CLAIMS

What is claimed is:

1. A downhole hydraulic jetting assembly for forming lateral bore holes within a subsurface formation from a parent wellbore, the parent wellbore having an inner diameter, and the jetting assembly comprising:

an internal system comprising:

a jetting hose having a proximal end and a distal end; and

a jetting nozzle disposed at the distal end of the jetting hose; and

an external system comprising:

a first elongated tubular body defining an outer conduit, the outer conduit having an upper end configured to be operatively attached to a tubing conveyance medium for running the assembly into the wellbore, a lower end, and an internal bore there between;

a second elongated tubular body residing within the bore of the outer conduit and defining a jetting hose carrier, the jetting hose carrier being dimensioned to slidably receive the jetting hose;

a micro-annulus formed between the jetting hose and the surrounding jetting hose carrier, the micro-annulus being sized to prevent buckling of the jetting hose as it slides within the jetting hose carrier during operation of the assembly; and

a whipstock member disposed proximate the lower end of the outer conduit, the whipstock member having an arcuate face;

wherein the assembly is configured to (i) translate the jetting hose out of the jetting hose carrier and against the whipstock face by a translation force, and then (ii) pull the jetting hose back into the jetting hose carrier after a lateral borehole has been formed.

2. The downhole hydraulic jetting assembly of claim 1, wherein:

the translation force comprises a mechanical force;

the jetting hose is at least 10 feet in length; and

the assembly further comprises an internal tractor system residing downstream from the lower end of the outer conduit, the internal tractor system comprising:

an inner conduit portion defining a part of the jetting hose carrier for receiving the jetting hose;

an outer conduit portion defining a part of the outer conduit, the outer conduit portion defining a plurality of radially-disposed prongs;

a wiring chamber housing electrical wires, data cables, or both within one of the plurality of prongs; and

at least one pair of grippers residing within opposing prongs, with each gripper being configured to engage and mechanically move the jetting hose along the jetting hose carrier when rotatably actuated.

3. The hydraulic jetting assembly of claim 2, wherein:

each prong of the outer conduit portion provides an inner chamber around the inner conduit portion;

a first of the inner chambers is configured to conduct the jetting fluid down the assembly;

a second of the inner chambers is configured to house the electrical wires, data cables, or both; and

at least third and fourth opposing inner chambers house each of the grippers.

4. The hydraulic jetting assembly of claim 3, wherein:

each of the grippers has a concave face configured to frictionally engage an outer diameter of the jetting hose; and

each of the grippers is part of a gripper assembly comprising an electrical motor which is geared to rotationally drive the grippers as the grippers engage and translate the jetting hose.

5. The hydraulic jetting assembly of claim 4, wherein:

the outer conduit portion has a star-shaped profile; and

each of the inner chambers has a near-triangular shaped profile.

6. The hydraulic jetting assembly of claim 4, wherein:

an external distance from end-to-end of opposing inner chambers is dimensioned to substantially centralize the internal tractor system in the parent wellbore; and

the jetting hose is at least 25 feet in length.

7. The downhole hydraulic jetting assembly of claim 1, wherein:

the translation force comprises a hydraulic force;

the jetting hose is at least 10 feet in length; and

the assembly further comprises:

a main control valve residing between the tubing conveyance medium and the upper end of the outer conduit, the main control valve being movable between a first position and a second position, wherein in the first position the main control valve directs jetting fluids pumped into the wellbore into the jetting hose, and in the second position the main control valve directs hydraulic fluid pumped into the wellbore into an annular region formed between the jetting hose carrier and the surrounding outer conduit.

8. The downhole hydraulic jetting assembly of claim 7, further comprising:

an upper seal assembly connected to the jetting hose at an upper end and sealing the micro-annulus;

a jetting hose pack-off section connected to an inner diameter of the inner conduit and sealing the micro-annulus proximate a lower end of the inner conduit, and slideably receiving the jetting hose; and

a pressure regulator valve placed along the micro-annulus controlling fluid pressure within the micro-annulus;

wherein the assembly is configured such that:

placement of the main control valve in its first position allows an operator to pump jetting fluids into the tubing conveyance medium, through the main control valve, and against the upper seal assembly in the micro-annulus, thereby pistonly pushing the jetting hose and connected nozzle downhole in an uncoiled state while directing jetting fluids through the nozzle; and

placement of the main control valve in its second position allows an operator to pump hydraulic fluids into the tubing conveyance medium, through the main control valve, into the annular region between the jetting hose carrier and the surrounding outer

conduit, through the pressure regulator valve and into the micro-annulus, thereby pulling the jetting hose back up into the inner conduit in its uncoiled state.

9. The downhole hydraulic jetting assembly of claim 8, wherein:

the micro-annulus defines an elongated pressure chamber formed between the movable upper seal assembly and the jetting hose pack-off section;

the main control valve resides proximate an upper end of the outer conduit; and

the jetting hose carrier is dimensioned to hold the jetting hose from the upper sealing assembly down proximate to the jetting nozzle when the assembly is in a run-in position.

10. The hydraulic jetting assembly of claim 9, wherein the pressure regulator valve is configured such that:

(i) when pressure is released from the micro-annulus and fluids are injected through the main control valve in its first position, the upper seal assembly glides down an inner bore of the jetting hose carrier while still sealing, thereby pushing the jetting hose forward through the jetting hose carrier without buckling; and

(ii) when pressure is increased in the micro-annulus by the injection of fluids through the main control valve in its second position, increased fluid pressure against the upper seal assembly urges the jetting hose to glide back up the jetting hose carrier.

11. The hydraulic jetting assembly of claim 10, wherein:

the jetting hose is at least 25 feet in length;

a controlled release of fluids from the micro-annulus and through the pressure regulator valve regulates the jetting hose's rate of descent down-the-hole; and

a controlled intake of fluids through the regulator valve and into the micro-annulus regulates the jetting hose's rate of ascent up-the-hole.

12. The downhole hydraulic jetting assembly of claim 11, wherein:

the translation force comprises both the hydraulic force and a mechanical force; and

the assembly further comprises an internal tractor system residing downstream from the lower end of the outer conduit, the internal tractor system comprising:

an inner conduit portion defining a part of the jetting hose carrier for receiving the jetting hose;

an outer conduit portion defining a part of the outer conduit, the outer conduit portion having a star-shaped profile defining a plurality of radially-disposed prongs;

a wiring chamber housing electrical wires, data cables, or both within one of the plurality of prongs; and

at least one pair of grippers residing within opposing prongs, with each gripper being configured to engage and mechanically move the jetting hose along the jetting hose carrier when rotatably actuated.

13. The hydraulic jetting assembly of claim 12, wherein:

each of the grippers has a concave face configured to frictionally engage an outer diameter of the jetting hose; and

each of the grippers is part of a gripper assembly comprising an electrical motor which is geared to rotationally drive the grippers and translate the jetting hose into and out of the inner conduit portion as the grippers engage the jetting hose.

14. The hydraulic jetting assembly of claim 1, wherein the whipstock member is movable from a first run-in position to a second set and operating position, with the face of the whipstock member being configured to receive the nozzle and connected jetting hose in its set position as the jetting hose is advanced along the jetting hose carrier, and then direct the nozzle against the surrounding wellbore inner diameter to form a window.

15. The hydraulic jetting assembly of claim 14, wherein:

the wellbore is completed with a string of production casing;

the window is a casing exit;

the inner diameter is an inner diameter of the production casing; and

the face of the whipstock member generates a minimum bend radius for the jetting hose that is less than or equal to the inner diameter of the wellbore.

16. The hydraulic jetting assembly of claim 15, wherein the face of the whipstock member generates a bend radius for the jetting hose across the entire inner diameter of the production casing.

17. The hydraulic jetting assembly of claim 16, wherein:

the tubing conveyance medium comprises a string of coiled tubing;

the coiled tubing carries electrical wires, data cables, or combinations thereof along its length;

the internal system further comprises a battery pack for providing power to electrical components within the assembly, the battery pack residing at the proximal end of the jetting hose; and

the assembly further comprises a docking station located at an upper end of the external system configured to mate with the battery pack, the docking station having a processor and being in communication with an operator at the surface by means of the electrical wires, the data cables or both of the string of coiled tubing.

18. The hydraulic jetting assembly of claim 17, wherein the string of coiled tubing comprises a wall or a sheath that houses the electrical wires, the data cables, or both along its length, extending down to the docking station.

19. The hydraulic jetting assembly of claim 17, wherein the battery pack comprises:

a series of batteries located in an elongated, fluid-sealed housing; and

an end cap located at each of opposing ends of the battery pack, wherein the end caps are shaped to deflect jetting fluid during operation of the assembly.

20. The hydraulic jetting assembly of claim 19, wherein the docking station houses a micro-processor, a micro-transmitter, a micro-receiver, electrical current regulators, or combinations thereof.

21. The hydraulic jetting assembly of claim 20, wherein the docking station is configured to transfer: (1) power to the battery pack, said power either originating from generation at the

surface, or from generation by a mud turbine below the whipstock member, said power being transmitted via electrical wiring provided along the external system; and (2) data to and from the micro-transmitter and micro-receiver in the docking station, between an at least one geo-spatial chip housed at or near the nozzle and the operator at the surface.

22. The hydraulic jetting assembly of claim 21, further comprising:

at least three longitudinally oriented actuator wires connected to a distal end of the jetting nozzle, the actuator wires being equi-distantly spaced about the circumference of the jetting hose at its distal end, and further being configured to contract in response to electrical current sent through the actuator wires, whereby differing amounts of electrical current directed through the actuator wires will induce a bending moment to orient the jetting nozzle; and

wherein the micro-processor is configured to control electrical current regulators feeding current to the respective actuator wires, and thus control a geo-orientation of the nozzle for directional hydraulic boring.

23. The hydraulic jetting assembly of claim 22, wherein:

the geo-location signals of the at least one geo-spatial chip are indicative of both the location and orientation of the jetting nozzle, such signals being transmitted as data from the geo-spatial chip to the micro-receiver in the battery pack via the electrical wiring, the data cables, or both, bundled in the jetting hose;

contraction of each of the actuator wires is in direct proportion to an amount of electrical current each wire receives, thereby enabling geo-steering of the nozzle; and

wherein the actuator wires are fabricated from a material comprising nickel, titanium or a combination thereof.

24. The hydraulic jetting assembly of claim 23, wherein

the micro-transmitter housed in the battery pack's end cap is configured to wirelessly transmit the data received from the micro-receiver to a micro-receiver housed in the docking station; and

the docking station is configured to further transmit the data to a processor at the surface (i) wirelessly, (ii) via electrical wires bundled in the coiled tubing, or (iii) via data cables bundled in the coiled tubing.

25. The hydraulic jetting assembly of claim 24, wherein the bending moment applied to the distal end of the jetting hose is configured to be controlled by an operator at the surface through the delivery of geo-location signals sent to a micro-transmitter in the docking station through (i) wireless signals sent downhole, (ii) the electrical wires bundled in the coiled tubing, or (iii) the data cables bundled in the coiled tubing, such geo-location signals adjusting the current being transmitted through the actuator wires.

26. The hydraulic jetting assembly of claim 24, wherein:

the electrical wiring along the jetting hose originates within housing or the end caps of the battery pack, and is conducted by elongated columnar supports connecting the battery pack to the jetting hose;

the columnar supports have a length tuned to separate the batteries from a fluid inlet at an upper end of the jetting hose; and

the columnar supports are spaced apart to provide an inlet flow area for the jetting fluid, after the jetting fluid is pumped down an annular region between the battery pack and the inner conduit.

27. The hydraulic jetting assembly of claim 16, wherein:

the upper seal assembly resides downstream of the battery pack; and

the jetting hose carrier comprises a continuous wiring chamber providing electrical connection from the docking station to electrical components below the whipstock member.

28. The hydraulic jetting assembly of claim 16, further comprising:

a tractor disposed below the whipstock member configured to convey the assembly along a horizontal or highly deviated portion of the wellbore;

a mud motor also disposed below the whipstock member for receiving hydraulic fluid from the string of coiled tubing, and converting it to electrical power; and

a logging tool also disposed below the whipstock member powered by electricity sourced from the mud motor, a power generation source located at the surface, or both.

29. The hydraulic jetting assembly of claim 28, further comprising:
a packer or a retrievable bridge plug located below the whipstock member.

30. The hydraulic jetting assembly of claim 28,wherein:
the translation force comprises a hydraulic force;
the jetting hose is at least 25 feet in length; and
the assembly further comprises:
a main control valve residing between the tubing conveyance system and the upper end of the outer conduit, the main control valve being movable between a first position and a second position, wherein in the first position the main control valve directs jetting fluids pumped into the wellbore into the jetting hose, and in the second position the main control valve directs hydraulic fluid pumped into the wellbore into an annular region formed between the jetting hose carrier and the surrounding outer conduit.

31. The hydraulic jetting assembly of claim 30, wherein the logging tool comprises a gamma ray log, a casing collar locator, a gyroscopic orientation tool, or combinations thereof.

32. The hydraulic jetting assembly of claim 30, wherein the coiled tubing itself is a component of a bundled product that comprises continuous strands of electrical wire, data cables, or both, residing within a sheath.

33. The hydraulic jetting assembly of claim 32, wherein the string of coiled tubing comprises:
a coiled tubing crossover connection member connecting the coiled tubing to the main control valve, whereby electrical wiring and data cables within the sheath are sealed and transferred into a wiring chamber within the main control valve.

34. The hydraulic jetting assembly of claim 30, wherein the main control valve comprises:

a jetting fluid passage for receiving the jetting fluid in the first position, and a hydraulic fluid passage for receiving the hydraulic fluid in the second position, wherein each of the jetting fluid passage and the hydraulic fluid passage run longitudinally along the main control valve and parallel to each other;

a wiring conduit for housing the electrical wires, the data cables, or both;

a motor;

a passage cover pivot powered by the motor; and

a sealing passage cover moved by the passage cover pivot in order to selectively direct the jetting fluid and the hydraulic fluid into the appropriate passage in response to signals from the operator at the surface.

35. The downhole hydraulic jetting assembly of claim 34, wherein the passage cover pivot comprises a biasing mechanism responsive to fluid pressure, wherein fluids flow through the hydraulic fluid passage at a first fluid pressure, and the biasing mechanism is overcome to move the sealing passage cover to the hydraulic fluid passage at a second greater pressure, thereby causing jetting fluids to flow into the jetting fluid passage.

36. The downhole hydraulic jetting assembly of claim 34, further comprising:

an upper seal assembly connected to the jetting hose at an upper end and sealing the micro-annulus;

a jetting hose pack-off section connected to an inner diameter of the inner conduit and sealing the micro-annulus proximate a lower end of the inner conduit, and slidably receiving the jetting hose; and

a pressure regulator valve placed along the micro-annulus controlling fluid pressure within the micro-annulus;

wherein the assembly is configured such that:

placement of the main control valve in its first position allows an operator to pump jetting fluids into the tubing conveyance system, through the main control valve, and against the upper seal assembly in the micro-annulus, thereby pistonly pushing the jetting hose and connected nozzle downhole in an uncoiled state while directing jetting fluids through the nozzle; and

placement of the main control valve in its second position allows an operator to pump hydraulic fluids into the tubing conveyance system, through the main control valve, into the annular region between the jetting hose carrier and the surrounding outer conduit, through the pressure regulator valve and into the micro-annulus, thereby pulling the jetting hose back up into the outer conduit in its uncoiled state.

37. The downhole hydraulic jetting assembly of claim 36, wherein the jetting hose pack-off section comprises:

an outer conduit portion defining a part of the outer conduit, the outer conduit portion having a plurality of prongs forming a star-shaped profile;

an inner conduit portion defining a part of the jetting hose carrier for slidably receiving the jetting hose; and

a series of seals residing within the inner conduit portion of the jetting hose pack-off section, sealing the jetting hose from pressure from an upstream direction, followed by an adjacent series of seals sealing the jetting hose from pressure from a downstream direction, both sets of seals resting between an upstream seal stop and a downstream seal stop, thereby limiting travel of the seals via attachment to the exterior of the jetting hose, with the seals serving as a downstream seal of the micro-annulus.

38. The downhole hydraulic jetting assembly of claim 37, wherein:

each of the plurality of prongs of the outer conduit portion of the jetting hose pack-off section provides for an inner chamber, the inner chambers being spaced equi-distant around the inner conduit portion of the jetting hose pack-off section;

the external distance from end-to-end of the prongs is dimensioned to substantially centralize the jetting hose pack-off section within the surrounding production casing;

one of the inner chambers is used to conduct hydraulic fluid down to the pressure regulator valve; and

another of the inner chambers houses a wiring chamber.

39. The downhole hydraulic jetting assembly of claim 36, further comprising:

an upper swivel residing between the jetting hose pack-off section and the whipstock member, the upper swivel having an upper transition section that transitions from a star-shaped profile to a circular profile, and a lower bearing section having bearings configured to permit relative rotational movement between the transition section and the whipstock member, and having a centralized passage configured to receive and guide the jetting hose into the whipstock member; and

a lower swivel residing below the whipstock member, the lower swivel having an upper bearing section also having bearings that permit relative rotational movement between the whipstock member and any tools connected below the lower swivel; and

wherein:

the bearings sections of the upper and lower swivels permit incremental rotational re-orienting of the whipstock member while precluding the transmission of torque upstream of the upper swivel and downstream of the lower swivel; and

each of the upper and lower swivels comprises a sheath residing between the jetting hose carrier and the surrounding outer conduit, the sheath housing (1) the electrical wiring chamber; and (2) a hydraulic chamber that transports hydraulic fluid.

40. The downhole hydraulic jetting assembly of claim 39, wherein the upper section of the upper swivel comprises a through-opening through which the jetting hose exits to encounter the face of the whipstock.

41. The downhole hydraulic jetting assembly of claim 40, wherein each of the upper and lower swivels comprises:

an outer tubular body;

a middle tubular body;

an inner tubular body; and

inner and outer bearings making up the bearing sections.

42. The hydraulic jetting assembly of claim 1, further comprising:

a retrievable bridge plug or a packer disposed below the whipstock member.

43. A jetting hose carrier system, comprising:

an elongated inner conduit dimensioned to slidably receive a jetting hose and serving as a jetting hose carrier, wherein a micro-annulus is formed between the jetting hose and the surrounding inner conduit, with the micro-annulus being dimensioned to prevent the jetting hose from buckling;

an elongated outer conduit encompassing the inner conduit, wherein an annular region is formed between the inner conduit and the surrounding outer conduit, the outer conduit being dimensioned to be run into a string of production casing within a wellbore while accommodating stimulation treatments through the annular region;

a wiring chamber housing electrical wires, data cables, or both within the annular region between the inner and outer conduits and running the length of the outer conduit;

a fluid chamber formed within the annular region, the fluid chamber having a flow area equivalence of at least 0.75 in^2 pipe diameter; and

a fluid pressure regulator valve residing proximate a distal end of the inner conduit, the pressure regulator valve being configured to move fluids between the fluid chamber and the micro-annulus to effectuate movement of the jetting hose within the inner conduit.

44. The jetting hose carrier system of claim 43, further comprising:

an upper seal assembly residing at an upstream end of the jetting hose, the upper seal assembly comprising one or more seals fixedly attached to an outer diameter of the jetting hose, and with the upper seal assembly being slidably movable within the inner conduit and forming an upstream boundary of the micro-annulus;

a jetting hose pack-off system comprising a series of stationary seals at a downstream end of the inner conduit, the stationary seals forming a downstream boundary of the micro-annulus;

and whereby the fluid pressure regulator valve is arranged so that hydraulic fluid can be injected into the micro-annulus above the jet hose pack-off system to propel the jetting hose in an upstream direction, and the hydraulic fluid can then be released from the micro-annulus through the pressure regulator valve, thereby controlling advancement of the jetting hose in a downstream direction.

45. A downhole hydraulic jetting assembly for forming lateral bore holes within a subsurface formation from an existing wellbore, the existing wellbore having an inner diameter, and the jetting assembly comprising:

an internal system comprising:

a jetting hose having a proximal end and a distal end; and

a jetting nozzle disposed at the distal end of the jetting hose; and

an external system comprising:

a first elongated tubular body defining an outer conduit, the outer conduit having an upper end configured to be operatively attached to a tubing conveyance system for running the assembly into the production casing, a lower end, and an internal bore there between;

a second elongated tubular body residing within the bore of the outer conduit and defining a jetting hose carrier, the jetting hose carrier slidably receiving the jetting hose;

a micro-annulus formed between the jetting house and the surrounding jetting hose carrier, the micro-annulus being sized to prevent buckling of the jetting hose as it slides within the jetting hose carrier during operation of the assembly; and

a whipstock member disposed below the lower end of the outer conduit, the whipstock member having an arcuate face;

wherein:

the assembly is configured to (i) translate the jetting hose out of the jetting hose carrier and against the whipstock face by a translation force to a desired point of wellbore exit, (ii) upon reaching the desired point of wellbore exit, direct jetting fluid through the jetting hose and the connected jetting nozzle until an exit is formed, (iii) continue jetting forming a lateral borehole into the subsurface formation, and then (iv) pull the jetting hose back into the jetting hose carrier after a lateral borehole has been formed by applying the translation force in a second opposite direction; and

the jetting nozzle comprises:

a rotor body having one or more fluid discharge ports for delivering jetting fluid from the jetting hose;

a stator body; and

wire-wrapped stator poles configured to induce an electromagnetic field about the rotor body upon receipt of electrical current, which thereby induces rotation of the rotor body at a rotational speed corresponding to an electrical current feed.

46. The downhole hydraulic jetting assembly of claim 45, wherein the electrical current feed is delivered through at least three longitudinally oriented electrically conductive power wires disposed equi-distantly about the jetting hose.

47. The downhole hydraulic jetting assembly of claim 46, wherein at least a distal portion of the electrically conductive power wires are fabricated from a material that, upon electrical excitement, will contract in proportion to the respective current feeds received therein such that differentiation of current feeds through the three power wires will cause a proportional contraction of the respective power wires, thus inducing a bending moment at the distal end of the jetting hose.

48. The downhole hydraulic jetting assembly of claim 47, wherein the electrically conductive power wires are fabricated from a conductive material comprising nickel, titanium or a combination thereof.

49. The downhole hydraulic jetting assembly of claim 47, wherein the jetting nozzle further comprises:

one or more geo-spatial chips located proximate the stator body; and

wherein the one or more geo-spatial chips is configured to determine orientation of the nozzle, and transmit real-time geo-location data through electrical wires or data cables to a wireless micro-transmitter upstream of the micro-annulus.

50. The downhole hydraulic jetting assembly of claim 49, further comprising:

a coiled tubing string for conveying the external system and the connected internal system from a surface into the wellbore; and

a battery pack associated with the internal system configured to provide the electrical feed;

and wherein:

the micro-transmitter resides proximate the battery pack;

the external system further comprises a docking station configured to dock with the battery pack and to communicate with the micro-transmitter; and

the geo-location data is transmitted wirelessly by the micro-transmitter to a micro-receiver within the docking station, then relayed to the surface through electrical wires or through data cables provided along the coiled tubing string, or to the surface wirelessly.

51. The downhole hydraulic jetting assembly of claim 50, wherein the geo-location data is processed (i) through a micro-processor located in the internal system's battery pack, (ii) through a microprocessor located in the external system's docking station, or (iii) in a surface control system.

52. The downhole hydraulic jetting assembly of claim 51, wherein, in response to receipt of geo-location data at the surface, the assembly is configured to permit the operator or surface control system to send instructions to the docking station downhole to send new rates of electrical current feed to the power wires to induce bending moments toward the distal end of the jetting hose hosting the jetting nozzle, thereby permitting the operator to:

vary the orientation and inclination of the jetting nozzle, in real time, as it is discharges jetting fluid and generates a path of a lateral borehole; and

vary rotational speed of the jetting nozzle;

thereby achieving a desired lateral borehole path and penetration rate within a host pay zone.

53. The downhole hydraulic jetting assembly of claim 49, wherein the geo-location data is sent to a control system at the surface that is configured to process the geo-location data and, in response, generate signals to adjust the electrical current feed to the power wires according to a pre-programmed geo-trajectory of a lateral borehole.

54. The downhole hydraulic jetting assembly of claim 51, wherein:

the translation force comprises a hydraulic force;

the jetting hose is at least 25 feet in length;

the assembly further comprises:

a main control valve residing between the tubing conveyance system and the upper end of the outer conduit, the main control valve being movable between a first position and a second position, wherein in the first position the main control valve directs jetting fluids pumped into the wellbore into the jetting hose, and in the second position the main control valve directs hydraulic fluid pumped into the wellbore into an annular region formed between the jetting hose carrier and the surrounding outer conduit;

an upper seal assembly connected to the jetting hose at an upper end and sealing the micro-annulus;

a jetting hose pack-off section connected to an inner diameter of the inner conduit and sealing the micro-annulus proximate a lower end of the inner conduit, and slidably receiving the jetting hose; and

a fluid intake funnel located at an upstream end of the jetting hose, the fluid intake funnel being configured to receive jetting fluids into the jetting hose when the main control valve is in its first position; and

wherein the micro-annulus is bounded at its upstream end by an interface of seals of the upper seal assembly, these upstream seals being movable within the inner conduit, and at its downstream end by seals of the jetting hose pack-off section, these downstream seals remaining generally stationary relative to the wellbore during operation.

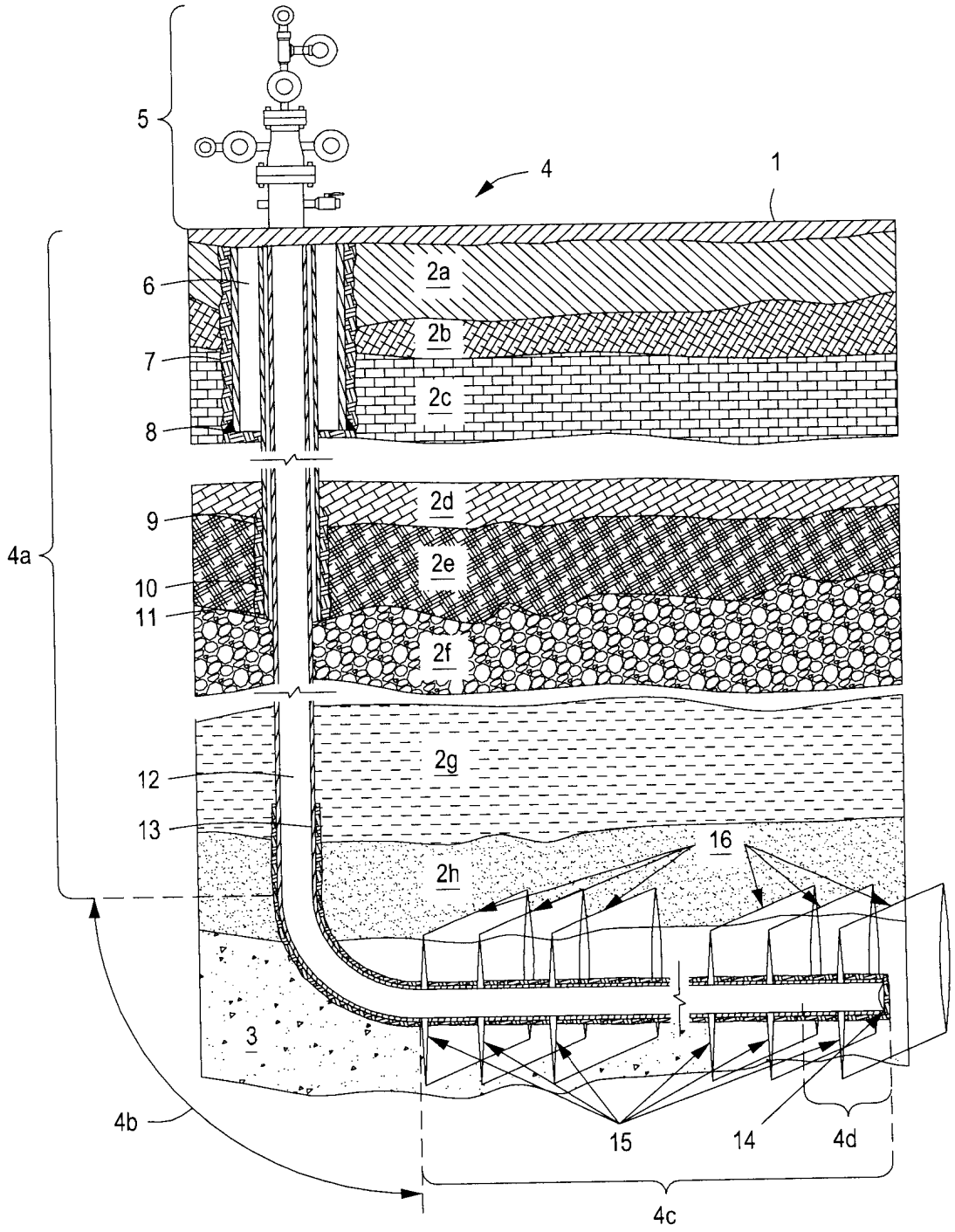


FIG. 1A

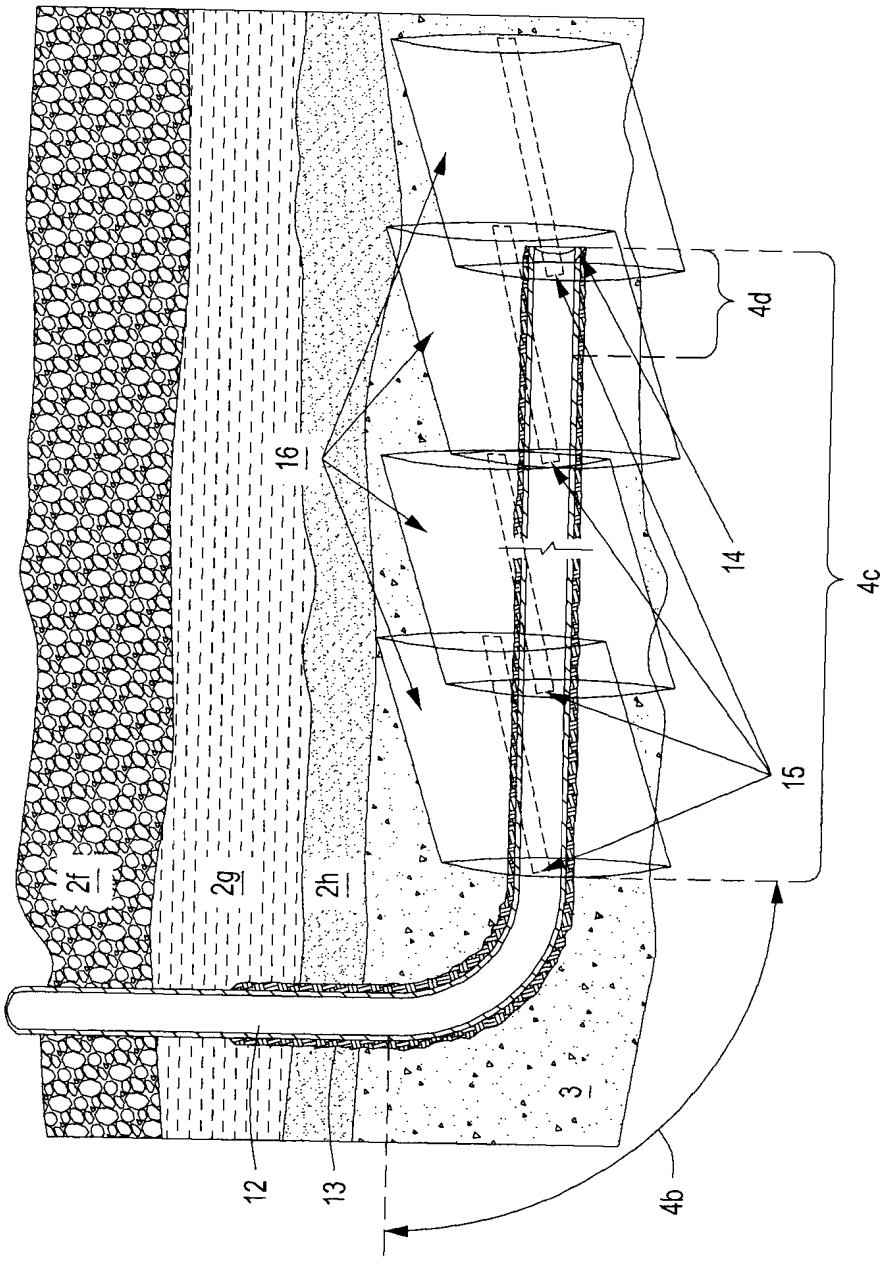


FIG. 1B

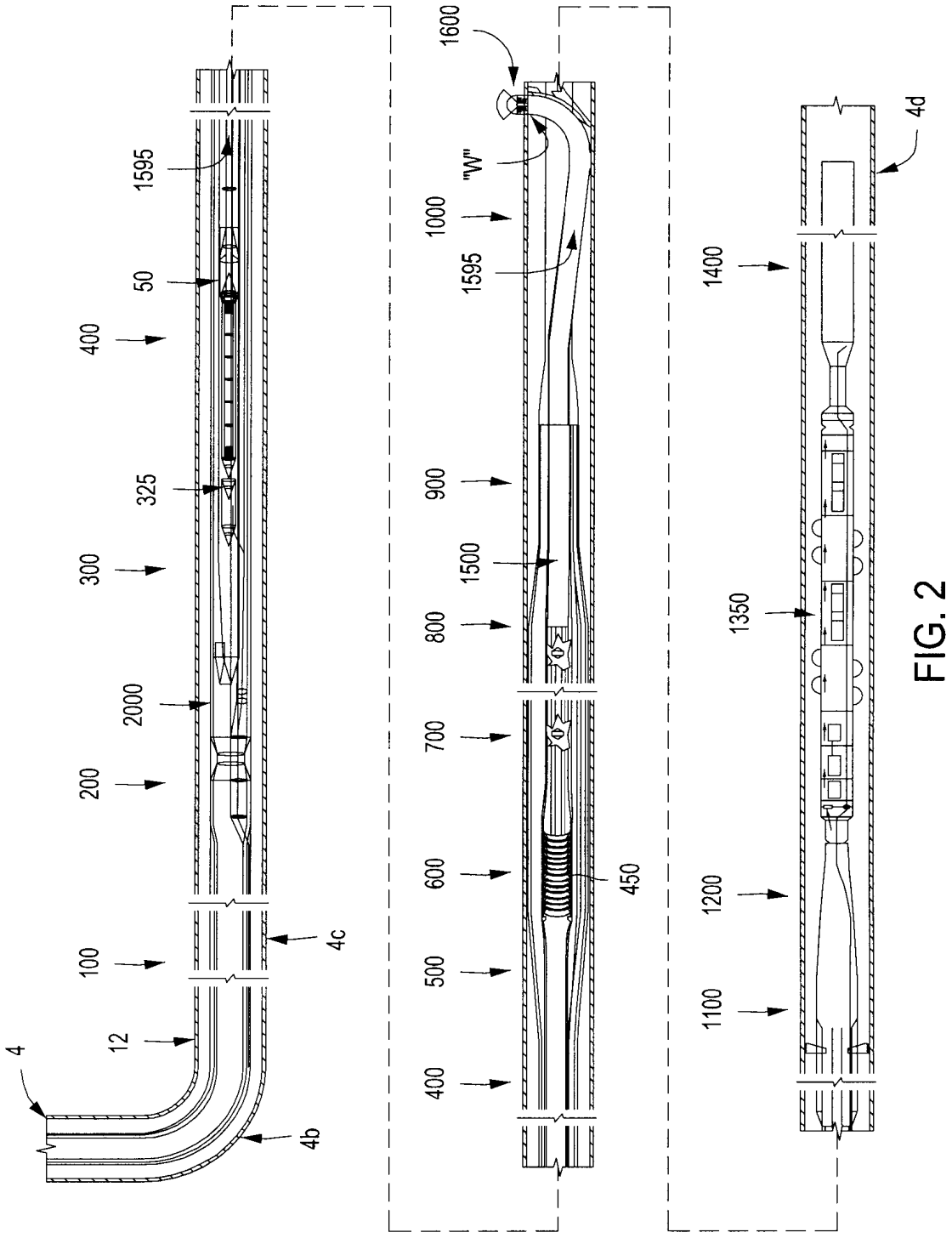

4
12
100
200
2000
300
325
400
50
1595
4c
4b
400
500
600
700
800
1500
900
1000
"W"
1595
1600
450
1100
1200
1350
1400
4d

FIG. 2

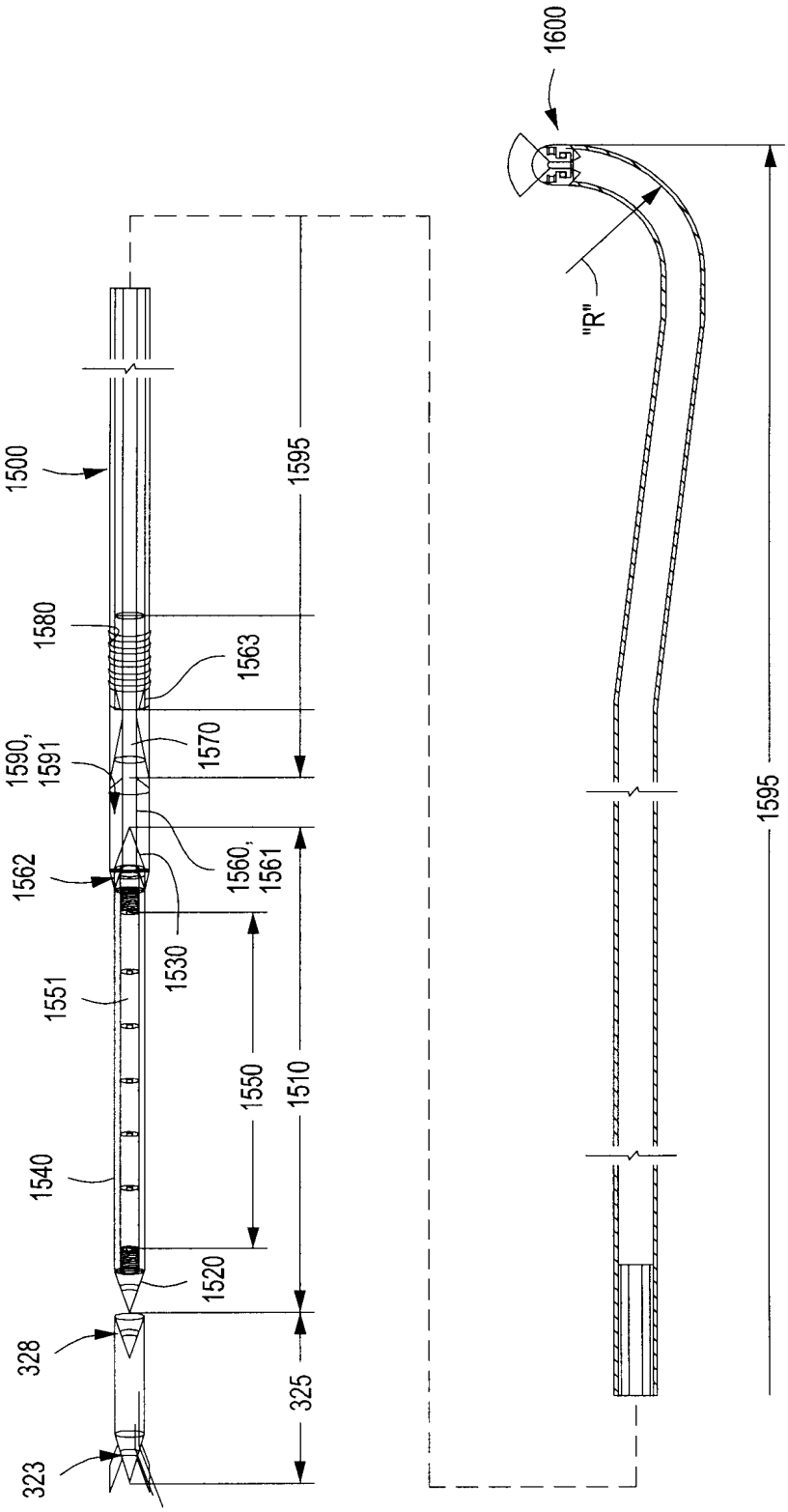

1600
"R"
1595
1500
1595
1580
1563
1590,
1591
1570
1562
1560,
1561
1530
1551
1550
1510
1540
1520
328
325
323

FIG. 3

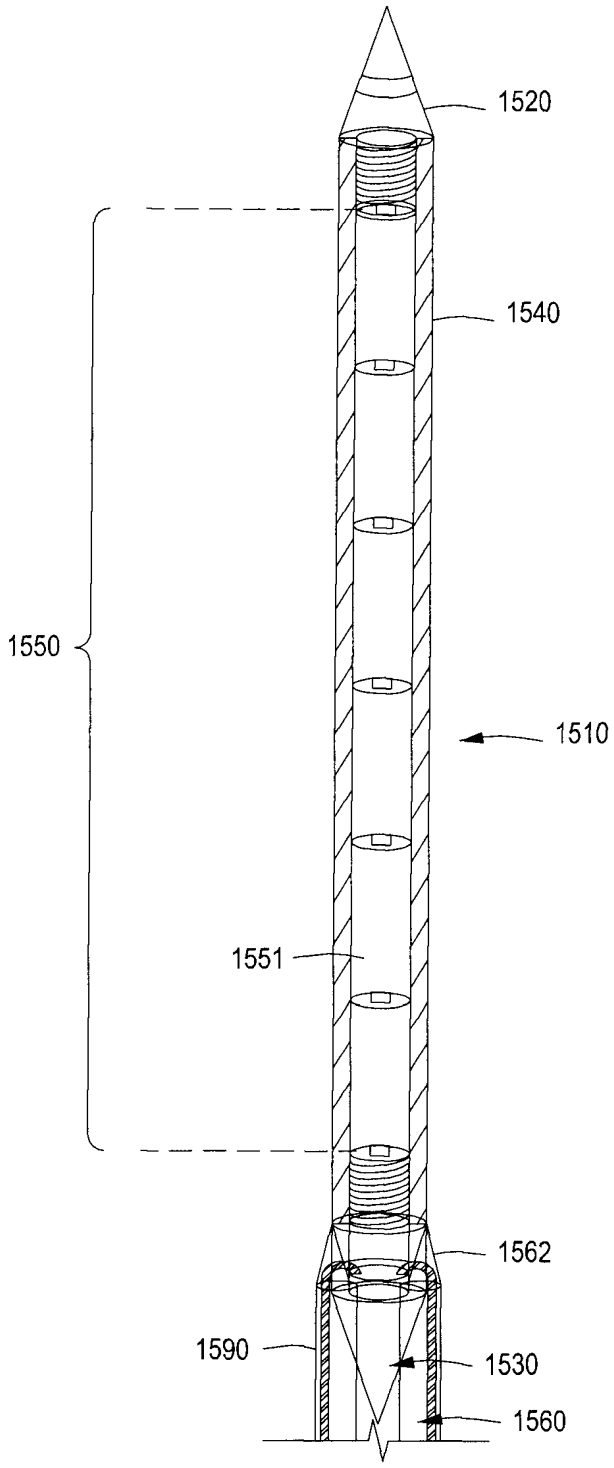


FIG. 3A

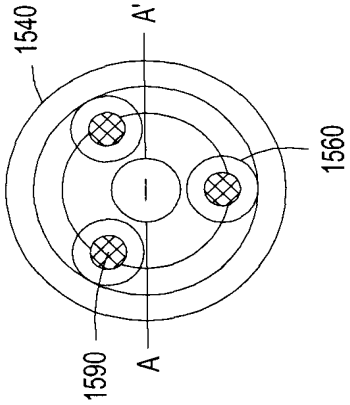


FIG. 3B-1a

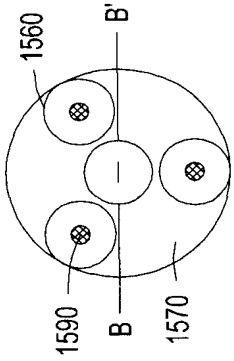


FIG. 3B-1b

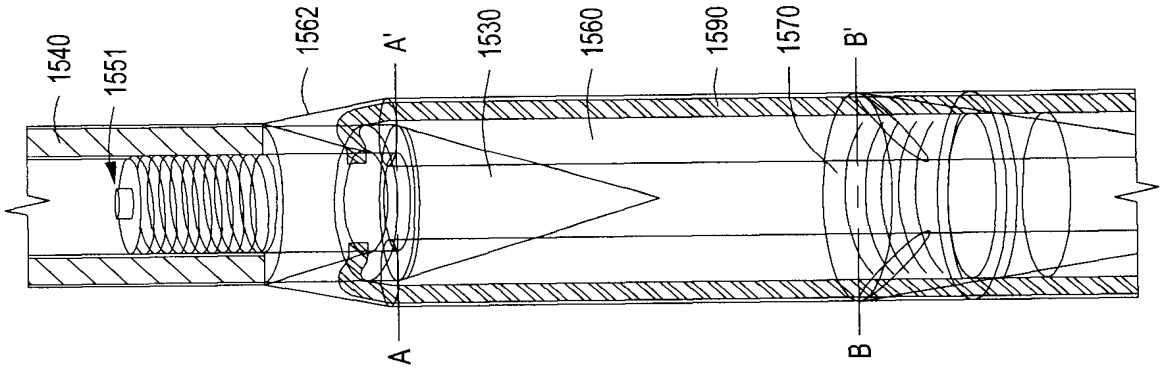


FIG. 3B-1

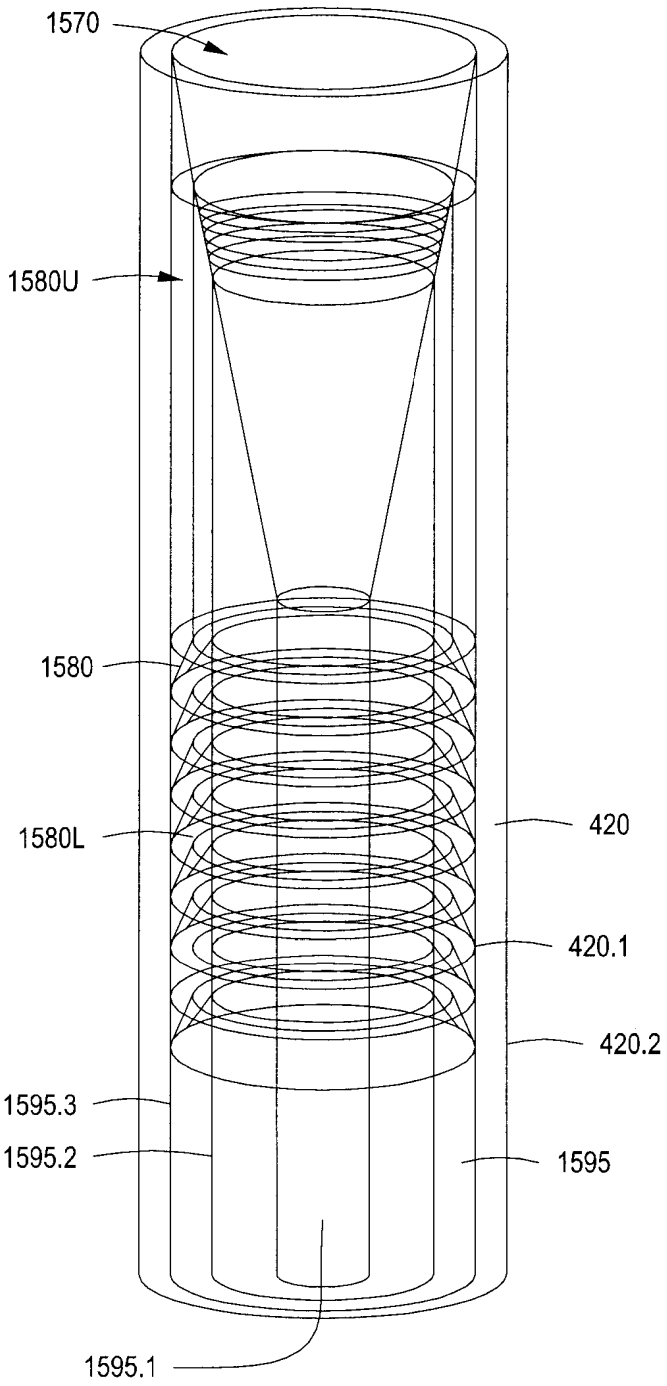


FIG. 3C

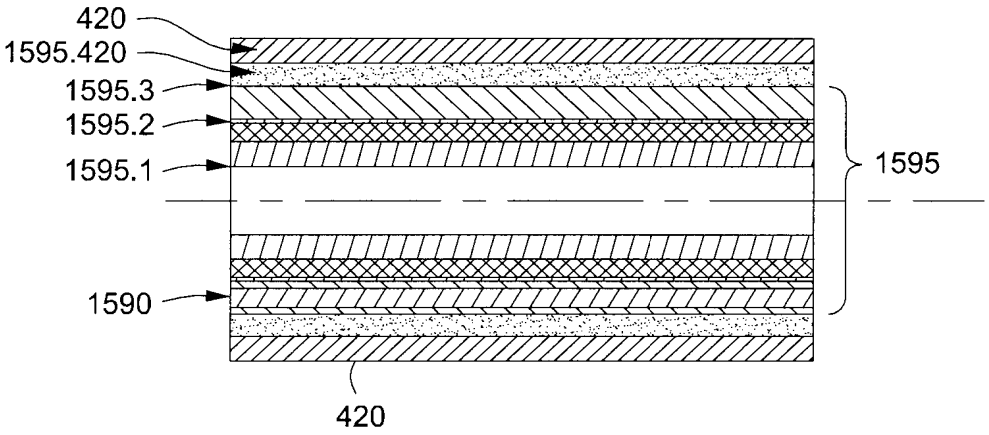


FIG. 3D-1

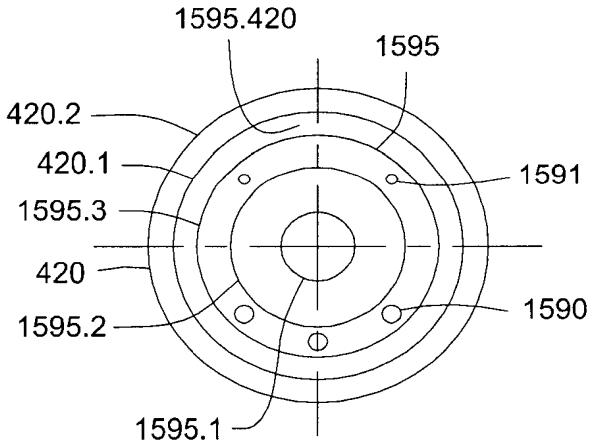


FIG. 3D-1a

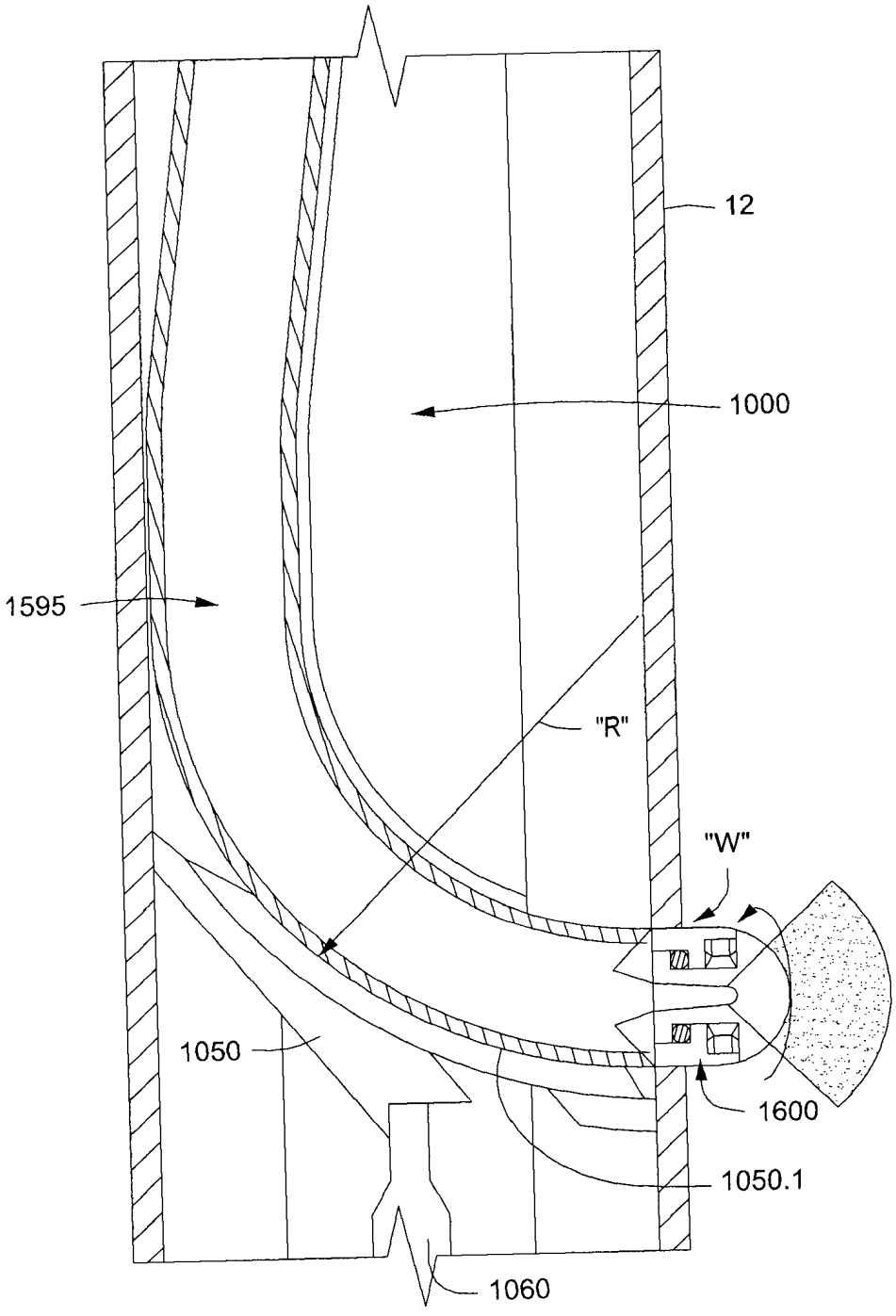


FIG. 3E

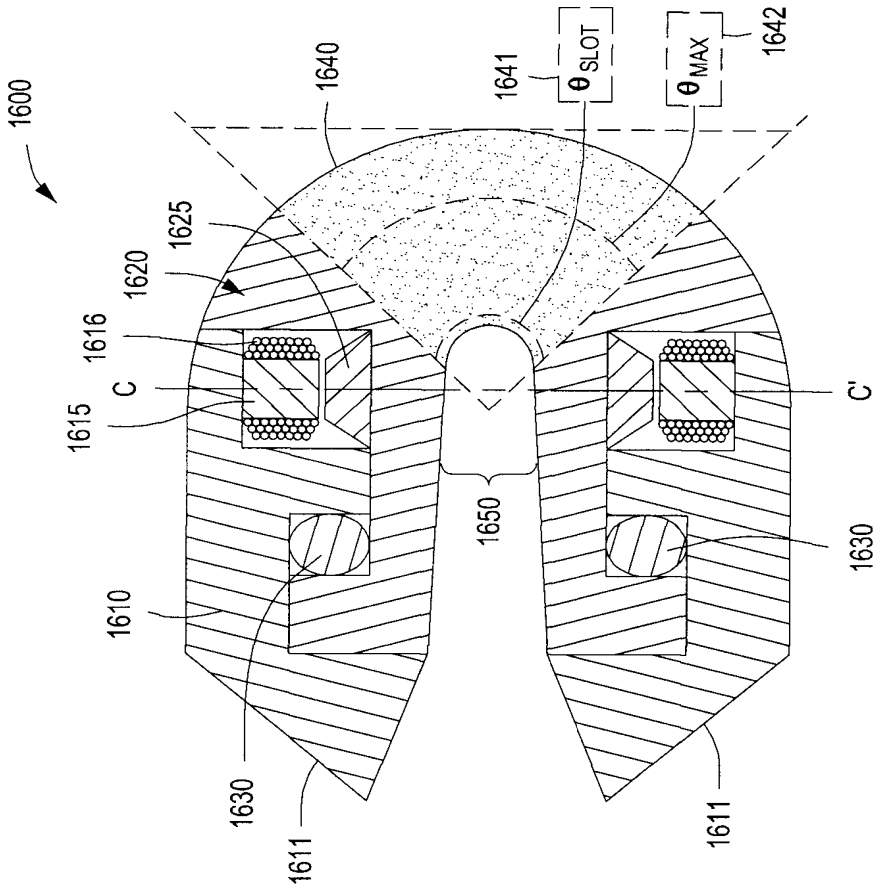


FIG. 3F-1b

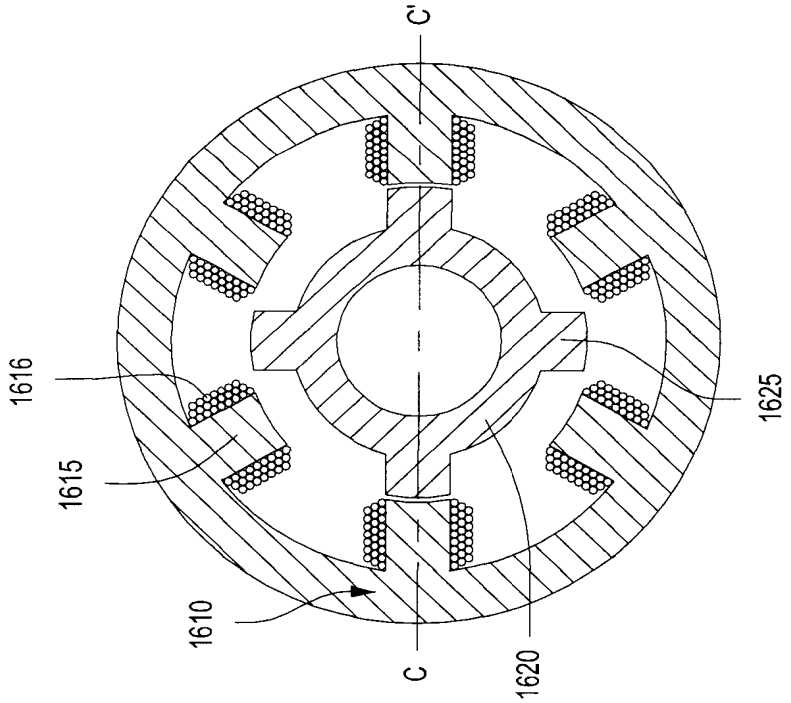


FIG. 3F-1a

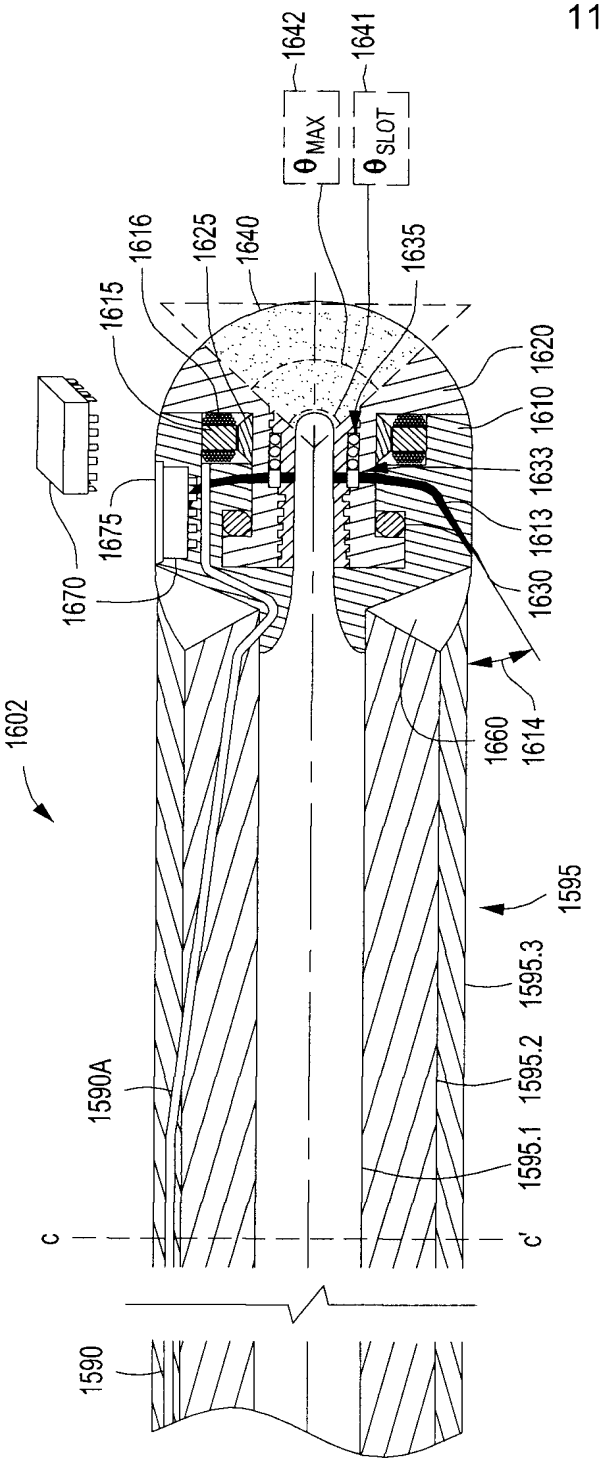


FIG. 3F-1c

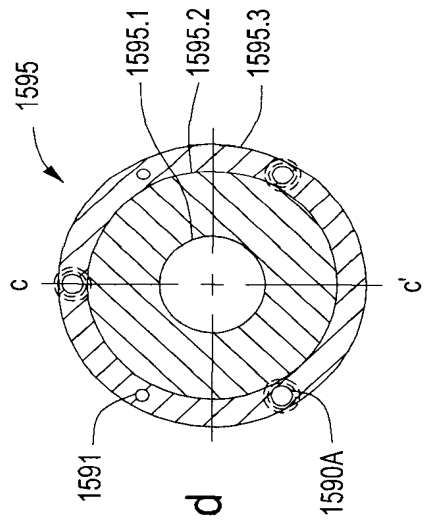


FIG. 3F-1d

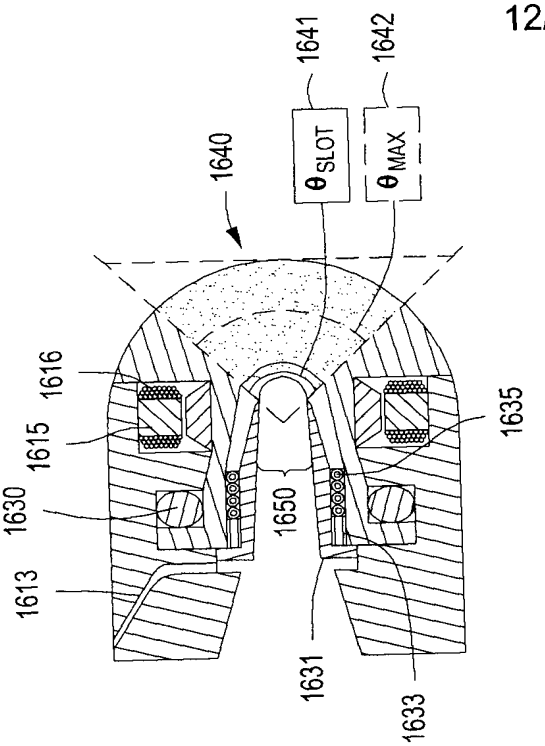


FIG. 3F-2b

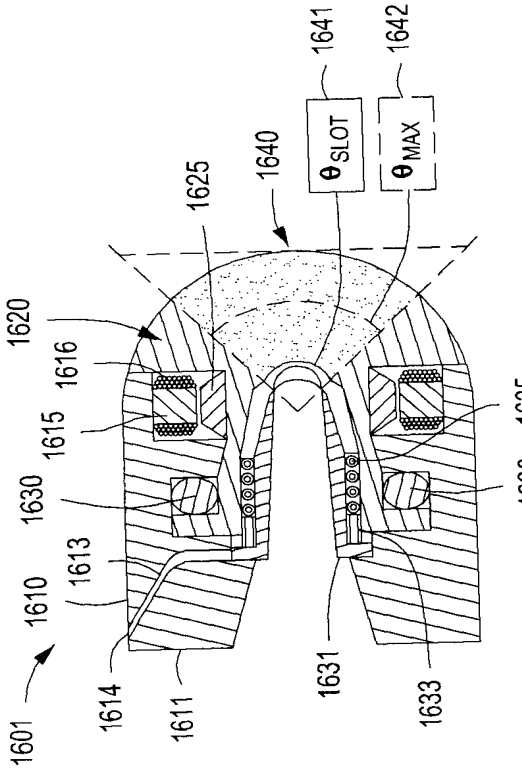


FIG. 3F-2a

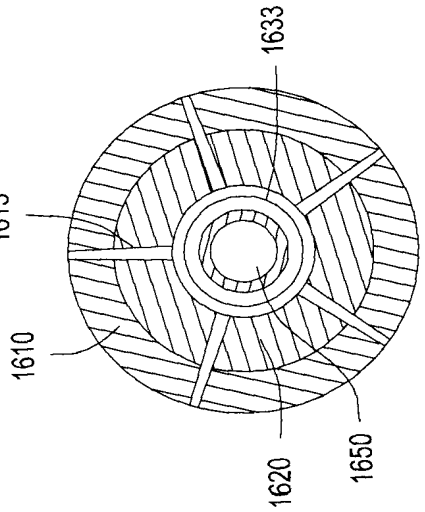


FIG. 3F-2c

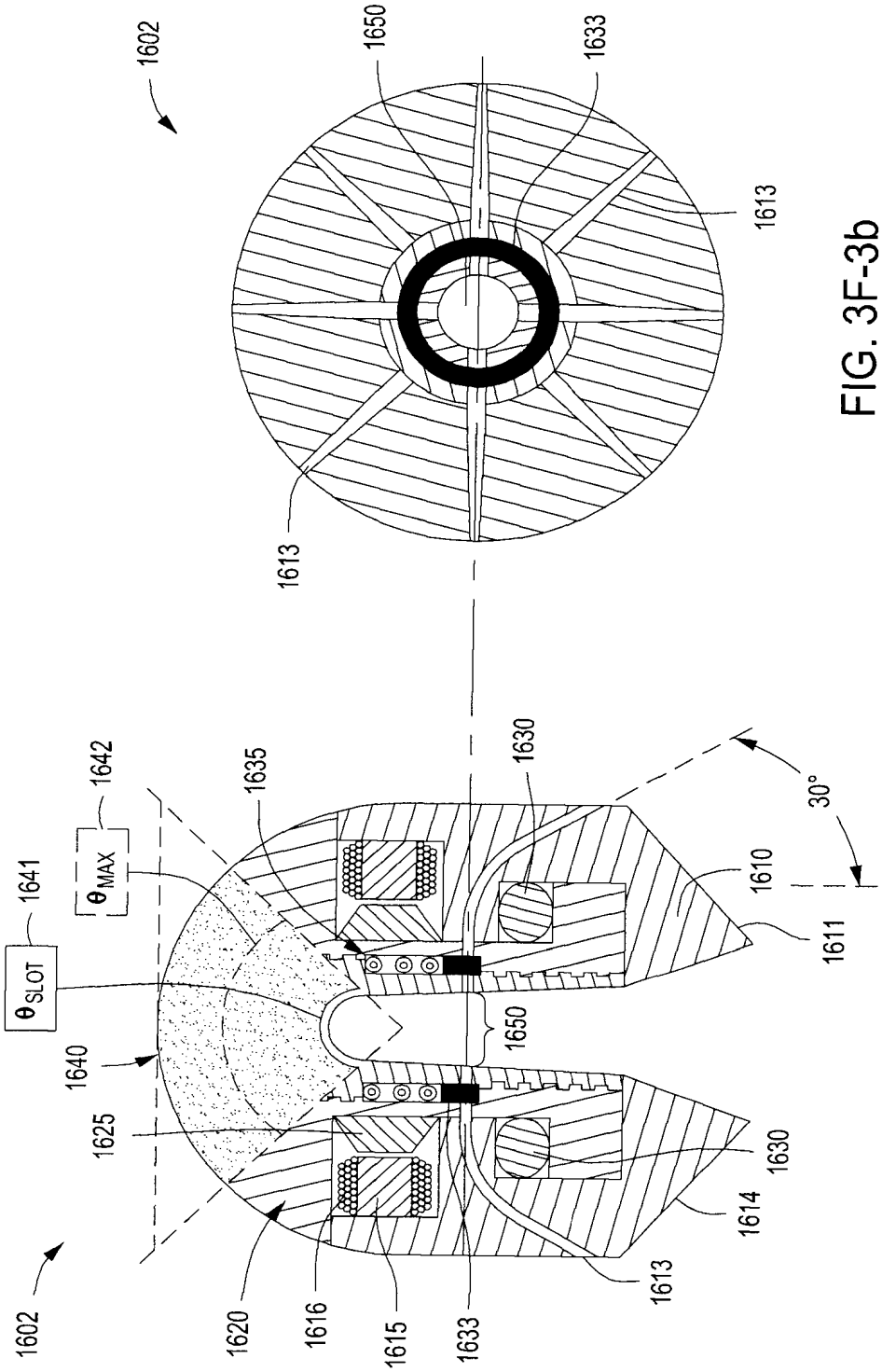


FIG. 3F-3b

FIG. 3F-3a

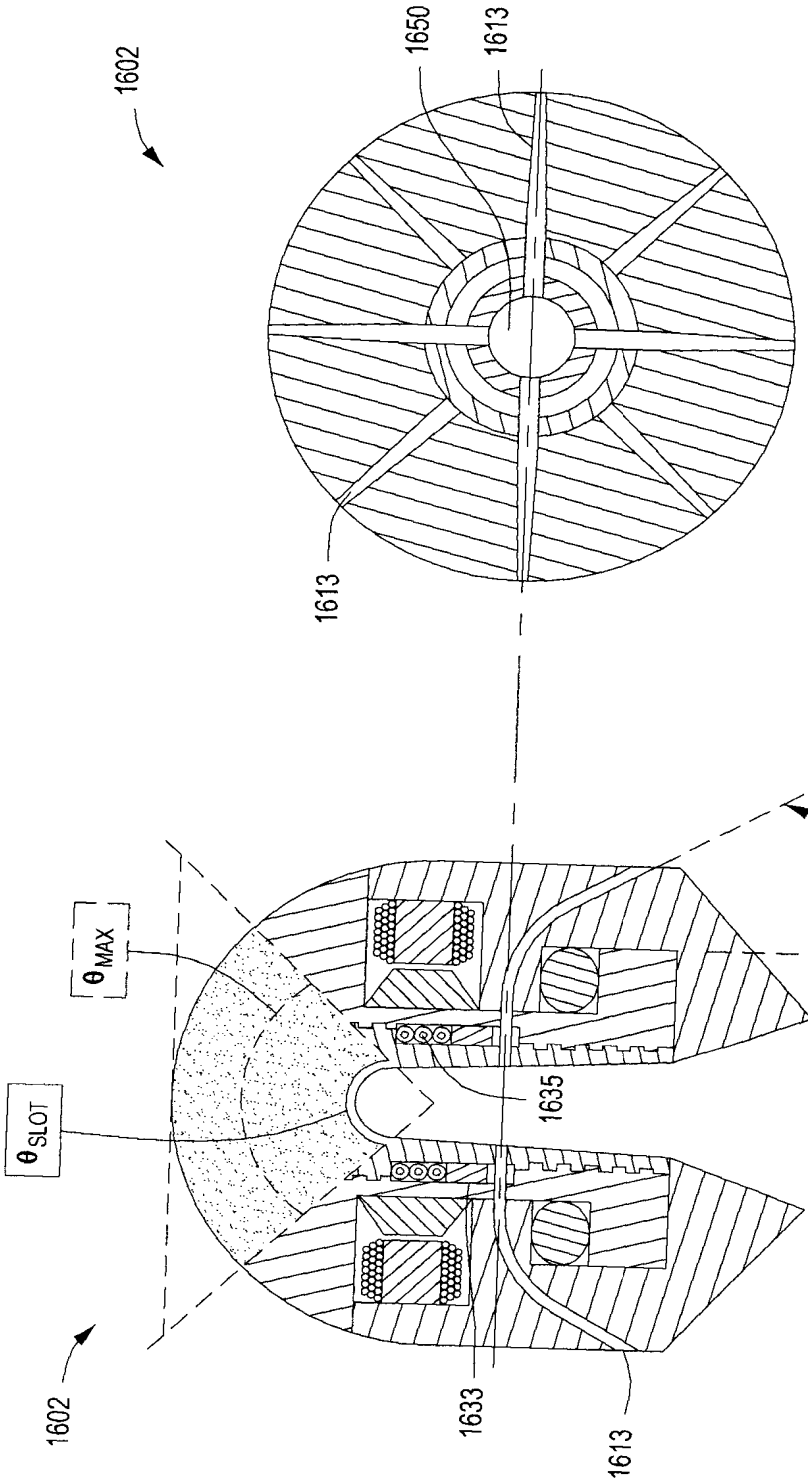


FIG. 3F-3d

FIG. 3F-3c

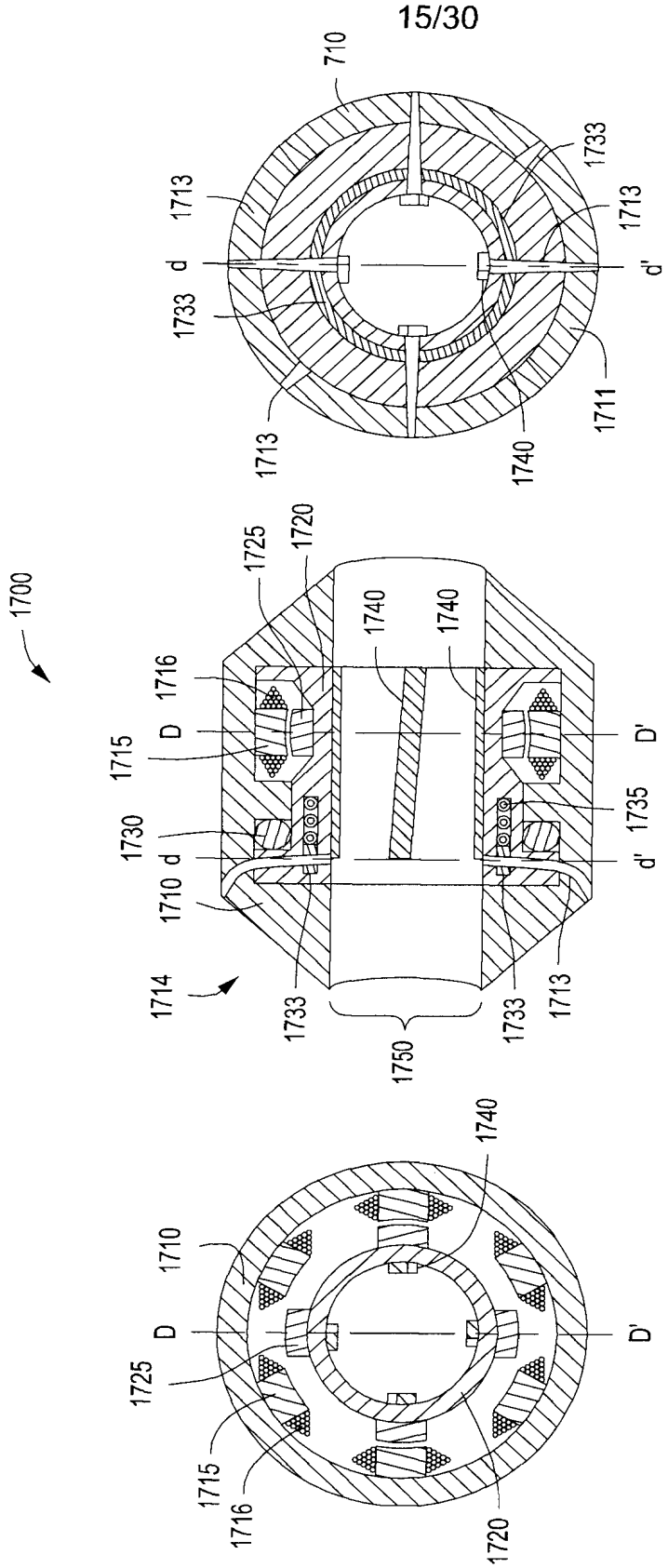


FIG. 3G-1c

FIG. 3G-1b

FIG. 3G-1a

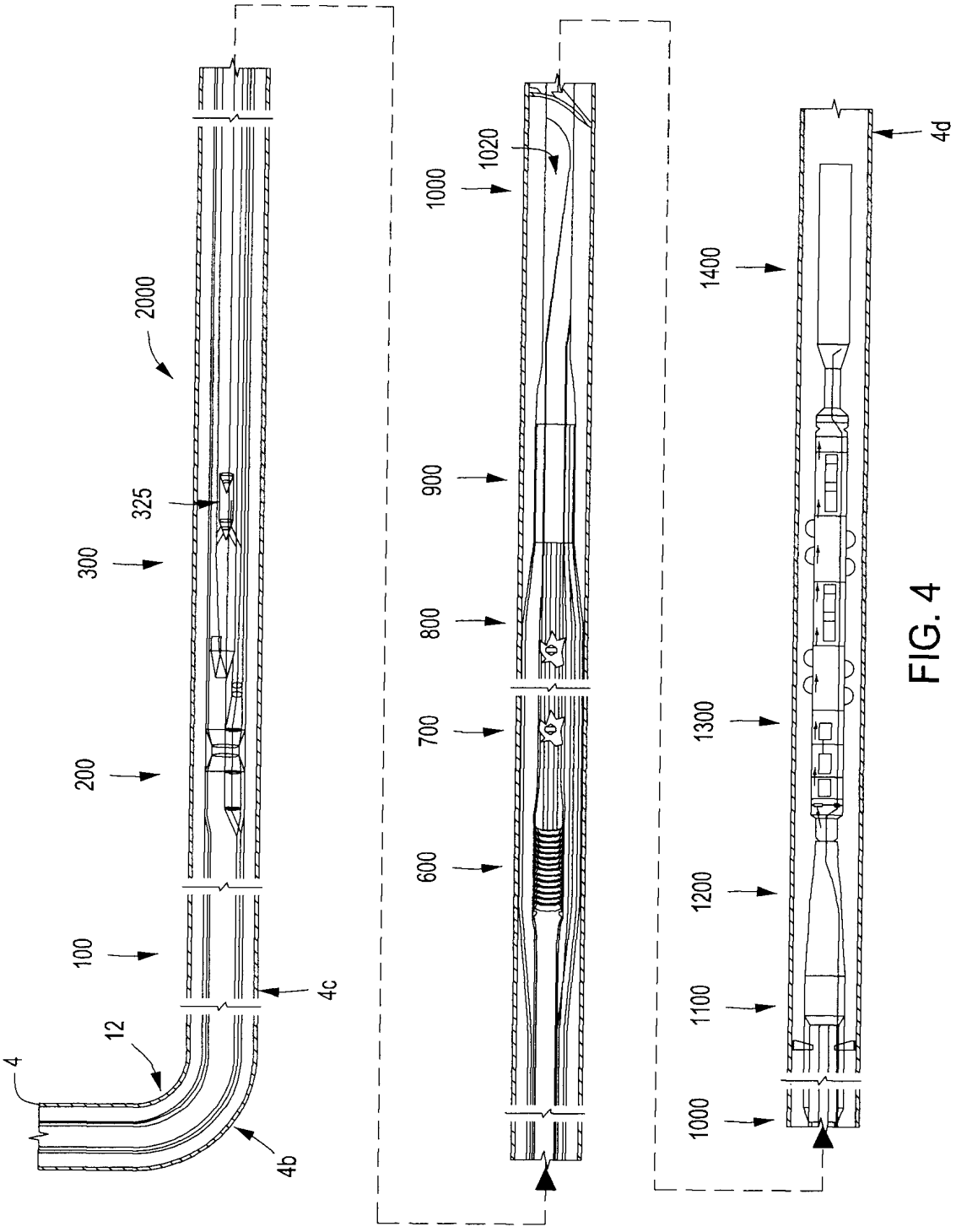

2000
325
300
200
100
4c
12
4
4b
1000
1020
900
800
700
600
1400
4d
1300
1200
1100
1000

FIG. 4

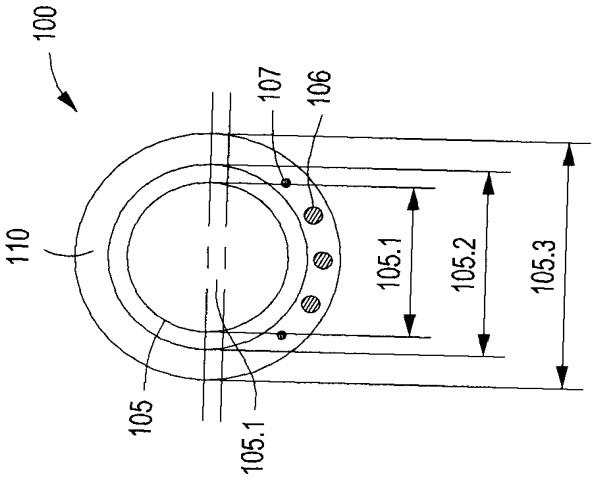


FIG. 4A-1a

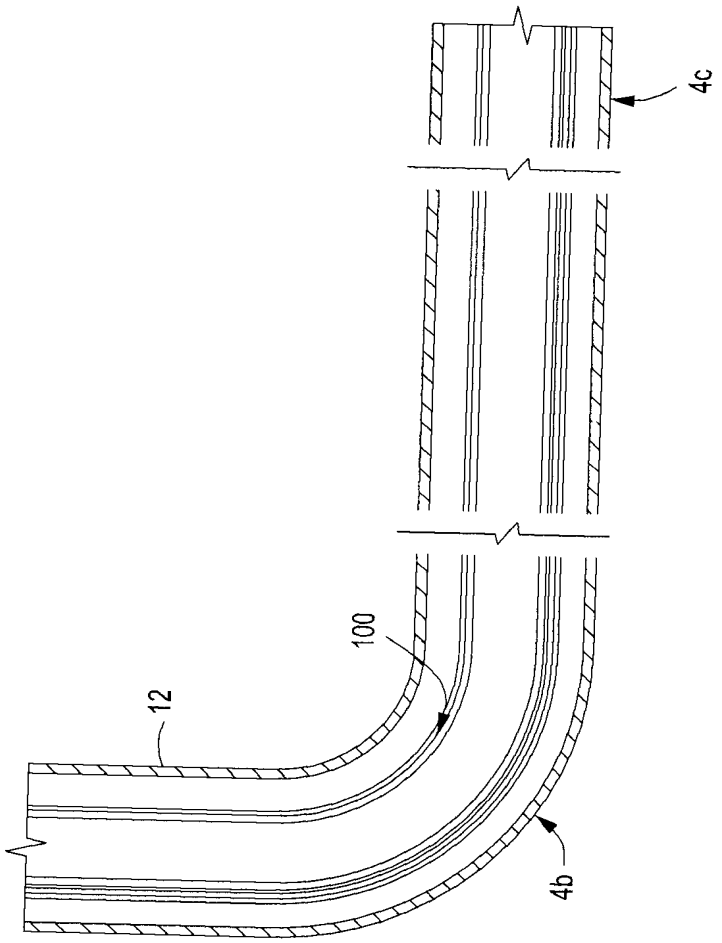


FIG. 4A-1

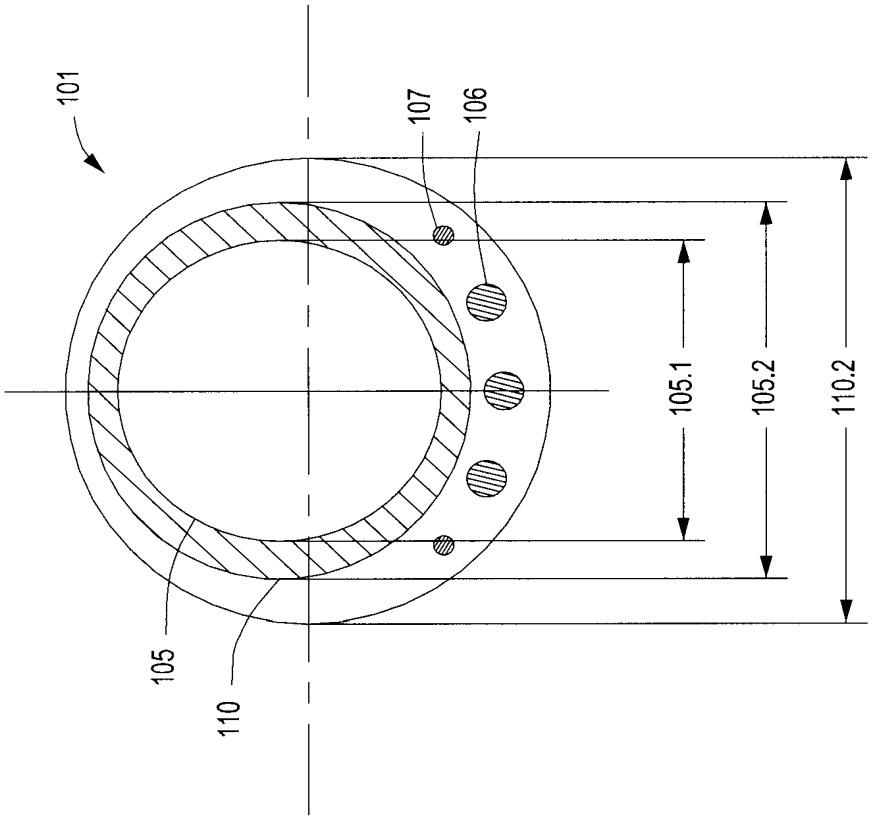


FIG. 4A-2

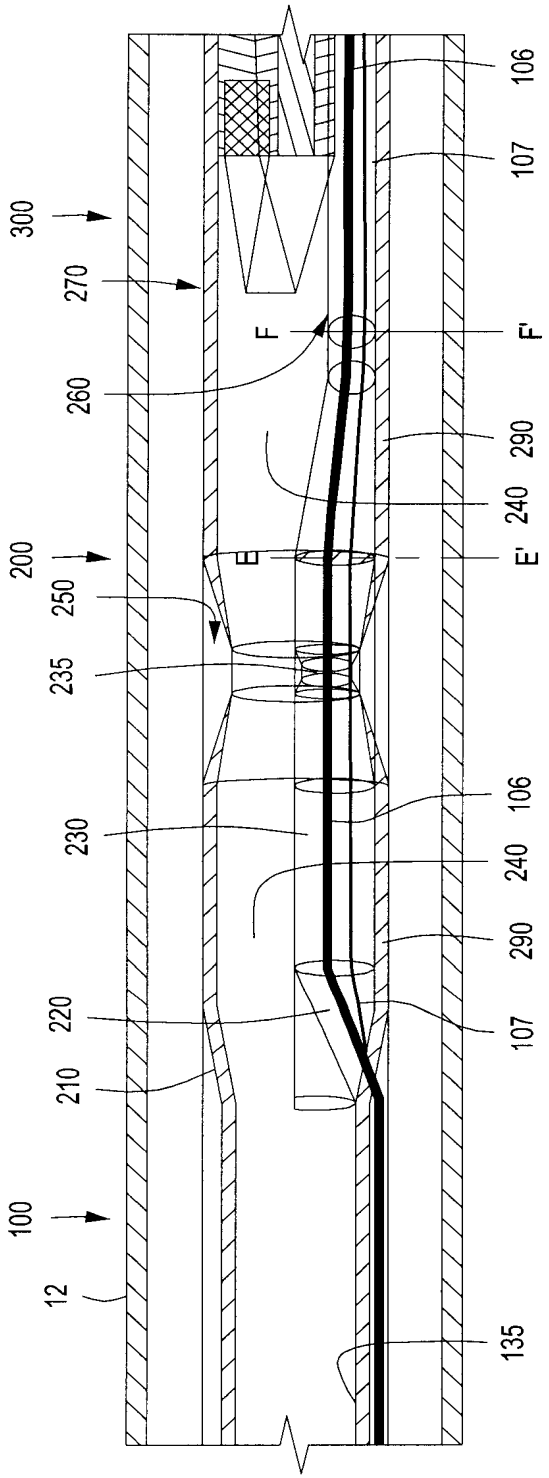


FIG. 4B-1

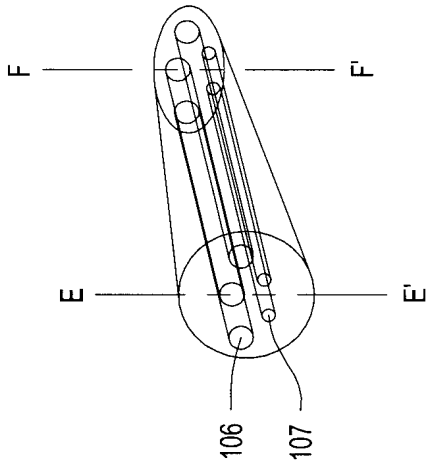


FIG. 4B-1a

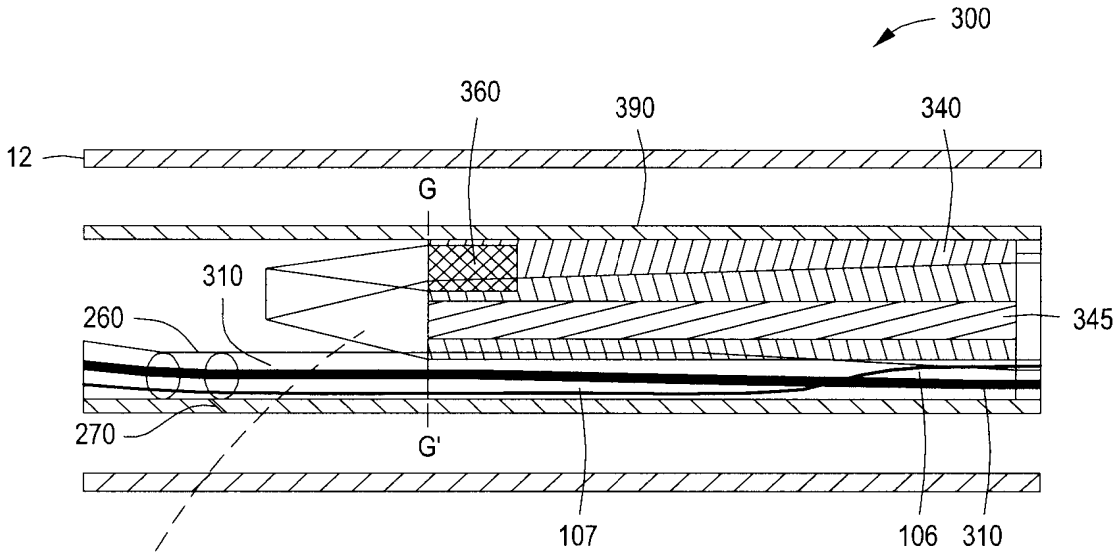


FIG. 4C-1

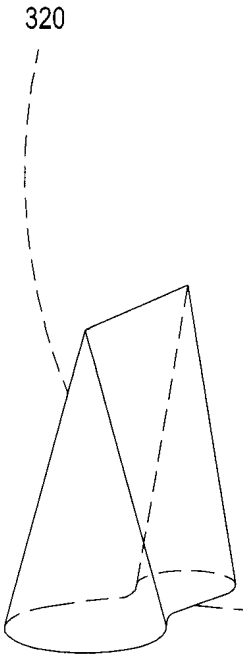


FIG. 4C-1b

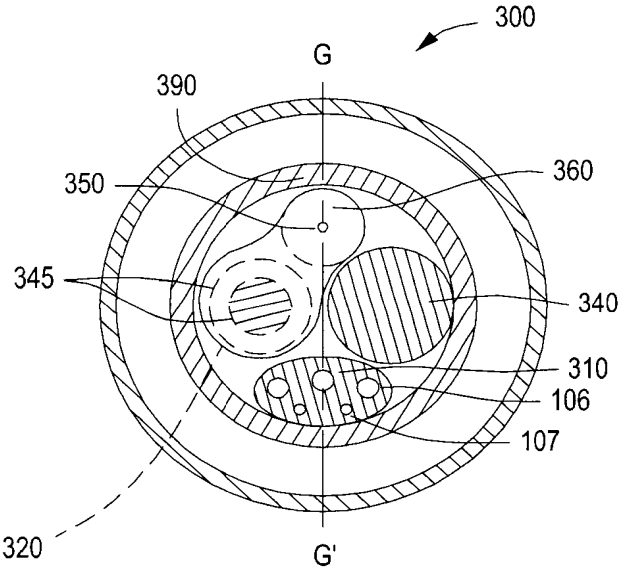


FIG. 4C-1a

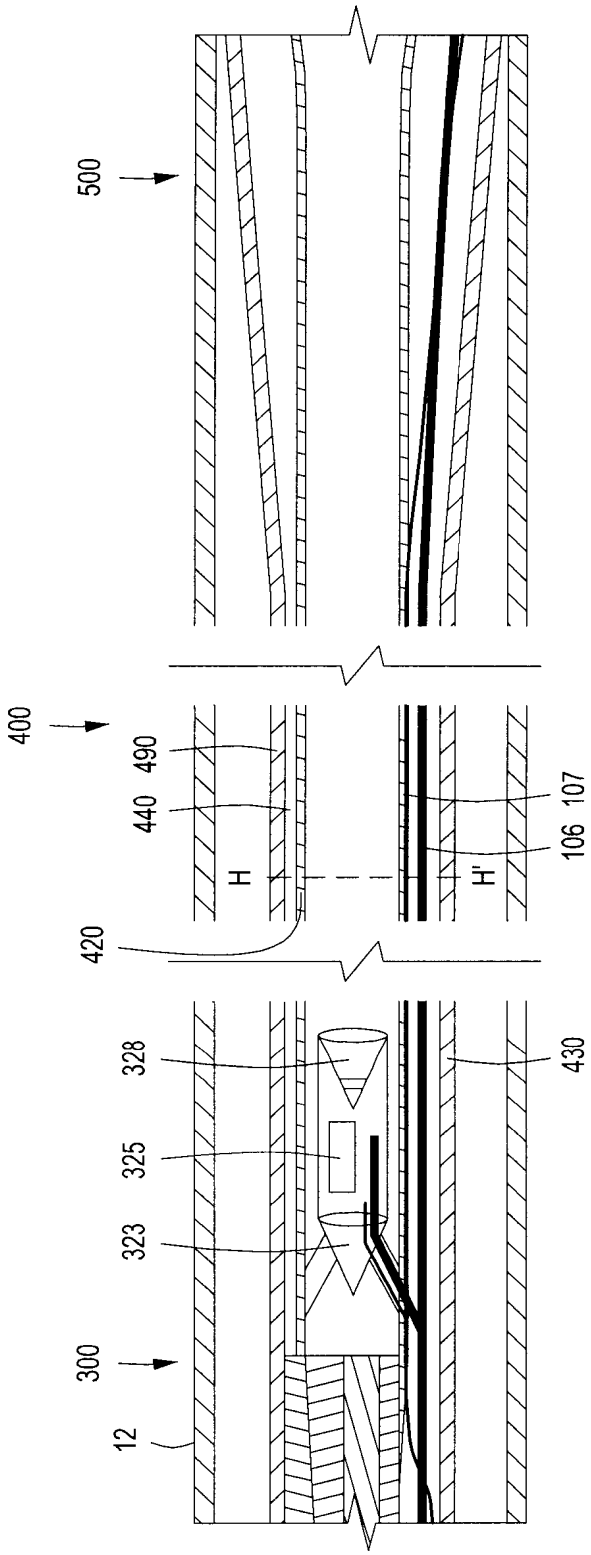


FIG. 4D-1

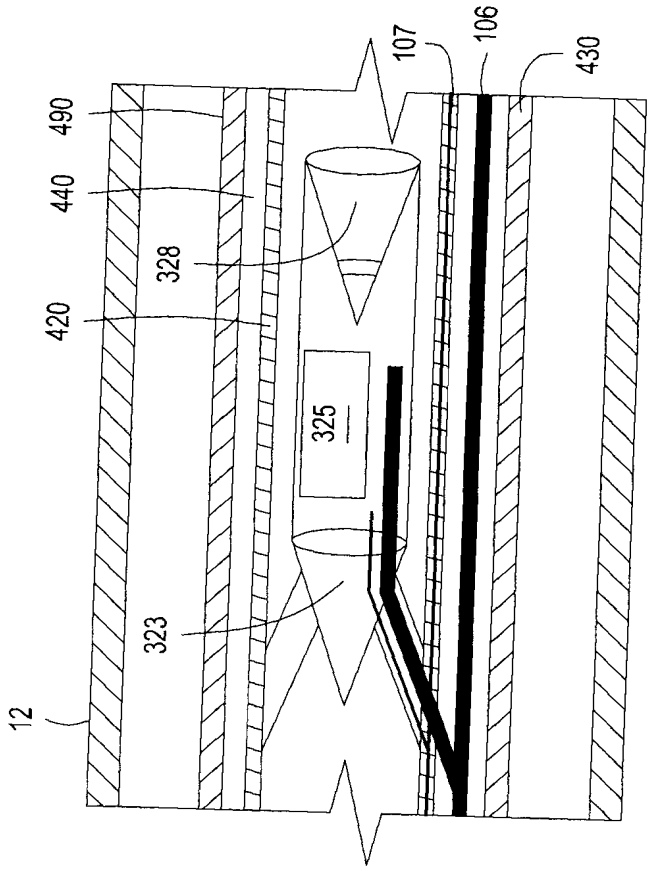


FIG. 4D-1b

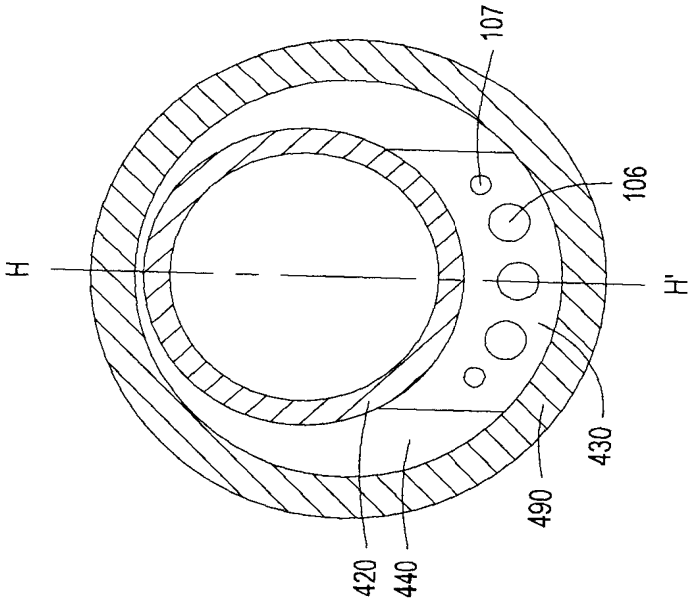


FIG. 4D-1a

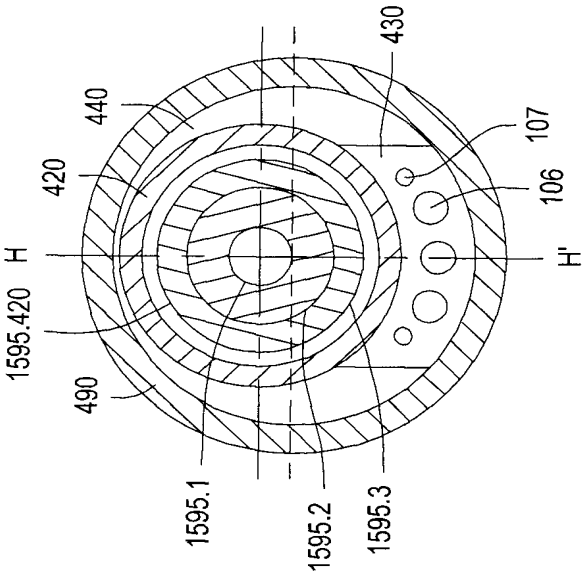


FIG. 4D-2a

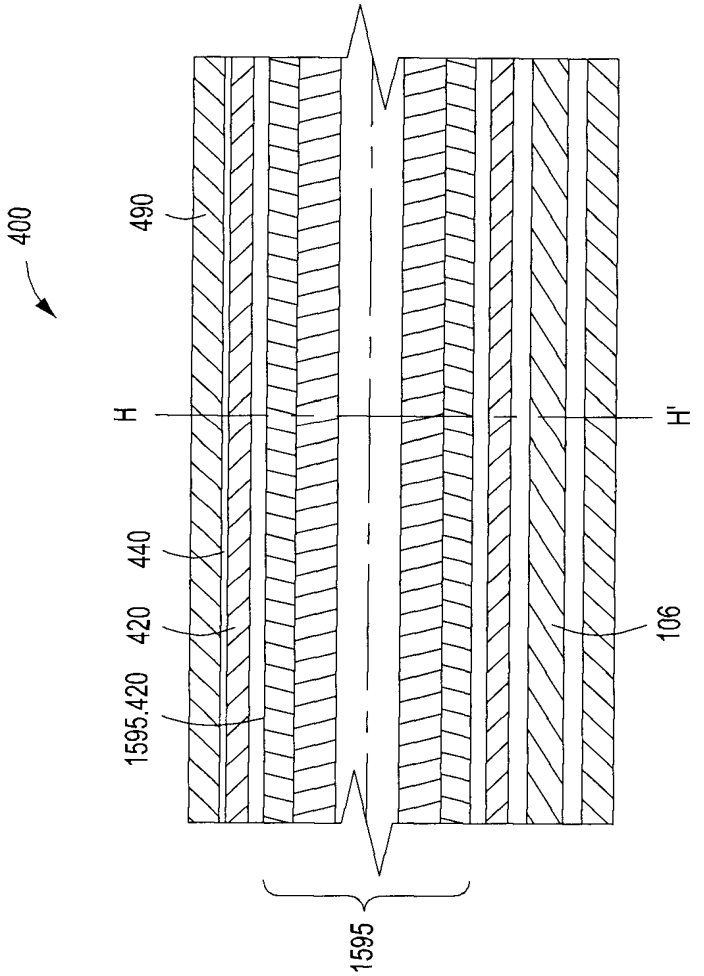


FIG. 4D-2

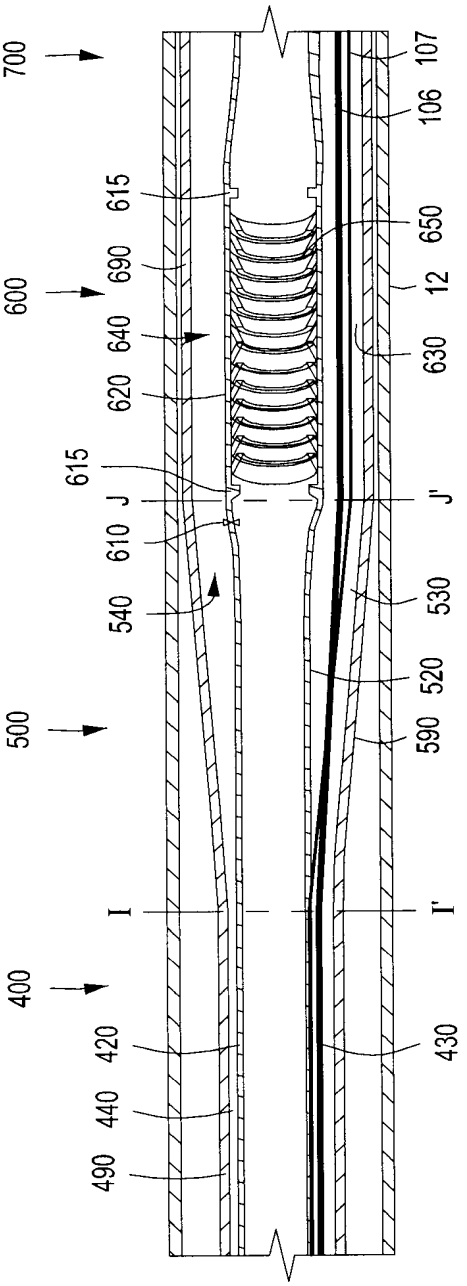


FIG. 4E-1

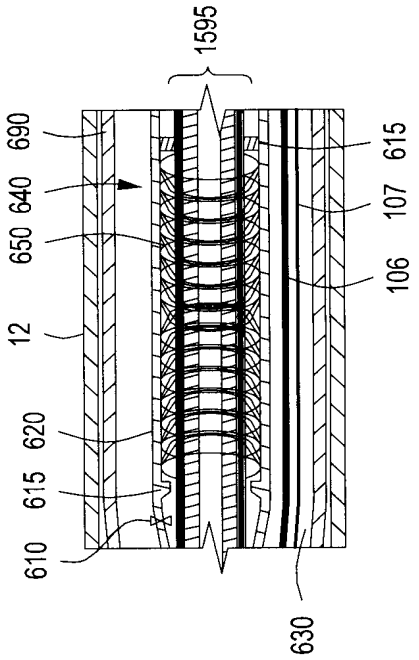


FIG. 4E-2

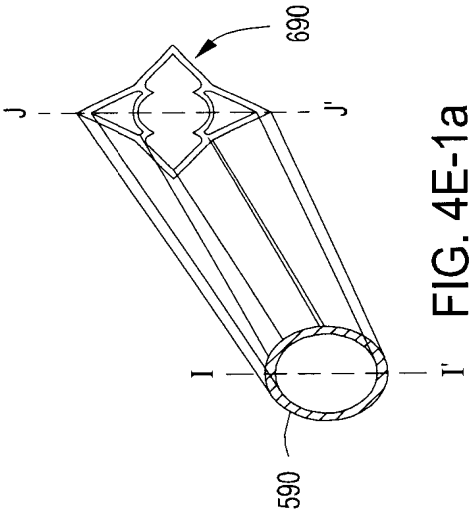


FIG. 4E-1a

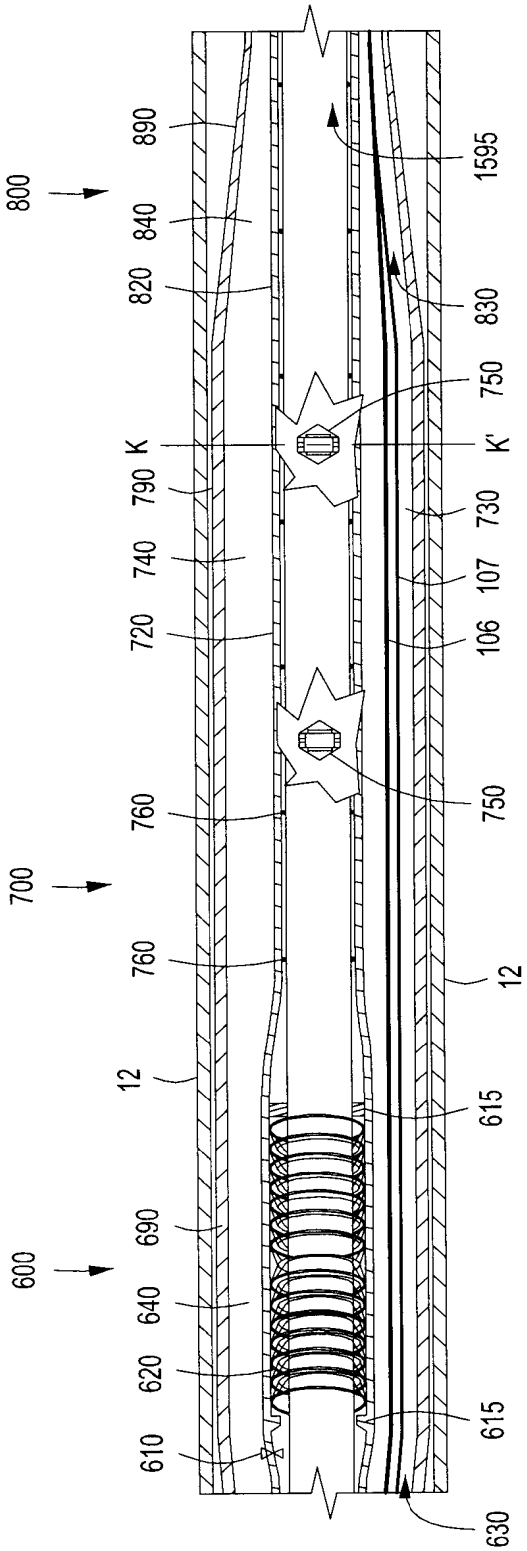

800
890
840
820
K
790
740
720
760
700
760
12
690
600
640
620
610
1595
830
750
K'
730
107
106
750
12
615
615
630

FIG. 4F-1

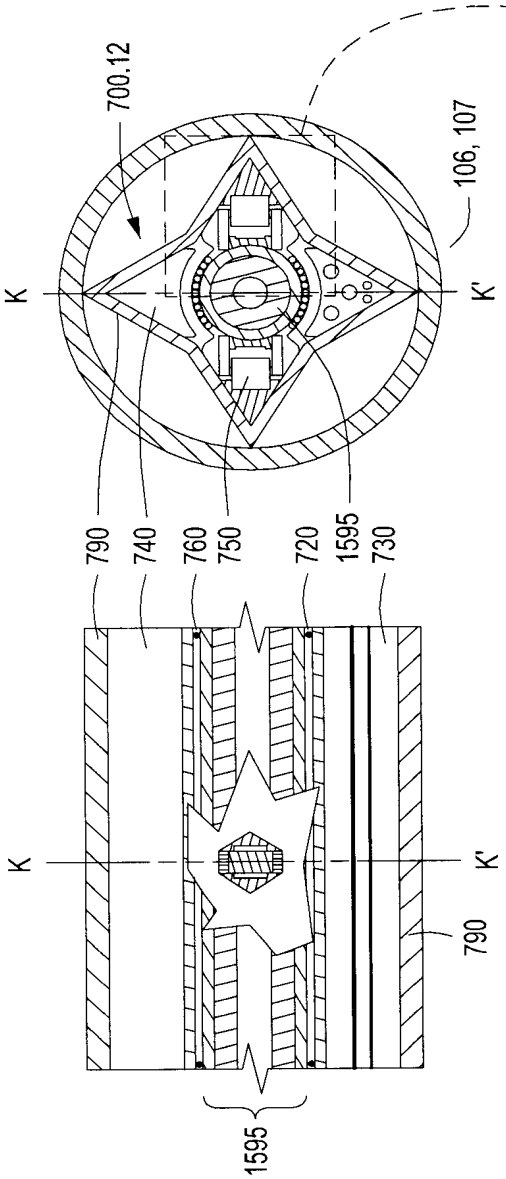


FIG. 4F-2

FIG. 4F-2a

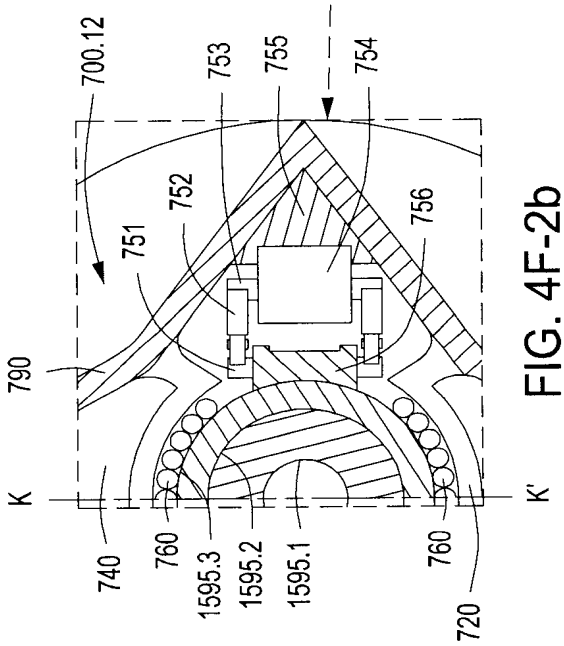


FIG. 4F-2b

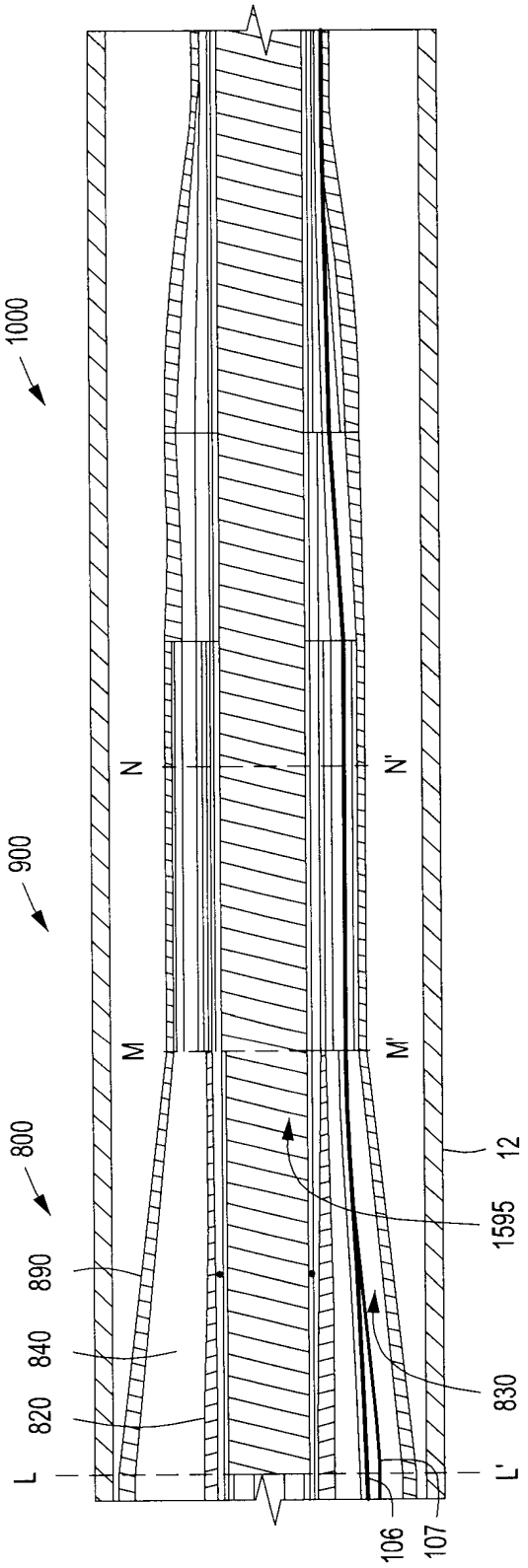


FIG. 4G-1

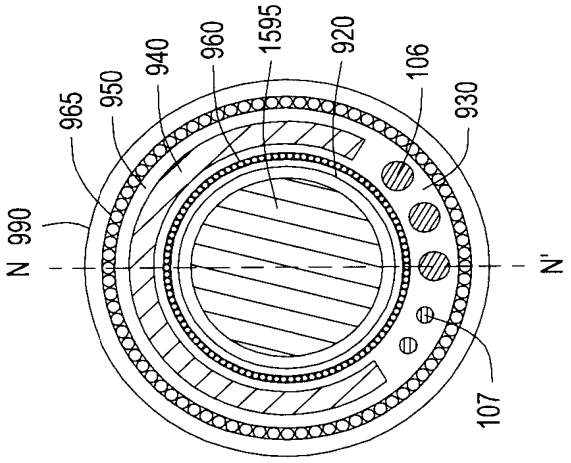


FIG. 4G-1b

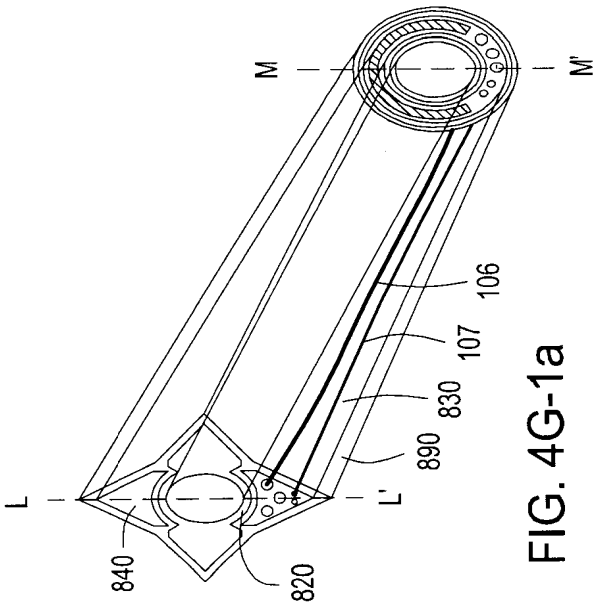


FIG. 4G-1a

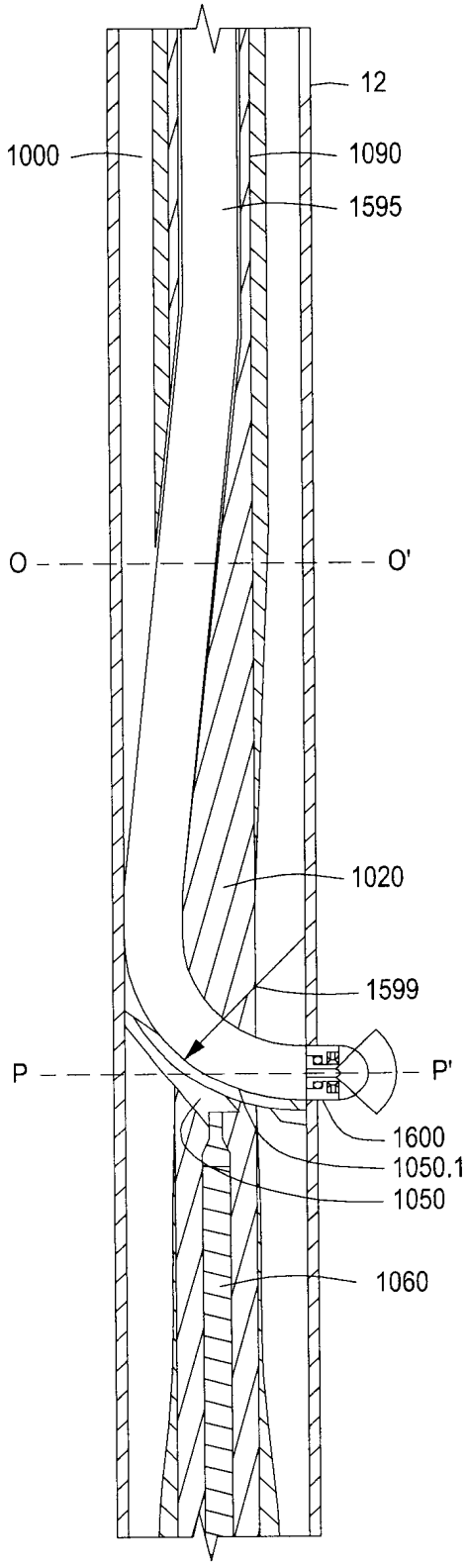


FIG. 4H-1

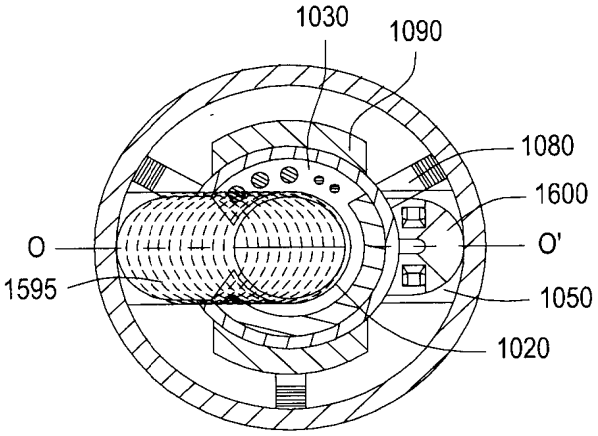


FIG. 4H-1a

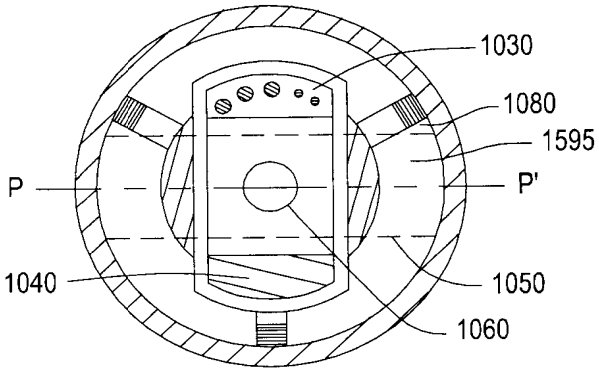


FIG. 4H-1b

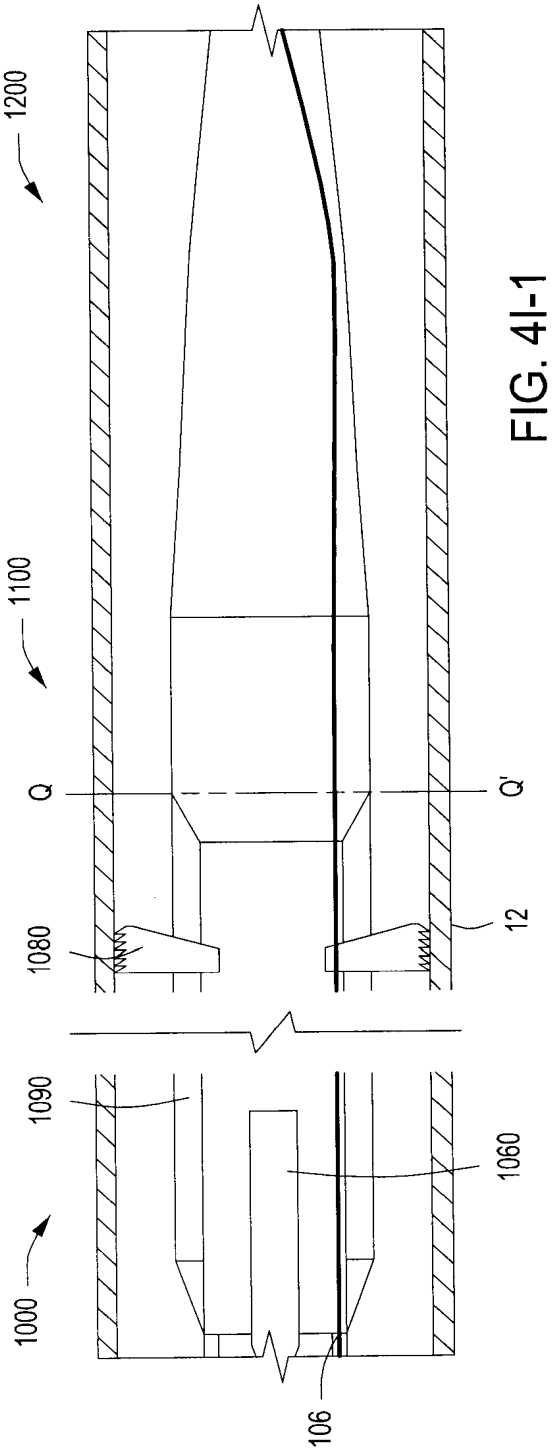


FIG. 4I-1

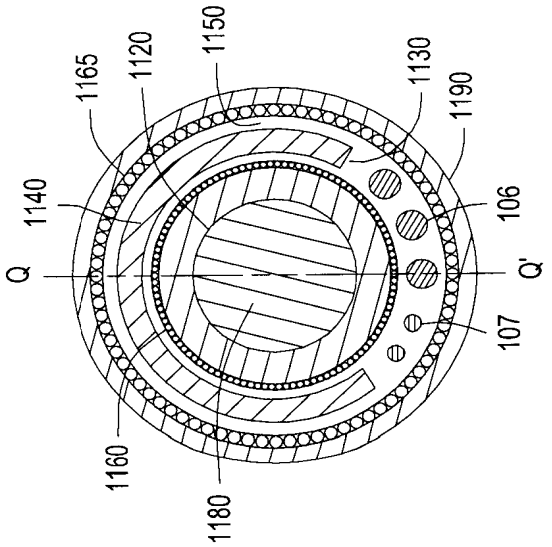


FIG. 4I-1a

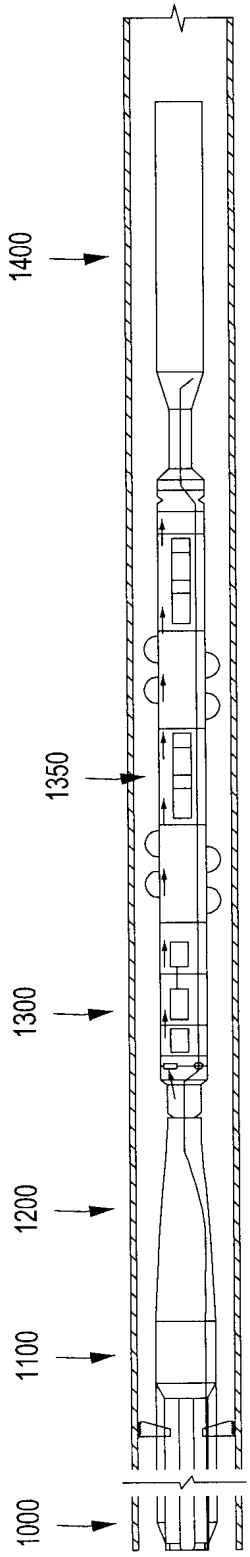
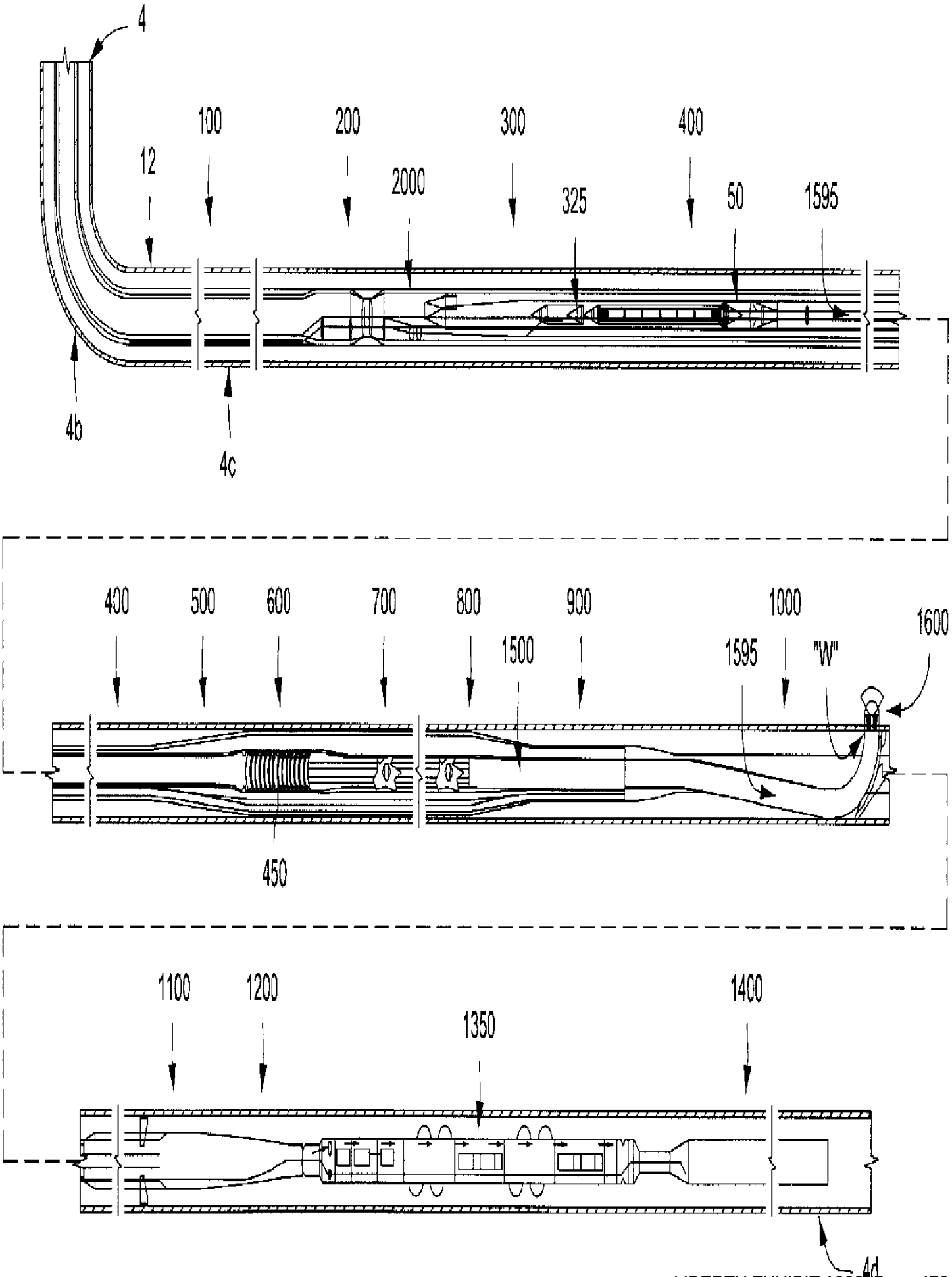


FIG. 4J


4
100
200
300
400
12
2000
325
50
1595
4b
4c
400
500
600
700
800
900
1000
1600
1500
1595
"W"
450
1100
1200
1400
1350
4d

Office de la Propriété Intellectuelle du Canada
Un organisme d'Industrie Canada

Canadian Intellectual Property Office
An agency of Industry Canada

CA 2919666 A1 2016/08/24

(21) 2 919 666

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) **Date de dépôt/Filing Date:** 2016/02/02

(41) **Mise à la disp. pub./Open to Public Insp.:** 2016/08/24

(30) **Priorités/Priorities:** 2015/02/24 (US62/120,212); 2015/07/29 (US62/198,575); 2016/01/28 (US15/009,623)

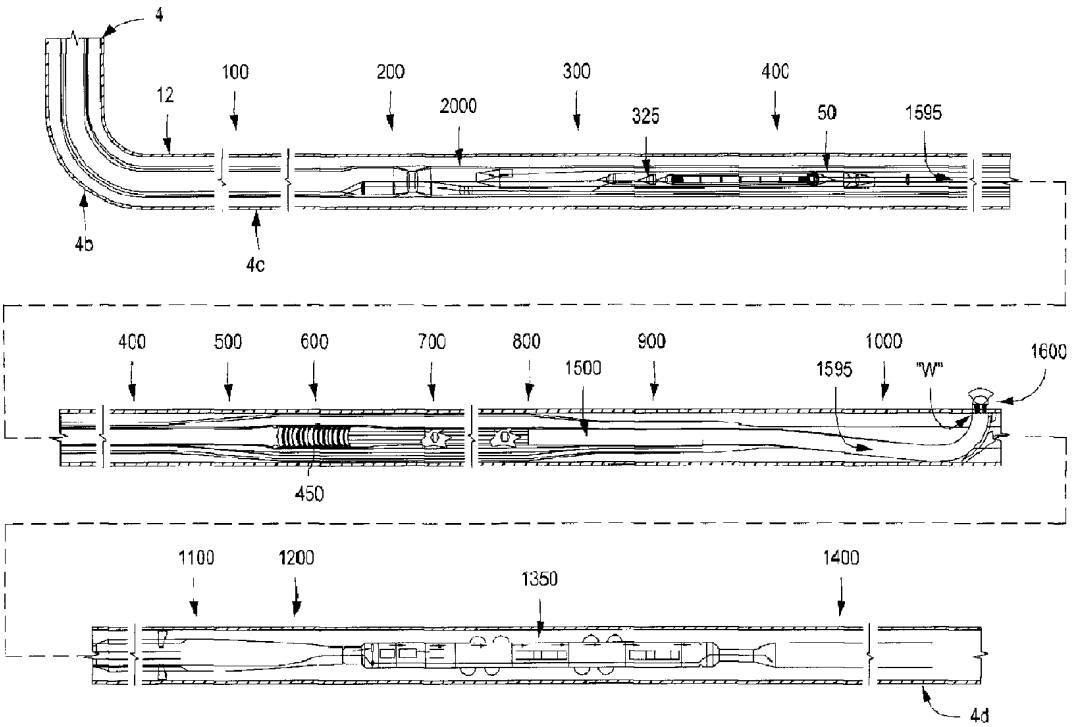
(51) **Cl.Int./Int.Cl.** ***E21B 7/18*** (2006.01), ***E21B 43/11*** (2006.01), ***E21B 43/26*** (2006.01), ***E21B 47/04*** (2012.01), ***E21B 47/12*** (2012.01), ***E21B 7/06*** (2006.01)

(71) **Demandeur/Applicant:**
COILED TUBING SPECIALTIES, LLC, US

(72) **Inventeur/Inventor:**
RANDALL, BRUCE L., US

(74) **Agent:** DEETH WILLIAMS WALL LLP

(54) **Titre : METHODE DE FORMAGE DE TROUS DE FORAGE LATERAUX**
(54) **Title: METHOD OF FORMING LATERAL BOREHOLES**



(57) **Abrégé/Abstract:**
A method of forming a lateral borehole in a pay zone located within an earth subsurface is provided. The method includes determining a depth of a pay zone in the earth subsurface, and then forming a wellbore within the pay zone. The method also includes conveying a hydraulic jetting assembly into the wellbore on a working string. The assembly includes a jetting hose carrier, and a jetting hose within the jetting hose carrier having a nozzle connected at a distal end. The method additionally includes setting a whipstock in the wellbore along the pay zone, and translating the jetting hose out of the jetting hose carrier to advance the nozzle along the face of the whipstock. The method then includes injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a lateral borehole within the rock matrix, and further injecting the fluid while further translating the jetting hose and connected nozzle along the face of the whipstock without coiling or uncoiling the hose, thereby forming a lateral borehole that extends at least feet from the wellbore.

