built to only actuate a CLT **1** designed to match only a CLT with configuration "CS1". Almost unlimited combinations of fluid patterns, or codes, can be built by varying the distances or geometries mentioned above. This is analogous, to some extent, to the wireline shifting tool profiles where R, X, or XN profiles of shifting tools only match R, X, or XN profiles in nipples, respectively.

**[0066]** FIG. **1** also shows seals arrangements on the SLT **2**, i.e., seals **30**, **31**, and **32**. These seals form a full or partial seal in bore **3** on each side of flow paths **16** or **17** and on each side of ports **7** and **8**. These seals, or any combination of seals, can seal around any combination of flow paths or porting arrangements. Flow paths can be as simple as one port and one flow path or multiple flow paths and ports. The recesses can be used to direct flow around the tool as desired to achieve any flow logic desired.

**[0067]** FIG. **1** shows three sets of Labyrinth seals **30**, **31**, **32** on the outside of the SLT **2**. The Labyrinth type seal is a single groove or multiple grooves on the O.D. of the SLT **2**. The O.D. **33** of the SLT **2** can simply be a close tolerance fit in bore **3** to create a partial seal or pressure drop in locations **34**, **35**, **36**, and **37**. The seal **33** can be of any type sufficient to allow a pressure buildup sufficient to move the piston **4** in the CLT **1**. In others words, the seals **33** can leak and do not have to be perfect seals. If a near-perfect or perfect seal **33** is desired, other types of seals can be used such as elastomer or elastomers, plastics, non-elastomers, expandable such as in FIG. **8**, or retractable type seals. Seals could be o-rings, v-rings, Chevron stacks, bonded seals, molded seals, cup type seals, etc. It is preferable to use a seal, such as a Labyrinth seal **33** that has clearance inside of the CLT **1** and does not impart friction inside of the CLT **1** and does not tend to stick inside of the CLT **1** and the type that can seal multiple times without replacement. It is also desirable to have a seal, like a Labyrinth seal **33** that will tolerate various types of particles found down hole, i.e., sand, proppants, scale, etc. It is also desirable to have a seal, like a Labyrinth seal **33**, which is not degradable by downhole temperature and various chemicals.

**[0068]** FIG. **1** shows the SLT **2** being conveyed into the well by work string **38**. Let it be understood that the CLT **1** can be part of the casing string in the well or part of a completion or other tubular string in the well, as shown in FIG. **7**. An objective is to convey the SLT **2** to sufficient proximity of the CLT **1** to activate the CLT **1**.

**[0069]** Conveyance methods can be by use of a workstring **38** which can be jointed pipe or coiled tubing. Also the SLT **2** can be conveyed by electric line, wireline, or a tractor, all of which would need special pressure generating tools that can pump fluid to the SLT **2**. Another option is to place a landing nipple above the CLT **1** and the SLT **2** can be attached to a wireline or coiled tubing conveyed lock or locator that positions it in the landing nipple. The positioning would be such that the SLT **2** and CLT **1** fluid paths line up. Once the fluid paths are lined up, pressure can be applied down tubing or casing to activate a CLT **1**.

**[0070]** FIG. **1** shows an orifice **39** and an orifice **40** located in housing **41**. The orifices are downhole locating devices. If fluid is pumped through flow path **16** at a given rate and pressure through the SLT **2** and then moved through the orifice **39** or **40**, the orifice will cause a pressure change, through **10** or **18**, at the surface because the orifice will allow flow of fluid. When seals **33** of the SLT **2** enter the bore **42** of housing **41** the flow rate out of flow path **16** will be restricted. When seals **33** allow fluid communication with the orifice **40**, or any combination of orifice, fluid flows through the orifice and into annular space **43**. Distance spacing **23** can be adjusted to allow a fluid return path through orifice **39** and into annular space **18**. A surface operator can detect one or more pressure changes, based on the orifice geometric pattern, to tell him where the SLT **2** is relative to the CLT **1**. The pressure changes can be pre-calibrated at the surface so the operator will know what pressure change or sequence of pressure changes to expect for a particular CLT **1**. Pressure changes or patterns can be created by changing orifice size, the number of orifices, replacing conventional orifices with a series of bores and recesses (also referred herein and in the claims as "orifices" or "orifice means") or any scheme that will cause pressure changes downhole.