ABSTRACT

A method of forming a lateral borehole in a pay zone located within an earth subsurface is provided. The method includes determining a depth of a pay zone in the earth subsurface, and then forming a wellbore within the pay zone. The method also includes conveying a hydraulic jetting assembly into the wellbore on a working string. The assembly includes a jetting hose carrier, and a jetting hose within the jetting hose carrier having a nozzle connected at a distal end. The method additionally includes setting a whipstock in the wellbore along the pay zone, and translating the jetting hose out of the jetting hose carrier to advance the nozzle along the face of the whipstock. The method then includes injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a lateral borehole within the rock matrix, and further injecting the fluid while further translating the jetting hose and connected nozzle along the face of the whipstock without coiling or uncoiling the hose, thereby forming a lateral borehole that extends at least 5 feet from the wellbore.

METHOD OF FORMING LATERAL BOREHOLES

BACKGROUND OF THE INVENTION

[1] This section is intended to introduce selected aspects of the art, which may be associated with various embodiments of the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

Field of the Invention

[2] The present disclosure relates to the field of well completion. More specifically, the present disclosure relates to the completion and stimulation of a hydrocarbon-producing formation by the generation of small diameter boreholes from an existing wellbore using a hydraulic jetting assembly. The present disclosure further relates to the controlled generation of multiple lateral boreholes that extend many feet into a subsurface formation, in one trip.

Discussion of Technology

[3] In the drilling of an oil and gas well, a near-vertical wellbore is formed through the earth using a drill bit urged downwardly at a lower end of a drill string. After drilling to a predetermined bottomhole location, the drill string and bit are removed and the wellbore is lined with a string of casing. An annular area is thus formed between the string of casing and the formation penetrated by the wellbore. Particularly in a vertical wellbore, or the vertical section of a horizontal well, a cementing operation is conducted in order to fill or "squeeze" the entire annular volume with cement along part or all of the length of the wellbore. The combination of cement and casing strengthens the wellbore and facilitates the zonal isolation, and subsequent completion, of certain sections of potentially hydrocarbon-producing pay zones behind the casing.

[4] Within the last two decades, advances in drilling technology have enabled oil and gas operators to economically "kick-off" and steer wellbore trajectories from a generally vertical orientation to a generally horizontal orientation. The horizontal "leg" of each of these wellbores now often exceeds a length of one mile. This significantly multiplies the wellbore exposure to a target hydrocarbon-bearing formation (or "pay zone"). For example, for a given target pay zone having a (vertical) thickness of 100 feet, a one mile horizontal leg exposes 52.8 times as much pay zone to a horizontal wellbore as compared to the 100-foot exposure of a conventional vertical wellbore.

[5] **Figure 1A** provides a cross-sectional view of a wellbore **4** having been completed in a horizontal orientation. It can be seen that a wellbore **4** has been formed from the earth surface **1**, through numerous earth strata **2a**, **2b**, . . . **2h** and down to a hydrocarbon-producing formation **3**. The subsurface formation **3** represents a "pay zone" for the oil and gas operator. The wellbore **4** includes a vertical section **4a** above the pay zone, and a horizontal section **4c**. The horizontal section **4c** defines a heel **4b** and a toe **4d** and an elongated leg there between that extends through the pay zone **3**.

[6] In connection with the completion of the wellbore **4**, several strings of casing having progressively smaller outer diameters have been cemented into the wellbore **4**. These include a string of surface casing **6**, and may include one or more strings of intermediate casing **9**, and finally, a production casing **12**. (Not shown is the shallowest and largest diameter casing referred to as conductor pipe, which is a short section of pipe separate from and immediately above the surface casing.) One of the main functions of the surface casing **6** is to isolate and protect the shallower, fresh water bearing aquifers from contamination by any wellbore fluids. Accordingly, the conductor pipe and the surface casing **6** are almost always cemented **7** entirely back to the surface **1**.

[7] The process of drilling and then cementing progressively smaller strings of casing is repeated several times until the well has reached total depth. In some instances, the final string of casing **12** is a liner, that is, a string of casing that is not tied back to the surface **1**. The final string of casing **12**, referred to as a production casing, is also typically cemented **13** into place. In the case of a horizontal completion, the production casing **12** may be cemented, or may

provide zonal isolation using external casing packers ("ECP's), swell packers, or some combination thereof.

[8] Additional tubular bodies may be included in a well completion. These include one or more strings of production tubing placed within the production casing or liner (not shown in **Figure 1A**). In a vertical well completion, each tubing string extends from the surface **1** to a designated depth proximate the production interval **3**, and may be attached to a packer (not shown). The packer serves to seal off the annular space between the production tubing string and the surrounding casing **12**. In a horizontal well completion, the production tubing is typically landed (with or without a packer) at or near the heel **4b** of the wellbore **4**.

[9] In some instances, the pay zone **3** is incapable of flowing fluids to the surface **1** efficiently. When this occurs, the operator may install artificial lift equipment (not shown in **Figure 1A**) as part of the wellbore completion. Artificial lift equipment may include a downhole pump connected to a surface pumping unit via a string of sucker rods run within the tubing. Alternatively, an electrically-driven submersible pump may be placed at the bottom end of the production tubing. Gas lift valves, hydraulic jet pumps, plunger lift systems, or various other types of artificial lift equipment and techniques may also be employed to assist fluid flow to the surface **1**.

[10] As part of the completion process, a wellhead **5** is installed at the surface **1**. The wellhead **5** serves to contain wellbore pressures and direct the flow of production fluids at the surface **1**. Fluid gathering and processing equipment (not shown in **Figure 1A**) such as pipes, valves, separators, dehydrators, gas sweetening units, and oil and water stock tanks may also be provided. Subsequent to completion of the pay zone(s) followed by installation of any requisite downhole tubulars, artificial lift equipment, and the wellhead **5**, production operations may commence. Wellbore pressures are held under control, and produced wellbore fluids are segregated and distributed appropriately.

[11] Within the United States, many wells are now drilled principally to recover oil and/or natural gas, and potentially natural gas liquids, from pay zones previously thought to be too impermeable to produce hydrocarbons in economically viable quantities. Such "tight" or "unconventional" formations may be sandstone, siltstone, or even shale formations.

Alternatively, such unconventional formations may include coalbed methane. In any instance, "low permeability" typically refers to a rock interval having permeability less than 0.1 millidarcies.

[12] In order to enhance the recovery of hydrocarbons, particularly in low-permeability formations, subsequent (i.e., after perforating the production casing or liner) stimulation techniques may be employed in the completion of pay zones. Such techniques include hydraulic fracturing and/or acidizing. In addition, "kick-off" wellbores may be formed from a primary wellbore in order to create one or more new directionally or horizontally completed boreholes. This allows a well to penetrate along the plane of a subsurface formation to increase exposure to the pay zone. Where the natural or hydraulically-induced fracture plane(s) of a formation is vertical, a horizontally completed wellbore allows the production casing to intersect, or "source," multiple fracture planes. Accordingly, whereas vertically oriented wellbores are typically constrained to a single hydraulically-induced fracture plane per pay zone, horizontal wellbores may be perforated and hydraulically fractured in multiple locations, or "stages," along the horizontal leg **4c**.

[13] **Figure 1A** demonstrates a series of fracture half-planes **16** along the horizontal section **4c** of the wellbore **4**. The fracture half-planes **16** represent the orientation of fractures that will form in connection with a perforating/fracturing operation. According to principles of geo-mechanics, fracture planes will generally form in a direction that is perpendicular to the plane of least principal stress in a rock matrix. Stated more simply, in most wellbores, the rock matrix will part along vertical lines when the horizontal section of a wellbore resides below 3,000 feet, and sometimes as shallow as 1,500 feet, below the surface. In this instance, hydraulic fractures will tend to propagate from the wellbore's perforations **15** in a vertical, elliptical plane perpendicular to the plane of least principle stress. If the orientation of the least principle stress plane is known, the longitudinal axis of the leg **4c** of a horizontal wellbore **4** is ideally oriented parallel to it such that the multiple fracture planes **16** will intersect the wellbore at-or-near orthogonal to the horizontal leg **4c** of the wellbore, as depicted in **Figure 1A**.

[14] The desired density of perforated and fractured intervals within the pay zone **3** along the horizontal leg **4c** is optimized by calculating:

- the estimated ultimate recovery ("EUR") of hydrocarbons each fracture will drain, which requires a computation of the Stimulated Reservoir Volume ("SRV") that each fracture treatment will connect to the wellbore via its respective perforations; less
- any overlap with the respective SRV's of bounding fracture intervals; coupled with
- the anticipated time-distribution of hydrocarbon recovery from each fracture; versus
- the incremental cost of adding another perforated/fractured interval.

The ability to replicate multiple vertical completions along a single horizontal wellbore is what has made the pursuit of hydrocarbon reserves from unconventional reservoirs, and particularly shales, economically viable within relatively recent times. This revolutionary technology has had such a profound impact that currently Baker Hughes Rig Count information for the United States indicates only about one-fourth (26%) of wells being drilled in the U.S. are classified as "Vertical", whereas the other three-fourths are classified as either "Horizontal" or "Directional" (62% and 12%, respectively). That is, horizontal wells currently comprise approximately two out of every three wells being drilled in the United States.

[15] The additional costs in drilling and completing horizontal wells as opposed to vertical wells is not insignificant. In fact, it is not at all uncommon to see horizontal well drilling and completion ("D & C") costs top multiples (double, triple, or greater) of their vertical counterparts. Depending on the geologic basin, and particularly the geologic characteristics that govern such criteria as drilling penetration rates, required drilling mud rheology, casings design and cementation, etc., significant additional costs for drilling and completing horizontal wells include those involved in controlling the radius of curvature of the kick-off, and guidance of the bit and drilling assembly (including MWD and LWD technologies) in initially obtaining, then maintaining the preferred at-or-near horizontal trajectory of the wellbore **4** within the pay zone **3**, and the overall length of the horizontal

section **4c**. The critical process of obtaining wellbore isolation between frac stages, as with additional cementing and/or ECP's, are often significant additions to the increased completion expenses, as are costs for "plug-and-perf" or sleeve or port (typically ball-drop actuated) completion systems.

[16] In many cases, however, the greatest single cost in drilling and completing horizontal wells is the cost associated with pumping the multiple hydraulic fracture treatments themselves. It is not uncommon for the sum of the costs of a given horizontal well's hydraulic fracturing treatments to approach, or even exceed, 50% of its total drilling and completion cost.

[17] Crucial to the economic success of any horizontal well is the achievement of satisfactory hydraulic fracture geometries within the pay zone being completed. Many factors can contribute to the success or failure in achieving the desired geometries. These include the rock properties of the pay zone, pumping constraints imposed by the wellbore's construction and/or surface pumping equipment, and characteristics of the fracturing fluids. In addition, proppants of various mesh (sieve) sizes are typically added to the fracturing mixture to maintain the hydraulic pressure-induced fracture width in a "propped open" state, thereby increasing the fracture's conductive capacity for producing hydrocarbon fluids.

[18] Often, in order to achieve desired fracture characteristics (fracture width, fracture conductivity, and particularly, fracture half-length) within the pay zone, an overall fracture height must be created that considerably exceeds the boundaries of the pay zone. Fortunately, vertical out-of-zone fracture height growth is usually confined to a few multiples of the overall pay formation's thickness (i.e., ten's or hundreds' of feet), and thereby cannot pose a threat to contamination of much shallower fresh water sources, almost always separated from the pay zone by multiple thousands of feet of rock formations. See K. Fisher and N. Warpinski, "*Hydraulic Fracture-Height Growth: Real Data*," SPE Paper No. 145,949, SPE Annual Technical Conference and Exhibit, Denver Colorado (Oct. 30 - Nov. 2, 2012).

[19] Nevertheless, this increases the amount of fracturing fluid and proppant needed at the various "frac" stages, and further increases the required pumping horsepower. It is known that for a typical fracturing job, significant volumes of fracturing fluids, fluid additives, proppants, hydraulic ("pumping") horsepower (or, "HHP"), and their correlative costs are

expended on non-productive portions of the fractures. This represents a multi-billion dollar problem each year within the U.S. alone.

[20] Further complicating the planning of a horizontal wellbore are the uncertainties associated with fracture geometries within unconventional reservoirs. Many experts believe, based on analyses of real-time data from both tilt meter and micro-seismic surveys, that fracture geometries in less permeable, and particularly, more brittle, unconventional reservoirs can yield highly complex fracture geometries. That is, as opposed to the relatively simplistic bi-wing elliptical model perceived to fit most conventional reservoirs (and as shown in the idealistic rendition in **Figure 1A**), fracture geometries in unconventional reservoirs can be frustratingly unpredictable.

[21] In most cases, far-field fracture length and complexity is deemed detrimental (rather than beneficial) due to excessive fluid leak-off and/or reduced fracture width that can cause early screen-outs. Hence, whether fracture complexity (or, the lack thereof) enhances or reduces the SRV that the fracture network will enable the wellbore to drain is typically determined on a case-by-case (e.g., reservoir-by-reservoir) basis.

[22] Thus, it is desirable, particularly in horizontal wellbore completions for tight reservoirs, to obtain greater control over the geometric growth of the primary fracture network extending perpendicularly outward from the horizontal leg **4c**. It is further desirable to extend the length of the fracture network azimuth without significantly trespassing the horizontal pay zone **3** boundaries. Further, it is desirable to decrease the well density required to drain a given reservoir volume by increasing the effectiveness of the fracture network between wellbores through the use of two or more hydraulically-jetted mini-laterals along a horizontal leg. Still further, it is desirable to provide this guidance, constraint, and enhancement of SRV's by the creation of one or more mini-lateral boreholes as a replacement of conventional casing portals provided by the use of conventional completion procedures requiring perforations, sliding sleeves, and the like.

[23] Accordingly, a need exists for a downhole assembly having a jetting hose and a whipstock, whereby the assembly can be conveyed into any wellbore interval of any inclination, including an extended horizontal leg. A need further exists for a hydraulic jetting system that provides for substantially a 90° turn of the jetting hose opposite the point of a

casing exit, preferably utilizing the entire casing inner diameter as the bend radius for the jetting hose, thereby providing for the maximum possible inner diameter of jetting hose, and thus providing the maximum possible hydraulic horsepower to the jetting nozzle. A need further exists for a system that includes a whipstock deployable on a string of coiled tubing, wherein the whipstock can be reoriented in discreet, known increments, and not depend upon pipe rotation at the surface translating downhole.

[24] Additional needs exist that, in certain embodiments, are addressed herein. A need exists for improved methods of forming lateral wellbores using hydraulically directed forces, wherein the desired length of jetting hose can be conveyed even from a horizontal wellbore. Further, a need exists for a method of forming mini-lateral boreholes off of a horizontal leg that assist in confining subsequent SRV's up to, but not significantly beyond, pay zone boundaries. Still further, a need exists for a method by which a whipstock and jetting hose can be conveyed and operated with hydraulic and/or mechanical push forces that enable movement of the jetting nozzle and connected hose into the formation, retrieved, re-oriented and re-deployed and re-operated multiple times at as many parent wellbore depths and mini-lateral azimuth orientations as desired, to generate multiple mini-lateral bore holes within not only vertical, but highly directional and even horizontal portions of wellbores in a single trip. A need further exists to be able to convey the jetting hose in an uncoiled state, such that the bend radius within the production casing and along the whipstock is the tightest bending constraint the hose must satisfy.

[25] A need further exists for a method of hydraulically fracturing mini-lateral boreholes jetted off of the horizontal leg of a wellbore immediately following lateral borehole formation, and without the need of pulling the jetting hose, whipstock, and conveyance system out of the parent wellbore. A need further exists for a method of contouring clusters of lateral boreholes' paths based upon real-time analysis of geophysical (micro-seismic and/or tiltmeter and/or ambient micro-seismic) descriptions of resultant SRV development (or lack thereof) from pumping a given stimulation (frac) stage. Additionally, a need exists for a method of optimizing the recompletion of an existing horizontal well by optimizing the placement and contouring of new lateral borehole clusters / stimulation stages based upon the performance (or, more specifically, non-performance such as observed by production logging or permanent

ambient micro-seismic installations) of existing conventional perforation clusters and their respective stimulation stage's SRV. Stated another way, a need exists for a method of remotely controlling the erosional excavation path of the jetting nozzle and connected hydraulic hose, such that a lateral borehole, or multiple lateral borehole "clusters," can be contoured to best control the SRV geometry resulting from a subsequent stimulation treatment stage.

SUMMARY OF THE INVENTION

[26] The systems and methods described herein have various benefits in the conducting of oil and gas well completion activities. In the present disclosure, a method of forming a lateral borehole in a pay zone is first claimed. The pay zone exists within an earth subsurface. In one embodiment, the method first comprises determining a depth of the pay zone in a subsurface formation. The pay zone defines a rock matrix that has been identified as holding, or at least potentially holding, hydrocarbon fluids or organic-rich rock. In one aspect, the method also includes determining a thickness of the pay zone.

[27] The method additionally includes forming a wellbore within the pay zone. In a preferred embodiment, the wellbore has deviated section or, more preferably, is completed horizontally. In these instances, forming the wellbore means forming a parent wellbore at an angle offset from vertical, or even forming a wellbore along a generally horizontal plane.

[28] The method further includes conveying a hydraulic jetting assembly into the wellbore on a working string. Preferably, the working string is a string of coiled tubing having a sheath for holding electrical wires and, optionally, fiber optic data cables.

[29] The downhole hydraulic jetting assembly is useful for jetting multiple lateral boreholes from an existing parent wellbore into the subsurface formation. The assembly is basically comprised of two synergetic systems:

(1) an internal hose system ("the internal system"), which defines an elongated jetting hose having at its proximal end a jetting fluid inlet, and at its terminal end a jetting nozzle configured to be directed to and through a parent wellbore exit location; and

(2) an external hose conveyance, deployment and retrieval system ("the external system") that is run on the working string to provide the defined path of travel (including a whipstock) within a wellbore, with the external system being configured to carry the elongated jetting hose into a wellbore and "push" it against a whipstock set in the wellbore to urge the jetting nozzle forward into the surrounding formation.

[30] In the case of a cased wellbore, a window is formed through the casing using the jetting hose and connected nozzle, followed by the formation of a lateral borehole out into a hydrocarbon-bearing pay zone. The configuration and operation of these two synergetic systems provide that the whipstock may be re-oriented and/or re-located, and the jetting hose re-deployed into the casing and re-retrieved, for the jetting of multiple casing exits and lateral boreholes in the same trip.

[31] As noted, the internal system comprises a jetting hose having a proximal end and a distal end. A fluid inlet resides at the proximal end, while a jetting nozzle is disposed at the distal end. Preferably, a power supply such as a battery pack resides at the proximal end for providing power to electrical components of the jetting assembly.

[32] The external system comprises a pair of tubular bodies. These represent an outer conduit and an inner conduit. The outer conduit has an upper end configured to be operatively attached to the working string, or "tubing conveyance medium," for running the jetting hose assembly into the production casing, a lower end, and an internal bore there between. The inner conduit resides within the bore of the outer conduit and serves as a jetting hose carrier. The jetting hose carrier slidably receives the jetting hose during operation.

[33] A micro-annulus is formed between the jetting hose and the surrounding jetting hose carrier. The micro-annulus is sized to prevent buckling of the jetting hose as it slides within the jetting hose carrier during operation of the assembly. The micro-annulus is further configured to allow the operator to control the amount and flow direction of hydraulic fluid between the jetting hose and the surrounding inner conduit, which then converts to a fluid force that can either: (1) maintain the jetting hose in a taught configuration as it is urged

downstream; or (2) urge the jetting hose in an upstream direction as it is retrieved back into the inner conduit.

[34] The jetting hose assembly also includes a whipstock member. The whipstock member is disposed below the lower end of the outer conduit. The whipstock member includes a concave face for receiving and directing the jetting nozzle and connected hose during operation of the assembly.

[35] The jetting hose assembly is configured to (i) translate the jetting hose out of the jetting hose carrier and against the arcuate whipstock face by a translation force to a desired point of wellbore exit, (ii) upon reaching the desired point of wellbore exit, direct jetting fluid through the jetting hose and the connected jetting nozzle until an exit is formed, (iii) continue jetting along an operator's designed geo-trajectory forming a lateral borehole into the rock matrix within the pay zone, and then (iv) pull the jetting hose back into the jetting hose carrier after a lateral borehole has been formed to allow the location of the whipstock device within the wellbore to be adjusted.

[36] In one aspect, the whipstock is configured so that a face of the whipstock provides a bend radius for the jetting hose across the entire wellbore. In the case of a cased hole, the jetting hose will bend across the entire inner diameter of the production casing. Thus, the hose contacts the production casing on one side, bends along the face of the whipstock, and then extends to a casing exit on an opposite side of the production casing. This jetting hose bend radius spanning the entire I.D. of the production casing provides for utilization of the greatest possible diameter of jetting hose, which in turn provides for maximum delivery of hydraulic horsepower through the jetting hose to the jetting nozzle.

[37] The external system is configured such that it contains, conveys, deploys, and retrieves the jetting hose of the internal system in such a way as to maintain the hose in an uncoiled state. Thus, the minimum bend radius that the hose must satisfy is that of the bend radius within the production casing, along the whipstock face, at the point of a desired casing exit. In addition, the coiled tubing-based conveyance of these synergetic internal/external systems provides for simultaneous running of other conventional coiled tubing tools in the

same tool string. These may include a packer, a mud motor, a downhole (external) tractor, logging tools, and/or a retrievable bridge plug residing below the whipstock member.

[38] Returning to the method at hand, the method also comprises setting the whipstock at a desired first casing exit location along the wellbore. The face of the whipstock bends the jetting hose substantially across the entire inner diameter of the wellbore while the jetting hose is translated out of the jetting hose carrier. The method additionally includes translating the jetting hose out of the jetting hose carrier to advance the jetting nozzle to the face of the whipstock. The method then includes injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a lateral borehole within the rock matrix in the pay zone.

[39] The method also includes further injecting the jetting fluid while further translating the jetting hose and connected jetting nozzle through the jetting hose carrier and along the face of the whipstock. In this way, a first lateral borehole that extends at least 5 feet from the horizontal wellbore is formed.

[40] In the present disclosure, a unique electric-driven, rotatable jetting nozzle is optionally provided for the external system. The nozzle can emulate the hydraulics of conventional hydraulic perforators, thereby precluding the need for a separate run with a milling tool to form a casing exit. The nozzle optionally includes rearward thrusting jets about the body to enhance forward thrust and borehole cleaning during mini-lateral formation, and to provide clean-out and, possibly, borehole expansion, during pull-out.

[41] Within the external system, regulation of the hydraulic forces of both: (a) the jetting fluid's hydraulic force that urges the internal hose system downstream; and, (b) the hydraulic fluid's hydraulic force that urges the hose system back upstream, are both controlled with valves at the top and base of the carrier system, and seal assemblies both at the top of the jetting hose and at the base of the carrier system. In addition, the external system may include an internal tractor system that provides a mechanical force for selectively urging the jetting hose upstream or downstream.

[42] It is observed that known jetting systems generally rely only on "slack-off" weight of a continuous coiled tubing and/or jetting hose string for "push" force. However, this source of propulsion would be quickly dissipated by helical buckling (e.g., due to friction forces between the jetting hose and wellbore tubulars) in a highly directional or horizontal wellbore. Once the point of helical buckling is reached, supplemental push force from additional slack-off of the string tied to the surface is no longer attainable. The "can't-push-a-rope" limitation of other systems is uniquely overcome herein by the combination of hydraulic and mechanical (tractor) forces, enabling the formation of mini-laterals off of an extended-reach horizontal wellbore.

[43] The hydraulic jetting assembly herein is able to generate lateral bore holes in excess of 10 feet, or in excess of 25 feet, and even in excess of 300 feet, depending on the length of the jetting hose and its jetting hose carrier. Length of penetration and penetration rate itself may also be influenced by the hydraulic jetting-resistance qualities of the host rock. These jetting-resistance qualities may include compressive strength, pore pressure, cementation, and other features inherent to the lithology of the host rock matrix. In any instance, the lateral boreholes may have a diameter of about 1.0" or greater and may be formed at penetration rates much higher than any of the systems that have preceded it that have in common completing a 90° turn of the jetting hose within the production casing.

[44] The present system will have the capacity to generate lateral boreholes from portions of horizontal and highly directional parent wellbores heretofore thought unreachable. Anywhere to which conventional coiled tubing can be tractored within a cased wellbore, lateral boreholes can now be hydraulically jetted. Similarly, superior efficiencies will be captured as multiple intervals of lateral boreholes are formed from a single trip. Wherever satisfactory fracturing hydraulics (pump rates and pressures) are attainable via the coiled tubing-casing annulus, the entire horizontal leg of a newly drilled well may be "perforated and fractured" in stages without need of frac plugs, sliding sleeves or dropped balls.

[45] In one embodiment, multiple lateral boreholes and, optionally, side mini-lateral boreholes, together form a network or cluster of ultra-deep perforations in the rock matrix. Such a network may be designed by the operator to optimally drain a pay zone. Preferably, the

lateral boreholes extend away from the parent wellbore at a normal, or right, angle, and extend to an upper or lower boundary of the pay zone. Other angles may be used as well to take advantage of the richest portions of a pay zone. In any respect, the method may then include producing hydrocarbons. Where multiple boreholes are formed at different orientations from the wellbore and at different depths, hydrocarbons may be produced from a network of lateral boreholes. Moreover, the operation may choose to conduct subsequent formation fracturing operations from the lateral boreholes, thereby further extending the SRV.

[46] In one aspect, geometries of lateral boreholes and side min-lateral boreholes are customized within the host pay zone. The boreholes can then optimally receive a subsequent stimulation (particularly, hydraulic fracturing) treatments. This, in turn, enables optimization of the resultant Stimulated Reservoir Volume ("SRV") to be obtained from each pumping stage. During fracturing, the operator may receive real-time geophysical data, such as micro-seismic, tiltmeter, and/or ambient micro-seismic data, indicative of the effectiveness of formation treatments and SRV development. In one aspect, during a horizontal wellbore's completion or re-completion, real-time customization of the next cluster's lateral borehole geometries may be conducted prior to pumping a next stage.

[47] In one embodiment, hydrocarbons are produced from the wellbore for a period of time before the lateral borehole is formed. Thus, a novel "re-fracturing" method is provided.

[48] In a variation, the method comprises:

- forming perforations along the horizontal wellbore in sequential stages using one or more perforating guns;
- hydraulically fracturing the rock matrix along the horizontal wellbore through the perforations in sequential stages;
- conducting a flowback operation to at least partially remove hydraulic fluids injected in connection with the hydraulic fracturing; and
- optionally, producing hydrocarbon fluids for a period of time before forming the lateral borehole.

[49] In another alternate embodiment, the method further comprises:

- retracting the jetting hose and connected nozzle from the first casing exit after forming the first lateral borehole;
- re-orienting the whipstock at the desired first location;
- injecting hydraulic jetting fluid through the jetting hose and connected nozzle, thereby forming a second casing exit;
- further injecting the jetting fluid through the jetting hose and connected nozzle, thereby excavating rock matrix in the pay zone; and;
- still further injecting the jetting fluid while advancing the jetting hose and connected nozzle, thereby forming a second lateral borehole that also extends at least 5 feet from the horizontal wellbore from the second casing exit.

[50] In this embodiment, each of the first and second lateral boreholes may have an internal diameter of between about 0.4 and 2.5 inches. In one aspect, the second lateral borehole is offset from the first lateral borehole by between 10-degrees and 180-degrees. The method may then further include producing hydrocarbon fluids from the first and second lateral boreholes together.

[51] In another alternate embodiment, the method further comprises:

- retracting the jetting hose and connected nozzle from the first casing exit after forming the first lateral borehole;
- retracting the jetting hose and connected nozzle from the first casing exit;
- moving the whipstock to a desired second location, preferably further uphole;
- injecting hydraulic jetting fluid through the jetting hose and connected nozzle, thereby forming a second casing exit at the second location;
- further injecting the jetting fluid through the jetting hose and connected nozzle, thereby excavating rock matrix in the pay zone at the second location; and

- still further injecting the jetting fluid while advancing the jetting hose and connected nozzle, thereby forming a second lateral borehole that also extends at least 5 feet from the horizontal wellbore along the second desired location.

[52] In this embodiment, the first and second lateral boreholes may be separated by about 5 to 200 feet. Preferably, each of the first and second lateral boreholes is at least 25 feet in length and, more preferably, at least 100 feet in length.

[53] In any of the above embodiments, the method may further comprise injecting fracturing fluids through an annulus formed between the external conduit and the surrounding production casing, and injecting the fracturing fluids into one or more lateral boreholes at an injection pressure sufficient to part the rock matrix in the pay zone. The hydraulic jetting assembly may further comprise a packer or a retrievable bridge plug disposed below the whipstock member, and the method may further comprise setting the packer or bridge plug before injecting a fracturing fluid. Alternatively or in addition, an acid treatment may be washed down through the annular region and into the lateral boreholes, preferably prior to fracturing. Given the system's ability to controllably "steer" a jetting nozzle and thereby contour the path of a lateral borehole (or, "clusters" of boreholes), fracturing fluids can be more optimally "guided" and constrained within a pay zone.

[54] In any of the above methods, the translation force used in moving the jetting hose out of the jetting hose carrier may be a hydraulic force. The jetting hose and associated jetting hose carrier are preferably each at least 10 feet in length and, more preferably, at least 50 feet in length.

[55] In one embodiment, the jetting hose assembly further comprises a main control valve. The main control valve is disposed proximate the upper end of the outer conduit, and is movable between a first position and a second position. In the first position the main control valve directs jetting fluids pumped into the wellbore into the jetting hose, while in the second position the main control valve directs hydraulic fluid pumped into the wellbore into the annular region formed between the jetting hose carrier and the surrounding outer conduit. Placement of the main control valve in its first position allows an operator to pump jetting fluids into the working string, through the main control valve, and against the upper seal

assembly in the micro-annulus, thereby pistonly pushing the jetting hose and connected nozzle downhole in an uncoiled state while directing jetting fluids through the nozzle. Placement of the main control valve in its second position allows an operator to pump hydraulic fluids into the working string, through the main control valve, into the annular region between the jetting hose carrier and the surrounding outer conduit, through the pressure regulator valve and into the micro-annulus, thereby pulling the jetting hose back up into the inner conduit in its uncoiled state.

[56] In one preferred embodiment, the translation force comprises both the hydraulic force and a separate mechanical force. In this instance, the jetting hose assembly further comprises an internal tractor system residing downstream from the lower end of the outer conduit. The internal tractor system comprises an inner conduit portion defining a part of the jetting hose carrier for receiving the jetting hose, an outer conduit portion defining a part of the outer conduit, the outer conduit portion having a star-shaped profile defining a plurality of radially-disposed prongs, a wiring chamber housing electrical wires, data cables, or both within one of the plurality of prongs, and at least one pair of grippers residing within opposing prongs, with each gripper being configured to engage and mechanically move the jetting hose along the jetting hose carrier when rotatably actuated.

[57] In one embodiment, the hydraulic jetting assembly further comprises a docking station located at an upper end of the external system. The docking station is configured to mate with the battery pack. The docking station having a micro-processor and is in communication with an operator at the surface by means of the electrical wires, the data cables or both of the coiled tubing. In this arrangement, the method may further comprise:

- sending commands from the surface to the docking station;
- sending data from a logging tool downstream from the whipstock to the docking station; and
- sending data from the docking station to the surface.

[58] The docking station preferably also houses a micro-processor along with a micro-transmitter, a micro-receiver, an electrical current regulator, or combinations thereof. The

docking station may be configured to transfer: (1) power to the battery pack, said power either originating from generation at the surface, or from generation by a mud turbine below the whipstock member, said power being transmitted via electrical wiring provided along the external system; and (2) data to and from the micro-transmitter and micro-receiver in the docking station, between one or more geo-spatial chips housed at or near the nozzle and the operator at the surface. The micro-transmitter housed in the battery pack is configured to wirelessly transmit the data received from the micro-receiver to a micro-receiver housed in the docking station. The docking station is configured to further transmit the data to a processor at the surface (i) wirelessly, (ii) via electrical wires bundled in the coiled tubing, or (iii) via data cables bundled in the coiled tubing.

[59] In one arrangement, the method further comprises

- obtaining geo-mechanical data for the pay zone, the data comprising porosity, permeability, Poisson ratio, modulus of elasticity, shear modulus, Lame' constant, Vp/Vs, or combinations thereof;
- conducting a geo-mechanical analysis of the rock matrix in the pay zone to determine a direction of least minimum principle stress; and
- forming at least two lateral boreholes in the pay zone using the downhole hydraulic jetting assembly by steering the nozzle (i) in a direction perpendicular to the direction of least minimum principle stress, or (ii) in a direction parallel to the direction of least minimum principle stress.

[60] In one arrangement, a longitudinal axis of the horizontal wellbore is oriented parallel to the plane of least principle stress of the rock matrix comprising the pay zone. In addition, the first lateral borehole is formed in a direction perpendicular to the plane of least principle stress of the rock matrix. Conducting a geo-mechanical analysis of the rock matrix may comprise creating a finite element mesh representing the pay zone, wherein the mesh defines a plurality of nodes representing points in space. Each point has potential displacement in more than one direction. The analysis may further involve predicting changes in the stress profile within the rock matrix as a result of the formation of the lateral boreholes.

[61] In another arrangement, the downhole hydraulic jetting assembly and the methods herein operate in conjunction with a guidance system. The guidance system includes the use of at least three longitudinally oriented actuator wires connected to a distal end of the jetting nozzle. The actuator wires are equi-distantly spaced about the circumference of the jetting hose at its distal end, and are fabricated from a conductive material that contracts in response to electrical current. Differing amounts of electrical current directed through the actuator wires will induce a bending moment to orient the jetting nozzle in a desired direction. In this arrangement, the micro-processor is configured to control electrical current regulators feeding current to the respective actuator wires. This, in turn, controls a geo-orientation of the nozzle for directional hydraulic boring.

[62] In one aspect of the guidance system, geo-location signals are sent by one or more geo-spatial chips residing along or near the nozzle. The geo-location signals are indicative of the location of the nozzle, its orientation, or both. The geo-location signals are transmitted as data from the geo-spatial chips to the micro-receiver in the battery pack. Signals may be sent via electrical wiring or data cables bundled in the jetting hose. The micro-transmitter housed in the battery pack's end cap is configured to wirelessly transmit the data received from the micro-receiver to a corresponding micro-receiver housed in the docking station. In addition, the docking station may be configured to further transmit the data to a processor at the surface. This geo-date may be sent wirelessly, via electrical wires bundled in the coiled tubing, or via data cables bundled in the coiled tubing.

[63] Geo-trajectory instructions may likewise be sent from a control system residing either at the surface, or in the micro-processor residing in the docking station, downhole. The control system sends signals to one or more current regulators for regulating an amount of current to be sent to each individual actuator wire downhole. Contraction of each of the actuator wires is in direct proportion to an amount of electrical current each wire receives. The contraction, in turn, creates a bending moment, thereby enabling geo-steering of the nozzle according to a desired trajectory. In a preferred embodiment, the bending moment applied to the distal end of the jetting hose is controlled by an operator at the surface through the delivery of geo-trajectory signals sent to a micro-transmitter in the docking station.

Brief Description of the Drawings

[64] So that the manner in which the present inventions can be better understood, certain illustrations, charts and/or flow charts are appended hereto. It is to be noted, however, that the drawings illustrate only selected embodiments of the inventions and are therefore not to be considered limiting of scope, for the inventions may admit to other equally effective embodiments and applications.

[65] Figure 1A is a cross-sectional view of an illustrative horizontal wellbore. Half-fracture planes are shown in 3-D along a horizontal leg of the wellbore to illustrate fracture stages and fracture orientation relative to a subsurface formation.

[66] Figure 1B is an enlarged view of the horizontal portion of the wellbore of Figure 1A. Conventional perforations are replaced by ultra-deep perforations, or mini-lateral boreholes, to create fracture wings.

[67] Figure 2 is a longitudinal, cross-sectional view of a downhole hydraulic jetting assembly of the present invention, in one embodiment. The assembly is shown within a horizontal section of a production casing. The jetting assembly has an external system and an internal system.

[68] Figure 3 is a longitudinal, cross-sectional view of the internal system of the hydraulic jetting assembly of Figure 2. The internal system extends from an upstream battery pack end cap (that mates with the external system's docking station) at its proximal end to an elongated hose having a jetting nozzle at its distal end.

[69] Figure 3A is a cut-away perspective view of the battery pack section of the internal system of Figure 3.

[70] Figure 3B-1 is a cut-away perspective view of a jetting fluid inlet located between the base of the battery pack section and the jetting hose. A jetting fluid receiving funnel is shown for receiving fluids into the jetting hose of the internal system of Figure 3.

[71] Figure 3B-1.a is an axial, cross-sectional view of the internal system of Figure 3 taken at the top of the bottom end cap of the battery pack section.

[72] Figure 3B-1.b is an axial, cross-sectional view of the internal system of Figure 3 taken at the top of the jetting fluid inlet.

[73] Figure 3C is a cut-away perspective view of an upper portion of the internal system of Figure 3, from the base of the jetting hose's fluid receiving funnel through the jetting hose's upper seal assembly.

[74] Figure 3D-1 presents a cross-sectional view of a bundled jetting hose, with electrical wiring and data cabling, as may be used in the internal system of Figure 3.

[75] Figure 3D-1a is an axial, cross-sectional view of the bundled jetting hose of Figure 3D-1. Both electrical wires and fiber optical (or data) cables are seen.

[76] Figure 3E is an expanded cross-sectional view of the terminal end of the jetting hose of Figure 3D-1, showing the jetting nozzle of the internal system of Figure 3. The bend radius of the jetting hose is shown within a cut-away section of the whipstock of the external system of Figure 3.

[77] Figures 3F-1a through 3G-1c present enlarged, cross-sectional views of the jetting nozzle of Figure 3E, in various embodiments.

[78] Figure 3F-1a is an axial, cross-sectional view showing a basic nozzle body. The nozzle body includes a rotor and a surrounding stator.

[79] Figure 3F-1b is a longitudinal, cross-sectional view of a jetting nozzle, taken across line C-C′ of Figure 3F-1a. Here, the nozzle uses a single discharge slot at the tip of the rotor. The nozzle also includes bearings between the rotor and the surrounding stator.

[80] Figure 3F-1c is a longitudinal cross-sectional view of the jetting nozzle of Figure 3F-1b, in a modified embodiment. Here, the jetting nozzle includes a geo-spatial chip, and is shown connected to a jetting hose via welding.

[81] Figure 3F-1d is an axial, cross-sectional view of the jetting hose of Figure 3F-1c, taken across line c-c'.

[82] Figures 3F-2a and 3F-2b present longitudinal, cross-sectional views of the nozzle of Figure 3E, in an alternate embodiment. Along with a single discharge slot at the tip of the rotor, five rearward thrust jets are placed in the body of the stator, actuated by forward displacement of a slideable nozzle throat insert against a slideable collar and biasing mechanism.

[83] In Figure 3F-2a, the insert and collar are in their closed position. In Figure 3F-2b, the insert and collar are in their open position allowing fluid to flow through the rearward thrust jets. The jets are opened when a sufficient pumping pressure overcomes the resistance of a spring.

[84] Figure 3F-2c is an axial, cross-sectional view of the nozzle of Figure 3F-2a. Five rearward thrust jets are shown for generating a rearward thrust force.

[85] Figures 3F-3a and 3F-3c provide longitudinal, cross-sectional views of the jetting nozzle of Figure 3E, in another alternate embodiment. Here, multiple rearward thrust jets residing in both the stator body and the rotor body are used. In this arrangement, an electromagnetic force pulling on a magnetic collar, biased by a spring, is used for opening/closing the rearward thrust jets.

[86] In Figure 3F-3a, the collar of the jetting nozzle is in its closed position. In Figure 3F-2b, the collar is in its open position allowing fluid to flow through the rearward thrust jets.

[87] Figures 3F-3b and 3F-3d show axial, cross-sectional views of the jetting nozzle correlative to Figures 3F-3a and 3F-3c, respectively. Eight rearward thrust jets are seen. This embodiment provides for intermittent alignment of the four jetting ports in the rotor with either of the two sets of four jetting ports in the stator to produce a pulsating rearward thrust flow.

[88] Figure 3G-1a is an axial, cross-sectional view showing a basic collar body for a jetting collar that can be placed within a length of jetting hose. The collar body again includes a rotor and a surrounding stator. The view is taken across line D-D' of Figure 3G-1b.

[89] Figure 3G-1b is a longitudinal, cross-sectional view of the jetting collar of Figure 3G-1a. As with the jetting nozzle of Figures 3F-3a through 3F-3d, two sets of four jetting ports in the stator intermittently align with the four jetting ports in the rotor to produce pulsating rearward thrust flow.

[90] Figure 3G-1c is an axial, cross-sectional view of the jetting nozzle of Figure 3G-1b, taken across line d-d'.

[91] Figure 4 is a longitudinal, cross-sectional view of the external system of the downhole hydraulic jetting assembly of Figure 2, in one embodiment. The external system resides within production casing of the horizontal leg of the wellbore of Figure 2.

[92] Figure 4A-1. is an enlarged, longitudinal cross-sectional view of a portion of a bundled coiled tubing conveyance medium which conveys the external system of Figure 4 into and out of the wellbore.

[93] Figure 4A-1a is an axial, cross-sectional view of the coiled tubing conveyance medium of Figure 4A-1. In this embodiment, an inner coiled tubing is "bundled" concentrically with both electrical wires and data cables within a protective outer layer.

[94] Figures 4A-2 is another axial, cross-sectional view of the coiled tubing conveyance medium of Figure 4A-1a, but in a different embodiment. Here, the inner coiled tubing is "bundled" eccentrically within the protective outer layer to provide more evenly-spaced protection of the electrical wires and data cables.

[95] Figure 4B-1 is a longitudinal, cross-sectional view of a crossover connection, which is the upper-most member of the external system of Figure 4. The crossover section is configured to join the coiled tubing conveyance medium of Figure 4A-1 to a main control valve.

[96] Figure 4B-1a is an enlarged, perspective view of the crossover connection of Figure 4B-1, seen between cross-sections E-E′ and F-F′. This view highlights the wiring chamber's general transition in cross-sectional shape from circular to elliptical.

[97] Figure 4C-1 is a longitudinal, cross-sectional view of the main control valve of the external system of Figure 4.

[98] Figure 4C-1a is a cross-sectional view of the main control valve, taken across line G-G′ of Figure 4C-1.

[99] Figure 4C-1b is a perspective view of a sealing passage cover of the main control valve, shown exploded away from Figure 4C-1a.

[100] Figure 4D-1 is a longitudinal, cross-sectional view of a jetting hose carrier section of the external system of Figure 4. The jetting hose carrier section is attached downstream of the main control valve.

[101] Figure 4D-1a shows an axial, cross-sectional view of the main body of the jetting hose carrier section, taken along line H-H′ of Figure 4D-1.

[102] Figure 4D-1b is an enlarged view of a portion of the jetting hose carrier section of Figure 4D.1. A docking station of the external system is more clearly seen.

[103] Figure 4D-2 is an enlarged, longitudinal, cross-sectional view of the external system's jetting hose carrier section of Figure 4D-1, with inclusion of the jetting hose of the internal system from Figure 3.

[104] Figure 4D-2a provides an axial, cross-sectional view of the jetting hose carrier section of Figure 4D-1, with the jetting hose residing therein.

[105] Figure 4E-1 is a longitudinal, cross-sectional view of selected portions of the external system of Figure 4. Visible are a jetting hose pack-off section, and an outer body transition from the preceding circular body (I-I′) of the jetting hose carrier section to a star-shaped body (J-J′) of the jetting hose pack-off section

[106] Figure 4E-1a is an enlarged, perspective view of the transition between lines I-I' and J-J' of Figure 4E-1.

[107] Figure 4E-2 shows an enlarged view of a portion of the jetting hose pack-off section. Internal seals of the pack-off section conform to the outer circumference of the jetting hose (Figure 3) residing therein. A pressure regulator valve is shown schematically adjacent the pack-off section.

[108] Figure 4F-1 is a further downstream longitudinal, cross-sectional view of the external system of Figure 4. The jetting hose pack-off section and the outer body transition from Figure 4E-1 are again shown. Also visible here is an internal tractor system. Note each of the aforementioned components are shown with a longitudinal cross-sectional view of the jetting hose of Figure 3 residing therein.

[109] Figure 4F-2 is an enlarged, longitudinal, cross-sectional view of a portion of the internal tractor system of Figure 4-F1, again with a cross-section of the jetting hose residing therein. An internal motor, gear and gripper assembly is also shown.

[110] Figure 4F-2a is an axial, cross-sectional view of the internal tractor system of Figure 4F-2, taken across line K-K′ of Figures 4F-1 and 4F-2.

[111] Figure 4F-2b is an enlarged half-view of a portion of the internal tractor system of Figure 4F-2a.

[112] Figure 4G-1 is still a further downstream longitudinal, cross-sectional view of the external system of Figure 4. This view shows a transition from the internal tractor to an upper swivel, followed by the upper swivel of the external system.

[113] Figure 4G-1a depicts a perspective view of the outer body transition between the internal tractor system to the upper swivel. This is a star-shape (L-L') to a circle-shape (M-M') transition of the outer body.

[114] Figure 4G-1b provides an axial, cross-sectional view of the upper swivel of Figure 4-G1, taken across line N-N′.

[115] Figure 4H-1 is a cross-sectional view of a whipstock member of the external system of Figure 4, but shown vertically instead of horizontally. The jetting hose of the internal system (Figure 3) is shown bending across the whipstock, and extending through a window in

the production casing. The jetting nozzle of the internal system is shown affixed to the distal end of the jetting hose.

[116] Figure 4H-1a is an axial, cross-sectional view of the whipstock member, with a perspective view of sequential axial jetting hose cross-sections depicting its path downstream from the center of the whipstock member at line O-O′ to the start of the jetting hose's bend radius as it approaches line P-P′.

[117] Figure 4H-1b depicts an axial, cross-sectional view of the whipstock member at line P-P′.

[118] Figure 4I-1 is a longitudinal, cross-sectional view of a bottom swivel within the external system of Figure 4, residing just downstream of slips (shown engaging the surrounding production casing) near the base of the preceding whipstock member.

[119] Figure 4I-1a provides an axial, cross-sectional view of a portion of the bottom swivel of Figure 4I-1, taken across line Q-Q′.

[120] Figure 4J is another longitudinal view of the bottom swivel of Figure 4I-1. Here, the bottom swivel is connected to a transition section, which in turn is connected to a conventional mud motor, an external tractor, and a logging sonde, thus completing the entire downhole tool string. For simplification, neither a packer nor a retrievable bridge plug has been included in this configuration.

Detailed Description of Certain Embodiments

Definitions

[121] As used herein, the term "hydrocarbon" refers to an organic compound that includes primarily, if not exclusively, the elements hydrogen and carbon. Hydrocarbons generally fall into two classes: aliphatic, or straight chain hydrocarbons, and cyclic, or closed ring hydrocarbons, including cyclic terpenes. Examples of hydrocarbon-containing materials include any form of natural gas, oil, coal, and bitumen that can be used as a fuel or upgraded into a fuel.

[122] As used herein, the term "hydrocarbon fluids" refers to a hydrocarbon or mixtures of hydrocarbons that are gases or liquids. For example, hydrocarbon fluids may include a hydrocarbon or mixtures of hydrocarbons that are gases or liquids at formation conditions, at processing conditions, or at ambient conditions. Hydrocarbon fluids may include, for example, oil, natural gas, condensate, coal bed methane, shale oil, shale gas, and other hydrocarbons that are in a gaseous or liquid state.

[123] As used herein, the term "fluid" refers to gases, liquids, and combinations of gases and liquids, as well as to combinations of gases and solids, and combinations of liquids and solids.

[124] As used herein, the term "subsurface" refers to geologic strata occurring below the earth's surface.

[125] The term "subsurface interval" refers to a formation or a portion of a formation wherein formation fluids may reside. The fluids may be, for example, hydrocarbon liquids, hydrocarbon gases, aqueous fluids, or combinations thereof.

[126] The terms "zone" or "zone of interest" refer to a portion of a formation containing hydrocarbons. Sometimes, the terms "target zone," "pay zone," or "interval" may be used.

[127] As used herein, the term "wellbore" refers to a hole in the subsurface made by drilling or insertion of a conduit into the subsurface. A wellbore may have a substantially circular cross section, or other cross-sectional shape. As used herein, the term "well," when referring to an opening in the formation, may be used interchangeably with the term "wellbore."

[128] The term "jetting fluid" refers to any fluid pumped through a jetting hose and nozzle assembly for the purpose of erosionally boring a lateral borehole from an existing parent wellbore. The jetting fluid may or may not contain an abrasive material.

[129] The term "abrasive material" or "abrasives" refers to small, solid particles mixed with or suspended in the jetting fluid to enhance erosional penetration of: (1) the pay zone;

and/or (2) the cement sheath between the production casing and pay zone; and/or (3) the wall of the production casing at the point of desired casing exit.

[130] The terms "tubular" or "tubular member" refer to any pipe, such as a joint of casing, a portion of a liner, a joint of tubing, a pup joint, or coiled tubing.

[131] The terms "lateral borehole" or "mini-lateral" or "ultra-deep perforation" ("UDP") refer to the resultant borehole in a subsurface formation, typically upon exiting a production casing and its surrounding cement sheath in a parent wellbore, with said borehole formed in a known or prospective pay zone. For the purposes herein, a UDP is formed as a result of hydraulic jetting forces erosionally boring through the pay zone with a jetting fluid directed through a jetting hose and out a jetting nozzle affixed to the terminal end of the jetting hose. Preferably, each UDP will have a substantially normal trajectory relative to the parent wellbore.

[132] The terms "steerable" or "guidable", as applied to a hydraulic jetting assembly, refers to a portion of the jetting assembly (typically, the jetting nozzle and/or the portion of jetting hose immediately proximal the nozzle) for which an operator can direct and control its geo-spatial orientation while the jetting assembly is in operation. This ability to direct, and subsequently re-direct the orientation of the jetting assembly during the course of erosional excavation can yield UDP's with directional components in one, two, or three dimensions, as desired.

[133] The terms "perforation cluster" or "UDP cluster" refer to a designed grouping of lateral boreholes off a parent well casing. These groupings are ideally designed to receive and transmit a specific "stage" of a stimulation treatment, usually in the course of completing or recompleting a horizontal well by hydraulic fracturing (or "fracking").

[134] The term "stage" references a discreet portion of a stimulation treatment applied in completing or recompleting a specific pay zone, or specific portion of a pay zone. In the case of a cased horizontal parent wellbore, up to 10, 20, 50 or more stages may be applied to their respective perforation (or UDP) clusters. Typically, this requires some form of zonal isolation prior to pumping each stage.

[135] The terms "contour" or "contouring" as applied to individual UDP's, or groupings of UDP's in a "cluster", refers to steerably excavating the UDP (or lateral borehole) so as to optimally receive, direct, and control stimulation fluids, or fluids and proppants, of a given stimulation (typically, fracking) stage. This ability to '...optimally receive, direct, and control...' a given stage's stimulation fluids is designed to retain the resultant stimulation geometry "in zone", and/or concentrate the stimulation effects where desired. The result is to optimize, and typically maximize, the Stimulated Reservoir Volume ("SRV").

[136] The terms "real time" or "real time analysis" of geophysical data (such as micro-seismic, tiltmeter, and or ambient micro-seismic data) that is obtained during the course of pumping a stage of a stimulation (such as fracking) treatment means that results of said data analysis can be applied to: (1) altering the remaining portion of the stimulation treatment (yet to be pumped) in its pump rates, treating pressures, fluid rheology, and proppant concentration in order to optimize the benefits therefrom; and, (2) optimizing the placement of perforations, or contouring the trajectories of UDP's, within the subsequent "cluster(s)" to optimize the SRV obtained from the subsequent stimulation stages.

Description of Specific Embodiments

[137] A downhole hydraulic jetting assembly is provided herein. The jetting assembly is designed to direct a jetting nozzle and connected hydraulic hose through a window formed along a string of production casing, and then "jet" one or more boreholes outwardly into a subsurface formation. The lateral boreholes essentially represent ultra-deep perforations that are formed by using hydraulic forces directed through a flexible, high pressure jetting hose, having affixed to its distal end a high pressure jetting nozzle. The subject assembly capitalizes on a single hose and nozzle apparatus to continuously jet, optionally, both a casing exit and the subsequent lateral borehole.

[138] **Figure 1A** is a schematic depiction of a horizontal well **4**, with wellhead **5** located above the earth's surface **1**, and penetrating several series of subsurface strata **2a** through **2h** before reaching a pay zone **3**. The horizontal section **4c** of the wellbore **4** is depicted between a "heel" **4b** and a "toe" **4d**. Surface casing **6** is shown as cemented **7** fully from the surface

casing shoe **8** back to surface **1**, while the intermediate casing string **9** is only partially cemented **10** from its shoe **11**. Similarly, production casing string **12** is only partially cemented **13** from its casing shoe **14**, though sufficiently isolating the pay zone **3**. Note how in the **Figure 1A** depiction of a typical horizontal wellbore, conventional perforations **15** within the production casing **12** are shown in up-and-down pairs, and are depicted with subsequent hydraulic fracture half-planes (or, "frac wings") **16**.

[139] **Figure 1B** is an enlarged view of the lower portion of the wellbore **4** of **Figure 1A**. Here, the horizontal section **4c** between the heel **4b** and the toe **4d** is more clearly seen. In this depiction, application of the subject apparati and methods herein replaces the conventional perforations (**15** in **Figure 1A**) with pairs of opposing horizontal UDP's **15** as depicted in **Figure 1B**, again with subsequently generated fracture half-planes **16**. Specifically depicted in **Figure 1B** is how the frac wings **16** are now better confined within the pay zone **3**, while reaching much further out from the horizontal wellbore **4c** into the pay zone **3**. Stated another way, in-zone fracture propagation is significantly enhanced by the pre-existence of the UDP's **15** as generated by the assembly and methods disclosed herein.

[140] **Figure 2** provides a longitudinal, cross-sectional view of a downhole hydraulic jetting assembly **50** of the present invention, in one embodiment. The jetting assembly **50** is shown residing within a string of production casing **12**. The production casing **12** may have, for example, a 4.5-inch O.D. (4.0-inch I.D.). The production casing **12** is presented along a horizontal portion **4c** of the wellbore **4**. As noted in connection with **Figures 1A** and **1B**, the horizontal portion **4c** defines a heel **4b** and a toe **4d**.

[141] The jetting assembly **50** generally includes an internal system **1500** and an external system **2000**. The jetting assembly **50** is designed to be run into a wellbore **4** at the end of a working string, sometimes referred to herein as a "conveyance medium." Preferably, the working string is a string of coiled tubing **100**. The conveyance medium **100** may be conventional coiled tubing. Alternatively, a "bundled" product that incorporates electrically conductive wiring and data conductive cables (such as fiber optic cables) around the coiled tubing core, protected by an erosion/abrasion resistant outer layer(s), such as PFE and/or Kevlar, or even another (outer) string of coiled tubing may be used. It is observed that fiber

optic cables have a practically negligible diameter, and are oilfield-proven to be efficient in providing direct, real-time data transmission and communications with downhole tools. Other emerging transmission media such as carbon nanotube fibers may also be employed.

[142] Other conveyance media may be used for the jetting assembly **50**. These include, for example, a standard e-coil system, a customized FlatPAK® assembly, PUMPTEK's® Flexible Steel Polymer Tubing ("FSPT") or Flexible Tubing Cable ("FTC") tubing. Alternatively, tubing have PTFE (Polytetrafluorethylene) and Kevlar®-based materials, or Draka Cableteq USA, Inc.'s® Tubing Encapsulated Cable ("TEC") system may be used. In any instance, it is desirable that the conveyance medium **100** be flexible, somewhat malleable, non-conductive, pressure resistant (to withstand high pressure fracturing fluids optionally being pumped down the annulus), temperature resistant (to withstand bottom hole wellbore operating temperatures, often in excess of 200° F, and sometimes exceeding 300° F), chemical resistant (at least in resistance to the additives included in the frac fluids), friction resistant (to minimize the downhole pressure loss due to friction while pumping the frac treatment), erosion resistant (to withstand the erosive effects of afore-mentioned annular fracturing fluids) and abrasion resistant (to withstand the abrasive effects of proppants suspended in the aforementioned annular fracturing fluids).

[143] If a standard coiled tubing string is employed, communications and data transmission may be accomplished by hydro-pulse technology (or so-called mud-pulse telemetry), acoustic telemetry, EM telemetry, or some other remote transmission/reception system. Similarly, electricity for operating the apparatus may be generated downhole by a conventional mud motor(s), which would allow the electrical circuitry for the system to be confined below the end of the coiled tubing. The present hydraulic jetting assembly **50** is not limited by the data transmission system or the power transmission or the conveyance medium employed unless expressly so stated in the claims.

[144] It is preferred to maintain an outer diameter of the coiled tubing **100** that leaves an annular area within the approximate 4.0" I.D. of the casing **12** that is greater than or equal to the cross-sectional area open to flow for a 3.5" O.D. frac (tubing) string. This is because, in the preferred method (after jetting one or more, preferably two opposing mini-laterals, or even

specially contoured "clusters" of small-diameter lateral boreholes), fracture stimulation can immediately (after repositioning the tool string slightly uphole) take place down the annulus between the coiled tubing conveyance medium **100** plus the external system **2000**, and the well casing **12**. For 9.2#, 3.5" O.D. tubing (i.e., frac string equivalent), the I.D. is 2.992 inches, and the cross-sectional area open to flow is 7.0309 square inches. Back-calculating from this same 7.0309 in^2 equivalency yields a maximum O.D. available for both the coiled tubing conveyance medium **100** and the external system **2000** (having generally circular cross-sections) of 2.655". Of course, a smaller O.D. for either may be used provided such accommodate a jetting hose **1595**.

[145] In the view of **Figure 2**, the assembly **50** is in an operating position, with a jetting hose **1595** being run through a whipstock **1000**, and a jetting nozzle **1600** passing through a first window "**W**" of the production casing **12**. At the end of the jetting assembly **50**, and below the whipstock **1000**, are several optional components. These include a conventional mud motor **1300**, an external (conventional) tractor **1350** and a logging sonde **1400**. These components are shown and described more fully below in connection with **Figure 4**.

[146] **Figure 3** is a longitudinal, cross-sectional view of the internal system **1500** of the hydraulic jetting assembly **50** of **Figure 2**. The internal system **1500** is a steerable system that, when in operation, is able to move within and extend out of the external system **2000**. The internal system **1500** is comprised primarily of:

(1) power and geo-control components;

(2) a jetting fluid intake;

(3) the jetting hose **1595**; and

(4) the jetting nozzle **1600**.

[147] The internal system **1500** is designed to be housed within the external system **2000** while being conveyed by the coiled tubing conveyance medium **100** and the attached external system **2000** in to and out of the parent wellbore **4**. Extension of the internal system **1500** from and retraction back into the external system **2000** is accomplished by the application of: (a) hydraulic forces; (b) mechanical forces; or (c) a combination of hydraulic and mechanical

forces. Beneficial to the design of the internal **1500** and external **2000** systems comprising the hydraulic jetting apparatus **50** is that transport, deployment, or retraction of the jetting hose **1595** never requires the jetting hose to be coiled. Specifically, the jetting hose **1595** is never subjected to a bend radius smaller than the I.D. of production casing **12**, and that only incrementally while being advanced along the whipstock **1050** of the jetting hose whipstock member **1000** of the external system **2000**. Note the jetting hose **1595** is typically ¼th" to $^{5}/_{8}$ths" I.D., and up to approximately 1" O.D., flexible tubing that is capable of withstanding high internal pressures.

[148] The internal system **1500** first includes a battery pack **1510**. **Figure 3A** provides a cut-away perspective view of the battery pack **1510** of the internal system **1500** of **Figure 3**. Note this section **1510** has been rotated 90° from the horizontal view of **Figure 3** to a vertical orientation for presentation purposes. An individual AA battery **1551** is shown in a sequence of end-to-end like batteries forming the battery pack **1550**. Protection of the batteries **1551** is primarily via a battery pack casing **1540** which is sealed by an upstream battery pack end cap **1520** and a downstream battery pack end cap **1530**. These components (**1540**, **1520**, and **1530**) present exterior faces exposed to the high pressure jetting fluid stream. Accordingly, they are preferably constructed of or are coated with a non-conductive, highly abrasion/erosion/corrosion resistant material.

[149] The upstream battery pack end cap **1520** has a conductive ring about a portion of its circumference. When the internal system **1500** is "docked" (i.e., matingly received into a docking station **325** of the external system **2000**) the battery pack end cap **1520** can receive and transmit current and, thus, re-charge the battery pack **1550**. Note also that the end caps **1520** and **1530** can be sized so as to house and protect any servo, microchip, circuitry, geospatial or transmitter/receiver components within them.

[150] The battery pack end-caps **1520**, **1530** may be threadedly attached to the battery pack casing **1540**. The battery pack end-caps **1520**, **1530** may be constructed of a highly erosive- and abrasive-resistant, high pressure material, such as titanium, perhaps even further protected by a thin, highly erosive- or abrasive-resistant coating, such as polycrystalline diamond. The shape and construction of the end-caps **1520**, **1530** are preferably such that they

can deflect the flow of high pressure jetting fluid without incurring significant wear. The upstream end cap **1520** must deflect flow to an annular space (not shown in **Figure 3**) between the battery casing **1540** and a surrounding jetting hose conduit **420** (seen in **Figure 3C**) of a jetting hose carrier system (shown at **400** in **Figure 4D-1**). The downstream end-cap **1530** bounds part of the flow path of the jetting fluid from this annular space down into the I.D. of the jetting hose **1595** itself through a jetting fluid receiving (or, "intake") funnel (shown at **1570** in **Figure 3B-1**).

[151] Thus, the path of the high pressure hydraulic jetting fluid (with or without abrasives) is as follows:

(1) Jetting fluid is discharged from a high pressure pump at the surface **1** down the I.D. of the coiled tubing conveyance medium **100**, at the end of which it enters the external system **2000**;

(2) Jetting fluid enters the external system **2000** through a coiled tubing transition connection **200**;

(3) Jetting fluid enters the main control valve **300** through a jetting fluid passage **345**;

(4) Because the main control valve **300** is positioned to receive jetting fluid (as opposed to hydraulic fluid), a sealing passage cover **320** will be positioned to seal a hydraulic fluid passage **340**, leaving the only available fluid path through the jetting fluid passage **345**, the discharge of which is sealingly connected to the jetting hose conduit **420** of the jetting hose carrier system **400**;

(5) Upon entering the jetting hose conduit **420**, the jetting fluid will first pass by a docking station **325** (which is affixed within the jetting hose conduit **420**) through the annulus between the docking station **325** and the jetting hose conduit **420**;

(6) Because the jetting hose **1595** itself resides in the jetting hose conduit **420**, the high pressure jetting fluid must now either go through or around the jetting hose **1595**; and

(7) Because of the internal system's **1500** seal **1580U**, which seals the annulus between the jetting hose **1595** and the jetting hose conduit **420**, jetting fluid cannot go around the jetting hose **1595** (note this hydraulic pressure on the seal assembly **1580** is the force that tends to pump the internal system **1500**, and hence the jetting hose **1595**, "down the hole") and thus jetting fluid is forced to go through the jetting hose **1595** according to the following path:

(a) jetting fluid first passes the top of the internal system **1500** at the upstream battery pack end cap **1520**,

(b) jetting fluid then passes through the annulus between the battery pack casing **1540** and the jetting hose conduit **420** of the jetting hose carrier system **400**;

(c) after jetting fluid passes the downstream battery pack end cap **1530**, it is forced to flow between battery pack support conduits **1560**, and into a jetting fluid receiving funnel **1570**; and

(d) because the jetting fluid receiving funnel **1570** is rigidly and sealingly connected to the jetting hose **1595**, jetting fluid is forced into the I.D. of jetting hose **1595**.

[152] Worthy of note in the above-described jetting fluid flow sequence are the following initiation conditions:

(i) an internal tractor system **700** is first engaged to translate a discreet length of jetting hose **1595** in a downstream direction, such that the jetting nozzle **1600** and jetting hose **1595** enter the jetting hose whipstock **1000** and specifically, after traveling a fixed distance within the inner wall (shown at **1020** in **Figure 4H-1**), are forced radially outward to engage first the interior wall of production casing **12** and then engage the upper curved face **1050.1** of whipstock member **1050**, at which point,

(ii) the jetting hose **1595** is curvedly 'bent' approximately 90°, assuming its pre-defined bend radius (shown at **1599** in **Figure 4H-1**) and directing the jetting nozzle

1600 attached to its terminal end to engage the precise point of desired casing exit **"W"** within the I.D. of the production casing **12**; at which point

(iii) increased torque within the internal tractor system's **700** gripper assemblies **750** is then realized, a signal for which is immediately conveyed electronically to the surface, signaling the operator to shut down rotation of the grippers (illustrative griper seen at **756** in **Figure 4F-2b**).

(Practically, such shut-down could be pre-programmed into the operating system at a certain torque level.) Note that during stages (i) through (iii), a pressure regulator valve (seen at **610** in **Figure 4E-2**) is in an "open" position This allows hydraulic fluid in the annulus between the jetting hose **1595** and the surrounding jetting hose conduit **420** to bleed-off. Once the tip of jetting nozzle **1600** engages the I.D. (casing wall) of production casing **12**, then the operator may:

(iv) reverse the direction of rotation of the grippers **756** to translate the jetting hose **1595** back into the jetting hose (or inner) conduit **420**; and

(v) switch a main control valve **300** to begin pumping hydraulic fluid though the hydraulic fluid passage **340**, down the conduit-carrier annulus **440**, through the pressure regulator valve **610**, and into the jetting hose **1595** / jetting hose conduit **420** annulus **1595.420** to both: (1) pump upwards against lower seals **1580L** of the jetting hose's seal assembly **1580** to re-extend the jetting hose **1595** in a taught position; and, (2) assist the (now reversed) gripper assemblies **750** in positioning the internal system **1500** such that the jetting nozzle **1600** has the desired stand-off distance (preferably less than 1 inch) between itself and the I.D. of the production casing **12** to begin jetting the casing exit.

Upon reaching this desired stand-off distance, rotation of grippers **756** ceases, and pressure regulator valve **610** is closed to lock down the internal system at the desired, fixed position for jetting the casing exit **"W"**.

[153] Referring back to **Figure 3A**, in one embodiment the interior of the downstream end-cap **1530** houses a micro-geo-steering system. The system may include a micro-transmitter, a micro-receiver, a micro-processor, and one or more current regulators. This geo-

steering system is electrically or fiber-optically connected to a small geo-spatial IC chip (shown at **1670** in **Figure 3F-1c** and discussed more fully below) located in the body of the jetting nozzle **1600**. In this way, nozzle orientation data may be sent from the jetting nozzle **1600** to the micro-processor (or appropriate control system) which, coupled with the values of dispensed hose length, can be used to calculate the precise geo-location of the nozzle at any point, and thus the contour of the UDP's path. Conversely, geo-steering signals may be sent from the control system (such as a micro-processor in the docking station or at the surface) to modify, through one or more electrical current regulators, individualized current strengths down to each of the (at least three) actuator wires (shown at **1590A** in **Figure 3F-1c**), thus redirecting the nozzle as desired.

[154] The geo-steering system can also be utilized to control the rotational speed of a rotor body within the jetting nozzle **1600**. As will be described more fully below, the rotating nozzle configuration utilizes the rotor portion **1620** of a miniature direct drive electric motor assembly to also form a throat and end discharge slot **1640** of the rotating nozzle itself. Rotation is induced via electromagnetic forces of a rotor/stator configuration. In this way, rotational speeds can be governed in direct proportion to the current supplied to the stators.

[155] As depicted in **Figures 3F-1** through **3F-3**, the upstream portion of the rotor (in this depiction, a four-pole rotor) **1620** includes a near-cylindrical inner diameter (the I.D. actually reduces slightly from the fluid inlet to the discharge slot to further accelerate the fluid before it enters the discharge slot) that provides a flow channel for the jetting fluid through the center of the rotor **1620**. This near-cylindrical flow channel then transitions to the shape of the nozzle's **1600** discharge slot **1640** at its far downstream end. This is possible because, instead of the typical shaft and bearing assembly inserted longitudinally through the center diameter of the rotor **1620**, the rotor **1620** is stabilized and positioned for balanced rotation about the longitudinal axis of the rotor **1620** by a single set of bearings **1630** positioned about the interior of the upstream butt end, and outside the outer diameter of the flow channel ("nozzle throat") **1650**, such that the bearings **1630** stabilize the rotor body **1620** both longitudinally and axially.

[156] Referring now to **Figure 3B-1a**, and again discussing the internal system **1500**, a cross-sectional view of the battery pack section **1510**, taken across line **A-A'** of **Figure 3B-1** is

shown. The view is taken at the top of the bottom end cap **1530** of the battery pack **1510** looking down into a jetting fluid receiving funnel **1570**. Visible in this figure are three wires **1590** extending away from the battery pack **1510**. Using the wires **1590**, power is sent from the "AA"-size lithium batteries **1551** to the geo-steering system for controlling the rotating jet nozzle **1600**. By adjusting current through the wires **1590**, the geo-steering system controls the rate of rotation of the rotor **1620** along with its orientation.

[157] Note that because the longitudinal axis of the nozzle's discharge stream is designed to be continuous to and aligned with that of the nozzle throat, there is virtually no axial moment acting on the nozzle from thrust of the exiting jetting fluid. That is, as the nozzle is designed to operate in an axially "balanced" condition, the torque moment required to actually rotate the nozzle about its longitudinal axis is relatively small. Similarly, in that relatively low rotational speeds (RPM's) are required for rotational excavation, the electromagnetic force required from the nozzle's rotor/stator interaction is relatively small as well.

[158] Note from **Figure 3** that the jetting nozzle **1600** is located at the far downstream end of the jetting hose **1595**. Though the diameters of the components of the internal system **1500** must meet some rather stringent diameter constraints, the respective lengths of each component (with the exception of the jetting nozzle **1600** and, if desired, one or more jetting collars) are typically far less restricted. This is because the jetting nozzle **1600** and collars are the only components affixed to the jetting hose **1595** that will ever have to make the approximate 90° bend as directed by the whipstock face **1050.1**. All other components of the internal system **1500** will always reside at some position within the jetting hose carrier system **400**, and above the jetting hose pack-off section **600** (discussed below).

[159] The length of many of the components can also be adjusted. For example, though the battery pack **1510** in **Figure 3A** is depicted to house six AA batteries **1551**, a much greater number could be easily accommodated by simply constructing a longer battery pack casing **1540**. Similarly, the battery pack end-caps **1520**, **1530**, the support columns **1560**, and the fluid intake funnel **1570** may be substantially elongated as well to accommodate fluid flow and power needs.

[160] Referring again to the docking station **325**, the docking station **325** serves as a physical "stop" beyond which the internal system **1500** can no longer travel upstream. Specifically, the upstream limit of travel of the internal system **1500** (comprised primarily of the jetting hose **1595**) is at that point where the upstream battery pack end cap **1520** lodges (or, "docks") within a bottom, conically-shaped receptacle **328** of the docking station **325**. The receptacle **328** serves as a lower end cap. The receptacle **328** provides matingly conductive contacts which line up with the upstream battery pack end cap **1520** to form a docking point. In this way, a transfer of data and/or electrical power (specifically, to recharge batteries **1551**) can occur while "docked."

[161] The docking station **325** also has a conically-shaped end-cap **323** at the upstream (proximal) end of the docking station **325**. The conical shape serves to minimizing erosive effects by diverting the flow of jetting fluid around the body thereof, thereby aiding in the protection of the system components housed within the docking station **325**. Depending on the guidance, steering, and communications capabilities desired, an upper portion **323** of the docking station **325** can house the servo, transmission, and reception circuitry and electronics systems designed to communicate directly (either in continuous real time, or only discretely while docked) with counterpart systems in the internal system **1500**. Note, as shown in **Figure 3**, the O.D. of the cylindrical docking station **325** is approximately equal to that of the jetting hose **1595**.

[162] The internal system **1500** next includes a jetting fluid receiving funnel **1570**. **Figure 3B-1** includes a cut-away perspective view of the jetting fluid receiving funnel **1570**, with an axial cross-sectional view along **B-B'** shown as **Figure 3B-1b**. The jetting fluid receiving funnel **1570** is located below the base of the battery pack section **1510**, shown and described above in connection with **Figure 3A**. As the name implies, the jetting fluid receiving funnel **1570** serves to guide the jetting fluid into the interior of the jetting hose **1595** during the casing exit and mini-lateral formation process. Specifically, the annular flow of jetting fluid (e.g., passing along the outside of battery pack casing **1540** and subsequently the battery pack end cap **1530**, and inside the I.D. of jetting hose conduit **420**) is forced to transition to flow between the three battery pack support conduits **1560**, because an upper seal (seen in **Figure 3** at **1580U**) precludes any fluid flow along a path exterior to the jetting hose

1595. Thus, all flow of jetting fluid (as opposed to hydraulic fluid) is forced between conduits **1560** and into fluid receiving funnel **1570**.

[163] In the design of **Figure 3B-1**, three columnar supports **1560** are used to house the wires **1590**. The columnar supports **1560** also provide an area open to fluid flow. The spacing between the supports **1560** is designed to be significantly greater than that provided by the I.D. of the jetting hose **1595**. At the same time, the supports **1560** have I.D.'s large enough to house and protect up to an AWG #5 gauge wire **1590**. The columnar supports **1560** also support the battery pack **1510** at a specific distance above the jetting fluid intake funnel **1570** and the jetting hose seal assembly **1580**. The supports **1560** may be sealed with sealing end caps **1562**, such that removal of the end caps **1562** provides access to the wiring **1590**.

[164] **Figure 3B-1b** provides a second axial, cross-sectional view of the fluid intake funnel **1570**. This view is taken across line **B-B'** of **Figure 3B-1**. The three columnar supports **1560** are again seen. The view is taken at the top of the jetting fluid inlet, or receiving funnel **1570**.

[165] Downstream from the jetting fluid receiving funnel **1570** is a jetting hose seal assembly **1580**. **Figure 3C** is a cut-away perspective view of the seal assembly **1580**. In the view of **Figure 3C**, columnar support members **1560** and electrical wiring **1590** have been removed for the sake of clarity. However, the receiving funnel **1570** is again seen at the upper end of the seal assembly **1580**.

[166] Also visible in **Figure 3C** is an upper end of the jetting hose **1595**. The jetting hose **1595** has an outermost jetting hose wrap O.D. **1595.3** (also seen in **Figure 3D-1a**) that, at points, may engage the jetting hose conduit **420**. A micro-annulus **1595.420** (shown in **Figures 3D-1** and **3D-1a**) is formed between the jetting hose **1595** and the surrounding conduit **420**. The jetting hose **1595** also has a core (O.D. **1595.2,** I.D. **1595.1**) that transmits jetting fluid during the jetting operation. The jetting hose **1595** is fixedly connected to the seal assembly **1580**, meaning that the seal assembly **1580** moves with the jetting hose **1595** as the jetting hose advances into a mini-lateral.

[167] As previously described, the upper seal **1580U** of the jetting hose's seal assembly **1580** (shown as a solid portion with a slightly concave upwards upper face) precludes any continued downstream flow of jetting fluid outside of the jetting hose **1595**. Similarly, the lower seal **1580L** of this seal assembly **1580** (shown as a series of concave-downwards cup faces) precludes any upstream flow of hydraulic fluid from below. Note how any upstream-to-downstream hydraulic pressure from the jetting fluid will tend to expand the jetting fluid intake funnel **1570** and, thus, urge the upper seal **1580U** of the seal assembly **1580** radially outwards to sealingly engage the I.D. **420.1** of the jetting hose carrier's (inner) jetting hose conduit **420**. Similarly, any downstream-to-upstream hydraulic pressure from the hydraulic fluid radially expands bottom cup-like faces making up the lower seal **1580L** to sealingly engage the I.D. **420.1** of the jetting hose carrier's inner conduit **420**. Thus, when jetting fluid pressure is greater than the trapped hydraulic fluid pressure, the overbalance will tend to "pump" the entire assembly "down-the-hole". Conversely, when the pressure overbalance is reversed, hydraulic fluid pressure will tend to "pump" the entire seal assembly **1580** and connected hose **1595** back "up-the-hole".

[168] Returning to **Figures 2** and **3**, the upper seal **1580U** provides an upstream pressure and fluid-sealed connection for the internal system **1500** to the external system **2000**. (Similarly, as will be discussed further below, a pack-off seal assembly **650** within a pack-off section **600** provides a downstream pressure and fluid-sealed connection between the internal system **1500** and the external system **2000**.) The seal assembly **1580** includes seals **1580U**, **1580L** that hold incompressible fluid between the hose **1595** and the surrounding conduit **420**. In this way, the jetting hose **1595** is operatively connected to the coiled tubing string **100** and sealingly connected to the external system **2000**.

[169] **Figure 3C** illustrates utility of the sealing mechanisms involved in this upstream seal **1580**. During operation, jetting fluid passes:

(1) through an annulus **420.2** between the battery pack casing **1540** and the jetting hose carrier inner conduit **420**;

(2) between the battery pack support conduits **1560**;

(3) into the fluid receiving funnel **1570**;

(4) down the core **1595.1** (I.D.) of the jetting hose **1595**; and

(5) then exits the jetting nozzle **1600**.

[170] As noted, the downward hydraulic pressure of the jetting fluid acting upon the axial cross-sectional area of the jetting hose's fluid receiving funnel **1570** creates an upstream-to-downstream force that tends to "pump" the seal assembly **1580** and connected jetting hose **1595** "down the hole." In addition, because the components of the fluid receiving funnel **1570** and the supporting upper seal **1580U** of the seal assembly **1580** are slightly flexible, the net pressure drop described above serves to swell and flare the outer diameters of upper seal **1580U** radially outwards, thus producing a fluid seal that precludes fluid flow behind the hose **1595**.

[171] **Figure 3D-1** provides a longitudinal, cross-sectional view of the "bundled" jetting hose **1595** of the internal system **1500** as it resides in the jetting hose carrier's inner conduit **420**. Also included in the longitudinal cross section are perspective views (dashed lines) of electrical wires **1590** and data cables **1591**. Note from the axial cross-sectional view of **Figure 3D-1a**, that all of the electrical wires **1590** and data cables **1591** in the "bundled" jetting hose **1595** safely reside within the outermost jetting hose wrap **1595.3**.

[172] In the preferred embodiment, the jetting hose **1595** is a "bundled" product. The hose **1595** may be obtained from such manufacturers as Parker Hannifin Corporation. The bundled hose includes at least three electrically conductive wires **1590**, and at least one, but preferably two dedicated data cables **1591** (such as fiber optic cables), as depicted in **Figures 3B-1b** and **3D-1a**. Note these wires **1590** and fiber optic strands **1591** are located on the outer perimeter of the core **1595.2** of the jetting hose **1595**, and surrounded by a thin outer layer of a flexible, high strength material or "wrap" (such as Kevlar®) **1595.3** for protection. Accordingly, the wires **1590** and fiber optic strands **1591** are protected from any erosive effects of the high-pressure jetting fluid.

[173] Moving now down the hose **1595** to the distal end, **Figure 3E** provides an enlarged, cross sectional view of the end of the jetting hose **1595**. Here, the jetting hose **1595** is passing through the whipstock member **1000**, and ultimately along the whipstock face **1050.1** to casing exit "**W**". A jetting nozzle **1600** is attached to the distal end of the jetting hose **1595**. The

jetting nozzle **1600** is shown in a position immediately subsequent to forming an exit opening, or window "**W**" in the production casing **12**. Of course, it is understood that the present assembly **50** may be reconfigured for deployment in an uncased wellbore.

[174] As described in the related applications, the jetting hose **1595** immediately preceding this point of casing exit "**W**" spans the entire I.D. of the production casing **12**. In this way, a bend radius "**R**" of the jetting hose **1595** is provided that is always equal to the I.D. of the production casing **12**. This is significant as the subject assembly **50** will always be able to utilize the entire casing (or wellbore) I.D. as the bend radius "**R**" for the jetting hose **1595**, thereby providing for utilization of the maximum I.D./O.D hose. This, in turn, provides for placement of maximum hydraulic horsepower ("HHP") at the jetting nozzle **1600**, which further translates in the capacity to maximize formation jetting results such as penetration rate, or the lateral borehole diameter, or some optimization of the two.

[175] It is observed here that there is a consistency of three "touch points" for the bend radius "**R**" of the jetting hose **1595**. First, there is a touch point where the hose **1595** contacts the I.D. of the casing **12**. This occurs at a point directly opposite and slightly (approximately one casing I.D. width) above the point of casing exit "**W**." Second, there is a touch point along a whipstock curved face **1050.1** of the whipstock member **1000** itself. Finally, there is a touch point against the I.D. of the casing **12** at the point of casing exit "**W**," at least until the window "**W**" is formed.

[176] As depicted in **Figure 3E** (and in **Figure 4H-1**), the jetting hose whipstock member **1000** is in its set and operating position within the casing **12**. (U.S. Patent No. 8,991,522, also demonstrates the whipstock member **1050** in its run-in position.) The actual whipstock **1050** within the whipstock member **1000** is supported by a lower whipstock rod **1060**. When the whipstock member **1000** is in its set-and-operating position, the upper curved face **1050.1** of the whipstock member **1050** itself spans substantially the entire I.D. of the casing **12**. If, for example, the casing I.D. were to vary slightly larger, this would obviously not be the case. The three aforementioned "touch points" of the jetting hose **1595** would remain the same, however, albeit while forming a slightly larger bend radius "**R**" precisely equal to the (new) enlarged I.D. of casing **12**.

[177] As described in greater detail in the co-owned U.S. Patent No. 8,991,522, the whipstock rod is part of a tool assembly that also includes an orienting mechanism, and an anchoring section that includes slips. Once the slips are set, the orienting mechanism utilizes a ratchet-like action that can rotate the upstream portion of the whipstock member **1000** in discreet 10° increments. Thus, the angular orientation of the whipstock member **1000** within the wellbore may be incrementally changed downhole.

[178] In one embodiment, the whipstock **1050** is a single body having an integral curved face configured to receive the jetting hose and redirect the hose about 90 degrees. Note the whipstock **1050** is configured such that, at the point of casing exit when in set and operating position, it forms a bend radius for the jetting hose that spans the entire ID of the parent wellbore's production casing **12**.

[179] **Figure 4H-1** is a cross-sectional view of the whipstock member **1000** of the external system of **Figure 4**, but shown vertically instead of horizontally. The jetting hose of the internal system (**Figure 3**) is shown bending across the whipstock face **1050**, and extending through a window "**W**" in the production casing **12**. The jetting nozzle of the internal system **1500** is shown affixed to the distal end of the jetting hose **1595**.

[180] **Figure 4H-1a** is an axial, cross-sectional view of the whipstock member **1000**, with a perspective view of sequential axial jetting hose cross-sections depicting its path downstream from the center of the whipstock member **1000** at line **O-O′** to the start of the jetting hose's bend radius as it approaches line **P-P′**.

[181] **Figure 4H-1b** depicts an axial, cross-sectional view of the whipstock member **1000** at line **P-P′**. Note the adjustments in location and configuration of both the whipstock member's wiring chamber and hydraulic fluid chamber from line **O-O′** to line **P-P′**.

[182] As noted above, the present assembly **50** is preferably used in connection with a nozzle having a unique design. **Figures 3F-1a** and **3F-1b** provide enlarged, cross-sectional views of the nozzle **1600** of **Figure 3**, in a first embodiment. The nozzle **1600** takes advantage of a rotor/stator design, wherein the forward portion **1620** of the nozzle **1600**, and hence the forward jetting slot (or "port") **1640**, is rotated. Conversely, the rearward portion of the nozzle

1600, which itself is directly connected to jetting hose **1595**, remains stationary relative to the jetting hose **1595**. Note in this arrangement, the jetting nozzle **1600** has a single forward discharge slot **1640**.

[183] First, **Figure 3F-1a** presents a basic nozzle body having a stator **1610** . The stator **1610** defines an annular body having a series of inwardly facing shoulders **1615** equi-distantly spaced therein. The nozzle **1600** also includes a rotor **1620**. The rotor **1620** also defines a body and has a series of outwardly facing shoulders **1625** equi-distantly spaced therearound. In the arrangement of **Figure 3F-1a**, the stator body **1610** has six inwardly-facing shoulders **1615**, while the rotor body **1620** has four outwardly-facing shoulders **1625**.

[184] Residing along each of the shoulders **1615** is a small diameter, electrically conductive wire **1616** wrapping the stator's inwardly facing shoulders (or "stator poles") **1615** with multiple wraps. Movement of electrical current through the wires **1616** thus creates electro-magnetic forces in accordance with a DC rotor/stator system. Power to the wires is provided from the batteries **1551** (or battery pack **1550**) of **Figure 3A**.

[185] As noted above, the stator **1610** and rotor **1620** bodies are analogous to a direct drive motor. The stator **1610** (in this depiction, a six-pole stator) of this direct drive electric motor analog is included within the outer body of the nozzle **1600** itself, with each pole protruding directly from the body **610**, and commensurately wrapped in electric wire **1616**. The current source for the wire **1616** wrapping the stator poles is derived through the 'bundled' electrical wires**1590** of the jetting hose **1595**, and is thereby manipulated by the current regulator and micro-servo mechanism housed in the conically-shaped battery pack's (downstream) end-cap **1530**. Rotation of the rotor **1620** of the nozzle **1600**, and particularly the speed of rotation (RPM's), is controlled via induced electro-magnetic forces of a DC rotor/stator system.

[186] Note that **Figure 3F-1a** could serve as a representative axial cross section of essentially any basic direct current electromagnetic motor, with the central shaft/bearing assembly removed. By eliminating a central shaft and bearings, the nozzle **1600** can now accommodate a nozzle throat **1650** placed longitudinally through its center. The throat **1650** is suitable for conducting high pressure fluid flow.

[187] **Figure 3F-1b** provides a longitudinal, cross-sectional view of the nozzle **1600** of **Figure 3F-1a**, taken across line **C-C'** of **Figure 3F-1b**. The rotor **1620** and surrounding stator **1610** are again seen. Bearings **1630** are provided to facilitate relative rotation between the stator body **1610** and the rotor body **1620**.

[188] It is observed in **Figure 3F-1b** that the nozzle throat **1650** has a conically-shaped narrowing portion before terminating in the single fan-shaped discharge slot **1640**. This profile provides two benefits. First, additional non-magnetic, high-strength material may be placed between the throat **1650** and the magnetized rotor portion **1625** of the forward portion of the nozzle body **1620**. Second, final acceleration of the jetting fluid through the throat **1650** is accommodated before entering the discharge slot **1640**. The size, placement, load capacity, and freedom of movement of the bearings **1630** are considerations as well. The forward slot **1640** begins with a relatively semi-hemispherically shaped opening, and terminates at the forward portion of the nozzle **1600** in a curved, relatively elliptical shape (or, optionally, a curved rectangle with curved small ends.)

[189] Simulations were conducted with the single planar slot slightly twisted such that the discharge angle(s) of the fluid generated sufficient thrust so as to rotate the nozzle **1600**. The observed problem was that nozzle rotation rates were hypersensitive to changes in fluid flow rates, leaving the concern of instantaneous and frequent overloading (with resultant failure) of the bearings **1630**. The solution was to design, as nearly as possible, a balanced single slot system, such that there is no appreciable axial thrust generated by fluid discharge. In other words, the nozzle **1600** is no longer sensitive to injection rate.

[190] At this point it is important to note the basic nozzle design criteria for the flow capacity of the combined flow path comprised of the throat **1650** and slot **1640** elements. That is, that these inner throat **1650** and slot **1640** elements of the nozzle **1600** retain dimensions that can approximate the dimensions, and resultant hydraulics, of conventional hydraulic jet casing perforators. Specifically, the nozzle **1600** depicted in **Figures 3F-1a** and **3F-1b** throat **1650** and slot **1640** dimensions that can approximate the perforating hydraulics obtained by a perforator's 1/8th-inch orifice. Note that the terminal width of slot **1640** can not only accommodate 100 mesh sand as an abrasive, but the larger sizes such as 80 mesh sand as well.

[191] Angles Θ_{SLOT} **1641** and Θ_{MAX} **1642** are shown in **Figure 3F-1b**. (These angles are also shown in **Figures 3F-2b** and **3F-3b**, discussed below.) Angle Θ_{SLOT} **1641** represents the actual angle of the outer edges of the slot **1640**, and angle Θ_{MAX} **1642** represents the maximum Θ_{SLOT} **1641** achievable within the existing geometric and construction constraints of the nozzle **1600**. In **Figures 3F-1b, 3F-2b** and **3F-3b**, both angles Θ_{SLOT} **1641** and Θ_{MAX} **1642** are shown at 90 degrees. This geometry, coupled with rotation of the rotor body **1620** (and, consequently, rotation of the jetting slot **1640**) provides for the erosion of a hole diameter that is at least equal to the nozzle's outer diameter even at a stand-off (e.g., the distance from the very tip of the nozzle **1600** at the longitudinal center line to the target rock along the same centerline) of zero.

[192] **Figures 3F-2a** and **3F-2b** provide longitudinal, cross-sectional views of the jetting nozzle of **Figure 3E**, in an alternate embodiment. In this embodiment, multiple ports are used, including both a forward discharge port **1640** and a plurality of rearward thrust jets **1613**, for a modified nozzle **1601**.

[193] The nozzle configuration of **Figures 3F-2a** and **3F-2b** is identical to the nozzle configuration **1600** of **Figure 3F-1a**, with the exception of three additional components:

(1) the use of rearward thrusting jets **1613**;

(2) the use of a slideable collar **1633** biased by a biasing mechanism (spring) **1635**; and

(3) the use of a slideable nozzle throat insert **1631**.

The first of these three additional components, rearward thrusting jets **1613**, provide a rearward thrust that effectively drags the jetting hose **1595** along the lateral borehole, or mini-lateral, as it is formed. Preferably, five rearward thrust jets **1613** are used along the body **1610**, although variations of the number and/or exit angles **1614** of the jets **1613** may be utilized.

[194] **Figure 3F-2c** is an axial, cross-sectional view of the jetting nozzle **1601** of **Figures 3F-2a** and **3F-2b**. This demonstrates the star-shaped jet pattern created by the multiple rearward thrust jets **1613**. Five points are seen in the star, indicating five illustrative rearward thrust jets **1613**.

[195] Note particularly in a homogeneous host pay zone, the forward (jetting) hydraulic horsepower requirement necessary to excavate fresh rock at a given rate of penetration would be essentially constant. The rearward thrust hydraulic horsepower requirement, however, is constantly increasing in proportion to the growth in length of the mini-lateral. As continued extension of the mini-lateral requires dragging an ever-increasing length of jetting hose **1595** along an ever-increasing distance, the rearward thrusting hydraulic horsepower requirement to maintain forward propulsion of the jetting nozzle **1601** and hose **1595** increases commensurately.

[196] It may be required to consume upwards of two-thirds of available horsepower through the rearward thrust jets **1613** in order to extend the jetting hose **1595** and connected nozzles **1601**, **1602** to the furthest lateral extent. If this maximum requirement is utilized constantly throughout the borehole jetting process, much of the available horsepower will be wasted in the early stages in jetting the bore. This is particularly detrimental when the same jetting nozzle and assembly utilized in rock excavation is also utilized to form the initial casing exit "**W**." Further, if the same rearwards jetting forces cutting the 'points' of the star-shaped rock excavation are active in the wellbore tubulars (particularly, while jetting the casing exit "**W**") significant damage to the nearby tool string (particularly, the whipstock member **1000**) and the well casing **12** could result. Hence, the optimum design would provide for the activation/deactivation of the rearward thrust jets **1613** when desired, particularly, after the casing exit is formed and after the first 5 or 10 feet of lateral borehole is formed.

[197] There are several possible mechanisms by which jet activation/deactivation may be enabled to help conserve HHP and protect the tool string and tubulars. One approach is mechanical, whereby the opening and closing of flow to the jets **1613** is actuated by overcoming the force of a biasing mechanism. This is shown in connection with the spring **1635** of **Figures 3F-2a** and **3F-2b**, where a throat insert **1631** and a slideable collar **1633** are moved together to open rearward thrust jets **1613**. Another approach is electromagnetic, wherein a magnetic port seal is pulled against a biasing mechanism (spring **1635**) by electromagnetic forces. This is shown in connection with **Figures 3F-3a** and **3F-3c**, discussed below.

[198] The second of the three additions incorporated into the nozzle design of **Figures 3F-2a** and **3F-2b** is that of a slideable collar **1633**. The collar **1633** is biased by a biasing mechanism (spring) **1635**. The function of this collar **1633**, whether directly or indirectly (by exerting a force on the slideable nozzle throat insert **1631**), is to temporarily seal the fluid inlets of the thrust jets **1613**. Note that this sealing function by the slideable collar **1633** is "temporary"; that is, unless a specific condition determined by the biasing mechanism **1635** is satisfied. As shown in the embodiment presented in **Figures 3F-2a** and **3F-2b**, the biasing mechanism **1635** is a simple spring.

[199] In **Figure 3F-2a**, the collar **1633** is in its closed position, while in **Figure 3F-2b** the collar **1633** is in its open position. Thus, a specific differential pressure exerted on the cross-sectional area of the slideable nozzle throat insert **1631** has overcome the pre-set compressive force of the spring **1635**.

[200] The third of the three additions incorporated into the nozzle **1601** design of **Figures 3F-2a** and **3F-2b** is that of a slideable nozzle throat insert **1631**. The slideable throat insert **1631** has two basic functions. First, the insert **1631** provides an intentional and pre-defined protrusion into the flow path within the nozzle throat **1650**. Second, the insert **1631** provides an erosion- and abrasion-resistant surface within the highest fluid velocity portion of the internal system **1500**. For the first of these functions, the degree of protrusion to be designed into the slideable nozzle throat insert **1631** is a function of at what point in mini-lateral formation the operator anticipates actuating the thrust jets **1613**.

[201] To illustrate, suppose that system hydraulics provide for a suitable pump rate of 0.5 BPM through the nozzle **1601** at the point of casing exit "**W**," and that this can be sustained at a surface pumping pressure of 8,000 psi. Suppose further that actuation of the thrust jets **1613** in the nozzle **1601** is not required until the nozzle **1601** achieves a lateral distance of 50 feet from the parent wellbore. That is, particularly while jetting the casing exit **"W"** itself and an abrasive mixture (say, of 1.0 ppg of 100 mesh sand in a 1 pound guar-based fresh water gel system) is being pumped, none of the jets**1613** have been opened (which could risk clogging by the abrasive in the jetting fluid mixture.) Consequently, no abrasives are included in the jetting fluid after it is sure that the nozzle **1600** has sufficiently cleared the casing exit "**W**".

Accordingly, while jetting the hole in production casing **12** to form casing exit "**W**", no rearwards jetting forces from fluids expelled through thrust jets **1613** can pose a threat to unintentionally damage either the jetting hose **1595**, the whipstock member **1000**, or the production casing **12**.

[202] Later, after generating the casing exit "**W**" plus a mini-lateral length of, say, approximately 50 feet, the pump pressure is increased to 9,000 psi, the incremental 1,000 psi increase in surface pumping pressure being sufficient to overcome the force of the biasing mechanism **1635** and act against the cross-sectional area of the protrusion of the insert **1631** to actuate the jets **1613**. Thus, at mini-lateral length of 50 feet from the parent wellbore **4**, the thrust jets **1613** are actuated, and high pressure rearwards thrust flow is generated through the jets **1613**.

[203] Suppose these conditions are sufficient to continue jetting a mini-lateral out to a lateral length of 300 feet. At 300 feet, the length of jetting hose laying against the floor of the mini-lateral is causing a commensurate frictional resistance such that it and the thrust forces generated through the thrust jets **1613** are in approximate equilibrium. (Instrumentation such as tensiometers, for example, would indicate this.) At this point, the pump rate is increased to, say, 10,000 psi, and the rearward thrust jets **1613** remain actuated, but at higher differential pressures and flow rates, thus generating higher pull force on the jetting hose **1595**.

[204] **Figures 3F-3a and 3F-3c** provide longitudinal, cross-sectional views of a jetting nozzle **1602**, in yet another alternate embodiment. Here, multiple rearward thrust jets **1613,** and a single forward jetting slot **1640**, are again used. A collar **1633** and spring **1635** are again used for providing selective fluid flow through rearward thrust jets **1613**.

[205] **Figures 3F-3b** and **3F-3d** provide axial, cross-sectional views of the jetting nozzle **1602** of **Figures 3F-3a** and **3F-3c**, respectively. These demonstrate the star-shaped jet pattern created by the multiple jets **1613**. Eight points are seen in the star, indicating two sets of four (alternating) illustrative thrust jets **1613**. In **Figures 3F-3a** and **3F-3b**, the collar **1633** is in its closed position, while in **Figures 3F-3c** and **3F-3d** the collar **1633** is in its open position permitting fluid flow through the jets **1613**. The biasing force provided by the spring **1635** has been overcome.

[206] The nozzle **1602** of **Figures 3F-3a** and **3F-3c** is similar to the nozzle **1601** of **Figures 3F-2a** and **3F-2b**; however, in the arrangement of **Figures 3F-3a** and **3F-3c**, an electro-magnetic force generating a downstream magnetic pull against the slideable collar **1633**, sufficient to overcome the biasing force of the biasing mechanism (spring) **1635**, replaces the hydraulic pressure force against the slideable throat insert **1631** in the jetting nozzle **1601** of **Figures 3F-2a** and **3F-2b**.

[207] The nozzle **1602** of **Figures 3F-3a and 3F-3c** presents yet another preferred embodiment of a rotating nozzle **1602**, also suitable for forming casing exits and continued excavation through a cement sheath and host rock formation. In **Figures 3F-3a** and **3F-3c** (and in Figure **3G-1**, described in more detail below), it is the electromagnetic force generated by the rotor/stator system that must overcome the spring **1635** force to open hydraulic access to the rearward thrust jets **1613** (and **1713**). (Note that in **Figure 3G-1**, depicting an in-line hydraulic jetting collar, discussed more fully below, direct mechanical connection of internal turbine fins **740** to the slideable collar **733** change the biasing criteria to one of differential pressure, as with the jetting nozzle depicted in **Figure 3F-2a**). The key here is the ability to keep the fluid inlets to the rearward thrust jets **1613** (and **1713**) closed until the operator initiates opening them, specifically by increasing the pump rate, such that either (or both) the differential pressure through the nozzle and/or the nozzle rotation speed's proportional increase of electromagnetic pull on the slideable collars **1633 / 1733** opens access to the fluid inlets of the thrust jets **1613 / 1713**.

[208] It is also observed that in the nozzle **1602**, the number of rearward thrust jets **1613**, though also symmetrically placed about the circumference of the rotor **1610**, has been increased from a single set of five to two sets of four. Note that each of the four jets **1613** within each of the two sets are also symmetrically placed about the rotor **1610** circumference, orthogonally relative to each other; hence, the two sets of jets **1613** must overlap. Additionally, the path of each jet now not only travels through the rearward (stator) portion **1610** of the nozzle **1602**, but now also through the forward (rotor) section **1620** of the nozzle **1602**. Note, however, as depicted in **Figures 3F-3b** and **3F-3d**, whereas there are eight individual jet passages through the rearward (stator) portion **1610** of the nozzle **1602**, there are only four passing through the forward (rotor) section **1620** of the nozzle **1600**. Hence, rotation

of the forward (rotor) section **1620** of the nozzle **1602** will only provide for the alignment of, and subsequent fluid flow through, only one set of four jets **1613** at a time. In fact, for most of a single rotation's duration, the flow channels of the rotor **1620** will have no access to those of the stator **1610**, and are thereby effectively sealed. The result will be an oscillating (or, "pulsating") jetting flow through the rearward thrust jets **1613**.

[209] The commensurate subtraction of jetting fluid volumes going through the nozzle port **1640** produces a commensurate pulsating forward jetting flow for excavation, as well. The benefits of pulsating flow over and against continuous flow for excavation systems are well documented, and will not be repeated here. Note, however, the subject nozzle design not only captures the rock excavation benefits of a rotating jet, but also the benefits of a pulsating jet.

[210] Another embodiment of a thrust collar that employs an electromagnetic force is provided in **Figures 3G-1a** and **3G-1b**. **Figures 3G-1a** presents an axial, cross-sectional view of a basic body for a thrust jetting collar **1700** of the internal system **1500** of **Figure 3**. The view is taken through line **D-D'** of **Figure 3G-1b**. Here, as with the jetting nozzle **1602**, two layers of rearward thrust jets **1713** are again offered.

[211] The collar **1700** has a rear stator **1710** and an inner (rotating) rotor **1720**. The stator **1710** defines an annular body having a series of inwardly facing shoulders **1715** equi-distantly spaced therein, while the rotor **1720** defines a body having a series of outwardly facing shoulders **1725** equi-distantly spaced therearound. In the arrangement of **Figure 3G.1.a**, the stator body **1710** has six inwardly-facing shoulders **1715**, while the rotor body **1720** has four outwardly-facing shoulders **1725**.

[212] Residing along each of the shoulders **1715** is a small diameter, electrically conductive wire **1716** wrapping the stator's **1710** inwardly facing shoulders (or, "stator poles") **1715** with multiple wraps. Movement of electrical current through the wires **1716** thus creates electro-magnetic forces in accordance with a DC rotor/stator system. Power to the wires is provided from the batteries **1551** of **Figure 3A**.

[213] **Figure 3G-1b** is a longitudinal, cross-sectional view of the nozzle **1700**. **Figure 3G-1c** is an axial cross section intersecting the thrust jets **1713** along line **d-d'** of **Figure 3G-1b**.

[214] **Figures 3G-1a** thru **3G-1c** show the embodiment of similar concepts for the rotating nozzles **1600**, **1601**, and **1602**, but with modifications adapting the apparatus for use as an in-line thrust jetting collar **1700**. Note particularly the retention of a flow-through rotor **1725** providing a collar throat **1750**, coupled with a stator **1715** and bearings **1730**. However, the stationary flow channels for the rearward thrusting jets **1713** penetrating the stator **1710** are staggered, being in two sets of four. The single set of four orthogonal jets penetrating the rotor **1725** will, for each full rotation, "match-up" four times each with the jets penetrating the stator **1710**, each match-up providing a four-pronged instantaneous pulsed flow spaced equi-distant about the outer circumference of the collar **1700**. Similar to the rotating nozzle **1602**, the slideable collar **1733** is moved electromagnetically against a biasing mechanism (spring) **1735** to actuate flow through the rearward thrust jets **1713**.

[215] **Figure 3G-1c** is another cross-sectional view, showing the star pattern of the rearward thrust jets **1713**. Eight points are seen.

[216] A unique opportunity exists to configure the collar **1733** as either a net power consumer or a net power provider. The former would rely on the battery pack-provided power, just as the jetting nozzle **1600** does, to fire the stator, rotate the rotor, and generate the requisite electromagnetic field. The latter is accomplished by incorporating interior, slightly angled turbine fins **1740** within the I.D. of the rotor **1720**, hence harnessing the hydraulic force of the jetting fluid as it is pumped through the collar**1700**. Such force would be dependent only on the pump rate and the configuration of the turbine fins **1740**.

[217] In one aspect, internal turbine fins **1740** are placed equi-distant about the collar throat **1750**, such that hydraulic forces are harnessed both to rotate the rotor **1720** and to supply a net surplus of electrical current to be fed back into the internal system's circuitry. This may be done by sending excess current back up wires **1590**. The ability to incorporate a rotor/stator configuration into construction of the rearward thrust jet collar enables a full-opening I.D. equal to that of the jetting hose. More than ample hydroelectric power could be obtained to

generate the electromagnetic field needed to operate the slideable port collar **1733**, the surplus being available to be fed into the now "closed" electrical system incurred once the internal system **1500** disengages from the docking station **325**. Hence, this surplus hydroelectric power generated by the collar **1700** may beneficially be used to maintain charges of the batteries **1551** in the battery pack **1550**.

[218] It is observed that the various nozzle designs **1600**, **1601, 1602** discussed above are designed to jet not only through a rock matrix, but also through the steel casing and the surrounding cement sheath of the wellbore **4c** in order to reach the rock. The nozzle designs incorporate the ability to handle relatively large mesh-size abrasives through the forward nozzle jetting port **1640** prior to engaging the RTJ's **1613**. It is understood though that other nozzle designs may be used that accomplish the purpose of forming mini-laterals but which are not so robust as to cut through steel.

[219] In the various nozzle designs **1600**, **1601, 1602** discussed above, a single forward port in a hemispherically-shaped nozzle is used. The forward port **1640** is defined by the angles θ_{MAX} (whereby the width of the jet is equal to the width of the nozzle when the outermost edge of the jet reaches a point forward equivalent to the nozzle tip) and θ_{SLOT} (the actual slot angle). Note $\theta_{SLOT} \leq \theta_{MAX}$. For presentation purposes herein, $\theta_{SLOT} = \theta_{MAX}$, such that even if the tip of the rotating nozzle was against the host rock (or casing I.D.) face while jetting, it would still excavate a tunnel diameter equal to the outer (maximum) nozzle diameter. It is this single-plane, rotating slot configuration that will provide a maximum width in order to accommodate ample pass-through capacity for any abrasives that may be incorporated in the jetting fluid.

[220] The preferred rearward orifice jet orientation is from 30° to 60° from the longitudinal axis. The rearward thrust jets **1613/1713** are designed to be symmetrical about the circumference of the nozzle's/collar's stator body **1610/1710**. This maintains a purely forwards orientation of the jetting nozzle **1600**, **1601**, **1602** along the longitudinal axis. Accordingly, there should be at least three jets **1613/1713** spaced equi-distant about the circumference, and preferably at least five equi-distant jets **1613/1713**.

[221] As noted above, the nozzle in any of its embodiments may be deployed as part of a guidance, or geo-steering, system. In this instance, the nozzle will include at least one geo-spatial IC chip, and will employ at least three actuator wires. The actuator wires **1590A** are spaced equi-distant about the distal end of the jetting hose and extend into the nozzle, and receive electrical current, or excitation, from the electrical wires **1590** already provided in the jetting hose **1595**.

[222] **Figure 3F-1c** is a longitudinal cross-sectional view of the jetting nozzle **1600** of **Figure 3F-1b**, in a modified embodiment. Here, the jetting nozzle **1600** is shown connected to a jetting hose **1595**. The connection may be a threaded connection; alternatively, the connection may be by means of welding. In **Figure 3F-1c**, an illustrative weld connection is shown at **1660**.

[223] In the arrangement of **Figure 3F-1c**, the jetting nozzle **1600** includes a geo-spatial IC chip **1670**. The geo-spatial chip **1670** resides within a port seal **1675**. The geo-spatial chip **1670** may comprise a two-axial or a three-axial accelerometer, a bi-axial or a tri-axial gyroscope, a magnetometer, or combinations thereof. The present inventions are not limited by the type or number of geo-spatial chips, or their respective locations within the assembly, used unless expressly so stated in the claims. Preferably, the chip **1670** will be associated with a micro-electro-mechanical system residing on or near the nozzle body such as shown and described in connection with the nozzle embodiments (**1600**, **1601**, **1602**) described above.

[224] **Figure 3F-1d** is an axial-cross-sectional view of the jetting hose **1590** of **Figure 3F-1c**, taken across line **c-c'**. Visible in this view are power wires **1590** and actuator wires **1590A**. Also visible are optional fiber optic data cables **1591**. The wires **1590**, **1590A**, **1591** may be used to transmit geo-location data from the chip **1670** up to a micro-processor in the battery pack section **1550**, and then wirelessly to a receiver located in the docking station (shown best at **325** in **Figure 4D-1b**), wherein the receiver communicates with the micro-processor in the docking station **325**. Preferably, the micro-processor in the docking station **325** processes the geo-location data, and makes adjustments to electrical current in the actuator wires **1590A** (using one or more current regulators), in order to ensure that the nozzle is oriented to hydraulically bore the lateral boreholes in a pre-programmed direction.

[225] The micro-transmitter in the battery pack is preferably housed in the battery pack's downstream end cap **1530**, while the docking station **325** is preferably affixed to the interior of a jetting hose carrier system **400** (described below in connection with **Figures 3A, 3B-1,** and **4D-1**). The receiver housed in the docking station **325** may be in electrical or optical connection with a micro-processor at the surface **1**. For example, a fiber optic cable **107** may run along the coiled tubing conveyance system **100**, to the surface **1**, where the geo-location data is processed as part of a control system.

[226] The reverse (surface-to-downhole instrumentation) communication is likewise facilitated by hard-wired (again, preferably fiber optic) connection of surface instrumentation, through fiber optic cable **107** within coiled tubing conveyance medium **100** and external system **2000**, to a specific terminus receiver (not shown) housed within the docking station **325**. An adjoining wireless transmitter within the docking station **325** then transmits the operator's desired commands to a wireless receiver housed within the end cap **1530** of the internal system **1500**. This communication system allows an operator to execute commands setting both the rotational speed and/or the trajectory of the jetting nozzle **1600**.

[227] When the nozzle **1600** exits the casing, the operator knows the location and orientation of the nozzle **1600**. By monitoring the length of jetting hose **1590** that is translated out of the jetting hose carrier, integrated with any changes in orientation, the operator knows the geo-location of the nozzle **1600** in the reservoir.

[228] In one option, a desired geo-trajectory is first sent as geo-steering command from the surface **1**, down the coiled tubing **100**, and to the micro-processor associated with the docking station **325**. Upon receiving a geo-steering command from the surface **1**, such as from an operator or a surface control system, the micro-processor will forward the signals on wirelessly to a corresponding micro-receiver associated with the battery pack section **1550**. That signal will engage one or more current regulators to alter the current conducted down one, two, or all three of the at least three electric wires **1590**, connected directly to the jetting nozzle **1600**. Note that at least part of these electrical wire connections, preferably segments closest to the jetting nozzle **1600**, are comprised of actuator wires **1590A**, such as the Flexinol® actuator wires manufactured by Dynalloy, Inc. These small diameter, nickel-titanium wires contract

when electrically excited. This ability to flex or shorten is characteristic of certain alloys that dynamically change their internal structure at certain temperatures. The contraction of actuator wires is opposite to ordinary thermal expansion, is larger by a hundredfold, and exerts tremendous force for its small size. Given close temperature control under a constant stress, one can get precise position control, i.e., control in microns or less. Accordingly, given (at least) three separate actuator wires **1590A** positioned at-or-near equidistant around the perimeter and within the body of the jetting hose (toward its end, adjacent to the jetting nozzle **1600**), a small increase in current in any given wire will cause it to contract more than the other two, thereby steering the jetting nozzle **1600** along a desired trajectory. Given an initial depth and azimuth via the geo-spatial IC chip in the nozzle **1600**, a determined path for a lateral borehole **15** may be pre-programmed and executed automatically.

[229] Of interest, the actuator wires **1590A** have a distal segment residing along a chamber or sheath, or even interwoven within the matrix of the distal segment of the jetting hose **1595**. Further, the distal end of the actuator wires **1590A** may continue partially into the nozzle body, wrapping the stator poles **1615** to connect to, or even form the electro-magnetic coils **1616**. This is also demonstrated in **Figure 3F-1c**. In this way, electrical power is provided from the battery pack section **1550** to induce the relative rotational movement between the rotor body and the stator body.

[230] As can be seen from the above discussion, an internal system **1500** for a hose jetting assembly **50** is provided. The system **1500** enables a powerful hydraulic nozzle (**1600**, **1601**, **1602**) to jet away subsurface rock in a controlled (or steerable) manner, thereby forming a mini-lateral borehole that may extend many feet out into a formation. The unique combination of the internal system's **1500** jetting fluid receiving funnel **1570**, the upper seal **1580U**, the jetting hose **1595**, in connection with the external system's **2000** pressure regulator valve **610** and pack-off section **600** (discussed below) provide for a system by which advancement and retraction of the jetting hose **1595**, regardless of the orientation of the wellbore **4**, can be accomplished entirely by hydraulic means. Alternatively, mechanical means may be added through use of an internal tractor system **700**, described more fully below.

[231] Not only can the above-listed components be controlled to determine the direction of the jetting hose **1595** propulsion (e.g., either advancement or retraction), but also the rate of propulsion. The rate of advancement or retraction of the internal system **1500** may be directly proportional to the rate of fluid (and pressure) bleed-off and/or pump-in, respectively. Specifically, "pumping the hose **1595** down-the-hole" would have the following sequence:

(1) the micro-annulus **1595.420** between the jetting hose **1595** and the jetting hose carrier's inner conduit **420** is filled by pumping hydraulic fluid through the main control valve **310**, and then through the pressure regulator valve **610**; then

(2) the main control valve **310** is switched electronically using surface controls to begin directing jetting fluid to the internal system **1500**; which

(3) initiates a hydraulic force against the internal system **1500** directing jetting fluid through the intake funnel **1570**, into the jetting hose **1595**, and "down-the-hole"; such force being resisted by

(4) compressing hydraulic fluid in the micro-annulus **1595.420**; which is

(5) bled-off, as desired, from surface control of the pressure regulator valve **610**, thereby regulating the rate of "down-the-hole" decent of the internal system **1500**.

[232] Similarly, the internal system **1500** can be pumped back "up-the-hole" by directing the pumping of hydraulic fluid through (first) the main control valve **310** and (secondly) through the pressure regulator valve **610**, thereby forcing an ever-increasing (expanding) volume of hydraulic fluid into the micro-annulus **1595.420** between the jetting hose **1595** and the jetting hose conduit **420**, which pushes upwardly against the bottom seals **1580L** of the jetting hose seal assembly **1580**, thereby driving the internal system **1500** back "up-the-hole". The direction and rate of propulsion of the internal system **1500** by hydraulic means can be either augmented or replaced by propulsion of the internal system **1500** via the mechanical means of the internal tractor system **700**, also described below.

[233] Beneficially, once the jetting hose assembly **50** is deployed to a downhole location adjacent a desired point of casing exit "**W**" within a parent wellbore **4** of any inclination (including at-or-near horizontal), the entire length of jetting hose **1595** can be deployed and retrieved without any assistance from gravitational forces. This is because the propulsion

forces used to both deploy and retrieve the jetting hose **1595**, and to maintain its proper alignment while doing so, are either hydraulic or mechanical, as described more fully, below. Note also these propelling hydraulic and mechanical forces are available in more than sufficient quantities as to overcome any frictional forces from movement of the internal system **1500** (including, specifically, the jetting hose **1595**) within the external system **2000** (including, specifically, the jetting hose conduit **420**) induced by any non-vertical alignment, and to maintain the hose **1595** in a substantially taught state along the hose length within the external system **2000**. Hence, these hydraulic and mechanical propulsion forces overcome the "can't-push-a-rope" limitation in its entirety.

[234] Hydraulic force to advance the jetting hose **1595** within and subsequently out of the external system **2000** will be observed any time jetting fluid is being pumped; specifically, force in a plane parallel to the longitudinal axis of the jetting hose **1595**, in an upstream-to-downstream direction, as hydraulic force is exerted against the upstream end-cap of the battery pack **1520**, the fluid intake funnel **1570**, the interior face of the jetting nozzle **1600**, e.g., any internal system **1500** surface that is both: (a) exposed to the flow of jetting fluid; and, (b) having a directional component not parallel to the longitudinal axis of the parent wellbore. As these surfaces are rigidly attached to the jetting hose **1595** itself, this upstream-to-downstream force is conveyed directly to the jetting hose **1595** whenever jetting fluid is being pumped from the surface **1**, down the coiled tubing conveyance medium **100** (seen in **Figure 2**), and through the jetting fluid passage **345** within the main control valve **300** (described below in connection with **Figure 4C-1**). Note the function of the only other valve in this system, the pressure regulator valve **610** located just upstream of the pack-off seal assembly **650** of pack-off section **600** (seen and described in connection with **Figures 4E-1** and **4E-2**), is simply to release pressure from the compression of hydraulic fluid within the jetting hose **1595** / jetting hose conduit **420** annulus **1595.420** (seen in **Figures 3D-1a** and **4D-2**) commensurate with the operator's desired rate of decent of the internal system **1500**.

[235] Conversely, hydraulic forces are operational in propelling the internal system **1500** in a downstream-to-upstream direction whenever hydraulic fluid is being pumped from the surface **1**, down the coiled tubing conveyance medium **100**, and through the hydraulic fluid passage **340** within the main control valve **300**. In this configuration, the pressure regulator

valve **610** allows the operator to direct injected fluids into the jetting hose **1595** / jetting hose conduit **420** annulus **1595.420** commensurate with the operator's desired rate of ascent of the internal system **1500**. Thus, hydraulic forces are available to assist in both conveyance and retrieval of the jetting hose **1595**.

[236] Similarly, mechanical forces applied by the internal tractor system **700** assist in conveyance, retrieval, and maintaining alignment of the jetting hose **1595**. The close tolerance between the O.D. of the jetting hose **1595** and the I.D. of the jetting hose conduit **420** of jetting hose carrier system **400**, thus defining annulus **1595.420**, serves to provide confining axial forces that assist in maintaining the alignment of the hose **1595**, such that the portion of the hose **1595** within the jetting hose carrier system **400** can never experience significant buckling forces. Direct mechanical (tensile) force for both deployment and retrieval of the jetting hose **1595** is applied by direct frictional attachment of grippers **756** of specially-designed gripper assemblies **750** of the internal tractor system **700** to the jetting hose **1595** , discussed below in connection with **Figures 4F-1** and **4F-2**.

[237] As described above, jetting hose conveyance is also assisted by the hydraulic forces emanating from the rearward thrusting jets **1613** of the jetting nozzle **1601, 1602** itself; and, if included, from the rearward thrust jets **1713** of any added jetting collar(s) **1700**. These furthest downstream hydraulic forces serve to advance the jetting hose **1595** forward into the pay zone **3** simultaneously with the creation of the UDP **15 (Figure 1B)**, maintaining the forward-aimed jetting fluid proximally to the rock face being excavated. The balance between deploying hydraulic energy forward proximate to the nozzle (for excavating new hole) versus rearward (for propulsion) requires balance. Too much rearward propulsion, and there is not enough residual hydraulic horsepower focused forward to excavate new hole. If there is too much forward propulsion expulsion of jetting fluid, there is insufficient fluid available for the rearward thrust jets **1613** / **1713** to generate the requisite horsepower to drag the jetting hose along the lateral borehole. Hence, the ability to redirect either rearward or forward focused hydraulic horsepower through the nozzle *in situ* as described herein is a major enhancement.

[238] For presentation purposes, two configurations of rearward thrust jets **1613/1713** have been included herein – one for pulsating flow wherein eight rearward thrust jets, each

inclined at 30° from the longitudinal axis and spaced equi-distant about the circumference, are grouped into two sets of four, with rearwards flow alternating (or 'pulsing') between the two sets; and one for continuous flow, wherein a single set of five jets, each inclined at 30° from the longitudinal axis and spaced equi-distant about the circumference, are shown. However, other jet numbers and angles may be employed.

[239] The **Figure 3** series of drawings, and the preceding paragraphs discussing those drawings, are directed to the internal system **1500** for the hydraulic jetting assembly **50**. The internal system **1500** provides a novel system for conveying the jetting hose **1595** into and out of a parent wellbore **4** for the subsequent steerable generation of multiple mini-lateral boreholes **15** in a single trip. The jetting hose **1595** may be as short as 10 feet or as long as 300 feet or even 500 feet, depending on the thickness and compressive strength of the formation or the desired geo-trajectory of each lateral borehole.

[240] As noted, the hydraulic jetting assembly **50** also provides an external system **2000**, uniquely designed to convey, deploy, and retrieve the internal system **1500** previously described. The external system **2000** is conveyable on conventional coiled tubing **100**; but, more preferably, is deployed on a "bundled" coiled tubing product (**Figures 3D-1a**, **4A-1** and **4A-1a**) providing for real-time power and data transmission.

[241] Consistent with the related and co-owned patent documents cited herein, the external system **2000** includes a jetting hose whipstock member **1000** including a whipstock **1050** having a curved face **1050.1** that preferably forms the bend radius for the jetting hose **1595** across the entire I.D. of the production casing **12**. The external system **2000** may also include a conventional tool assembly comprised of mud motor(s) **1300**, (external) coiled tubing tractor(s) **1350**, logging tools **1400** and/or a packer or a bridge plug (preferably, retrievable) that facilitate well completion. In addition, the external system **2000** provides for power and data transmission throughout, so that real time control may be provided over the downhole assembly **50**.

[242] **Figure 4** is a longitudinal, cross-sectional view of an external system **2000** of the downhole hydraulic jetting assembly **50** of **Figure 2**, in one embodiment. The external system **2000** is presented within the string of production casing **12**. For clarification, **Figure 4**

presents the external system **2000** as "empty"; that is, without containing the components of the internal system **1500** described in connection with the **Figure 3** series of drawings. For example, the jetting hose **1595** is not shown. However, it is understood that the jetting hose **1595** is largely contained in the external system during run-in and pull-out.

[243] In presenting the components of the external system **2000**, it is assumed that the system **2000** is run into production casing **12** having a standard 4.50" O.D. and approximate 4.0" I.D. In one embodiment, the external system **2000** has a maximum outer diameter constraint of 2.655" and a preferred maximum outer diameter of 2.500". This O.D. constraint provides for an annular (i.e., between the system **2000** O.D. and the surrounding production casing **12** I.D.) area open to flow equal to or greater than 7.0309 in^2, which is the equivalent of a 9.2#, 3.5" frac (tubing) string.

[244] The external system **2000** is configured to allow the operator to optionally "frac" down the annulus between the coiled tubing conveyance medium **100** (with attached apparatus) and the surrounding production casing **12**. Preserving a substantive annular region between the O.D. of the external system **2000** and the I.D. of the production casing **12** allows the operator to pump a fracturing (or other treatment) fluid down the subject annulus immediately after jetting the desired number of lateral bores and without having to trip the coiled tubing **100** with attached apparatus **2000** out of the parent wellbore **4**. Thus, multiple stimulation treatments may be performed with only one trip of the assembly **50** in to and out of the parent wellbore **4**. Of course, the operator may choose to trip out of the wellbore for each frac job, in which case the operator would utilize standard (mechanical) bridge plugs, frac plugs and/or sliding sleeves. However, this would impose a much greater time requirement (with commensurate expense), as well as much greater wear and fatigue of the coiled tubing-based conveyance medium **100**.

[245] In actuality, rigorous adherence to the (O.D.) constraint is perhaps only essential for the coiled tubing conveyance medium **100**, which may comprise over 90% of the length of the system **50**. Slight violations of the O.D. constraint over the comparatively minute lengths of the other components of the external system **2000** should not impose significant annular hydraulic pressure drops as to be prohibitive. If these outer diameter constraints can be

satisfied, while maintaining sufficient inner diameters so as to accommodate the design functionality of each of the components (particularly of the external system **2000**), and this can be accomplished for a system **50** that operates in the smaller of standard oilfield production casing **4** sizes of 4.5" O.D., then there should be no significant barriers to adapting the system **50** to any of the larger standard oilfield production casing sizes (5.5", 7.0", etc.).

[246] Presentation of each of the major components of the external system **2000**, which follows below, will be in an upstream-to-downstream direction. Note in **Figure 4** the demarcation of the major components of the external system **2000**, with the corresponding Figure(s) herein:

a. the coiled tubing conveyance medium **100**, presented in **Figures 4A-1** and **4A-2**;

b. the first crossover connection (the coiled tubing transition) **200**, presented in **Figure 4B-1**;

c. the main control valve **300**, presented in **Figure 4C.1**;

d. the jetting hose carrier system, **400** with its docking station **325**, presented in **Figures 4D-1** and **4D-2**;

e. the second crossover connection **500** (transitioning the outer body from circular to star-shaped) and the jetting hose pack-off section **600**, presented in **Figures 4E-1** and **4E-2**;

f. the internal tractor system **700** and the third crossover connection **800**, presented in **Figures 4F-1** and **4F-2**;

g. the third crossover connection **800** and the upper swivel **900**, presented in **Figure 4G-1**;

h. the whipstock member **1000**, presented in **Figure 4H-1**;

i. the lower swivel **1100**, presented in **Figure 4I-1**; and, lastly,

j. the transitional connection **1200** to the conventional coiled tubing mud motor **1300** and a conventional coiled tubing tractor **1350**,

coupled to a conventional logging sonde **1400**, presented in **Figure 4J**.

[247] **Figure 4A-1** is a longitudinal, cross-sectional view of a "bundled" coiled tubing conveyance medium **100**. The conveyance medium **100** serves as a conveyance system for the downhole hydraulic jetting assembly **50** of **Figure 2**. The conveyance medium **100** is shown residing within the production casing **12** of a parent wellbore **4**, and extending through a heel **4b** and into the horizontal leg **4c**.

[248] **Figure 4A-1a** is an axial, cross-sectional view of the coiled tubing conveyance medium **100** of **Figure 4A-1**. It is seen that the conveyance medium **100** includes a core **105**. In one aspect, the coiled tubing core **105** is comprised of a standard 2.000" O.D. (**105.2**) and 1.620" I.D. (**105.1**), 3.68 lbm/ft. HSt110 coiled tubing string, having a Minimum Yield Strength of 116,700 lbm and an Internal Minimum Yield Pressure of 19,000 psi. This standard sized coiled tubing provides for an inner cross-sectional area open to flow of 2.06 in^2. As shown, this "bundled" product **100** includes three electrical wire ports **106** of up to .20" in diameter, which can accommodate up to AWG #5 gauge wire, and 2 data cable ports **107** of up to .10" in diameter.

[249] The coiled tubing conveyance medium **100** also has an outermost, or "wrap," layer **110**. In one aspect, the outer layer **110** has an outer diameter of 2.500", and an inner diameter bonded to and exactly equal to that of the O.D. **105.2** of the core coiled tubing string **105** of 2.000".

[250] Both the axial and longitudinal cross-sections presented in **Figures 4A-1** and **4A-1a** presume bundling the product **100** concentrically, when in actuality, an eccentric bundling may be preferred. An eccentric bundling provides more wrap layer protection for the electrical wiring **106** and data cables **107**. Such a depiction is included as **Figure 4A-2** for an eccentrically bundled coiled tubing conveyance medium **101**. Fortunately, eccentric bundling would have no practical ramifications on sizing pack-off rubbers or wellhead injector components for lubrication into and out of the parent wellbore, since the O.D. **105.2** and circularity of the outer wrap layer **110** of an eccentric conveyance medium **101** remain unaffected.

[251] The conveyance medium **101** may have, for example, an internal flow area of 2.0612 in^2, a core wall thickness **105** of 0.190 in^2, and an average outer wall thickness of 0.25 in^2. The outer wall **110** may have a minimum thickness of 0.10 in^2.

[252] Note the main design criteria of the conveyance medium, whether concentrically **100** or eccentrically **101** bundled, is to provide real-time power (via electrical wiring **106**) and data (via data cabling **107**) transmission capacities to an operator located at the surface **1** while deploying, operating, and retrieving apparatus **50** in the wellbore **4**. For example, in a standard e-coil system, components **106** and **107** would be run within the coiled tubing core **105**, thereby exposing them to any fluids being pumped via the I.D. **105.1** of the core **105**. Given the subject method provides for pumping abrasives within a high-pressure jetting fluid (particularly, while eroding casing exit "**W**" from within production casing **12**), it is preferred instead to locate components **106** and **107** at the O.D. **105.2** of the core **105**.

[253] Similarly, the subject method provides for pumping proppants within high pressure hydraulic fracturing fluids down the annulus between the coiled tubing conveyance medium **100** (or **101**) and production casing **12**. Hence, the protective coiled tubing wrap layer **110** is preferably of sufficient thickness, strength, and erosive resistance to isolate and protect components **106** and **107** during fracturing operations.

[254] The present conveyance medium **100** (or **101**) also maintains a sufficiently large inner diameter **105.1** of the core wall **105** such as to avoid appreciable friction losses (as compared to the losses incurred in the internal system **1500** and external system **2000**) while pumping jetting and/or hydraulic fluids. At the same time, the system maintains a sufficiently small outer diameter **110.2** so as to avoid prohibitively large pressure losses while pumping hydraulic fracturing fluids down the annulus between the coiled tubing conveyance medium **100** (or **101**) and the production casing **12**. Further, the system **50** maintains a sufficient wall thickness for the outer wrap layer **110**, whether it is concentrically or eccentrically wrapped about the inner coiled tubing core **105**, so as to provide adequate insular protection and spacing for the electrical transmission wiring **106** and the data transmission cabling **107**. It is understood that other dimensions and other tubular bodies may be used as the conveyance medium for the external system **2000**.

[255] Moving further down the external system **2000**, **Figure 4B-1** presents a longitudinal, cross-sectional view of the first crossover connection, the coiled tubing crossover connection **200**. **Figure 4B-1**a shows a portion of the coiled tubing crossover connection **200** in perspective view. Specifically, the transition between lines **E-E'** and line **F-F'** is shown. In this arrangement, an outer profile transitions from circular to oval to bypass the main control valve **300**.

[256] The main functions of this crossover connection **200** are as follows:

(1) To connect the coiled tubing conveyance medium **100** (or **101**) to the jetting assembly **50** and, specifically, to the main control valve **300**. In **Figure 4B-1**, this connection is depicted by the steel coiled tubing core **105** connected to the main control valve's outer wall **290** at connection point **210**.

(2) To transition the electrical cables **106** and data cables **107** from the outside of the core **105** of the coiled tubing conveyance medium **100** (or **101**) to the inside of the main control valve **300**. This is accomplished with wiring port **220** facilitating the transition of wires/cables **106**/**107** inside outer wall **290**.

(3) To provide an ease-of-access point, such as the threaded and coupled collars **235** and **250**, for the splicing/connection of electrical cables **106** and data cables **107.**

and

(4) To provide separate, non-intersecting and non-interfering pathways for electrical cables **106** and data cables **107** through a pressure- and fluid-protected conduit, that is, a wiring chamber **230**.

[257] The next component in the external system **2000** is a main control valve **300**. **Figure 4C-1** provides a longitudinal, cross-sectional view of the main control valve **300**. **Figure 4C-1a** provides an axial, cross-sectional view of the main control valve **300**, taken across line **G-G'** of **Figure 4C-1**. The main control valve **300** will be discussed in connection with both **Figures 4C-1** and **4C-1a** together.

[258] The function of the main control valve **300** is to receive high pressure fluids pumped from within the coiled tubing **100**, and to selectively direct them either to the internal system **1500** or to the external system **2000**. The operator sends control signals to the main control valve **300** by means of the wires **106** and/or data cable ports **107**.

[259] The main control valve **300** includes two fluid passages. These comprise a hydraulic fluid passage **340** and a jetting fluid passage **345**. Visible in **Figures 4C-1, 4C-1a** and **4C-1b** (longitudinal cross-sectional, axial cross-sectional, and perspective view, respectively) is a sealing passage cover **320**. The sealing passage cover **320** is fitted to form a fluid-tight seal against inlets of both the hydraulic fluid passage **340** and the jetting fluid passage **345**. Of interest, **Figure 4C-1b** presents a three dimensional depiction of the passage cover **320**. This view illustrates how the cover **320** can be shaped to help minimize frictional and erosional effects.

[260] The main control valve **300** also includes a cover pivot **350**. The passage cover **320** rotates with rotation of the passage cover pivot **350**. The cover pivot **350** is driven by a passage cover pivot motor **360**. The sealing passage cover **320** is positioned by the passage cover pivot **350** (as driven by the passage cover pivot motor **360**) to either: (1) seal the hydraulic fluid passage **340**, thereby directing all of the fluid flow from the coiled tubing **100** into the jetting fluid passage **345**, or (2) seal the jetting fluid passage **345**, thereby directing all of the fluid flow from the coiled tubing **100** into the hydraulic fluid passage **340**.

[261] The main control valve **300** also includes a wiring conduit **310**. The wiring conduit **310** carries the electrical wires **106** and data cables **107**. The wiring conduit **310** is optionally elliptically shaped at the point of receipt (from the coiled tubing transition connection **200**, and gradually transforms to a bent rectangular shape at the point of discharging the wires **106** and cables **107** into the jetting hose carrier system **400**. Beneficially, this bent rectangular shape serves to cradle the jetting hose conduit **420** throughout the length of the jetting hose carrier system **400**.

[262] The next component of the external system **2000** is a jetting hose carrier system **400**. **Figure 4D-1** is a longitudinal, cross-sectional view of the jetting hose carrier system **400**. The jetting hose carrier system **400** is attached downstream of the main control valve **300**. The

jetting hose carrier system **400** is essentially an elongated tubular body that houses the docking station **325**, the internal system's battery pack section **1550**, the jetting fluid receiving funnel **1570**, the seal assembly **1580** and connected jetting hose **1595**. In the view of **Figure 4D-1**, only the docking station **325** is visible so that the profile of the jetting hose carrier system **400** itself is more clearly seen.

[263] **Figure 4D-1a** is an axial, cross-sectional view of the jetting hose carrier system **400** of **Figure 4D.1**, taken across line **H-H'** of **Figure 4D-1**. **Figure 4D-1b** is an enlarged view of a portion of the jetting hose carrier system **400** of **Figure 4D-1**. Here, the docking station **325** is visible. The jetting hose carrier system **400** will be discussed with reference to each of **Figures 4D-1**, **4D-1a** and **4D-1b**, together.

[264] The jetting hose carrier system **400** defines a pair of tubular bodies. The first tubular body is a jetting hose conduit **420**. The jetting hose conduit **420** houses, protects, and stabilizes the internal system **1500** and, particularly, the jetting hose **1595**. As previously presented in the discussion of the internal system **1500**, it is the size (specifically, the I.D.), strength, and rigidity of this fluid-tight and pressure-sealing conduit **420** that provides the pathway and particularly, the micro-annulus (shown at **1595.420** in **Figure 3D-1a**, **Figure 4D-2** and **Figure 4D-2a**) for the jetting hose **1595** of internal system **1500** to be "pumped down" and reversibly "pumped up" the longitudinal axis of the external system **2000** as it operates within the production casing **12**.

[265] The jetting hose carrier section **400** also has an outer conduit **490**. The outer conduit **490** resides along and circumscribes the inner conduit **420**. In one aspect, the outer conduit **490** and the jetting hose conduit **420** are simply concentric strings of 2.500" O.D. and 1.500" O.D. HSt100 coiled tubing, respectively. The inner conduit, or jetting hose conduit **420**, is sealed to and contiguous with the jetting fluid passage **345** of the main control valve **300**. When high pressure jetting fluid is directed by the valve **300** into the jetting fluid passage **345**, the fluid flows directly and only into the jetting hose conduit **420** and then into the jetting hose **1595**.

[266] An annular area **440** exists between the inner (jetting hose) conduit **420** and the surrounding outer conduit **490**). The annular area **440** is also fluid tight, directly sealed to and

contiguous with the hydraulic fluid passage **340** of the control valve **300**. When high pressure hydraulic fluid is directed by the main control valve **300** into the hydraulic fluid passage **340**, the fluid flows directly into the conduit-carrier annulus **440**.

[267] The jetting hose carrier section **400** also includes a wiring chamber **430**. The wiring chamber **430** has an axial cross-section of an upwardly-bent rectangular shape, and receives the electrical wires **106** and data cables **107** from the main control valve's **300** wiring conduit **310**. This fluid-tight chamber **430** not only separates, insulates, houses, and protects the electrical wires **106** and data cables **107** throughout the entire length of the jetting hose carrier section **400**, but its cradle shape serves to support and stabilize the jetting hose conduit **420**. Note the jetting hose carrier section **400** wiring chamber **430** and inner (jetting hose) conduit **420** may or may not be attached either to each other, and/or to the outer conduit **490**.

[268] In addition to housing and protecting wires **106** and data transmission cables **107**, the wiring conduit **430** within the jetting hose carrier system **400** supports the jetting hose conduit's **420** horizontal axis at a position slightly above a horizontal axis that would bifurcate the outer conduit **490**. Different types of materials may be utilized in its construction, given its design constraints are significantly less stringent than those for the outer layer(s) of the CT-based conveyance medium, particularly in regard to chemical and abrasion resistance, as the exterior of the wiring conduit **430** will only be exposed to hydraulic fluid – never jetting or fracturing fluids.

[269] Additional design criteria for the wiring conduit **430** may be invoked if it is desired for it to be rigidly attached to either the jetting hose conduit **420**, the outer conduit **490**, or both. In one aspect, the wiring conduit **430** has a width of approximately 1.34", and provides three 0.20" diameter circular channels for electrical wiring, and two 0.10" diameter circular channels for data transmission cables. It is understood that other diameters and configurations for the wiring conduit **430** may vary, depending on design objectives, so long as an annular area **440** open to flow of hydraulic fluid is preserved.

[270] Also visible in **Figure 4D-1** is the docking station **325**. The docking station **325** resides immediately downstream of the connection between the main control valve **300** and the jetting hose carrier system **400**. The docking station **325** is rigidly attached within the interior

of the jetting hose conduit **420**. The docking station **325** is held in the jetting hose conduit **420** by diagonal supports. The diagonal supports are hollow, the interior(s) of which serving as a fluid- and pressure-tight conduit(s) of leads of electrical wires **106** and data cables **107** into the communications/control/electronics systems of the docking station **325**. This is similar to functions of the battery pack support conduits **1560** of the internal system **1500**. Whether connected to a servo device, a transmitter, a receiver, or other device housed within the docking station **325**, these devices are thereby "hard-wired" via electrical wires **106** and data cables **107** to an operator's control system (not shown) at the surface **1**.

[271] **Figure 4D-2** provides an enlarged, longitudinal cross-sectional view of a portion of the jetting hose carrier system **400** of external system **2000**, depicting its operational hosting of a commensurate length of jetting hose **1595**. **Figure 4D-2a** provides an axial, cross-sectional view of the jetting hose carrier system **400** of **Figure 4D-2**, taken across line **H-H'**. Note that the cross-sectional view of **Figure 4D-2a** matches the cross-sectional view of **Figure 4D-1a**, except that the conduit **420** in **Figure 4D-1a** is "empty," meaning that the jetting hose **1595** is not shown.

[272] The length of the jetting hose conduit **420** is quite long, and should be approximately equivalent to the desired length of jetting hose **1595**, and thereby defines the maximum reach of the jetting nozzle **1600** orthogonal to the wellbore **4**, and the corresponding length of the mini-lateral **15**. The inner diameter specification defines the size of the micro-annulus **1595.420** between the jetting hose **1595** and the surrounding jetting hose conduit **420**. The I.D. should be close enough to the O.D. of the jetting hose **1595** so as to preclude the jetting hose **1595** from ever becoming buckled or kinked, yet it must be large enough to provide sufficient annular area for a robust set of seals **1580L** by which hydraulic fluid can be pumped into the sealed micro-annulus **1595.420** to assist in controlling the rate of deployment of the jetting hose **1595**, or assisting in hose retrieval.

[273] It is the hydraulic forces within the sealed micro-annulus **1595.420** that keep the segment of jetting hose (above the internal tractor system **700**) straight, and slightly in tension. The I.D. of jetting hose conduit **420** can likewise not be too close to the O.D. of the jetting hose **1595** so as to place unnecessarily high frictional forces between the two. The O.D. of the

jetting hose conduit **420** (in conjunction with the I.D. of the outer conduit **490**, less the external dimensions of the jetting hose carrier's wiring chamber **430**) define the annular area **440** through which hydraulic fluid is pumped. Certainly, if the jetting hose carrier system's inner conduit **420** O.D. is too large, it thereby invokes undue frictional losses in pumping hydraulic fluid. However, if not large enough, then the inner conduit **420** will not have sufficient wall thickness to support either the inner or outer operating pressures required. Note, for the subject apparatus designed to be deployed in 4.5" wellbore casing, the inner string is comprised of 1.5" O.D. and 1.25" I.D. (i.e., .125" wall thickness) coiled tubing. If this were 1.84#/ft., HSt110, for example, it would provide for an Internal Minimum Yield Pressure rating of 16,700 psi. Similarly, the outer conduit **490** can be constructed of standard coiled tubing. In one aspect, the outer conduit **490** is comprised of 2.50" O.D. and 2.10" I.D., thereby providing for a wall thickness of 0.20".

[274] Progressing again uphole-to-downhole, the external system **2000** next includes the second crossover connection **500,** transitioning to the jetting hose pack-off section **600**. **Figure 4E-1** provides an elongated, cross-sectional view of both the crossover connection (or transition) **500** and the jetting hose pack-off section **600**. Figure **4E-1a** is an enlarged perspective view highlighting the transition's **500** outer body shape, transitioning from circular- to star-shaped. Axial cross-sectional lines **I-I'** and **J-J'** illustrate the profile of the transition **500** fittingly matching the dimensions of the outer wall **490** of jetting hose carrier system **400** at its beginning, and an outer wall **690** of the pack-off section **600** at its end.

[275] **Figure 4E-2** shows an enlarged portion of the jetting hose pack-off section **600** of **Figure 4E-1**, and particularly sealing assembly **650**. The transition **500** and the jetting hose pack-off section **600** will be discussed with reference to each of these views together.

[276] As its name implies, the main function of the jetting hose pack-off section **600** is to "pack-off", or seal, an annular space between the jetting hose **1595** and a surrounding inner conduit **620**. The jetting hose pack-off section **600** is a stationary component of the external system **2000.** Through transition **500**, and partially through pack-off section **600**, there is a direct extension of the micro-annulus **1595.420**. This extension terminates at the pressure/fluid seal of the jetting hose **1595** against the inner faces of seal cups making up the pack-off seal

assembly **650**. Immediately prior to this terminus point is the location of the pressure regulator valve, shown schematically as component **610** in **Figures 4E-1** and **4E-2**. It is this valve **610** that serves to either communicate or segregate the annulus **1595.420** from the hydraulic fluid running throughout the external system **2000**. The hydraulic fluid takes its feed from the inner diameter of the coiled tubing conveyance medium **100** (specifically, from the I.D. **105.1** of coiled tubing core **105**) and proceeds through the continuum of hydraulic fluid passages **240**, **340**, **440**, **540**, **640**, **740**, **840**, **940**, **1040**, and **1140**, then through the transitional connection **1200** to the coiled tubing mud motor **1300**, and eventually terminating at the tractor **1350**. (Or, terminating at the operation of some other conventional downhole application, such as a hydraulically set retrievable bridge plug.)

[277] The crossover connection **500** from the jetting hose carrier system **400** to the pack off section **600** is notable for several reasons:

[278] First, within this transition **500**, the free flow of hydraulic fluid from the conduit-carrier annulus **440** of the jetting hose carrier section **400** will be re-directed and re-compartmentalized within the upper (triangular-shaped) quadrant of the star-shaped outer conduit **690**. Toward the upstream end of the inner conduit **620** is the pressure regulator valve **610**. The pressure regulator valve **610** provides for increasing or decreasing the hydraulic fluid (and commensurately, the hydraulic pressure) in the micro-annulus **1595.420** between the jetting hose **1595** and the surrounding jetting hose conduit **420**. It is the operation of this valve **610** that provides for the internal system **1500** (and specifically, the jetting hose **1595**) to be "pumped down," and then reversibly "pumped up" the longitudinal axis of the production casing **12**.

[279] The upwardly bent, rectangular-shaped fluid-tight chamber **430** that separates, insulates, houses, and protects the electrical wires **106** and data cables **107** along the length of the jetting hose carrier body **400** is transitioned via wiring chamber **530** into a lower (triangular-shaped) quadrant **630** of the star-shaped outer body **690** of the pack-off section **600**. This preserves the separation, insulation, housing, and protection of the electrical wires **106** and the data cables **107** in the jetting hose pack-off section **600**. The star-shaped outer body **690** forms an annulus between itself and the I.D. of the surrounding production casing **12**.

[280] Given the prong-tip-to-opposite-prong-tip distances of the four-pronged star-shaped outer conduit **690** are just slightly less than the I.D. of the production casing **12**, the pack-off section **600** also serves to nearly centralize the jetting hose **1595** in the parent wellbores production casing **12**. As will be explained later, this near-centralization will translate through the internal tractor system **700** so as to beneficially centralize the upstream end of the whipstock member **1000**.

[281] Recall the outer diameter of the upstream end of the jetting hose **1595** is hydraulically sealed against the inner diameter of the inner conduit **420** of the jetting hose carrier system **400** by virtue of the jetting hose's upper **1580U** and lower **1580L** seals, forming a single seal assembly **1580**. The seals **1580U** and **1580L**, being formably affixed to the jetting hose **1595**, travel up and down the inner conduit **420**. Similarly, the outer diameter of the downstream end of the jetting hose **1595** is hydraulically sealed against the inner diameter of the pack-off section's **600** inner conduit **620** by virtue of the seal assembly **650** of the pack-off section **600**. Thus, when the internal system **1500** is "docked" (i.e., when the upstream battery pack end cap **1520** is in contact with the external system's docking station **325**) then the distance between the two seal assemblies **1580**, **620** approximates the full length of the jetting hose **1595**. Conversely, when the jetting hose **1595** and jetting nozzle **1600** have been fully extended into the maximum length lateral borehole (or UDP) **15** attainable by the jetting assembly **50**, then the distance between the two seal assemblies **1580**, **620** is negligible. This is because, though the internal system's jetting hose seal assembly **1580** essentially travels the entire length of the external system's **2000** jetting hose carrier system **400**, the seal assembly **650** (of the pack-off section **600** in the external system **2000**) is relatively stationary, as the seal cups comprising seal assembly **650** must reside between opposing seal cup stops **615**.

[282] Note further how the alignment of the two opposing sets of seal cups comprising seal assembly **650** (e.g., an upstream set facing upstream, placed back-to-back with a downstream set facing downstream) thereby provides a pressure/fluid seal against differential pressure from either the upstream direction or the downstream direction. These opposing sets of seal cups comprising seal assembly **650** are shown with a longitudinal cross section of jetting hose **1595** running concentrically through them, in the enlarged view of **Figure 4E-2**.

[283] As noted, the pressure maintained in the micro-annulus **1595.420** by the pressure regulator valve **610** provides for the hydraulic actions of "pumping the hose down the hole" or, reversibly, "pumping the hose up the hole". These annular hydraulic forces also serve to mitigate other, potentially harmful forces that could be imposed on the jetting hose **1595**, such as buckling forces when advancing the hose **1595** downstream, or internal burst forces while jetting. Hence, combined with the upper hose seal assembly **1580** and the jetting hose conduit **420**, the jetting hose pack-off section **600** serves to maintain the jetting hose **1595** in an essentially taut condition. Hence, the diameter of the hose **1595** that can be utilized will be limited only by the bend radius constraint imposed by the I.D. of the wellbore's production casing **12**, and the commensurate pressure ratings of the hose **1595**. At the same time, the length of the hose **1595** that may be utilized is certainly well into the hundreds of feet.

[284] Note the most likely limiting constraint of hose **1595** length will not be anything imposed by the external system **2000**, but instead will be the hydraulic horsepower distributable to the rearward thrust jets **1613/1713**, such that sufficient horsepower can remain forward-focused for excavating rock. As one might expect, the length (and commensurate volume) of mini-laterals that can be jetted will ultimately be a function of rock strength in the subsurface formation. This length limitation is quite unlike the system posited in U.S. Patent No. 6,915,853 (Bakke, *et al.*) that attempts to convey the entirety of the jetting hose downhole in a coiled state within the apparatus itself. That is, in Bakke, *et al.*, the hose is stored and transported while in horizontally stacked, 360° coils contained within the interior of the device. In this case, the bend radius/pressure hose limitations are imposed by (among other constraints), not the I.D. of the casing, but by the I.D. of the device itself. This results in a much smaller hose I.D./O.D., and hence, geometrically less horsepower deliverable to Bakke's jetting nozzle.

[285] In operation, after a UDP **15** has been formed and the main control valve **300** has been shifted to shut-off the flow of hydraulic jetting fluid to the internal system **1500** and is then providing flow of hydraulic fluid to the external system **2000**, the pressure regulator valve **610** can feed flow into the micro-annulus **1595.420** in the opposite direction. This downstream-to-upstream force will "pump" the assembly back into the wellbore **4** and "up the

hole," as the bottom, downwards facing cups **1580L** of the seal assembly **1580** will trap flow (and pressure) below them.

[286] The next component within the external system **2000** (again, progressing uphole-to-downhole) is an optional internal tractor system **700**. **Figure 4F-1** provides an elongated, cross-sectional view of the tractor system **700**, downstream from the jetting hose pack-off section **600**. **Figure 4F-2** shows an enlarged portion of the tractor system **700** of **Figure 4F-1**. **Figure 4F-2a** is an axial, cross-sectional view of the internal tractor system **700**, taken across line **K-K'** of **Figures 4F-1** and **4F-2**. Finally, **Figure 4F-2b** is an enlarged half-view of a portion of the internal tractor system **700** of **Figure 4F-2a**. The internal tractor system **700** will be discussed with reference to each of these four views together.

[287] It is first observed that two types of tractor systems are known. These are the wheeled tractor systems and the so-called inch-worm tractor systems. Both of these tractor systems are "external" systems, meaning that they have grippers designed to engage the inner wall of the surrounding casing (or, if in an open hole, to engage the borehole wall). Tractor systems are used in the oil and gas industry primarily to advance either a wireline or a string of coiled tubing (and connected downhole tools) along a horizontal (or highly deviated) wellbore – either uphole or downhole.

[288] In the present assembly **50**, a unique tractor system has been developed which employs "internal," grippers. This means that gripper assemblies **750** are aimed inwardly, for the purpose of either advancing or retracting the jetting hose **1595** relative to the external system **2000**. The result of this inversion is that the coiled tubing string **100** and attached external system **2000** can now be stationary while the somewhat flexible hose **1595** is being translated in the wellbore **4c**. The outwardly-aimed electrically driven wheels of a conventional ("external") tractor are replaced with inwardly-aimed concave grippers **756**. The result is the inwardly-aimed concave grippers **756** frictionally attach to the jetting hose **1595**, with subsequent rotation of the grippers **756** propelling the jetting hose **1595** in a direction that corresponds with the direction of rotation.

[289] Note specifically the following consequence of this inversion: In a conventional system, the relative movement that occurs is that of the rigidly gripper-attached body (i.e., the

coiled tubing) relative to the stationary, frictionally attached body (i.e., the borehole wall). Conversely, the subject internal tractor system is rigidly attached to the stationary body (i.e., the external system **2000**) and the grippers **756** rotate to move the jetting hose **1595**. Accordingly, when the internal tractor system **700** is actuated, the whipstock member **1000** will already be in its set and operating position; e.g., the slips of the whipstock member **1000** will be engaged with the inner wall of the casing **12**. Hence, all advancement/retraction of the jetting hose **1595** by the tractor system **700** takes place when the external system **2000** itself is set and is stationary within the production casing **12**.

[290] It is next observed that the internal tractor system **700** preferably maintains the star-shape profile of the jetting hose pack-off system **600**. The star shape profile of the internal tractor system **700**, with its four points, helps centralizes the tractor system **700** within the production casing **12**. This is beneficial inasmuch as the slips of the whipstock member **1000** (located relatively close to tractor system **700**, due to the short lengths of the third crossover connection (or transition) **800** and upper swivel **900** between them, discussed below) will be engaged when operating the tractor system **700**, meaning that centralization of the tractor system **700** serves to align the defined path of the jetting hose **1595** and precludes any undo torque at the connection with the jetting hose whipstock device **1000**. It is observed in **Figures 4F-1** and **4F-2a** that the position of the jetting hose **1595** is approximately centered, both within the tractor system **700** and, therefore, within the production casing **12**. This places the hose **1595** in optimum position to be either fed into or retracted from the jetting hose whipstock device **1000**.

[291] In addition to centralizing the hose **1595**, another function served by the star-shape profile of the tractor system **700** is that it accommodates interior room for placement of two opposing sets of gripper assemblies **750**. Specifically, the gripper assemblies **750** reside inside the 'dry' working room of the two side chambers, while simultaneously providing for separate chambers for the electrical wires **106** and data cabling **107** (shown in lower chamber **730**) and the hydraulic fluid (in upper chamber **740**). At the same time, ample cross-sectional flow area is preserved between the tractor system **700** and the I.D. of the production casing **12** within their respective annular area **700.12** for conducting fracturing fluids.

[292] As shown within the 4.5" production casing **12**, the annular area **700.12** open to flow is approximately 10.74 in^2, equating to an equivalent pipe diameter (I.D.) of 3.69 in. Recall the design objective is to maintain an annular flow area greater than or equal to the interior area of a typical 3.5" O.D. (2.922" I.D., 10.2#/ft.) frac string, i.e. 6.706 in^2. Note then, if the tip-to-tip dimension of opposing prongs of the "star" is, for example, 3.95 in, and (to gain additional internal volume within the four chambers of the tractor system **700**) the star shape were changed to a perfect square, then the external area of the square would be 7.801 in^2, and the remaining annular area (open to flow of frac fluid) inside the 4.00" I.D. production casing would be 4.765 in^2, which is equivalent to a 2.463" pipe I.D. Hence, though the base of each triangular chamber within the star shape could be somewhat expanded to provide additional internal volumes or wall thickness, the outer perimeter cannot be completely squared-off and still satisfy the preferred 3.5" frac string criteria. Note, however, there is no reason the triangular dimensions of each chamber must remain symmetrical; e.g., the dimensions could be varied individually in order to accommodate each chamber's internal volume requirements, just as long as the 3.5" frac string requirement is still preferably satisfied.

[293] Each of the gripper assemblies **750** is comprised of a miniature electric motor **754**, and a motor mount **755** securing the motor **754** to the outer wall **790**. In addition, each of the gripper assemblies **750** includes a pair of axles. These represent a gripper axle **751** and a gripper motor axle **753**. Finally, each of the gripper assemblies **750** includes gripper gears **752**.

[294] The tractor system **700** also includes bearing systems **760**. The bearing systems **760** are placed along the length of inner walls **720**. These bearing systems **760** isolate frictional forces against the jetting hose **1595** at the contact points of the grippers **756**, and eliminate unwanted frictional drag against the inner walls **720**.

[295] Rearward rotation of the grippers **756** serve to advance the hose **1595**, while forward rotation of the grippers **756** serves to retract the hose **1595**. Propulsion forces provided by the grippers **756** help advance the jetting hose **1595** by pulling it through the jetting hose carrier system **400**, transition **500**, and pack-off section **600**, and assist in advancing the jetting hose **1595** by pushing it into the lateral borehole **15** itself.

[296] The view of **Figure 4F-1** depicts only two sets of opposing gripper assemblies **750**. However, gripper assemblies **750** may be added to accommodate virtually any length and construction of jetting hose **1595**, depending on compressional, torsional and horsepower constraints. Additional gripper assemblies **750** should add tractor force, which may be desirable for extended length lateral boreholes **15**. Though it is presumed maximum grip force will be obtained when pairs of gripper assemblies **750** are placed axially opposing one another in the same plane (as shown in **Figure 4F-2.a**), that is, maximizing a "pinch" force on the jetting hose **1595**, other arrangements/placements of gripper systems **750** are within the scope of this aspect of the inventions.

[297] Optionally, the internal tractor system **700** also includes a tensiometer. The tensiometer is used to provide real-time measurement of the pulling tension of the upstream section of hose **1595** and the pushing compression on the downstream section of hose **1595**. Similarly, mechanisms could be included to individualize the applied compressional force of each set of grippers **756** upon the jetting hose **1595**, so as to compensate for uneven wear of the grippers **756**.

[298] Again proceeding in presentation of the external system's **2000** main components from upstream-to-downstream, **Figure 4G-1** shows a longitudinal, cross-sectional view of the internal tractor-to-upper swivel (or third) crossover connection **800**, and the upper swivel **900** itself. Figure **4G-1a** depicts a perspective view of the crossover connection **800** between its upstream and downstream ends, denoted by lines **L-L'** and **M-M'**, respectively. **Figure 4G-1b** presents an axial, cross-sectional view within the upper swivel **900** along line **N-N'**. The third transition **800** and upper swivel **900** are discussed in connection with **Figures 4G-1**, **4G-1a** and **4G-1b** together.

[299] The transition **800** functions similarly to previous transitional sections (**200**, **500**) of the external system **2000** discussed herein. Suffice it to say the main function of the transition **800** is to convert the axial profile of the star-shaped internal tractor system **700** back to a concentric circular profile as used for the swivel **900**, and to do so within I.D. restrictions that meet the 3.5" frac string test.

[300] The upper swivel **900** simultaneously accomplishes three important functions:

(1) First, it allows the indexing mechanism to rotate the connected whipstock member **1000** without torqueing any upstream components of the system **50**.

(2) Second, it provides for rotation of the whipstock **1000** while yet maintaining a straight path for the electrical wiring **106** and data cabling **107** through wiring chamber **930** between the transition **800** and the whipstock member **1000**; while simultaneously providing.

(3) Third, it provides a horseshoe-shaped hydraulic fluid chamber **940** that accommodates rotation of the whipstock member **1000** while yet maintaining a contiguous hydraulic flow path between the transition **800** and the whipstock member **1000**.

[301] Desirable for the simultaneous satisfaction of the above design criteria are the double sets of bearings **960** (the inner bearings) and **965** (the outer bearings). In one aspect, the upper swivel **900** has an O.D. of 2.6 in.

[302] The outer wall **990** of the upper swivel **900** maintains the circular profile achieved by an outer wall **890** of transition **800**. Similarly, concentric circular profiles are obtained in the upper swivel's **900** middle body **950** and inner wall **920**. These three sequentially and concentrically smaller cylindrical bodies (**990**, **950**, and **920**) provide for placement of an inner set of circumferential bearings **960** (between the inner wall **920** and the middle body **950**) and an outer set of circumferential bearings **965** (between the middle body **950** and the outer wall **990**). The larger cross-sectional area of the middle body **950** allows it to host a horseshoe-shaped hydraulic fluid chamber **940**, and an arc-shaped wiring chamber **930**. The bearings **960**, **965** facilitate relative rotation of the three sequentially and concentrically smaller cylindrical bodies **990**, **950**, and **920**. The bearings **960**, **965** also provide for rotatable translation of the whipstock member **1000** below the upper swivel **900** (also shown in **Figure 4G-1**) while in its set and operating position. This, in turn, provides for a change in orientation of subsequent lateral boreholes jetted from a given setting depth in the parent wellbore **4**. Stated another way, the upper swivel **900** allows an indexing mechanism (described in the related U.S. Patent No. 8,991,522 and incorporated herein in its entirety) to rotate the

whipstock member **1000** without torqueing any upstream components of the external system **2000**.

[303] It is also observed that the upper swivel **900** provides for rotation of the whipstock member **1000** while yet maintaining a straight path for the electrical wiring **106** and data cabling **107**. The upper swivel **900** also permits the horseshoe-shaped hydraulic fluid chamber **940** to provide for rotation of the whipstock member **1000** while yet maintaining a contiguous hydraulic flow path down to the whipstock member **1000** and beyond.

[304] Returning to **Figure 4**, and as noted above, the external system **2000** includes a whipstock member **1000**. The jetting hose whipstock member **1000** is a fully reorienting, resettable, and retrievable whipstock means similar to those described in the precedent works of U.S. Provisional Patent Application No. 61/308,060 filed February 25, 2010, U.S. Patent No. 8,752,651 filed February 23, 2011, and U.S. Patent No. 8,991,522 filed August 5, 2011. Those applications are again referred to and incorporated herein for their discussions of setting, actuating and indexing the whipstock. Accordingly, detailed discussion of the jetting hose whipstock device **1000** will not be repeated herein.

[305] **Figure 4H.1** provides a longitudinal cross-sectional view of a portion of the wellbore **4** from **Figure 2**. Specifically, the jetting hose whipstock member **1000** is seen. The jetting hose whipstock member **1000** is in its set position, with the upper curved face **1050.1** of the whipstock **1050** receiving a jetting hose **1595**. The jetting hose **1595** is bending across the hemispherically-shaped channel that defines the face **1050.1**. The face **1050.1**, combined with the inner wall of the production casing **12**, forms the only possible pathway within which the jetting hose **1595** can be advanced through and later retracted from the casing exit "**W**" and lateral borehole **15**.

[306] A nozzle **1600** is also shown in **Figure 4H.1**. The nozzle **1600** is disposed at the end of the jetting hose **1595**. Jetting fluids are being dispersed through the nozzle **1600** to initiate formation of a mini-lateral borehole into the formation. The jetting hose **1595** extends down from the inner wall **1020** of the jetting hose whipstock member **1000** in order to deliver the nozzle **1600** to the whipstock member **1050**.

[307] As discussed in U.S. Patent No. 8,991,522, the jetting hose whipstock member **1000** is set utilizing hydraulically controlled manipulations. In one aspect, hydraulic pulse technology is used for hydraulic control. Release of the slips is achieved by pulling tension on the tool. These manipulations were designed into the whipstock member **1000** to accommodate the general limitations of the conveyance medium (conventional coiled tubing) **100**, which can only convey forces hydraulically (e.g., by manipulating surface and hence, downhole hydraulic pressure) and mechanically (i.e., tensile force by pulling on the coiled tubing, or compressive force by utilizing the coiled tubing's own set-down weight).

[308] The jetting hose whipstock member **1000** is herein designed to accommodate the delivery of wires **106** and data cables **107** further downhole. To this end, a wiring chamber **1030** (conducting electrical wires **106** and data cables **107**) is provided. Power and data are provided from the external system **2000** to conventional logging equipment **1400**, such as a Gamma Ray – Casing Collar Locator logging tool, in conjunction with a gyroscopic tool. This would be attached immediately below a conventional mud motor **1300** and coiled tubing tractor **1350**. Hence, for this embodiment, hydraulic conductance through the whipstock **1000** is desirable to operate a conventional ("external") hydraulic-over-electric coiled tubing tractor **1350** immediately below, and electrical (and preferably, fiber optic) conductance to operate the logging sonde **1400** below the coiled tubing tractor **1350**. The wiring chamber **1030** is shown in the cross-sectional views of **Figures 4H-1a** and **4H-1b**, along lines **O-O′** and **P-P′**, respectively, of **Figure 4H-1**.

[309] Note that this tractor **1350** is placed below the point of operation of the jetting nozzle **1600**, and therefore will never need to conduct either the jetting hose **1595** or high pressure jetting fluids to generate either the casing exit "**W**" or subsequent lateral borehole. Hence, there are no I.D. constraints for this (bottom) coiled tubing tractor **1350** other than the wellbore itself. The coiled tubing tractor **1350** may be either of the conventional wheel ("external roller") type, or the gripper (inch worm) type.

[310] A hydraulic fluid chamber **1040** is also provided along the jetting hose whipstock member **1000**. The wiring chamber **1030** and the fluid chamber **1040** become bifurcated while transitioning from semi-circular profiles (approximately matching their respective counterparts

930 and **940** of the upper swivel **900**) to a profile whereby each chamber occupies separate end sections of a rounded rectangle (straddling the whipstock member **1050**). Once sufficiently downstream of the whipstock member **1050**, the chambers can be recombined into their original circular pattern, in preparation to mirror their respective dimensions and alignments in a lower swivel **1100**. This enables the transport of power, data, and high pressure hydraulic fluid through the whipstock member **1000** (via their respective wiring chamber **1030** and hydraulic fluid chamber **1040**) down to the mud motor **1300**.

[311] Below the whipstock member **1000** and the nozzle **1600** but above the tractor **1350** is an optional lower swivel **1100**. **Figure 4I-1** is a longitudinal cross-sectional view of the lower swivel **1100**, as it resides between the jetting hose whipstock member **1000** and crossover connection **1200**, and within the production casing **12**. A slip **1080** is shown set within the casing **12**. **Figure 4I-1a** is an axial cross-sectional view of the lower swivel **1100**, taken across **line Q-Q'** of **Figure 4I.1**. The lower swivel **1100** will be discussed with reference to **Figures 4I-1** and **4I-1a** together.

[312] The lower swivel **1100** is essentially a mirror-image of the upper swivel **900**. As with the upper swivel **900**, the lower swivel **1100** includes an inner wall **1120**, a middle body **1150**, and an outer wall **1190**. In a preferred embodiment, the outer conduit has an O.D. of 2.60", or slightly less. The constraint of the O.D. outer conduit **1190** is the self-imposed 3.5" frac string equivalency test.

[313] The middle body **1150** further houses wiring chamber **1130** and a hydraulic fluid chamber **1140**. The fluid chamber **1140** transports hydraulic fluid to crossover connection **1200** and eventually to the mud motor **1300**.

[314] The lower swivel **1100** also includes a wiring chamber **1130** that houses electrical wires **106** and data cables **107**. Continuous electrical and/or fiber optic conductance may be desired when real time conveyance of logging data (gamma ray and casing collar locator, "CCL" data, for example) or orientation data (gyroscopic data, for example) is desired. Additionally, continuous electrical and/or fiber optic conductance capacity enables direct downhole assembly manipulation from the surface **1** in response to the real time data received.

[315] It is noted that while the inner conduit **920** of the upper swivel **900** defines a hollow core of sufficient dimensions to receive and conduct the jetting hose **1595**, the lower swivel **1100** has no such requirement. This is because in the design of the assembly **50** and the methods of usage thereof, the jetting hose **1595** is never intended to proceed downstream to a point beyond the whipstock member **1050**. Accordingly, the innermost diameter of the lower swivel **1100** may in fact be comprised of a solid core, as depicted in **Figure 4I-1a**, thereby adding additional strength qualities.

[316] The lower swivel **1100** resides between the jetting hose whipstock member **1000** and any necessary crossover connections **1200** and downhole tools, such as a mud motor **1300** and the coiled tubing tractor **1350**. Logging tools **1400**, a packer, or a bridge plug (preferably retrievable, not shown) may also be provided. Note that, depending on the length of the horizontal portion **4c** of the wellbore **4**, the respective sizes of the conveyance medium **100** and production casing **12**, and hence the frictional forces to be encountered, more than one mud motor **1300** and/or CT tractor **1350** may be needed.

[317] The final figure presented is **Figure 4J**. **Figure 4J** depicts the final transitional component **1200**, the conventional mud motor **1300**, and the (external) coiled tubing tractor **1350**. Along with the tools listed above, the operator may also choose to use a logging sonde **1400** comprised of, for example, a Gamma Ray – Casing Collar Locator and gyroscopic logging tools. The gyroscopic logging tools provide real-time data describing not only the precise downhole location, but the initial alignment of the whipstock face **1050.1** of the preceding jetting hose whipstock member **1000**. This data is useful in determining:

(1) how many degrees of re-alignment, via the whipstock face **1050.1** alignment, are desired to direct the initial lateral borehole along its preferred azimuth; and

(2) subsequent to jetting the first lateral borehole, how many degrees of re-alignment are required to direct subsequent lateral borehole(s) along their respective preferred azimuth(s).

[318] It is anticipated that, in preparation for a subsequent hydraulic fracturing treatment in a horizontal parent wellbore **4c**, an initial borehole **15** will be jetted substantially perpendicular to and at or near the same horizontal plane as the parent wellbore **4c**, and a

second lateral borehole will be jetted at an azimuth of 180° rotation from the first (again, perpendicular to and at or near the same horizontal plane as the parent wellbore). In thicker formations, however, and particularly given the ability to steer the jetting nozzle **1600** in a desired direction, more complex lateral bores may be desired. Similarly, multiple lateral boreholes (from multiple setting points typically close together) may be desired within a given "perforation cluster" that is designed to receive a single hydraulic fracturing treatment stage. The complexity of design for each of the lateral boreholes will typically be a reflection of the hydraulic fracturing characteristics of the host reservoir rock for the pay zone **3**. For example, an operator may design individually contoured lateral boreholes within a given "cluster" to help retain a hydraulic fracture treatment predominantly "in zone."

[319] It can be seen that an improved downhole hydraulic jetting assembly **50** is provided herein. The assembly **50** includes an internal system **1500** comprised of a guidable jetting hose and rotating jetting nozzle that can jet both a casing exit and a subsequent lateral borehole in a single step. The assembly **50** further includes an external system **2000** containing, among other components, a carrier apparatus that can house, transport, deploy, and retract the internal system to repeatably construct the requisite lateral boreholes during a single trip into and out of a parent wellbore **4**, and regardless of its inclination. The external system **2000** provides for annular frac treatments (that is, pumping fracturing fluids down the annulus between the coiled tubing deployment string and the production casing **12**) to treat newly jetted lateral boreholes. When combined with stage isolation provided by a packer and/or spotting temporary or retrievable plugs, thus providing for repetitive sequences of plug-and-UDP-and-frac, completion of the entire horizontal section **4c** can be accomplished in a single trip.

[320] In one aspect, the assembly **50** is able to utilize the full I.D. of the production casing **12** in forming the bend radius **1599** of the jetting hose **1595**, thereby allowing the operator to use a jetting hose **1595** having a maximum diameter. This, in turn, allows the operator to pump jetting fluid at higher pump rates, thereby generating higher hydraulic horsepower at the jetting nozzle **1600** at a given pump pressure. This will provide for substantially more power output at the jetting nozzle, which will enable:

(1) optionally, jetting larger diameter lateral boreholes within the target formation;

(2) optionally, achieving longer lateral lengths;

(3) optionally, achieving greater erosional penetration rates; and

(4) achieving erosional penetration of higher strength and threshold pressure (σ_M and P_{Th}) oil/gas formations heretofore considered impenetrable by existing hydraulic jetting technology.

[321] Also of significance, the internal system **1500** allows the jetting hose **1595** and connected jetting nozzle **1600** to be propelled independently of a mechanical downhole conveyance medium. The jetting hose **1595** is not attached to a rigid working string that "pushes" the hose and connected nozzle **1600**, but instead uses a hydraulic system that allows the hose and nozzle to travel longitudinally (in both upstream and downstream directions) within the external system **2000**. It is this transformation that enables the subject system **1500** to overcome the "can't-push-a-rope" limitation inherent to all other hydraulic jetting systems to date. Further, because the subject system does not rely on gravitational force for either propulsion or alignment of the jetting hose/nozzle, system deployment and hydraulic jetting can occur at any angle and at any point within the host parent wellbore **4** to which the assembly **50** can be "tractored" in.

[322] The downhole hydraulic jetting assembly allows for the formation of multiple mini-laterals, or bore holes, of an extended length and controlled direction, from a single parent wellbore. Each mini-lateral may extend from 10 to 500 feet, or greater, from the parent wellbore. As applied to horizontal wellbore completions in preparation for subsequent hydraulic fracturing ("frac") treatments in certain geologic formations, these small lateral wellbores may yield significant benefits to optimization and enhancement of fracture (or fracture network) geometry and subsequent hydrocarbon production rates and reserves recovery. By enabling: (1) better extension of the propped fracture length; (2) better confinement of the fracture height within the pay zone; (3) better placement of proppant within the pay zone; and (4) further extension of a fracture network prior to cross-stage breakthrough, the lateral boreholes may yield significant reductions of the requisite fracturing fluids, fluid additives, proppants, hydraulic horsepower , and hence related fracturing costs previously required to obtain a desired fracture geometry, if it was even attainable at all. Further, for a

fixed input of fracturing fluids, additives, proppants, and horsepower, preparation of the pay zone with lateral boreholes prior to fracturing could yield significantly greater Stimulated Reservoir Volume, to the degree that well spacing within a given field may be increased. Stated another way, fewer wells may be needed in a given field, providing a significance of cost savings. Further, in conventional reservoirs, the drainage enhancement obtained from the lateral boreholes themselves may be sufficient as to preclude the need for subsequent hydraulic fracturing altogether.

[323] As an additional benefit, the downhole hydraulic jetting assembly **50** and the methods herein permit the operator to apply radial hydraulic jetting technology without "killing" the parent wellbore. In addition, the operator may jet radial lateral boreholes from a horizontal parent wellbore as part of a new well completion. Still further, the jetting hose may take advantage of the entire I.D. of the production casing. Further yet, the reservoir engineer or field operator may analyze geo-mechanical properties of a subject reservoir, and then design a fracture network emanating from a customized configuration of directionally-drilled lateral boreholes.

[324] The hydraulic jetting of lateral boreholes may be conducted to enhance fracture and acidization operations during completion. As noted, in a fracturing operation, fluid is injected into the formation at pressures sufficient to separate or part the rock matrix. In contrast, in an acidization treatment, an acid solution is pumped at bottom-hole pressures less than the pressure required to break down, or fracture, a given pay zone. (In an acid frac, however, pump pressure intentionally exceeds formation parting pressure.) Examples where the pre-stimulation jetting of lateral boreholes may be beneficial include:

(a) prior to hydraulic fracturing (or prior to acid fracturing) in order to help confine fracture (or fracture network) propagation within a pay zone and to develop fracture (network) lengths a significant distance from the parent wellbore before any boundary beds are ruptured, or before any cross-stage fracturing can occur; and

(b) using lateral boreholes to place stimulation from a matrix acid treatment far beyond the near-wellbore area before the acid can be "spent," and before pumping pressures approach the formation parting pressure.

[325] The downhole hydraulic jetting assembly **50** and the methods herein permit the operator to conduct acid fracturing operations through a network of lateral boreholes formed through the use of a very long jetting hose and connected nozzle that is advanced through the rock matrix. In one aspect, the operator may determine a direction of a pressure sink in the reservoir, such as from an adjacent producer. The operator may then form one or more lateral boreholes in an orthogonal direction, and then conduct acid fracturing through that borehole. In this instance, fractures will open in the direction of the pressure sink.

[326] The operator may alternatively consider or determine a flux-rate of acid (or other formation-dissolving fluid) in the rock matrix. In this instance, the acid is not injected at a formation parting pressure, but allows wormholes to form in the direction of the pressure sink. The operator may also conduct the steps of creating a pressure boundary in the reservoir by injecting fluids into a first lateral borehole in a first direction, and then performing acid-fracturing through a second lateral borehole in a second direction offset from the first direction. The acid fractures are in the form of wormholes in a direction that does not intersect the pressure boundary.

[327] The downhole hydraulic jetting assembly **50** and the methods herein also permit the operator to pre-determine a path for the jetting of lateral boreholes. Such boreholes may be controlled in terms of length, direction or even shape. For example, a curved borehole or each "cluster" of curved boreholes may be intentionally formed to further increase SRV exposure of the formation **3** to the wellbore **4c**. Wellbores may optionally be formed in corkscrew patterns to further expose the formation **3** to the wellbore **4c**.

[328] The downhole hydraulic jetting assembly **50** and the methods herein also permit the operator to re-enter an existing wellbore that has been completed in an unconventional formation, and "re-frac" the wellbore by forming one or more lateral boreholes using hydraulic jetting technology. The hydraulic jetting process would use the hydraulic jetting assembly **50**

of the present invention in any of its embodiments. There will be no need for a workover rig, a ball dropper / ball catcher, drillable seats or sliding sleeve assemblies.

[329] The downhole hydraulic jetting assembly **50** and the methods herein also permit the operator to create a network of lateral boreholes that includes side mini-lateral boreholes formed off of newly-created boreholes. Such a method may include the steps of:

(a) partially withdrawing the jetting hose and connected nozzle from the first lateral borehole;

(b) identifying a location of the jetting nozzle within the rock matrix;

(c) re-orienting the jetting nozzle; and

(d) injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a first side mini-lateral borehole within the rock matrix in the pay zone off of the first lateral borehole.

[330] The method may further comprise:

(e) withdrawing the jetting hose and connected nozzle from the first side mini-lateral borehole;

(f) repeating steps (a) through (c); and

(g) injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a second side mini-lateral borehole within the rock matrix in the pay zone off of the first mini-lateral borehole.

[331] The method may further comprise (h) repeating steps (a) through (g) at least once to form a network of side mini-lateral boreholes, the network being configured to optimize a Stimulated Reservoir Volume (SRV) (i) from a subsequent hydraulic fracturing treatment, (ii) from a subsequent acid treatment, or (iii) both. Alternatively, the method may further comprise:

(i) repeating steps (a) through (g) at least once to form a network of side mini-lateral boreholes;

(j) injecting fracturing fluids through an annulus formed between the external conduit and the surrounding production casing;

(k) further injecting the fracturing fluids into the network of side mini-lateral boreholes at an injection pressure sufficient to part the rock matrix in the pay zone to form a network of hydraulic fractures; and

(l) monitoring the growth of the network of hydraulic fracture and Stimulated Reservoir Volume (SRV) emanating from the network of mini-lateral boreholes in real time using (i) tiltmeters, (ii) micro-seismic surveys, (iii) ambient micro-seismic surveys, (iv) microphones, or combinations thereof.

[332] The method may then include producing hydrocarbon fluids from the network of side mini-lateral boreholes.

[333] Based on the downhole hydraulic jetting assembly **50** described above, a unique method of forming a wellbore may be conducted. The method, in one embodiment, includes:

- running a jetting hose into a horizontal section of a parent wellbore using a conveyance medium, the jetting hose having a nozzle at a distal end;
- injecting a jetting fluid through the jetting hose and connected nozzle while advancing the jetting hose and connected nozzle into a surrounding formation, thereby forming a first lateral borehole off of the horizontal section from a first wellbore exit location;
- withdrawing the jetting hose and connected nozzle from the first lateral borehole at the first wellbore exit location, and re-locating the nozzle to a second wellbore exit location (either by placing a whipstock at a different depth, or by placing the whipstock at the same depth but at a different angular orientation) in the same trip; and
- injecting a jetting fluid through the jetting hose and connected nozzle while advancing the jetting hose and connected nozzle into the surrounding formation, thereby forming a second lateral borehole off of the horizontal section from the second wellbore exit location.

[334] In this method, advancing the jetting hose into each of the lateral boreholes is done at least in part through a hydraulic force acting on a sealing assembly along (such as at an upstream end of) the jetting hose. Further, the jetting hose is advanced and subsequently withdrawn without coiling or uncoiling the jetting hose in the wellbore.

[335] In one embodiment, advancing the jetting hose into each of the lateral boreholes is further done through a mechanical force applied by rotating grippers of a mechanical tractor assembly located within the wellbore, wherein the grippers frictionally engage an outer surface of the jetting hose.

[336] In another embodiment, advancing the jetting hose into each of the lateral boreholes is accomplished by forward thrust forces generated from flowing jetting fluid through rearward thrust jets located in the jetting assembly. These rearward thrust jets are specifically located in the jetting nozzle, or in a combination of the nozzle and one or more in-line jetting collars strategically located along the jetting hose. Preferably, the nozzle permits a flow of the jetting fluid through rearward thrust jets in response to a designated hydraulic pressure level. In this instance, the flowing of fluid through the rearward thrust jets is only activated after the jetting hose has advanced into each borehole at least 5 feet from the parent wellbore. The additional rearward thrust jets located in the in-line jetting collar(s) are then activated at incrementally higher operating pressures, typically when the jetting hose has been extended such a significant length from the parent wellbore that the rearward thrust jets within the nozzle alone can no longer generate significant pull force to continue dragging the full length of jetting hose along the lateral borehole.

[337] In a related aspect, the method may include monitoring tensiometer readings at a surface. The tensiometer readings are indicative of drag experienced by the jetting hose as lateral boreholes are formed. In this instance, the flowing of fluid through the rearward thrust jets is activated in each of the plurality of boreholes in response to a designated tensiometer reading.

CLAIMS

What is claimed is:

1. A method of forming a lateral borehole in a pay zone located within an earth subsurface, comprising:

determining a depth of a pay zone in the earth subsurface, the pay zone defining a rock matrix;

forming a wellbore within the pay zone;

conveying a hydraulic jetting assembly into the wellbore on a working string, the hydraulic jetting assembly comprising:

an external system having:

an external conduit,

a whipstock member placed a lower end of the external conduit and having a concave face, and

a jetting hose carrier residing within the external conduit above the whipstock and forming an annular region between the jetting hose carrier and the surrounding external conduit; and

an internal system having:

a jetting hose having a proximal end and a distal end,

a jetting nozzle disposed at a distal end of the jetting hose, and

a micro-annulus formed between the jetting hose and the surrounding jetting hose carrier, the micro-annulus being sized to allow the jetting hose to be translated out of and back into the jetting hose carrier without buckling;

setting the whipstock at a desired first casing exit location along the wellbore, wherein the face of the whipstock is configured to bend the jetting hose substantially across an entire inner diameter of the wellbore when the jetting hose is translated out of the jetting hose carrier;

translating the jetting hose out of the jetting hose carrier to advance the jetting nozzle to the face of the whipstock;

injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a lateral borehole within the rock matrix in the pay zone;

further injecting the jetting fluid while further translating the jetting hose and connected jetting nozzle through the jetting hose carrier and along the face of the whipstock, thereby forming a first lateral borehole that extends at least 5 feet from the horizontal wellbore.

2. The method of claim 1, wherein the assembly is configured to (i) translate the jetting hose out of the jetting hose carrier and against the whipstock face by a translation force to a desired point of wellbore exit, (ii) upon reaching the desired point of wellbore exit, direct jetting fluid through the jetting hose and the connected jetting nozzle until an exit is formed, (iii) continue jetting forming a lateral borehole into the rock matrix within the pay zone, and then (iv) pull the jetting hose back into the jetting hose carrier after a lateral borehole has been formed to allow a location of the whipstock within the wellbore to be adjusted.

3. The method of claim 2, wherein:

the wellbore is completed with a string of production casing;

the inner diameter of the wellbore is the inner diameter of the production casing; and

the method further comprises further injecting hydraulic jetting fluid through the jetting hose and connected nozzle, thereby cutting a first casing exit through the production casing before excavating the borehole in the rock matrix.

4. The method of claim 3, further comprising:

producing hydrocarbon fluids from the wellbore for a period of time before forming the lateral borehole.

5. The method of claim 3, wherein:

the wellbore is a horizontal wellbore; and

the method further comprises determining a vertical thickness of the pay zone

wherein forming a lateral borehole comprises hydraulically forming a lateral borehole that extends to proximate an upper boundary or to proximate a lower boundary of the pay zone.

6. The method of claim 5, further comprising:

identifying a particular hydrocarbon-rich portion of the pay zone; and

directing the lateral borehole through the hydrocarbon-rich portion.

7. The method of claim 5, further comprising:

forming perforations along the horizontal wellbore in sequential stages using one or more perforating guns;

hydraulically fracturing the rock matrix along the horizontal wellbore through the perforations in sequential stages; and

conducting a flowback operation to at least partially remove hydraulic fluids injected in connection with the hydraulic fracturing before forming the later borehole.

8. The method of claim 5, wherein:

the lateral borehole penetrates through the rock matrix in a direction that is substantially orthogonal to the horizontal wellbore; and

forming a lateral borehole comprises hydraulically forming a lateral borehole that extends to proximate an upper boundary or to proximate a lower boundary of the pay zone.

9. The method of claim 5, further comprising:

retracting the jetting hose and connected nozzle from the first casing exit;

re-orienting the whipstock at the desired first location;

injecting hydraulic jetting fluid through the jetting hose and connected nozzle, thereby forming a second casing exit;

further injecting the jetting fluid through the jetting hose and connected nozzle, thereby excavating rock matrix in the pay zone; and

still further injecting the jetting fluid while advancing the jetting hose and connected nozzle, thereby forming a second lateral borehole that also extends at least 5 feet from the horizontal wellbore from the second casing exit.

10. The method of claim 9, wherein each of the first and second lateral boreholes has an internal diameter of between about 0.4 and 2.5 inches.

11. The method of claim 10, wherein the second lateral borehole is offset from the first lateral borehole by between 10-degrees and 180-degrees.

12. The method of claim 11, further comprising:

producing hydrocarbon fluids from the first and second lateral boreholes.

13. The method of claim 5, further comprising:

retracting the jetting hose and connected nozzle from the first casing exit;

moving the whipstock to a desired second location;

injecting hydraulic jetting fluid through the jetting hose and connected nozzle, thereby forming a second casing exit at the second location;

further injecting the jetting fluid through the jetting hose and connected nozzle, thereby excavating rock matrix in the pay zone at the second location; and

still further injecting the jetting fluid while advancing the jetting hose and connected nozzle, thereby forming a second lateral borehole that also extends at least 5 feet from the horizontal wellbore along the second desired location.

14. The method of claim 13, wherein each of the first and second lateral boreholes has an internal diameter of between about 0.4 and 2.5 inches.

15. The method of claim 14, wherein the second lateral borehole is separated from the first lateral borehole by 5 to 200 feet.

16. The method of claim 5, further comprising:

injecting fracturing fluids through an annulus formed between the external conduit and the surrounding production casing; and

injecting the fracturing fluids into the first lateral borehole at an injection pressure sufficient to part the rock matrix in the pay zone.

17. The method of claim 16, wherein:

the hydraulic jetting assembly further comprises a retrievable bridge plug disposed below the whipstock member; and

the method further comprises setting the bridge plug before injecting a fracturing fluid.

18. The method of claim 17, further comprising:

injecting an acid treatment through the annulus and into the lateral borehole before the hydraulic fracturing.

19. The method of claim 5, wherein:

the translation force comprises a hydraulic force;

the jetting hose is at least 10 feet in length; and

the assembly further comprises:

a main control valve disposed proximate the upper end of the outer conduit, the main control valve being movable between a first position and a second position, wherein in the first position the main control valve directs jetting fluids pumped into the wellbore into the jetting hose, and in the second position the main control valve directs hydraulic fluid pumped into the wellbore into the annular region formed between the jetting hose carrier and the surrounding outer conduit.

20. The method of claim 19, the jetting assembly further comprises:

an upper seal assembly connected to the jetting hose at an upper end and sealing the micro-annulus;

a jetting hose pack-off section connected to an inner diameter of the inner conduit and sealing the micro-annulus proximate a lower end of the jetting hose carrier, and slidably receiving the jetting hose; and

a pressure regulator valve placed along the micro-annulus controlling fluid pressure within the micro-annulus.

21. The method of claim 20, wherein the assembly is configured such that:

placement of the main control valve in its first position allows an operator to pump jetting fluids into the working string, through the main control valve, and against

the upper seal assembly in the micro-annulus, thereby pistonly pushing the jetting hose and connected nozzle downhole in an uncoiled state while directing jetting fluids through the nozzle; and

placement of the main control valve in its second position allows an operator to pump hydraulic fluids into the working string, through the main control valve, into the annular region between the jetting hose carrier and the surrounding outer conduit, through the pressure regulator valve and into the micro-annulus, thereby pulling the jetting hose back up into the inner conduit in its uncoiled state.

22. The method of claim 21, wherein:

the micro-annulus defines an elongated pressure chamber formed between the movable upper seal assembly and the jetting hose pack-off section;

the main control valve resides proximate an upper end of the outer conduit;

the jetting hose carrier is dimensioned to hold the jetting hose from the upper sealing assembly down proximate to the jetting nozzle when the assembly is in a run-in position; and

the method further comprises sending a signal from the surface to the main control valve to place the main control valve in its first position.

23. The method of claim 22, wherein the pressure regulator valve is configured such that:

(i) when pressure is released from the micro-annulus and fluids are injected through the main control valve in its first position, the upper seal assembly glides down an inner bore of the jetting hose carrier while still sealing, thereby pushing the jetting hose forward through the jetting hose carrier without buckling; and

(ii) when pressure is increased in the micro-annulus by the injection of fluids through the main control valve in its second position, increased fluid pressure against the upper seal assembly urges the jetting hose to glide back up the jetting hose carrier.

24. The method of claim 23, wherein:

the jetting hose is at least 25 feet in length;

a controlled release of fluids from the micro-annulus and through the pressure regulator valve regulates the jetting hose's rate of descent down-the-hole; and

a controlled intake of fluids through the regulator valve and into the micro-annulus regulates the jetting hose's rate of ascent up-the-hole.

25. The method of claim 24, wherein:

the translation force comprises both the hydraulic force and a mechanical force; and

the assembly further comprises an internal tractor system residing downstream from the lower end of the outer conduit, the internal tractor system comprising:

an inner conduit portion defining a part of the jetting hose carrier for receiving the jetting hose;

an outer conduit portion defining a part of the outer conduit, the outer conduit portion having a star-shaped profile defining a plurality of radially-disposed prongs;

a wiring chamber housing electrical wires, data cables, or both within one of the plurality of prongs; and

at least one pair of grippers residing within opposing prongs, with each gripper being configured to engage and mechanically move the jetting hose along the jetting hose carrier when rotatably actuated.

26. The method of claim 25, wherein:

each of the grippers has a concave face configured to frictionally engage an outer diameter of the jetting hose; and

each of the grippers is part of a gripper assembly comprising an electrical motor which is geared to rotationally drive the grippers and translate the jetting hose into and out of the inner conduit portion as the grippers engage the jetting hose.

27. The method of claim 5, wherein:

the translation force comprises a mechanical force;

the jetting hose is at least 10 feet in length; and

the assembly further comprises an internal tractor system residing downstream from the lower end of the outer conduit, the internal tractor system comprising:

an inner conduit portion defining a part of the jetting hose carrier for receiving the jetting hose;

an outer conduit portion defining a part of the outer conduit, the outer conduit portion defining a plurality of radially-disposed prongs;

a wiring chamber housing electrical wires, data cables, or both within one of the plurality of prongs; and

at least one pair of grippers residing within opposing prongs, with each gripper being configured to engage and mechanically move the jetting hose along the jetting hose carrier when rotatably actuated.

28. The method of claim 27, wherein:

each prong of the outer conduit portion provides an inner chamber around the inner conduit portion;

a first of the inner chambers is configured to conduct the jetting fluid down the assembly;

a second of the inner chambers is configured to house the electrical wires, data cables, or both;

at least third and fourth opposing inner chambers house grippers;

each of the grippers has a concave face configured to frictionally engage an outer diameter of the jetting hose; and

each of the grippers is part of a gripper assembly comprising an electrical motor which is geared to rotationally drive the grippers as the grippers engage and translate the jetting hose.

29. The method of claim 5, wherein:

the working string a string of coiled tubing;

the coiled tubing carries electrical wires, data cables, or combinations thereof along its length;

the internal system further comprises a battery pack for providing power to electrical components within the assembly, the battery pack residing at the proximal end of the jetting hose; and

the assembly further comprises a docking station located at an upper end of the external system configured to mate with the battery pack, the docking station having a processor and being in communication with an operator at the surface by means of the electrical wires, the data cables or both of the coiled tubing.

30. The method of claim 29, further comprising:

sending commands from the surface to the docking station;

sending data from a logging tool downstream from the whipstock to the docking station; and

sending data from the docking station to the surface.

31. The method of claim 29, wherein:

the string of coiled tubing comprises a wall or a sheath that houses the electrical wires, the data cables, or both along its length, extending down to the docking station; and

the battery pack comprises a series of batteries located in an elongated, fluid-sealed housing, and an end cap located at each of opposing ends of the battery pack, wherein the end caps are shaped to deflect jetting fluid during operation of the assembly.

32. The method of claim 31, wherein the docking station:

houses a micro-processor, a micro-transmitter, a micro-receiver, an electrical current regulator, or combinations thereof; and

is configured to transfer: (1) power to the battery pack, said power either originating from generation at the surface, or from generation by a mud turbine below the whipstock member, said power being transmitted via electrical wiring provided along the external system; and (2) data to and from the micro-transmitter and micro-receiver in the docking station, between an at least one geo-spatial chip housed at or near the nozzle and the operator at the surface.

33. The method of claim 32, further comprising:

at least three longitudinally oriented actuator wires connected to a distal end of the jetting nozzle, the actuator wires being equi-distantly spaced about the circumference of the jetting hose at its distal end, and further being configured to contract in response to electrical current sent through the actuator wires, whereby differing amounts of electrical current directed through the actuator wires will induce a bending moment to orient the jetting nozzle; and

wherein the micro-processor is configured to control electrical current regulators feeding current to the respective actuator wires, and thus control a geo-orientation of the nozzle for directional hydraulic boring.

34. The hydraulic jetting assembly of claim 33, wherein:

the geo-location signals of the at least one geo-spatial chip are indicative of both the location and orientation of the jetting nozzle, such signals being transmitted as data from the geo-spatial chips to the micro-receiver in the battery pack via (i) the electrical wiring, the data cables, or (iii) both, bundled in the jetting hose;

contraction of each of the actuator wires is in direct proportion to an amount of electrical current each wire receives, thereby enabling geo-steering of the nozzle; and

wherein the actuator wires are fabricated from a material comprising nickel, titanium or a combination thereof.

35. The hydraulic jetting assembly of claim 34, wherein

the micro-transmitter housed in the battery pack's end cap is configured to wirelessly transmit the data received from the micro-receiver to a micro-receiver housed in the docking station; and

the docking station is configured to further transmit the data to a processor at the surface (i) wirelessly, (ii) via electrical wires bundled in the coiled tubing, or (iii) via data cables bundled in the coiled tubing.

36. The hydraulic jetting assembly of claim 35, wherein the bending moment applied to the distal end of the jetting hose is configured to be controlled by an operator at the surface through the delivery of geo-location signals sent to a micro-transmitter in the docking station through (i) wireless signals sent downhole, (ii) the electrical wires bundled in the coiled tubing, or (iii) the data cables bundled in the coiled tubing, such geo-location signals adjusting the currents being transmitted through the actuator wires.

37. The method of claim 5, further comprising:

obtaining geo-mechanical data for the pay zone, the data comprising porosity, permeability, Poisson ratio, modulus of elasticity, shear modulus, Lame' constant, Vp/Vs, or combinations thereof;

conducting a geo-mechanical analysis of the rock matrix in the pay zone to determine a direction of least minimum principle stress; and

forming at least two lateral boreholes in the pay zone using the downhole hydraulic jetting assembly by steering the nozzle (i) in a direction perpendicular to the direction of least minimum principle stress, or (ii) in a direction parallel to the direction of least minimum principle stress.

38. The method of claim 37, wherein:

a longitudinal axis of the horizontal wellbore is oriented parallel to the plane of least principle stress of the rock matrix comprising the pay zone; and

the first lateral borehole is formed in a direction perpendicular to the plane of least principle stress of the rock matrix.

39. The method of claim 37, wherein conducting a geo-mechanical analysis of the rock matrix comprises creating a finite element mesh representing the pay zone, the mesh defining a plurality of nodes representing points in space, each point having potential displacement in more than one direction; and predicting changes in strain within the rock matrix as a result of the formation of the lateral boreholes.

40. The method of claim 5, further comprising:

(a) partially withdrawing the jetting hose and connected nozzle from the first lateral borehole;

(b) identifying a location of the jetting nozzle within the rock matrix;

(c) re-orienting the jetting nozzle; and

(d) injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a first side mini-lateral borehole within the rock matrix in the pay zone off of the first lateral borehole.

41. The method of claim 40, further comprising:

(e) withdrawing the jetting hose and connected nozzle from the first side mini-lateral borehole;

(f) repeating steps (a) through (c); and

(g) injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby excavating a second side mini-lateral borehole within the rock matrix in the pay zone off of the first mini-lateral borehole

42. The method of claim 41, further comprising:

(h) repeating steps (a) through (g) at least once to form a network of side mini-lateral boreholes, the network being configured to optimize a Stimulated Reservoir Volume (SRV) (i) from a subsequent hydraulic fracturing treatment, (ii) from a subsequent acid treatment, or (iii) both.

43. The method of claim 42, further comprising:

(i) repeating steps (a) through (g) at least once to form a network of side mini-lateral boreholes;

(j) injecting fracturing fluids through an annulus formed between the external conduit and the surrounding production casing;

(k) further injecting the fracturing fluids into the network of side mini-lateral borehole at an injection pressure sufficient to part the rock matrix in the pay zone to form a network of hydraulic fractures; and

(l) monitoring the growth of the network of hydraulic fracture and Stimulated Reservoir Volume (SRV) emanating from the network of mini-lateral boreholes in real time using (i) tiltmeters, (ii) micro-seismic surveys, (iii) microphones, (iv) ambient micro-seismic surveys, (v) or combinations of such data.

44. The method of claim 43, further comprising:

(l) based upon the real-time geophysical data, custom designing geometries of a next network of lateral boreholes to optimally receive a hydraulic fracturing treatment stage in order to optimize SRV to be obtained from that particular stage; and

(m)producing hydrocarbon fluids from the network.

45. A method of forming a wellbore, comprising:

running a jetting hose into a horizontal section of a parent wellbore using a conveyance medium, the jetting hose having a nozzle at a distal end;

injecting a jetting fluid through the jetting hose and connected nozzle while advancing the jetting hose and connected nozzle into a surrounding formation, thereby forming a first lateral borehole off of the horizontal section from a first wellbore exit location;

withdrawing the jetting hose and connected nozzle from the first lateral borehole at the first wellbore exit location, and re-locating the nozzle to a second wellbore exit location in the same trip; and

injecting a jetting fluid through the jetting hose and connected nozzle while advancing the jetting hose and connected nozzle into the surrounding formation, thereby forming a second lateral borehole off of the horizontal section from the second wellbore exit location;

wherein advancing the jetting hose into each of the lateral boreholes is done at least in part through a hydraulic force acting on a sealing assembly along the jetting hose and without coiling or uncoiling the jetting hose in the wellbore.

46. The method of claim 45, wherein advancing the jetting hose into each of the lateral boreholes is further done through a mechanical force applied by rotating grippers of a mechanical tractor assembly located within the wellbore, wherein the grippers frictionally engage an outer surface of the jetting hose.

47. The method of claim 45, wherein advancing the jetting hose into each of the lateral boreholes is further done through flowing jetting fluid through rearward thrust jets located in the nozzle, or through thrust jets located in the nozzle and one or more in-line jetting collars.

48. The method of claim 47, wherein the flow of the jetting fluid through the rearward thrust jets of the nozzle is in response to a designated hydraulic pressure level, and subsequent flow through the thrust jets of the one or more jetting collars is at an incrementally higher hydraulic pressure level.

49. The method of claim 48, wherein the flowing of fluid through the rearward thrust jets of the nozzle is only activated after the jetting hose has advanced into each borehole at least 5 feet from the horizontal section.

50. The method of claim 48, further comprising:

monitoring tensiometer readings at a surface, the tensiometer readings being indicative of drag experienced by the jetting hose as lateral boreholes are formed; and

wherein the flowing of fluid through the rearward thrust jets of the one or more collars is incrementally activated in each of the plurality of boreholes in response to a designated tensiometer reading.

51. The method of claim 45, wherein:

the seal assembly is at an upstream end of the jetting hose; and

each of the lateral boreholes has a diameter of between 0.5 and 2.5 inches.

52. The method of claim 45, wherein:

the jetting hose comprises:

a tubular stator body forming a bore along a longitudinal axis of the nozzle;

a tubular rotor body residing within the bore of the stator body, and also forming a bore along the longitudinal axis of the nozzle;

one or more bearings residing between the stator body and the surrounding rotor body to accommodate relative rotational movement between the rotor body and the stator body;

electro-magnetic coils which designed to induce the relative rotational movement between the rotor body and the stator body in response to electrical current;

a proximal end configured to sealingly connect to an end of a jetting hose, and to receive a jetting fluid; and

a discharge slot at the end of the rotor body configured to deliver the high pressure jetting fluid at a designated spray angle for erosion of a rock matrix;

the jetting hose comprises:

power wires for transmitting electrical energy towards the nozzle; and

at least three actuator wires proximate the nozzle configured to contract in response to receiving the electrical energy from the power wires; and

the method further comprises steering the nozzle while forming at least one of the of lateral boreholes by adjusting electrical current through the power wires and the at least three actuator wires, wherein the actuator wires induce a bending moment to the nozzle, thereby controlling a direction of the high pressure jetting fluid passing through the discharge slot.

53. The method of claim 52, wherein:

the nozzle further comprises at least one geo-spatial chip;

the jetting hose further comprises electrical wires or data cables for sending geo-location signals from the nozzle to a processor; and

steering the nozzle comprises:

sending geo-trajectory instructions from the processor to a current regulator configured to control electrical energy received by the at least three actuator wires.

54. The method of claim 53, wherein:

the geo-location signals comprise orientation and azimuth of the nozzle; and

each of the lateral boreholes is at least 25 feet in length.

55. The method of claim 54, further comprising:

determining upper and lower boundaries of the formation; and

advancing the nozzle into each of the lateral boreholes from the wellbore no further than the boundaries.

56. The method of claim 45, wherein:

the wellbore is completed with a string of production casing;

the conveyance medium is a string of coiled tubing; and

the jetting hose is part of a hydraulic jetting assembly comprising:

an internal system comprising:

a jetting hose having a proximal end and a distal end, the jetting hose being at least 10 feet in length; and

a jetting nozzle disposed at the distal end of the jetting hose; and

an external system comprising:

a first elongated tubular body defining an outer conduit, the outer conduit having an upper end configured to be operatively attached to the coiled tubing for running the assembly into the production casing, a lower end, and an internal bore there between;

a second elongated tubular body residing within the bore of the outer conduit and defining a jetting hose carrier, the jetting hose carrier slidably receiving the jetting hose, and forming an annular region between the jetting hose carrier and the surrounding outer conduit;

a whipstock member placed at lower end of the external conduit and having a concave face, and

a micro-annulus formed between the jetting hose and the surrounding jetting hose carrier, the micro-annulus being sized to allow the jetting hose to be translated out of and back into the jetting hose carrier without buckling; and

the method further comprises:

setting the whipstock at a desired first casing exit location along the horizontal wellbore, wherein the face of the whipstock is configured to bend the jetting hose substantially across an entire inner diameter of the wellbore when the jetting hose is translated out of the jetting hose carrier;

translating the jetting hose out of the jetting hose carrier to advance the jetting nozzle to the face of the whipstock to form the lateral boreholes.

57. The method of claim 56, wherein:

the jetting hose is at least 100 feet in length; and

each of the lateral boreholes extends at least 75 feet from the horizontal section.

58. The method of claim 45, wherein the parent wellbore comprises:

a string of production casing placed substantially along the horizontal section; and

perforations within the production casing, through which hydraulic fracturing and subsequent production operations have previously been conducted before the first and second lateral boreholes were formed; and

the method further comprises:

identifying non-performing or under-performing intervals of the pay zone; and

recompleting the parent wellbore by jetting windows through the production casing at one or more wellbore exit locations adjacent corresponding non-performing or under-performing intervals using the jetting hose and connected jetting nozzle, and forming new lateral boreholes.

59. The method of claim 58, further comprising:

(i) injecting hydraulic jetting fluid through the jetting hose and connected jetting nozzle, thereby steerably excavating one or more side mini-lateral boreholes within the rock matrix in the pay zone off of selected lateral boreholes, (ii) pumping a new hydraulic fracture treatment into each lateral borehole to form fractures, or (iii) both.

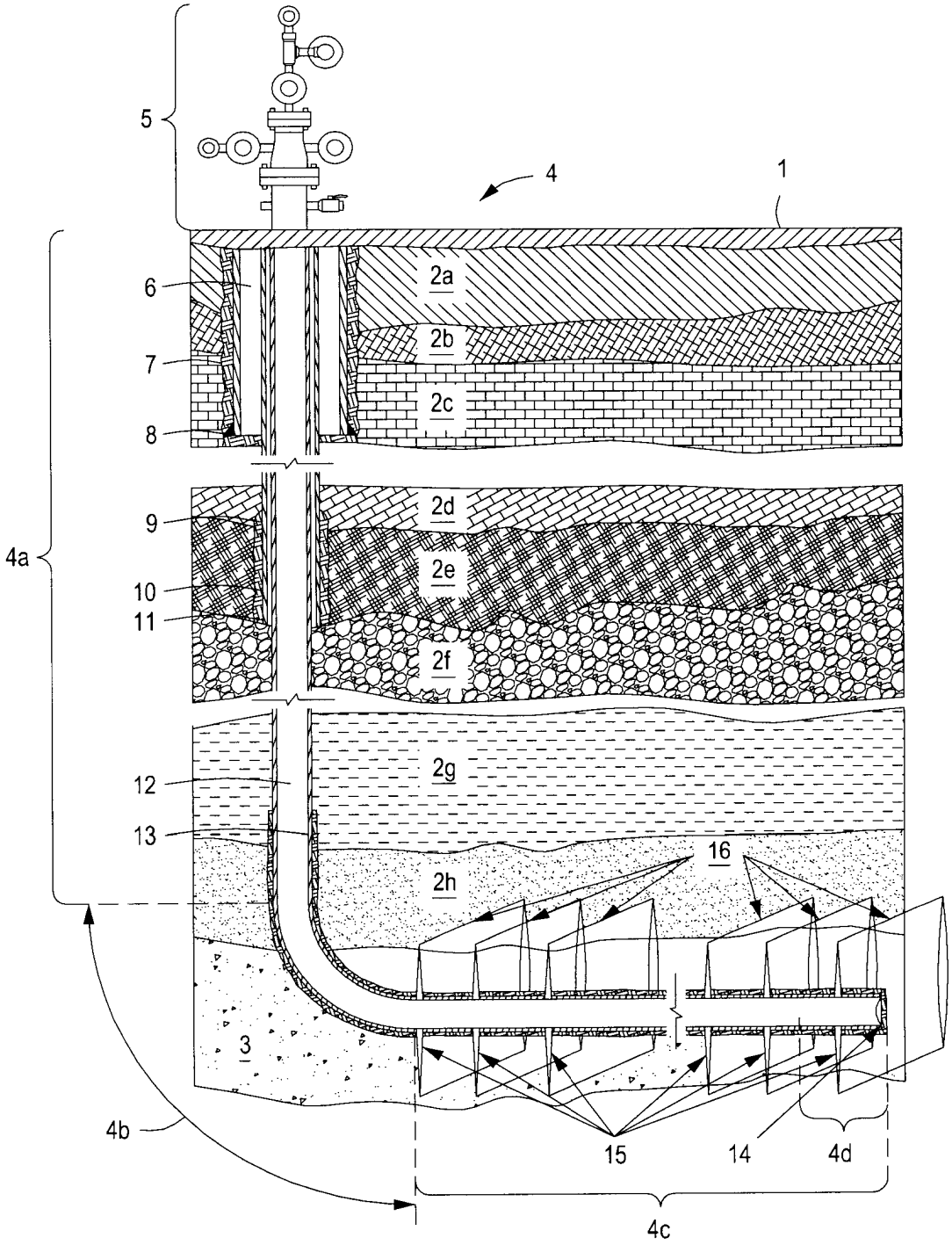


FIG. 1A

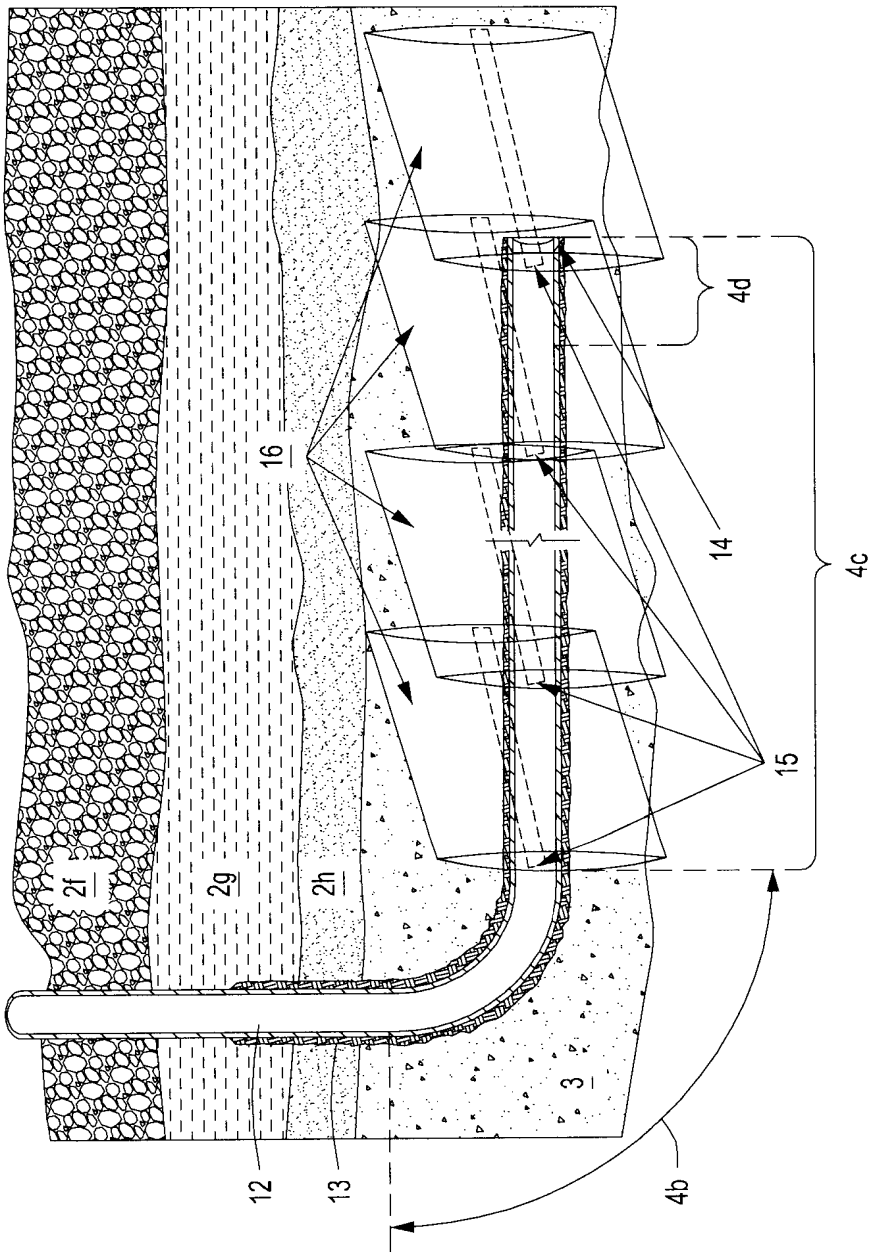


FIG. 1B

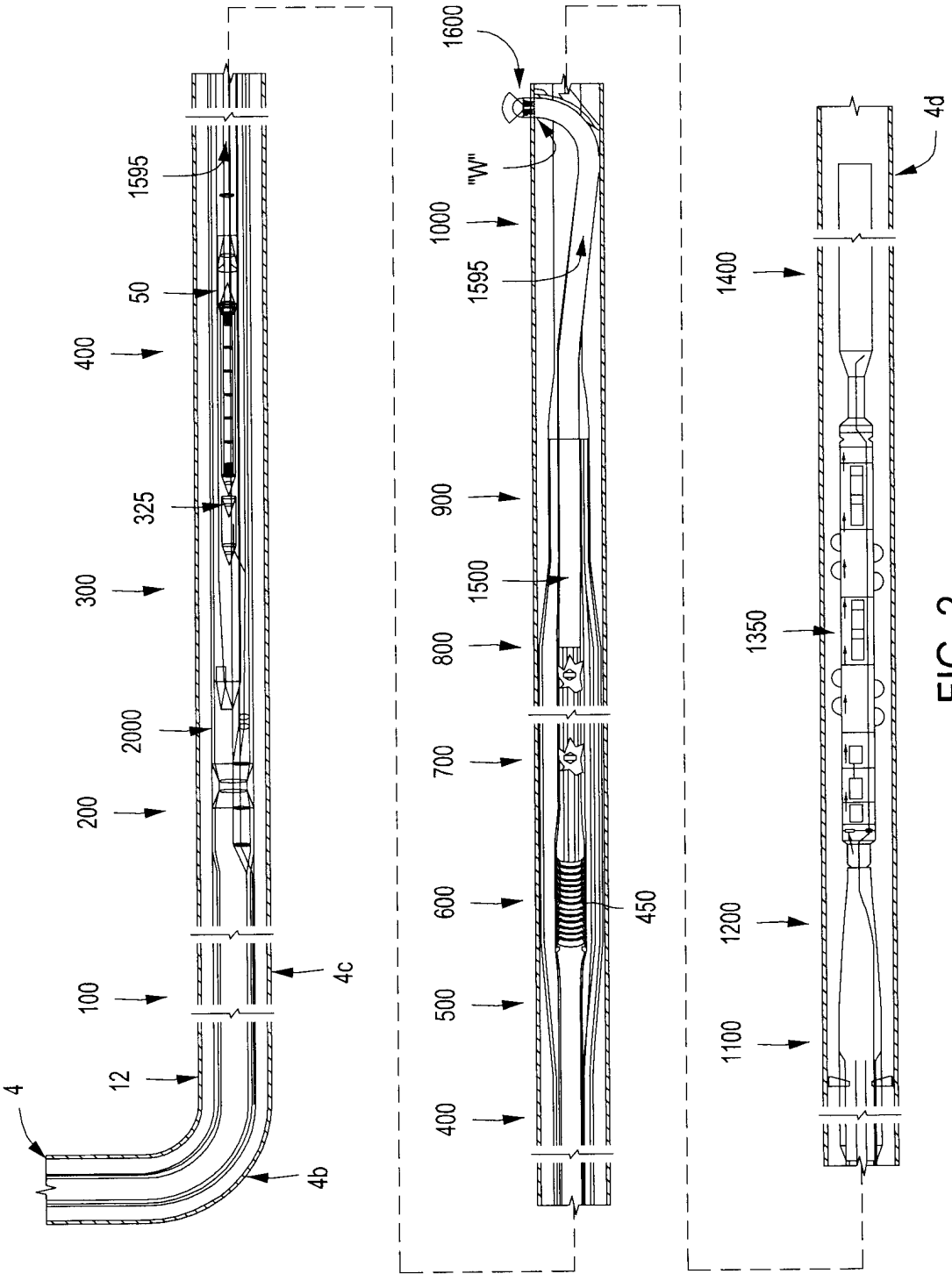

4
12
100
200
2000
300
325
400
50
1595
4c
4b
1600
"W"
1000
1595
900
1500
800
700
600
500
400
450
4d
1400
1350
1200
1100