**[0071]** Once the desired location, or CLT **1**, is found, the SLT **2** can be moved up or down a given distance in order to position the SLT seals **33** around the CLT ports **7**, **8**, or **9**. Of course, tubing stretch or elongation due to pressure application must be taken into consideration at the anticipated applied pressure. If seals and port spacing are long enough, tubing movement is less of an issue. It should be noted that SLT **2** positioning may not be a critical issue, because in some cases, the SLT **2** can be slowly moved through the CLT **1** while applying pressure to activate the CLT **1**.

**[0072]** Also shown in FIG. **1**, is an optional pass-thru hole, or holes, **117**. The flow path created by hole (s)**117** allows pressures near **18** and **118** to equalize in cases where dead space **118** exists below the SLT **2**. The dead space may exist below SLT **2** when there is no fluid communication with the formation or in the well above the SLT **2**. When fluid is pumped thru flow-path **10**, fluid leakage may occur past seals **31** and **32**. Fluid leakage past seal **32** must flow back up thru hole **117** when space **118** has no communication with its surroundings. Hole **117** allows pressure **18** and **35** to stay balanced, or near balanced, so an increase in pressure at either location **35** or **18**, does not tend to force the SLT **2** up or down.

**[0073]** FIGS. **2** and **3** illustrate how an activation sleeve **14** of a CLT **44** is activated by the SLT **2** to open a sliding sleeve **45** to create a flow path **46** from the tubing side **10** to the annulus side **47**. Applied pressure **16** builds pressure in chamber **52** to move piston **4** upward into chamber **51** while fluid moves to low pressure side **17**. The hydraulic force on piston **4** opens the sliding sleeve **45**. The annulus side **47** can communicate with an oil or gas producing formation, or formations. This CLT **44** configuration can be used to open or close sliding sleeves located adjacent or in close proximity to in one or more formations, formations that are either isolated or non-isolated, for either injection into a formation, stimulating a formation, or producing from a formation. Once the sleeve

**45** is opened, the SLT **2** can be positioned so that it can be used to fracture a selected zone as shown with flow path **46**.

**[0074]** The casing **48** has holes or perforations **49** so that the flow **47** communicates with formation **50**. An anchoring device can be attached close to the SLT to hold it in position while fracturing is taking place. The anchoring device for the SLT plays no part of this invention. Any one of a number of conventional means known to those skilled in the art may be utilized.

**[0075]** As shown in FIG. **2**, the sliding sleeve **45** may be closed when pressure direction is reversed in the SLT **2**. Pressure is increased at port **17** which moves piston **4** down into chamber **52** which closes the sliding sleeve **45**.

**[0076]** FIG. **4** illustrates the configuration of a CLT **53** that interfaces with a packer **54** in order to set, or release, the packer **54**. Pressure **17** is applied to stroke piston **4** downward the compress and set the packer although pressure **10** could also be used if the SLT **2** were moved upward to change the porting arrangement. In this schematic the orifice locator has been moved to the top of the completion tool and CLT. Orifice **55** and **57** are located in tubular housing **56**. This drawing is for illustration only since the apparatus for setting the packer and the packer require more detail. It should be noted that packers require setting loads in the range of 50,000 pounds to fully set and the SLT **2** has hydraulic pressure capability to generate these forces when working on piston **4** areas. In order to get additional force it is possible to attach two or more pistons (similar to **4**) and simultaneously add more seals and ports to the SLT **2** geometry.

**[0077]** FIG. **5** illustrates the configuration of a CLT **58**. Fluid is pumped through path **10** to move sleeve **60** that allows a flapper valve **59** to close when sleeve **60** moves above the flapper **61**. Of course, the flapper valve design can be modified so that the SLT (**2**) can both open and close a flapper, or a ball valve, or any other type of valve. The flow path configuration between the CLT and SLT is such that a valve can be opened and closed in a single trip into the well. It is also possible to build one flow configuration that opens a valve and a second configuration that closes a valve.

**[0078]** FIG. **6** illustrates a CLT **62** configuration for activating a Tubing Conveyed or Casing Conveyed perforating gun **63**. The SLT **2** can be used in vertical or horizontal wells and can selectively detonate guns at any position in the well. In this configuration, the geometry around the piston changes. The piston **64** is no longer attached to an activation sleeve, but instead, has an added seal **65**. Seals **65** and **66** prevent pressure from entering port **67** until the piston **64** moves up or down to uncover port **67**. Once port **67** is uncovered, pressure **10** or **18** can be applied through the SLT **2**, through port **67**, and into a timer or firing mechanism **68** to initiate firing of the perforating guns **63**. Of course firing mechanism can be located anywhere in the perforating gun.