FIG. 2

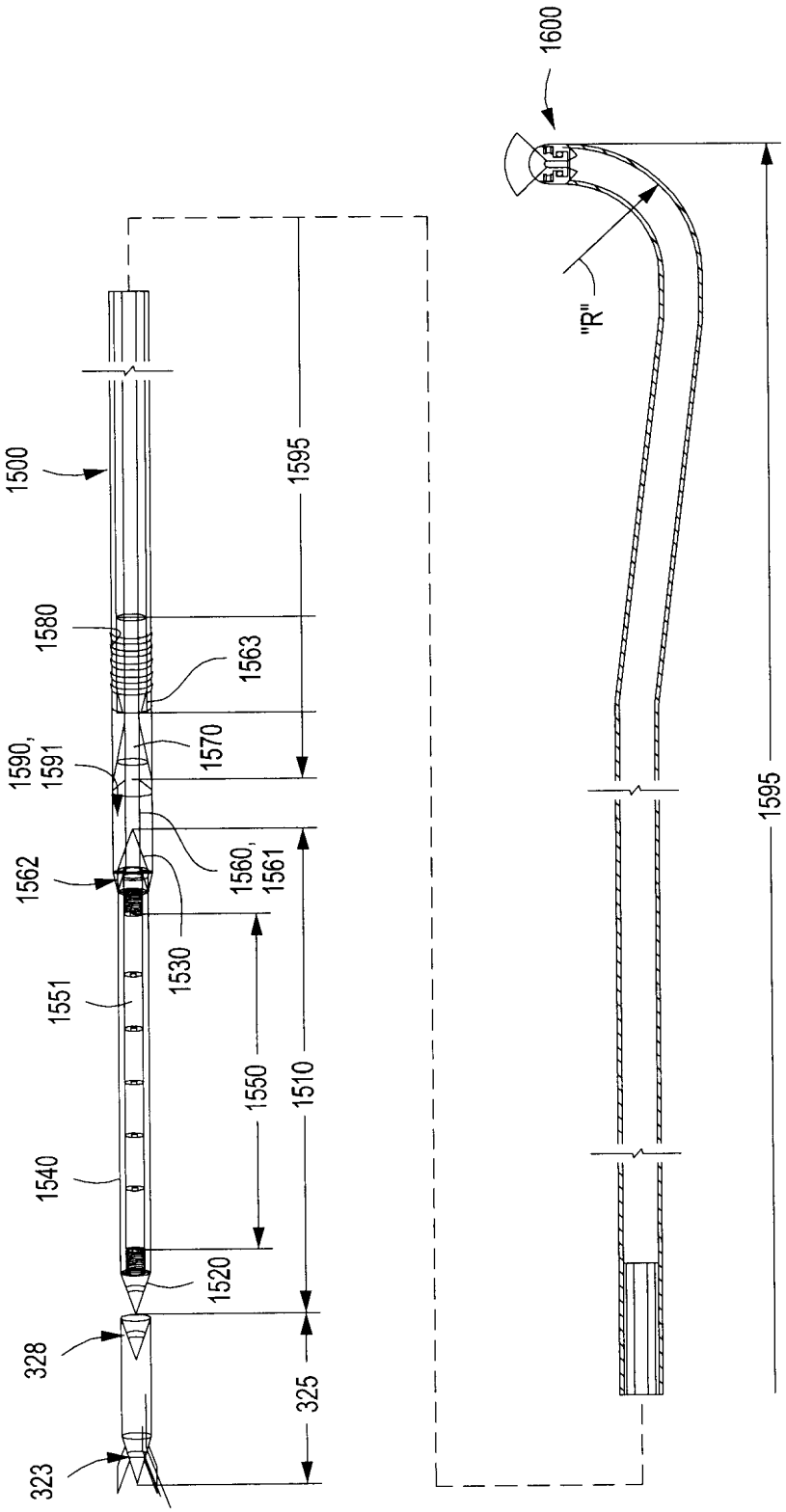

1600
"R"
1595
1500
1580
1563
1590,
1591
1570
1562
1560,
1561
1530
1551
1550
1510
1540
1520
328
325
323

FIG. 3

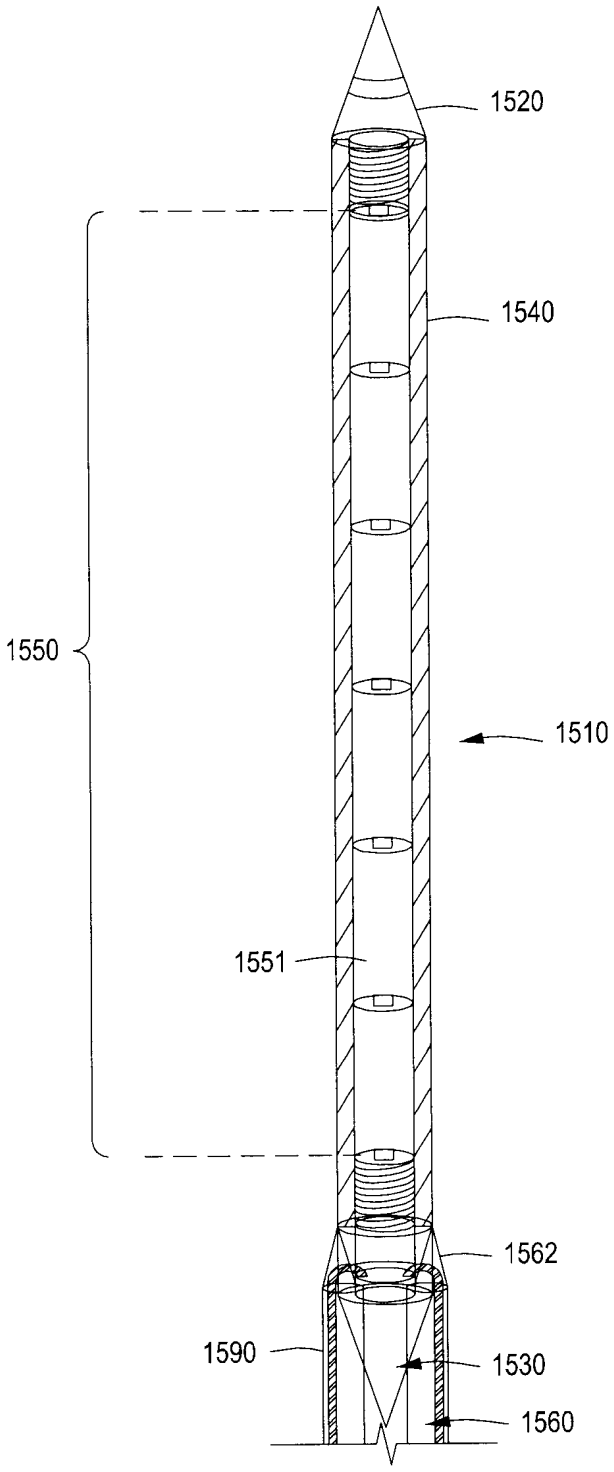


FIG. 3A

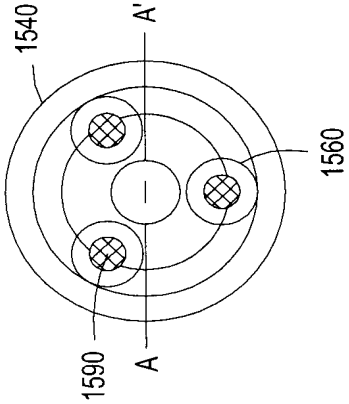


FIG. 3B-1a

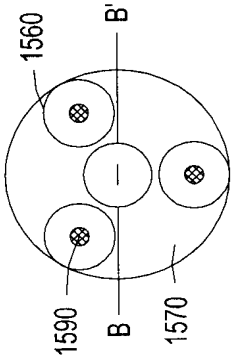


FIG. 3B-1b

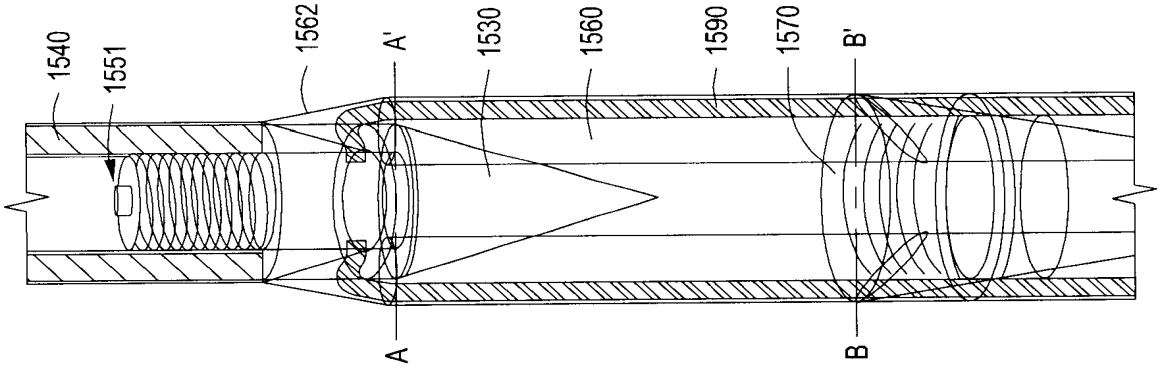


FIG. 3B-1

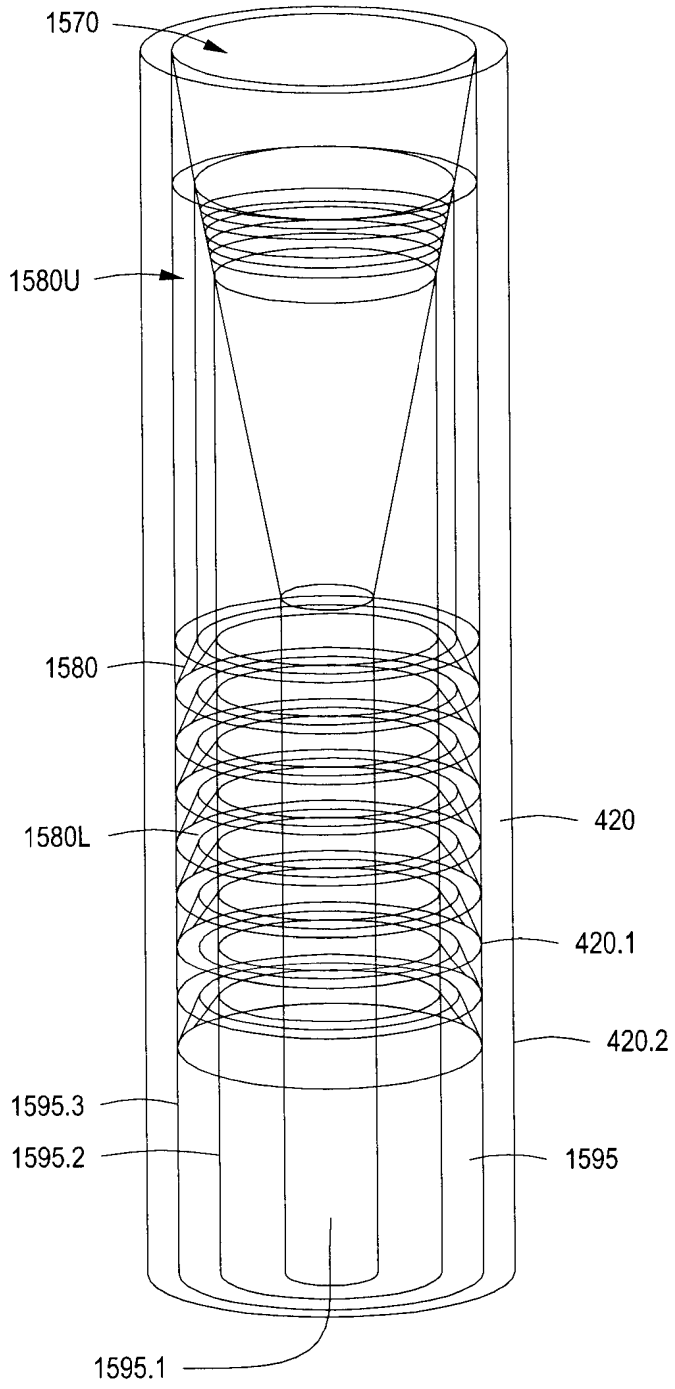


FIG. 3C

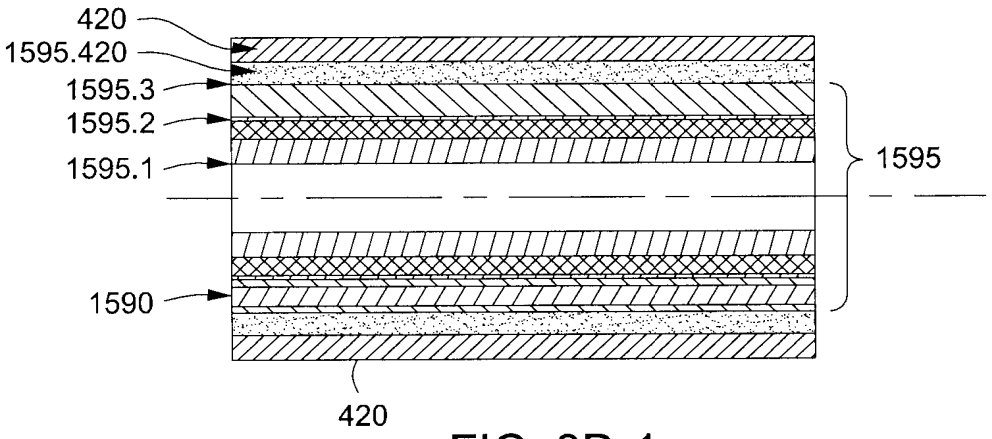


FIG. 3D-1

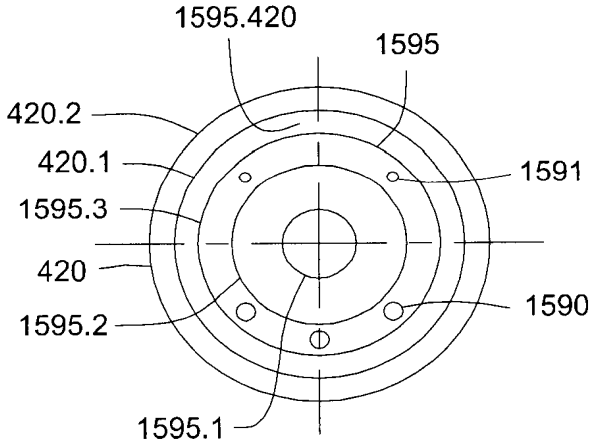


FIG. 3D-1a

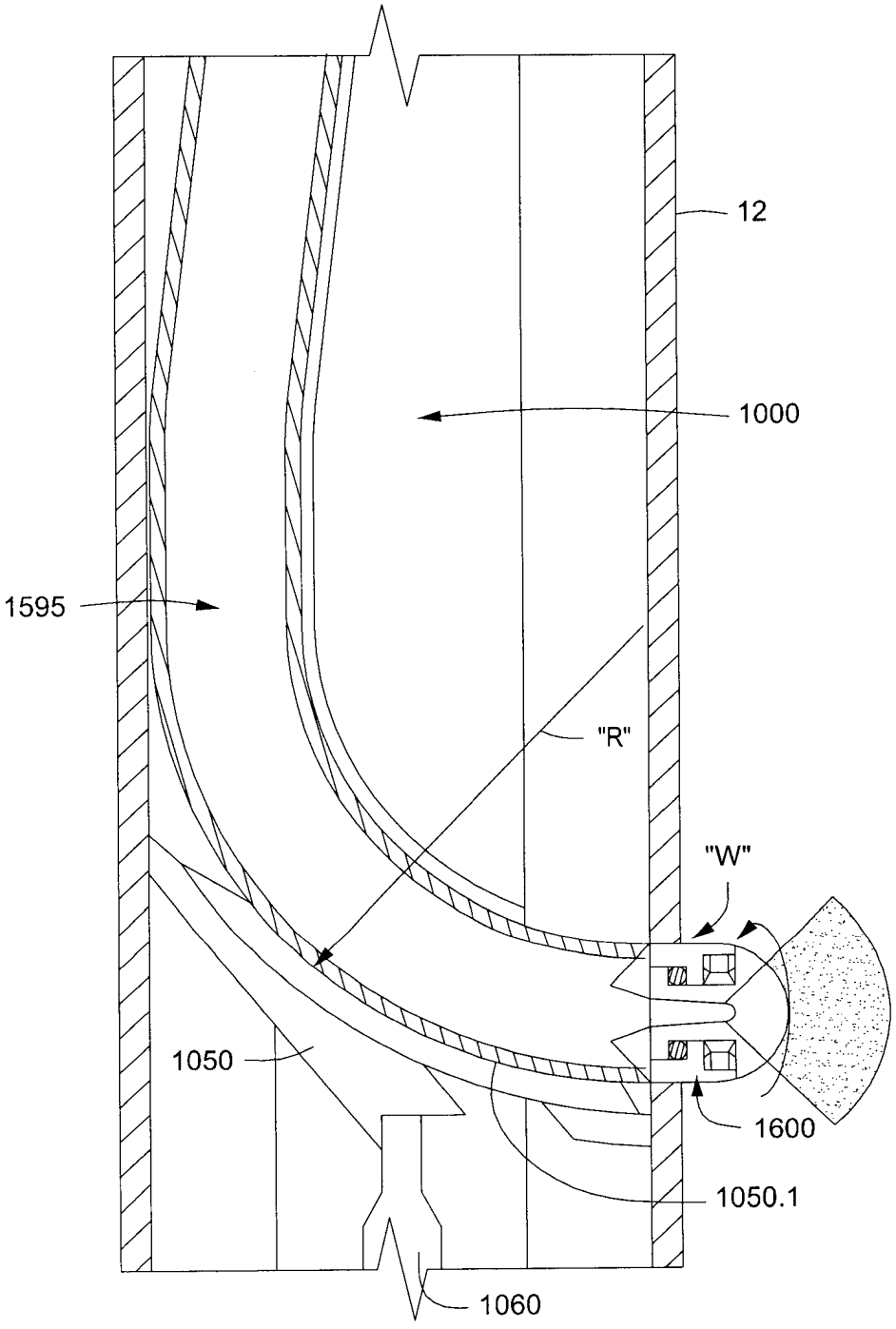


FIG. 3E

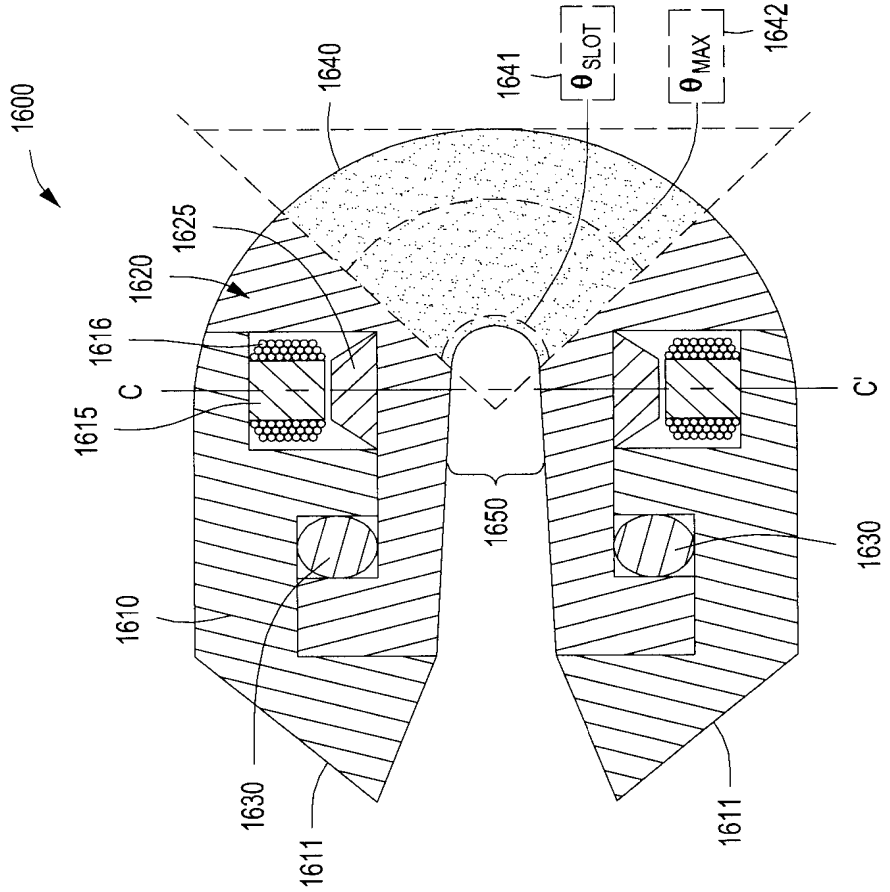


FIG. 3F-1b

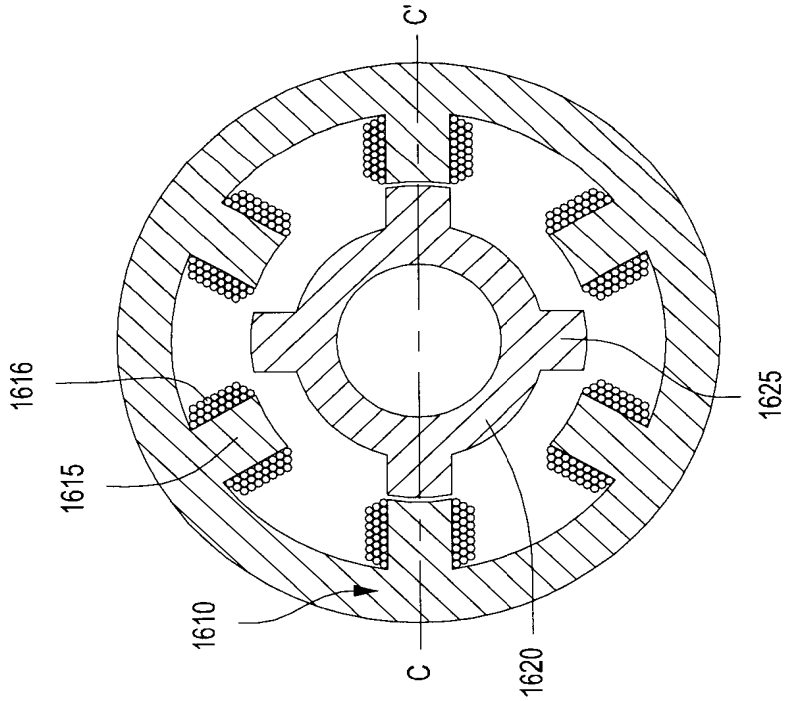


FIG. 3F-1a

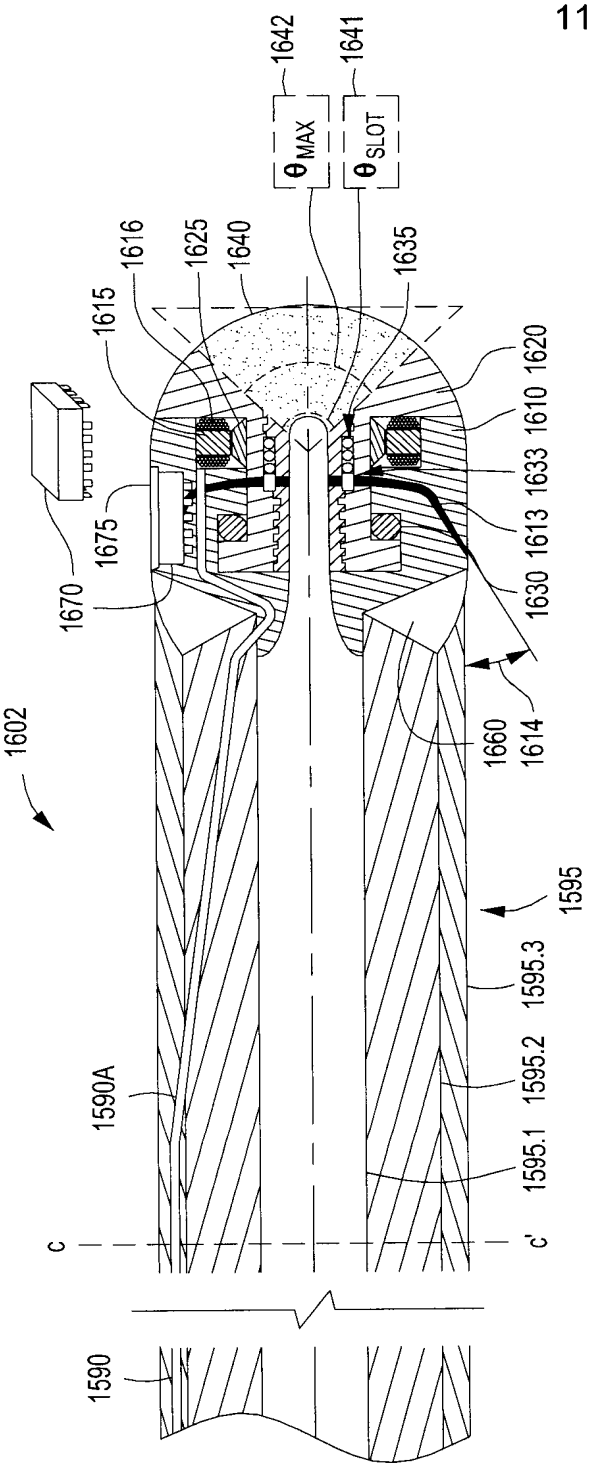


FIG. 3F-1c

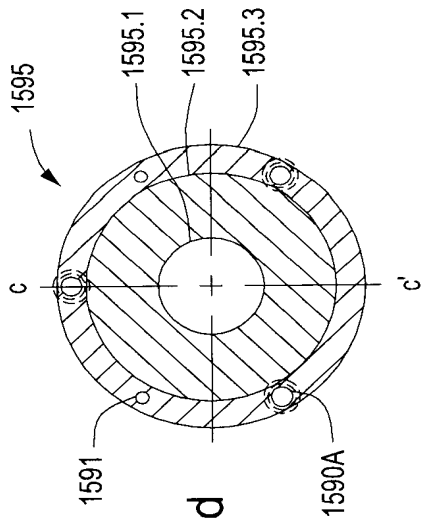


FIG. 3F-1d

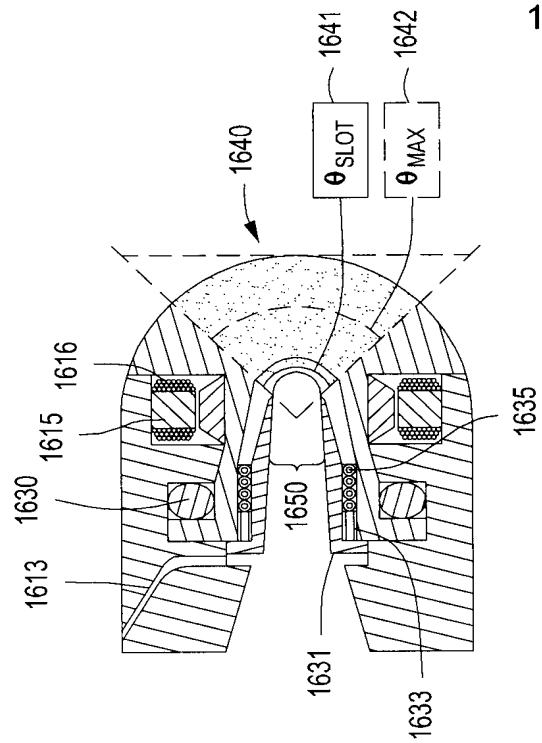


FIG. 3F-2b

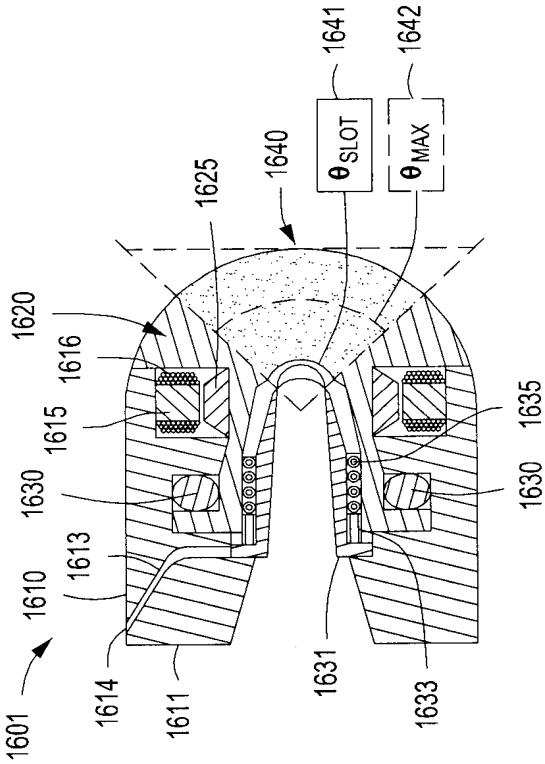


FIG. 3F-2a

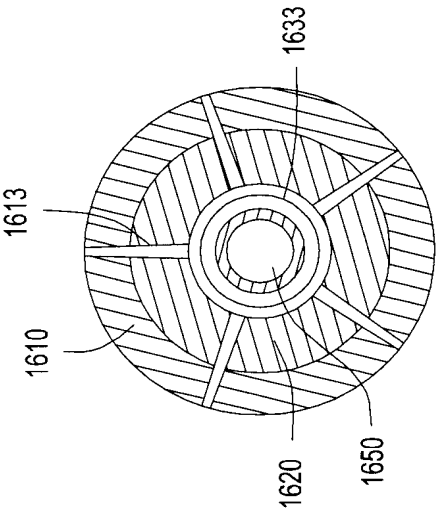


FIG. 3F-2c

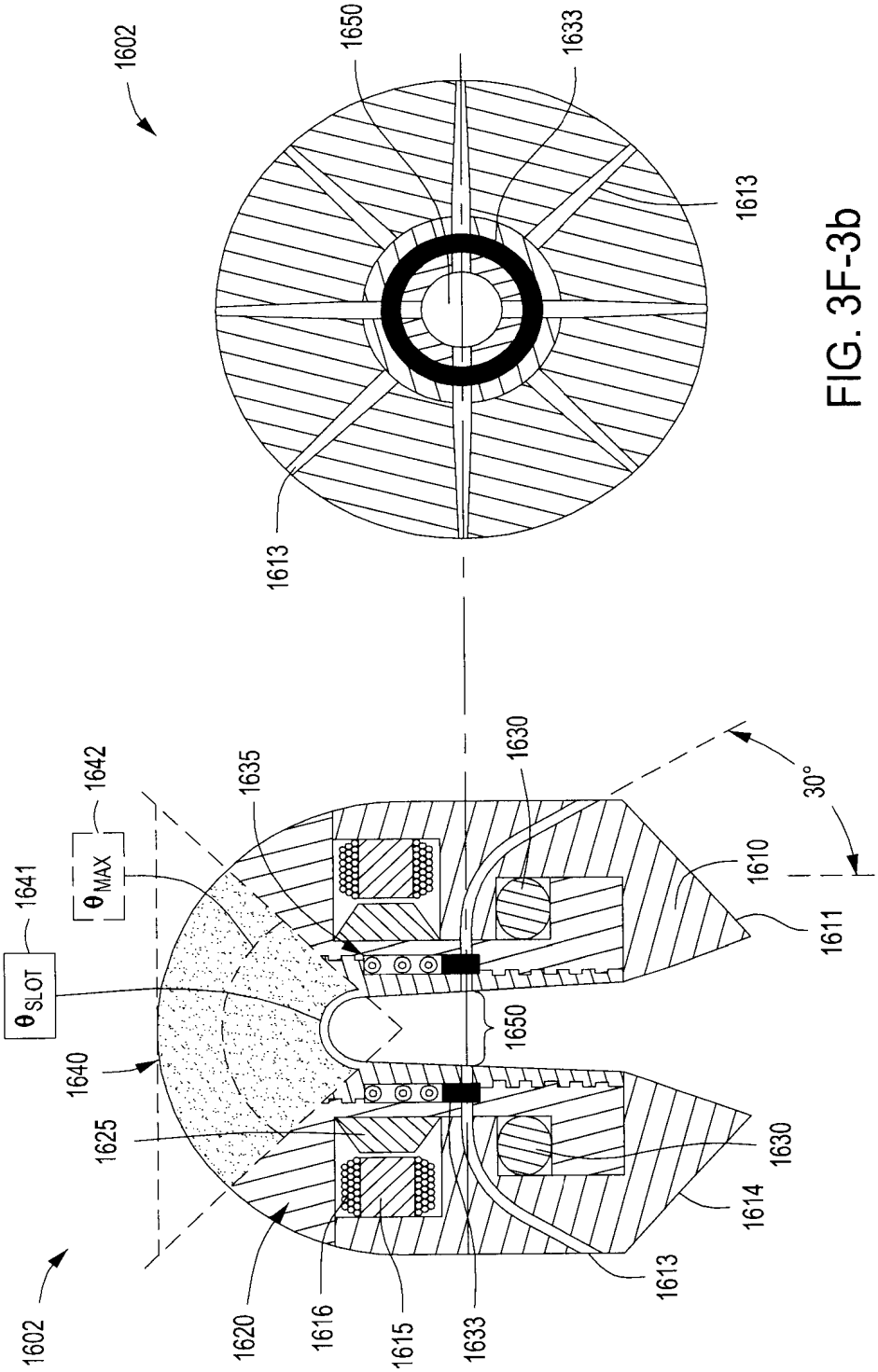


FIG. 3F-3b

FIG. 3F-3a

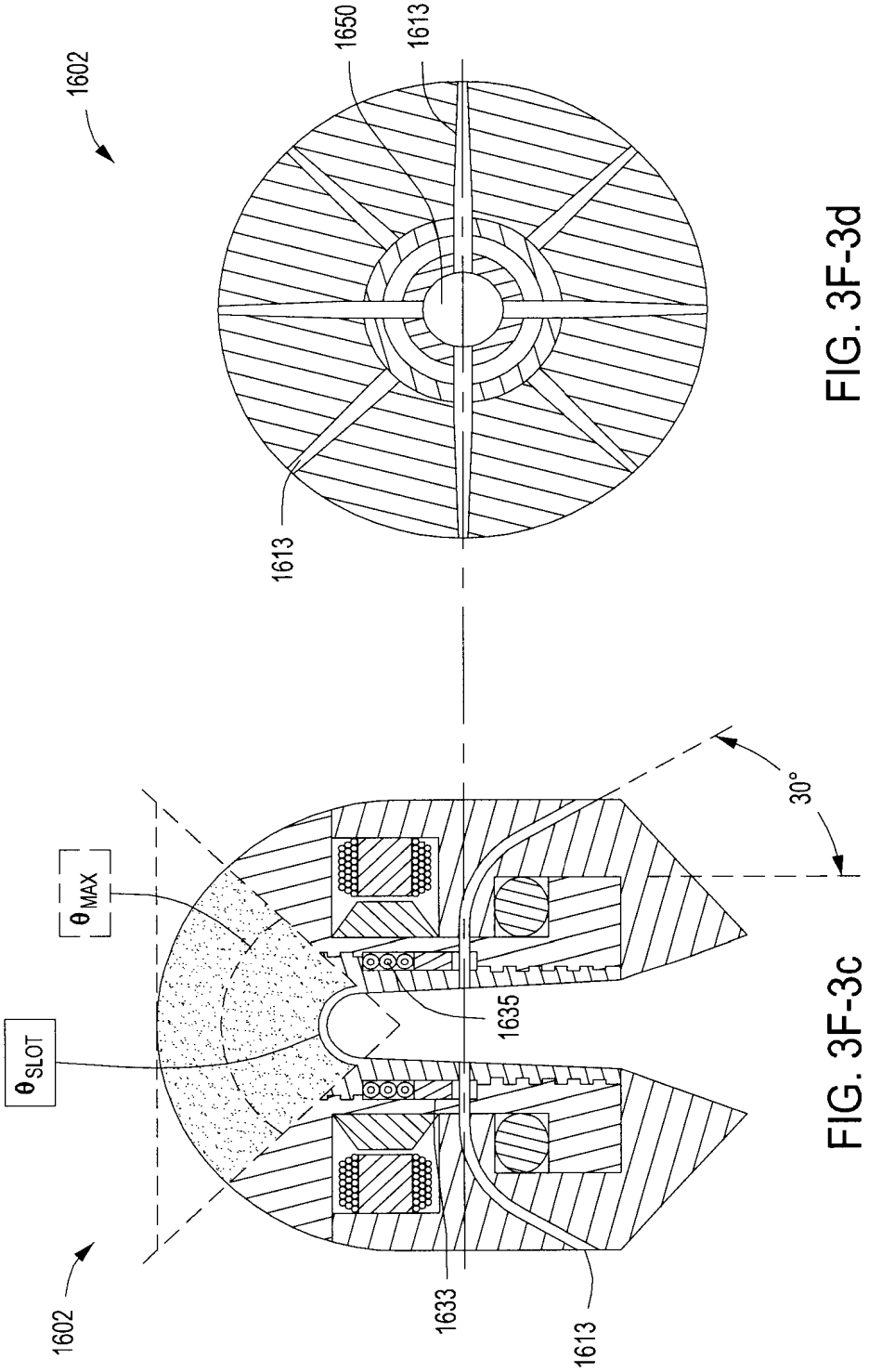


FIG. 3F-3d

FIG. 3F-3c

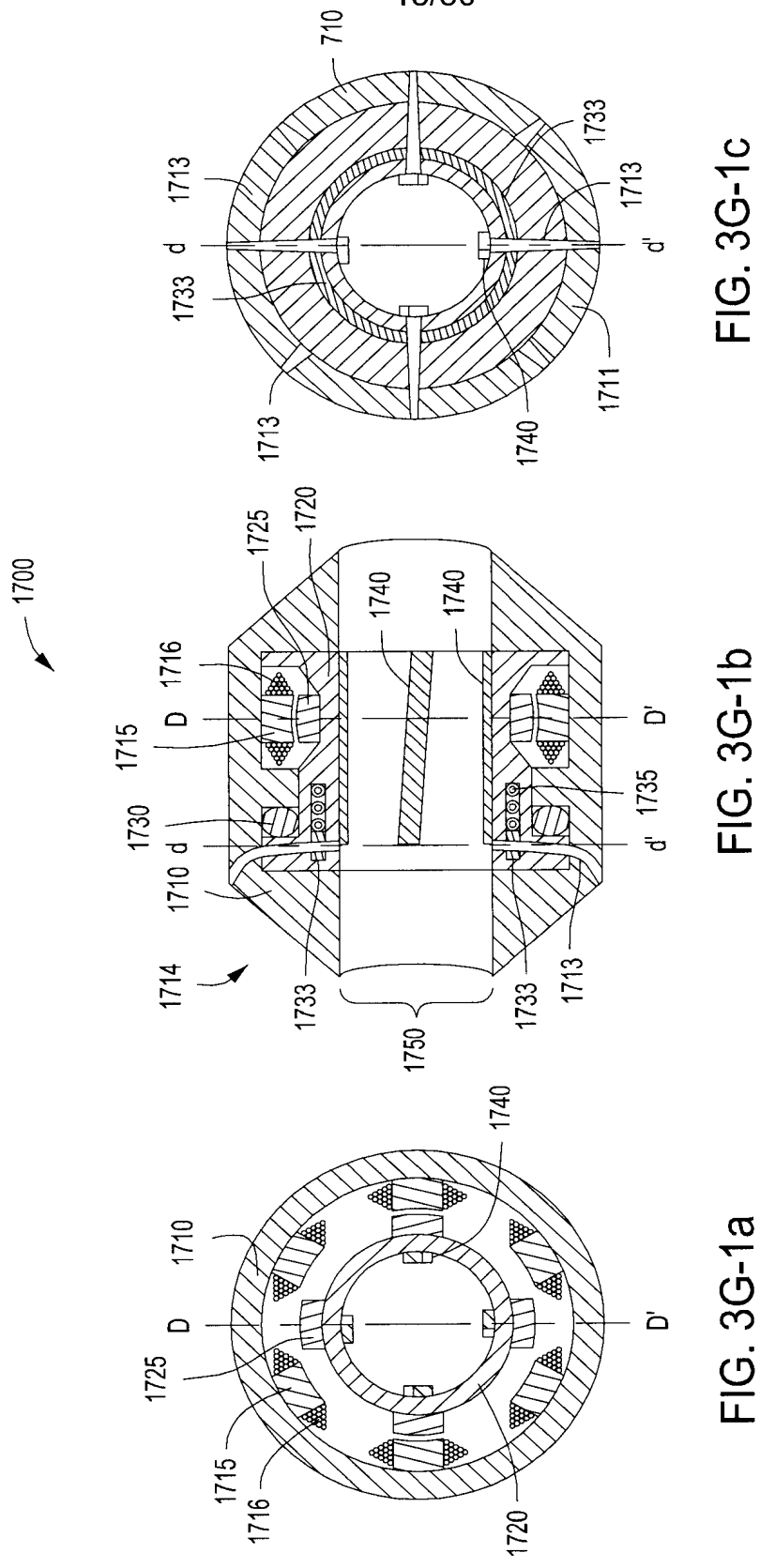


FIG. 3G-1c

FIG. 3G-1b

FIG. 3G-1a

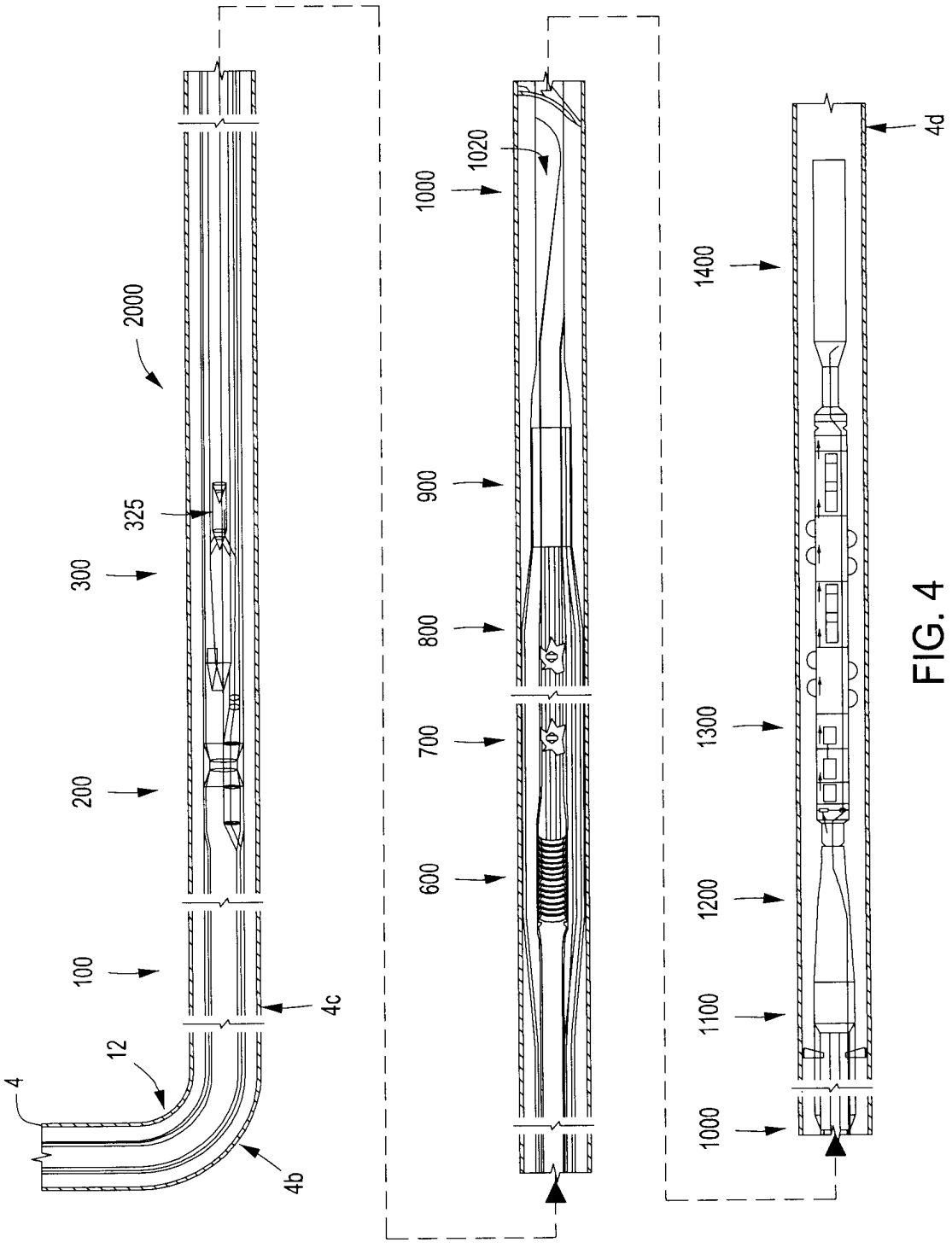

2000
325
300
200
100
12
4
4c
4b
1000
1020
900
800
700
600
1400
1300
1200
1100
1000
4d

FIG. 4

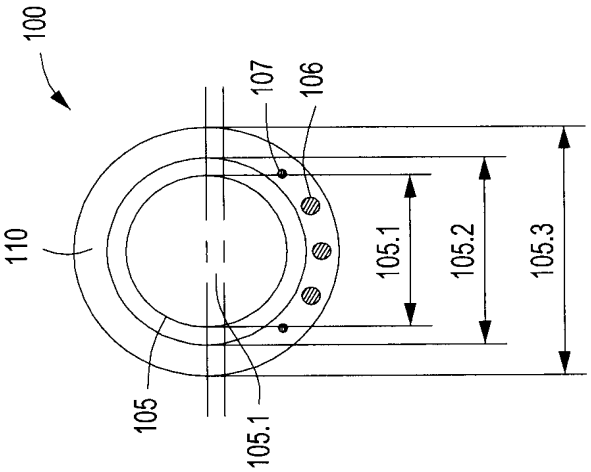


FIG. 4A-1a

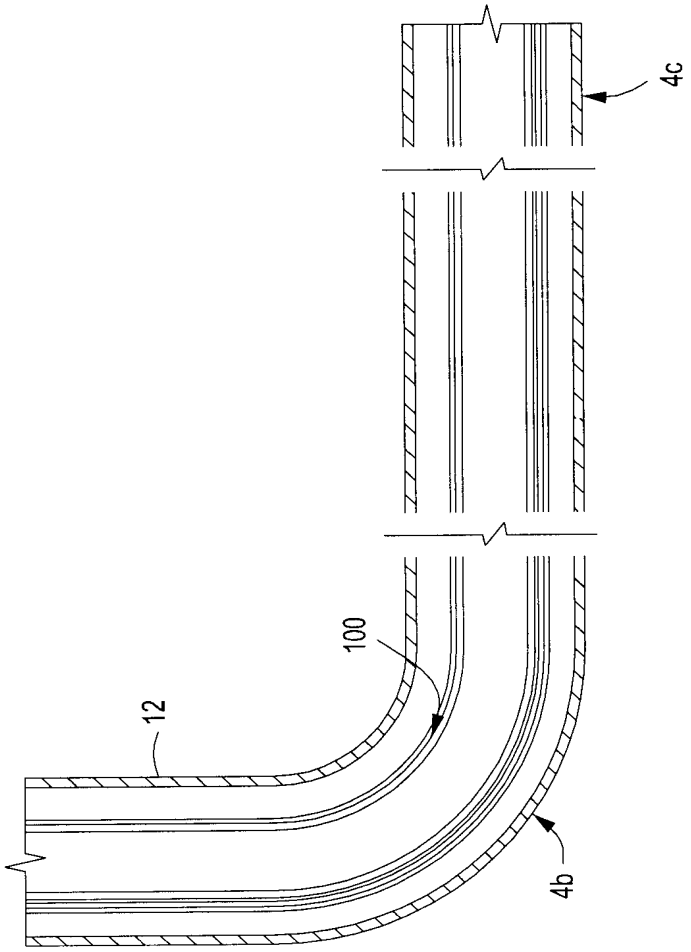


FIG. 4A-1

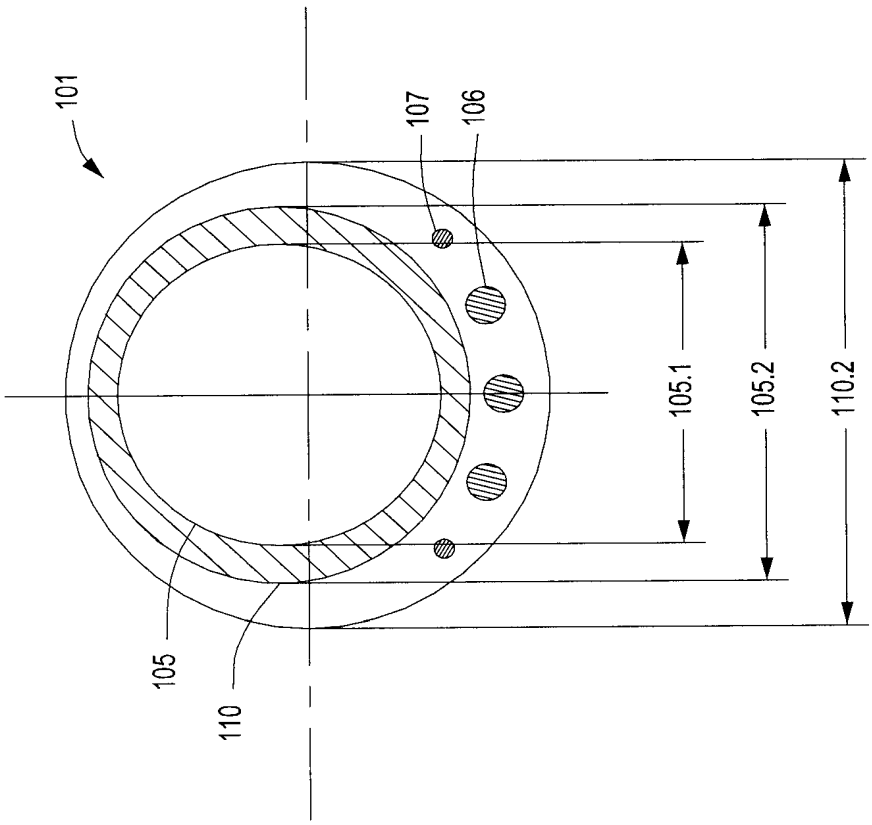


FIG. 4A-2

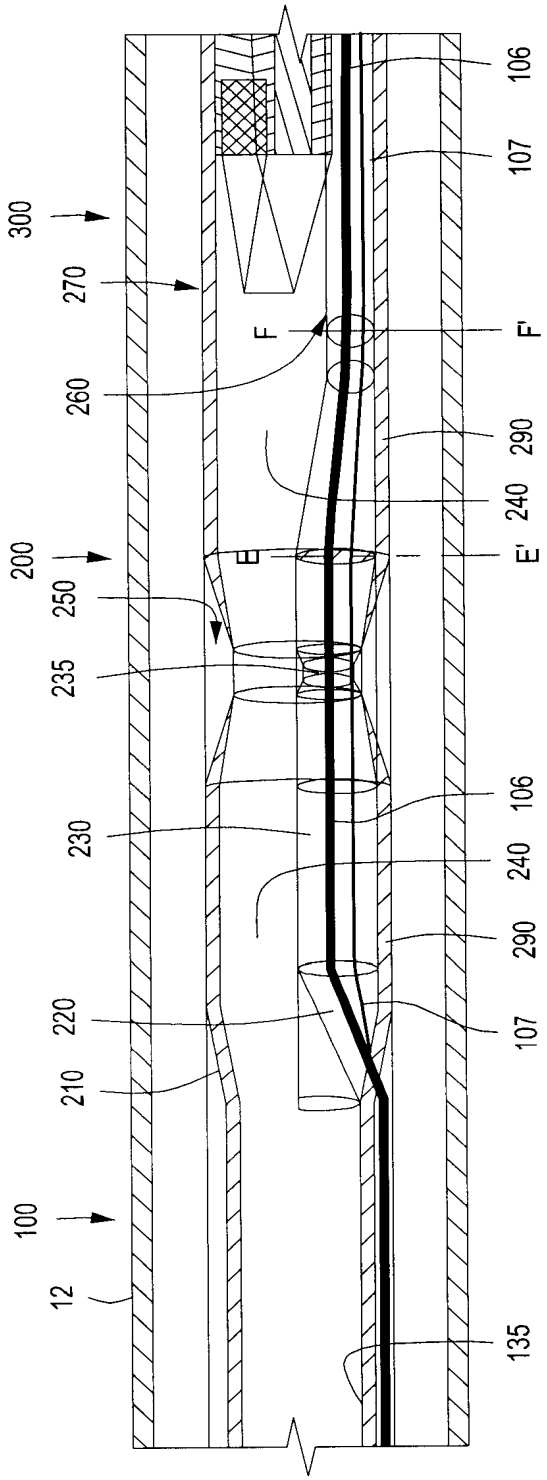


FIG. 4B-1

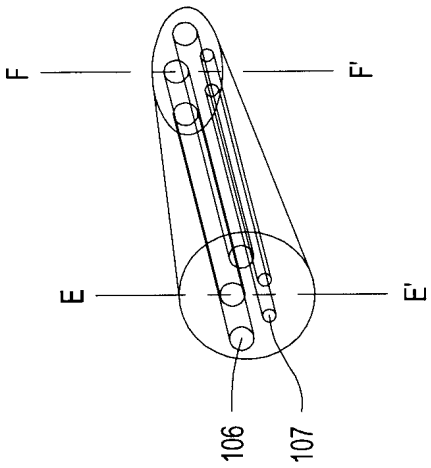


FIG. 4B-1a

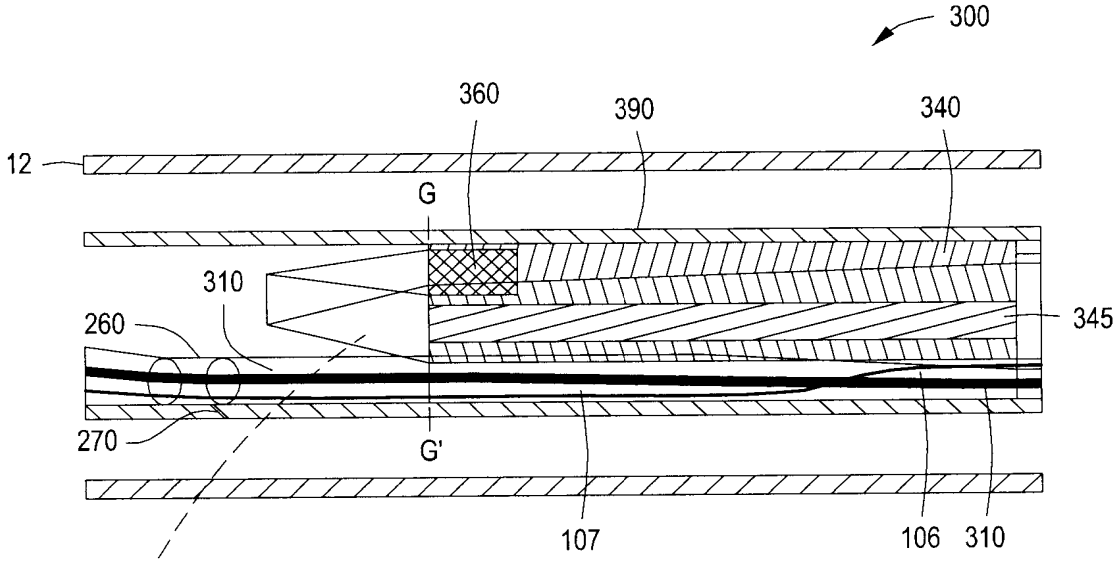


FIG. 4C-1

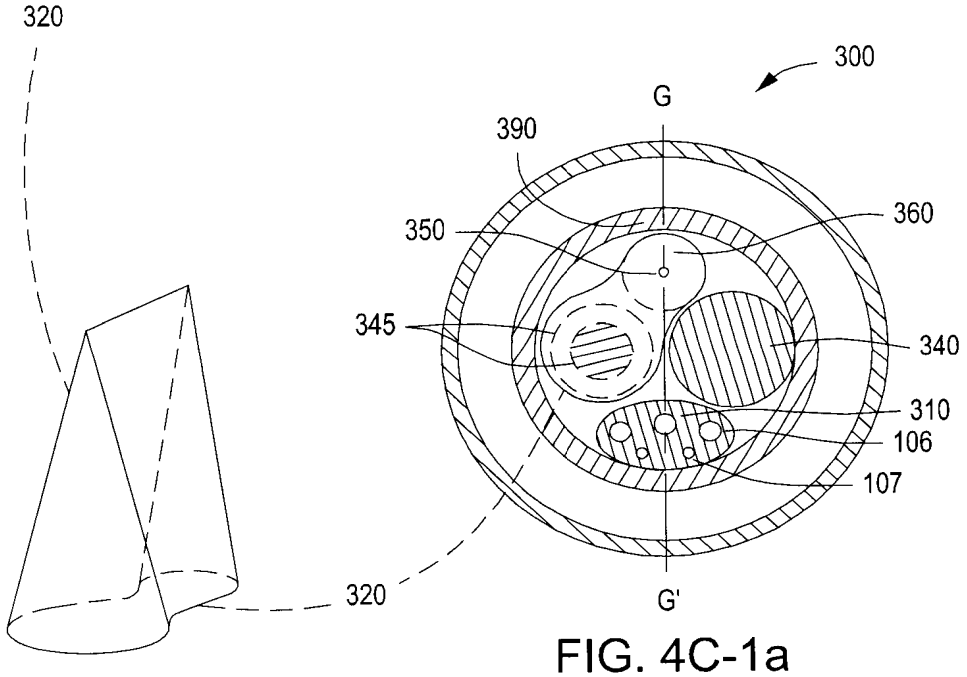


FIG. 4C-1a

FIG. 4C-1b

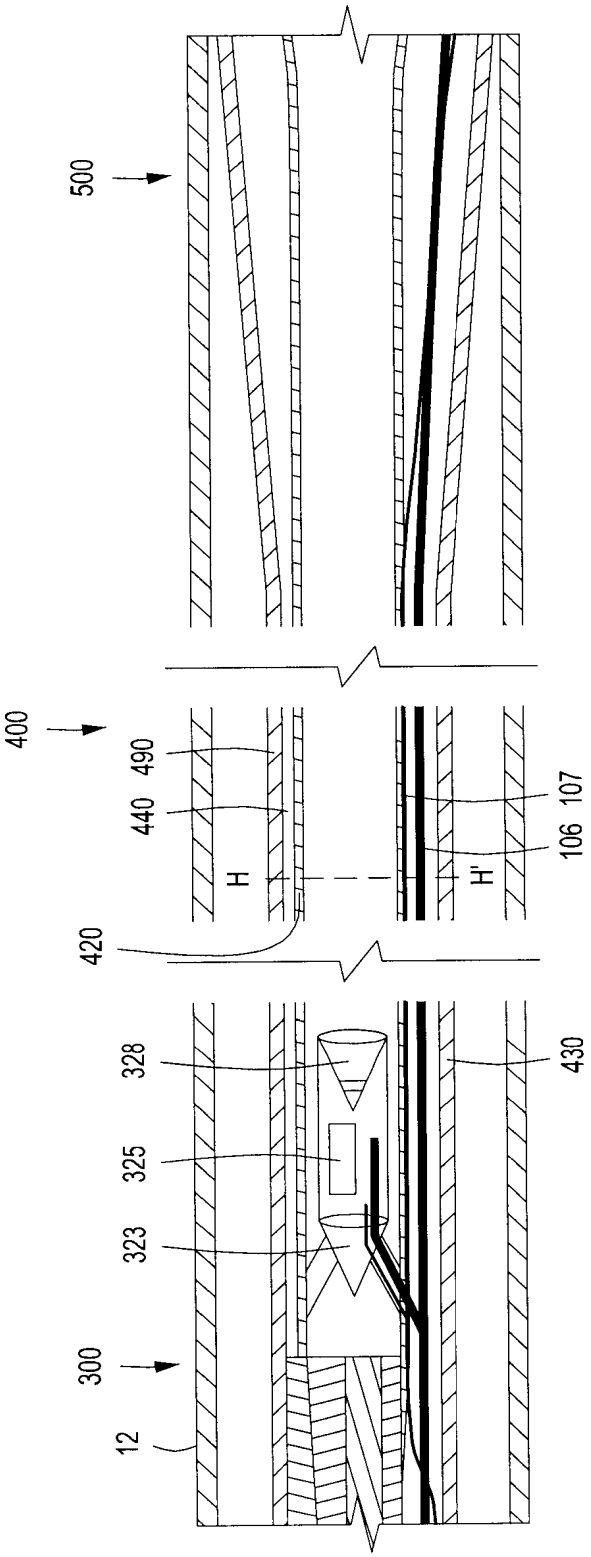


FIG. 4D-1

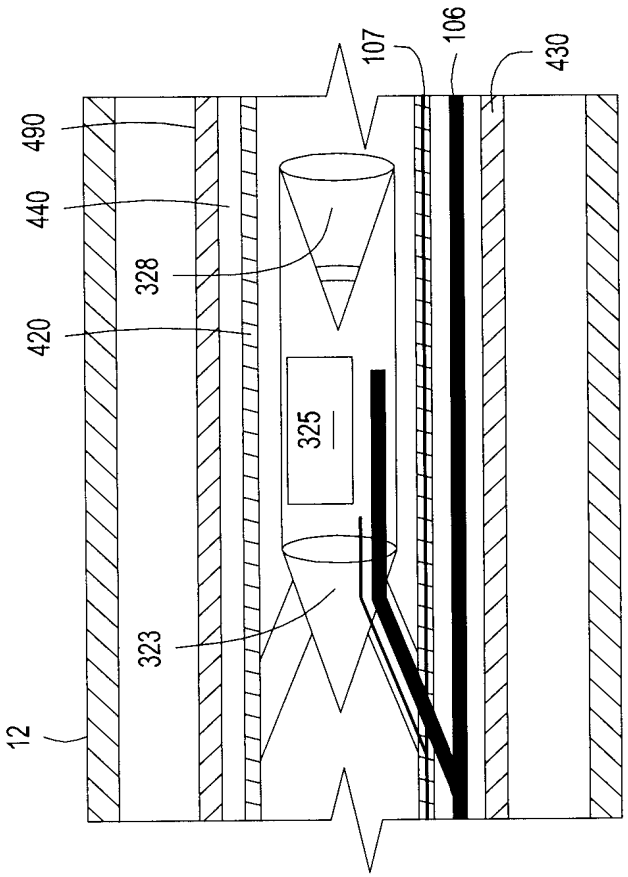


FIG. 4D-1b

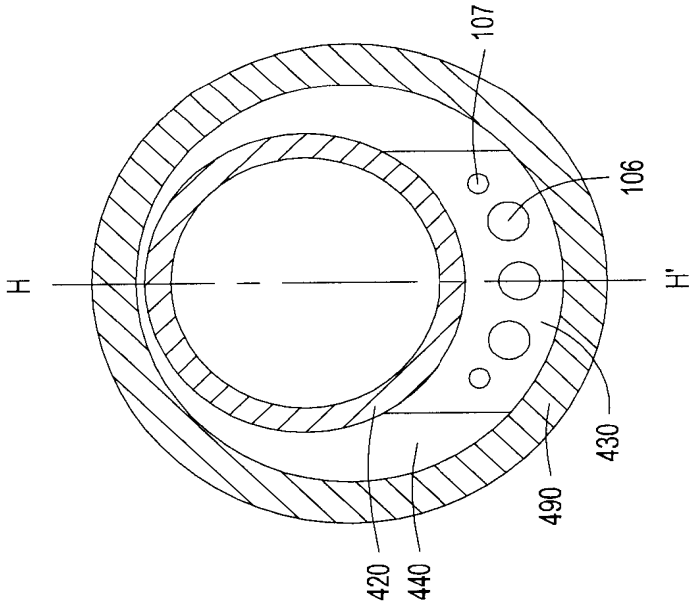


FIG. 4D-1a

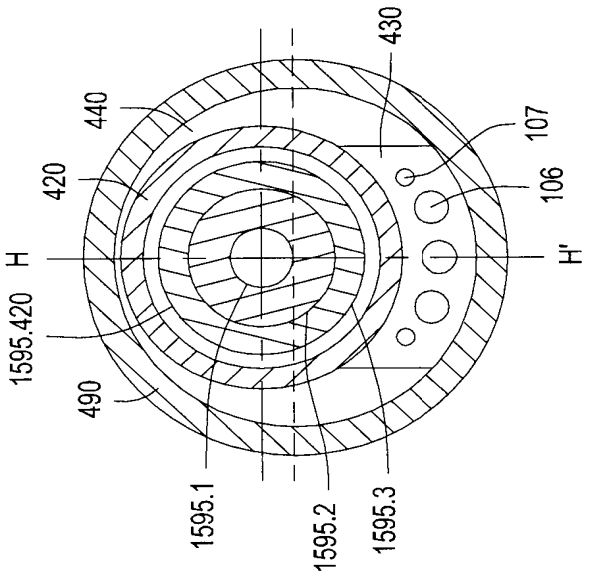


FIG. 4D-2a

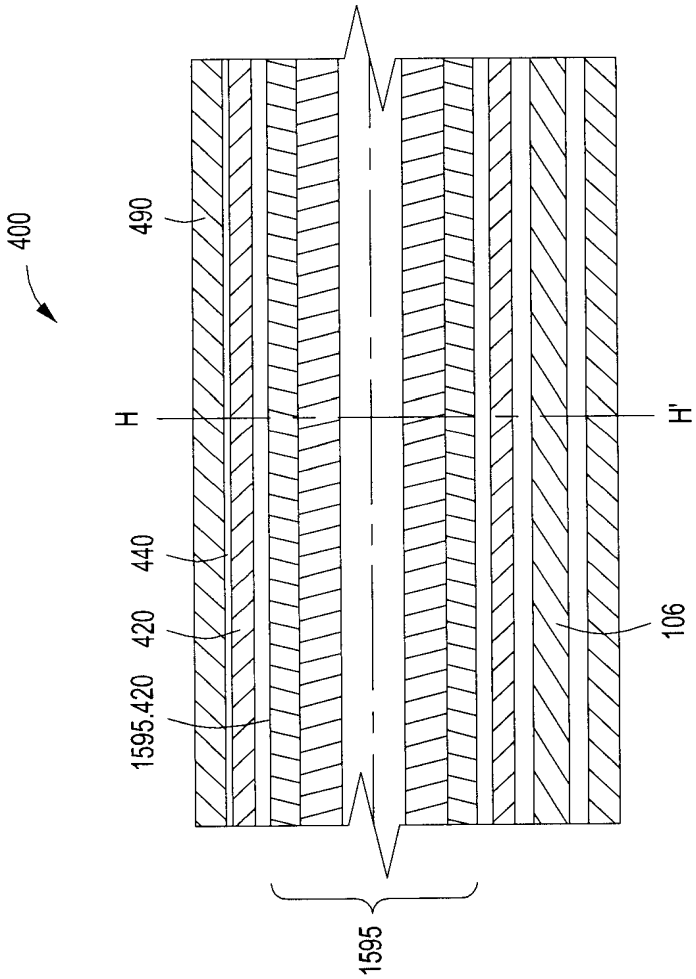


FIG. 4D-2

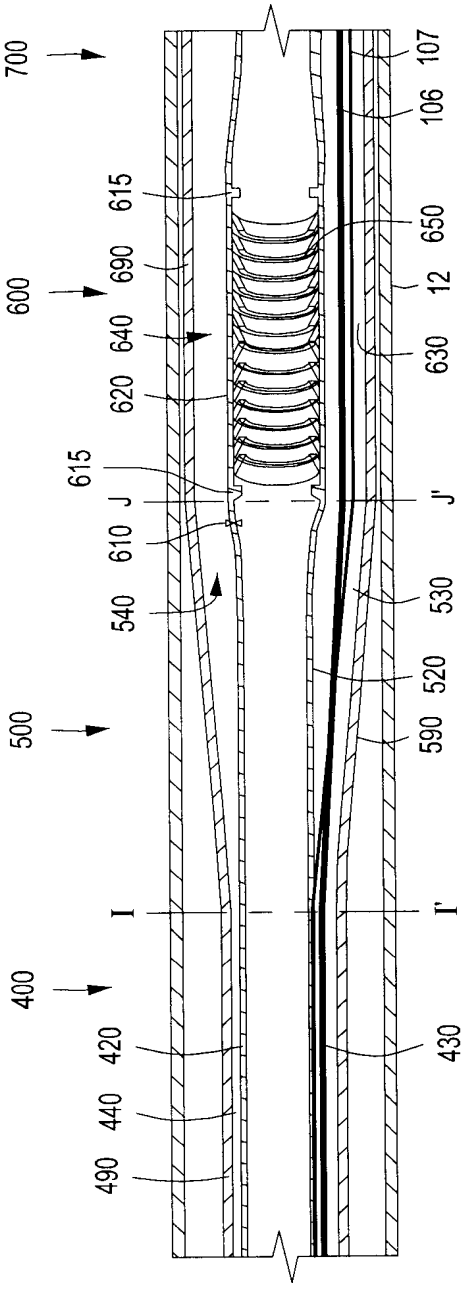


FIG. 4E-1

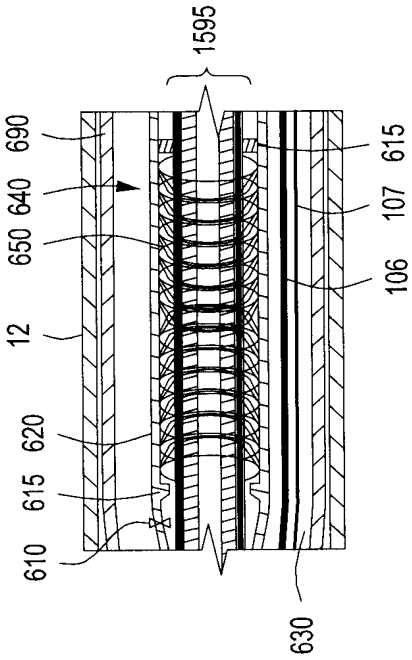


FIG. 4E-2

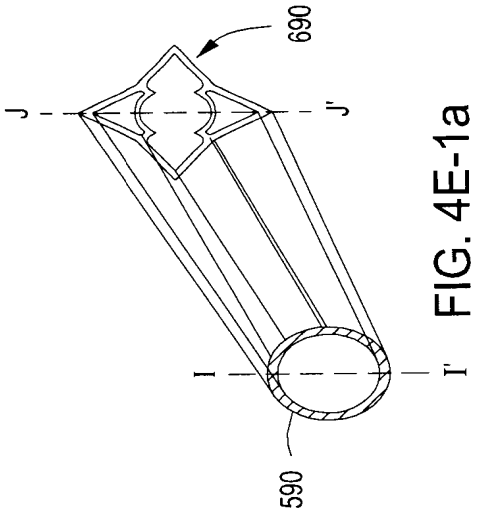


FIG. 4E-1a

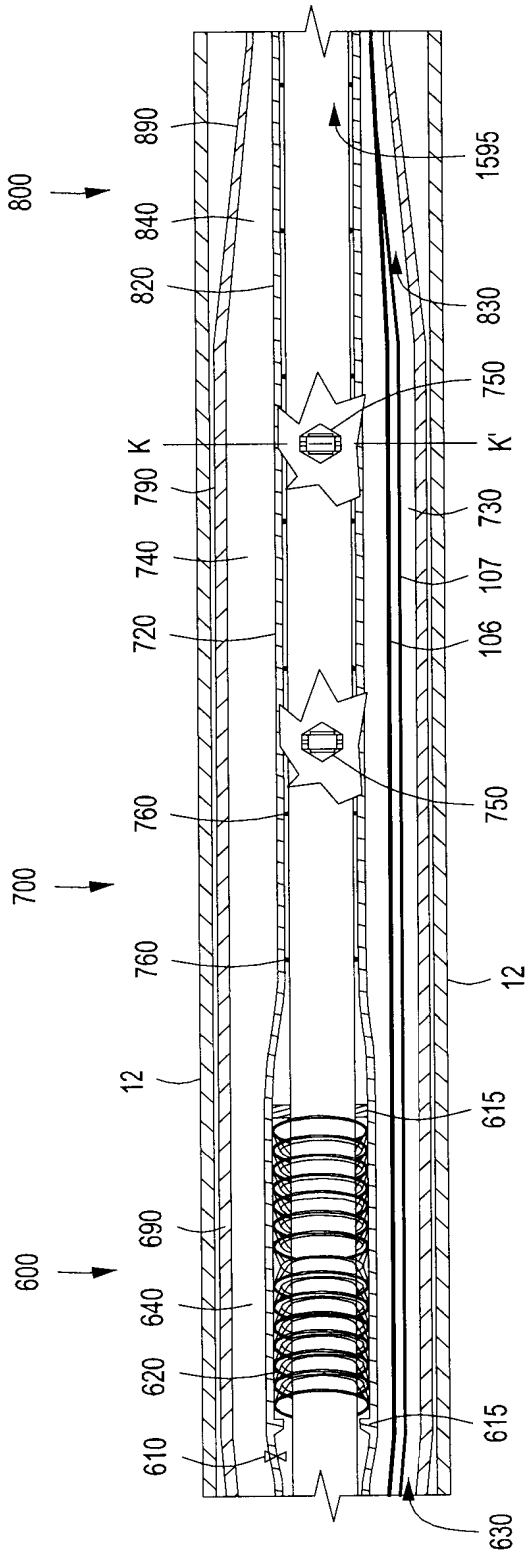

800
890
840
820
790
740
720
760
700
760
12
690
600
640
620
610
1595
830
750
K
K'
730
107
106
750
12
615
615
630

FIG. 4F-1

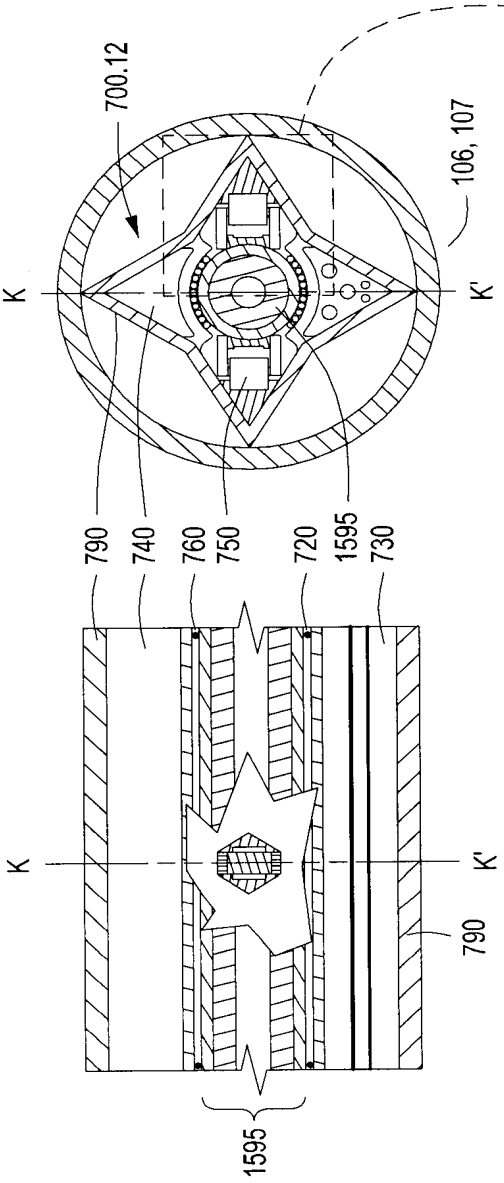


FIG. 4F-2

FIG. 4F-2a

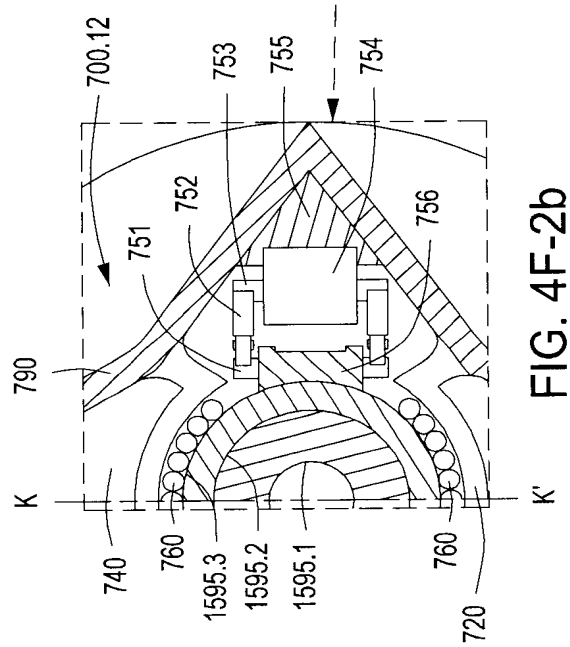


FIG. 4F-2b

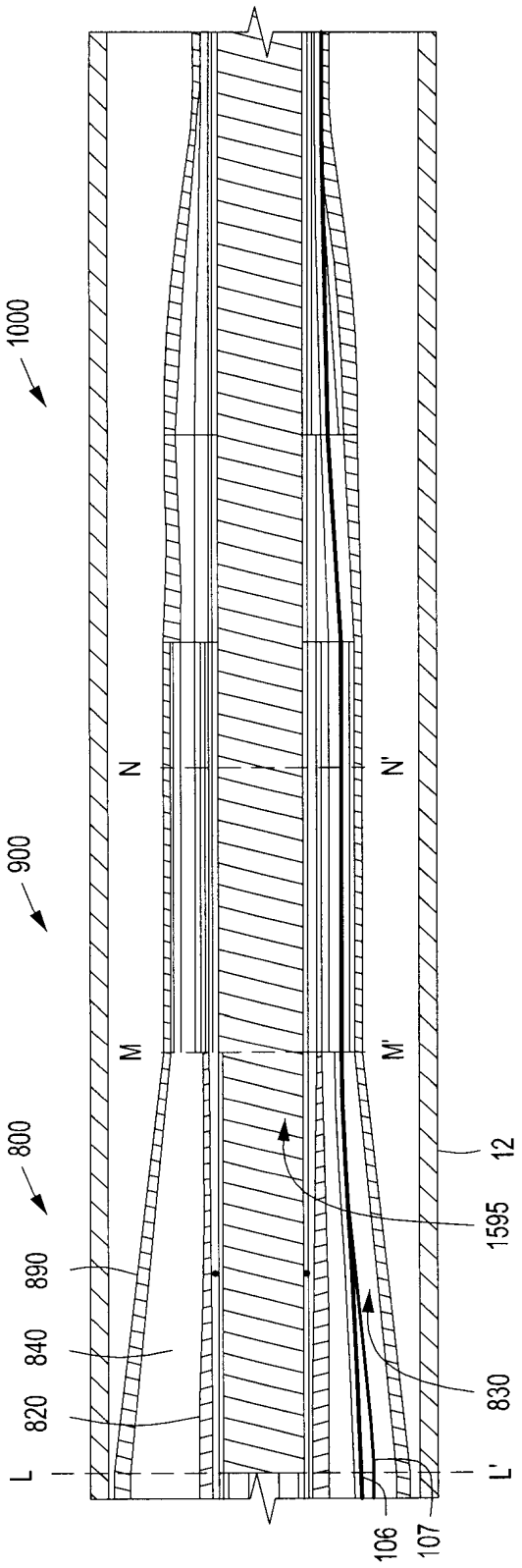


FIG. 4G-1

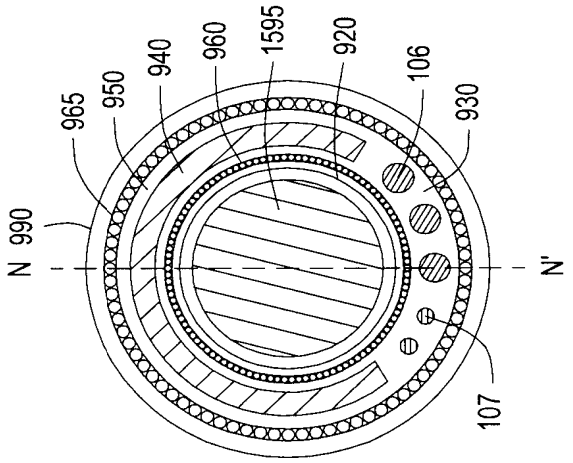


FIG. 4G-1b

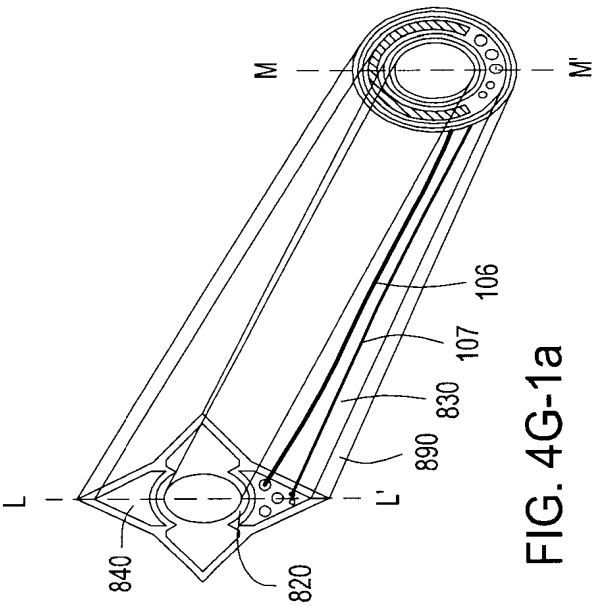


FIG. 4G-1a

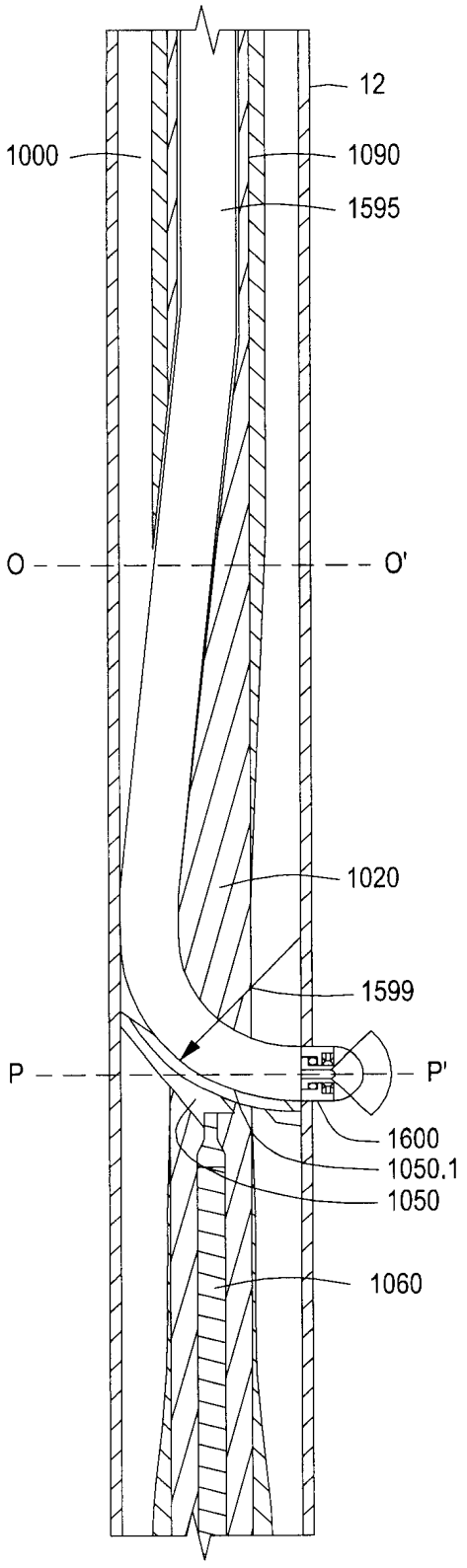


FIG. 4H-1

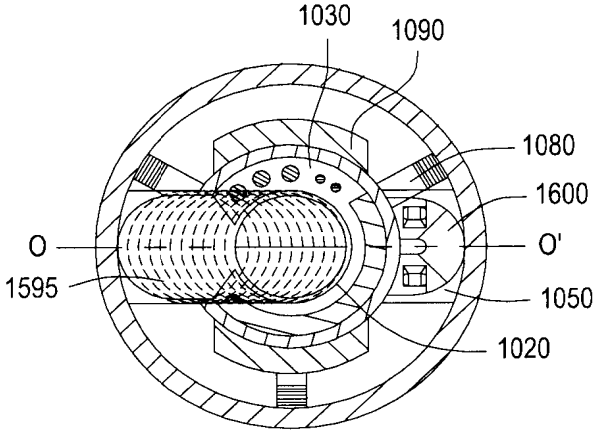


FIG. 4H-1a

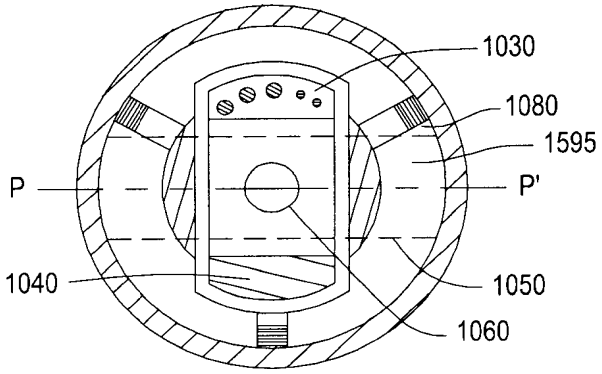


FIG. 4H-1b

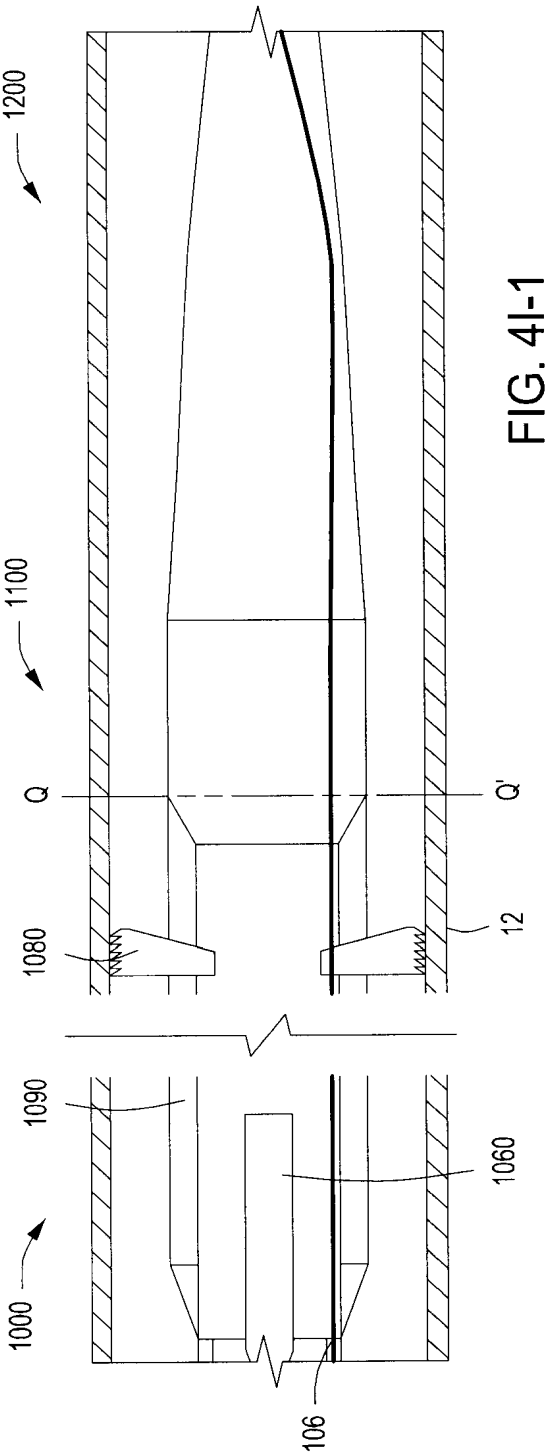


FIG. 4I-1

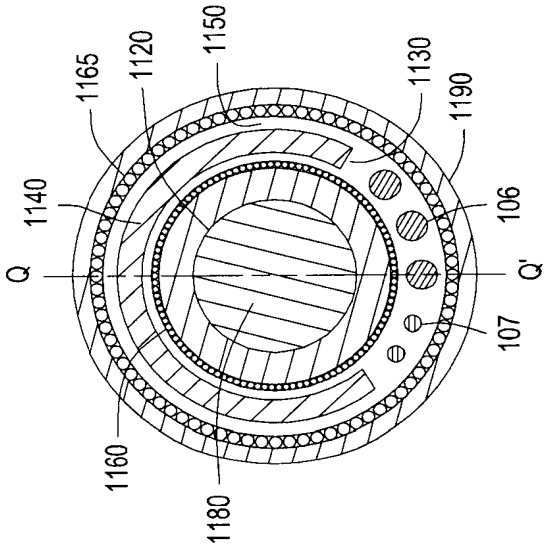


FIG. 4I-1a

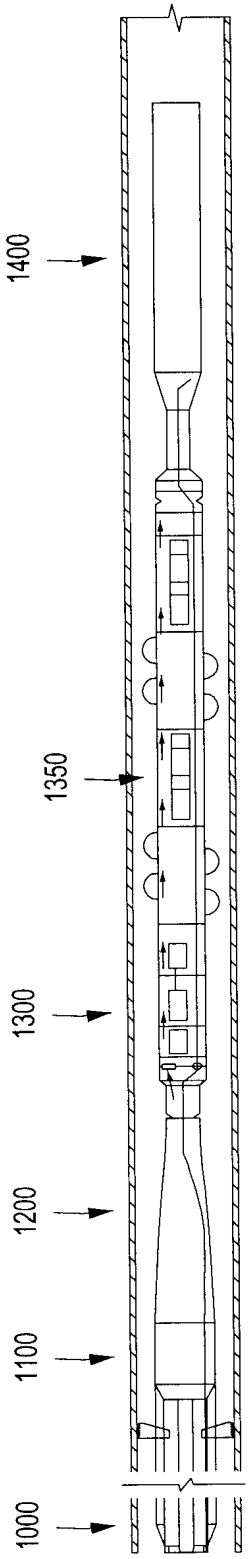
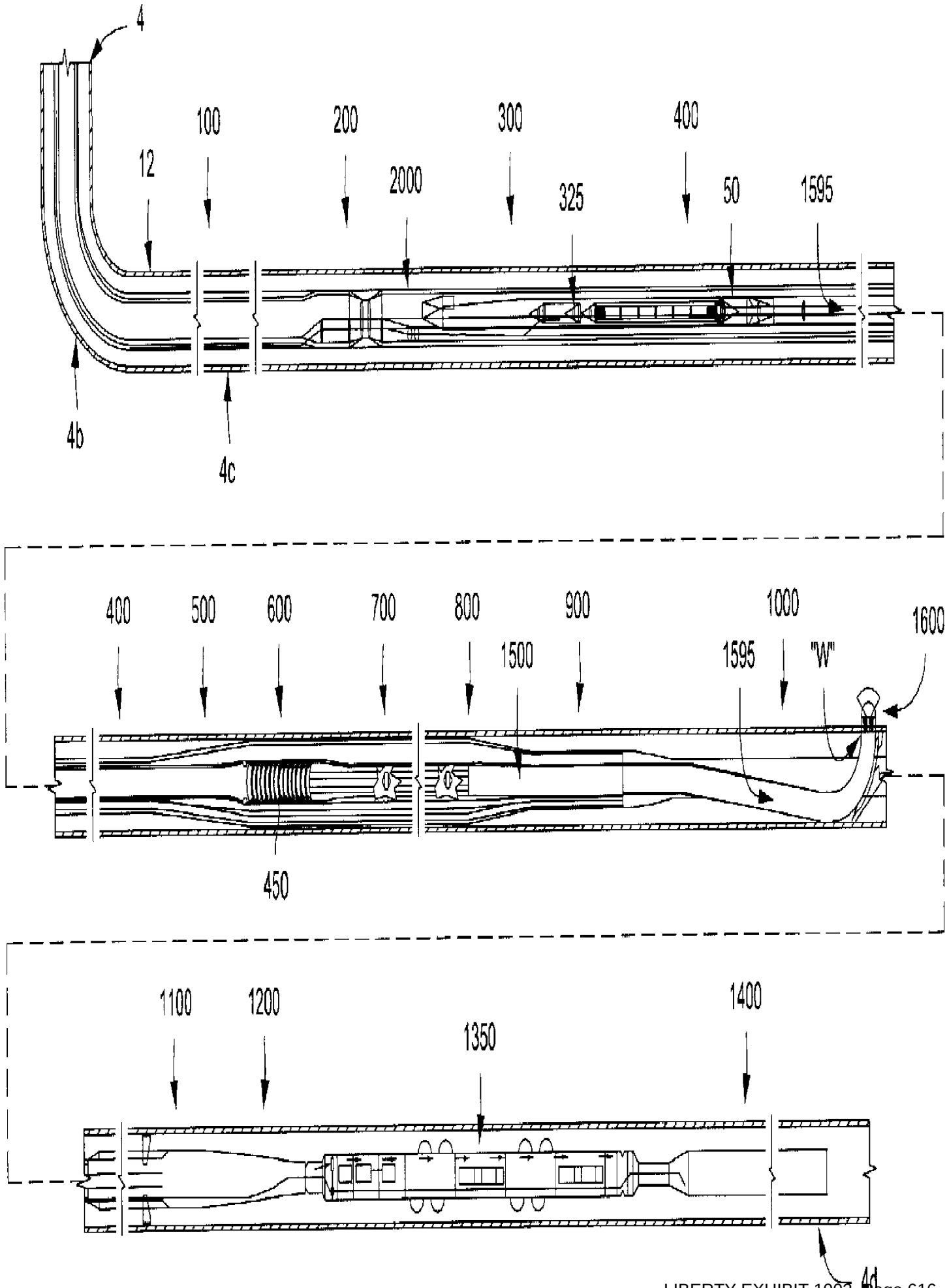


FIG. 4J


4
100
200
300
400
12
2000
325
50
1595
4b
4c
400
500
600
700
800
900
1000
1600
1500
1595
"W"
450
1100
1200
1400
1350
4d

ABSTRACT

A system and method that remotely monitors and controls proppant usage in a fracturing operation. The system and method allow operators to wirelessly monitor and control proppant storage units from inside a datavan through sensors and control mechanisms that interface with fracturing software to schedule the flow of the proppant. A sensor monitors the weight, container level, or volume of the proppant being used to keep the induced hydraulic fracture open. A serial to Ethernet converter converts this information and sends it wirelessly to a datavan. A user at the datavan controls the proppant usage through a display in the datavan of the storage units with the appropriate weight. The container monitoring software links with the fracturing software, providing real-time information about proppant usage so that the user can properly schedule proppant flow to the well through valves, conveyor belts, and other control mechanisms.

CROSS-REFERENCE TO RELATED APPLICATIONS

[001] This application claims priority to U.S. Provisional Patent Application No. 62/204,331 filed on August 12, 2015 and is a continuation-in-part of, and claims priority to and the benefit of co-pending U.S. Patent Application Serial No. 15/202,085 filed July 5, 2016, which is a continuation of U.S. Patent No. 9,410,410 filed November 16, 2012, the full disclosures of which are hereby incorporated by reference herein for all purposes.

BACKGROUND OF THE INVENTION

1. Technical Field

[002] Embodiments of the present disclosure relate to systems and methods for wirelessly monitoring and controlling proppant usage in real time in a hydraulic fracturing operation.

2. Description of Related Art

[003] Horizontal drilling and hydraulic fracturing are two ways in which unconventional sources of hydrocarbons can be tapped to provide energy resources. Hydraulic fracturing (fracking) operations typically require powering numerous components in order to recover oil and gas resources from the ground. For example, pumps that inject fracking fluid down the wellbore, blenders that mix proppant into the fluid, cranes, wireline units, and many other components all must perform different functions in concert to carry out fracturing operations.

[004] Fracturing operations are highly complex and involve pumping fracturing fluid at a high pressure to hydraulically fracture the reservoir rock in the well in order to form fractures and stimulate production of hydrocarbons. The formed fractures can then be used to access hydrocarbons that could not have been accessed with traditional oil & gas well techniques. The fracturing fluid that is pumped down into the well usually includes a proppant that is a solid particulate such as sand or ceramic beads. In many known fracking systems, proppant, such as sand, glass beads, ceramic material, bauxite, dry powders, rock salt, benzoic acid, fiber material,

or cement plastics, is mixed with other materials and enhances the flow capacity of the fractures. The proppant props open the fractures and remains in the fractures after the end of the hydraulic fracturing operation.

[005] The proppant is supplied to the blenders and mixers and then to the well through a proppant delivery system located at the wellsite. The proppant is usually stored in large containers that are heavy and are connected to conveyor belts which lead to other mixing equipment and finally into the wellbore, where the mixture is pumped into the reservoir. The containers usually are refilled at the site by trucks that come in and empty the proppant into them. Gates are controlled by the user to open and close the proppant containers. However, in this operational scenario operators of the hydraulic fracturing system need to be stationed outside at the containers using hydraulic valves, or a short range wireless remote control that is hand held for controls.

[006] The operators report in to the datavan using a radio headset to communicate the container weights or fill levels. This is inconvenient and there are not always extra personnel available for the task. Also, having a worker walk over to the container to adjust the flow takes minutes, which is a long time to have to manually check the proppant level. Further there is airborne silica around the container, which can cause silicosis. Silicosis is lung fibrosis caused by inhalation of dust containing silica. Silica is usually found in the sand used as a proppant. Operators are also exposed to dangerous weather in extremely cold, hot, or hazardous environments. Also, operators would normally have to determine what container and how much to use manually, which can lead to operator error. The incorrect aggregate of proppant could be used by selecting the wrong container.

[007] Another issue with the manual control of the containers is that when the gates controlling proppant flow from the containers are left open spilling product, this causes profit loss. It also causes environmental harm and there is a major safety concern. When a wrong container is open and the incorrect aggregate or proppant is sent out to be mixed with the fracturing slurry, it is hard to figure out what tank the proppant came from and can result in a violation of customer contract. There is also confusion that occurs at the pre-stage planning because operators are unsure what container is being used and how the containers are being scheduled for later use.

[008] These and other problems with manually monitoring and controlling the proppant usage have been observed in the field.

SUMMARY OF THE INVENTION

[009] The method and system of the present invention provide real-time remote monitoring of proppant, such as sand and glass beads, as it is being fed from proppant containers and mixed into the fracturing fluid. Operators inside a datavan are able to wirelessly monitor the weight, container level or volume of the proppant and control the proppants in the proppant containers through remote monitoring software in a datavan.

[0010] Embodiments of systems and methods of the present disclosure include a proppant container with control box connected to a sensor for monitoring the amount of proppant, an RS232 or RS435 serial data protocol on the control box, a wireless Ethernet converter to send the signal from the control box located at the proppant container, a wireless receiver with signal out ports for serial or Ethernet ports to receive the data from the sensor to the datavan and a piece of software on an information handling system in the datavan that computes the total and allows the user to interface with the fracturing control software to schedule proppant usage and flow.

[0011] Embodiments of the invention include software that acquires and displays the proppant data to a user in a datavan, and power supplies that supply power to the serial to Ethernet converter, measuring sensor, and transmitter.

[0012] Embodiments of the invention also include wireless control of the storage containers and conveyor belts.

[0013] Embodiments of the invention include a serial to Ethernet converter that takes the serial data output from a sensor at a proppant container and converts it to the Ethernet protocol to be sent to a datavan with an Ethernet receiver where it is processed and displayed to a user who is monitoring and controlling the proppant flow. The software also allows for scheduling and remote monitoring of the weight, volume and amount of proppant in each proppant container.

The monitoring software, which receives the signal from the proppant equipment can also communicate with fracturing software in the datavan to allow for more automation of the fracturing process as a whole.

[0014] Embodiments of the invention can schedule and automate which containers to run the proppant from, allowing for the proper mixture of proppants from different containers to make up the fracturing fluid.

[0015] Embodiments of the invention can relay the container weight to a datavan information handling system, a personal laptop or a separate Human Machine Interface (HMI) mounted in the datavan.

[0016] Embodiments of the present invention measure the containers weight by gamma ray gauges, radar gauges, laser gauges, and ultrasonic gauges. Also weight measuring load cells and pressure sensors along the vertical height of the vessel can be used.

[0017] Embodiments of the invention include that the communications can be wired or wireless.

[0018] Embodiments of the invention can convert the serial data to wireless, but it is possible to transmit the signal without converting it first.

[0019] Embodiments of the invention can include only the monitoring of the proppant flow and not control.

[0020] Embodiments of the invention can be used on several type of proppant storage containers including silos, capable of holding 200,000 lbs to 300,000 lbs, kings, or sand hogs, large trailer mounted containers similar to a fracturing tank on wheels that holds from 300,000 lbs to 400,000 lbs, or smaller individual proppant boxes, which hold from 40,000 lbs to 60,000 lbs and can be set directly on a conveyor belt.

BRIEF DESCRIPTION OF DRAWINGS

[0021] The foregoing aspects, features, and advantages of embodiments of the present disclosure will further be appreciated when considered with reference to the following description of embodiments and accompanying drawings. In describing embodiments of the disclosure illustrated in the appended drawings, specific terminology will be used for the sake of clarity. However, the disclosure is not intended to be limited to the specific terms used, and it is to be understood that each specific term includes equivalents that operate in a similar manner to accomplish a similar purpose.

[0022] FIG. 1 is a block diagram of an embodiment of the present invention.

[0023] FIG. 2 is a block diagram of a second embodiment of the invention.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

[0024] The foregoing aspects, features, and advantages of the present disclosure will be further appreciated when considered with reference to the following description of embodiments and accompanying drawings. In describing the embodiments of the disclosure illustrated in the appended drawings, specific terminology will be used for the sake of clarity. However, the disclosure is not intended to be limited to the specific terms used, and it is to be understood that each specific term includes equivalents that operate in a similar manner to accomplish a similar purpose.

[0025] The present invention provides a system and method for wirelessly monitoring and controlling proppant flow from proppant storage containers in a hydraulic fracturing operation. The proppant can include sand, glass beads and other known materials that is mixed into a fracturing fluid and that is pumped through a wellbore into a well in order to create fractures and extract hydrocarbons. The proppant storage containers can be stationary or attached to a trailer and can be of various sizes depending on the application.

[0026] Components of a system for monitoring proppant usage and flow can include a control box at the proppant container with sensors which are coupled to the proppant storage container and have serial connections, such as RS232 or RS485 serial connectors, a wireless Ethernet converter to send data signals indicating the readings of the sensors that monitor the weight of the container in real time, and a wireless receiver with signal out ports for serial or Ethernet that receives the signals sent from the control box and formulates them for viewing to a user in a datavan. A variety of power supplies can be used to power the converters. In addition, the software to acquire and display the data, as well as to communicate with the fracturing control software can be included as well. For the control of the storage, there can be a control

box outside or inside the proppant storage containers that can contain wiring and a display for operations that is wirelessly connected to the datavan.

[0027] FIG. 1 shows in schematic form an embodiment of a system 100 for remote and real-time monitoring of proppant storage in a container. In one example of the system 100, there is a datavan 102 where a user operates an information handling system 107 with a processor and memory for storing computer readable media accessible by the processor with instructions and with a display 106.. The information handling system 107 may also include nonvolatile storage area accessible by the processor, and logics for performing each of the steps described herein. In the illustrated example, the information handling system 107 interfaces with a wireless receiver 108 that can be connected to a LAN or other type of wireless network through normal wireless connections or serial to Ethernet devices. Serial to Ethernet devices can be provided by Moxa (640 Herman Road, Suite 5, Jackson, NJ 08527, http://www.moxastore.com), which manufactures serial to Ethernet devices and servers. Other wireless receivers can also be customized for this particular application. Due to the distances between equipment being up to 400 feet, and other electromagnetic inference, Ethernet may not be reliable and therefore another suitable long range protocol may be used such as Radio Frequency (AM or FM).

[0028] In the exhibit shown in FIG. 1, the datavan 102 communicates with a proppant container 114 through a control box 104 at a well site 112. The proppant monitoring system 100 includes a control box 104 shown connected to a proppant container 114. The control box 104 can contain circuitry and wiring along with computer readable media for storing instructions and a processor and input means for the user to manually operate the container 114. In most embodiments the control box 104 will be attached to and be a part of the proppant container 114. Included in the control box 104 is a serial receiver 128 that can connect to a serial to Ethernet

converter 110, also potentially produced by Moxa. The control box 104 can further contain a wireless transmitter 130 for transmitting information to the datavan 102.

[0029] Further, the control box 104 has a serial receiver 128 that is connected via a serial cable to a serial transmitter 126 in a proppant container 114. The proppant container has a sensor 118 which monitors the weight of the proppant container 114 and its contents. The sensor 118 gathers information about the weight of the proppant in the container and sends it via serial or analog connection to the serial transmitter 126 to the control box 104 through its own serial receiver 128. That information is then converted by a serial to Ethernet converter 110 and sent via wireless transmitter 130 to the datavan 102. Proppant can be selectively dispensed from proppant container 114 by opening and closing gate 120, such as with an actuator 122. Sensor readings from sensor 118 are constantly sent back to the datavan 102 through the serial to Ethernet converter 110. There is also a conveyor 124 that can be selectively activated in this embodiment.

[0030] The weight of the proppant container 114 and its contents can be relayed to one or more of the datavan information handling system 107, a personal laptop, and/or a separate human machine interface (HMI) mounted in the datavan 102 through the control box 104. In the datavan a wireless receiver 108 receives the data (wireless transmission is indicated by a dashed line in FIG. 1) and then the information is sent to the information handling system 107 and displayed to the user via a display 106 in multiple formats. The connections between the wireless receiver 108 and the information handling system 107 can be Ethernet or the wireless receiver can be directly installed in the information handling system 107. Further the connection between the information handling system 107 and the display 106 can be Ethernet or serial connection types.

[0031] In addition, the amount of proppant in the proppant container 114 can be gauged by measuring its total weight and subtracting the weight of the proppant container 114 itself, such as with a load cell. In one example a load cell includes a strain gauge that mounts to the proppant container 114 and emits a signal that is representative of the weight of proppant in the proppant container 114. This embodiment is not limited to any one sensor and there are several different ways an accurate weight measurement can be obtained. Optionally, volume of the proppant can be measured. Gamma ray (radioactive) gauges, radar gauges, laser gauges, and ultrasonic gauges can optionally be used in place of weight measuring load cells or as a redundancy to load cells. Even pressure sensors along the vertical height of the proppant container 114 can be used. Furthermore, the communications can be either wired or wireless. Although the above-discussed embodiments seek to convert the serial communications to Ethernet, it is possible to transmit serial data wirelessly without converting it. Proppant is tracked based on weight using load cells, and if a level sensor is used such as a gamma, radar, laser or sonic sensor, then the geometry of the container is taken into consideration when the weight is calculated. An algorithm is used that takes into account the current proppant level, the proppant weight per volume, the density of the proppant and the geometry of the container.

[0032] According to one embodiment of the invention shown in FIG. 1, the signal and electrical characteristics of communications associated with the control box 104 and weight sensor 118 can be in accordance with Serial RS232 or RS485 protocol standards. Serial RS232 or RS485 protocols are standard communications protocols within the industry and other embodiments of the invention can include different standards. Optionally the operation of the control box 104 and weight sensor 118 can be in accordance with Ethernet standards, and the data from these devices transmitted wirelessly to the datavan 102. The datavan 102 can then

receive the wireless signal and output it to display 106. The display 106 shows a representation of each container and a number with the appropriate scale weight. To keep each container unconfused and receiving properly, an output signal and an input signal can be separated on respectively numbered com ports. For example, container one can be received through com port one, container two can be routed to com port two, etc. Another option is to order the data sent in the serial stream so that the first value in the data packet can pertain to the weight of the first container, the second value can pertain to the second container, and so on.

[0033] In an example of operation, the weight or volume of the proppant (or sand) in the proppant container 114 is monitored, either instantaneously or over time, and compared to a designated weight (or volume) or change in weight (or volume) over time. To ensure a sufficient amount of proppant is on hand in the container(s) 114 for use in the fracturing process, a threshold low point of proppant in the container 114 is established, and operations protocol is to keep the amount of proppant in the container 114 to be at least or greater than the threshold low point. Thus an advantage of employing the monitoring system 100 described herein is that by monitoring the proppant amount in the container 114 with the controls described herein, if the threshold low point is approached, or soon to be approached, proppant can be added to that particular container 114. In another example of operation, if a rate change of weight of a proppant container 114 deviates from a designated value, the gate 120 on the particular proppant container 114 can be adjusted so that the rate change of weight is at or close to the designated value. Excursions of the rate change of weight from the designated value, which can be less than or greater than the designated rate change of weight of the proppant container, can indicate that the amount of proppant being dispensed from the container 114 exceeds a capacity of proppant handling hardware, such as a conveyor, thereby resulting in spillage of proppant, or generating

proppant dust. This can be corrected (via monitoring software in the information handling system) that identifies the rate of weight change excursion and contains instructions to send controlling commands to the actuator 122 that in turn adjust a position of the gate 120 to affect a flow of proppant from the container 114. Additionally, monitoring a rate of weight change of a proppant container 114 can provide an indication of how much, if any, proppant is being dispensed from the container 114. Thus if it is desired that proppant be dispensed from a one of the containers 114, but not from another one of the containers 114, logics in the information handling system 107 can compare monitored rate weight changes of proppants in the containers 114 to determine if proppant is being dispensed from designated proppant containers 114, and if not, command signals can be transmitted from the information handling system 107 to the actuator 122 to open a gate 120 on a container 114 from which proppant is to be dispensed, and close a gate 120 on a container 114 from which proppant is not to be dispensed.

[0034] FIG. 2 shows in schematic form an alternate embodiment of a system 200 for monitoring and controlling proppant flow. The wireless proppant monitoring and controlling system 200 of FIG. 2 includes a datavan 202 with a wireless connection inside via a wireless transceiver 208. The datavan 202 can contain a human machine interface (HMI) 206 such as a display and an information handling system (IHS) 207 with a processor, memory and storage for storing the data gathered through the wireless connection. A control box 204 contains a serial transceiver 228 that selectively communicates with a sensor 218 for monitoring the weight of the proppant container 214 and its contents via a serial transceiver 226.

[0035] In the example of FIG. 2, the information is transmitted after it is sent from the sensor 218 via analog connection from a serial transceiver 226 to another serial transceiver 228 in the control box 204. The information is then sent through a serial connection to another information

handling system (IHS) 234 in the control box 204. This IHS 234 may have another human machine interface (HMI) 232 connected to it for access by a user. The IHS 234 then selectively converts the data through a serial to Ethernet converter 210 and sends it back to the datavan 202 through a wireless transceiver 230 on the control box 204 where it is processed by the wireless transceiver 208. The datavan 202 can control an actuator 222 on the proppant container 214 by sending a control command through the HMI 206 connected to the IHS 207 at the datavan 202 through the wireless transceiver 208 to the control box 204. The wireless transceiver 230 in the control box 204 receives the command, converts it to serial through the serial to Ethernet converter 210, sends it to the IHS 234, which then sends it to the proppant container 214 through the serial transceiver 228. A serial transceiver 226 at the proppant container receives the command and actuates the actuator 222 connected to the gate 220. The serial transceiver 226 can also actuate the conveyor 224 as shown in FIG.2.

[0036] The information related to the weight of the container from the sensor 218 can also be catalogued and displayed to a user in the datavan 202. The information can be updated in real time through the wireless connection in the datavan 202 and the user can also control the operations of the conveyor belts 224 and actuator 222 that release the proppant through an actuator 222, which in some embodiments is an proportional hydraulic valve, into the mixing system by interfacing with fracturing software that is also stored in the datavan 202. In one embodiment there are multiple computers in the datavan, one that is in charge of proppant delivery and another for the fracturing operation. These different computers run programs that can share data between themselves. In another embodiment the proppant monitoring and control system will be integrated into fracturing software which monitors the entire fracturing operation.

[0037] To control proppant flow from the containers, the same software can be modified to send commands through the same wireless transceiver 208 on the datavan 202 to the wireless transceiver 230 at the control box 204 at the well site 212 where it can then be converted back to serial for use by the control box's own IHS 234 to open/close sand gates, speed up/slow down the conveyor belt 224, *etc*. The monitoring and control system that receives the signal from the control box 204 and proppant container 214 can also communicate with a portion of the fracturing system in the datavan 202 to allow for a higher level of automation if desired (as described below). Proppant in the container 214 may be released through the wireless control of the valve gate 220 located at the container 214. This can release proppant onto a conveyor 224 for mixing into the fracturing slurry. This data can be used with the data that is gathered from the weight sensor 218 to more accurately control the proppant flow.

[0038] In some alternate embodiments, the system 200 allows for two way communications to allow for monitoring and control of the container 214 and conveyor belt (also referred to as a dual belt) 224. In addition, system 200 can be used on several different types of proppant storage containers including silos (tall containers similar to farm silos capable of holding 200,000 lbs to 300,000 lbs), sand kings (sometimes called sand hogs, large trailer mounted containers similar in idea to a frac tank on wheels, capable of holding 300,000 lbs to 400,000 lbs), or sand boxes (which are smaller containers which are set on top of the conveyor belt and unloaded which can contain 40,000 lbs to 60,000 lbs). The sand equipment units can be electric powered, diesel powered, gravity fed, and/or solar powered. In addition, the system 200 is not limited to use with vertical sand silos, but the can be applied to other sand storage equipment as well. Various sensors can be added to the system to control the flow of proppant and weight and the embodiment described above should not be limited to a single configuration.

[0039] One advantage of the system 200 is the ability to keep personnel away from air born silica that exists around proppant storage units, and which can cause silicosis or other health problems. Silicosis is lung fibrosis caused by the inhalation of dust containing silica. Operators can also be kept out of the weather in extremely cold, hot, or hazardous environments. Another advantage is the removal of human error of dispensing proppant from the wrong storage container. In some embodiments of the invention, there are multiple gates on the container or containers and different levels of open and close for the multiple gates that can be set by the user at the datavan. Some gates can only open fully or close fully as well depending on the application.

[0040] In some embodiments, a live video feed can be directed from the container 214 to the datavan 202 through a camera 236 that sends a Radio-Frequency (RF) signal back to the IHS 234 at the control box 204, thereby making it possible to know instantly if a gate 220 was left open, spilling product on the ground and costing profit loss or causing an environmental or safety hazard, or conversely, if a gate commanded to open was stuck shut due to a mechanism failure. An improperly operating gate can cause the failure of a fracturing operation. This information is converted to wireless and transmitted to the datavan 202. Datavan operators can also use the video feed to determine if the wrong container was opened, causing an incorrect aggregate to be mixed into the fracturing slurry. The same weight monitoring can also allow datavan operators to see if a certain container is being unloaded into which will help prevent confusion regarding logistics and pre-stage planning.

[0041] Set points for proppant delivery and conveyor speed can be a simple PID closed feedback loop. A sensor can monitor the speed of the conveyor and that sensor sends a signal to the datavan via the system to indicate if the desired speed has been reached. If the sensor

indicates it has reached the proper speed, then the conveyor will hold the speed. If it indicates the speed value has been overshot, the system will send out a command signal to slow down the belt. This process is repeated multiple times until the correct weight goal has been achieved by the system The P, I, and D values will determine the stability and response time of the control system, and these values are dependent upon the user's desired response times, and the determined amount of overshoot and undershoot that is tolerable in the positioning of the gate. User entered set points for the desired weight of sand remaining in the container(s) will signal the end of the job once that weight is reached and will trigger the gate(s) to close, thus ending the feedback control loop. Further, other components in the fracturing system, such as the blender can alter these values as part of the overall fracturing software depending on the uses of the system.

[0042] According to certain embodiments, which include multiple containers, it is possible to schedule and automate which of these containers to access. For example, the fracturing system can issue a command to close a 40/70 aggregate sand container, while simultaneously issuing a command to open a 20/40 aggregate container. In an embodiment, closing a particular sand (or proppant) container involves closing the gate 220 on the container 214 through which proppant/sand is dispensed from the container 214 to suspend the flow of proppant from the container 214. Similarly, in one example, opening a container 214 is done by opening the respective gate 220 on the container 214 so that proppant can be dispensed to a designated conveyor 224. Opening and closing the gates 220 can be performed by activating the respective actuators 222 coupled with the gates 220. The speed of a belt on conveyor 224 can be controlled remotely, as well as the container outlet gate 220 which can be choked to control the amount of sand being fed to the belt. If wellhead pressure exceeds a set point, or if an emergency stop (E-

Stop/E-Kill) button or emergency power off (EPO) button is pressed, the gates 220 on the containers can be automatically closed thereby preventing lost product (proppant). The conveyor belt 224 can also be linked to the E-Stop and EPO in case of an emergency.

[0043] The connections between the HMI 206 and the IHS 207 can be serial or Ethernet. The dashed line in FIG. 2 represents wireless communications between the wireless transceiver 230 in the control box 204 and the wireless transceiver in the datavan 202, but also wired communications can be used as well. The HMI 232 on the control box 204 can also be external or internal and the IHS 234 can be a small programmable logic control device. The actuator 222 can also be an electrical or air actuator instead of a proportional hydraulic valve. Additionally, the conveyor can be a part of the proppant container, or a separate piece of equipment.

[0044] A further embodiment of the invention includes a blender that is connected to the IHS 207 of the datavan 202. The blender can have an information handling system and a human machine interface that communicates with the datavan 202 in order to further control the proppant flow. The blender is capable of making changes to the proppant flow in a similar manner as the datavan 202. The blender can send control signals to the datavan 202 through its own information handling system to the IHS 207 of the datavan indicating a certain flow of proppant and these signals can be sent to the control box 204 and the proppant container 214. Therefore any changes requested by a user operating the blender are taken into consideration when delivering the proppant. The connections can be either serial or Ethernet, but are not limited in this embodiment.

[0045] Embodiments of the system 200 described herein allow for the wireless monitoring and control of proppant and proppant storage containers 214 in a remote location. Proppant container 214 in the embodiment of Fig. 2 contains a single type of proppant, however, it is

possible to have multiple proppants in multiple containers with multiple valves actuated remotely, or different compartments in the same container which contain different aggregates of proppant, so that the user in the datavan 202 can schedule a different mixture of proppants for the desired fracturing fluid and application. Persons of ordinary skill in the art will appreciate that the systems and methods described herein are not limited to the particular structures described but that changes to the invention can be made that are consistent with this disclosure.

CLAIMS

What is claimed is:

1. A system for use with a fracturing operation comprising:

a weight monitoring system in selective cooperation with a proppant container that selectively contains proppant used in fracturing;

an information handling system in communication with the weight monitoring system; and

a proppant dispensing system coupled with the proppant container and that is in communication with and selectively activated by the information handling system.

2. The system of claim 1, further including a serial to Ethernet converter for sending and receiving Ethernet data to and from the information handling system, and for sending and receiving serial data to and from the proppant container.

3. The system of claim 1, wherein the information handling system selectively sends commands to actuate a valve coupled with the proppant container to provide a designated amount of proppant for use by a fracturing operation.

4. The system of claim 1, where the information handling system alerts a user if an amount of proppant in the proppant container is below a threshold level, and where the information handling system estimates the amount of proppant in the proppant container based on a signal received from the weight monitoring system.

5. The system of claim 1, where the weight monitoring system comprises a sensor for measuring one or more of a weight of the proppant container, a level of proppant in the proppant container, and a volume of proppant in the proppant container, and wherein the sensor comprises a measuring device selected from the group consisting of gamma ray gauges, radar

gauges, laser gauges, weight measuring load cells, pressure sensors, ultrasonic gauges, and combinations thereof.

6. The system of claim 1, where the control is either wired or wireless.

7. The system of claim 1, where the proppant storage containers include one of silos or trailer mounted containers.

8. The system of claim 1, where the equipment is electric powered, diesel powered, gravity fed or solar powered.

9. The system of claim 1, further comprising:

a plurality of electric pumps fluidly connected to the well and powered by at least one electric motor, and configured to pump fluid into the wellbore at high pressure so that the fluid passes from the wellbore into the formation, and fractures the formation; and

a variable frequency drive connected to the electric motor to control the speed of the motor, wherein the variable frequency drive frequently performs electric motor diagnostics to prevent damage to the at least one electric motor.

10. A method for conducting a fracturing operation comprising:

sensing an amount of proppant contained in at least one proppant storage container;

comparing the amount of proppant sensed in the proppant storage container with a designated amount of proppant; and

regulating a flow of proppant from the proppant storage container based on the step of comparing the amount of proppant sensed and the designated amount of proppant.

11. The method of claim 10, further comprising a scheduling step that includes interfacing with a fracturing system that can actuate valves and other control mechanisms to provide proppant to fracturing operations on conveyor belts.

12. The method of claim 10, further comprising directing an amount of proppant toward a well through the use of conveyor belts that are controlled by a user at a datavan.

13. The method of claim 10, further comprising generating an alert if proppant in the proppant storage container goes below a threshold level.

14. The method of claim 10, where the sensing the amount of proppant in the proppant storage container comprises using a device that is selected from the group consisting of gamma ray gauges, radar gauges, laser gauges, weight measuring load cells, pressure sensors, ultrasonic gauges.

15. The method of claim 10, where the transmitting step is either wired or wireless.

16. The method of claim 10, where the proppant storage containers include one of silos or trailer mounted containers.

17. The method of claim 10, where the equipment is electric powered, diesel powered, gravity fed or solar powered.

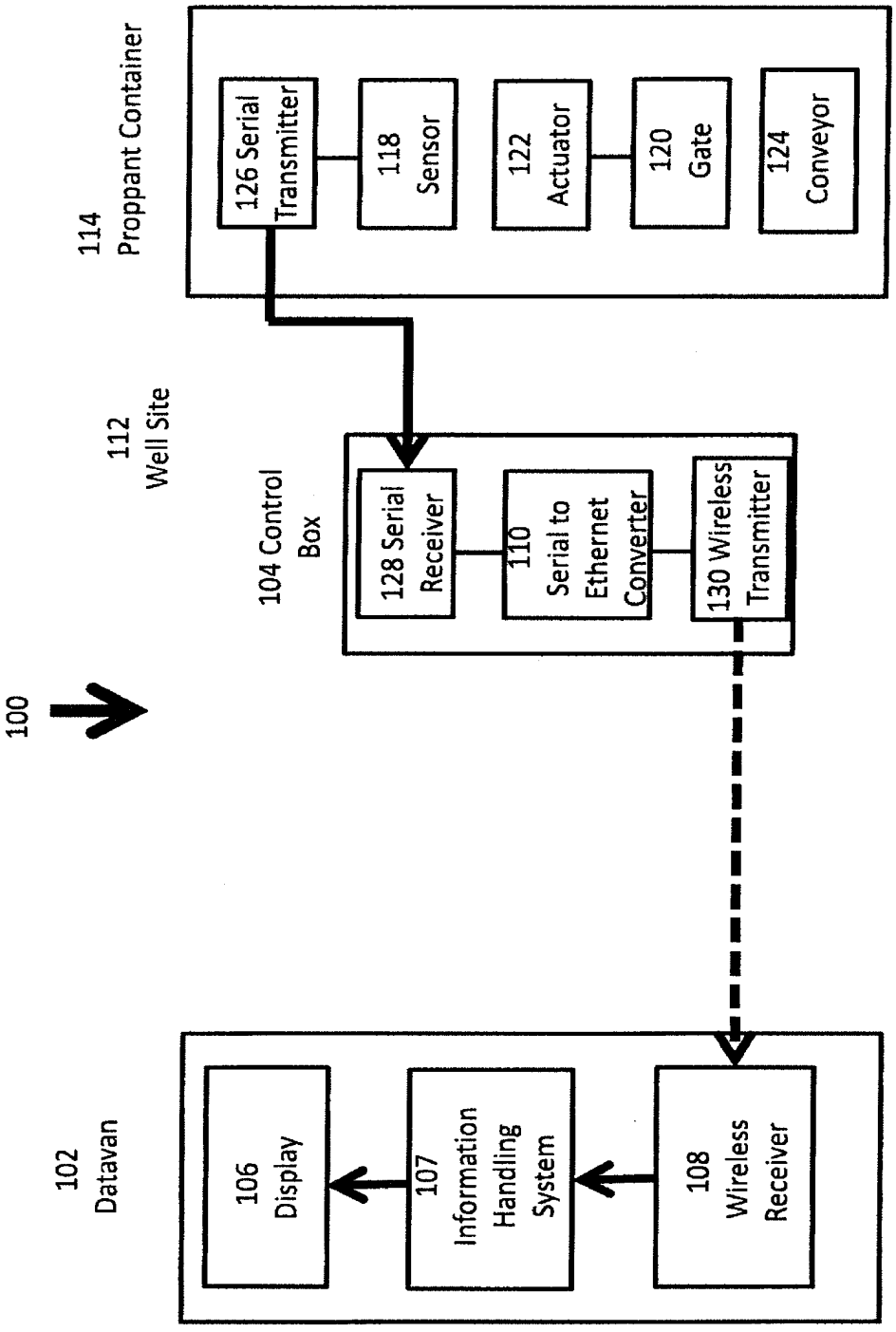

100
102
Datavan
106
Display
107
Information
Handling
System
108
Wireless
Receiver
104 Control
Box
128 Serial
Receiver
110
Serial to
Ethernet
Converter
130 Wireless
Transmitter
112
Well Site
114
Proppant Container
126 Serial
Transmitter
118
Sensor
122
Actuator
120
Gate
124
Conveyor

FIG. 1

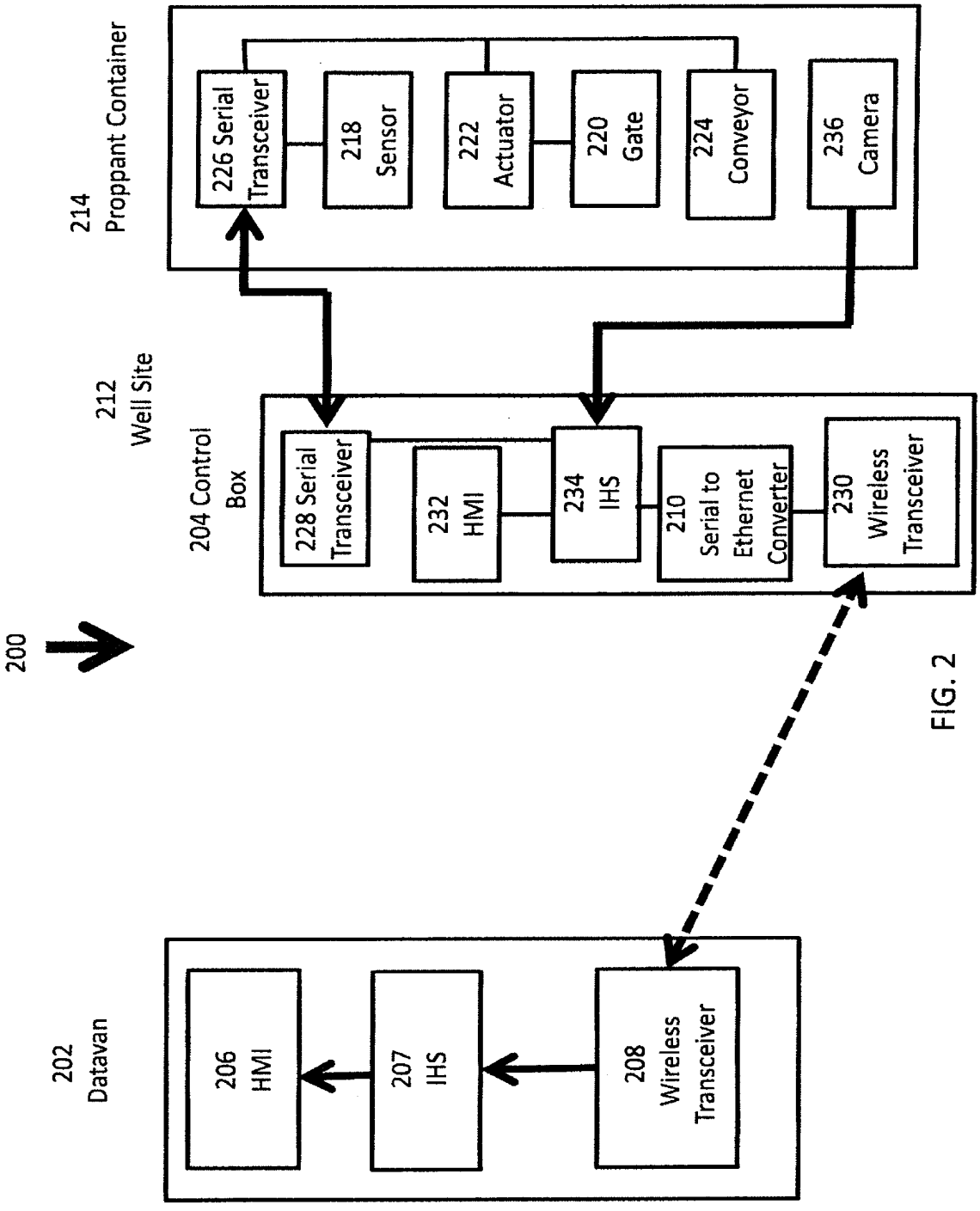
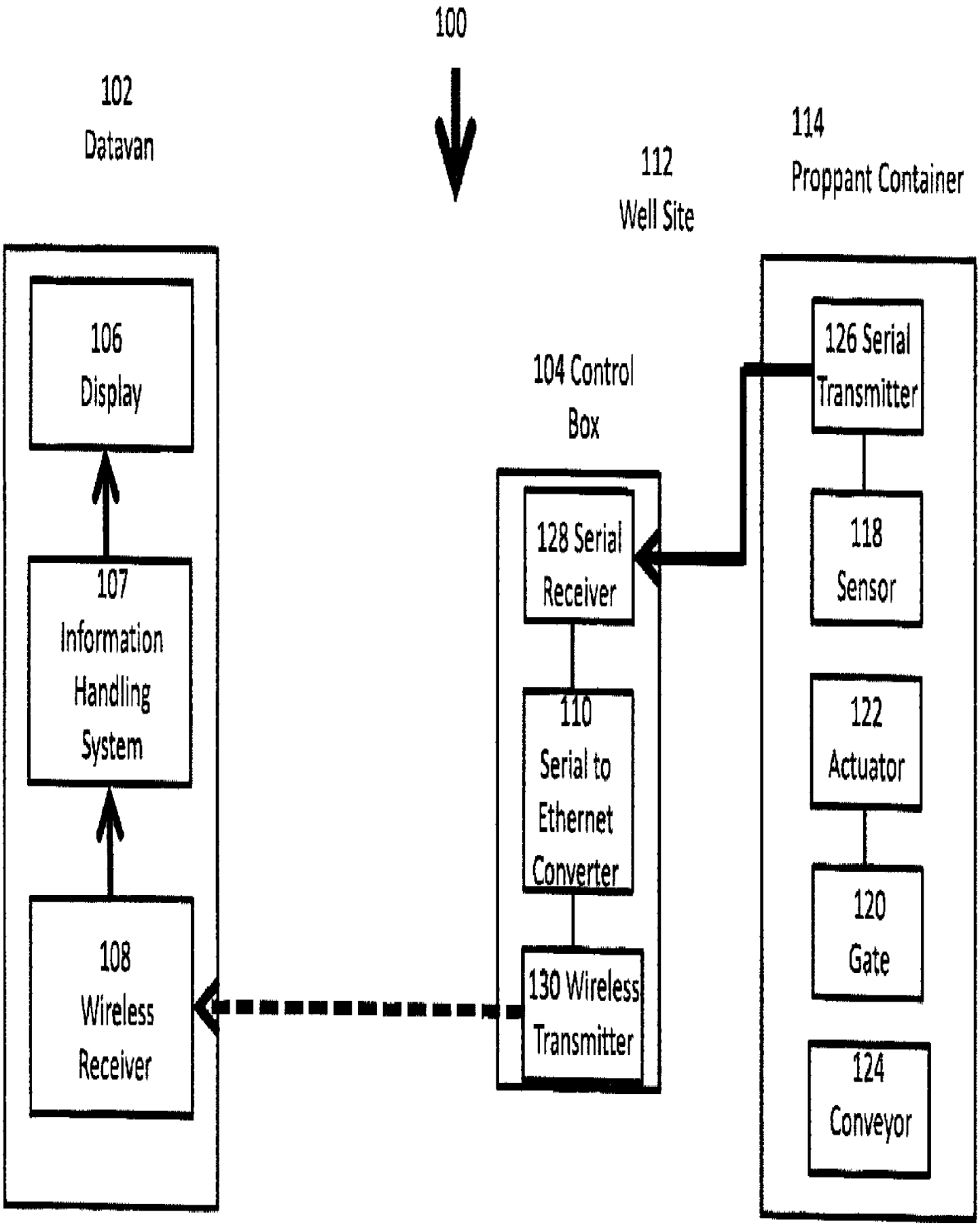

200
202
Datavan
206
HMI
207
IHS
208
Wireless
Transceiver
212
Well Site
204 Control
Box
228 Serial
Transceiver
232
HMI
234
IHS
210
Serial to
Ethernet
Converter
230
Wireless
Transceiver
214
Proppant Container
226 Serial
Transceiver
218
Sensor
222
Actuator
220
Gate
224
Conveyor
236
Camera

FIG. 2


100
102
Datavan
112
Well Site
114
Proppant Container
106
Display
107
Information
Handling
System
108
Wireless
Receiver
104 Control
Box
128 Serial
Receiver
110
Serial to
Ethernet
Converter
130 Wireless
Transmitter
126 Serial
Transmitter
118
Sensor
122
Actuator
120
Gate
124
Conveyor

Office de la Propriété Intellectuelle du Canada
Un organisme d'Industrie Canada

Canadian Intellectual Property Office
An agency of Industry Canada

CA 2945579 A1 2017/04/16

(21) 2 945 579

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) Date de dépôt/Filing Date: 2016/10/17

(41) Mise à la disp. pub./Open to Public Insp.: 2017/04/16

(30) Priorités/Priorities: 2015/10/16 (US62/242,566); 2016/07/05 (US15/202,085)

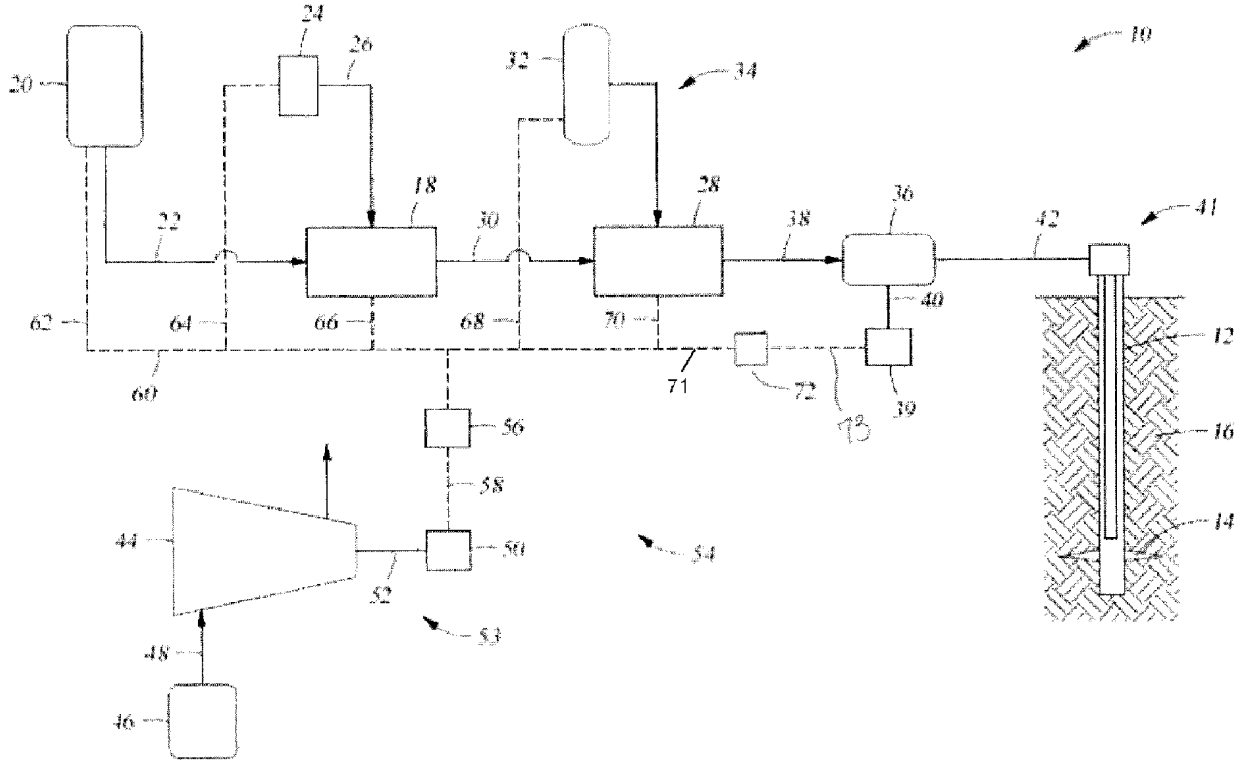
(51) Cl.Int./Int.Cl. *E21B 43/26* (2006.01), *E21B 43/267* (2006.01), *E21B 47/00* (2012.01)

(71) Demandeur/Applicant:
US WELL SERVICES, LLC, US

(72) Inventeurs/Inventors:
OEHRING, JARED, US;
HINDERLITER, BRANDON N., US

(74) Agent: BERESKIN & PARR LLP/S.E.N.C.R.L.,S.R.L.

(54) Titre : SURVEILLANCE A DISTANCE D'EQUIPEMENT DE FRACTURATION HYDRAULIQUE
(54) Title: REMOTE MONITORING FOR HYDRAULIC FRACTURING EQUIPMENT



(57) Abrégé/Abstract:
A hydraulic fracturing system for fracturing a subterranean formation including a pump in communication via pump components with a wellbore that intersects the formation, and that pressurizes fluid in the wellbore, the fluid comprising a fracturing fluid slurry.

(21) 2 945 579

(13) A1

(57) Abrégé(suite)/Abstract(continued):
The system further includes hydraulic fracturing system components for making the fracturing fluid slurry, and a monitoring system that selectively captures and transmits real time images of at least one of the hydraulic fracturing system components or pump components to enable remote monitoring of the at least one of the hydraulic fracturing system components or pump components.

ABSTRACT

[0044] A hydraulic fracturing system for fracturing a subterranean formation including a pump in communication via pump components with a wellbore that intersects the formation, and that pressurizes fluid in the wellbore, the fluid comprising a fracturing fluid slurry. The system further includes hydraulic fracturing system components for making the fracturing fluid slurry, and a monitoring system that selectively captures and transmits real time images of at least one of the hydraulic fracturing system components or pump components to enable remote monitoring of the at least one of the hydraulic fracturing system components or pump components.

REMOTE MONITORING FOR HYDRAULIC FRACTURING EQUIPMENT

BACKGROUND OF THE INVENTION

1. Field of Invention

[0001] The present disclosure relates to hydraulic fracturing operations in a subterranean formations. In particular, the present disclosure relates to a hydraulic fracturing system with imaging devices that are strategically positioned to remotely monitor portions of the system.

2. Description of Prior Art

[0002] Hydraulic fracturing is a technique used to stimulate production from some hydrocarbon producing wells. The technique usually involves injecting fluid into a wellbore at a pressure sufficient to generate fissures in the formation surrounding the wellbore. Typically the pressurized fluid is injected into a portion of the wellbore that is pressure isolated from the remaining length of the wellbore so that fracturing is limited to a designated portion of the formation. The fracturing fluid slurry, whose primary component is usually water, includes proppant (such as sand or ceramic) that migrate into the fractures with the fracturing fluid slurry and remain to prop open the fractures after pressure is no longer applied to the wellbore. A primary fluid for the slurry other than water, such as nitrogen, carbon dioxide, foam (nitrogen and water), diesel, or other fluids is sometimes used as the primary component instead of water. Typically hydraulic fracturing fleets include a data van unit, blender unit, hydration unit, chemical additive unit, hydraulic fracturing pump unit, sand equipment, and other equipment.

[0003] The process of making the fracturing fluid slurry necessarily includes combining, such as in the blender, hydration unit, chemical additive unit, etc., the individual components of the slurry. Such operation can be dangerous to operating personnel. For example, moving proppant into the blender unit can generate silica dust which, if inhaled by personnel, can cause permanent damage to the lungs. Common proppant types include silica sand, resin coated sand, and ceramic beads. Ceramic can be very harmful to inhale, and typically consists of very fine particles that become airborne and are difficult to filter out. Resin coated sand is the most dangerous and harmful to inhale since the resin coating can chip off and become airborne dust particles. Silica itself is very harmful to inhale as well.

[0004] Other components, such as chemicals, can be damaging and present hazards as well. One dangerous source of chemical contact comes from residue on tankers, trailer decks, reused hoses and camlock fittings, or leaky valves. In addition, there is always a risk for a major hose or chemical pump failure, or a tank/tote puncture. Some chemicals (such as, for example the viscosifier guar gel, and some friction reducers) can be hazardous because of how slick and slippery they are. Thus, a small amount on the skin, clothing, ground, or equipment can cause personnel to slip and fall, or lose their grip while climbing ladders, leading to injuries.

[0005] In addition, chemicals such as acids and breakers (for breaking down viscosifiers) are extremely corrosive to skin, damaging to inhale, can cause blindness, and other immediate hazards. Chemicals such as breakers are also very flammable, which becomes a hazard if there is a chance of contact with, for example, diesel fuel or gasoline. On diesel powered fracturing sites, it is very common for personnel to have diesel or oil residue on their hands, boots, or clothes.

[0006] Furthermore, in fracturing operations, it is also common to use biocides to kill bacteria deep in a well, such as to prevent deadly hydrogen sulfide gas build up. Biocides can be very damaging to living tissue, especially if ingested or inhaled. Additional chemicals that are dangerous if ingested or inhaled include stabilizers, pH buffers, and inhibitors.

[0007] In addition to the above, hydraulic fracturing operations can be dangerous for operating personnel because of high pressure and high voltage equipment. For example, high pressure zones are present where the discharge piping leaves the hydraulic fracturing pumps at pressures of up to 15,000 pounds per square inch (psi) or more. If the pipes fail, they can explode, causing shrapnel to fly. Furthermore, iron pipes can shift and pivot with the pressure release striking employees.