**[0079]** FIG. **6** illustrates that the piston **4** (of FIG. **1**) or **64** can be in several forms. The piston, rather than communicating with a port **67**, can act as a locking mechanism, for example. When the piston moves, it can cam out from under a collet, or set of keys, or a switch, or some other device that is directly or indirectly connected to an activating device which eventually activates some type of downhole tool, or CLT. Once again, the option exists to have no piston at all so the SLT communicates directly with some type of device. Also, it should be apparent that this piston arrangement is not limited to perforating guns. Also shown in FIG. **6** is the orifice location finder **69** which is optional and may be located anywhere relative to the CLT **62**.

**[0080]** FIGS. **7***a*, **7***b*, and **7***c* illustrates a possible completion hookup **70** inside of casing **71** in formation **72**. The hookup **70** consists of multiple CLT's **73**,**74**,**75**,**76**, **77**, and **78** and more than one zone of interest, zones **79** and **80**. The hookup shows two zones of tools with each zone having a CLT actuated packer **81**, sliding sleeve **82**, and perforating gun **83**. A SLT **2** attached to workstring **38** can be moved from position to position to activate each CLT as desired. Those familiar with the state-of-the-art can readily see that different types of CLT's can be placed in any position and as many times as desired.

**[0081]** FIGS. **8***a*, **8***b*, and **8***c* show the SLT **84** positioned inside of a tubular **86** and the tubular has holes **87** which may be perforations that connect to a formation or machined holes that communicate with a CLT.

**[0082]** FIG. **8**A illustrates the SLT **84** with expandable labyrinth seals **85** rather than fixed O.D. labyrinth seals as seen in the SLT **2** (of FIG. **1**). The labyrinth seals **85** are one or more grooves placed on the O.D. of the expandable pads **88**. Although, the option exists where the pads **88** have no labyrinth grooves. In this figure, the pads **88** are biased outward by use of springs **89** under the pads to force contact, or near contact, with the I.D. of the tubular **86**. The pads **88** approach or achieve a **360** degree contact around the I.D. of the tubular **86**. FIG. **8**B shows grooves **95** between two or more sections of pads **96** and **97**. The pads **96** and **97** are blocked by off-sets **93** and **94** built into the sides of the pads **96** and **97**. The off-sets **93** and **94** restrict fluid movement between the pads **96** and **97** when the pads are expanded to meet the I.D. of the tubular **86**. Each section of pad has a set of off-sets. The pads **88** are retained to the SLT **84** by lips **90** on the pad **88** protruding under mating lips **91** on housing **92**. The components of the pads and the body of the SLT **84** restrict fluid flow past the pads thereby directing fluid through flow path **16** and into CLT holes or perforations **87** in the tubular **86**.

**[0083]** FIG. **8**B illustrates the SLT **84** in a similar manner as FIG. **8**A except the pads **88** are biased outward hydraulically with pressure from hole **16** through ports **98** and into chamber **99** located under each set of expandable pads **96** and **97**.

**[0084]** FIG. **8**C illustrates the SLT **84** with the pads **96** and **97** fully expanded against the I.D. **100** of the tubular **86** due to spring loading under the pads. The hydraulic version would be similarly expanded since pressure at **98** is higher than pressure at **101**. In either case, the expanded pads direct fluid, or slurry, into and through the tubular holes **87**.

**[0085]** FIG. **9** illustrates a downhole tool hookup for perforating one or more zones with a Tubing Conveyed Perforating Gun (TCP). One or more CLT's, **102** and **103** are positioned above one or more TCP guns **111** and **112**. When the SLT **2** is positioned inside the CLT **102**, pressure at **16** works on piston **104** and shears screw **106**, or locking device, to allow fluid from **16** to communicate with control line **107**. Control line **107** either hydraulically, electrically, optically, etc. communicates with firing head **110** and triggers firing head **110** to detonate TCP gun **112**. It may be desirable to detonate the lowermost guns **112** first to assure that the control line **107** is not damaged by detonation of guns **111**. If a control line **107** is damaged, it is possible to shift or bias piston **104** back to the closed position to shut off fluid communication through the control line **107**, if the control is hydraulic. Shear screws **106**, or locks, are of sufficient strength to prevent a piston **104**, from another CLT **103**, from moving due to TCP shock loads from TCP gun detonation **112**. After TCP gun **112** is detonated the SLT**2** may be moved to CLT **103**. Pressure applied from **16** moves piston **105** so that communication is achieved through control line **108** which activates firing head **109** and detonates TCP gun **111**. Multiple CLT's can communicate with multiple TCP guns in any manner, i.e., CLT **102** can only fire gun **111**, CLT **102** can only fire gun **112**, CLT **102** can simultaneously fire both guns **111** and **112**, CLT **103** can do the same as CLT **102**, or both CLT **102** and CLT **103** can both fire a gun or guns to provide a means to have a backup firing method. Firing of the guns **111** and **112** will perforate casing **113** and communicate with formations **114** and **115**. Therefore, any combination of CLT's and guns can be used to fire guns selectively, simultaneously, or provide redundancy in the firing system. Also, the SLT **2** may be moved from the bottom up or the top down to fire guns in any sequence.

**[0086]** Also shown in FIG. **6** is the orifice location finder **69** which is optional and may be located anywhere relative to the CLT **62**.

**[0087]** The TCP guns **111** and **112**, or more, can be spaced out through multiple zones **114** and **115**, or more, to selectively perforate zones without the need to move the workstring **116**. Also the workstring **38** can be moved to reposition guns relative to each zone before detonation without pulling the SLT **2** out of the well by use of jointed pipe at the surface.

**[0088]** A dual string handling system can be used on the rig to move the tubing conveyed guns up the hole along with the SLT work string **38** as joints are removed from workstring **116**.

## DESCRIPTION OF OPERATION

**[0089]** A single or series of Completion Logic Tools (CLT's), aka the completion, may be positioned in well casing, as in FIG. **7***a*, **7***b*, or **7***c*, or in open hole, or may be cemented in open hole. The objective is to activate any type of CLT, examples are shown in FIG. **2**, **3**, **4**, **5**, **6**, **7**, **8** or **9**, by conveying into the well a service Fluid Logic Tool (SLT) by anyone of the above mentioned conveying methods or by running the SLT in place with some other part of the completion and making a connection at a later time. A particular SLT may be run that only activates a particular type of CLT or series of CLT's. A particular SLT may be run to activate all CLT's.

**[0090]** A typical operational sequence may be conveying the SLT to the bottom of the completion. Once the SLT is below the lowermost CLT, fluid is circulated down the workstring and into the SLT flow path **10**, see FIG. **1**. Flow rate and pressure are maintained while moving the workstring upward to activate the first CLT. As an option, when the SLT enters a restriction **42** between orifice **39** and **40**, see FIG. **1**, a pressure change and flow rate change will occur signaling the operator of the position of the SLT relative to the inside of the CLT. The presence of the orifice **39** or **40** will provide increased flow, at a rate predetermined by surface tests. Also, the longitudinal spacing between orifice and number of orifice will provide a "finger print" that identifies the CLT to be activated. Once it is verified that the SLT is in the proper CLT, the SLT is moved slowly upward until the porting arrangements between the CLT and SLT sufficiently match to create a flow path to the piston **4**, FIG. **1**, of the CLT.

**[0091]** As shown in FIG. **1**, the fluid will enter port **8**, act on the piston **4**, shear and move the piston while fluid above the piston exits port **7** allowing the piston to move and begin the actuation process of the CLT. Of course the flow path can be reversed to enter flow Path **7** and exit port **8** to move the piston back the other direction if it may be desired to de-activate or re-cock a CLT. The pressure required to move the piston will vary depending on the piston area, frictional forces, shear screw value, etc. The piston can be designed to completely move across port **7** to create a flow path from port **8** to **7** to achieve return fluid up through flow path **17** so that returns can be sensed at the surface. The return fluid can act as a tell-tale that the piston has shifted.

**[0092]** It should be understood that application of surface pressure into the workstring may cause the workstring to elongate therefore longitudinal spacing of the ports may have to be lengthened, or adjusted, to compensate for tubing movement. Or it may be necessary move the workstring up or down to compensate for tubing movement due to an increase in pressure inside the workstring.

**[0093]** Another operational sequence may be to "sweep" the SLT upward through the CLT or CLT's. In this case, the workstring is slowly moved upward while pumping down the workstring at a constant pressure and flow rate. Pressure is maintained high enough to shift the pistons and activate the CLT's. The spacing of the ports is such that pressure is applied long enough to the CLT's to fully activate the CLT's while the workstring continues its motion upward. Movement of the SLT can be either up or down, if desired.

**[0094]** FIGS. **7***a*, **7***b*, and **7***c* show a typical completion in a zone with a packer, a sliding sleeve, and a perforating gun. An operational sequence may be to move the SLT to set the CLT packer, then open the CLT sliding sleeve, then detonate the CLT perforating gun, then move the SLT to straddle the sliding sleeve, then pump a frac job into the formation, next reverse out, and last, close the sliding sleeve. In this case, not shown, a sand control screen can be positioned in close proximity to the perforating guns. The sand control screen may be shut off with sliding sleeves to prevent production flow and reopened at a later time.