[0008] Some voltages in the electric hydraulic fracturing systems can reach up to 13,800 volts or more. Dangers in high voltage zones include arc flashes, fires, electrocution, and explosions. Hazards can result from breaker or cable coupler failures, or even natural gas vapors entering the area. It is desirable, therefore, to design a hydraulic fracturing system to minimize such dangerous exposure of operating personnel.

SUMMARY OF THE INVENTION

[0009] The present technology provides a hydraulic fracturing system for fracturing a subterranean formation, including a pump in communication via pump components with a wellbore that intersects the formation, and that pressurizes fluid in the wellbore, the fluid including a fracturing fluid slurry. The system further includes hydraulic fracturing system components for making the fracturing fluid slurry, and a monitoring system that selectively captures and transmits real time images of at least one of the hydraulic fracturing system

components or pump components to enable remote monitoring of the at least one of the hydraulic fracturing system components or pump components.

[0010] In some embodiments, the monitoring system can include a camera, a controller, a display, a human machine interface, and communication means between the camera, controller, human machine interface, and the monitor. In addition, the display can include a monitor from which the images are viewed. In some example embodiments, the display can be disposed within a passenger compartment mounted to a fluid blender, so that the images can be viewed by operations personnel in the passenger compartment.

[0011] According to some embodiments, the hydraulic fracturing components can be selected from the group consisting of a chemical tanker, a hydration unit, a hopper, a blender unit, and auger associated with a blender unit, a conveyor, and an acid tanker. In addition, the pump components can be selected from the group consisting of intake piping, discharge piping, hoses, fittings, and valves associated with a hydraulic fracturing pump. Furthermore, the monitoring system can include a camera disposed on a trailer, and wherein the hydraulic fracturing components or pump components include hose or pipe connections on the trailer. In alternate embodiments, the monitoring system can include a camera disposed on a first trailer, and wherein the hydraulic fracturing components or pump components include hose or pipe connections on a second trailer that is adjacent the first trailer.

[0012] In some example embodiments, the monitoring system can selectively capture and transmit real time images of a silica exposure zone, or of an opening to a vessel, so that a level within the vessel is discernible in the images. In some embodiments, the vessel can contain proppant, acid, or chemicals.

[0013] Another embodiment of the present technology provides including the steps of driving a pump to pressurize fluid in a hydraulic fracturing system containing hydraulic fracturing components and pump components, fracturing the formation by directing the pressurized fluid into a wellbore that intersects the formation, and monitoring the hydraulic fracturing system. The step of monitoring the hydraulic fracturing system includes obtaining images of hydraulic fracturing components and pump components of the hydraulic fracturing system, and viewing the images remotely.

[0014] In some embodiments, the hydraulic fracturing components and pump components can be disposed in areas where there is a greater possibility of personal injury than where the images are being viewed. In some embodiments, step of obtaining images can be performed by a camera that is disposed adjacent at least one of the hydraulic fracturing components or the pump components, and the step of viewing can be performed within an enclosure.

[0015] In certain other embodiments, the method can include selectively obtaining images of different hydraulic fracturing components or pump components on a single monitor. Furthermore, the hydraulic fracturing components and pump components can include discharge piping that is in fluid communication with the pump, and vessel openings, and the images of the hydraulic fracturing system can include images of at least one of a silica exposure zone, hose connections,a high pressure zone that includes discharge pumps or discharge pipes or both, a chemical exposure zone, high voltage zones, and natural gas supply piping.

BRIEF DESCRIPTION OF DRAWINGS

[0016] Some of the features and benefits of the present invention having been stated, others will become apparent as the description proceeds when taken in conjunction with the accompanying drawings, in which:

[0017] FIG. 1 is a schematic example of a hydraulic fracturing system for use in fracturing a subterranean formation.

[0018] FIG. 2 is a plan schematic view of an alternate example of the system of FIG. 1, and which includes examples of visual monitoring equipment.

[0019] FIG. 3 is a perspective view of an example of a visual monitoring device mounted on a blender, where the blender is included with the hydraulic fracturing system of FIG. 1.

[0020] FIGS. 4 and 5 are perspective views of an example of a monitor displaying images captured by a visual monitoring device.

[0021] FIGS. 6 and 7 are lower and upper views of an example of a visual monitoring device that is mounted on the blender of FIG. 3.

[0022] While the invention will be described in connection with the preferred embodiments, it will be understood that it is not intended to limit the invention to that embodiment. On the contrary, it is intended to cover all alternatives, modifications, and equivalents, as may be included within the spirit and scope of the invention as defined by the appended claims.

DETAILED DESCRIPTION OF INVENTION

[0023] The method and system of the present disclosure will now be described more fully hereinafter with reference to the accompanying drawings in which embodiments are shown. The method and system of the present disclosure may be in many different forms and should not be construed as limited to the illustrated embodiments set forth herein; rather, these embodiments are provided so that this disclosure will be thorough and complete, and will fully convey its scope to those skilled in the art. Like numbers refer to like elements throughout. In an embodiment, usage of the term "about" includes +/- 5% of the cited magnitude. In an embodiment, usage of the term "substantially" includes +/- 5% of the cited magnitude.

[0024] It is to be further understood that the scope of the present disclosure is not limited to the exact details of construction, operation, exact materials, or embodiments shown and described, as modifications and equivalents will be apparent to one skilled in the art. In the drawings and specification, there have been disclosed illustrative embodiments and, although specific terms are employed, they are used in a generic and descriptive sense only and not for the purpose of limitation.

[0025] Figure 1 is a schematic example of a hydraulic fracturing system 10 that is used for pressurizing a wellbore 12 to create fractures 14 in a subterranean formation 16 that surrounds the wellbore 12. Included with the system 10 is a hydration unit 18 that receives fluid from a fluid source 20 via line 22, and also selectively receives additives from an additive source 24 via line 26. Additive source 24 can be separate from the hydration unit 18 as a stand-alone unit, or can be included as part of the same unit as the hydration unit 18. The fluid, which in one example is water, is mixed inside of the hydration unit 18 with the additives. In an embodiment,

the fluid and additives are mixed over a period of time, to allow for uniform distribution of the additives within the fluid. In the example of Figure 1, the fluid and additive mixture is transferred to a blender unit 28 via line 30. A proppant source 32 contains proppant, which is delivered to the blender unit 28 as represented by line 34, where line 34 can be a conveyer. Inside the blender unit 28, the proppant and fluid/additive mixture are combined to form a fracturing slurry, which is then transferred to a fracturing pump system 36 via line 38; thus fluid in line 38 includes the discharge of blender unit 28 which is the suction (or boost) for the fracturing pump system 36.

[0026] Blender unit 28 can have an onboard chemical additive system, such as with chemical pumps and augers. Optionally, additive source 24 can provide chemicals to blender unit 28; or a separate and standalone chemical additive system (not shown) can be provided for delivering chemicals to the blender unit 28. In an example, the pressure of the slurry in line 38 ranges from around 80 psi to around 100 psi. The pressure of the slurry can be increased up to around 15,000 psi by pump system 36. A motor 39, which connects to pump system 36 via connection 40, drives pump system 36 so that it can pressurize the slurry. In one example, the motor 39 is controlled by a variable frequency drive ("VFD").

[0027] After being discharged from pump system 36, slurry is pumped into a wellhead assembly 41. Discharge piping 42 connects discharge of pump system 36 with wellhead assembly 41 and provides a conduit for the slurry between the pump system 36 and the wellhead assembly 41. In an alternative, hoses or other connections can be used to provide a conduit for the slurry between the pump system 36 and the wellhead assembly 41. Optionally, any type of fluid can be pressurized by the fracturing pump system 36 to form injection fracturing fluid that is then

pumped into the wellbore 12 for fracturing the formation 14, and is not limited to fluids having chemicals or proppant.

[0028] An example of a turbine 44 is provided in the example of Figure 1. The turbine can be gas powered, receiving a combustible fuel from a fuel source 46 via a feed line 48. In one example, the combustible fuel is natural gas, and the fuel source 46 can be a container of natural gas or a well (not shown) proximate the turbine 44. Combustion of the fuel in the turbine 44 in turn powers a generator 50 that produces electricity. Shaft 52 connects generator 50 to turbine 44. The combination of the turbine 44, generator 50, and shaft 52 define a turbine generator 53. In another example, gearing can also be used to connect the turbine 44 and generator 50.

[0029] An example of a micro-grid 54 is further illustrated in Figure 1, and which distributes electricity generated by the turbine generator 53. Included with the micro-grid 54 is a transformer 56 for stepping down voltage of the electricity generated by the generator 50 to a voltage more compatible for use by electrically powered devices in the hydraulic fracturing system 10. In another example, the power generated by the turbine generator and the power utilized by the electrically powered devices in the hydraulic fracturing system 10 are of the same voltage, such as 4160 V, so that main power transformers are not needed. In one embodiment, multiple 3500 kVA dry cast coil transformers are utilized. Electricity generated in generator 50 is conveyed to transformer 56 via line 58. In one example, transformer 56 steps the voltage down from 13.8 kV to around 600 V. Other step down voltages can include 4,160 V, 480 V, or other voltages.

[0030] The output or low voltage side of the transformer 56 connects to a power bus 60, lines 62, 64, 66, 68, 70, and 71 connect to power bus 60 and deliver electricity to electrically powered

components of the system 10. More specifically, line 62 connects fluid source 20 to bus 60, line 64 connects additive source 24 to bus 60, line 66 connects hydration unit 18 to bus 60, line 68 connects proppant source 32 to bus 60, line 70 connects blender unit 28 to bus 60, and line 71 connects bus 60 to an optional variable frequency drive ("VFD") 72. Line 73 connects VFD 72 to motor 39. In one example, VFD 72 can be used to control operation of motor 39, and thus also operation of pump 36.

[0031] In an example, additive source 24 contains ten or more chemical pumps for supplementing the existing chemical pumps on the hydration unit 18 and blender unit 28. Chemicals from the additive source 24 can be delivered via lines 26 to either the hydration unit 18 and/or the blender unit 28. In one embodiment, the elements of the system 10 are mobile and can be readily transported to a wellsite adjacent the wellbore 12, such as on trailers or other platforms equipped with wheels or tracks.

[0032] Referring now to Figure 2 shown in a plan schematic view is an example of the hydraulic fracturing system 10 as arranged at a well site 80. In this example, a series of cameras $82_{1\text{-}13}$ are shown strategically located about the system 10 in order to capture real time images of designated portions of the hydraulic fracturing system 10. Image zones $84_{1\text{-}13}$ are shown that are associated with each of the cameras $82_{1\text{-}13}$ and depict an example of objects in an area or space whose image is captured by the cameras $82_{1\text{-}13}$. Cameras $82_{1,2}$ of Figure 2 are depicted mounted respectively on chemical tankers $86_{1,2}$ and are oriented so that their respective image zones $84_{1,2}$ encompass rear portions of the chemical tankers $86_{1,2}$. Thus the image(s) captured by cameras $82_{1,2}$ includes images of the rear portions of the chemical tankers $86_{1,2}$. Specific hardware imaged in one example of the image zones $84_{1,2}$ include hose connections and booster pumps (not shown) on the rear of these tankers $86_{1,2}$. Optionally, the image zones $84_{1,2}$ may extend to an

adjacent chemical trailer 88 shown adversely located adjacent tankers $86_{1,2}$. Mounted on hydration unit 18 is camera 82_3 whose image zone 84_3 covers a rear portion of chemical tanker 88; images captured by camera 82_3 may be analyzed for leaks or failed hose connections. Trailer mounted blender units $28_{1,2}$ are shown disposed on a side of hydration unit 18 and opposite from chemical trailer 88. Ends of the trailers includes hoppers $90_{1,2}$ that selectively contain sand or proppant that is drawn from the hoppers $90_{1,2}$ with auger sets $92_{1,2}$. Cameras $82_{6,7}$ are mounted on augers $92_{1,2}$, and wherein the associated image zones $84_{6,7}$ of the cameras $86_{6,7}$ includes the hoppers $90_{1,2}$. Thus, analyzing information collected by cameras $82_{6,7}$ can provide information indicating a level of sand or proppant within hoppers $90_{1,2}$, without an operator approaching the hoppers $90_{1,2}$.

[0033] As described above, the sand or proppant drawn from hoppers $90_{1,2}$ by augers $94_{1,2}$ is deposited within tubs $94_{1,2}$ where it can be mixed with fluids in order to form a slurry. Cameras $82_{4,5}$ are mounted on blender units $28_{1,2}$ respectively, and have image zones $84_{4,5}$ that capture the opening of the hoppers $90_{1,2}$. Thus analyzing data or images captured by cameras $82_{4,5}$ provides information real time about the level of the slurry mixture within hoppers $90_{1,2}$, again without an operator approaching the hoppers $90_{1,2}$.

[0034] Camera 82_9 is shown mounted on a dust collector 96 which is disposed adjacent an end of conveyor 34 that is distal from blender units $28_{1,2}$. The image zone 84_9 encompasses an end of conveyor 34 distal from blender units $28_{1,2}$. Silos $98_{1\text{-}5}$ or other proppant dispensers are shown disposed on alternating sides of conveyor 34 and which can be used to dispense sand or proppant onto conveyor 34, which then deposits the sand or proppant into the hoppers $90_{1,2}$. Camera 82_8 has a corresponding image zone 84_8 that captures information along conveyor 34 proximate to hoppers $90_{1,2}$ and distal from dust collector 96. Shown having an end proximate where conveyor

34 interfaces with hoppers $90_{1,2}$ is an acid tanker 100 which can optionally be used to deposit acidic material into the fluid being deposited into the wellbore 12 (Figure 1). Camera 82_{11} is mounted on acid tanker 100 and shown having an image zone 84_{11} that encompasses openings on the acid tanker 100 so that levels of material within acid tanker 100 can be monitored by viewing images captured by camera 82_{11}. Camera 82_{11} can be useful to make sure the acid tanker 100 does not overflow, which condition could be caused by a valve failure and resultant fluid backflush. Typically, an operator monitors the acid tanker, and regularly gives hand signals to indicate the operating conditions of the acid tanker 100. Hand signals are preferable to radios when communicating such information, since the operator near the acid tanker typically dresses in protective clothing that can make it difficult to use a radio. Camera 82_{11} can be used either to view the acid tanker itself, or also to view the operator displaying hand signals.

[0035] Arranged in rows and transverse to acid tanker 100 are pump trucks $102_{1\text{-}12}$, which make up the pump system 36 for pressurizing the slurry so that it can be injected into wellhead 41. Discharge piping 42 is shown extending along a path adjacent each of the pump trucks $102_{1\text{-}12}$ and having an end connected to wellhead assembly 41. Cameras $82_{10,12}$ are shown with image zones $84_{10,12}$ that cover hoses, fittings, and an area where discharge leads from the specific pumps on the pump trucks $102_{1,12}$ interface with discharge piping 42. While a pair of cameras $82_{10,12}$ are illustrated, cameras may be provided for each pair of the pump trucks $102_{1,12}$ or each one individually. Shown spaced away from the rows of pump trucks $102_{1\text{-}12}$ is a data van 104 and on which camera 82_{13} is mounted. The corresponding image zone 84_{13} of camera 82_{13} is directed towards wellhead assembly 41 and can observe the wellhead assembly 41 as well as all discharge piping 42 and at least some of the leads connecting to piping 42. Thus situated, camera 82_{13} allows personnel to stay out of the high pressure zones around the pumps. This is useful because

is a pipe fails at high pressure, it can seriously injure personnel with, for example, flying shrapnel.

[0036] Shown in an end perspective view in Figure 3 is an example of camera $82_{6,7}$ mounted on one of the auger elements that make up auger system $92_{1,2}$. Here each of the auger elements includes a tube and a screw-like member that rotates within the tube in order to urge the proppant upward from the hopper $90_{1,2}$ and into hopper $94_{1,2}$ (Figure 2). Further illustrated in Figure 3 is an example of a hydraulic system 106 for raising and lowering the auger system, $92_{1,2}$. As shown, camera $82_{6,7}$ is mounted to one of the auger tubes via a bolted connection.

[0037] Figure 4 illustrates an example of viewing an image of hopper $90_{1,2}$ within a blender cab $108_{1,2}$ that is part of the blender unit $28_{1,2}$ (Figure 2). A monitor $110_{1,2}$ is mounted within cab $108_{1,2}$ that is in communication with camera $82_{6,7}$. Accordingly, a designated portion within system 10 (Figure 2) can be remotely viewed by operations personnel in an enclosed space and away from an area that may present hazards to personnel. Alternately, this camera feed can also be viewed within the datavan.

[0038] Figure 5 illustrates one example where operations personnel can selectively change the image being viewed to that of a separate camera. For example, within cab $108_{1,2}$, monitor $110_{1,2}$ is displaying an example of mixing tub $94_{1,2}$. In an example, changing the display on the monitor $110_{1,2}$ to view other images is accomplished by an operator manipulating a human machine interface ("HMI") which can be a keyboard, joystick, panel, or any other device that allows a user to adjust operation or control of what is being viewed on monitor $110_{1,2}$. Again, the image of the tub $94_{1,2}$ is being remotely viewed in an enclosed space that is away from a potentially hazardous area.

LIBERTY EXHIBIT 1002, Page 657

[0039] Figure 6 illustrates an example of camera $82_{4,5}$ mounted on blender unit $28_{1,2}$ (Figure 2) and outside of cab $108_{1,2}$. Here, the end of the camera $82_{4,5}$ having a lens is pointing away from cab $108_{1,2}$ and mounting hardware in brackets are shown suspending camera $82_{4,5}$ at a strategically located orientation so that designated portions can be monitored with camera $82_{4,5}$.

[0040] Figure 7 shows in a perspective view an example of camera $82_{4,5}$ taken from a rear view and having lead $112_{4,5}$ leading from camera $82_{4,5}$ so that images captured by camera $82_{4,5}$ can be processed and transmitted to a location that is remote to camera $82_{4,5}$ for viewing.

[0041] Referring back to Figure 2, a schematic example of monitoring system 114 is shown which includes cameras $82_{1\text{-}13}$, monitor 110, a communication means 116, controller 118, and human machine interface 120. Communication means 116 can be any form of communicating data that represents images within system 114, and can be wireless, hard-wired, or fiber optic material. Controller 118 can be an information handling system, and may include a processor, memory accessible by the processor, non-volatile storage area accessible by the processor, and logics for performing each of the steps required for operation of the controller 118.

[0042] Advantages of the monitoring system 114 described herein are that all parts of silica exposure zones, including the silos $98_{1\text{-}5}$, or any other sand storage container, sand conveyor, and dust vacuum system, can be monitored without the requirement for operations personnel to enter this region, thereby shielding personnel from harmful silica dust. Moreover, high-pressure zones where high-pressure fluid is being pumped within piping can be imaged without requiring operations personnel to be proximate the piping when high pressure fluid is within the piping. Chemical areas can also be monitored remotely and so that operations personnel are not subject to exposure to hazardous chemicals. Moreover, areas of the system 10 that contain cables at a

high voltage may also be remotely monitored thereby avoiding the need for personnel to enter these zones. In addition, cameras can be used to monitor fuel gas lines for the turbines that power the electric motors on an electric fleet. In one optional embodiment, mounts for the cameras 82_{1-13} are able to pivot on two axes and can be adjusted up down and left and right. The imaging can be displayed on video and discernible by operations personnel such that visual images reproduced real time. In one alternative, infrared imaging is performed.

[0043] The present invention described herein, therefore, is well adapted to carry out the objects and attain the ends and advantages mentioned, as well as others inherent therein. While a presently preferred embodiment of the invention has been given for purposes of disclosure, numerous changes exist in the details of procedures for accomplishing the desired results. These and other similar modifications will readily suggest themselves to those skilled in the art, and are intended to be encompassed within the spirit of the present invention disclosed herein and the scope of the appended claims.

CLAIMS

What is claimed is.

1. A hydraulic fracturing system for fracturing a subterranean formation comprising:

a pump in communication via pump components with a wellbore that intersects the formation, and that pressurizes fluid in the wellbore, the fluid comprising a fracturing fluid slurry;

hydraulic fracturing system components for making the fracturing fluid slurry; and

a monitoring system that selectively captures and transmits real time images of at least one of the hydraulic fracturing system components or pump components to enable remote monitoring of the at least one of the hydraulic fracturing system components or pump components.

2. The hydraulic fracturing system of Claim 1, wherein the monitoring system comprises:

a camera;

a controller;

a display;

a human machine interface; and

communication means between the camera, controller, human machine interface, and the monitor.

3. The hydraulic fracturing system of Claim 1, wherein the display comprises a monitor from which the images are viewed.

4. The hydraulic fracturing system of Claim 3, wherein the display is disposed within a passenger compartment mounted to a fluid blender, so that the images can be viewed by operations personnel in the passenger compartment.

5. The hydraulic fracturing system of Claim 1, wherein the hydraulic fracturing components are selected from the group consisting of a chemical tanker, a hydration unit, a hopper, a blender unit, and auger associated with a blender unit, a conveyor, and an acid tanker.

6. The hydraulic fracturing system of Claim 1, wherein the pump components are selected from the group consisting of intake piping, discharge piping, hoses, fittings, and valves associated with a hydraulic fracturing pump.

7. The hydraulic fracturing system of Claim 1, wherein the monitoring system comprises a camera disposed on a trailer, and wherein the hydraulic fracturing components or pump components comprise hose or pipe connections on the trailer.

8. The hydraulic fracturing system of Claim 1, wherein the monitoring system comprises a camera disposed on a first trailer, and wherein the hydraulic fracturing components or pump components comprise hose or pipe connections on a second trailer that is adjacent the first trailer.

9. The hydraulic fracturing system of Claim 1, wherein the monitoring system selectively captures and transmits real time images of a silica exposure zone.

10. The hydraulic fracturing system of Claim 1, wherein the monitoring system selectively captures and transmits real time images of an opening to a vessel, so that a level within the vessel is discernable in the images.

11. The hydraulic fracturing system of Claim 10, wherein the vessel contains proppant.

12. The hydraulic fracturing system of Claim 10, wherein the vessel contains acid.

13. The hydraulic fracturing system of Claim 10, wherein the vessel contains chemicals.

14. A method of fracturing a subterranean formation comprising:

driving a pump to pressurize fluid in a hydraulic fracturing system containing hydraulic fracturing components and pump components;

fracturing the formation by directing the pressurized fluid into a wellbore that intersects the formation; and

monitoring the hydraulic fracturing system by:

obtaining images of hydraulic fracturing components and pump components of the hydraulic fracturing system; and

viewing the images remotely.

15. The method of Claim 14, wherein the hydraulic fracturing components and pump components are disposed in areas where there is a greater possibility of personal injury than where the images are being viewed.

16. The method of Claim 14, wherein the step of obtaining images is performed by a camera that is disposed adjacent at least one of the hydraulic fracturing components or the pump components.

17. The method of Claim 16, wherein the step of viewing is performed within an enclosure.

18. The method of Claim 14, further comprising:

selectively obtaining images of different hydraulic fracturing components or pump components on a single monitor.

19. The method of Claim 14, wherein the hydraulic fracturing components and pump components comprise discharge piping that is in fluid communication with the pump, and vessel openings, and wherein the images if of the hydraulic fracturing system include images of at least one of a silica exposure zone, hose connections, a high pressure zone that includes discharge pumps or discharge pipes or both, a chemical exposure zone, high voltage zones, and natural gas supply piping.

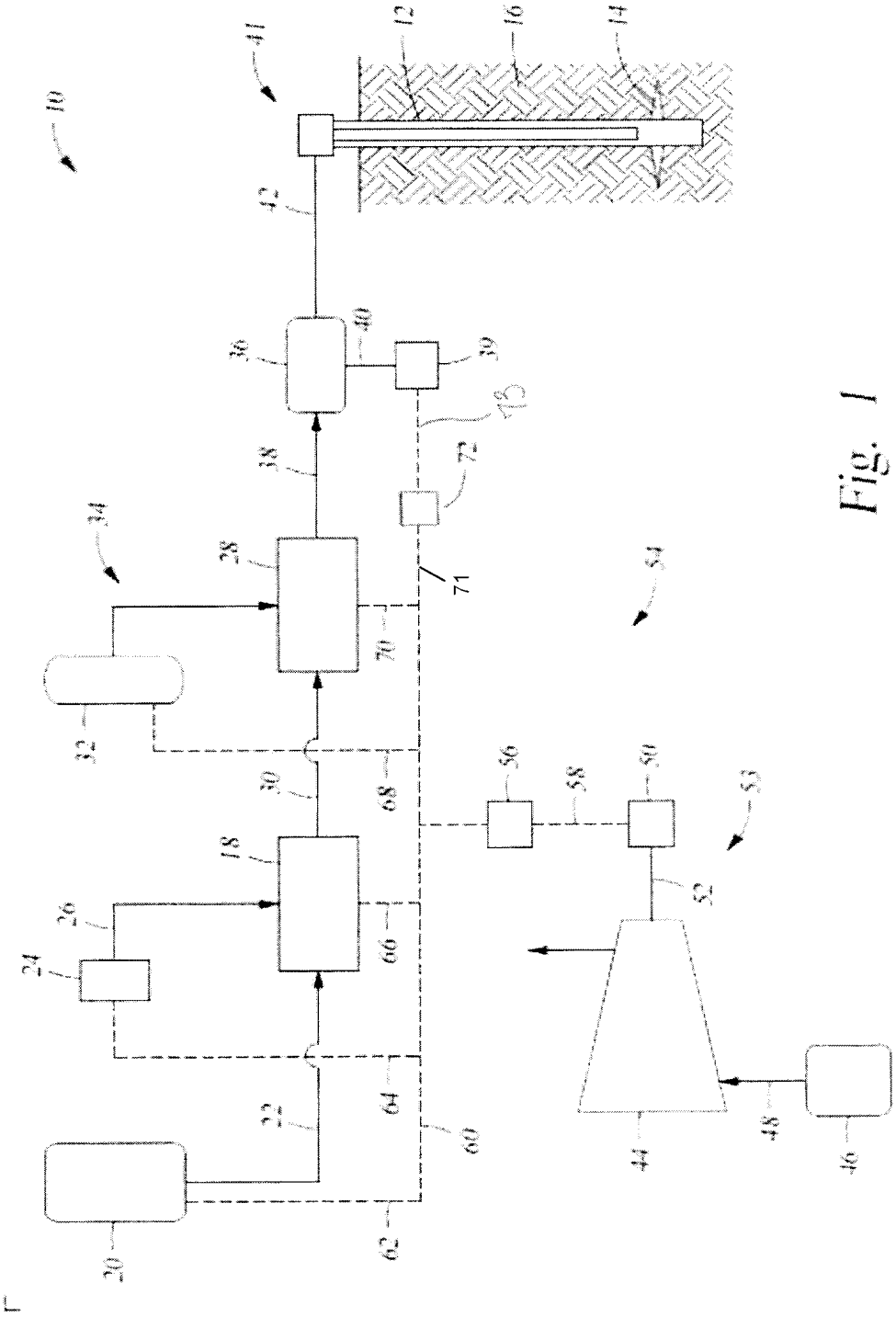

10
12
14
16
41
42
36
38
40
39
15
72
71
34
28
70
32
54
30
68
56
58
60
53
18
26
24
66
52
22
64
60
20
62
44
48
46

Fig. 1

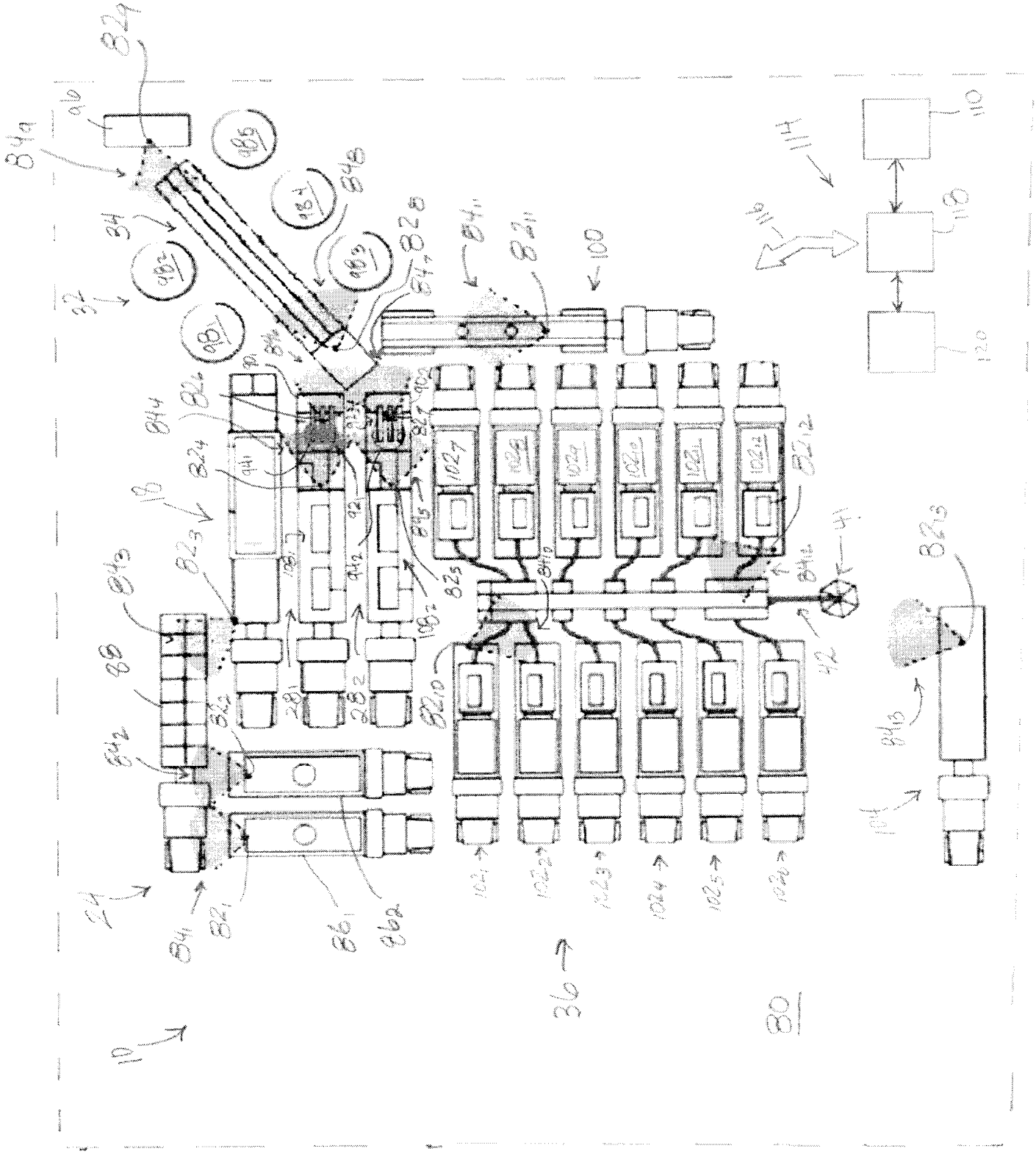
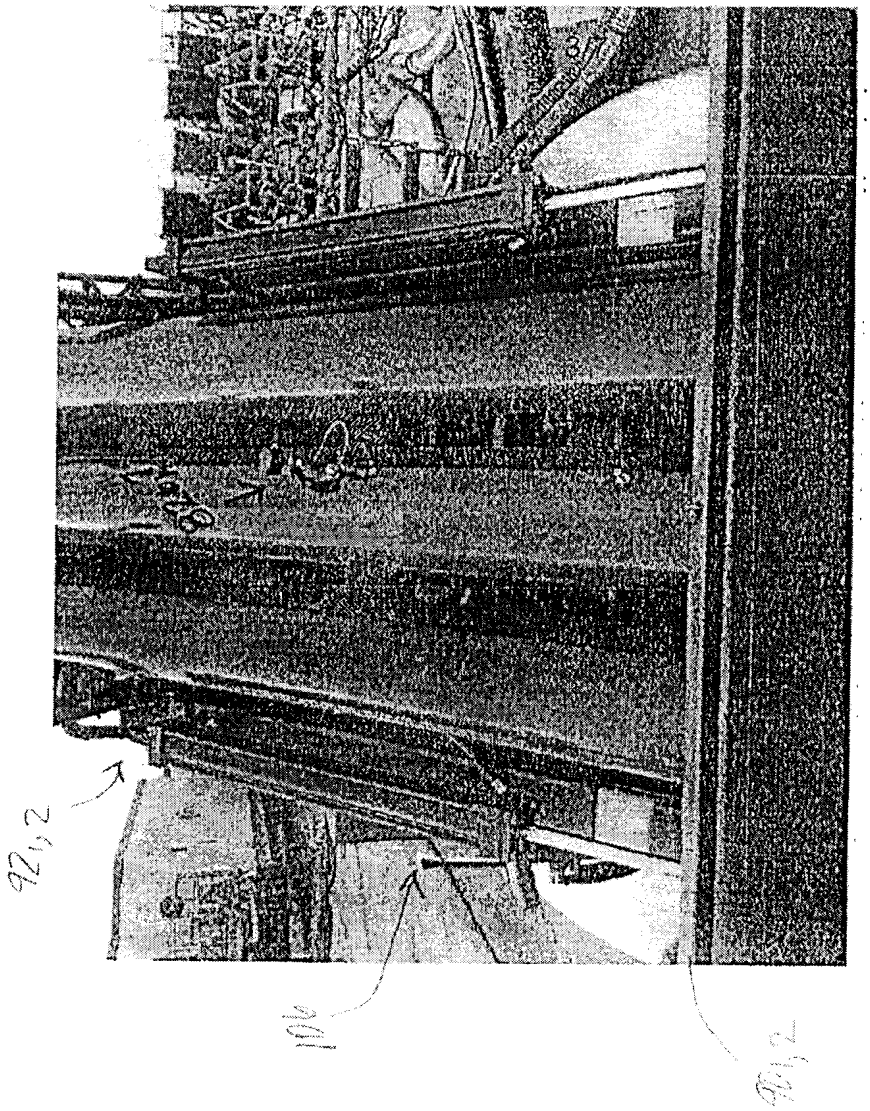


FIG. 2


92, 2
104
90, 2
Fig. 3

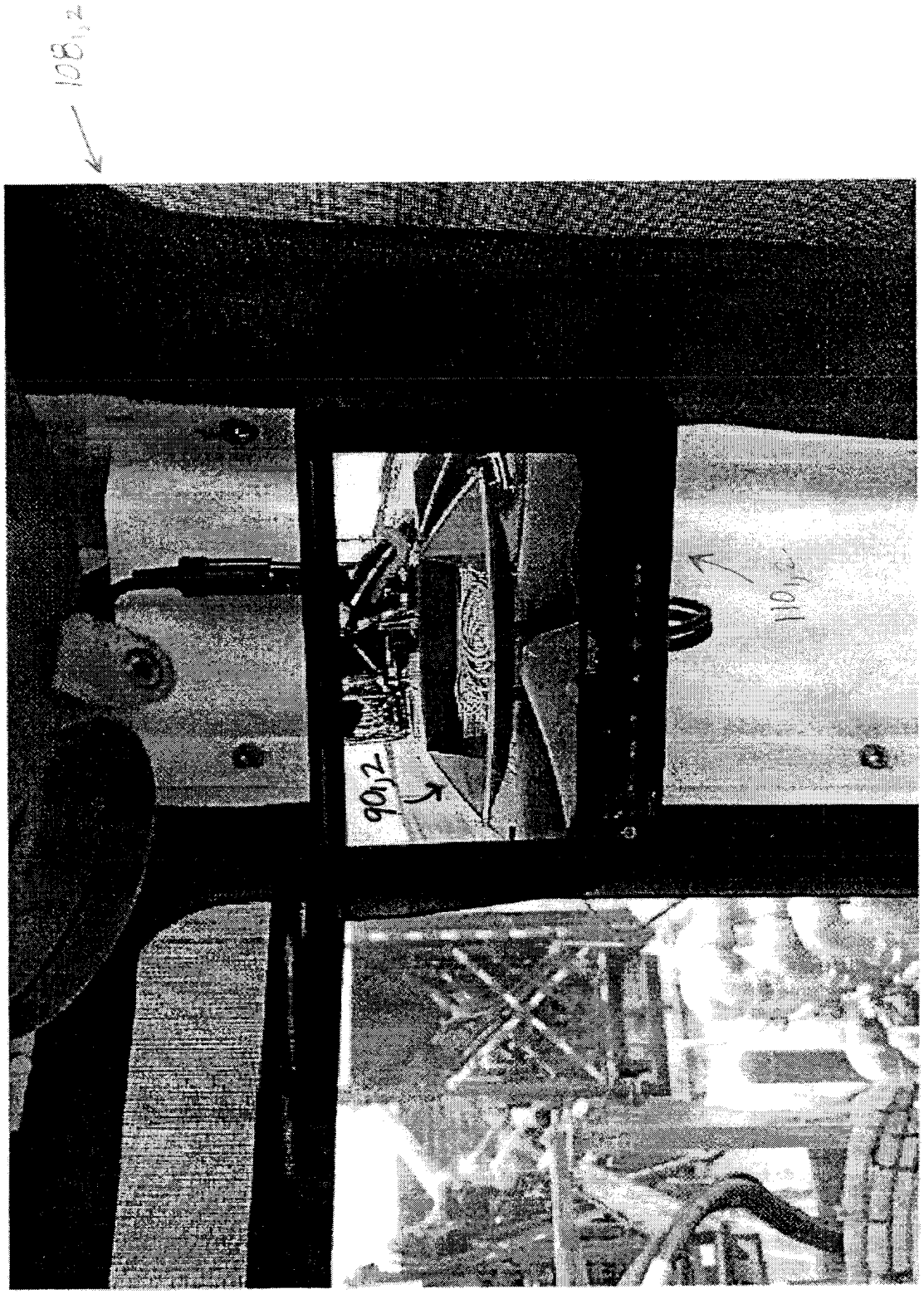


FIG. 4

FIG. 5

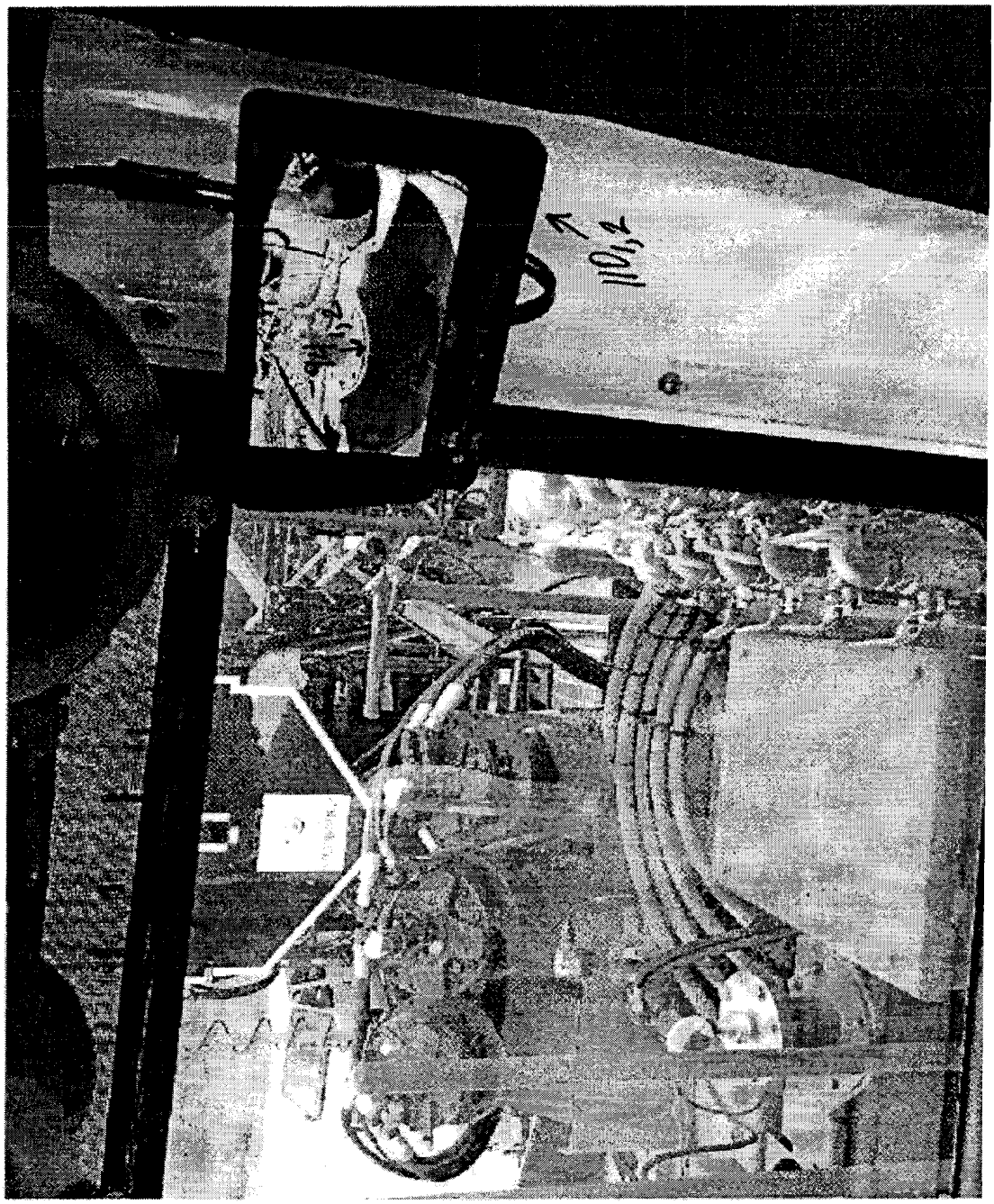


Fig. 6

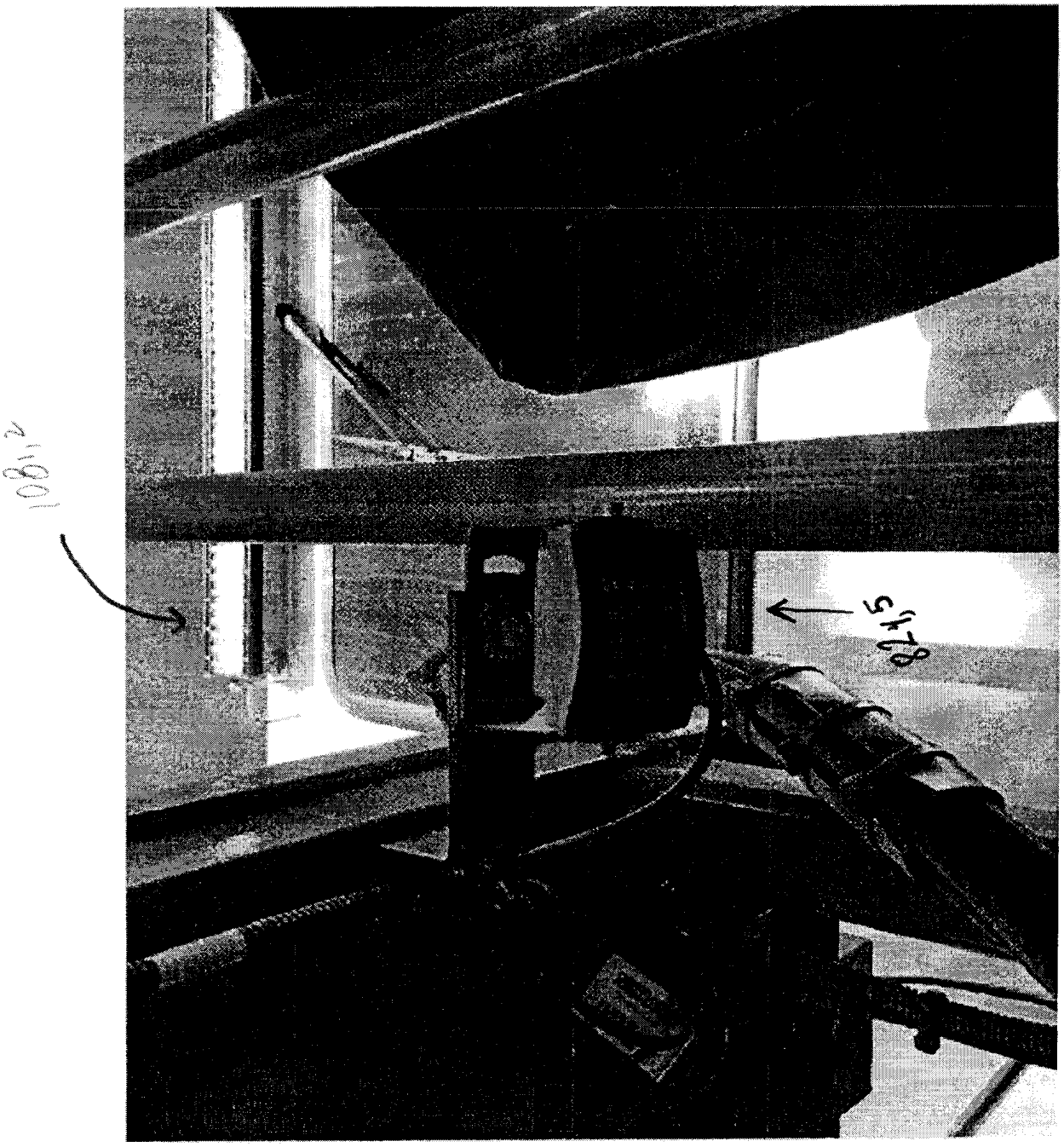
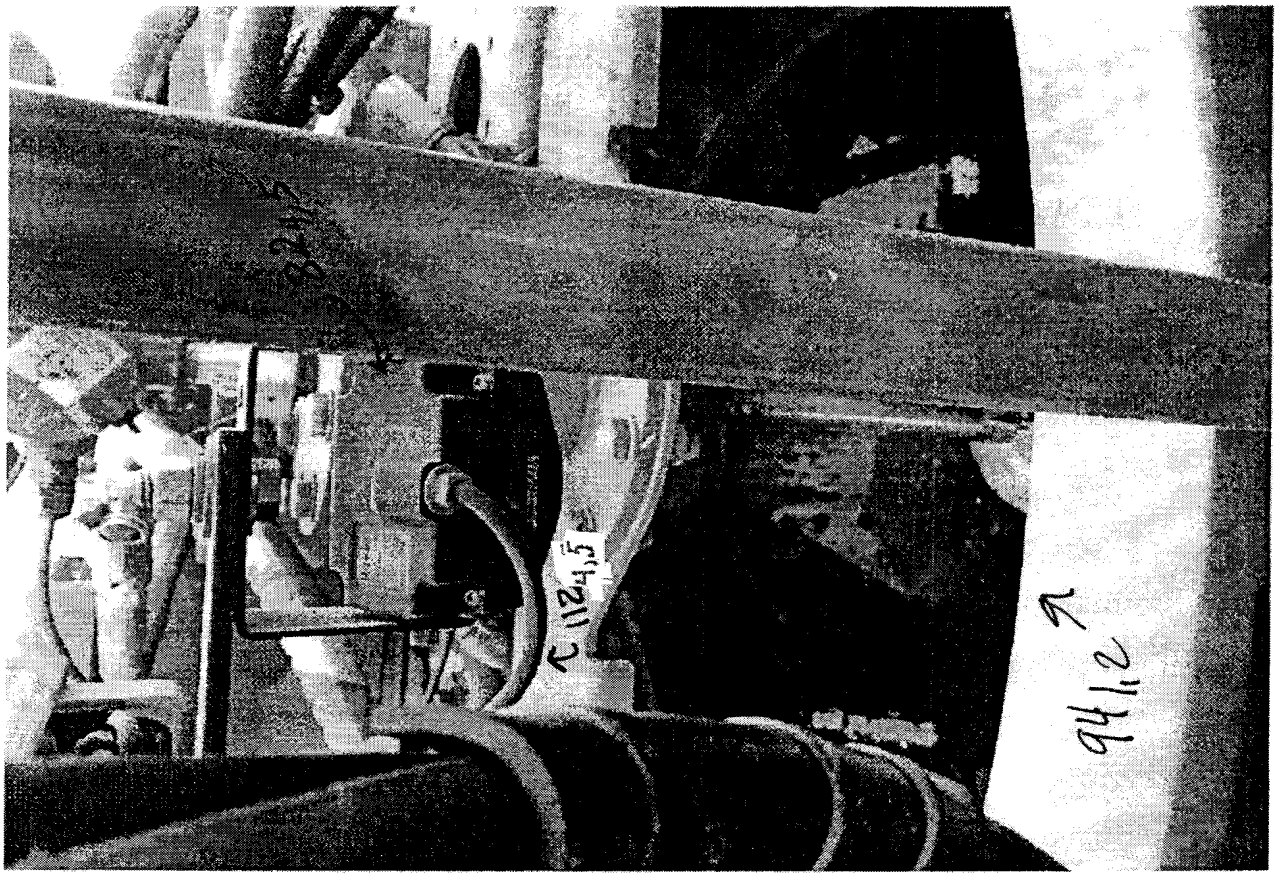
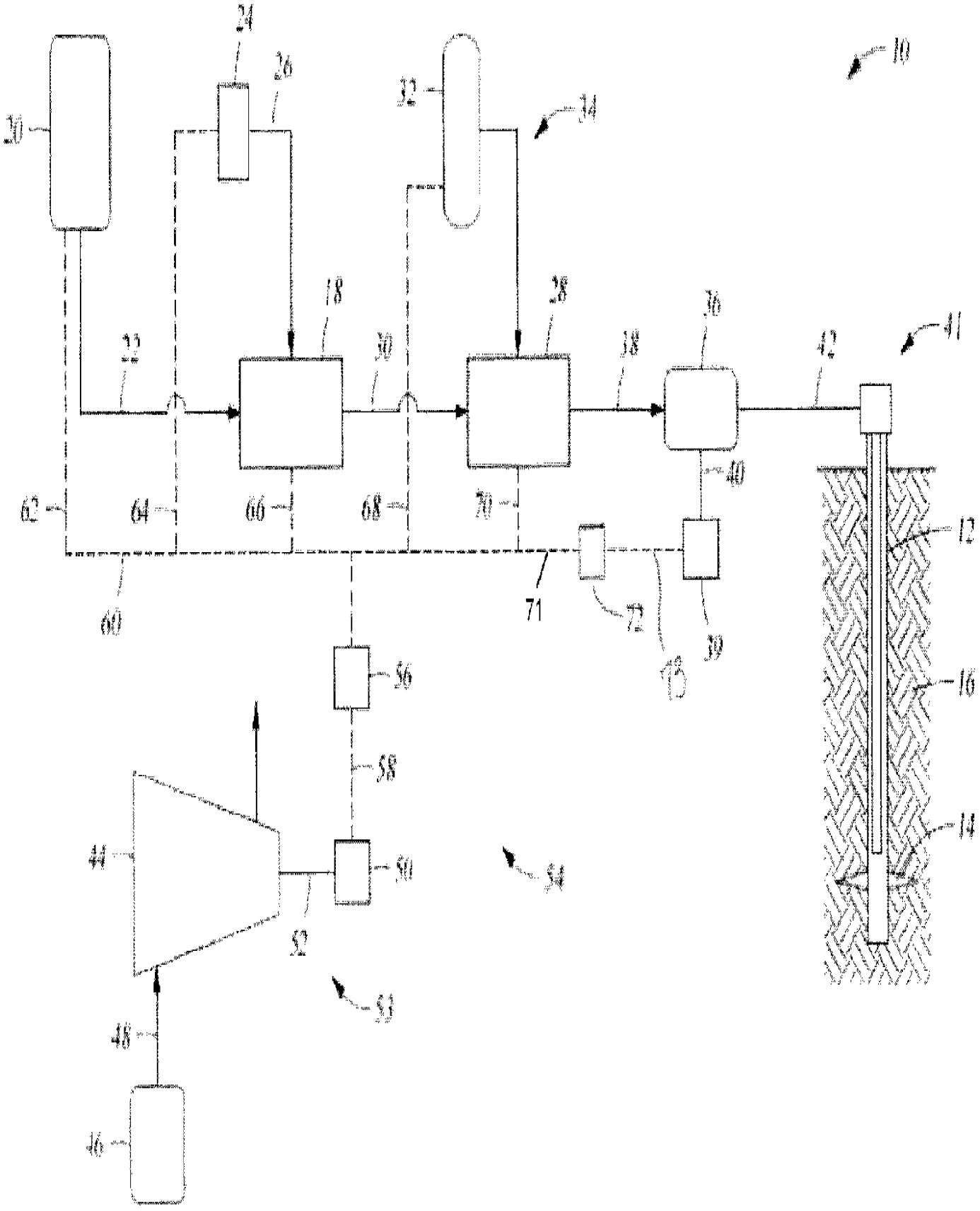


FIG. 7




24
26
32
34
10
20
18
28
36
41
22
30
38
42
40
62
64
66
68
70
12
71
72
60
39
56
16
58
44
50
54
14
52
53
48
46

Office de la Propriété Intellectuelle du Canada
Un organisme d'Industrie Canada

Canadian Intellectual Property Office
An agency of Industry Canada

CA 2978706 A1 2016/09/09

(21) 2 978 706

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(86) Date de dépôt PCT/PCT Filing Date: 2016/03/03
(87) Date publication PCT/PCT Publication Date: 2016/09/09
(85) Entrée phase nationale/National Entry: 2017/09/05
(86) N° demande PCT/PCT Application No.: US 2016/020724
(87) N° publication PCT/PCT Publication No.: 2016/141205
(30) Priorité/Priority: 2015/03/04 (US62/128,291)

(51) Cl.Int./Int.Cl. *E21B 44/00* (2006.01),
E21B 43/26 (2006.01)

(71) Demandeur/Applicant:
STEWART & STEVENSON, LLC, US

(72) Inventeurs/Inventors:
PAYNE, MARK, US;
LIN, HAOMIN, US;
ROBERTSON, TOM, US

(74) Agent: OSLER, HOSKIN & HARCOURT LLP

(54) Titre : SYSTEMES DE FRACTURATION DE PUITS A MOTEURS ELECTRIQUES ET PROCEDES D'UTILISATION
(54) Title: WELL FRACTURING SYSTEMS WITH ELECTRICAL MOTORS AND METHODS OF USE

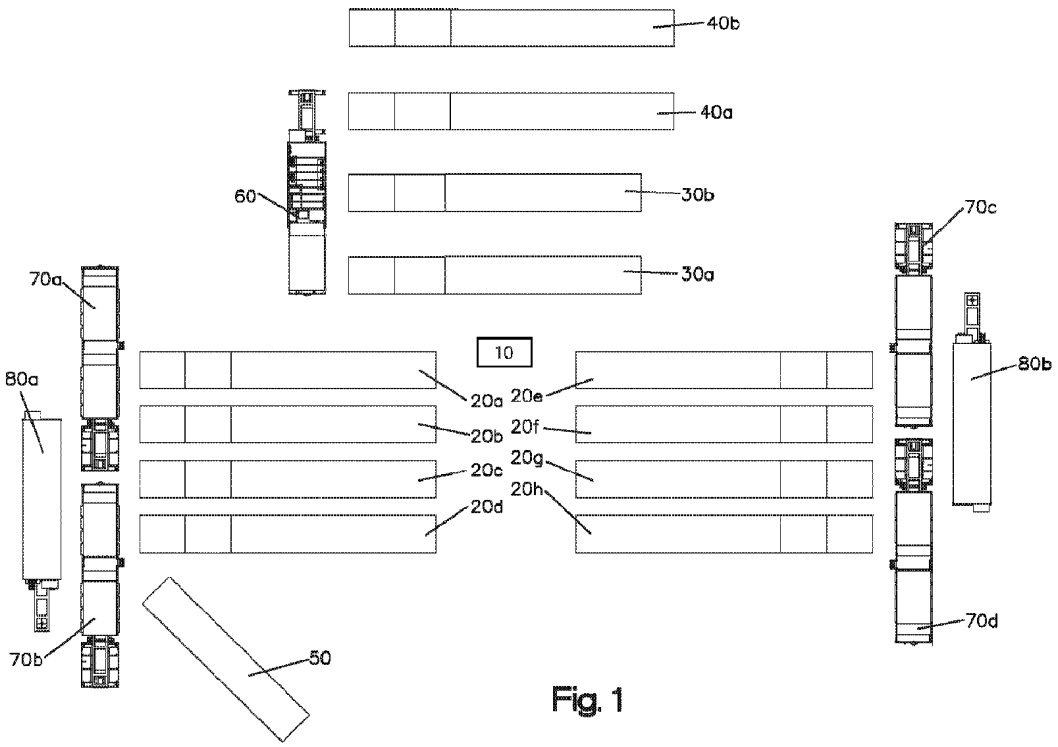


Fig. 1

(57) Abrégé/Abstract:
A system for stimulating oil or gas production from a wellbore includes a hydraulic fracturing pump unit having one or more hydraulic fracturing pumps driven by one or more electrical fracturing motors, a variable frequency drive (VFD) controlling the electrical fracturing motors, a fracturing pump blower unit driven by a blower motor, and a fracturing pump lubrication unit having a lubrication pump driven by a lubrication motor and a cooling fan driven by a cooling motor. The system may further include a blender unit and a hydration unit. A system control unit may control the operational parameters of the system.

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
9 September 2016 (09.09.2016)

WIPO | PCT

(10) International Publication Number
WO 2016/141205 A3

(51) International Patent Classification:
B01F 15/02 (2006.01) *E21B 43/26* (2006.01)
E21B 41/00 (2006.01)

(21) International Application Number:
PCT/US2016/020724

(22) International Filing Date:
3 March 2016 (03.03.2016)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
62/128,291 4 March 2015 (04.03.2015) US

(71) Applicant: **STEWART & STEVENSON, LLC** [US/US]; 1000 Louisiana Street, Suite 5900, Houston, TX 77002 (US).

(72) Inventors; and
(71) Applicants : **PAYNE, Mark** [US/US]; 10750 Telge Road, Houston, TX 77095 (US). **LIN, Haomin** [US/US]; 10750 Telge Road, Houston, TX 77095 (US). **ROBERTSON, Tom** [US/US]; 10750 Telge Road, Houston, TX 77095 (US).

(74) Agents: **PHILLIPS, George** et al.; Jones Day, 222 East 41st Street, New York, NY 10017-6702 (US).

(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Published:

— *with international search report (Art. 21(3))*

— *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments (Rule 48.2(h))*

[Continued on next page]

(54) **Title**: WELL FRACTURING SYSTEMS WITH ELECTRICAL MOTORS AND METHODS OF USE

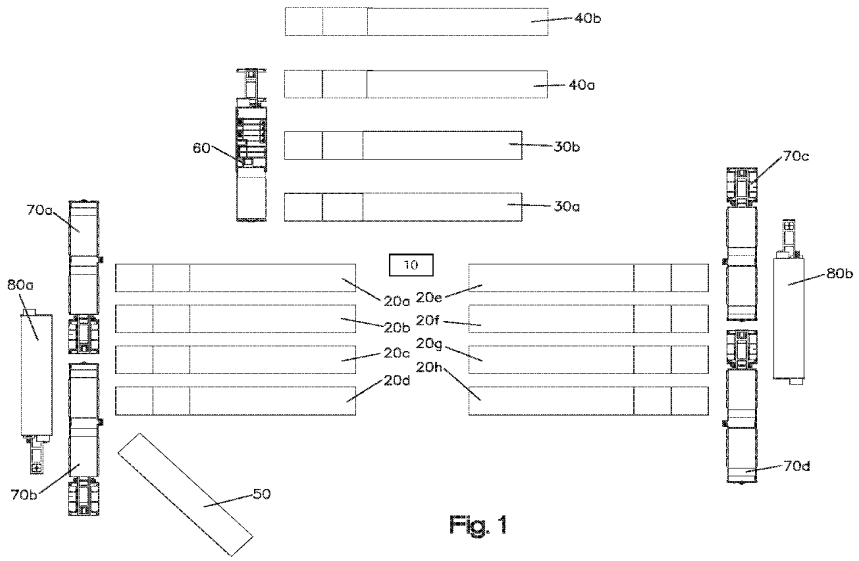


Fig. 1

(57) **Abstract**: A system for stimulating oil or gas production from a wellbore includes a hydraulic fracturing pump unit having one or more hydraulic fracturing pumps driven by one or more electrical fracturing motors, a variable frequency drive (VFD) controlling the electrical fracturing motors, a fracturing pump blower unit driven by a blower motor, and a fracturing pump lubrication unit having a lubrication pump driven by a lubrication motor and a cooling fan driven by a cooling motor. The system may further include a blender unit and a hydration unit. A system control unit may control the operational parameters of the system.

WO 2016/141205 A3

WO 2016/141205 A3

(88) Date of publication of the international search report:
27 October 2016

WELL FRACTURING SYSTEMS WITH ELECTRICAL MOTORS AND METHODS OF USE

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the benefit of U.S. Provisional Application No. 62/128,291, filed on March 4, 2015, which is incorporated herein by reference in its entirety for all purposes.

BACKGROUND

1. Field

[0002] The following description relates to remotely monitoring and controlling electrical motors in oil and gas well stimulation hydraulic fracturing applications. For example, an apparatus and method allows an operator to remotely monitor and control, through wired connections and/or wirelessly, one or more alternating current motors in oil and gas well stimulation hydraulic fracturing applications.

2. Description of Related Art

[0003] Hydraulic fracturing is the process of injecting treatment fluids at high pressures into existing oil or gas wells in order to stimulate oil or gas production. The process involves the high-pressure injection of "fracking fluid" (primarily water, containing sand or other proppants suspended with the aid of thickening agents) into a wellbore to create cracks in the deep-rock formations through which natural gas, petroleum, and brine will flow more freely. When the hydraulic pressure is removed from the well, small grains of hydraulic fracturing proppants (such as sand or aluminum oxide) hold the fractures open. A typical stimulation treatment often requires several high pressure fracturing pumps operating simultaneously to meet pumping rate requirements.

[0004] Hydraulic-fracturing equipment typically consists of one or more slurry blender units, one or more chemical hydration units, one or more fracturing pump units (powerful triplex or quintuplex pumps) and a monitoring unit. Associated equipment includes fracturing tanks, one or more units for storage and handling of proppant and/or chemical additives, and a variety of gauges and meters monitoring flow rate, fluid density, and treating pressure. Fracturing

equipment operates over a range of pressures and injection rates, and can reach 100 megapascals (15,000 psi) and 265 litres per second (9.4 cu ft/s) (100 barrels per minute).

[0005] Hydraulic fracture treatment can be monitored by measuring the pressure and rate during the formation of a hydraulic fracture, with knowledge of fluid properties and proppant being injected into the well. This data, along with knowledge of the underground geology can be used to model information such as length, width and conductivity of a propped fracture. By monitoring the temperature and other parameters of the well, engineers can determine collection rates, and how much fracking fluid different parts of the well use.

[0006] Diesel engines have been used as the primary driving mechanism for fracturing pumps in the past. Using diesel engines, however, has serious disadvantages, including the relative inefficiency of the internal combustion engine and the fact that its operation is costly. In addition, off-road diesel engines of the types used for hydraulic fracturing are noisy while pumping, limiting the areas in which they may be used. Also, diesel engines have many moving parts and require continuous monitoring, maintenance, and diagnostics. Ancillary subsystems are typically driven hydraulically in traditional diesel-driven systems, which also contribute to other operational problems.

[0007] In view of the above deficiencies, electrical motors for hydraulic fracturing operations potentially offer an attractive alternative. Electrical motors are lighter, have fewer moving parts, and can more easily be transported. Further, the control of electrical motors provides many advantages over traditional diesel-driven, variable gear ratio powertrains, for example, through more precise, continuous speed control. During operation, electrical motors may be controlled with specific speed settings and can be incremented or decremented in single RPM (revolutions per minute) intervals without interruption. Also, automatic control operations can allow for the most efficient distribution of power throughout the entire system. The use of electrical motors obviates the need for supplying diesel fuel to more traditional fracturing pumps, and reduces the footprint of the site, and its environmental impact. Other advantages of electrical motors include, but are not limited to, the ability to independently control and operate ancillary subsystems.

[0008] Electrical motors are available in two main varieties, dependent on the methods of voltage flow for transmitting electrical energy: direct current (DC) and alternating current (AC).

With DC current, the current flow is constant and always in the same direction, whereas with AC current the flow is multi-directional and variable. The selection and utilization of AC motors offers lower cost operation for higher power applications. In addition, AC motors are generally smaller, lighter, more commonly available, and less expensive than equivalent DC motors. AC motors require virtually no maintenance and are preferred for applications where reliability is critical.

[0009] Additionally, AC motors are better suited for applications where the operating environment may be wet, corrosive or explosive. AC motors are better suited for applications where the load varies greatly and light loads may be encountered for prolonged periods. DC motor commutators and brushes may wear rapidly under this condition. VFD drive technology used with AC motors has advanced significantly in recent times to become more compact, reliable and cost-effective. DC drives had a cost advantage for a number of years, but that has changed with the development of new power electronics like IGBT's (Insulated-gate bipolar transistors).

[00010] Despite the potential advantages associated with electrical motors of both types, and the continuing need for improvement, the use and control of hydraulic fracturing operations using electrical motors has not been successfully implemented in practice.

SUMMARY

[00011] This summary is provided to introduce a selection of concepts in a simplified form that are further described below in the Detailed Description. It is not intended to identify essential features of the invention, or to limit the scope of the attached claims.

[00012] In an aspect, a system for stimulating oil or gas production from a wellbore is disclosed, which includes a hydraulic fracturing pump unit having two or more fluid pumps, each fluid pump being driven by an alternating current (AC) electrical pump motor coupled to the fluid pump, and a variable frequency drive (VFD) controlling the electrical pump motor; an electrically powered hydraulic blender unit configured to provide treatment fluid to at least one of said one or more fluid pumps for delivery to the wellbore, wherein the blender unit comprises at least one AC electrical blending motor; and a system control unit communicating with each of said hydraulic fracturing pump unit and electrically powered hydraulic blender unit, for

controlling operational parameters of each of the units where the system control unit is configured to separately control parameters of each of the two or more fluid pumps of the hydraulic fracturing pump unit.

[00013] In another aspect, a system for stimulating oil or gas production from a wellbore is disclosed, which includes a hydraulic fracturing pump unit having a hydraulic fracturing pump driven by an electrical fracturing motor; a variable frequency drive (VFD) controlling the electrical fracturing motor; a fracturing pump blower unit driven by an electrical blower motor; and a fracturing pump lubrication unit comprising a lubrication pump driven by an electrical lubrication motor, and a cooling fan driven by an electrical cooling motor; an electrically powered hydraulic blender unit configured to provide treatment fluid to the hydraulic fracturing pump unit for delivery to the wellbore, the blender unit comprising at least one electrical blending motor; and a system control unit including a hydraulic fracturing pump unit controller configured to control the hydraulic fracturing pump unit; a hydraulic blender unit controller configured to control the hydraulic blender unit; and a hydration unit controller configured to control the hydration unit.

[00014] In yet another aspect, a system control unit for use with a system for stimulating oil or gas production from a wellbore is disclosed, which includes a hydraulic fracturing pump unit controller configured to control a hydraulic fracturing pump unit having one or more hydraulic fracturing electrical motors, the hydraulic fracturing pump unit controller including a hydraulic fracturing pump controller configured to control a hydraulic fracturing pump; and a hydraulic fracturing blower unit controller configured to control a hydraulic fracturing pump blower unit; and a hydraulic fracturing lubrication unit controller configured to control a hydraulic fracturing pump lubrication unit; and a hydraulic blender unit controller configured to control a hydraulic blender pump unit having one or more hydraulic blender electrical motors, the hydraulic blender pump unit controller including a blender control unit for controlling the operation of one or more blender units, a blender slurry power unit (SPU) pump control unit for controlling the operation of one or more blender SPU units, a blender SPU blower control unit for controlling the operation of one or more blender SPU blower units, and a blender blower control unit for controlling the operation of one or more blender blower units.

[00015] In an additional aspect, a method is disclosed for stimulating oil or gas production from a wellbore using an electrically powered fracturing system includes establishing a data channel connecting at least one hydraulic fracturing unit and an electrical fracturing blender with a control unit of the system; controlling, using one or more variable frequency drives (VFDs), a plurality ($N \geq 2$) of electrical fracturing motors powered by alternating current (AC) electricity to drive at least one fluid pump of the at least one hydraulic fracturing unit; controlling, using a VFD, at least one electrical blending motor powered by alternating current (AC) electricity to produce a fracturing fluid from an electrical fracturing blender; and pumping, using the at least one fluid pump driven by the plurality of electrical fracturing motors, a blended fracturing fluid down a wellbore located at the well site, where speed sets of each AC motor are controlled individually based upon at least one of a desired set of hydraulic fracturing design parameters including injection rate or pressures, pressure limits established for the individual pumps; and measured aggregate flow rate of the pumped fluid.

[00016] Other features and aspects may be apparent from the following detailed description and the drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

[00017] The foregoing summary, as well as the following detailed description, will be better understood when read in conjunction with the appended drawings. For the purpose of illustration, certain examples of the present description are shown in the drawings. It should be understood, however, that the invention is not limited to the precise arrangements and instrumentalities shown. The accompanying drawings illustrate an implementation of systems, apparatuses, and methods consistent with the present description and, together with the description, serve to explain advantages and principles consistent with the invention, as defined in the attached claims.

[00018] FIG. 1 is a diagram illustrating an example of a hydraulic fracturing fleet layout for a well fracturing system using electrical motors.

[00019] FIGS. 2A and 2B are diagrams illustrating an example of an electrical one line drawing for the overall well fracturing system including turbine generators, switchgear modules,

transformers, electrical subsystems for one or more fracturing pump units, and electrical subsystems for one or more blender units and hydration units.

[00020] FIG. 3 is a diagram illustrating an example of an electrical diagram for a fracturing unit control system located on a fracturing trailer, truck, or skid.

[00021] FIG. 4 is a diagram illustrating an example of an electrical diagram for a blender unit and a hydration unit control system located on an auxiliary trailer, truck, or skid.

[00022] FIG. 5 is a block diagram illustrating an example of a hydraulic fracturing system for a well fracturing system using electrical motors.

[00023] FIG. 6 is a block diagram illustrating an example of a fracturing pump unit for a well fracturing system using electrical motors.

[00024] FIG. 7 is a block diagram illustrating an example of a blender unit for a well fracturing system using electrical motors.

[00025] FIG. 8 is a block diagram illustrating an example of a hydration unit for a well fracturing system using electrical motors.

[00026] FIG. 9 is a diagram illustrating an example of a system control unit for controlling a well fracturing system using electrical motors.

[00027] FIG. 10 is a diagram illustrating an example of a fracturing pump motor control state chart.

[00028] FIG. 11 is a diagram illustrating an example of a lubrication system control state chart.

[00029] FIG. 12 is a diagram illustrating an example of motor blower control state chart.

[00030] FIG. 13 is a diagram illustrating an example graph of AC motor efficiency as a function of rated Power output.

[00031] FIG. 14 is a diagram illustrating an example of a starter/breaker performance graph, velocity ramp S curve over a 30 second time period.

[00032] FIGS. 15A, 15B, 15C, 15D, and 15E are algorithmic block diagrams illustrating examples of the operations of the system control unit in automatic target rate and/or automatic target pressure modes.

[00033] Throughout the drawings and the detailed description, unless otherwise described, the same drawing reference numerals will be understood to refer to the same elements, features, and structures. The relative size and depiction of these elements may be exaggerated for clarity, illustration, and convenience.

DETAILED DESCRIPTION

[00034] The following detailed description is provided to assist the reader in gaining a comprehensive understanding of the methods, apparatuses, and/or systems described herein. Various changes, modifications, and substantial equivalents of the systems, apparatuses and/or methods described herein will be apparent to those of ordinary skill in the art. In certain cases, descriptions of well-known functions and constructions have been omitted for increased clarity and conciseness.

[00035] The control of AC motors provides several advantages over traditional diesel-driven, including variable gear ratio powertrains based on the more precise, continuous speed control. During operation, the described methods and systems enable the AC motors to be controlled with specific speed settings based on a specific speed input and can be incremented or decremented in single RPM (revolutions per minute) intervals without interruption.

[00036] This following description also relates to a method to control and monitor from a remote location the previously described AC motors. A wired or wireless data channel can be established that connects the hydraulic fracturing equipment to a remote monitoring and control station. The remote monitoring and control station may include a human machine interface (HMI) that allows the AC motors' speed set points to be entered and transmitted such that the speed of the AC motors can be individually controlled. The fracturing pump units' individual pumping rates and combined manifold pressure can therefore be regulated by a remote controller operating from a distance.

[00037] In an example, the HMI may include a desktop computer, monitor, and keyboard, but can be extended to other HMI devices, such as touch enabled tablet computers and mobile

phones. The HMI may be connected via a data channel to a distributed programmable automation controller (PAC) on each hydraulic fracturing unit. The PAC relays the speed set point from the operator at the HMI to a variable frequency drive (VFD). The VFD provides ac current which turns the mechanically coupled motor and fracturing pump. In this example, the PAC also acts a safety device. If an unsafe condition is detected, for example, an over pressure event, the PAC can independently override the remote operator's command and take whatever action is appropriate, for example, shutting off the VFD,

[00038] In addition to the prime movers, additional AC motors provide the means for powering and controlling ancillary subsystems, such as lubrication pumps and cooling fans, which were conventionally driven hydraulically. The following description also relates to control, either manually or automatically, of any ancillary subsystem electric motors over the same data channel used to control the prime mover. Lubrication systems may be used in the overall operation of equipment in oil and gas well stimulation hydraulic fracturing application and the ability to independently control these systems through the use of AC motors is an advantage over diesel-driven engine applications.

[00039] The system supervisory control can also include a higher level automation layer that synchronizes the AC motors' operation. Using this method, an operator can enter a target injection rate and pump pressure limit, or alternatively, a target injection pressure and a pump rate limit, whereby an algorithm automatically adjusts the AC motors' speed set points to collectively reach the target quantity, while not collectively exceeding the limit quantity. This high level automation layer can operate in either open loop or closed loop control modes.

[00040] FIG. 1 illustrates an example of a hydraulic fracturing fleet layout for a well fracturing system using electrical motors. FIGS. 2A and 2B is a diagram illustrating an example of an electrical one line drawing for the overall well fracturing system.

[00041] Referring to FIGS. 1, 2A, and 2B the hydraulic fracturing fleet includes fracturing pump unit trailers, trucks, or skids **20a**, **20b**, **20c**, **20d**, **20e**, **20f**, **20g**, **20h** that are positioned around a well head **10**. In this example, the fracturing fleet includes eight fracturing pump unit trailers, trucks, or skids **20a**–**20h** with each of the fracturing pump unit trailers, trucks, or skids **20a**–**20h** including one of the eight fracturing unit control systems **400a**, **400b, 400c, 400d, 400e, 400f, 400g, 400h** illustrated in FIGS. 2A and 2B. Adjacent to the fracturing pump unit trailers,

trucks or skids **20a–20h** are transformer trailers, trucks, or skids **70a**, **70b**, **70c**, **70d** that are configured to change the input voltage to a lower output voltage. In this example, four transformer trailers, trucks, or skids **70a–70d** are used and each of the transformer trailers, trucks, or skids **70a–70d** includes a pair of the eight fracturing transformer units **300a**, **300b, 300c, 300d, 300e, 300f, 300g, 300h** illustrated in FIGS. 2A and 2B, one for each of the fracturing pump units **400a–400h**.

[00042] Still referring to FIGS. 1, 2A, and 2B, the hydraulic fracturing fleet further includes a pair of switchgear trailers, trucks, or skids **80a**, **80b**. The switchgear trailers, trucks, or skids **80a**, **80b** include two switchgear modules **200a**, **200b** that are electrically connected to four turbine generators **100a**, **100b**, **100c**, **100d** for protecting and isolating the electrical equipment. The hydraulic fracturing fleet also includes a blender unit trailer, truck, or skid **30a**, a backup blender unit trailer**,** truck, or skid **30b**, a hydration unit trailer, truck, or skid **40a**, and a backup hydration unit trailer, truck, or skid **40b**. The motors and pumps for the blender and hydration units are physically on each of the respective blender and hydration unit trailers, truck, or skid **30a**, **30b**, **40a**, **40b**, while an auxiliary trailer, truck, or skid **60** houses the two blender/hydration transformer units **300i**, **300j** and the blender/hydration control systems **500a**, **500b** illustrated in FIGS. 2A and 2B. Additionally, a data van or system control center **50** is provided for allowing an operator to remotely control all systems from one location.

[00043] While a specific number of units and trailers, trucks, or skids and a specific placement and configuration of units and trailers, trucks, or skids is provided, the number and position of the units is not limited to those described herein. Further, the position of a unit on a particular trailer truck, or skid is not limited to the position(s) described herein. For example, while the blender/hydration control systems **500a**, **500b** are described as being positioned on an auxiliary trailer, truck, or skid **60**, it will be appreciated that the blender/hydration control systems **500a**, **500b** may be positioned directly on the respective blender and hydration unit trailers, trucks, or skids **30a**, **30b**, **40a**, **40b**. Accordingly, the figures and description of the numbers and configuration are intended to only illustrate preferred embodiments.

[00044] FIG. 3 is a diagram illustrating an example of an electrical one line drawing for a fracturing unit control system **400a** located on a fracturing pump unit trailer, truck, or skid **20a**.

[00045] Referring to FIG. 3, a fracturing unit control system **400a** includes the operating mechanisms for a fracturing pump unit **700** (described in more detail below). The operating mechanisms for the fracturing pump unit include a variable frequency drive housing that houses a first frac motor variable frequency drive ("VFD") **410a** for driving a first frac motor **411a**, a second frac motor VFD **410b** for operating a second frac motor **411b**, a power panel with a first connection **412** and a second connection **417**. The first connection **412** is connected to fracturing pump unit subsystem control switches **413** for operating fracturing pump unit subsystems including first and second lubrication motors **414a**, **414b**, first and second cooler motors **415a**, **415b**, and first and second blower motors **416a**, **416b**. The second connection **417** is connected to a lighting panel **418** for operating miscellaneous systems including outdoor lighting, motor space heaters, and other units.

[00046] FIG. 4 is a diagram illustrating an example of an electrical one line drawing for a blender/hydration control system **500a** located on an auxiliary trailer, truck, or skid **60**.

[00047] Referring to FIG. 4, a blender/hydration control system **500a** includes the operating mechanisms for a blender unit **800** and a hydration unit **900** (described in more detail below). The operating mechanisms for the blender unit include a slurry power unit VFD **510** for operating a slurry power unit motor **511**, a first blower control switch **512** for operating the blower motor **513** of the slurry power unit blower, a hydraulic power unit control switch **514** for operating a hydraulic power unit motor **515,** and a second blower control switch **516** for operating the blower motor **517** of the hydraulic power unit blower**.** The operating mechanisms for the hydration unit include a hydraulic power unit control switch **518** for operating a hydraulic power unit motor **519**, and a blower control switch **520** for operating the blower motor **521**. In addition, the blender/hydration control system **500a** includes a connection **522** to a lighting panel **523** for operating miscellaneous systems including lighting, motor space heaters, and other units.

[00048] FIG. 5 is a diagram illustrating an example of a hydraulic fracturing system **600** for a well fracturing system using electrical motors and including a system control unit **650**.

[00049] Referring to FIG. 5, the hydraulic fracturing system **600** includes a system control unit **650**, one or more hydraulic fracturing pump units **700**, for example eight hydraulic fracturing pump units **700a-700h**, one or more blender units **800**, for example two blender units **800a**, **800b**. In a preferred embodiment, the system also includes one or more hydration units

900, for example two hydration units **900a**, **900b**. Each of the fracturing pump units **700a-700h**, the blender units **800a**, **800b**, and the hydration units **900** may include one or more programmable automated controllers (PACs), a control/communication unit that is connected to the system control unit **650** via one or more data channels, preferably for bilateral communication.

[00050] Referring to FIG. 6, the hydraulic fracturing pump unit **700** includes one or more electric motor-driven fracturing pumps **710,** for example two fracturing pumps **710a**, **710b**. Each fracturing pump **710a**, **710b** may include a corresponding blower unit **720a**, **720b** and a corresponding lubrication unit **730a, 730b**. Each of the fracturing pumps **710a**, **710b** may be operated independently using a local control panel or from the system control unit **650**. One or more PACs **702a**, **702b** may be used by the fracturing pumps **710a**, **710b** and/or the blower units and lubrication units to communicate with the system control unit **650**. The positioning of the PACs in FIG. 6 is for illustration purposes only, it will be understood that physically each PAC can be located proximate to the respective unit.

[00051] As described above in reference to FIG. 3, the frac motor **411a** of a fracturing pump **710a** is controlled by a frac VFD **410a**. The control system provides a RUN/STOP signal to the VFD **410a** to control the status of the frac motor **411a**. The control system provides a speed request signal to the VFD **410a** to control the speed of the frac motor **411a**. The motor speed is displayed and can be controlled locally and remotely.

[00052] A normal stop (RUN/STOP) will control each fracturing pump unit **700a** independently (for example, a first fracturing pump **710a** and a second fracturing pump **710b** on the same frac trailer, truck, or skid **20a** will each be controlled independently). An e-stop will be supplied to stop an entire fracturing pump unit **700a** (i.e. the frac VFDs **410a, 410b** and the frac motors **411a, 411b** of a first and second pumps **710a**, **710b** on the trailer, truck, or skid **20a** are shut down). A master e-stop will be supplied to shut down all deployed fracturing pump units **700a-700h** (i.e. all VFDs and all motors on all trailers, trucks, or skids **20a-20h** are shut down).

[00053] Included in the remote control method is an automated alarm management system, such that if any operating parameter exceeds its normal range, an indicator will be overlaid at the system control unit **650** to alert the operator. The operator can then choose what action to take, for example, bringing the affected unit offline. The alarm management system can be extended

to suggest to the operator the appropriate response(s) to the alarm event, and what options exist. One benefit of the automated alarm management system is that multiple processes and subsystems on each pumping unit can be monitored autonomously, thus enabling an operator to focus on primary objectives, that is, pumping rates and pressures, while ensuring safe operation across multiple pumping units **700a-700h**.

[00054] The frac VFD **410a** provides a VFD FAULT contact to the control system to indicate if a fault condition is present, and the control system provides local/remote alarm indication of the VFD FAULT. In case a VFD FAULT occurs, the system control unit **650** of the data van **50** will display a generic fault warning. The VFD FAULT can be reset based on predefined intervals of time from the data van **50**; if a VFD FAULT occurs more frequently than the predefined interval then, in an example, that VFD FAULT can only be reset from the frac VFD **410**.

[00055] The frac motor **411a** contains a space heater to help ensure that the motor windings are dry before operation. Typical practice is to have the space heaters energized for at least 24-hours before running the motor. The space heater has two (2) operating modes: AUTO and OFF. In AUTO mode the heater is turned on when the control system is energized and the pump-motor is OFF. The heater is turned off whenever the pump-motor is commanded to RUN. The heater is turned on again anytime the pump-motor is stopped (Normal Stop). If an Emergency Stop occurs, the heat is turned off immediately.

[00056] In an example, the hydraulic fracturing pump unit **700a** may be supplied with a multi-color light tower for each pump **710a**, **710b**. The beacon lights illuminate (steady) based on the following: Color 1: frac motor **411a** is not running and is not enabled to run; Color 2: frac motor **411a** is running OR has been enabled to run; Color 3: the pump discharge pressure for the frac motor **411a** is greater than a pre-defined psig setpoint.

[00057] In an example, one or more resistance temperature detectors (RTDs) may be placed onto each AC frac motor **411a**; on each of three phase windings, on the front motor bearing(s), and on the rear motor bearing(s). In the example where twenty (20) or more pumps **710a, 710b** are used simultaneously, the AC frac motor **411a** temperatures alone may represent 100+ operational values, an otherwise overwhelming quantity that the automated alarm management system renders workable.

[00058] In a preferred embodiment, the frac motors **411a** may have multiple bearings, each with a temperature sensor. The bearing temperatures may be displayed locally and remotely. If either bearing temperature of the frac motor **411a** reaches a programmed alarm setpoint, the control system should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated. If either bearing temperature of the frac motor **411a** reaches a programmed setpoint at which the bearing could sustain damage, the control system should activate/indicate a shutdown. The shutdown is latched until the Alarm Reset switch is operated.

[00059] In a preferred embodiment, the frac motor **411a** also has multiple windings (one for each AC phase) each with a temperature sensor. The windings are labeled in accordance to the AC phases. The winding temperatures may be displayed locally and remotely. If any winding temperature reaches a programmed alarm setpoint, the control system should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated. If any winding temperature reaches a programmed setpoint at which the winding could sustain damage, the control system should activate/indicate a shutdown. The shutdown is latched until the Alarm Reset switch is operated.

[00060] In this example, a hydraulic fracturing pump **710a** may include a pressure transmitter that provides a signal for the pump discharge pressure. The pump discharge pressure is displayed locally and remotely at the system control unit **650**. An Overpressure setpoint can be adjusted on the control system that is triggered by the pump discharge pressure. If the pump discharge pressure exceeds the Overpressure setpoint, the control system stops the frac motor **411a** via the RUN/STOP control to the frac VFD **410a**. The control system should activate/indicate a shutdown. The Overpressure shutdown is latched until the Alarm Reset switch is operated.

[00061] Still referring to FIG. 6, the hydraulic fracturing pump unit **700a** also includes a frac motor blower unit **720a, 720b** for each of the fracturing pumps **710a**, **710b**.

[00062] The frac motor **411a** has an electric motor-driven blower unit **720a** for cooling the frac motor **411a**. The blower motor **416a**, described above in reference to FIG. 3, has multiple operating modes: AUTO, MANUAL and OFF. In AUTO mode the blower motor **416a** is started any time the frac motor **411a** is running and remains on for a "cool down" period based on a predefined interval of time after the frac motor **411a** is stopped (Normal Stop). If an Emergency

Stop occurs, the blower motor **416a** stops immediately and there is not a "cool down" period. In MANUAL mode the blower motor **416a** runs continuously, regardless of the pump-motor's status. In OFF mode the blower motor **416a** does not run, regardless of the frac motor's **411a** status.

[00063] The blower unit **720a** includes a pressure switch that senses the blower outlet pressure to confirm that the blower unit **720a** is operating satisfactorily. Any time that the blower unit **720a** is running, the pressure switch should be activated. If the blower unit **720a** is running and the pressure switch is NOT activated, then the control system of the system control unit **650** should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated.

[00064] Still referring to FIG. 6, the hydraulic fracturing pump unit **700a** also includes a frac motor lubrication unit **730a**, **730b** for each of the fracturing pumps **710a**, **710b**.

[00065] Each frac motor lubrication unit **730a**, **730b** includes a lubrication pump operated by an electrical lubrication motor **414a**, a cooling fan operated by a cooler motor **415a**, a pressure transmitter and a temperature transmitter. Any time the control system commands the frac VFD **410a** to RUN it first turns on the lubrication pump **414a**, confirms lubrication oil pressure is greater than a predefined PSIG setpoint, then enables the frac VFD **410a** to start the frac motor **411a**. Whenever the control system commands the frac VFD **410a** to STOP, it also turns off the lubrication pump and lubrication motor **414a** following the same "cool down" period described above for the motor blower control.

[00066] Any time the control system commands the frac VFD **410a** to RUN, the lubrication system cooling fan and cooling motor **415a** is enabled to run. Once the lubrication temperature reaches a predefined temperature maximum threshold, the control system turns on the cooling fan and cooling motor **415a**. Whenever the lubrication temperature is below a predefined temperature midrange minimum threshold, the control system turns the cooling fan and cooling motor **415** off. The fan is also turned off whenever the lubrication pump and lubrication motor **414a** are turned off.

[00067] If an Emergency Stop occurs, the lubrication motor **414a** and cooling fan motor **415a** are stopped immediately and there is not a "cool down" period. When enabled to run, if the lubrication temperature exceeds a predefined threshold or lubrication pressure falls below a

predefined PSIG setpoint, the control system should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated. When enabled to run, if the lubrication pressure is below a minimum predefined PSIG set point for a predefined time interval, the control system should activate/indicate a shutdown. The shutdown is latched until the Alarm Reset switch is operated. In this example, the lubrication system pressure and temperature are both displayed locally and remotely at the system control unit **650**.

[00068] The shutdowns described for the hydraulic fracturing pump unit **700a** can be enabled/disabled via a master override setting at the local or remote system control unit **650**. When shutdowns are disabled the control system still provides a visual indicator advising the operator to manually shut the unit down. When shutdowns are enabled, the unit is shut down automatically without operator intervention.

[00069] FIG. 7 is a diagram illustrating an example of a hydraulic fracturing blender unit **800A** for a well fracturing system using electrical motors. The blender unit generally functions to prepare the slurries and gels used in stimulation treatments by the overall system. In a preferred embodiment, it is computer controlled, enabling the flow of chemicals and ingredients to be efficiently metered and to exercise control over the blend quality and delivery rate.

[00070] Referring to FIG. 7, the hydraulic fracturing blender unit **800a** may include two or more electric motor-drives that may be operated independently using a local control panel or from the system control unit **650**. One motor, the hydraulic power unit motor **515,** drives a hydraulic power unit **810** and the other, a slurry power unit motor **511**, a slurry power unit **820**. One or more PACs **802a**, **802b** may be used by the hydraulic power unit and blower **810**, **840** and the slurry power unit and blower **820**, **830** to communicate with the system control unit **650**.

[00071] The slurry power unit ("SPU") motor **511** is controlled by the slurry power unit VFD **510**. The control system provides a RUN/STOP signal to the slurry power unit VFD **510** to control the status of the SPU motor **511**. The control system provides a speed request signal to the slurry power unit VFD **510** that allows the speed of the motor **511** to be varied across the entire speed range. The motor **511** speed is displayed and can be controlled locally.

[00072] The slurry power unit VFD **510** provides a VFD FAULT contact to the control system to indicate if a fault condition is present, and the control system provides local/remote

alarm indication of the VFD FAULT. The VFD FAULT can be reset based on predefined intervals of time from the data van **50**; if a VFD FAULT occurs more frequently than the predefined interval then, in an example, that VFD FAULT can only be reset from the VFD

[00073] The SPU motor **511** may include a space heater to help ensure that the motor windings are dry before operation. Typical practice is to have the space heaters energized at least for 24-hours before running the motor. The space heater has multiple operating modes: AUTO and OFF. In AUTO mode the heater is turned on the control system is energized and the SPU motor **511** is OFF. The heater is turned off whenever the SPU motor **511** is commanded to RUN. The heater is turned on again anytime the SPU motor is stopped (Normal Stop). If an Emergency Stop occurs, the heat is turned off immediately.

[00074] In a preferred embodiment, the SPU motor **511** may have multiple bearings, each with a temperature sensor. The bearing temperatures are displayed locally and remotely. If either bearing temperature reaches a programmed alarm setpoint, the control system should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated. If either bearing temperature reaches a programmed setpoint at which the bearing could sustain damage, the control system should activate/indicate a shutdown. The shutdown is latched until the Alarm Reset switch is operated.

[00075] In a preferred embodiment, the SPU motor **511** also has multiple windings (one for each AC phase) each with a temperature sensor. The windings are labeled A, B and C corresponding to the AC phases. The winding temperatures are displayed locally and remotely. If any winding temperature reaches a programmed alarm setpoint, the control system should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated. If any winding temperature reaches a programmed setpoint at which the winding could sustain damage, the control system should activate/indicate a shutdown. The shutdown is latched until the Alarm Reset switch is operated.

[00076] Still referring to FIG. 7, the hydraulic fracturing blender unit **800a** also includes a hydraulic power unit **810**. In a preferred example, the hydraulic power unit (HPU) motor **515** is operated at a fixed speed. The control system provides a RUN/STOP signal to the motor control center (MCC) to control the status of the HPU motor **515**. The motor speed is fixed; the motor can be controlled On/Off locally.

[00077] The HPU motor **515** may include a space heater to help ensure that the motor windings are dry before operation. The space heaters may be energized at least for 24-hours before running the motor. The space heater has two (2) operating modes: AUTO and OFF. In AUTO mode the heater is turned on the control system is energized and the HPU motor is OFF. The heater is turned off whenever the HPU motor **515** is commanded to RUN. The heater is turned on again anytime the HPU motor **515** is stopped (Normal Stop). If an Emergency Stop occurs, the heat is turned off immediately.

[00078] In a preferred embodiment, the HPU motor **515** may have multiple bearings, each with a temperature sensor. The bearing temperatures are displayed locally and remotely. If either bearing temperature reaches a programmed alarm setpoint, the control system should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated. If either bearing temperature reaches a programmed setpoint at which the bearing could sustain damage, the control system should activate/indicate a shutdown. The shutdown is latched until the Alarm Reset switch is operated.

[00079] In a preferred embodiment, the HPU motor **515** also has multiple windings (one for each AC phase) each with a temperature sensor. The windings are labeled A, B and C corresponding to the AC phases. The winding temperatures are displayed locally and remotely. If any winding temperature reaches a programmed alarm setpoint, the control system should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated. If any winding temperature reaches a programmed setpoint at which the winding could sustain damage, the control system should activate/indicate a shutdown. The shutdown is latched until the Alarm Reset switch is operated.

[00080] Still referring to FIG. 7, the hydraulic fracturing blender unit **800a** also includes an SPU electric motor-driven blower unit **830** and an HPU electric motor-driven blower unit **840**.

[00081] The SPU motor **511** has an SPU electric motor-driven blower **830** for cooling the SPU motor **511**. The SPU blower motor **513**, described above in reference to FIG. 4, has multiple operating modes: AUTO, MANUAL and OFF. In AUTO mode the SPU blower motor **513** is started any time the SPU motor **511** is running and remains on for a "cool down" period based on a predefined interval of time after the SPU motor **511** is stopped (Normal Stop). If an Emergency Stop occurs, the SPU blower motor **513** stops immediately and there is not a "cool

down" period. In MANUAL mode the SPU blower motor **513** runs continuously, regardless of the SPU motor's **511** status. In OFF mode the SPU blower motor **513** does not run, regardless of the SPU motor's **511** status.

[00082] The SPU blower unit **830** includes a pressure switch that senses the blower outlet pressure to confirm that the SPU blower unit **830** is operating satisfactorily. Any time that the SPU blower unit **830** is running, the pressure switch should be activated. If the SPU blower unit **830** is running and the pressure switch is NOT activated, then the control system of the system control unit **650** should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated.

[00083] The HPU motor **515** has an HPU electric motor-driven blower unit **840** for cooling the HPU motor **515**. The HPU blower motor **517**, described above in reference to FIG. 4, has multiple operating modes: AUTO, MANUAL and OFF. In AUTO mode the HPU blower motor **517** is started any time the HPU motor **515** is running and remains on for a "cool down" period based on a predefined interval of time after the HPU motor **515** is stopped (Normal Stop). If an Emergency Stop occurs, the HPU blower motor **517** stops immediately and there is not a "cool down" period. In MANUAL mode the HPU blower motor **517** runs continuously, regardless of the HPU motor's **515** status. In OFF mode the HPU blower motor **517** does not run, regardless of the HPU motor's **515** status.

[00084] The HPU blower unit **840** includes a pressure switch that senses the blower outlet pressure to confirm that the HPU blower unit **840** is operating satisfactorily. Any time that the HPU blower unit **840** is running, the pressure switch should be activated. If the HPU blower unit **840** is running and the pressure switch is NOT activated, then the control system of the system control unit **650** should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated.

[00085] The shutdowns described for the hydraulic fracturing blender unit **800a** can be enabled/disabled via a master override setting at the local or remote system control unit **650**. When shutdowns are disabled the control system still provides a visual indicator advising the operator to manually shut the unit down. When shutdowns are enabled, the unit is shut down automatically without operator intervention.

[00086] FIG. 8 is a diagram illustrating an example of a hydraulic fracturing hydration unit **900A** for a well fracturing system using electrical motors. This unit is used in a preferred embodiment of the system and generally functions to mix water and chemical additives to make the frac fluid. The chemical additives, such as guar gum (also found in many foods), are added to help the water to gel. The mixing process in the hydration unit takes a few minutes, allowing for the water to gel to the right consistency.

[00087] Referring to FIG. 8, the hydraulic fracturing hydration unit **900a** contains one or more electric motor-drives that can be operated from a local control panel or from the system control unit **650**. One or more PACs **902a** may be used by a hydration HPU unit and blower **910**, **920** to communicate with the system control unit **650**.

[00088] The hydraulic fracturing hydration unit **900a** also includes a hydration blower unit **920**. The hydration HPU motor **521** has an electric motor-driven hydration HPU blower unit **920** for cooling the hydration HPU motor **521**. The hydration HPU blower motor **519** has three (3) operating modes: AUTO, MANUAL and OFF. In AUTO mode the hydration HPU blower motor **519** is started any time the hydration HPU motor **521** is running and remains on for a "cool down" period based on a predefined interval of time after the hydration HPU motor **521** is stopped (Normal Stop). If an Emergency Stop occurs, the hydration HPU blower motor **519** stops immediately and there is not a "cool down" period. In MANUAL mode the hydration HPU blower motor **519** runs continuously, regardless of the hydration HPU motor's **521** status. In OFF mode the hydration HPU blower motor **519** does not run, regardless of the hydration HPU motor's **521** status.

[00089] The hydration HPU blower motor **519** includes a pressure switch that senses the blower outlet pressure to confirm that the blower is operating satisfactorily. Any time that the blower is running, the pressure switch should be activated. If the blower is running and the pressure switch is NOT activated, then the control system should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated.

[00090] The hydration HPU motor **521** may include a space heater to help ensure that the motor windings are dry before operation. The space heaters may be energized at least for 24-hours before running the hydration HPU motor **521**. The space heater has two (2) operating modes: AUTO and OFF. In AUTO mode the heater is turned on the control system is energized

and the hydration HPU motor **521** is OFF. The heater is turned off whenever the hydration HPU motor **521** is commanded to RUN. The heater is turned on again anytime the hydration HPU motor **521** is stopped (Normal Stop). If an Emergency Stop occurs, the heat is turned off immediately.

[00091] In a preferred embodiment, the hydration HPU motor **521** may have multiple bearings, each with a temperature sensor. The bearing temperatures are displayed locally and remotely. If either bearing temperature reaches a programmed alarm setpoint, the control system should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated. If either bearing temperature reaches a programmed setpoint at which the bearing could sustain damage, the control system should activate/indicate a shutdown. The shutdown is latched until the Alarm Reset switch is operated.

[00092] In a preferred embodiment, the hydration HPU motor **521** may also have multiple windings (one for each AC phase) each with a temperature sensor. The windings are labeled A, B and C corresponding to the AC phases. The winding temperatures are displayed locally and remotely. If any winding temperature reaches a programmed alarm setpoint, the control system should indicate an alarm. The alarm is latched until the Alarm Reset switch is operated. If any winding temperature reaches a programmed setpoint at which the winding could sustain damage, the control system should activate/indicate a shutdown. The shutdown is latched until the Alarm Reset switch is operated.

[00093] The shutdowns described for the hydraulic fracturing hydration unit **900A** can be enabled/disabled via a master override setting at the local or remote system control unit **650**. When shutdowns are disabled the control system still provides a visual indicator advising the operator to manually shut the unit down. When shutdowns are enabled, the unit is shut down automatically without operator intervention.

[00094] FIG. 9 is a diagram illustrating an example of a system control unit **650** for controlling a well fracturing system using electrical motors.

[00095] In a preferred embodiment, a system control unit **650** is a single point control unit for remotely operating a well fracturing system. The single point remote operation of the well

fracturing system allows an operator to remotely control all of the units of the well fracturing system from a single, remote location such as a data van **50.**

[00096] Referring to FIG. 9, the system control unit **650** includes one or more fracturing control units **652a–652h**, one or more fracturing blender control units **654a, 654b**, and one or more fracturing hydration control units **656a**, **656b**. In this example, the system control unit **650** includes eight fracturing control units **652a–652h**, two fracturing blender control units **654a, 654b**, and two fracturing hydration control units **656a**, **656b**

[00097] The fracturing control unit **652a** includes a fracturing pump control unit **662a** for controlling the operation of one or more fracturing pumps **710a, 710b**, a fracturing blower control unit **664a** for controlling the operation of one or more fracturing blower units **720a, 720b**, and a lubrication control unit **664a** for controlling the operation of one or more lubrication units **730a, 730b**.

[00098] The fracturing blender control unit **654a** includes a blender HPU pump control unit **672a** for controlling the operation of one or more blender HPU units **810,** a blender SPU pump control unit **674a** for controlling the operation of one or more blender SPU units **820,** a blender SPU blower control unit **676a** for controlling the operation of one or more blender SPU blower units **830**, a blender HPU blower control unit **678a** for controlling the operation of one or more blender HPU blower units **840.**

[00099] The fracturing hydration control unit **656a** includes a hydration HPU pump control unit **682a** for controlling the operation of one or more hydration HPU units **910**, and a blender HPU blower control unit **684a** for controlling the operation of one or more hydration HPU blower units **920.**

[000100] FIG. 10 is a diagram illustrating an example of a fracturing pump motor control state chart. FIG. 11 is a diagram illustrating an example of a lubrication system control state chart. FIG. 12 is a diagram illustrating an example of motor blower control state chart.

[000101] Referring to the control state charts illustrated in FIGS. 10-12, in an example, the automatic and/or manual control operations of one or more of the hydraulic fracturing pump units **700a-700h** may be controlled accordingly. For example, the operation of the overall system including each fracturing pump **710a**, **710b**, each blower unit **720a, 720b**, and each

lubrication unit **730a, 730b** is illustrated in FIG. 10. For FIG. 10, all states, including off state, can transition directly to the Emergency Stop state. The space heater is on only if the blower is off. The beacon light turns red whenever the pump discharge pressure is greater than a pre-defined setpoint.

[000102] The operation of the lubrication unit **730a, 730b** is illustrated in FIG. 11. For FIG. 11, if the cooling fan is enable it will turn on when oil temperature is high and turn off when low automatically. The operation of the blower unit **720a, 720b** is illustrated in FIG. 12 and the state chart is followed when the blower is in Auto mode, which is set by hardware, i.e. the electrical circuit.

[000103] Referring to FIGS. 13 and 14, an embodiment includes a method for computational control of the speeds of the AC motors such that hydraulic fracturing design parameters, among these being injection rate and pressures, can be automatically achieved. Using this method, an operator can enter a target injection rate and injection pressure limit, or alternatively, a target injection pressure and injection rate limit, whereby an algorithm automatically adjusts the AC motors' speed set points to collectively reach the target quantity, while not collectively exceeding the limit quantity. For example, not all fracturing motors are used and some fracturing motors are backup motors. In response to an input from an operator or a user that increases the target injection rate, or in response to failure of one or more other fracturing motors, one or more backup fracturing motors can be automatically powered and initiated.

[000104] In this embodiment, Darcy's law, generally expressed as:

[000105] $$q = \frac{-\kappa}{\mu}\nabla p,$$

[000106] where q is discharge rate per unit area, κ is intrinsic permeability, μ is viscosity, and ∇p is the pressure gradient vector, is employed as a means to computationally predict the change in injection pressure which will result from a proposed change in speed of any combination of the AC motors. Alternatively, the change in injection rate required to reach a desired injection pressure can be predicted. The Darcy parameters need not be measured directly; an embodiment may estimate the parameters from available surface measurements. This embodiment allows the fracturing motors to produce process outputs, namely injection rates

LIBERTY EXHIBIT 1002, Page 696

or pressures, that adhere as closely as possible to the fracture design targets without exceeding specified limit parameters, as deemed necessary to preserve the integrity of the formation fracture, the well bore, and the equipment onsite.

[000107] For example, the intrinsic permeability and viscosity values may be calculated at time T_0 by dividing the measured change in discharge rate from time T_{-1} to T_0 by the measured change in pressure from time T_{-1} to T_0. Using the calculated ratio of intrinsic permeability and viscosity, the pressure at time T_1 may be estimated for a different discharge rate at time T_1, thereby predicting the pressure change with a change in the discharge rate.

[000108] In a preferred embodiment, VFD process data, not limited to currents and frequency, temperatures, power, percent of rated load, torque and percent of torque, output voltage and motor load, and system status can be collected, communicated by a communications channel to the system control unit to raise an alarm to the user whenever any of the operating parameters exceeds a corresponding threshold value. This allows an operator to intervene such that the VFD workload can be shared equally among the available VFDs at the wellsite, thus minimizing the number of VFD faults and thermal shut down events caused by over driving particular pieces of fracturing equipment.

[000109] An embodiment can combine the automatic pumping rate and automatic pumping pressure control of with the VFD load management to automatically distribute VFD power output among the wellsite equipment, producing the same load management benefits but without requiring operator intervention.

[000110] Referring specifically to FIG. 13, an embodiment combining the methods and apparatus described above may be designed to automatically select and control an optimal quantity of available AC motors and VFDs, such that each motor selected runs as closely to its maximum operating efficiency as possible. As illustrated in FIG. 13, AC induction motors have an efficiency to power output relationship similar to that shown. Computationally, an optimal number of AC motors can be selected, and such selection can be varied over time, such that each operates as closely to its rated power output, and thus highest efficiency as possible, subject to the fracture design parameters and the number and types of pumping equipment available.

[000111] Referring specifically to FIG. 14, the VFD controls the acceleration and deceleration of motors/pumps based on a programmed "S" curve. The "S" curve is established to ensure that the mass and inertia of the motors/pumps is properly managed to avoid damage or nuisance shutdowns of the VFD. FIG. 14 is an example graphical representation of such an "S" curve. The VFD operates in one of the various pre-defined pulse width modulated control techniques such as Constant Torque or Sensor-less Vector, based on enabling the maximum starting capability against higher wellhead pressures.

[000112] FIGS. 15A–15E are algorithmic block diagrams illustrating examples of the operation of the system control unit in automatic target rate and/or automatic target pressure modes.

[000113] Referring to FIG. 15A, an operation of detecting whether auto rate control or auto pressure control is selected by an operator begins with a start task timer step **1000**, if a task timer event is achieved in step **1010**, the operation proceeds to detecting if auto rate control mode is selected in step **1020**. If auto rate control mode is selected, the operation proceeds to the auto rate control module described in FIG. 15B. If not selected, the operation proceeds to detecting if auto pressure control mode is selected in step **1030**. If auto pressure control mode is selected, the operation proceeds to the auto pressure control module described in FIG. 15C. If neither mode is selected, manual control by the operator is being used and the operation loops back to detecting a task timer event in step **1010**.

[000114] Referring to FIGS. 15B and 15C, if auto rate control or auto pressure control is selected, an operation of determining whether to decrease injection rate, increase injection rate, or maintain the current injection rate based on a target injection rate or a target pressure rate is implemented. In this example, p is the measured injection pressure, p_{Target} is the target injection pressure, p_{Limit} is the injection pressure limit, $p_{Tolerance}$ is the acceptable margin of injection pressure error, p_{Error} is the injection pressure error defined as $p_{Limit} - p$ when in auto rate control and defined as $p_{Target} - p$ when in auto pressure control.

[000115] Similarly, q is the measured injection rate, q_{Target} is the target injection rate, q_{Limit} is the injection rate limit, $q_{Tolerance}$ is the acceptable margin of injection rate error, q_{Error} is the injection rate error defined as q_{Limit}-q when in auto pressure control and defined as q_{Target}-q when in auto rate control.

[000116] As illustrated in FIGS. 15B and 15C, a first step **1040a**, **1040b** of calculating the error values is implemented followed by a next step **1050a**, **1050b** of determining whether the measured pressure or measured injection rate exceeds a tolerance value in addition to the target injection rate or a target pressure, depending on whether auto rate or auto pressure is selected, for determining whether injection rate should be decreased following the decrease injection rate module of FIG. 15E. If not, the measured pressure or the measured injection rate is compared to the pressure limit or injection rate limit and the limit minus the tolerance value to determine whether the value falls within a "do not exceed" band in a next step **1060a**, **1060b**. If yes, the current injection rate is maintained. If not, the measured pressure or the measured injection rate is compared with the pressure limit or the injection rate limit to determine if the injection rate should be decreased in step **1070a, 1070b**. If the measured value is not greater than the limit value, then the measured pressure or the measured injection rate is compared with the target pressure minus the tolerance value or the target injection rate minus the tolerance value in a next step **1080a**, **1080b** to determine whether the injection rate should be increased following the increase injection rate module of FIG. 15D.

[000117] Referring to FIGS. 15D and 15E, an increase injection rate module or a decrease injection rate module is illustrated, respectively, for determining which pump to increase the injection rate for and the value of the change in revolutions per minute (RPM) for the selected pump. Referring to both figures, in a first step **1090a**, **1090b**, the viscosity and permeability factor is estimated, and then in step(s) **1100a**, **1100b** the required change in injection rate, $q_{Increment}$, is calculated as a function of κ, μ, and p_{Error}. In the next operations **1200a**, **1200b**, the pump for which the injection rate is increased or decreased is selected. In a preferred embodiment, the processing algorithm of the system control unit seeks to maximize the efficiency of the overall system operation. Because electrical motors are most efficient when the operate at or near 100% capacity, the algorithm generally seeks to have all corresponding pumps operate at or near such capacity and brings less-efficiently utilized pumps offline. For the operations **1200a** used to determine which pump is selected for an increase in injection rate, if any pump is not operating at its rated power, the pump selected is the pump with the lowest current power output. If all pumps are operating at rated power and a standby pump is available, the standby pump is selected for an increase in injection rate. For the operations **1200b** used to determine which pump is selected for a decrease in injection rate, if any pump is operating at less

than 50% of rated power then the pump with the lowest current power output is selected for a decrease in injection rate in order to ultimately use less pumps in the overall system. If no pump is operating at less than 50% then the pump with the highest current power output is selected a decrease in injection rate in order to more evenly distribute the load among the pumps.

[000118] Still referring to FIGS. 15D and 15E, the next operations **1300a**, **1300b** are used to determine the value of the change of RPMs (ΔRpm), a positive value in FIG. 15D where an increase in injection rate is applied and a negative value in FIG. 15E where a decrease in injection rate is applied. In this example, two values of ΔRpm may be used and the more conservative action for pressure of the well site is selected. In other words, when increasing injection rate, the ΔRpm causing a smaller increase in injection rate is used and when decreasing injection rate the ΔRpm causing a larger decrease in injection rate is used. FIGS. 15D and 15E illustrate two examples of achieving this operation. In FIG. 15D, two ΔRPMs are calculated based on $q_{Increment}$ and q_{Error}, and the smaller ΔRPM is selected for increasing the selected pump injection rate. In FIG. 15E, the smaller value (or the larger negative value) between $q_{Increment}$ and q_{Error} is selected to calculate the ΔRpm thereby using the ΔRpm with the largest negative value and applying a greater decrease of injection rate to the selected pump.

[000119] As shown in the figures and discussed above, ΔRpm is calculated as a function of either $q_{Increment}$ or q_{Error} and pump characteristics. Specifically, ΔRpm is calculated as a function of pump volume per revolution which is given by

[000120] $V_{rev} = n \times \pi r^2 l$

[000121] where n is the number of pump plungers, r is the radius of the plungers, and l is the plunger stroke.

[000122] Different equipment and devices may be used to make and use the above described embodiments of the well fracturing system. In an example, the equipment used in the electrical hydraulic fracturing system may be selected from certain commercially available options. By means of illustration only, for the hydraulic fracturing pump units, the selected VFD may be a Toshiba GX7 Rig Drive 1750 HP, 600 V, 1700 AMP 6-pulse Variable Frequency Drive. In a preferred embodiment, there is one (1) Toshiba GX7 VFD per pump system (i.e. VFD, Motor, Pump, and PAC). The selected AC Motor may be an AmeriMex "Dominator" Horizontal AC

Cage induction motor rated output is 1750 HP. In a preferred embodiment, there is one (1) AmeriMex AC Motor per pump system (i.e. VFD, Motor, Pump, and PAC). The selected pumps can be either Gardner Denver GD-2250 Triplex Pumps with maximum input of 2250 HP or Weir/SPM TWS-2250 Triplex pumps with maximum input of 2250 HP. In a preferred embodiment, there is one (1) Pump per pump system (i.e. VFD, Motor, Pump, and PAC). Another configuration includes Quintuplex with maximum input of 2500 HP; and alternate material fluid ends for extended life. The selected programmable automation controller (PAC) may be the STW ESX-3XL 32-bit controller. In a preferred embodiment, there is one (1) STW PAC per pump system.

[000123] For the hydraulic fracturing blender unit, the selected VFDs may be a Toshiba GX7 Rig Drive 1750 HP, 600 V, 1700 AMP 6-pulse Variable Frequency Drives. In a preferred example, there is one (1) Toshiba GX7 VFD per Slurry Power Unit System (i.e. VFD and Motor). For the Slurry Power Unit (SPU), the selected AC Motors may be the AmeriMex "Dominator" Horizontal AC Cage induction motors rated output is 1150 HP. In a preferred example, there is one (1) AmeriMex AC Motor per Slurry Power Unit System (i.e. VFD and Motor). For the Hydraulic Power Unit (HPU), the selected AC Motors may be the AmeriMex "Dominator" Horizontal AC Cage induction motors rated output is 600 HP. In a preferred example, there is one (1) AmeriMex AC Motor per Hydraulic Power Unit System. The selected programmable automation controller (PAC) may be the STW ESX-3XL 32-bit controller. In a preferred example, there is one (1) STW PAC per Slurry Power Unit System (i.e. VFD and Motor) and one (1) STW PAC per Hydraulic Power Unit System.

[000124] For the hydration unit, the Hydraulic Power Unit (HPU) selected AC Motors may be the AmeriMex "Dominator" Horizontal AC Cage induction motors rated output is 600 HP. In a preferred example, there is one (1) AmeriMex AC Motor per Hydraulic Power Unit System. The selected programmable automation controller (PAC) may be the STW ESX-3XL 32-bit controller. In a preferred example, there is one (1) STW PAC per Hydraulic Power Unit System.

[000125] Manufacturers of the above described equipment may include, but are not limited to, Toshiba, Siemens, ABB, GE, Gardner-Denver, Weir/SPM, CAT, FMC, STW, and National Instruments.

[000126] Wireless communication among different units of the system and the system control unit may be performed using one or more wireless internet modules within one or more units. A wireless Internet module may be a module for access to wireless Internet, and forming a wireless LAN/Wi-Fi (WLAN), a Wireless broadband (Wibro), a World Interoperability for Microwave Access (Wimax), a High Speed Downlink Packet Access (HSDPA), and the like.

[000127] It should be understood that similar to the other processing flows described herein, the steps and the order of the steps in the flowchart described herein may be altered, modified, removed and/or augmented and still achieve the desired outcome. A multiprocessing or multitasking environment could allow two or more steps to be executed concurrently.

[000128] While examples have been used to disclose the invention, including the best mode, and also to enable any person skilled in the art to make and use the invention, the patentable scope of the invention is defined by claims, and may include other examples that occur to those of ordinary skill in the art. Accordingly the examples disclosed herein are to be considered non-limiting.

[000129] It is further noted that the systems and methods may be implemented on various types of data processor environments (e.g., on one or more data processors) which execute instructions (e.g., software instructions) to perform operations disclosed herein. Non-limiting examples include implementation on a single general purpose computer or workstation, or on a networked system, or in a client-server configuration, or in an application service provider configuration. For example, the methods and systems described herein may be implemented on many different types of processing devices by program code comprising program instructions that are executable by the device processing subsystem. The software program instructions may include source code, object code, machine code, or any other stored data that is operable to cause a processing system to perform the methods and operations described herein. Other implementations may also be used, however, such as firmware or even appropriately designed hardware configured to carry out the methods and systems described herein. For example, a computer can be programmed with instructions to perform the various steps of the flowcharts or state charts shown in FIGS. 10-12.

[000130] The systems' and methods' data (e.g., associations, mappings, data input, data output, intermediate data results, final data results, etc.) may be stored and implemented in one or more

different types of computer-implemented data stores, such as different types of storage devices and programming constructs (e.g., RAM, ROM, Flash memory, flat files, databases, programming data structures, programming variables, IF-THEN (or similar type) statement constructs, etc.). It is noted that data structures describe formats for use in organizing and storing data in databases, programs, memory, or other computer-readable media for use by a computer program.

[000131] The systems and methods may be provided on many different types of computer-readable storage media including computer storage mechanisms (e.g., non-transitory media, such as CD-ROM, diskette, RAM, flash memory, computer's hard drive, etc.) that contain instructions (e.g., software) for use in execution by a processor to perform the methods' operations and implement the systems described herein.

[000132] The computer components, software modules, functions, data stores and data structures described herein may be connected directly or indirectly to each other in order to allow the flow of data needed for their operations. It is also noted that a module or processor includes but is not limited to a unit of code that performs a software operation, and can be implemented for example as a subroutine unit of code, or as a software function unit of code, or as an object (as in an object-oriented paradigm), or as an applet, or in a computer script language, or as another type of computer code. The software components and/or functionality may be located on a single computer or distributed across multiple computers depending upon the situation at hand.

[000133] It should be understood that as used in the description herein and throughout the claims that follow, the meaning of "a," "an," and "the" includes plural reference unless the context clearly dictates otherwise. Also, as used in the description herein and throughout the claims that follow, the meaning of "in" includes "in" and "on" unless the context clearly dictates otherwise. Finally, as used in the description herein and throughout the claims that follow, the meanings of "and" and "or" include both the conjunctive and disjunctive and may be used interchangeably unless the context expressly dictates otherwise; the phrase "exclusive or" may be used to indicate situation where only the disjunctive meaning may apply.

WHAT IS CLAIMED IS:

1. A system for stimulating oil or gas production from a wellbore, comprising:

(a) a hydraulic fracturing pump unit having

two or more fluid pumps, each fluid pump being driven by an alternating current (AC) electrical pump motor coupled to said fluid pump, and a variable frequency drive (VFD) controlling the electrical pump motor;

(b) an electrically powered hydraulic blender unit configured to provide treatment fluid to at least one of said one or more fluid pumps for delivery to the wellbore, wherein the blender unit comprises at least one AC electrical blending motor; and

(c) a system control unit communicating with each of said hydraulic fracturing pump unit and electrically powered hydraulic blender unit, for controlling operational parameters of each of said units,

wherein the system control unit is configured to separately control parameters of each of said two or more fluid pumps of the hydraulic fracturing pump unit.

2. The system of claim 1, further comprising a hydration unit for mixing water and chemical additives to provide a frac fluid supplied to the hydraulic blender unit, and wherein the system control unit further controls operational parameters of the hydration unit.

3. The system of claim 2, wherein the system control unit is configured to communicate wirelessly with each of said hydraulic fracturing pump unit, electrically powered hydraulic blender unit, and a hydration unit.

4. The system of claim 2, wherein the system control unit communicates with at least one of said hydraulic fracturing pump unit, electrically powered hydraulic blender unit and a hydration unit over a physical medium, such as a cable or an optical fiber.

5. The system of claim 1 further comprising at least two hydraulic fracturing pump units, and one or more of said at least two hydraulic fracturing pump units having a programmable automation controller (PAC) communicating with the system control unit.

6. The system of claim 1, wherein at least two fluid pumps of the hydraulic fracturing pump unit have different pumping capacities, and the system control unit is configured to dynamically initialize and maintain operating parameters of the fluid pumps of the hydraulic fracturing pump unit based on information about the flow rate of each fluid pump and the flow rate of the electrically powered hydraulic blender unit.

7. The system of claim 2, wherein each of said hydraulic fracturing pump unit, hydraulic blender unit and hydration unit comprise at least one programmable automation controller (PAC) configured to receive commands from the system control unit.

8. The system of claim 7, wherein the system control unit comprises a human machine interface (HMI) connected via a data channel to the at least one PAC of said hydraulic fracturing pump unit, hydraulic blender unit and hydration unit.

9. The system of claim 1, wherein the hydraulic fracturing pump unit is removably mounted on a trailer, truck, or skid that is connected to a manifold system for delivery of slurry to the wellbore, the system further comprising a backup hydraulic fracturing pump unit mounted on the same or different trailer, truck or skid, said backup hydraulic fracturing pump unit further being connected to the manifold system to supplement or replace the hydraulic fracturing pump unit if needed.

10. The system of claim 2, wherein each of said hydraulic fracturing pump unit, hydraulic blender unit and hydration unit further comprises ancillary systems including one or more of (i) a lubrication pump system, (ii) cooling pump system, and (iii) a blower system.

11. The system of claim 7, wherein said at least one PAC is configured to autonomously monitor operating parameters of the associated system unit, and cause the system unit to shut down in case the operating parameters of the system unit exceed predetermined limits.

12. A system for stimulating oil or gas production from a wellbore, comprising:

a hydraulic fracturing pump unit having

a hydraulic fracturing pump driven by an electrical fracturing motor;

a variable frequency drive (VFD) controlling the electrical fracturing motor;

a fracturing pump blower unit driven by an electrical blower motor; and

a fracturing pump lubrication unit comprising a lubrication pump driven by an electrical lubrication motor, and

a cooling fan driven by an electrical cooling motor;

an electrically powered hydraulic blender unit configured to provide treatment fluid to the hydraulic fracturing pump unit for delivery to the wellbore, the blender unit comprising at least one electrical blending motor; and

a system control unit comprising

(i) a hydraulic fracturing pump unit controller configured to control the hydraulic fracturing pump unit; and

(ii) a hydraulic blender unit controller configured to control the hydraulic blender unit.

13. The system of claim 12, further comprising a hydration unit having at least one electrical hydration motor; and wherein the system control unit further comprises (iii) a hydration unit controller configured to control operational parameters of the hydration unit.

14. The system of claim 12, wherein the hydraulic blender unit comprises a slurry-power unit (SPU) that is driven by an SPU motor, and a hydraulic power unit (HPU) that is driven by a HPU motor.

15. The system of claim 12 wherein the hydraulic blender unit further comprises a SPU blower unit that is driven by an SPU blower motor and an HPU blower unit that is driven by a HPU blower motor.

16. The system of claim 13, wherein the hydration unit comprises a hydration HPU that is driven by a hydration HPU motor and a hydration HPU blower unit that is driven by a hydration HPU blower motor.

17. The system of claim 13, wherein the system control unit is configured to communicate bidirectionally with each of said hydraulic fracturing pump unit, electrically powered hydraulic blender unit, and hydration unit.

18. The system of claim 13, wherein each of said hydraulic fracturing pump unit, electrically powered hydraulic blender unit, and hydration unit further comprises at least one programmable automation controller (PAC) for communicating with the system control unit.