**[0095]** To better understand the operation of the SLT in a CLT it is beneficial to explain how to achieve pressure and flow rate necessary to activate a CLT. Fluid can be pumped down the workstring in terms of gallons per minute (GPM). The GPM is based on the typical size of fluid pumps on rigs. Typically most rigs have 5 BPM mud pumps so the objective is to generate at least 3000 PSI at the CLT using a mud pump. Typically packers are set or activated with pressures in the range from 2500 PSI to 4000 PSI. About 3000 PSI can be achieved with 105 gal/min. With 42 gallons in a barrel, a pump rate of 2.5 BPM is needed to achieve 3000 PSI. Further testing should show that pump rates higher than 2.5 BPM will generate pressures up to 4000 PSI with ¼" diameter orifice. This is static pressure at the tool even though fluid is leaking around the O.D. of the SLT. In some cases, it may be necessary to calculate surface applied pressure in combination with well hydrostatic pressures to determine actual pressure at the tool. For salt water, the weight of the fluid is 0.5 PSI/foot, so in a 10,000 foot well hydrostatic pressure could be 5,000 PSI. Depending on the fluid position in the tubing and annulus, hydrostatic pressure may have to be added or subtracted from the surface applied pressure to get actual pressure at the CLT.

**[0096]** Orifice size communicating with the Piston in the CLT needs to be of sufficient size to supply fluid volume necessary to move the piston up or down. The smaller the orifice, the longer it will take the piston to move due to volume displacement. A ¼" size orifice was used in a test because that is a typical size of orifice used in hydraulic set packers when the packers are set by application of tubing pressure. Flow rate formulae, such as Flow Rate=Orifice Area×Velocity, and other formulae, can be used to calculate the flow rate required to make a piston move within a specified time range.

**[0097]** Of course the piston moves when pressure is applied to a specific area on the piston, and the piston can be shear-pinned to shear at a specified pressure. This is important if the SLT is sweeping through the CLT. Seal spacing is lengthened or shortened based on the speed the SLT is moving through the CLT and also based on tubing stretch calculations.

**[0098]** Seal spacing may be increased to compensate for tubing elongation when pressure is applied to the tubing. A simple formulae $\Delta P=12Et\Delta L/[RL(0.5-v)]$, from "Roark's Formulas For Stress and Strain", seventh addition, is used to calculate the workstring movement with applied surface pressure.

**[0099]** If the SLT is run un-anchored, i.e., tubing movement can occur, then the seal spacing on each side of the port in the SLT may be increased and the bore length on each side of the receiving port in the CLT may be increased, to assure that the SLT properly communicates with the CLT. If the SLT has an anchoring device on the workstring, then the seal and bore spacing can be reduced since very little tubing movement will occur at the SLT when pressure is applied.

**[0100]** Referring to FIG. **1**, if pumping down the workstring, it would be desired that the input flow area at point **16** must always be greater than the flow area at orifice **8**+the annular flow area around the SLT and inside the CLT at seal **31**, if seal point **31** is a leaking type seal. If multiple seal location are leaking type seals, i.e., seals **30**, **31**, and **32**, then these flow areas plus the orifice flow areas must be greater than the input flow area at point **28**. If pumping down the annulus at point **18**, then input flow area thru port **17** must be greater than the orifice **7** flow area+the annular flow area past any seals or restrictions around the SLT.

**[0101]** In summary, in order to build pressure on the piston **4**, the input flow areas must provide enough flow to achieve an adequate pressure increase at the piston, or activating device, in order to activate a CLT. For example, if the piston **4**, or activating device, requires 3,000 PSI to begin the activation process of a CLT, then input flow area must be great enough to achieve this pressure increase while also giving up fluid at any leak path locations around the SLT. Of course, if the seals **30**, **31**, and **32** are non-leaking type seals then the fluid input requirements at point **16** may be reduced in order to activate a CLT device.

**[0102]** The above formulae may be expanded if additional orifice means at point **8** are present. For example, if there are three pistons programmed into the fluid path geometry, each having an orifice arrangement on each side of the pistons. Each piston actuates a different downhole device at a single position of the SLT. The input flow area at **28**, must then be great enough to supply multiple orifice and multiple leaking seal paths.

**[0103]** The above also applies to the position finding orifice **39** and **40**. The input flow area at location **28** needs to be of sufficient size to achieve a pressure change at the surface when the SLT passes through bore **42** and crosses orifice **39** or **40**. Furthermore, the flow area through balance port **117**, should be of sufficient size to balance pressure above and below the SLT, if the SLT is not anchored in position. Ideally flow area **117** should be greater than input flow area **28**, but may not be absolutely necessary.

**[0104]** The above discussion primarily relates to activating a CLT with a SLT. Referring to FIG. **3**, where the SLT moves to a gravel packing, acidizing, or frac position, in this case inside of a sliding sleeve **45** (FIG. **2**), flow area **10** must be of sufficient size to handle to require fluid volume to achieve stimulation of the well formation. For example, the flow area I.D. at **10** may have to have a 1.5" I.D. to allow a pump rate of 15 BPM through the tool and into the formation **50**. Of course, the flow area can be adjusted to the size needed to achieve the required flow rate based on the available room inside of the CLT. It should also be understood that a SLT can be custom designed to apply pressure to the inside of any type of completion tool other than a CLT, if the completion tool geometry can be matched between the SLT and the completion tool.

**[0105]** For those who understand the art of completing wells, it should be apparent that many combinations of CLT's can be created and that the SLT has great flexibility to operate in deferent types of hookups or completions.

**[0106]** The invention being thus described, it will be obvious that the same may be varied in many ways. Such variations are not to be regarded as a departure from the spirit and scope of the invention, and all such are intended to be included within the scope of the non-limiting claims.

What is claimed and desired to be secured by Letters Patent is:

**1**) An operating tool using programmed fluid logic applied through an operating fluid for use in a subterranean well and activatable by use of an operating conduit having first and second flow paths therein communicating with a source for said operating fluid to manipulate one or more secondary tools within said well, comprising:

(1) an outer member carried into said well on a first tubular conduit including an outer cylindrical housing and an inner cylindrical housing, and defining a fluid chamber between said housings;

(2) an inner member positionable within said outer member and carried into said well on a second tubular conduit;

(3) an activation sleeve disposed within said outer member and selectively moveable therein in at least one direction to manipulate an auxiliary device within said well;

(4) a piston head in selective operative communication with said sleeve and defining first and second piston head surfaces;

(5) a plurality of orifice means, one of said orifice means being in communication with one of said piston head surfaces, and another of said orifice means in communication with the other of said piston head surfaces, each of said orifice means including at least one orifice profile defined on at lest one of said outer and inner members, said orifice means providing sufficient operating fluid flow and pressure at said piston head to manipulate said activating sleeve; and

(6) a plurality of fluid transmitting ports disposed through the inner cylindrical housing for transmitting the programmed fluid logic in the operating fluid at a predetermined flow rate and pressure delivered by the operating conduit within one of the operating tool flow paths, through the orifice means into one of said ports and upon one of said piston head surfaces, to move said piston

head and said activation sleeve in one direction and during said movement, to direct fluid in said chamber adjacent the second piston head surface out of said chamber through another of said fluid transmitting ports, thence into the second flow path of the operating conduit.

**2**) An operating tool using programmed fluid logic applied through an operating fluid for use in a subterranean well and activatable by use of an operating conduit having first and second flow paths therein communicating with a source for said operating fluid to manipulate a plurality of secondary tools within said well, comprising:

(1) an outer member carried into said well on a first tubular conduit including an outer cylindrical housing and an inner cylindrical housing, and defining a fluid chamber between said housings;

(2) an inner member positionable within said outer member and carried into said well on a second tubular conduit;

(3) a plurality of activation sleeves disposed within said outer member, each said sleeve being independently and selectively moveable therein in at least one direction to manipulate an associated auxiliary device within said well;

(4) a piston head carried on each said sleeve and defining first and second piston head surfaces;

(5) a plurality of orifice means associated with each of said piston heads, one of each of said orifice means being in communication with one of each of said piston head surfaces, and another of said orifice means in communication with the other of each of said piston head surfaces, each of said orifice means including at least one orifice profile defined on at least one of said outer and inner members, said orifice means providing sufficient but varying operating fluid flows at pre-determined pressures at each of said piston heads to manipulate said associated activating sleeve; and

(6) a plurality of fluid transmitting ports disposed through the inner cylindrical housing for transmitting the programmed fluid logic in the operating fluid at specific flow rates and pressures delivered by the operating conduit within one of the operating tool flow paths, through the respective orifice means into one of said respective said ports and upon one of said piston head surfaces, to move the respective said piston head and said respective activation sleeve in one direction and during said movement, to direct fluid in said respective chamber adjacent a second piston head surface out of said chamber through another of said fluid transmitting ports, thence into the second flow path of the operating conduit.