19. The system of claim 12, wherein the hydraulic fracturing pump unit comprises at least two fluid pumps having different pumping capacities, and the system control unit is configured to dynamically initialize and maintain operating parameters of the fluid pumps of the hydraulic fracturing pump unit based on information about the flow rate of each fluid pump and the flow rate of the electrically powered hydraulic blender unit.

20. The system of claim 18, wherein each of said PACs is further configured to receive monitoring data concerning the operating parameters of the respective unit and to communicate said monitoring data to the system control unit.

21. The system of claim 18, wherein the system control unit comprises a human machine interface (HMI) connected via a data channel to the at least one PAC of said hydraulic fracturing pump unit, hydraulic blender unit and hydration unit.

22. The system of claim 12, wherein the hydraulic fracturing pump unit is removably mounted on a trailer, truck, or skid that is connected to a manifold system for delivery of slurry to the wellbore, the system further comprising a backup hydraulic fracturing pump unit mounted on the trailer, truck, or skid, said backup hydraulic fracturing pump unit further being connected to the manifold system to supplement or replace the hydraulic fracturing pump unit as needed.

23. A system control unit for use with a system for stimulating oil or gas production from a wellbore, the system control unit comprising:

(a) a hydraulic fracturing pump unit controller configured to control a hydraulic fracturing pump unit having one or more hydraulic fracturing electrical motors, the hydraulic fracturing pump unit controller comprising

(i) a hydraulic fracturing pump controller configured to control a hydraulic fracturing pump; and

(ii) a hydraulic fracturing blower unit controller configured to control a hydraulic fracturing pump blower unit; and

(iii) a hydraulic fracturing lubrication unit controller configured to control a hydraulic fracturing pump lubrication unit; and

(b) a hydraulic blender unit controller configured to control a hydraulic blender pump unit having one or more hydraulic blender electrical motors, the hydraulic blender pump unit controller comprising

(i) a blender control unit for controlling the operation of one or more blender units,

(ii) a blender slurry power unit (SPU) pump control unit for controlling the operation of one or more blender SPU units,

(iii) a blender SPU blower control unit for controlling the operation of one or more blender SPU blower units, and

(iv) a blender blower control unit for controlling the operation of one or more blender blower units.

24. The system control unit of claim 23 further comprising

(c) a hydration unit controller configured to control a hydration unit having one or more hydration electrical motors, the hydration unit controller comprising

(i) a hydration pump control unit for controlling the operation of one or more hydration units, and

(ii) a hydration blower control unit for controlling the operation of one or more hydration blower units.

25. The system of claim 24 further comprising a human machine interface (HMI) communicating with at least one programmable automation controller (PAC) in the hydraulic fracturing pump unit, hydraulic blender unit and hydration unit.

26. The system control unit of claim 23, wherein the system control unit is located in the physical vicinity of the hydraulic fracturing pump unit and hydraulic blender unit and communicates bidirectionally over a physical medium, such as a cable or an optical fiber, with at least one PAC on the hydraulic fracturing pump unit and hydraulic blender unit.

27. The system control unit of claim 23, wherein the system control unit is located remotely from the hydraulic fracturing pump unit and hydraulic blender unit, and communicating wirelessly with at least one PAC on the hydraulic fracturing pump unit and hydraulic blender unit.

28. The system of claim 1, wherein the system control unit further comprises means for controlling an injection rate of the system.

29. The system of claim 12, wherein the system control unit further comprises means for controlling an injection rate of the system.

30. The system control unit of claim 23, further comprising means for controlling selection of active pumps, and for setting operating parameters of the active pumps.

31. A method for stimulating oil or gas production from a wellbore using an electrically powered fracturing system, the method comprising:

(a) establishing a data channel connecting at least one hydraulic fracturing pump unit and an electrical fracturing blender unit with a control unit of the system;

(b) controlling, using one or more variable frequency drives (VFDs), a plurality ($N \geq 2$) of electrical motors to drive at least one fluid pump of the at least one hydraulic fracturing pump unit;

(c) controlling, using one or more VFDs, at least one electrical blending motor to produce a fracturing fluid from an electrical fracturing blender unit; and

(d) pumping, using the at least one fluid pump driven by the plurality of electrical fracturing motors, a blended fracturing fluid down a wellbore located at the well site,

wherein operating parameters of each of the plurality of electrical motors in step (b) are controlled based upon (i) hydraulic fracturing design parameters including target injection rate or target pressure, and (ii) measured aggregate injection rate of the pumped fracturing fluid or measured aggregate pressure.

32. The method of claim 31, wherein step (b) further comprises the step of driving two or more fluid pumps, and controlling selection of one of the two or more fluid pumps and changing operating parameters of the selected fluid pump.

33. The method of claim 32, wherein target injection rate or target injection pressure parameters are provided using a human machine interface (HMI).

34. The method of claim 31, wherein controlling VFDs in step (b) is performed automatically based on predetermined design parameters.

35. The method of claim 31, wherein controlling VFDs in step (b) is performed manually from a human machine interface (HMI) in the control unit of the system.

36. The method of claim 31, further comprising the step of monitoring operating parameters of the individual electrical motors in steps (b) and (c), and taking individual motors off line in case the operating parameters exceed predetermined thresholds.

37. The method of claim 31, further comprising the step of controlling one or more backup pumps in case an individual motor is taken off line or additional injection rate is required.

38. A system for stimulating oil or gas production from a wellbore, comprising:

(a) a hydraulic fracturing pump unit having

a fluid pump being driven by an alternating current (AC) electrical pump motor coupled to said fluid pump, and a variable frequency drive (VFD) controlling the electrical pump motor;

(b) an electrically powered hydraulic blender unit configured to provide treatment fluid to at least one of said one or more fluid pumps for delivery to the wellbore, wherein the blender unit comprises at least one AC electrical blending motor; and

(c) a system control unit communicating with each of said hydraulic fracturing pump unit and electrically powered hydraulic blender unit, for controlling operational parameters of each of said units,

wherein the system control unit is configured to remotely control parameters of said fluid pump of the hydraulic fracturing pump unit.

39. The system of claim 38, further comprising a hydration unit for mixing water and chemical additives to provide a frac fluid supplied to the hydraulic blender unit, and wherein the system control unit further controls operational parameters of the hydration unit.

40. The system of claim 39, wherein the system control unit is configured to communicate wirelessly with each of said hydraulic fracturing pump unit, electrically powered hydraulic blender unit, and a hydration unit.

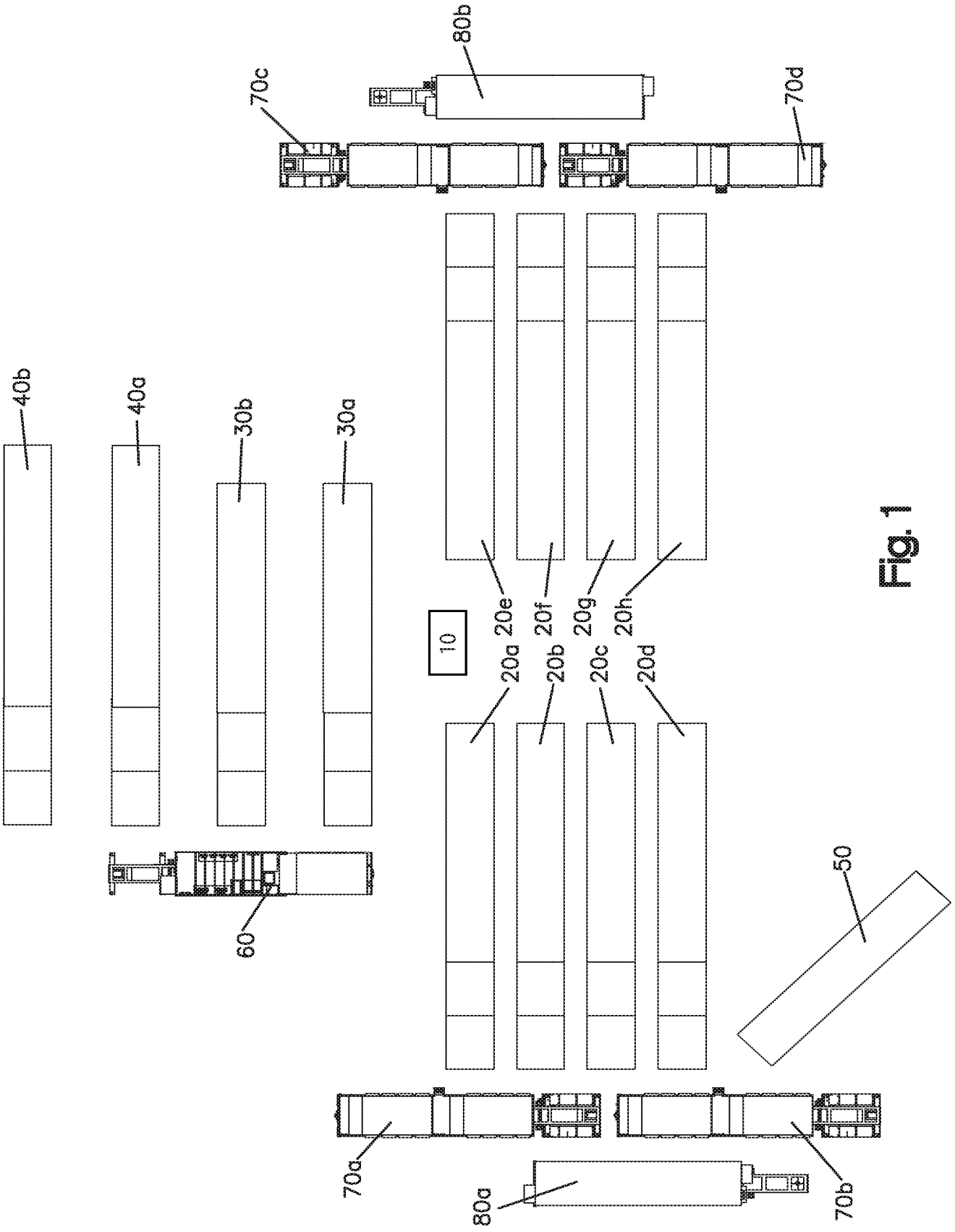

80b
70c
70d
40b
40a
30b
30a
20e
20f
20g
20h
10
20a
20b
20c
20d
50
60
70a
80a
70b

Fig. 1

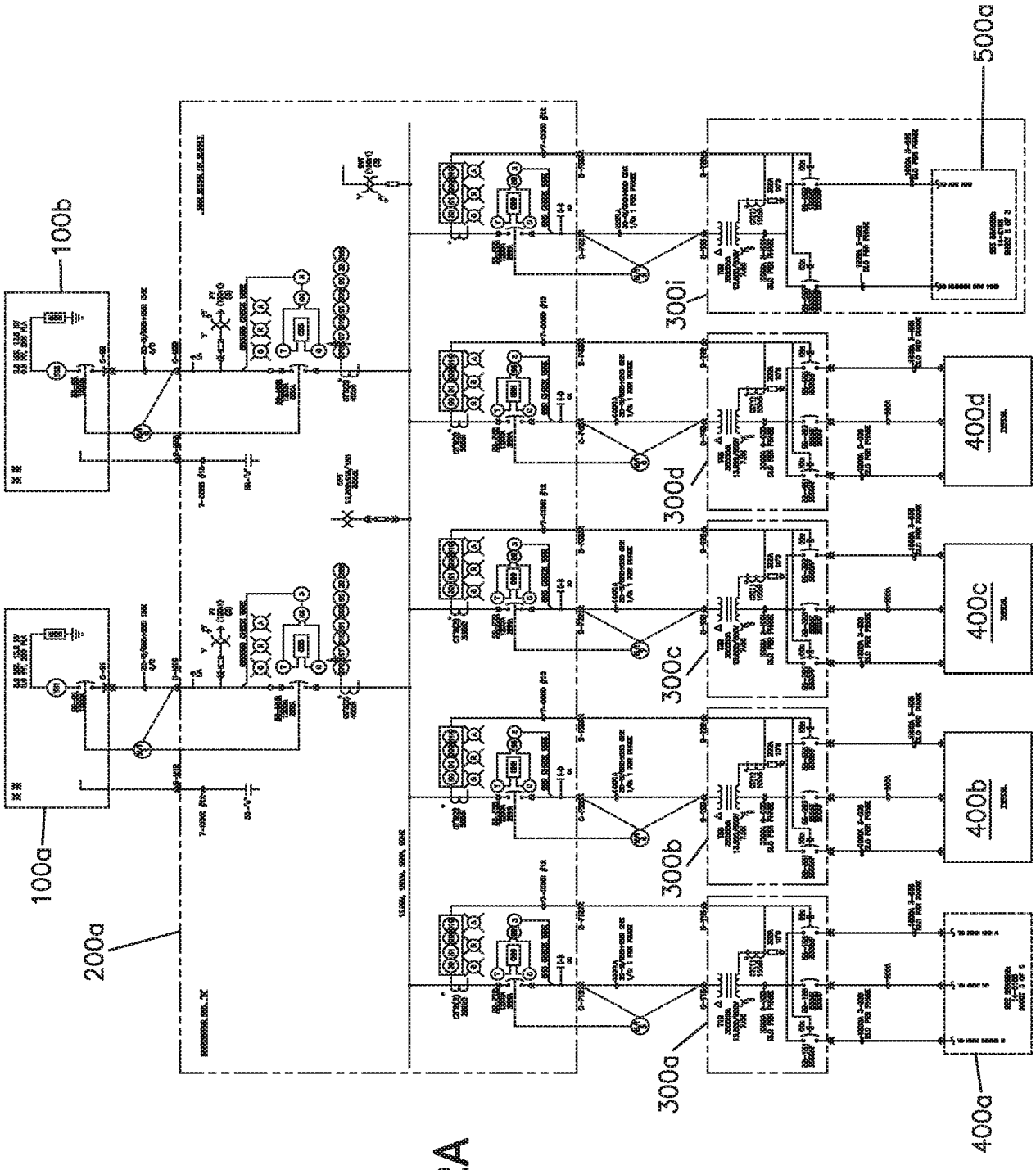

100b
100a
200a
300i
300d
300c
300b
300a
400d
400c
400b
400a
500a

Fig. 2A

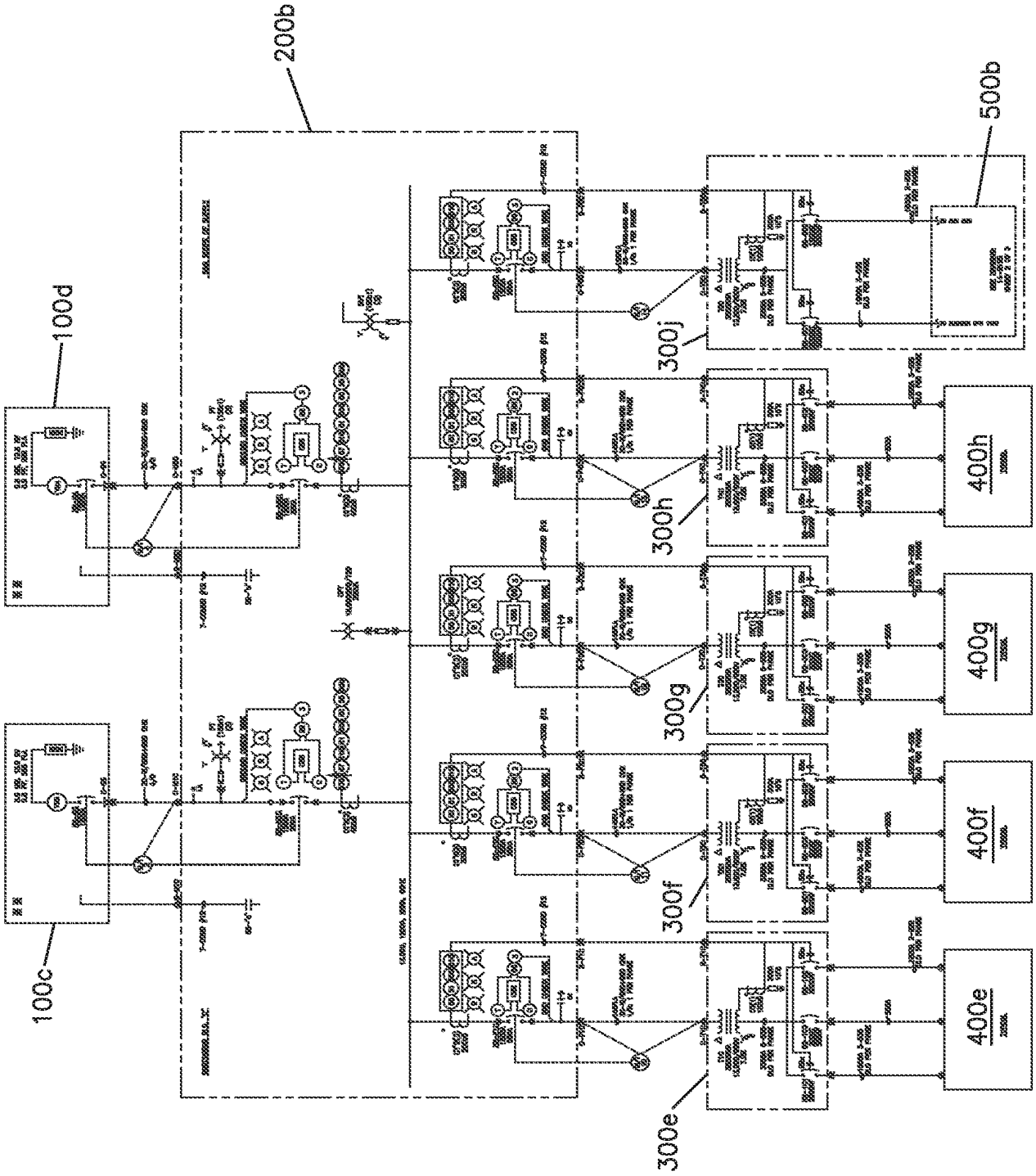

200b
500b
100d
100c
300j
300h
300g
300f
300e
400h
400g
400f
400e

Fig. 2B

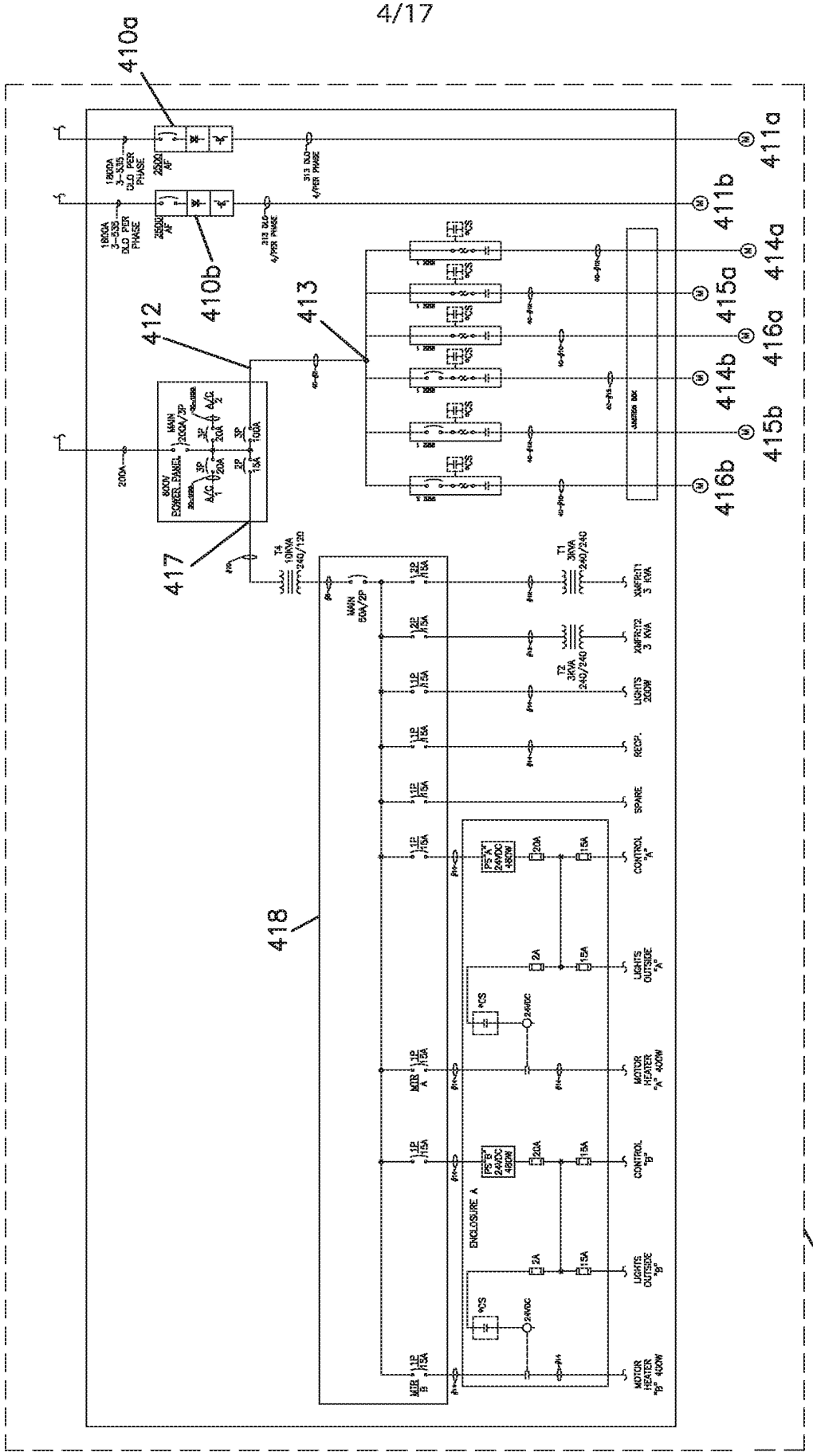

410a
410b
411a
411b
412
413
414a
414b
415a
415b
416a
416b
417
418
400a
ENCLOSURE A
MAIN 50A/2P
MAIN 200A/3P
MAIN BOMER PANEL
LIGHTS 220W
RECEP.
SPARE
CONTROL "A"
CONTROL "B"
LIGHTS OUTSIDE "A"
LIGHTS OUTSIDE "B"
MOTOR HEATER "A" 400W
MOTOR HEATER "B" 400W
PS "A" 24VDC 480W
PS "B" 24VDC 480W

Fig. 3

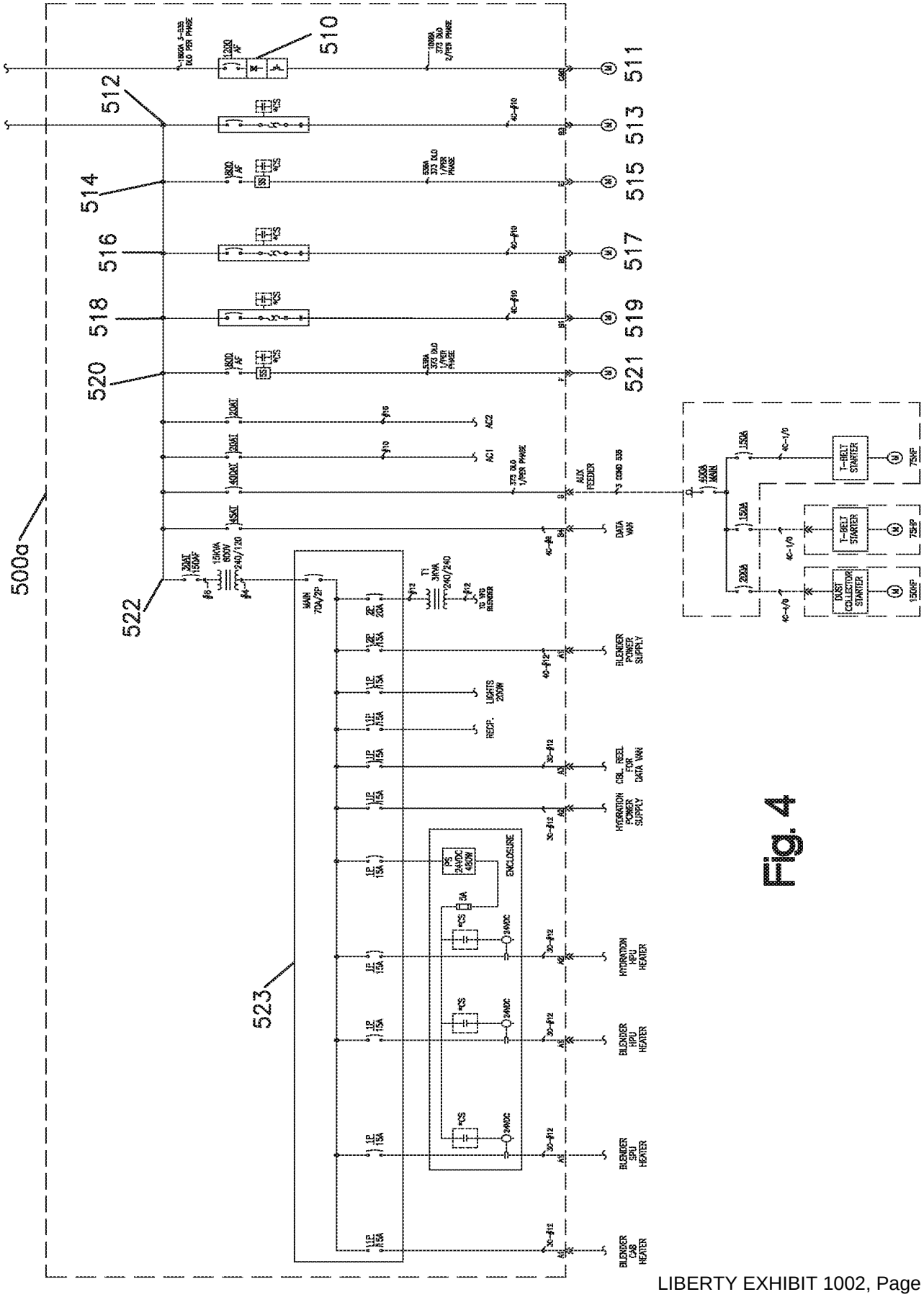

500a
510
511
512
513
514
515
516
517
518
519
520
521
522
523
AUX FEEDER
DATA VAN
AC1
AC2
BLENDER POWER SUPPLY
HYDRATION POWER SUPPLY
HYDRATION HPU HEATER
BLENDER HPU HEATER
BLENDER SPU HEATER
BLENDER CAB HEATER
ENCLOSURE
T-BELT STARTER
T-BELT STARTER
DUST COLLECTOR STARTER

Fig. 4

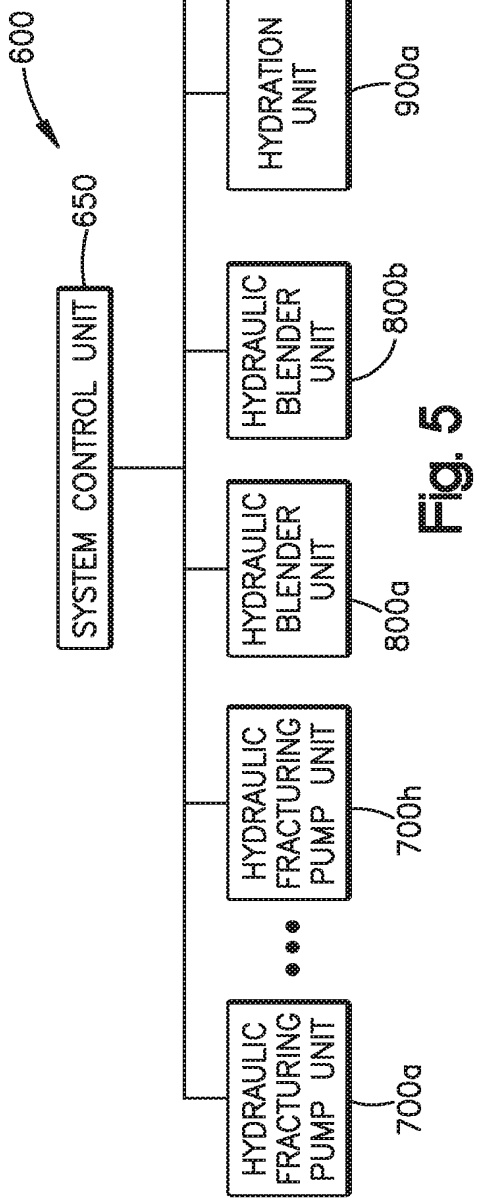

600
650
SYSTEM CONTROL UNIT
HYDRAULIC FRACTURING PUMP UNIT
700a
HYDRAULIC FRACTURING PUMP UNIT
700h
HYDRAULIC BLENDER UNIT
800a
HYDRAULIC BLENDER UNIT
800b
HYDRATION UNIT
900a
HYDRATION UNIT
900b

Fig. 5

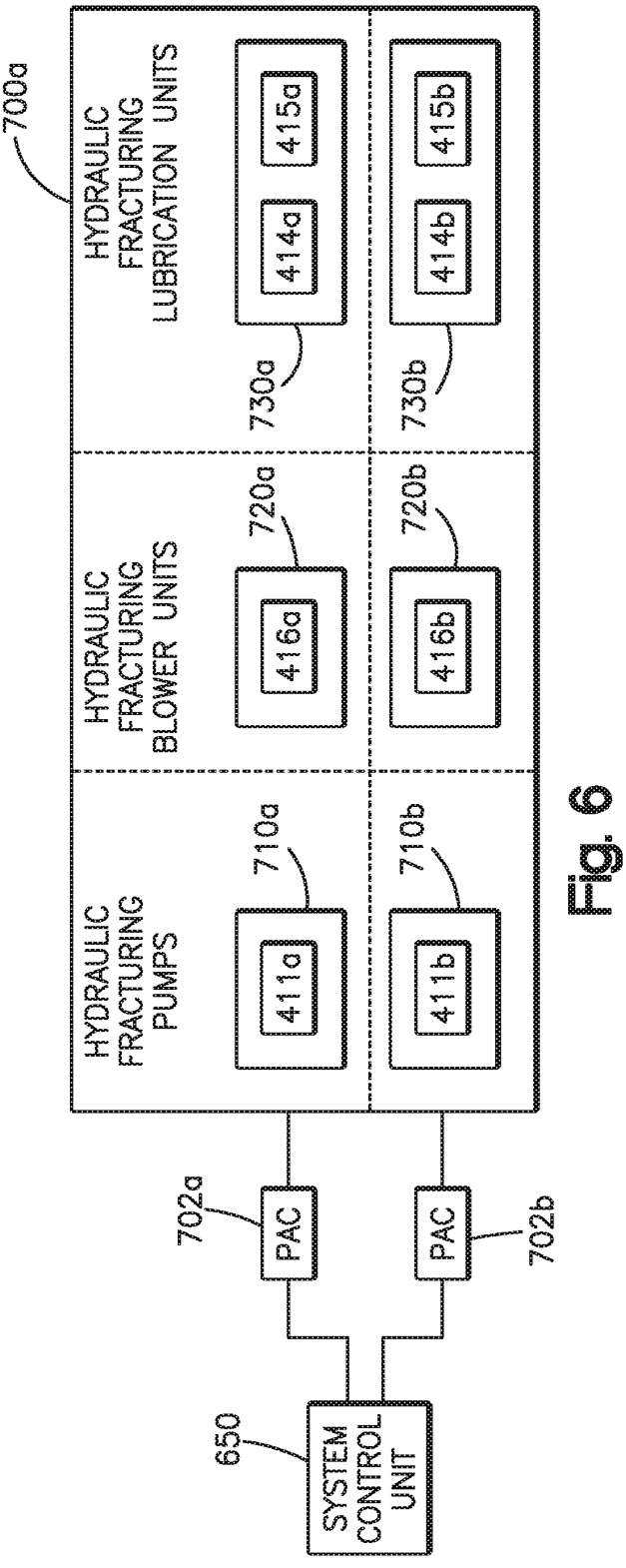

700a
HYDRAULIC FRACTURING PUMPS
HYDRAULIC FRACTURING BLOWER UNITS
HYDRAULIC FRACTURING LUBRICATION UNITS
411a
411b
710a
710b
416a
416b
720a
720b
414a
414b
415a
415b
730a
730b
PAC
PAC
702a
702b
650
SYSTEM CONTROL UNIT

Fig. 6

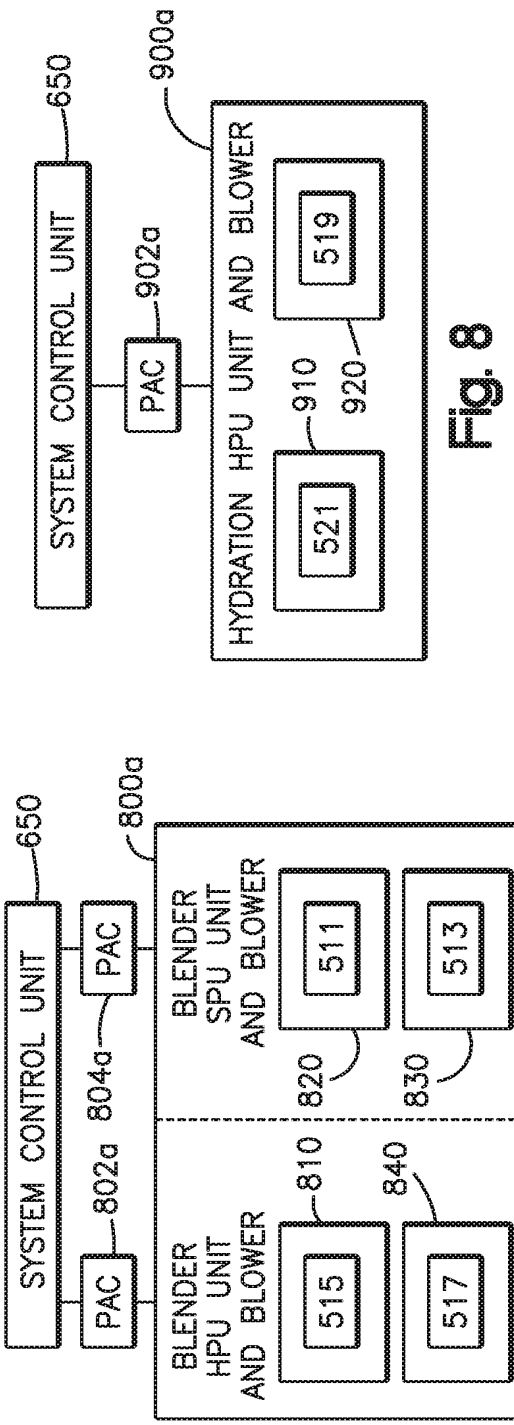


Fig. 7

Fig. 8

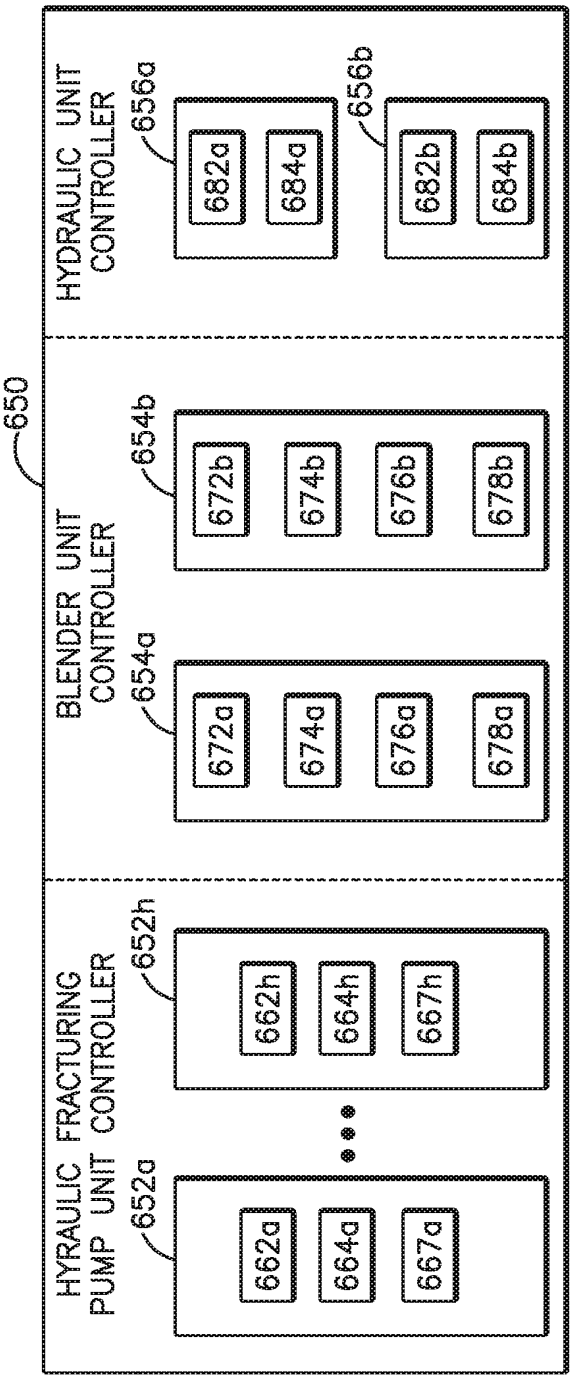


Fig. 9

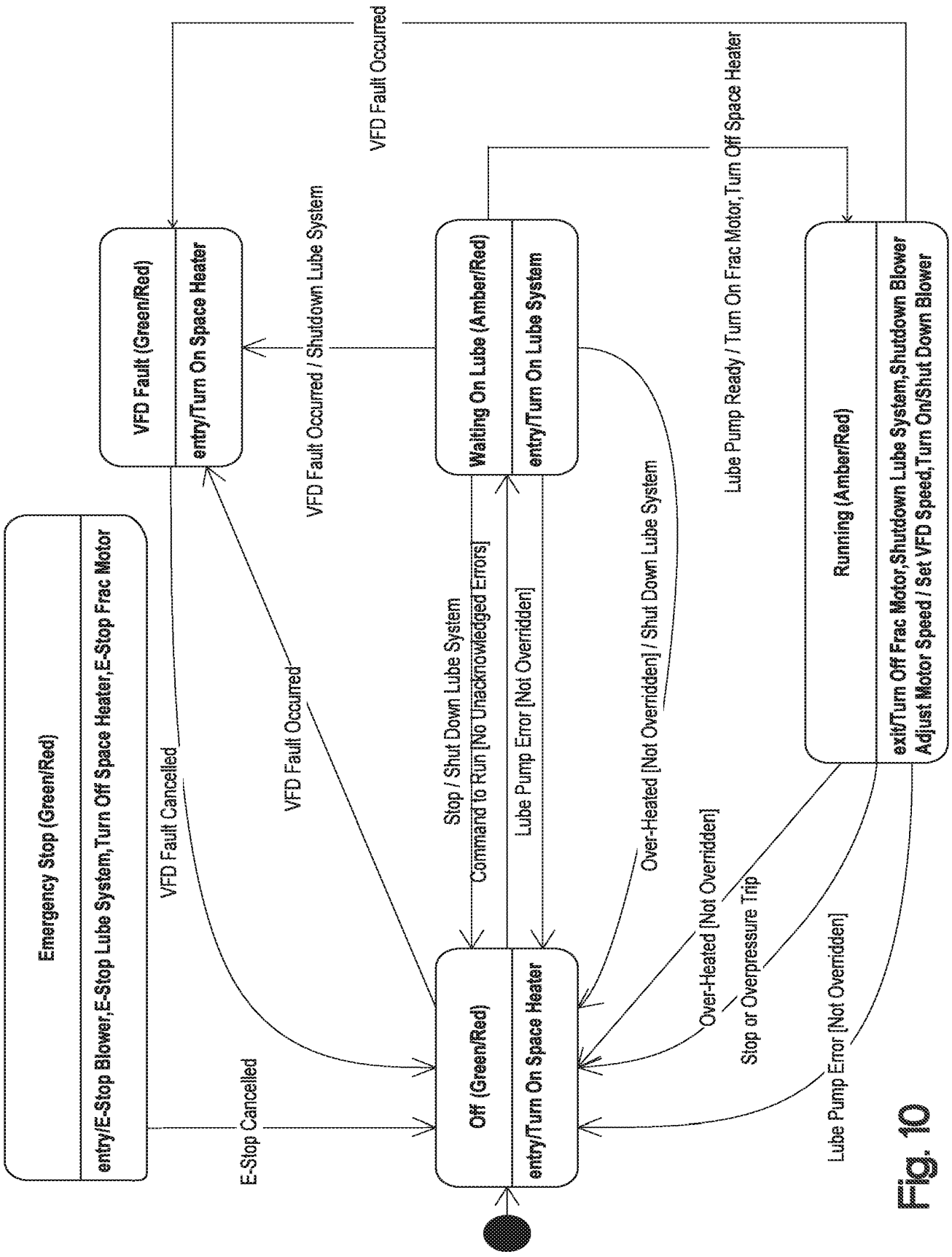

Emergency Stop (Green/Red)
entry/E-Stop Blower,E-Stop Lube System,Turn Off Space Heater,E-Stop Frac Motor
VFD Fault (Green/Red)
entry/Turn On Space Heater
Waiting On Lube (Amber/Red)
entry/Turn On Lube System
Running (Amber/Red)
exit/Turn Off Frac Motor,Shutdown Lube System,Shutdown Blower
Adjust Motor Speed / Set VFD Speed,Turn On/Shut Down Blower
Off (Green/Red)
entry/Turn On Space Heater
VFD Fault Occurred
VFD Fault Occurred / Shutdown Lube System
VFD Fault Occurred
VFD Fault Cancelled
E-Stop Cancelled
Stop / Shut Down Lube System
Command to Run [No Unacknowledged Errors]
Lube Pump Error [Not Overridden]
Over-Heated [Not Overridden] / Shut Down Lube System
Lube Pump Ready / Turn On Frac Motor,Turn Off Space Heater
Over-Heated [Not Overridden]
Stop or Overpressure Trip
Lube Pump Error [Not Overridden]

Fig. 10

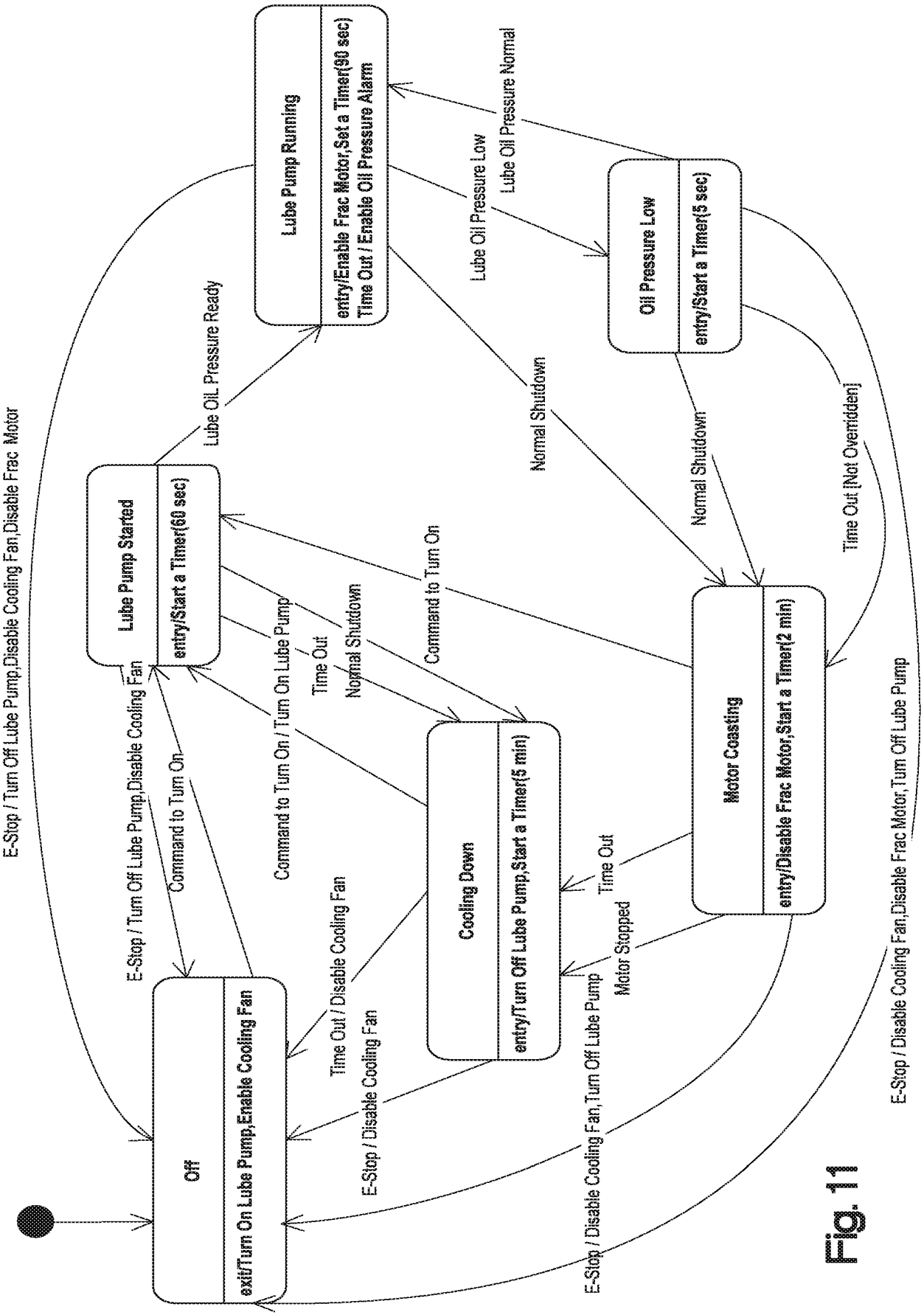

Lube Pump Running
entry/Enable Frac Motor,Set a Timer(90 sec)
Time Out / Enable Oil Pressure Alarm
Oil Pressure Low
entry/Start a Timer(5 sec)
Lube Pump Started
entry/Start a Timer(60 sec)
Motor Coasting
entry/Disable Frac Motor,Start a Timer(2 min)
Cooling Down
entry/Turn Off Lube Pump,Start a Timer(5 min)
Off
exit/Turn On Lube Pump,Enable Cooling Fan
Lube Oil Pressure Low
Lube Oil Pressure Normal
Lube OiL Pressure Ready
Normal Shutdown
Normal Shutdown
Time Out [Not Overridden]
Command to Turn On
Command to Turn On / Turn On Lube Pump
Time Out
Normal Shutdown
E-Stop / Turn Off Lube Pump,Disable Cooling Fan
Command to Turn On
E-Stop / Turn Off Lube Pump,Disable Cooling Fan,Disable Frac Motor
Time Out / Disable Cooling Fan
E-Stop / Disable Cooling Fan
Time Out
Motor Stopped
E-Stop / Disable Cooling Fan,Turn Off Lube Pump
E-Stop / Disable Cooling Fan,Disable Frac Motor, Turn Off Lube Pump

Fig. 11

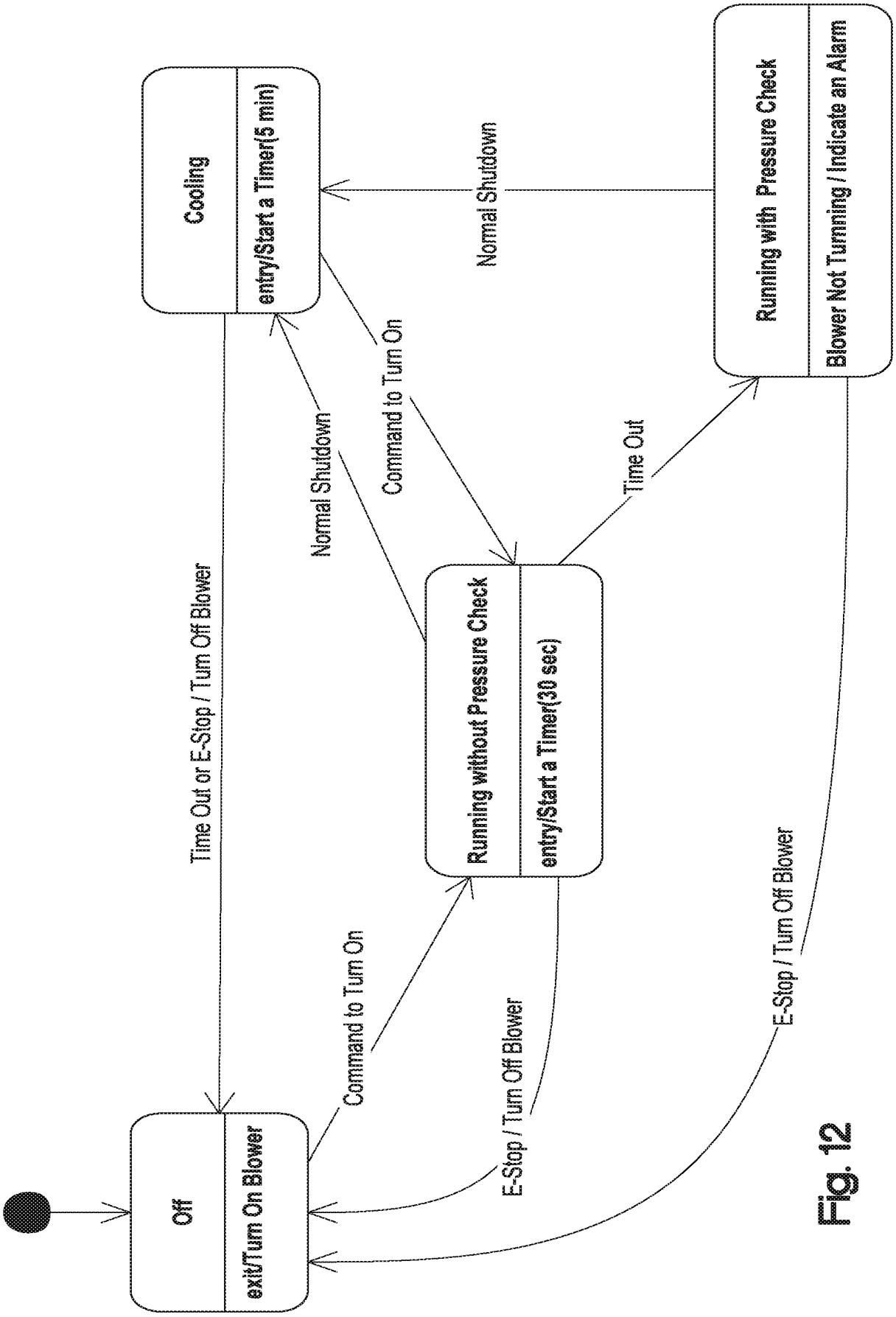

Cooling
entry/Start a Timer(5 min)
Running with Pressure Check
Blower Not Turning / Indicate an Alarm
Running without Pressure Check
entry/Start a Timer(30 sec)
Off
exit/Turn On Blower
Normal Shutdown
Command to Turn On
Normal Shutdown
Command to Turn On
Time Out
Time Out or E-Stop / Turn Off Blower
Command to Turn On
E-Stop / Turn Off Blower
E-Stop / Turn Off Blower

Fig. 12

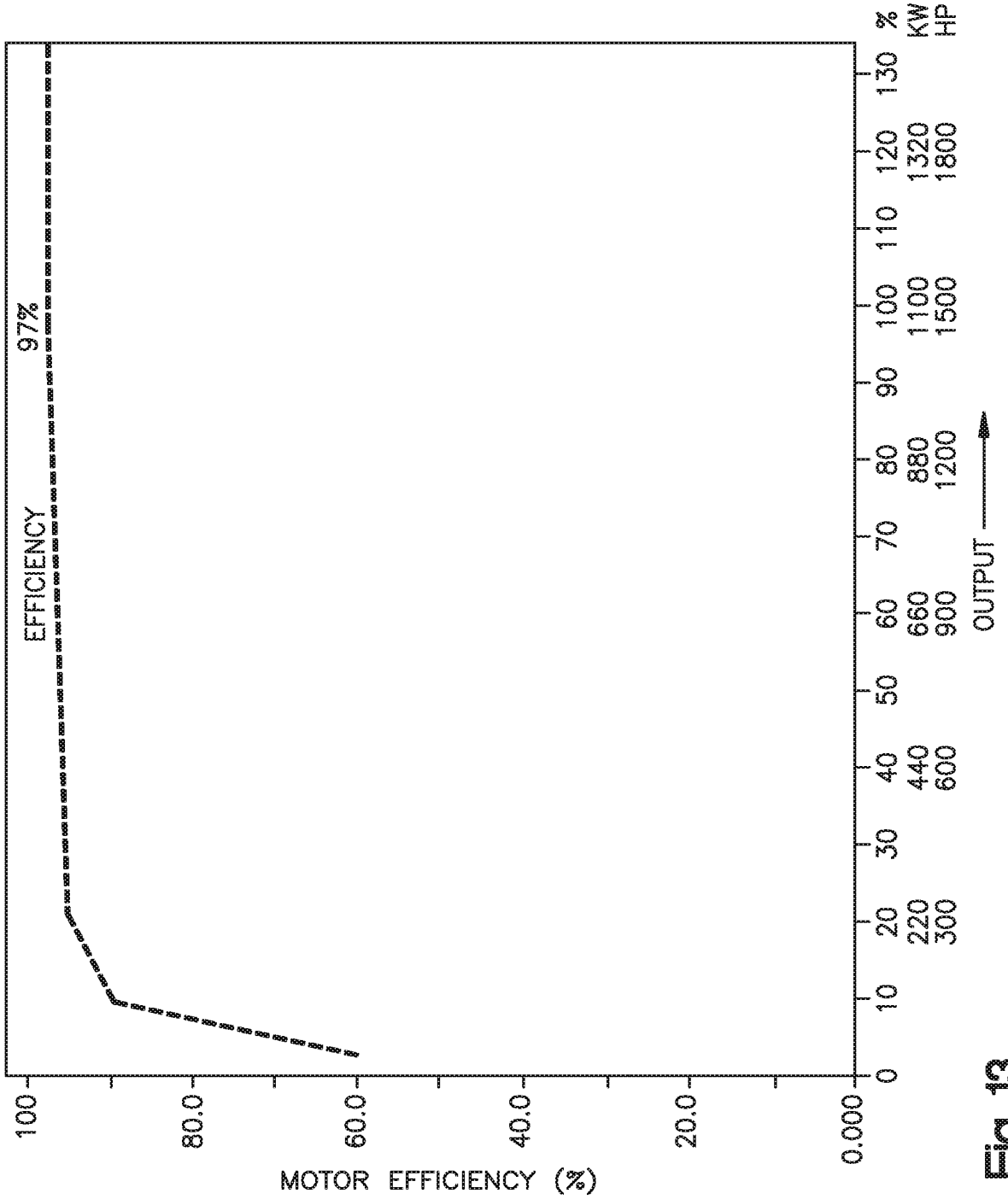

EFFICIENCY
97%
100
80.0
60.0
40.0
20.0
0.000
MOTOR EFFICIENCY (%)
0
10
20
30
40
50
60
70
80
90
100
110
120
130
%
220
300
440
600
660
900
880
1200
1100
1500
1320
1800
KW
HP
OUTPUT

Fig. 13

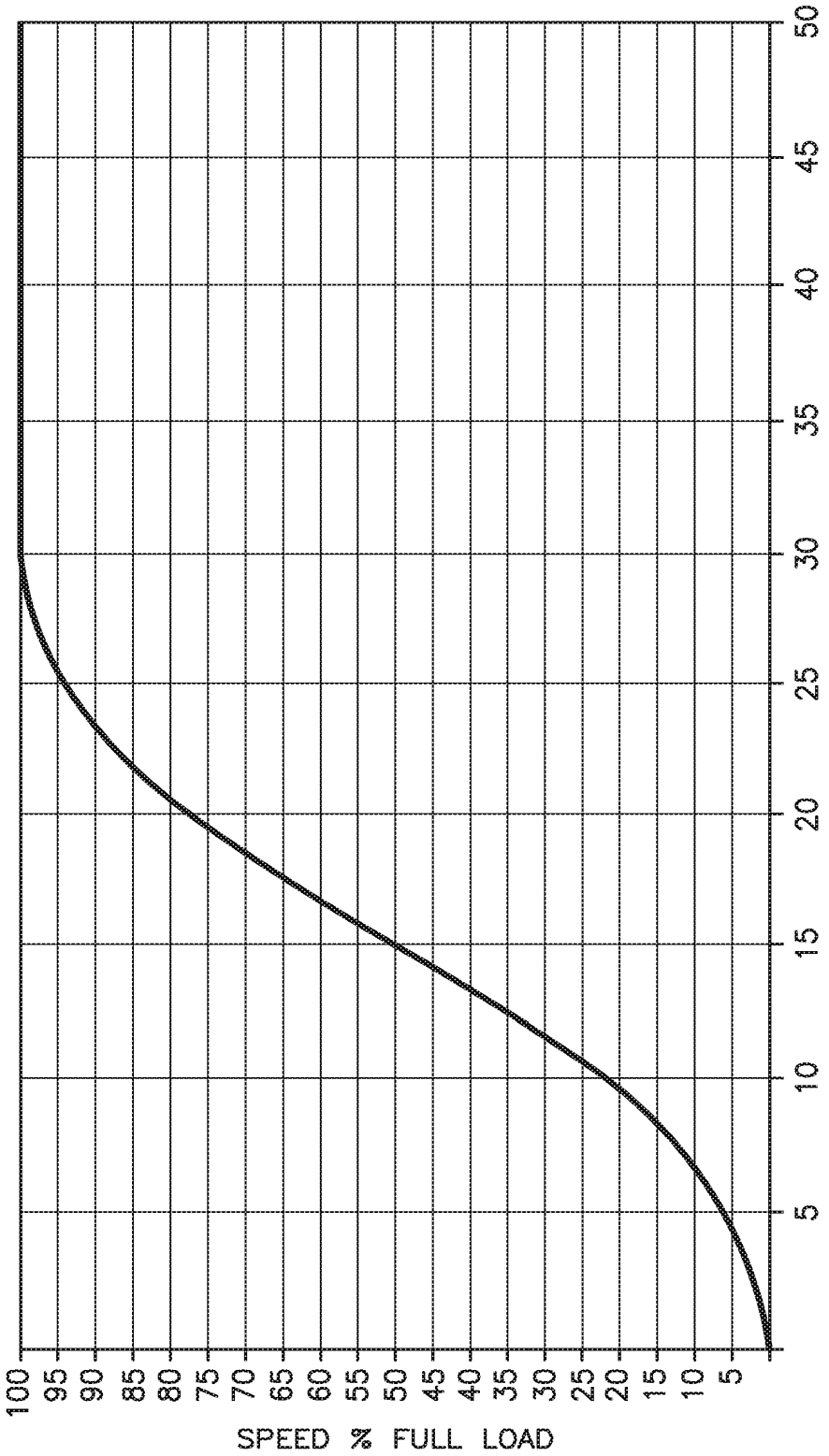

SPEED % FULL LOAD
100
95
90
85
80
75
70
65
60
55
50
45
40
35
30
25
20
15
10
5
TIME (SECONDS)
5
10
15
20
25
30
35
40
45
50

Fig. 14

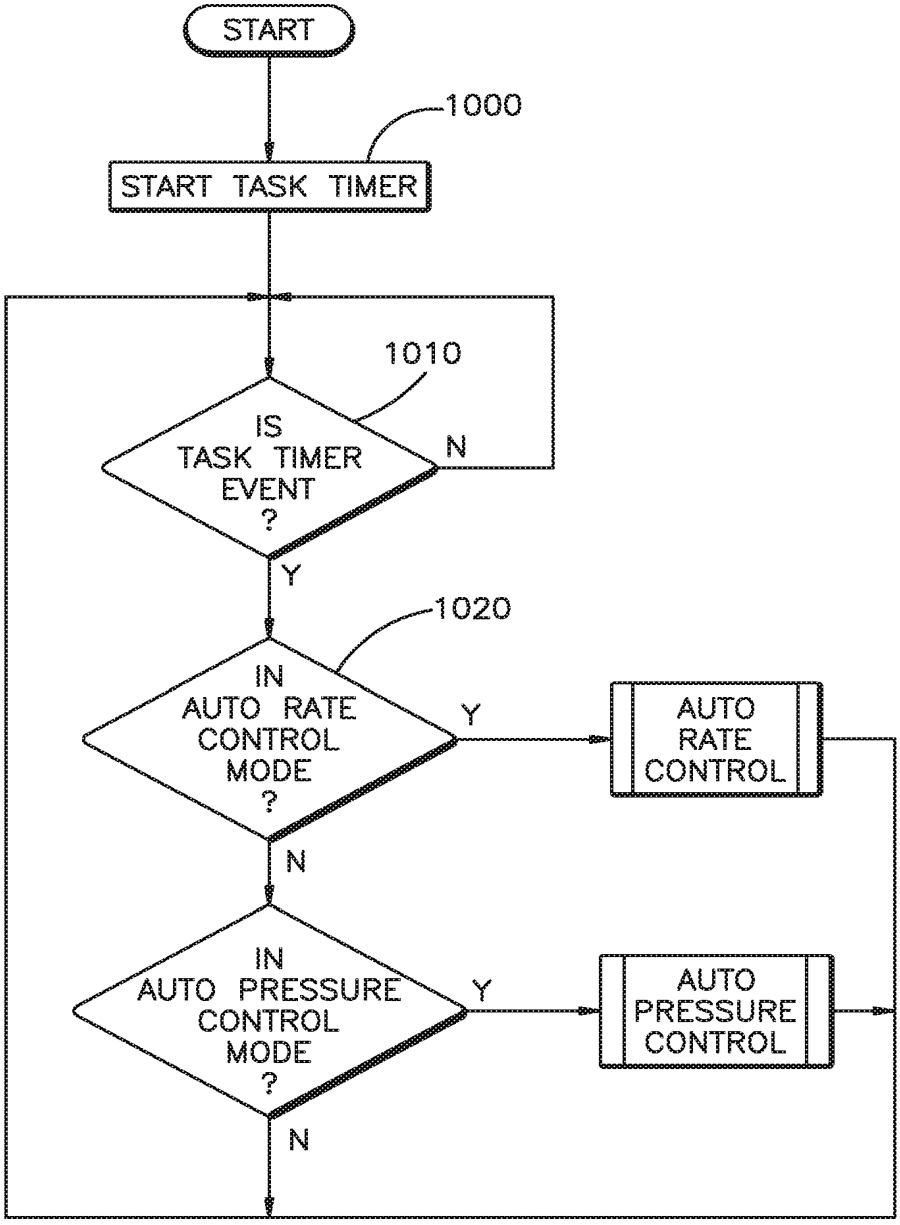

START
1000
START TASK TIMER
1010
IS TASK TIMER EVENT ?
N
Y
1020
IN AUTO RATE CONTROL MODE ?
Y
AUTO RATE CONTROL
N
IN AUTO PRESSURE CONTROL MODE ?
Y
AUTO PRESSURE CONTROL
N

Fig. 15A

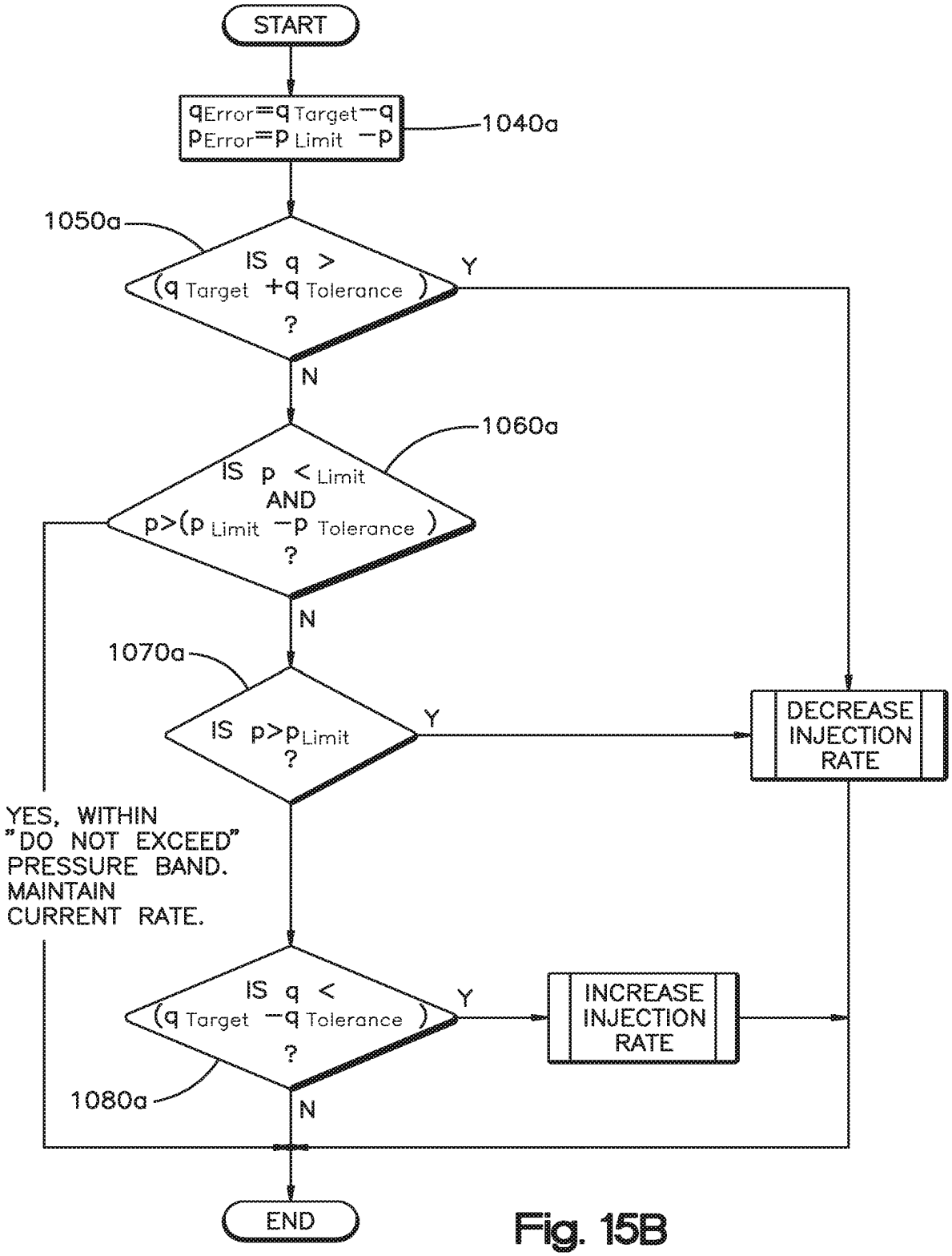

START
qError=qTarget−q
pError=pLimit −p
1040a
1050a
IS q > (qTarget +qTolerance) ?
Y
N
1060a
IS p < Limit AND p>(pLimit −pTolerance) ?
N
1070a
IS p>pLimit ?
Y
DECREASE INJECTION RATE
YES, WITHIN "DO NOT EXCEED" PRESSURE BAND. MAINTAIN CURRENT RATE.
IS q < (qTarget −qTolerance) ?
Y
INCREASE INJECTION RATE
1080a
N
END

Fig. 15B

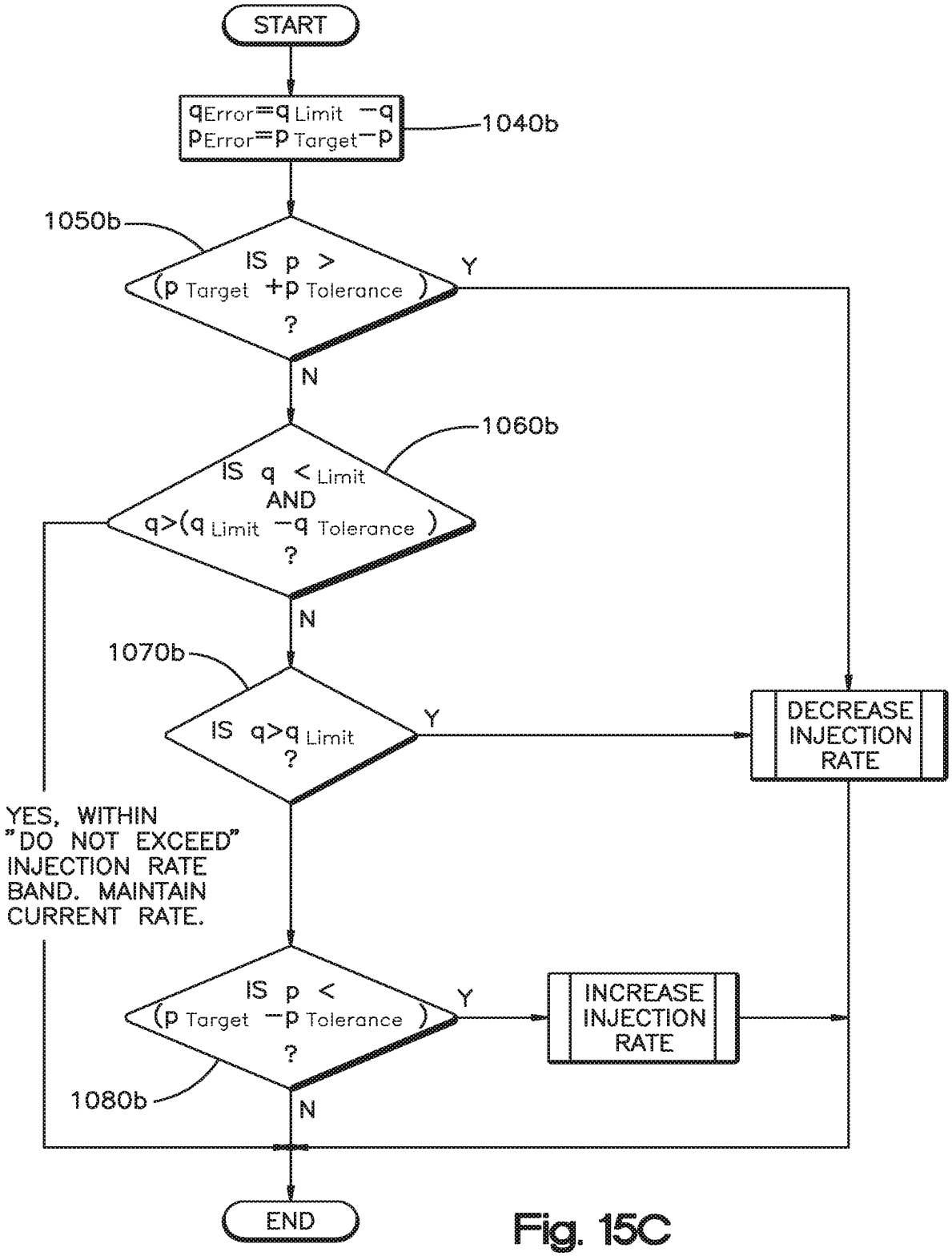

START
qError=q Limit −q
pError=p Target−p
1040b
1050b
IS p > (p Target +p Tolerance) ?
Y
N
1060b
IS q < Limit AND q>(q Limit −q Tolerance) ?
N
1070b
IS q>q Limit ?
Y
DECREASE INJECTION RATE
YES, WITHIN "DO NOT EXCEED" INJECTION RATE BAND. MAINTAIN CURRENT RATE.
IS p < (p Target −p Tolerance) ?
Y
INCREASE INJECTION RATE
1080b
N
END

Fig. 15C

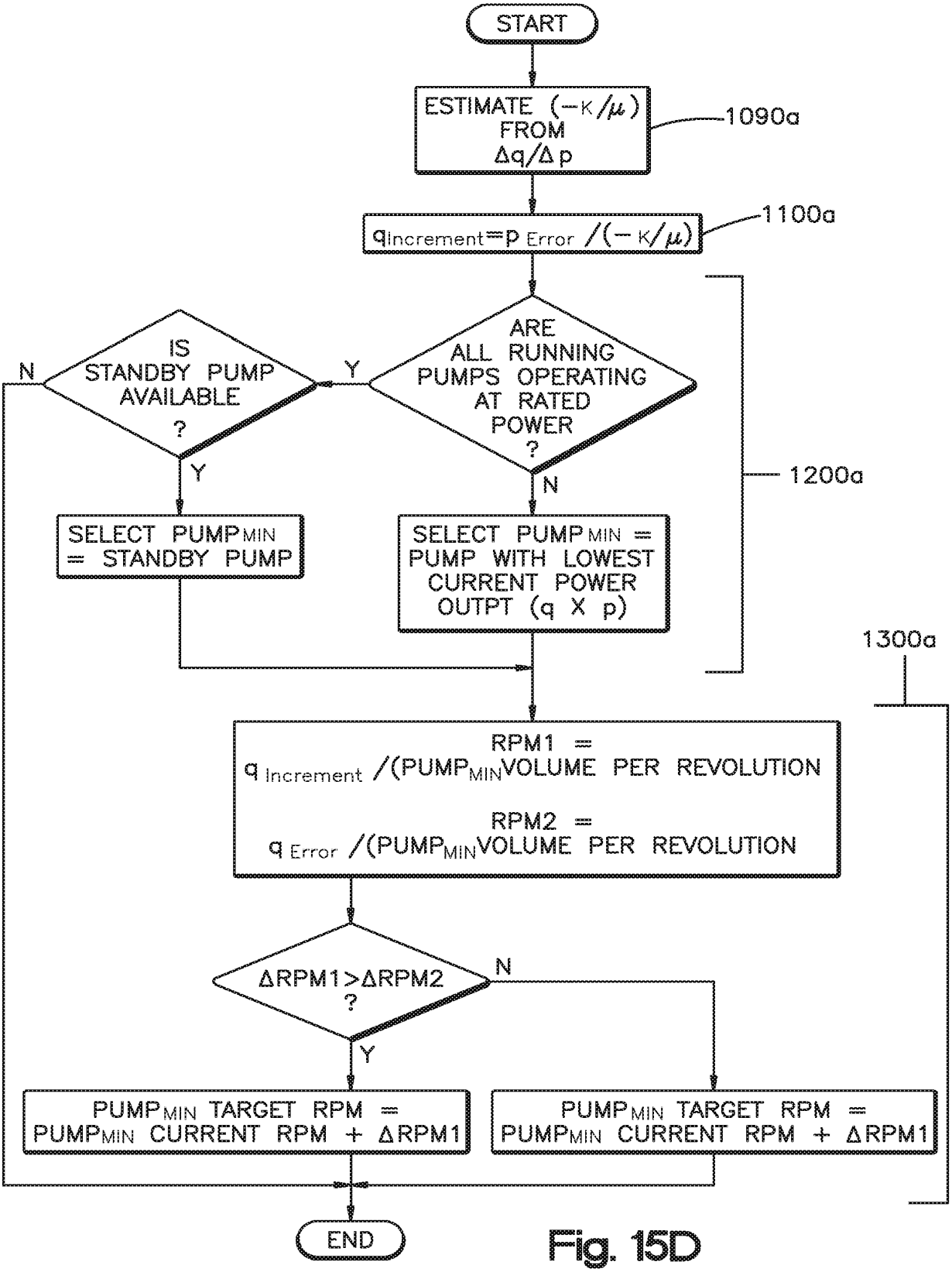

START
ESTIMATE (−K/μ) FROM Δq/Δp
1090a
qIncrement=p Error /(−K/μ)
1100a
ARE ALL RUNNING PUMPS OPERATING AT RATED POWER ?
Y
N
IS STANDBY PUMP AVAILABLE ?
N
Y
1200a
SELECT PUMPMIN = STANDBY PUMP
SELECT PUMPMIN = PUMP WITH LOWEST CURRENT POWER OUTPT (q X p)
1300a
RPM1 = q Increment /(PUMPMIN VOLUME PER REVOLUTION
RPM2 = q Error /(PUMPMIN VOLUME PER REVOLUTION
ΔRPM1>ΔRPM2 ?
N
Y
PUMPMIN TARGET RPM = PUMPMIN CURRENT RPM + ΔRPM1
PUMPMIN TARGET RPM = PUMPMIN CURRENT RPM + ΔRPM1
END

Fig. 15D

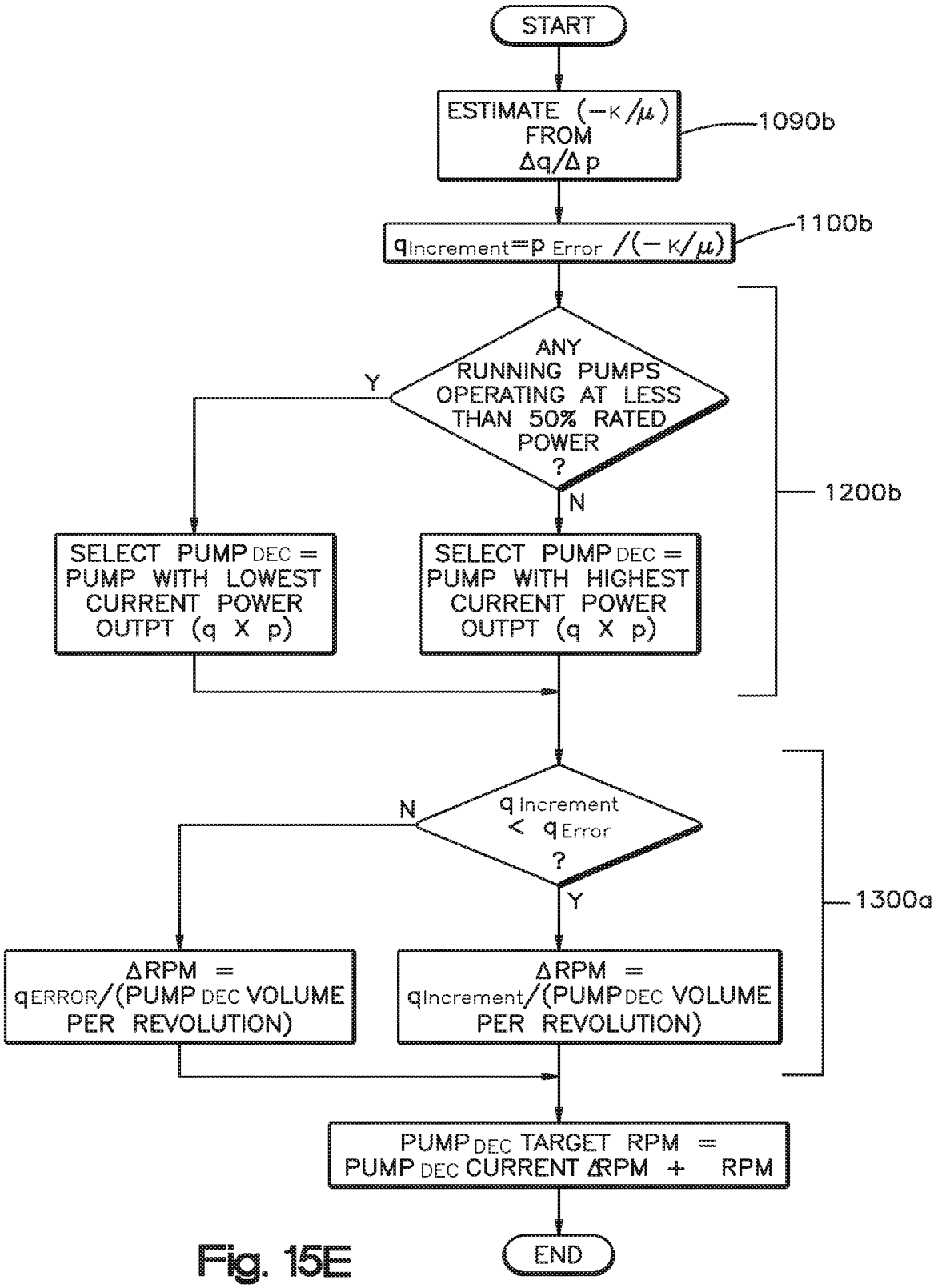

START
ESTIMATE (−K/μ) FROM Δq/Δp
1090b
qIncrement = p Error /(−K/μ)
1100b
ANY RUNNING PUMPS OPERATING AT LESS THAN 50% RATED POWER ?
Y
N
1200b
SELECT PUMP DEC = PUMP WITH LOWEST CURRENT POWER OUTPT (q X p)
SELECT PUMP DEC = PUMP WITH HIGHEST CURRENT POWER OUTPT (q X p)
qIncrement < qError ?
N
Y
1300a
ΔRPM = qERROR/(PUMP DEC VOLUME PER REVOLUTION)
ΔRPM = qIncrement/(PUMP DEC VOLUME PER REVOLUTION)
PUMP DEC TARGET RPM = PUMP DEC CURRENT ΔRPM + RPM
END

Fig. 15E

Innovation, Sciences et Développement économique Canada
Office de la Propriété Intellectuelle du Canada

Innovation, Science and Economic Development Canada
Canadian Intellectual Property Office

CA 3000322 A1 2013/04/18

(21) 3 000 322

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) Date de dépôt/Filing Date: 2012/10/09

(41) Mise à la disp. pub./Open to Public Insp.: 2013/04/18

(62) Demande originale/Original Application: 2 849 825

(30) Priorité/Priority: 2011/10/09 (US13/269,596)

(51) Cl.Int./Int.Cl. *E21B 47/085* (2012.01), *E21B 41/00* (2006.01), *E21B 43/30* (2006.01), *E21B 47/0224* (2012.01), *E21B 43/26* (2006.01)

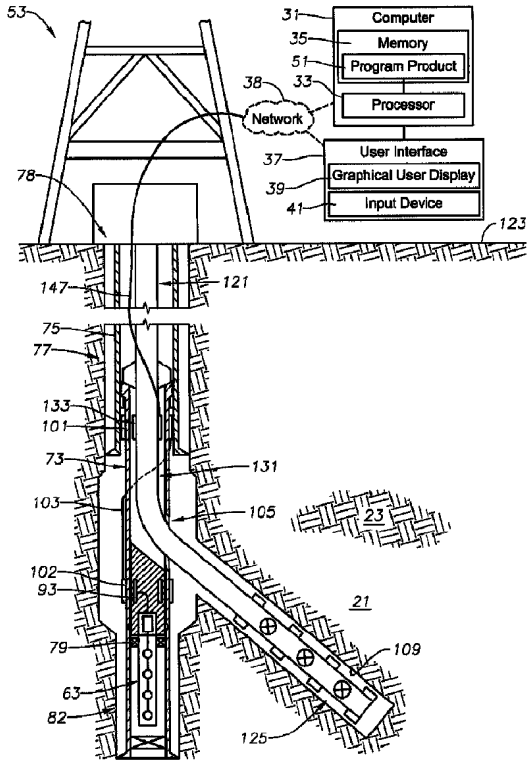
(71) Demandeur/Applicant:
SAUDI ARABIAN OIL COMPANY, SA

(72) Inventeurs/Inventors:
BARTKO, KIRK M., SA;
BOULDIN, BRETT WAYNE, SA...

(74) Agent: FINLAYSON & SINGLEHURST

(54) Titre : PROCEDE DE CONTROLE ET DE TRANSMISSION EN TEMPS REEL VERS LA SURFACE D'EVENEMENTS SISMIQUES DANS UNE FRACTURE HYDRAULIQUE PAR L'AVANT-TROU DU PUITS DE TRAITEMENT UTILISE COMME PUITS DE SURVEILLANCE

(54) Title: METHOD FOR REAL-TIME MONITORING AND TRANSMITTING HYDRAULIC FRACTURE SEISMIC EVENTS TO SURFACE USING THE PILOT HOLE OF THE TREATMENT WELL AS THE MONITORING WELL



(57) Abrégé/Abstract:
Methods for determining hydraulic fracture geometry and/or areal extent of an area of interest (21) in a reservoir (23), are provided. An exemplary method includes isolating downhole acoustic receiver equipment (63) in a lower portion of a first wellbore (78) from

(21) 3 000 322

(13) A1

(57) Abrégé(suite)/Abstract(continued):
fracturing operations located in a second wellbore (109) connected to the first wellbore (78). Communications between surface equipment (31, 38) in the downhole acoustic receiver equipment (63) is provided through a communications conduit bypass (101, 133; 103; 102, 93) that permits well operations in the second wellbore (109) without interfering with communications between the surface equipment (31, 38) and the downhole acoustic receiver equipment (63).

METHOD FOR REAL-TIME MONITORING AND TRANSMITTING HYDRAULIC FRACTURE SEISMIC EVENTS TO SURFACE USING THE PILOT HOLE OF THE TREATMENT WELL AS THE MONITORING WELL

ABSTRACT

Methods for determining hydraulic fracture geometry and/or areal extent of an area of interest (21) in a reservoir (23), are provided. An exemplary method includes isolating downhole acoustic receiver equipment (63) in a lower portion of a first wellbore (78) from fracturing operations located in a second wellbore (109) connected to the first wellbore (78). Communications between surface equipment (31, 38) in the downhole acoustic receiver equipment (63) is provided through a communications conduit bypass (101, 133; 103; 102, 93) that permits well operations in the second wellbore (109) without interfering with communications between the surface equipment (31, 38) and the downhole acoustic receiver equipment (63).

METHOD FOR REAL-TIME MONITORING AND TRANSMITTING HYDRAULIC FRACTURE SEISMIC EVENTS TO SURFACE USING THE PILOT HOLE OF THE TREATMENT WELL AS THE MONITORING WELL

This application is a division of application no. 2,849,825 filed in Canada on October 9, 2012 upon the National Entry of PCT/US2012/059361.

BACKGROUND OF THE INVENTION

1 Field of the Invention

[0001] The present invention relates in general to the field of hydraulic fracturing, monitoring, and data transmission of microseismic information from a zone of interest within a reservoir, and more particularly, to the utilization and employment of electrically and physically isolated downhole acoustic monitoring equipment within a fracturing treatment well to detect microseismic events during fracturing operations.

2. Description of the Related Art

[0002] Hydraulic fracturing has been used for over 60 years in more than one million wells to improve the productivity of a hydrocarbon bearing formation, particularly those drilled in low permeability reservoirs. An estimated 90% of the natural gas wells in the United States alone use hydraulic fracturing to produce gas at economic rates. Successful hydraulic fracturing is generally considered vital for economic production of natural gas from shale beds and other 'tight gas' plays.

[0003] Fracturing treatment operations are typically employed in vertical, deviated, and horizontal wells. In a typical well development operation, the wellbore of the treatment well is drilled through the desired formation where the fracture treatment will take place.

[0004] The hydraulic fracture is formed by pumping a fluid into the wellbore at a rate sufficient to increase the pressure downhole to a value in excess of the fracture gradient of the formation rock in the area of interest. The pressure causes the formation to crack, allowing the fracturing fluid to enter and extend the crack further into the formation. One method to keep this fracture open after the injection stops is to add a solid proppant to the fracture fluid. The

proppant, which is commonly sieved round sand or other nonporous material, is carried into the fracture. This sand is chosen to be higher in permeability than the surrounding formation, and the propped hydraulic fracture then becomes a high permeability conduit through which the formation fluids can flow to the well.

[0005] Determining the size and orientation of completed hydraulic fractures is quite difficult and expensive, and in less expensive alternatives, highly inaccurate. It is well known that hydraulic fractures create a series of small "earthquakes" that can be mapped to show the position of the fracture event. The technology currently in use deploys a series of microseismic detectors typically in the form of geophones inside a separate monitoring well to measure fracturing events while pumping a hydraulic fracture treatment. Deployment of geophones or tilt meters on the surface can also be used, but the resolution is significantly less as you go deeper in the well.

[0006] Tiltmeter arrays, deployed on the surface or in a nearby monitoring well, measure the horizontal gradient of the vertical displacement. Microseismic detector arrays, deployed in a nearby monitoring well or on the surface adjacent the zone of interest if it is not too deep and/or environmental noise is not too excessive, can detect individual microseismic events associated with discrete fracture opening events. The microseismic event can be located in three dimensions by a triangulation methodology based on comparing acoustic arrival times at various sensors in a receiver array. By mapping the location of small seismic events that are associated with the growing hydraulic fracture during the fracturing process, the approximate geometry of the fracture can be inferred.

[0007] Although the use of a monitoring well located separate from the treatment well is often preferred as it provides improved accuracy, particularly in areas with high environmental noise and/or relatively inaccessible surface conditions, the cost of drilling a monitor well is typically in the area of $10 million and requires 30-50 days of drilling rig time. Further, availability of surface real estate or other factors can prevent the monitoring well from being drilled sufficiently close to the area of interest, and thus, results in a degraded performance.

[0008] In order to try to reduce capital costs and deployment time, some progressive operators have, with minimal success, attempted to build a combination monitoring and

treatment well by placing the acoustical sensors in the annulus of the treatment well. Some other operators, have instead chosen to deploy the acoustic sensors directly in the treatment flow path.

[0009] Recognized by the inventors, however, is that as a result of the pumping of the fracturing fluid, such acoustic sensors located along the annulus of the treatment well or within the flow path encounter substantial noise during the hydraulic fracturing events, which in turn, results in the collection of acoustic data having an excessively low signal-to-noise ratio. Accordingly, also recognized by the inventors is that this type of monitoring can generally only provide usable data when the fracture is closing, and thus, causes the operator to miss the fracturing events occurring while pumping the fracturing slurry.

[00010] Further recognized by the inventors is that due to the exposure limitations of the electrical data/power conduit (e.g., run with the acoustic sensors to transmit data to the surface), the operator is limited to certain slurry concentrations and is limited by the amount of total pressure that can be applied while fracturing due to the pressure limitation of the electric line cable heads. Still further, recognized by the inventors is that the deployment of acoustic sensors within the treatment flow or in the annulus adjacent current or potential future sidetracking operations can impede such operations.

[00011] Recognized, therefore, by the inventors is that there is a need for systems and processes that requires only a single treatment well to reduce capital costs and deployment time, that includes provisions for isolating the acoustic sensors to provide for gathering during pumping of the fracturing slurry downhole, acoustic data having an acceptable signal-to-noise ratio. Also recognized by the inventors is that there is a need for systems and processes that allow for high slurry concentrations and that allow for a total pressure necessary for optimal fracturing without concern for the pressure limitations of electric conduit/line cable heads in the communication pathway of the acoustic sensors, and/or that does not impede current or future sidetracking operations.

SUMMARY OF THE INVENTION

[00012] In view of the foregoing, various embodiments of the present invention advantageously provide systems and methods of/processes for determining hydraulic fracture geometry and areal extent of a zone of interest, that require utilization of only portions of a single

treatment well to reduce capital costs and deployment time, that includes provisions for isolating acoustic monitoring sensors to provide for gathering acoustic data having an acceptable signal-to-noise ratio real-time during pumping of the fracturing slurry, that allows for high slurry concentrations, that allows for a total pressure necessary for optimal fracturing, without concern for the pressure limitations of the electric line cable heads, and/or that does not impede current or future sidetracking operations, and that can be employed for seismic monitoring in all types of hydraulic fracture operations, including fracturing unconventional or shale gas reservoirs.

[00013] More specifically, an example of an embodiment of a method to determine hydraulic fracture geometry and areal extent of a zone of interest in a reservoir, can include various steps including those to establish the well and to deploy the acoustic and communications equipment. According to an embodiment of the present invention, a well is drilled through a zone of interest and is either cased and cemented or left in an openhole environment. A kickover or other deflection-type tool is then deployed with the geophones or other acoustic receivers hung below at predetermined intervals to capture fracture events below, above and within the zone of interest. The geophones or other acoustic receivers are coupled to the casing or open hole section. Coupling of the geophones or other acoustic receivers can be accomplished by cementing them in place or hanging the geophones or other acoustic receivers in the cased or open hole with centralizers. A packer can also be used to isolate pressure from the fracturing operations and to isolate the geophones. If left un-cemented the deployed kickover/deflecting tool and geophones or other acoustic receivers can be retrieved at a later date.

[00014] During fracturing operations, data is transmitted up hole using, for example, a down hole electrical coupler to make an electrical connection down hole in well test operations. Utilization of coupling device can advantageously remove any physical contact between electrical connections and wellbore fluids. According to an exemplary configuration, power and/or communication signals are transmitted through the coupler via an A/C current that creates an electromagnetic (EM) field transmitted to the female coupler. As such, an advantage of this system is the positive power and communication provided across the coupling device.

[00015] Upon completion of the fracturing operation, a surface computer having received the acoustic data describing each microseismic fracture and then producing and graphically displaying a map of the hydraulic fracture geometry and extent of such fracturing.

[00016] According to another embodiment of a method, the method can include the steps of positioning an acoustic assembly within a first wellbore adjacent the zone of interest in the reservoir and drilled within a portion of a reservoir to receive a hydraulic fracturing treatment defining the zone of interest. The acoustic assembly can include an acoustic receiver controller, e.g., seismic brain, and a set of one or more acoustic sensors, e.g., geophones, tilt meters, etc., to capture fracture events within the zone of interest. The steps can also include isolating the set of one or more acoustic sensors from acoustic interference associated with delivery of fracturing fluid through a conduit string extending through portions of the first wellbore and into the second wellbore when performing the hydraulic fracturing of the reservoir in the zone of interest. Such isolization can advantageously serve to minimize noise encountered by the set of one or more acoustic sensors and associated with movement of fracturing fluid.

[00017] The steps can also include inserting a drilling deflector into the first wellbore, drilling a second wellbore to receive a fracturing fluid, and typically before drilling the second wellbore if not pre-drilled, positioning a communication conduit bypass within the first wellbore to extend from a first location above an interface with the second wellbore to a second location below the interface with the second wellbore.

[00018] The steps can also include detecting microseismic events associated with the performance of the hydraulic fracturing by employing the set of acoustic sensors, and communicating to a surface unit the real-time microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest through the second wellbore. In order to provide for such communication, the steps can further include coupling the acoustic receiver controller to a first coupler connected to a first end of the communication conduit bypass and positioned adjacent the second location below the lateral aperture, and coupling surface equipment to a second inductive coupler connected to a second opposite and of the communication conduit bypass and positioned adjacent the first location, for example, above the lateral aperture.

[00019] According to another embodiment of a method, the method can include the steps of positioning a kickover tool within a production liner in a first wellbore drilled within a portion of a reservoir to receive a hydraulic fracturing treatment defining a zone of interest, and positioning an acoustic assembly within the production liner in the first wellbore below major portions of the

kickover tool and adjacent the zone of interest in the reservoir. The acoustic assembly can include an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events below, above, and within the zone of interest. The steps can also include isolating the set of one or more acoustic sensors from acoustic interference associated with delivery of fracturing fluid through a conduit string extending through portions of the first wellbore and into the second wellbore when performing the hydraulic fracturing of the reservoir in the zone of interest to thereby minimize noise encountered by the set of one or more acoustic sensors and associated with movement of fracturing fluid.

[00020] The steps can further include opening a lateral aperture in the production liner to form an entrance to a second wellbore to receive a fracturing fluid, and positioning a communication conduit bypass within the first wellbore to extend from a first location above the lateral aperture to a second location below the lateral aperture. The positioning of the communication conduit bypass is normally accomplished during deployment of the production liner in conjunction with the deployment of the acoustic assembly, and is later completed upon deployment of a tubing string.

[00021] The steps can also include detecting microseismic events associated with the performance of the hydraulic fracturing through employment of the set of acoustic sensors, and communicating to a surface unit, real-time microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest. The communications can be enabled by inductively coupling the acoustic receiver controller to a first inductive coupler connected to a first end of the communication conduit bypass and positioned adjacent the second location below the lateral aperture, inductively coupling surface equipment to a second inductive coupler connected to a second opposite and of the communication conduit bypass and positioned adjacent the first location above the lateral aperture.

[00022] According to another embodiment of a method, the method can include the steps of running a lower completion including wellbore sensors attached to a first connector within a tubular, running a communication conduit (lower umbilical) extending from a position outside the tubular adjacent the first connector to a position adjacent an operable position of a second connector, drilling a lateral wellbore oriented at least partially lateral to an orientation of the

tubular and positioned at a location above the first connector and below the second connector, while avoiding intersection with the lower umbilical, and running an upper completion with a communication conduit (upper umbilical) attached to the second connector. The method can also include running a lateral completion attached below the upper completion, and/or providing a reservoir monitoring sensor or sensors with the lateral completion and connecting a lateral umbilical cord to extend from the sensor to a tee connection in the upper umbilical cord. The lateral completion can also carry a plurality of flow management components including inflow control valves, inflow control devices, and/or isolation packers.

[00023] According to an embodiment of the method, the steps can include sensing an acoustic event resulting from hydraulic fracturing of the formation adjacent the producing well and associated with the fracturing operations conducted through the lateral completion. Wellbore sensors, for example, in the form of acoustic sensors are positioned to detect the acoustic event at different times to facilitate locating the acoustic event. The steps can also or alternatively include the plurality of acoustic sensors sensing an acoustic event resulting from hydraulic fracturing associated with a lateral completion of an adjacent well. The steps can also or alternatively include positioning a packer below the lateral wellbore and above the plurality of acoustic sensors to minimize noise associated with movement of fracturing fluid through the lateral completion and encountered by the plurality of acoustic sensors to enhance data quality.

[00024] According to another embodiment of a method, the method can include the steps of providing a plurality of producing wells each producing well including an upper completion, a lower completion, and a lateral completion extending into a lateral wellbore, combining the functions of a subterranean observation well and a subterranean producing well into each separate one of the plurality of producing wells for each of the producing wells, and sensing an acoustic event resulting from hydraulic fracturing associated with the lateral completion of one of the plurality of producing wells. The combining the functions is performed, for example, by positioning a plurality of acoustic sensors in the lower completion, and hydraulically isolating the plurality of acoustic sensors from fracturing fluid flowing through the upper completion and the lateral completion. The isolation is provided via an isolation device such as a packer positioned below the lateral wellbore and above the plurality of acoustic sensors to minimize noise associated with movement of the fracturing fluid through the lateral completion and encountered by the plurality of acoustic sensors. Additionally, the sensing is advantageously

performed by one or more of the plurality of acoustic sensors in at least two of the plurality of producing wells to enhance data accuracy.

[00025] According to an example of an embodiment of the present invention, a system to determine hydraulic fracture geometry and areal extent of a zone of interest in a reservoir, can include a main casing string extending within a first portion of a first wellbore, and a production liner connected to an inner surface of a portion of the casing string and extending into a second portion of the first wellbore and having a lateral aperture adjacent an opening into a lateral branch wellbore. The system can also include a kickover or other deflection tool positioned within the production liner at a location below major portions of the lateral aperture to facilitate the performance of drilling operations associated with the lateral branch wellbore and to isolate an acoustic assembly positioned within the production liner below the kickover tool adjacent a zone of interest from fracturing operations. The acoustic assembly can include an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events below, above, and within the zone of interest.

[00026] The system can also include a packer positioned within a bore of the production liner below major portions of the kickover tool and at a location above the set of one or more acoustic sensors to isolate the set of one or more acoustic sensors from acoustic interference associated with delivery of the fracturing fluid and/or can include a packer positioned within the bore of the production liner at a location below the set of acoustic sensors to hydraulically isolate the acoustic sensors within the bore of the production liner and/or to reduce acoustic interference from the fracturing components of the system.

[00027] The system also includes a tubing string extending through the first portion of the first wellbore, an upper portion of the second portion of the first wellbore, the lateral aperture, and portions of the lateral branch wellbore to deliver a fracturing fluid, and an inductive communication assembly positioned to receive data signals from the acoustic receiver controller and/or to provide power thereto and positioned to provide electrical isolation between lower completion equipment and upper completion equipment. According to a preferred configuration, the inductive communication assembly includes a communication conduit bypass positioned within the first wellbore and extending from a location above the lateral aperture to a location below the lateral aperture to prevent interference with the fracturing equipment or deployment

thereof. Advantageously, the inductive communications assembly includes two sets of inductive couplings to isolate up hole communication components from the communication components adjacent the lateral branch wellbore and to isolate such communication components from the acoustic assembly components located below the kickover tool. Notably, desired electrical and physical isolations can be achieved by using such inductive coupling technology to connect surface equipment with the downhole acoustic monitoring equipment.

[00028] A system according to another embodiment of the present invention can include a first wellbore including a first portion containing fluid delivery conduits and a second portion containing an acoustic assembly positioned adjacent a zone of interest within a reservoir. The acoustic assembly can include an acoustic receiver controller and a set of one or more acoustic sensors in communication therewith to capture fracture events below, above, and within the zone of interest. The system also include a second wellbore connected to the first wellbore at a lateral aperture in the first wellbore located above the acoustic assembly and containing a fracture treatment system, whereby the second wellbore and fracturing treatment system is hydraulically isolated from the second portion of the first wellbore containing the acoustic assembly. The system can further include an inductively coupled communication conduit bypass positioned within the first and the second portions of the first wellbore and extending from a location above the lateral aperture to a location below the lateral aperture to provide well operations in the second wellbore devoid of any acoustic monitoring equipment and associated interfering communication conduits.

[00029] A system according to another embodiment of the present invention can include a lower completion comprising wellbore sensors (e.g., acoustic sensors, etc.) positioned within a tubular, a lower umbilical extending from a position outside the tubular to a position adjacent an operable position of a first connector, a lateral wellbore positioned to avoid intersection with the lower umbilical and oriented at least partially lateral to an orientation of the tubular, and an upper completion run with an upper umbilical attached to the first connector. According to an exemplary configuration, the lower umbilical and tubular containing the wellbore sensors are configured to be run together. According to an exemplary configuration, the first connector connects to the upper umbilical. A second connector within a bore of the tubular connects to the wellbore sensors. An entranceway to the lateral wellbore is positioned at a location above the

second connector and below the first connector. According to an exemplary configuration, the first and the second connectors are configured to inductively couple to the lower umbilical.

[00030] According to an exemplary configuration, a packer is positioned below an entranceway to the lateral wellbore and above the plurality of acoustic sensors to minimize noise associated with movement of fracturing fluid through the lateral completion and encountered by the plurality of acoustic sensors and to isolate pressure encountered by the acoustic sensors. According to another exemplary configuration, the plurality of acoustic sensors are cemented in place to minimize noise encountered by the plurality of acoustic sensors and to isolate pressure.

[00031] A system according to another embodiment the present invention can include a lower completion comprising wellbore sensors (e.g., acoustic sensors, etc.) positioned within a tubular and positioned within a formation layer of interest, a lower umbilical extending from a position outside a portion of the tubular containing the well sensors to a position adjacent an operable position of a first connector, a lateral wellbore oriented at least partially lateral to an orientation of the tubular and positioned at least substantially within the formation layer of interest to thereby provide fracturing within the formation layer of interest. An upper completion run with an upper umbilical attached to the connector, whereby the connector operably coupled to the lower umbilical. According to an exemplary configuration, the connector is a first connector connecting to the upper umbilical, and the wellbore sensors are connected to at least portions of a second connector having at least portions positioned within a bore of the tubular. According to an exemplary configuration, the entranceway to the lateral wellbore is positioned at a location above the second connector and below the first connector.

[00032] According to an exemplary configuration, a lateral completion is horizontally aligned at least substantially between upper and lower boundaries of the formation layer of interest to provide fracturing within the formation layer of interest. According to such configuration, the portion of the tubular containing the acoustic sensors is positioned between upper and lower boundaries of the formation layer of interest. According to an exemplary configuration, a portion of the formation layer of interest is fractured above and below the lateral completion. According to such exemplary configuration, the acoustic sensors are positioned to receive fracturing data for portions of the formation layer of interest located above the lateral completion

and receive fracturing data from portions of the formation layer of interest located below the lateral completion.

[00033] Various embodiments of the present invention advantageously allow real time data transmission of seismic event data from the treatment well while pumping a hydraulic fracture treatment. Conventional practice is to drill an observation/monitoring well and to deploy geophones to monitor fracture seismic events during the fracture treatment or to deploy geophones at the surface. Often observation/monitoring wells or the surface is too far from the fracture treatment to allow collection of good quality monitoring data, and there substantial costs associated with establishing an observation/monitoring well. Accordingly, to solve such problems, various embodiments of the present invention advantageously provide for utilization of a single treatment well to perform fracture seismic mapping without a need for a separate monitoring well or surface equipment deployment. This can be accomplished by deploying the acoustic sensors downhole in a portion of the treatment well, below the sidetrack well used for delivering the fracturing fluid. This portion of the treatment well can be, for example, a portion of the pilot hole for the treatment well extending beyond the desired entrance location of the sidetrack well. Advantageously, use of, for example, the original pilot hole in a sidetrack provides a significant reduction in the cost of fracture wrapping by eliminating the drilling and completion of a separate monitoring well, which may typically cost $10.0 MM and 30-50 days of drilling rig time.

[00034] Various embodiments of the present invention also advantageously provide for isolating the acoustic sensors to provide for gathering acoustic data having an acceptable signal-to-noise ratio real-time during pumping, and/or provide for use of slurry concentrations greater than 4 PPA, by running the sensors below the kickover tool and/or installing a packer below the kickover tool to contain the acoustic sensors within the extended section of the main portion of the treatment well (e.g., the pilot hole)--separating the slurry carrying components and acoustic communications components so that they do not contact or otherwise communicate with each other. Advantageously, by placing the geophones below the kickover tool, the noise issue is reduced or eliminated with the use of simple filtering technology. Additionally, slurry limitations are eliminated, treating pressure is not limited to the tool deployed, and the geophones can be pre-positioned below, directly across the zone of interest and above the treatment interval.

[00035] Further, various embodiments of the present invention utilize an inductive coupler technology to provide for transmission of data to surface with real time measurements, which allows the acoustic sensors and acoustic receiver controller (e.g., seismic brain), to not only remain physically/hydraulically isolated, but also, electrically isolated--i.e., no electrical passageways or conduits providing communications between the acoustic receiver controller (e.g., seismic brain) and surface computer, need to be extended through the kickover tool or packer. The inductive coupler removes any physical contact between electrical connections and wellbore fluids. Power is transmitted through the coupler via an A/C current that creates an electromagnetic (EM) field transmitted to the female coupler. An additional advantage of this system is the positive power and communication provided across the coupling device.

[00035A] According to another embodiment of a method of determining hydraulic fracture geometry in a reservoir by combining functions of a first subterranean well and functions of a second subterranean well into a single well, the method comprises the steps of 1) running a lower completion comprising wellbore sensors positioned within a well casing, 2) running a communication conduit defining a lower umbilical, the lower umbilical extending from a position outside the well casing containing the well sensors, adjacent an operable position of a second connector, to a position adjacent an operable position of a first connector, 3) drilling a lateral wellbore, avoiding intersection with the lower umbilical, the lateral wellbore oriented at least partially lateral to an orientation of the well casing, and 4) running an upper completion with a communication conduit defining an upper umbilical, the upper umbilical operably connected to the first connector.

[00035B] According to another embodiment of a method of determining hydraulic fracture geometry in a reservoir by combining functions of a first subterranean well and functions of a second subterranean well into a single well, the method comprises the steps of 1) running a lower completion comprising wellbore sensors positioned within a well casing, the wellbore sensors positioned within a formation layer of interest, 2) running a communication conduit defining a lower umbilical, the lower umbilical extending from a position outside a portion of the well casing containing the well sensors to a position adjacent an operable position of a connector, 3) drilling a lateral wellbore, the lateral

wellbore oriented at least partially lateral to an orientation of the well casing and positioned at least substantially within the formation layer of interest to thereby provide fracturing within the formation layer of interest, and 4) running an upper completion with a communication conduit defining an upper umbilical, the upper umbilical attached to the connector, the connector operably coupled to the lower umbilical.

[00035C] According to another embodiment of a method of determining hydraulic fracture geometry of a zone of interest in a reservoir, the method comprises the steps of 1) providing a plurality of wells, each well comprising an upper completion, a lower completion, and a lateral completion extending into a lateral wellbore, 2) combining functions of a first subterranean well and functions of a second subterranean well into each separate one of the plurality of wells, by performing the following for each of the plurality of wells a) positioning a plurality of acoustic sensors in the lower completion, and b) hydraulically isolating the plurality of acoustic sensors from fracturing fluid flowing through the upper completion and the lateral completion, the isolation provided via an isolation device positioned below the lateral wellbore and above the plurality of acoustic sensors to minimize noise associated with movement of the fracturing fluid through the lateral completion and encountered by the plurality of acoustic sensors, and 3) sensing an acoustic event resulting from hydraulic fracturing associated with the lateral completion of one of the plurality of wells, the sensing performed by one or more of the plurality of acoustic sensors in at least two of the plurality of wells.

[00035D] According to another embodiment of a method of determining hydraulic fracture geometry of a zone of interest in a reservoir, the method comprises the steps of 1) positioning an acoustic assembly within a first wellbore adjacent the zone of interest in a reservoir, the first wellbore drilled within a portion of the reservoir to receive a hydraulic fracturing treatment defining the zone of interest, the acoustic assembly including an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events within the zone of interest, 2) inserting a drilling deflector into the first wellbore, 3) drilling a second wellbore to receive a fracturing fluid, 3) positioning a communication conduit bypass within the first wellbore to extend from a first location above an interface with the second wellbore to a second location below the interface with the second wellbore, 4) inductively coupling

the acoustic receiver controller to a first inductive coupler connected to a first end of the communication conduit bypass, the first inductive coupler positioned adjacent the second location below the lateral aperture, 5) inductively coupling surface equipment to a second inductive coupler connected to a second opposite end of the communication conduit bypass, the second inductive coupler positioned adjacent the first location above the lateral aperture, and 6) communicating real-time microseismic event data to a surface unit, the microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest through the second wellbore.

[00035E] According to another embodiment of a method of determining hydraulic fracture geometry of a zone of interest in a reservoir, the method comprises the steps of 1) positioning a kickover tool within a production liner in a first wellbore drilled within a portion of a reservoir to receive a hydraulic fracturing treatment defining a zone of interest, 2) positioning an acoustic assembly within the production liner in the first wellbore below major portions of the kickover tool and adjacent the zone of interest in the reservoir, the acoustic assembly including an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events within the zone of interest, 3) opening a lateral aperture in the production liner, the lateral aperture forming an entrance to a second wellbore to receive a fracturing fluid, 4) positioning a communication conduit bypass within the first wellbore to extend from a first location above the lateral aperture to a second location below the lateral aperture, 5) inductively coupling the acoustic receiver controller to a first inductive coupler connected to a first end of the communication conduit bypass, the first inductive coupler positioned adjacent the second location below the lateral aperture, 6) inductively coupling surface equipment to a second inductive coupler connected to a second opposite end of the communication conduit bypass, the second inductive coupler positioned adjacent the first location above the lateral aperture, and 7) communicating real-time microseismic event data to a surface unit, the microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest.

[00036] Various embodiments of the present invention further advantageously provide for the use of a total pressure necessary for optimal fracturing, without concern for the pressure limitations of electric line cable heads providing communications between an acoustic assembly and a surface unit, and/or provide for employment of a monitoring system within the treatment well that does not impede current or future sidetracking operations. By employing the inductive coupling technology, electrical telemetry is transferred from inside the well to external of the production liner at a location above an anticipated or existing aperture in the production liner by a first inductive coupling and is returned to be inside the well and at location below the anticipated or existing location of the kickover tool by a second inductive coupling, with the cabling between the two couplings routed external to the production liner away from the location of the anticipated or existing aperture in the production liner.

BRIEF DESCRIPTION OF THE DRAWINGS

[00037] So that the manner in which the features and advantages of the invention, as well as others which will become apparent, may be understood in more detail, a more particular description of the invention briefly summarized above may be had by reference to the embodiments thereof which are illustrated in the appended drawings, which form a part of this specification. It is to be noted, however, that the drawings illustrate only various embodiments of the invention and are therefore not to be considered limiting of the invention's scope as it may include other effective embodiments as well.

[00038] FIG. 1 is a schematic diagram of a general system architecture of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to an embodiment of the present invention;

[00039] FIG. 2 is a schematic diagram of the downhole portion of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to an embodiment of the present invention;

[00040] FIGS. 3-11 provide a series of schematic diagrams illustrating the development of a main wellbore, a wellbore for performing fracturing operations, and deployment of the downhole portion of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to embodiments of the present invention;

[00041] FIG. 12 is a schematic diagram illustrating operational employment of downhole portions of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest within a reservoir according to an embodiment of the present invention;

[00042] FIG. 13 is a schematic diagram of an inductive circuit according to an embodiment of the present invention;

[00043] FIG. 14 is a schematic diagram illustrating duplicate portions of a system for determining hydraulic fracture geometry and areal extent of an area/zone of interest employed in a pair of adjacent producing wells, commonly receiving, processing, and providing complementary data for each other according to an embodiment of the present invention;

[00044] FIG. 15 is a schematic diagram illustrating a plurality of taps in a primary umbilical cord illustrating use of the umbilical cord as a primary communications link between both downhole acoustic sensors and reservoir monitoring sensors according to an embodiment of the present invention;

[00045] FIG. 16 is a schematic diagram illustrating application of a plurality of flow control devices according to an embodiment of the present invention; and

[00046] FIG. 17 is a schematic diagram illustrating a communication line connection configuration between surface components and downhole acoustic sensors according to an embodiment of the present invention.

DETAILED DESCRIPTION

[00047] The present invention will now be described more fully hereinafter with reference to the accompanying drawings, which illustrate embodiments of the invention. This invention may, however, be embodied in many different forms and should not be construed as limited to the illustrated embodiments set forth herein. Rather, these embodiments are provided so that this disclosure will be thorough and complete, and will fully convey the scope of the invention to those skilled in the art. Like numbers refer to like elements throughout. Prime notation, if used, indicates similar elements in alternative embodiments.

[00048] Various embodiments of the present invention advantageously provide systems and methods for real-time monitoring of hydraulic fractures using the treatment well pilot hole. According to an exemplary embodiment of the present invention, the well is drilled through the desired formation where the fracture treatment will take place. A kickover or other deflecting tool is then lowered into the wellbore and oriented to the preferred fractured orientation. Below the kick-over tool are acoustical sensors. At least one sensor is run, but preferably a series of sensors are run below the kickover tool. With the kickover tool in place, a sidetrack is drilled either as a vertical or horizontal wellbore. Advantageously, multiple sidetracks can be placed if required by stacking the kickover tools. Noise while pumping the fracturing fluid will be further minimized by placing a packer located below the kickover tool. The following provides additional details according to an exemplary embodiments of the present invention.

[00049] As shown in FIG. 1, a system 30 to determine hydraulic fracture geometry and areal extent of an area of interest 21 of a reservoir 23 can include a fracture mapping computer 31 having a processor 33, memory 35 coupled to the processor 33 to store software and database records therein, and a user interface 37 which can include a graphical display 39 for displaying graphical images, and a user input device 41 as known to those skilled in the art, to provide a user access to manipulate the software and database records. Note, the computer 31 can be in the form of a personal computer or in the form of a server or server farm serving multiple user interfaces 37 or other configuration known to those skilled in the art. Accordingly, the user interface 37 can be either directly connected to the computer 31 or through a network 38 as known to those skilled in the art.

[00050] The system 30 can also include a database (not shown) stored in the memory 35 (internal or external) of the fracture mapping computer 31 and having data indicating position points of detected seismic events, and can include fracture mapping program product 51 stored in memory 35 of the fracture mapping computer 31 and adapted to receive signals from an acoustic receiver controller 61. Note, the fracture mapping program product 51 can be in the form of microcode, programs, routines, and symbolic languages that provide a specific set for sets of ordered operations that control the functioning of the hardware and direct its operation, as known and understood by those skilled in the art. Note also, the fracture mapping program product 51, according to an embodiment of the present invention, need not reside in its entirety in volatile memory, but can be selectively loaded, as necessary, according to various methodologies as known and understood by those skilled in the art. Still further, at least portions of the fracture mapping program product 51 can be stored in memory of the acoustic receiver controller 61 and/or executed by acoustic receiver controller 61.

[00051] As shown in FIGS. 1 and 2, the system 30 also includes an acoustic assembly 63 including the acoustic receiver controller (e.g., seismic brain) 61 and a set of at least one, but more typically a plurality of acoustic sensors (e.g., geophones, hydrophones, etc.) 65 hung below a kickover or other drilling deflection-type tool 71 positioned within a production or other liner 73, itself hung within a casing 75 itself positioned within a main portion 77 of a typically vertical wellbore 78. In a cased hole configuration, liner 73 is hung within casing 75 using a casing hangar 74 or other means as understood by one of ordinary skill in the art.

[00052] According to the illustrated embodiment of the system 30, the set of acoustic sensors 65 include multiple spaced apart sensors spaced at a predetermined distance or distances capture the same set of fracturing events, but at different travel times, to allow for triangulation of the received acoustic signals emanating from each separate fracture event. Note, as shown in FIG. 2, a packer or packers 79, 84 as known and understood by those of ordinary skill in the art can optionally be installed within the bore 76 of the production liner 73 prior to the installation of kickover tool 71. According to one embodiment, the packer 79 is positioned below the kickover tool 71 at a location above the acoustic assembly 63 to isolate the sensors 65 from acoustic interference. In such embodiment, a centralizer (not shown) or other connection device can be used to stabilize the sensors 65 within the bore 76 of the liner 73. According to an alternative embodiment, the packer 84 as installed below the acoustic assembly 63 to hydraulically seal

chamber 80 within liner 73 to contain the acoustic assembly 63, and in conjunction with the kickover tool 71 (or other whipstock-type tool) and/or another packer 79 adjacent thereto, to thereby prevent hydraulic incursions.

[00053] According to the illustrated embodiment of the system 30, wellbore 78 includes the main or "upper formation" portion 77 and a "lower formation" portion 81 primarily comprising the pilot hole 82 drilled to guide drilling of the main portion 77 of the wellbore 78. As shown in the figures, according to such configuration, the acoustic assembly 63 and at least portions of the kickover tool 71 are landed within the lower portion 81 of the wellbore 78 (e.g., within chamber 80), and/or physically connected to hang from the kickover tool 71.

[00054] A locator key 83 comprising a recess-protuberance combination, illustrated as a recess 85 in the liner 73 and an annular protuberance 87 or set of one or more individual protuberances extending radially from the lower portion of the kickover tool 71, can be utilized to properly orient the kickover tool 71 and/or the set of acoustic sensors 65. Note, other means including a protuberance-recess combination or utilization of a centralizer (not shown) supporting or landing the set of acoustic sensors 65 and/or the kickover tool 71, or other means known to one of ordinary skill in the art, however, is/are within the scope of the present invention.

[00055] According to the illustrated embodiment of the system 30, the kickover tool 71 includes a recess 89 containing at least portions of the acoustic receiver controller 61 or associated connection hardware (not shown) as understood by one of ordinary skill in the art. The kickover tool 71 also includes an annular recess 91 housing a male inductive coupler 93 (individual or assembly) connected to an electrical conduit 95 connected to or otherwise in communication with the acoustic receiver controller 61. Note, the locator key 83 provides both positioning of the kickover tool 71 and positioning of the male inductive coupler 93. Note also, as described is being electrical conduit, conduit 91 can take other forms including optical, RF, etc. or combination thereof.

[00056] Further, according to the illustrated embodiments of the system 30, the liner 73 is landed within a lower end of the casing 75, preferably at least partially within a portion 97 of the wellbore 78 extended out, for example, by an "undee" ream bit (not shown), using means as known and understood by one of ordinary skill in the art. According to a preferred configuration, the external surface 99 of the liner 73 carries a set of female inductive couplers

101, 102 connected via a communication conduit, e.g., electrical cable 103 routed along the external surface 99 of the liner 73, above and below a radial aperture 105, respectively. The radial aperture 105 is pre-formed prior to landing of the liner 73 or later cut through the exterior wall 99 of the liner 73 to provide a pathway for a "sidekick" drilled as a horizontal or vertical wellbore (e.g., lateral wellbore 109) carrying the various fracturing equipment 111. As such, beneficially, the female inductive couplers 101, 102 and the cable 103 do not impede fracturing operations or formation of the lateral wellbore 109.

[00057] The system 30 also includes a string of tubing 121 extending from a surface 123 (FIG. 1), through the main portion 77 of the wellbore 78 and casing 75, through the bore of liner 73 above aperture 105, through aperture 105, and into wellbore 109. The portion 125 of the tubing string 121 contained within wellbore 109 can include the various fracturing equipment 111 including multiple sets of perforations 127 to pass fracturing fluid into the reservoir 23, and can include multiple fracturing valves 129 to control fluid (e.g. slurry) delivery within each set of perforations 127, to thereby provide for multi-stage fracturing.

[00058] A portion 131 of the tubing string 121 located above the aperture 105 can house or otherwise carry a male inductive coupler 133 on its exterior surface 99. The male inductive coupler 133 is sized to be deployed within the inner diameter 137 of liner 73. When properly deployed with portion 131 of tubing string 121, male inductive coupler 133 is positioned to complement the female inductive coupler 101 connected to the exterior surface 99 of liner 73. Correspondingly, the portion 131 can include a tubing locator 141 sized to extend through casing 75 and to land upon an upper portion 143 of the casing hangar 74 hanging liner 73 (defining a landing point or surface 143). The male inductive coupler 133 is spaced apart at a predetermined longitudinal distance from the tubing locator 141 so that when the tubing locator 141 is landed upon landing point/surface 143, the male inductive coupler 133 is in a proper juxtaposition with female inductive coupler 101. The locator key 83, described previously, locates the male inductive coupler 93 in the proper juxtaposition with female inductive coupler 102, to thereby form a properly matched inductive circuit 145 (see, e.g., FIG. 13).

[00059] A communication conduit, e.g. electrical cable 147 is physically connected to outer surface portions of the exterior surface 135 of the tubing string 121 and electrically connected to male inductive coupler 133, e.g., via a wet connector, to provide data to computer 31.

Beneficially, the electrical and physical isolations can be achieved by using inductive coupler pairs 101, 133, and 102, 93, to connect the surface equipment (e.g., computer 31) with the downhole acoustic monitoring assembly 63. Note, although described as being electrical conductors, it should be understood that conduits/cables 103, 147 can take various forms including electrical, optical, electro-optical, wireless, hydraulic or a combination thereof and are often collectively referred to as umbilicals. Note also, as shown in FIG. 17, although illustrated in the form of an inductive coupling, conduit/cable 103 can be hard-line connected to the acoustic assembly 63 via a connection with/through kickover tool 71' and can be connected to conduit/cable 147 via connector 133' illustrated as being positioned adjacent landing point 143.

[00060] FIGS. 1 and 2 illustrate a "cased hole" configuration of the wellbores 78, 109. One of ordinary skill in the art, however, would recognize that one or more embodiments of the present invention fall within the scope of the system 30 employed in non-cased wellbores. Additionally, in the exemplary illustration, the casing 75 is 9 5/8 inch casing, the tubing liner is 7 inch, and the tubing string 121 is 4 1/2 tubing, and the lateral wellbore 109 is 6 1/8 inch. Various other sizes as known to those of ordinary skill in the art, however, are within the scope of the present invention.