**3**) An operating tool using programmed fluid logic applied through an operating fluid for use in a subterranean well and activatable by use of an operating conduit having first and second flow paths therein communicating with a source for said operating fluid to manipulate one or more secondary tools within said well, comprising:

(1) an outer member carried into said well on a first tubular conduit including an outer cylindrical housing and an inner cylindrical housing, and defining a fluid chamber between said housings;

(2) an inner member positionable within said outer member and carried into said well on a second tubular conduit;

(3) an activation sleeve disposed within said outer member and selectively moveable therein in at least one direction to manipulate an auxiliary device within said well;

(4) pressure differential sensitive means in selective operative communication with said sleeve;

(5) a plurality of orifice means, each of said orifice means being in communication with said pressure differential sensitive means, each of said orifice means including at least one orifice profile defined on at lest one of said outer and inner members, said orifice means providing sufficient operating fluid flow and pressure at said pressure differential sensitive means to selectively manipulate said activating sleeve; and

(6) a plurality of fluid transmitting ports disposed through the inner cylindrical housing for transmitting the programmed fluid logic in the operating fluid at a flow rate and pressure within one of the operating tool flow paths, through the orifice means into one of said ports and upon said pressure differential sensitive means, to operatively communicate said pressure differential sensitive means with said activation sleeve to move said sleeve in one direction and during said movement, to direct fluid in said chamber adjacent said pressure differential sensitive means out of said chamber through another of said fluid transmitting ports, thence into the second flow path.

**4**) An operating tool using programmed fluid logic applied through an operating fluid for use in a subterranean well and activatable by use of said operating tool having first and second flow paths therein to manipulate a plurality of auxiliary devices within said well, comprising:

(1) an outer member carried into said well on a first tubular conduit including an outer cylindrical housing and an inner cylindrical housing, and defining a fluid chamber between said housings;

(2) an inner member positionable within said outer member and carried into said well on a second tubular conduit;

(3) a plurality of activation sleeves disposed within said outer member, each said sleeve being independently and selectively moveable therein in at least one direction to manipulate an associated auxiliary device within said well;

(4) pressure differential sensitive means in selective separate operative communication with each said sleeve;

(5) a plurality of orifice means associated with each of said pressure differential sensitive means, each of said orifice means including at least one orifice profile defined on at lest one of said outer and inner members, said orifice means providing sufficient but varying operating fluid flow rates at pressures at each of said pressure differential sensitive means sufficient to move an associated activating sleeve in a direction to manipulate an associated auxiliary device in said well; and

(6) a plurality of fluid transmitting ports disposed through the inner cylindrical housing for transmitting the programmed fluid logic in the operating fluid at flow rates and pressures within one of the operating tool flow paths, through the respective orifice means into one of said respective said ports and upon one of said pressure differential sensitive means, during manipulation of the respective said pressure differential sensitive means and said respective activation sleeve in one direction and during said manipulation, to direct fluid in said respec-

tive chamber adjacent a second pressure differential sensitive means out of said chamber through another of said fluid transmitting ports, thence into the second flow path.

**5**) An operating tool using programmed fluid logic applied through an operating fluid for use in a subterranean well and activatable by use of an operating device having first and second flow paths therein communicating with a source for said operating fluid to perform a service operation within said well, comprising:

(1) an outer member carried into said well on a first tubular conduit including an outer cylindrical housing and an inner cylindrical housing, and defining a fluid chamber between said housings;

(2) an inner member positionable within said outer member and carried into said well on a second conduit;

(3) activation means disposed within said outer member and selectively moveable therein in at least one direction to initiate said service operation within said well;

(4) pressure differential sensitive means in selective operative communication with said activation means;

(5) a plurality of orifice means, each of said orifice means being in communication with said pressure differential sensitive means, each of said orifice means including at least one orifice profile defined on at lest one of said outer and inner members, said orifice means providing sufficient operating fluid flow and pressure at said pressure differential sensitive means to selectively initiate said service operation; and

(6) a plurality of fluid transmitting ports disposed through the inner cylindrical housing for transmitting the programmed fluid logic in the operating fluid at a flow rate and pressure delivered within one of the operating tool flow paths, through the orifice means into one of said ports and upon said pressure differential sensitive means, to operatively communicate said pressure differential sensitive means with said activation means to move said means in one direction and during said movement, to direct fluid in said chamber adjacent said pressure differential sensitive means out of said chamber through another of said fluid transmitting ports, thence into the second flow path as the service operation is performed.

**6**) An operating tool using programmed fluid logic applied through an operating fluid for use in a subterranean well and activatable by use of an operating conduit having first and second flow paths therein communicating with a source for said operating fluid to perform a service operation within said well, comprising:

(1) an outer member carried into said well on a first tubular conduit including an outer cylindrical housing and an inner cylindrical housing, and defining a fluid chamber between said housings;

(2) an inner member positionable within said outer member and carried into said well on a second tubular conduit;

(3) activation means disposed within said outer member and selectively moveable therein in at least one direction to initiate said service operation within said well;

(4) pressure differential sensitive means in selective operative communication with said activation means;

(5) a plurality of orifice means, each of said orifice means being in communication with said pressure differential sensitive means, each of said orifice means including at least one orifice profile defined on at lest one of said outer and inner members, said orifice means providing sufficient operating fluid flow and pressure at said pressure differential sensitive means to selectively initiate said service operation; and

(6) a plurality of fluid transmitting ports disposed through the inner cylindrical housing for transmitting the programmed fluid logic in the operating fluid at a flow rate and pressure delivered to the operating tool and within one of the operating tool flow paths, through the orifice means into one of said ports and upon said pressure differential sensitive means, to operatively communicate said pressure differential sensitive means with said activation means to manipulate said activation means to direct fluid in said chamber adjacent said pressure differential sensitive means out of said chamber through another of said fluid transmitting ports, thence into the well as the service operation is performed.

**7**) An operating tool using programmed fluid logic applied through an operating fluid for use in a subterranean well and activatable by use of an operating conduit having first and second flow paths therein communicating with a source of a second operating fluid to perform a service operation within said well, comprising:

(1) an outer member carried into said well on a first tubular conduit including an outer cylindrical housing and an inner cylindrical housing, and defining a fluid chamber between said housings;

(2) an inner member positionable within said outer member and carried into said well on a second tubular conduit;

(3) activation means disposed within said outer member and selectively moveable therein in at least one direction to initiate said service operation using said second operating fluid within said well;

(4) pressure differential sensitive means in selective operative communication with said activation means;

(5) a plurality of orifice means, each of said orifice means being in communication with said pressure differential sensitive means, each of said orifice means including at least one orifice profile defined on at lest one of said outer and inner members, said orifice means providing sufficient operating fluid flow and pressure at said pressure differential sensitive means to selectively initiate said service operation; and

(6) a plurality of fluid transmitting ports disposed through the inner cylindrical housing for transmitting the programmed fluid logic in the operating fluid at a flow rate and pressure delivered to the operating tool and within one of the operating tool flow paths, through the orifice means into one of said ports and upon said pressure differential sensitive means, to operatively communicate said pressure differential sensitive means with said activation means to manipulate said activation means to direct said operating fluid in said chamber adjacent said pressure differential sensitive means out of said chamber through another of said fluid transmitting ports, thence to direct said second operating fluid through the well as the service operation is performed.

**8**) An operating tool using programmed fluid logic applied through an operating fluid for use in a subterranean well and activatable by use of an operating conduit having first and second flow paths therein communicating with a source for said operating fluid at the top of the well to perform a service operation within said well, comprising:

(1) an outer member carried into said well on a first tubular conduit including an outer cylindrical housing and an inner cylindrical housing, and defining a fluid chamber between said housings;

(2) an inner member positionable within said outer member and carried into said well on a second tubular conduit;

(3) an activation sleeve disposed within said outer member and selectively moveable therein in at least one direction to initiate said service operation within said well;

(4) pressure differential sensitive means in selective operative communication with said activation sleeve;

(5) a plurality of orifice means, each of said orifice means being in communication with said pressure differential sensitive means, each of said orifice means including at least one orifice profile defined on at lest one of said outer and inner members, said orifice means providing sufficient and pre-determined operating fluid flow and pressure at said pressure differential sensitive means to selectively initiate said service operation; and

(6) a plurality of fluid transmitting ports disposed through the inner cylindrical housing for transmitting the programmed fluid logic in the operating fluid at a predetermined flow rate and pressure delivered through the operating conduit to the operating tool and within one of the operating tool flow paths, through the orifice means into one of said ports and upon said pressure differential sensitive means, to operatively communicate said pressure differential sensitive means with said activation sleeve to manipulate said activation sleeve to direct operative fluid in said chamber adjacent said pressure differential sensitive means out of said chamber through another of said fluid transmitting ports, thence into the well as the service operation is performed.

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