[00061] FIGS. 3-12 illustrate examples of embodiments of a method of determining hydraulic fracture geometry and areal extent of an area/zone of interest 21 in a reservoir 23 by combining functions of a subterranean observation well and a subterranean producing well into a single producing well 53. Referring to FIG. 3, according to an example of an embodiment of the method, a wellbore 78 is drilled through the area/zone of interest 21 and is either cased and cemented or left in an openhole state. According to the illustrated method, a pilot hole 82 is first drilled followed by the main portion 77.

[00062] As illustrated in FIG. 3, an undee reaming bit (not shown) can be used to widen the portion of the wellbore 78 at a location where a sidekick (e.g., wellbore 109, FIG. 2) is to be drilled. As shown in FIG. 4, in the illustrated cased-hole configuration, casing 75 is run within the upper portion 77 of the wellbore 78 above the undee 97.

[00063] As illustrated in FIG. 5, liner 73 is hung within casing 75 using a casing hangar 74 or other means as understood by one of ordinary skill in the art. According to the illustrated configuration, liner 73 extends from above undee 97, through undee 97, and through significant

portions of the pilot hole 82 preferably having an inner diameter similar to that of the liner 73. As further illustrated in FIG. 5, liner 73 includes female inductive couplers 101, 102, connected to or embedded within an outer/exterior surface 99.

[00064] As illustrated in FIGS. 6 and 7, in order to acoustically isolate the set of acoustic sensors 65, a packer 79 can be positioned at a location below the kickover tool or other deflection-type tool 71 but above at least the acoustic sensors 65. In order to acoustically isolate further hydraulically isolate acoustic assembly 63, a packer 84 can also or alternatively be inserted within the bore 76 of the liner 73 at a location below the lowest (most downhole) expected point of the acoustic assembly 63.

[00065] As illustrated in FIG. 7, regardless of whether or not packer 79 is run, the method includes running a kickover or other deflection-type tool 71 to isolate the acoustic assembly 63 from the fracturing operations, described below. According to an exemplary configuration, the kickover tool 71 is deployed with geophones or other acoustic receivers 65 hung below at predetermined intervals to capture fracture events below, above and within the area/zone of interest 21. The geophones or other acoustic receivers 65 can be coupled to the inner surface of the tubing liner 73 or alternatively, directly to the open hole section of the pilot hole 82. Coupling of the geophones or other acoustic receivers 65 can be accomplished by cementing them in place in either the open hole or cased hole or hanging the geophones or other acoustic receivers 65 in the cased hole or the open hole using centralizers (not shown). Note, if left un-cemented, the kickover tool 71 and acoustic receivers 65 can be retrieved at a later date.

[00066] As illustrated in FIG. 8, according to another configuration, the casing 75, liner 73, kick over tool 71', packer 79, acoustic assembly 63, upper and lower communication conduits 103, 147, and the upper inductive coupler 101 can be run together. Although inductive coupler pair 102, 93 can also be run, according to such configuration, as shown in the figure, conduit 103 can instead be hardwired to acoustic controller 61 through passageway 72. FIG. 9 illustrates an embodiment whereby the acoustic sensors 65 of the acoustic assembly 63 are instead cemented to reduce noise and/or isolate pressure that would otherwise be encountered by the acoustic sensors 65.

[00067] Regardless of the running methodology, as illustrated in FIG. 10, having the kickover tool 71 positioned within liner 73 (or directly within the pilot hole 82 if no liner 73 was utilized), wellbore 109 is drilled through aperture 105 at a desired length and distance and depth.

[00068] As illustrated in FIG. 11, a tubing string 121 is run from surface 123 (FIG. 1), through the casing 75, through the bore of liner 73 above aperture 105, through aperture 105, and into wellbore 109. The portion 125 of the tubing string 121 contained within wellbore 109 can include the various fracturing equipment 111 including multiple sets of perforations 127 to pass fracturing fluid into the reservoir 23, and fracturing valves 129 to control fluid (e.g. slurry) delivery within each set of perforations 127. The portion 131 of the tubing string 121 located above the aperture 105 can house or otherwise carry the male inductive coupler 133 on its exterior surface 135. In order to place male inductive coupler 133 in a proper juxtaposition with female inductive coupler 101, the deployment of tubing string 121 includes landing a tubing locator 141 in contact with a landing point/surface 143.

[00069] As illustrated in FIG. 12, during pumping operations, microfractures begin generating acoustic signals which are received at different times by the separated acoustic receivers 65. As illustrated in FIG. 13, in the illustrated embodiment whereby communications are established between the surface 123 (e.g., computer 31) and the acoustic sensors 65 utilizing inductive coupling, an inductive circuit is formed as illustrated, which can provide a reliable means to make an electrical connection down hole in well test operations. Processed acoustic data, processed by acoustic controller 61, is transmitted uphole via the illustrated circuit through the illustrated series of conductor connections and inductive couplings.

[00070] Beneficially, the utilization of the inductive coupling, particularly in conjunction with the establishment of separate electrical connections which do not across boundaries, can function to remove any physical contact between electrical connections and wellbore fluids. An advantage of this system/process is the positive communication provided across the coupling devices. The inductive couplings function so that communication signals emanating from acoustic controller 61 are transmitted through an A/C current created in male coupler 93, which creates an electromagnetic (EM) field transmitted to the female the coupler 102.

[00071] Similarly, FIG. 14 illustrates acoustic sensors 65 receiving acoustic signals from microfracture sources resulting from fracturing operations adjacent separate lateral wellbores

109, 109'. In this embodiment, however, the other lateral wellbore 109' is associated with an adjacent producing well 53'. Further, data from the respective acoustic controllers 61 associated with each respective producing well 53, 53' can be gathered by computer 31 via network 38 and compared. Alternatively, each producing well 53, 53' can have a separate computer 31 associated therewith in communication with each other through network 38 and/or another network as known to one of ordinary skill in the art.

[00072] According to another embodiment of the present invention, the system/process also includes an advantage whereby power can be delivered across the coupling devices to provide power to the acoustic assembly 63. In yet another embodiment of the present invention, an additional coupling can be made with inductive coupler 133, inductive coupler 101, and/or a Tee-type connection 151 or other form of tap or series of taps in cable 147 (FIG. 15) to provide power and/or communications to the fracturing equipment 111 from the surface 123 and/or provide support to reservoir monitoring sensors 128 such as, for example, pressure, temperature, flow, DTS sensors, etc.. According to an embodiment, a plurality of reservoir monitoring sensors 128 can provide various reservoir condition sensing functions to include providing or providing for determining conductivity for waterfront observation, along with others known to those of ordinary skill in the art.

[00073] FIG. 16 illustrates another embodiment of the present invention whereby improved production control is achieved through application of one or more flow management components 153 such as, for example, inflow control valves, inflow control devices, and/or isolation packers.

[00074] This application claims priority to U.S. Non-Provisional Patent Application number 13/269,596 titled "Method for Real-Time Monitoring and Transmitting Hydraulic Fracture Seismic Events to Surface using the Pilot Hole of the Treatment Well as the Monitoring Well", filed October 9, 2011, and is related to U.S. Non-Provisional Patent Application Number 13/269,599, titled "System For Real-Time Monitoring and Transmitting Hydraulic Fracture Seismic Events To Surface Using The Pilot Hole Of The Treatment Well As the Monitoring Well," filed on October 9, 2011, which may be referred to for further details.

[00075] In the drawings and specification, there have been disclosed a typical preferred embodiment of the invention, and although specific terms are employed, the terms are used in a descriptive sense only and not for purposes of limitation. The invention has been described in

considerable detail with specific reference to these illustrated embodiments. It will be apparent, however, that various modifications and changes can be made within the spirit and scope of the invention as described in the foregoing specification. For example, in place of the inductive coupling portions of inductive coupling circuit 145, connectors such as, e.g., wet mate connectors can be employed as a substitute for the sets of inductive coupling, albeit with some degradation to the advantages of the above described embodiments of the featured system that employ inductive coupling.

What is claimed is:

1. A method of determining hydraulic fracture geometry of a zone of interest in a reservoir, the method comprising the steps of:

positioning an acoustic assembly within a first wellbore adjacent the zone of interest in a reservoir, the first wellbore drilled within a portion of the reservoir to receive a hydraulic fracturing treatment defining the zone of interest, the acoustic assembly including an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events within the zone of interest;

inserting a drilling deflector into the first wellbore, wherein the set of one or more acoustic sensors are connected to a down-hole facing portion of the drilling deflector prior to the drilling deflector being inserted to the first wellbore;

drilling a second wellbore to receive a fracturing fluid;

positioning a communication conduit bypass within the first wellbore to extend from a first location above an interface with the second wellbore to a second location below the interface with the second wellbore;

inductively coupling the acoustic receiver controller to a first inductive coupler connected to a first end of the communication conduit bypass, the first inductive coupler positioned adjacent the second location below the lateral aperture;

inductively coupling surface equipment to a second inductive coupler connected to a second opposite end of the communication conduit bypass, the second inductive coupler positioned adjacent the first location above the lateral aperture;

isolating the set of one or more acoustic sensors from acoustic interference associated with delivery of fracturing fluid through a conduit string extending through portions of the first wellbore and into the second wellbore when performing the hydraulic fracturing of the reservoir in the zone of interest to thereby minimize noise encountered by the set of one or more acoustic sensors and associated with movement of fracturing fluid, the isolating comprising positioning a packer within a production liner containing the one or more acoustic sensors below major portions of the first wellbore containing the conduit string and above the set of one or more acoustic sensors to thereby minimize the noise encountered by the set of one or more acoustic sensors and associated with movement of the fracturing fluid; and

detecting microseismic events associated with the performance of the hydraulic fracturing, the step of detecting including employing the set of one or more acoustic sensors; and

communicating real-time microseismic event data to a surface unit, the microseismic event data describing the microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest through the second wellbore.

2. The method as defined in claim **1**, wherein the step of positioning a communication conduit bypass within the first wellbore includes the steps of:

determining an expected location of the lateral aperture through a production liner;

connecting the second inductive coupler to an outer facing surface of the production liner at a location above the expected location of the lateral aperture;

connecting first inductive coupler to an outer facing surface of the production liner at a location below the expected location of the lateral aperture;

connecting an electrical conduit along an outer surface of the production liner between the first and the second inductive couplers away from the expected location of the lateral aperture; and

running the production liner within the first wellbore.

3. The method as defined in claim **2**, wherein the steps of inductively coupling the acoustic receiver controller to the first inductive coupler and inductively coupling surface equipment to the second inductive coupler comprises the steps of:

connecting a third inductive coupler to an outward facing surface of a portion of a tubing segment at a predetermined longitudinal distance from a reference point associated with a tubing locator extending from an outer surface portion of the tubing segment, the predetermined longitudinal distance coinciding with a longitudinal distance from the reference point to the second inductive coupler when the tubing locator is landed upon a portion of the production liner; and

connecting a fourth inductive coupler to an outward facing surface of the drilling deflector at a predetermined longitudinal distance from a reference point associated therewith, the predetermined longitudinal distance coinciding with a longitudinal distance from the drilling

deflector reference point to the first inductive coupler when the drilling deflector is landed at a preselected location within the production liner.

4. The method as defined in claim **1**, wherein the second wellbore is devoid of any acoustic monitoring equipment and associated interfering communication conduits.

5. A method of determining hydraulic fracture geometry of a zone of interest in a reservoir, the method comprising the steps of:

positioning a kickover tool within a production liner in a first wellbore drilled within a portion of a reservoir to receive a hydraulic fracturing treatment defining a zone of interest;

positioning an acoustic assembly within the production liner in the first wellbore below major portions of the kickover tool and adjacent the zone of interest in the reservoir, the acoustic assembly including an acoustic receiver controller and a set of one or more acoustic sensors to capture fracture events within the zone of interest;

opening a lateral aperture in the production liner, the lateral aperture forming an entrance to a second wellbore to receive a fracturing fluid;

positioning a communication conduit bypass within the first wellbore to extend from a first location above the lateral aperture to a second location below the lateral aperture;

inductively coupling the acoustic receiver controller to a first inductive coupler connected to a first end of the communication conduit bypass, the first inductive coupler positioned adjacent the second location below the lateral aperture;

inductively coupling surface equipment to a second inductive coupler connected to a second opposite end of the communication conduit bypass, the second inductive coupler positioned adjacent the first location above the lateral aperture; and

communicating real-time microseismic event data to a surface unit, the microseismic event data describing microseismic events detected by the acoustic assembly when performing hydraulic fracturing of the reservoir in the zone of interest.

6. The method as defined in claim **5**, further comprising the steps of:

isolating the set of one or more acoustic sensors from acoustic interference associated with delivery of fracturing fluid through a conduit string extending through portions of the first

wellbore and into the second wellbore when performing the hydraulic fracturing of the reservoir in the zone of interest to thereby minimize noise encountered by the set of one or more acoustic sensors and associated with movement of fracturing fluid; and

detecting microseismic events associated with the performance of the hydraulic fracturing, the step of detecting including employing the set of acoustic sensors.

7. The method as defined in claim **6**, wherein the step of isolating the set of one or more acoustic sensors from acoustic interference includes the step of:

positioning a packer within the production liner below major portions of the kickover tool and above the set of one or more acoustic sensors to thereby minimize the noise encountered by the set of one or more acoustic sensors and associated with movement of the fracturing fluid.

8. The method as defined in claim **5**, wherein the steps of positioning a kickover tool within a production liner and positioning an acoustic assembly within the production liner are performed simultaneously, the method further comprising the step of:

connecting the set of one or more acoustic receivers to a down-hole facing portion of the kickover tool prior to performing the step of positioning the kickover tool in the production liner.

9. The method as defined in claim **5**, wherein the step of positioning a communication conduit bypass within the first wellbore includes the steps of:

determining an expected location of the lateral aperture through the production liner;

connecting the second inductive coupler to an outer facing surface of the production liner at a location above the expected location of the lateral aperture;

connecting first inductive coupler to an outer facing surface of the production liner at a location below the expected location of the lateral aperture;

connecting an electrical conduit along an outer surface of the production liner between the first and the second inductive couplers away from the expected location of the lateral aperture; and

running the production liner within the first wellbore.

10. The method as defined in claim **9**, wherein the steps of inductively coupling the acoustic receiver controller to the first inductive coupler and inductively coupling surface equipment to the second inductive coupler comprises the steps of:

connecting a third inductive coupler to an outward facing surface of a portion of a tubing segment at a predetermined longitudinal distance from a reference point associated with a tubing locator extending from an outer surface portion of the tubing segment, the predetermined longitudinal distance coinciding with a longitudinal distance from the reference point to the second inductive coupler when the tubing locator is landed upon a portion of the production liner; and

connecting a fourth inductive coupler to an outward facing surface of the kickover tool at a predetermined longitudinal distance from a reference point associated therewith, the predetermined longitudinal distance coinciding with a longitudinal distance from the kickover tool reference point to the first inductive coupler when the kickover tool is landed at a preselected location within the production liner.

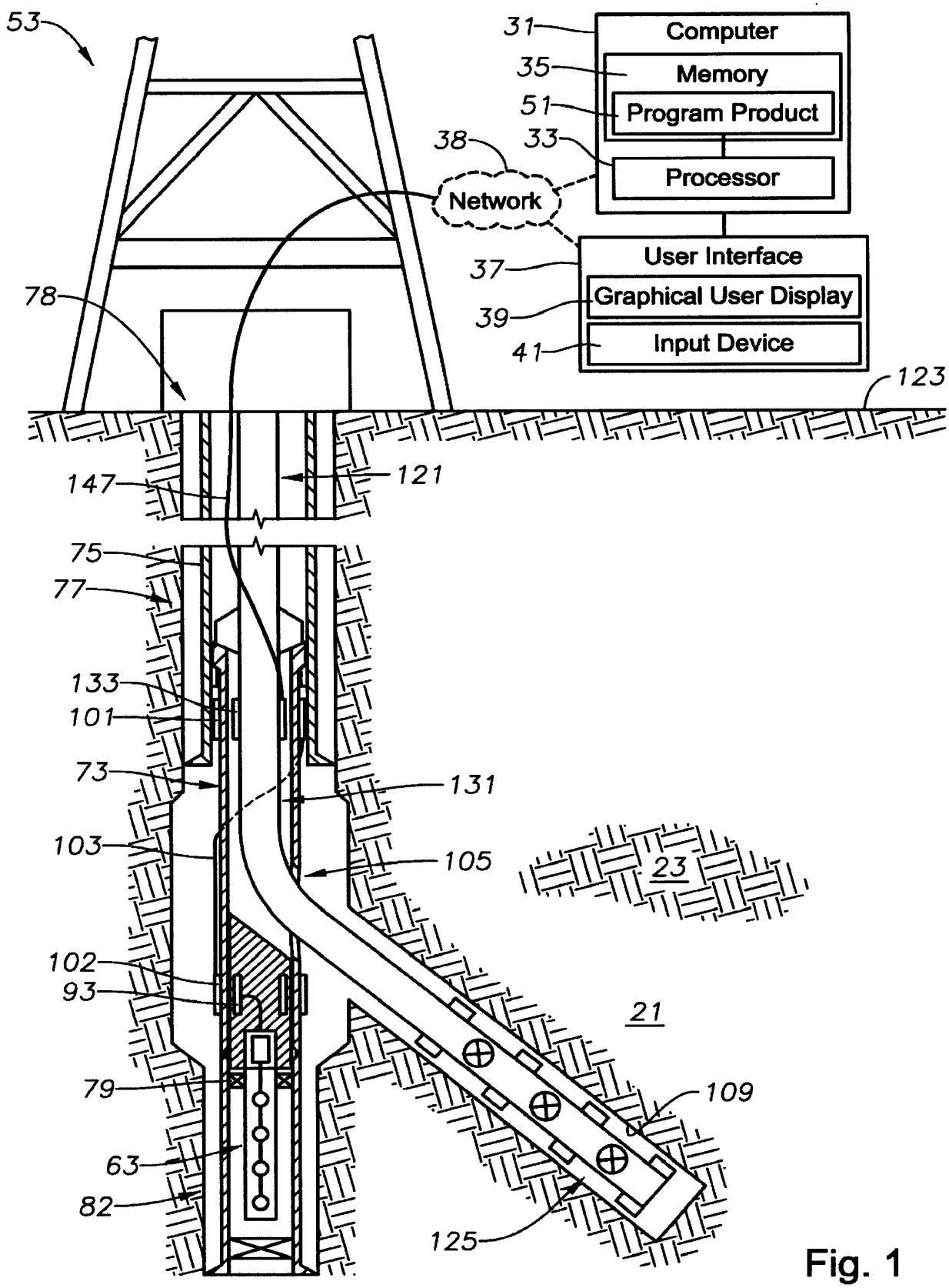

53
31
Computer
35
Memory
51
Program Product
38
33
Processor
Network
User Interface
37
Graphical User Display
39
41
Input Device
78
123
147
121
75
77
133
101
73
131
103
105
23
102
93
21
79
109
63
82
125

Fig. 1

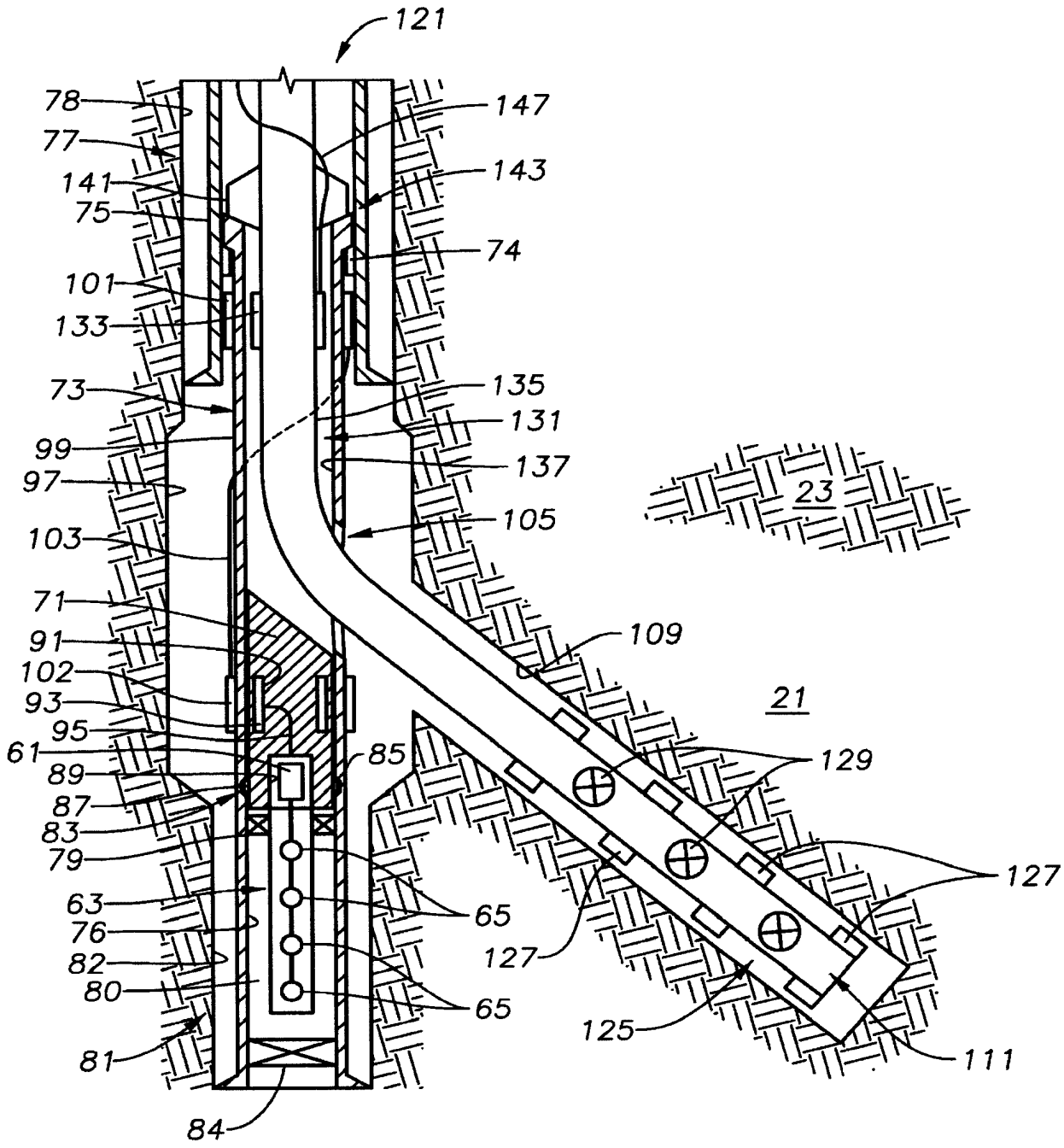

121
78
77
141
75
101
133
73
99
97
103
71
91
102
93
95
61
89
87
83
79
63
76
82
80
81
84
147
143
74
135
131
137
105
23
109
21
129
85
65
65
127
127
125
111

Fig. 2

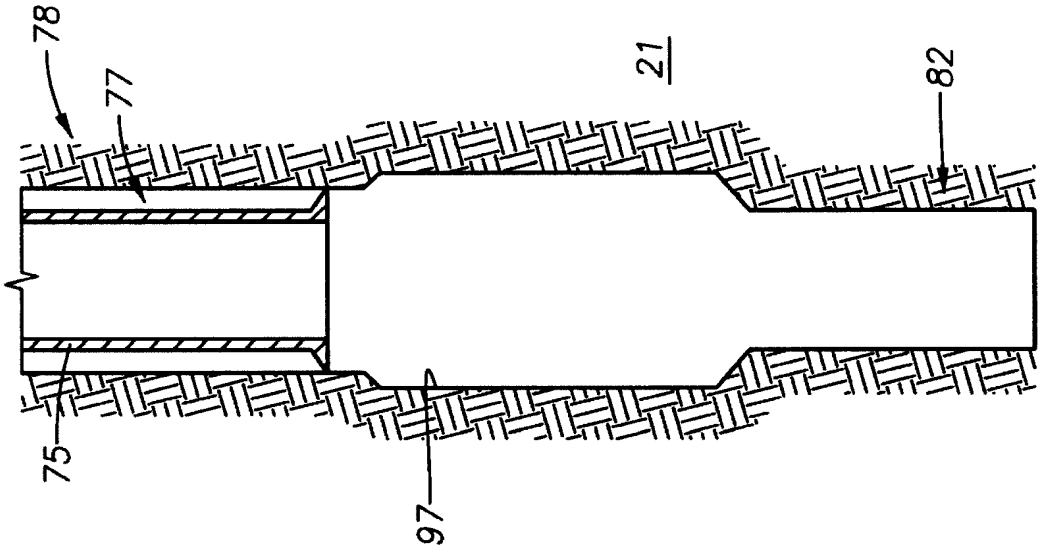


Fig. 4

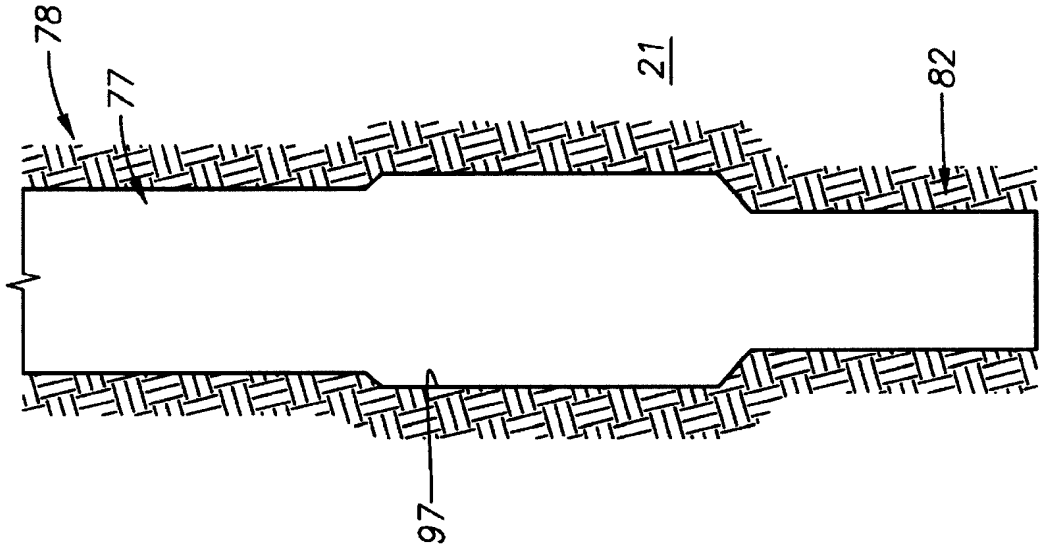


Fig. 3

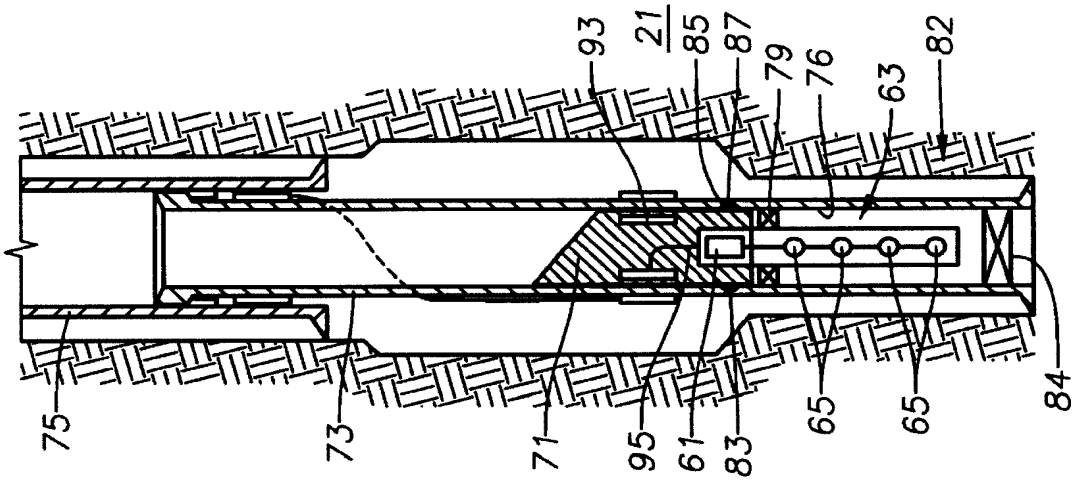


Fig. 7

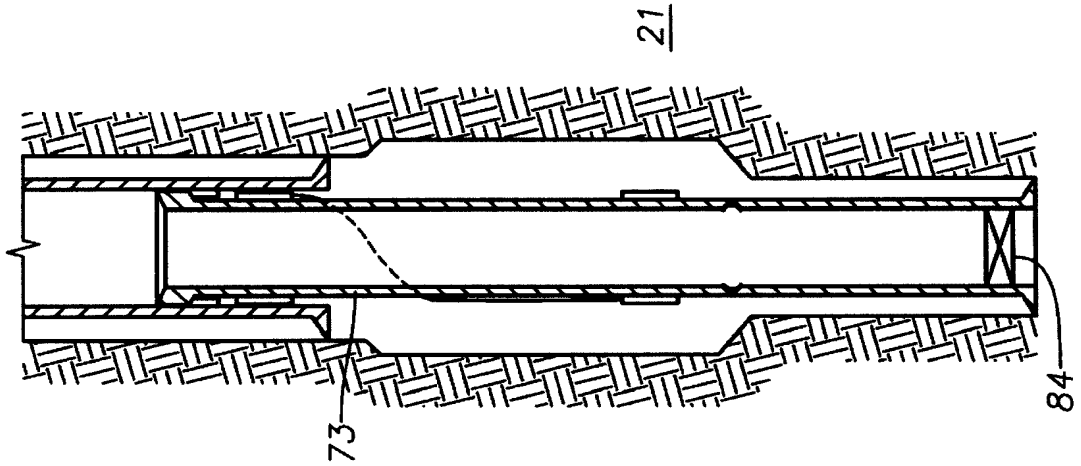


Fig. 6

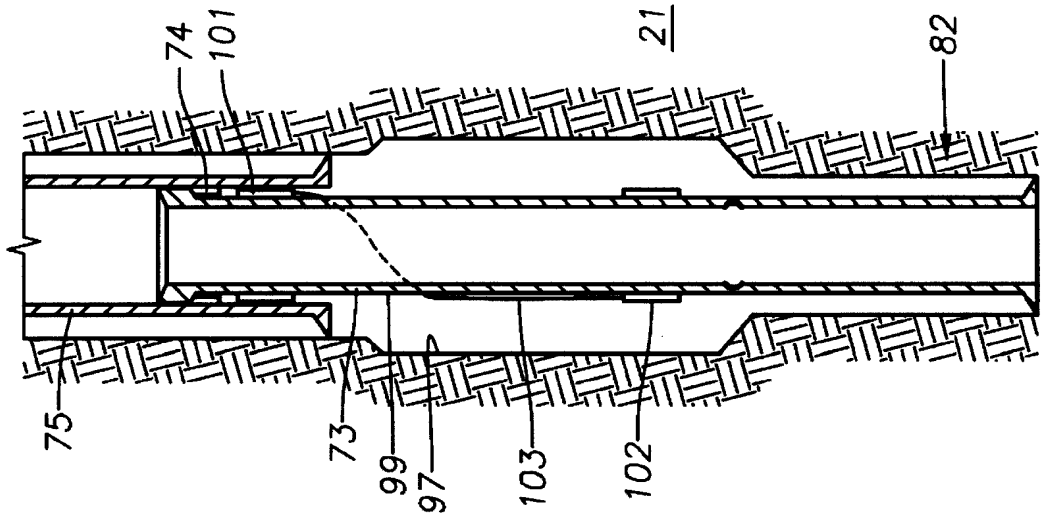


Fig. 5

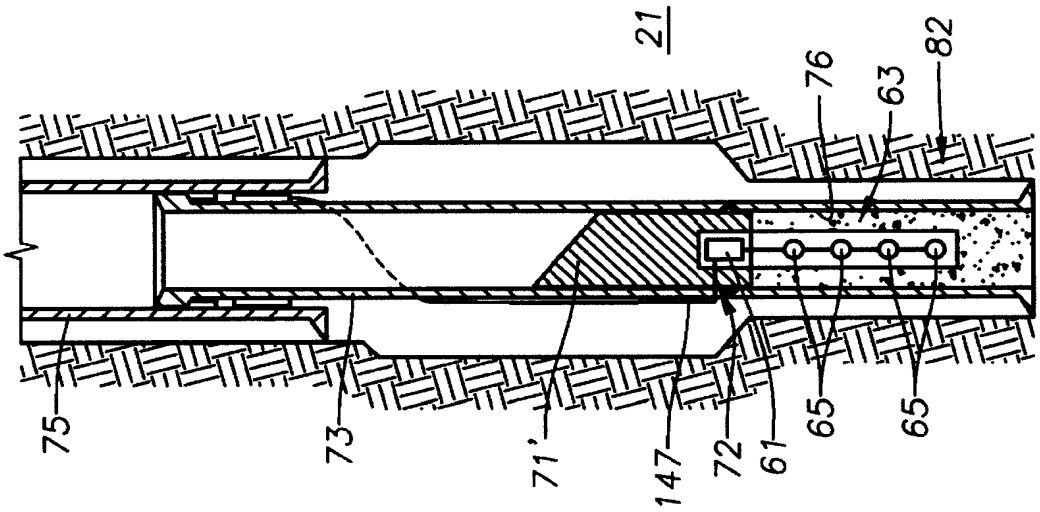

21
76
63
82
75
73
71'
147
72
61
65
65

Fig. 9

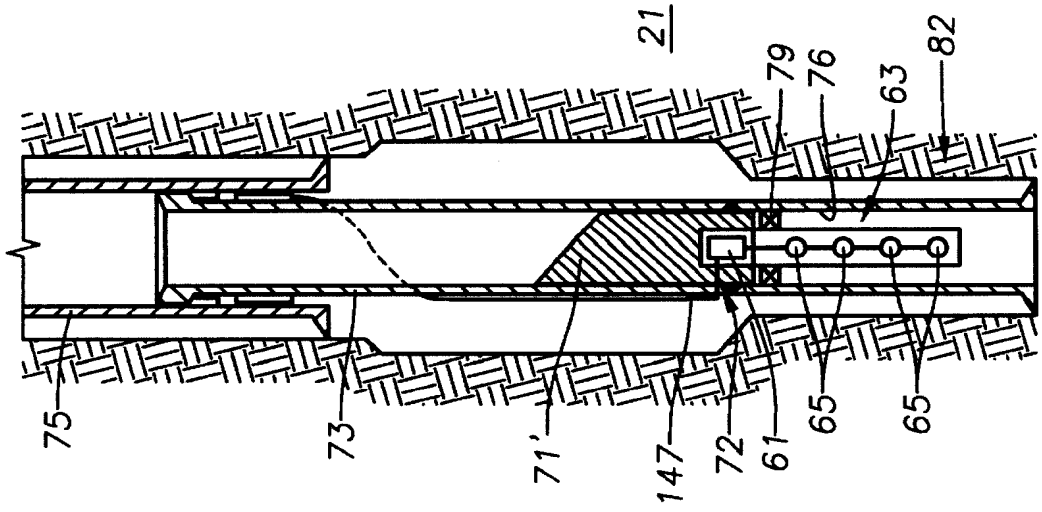

21
79
76
63
82
75
73
71'
147
72
61
65
65

Fig. 8

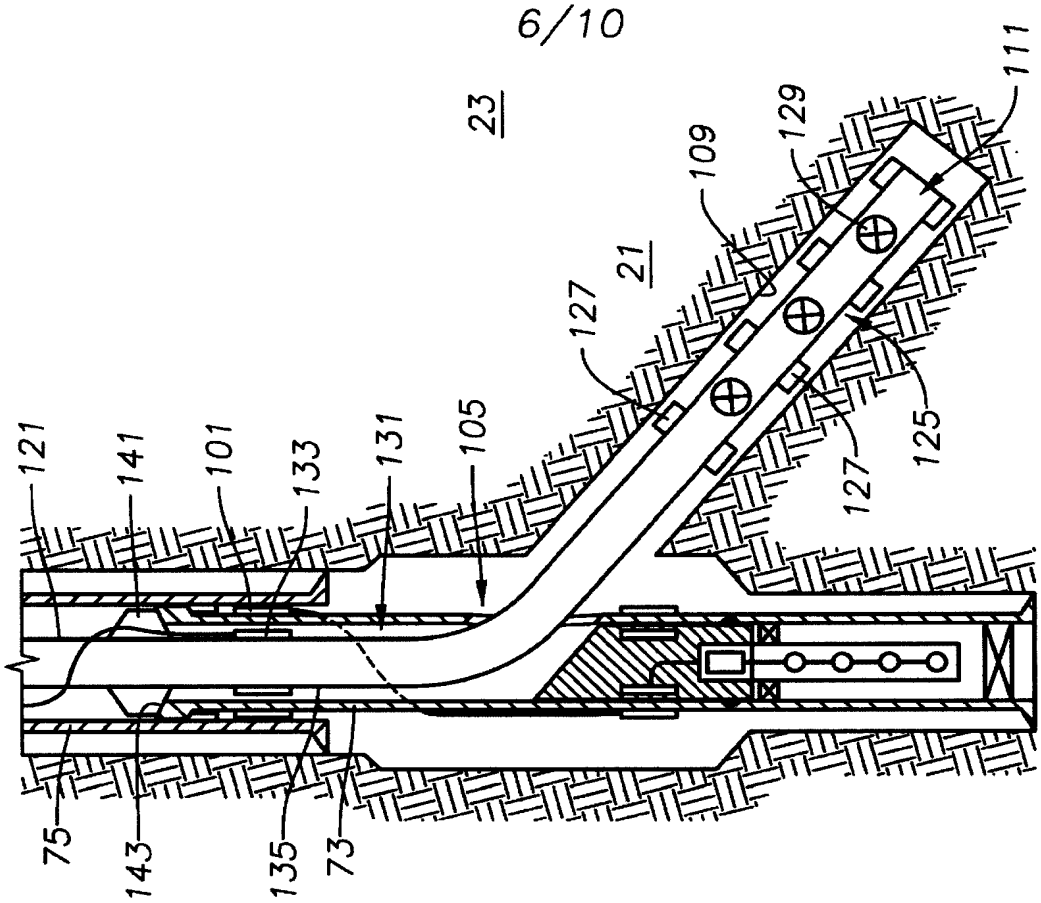

23
21
111
129
109
127
121
141
101
133
131
105
125
127
75
143
135
73

Fig. 11

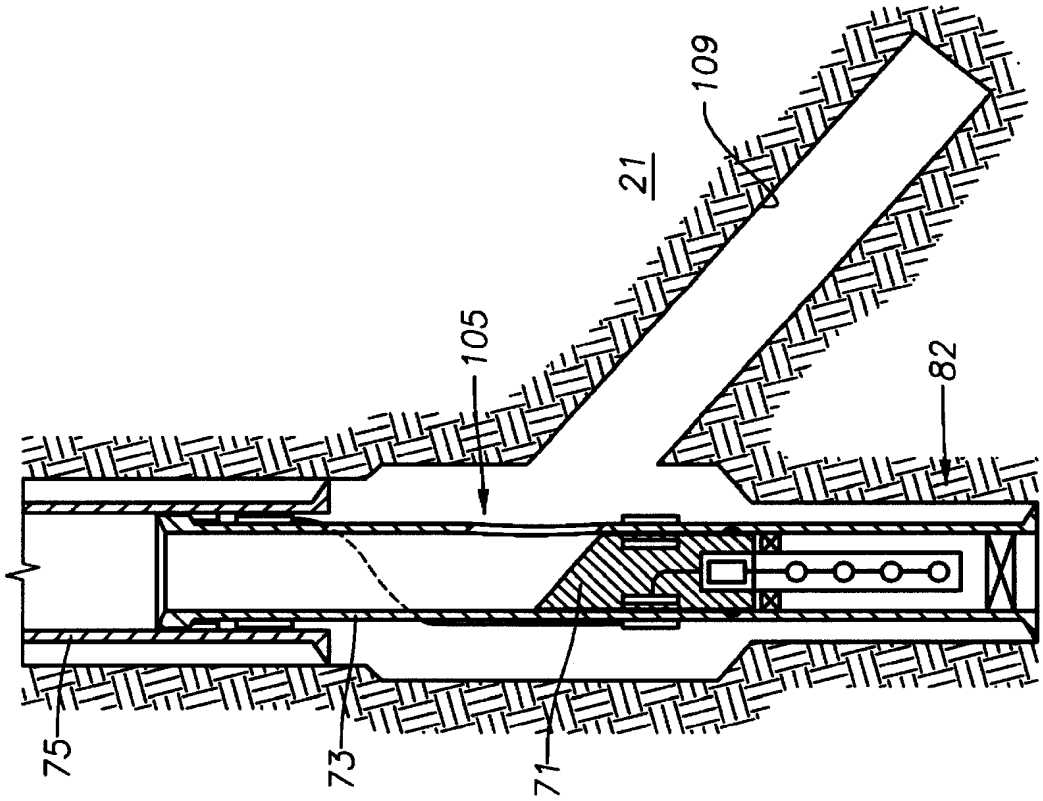

109
21
105
82
75
73
71

Fig. 10

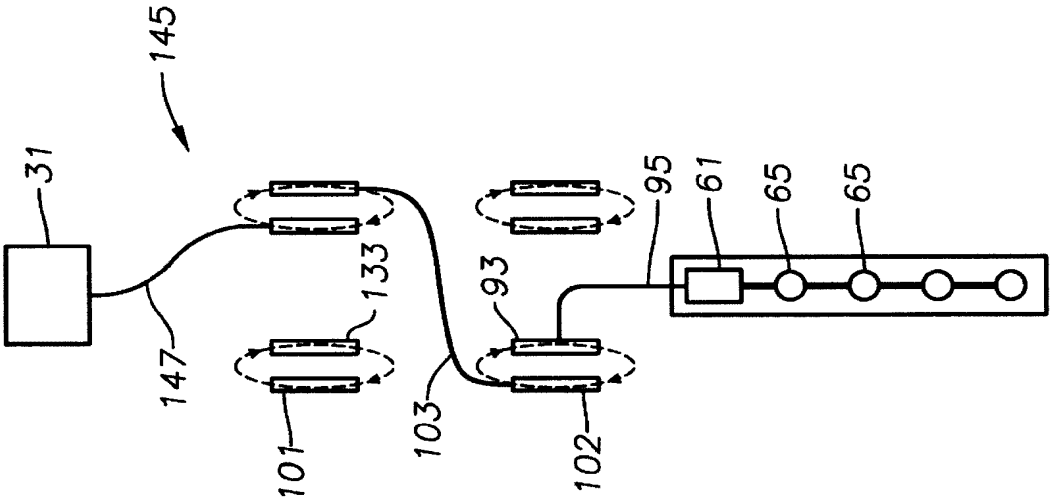


Fig. 13

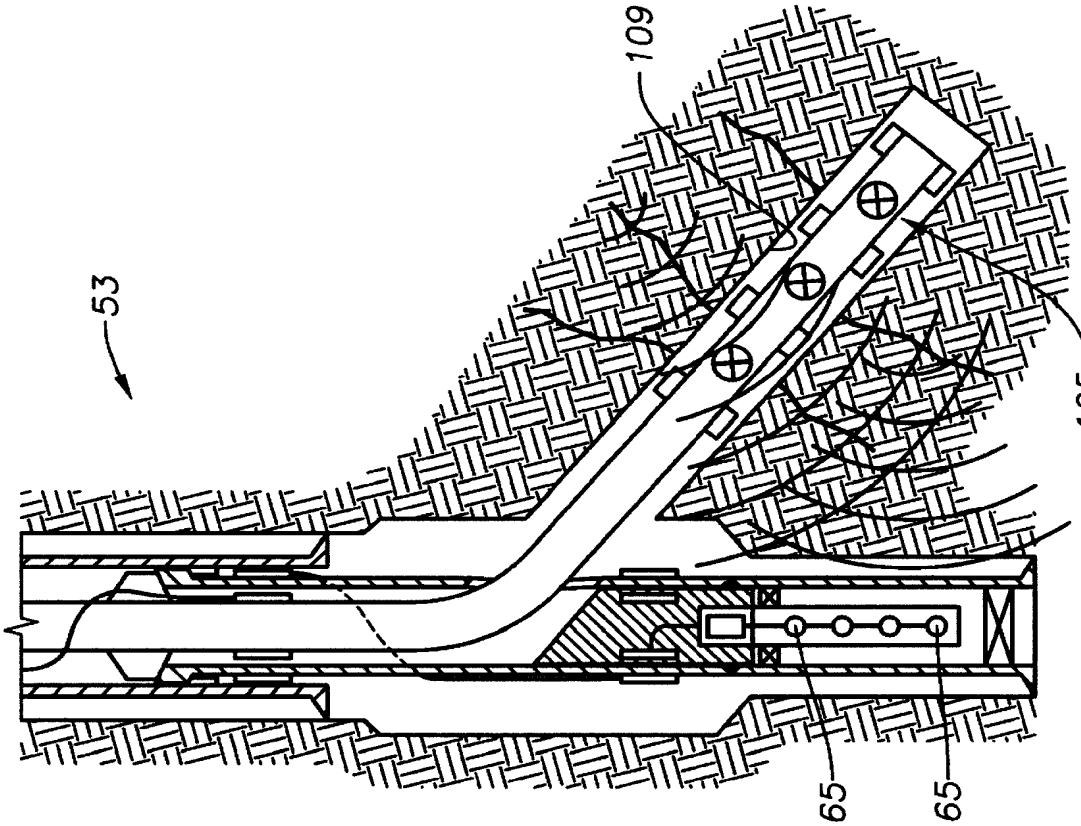


Fig. 12

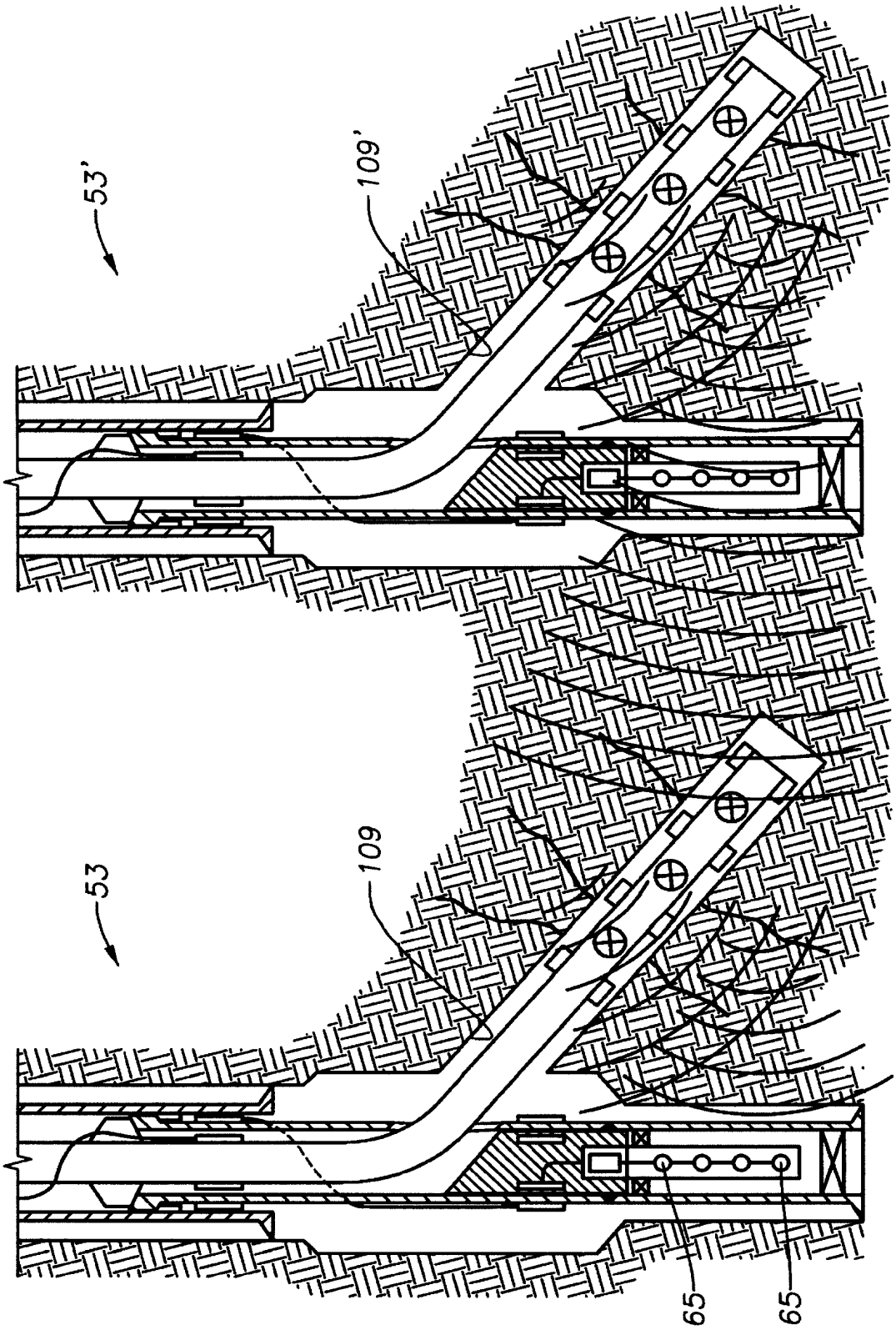


Fig. 14

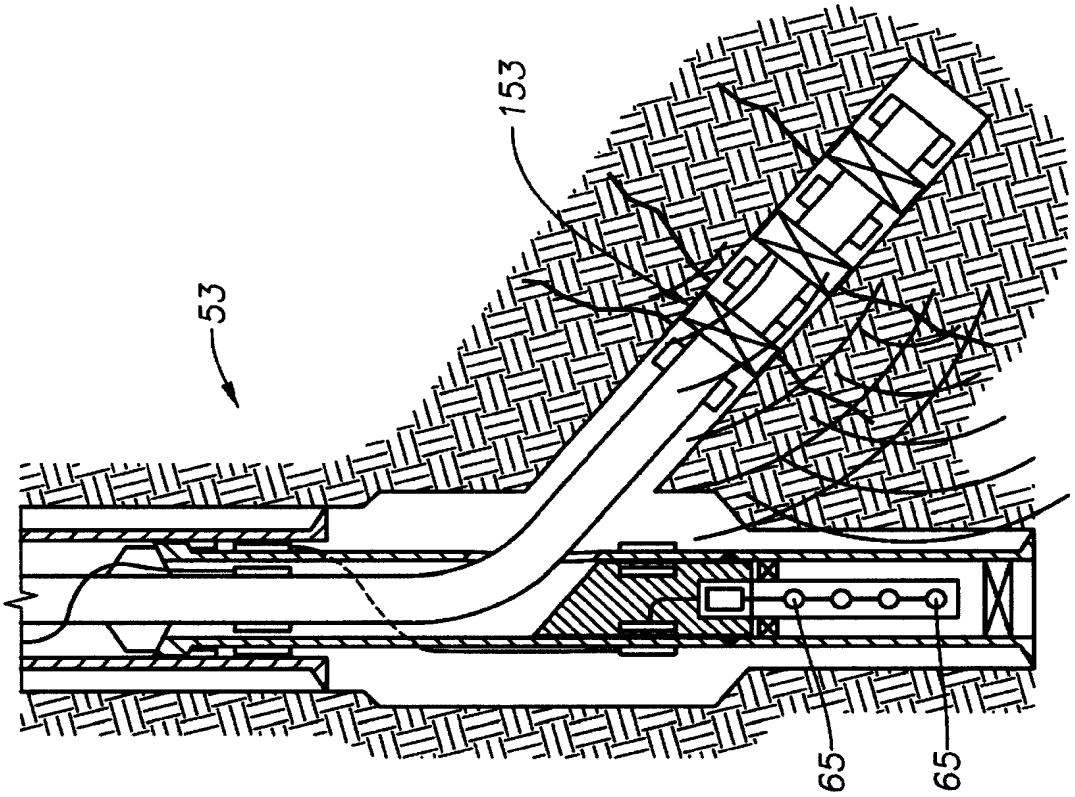


Fig. 16

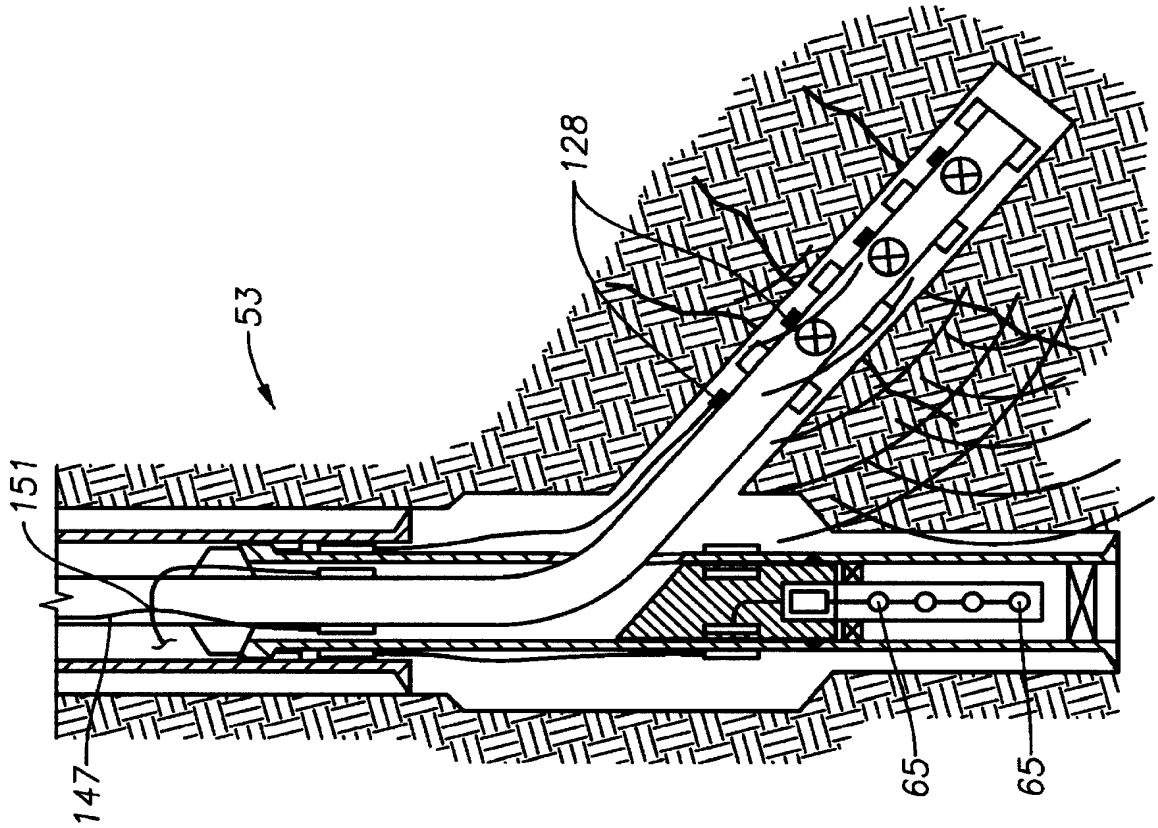


Fig. 15

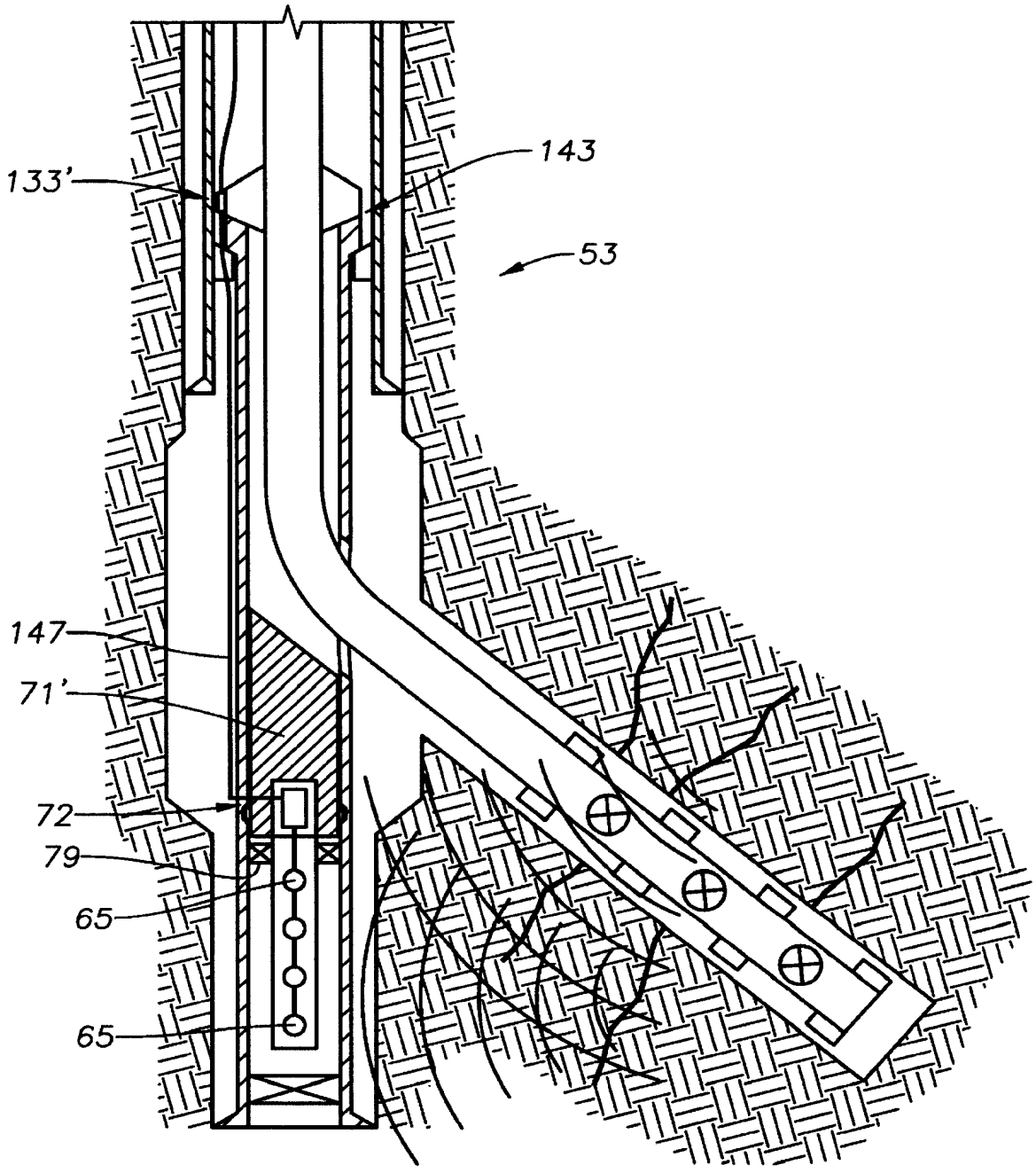


Fig. 17

Innovation, Sciences et Développement économique Canada
Office de la Propriété Intellectuelle du Canada

Innovation, Science and Economic Development Canada
Canadian Intellectual Property Office

CA 3006422 A1 2017/06/01

(21) 3 006 422

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(86) Date de dépôt PCT/PCT Filing Date: 2016/11/28
(87) Date publication PCT/PCT Publication Date: 2017/06/01
(85) Entrée phase nationale/National Entry: 2018/05/25
(86) N° demande PCT/PCT Application No.: GB 2016/053730
(87) N° publication PCT/PCT Publication No.: 2017/089834
(30) Priorités/Priorities: 2015/11/27 (GB1521012.3); 2016/05/24 (GB1609093.8)

(51) Cl.Int./Int.Cl. *E21B 43/12* (2006.01), *E21B 43/14* (2006.01), *E21B 43/26* (2006.01)

(71) Demandeur/Applicant:
SWELLFIX UK LIMITED, GB

(72) Inventeurs/Inventors:
GREEN, ANNABEL, GB;
HUNTER, JOHN, GB;
FROST, CLINT, GB

(74) Agent: MARKS & CLERK

(54) Titre : VANNE DE REGULATION DE DEBIT DE FOND DE TROU AUTONOME POUR CONTROLE DE PRESSION DE PUITS

(54) Title: AUTONOMOUS DOWNHOLE FLOW CONTROL VALVE FOR WELL PRESSURE CONTROL

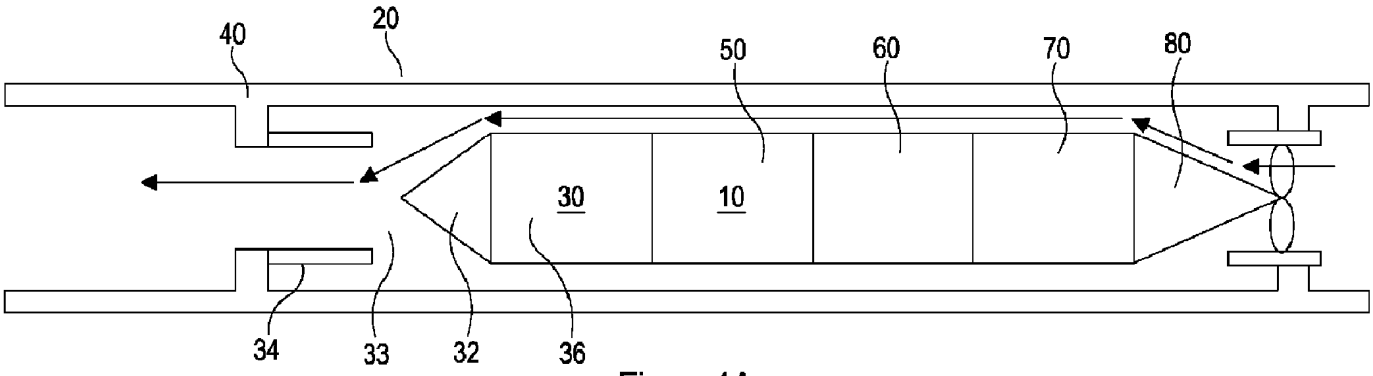


Figure 1A

(57) Abrégé/Abstract:
A downhole flow control device (10) is described having a flow control valve (30) and a sensor (50) in communication with the flow control valve. The sensor measures a downstream process parameter and the flow control valve is configured to control the fluid flow through the valve to achieve a target downstream process parameter value in response to the measured downstream process parameter. A control system for controlling the downhole flow control device and a method for controlling the downhole flow device are also provided.

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
1 June 2017 (01.06.2017)

WIPO | PCT

(10) International Publication Number
WO 2017/089834 A1

(51) International Patent Classification:
E21B 43/12 (2006.01) *E21B 43/26* (2006.01)
E21B 43/14 (2006.01)

(21) International Application Number:
PCT/GB2016/053730

(22) International Filing Date:
28 November 2016 (28.11.2016)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
1521012.3 27 November 2015 (27.11.2015) GB
1609093.8 24 May 2016 (24.05.2016) GB

(71) Applicant: **SWELLFIX UK LIMITED** [GB/GB]; 28 Abercrombie Court, Arnhall Business Park, Prospect Road, Westhill, Aberdeenshire AB32 6FE (GB).

(72) Inventors: **GREEN, Annabel**; Croft of Queensbriggs, Lumsden, Huntly, Aberdeenshire AB54 4JT (GB). **HUNTER, John**; 19 Mains Court, Westhill AB32 6QZ (GB). **FROST, Clint**; c/o Tendeka B.V., 28 Abercrombie Court, Arnall Business Park, Westhill, Aberdeenshire AB32 6FE (GB).

(74) Agent: **DOCHERTY, Andrew**; Marks & Clerk LLP, Aurora, 120 Bothwell Street, Glasgow G2 7JS (GB).

(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Published:

— *with international search report (Art. 21(3))*

— *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments (Rule 48.2(h))*

(54) Title: AUTONOMOUS DOWNHOLE FLOW CONTROL VALVE FOR WELL PRESSURE CONTROL

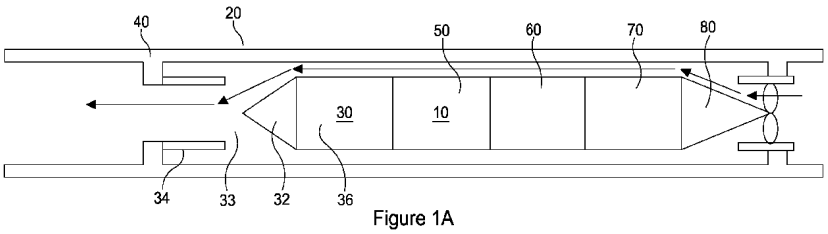


Figure 1A

(57) Abstract: A downhole flow control device (10) is described having a flow control valve (30) and a sensor (50) in communication with the flow control valve. The sensor measures a downstream process parameter and the flow control valve is configured to control the fluid flow through the valve to achieve a target downstream process parameter value in response to the measured downstream process parameter. A control system for controlling the downhole flow control device and a method for controlling the downhole flow device are also provided.

WO 2017/089834 A1

AUTONOMOUS DOWNHOLE FLOW CONTROL VALVE FOR WELL PRESSURE CONTROL

FIELD

The present disclosure relates to a flow control device, particularly a downhole flow control device and a method of controlling a flow control device.

BACKGROUND

Oil and gas fields typically comprise a number of wells which are processed by the same processing facility. The well conditions of each well may be different, for example, different wells may have different pressures. These differences can be due to, for example, penetrating different sections of the reservoir or different reservoir units. The variation in pressure can result in an imbalance of production across the wells.

Advanced completions or intelligent wells use valves or chokes in the reservoir that can be operated from the surface. These can be used to address or minimise the effect of imbalanced production across a formation.

Intelligent completion technology can be controlled from the surface using multiple hydraulic and/or electric control lines which have to pass through the wellhead into the completion annulus and run along the entire production line to where the valves are located. There are limitations associated with the use of control lines including the high costs associated with the equipment, complexity and risk during deployment.

Wireless intelligent completions utilise electronic controlled interval control valves which include sensors and in well processors which enables remote operation and control of the completion by the operator from the surface. Wireless telemetry, for example pressure pulses, is used to send and receive signals from downhole units to the surface. The ability of the downhole control valve to react to changes in the well environment remains in the hands of the operator on the surface.

During hydraulic fracturing operations, adjacent and nearby wells have to be isolated from the area being fractured. The wellhead is typically rated and designed to maintain a seal to isolate the well, however in practice a second barrier is usually provided to ensure pressure integrity. Two independent barriers for well control is normal practice and the second barrier is typically in the form of a retrievable plug installed downhole. After completion of the hydraulic fracturing operation, the plug is milled out. Any well within 0.5 to 1 mile of the fracking operation is required to be

protected in this manner and it may be required to carry out this operation 4 or 5 times per well. The costs of plugging and milling can quickly build up during a hydraulic fracturing operation.

SUMMARY

According to an aspect of the present disclosure, there is provided a downhole flow control device comprising:

a flow control valve;

a sensor in communication with the flow control valve, wherein the sensor measures a local process parameter; and

wherein the flow control valve is configured to control the fluid flow through the valve to achieve a target local process parameter value in response to the measured local process parameter.

In use, the downhole flow control device provides a means for monitoring and autonomously controlling the fluid production from a well. The flow control device will respond directly to changes in the downhole environment by changing the flow path through the valve as well conditions change without intervention from the surface of the well.

A local process parameter may be a process parameter measured in the vicinity of the flow control device. For example, the sensor may measure the downhole pressure at the location of the flow control device, and/or may measure the pressure drop across the flow control device, or measure the downhole pressure at the location of the flow control device.

The downhole flow control device may control the fluid flow through the flow control valve independently from external instruction, wherein external instruction comprises, for example, communication from the surface of the well, and/or input from an operator.

The downhole flow control device may be autonomous.

The local process parameter may be, for example, the downstream pressure, pressure drop across flow control valve, temperature, viscosity, or fluid composition, for example water content, measured in the vicinity of the flow control device when located downhole.

The target local process parameter value may be selected to maintain a surface process parameter of the well at a desired value or within a desired range.

The surface process parameter may be, for example, surface pressure or fluid flow rate.

For example, the local process parameter may be pressure and the target local process parameter value may be selected to maintain the surface pressure of the well.

The target local process parameter value may be determined through nodal analysis, for example nodal analysis may be performed on the well to determine a target process parameter value to produce a desired surface condition such as well head pressure.

The target local process parameter value may be programmed prior to deployment of the flow control device downhole.

The target local process parameter value may be re-programmable whilst the flow control device is in-situ. This increases the flexibility of the device to adjust to changing well conditions.

The target local process parameter value may be reprogrammed using downhole wireless communication such as wireless telemetry. This allows the flow control device to be re-programmable without the need for removal of the device from the well.

The flow control device may comprise wireless communication technology such as that described in WO2006/041308 and/or WO2006/041309. The flow control device may comprise a receiver and transmitter unit enabling it to be reconfigured using wireless telemetry.

Reconfiguring the flow control device may comprise a command to shutdown.

The local process parameter may be the same process parameter as the target process parameter, or it may be a different process parameter. For example, the target process parameter may be flow rate and the local process parameter may be pressure.

The flow control device may be configured to maintain the target downstream pressure at a predetermined level to keep the surface pressure at or below a predetermined level. The sensor may be selected to measure the local process parameter, for example a pressure sensor or a temperature sensor. The sensor may be chosen to measure any local process parameter, for example, pressure, temperature, flow rate, viscosity, fluid composition.

The flow control device may comprise a plurality of sensors configured to measure different local process parameters, for example a pressure sensor and temperature sensor.

The flow control device may be re-configurable to respond to different process parameters. For example, the flow control device may be configured to respond to a pressure reading from the sensor to achieve a target local pressure value, and the flow control device may be reconfigured to respond to a temperature reading and a pressure reading from temperature and pressure sensors to achieve a target downhole flowrate.

The flow control valve may comprise a choke valve.

The valve may comprise an electro-mechanical actuator, for example a piston or a sleeve.

The valve may be motor driven.

The valve may comprise a housing, wherein a piston is configured to extend and retract into or out of the housing to alter the flow area of the valve.

The valve may comprise an infinitely variable choke actuator.

The size of the flow control valve may be selected based on computational fluid dynamics (CFD) analysis performed to determine the range of valve size required to achieve the target local process parameter value.

A range of valve size may be preferable over a fixed valve size to account for declining reservoir pressure.

The flow control valve may further comprise a seal to facilitate the valve maintaining a seal when in a closed position.

The flow control device may comprise an electronics module.

The electronics module may act as a controller for the flow control valve.

The electronics module may act as the controller for the sensor.

The sensor and flow control valve may be controlled by a shared electronics module.

The electronics module may comprise an on-board processor.

The flow control device may use the target local process parameter value as a reference in a closed loop control system.

In use, the sensor may measure the local process parameter at set intervals. The processor may compare the measured local process parameter value with the target local process parameter value to determine if the actual local process parameter needs to be adjusted; the flow control valve may then alter the fluid flow through the valve to achieve the target local process parameter value.

The intervals may be selected depending on the process, for example measurements may be taken in second intervals, minute intervals, hour intervals, day intervals or week intervals.

The sensor may be configured to continuously measure the local process parameter as the flow control valve changes the fluid flow through the valve to achieve the target local process parameter value. The term “continuously” may comprise taking measurements at set intervals, where the intervals are short, for example taking a measurement every second, every five seconds, every 10 seconds. When the target local process parameter value has been reached, the flow control device may be configured to instruct the flow control valve to hold its position.

The flow control device may be configured to remain open until production is started. The flow control device may be located inside downhole tubing. This may allow for the flow control device to be retrievable.

The flow control device may be configured to form part of a downhole tubing string.

The tubing may be production tubing.

The flow control device may be located at any location within the production tubing, for example, the flow control device may be located to avoid hydrate formation. The flow control device may be located in the heel of the production tubing.

The flow control device may be an inflow control valve (ICV) for use in a production well.

The flow control device may be an inflow control valve for use in isolating at least a portion of the production well. For example, the flow control device may be used in hydraulic fracturing operations to isolate a distal portion of the well while hydraulic fracturing takes place in adjacent or nearby wells.

In use as an isolation valve, the target process parameter may be no fluid flow, or no fluid flow path or any process parameter associated with the flow valve being closed. The local process parameter may be, for example pressure or flow. The flow control valve may be configured such that when a pressure is detected within an accepted value or range, the flow control valve may close. The flow control valve may be configured such that when a flow rate of zero flow is detected, the flow control valve may close.

The flow control device may be configured to act as an isolation valve prior to running in hole.

The flow control device may be reconfigured to act as an isolation valve whilst in-situ downhole.

The flow control device may be designed to withstand a pressure up to a desired pressure value required to isolate the well, for example but not limited to, 8,000 psi, 10,000 psi.

A production well may be shut-in, for example from the surface, to stop production of the well. This may comprise closing a valve located at or near the surface of the production well. When a production well is shut-in, the downhole pressure at or near the flow control valve may increase.

The flow control device may be configured to detect when a shut-in of the well has taken place.

The flow control device may be configured to remain open until a shut-in of the well is detected. This may allow fluid flow through the flow control device during production of the well.

The flow control device may be used during the production of the well as a flow control device to maintain a desired surface process parameter and may be configured to be reconfigured whilst in-situ to be used as an isolation valve. For example the flow control device may be reconfigured using wireless telemetry to change the target process parameter to close the valve in response to a shut-in. The flow control device may be configured to measure the local pressure at set intervals. The intervals may be selected depending on the process, for example measurements may be taken in second intervals, minute intervals, hour intervals, day intervals or week intervals.

In use as an isolation valve, when a well is shut-in, the flow control device may detect an elevated local pressure. For example, an elevated pressure reading over a minimum period of time may indicate that the well has been closed and the flow control device may reconfigure to achieve the target process parameter of no fluid flow path through the valve.

The flow control device may be configured to recognise an elevated pressure value or increased pressure differential across the valve detected over a minimum time to be associated with a well shut-in. The minimum time may be, for example one minute, five minutes, ten minutes, fifteen minutes, twenty minutes, one hour, or any appropriate time interval required by the flow control device.

The flow control device may reconfigure to a closed position in response to a pressure indicating a shut-in of the well.

When the target local process parameter value has been reached, the valve may be closed and the flow control device may be configured to instruct the flow valve to hold this configuration.

In the closed position, the flow control device may maintain a seal and isolate at least a portion of the well, for example a distal portion of the well.

The flow control device may be configured to measure the local pressure whilst the flow control device is closed, for example, the flow control device may measure the local pressure at set intervals, for example every minute, or every five minutes, every ten minutes, every hour or any suitable interval, or the flow control device may be configured to measure the local pressure continuously whilst the flow control device is closed. The term "continuously" may comprise taking measurements at set intervals, where the intervals are short, for example taking a measurement every second, every five seconds, every 10 seconds.

The flow control device may be configured to open when the wellhead is opened, for example, after hydraulic fracturing operations have been completed.

The flow control device may be configured to open when the local pressure value above or below the valve corresponds to a value or within a pressure range associated with the well being open, or when a predetermined pressure differential across the valve is detected.

The flow control device may be configured to open or remain open when the local pressure is outside of an accepted range or value associated with the well being shut-in or associated with hydraulic fracturing operations occurring in adjacent or nearby wells, or the flow control device may be configured to open when the local pressure is within an accepted range associated with the well being open or hydraulic fracturing operations being complete. For example, when the well is opened or if hydraulic fracturing operations in nearby wells are stopped, the local pressure may decrease and the flow control device may be configured to respond to this pressure decrease by opening the flow control valve. A reduction in pressure measured over a minimum period of time may indicate that the well has been opened and the flow valve may open allowing the well to resume production.

The flow control device may be configured to remain closed until the flow control device is instructed to open, for example at such time as hydraulic fracturing operations in adjacent or nearby wells have been completed.

Instructing the flow control device to open may comprise sending a signal to the flow control device, for example using wireless telemetry. For example, a pressure

signal from the surface of the well may be sent to the flow control device when the well is opened following a shut-in, or in preparation for the well being opened following a shut-in. Upon receiving this pressure signal, the flow control device may open.

The flow control device may be configurable between an active and a passive configuration. In the passive configuration, the flow control device may measure a local process parameter, and compare the local process parameter to a target process parameter to, for example, determine whether the actual local process parameter needs to be adjusted. In the active configuration, the flow control valve may alter the fluid flow through the valve to achieve the target local process parameter value.

The flow control device may be configured to the active configuration during well shut-in. Additionally, or alternatively, the flow control device may be configured to the active configuration during production and/or when the wellhead is opened. The flow control device may be configured to the passive configuration once the target process parameter has been reached.

In the passive configuration, the flow control valve may not require to be altered. As such, in the passive configuration, the flow control device may consume less power than in the active configuration, thereby extending battery life, for example.

The flow control device may be configured to reset following opening after a shut-in such that the flow control device may remain open until another shut-in is detected.

The flow control device may be powered by a local power source.

The flow control device may be battery powered. The number of batteries may be selected according to the desired lifetime of the flow control device, for example one battery, two batteries, three batteries, or four batteries. The number of batteries may be limited by the rig-up height and handling of the flow control device.

The flow control device may be powered by a downhole generator. For example, the flow control device may be powered by a turbine for energy extraction from fluid flowing within a conduit, such as that described in UK patent publication number 2531025 and/or WO2016/055451 and/or WO2014118503.

According to a second aspect of the present disclosure, there is provided a control system for a downhole flow control device comprising:

a closed loop control system wherein a flow control valve located downhole adjusts to achieve a target local process parameter value in response to a measured local process parameter reading from a sensor in communication with the flow control valve.

The control system may comprise a plurality of sensors in communication with the flow control valve.

Each sensor may measure a different process parameter.

The target local process parameter value may be a reference in the closed loop control system.

The control system may be configured such that the sensor measures the downhole process parameter at set intervals. For example, the sensor may be configured to take measurements in second intervals, minute intervals, day intervals, week intervals or month intervals.

The control system may be configured to continuously measure the local process parameter as the flow valve adjusts the fluid flow through the valve to achieve the target local process parameter value. The term “continuously” may comprise taking measurements at set intervals, where the intervals are short, for example taking a measurement every second, every five seconds, every 10 seconds. When the target local process parameter value has been reached, the control system may be configured to instruct the flow valve to hold its position. The control system may be configured to be reprogrammable when required by well conditions, for example the target downhole process parameter value may be changed, the downhole process parameter may be changed, and the flow control valve may be shut down.

The control system may be reprogrammable whilst the downhole flow control device is in-situ.

The control system may be reprogrammable using downhole wireless telemetry, for example the wireless communication technology such as that described in WO2006/041308 and/or WO2006/041309.

The control system may be configured to set the flow control device to idle whilst no flow is detected. The control system may comprise an outer loop and an inner loop.

The outer loop may detect if the well is flowing and whether or not any communication is due to be received or sent from the flow control device. When flow is detected, the control system may move to the inner loop.

The inner control loop may determine if the measured downhole process parameter is within an accepted tolerance for the target local process parameter value and may adjust the flow valve accordingly. If the measured downhole process parameter is within the accepted tolerance for the target process parameter, the control system may move back to the outer loop.

The outer loop may measure a local downhole process parameter to determine whether the well has been shut-in at or near the surface. For example, an elevated local pressure over a minimum time may signal that the well has been shut-in. When a shut-in is detected, the control system may move to the inner loop. If no shut-in is detected, the outer control loop may take local downhole process parameters at set intervals.

The inner control loop may have a target local process parameter of no fluid flow, or no fluid flow path, or any process parameter associated with the flow control valve being closed. When the control system moves to the inner control loop, the control system may reconfigure the flow valve to achieve the target process parameter, for example the flow control valve will close.

The inner loop may measure the downhole process parameter at set intervals and whilst the downhole process parameter is within an accepted range, instruct the flow control valve to remain closed. If the downhole process parameter is not within the accepted range, the inner loop may instruct the flow valve to open and the control system may return to the outer loop.

For example, the downhole process parameter may be pressure. The inner loop may determine if the measured pressure or pressure differential across the flow control valve is within an accepted range for the flow valve to remain closed. The inner loop may determine if the measured pressure or pressure differential across the valve is within an accepted range for the flow valve to open. The accepted range may be a pressure or pressure range associated with the well being shut in or a pressure range associated with hydraulic fracturing operations taking place in adjacent or nearby wells, or the accepted range may be a pressure value or range associated with the wellhead being open, or associated with hydraulic fracturing operations being completed. If the inner loop determines the detected pressure value is below the accepted range or within the accepted range, the inner loop may instruct the flow control valve to open. For example, a decrease in local pressure to a pressure below the accepted range or within the accepted range, or a decrease in differential pressure across the valve may indicate that the wellhead has been opened and the flow valve can be opened.

The control system may be operable to set the flow control valve between the active configuration and the passive configuration. When the flow control valve is in the active configuration, the control system may operate using the inner loop. When the flow control valve is in the passive configuration, the control system may operate using the outer loop.

The control system may be configured to receive a communication from surface to open the flow valve. For example, a communication sent from the surface using wireless telemetry. The communication may be in the form of a pressure signal. Upon receipt of the communication, the control system may instruct the flow vale to open and the control system may return to the outer control loop.

Features described in relation to the flow control device of the first aspect apply mutatis mutandis to the second aspect.

According to a third aspect of the present disclosure, there is provided a method of controlling a downhole flow control device comprising:

programming a downhole flow control device with a target local process parameter value;

locating the downhole flow control device downhole, wherein the device comprises a flow control valve and a sensor in communication with the flow valve;

measuring a local process parameter with the sensor;

wherein the flow valve controls the fluid flow through the valve to achieve the target local process parameter in response to the measured local process parameter.

The method may be used to control fluid production from a well.

The method may comprise locating the downhole flow control device in production tubing, wherein the downhole flow device may form part of the tubing or be located inside the tubing.

The method may comprise a closed loop control system wherein the target local process parameter value is a reference.

The method may comprise reconfiguring the flow control device if necessary according to well conditions, for example the target downhole process parameter value may be changed, the downhole process parameter may be changed, and the flow control valve may be shut down.

The method may comprise reconfiguring the flow control device whilst the flow control device is in situ.

The method may comprise reconfiguring the flow control device using downhole wireless communication such as wireless telemetry, for example the wireless communication technology such as that described in WO2006/041308 and/or WO2006/041309.

The method may comprise operating the flow control valve during production of the well, for example where the target process parameter is selected to obtain a predetermined rate of production of the well. The target process parameter may be, for

example pressure, temperature, flow rate and viscosity. The local process parameter detected by the sensor may be, for example pressure, temperature, flow rate and viscosity. The local process parameter may be the same or different from the target process parameter.

The method may comprise operating the flow control valve as an isolation valve. In use as an isolation valve, the target process parameter may be no fluid flow, or no fluid flow path or any process parameter associated with the flow control valve being closed. The local process parameter may be pressure and the flow control valve may be configured such that when a pressure is detected within an accepted value or range, the flow control valve may close.

The method may comprise configuring the flow control device to operate as an isolation valve prior to running in hole.

The method may comprise configuring the flow control device to operate as an isolation valve whilst in-situ downhole.

The method may comprise isolating a portion of a well, for example a distal portion of the well.

The flow control device may be used to isolate a portion of the well during hydraulic fracturing operations to isolate a portion of the well while adjacent or nearby wells are being fractured.

The method may comprise detecting when the well has been shut-in. For example, the local process parameter may be pressure and the method may comprise the sensor measuring the downhole pressure. The method may comprise measuring the local pressure at set intervals. The intervals may be selected depending on the process, for example measurements may be taken in second intervals, minute intervals, hour intervals, day intervals or week intervals. An elevated pressure detected over a minimum period of time may indicate that the well has been closed and the flow valve may adjust to achieve the target process parameter of no fluid flow, wherein the fluid flow valve will close.

The method may comprise reconfiguring the flow control valve to a closed position to achieve the target local process parameter of zero flow, or zero fluid flow path in response to a pressure indicating a shut-in of the well.

The method may comprise maintaining the flow control valve in the closed position to isolate and seal a portion of the production well. The flow control valve may be designed to withstand a required pressure to isolate the well, for example but not limited to 8,000 psi or 10,000 psi.

The method may comprise opening the valve, for example when the well is opened. For example when a valve at the wellhead has been opened.

The method may comprise detecting when the well has been opened.

The method may comprise detecting if the measured local pressure or pressure differential is within an accepted range for the flow control valve to remain closed. The accepted range may be a pressure range associated with the well being shut in from surface or a pressure range associated with hydraulic fracturing operations taking place in adjacent wells. For example, when a well is shut-in, the pressure at or near the flow control valve may increase.

The method may comprise detecting if the measured local pressure or pressure differential across the valve is within an accepted range for the flow valve to open. The accepted range may be a reduced pressure range or pressure differential associated with the wellhead being open, or associated with hydraulic fracturing operations being completed.

The method may comprise determining if the measured pressure value is below the accepted range or within the accepted range and opening the flow control valve open. For example, a decrease in local pressure to a pressure below the accepted range or to within the accepted range may indicate that the wellhead has been opened and the flow valve can be opened.

The method may comprise sending a signal, for example a wireless communication to the flow control device to open the valve. For example, a pressure pulse sent from the surface may trigger the flow control valve to reopen.

The method may comprise operating the flow control valve during production of the well and reprogramming the flow control valve in-situ to operate as an isolation valve. The method may comprise operating the flow control valve as an isolation valve and reconfiguring the flow valve in-situ to operate during production of the well.

Features described in relation to the flow control device of the first aspect and the control system of the second aspect apply mutatis mutandis to the method of the third aspect.

According to a fourth aspect of the present disclosure, there is provided a downhole flow control device for isolating a portion of a well, the flow control device comprising:

a flow control valve;

a sensor in communication with the flow control valve, wherein the sensor measures a local process parameter; and

wherein the flow control valve is configured to close in response to the measured local process parameter.

In use, the downhole flow control device provides a means to isolate a portion of a well independently from external instruction, wherein external instruction comprises, for example, communication from the surface of the well, and/or input from an operator.

The flow control device may be autonomous.

The flow control device may be configured to isolate a portion of the well, for example a distal portion of the well during hydraulic fracturing operations on adjacent or nearby wells.

A local process parameter may be a process parameter measured in the vicinity of the flow control device. For example, the sensor may detect the downhole pressure at the location of the flow control device, and/or may measure the pressure drop across the fluid control device, or measure the downhole pressure at the location of the flow control device.

The local process parameter may be, for example, the downstream pressure or pressure drop across flow control valve measured in the vicinity of the flow control device when located downhole.

The flow control device may be located inside downhole tubing. This may allow for the flow control device to be retrievable.

The flow control device may be configured to form part of a downhole tubing string.

The tubing may be production tubing.

The flow control device may be located at any location within the production tubing, for example the flow control device may be located in the production tubing above the hydrocarbon bearing formation such that a distal portion of the well is isolated when the flow control valve is closed.

The flow control device may be an inflow control valve for use in isolating a portion of a production well. For example, the flow control device may be used to isolate a portion of the well while hydraulic fracturing takes place in adjacent or nearby wells.

In use as an isolation valve, the local process parameter may be, for example pressure or flow. The flow control valve may be configured such that when a pressure is detected within an accepted value or range, the flow control valve may close. The

flow control valve may be configured such that when a flow rate of zero flow is detected, the flow control valve may close.

The flow control device may be configured to act as an isolation valve prior to running in hole.

The flow control device may be reconfigured to act as an isolation valve whilst in-situ downhole.

The flow control device may be designed to withstand a pressure up to a desired pressure value required to isolate the well, for example but not limited to, 8,000 psi, 10,000 psi.

A production well may be shut-in, for example from the surface, to stop production of the well. This may comprise closing a valve located at or near the surface of the production well. When a production well is shut-in, the downhole pressure may increase and fluid flow will be zero.

The flow control device may be configured to detect when a shut-in of the well has taken place.

The flow control device may be configured to remain open until a shut-in of the well is detected. This may allow fluid flow through the flow control device during production of the well.

The flow control device may be used during the production of the well as a flow control device to maintain a desired surface process parameter and may be configured to be reconfigured whilst in-situ to be used as an isolation valve. For example the flow control device may be reconfigured using wireless telemetry to change the target process parameter to achieve a closed valve in response to a shut-in. The flow control device may be configured to measure the local pressure at set intervals. The intervals may be selected depending on the process, for example measurements may be taken in second intervals, minute intervals, hour intervals, day intervals or week intervals.

In use as an isolation valve, when a well is shut-in, the flow control device may detect an elevated local pressure. For example, an elevated pressure reading over a minimum period of time may indicate that the well has been closed and the flow control device may reconfigure to achieve the target process parameter of no fluid flow path through the valve.

The flow control device may be configured to recognise a pressure value or pressure differential across the valve detected over a minimum time to be associated with a well shut-in. The minimum time may be, for example one minute, five minutes,

ten minutes, fifteen minutes, twenty minutes, one hour, or any appropriate time interval required by the flow control device.

The flow control device may reconfigure to a closed position in response to a pressure indicating a shut-in of the well.

The flow control device may be configured to instruct the flow valve to hold this configuration.

In the closed position, the flow control device may maintain a seal and isolate at least a portion of the well, for example a distal portion of the well.

The flow control device may be configured to measure the local pressure whilst the flow control device is closed, for example, the flow control device may measure the local pressure at set intervals, for example every minute, or every five minutes, every ten minutes, every hour or any suitable interval, or the flow control device may be configured to measure the local pressure continuously whilst the flow control device is closed. The term "continuously" may comprise taking measurements at set intervals, where the intervals are short, for example taking a measurement every second, every five seconds, every 10 seconds.

The flow control device may be configured to open when the wellhead is opened, for example, after hydraulic fracturing operations have been completed.

The flow control device may be configured to open when the local pressure value above or below the valve corresponds to a value or within a pressure range associated with the well being open, or when a predetermined pressure differential across the valve is detected.

The flow control device may be configured to open or remain open when the local pressure is outside of an accepted range or value associated with the well being shut-in or associated with hydraulic fracturing operations occurring in adjacent or nearby wells, or the flow control device may be configured to open when the local pressure is within an accepted range associated with the well being open or hydraulic fracturing operations being complete. For example, when the well is opened or if hydraulic fracturing operations in nearby wells are stopped, the local pressure may decrease and the flow control device may be configured to respond to this pressure decrease by opening the flow control valve. A reduction in pressure measured over a minimum period of time may indicate that the well has been opened and the flow valve may open allowing the well to resume production.

The flow control device may be configured to remain closed until the flow control device is instructed to open, for example at such time as hydraulic fracturing operations in adjacent or nearby wells have been completed.

Instructing the flow control device to open may comprise sending a signal to the flow control device, for example using wireless telemetry. For example, a pressure signal from the surface of the well may be sent to the flow control device when the well is opened following a shut-in, or in preparation for the well being opened following a shut-in. Upon receiving this pressure signal, the flow control device may open.

The flow control device may be configured to reset following opening after a shut-in such that the flow control device may remain open until another shut-in is detected.

The flow control device may be reconfigured for use during production of the well. For example, the flow control device may be reconfigured to have a target local process parameter which is selected to maintain a desired surface process parameter. The flow control device may reconfigure the fluid flow path to achieve the target local process parameter is response to the measured local process parameter. The measured local process parameter may be re-programmed whilst the flow valve is in-situ.

The target local process parameter value and the local process parameter may be reconfigured using downhole wireless communication such as wireless telemetry. This allows the flow control device to be re-configurable without the need for removal of the device from the well.

The flow control device may comprise wireless communication technology such as that described in WO2006/041308 and/or WO2006/041309. The flow control device may comprise a receiver and transmitter unit enabling it to be reprogrammed using wireless telemetry.

The flow control valve may comprise a choke valve.

The valve may comprise an electro-mechanical actuator, for example a piston or a sleeve.

The valve may be motor driven.

The valve may comprise a housing, wherein a piston is configured to extend and retract into or out of the housing to alter the flow area of the choke valve.

The valve may comprise an infinitely variable choke actuator.

The size of the flow control valve may be selected based on computational fluid dynamics (CFD) analysis performed to determine the range of valve size required to achieve the target local process parameter value.

A range of valve size may be preferable over a fixed valve size to account for declining reservoir pressure.

The flow control valve may further comprise a seal to facilitate the valve maintaining a seal when in a closed position.

The flow control device may comprise an electronics module.

The electronics module may act as a controller for the flow control valve.

The electronics module may act as the controller for the sensor.

The sensor and flow control valve may be controlled by a shared electronics module.

The electronics module may comprise an on-board processor.

The flow control device may be powered by a local power source.

The flow control device may be battery powered. The number of batteries may be selected according to the desired lifetime of the flow control device, for example one battery, two batteries, three batteries, or four batteries. The number of batteries may be limited by the rig-up height and handling of the flow control device.

The flow control device may be powered by a downhole generator. For example, the flow control device may be powered by a turbine for energy extraction from fluid flowing within a conduit, such as that described in UK patent publication number 2531025 and/or WO2016/055451 and/or WO2014118503.

Features described in relation to other aspects of the present disclosure apply mutatis mutandis to the flow control vale of the fourth aspect.

According to another aspect of the present disclosure, there is provided a method of isolating a portion of a well during hydraulic fracturing operations, the method comprising

locating a flow control valve downhole,

closing the well;

closing flow control valve; and

performing hydraulic fracturing operations on an adjacent or nearby well.

The method may further comprise measuring a downhole process parameter with a sensor in communication with the flow control valve, wherein the flow control valve will close in response to the measured downhole process parameter.

The flow control valve may close without intervention from the surface of the well.

The downhole process parameter may be, for example pressure or flow.

The method may comprise detecting a pressure within an accepted value or range and closing the flow control valve.

The method may comprise detecting no fluid flow and closing the flow control valve.

The method may further comprise closing the well at or near the surface, for example by closing a valve located at or near the surface of the well.

The method may comprise detecting when a shut-in of the well has taken place.

The method may comprise configuring the flow control valve to remain open until a shut-in of the well is detected.

The method may further comprise producing through the valve. The method may further comprise producing when the valve is in an open or partially open configuration. The method may comprise configuring the flow control valve to maintain a desired surface process parameter, for example a pre-determined flow rate or pressure.

The method may comprise detecting an elevated local pressure and closing the flow control valve. For example, an elevated pressure reading over a minimum period of time may indicate that the well has been closed and the flow control device may close.

The method may comprise recognising a pressure value or pressure differential across the valve detected over a minimum time to be associated with a well shut-in. The minimum time may be, for example one minute, five minutes, ten minutes, fifteen minutes, twenty minutes, one hour, or any appropriate time interval required by the flow control device.

The method may comprise maintaining the flow control valve in the closed configuration. In the closed configuration, the flow control valve may maintain a seal and isolate at least a portion of the well, for example a distal portion of the well.

The method may comprise detecting the local pressure whilst the flow control valve is closed, for example, the flow control device may detect the local pressure at set intervals, for example every minute, or every five minutes, every ten minutes, every hour or any suitable interval, or the flow control valve may be configured to detect the local pressure continuously whilst the flow control valve is closed. The term “continuously” may comprise taking measurements at set intervals, where the intervals

are short, for example taking a measurement every second, every five seconds, every 10 seconds.

The method may further comprise opening the flow control valve. For example, the method may comprise opening the flow control valve after hydraulic fracturing operations on the adjacent or nearby well have been completed.

The method may comprise opening the flow control valve when the local pressure value above or below the valve corresponds to a value or within a pressure range associated with the well being open, or when a predetermined pressure differential across the valve is detected.

The method may comprise opening or holding the flow control valve open when the local pressure is outside of an accepted range or value associated with the well being shut-in or associated with hydraulic fracturing operations occurring in adjacent or nearby wells, or opening or holding the flow control valve open when the local pressure is within an accepted range associated with the well being open or hydraulic fracturing operations being complete. For example, when the well is opened or if hydraulic fracturing operations in nearby wells are stopped, the local pressure may decrease and the flow control valve may be configured to respond to this pressure decrease by opening the flow control valve. A reduction in pressure measured over a minimum period of time may indicate that the well has been opened and the flow valve may open allowing the well to resume production.

The method may comprise maintaining the flow control valve in the closed configuration until the flow control device is instructed to open, for example at such time as hydraulic fracturing operations in adjacent or nearby wells have been completed.

The method may further comprise instructing the flow valve to open. Instructing the flow control valve to open may comprise sending a signal to the flow control valve, for example using wireless telemetry. For example, a pressure signal from the surface of the well may be sent to the flow control valve when the well is opened following a shut-in, or in preparation for the well being opened following a shut-in. Upon receiving this pressure signal, the flow control device may open.

The method may further comprise reconfiguring the flow control valve to maintain a pre-determined production rate from the well. For example the flow control device may be reconfigured using wireless telemetry.

The method may comprise configuring the flow control valve between the active and passive configuration.

The method may comprise configuring the flow control valve to the active configuration during well shut-in.

Features described in relation to other aspects of the present disclosure apply mutatis mutandis to the method described in this aspect.

BRIEF DESCRIPTION OF THE DRAWINGS

These and other aspects of the present disclosure will now be described, by way of example only, with reference to the accompanying drawings, in which:

Figure 1a shows a schematic cut-away diagram of an in-line flow control device according to the present disclosure;

Figure 1b shows a schematic diagram of the flow control device shown in Figure 1a;

Figure 2a shows a schematic cut-away diagram of an annular flow control device according to the present disclosure;

Figure 2b shows a schematic diagram of the flow control device of Figure 2a;

Figure 3 shows a detailed schematic of the outer control and inner control loop for the fluid control device; and

Figure 4 shows a schematic of the flow control device of the present disclosure in use during a hydraulic fracturing operation.

DETAILED DESCRIPTION OF THE DRAWINGS

The downhole flow control device 10 in use is deployed within a wellbore which intercepts a subterranean formation which contains hydrocarbons. In the embodiment shown in Figures 1a and 1b, the flow control device 10 is deployed inside production tubing 20, configured to communicate fluids, such as gas, produced from the formation to the surface. Alternatively, the flow control device can form part of the production tubing, and will be run as part of the completion, either directly attached to the tail pipe or with the completion itself, as shown in Figures 2a and 2b.

The flow control device 10 has a flow control valve 30 in the form of a choke valve with an infinitely variable choke system. Choke valve 30 has an electro-mechanical piston 32 and a choke housing 34. The position of the piston 32 with respect to the choke housing forms a choke inlet 33. The valve 30 has a drive mechanism and motor 36 to move the piston of the choke valve. The flow control device has a sensor module 50 containing sensors to measure the desired process parameter. The skilled person will appreciate that the sensors may be chosen to

measure any downhole process parameter, for example, pressure, temperature, flow rate, viscosity, fluid composition. The sensors 55 are in communication with a sensor module 50 in the flow control device 10. An on-board electronics processor module 60 is present which controls both the sensors and the choke valve. The device 10 has a battery module 70 to provide power for the flow control device 10. The number of batteries selected will determine the lifetime of the valve. The batteries are thionyl chloride batteries, although any suitable batteries may be utilised. The number of batteries used is limited by the rig-up height and handling of the flow control device but the more batteries used the longer the life time of the flow control device, particularly in low temperature wells.

In addition to the battery module 70, the flow control device has a power generator 80. The power generator may be similar to that described in in UK patent publication number 2531025 and/or WO2016/055451 and/or WO2014118503. The skilled person will recognise that the flow control device may have either a battery module or a power generator or both as required by the intended use and design constraints of the flow control device.

Packers 40 will be present in the production tubing 20 between the flow control device 10 and the production tubing to isolate and seal the flow control device 10.

The fluid flow through the flow control device 10 is shown by the arrows in Figure 1a. As the piston 32 is moved away from or towards the choke housing 34, this increases or reduces the size of the choke inlet 33 and the fluid flow area through the valve 30 will be changed.

The flow control device 10 in position within the production tubing can also be seen in Figure 1b where flow ports 38 allowing fluid to flow into the valve are located at the upstream and downstream ends of the flow control device 10.

The flow control device 100 in Figure 2 is an annular flow control device 100 deployed as part of the production tubing 20 within downhole casing 25. The flow control device 100 has a flow control valve 300 in the form of a choke valve with an infinitely variable choke system. Choke valve 300 has an electro-mechanical variable position sleeve 320. The position of the sleeve 320 with respect to tubing 20 forms a choke inlet 330. The valve 300 has a drive mechanism and motor 360 to move the sleeve 320 towards or away from the tubing 20 reducing or increasing the size of the choke inlet 330. Similarly to the in-line embodiment of Figures 1a and 1b, the flow control device 100 has a sensor module 500 containing sensors to measure the desired process parameter. Again, the skilled person will appreciate that the sensors

may be chosen to measure any downhole process parameter, for example, pressure, temperature, flow rate, viscosity, fluid composition. The sensors 550 are in communication with a sensor module 500 in the flow control device 100. The sensors and choke valve are controlled by a shared on board electronics processor module 600. The device 100 has a battery module 700 to provide power for the flow control device 100 and a power generator module 800. The batteries are thionyl chloride batteries, although any suitable batteries may be utilised and the power generator may be similar to that described in in UK patent publication number 2531025and/or WO2016/055451 and/or WO2014118503. The skilled person will recognise that the flow control device may have either a battery module or a power generator or both as required by the intended use and design constraints of the flow control device.

Packers 40 are present in the casing 25 between the production tubing 20 and casing 25 to isolate and seal the flow control device 100. The flow through the flow control device 100 is shown by the arrows in Figure 2a. As the sleeve 320 is moved towards or away from the production tubing 20, this reduces or increases the size of the choke inlet 330 and the fluid flow area through the valve 30 will be adjusted.

The flow control device 100 in positon as part of the production tubing 20 located within casing 25 can also be seen in Figure 2b where flow ports 380 allowing fluid to flow into the valve are located at the upstream and downstream ends of the flow control device 10.

The flow control device 10, 100 is installed and located downhole. The location of the flow control device is selected to minimise hydrate formation. In this embodiment, the flow control device is installed at the heel of the well, where higher temperatures and pressures make hydrate formation unlikely. One skilled in the art will recognise that the flow control device may be installed at any location downhole as required by the particular production process.

The flow control device is programmed 10, 100 to target specific downhole well conditions in the vicinity of the flow control device, for example downstream pressure or choke pressure drop, prior to installation of the flow control device. The target local process parameter value is selected based on nodal analysis modelling to produce, for example, a required wellhead pressure. In this embodiment, the flow control device is programmed to have a target downstream pressure, although the skilled person will appreciate that any process parameter may be selected as the measured and target process parameter, for example, temperature, pressure, flow rate, viscosity, fluid composition.

The flow control device is autonomous. That is to say, the flow control device works by responding directly to a change in the environment of the well to change the flow path. The flow control device is programmed to maintain the target downstream pressure to keep the surface pressure at a manageable rate. The flow control device uses a closed loop control system where the target downstream pressure is the reference.

Once installed, the flow control device will be dormant until the well is placed on production. When production is detected the sensors will sample the downhole pressure at set intervals and pass this reading to the on-board processor. The processor will compare the measured value with the value set as the target pressure, and decide if the pressure needs to be adjusted or maintained.

If the pressure needs to be adjusted the piston will extend or retract into the choke housing, altering the fluid flow area as it moves. As flow through the valve changes, so does the upstream and downstream pressure. The flow control device sensors will continuously monitor the upstream and downstream pressure as the piston moves, and upon reaching the target pressure, the on-board processor will instruct the choke valve to hold that position.

It will be clear to the persons skilled in the art that the target local process parameter may be any useful, and measurable downhole process parameter, for example temperature, pressure, viscosity, fluid composition such as water content.

The measurement intervals of the flow control device are programmed such that when the well is placed on production, measurements are taken frequently in order for the target downstream pressure to be achieved. During periods of stable production, measurement intervals will be further apart and the valve will intermittently adjust to maintain production within the target conditions. This provides for optimum production as well conditions change over time.

An event such as plugging due to solids will be detected as a reduction in downstream pressure. The flow control device will instruct the choke valve to open to allow the solids to clear the choke, and will then re-adjust the choke position to once again maintain the target downstream pressure.

The flow control device can be reprogrammed during operations without retrieving the device from downhole. The flow control device has a receiver and transmitter unit located within the on-board electronics processor module 60 which utilise data from the sensors 55, enabling it to be reprogrammed using wireless telemetry. Wireless telemetry encompasses wireless downhole data communication as

known in the art, for example according to WO2006/041308 and WO2006/041309. Such reprogramming can include an adjustment to the target downstream pressure if required by changing well conditions, or a simple shutdown command.

A detailed description of the control process for the fluid control device is shown in Figure 3. The control process has two loops, an outer loop and an inner loop. The outer loop detects if the well is flowing and whether or not any communication is due to be received or sent from the flow control device. The inner control loop determines if the sampled data is within the accepted tolerance for the target process parameter value and adjusts the flow valve accordingly. A description of each block of the flow diagram is provided in Table 1. In some examples, control process of the fluid control device operating on the outer loop corresponds to the fluid control device having a passive configuration, while the fluid control device operating on the inner loop corresponds to the fluid control device having an active configuration.

In use, the flow control device is completely autonomous such that the choke valve will adjust the fluid flow area directly in response to the measured downstream pressure in order to meet the target downstream pressure. Aside from reprogramming, the flow control device will operate without any communication from the surface and therefore, in normal operating circumstances, will not require any input from an operator and will not require control or power lines from the surface. Further, the flow control device is configurable between an active and a passive configuration. In the passive configuration, the flow control device measures a local downstream process parameter at select intervals, and compares the local process parameter to a target process parameter, for example, to determine whether the actual local process parameter need to be adjusted. In the active configuration, the flow control valve alters the fluid flow through the valve to achieve the target local process parameter value.

Figure 4 illustrates a schematic of production wells 300 and 400. The flow control device 200 can be used as an inflow control valve for use in isolating a distal portion 320 of a production well 300. The flow control device 200 may be required during hydraulic fracturing operations to isolate a portion of the well 300 while hydraulic fracturing operations 600 take place in adjacent well 400. The flow control valve 200 is designed to withstand pressures of up to 10,000 psi.

Whilst the flow control valve 200 is being run in hole, the on-board processor will ignore pressure changes measured by the sensors. Once at setting depth and following setting of the device, the sensors will detect production flow and choke the valve twice, at a fixed time interval apart. The pressure pulses detected at surface as a

result of the valve choking confirm the flow control device is active. The flow control device will then remain open until a shut-in of the well is detected. Well 300 can be shut-in at surface by closing valve 310.

In use as an isolation valve, the flow control valve 200 has a target process parameter of no fluid flow path, that is the valve is closed and isolates the well. The sensors detect downhole pressure at set intervals and pass this reading to the on-board processor. The sensors are located within the sensor module of the flow control device and the reading is sent directly to the on-board processor which is also located downhole. Therefore, the valve can change the fluid flow path through the valve to achieve the target process parameter without intervention from the surface of the well. The processor will compare the measured value with a programmed value or range associated with the well being shut-in at the surface. When the well is shut-in, the downstream pressure will increase and the sensors will detect this pressure profile. The on-board processor is configured to recognise that an elevated pressure reading within an accepted range over a minimum period of time is associated with a shut-in of the wellhead and the on-board processor will instruct the valve to close. Thus, once the on-board processor recognises an elevated pressure reading, the flow control device 200 will configure from the passive configuration to the active configuration to close the flow control device 200. The rise in pressure associated with a shut-in is a preset value and the on board processor will detect if the rise in pressure has occurred and that the rise in pressure in maintained for preset period of time. For example, the on-board processor will look for a 15 bar increase in pressure that is maintained for at least 60 minutes. The increase in pressure could be more than 15 bar and could last infinitely. The preset values of pressure and time can be selected based on well analysis, reasoned judgements and estimates as appropriate for a particular production well.

Whilst the pressure readings detected by the sensors are outside of the accepted range or preset value, typically lower than the shut-in pressure, the flow control valve will remain open, allowing normal production of the well. In this manner, the flow control valve 200 will ignore any pressure variances that may result from, for example a downhole pump or a beam pump in the well and will close only when a shut-in is detected. Alternatively, the flow control valve 200 may be configured to detect production of the well as function of the difference between two pressure sensors and a shut-in would be detected when both sensors read the same or similar pressure.

When the valve has closed, the on-board processor will instruct the flow control valve to hold its position until valve 310 has been reopened or until the valve is instructed to open. The flow control valve will maintain an 8,000 psi static seal.

With both the surface valve 310 and flow control valve 200 closed, hydraulic fracturing operations can commence on neighbouring well 400. During hydraulic fracturing operations, high pressure fluid (indicated by the arrows in Figure 4) is pumped into production well 400 by pump 600 and into the hydrocarbon bearing formation 500. Proximal portion 320 of production well 300 is isolated from the high pressure hydraulic fracturing fluid by the flow control valve 200. The flow control valve 200 may be configured to continue to detect the downhole pressure at set intervals whilst in the valve is closed and may be configured to react to pressure from the reservoir 500 due to hydraulic fracturing operations.

The flow control device is configured to remain closed until a communication is received from surface instructing the valve to open following completion of hydraulic fracturing operations. The communication is in the form of a pressure pulse signal or multiple pressure signals within a set interval sent from the surface and received by the receiver unit located within the on-board processor module 60. In this application, over pressure is applied from the surface at a specific value for a specific period of time, for example 20 bar for 30 minutes. The on-board processor will detect this over pressure and instruct the flow control valve to open after a pre-determined time delay. When multiple pressure pulse signals are sent to the flow control valve 200, the time gap between each signal can be used to instruct the time delay before opening, the speed of opening of the valve and/or the position of opening, for example instruct the valve to open fully or to an intermediate open configuration.

Alternatively, the flow control valve 200 may be configured such that when the well is opened at valve 310 and the pressure detected by the sensors decreases, the on-board processer may instruct the flow valve 200 to open when a pre-determined pressure differential across the valve is detected by the flow control valve, such as 3,000 psi or 500 psi, that is associated with the well being open. The flow control device will then reset to open and normal production of the well can resume until the next well shut-in is detected by the flow control device.

The flow control valve 200 is configured to recognise pressure changes associated with a shut-in, and therefore, the flow control valve 200 is configured to ignore the high pressures associated with a hydraulic fracturing operation such that it is possible to carry out hydraulic fracturing operations on a production well 300 with the

flow control valve 200 installed. For example, a shut-in may result in a pressure change of between 15 and 30 bar and a hydraulic fracturing operation may be 300 to 600 bar; the flow control valve 200 is configured to recognise the associated pressure changes and will remain fully open during hydraulic fracturing operations of the well in which the valve 200 is installed.

The flow control device 200 can be configured act as an isolation valve and can be configured prior to running in hole to recognise and react to the specific pressure changes associated with a well shut-in and hydraulic fracturing operations, as described above. The flow control valve 200 can also be reconfigured whilst in-situ from the surface using wireless telemetry such that the preset pressure values are changed or to reconfigure the flow control valve to act as flow control device to maintain a surface production rate

Table 1 – Description of Process Control stages

Outer process control loop	
Idle	The control system will wait on "Idle" in the outer control loop on a timer (typically daily) that will instruct the flow control device to check if the well is flowing, to detect/send pressure pulse telegrams, and to do a regulation check.
Flowing conditions detected	The flow control device will only move to the telegram check if the device detects flowing conditions.
Telegram detected/due	If flowing conditions are detected, the device will check to see if any communication from the surface has been detected or is due to be sent. If not, flow control device will move onto regulation check
Time for regulation check	The flow control device will check to see if it is due to regulate the valve parameters. If so, the flow control device will enter the inner process control loop.
Inner process control loop	
Time for sample	The inner loop will sample at a much higher frequency, typical in seconds. If time for a sample it will access the data from the attached sensors.
Sample acquisition device	Processer will request and receive data from the attached sensors.
Within tolerance	The on-board processor will check to determine if the sampled data is within the pre-defined range for that parameter. If so, the device will go back to the outer loop. If not, the device will check if the well

	is flowing.
Well flowing	Shut in on surface can be detected by a build-up in tubing pressure. If the device detects this it will go back to the outer loop. If the flow control device detects the well is still flowing, the motor driving the piston/sleeve of the valve will be powered on to adjust the valve.
Adjust valve	The direction of the motor driving the valve will depend on whether the sample data is + or – of tolerance (moving the piston in or out of choke housing). The inner process control loop will continue until data is within tolerance or a shut in is detected, in which case the control system will return to idle on the outer control loop.

Claims

1. A downhole flow control device comprising:

a flow control valve;

a sensor in communication with the flow control valve, wherein the sensor measures a local process parameter; and

wherein the flow control valve is configured to control the fluid flow through the valve to achieve a target local process parameter value in response to the measured local process parameter.

2. The downhole flow control device of claim 1, wherein the fluid flow through the valve is adjusted independently from external instruction.

3. The downhole flow control device of claims 1 to 2, wherein the device is autonomous.

4. The downhole flow control device of any preceding claim, wherein the target local process parameter value is programmed prior to deployment of the flow control device downhole.

5. The downhole flow control device of claim 4, wherein the target local process parameter value can be reprogrammed whilst the flow control device is downhole.

6. The downhole flow control device of claim 4 or 5, wherein the target local process parameter value can be reprogrammed using downhole wireless communication.

7. The downhole flow control device of any preceding claim, wherein the local process parameter is the same as the target local process parameter.

8. The downhole flow control device of any of claims 1 to 6, wherein the local process parameter is different from the target local process parameter.

9. The downhole flow control device of any preceding claim comprising a plurality of sensors configured to measure different process parameters.

10. The downhole flow control device of any of claim 10, wherein the flow control device is reprogrammable to respond to different process parameters.

11. The downhole flow control device of any preceding claim wherein the target local process parameter value is selected to maintain a surface process parameter of the well at a desired value, or within a desired range.

12. The downhole flow control device of any preceding claim wherein the target local process parameter value is determined by nodal analysis.

13. The downhole flow control device of any preceding claim wherein the flow control valve is an infinitely variable choke valve.

14. The downhole flow control device of any preceding claim wherein the flow control device uses the target local process parameter value as a reference in a closed loop control system.

15. The downhole flow control device of any preceding claim, wherein the sensor is configured to measure the local process parameter at set intervals.

16. The downhole flow control device of any preceding claim, wherein the sensor is configured to measure the local process parameter continuously as the flow valve adjusts the fluid flow through the valve to achieve the local process parameter value.

17. The downhole flow control device of any preceding claim, wherein the flow control device is configured to be located inside downhole tubing.

18. The downhole flow control device of any of claims 1 to 16, wherein the flow control device is configured to form part of the downhole tubing.

19. The downhole flow control device of any preceding claim, wherein the flow control device is configured to be located downhole at a location selected to minimise the formation of hydrates.

20. The downhole flow control device of any preceding claim, wherein the flow control valve is configured to control the fluid flow path through the valve to close the flow path.

21. The downhole flow control device of claim 20 wherein the flow control device is configured to close in response to a pressure indicating a shut-in.

22. The downhole flow control device of claim 21 wherein the flow control device is configured to open when the well is opened after the shut-in.

23. The downhole flow control device of claim 21 wherein the flow control device is configured to remain closed until the device is instructed to open.

24. The downhole flow control device of claim 23 wherein the flow control device is instructed to open using wireless telemetry.

25. The downhole flow control device of any preceding claim, wherein the flow control device is configurable between an active configuration and a passive configuration.

26. The downhole flow control device of claim 25, wherein the flow control device is configured to the active configuration during well shut-in.

27. The downhole flow control device of claim 25, wherein the flow control device is configured to the passive configuration when the well is opened after a well shut-in.

28. A control system for a downhole flow control device comprising:

a closed loop control system wherein a flow control valve located downhole adjusts to achieve a target local process parameter value in response to a measured local process parameter reading from a sensor in communication with the flow control valve.

29. The control system of claim 28, wherein the target local process parameter value is a reference is the closed loop control system.

30. The control system of claim 28 or 29, configured to be reprogrammable whilst the flow control valve is located downhole.

31. The control system of claim 30, wherein the control system is reprogrammable using wireless downhole communication.

32. The control system of any of claims 28 to 31 wherein the target local process parameter is no fluid flow path through the valve.

33. The control system of claim 32 wherein the control system instructs the flow control valve to close to achieve the target local process parameter of no fluid flow in response to a pressure readings indicating a shut-in.

34. The control system of claim 33 wherein the control system instructs the flow control valve to open when the wellhead is opened after the shut-in.

35. The control system of claim 33 or 34 wherein the control system instructs the flow control valve to remain closed until the control system is instructed to open the valve.

36. The control system of any of claims 28 to 35, wherein the control system is operable to set the flow control valve between the active configuration and the passive configuration.

37. The downhole flow control device of claim 35 wherein the flow control device is instructed to open using wireless telemetry.

38. A method of controlling a downhole flow control device comprising:

programming a downhole flow control device with a target local process parameter value;

locating the downhole flow control device downhole, wherein the device comprises a flow control valve and a sensor in communication with the flow valve;

measuring a local process parameter with the sensor;

wherein the flow valve controls the fluid flow through the valve to achieve the target local process parameter in response to the measured local process parameter.

39. The method of claim 38 wherein the method is used to control fluid production from a well.

40. The method of claim 38 or 39 comprising locating the flow control device inside production tubing.

41. The method of claims 38 or 39 comprising locating the flow control device downhole as part of the production tubing.

42. The method of any of claims 38 to 41 comprising reprogramming the flow control device when required by well conditions whilst the flow control device is downhole.

43. The method of claims 42 comprising reprogramming the flow control device using wireless downhole communication.

44. The method of any of claims 38 to 43 comprising controlling the fluid flow path through the valve to close the flow path.

45. The method of claim 44 comprising closing the flow control valve in response to a pressure indicating a shut-in.

46. The method of claim 45 comprising keeping the control valve to closed until the flow control device is instructed to open the valve.

47. A downhole flow control device for isolating a portion of a well, the flow control device comprising:

a flow control valve;

a sensor in communication with the flow control valve, wherein the sensor measures a local process parameter; and

wherein the flow control valve is configured to close in response to the measured local process parameter.

48. The downhole flow control valve of claim 47, wherein the measured local process parameter is a pressure indicating a shut-in.

49. The downhole flow control valve of claims 47 or 48, wherein the valve is configured to remain closed until the valve is instructed to open.

50. The downhole flow control valve of claims 49, wherein flow control device is instructed to open the valve using wireless telemetry

51. A method of isolating a portion of a well during hydraulic fracturing operations, the method comprising

locating a flow control valve downhole,

closing the well;

closing flow control valve;

performing hydraulic fracturing operations on an adjacent or nearby well.

52. The method of claim 51 comprising measuring a downhole process parameter with a sensor in communication with the flow control valve, wherein the flow control valve will close in response to the measured downhole process parameter.

53. The method of claim 51 or 52 comprising closing the valve without intervention from the surface of the well.

54. The method of any of claims 51 to 53 comprising closing the well at or near the surface.

55. The method of any of claims 51 to 54 comprising detecting when a shut-in of the well has taken place.

56. The method of any of claims 51 to 55, comprising configuring the flow control valve to remain open until a shut-in of the well is detected.

57. The method of any of claims 51 to 56 comprising producing through valve.

58. The method of any of claims 51 to 57 comprising configuring the flow control valve to maintain a desired surface process parameter.

59. The method of claim 58 comprising configuring the flow control valve in-situ.

60. The method of any of claims 51 to 59 comprising detecting a pressure within an accepted value or range and closing the flow control valve.

61. The method of any of claims 51 to 60 comprising maintaining the flow control valve in the closed configuration.

62. The method of any of claims 51 to 61 comprising detecting the local pressure whilst the flow control valve is closed.

63. The method of any of claims 51 to 62 comprising opening the flow control valve.

64. The method of any of claims 51 to 63 comprising opening the flow control valve after hydraulic fracturing operations on the adjacent or nearby well have been completed.

65. The method of any of claims 51 to 63 comprising opening the flow control valve when a local pressure value or above or below the valve is within a pressure range associated with the well being open.

66. The method of any of claims 51 to 63 comprising maintaining the flow control valve in the closed configuration until the flow control device is instructed to open.

67. The method of any of claims 51 to 66, comprising configuring the flow control valve between an active configuration and a passive configuration.

68. The method of any of claims 51 to 67, comprising configuring the flow control valve to the active configuration during well shut-in.

69. The method claim 66 wherein instructing the flow valve to open comprises sending a signal to the flow control valve.

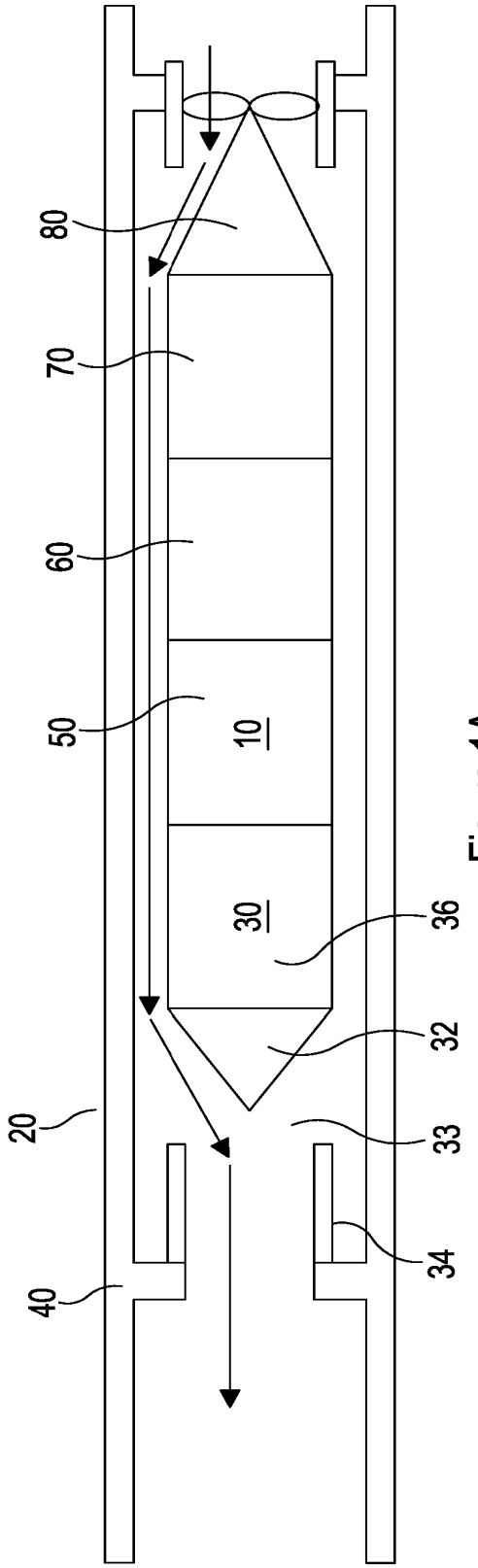


Figure 1A

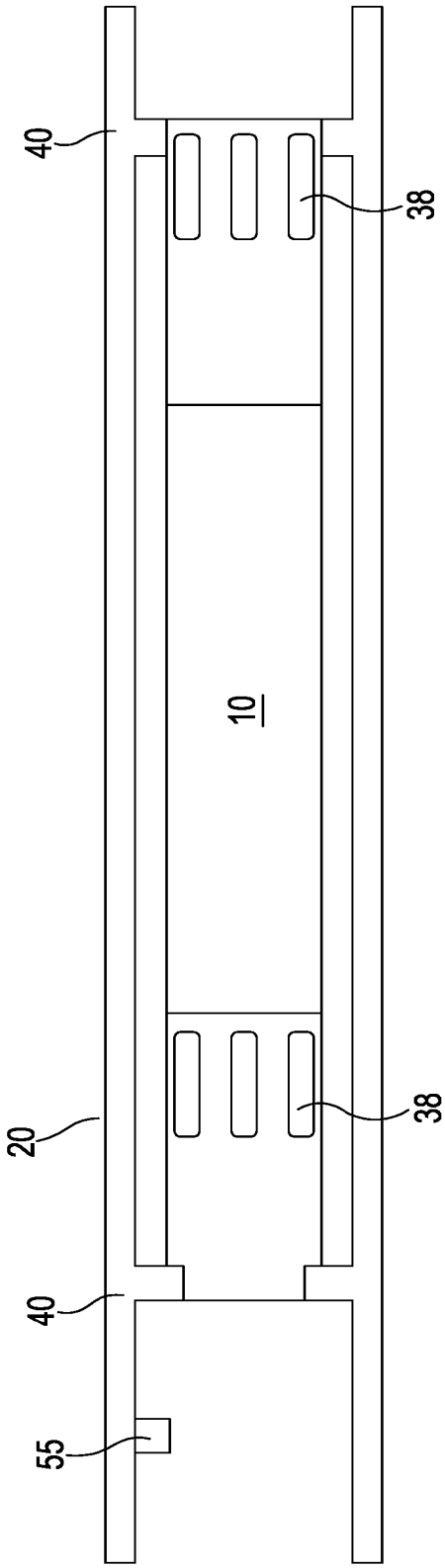


Figure 1B

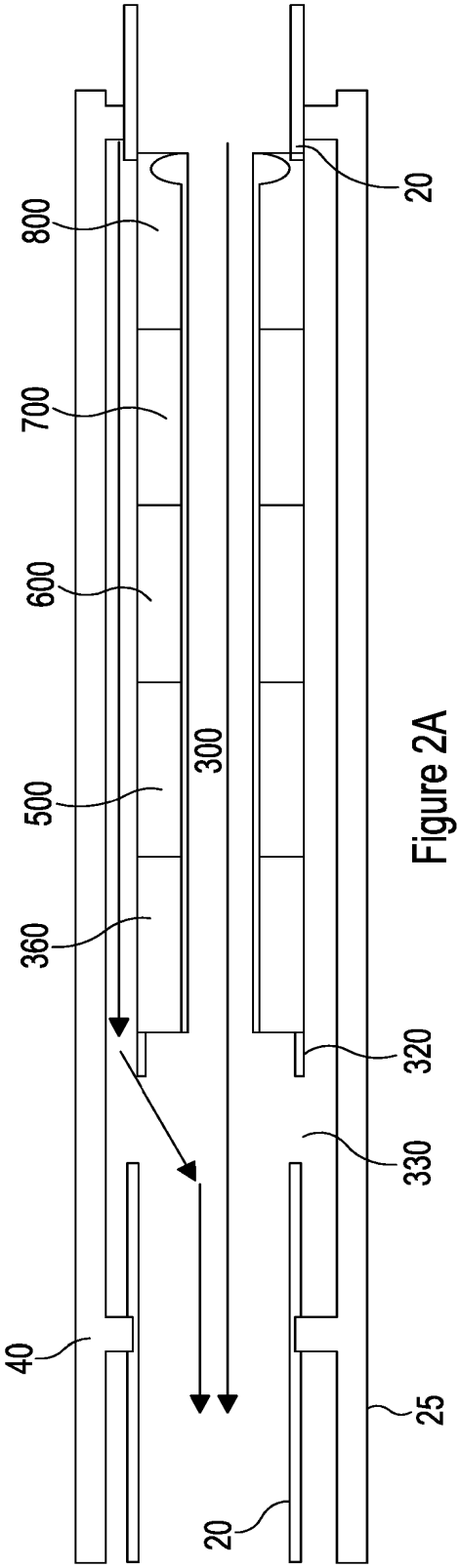


Figure 2A

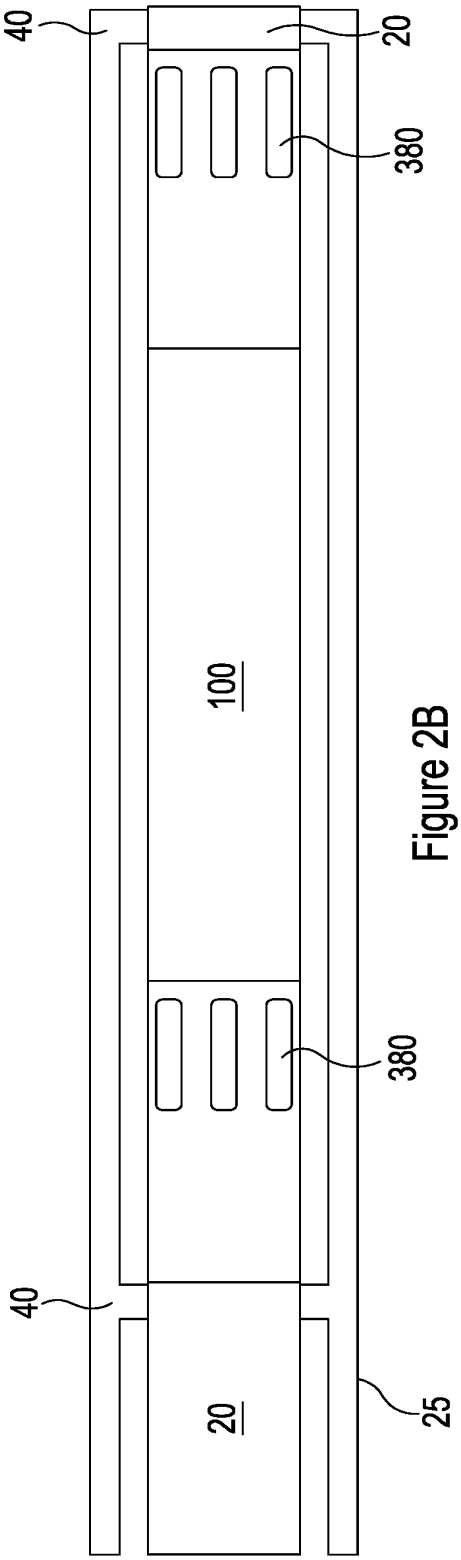


Figure 2B

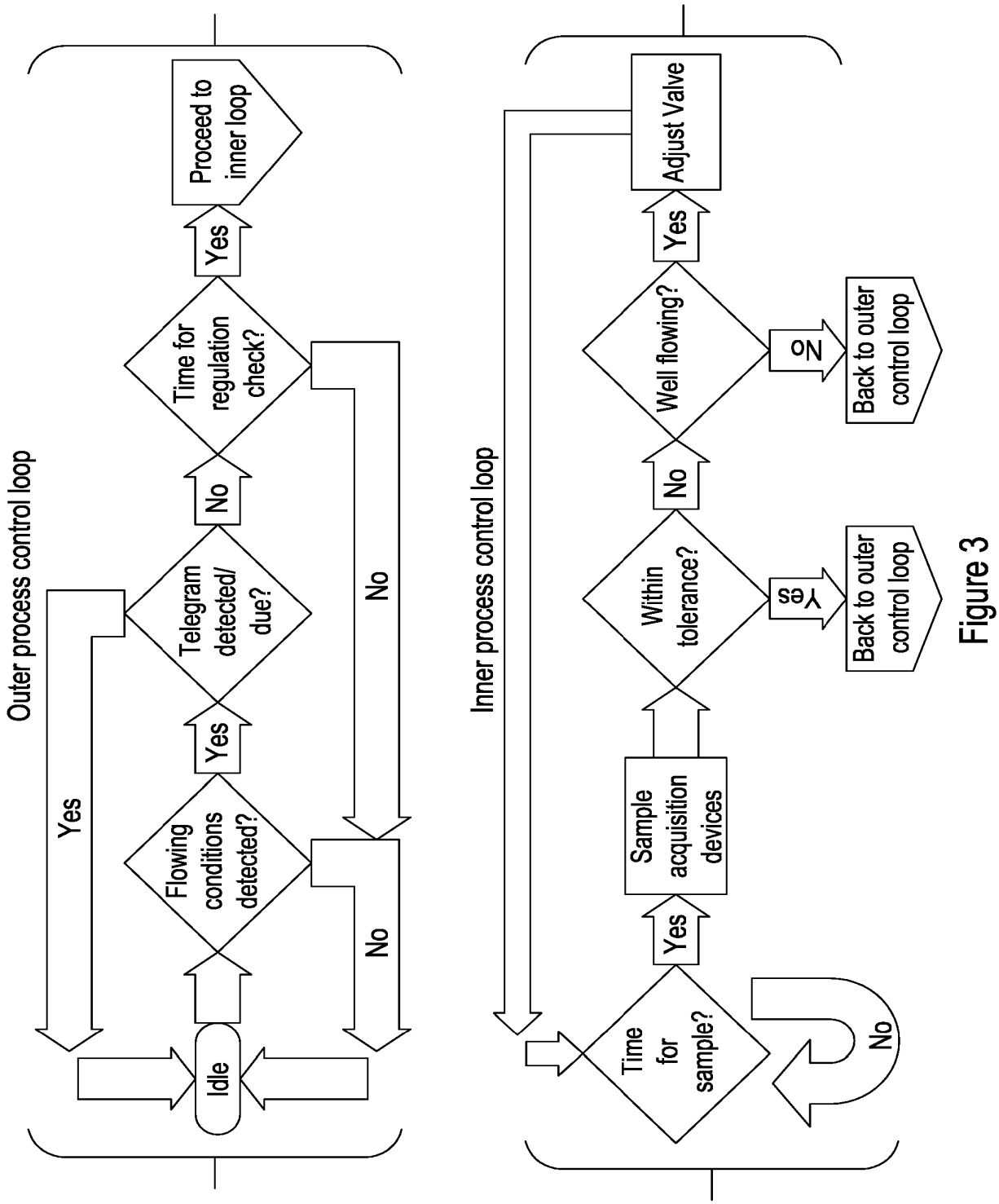

Outer process control loop
Idle
Flowing conditions detected?
Yes
No
Telegram detected/ due?
Yes
No
Time for regulation check?
Yes
No
Proceed to inner loop
Inner process control loop
Time for sample?
Yes
No
Sample acquisition devices
Within tolerance?
Yes
No
Back to outer control loop
Well flowing?
No
Yes
Back to outer control loop
Adjust Valve

Figure 3

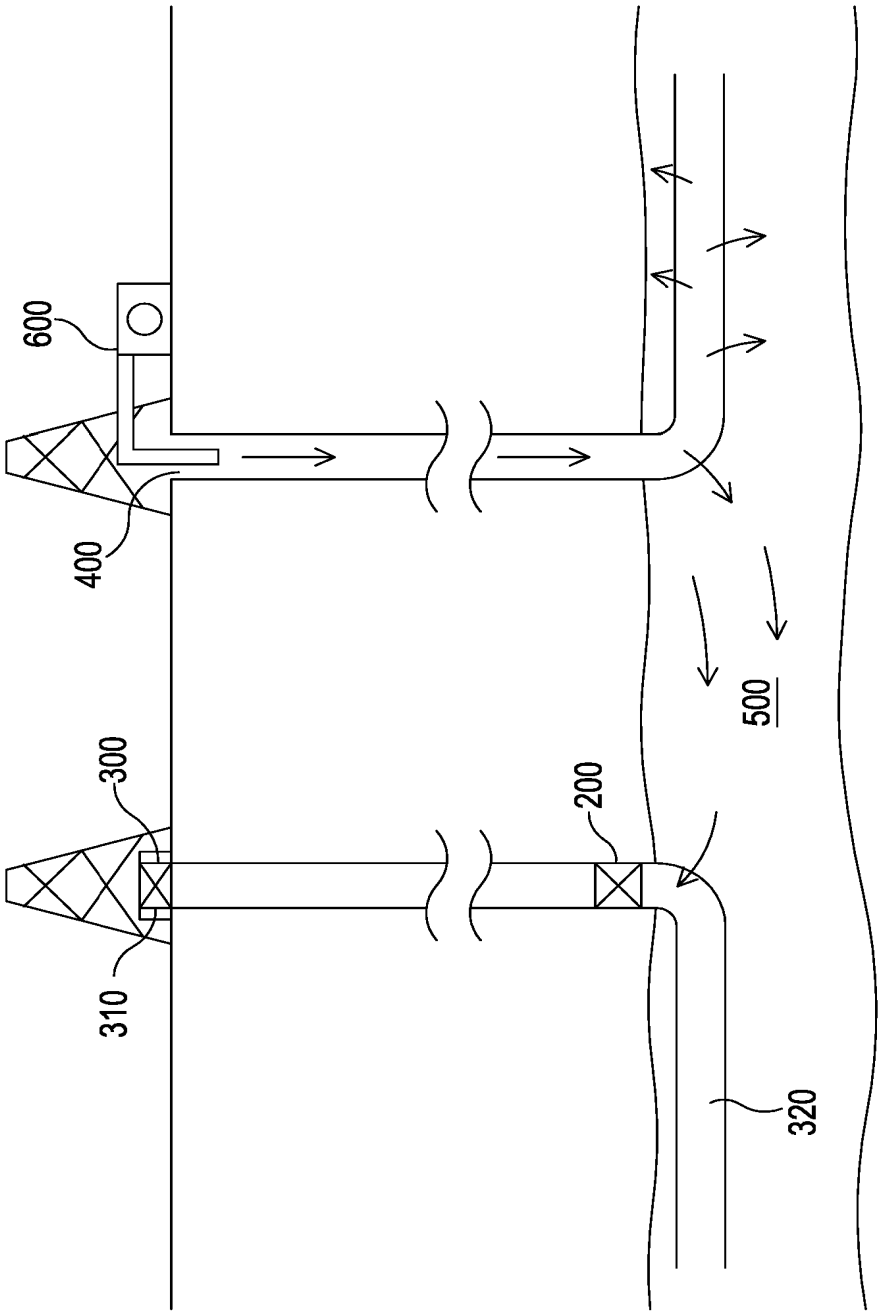


Figure 4

Innovation, Sciences et Développement économique Canada
Office de la Propriété Intellectuelle du Canada

Innovation, Science and Economic Development Canada
Canadian Intellectual Property Office

CA 3018485 A1 2017/08/10

(21) 3 018 485

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(86) Date de dépôt PCT/PCT Filing Date: 2017/02/06
(87) Date publication PCT/PCT Publication Date: 2017/08/10
(85) Entrée phase nationale/National Entry: 2018/09/20
(86) N° demande PCT/PCT Application No.: US 2017/016736
(87) N° publication PCT/PCT Publication No.: 2017/136841
(30) Priorités/Priorities: 2016/02/05 (US62/291,616); 2017/02/03 (US15/424,669)

(51) Cl.Int./Int.Cl. *E21B 43/26* (2006.01)
(71) Demandeur/Applicant:
GE OIL & GAS PRESSURE CONTROL LP, US

(72) Inventeurs/Inventors:
HERMAN, CHRISTOPHER TAYLOR, US;
KAJARIA, SAURABH, US;
LIN, JUSTIN KRISTOPHER, US;
FULLER, TIMOTHY, US

(74) Agent: CRAIG WILSON AND COMPANY

(54) Titre : SYSTEMES ET PROCEDES D'ENTRETIEN DE PUITS A DISTANCE
(54) Title: REMOTE WELL SERVICING SYSTEMS AND METHODS

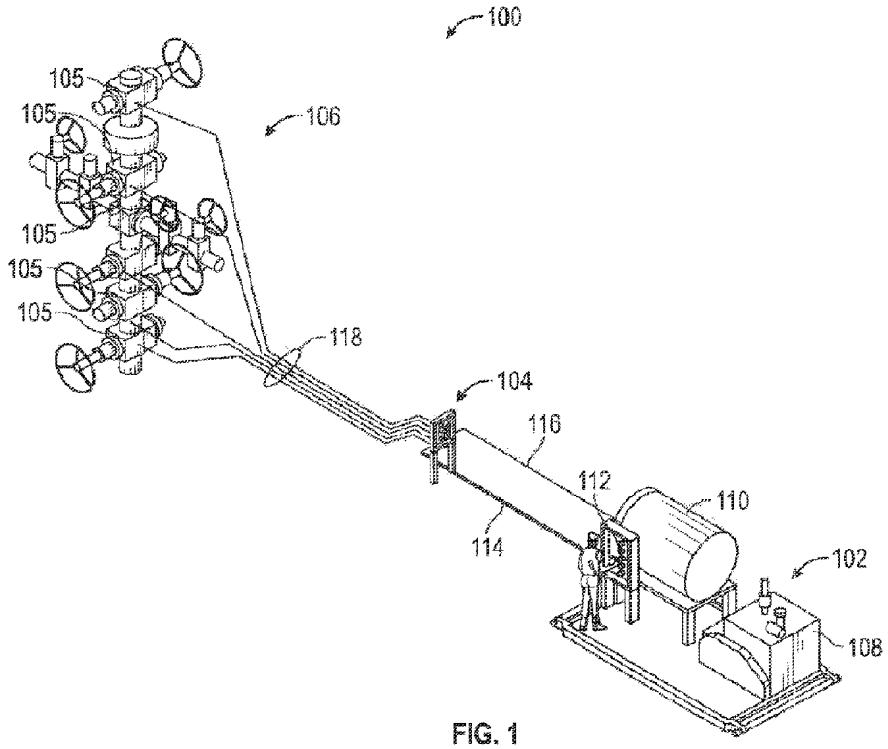


FIG. 1

(57) Abrégé/Abstract:
Embodiments of the present disclosure include a remote well servicing system including a control unit 102 and a remote servicing manifold 104. The control unit 102 further includes a service fluid source 110 and a control system 108. The remote servicing manifold 104 further includes a fluid input line 114 coupled to the service fluid source 110, a fluid output line 118 couplable to a well component 105, and a valve coupled to the fluid input line 114 and the fluid output line 118, wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source 110 to the well component 105. The remote servicing manifold 104 also includes a control line coupling the valve and the control system, wherein the control system controls actuation of the valve via the control line.

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
10 August 2017 (10.08.2017)

WIPO | PCT

(10) International Publication Number
WO 2017/136841 A1

(51) International Patent Classification:
E21B 43/26 (2006.01)

(21) International Application Number:
PCT/US2017/016736

(22) International Filing Date:
6 February 2017 (06.02.2017)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
62/291,616 5 February 2016 (05.02.2016) US
15/424,669 3 February 2017 (03.02.2017) US

(71) Applicant: **GE OIL & GAS PRESSURE CONTROL LP** [US/US]; 4424 West Sam Houston Parkway North, Suite 100, Houston, TX 77041 (US).

(72) Inventors: **HERMAN, Christopher, Taylor**; 4424 West Sam Houston Parkway North, Suite 100, Houston, TX 77041 (US). **KAJARIA, Saurabh**; 4424 West Sam Houston Parkway North, Suite 100, Houston, TX 77041 (US). **LIN, Justin, Kristopher**; 4424 W. Sam Houston Pkwy N, Suite 100, Houston, TX 77041 (US). **FULLER, Timothy**; Houston, TX 77041 (US).

(74) Agents: **POLLANDER, Laura, L.** et al.; Patent Counsel, General Electric Company, 901 Main Avenue, 3rd Floor, Norwalk, CT 06851 (US).

(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KH, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

[Continued on next page]

(54) Title: REMOTE WELL SERVICING SYSTEMS AND METHODS

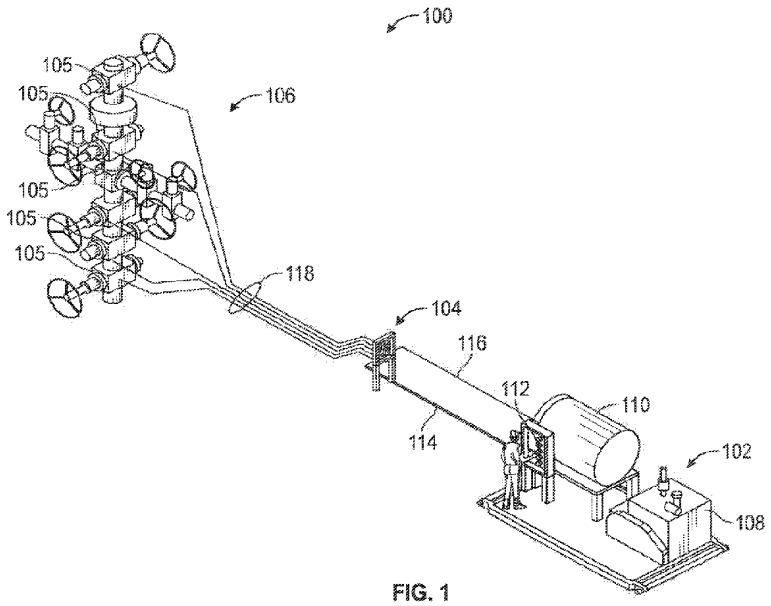


FIG. 1

(57) Abstract: Embodiments of the present disclosure include a remote well servicing system including a control unit 102 and a remote servicing manifold 104. The control unit 102 further includes a service fluid source 110 and a control system 108. The remote servicing manifold 104 further includes a fluid input line 114 coupled to the service fluid source 110, a fluid output line 118 couplable to a well component 105, and a valve coupled to the fluid input line 114 and the fluid output line 118, wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source 110 to the well component 105. The remote servicing manifold 104 also includes a control line coupling the valve and the control system, wherein the control system controls actuation of the valve via the control line.

WO 2017/136841 A1

WO 2017/136841 A1

Declarations under Rule 4.17:

— *as to applicant's entitlement to apply for and be granted a patent (Rule 4.17(ii))*

— *as to the applicant's entitlement to claim the priority of the earlier application (Rule 4.17(iii))*

Published:

— *with international search report (Art. 21(3))*

REMOTE WELL SERVICING SYSTEMS AND METHODS

RELATED APPLICATIONS

[0001] This application is related to and claims priority to U.S. Provisional Patent Application No. 62/291,616, which was filed on February 5, 2016. This application is a continuation-in-part of U.S. Patent Application No. 14/725,341, which was filed on May 29, 2015. The full disclosure of these related applications are hereby incorporated herein by reference in their entirety.

BACKGROUND

1. Field of the Invention

[0002] The present disclosure relates to servicing well equipment. More particularly, the present disclosure relates to systems and methods of remotely providing a service fluid to one or more well components via a remote servicing manifold.

2. Description of Related Art

[0003] Certain hydrocarbon production related operations, such as hydraulic fracturing, utilize well equipment that is made up of many parts. One example is a hydraulic fracturing tree, which has many valves. These valves may need to be greased or lubricated from time to time to ensure proper function and maximum operational life. Typically, this process is carried out manually by an operator at the well site. As such, the operator has to travel to the well site and manually make and break the valve fittings in order to grease the valve. This process is time consuming and costly.

SUMMARY

[0004] Applicants recognized the problems noted above herein and conceived and developed embodiments of systems and methods, according to the present disclosure, for remotely providing a service fluid to one or more well components via a remote servicing manifold.

[0005] In an embodiment, a remote well servicing system includes a remote servicing manifold, which includes a fluid input line couplable to a service fluid source, a fluid output line couplable to a well component, a valve coupled to the fluid input line and the fluid output line,

wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source to the well component, and a control line coupled to and controlling actuation of the valve.

[0006] In another embodiment, a remote well servicing system includes a control unit and a remote servicing manifold. The control unit further includes a service fluid source and a control system. The remote servicing manifold further includes a fluid input line coupled to the service fluid source, a fluid output line couplable to a well component, and a valve coupled to the fluid input line and the fluid output line, wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source to the well component. The remote servicing manifold also includes a control line coupling the valve and the control system, wherein the control system controls actuation of the valve via the control line.

[0007] In another embodiment, a method of remotely servicing a well component includes supplying a service fluid to a remote servicing manifold, actuating a valve on the remote servicing manifold, thereby permitting flow of the service fluid, and delivering the service fluid from the remote servicing manifold to a well component.

BRIEF DESCRIPTION OF DRAWINGS

[0008] The foregoing aspects, features, and advantages of the present disclosure will be further appreciated when considered with reference to the following description of embodiments and accompanying drawings. In describing the embodiments of the disclosure illustrated in the appended drawings, specific terminology will be used for the sake of clarity. However, the disclosure is not intended to be limited to the specific terms used, and it is to be understood that each specific term includes equivalents that operate in a similar manner to accomplish a similar purpose.

[0009] FIG. 1 is a schematic view of a remote well servicing system, in accordance with example embodiments of the present disclosure.

[0010] FIG. 2 is a diagram representation of a remote well servicing system, in accordance with example embodiments of the present disclosure.

[0011] FIG. 3A is a block diagram of a remote well servicing system with remote servicing manifolds having electro-pneumatic valve control, in accordance with example embodiments of the present disclosure.

[0012] FIG. 3B is a block diagram of a valve actuation system of the manifold of FIG. 3A, in accordance with example embodiments of the present disclosure.

[0013] FIG. 4A is a block diagram of a remote well servicing system with remote servicing manifolds having fully pneumatic valve control, in accordance with example embodiments of the present disclosure.

[0014] FIG. 4B is a block diagram of a valve actuation system of the manifold of FIG. 4A, in accordance with example embodiments of the present disclosure.

[0015] FIG. 5 is a block diagram of the remote well servicing system of FIG. 3A with the addition of a pressure boosting station at the manifolds, in accordance with example embodiments of the present disclosure.

[0016] FIG. 6 is a block diagram of the remote well servicing system of FIG. 4A with the addition of a pressure boosting station at the manifolds, in accordance with example embodiments of the present disclosure.

[0017] FIG. 7 is a block diagram of a remote well servicing system with pressure relief, in accordance with example embodiments of the present disclosure.

DETAILED DESCRIPTION

[0018] The foregoing aspects, features, and advantages of the present disclosure will be further appreciated when considered with reference to the following description of embodiments and accompanying drawings. In describing the embodiments of the disclosure illustrated in the appended drawings, specific terminology will be used for the sake of clarity. However, the disclosure is not intended to be limited to the specific terms used, and it is to be understood that each specific term includes equivalents that operate in a similar manner to accomplish a similar purpose.

[0019] When introducing elements of various embodiments of the present disclosure, the articles "a", "an", "the", and "said" are intended to mean that there are one or more of the

elements. The terms "comprising", "including", and "having" are intended to be inclusive and mean that there may be additional elements other than the listed elements. Any examples of operating parameters and/or environmental conditions are not exclusive of other parameters/conditions of the disclosed embodiments. Additionally, it should be understood that references to "one embodiment", "an embodiment", "certain embodiments", or "other embodiments" of the present disclosure are not intended to be interpreted as excluding the existence of additional embodiments that also incorporate the recited features. Furthermore, reference to terms such as "above", "below", "upper", "lower", "side", "front", "back", or other terms regarding orientation or direction are made with reference to the illustrated embodiments and are not intended to be limiting or exclude other orientations or directions.

[0020] Embodiments of the present disclosure include systems and methods for remotely monitoring and/or servicing a well, such as providing a service fluid without operator intervention at the well site. An example application of the present disclosure includes greasing well assemblies during hydrocarbon drilling and development operations, such as during hydraulic fracturing or when the wells are producing and under pressure. Doing so can reduce failures of the well assembly and the operation. The systems and techniques of the present disclosure may be used for a wide variety of wells and well operations, and is particularly advantageous for wells that are not easily accessible by operators, such as remote land wells, dry offshore wells, and unmanned platforms, where regular servicing can increase operational life.

[0021] FIG. 1 is a schematic view of a remote well servicing system 100, in accordance with an example embodiment of the present disclosure. The system 100 includes a control unit 102 and a remote servicing manifold 104. Generally, in many applications of the present disclosure, the manifold 104 selectively delivers a service fluid from the control unit 102 to one or more well components 105 of a well 106. The control unit 102 may include a control system 108 and a service fluid source 110. The control system 108 controls at least some aspects of the remote well servicing system 100. The service fluid source 110 may be any suitable type of vessel or reservoir for holding a service fluid. The service fluid may be any type of fluid that may be used to service a well component from time to time. For example, the service fluid source 110 may be a grease or lubricant storage container.

[0022] The control system 108 may include one or more processors and/or controllers for carrying out its control functions, including controlling the manifold 104. The control system 108 may also include a control panel 112 or interface through which an operator can interact with the control system 108, such as to input control commands or receive output information.

The control panel 112 may be located on the control unit 102, as illustrated in FIG. 1. Alternatively, the control panel 112 can be a part of a remote controller such as a pendant controller or a digital controller. As an example, the control panel 112 can be configured for touch screen operations and allow for straightforward and intuitive operation of the remove servicing operation. The control panel 112 can communicate via wires or wirelessly. Non-exhaustive wireless examples include wireless internet or telemetry, radio, microwave, ultrasonic, or infrared. In some embodiments, the control panel 112 may include a tablet computer, smart phone, personal computer, and the like, that allow for interaction with the control system 112 at one or more offsite locations.

[0023] The control unit 102 may be in the form of a wheeled mobile operation center or grease skid. Additional equipment may be located on the control unit that facilitation other operations, such as hydraulic fracturing. The control unit 102 may also include various other system components and control capabilities used to operate and monitor well equipment. Such components may include accumulators, hydraulic, electric, and pneumatic actuators, torque wrenches, pressure pumps, and various meters and visual indicators. Such components may be used to perform certain services at the well 106, such as diagnostic operations, as well as measuring temperature, pressure, oil and gas ratio, water content, and chemical tracers at the well 106.

[0024] The remote servicing manifold 104 is located away from the control unit 102. For example, in some applications, the manifold 104 is located twenty-five to one hundred feet from the control unit 102. However, in other example applications, the manifold 104 may be closer to or farther from the control unit 102. The manifold 104 includes a fluid input for receiving a service fluid and a control input for receiving a control signal. In some example embodiments, the fluid input is coupled to the service fluid source 110 at the control unit 102 via a supply line 114 and service fluid is delivered to the manifold 104 from the service fluid source 110 through the supply line 114. There may be a check valve coupled to the supply line 114 to prevent back flow. In some embodiments, the control input is coupled to the control system 108 at the control unit 102 via one or more control lines 116. The control lines 116 may include electrical lines, optical lines, pneumatic lines, and the like, and any combination thereof.

[0025] The manifold 104 includes one or more fluid outputs from which the service fluid can be delivered to one or more well components 105 through respective delivery lines 116. There may be one or more check valves coupled to the delivery line 116 to prevent back flow. In certain example applications, the manifold 104 may be located five to fifty feet away from the

well 106. However, in some other example applications, the manifold 104 may be located closer to or farther from the well 106. The control system 108 controls delivery of service fluid from the manifold to each of the well components 105 by selectively actuating respective valves within the manifold via the control lines 116. Delivery of service fluid to each of the well components 105 may be independently controlled. Alternatively, service fluid may be delivered to all or a subset of the well components simultaneously.

[0026] FIG. 2 is a diagram representation of a remote well servicing system 200, according to example embodiments of the present application. In one or more such embodiments, the system 200 includes a control unit 202 and a plurality of remote servicing manifolds 204. The control unit 202 supplies service fluid to the manifolds 204 via supply lines 214 and controls the manifolds 204 via control lines 216. There may be control lines 216 and supply lines 214 connecting the control unit 202 directly to each manifold 204. Alternatively or additionally, there may be control lines 216 and/or supply lines 214 between manifolds 204. In such embodiments, service fluid and/or control signals may be communicated to one of the manifolds 204 via another manifold 204 rather than directly from the control unit 202. For example, such a configuration may be advantageous in an application where one manifold 204 is physically located between the control unit 202 and another manifold 204. Delivering control signals and/or service fluid to the farther manifold 204 via the closer manifold 204 rather than directly from the control unit 204 may reduce the number or length of lines required.

[0027] In the embodiment illustrated in FIG. 2, a manifold 204 can provide service fluid to a plurality of well components 205 on the same well 206 as well as to well components on a plurality of wells 206, as represented by each individual supply line 218. Additionally, one well 206 may receive service fluid from multiple manifolds 204. In some embodiments, the same service fluid may be provided to each of the manifolds 204. In some other embodiments, the control unit 202 may provide different types of services fluids to different manifolds 204. The control unit 202 may also provide different types of service fluids to the same manifold 204. This embodiment may be particularly useful for applications in which different well components require different service fluids.

[0028] FIG. 3A is a block diagram of a remote well servicing system 300, illustrating a control unit 302 coupled to three remote servicing manifolds 304 with electro-pneumatic valve control, which are coupled to three wells 306, respectively, in accordance with example embodiments of the present disclosure. The control unit 302 includes at least one service fluid source 310 and may include a pump 320 for pumping the service fluid from the fluid source 310

to the manifolds 304. The service fluid is communicated from the control unit 302 to the manifold 304 via a supply line 314. The control unit 302 further includes an electrical controller 322 and a pneumatic source 324 that together control actuation of individual valves within the manifolds 304 that permit delivery of the service fluid to respective well components at the wells 306. The electrical controller 322 delivers electrical control signals to the manifold 304 via an electrical control line 316a and the pneumatic source delivers an air supply to the manifold 304 via a pneumatic control line 316b. Based on actuation of the valves in the manifolds, service fluid is selectively delivered to respective well components via fluid delivery lines 318. Thus, an operator or program can select to which well component(s) to provide service fluid. In some example embodiments, for each well component to which the manifold 304 provides service fluid, the manifold 304 includes a valve actuation system 350, as illustrated in FIG. 3B.

[0029] With reference to FIG. 3B, the valve actuation system 350 includes an electrical actuator such as a solenoid 326 which is controlled by an electrical signal from the electrical control line 316a. Upon actuation of the solenoid 326, a pneumatic actuator 328 receives air pressure from the pneumatic control line 316b and opens a valve, such as a needle valve 330. The needle valve is also coupled to the service fluid supply line 314 and the delivery line such that when open, the needle valve permits delivery of the service fluid to the well component 305. Alternatively, the needle valve 330 is coupled to a reservoir of service fluid within the manifold 304 and controls flow of service fluid from the reservoir to the well component 305 via the delivery line 318. In some embodiments, there is a valve actuation system 350 for every well component to which the manifold 304 is configured to deliver service fluid. In some other embodiments, one valve actuation system 350 may be configured to deliver service fluid to multiple well components 305 simultaneously.

[0030] FIG. 4A is a block diagram of a remote well servicing system 400, illustrating a control unit 402, three remote servicing manifolds 404 with fully pneumatic valve control, and three wells 406, in accordance with example embodiments of the present disclosure. The control unit 402 includes at least one service fluid source 410 and may include a pump 420 for pumping the service fluid from the fluid source 410 to the manifolds 404. The service fluid is communicated from the control unit 402 to the manifold 404 via a supply line 414. The control unit 402 further includes a pneumatic controller 424 that controls actuation of valves within the manifolds 404 by sending pneumatic signals through pneumatic control lines 416. Based on actuation of the valves in the manifolds, service fluid is selectively delivered to well components via respective fluid delivery lines 418. Thus, an operator or program can select which well

component(s) to provide service fluid to. In some embodiments, the manifold includes a valve actuation system 450 for each well component 405 to which the manifold 404 provides service fluid, as illustrated in FIG. 4B, in accordance in one or more embodiments. In one or more embodiments, the valve actuation system 450 includes a pneumatically valve 430 that is coupled to the delivery line 418 and permits flow of service fluid to the well component through the delivery line 418 upon actuation. The valve 430 can be selectively actuated via the pneumatic control line 416 to permit fluid communication between the supply line 414 and the delivery line 418 to deliver the service fluid to the well component 405. In some embodiments, there is a valve actuation system 450 for every well component 405 to which the manifold 504 is configured to deliver service fluid. In some other embodiments, one valve actuation system 450 may be configured to deliver service fluid to multiple well components 405 simultaneously.

[0031] FIG. 5 is a block diagram of a another embodiment of a remote well servicing system 500 similar to the remote well servicing system 300 of FIG. 3, with the addition of a pressure boosting station 560 at the manifold 504. The pressure boosting station 560 increases the pressure of the service fluid in the delivery line 518 to facilitate delivery of the service fluid to the well 506. The pressure boosting station may include a well service fluid reservoir 562 with a pump 564 such that the service fluid can be pumped through the delivery line 518 at a sufficient pressure to ensure delivery of the service fluid to the well. This may be particularly advantageous in application in which there is wellbore pressure acting against delivery of the service fluid or if the well 506 is at a great distance from or a higher altitude than the manifold 504. Similarly, FIG. 6 is a block diagram of a another embodiment of a remote well servicing system 600 similar to the remote well servicing system 400 of FIG. 4, with the addition of a pressure boosting station 660 at the manifold 604.

[0032] FIG. 7 is a block diagram of a remote well servicing system 700 with pressure relief, in accordance with example embodiments of the present disclosure. The well servicing system 700 includes a control unit 702 which provides service fluid to a remote servicing manifold 704 via a supply line 714 and also controls a pneumatic valve in the manifold via a pneumatic control line 716. The manifold 704 then delivers the service fluid to a well 706 via a delivery line upon actuation of the pneumatic valve. During operation, it may be the case there is a high pressure trapped within the pneumatic control line 716, the supply line 714, or the delivery line 718, such as after closing the valve after a servicing process. As such, bleed lines 770 may be coupled to the pneumatic control line 716, the supply line 714, and/or the delivery line 718. These may be multiple individual bleed lines 770 or one joined bleed line 770. In certain embodiments, the

bleed lines 770 are each coupled to a relief valve 772 that can be used to control release of pressure in the respective lines 714, 716, 718. The bleed lines 770 may empty into a collection tank for disposal. In some embodiments, the relief valves 772 may be controlled automatically based on a predetermined protocol such when pressure within a respective line exceeds a certain threshold. Specifically, this may be carried out electronically using a pressure sensor and controller that reads the pressure sensor and controls the relief valve 772 accordingly. This may also be carried out purely mechanically by using a relief valve 772 that is configured to trigger open upon being subject to a certain set-point pressure. Alternatively, the relief valves 772 can be controlled remotely or manually by an operator when needed.

[0033] Embodiments of the present disclosure provide a remote well servicing system that allows for servicing of well components, such as applying a servicing fluid, to be carried out without interrupting other well operations or the need to assemble or disassembly any equipment, and without on-site operator intervention.

[0034] The foregoing disclosure and description of the disclosed embodiments is illustrative and explanatory of the embodiments of the invention. Various changes in the details of the illustrated embodiments can be made within the scope of the appended claims without departing from the true spirit of the disclosure. The embodiments of the present disclosure should only be limited by the following claims and their legal equivalents.

CLAIMS

1. A remote well servicing system, comprising:

a remote servicing manifold, comprising:

a fluid input line couplable to a service fluid source;

a fluid output line couplable to a well component;

a valve coupled to the fluid input line and the fluid output line, wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source to the well component; and

a control line coupled to and controlling actuation of the valve.

2. The system of claim 1, wherein the control line comprises a pneumatic control line.

3. The system of claim 1, wherein the control line comprises a pneumatic control line and an electrical control line, and the control line controls actuation of the valve via a solenoid and a pneumatic actuator.

4. The system of claim 1, where the remote servicing manifold further comprises a pressure booster that increases the pressure in the fluid output line.

5. The system of claim 1, wherein the remote servicing manifold comprises a plurality of the fluid output lines, each couplable to a unique well component and communicative with the fluid input line via a unique valve.

6. The system of claim 1, wherein the remote servicing manifold is coupled to a bleed line, wherein service fluid in the remote service manifold, the fluid input line, and/or the fluid output line, is selectively directed into the bleed line to relieve pressure.

7. The system of claim 2, wherein the pneumatic control line is selectively coupled to a pneumatic bleed line to relieve pressure.

8. The system of claim 1, wherein the service fluid comprises a grease or a lubricant.

9. The system of claim 1, further comprising a controller that controls the valve via the control line, and wherein the controller is remotely or wirelessly located from the remote servicing manifold.

10. The system of claim 1, further comprising a controller that automatically controls the valve via the control line based on a predetermined condition.

11. A remote well servicing system, comprising:

a control unit, comprising:

a service fluid source; and

a control system;

a remote servicing manifold, comprising:

a fluid input line coupled to the service fluid source;

a fluid output line couplable to a well component;

a valve coupled to the fluid input line and the fluid output line, wherein the valve, when actuated, places the fluid input line in fluid communication with the fluid output line and permits delivery of a service fluid from the service fluid source to the well component; and

a control line coupling the valve and the control system, wherein the control system controls actuation of the valve via the control line.

12. The system of claim 11, further comprising a plurality of the remote service manifolds, each of which comprises a fluid input line coupled to the service fluid source at the control unit.

13. The system of claim 11, wherein the control system comprises a user interface.

14. The system of claim 11, wherein the remote servicing manifold comprises a plurality of the fluid output lines, each couplable to a unique well component and communicative with the fluid input line via a unique valve.

15. The system of claim 11, wherein the control system controls actuation of the valve based on a command received from a user device.

16. A method of remotely servicing a well component, comprising:

supplying a service fluid to a remote servicing manifold;

remotely actuating a valve on the remote servicing manifold, thereby permitting flow of the service fluid; and

delivering the service fluid from the remote servicing manifold to a well component.

17. The method of claim 16, further comprising delivering the service fluid from the remote servicing manifold to a plurality of well components simultaneously.

18. The method of claim 16, wherein the service fluid is a greasing fluid or a lubricant.

19. The method of claim 16, further comprising actuating the valve electrically, pneumatically, or electro-pneumatically.

20. The method of claim 16, further comprising relieving pressure in the remote servicing manifold by permitting flow of the service fluid into a bleed line.

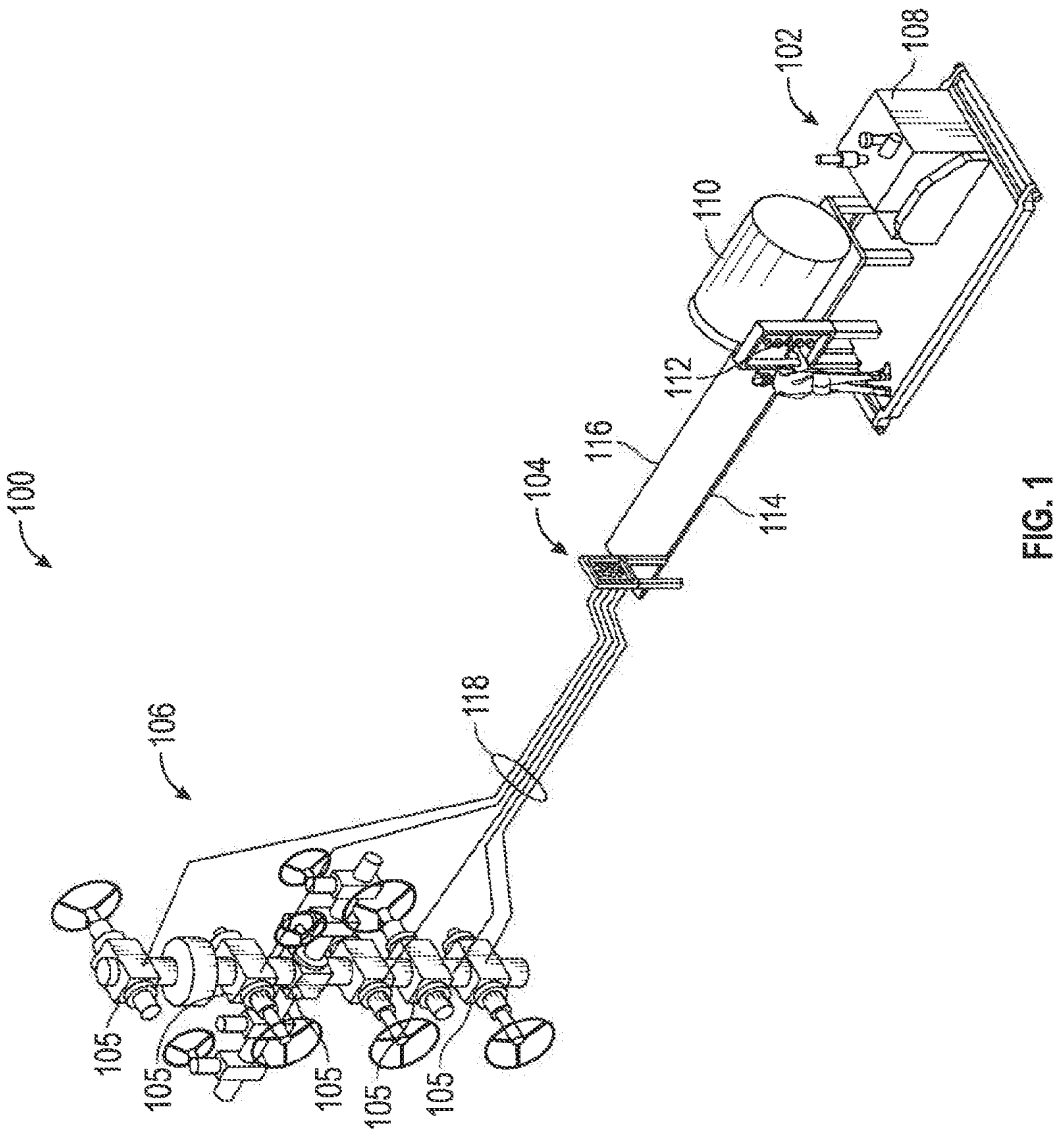


FIG. 1

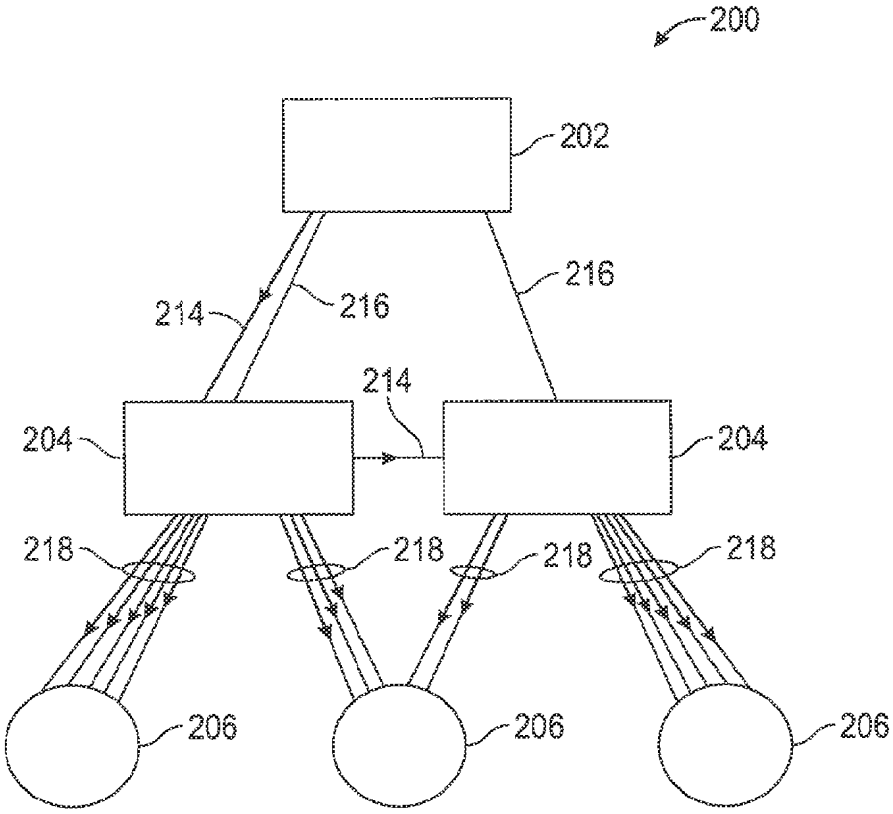


FIG. 2

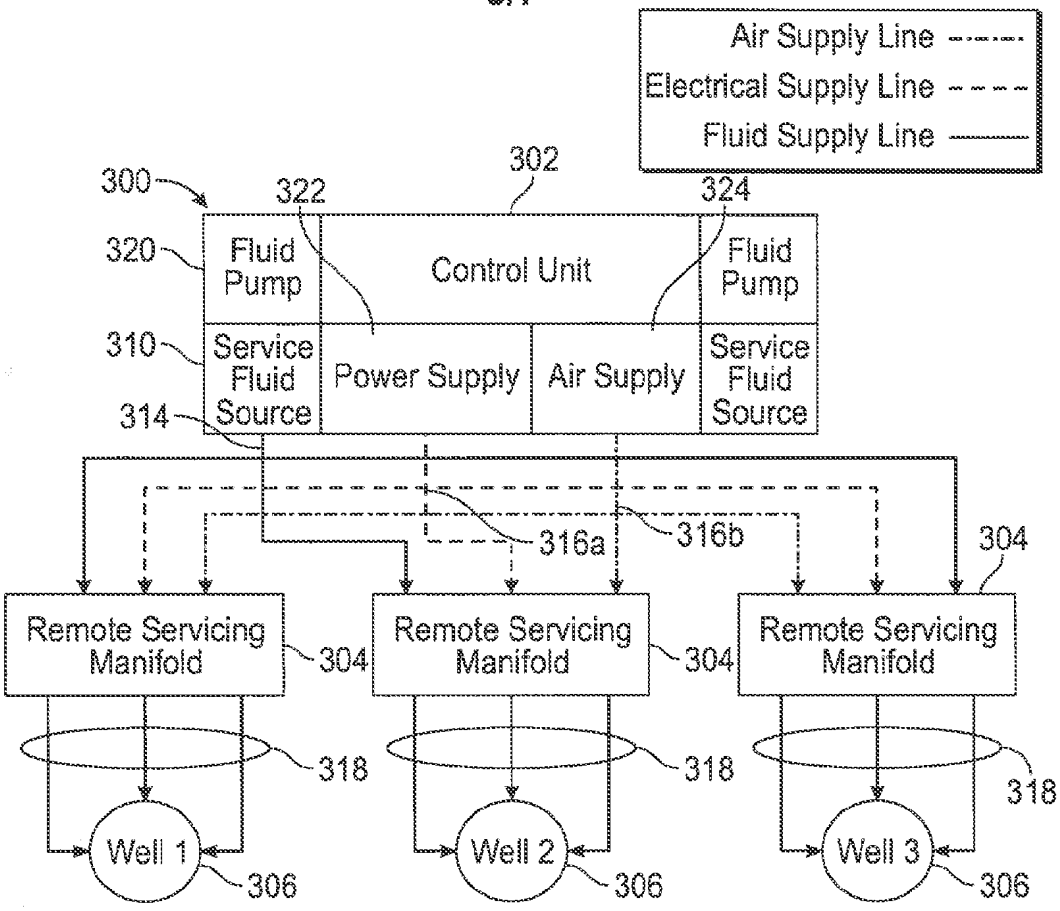

Air Supply Line
Electrical Supply Line
Fluid Supply Line
300
302
322
324
320
Fluid Pump
Control Unit
Fluid Pump
310
Service Fluid Source
Power Supply
Air Supply
Service Fluid Source
314
316a
316b
304
Remote Servicing Manifold
304
Remote Servicing Manifold
304
Remote Servicing Manifold
318
318
318
Well 1
306
Well 2
306
Well 3
306

FIG. 3A

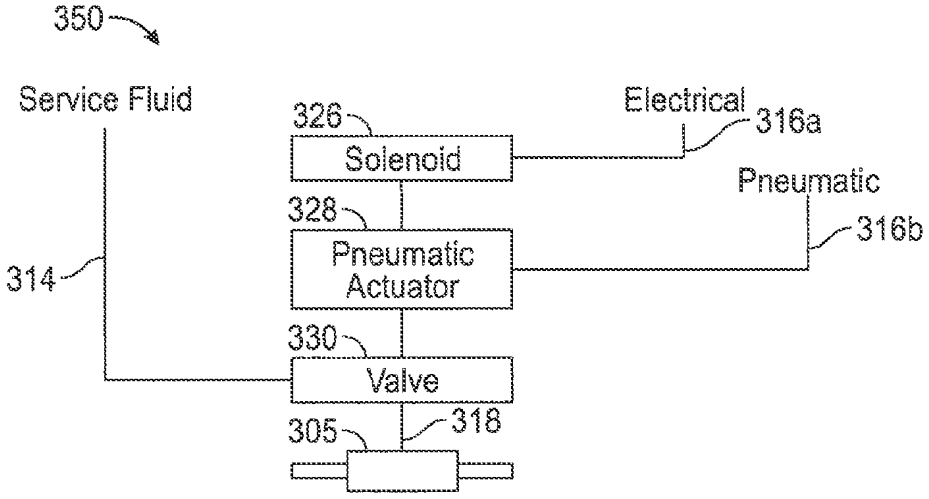

350
Service Fluid
326
Solenoid
Electrical
316a
Pneumatic
316b
328
Pneumatic Actuator
314
330
Valve
305
318

FIG. 3B

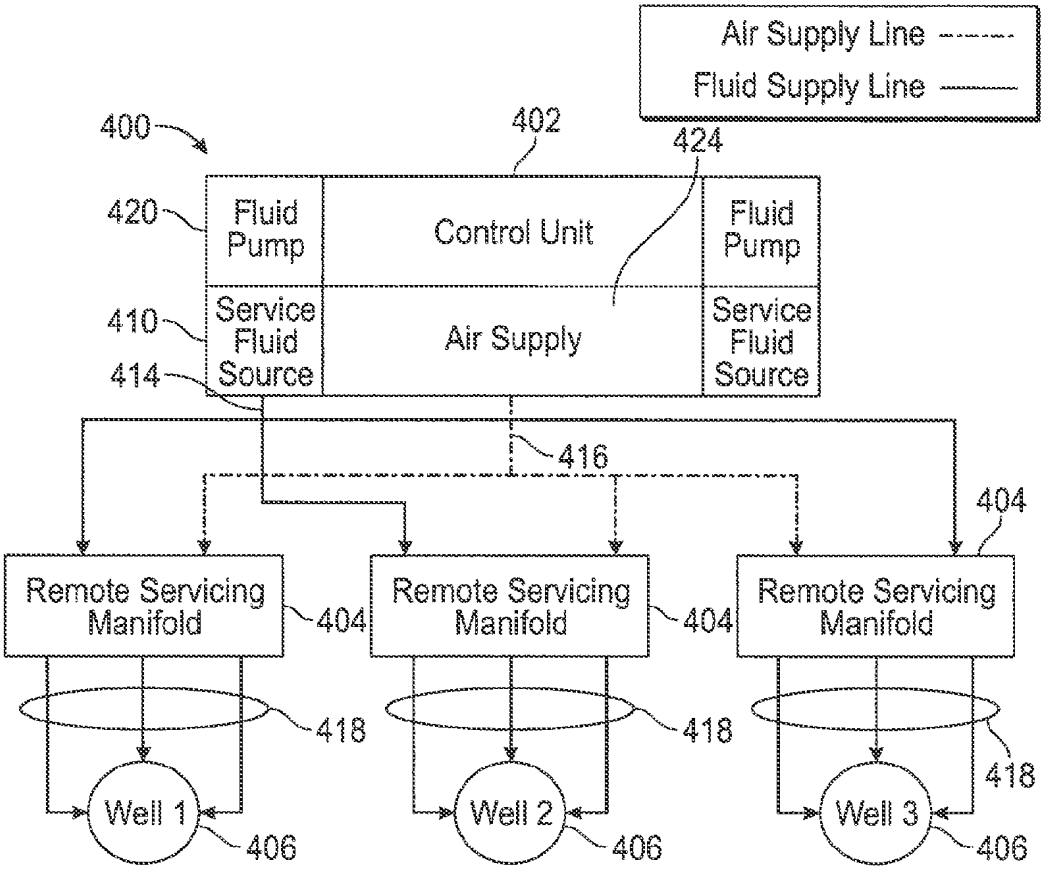

Air Supply Line
Fluid Supply Line
400
402
424
420
Fluid Pump
Control Unit
Fluid Pump
410
Service Fluid Source
Air Supply
Service Fluid Source
414
416
404
Remote Servicing Manifold
404
Remote Servicing Manifold
404
Remote Servicing Manifold
418
418
418
Well 1
406
Well 2
406
Well 3
406

FIG. 4A

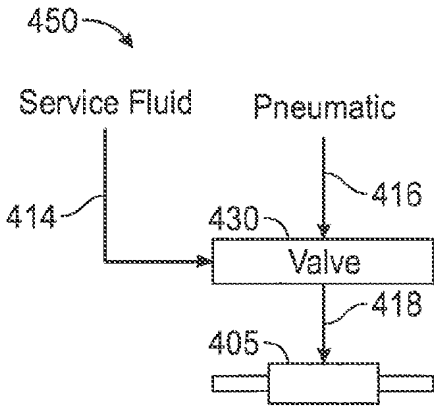

450
Service Fluid
Pneumatic
414
416
430
Valve
418
405

FIG. 4B

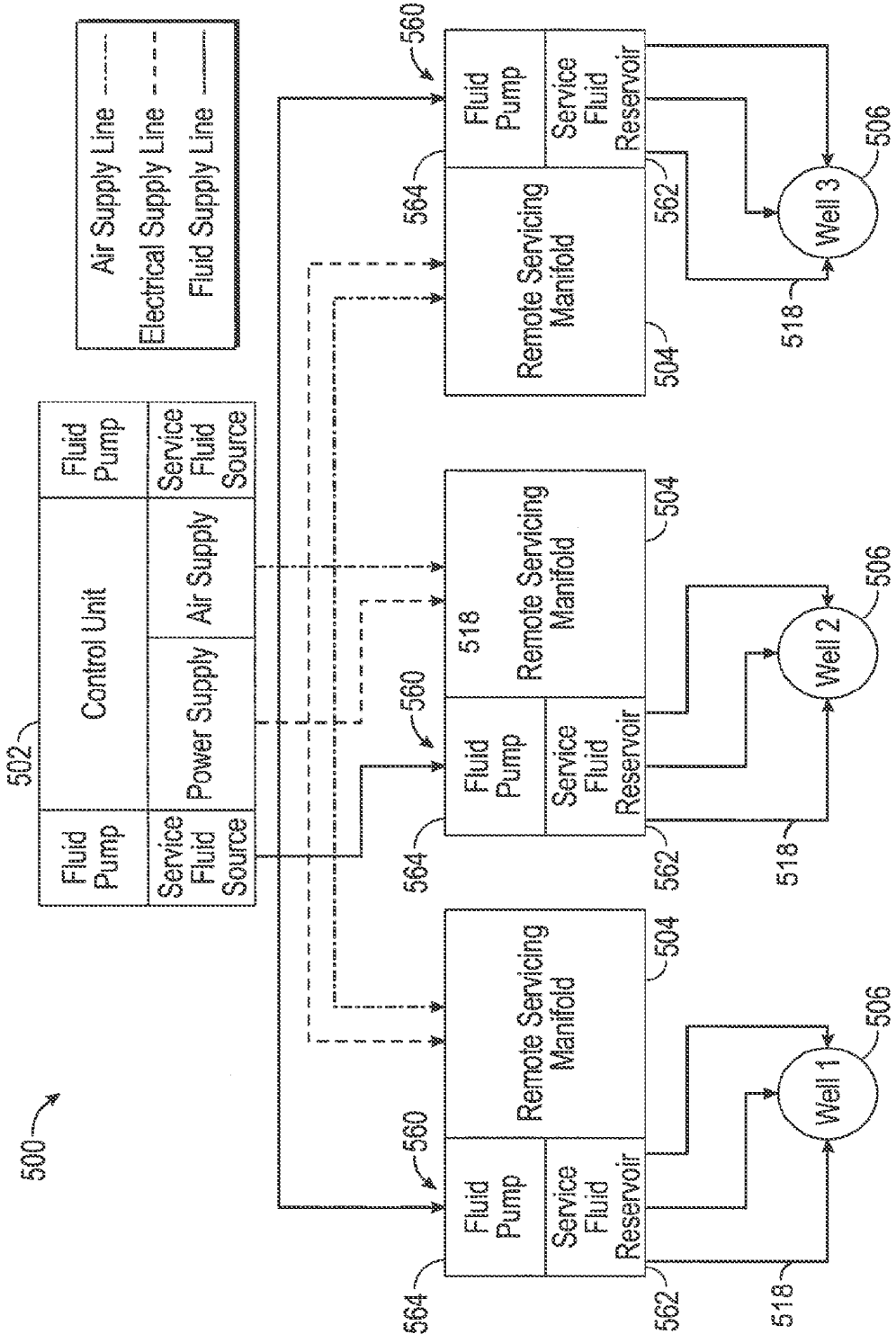

Air Supply Line
Electrical Supply Line
Fluid Supply Line
500
502
Control Unit
Fluid Pump
Service Fluid Source
Power Supply
Air Supply
Fluid Pump
Service Fluid Source
560
564
562
518
504
506
Remote Servicing Manifold
Fluid Pump
Service Fluid Reservoir
Well 1
Well 2
Well 3

FIG. 5

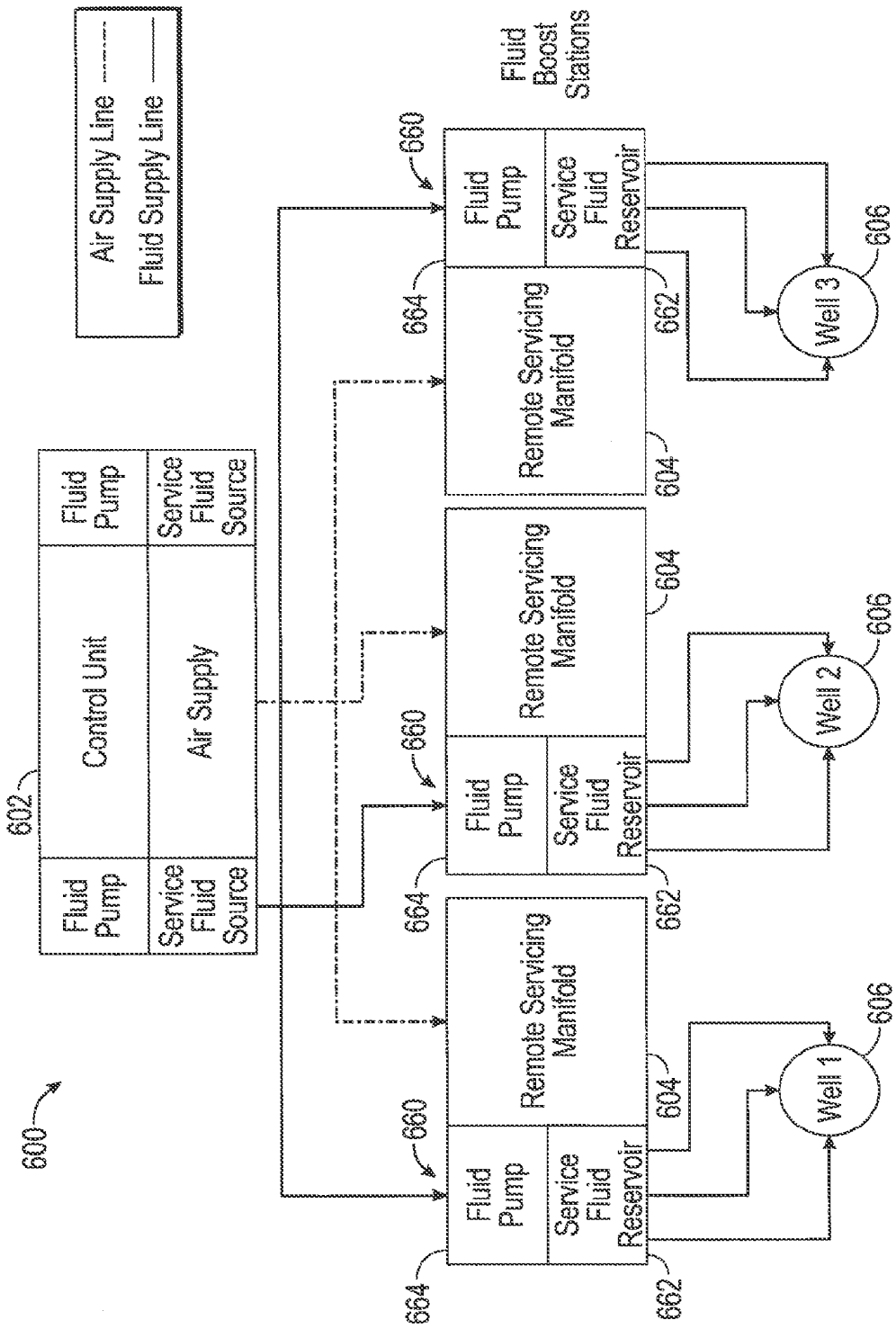

Air Supply Line
Fluid Supply Line
Fluid Boost Stations
600
602
Control Unit
Fluid Pump
Service Fluid Source
Air Supply
Fluid Pump
Service Fluid Source
660
Fluid Pump
Service Fluid Reservoir
664
662
Remote Servicing Manifold
604
Well 1
Well 2
Well 3
606

FIG. 6

7/7

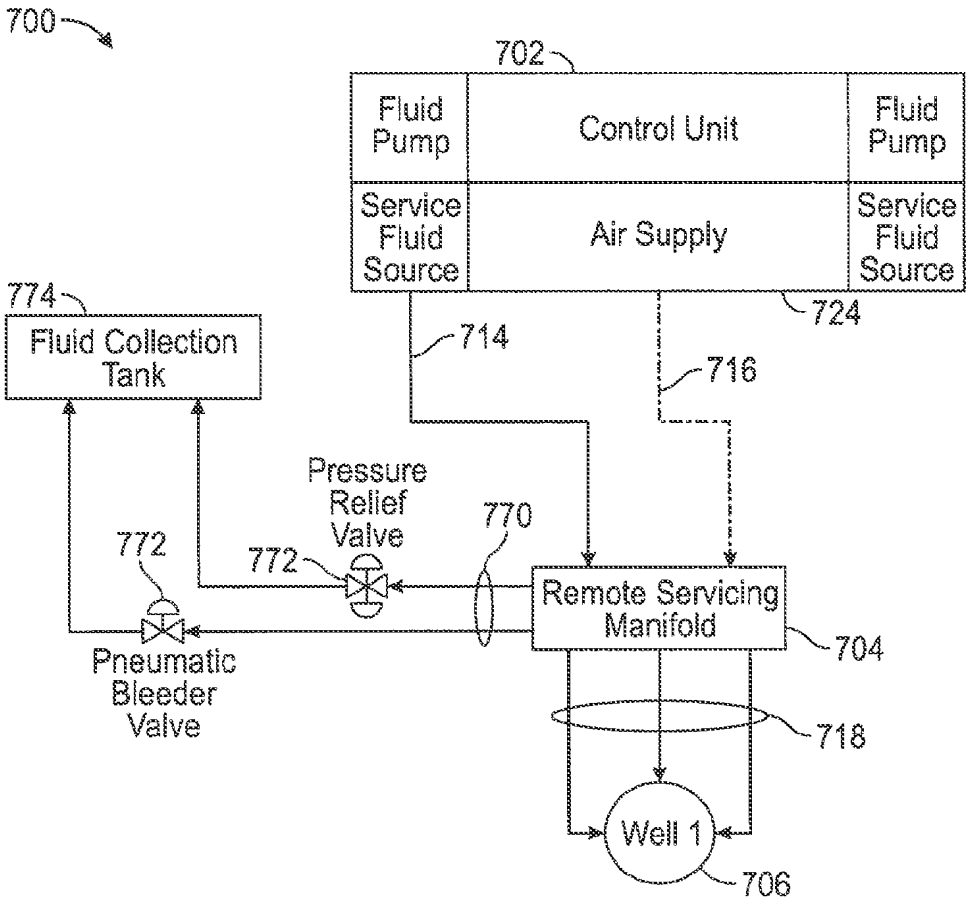

700
702
Fluid Pump
Control Unit
Fluid Pump
Service Fluid Source
Air Supply
Service Fluid Source
724
774
Fluid Collection Tank
714
716
Pressure Relief Valve
770
772
772
Remote Servicing Manifold
704
Pneumatic Bleeder Valve
718
Well 1
706

FIG. 7

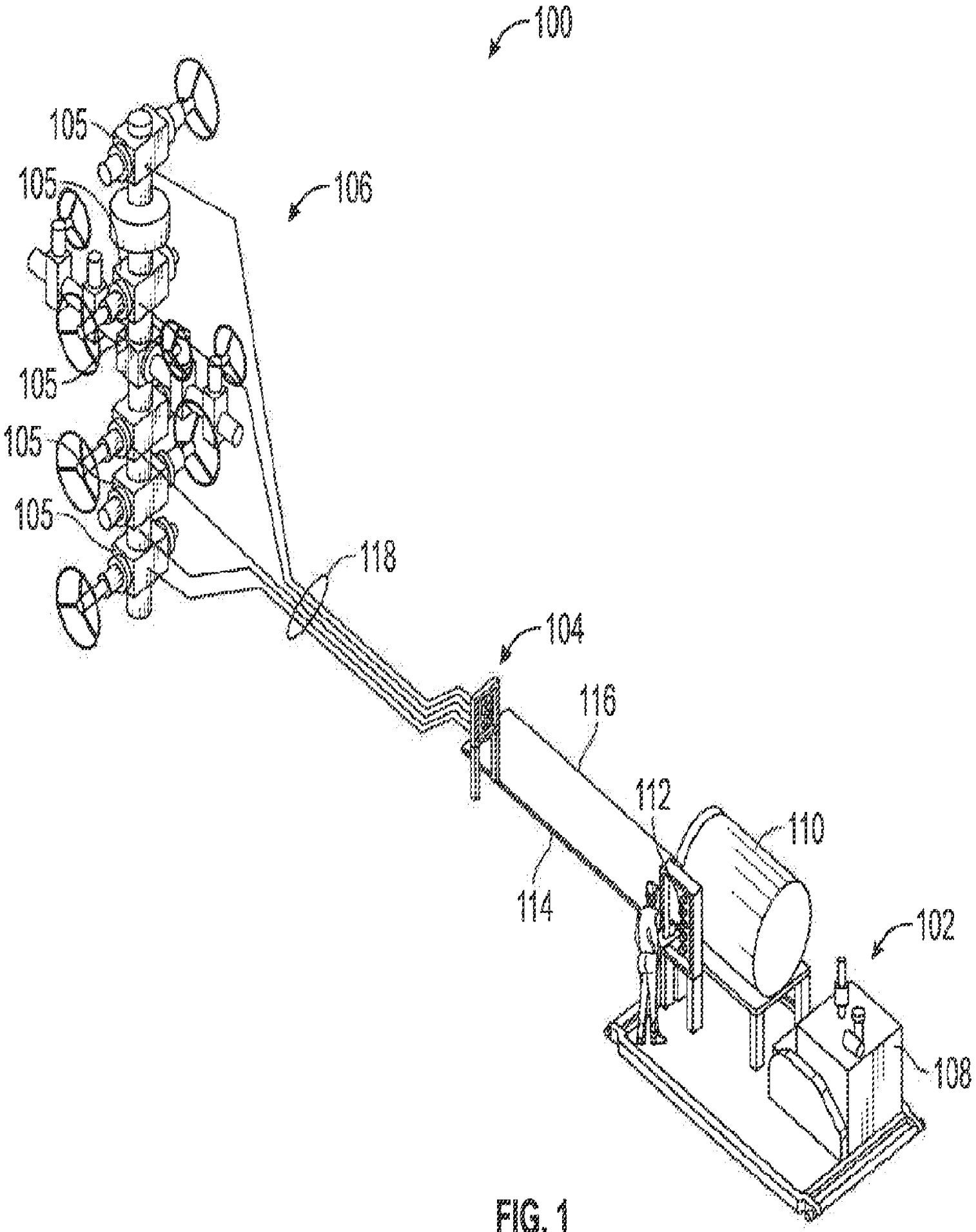


FIG. 1

Innovation, Sciences et Développement économique Canada
Office de la Propriété Intellectuelle du Canada

Innovation, Science and Economic Development Canada
Canadian Intellectual Property Office

CA 3050131 A1 2011/11/03

(21) 3 050 131

(12) DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION

(13) A1

(22) **Date de dépôt/Filing Date:** 2011/05/02

(41) **Mise à la disp. pub./Open to Public Insp.:** 2011/11/03

(62) **Demande originale/Original Application:** 2 797 081

(30) **Priorité/Priority:** 2010/04/30 (US61/330248)

(51) **Cl.Int./Int.Cl.** ***G01M 13/00*** (2019.01),
E21B 41/00 (2006.01), ***E21B 44/00*** (2006.01),
G01D 21/00 (2006.01), ***G06Q 10/00*** (2012.01)

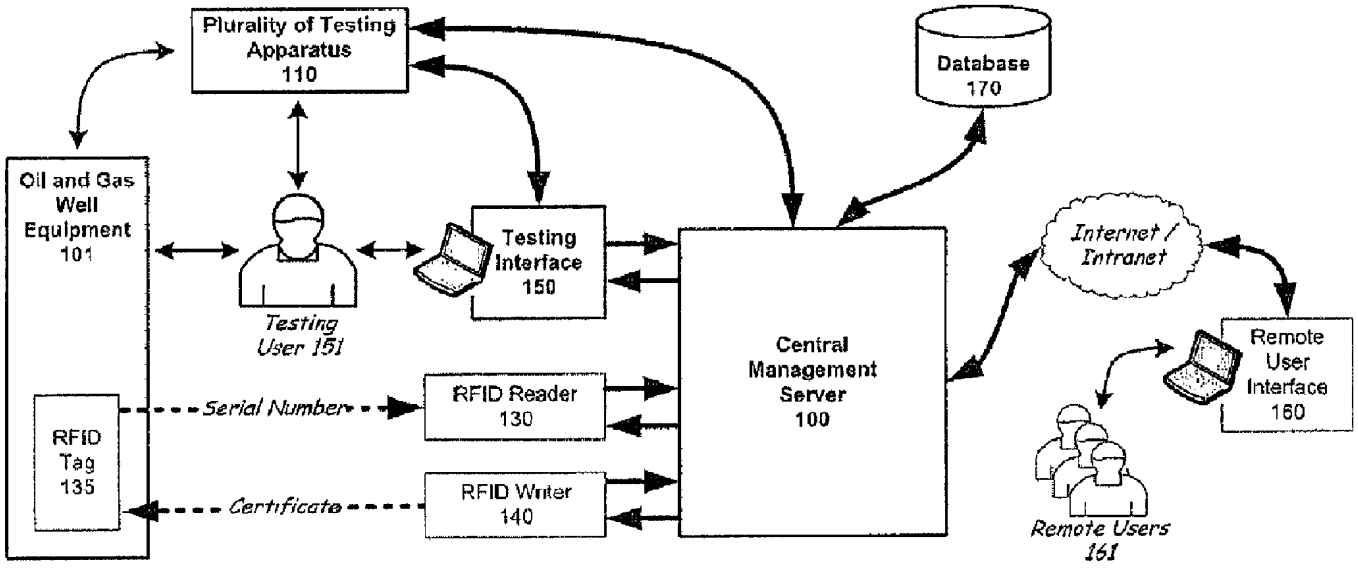
(71) **Demandeur/Applicant:**
S.P.M. FLOW CONTROL, INC., US

(72) **Inventeur/Inventor:**
HUNTER, SCOTT, US...

(74) **Agent:** PERRY + CURRIER

(54) **Titre : MACHINES, SYSTEMES, PROCEDES MIS EN OEUVRE PAR ORDINATEUR ET PRODUITS DE PROGRAMME INFORMATIQUE POUR TESTER ET CERTIFIER UN MATERIEL PETROLIER ET GAZIER**

(54) **Title: MACHINES, SYSTEMS, COMPUTER-IMPLEMENTED METHODS, AND COMPUTER PROGRAM PRODUCTS TO TEST AND CERTIFY OIL AND GAS EQUIPMENT**



(57) **Abrégé/Abstract:**
Embodiments of machines, systems, computer-implemented methods, and computer program products certify oil and gas well equipment. Embodiments identify a selected well equipment device, a device test specification, and testing sequences to be performed by a corresponding testing apparatus. Embodiments select a testing sequence responsive to the selected device. Embodiments control the testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs

(21) 3 050 131

(13) A1

(57) **Abrégé(suite)/Abstract(continued):**
the sequence responsive to the device test specification. Embodiments generate testing data for the selected testing sequence and link the testing data for the selected testing sequence to the device identifier for the device so that a certificate can be generated. Embodiments generate a certificate for the selected device responsive to the testing sequences having been performed upon the selected device and link the certificate for the selected device to the device identifier so that the certificate can be readily recalled.

LIBERTY EXHIBIT 1002, Page 838

ABSTRACT

Embodiments of machines, systems, computer-implemented methods, and computer program products certify oil and gas well equipment. Embodiments identify a selected well equipment device, a device test specification, and testing sequences to be performed by a corresponding testing apparatus. Embodiments select a testing sequence responsive to the selected device. Embodiments control the testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence responsive to the device test specification. Embodiments generate testing data for the selected testing sequence and link the testing data for the selected testing sequence to the device identifier for the device so that a certificate can be generated. Embodiments generate a certificate for the selected device responsive to the testing sequences having been performed upon the selected device and link the certificate for the selected device to the device identifier so that the certificate can be readily recalled.

MACHINES, SYSTEMS, COMPUTER-IMPLEMENTED METHODS, AND COMPUTER PROGRAM PRODUCTS TO TEST AND CERTIFY OIL AND GAS EQUIPMENT

Related Applications

[0001] This application claims priority and is related to U.S. Provisional Patent Application No. 61/330,248 filed April 30, 2010 titled "**Machines, Systems, Computer-Implemented Methods, And Computer Program Products To Test And Certify Oil And Gas Equipment,**" which is incorporated by reference in its entirety herein.

Field of the Invention

[0002] The present invention relates to oil and gas production. In more particular aspects, the present invention relates to testing and certification of equipment used in oil and gas production.

Background of the Invention

[0003] The production of oil and gas requires specialized well equipment, such as pipes, valves, joints, and fittings that operate in extreme conditions, including, for example, high pressure, temperature, volatility, and corrosivity. Such conditions promote the rapid wear of well equipment and increase the potential for failure. Moreover, when well equipment does fail, the impact of the failure is typically catastrophic. For example, the failure of well equipment can result in massive explosions that hurt workers, destroy property, and halt operations for a significant time—potentially costing millions of dollars in liabilities, repairs, and lost revenue.

[0004] Well equipment particularly susceptible to catastrophic failure includes, for example, the equipment used in the process of hydraulic fracturing known as "fracing" or "fracking." The process of fracing creates or extends fractures in subterranean rock formations by pumping fluid into the formation at high pressure. For example, fluid-driven fractures can be formed at the borehole in a drilling operation and then "grown" or extended into the rock formations. The injected fluid may contain "proppant" particles, such as grains of sand or ceramic, to lodge in the

fractures thereby keeping them open. Fracing is used to improve the rate at which oil and gas can be produced from a reservoir, and fracing is especially useful for extracting oil and gas from formations having low porosity and permeability, such as shale rock and other formations deep below the earth's surface. The equipment used in hydraulic fracturing for oil and gas wells can include, for example, a slurry blender, high pressure/volume fracturing pumps, high pressure treating iron, and other pipes, joints, valves, and fittings, which are known as "frac iron" or, simply, "iron." For example, frac iron can include swivel joints, pup joints, plug valves, check valves and relief valves.

[0005] To mitigate the likelihood and impact of their failure, frac iron must be periodically inspected and recertified according to certain specifications, which can be provided by, for example, a manufacturer or operator of the frac iron. Because of the likelihood and impact of failure, inspections can be performed as frequently as every 90 days. Inspections and recertifications typically require several different test procedures, which may include, for example, a visual check of bores, connections, seal surfaces; wall thickness measurements to check for erosion or corrosion, for example, using ultrasonic measurement; crack tests, for example, using magnetic particle measurement; and pressure tests, for example, of over 20,000 pounds per square inch (PSI).

[0006] Previously known methods to certify frac iron were lengthy and laborious, often lasting one to three weeks and requiring a human tester to control all testing, to record the results manually, and later to enter the results into a database—costing valuable production capacity due to downtime.

[0007] Also, previously known methods to certify frac iron were susceptible to inconsistencies due to the manually intensive nature of the certification, such as inconsistent performance of testing operations and inconsistent adherence to prescribed test specifications. Also, for example, certification records were created by manual input, introducing human error and recording and measurement variances into the certification records.

[0008] Also, previously known methods to certify frac iron were susceptible to operational inefficiencies. For example, certification records were kept in hard copy, which did not allow on-site operators to readily access certifications while in the field, which may be a remote

location such as an offshore rig. Furthermore, certification records and the test results associated therewith could not be tracked, updated, or reported on from a central control center.

Summary of the Invention

[0009] Embodiments of the present invention provide systems, methods, and machines for testing and certifying well equipment that enhance testing management, certification management, field operations management, and asset management. For example, embodiments of the present invention increase efficiency in testing and certifying well equipment by providing a systematic solution to control testing operations. Also, embodiments of the present invention increase efficiency in testing and certifying well equipment by seamlessly generating, storing, and processing testing data immediately upon performance of the testing operations, allowing a user to view the testing data in real time. Also, embodiments of the present invention increase efficiency in testing and certifying well equipment by dynamically generating certificates and reports responsive to the testing data according to multiple formats or user criteria.

[0010] Furthermore, well equipment testing according to embodiments of the present invention benefit from an increased likelihood of effective and safe operation because embodiments of the present invention systematically ensuring that testers use the proper test specifications and perform all test operations according to defined test sequences. Also, well equipment tested according to embodiments of the present invention benefit from an increased likelihood of effective and safe operation because embodiments of the present invention systematically ensure that equipment that fail any test sequence according to defined testing specifications are scrapped in the system and are unable to proceed in further testing or operation. Also, well equipment testing according to embodiments of the present invention benefit from an increased likelihood of effective and safe operation because operational crews can more readily access certificates, including comprehensive testing and certification data, on-demand and on-site. Furthermore, manufacturers and suppliers of well equipment can benefit from embodiments of the present invention by enhancing research and development efforts with greater knowledge of real-world wear patterns and wear rates for well equipment devices.

[0011] In view of the foregoing, applicant has provided a machine to manage periodic testing and certification of well equipment devices, the testing and certification being facilitated by a

plurality of testing apparatus performing one or more testing operations upon the well equipment devices. The machine comprises a processor, a non-transitory memory, an input/output unit to communicate with the plurality of testing apparatus, a database positioned to match a device identifier to a well equipment device, a test specification, and a plurality of testing sequences. The machine also comprises a testing module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the testing module being operable by the processor, the testing module comprising a set of instructions that, when executed by the processor, cause the testing module to perform operations. The operations of the testing module include identifying a selected well equipment device, a device test specification, and a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations.

[0012] The operations of the testing module further include selecting a testing sequence of the plurality of testing sequences, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device.

[0013] The operations of the testing module further include controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification. The operations of the testing module further include generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations.

[0014] The operations of the testing module further include linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in the database so that a certificate can be generated responsive thereto; and

[0015] The machine also comprises a certification module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the certification module

being operable by the processor, the certification module comprising a set of instructions that, when executed by the processor, cause the certification module to perform certain operations.

[0016] The operations of the certification module include identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device.

[0017] The operations of the certification module further include generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been performed upon the selected well equipment device responsive to the device test specification.

[0018] The operations of the certification module further include linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

[0019] Also in view of the foregoing, applicant has provided a system to certify oil and gas well equipment. The system comprises a plurality of devices to be used in well equipment to define a plurality of well equipment devices, each well equipment device of the plurality of well equipment devices having a device identifier associated therewith. The system further comprises a central management server positioned to identify a device test specification and a plurality of testing sequences for a selected well equipment device responsive to receiving a device identifier for the selected well equipment device, the device test specification and the plurality of testing sequences defining certification criteria for the well equipment device. The system further comprises a plurality of testing apparatus, each testing apparatus positioned to perform a testing sequence upon the well equipment device, the testing sequence being a sequence of testing operations, the sequence of testing operations being performed responsive to the device test specification. The system further comprises a plurality of controllers, each controller positioned to receive commands responsive to the certification criteria from the central management server and to control the plurality of testing apparatus performing the sequence of testing operations upon the selected well equipment device responsive to the device test specification. The system

further comprises a certificate generated responsive to the plurality of testing apparatus performing the plurality of testing sequences upon the well equipment device, the certificate indicating whether selected well equipment device has been tested according to the certification criteria within a pre-selected period of time.

[0020] Also in view of the foregoing, applicant has also provided a computer-implemented method to manage periodic testing of a plurality of well equipment devices, the testing being facilitated by a plurality of testing apparatus performing one or more testing operations upon the plurality of well equipment devices. The computer-implemented method comprises receiving a device identifier for a selected well equipment device of the plurality of well equipment devices. The computer-implemented method further comprises identifying the selected well equipment device, a device test specification, and plurality of testing sequences, the identifying operation being responsive to the receiving operation, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations. The computer-implemented method further comprises selecting a testing sequence of the plurality of testing sequences to define a selected testing sequence, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device. The computer-implemented method further comprises calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification. The computer-implemented method further comprises controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification. The computer-implemented method further comprises generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations. The computer-implemented method further comprises linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in a database so that a certificate can be generated responsive thereto.

[0021] Also in view of the foregoing, applicant has also provided a computer program product to manage periodic testing of a plurality of well equipment devices. The computer program product can be stored in a memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the computer program product being operable by a processor. The computer program product comprises a set of instructions that, when executed by the processor, cause the testing module to perform certain operations. The operations performed by the computer program product includes identifying a selected well equipment device, a device test specification, and a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations. The operations performed by the computer program product further includes selecting a testing sequence of the plurality of testing sequences, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device. The operations performed by the computer program product further includes controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification. The operations performed by the computer program product further includes generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations. The operations performed by the computer program product further includes linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in the database so that a certificate can be generated responsive thereto. The operations performed by the computer program product further includes identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device. The operations performed by the computer program product further includes generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been

performed upon the selected well equipment device responsive to the device test specification. The operations performed by the computer program product further includes linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

Brief Description of the Drawings

[0022] So that the manner in which the features and benefits of the invention, as well as others which will become apparent, may be understood in more detail, a more particular description of the invention briefly summarized above may be had by reference to the embodiments thereof which are illustrated in the appended drawings, which form a part of this specification. It is also to be noted, however, that the drawings illustrate only various embodiments of the invention and are therefore not to be considered limiting of the invention's scope as it may include other effective embodiments as well.

[0023] FIG. 1 is a schematic diagram illustrating exemplary data flows and interactions among components of a system to certify well equipment according to an embodiment of the present invention;

[0024] FIG. 2 is a schematic illustrating exemplary components and connections of a central management server to certify well equipment according to an embodiment of the present invention;

[0025] FIG. 3 is a flowchart illustrating exemplary program product logic and computer-implemented methods for certifying well equipment according to an embodiment of the present invention;

[0026] FIG. 4 is a database diagram illustrating exemplary data structures according to an embodiment of the present invention;

[0027] FIG. 5 is an exemplary certificate according to an embodiment of the present invention;

[0028] FIGs. 6-8 are flowcharts illustrating exemplary process flow according to embodiments of the present invention;

[0029] FIGs. 9-23 are exemplary testing interface displays according to embodiments of the present invention; and

[0030] FIGs. 24-25 are exemplary reporting interface displays according to embodiments of the present invention.

Detailed Description

[0031] The present invention will now be described more fully hereinafter with reference to the accompanying drawings, which illustrate various embodiments of the invention. This invention, however, may be embodied in many different forms and should not be construed as limited to the embodiments set forth herein. Rather, these embodiments are provided so that this disclosure will be thorough and complete, and will fully convey the scope of the invention to those skilled in the art. It is to be fully recognized that the different teachings of the various embodiments discussed below may be employed separately or in any suitable combination to produce desired results. The various characteristics mentioned above, as well as other features and characteristics described in more detail below, will be readily apparent to those skilled in the art upon reading the following detailed description of the various embodiments, and by referring to the accompanying drawings. In the drawings and description that follow, like parts are marked throughout the specification and drawings with the same reference numerals, respectively. The prime notation, if used, indicates similar elements in alternative embodiments. The drawings are not necessarily to scale. Certain features of the disclosure may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in the interest of clarity and conciseness.

[0032] Accordingly, embodiments of the present invention improve safety, effectiveness, and efficiency of operating well equipment by meeting the foregoing objectives to mitigate the likelihood and impact of the failure of such equipment. In embodiments of the present invention, "well equipment devices" includes the equipment and devices used in hydraulic fracturing for oil and gas wells, i.e. "high pressure hydraulic fracturing flow iron," "frac iron," or, simply, "iron."

Frac iron can include, for example, a slurry blender, high pressure/volume fracturing pumps, high pressure treating iron, and other pipes, joints, valves, and fittings. For example, frac iron can include swivel joints, pup joints, plug valves, check valves and relief valves. Furthermore, by way of example, frac iron can include any type of ball injector, crow's foot, air chamber, crossover, hose, pipes/piping, hose loop, ball injector tee body, tee, wye, lateral, ell, check valve, plug valve, wellhead adapter, swivel joint, plug, relief valve, densometer, cross, frac pump, or cement pump. Those skilled in the art will appreciate that embodiments of the present invention are not limited to uses related to in oil and gas wells, but, rather, embodiments of the present invention are applicable to processes for testing or certifying any industrial equipment or device, and at any stage in the lifespan of the equipment, including during or after manufacturing and before, during, or after use or ongoing operations.

[0033] FIG. 1 illustrates a central management server 100 for performing operations of a testing module 220 and a certification module 210. The central management server 100 is positioned to be in communication with a plurality of testing apparatus 110. The plurality of testing apparatus 110 is capable of performing testing operations on a selected well equipment device 101. The central management server 100 is positioned to systematically control the performing of testing operations upon the well equipment device 101, systematically record and process the results of such testing operations, and systematically generate a certificate responsive to such recording and processing. Embodiments of the present invention providing systems, methods, and machines to certify of well equipment and are further described herein with specific reference to the drawings.

Central Management Server 100

[0034] An embodiment of a central management server 100, as illustrated in FIG. 2, can be configured as a computer, a server, or a machine of distributed computers or servers that at least include non-transitory memory 240, program products 210, 220, and 230, a processor or processors 251, an input/output device or devices ("I/O") 252.

[0035] I/O 252 connects the central management server 100 to a database 170, a testing interface 150, and one or more testing apparatus 110 (although represented as one block, those of skill in the art will appreciate that a plurality of testing apparatus 110 may include one or more

links to the I/O) to thereby allow central management server 100 to send and receive commands and data. I/O 252 can be any I/O including, but not limited to a network card/controller connected by a PCI (Peripheral Component Interconnect) bus to the motherboard, or hardware built into the motherboard of the central management server 100 to connect same to the forgoing database, interface, and apparatus.

[0036] As those of skill in the art will appreciate, I/O 252 can connect the central management server 100 with any other compatible machine, server, system, device, or equipment having a suitable physical interface and that I/O 252 and/or computer program products 210, 220, and 230 on non-transitory memory 240 may be positioned to understand, convert, or translate application or communication protocols of such machines, servers, systems, devices, or equipment irrespective of native protocols. Also, one of skill in the art will understand that I/O 252 can include or otherwise incorporate any logical or physical technology necessary to effect a connection with any of the aforementioned devices, including, for example, hubs, switches, routers, converters, amplifiers, and wireless transceivers. For example, as is further described herein, I/O 252 can also connect the central management server 100 to devices for interacting with radio frequency identification (RFID) devices, such as an RFID reader or interrogator 130 and an RFID writer 140. The central management server 100 can further connect to a remote user interface 160 for interacting with a remote user 161, as is also discussed further herein. Also, the plurality of testing apparatus 110, RFID reader 130, and the RFID writer 140 may be configured as peripherals to the testing interface 150. Also, there a testing apparatus 110 interface 253, such as a programmable logic controller (PLC), an interface between the I/O 252 and the plurality of testing apparatus 110 to control the plurality of testing apparatus 110.

[0037] As can be seen in FIG. 2, the I/O 252 is connected to a processor 251. The processor 251 is the "brains" of the central management server, and as such executes program products 210, 220, and 230 and works in conjunction with the I/O 252 to direct data to the non-transitory memory 240 and to send data from the non-transitory memory 240 to the database 170, the testing interface 150, and one or more testing apparatus 110. The processor 251 can be any commercially available processor, or plurality of processors, adapted for use in or with the central management server 100, *e.g.*, Intel® Xeon® multicore processors, Intel® micro-

architecture Nehalem, and AMD Opteron™ multicore processors. As one skilled in the art will appreciate, processor 251 may also include components that allow the central management server 100 to be connected to a display, as will be understood by those skilled in the art, and keyboard or other peripherals that would allow a user to directly or indirectly access the processor 251 and non-transitory memory 240.

[0038] Non-transitory memory 240 stores computer program products 210, 220, and 230 having instructions for execution on the processor 251, and consists of both non-volatile memory, *e.g.*, hard disks, flash memory, optical disks, and the like, and volatile memory, *e.g.*, SRAM, DRAM, and SDRAM as required to support embodiments of the instant invention. As one skilled in the art will appreciate, though the non-transitory memory 240 is depicted on, *e.g.*, a motherboard, of the central management server 100, the non-transitory memory 240 may also be a separate component or device, *e.g.*, FLASH memory, connected to the central management server 100 through the I/O 252. The non-transitory memory 240 may also store applications that various workstations or remote units can access and run on the central management server 100. For example, a testing user 151 may access applications and computer program products stored on the non-transitory memory 240 and run on the processor 251 using the testing interface 150. Importantly, non-transitory memory 240 stores the program products 210, 220, and 230 of the instant invention. As one skilled in the art will understand, the program products 210, 220, and 230, along with one or more databases/tables/fields/records for data associated with the selected well equipment device 101 can be stored either in non-transitory memory 240 or in separate non-transitory memory associated, for example, with a storage medium such as database 170, positioned in communication with the central management server 100.

Database 170

[0039] As seen in FIG. 1 and FIG. 2, the database 170 is in communication with the central management server 100. Although the database 170 is illustrated according to an embodiment in which the database 170 is separate and distinct from the central management server 100, for example, as a database server, the present invention may also include any arrangement of the database 170 in communication with the central management server 100, including the database 170 being incorporated into the same computer, server, machine, or system constituting the

central management server 100, as one physical unit, for example, as an application or partition in the central management server 100 or as an installed component of the central management server 100 communicating with the processor 251 through the use of the I/O and having, for example, a database memory separate and distinct from memory 240, such as a hard drive, optical storage, or the like. Database 170, as is understood in the art, can include a processor directing data from a bus into the database memory, which can be, for example, a hard drive, optical storage or the like, and computer software that provides computers, including the central management server, access the data therein.

[0040] The database 170 can store therein a data structure or data structures relating to the well equipment devices 101 to be tested and all data generated during the execution of the testing module 211 and certification module 210, as is further discussed herein. In embodiments, database 170 is a relational database positioned to match data by using common data found between data sets, the data sets being organized according to tables 400, 410, 420, 430, 440, and 450 as seen in FIG. 4. As will be understood by those skilled in the art, FIG. 4 illustrates an exemplary set of data structures only, and there may be other unique table structures positioned to relate and match the data in manners commensurate with the embodiments of the present invention. Data stored in the database 170 may be updated as needed, for example, by a user with administrative access to the database to add new well equipment devices to the database as they become supported. As is described further herein with relation to the computer program products, database 170 can be positioned to store data in tables relating to the unique device tested 400, parts in a parts library 410, test specifications in a test specification library 420, test sequences in a test sequence library 430, test data in a test data repository 440, and certificate data in a certificate data repository 450. And as is described further herein, the database 170 is positioned to match common data appearing in the foregoing tables.

Testing Apparatus 110

[0041] As shown in FIG. 1 and FIG. 2, the plurality of testing apparatus 110 are in communication with the central management server 100. The plurality of testing apparatus 110 perform testing operations under the control of the central management server 110 and provide tools or devices to gather testing data 440 as shown in FIG. 4, *i.e.,* the data that serves as the

basis for the certification. In embodiments, the plurality of testing apparatus 110 at least includes an ultrasonic wall thickness meter ("UT meter") and a pressure test pump having a transducer. The plurality of testing apparatus 110 can include any other device or unit capable of being employed either manually or under automated control by the central management server 100 to interact with the well equipment device 101. Other testing apparatus 110 can include, for example, digital calipers. A local user may employ embodiments of the present invention, for example, by positioning the frac iron to be tested 101 in a testing station adapted for the test performed, and by manually configuring the frac iron 101 to safely and effectively interact with the testing apparatus 110 for the intended test.

[0042] Although shown as separate blocks in FIG. 1, the testing interface 150, which can be a personal computer (PC), can be connected to a peripheral testing apparatus 110 to control or collect data from a testing apparatus 110 connected as a peripheral to an input/output unit of the PC. The combination of the testing apparatus 110 and a PC may be referred to, collectively, as a testing apparatus 110. PC or testing interface 150 can connect to a peripheral testing apparatus 110 via any connection type known to those in the art, such as a Universal Serial Bus connection (USB), and such connection may include analog inputs and digital inputs, wired and wireless, and including analog-to-digital converters and amplifiers for digital inputs.

[0043] The plurality of testing apparatus 110 and a PC incorporated with a peripheral testing apparatus 110 can be a mobile unit or units having remote or wireless connectivity to central management server 100 using any protocols or standards known in the art, including Wi-Fi, GSM, and WIMAX, for example. Mobile units may also be synchronized with central management server through periodic wired or wireless connections when returning from field use. The PC can be, for example, any suitable PC known in the art and is preferably a Panasonic® Toughbook® or other portable, notebook, laptop, or tablet computer preferably designed to withstand vibration, drops, spills, extreme temperature, and other rough handling and conditions common to industrial use.

[0044] The UT meter can be, for example, an Olympus® MG2DL, or any similar UT meter known in the art. The UT meter can include, for example, features such as B-scan, gain adjust, auto sensitivity optimizations, echo-to-echo, differential mode, hi-low alarm, and live A-scan.

The UT meter can also include a file-based alphanumeric data logger and an interface program for transferring data bi-directionally to and from a PC. The testing apparatus 110 can include a PC, such as described above, for enabling data and control functions of a peripheral testing apparatus 110 such as a UT meter.

[0045] The pressure test pump and transducer can be any suitable pressure test pump known in the art. Preferably, embodiments of the invention employ an X45 series model 345 Viatran® test and control pressure sensor, which can, for example, operate in the range of 0-100,000 psi with output in the range of 4-20 mA. As is known in the art, the testing apparatus 110 can include a control interface such as a programmable logic controller (PLC) for communication with and control of the pressure test pump and transducer.

Testing User 151 and Testing Interface 150

[0046] As described above, a testing user 151 may employ embodiments of the present invention, for example, by positioning the frac iron to be tested 101 in a testing station adapted for the test to be performed, and will manually configure the frac iron 101 to safely and effectively interact with the testing apparatus 110 for the intended test. In other embodiments, the testing user may perform testing operations according to instructions provided by the central management server 110 and displayed, for example, on the testing interface 150. The testing user 151 may provide the means of manually gathering testing data 440 as shown in FIG. 4, *i.e.*, the data that serves as the basis for the certification. Testing operations, as described above with reference to the testing apparatus 110, may be systematic, manual, or hybrid systematic/manual. For example, a sequence of testing operations for testing wall thickness of the frac iron may include systematic test operations to be performed by a testing apparatus 110, such as a UT meter, and manual operations to be performed by a testing user 151, such as using digital calipers to measure wall thickness or other dimensions of the frac iron, as can be seen in FIGS. 15-16, for example. Likewise, other sequences of testing operations may be fully manual, such as the mag particle test discussed further herein.

[0047] Also as described above, the testing interface 150 may be a PC, which may be any desktop, laptop, notebook, tablet, or portable computer known to those in the art. As is known the art, the testing interface 150 can include any number of peripheral devices to interact with the

testing user 151, including a keyboard, mouse, control stick/joystick, and memory reader for receiving data input and a display screen, printer, and local storage device for outputting or storing data. Furthermore, embodiments of invention have a testing interface with a touch-sensitive screen (*e.g.*, using a stylus) for interactive display/input so that users can select parts responsive to viewing them on the display of the testing interface 150 and thereafter performing testing operations responsive to the selection, in communication with the testing module 210. The testing interface 150 may connect with the central management server 100 via any communications interface known to those of skill in the art, wired or wireless, and is preferably a secure local Intranet or other authenticated and encrypted communications network, including a VPN over the Internet.

Certificate 500

[0048] FIG. 5 sets forth an exemplary certificate 500 generated responsive to embodiments of the present invention. The certificate 500 relates to data stored in the database 170, for example, the certificate data 450 as shown in FIG. 4. The certificate 500, as is appreciated by those skilled in the art, can be a paper document printout or an electronic document in a format such as Adobe® Portable Document Format (.PDF), Microsoft® Word (.DOC or .DOCX), or a similar format. The certificate 500, for example, can be a paper document printout, as it is the custom in drilling and fracing operations for a paper document printout of a certificate to be presented to company personnel when well equipment is brought on-site in field operations. The company personnel takes possession of the physical document and reviews the testing parameters and testing results documented thereon to verify the quality of the equipment brought on site.

[0049] The certificate 500 can reference the well equipment device 101 by a unique device identifier, such as the serial number 501, which can relate to data stored in database 170 in the device information table 400. The certificate 500 can contain a summary indication as to whether certain test sequences were graded as a "PASS" or a "FAIL" 502. The grading operation, for example, can be performed by a certification module 220 computer program product operating on the central management server 100. The PASS or FAIL grading 502 can relate to data stored in the database 170, for example, the certificate data 450 and the testing data 440 shown in FIG. 4. The certificate 500 can also contain a summary or other rendering of

testing data responsive to testing operations being performed on the well equipment device 101, for example, a graphical representation of a pressure test 503. Graphical representation 503 can relate to data stored in the database 170 in the certificate data table 450 and the testing data table 440.

[0050] The certificate 500 can also contain a summary indication as to measured qualities of the selected well equipment device 101 and their relation to the qualities demanded by the test specification. For example, measured wall thickness value 505 appears adjacent to demanded wall thickness value 506. Additionally, drawing 504 shows a graphical representation of the parameters measured according to the test specification, as referenced by letter key (*e.g.*, "A," "B," and "C".).

[0051] In certain embodiments of the present invention, a certificate can be stored in a proprietary data table format so that a lightweight electronic copy of the certificate, and an "RFID certificate" can be stored directly onto RFID tag 135 attached to the selected well equipment 101. For example, as understood by those skilled in the art, the RFID certificate can be written to an RFID tag 135 attached to the well equipment so that the certificate can be readily accessed in the field using an RFID reader device 130 capable of recognizing the proprietary data table format. The RFID certificate can include all fields available on the paper certificate 500, including device identifier 501, pass or fail grading 502, tabular summary or rendering of test data 503, drawing 504, measured values 505, and demanded values 506. The tabular summary or rendering 503 and the drawing 504 can be encoded, for example, using lightweight vector-based primitive formats. Also, RFID certificate will allow new schemes for protecting certificate data heretofore unavailable for field use, for example, by having individual cells in the table that are protected according to user access schemes such as read-only, read-write, or no access. For example, the serial number and the certification may be read-only to all; the certificate data may be read-only to many and read-write to few; and custom fields may be user-configurable.

Testing Module 210

[0052] As is shown in FIG. 2, the testing module 210 may be a computer program product stored in the memory 240 on the central management server 100 and operable on the processor

251 thereof. Computer program product 210 contains instructions that are operable on the processor 251 that cause the testing module 210 and the central management server 100 to perform the operations discussed further herein.

[0053] The testing module 210 can interact with the processor to receive or transmit data, instructions, and other information from or to any of the devices connected to I/O 252. In embodiments discussed below, the testing module 210 at least interacts with the testing interface 150, testing apparatus 110, RFID reader 130, and database 170. Although testing interface 150 has been described to be a personal computer (PC), testing interface 150 can also be implemented in whole or in part as a user terminal interface on the central management server 100 itself, or using a keyboard, display, or media inputs and outputs connecting to the I/O 252. Testing interface 150 can also be a lightweight graphical user interface (GUI) operable over a web browser and viewable on any browser-enabled device, such as a PC, smart phone, or other equipment having a processor and computer functionality. Testing interface 150, for example, can receive user-selected identifiers or other user-selected values or parameters from a testing user as will be described in further detail below and can display identifiers, values, parameters, and other specification data, for example, as can be shown with reference to the selection, input, or display fields 900, 1000, 1100-1101, and 1200-1205 in FIGS. 9-12. Other user selection, input, or display fields are also shown elsewhere in FIGS. 13-25, as will be apparent to those having skill in the art.

[0054] The testing module 210 can receive a device identifier for a selected well equipment device 101, the selected well equipment device being a well equipment device positioned to undergo testing and certification, *i.e.,* in the testing warehouse, on a testing trailer, or otherwise positioned at a testing station. In the embodiment of the present invention, only one well equipment device is tested at any given time using any particular testing apparatus 110. It is possible, however, that multiple instances or threads of the testing module 210 can run on the processor 251 concurrently, with each instance being directed to the testing of a different piece of well equipment positioned for testing. It is also possible that multiple testing apparatus 110 of the same type may be employed to perform the same test sequence in simultaneous testing operations performed on multiple well equipment devices 101.

[0055] The testing module 210 can receive a serial number as a device identifier as shown in FIG. 6. The testing module 210 can receive a serial number as a device identifier, for example, by receiving input from the testing interface 150 as entered therein by a testing user 151. The testing module 210 can also receive a device identifier, such as a serial number, from a peripheral device, such as an RFID reader 130, as is discussed further herein.

[0056] The testing module 210 can identify the selected well equipment device responsive to the device identifier as shown in and match the selected well equipment to: (i) device library information as shown in FIG. 4 at table 400, the device library information including a part number, and (ii) a part library information at table 410 including type, test specification, and test profile, as shown in FIG. 7. If the testing module 210 is unable to identify the foregoing information as shown in FIG. 8 (*i.e.*, the device has not yet been tested), then the testing module 210 can prompt the testing user 151 to enter information to identify the device as shown in FIG. 9. Once the testing module 210 has matched the device 101 to a part number, the testing module 210 can match the device to a test specification and a test profile as shown in FIG. 4 at tables 420 and 430. The test specification can be criteria to which the testing operations will be performed, for example, as specified by the manufacturer or the customer. Test specifications can include, for example, a series of benchmark parameters as shown in FIG. 5 at 506. Test specifications can also include, for example, a schematic associated with the series of parameters as shown in FIG. 5 at 504.

[0057] The test profile as shown in FIG. 4 at table 430 may be a plurality of test sequences that are to be performed upon the well equipment device. A test profile may indicate that certain test sequences shall be run on certain parts, but not on others. For example, test profiles may be defined by "levels" as set forth by the logical process flows shown in FIGS. 6-9.

[0058] Level 1, as set forth in FIG. 6, can include, for example, making an inventory of all iron and entering al serial numbers or parts and specifications into the system. Then a testing user can visually examine and record any defects, damage, worn bodies, threads, and wing nuts on the iron. If the visual examine is acceptable, the tester can proceed with a wall thickness test, as discussed further herein. If the visual examination is unsuccessful, the user can scrap the iron in the database, mark the part with orange paint, and return or destroy the iron so that it becomes

unusable. If the wall thickness is acceptable, the customer can be contacted if the wall thickness is within 5% of the minimum value set forth in the testing specification. If not, the testing user can proceed to the pressure test. If the pressure test is acceptable, the final inspection to be signed off by leading supervisor. If continued testing is desired, the tester can proceed to Level 2 before performing the pressure test.

[0059] Level 2, as set forth in FIG. 7, can include, for example, dismantling and stripping down and discarding all rubber seals and worn or corroded parts, then cleaning and removing grease from affected parts with solvent. Also, the testing user can perform a surface preparation in caustic solution tank, de-scale surfaces area to remove dirt scale, rust, and paint, and pressure rinse to remove caustic solution. The testing user then performs the visual examination as specified for Level 1, and may scrap the part also as specified for Level 1. If proceeding to Level 3 is acceptable, the testing user goes to Level 3 before performing the pressure test. Otherwise, the pressure test can be performed as specified for Level 1.

[0060] Level 3, as set forth in FIG. 8, can include, for example, inspecting the part to make sure its free from all oil, grease, paint, scale, rust, and all contaminates that might degrade the result of this inspection. The testing user then coats area to be inspected with wet fluorescent bath and puts a yoke on the part to create magnetic field. The user can pass the part for the magnetic particle test if, using a black light to check for indications of cracks and rechecking at right angles, the user finds no indications of cracks. If the magnetic particle test fails, the user can scrap the iron in the database as set forth for Level 1. After cleaning the part and completing the inspection buyoff, the testing user can reassemble and fit with news seals and any spare parts required. Thereafter the testing user can perform the pressure test as specified for Level 1 and proceed to paint per the customer's specifications or according to standardized paint schemes as set forth in FIG. 8. After painting, the supervising leader must sign off on the final inspection.

[0061] Test sequences 1300 can include, for example, visual inspection, wall thickness inspection, disassembly/assembly, magnetic ("mag") particle inspection, pressure test, paint, and final inspection. As shown in FIG. 13, test sequences available for the device 101, (*i.e.*, available according to the test profile 430) can be displayed to the testing user 151 using the

testing interface 150 so that the testing user 151 may select one of the available test sequences to be performed.

[0062] Test sequences as shown in FIG. 13 may correspond to one of a plurality of testing apparatus 110. For example, the test sequence "wall thickness inspection" corresponds to the UT meter testing apparatus 110 and the test sequence "pressure test" corresponds to the pressure test pump and transducer. Other test sequences shown in FIG. 13 may correspond to manual procedures; for example, the test sequence "visual inspection" corresponds only to operations to be performed by the testing user 151. Each test sequence, as shown in table 440 of FIG. 4, corresponds to a sequence of testing operations to be performed upon the well equipment device 101.

[0063] Once the testing interface 150 displays the plurality of test sequences 440 available for the well equipment device, the testing user 151 can select a test sequence to be performed. The test sequence should correspond to the testing user positioning the selected well equipment device so that the testing apparatus 110 can perform the testing operations. For example, if the testing user 151 has selected the pressure test sequence, the testing user must also ensure that the appropriate testing apparatus 110 (*e.g.*, the pressure pump and transducer) is positioned upon the selected well equipment device so that the test can be properly performed.

[0064] If the testing user 151 has selected the pressure test sequence or the wall thickness inspection sequence, the testing module 210 will calibrate the testing apparatus 110 as shown in FIG. 14 and FIG. 15. In certain embodiments, the calibration 1400, 1500 can be performed responsive to the tolerances as specified in the test specification 420. Calibration can be performed, for example, by shoring a transducer of the testing apparatus 110 to return a rated pressure value or a baseline calibration setting by the manufacturer, as will be understood by those skilled in the art. Embodiments of the present invention can receive the baseline calibration setting returned and configure a calibration setting responsive thereto.

[0065] According to certain embodiments of the present invention, the testing module 210 systematically controls the performance of testing operations in certain test sequences. For such testing modules having full systematic control of performing the testing operations, *e.g.*, the pressure test sequence, the testing user 151 can initiate the performance of the testing operations

to be controlled by the central management server 100, as shown at control deck 1600 in FIG. 16. The testing module 210 can control the corresponding testing apparatus 110 for the selected testing sequence so that the corresponding testing apparatus 110 performs the sequence of testing operations upon the selected well equipment device 101. For example, the pressure test sequence can be performed responsive to the pressure criteria set forth in the test specification. As shown in FIG. 17, the pressure test proceeds systematically as shown in test chart 1700 and the test module controls the performance of a pressurization of the selected well equipment device 101 for a preselected period of time, for example, as specified in the test specification.

[0066] In further embodiments of the present invention, the testing module 210 systematically controls the performance of some testing operations and requires manual performance of other testing operations ("hybrid systematic/manual"). For testing modules having hybrid systematic/manual performance of testing operations, such as for wall thickness inspection, the testing user 151 can initiate the performance of the testing operations to be controlled by the central management server 100, and the central management server 100 can control the testing apparatus 110 as discussed above with respect to fully systematic testing. Also, the testing module 210 can prompt the testing user 151 with instructions for the testing user 151 to perform testing operations pursuant to the test specification. As shown in FIG. 18 and FIG. 19, the thickness at "Location A" can be measured and input 1800, 1900 either by the UT Meter or by the testing user 151 manually measuring Location A with a digital caliper. The testing module 210 transmits the schematic from the test specification to the testing interface 150 so that it may be displayed 1901 to the testing user 151 and instructs the testing user 151 how to perform the test operations with respect to the information set forth in the schematic and test specification.

[0067] In further embodiments of the present invention, the testing module 210 requires full manual performance of the testing operations for certain test sequences. For testing modules having full manual performance of testing operations, such as for the visual inspection sequence, the testing module 210 can prompt the testing user 151 with instructions for the testing user 151 to perform testing operations pursuant to the test specification. As shown in FIGs. 20-21, band information 2000 and paint parameters 2100 can be input by the testing user 151 responsive to instructions provided by the testing module 210 to the test interface 150, the testing module 210 providing such instructions responsive to the sequence of testing operations and the test

specification. As can be seen in FIG. 17, for example, the testing interface 150 can display the schematic 2001 from the test specification to the testing user 151 and instructs the user how to perform the test operations with respect to information set forth in the schematic and the test specification.

[0068] Responsive to systematic, manual, or hybrid systematic/manual performance of the test operation described above, the testing module 210 receives testing data either as captured by the testing apparatus 110 for the corresponding testing sequence or as captured by the testing user 151 and entered into the testing interface 150 according to specific instructions provided by the testing module 210, e.g., at banding menu 2000. As shown in FIG. 4, the testing data is stored in the table 440 and linked to the device library 400 for the selected well equipment device 101. Also as shown in FIG. 4, an exemplary embodiment of the testing data in table 440 can have individual cells for each testing sequence (*e.g.*, wall thickness, pressure test, visual inspection, etc.). The testing data in table 440 can be used, as is discussed further herein, to generate certification data by execution of the certification module 220 on the processor 251.

[0069] Additionally, further embodiments of the present invention include certain test sequences as described in FIGS. 6-9. These test sequences, for example, can include disassembly/assembly, magnetic particle ("mag particle") inspection, paint, and final inspection. Although an embodiment of the invention includes manual performance of the test operations for these sequences, each of these test sequences may be implemented either by systematic, manual, or hybrid systematic/manual performance of the testing operations. Regardless of whether the performance of the testing operations are performed systematically or manually, those skilled in the art will realize that all testing operations are performed responsive to a command or instruction being systematically issued by the testing module 210 when executed on the central management server 100. As such, any test operation described herein as manual can be performed systematically provided there exists a testing apparatus 110 that can receive an instruction from the central management server 100 to perform the operation. For example, the performance of test operations using a digital caliper may be performed either manually or systematically, although an embodiment employs manual performance of such operations. Those skilled in the art will understand that it is within the scope of the invention to employ a testing apparatus 110 having a digital caliper, actuator, and an control device to systematically

perform a wall thickness measurement using a digital caliper in addition to the embodiment employing manual performance. Likewise, it will be understood by those in the art that any manual operation described herein may also be performed systematically under the architecture of the central management server as set forth in FIG. 2.

Certification Module 220

[0070] As is shown in FIG. 2, the certification module 220 may be a computer program product stored in the non-transitory memory 240 on the central management server 100 and operable on the processor 251 thereof. Computer program product 220 contains instructions that are operable on the processor 251 that cause the certification module 220 and the central management server 100 to perform the operations discussed further herein.

[0071] The certification module 220 can interact with the processor to receive or transmit data, instructions, and other information from or to any of the devices connected to I/O 252. In addition both the certification module 220 and the testing module 210 are in communication with the processor 251 and the non-transitory memory 240 so that modules can pass or return variables between modules according to a shared API or access global variables being stored on the non-transitory memory 240 to ensure interoperability and open communication between computer program products in communication with the processor 251. Likewise, those skilled in the art will understand that computer program products 220 and 210 are capable of passing, returning, or referencing common variables regardless of whether computer program products are executed on the same processor 251, but that a common API will allow interoperability and open communications. In embodiments discussed below, the certification module 220 at least interacts with the testing interface 150, RFID reader 130, RFID writer 140, and database 170. Although testing interface 150 has been described to be a PC, testing interface 150 can also be implemented in whole or in part as a user terminal interface on the central management server 100 itself, using a keyboard, display, or media inputs and outputs connecting to the I/O 252. The testing interface 150 can also be a lightweight graphical user interface (GUI) operable over a web browser and viewable on any browser-enabled device, such as a PC, smart phone, or other equipment having a processor and computer functionality.

[0072] The certification module 220 can receive a device identifier for a selected well equipment device 101. As described above, "well equipment devices" includes the equipment and devices used in hydraulic fracturing for oil and gas wells, i.e. "high pressure hydraulic fracturing flow iron," "frac iron," or, simply, "iron." Frac iron can include, for example, a slurry blender, high pressure/volume fracturing pumps, high pressure treating iron, and other pipes, joints, valves, and fittings. For example, frac iron can include swivel joints, pup joints, plug valves, check valves and relief valves. Furthermore, by way of example, frac iron can include any type of ball injector, crow's foot, air chamber, crossover, hose, pipes/piping, hose loop, ball injector tee body, tee, wye, lateral, ell, check valve, plug valve, wellhead adapter, swivel joint, plug, relief valve, densometer, cross, frac pump, or cement pump. The selected well equipment device is a well equipment device that has previously undergone testing, for example, as described above with respect to the testing module 210. The certification module 220 can receive a device identifier, for example, responsive to receiving input from the testing interface 150 as entered therein by a testing user 151. The certification module 220 can also receive a device identifier, for example, responsive to receiving input from a remote user interface as entered therein by a remote user 161. Furthermore, the certification module 220 can receive a device identifier from the testing module 210 responsive to the testing module 210 having completed execution of the testing operations and the generation and linking of the testing data in the database 170. The certification module 220 can identify a selected well equipment device responsive to the device identifier and generate and link certification data in database 170, for example, in certification table 450, responsive to the testing data. For example, the certification data 450 can include all data as can be entered onto certificate 500 as a summary or other rendering of testing data responsive to testing operations being performed on the well equipment device 101, for example, a graphical representation of a pressure test 503. The certification module 220 can include logic to generate charts and data modeling based upon testing data, which is raw data stored, for example, in table 440. Further examples of summaries or renderings of raw testing data responsive to the testing operations appear on the face of certificate 500. As a result of the linking operation, the certification data 440 can be readily accessed or queried according to a serial number for a well equipment device.

[0073] The certification module 220 can also generate certification data in a format responsive the proprietary data table format for the exemplary RFID certificate. For example,

certification module 220 may generate certificate data according to specific standards or protocols employed in the proprietary standard, for example, cell size, packet size, header length, payload length, etc. The RFID certificate can be generated so that it is ready to be stored to the media attached to the well equipment without further processing. The certification module 220 may also include logic for rendering graphics stored as certification data, such as the schematics and charts, into a lightweight graphics formats such as vector graphics formats. The RFID certificate, for example, can include all fields available on the paper document, including device identifier 501, pass or fail grading 502, tabular summary or rendering of test data 503, drawing 504, measured values 505, and demanded values 506. The tabular summary or rendering 503 and the drawing 504 can be encoded in lightweight vector graphics formats, for example.

Reporting Module 230 and Enterprise Resource Planning Interface

[0074] As is shown in FIG. 2, the reporting module 230 may be a computer program product stored in the non-transitory memory 240 on the central management server 100 and operable on the processor 251 thereof. Computer program product 230 contains instructions that are operable on the processor 251 that cause reporting module 230 and the central management server 100 to perform the operations discussed further herein.

[0075] The reporting module 230 can interact with the processor 251 to receive or transmit data, instructions, and other information from or to any of the devices connected to I/O 252. In addition, both the reporting module 230 and the testing module 210 are in communication with the processor 251 and non-transitory memory 240 so that these two modules can pass or return variables between each other according to a common application programming interface (API) or shared global variables being stored on the non-transitory memory 240, thereby enhancing interoperability and open communication between the modules. Likewise, those skilled in the art will understand that computer program products 230 and 220 are capable of passing, returning, or referencing common variables regardless of whether computer program products are executed on the same processor 251 and that a common API will allow interoperability and open communications as described above. In embodiments discussed below, the reporting module 230 at least interacts with the testing module 210, certification module 220, and database 170. Although remote user interface 160 may be a PC as has been described for testing interface 150,

remote user interface 160 can also be implemented in whole or in part as a user terminal interface on the central management server 100 itself, using a keyboard, display, or media inputs and outputs connecting to the I/O 252. Remote user interface 160 can also be a lightweight graphical user interface (GUI) operable over a web browser and viewable on any browser-enabled device, such as a PC, smart phone, or other equipment having a processor and computer functionality.

[0076] The reporting module 230 can receive a device identifier for a selected well equipment device 101, the selected well equipment device being a well equipment device that has previously undergone testing, for example, as described above with respect to the testing module 210. The reporting module 230 can receive a device identifier, for example, responsive to receiving input from the testing interface 150 as entered therein by a testing user 151. The reporting module 230 can also receive a device identifier from any other module, as discussed above. In response to receiving the device identifier, the reporting module 230 can match the device identifier to any desired data in the database 170, for example, testing data in the database at testing data table 440, certification data in the certification data table 450, device library data from the device library table 410, and test specification data from the specification library 420. The reporting module, responsive to the device identifier, can return any of the test specification for the selected well equipment device 101, testing data for a plurality of testing sequences performed on the selected well equipment device 101, and certificate data for the selected well equipment device 101, for example, according to the database structure provided in FIG. 4.

[0077] The reporting module 230 may also receive an indication or selection of additional variables for reporting purposes, for example, a part number, work order number, etc. In the event that the reporting module 230 receives an additional variable, the reporting module 230 can or expand or refine the matched data with respect to the additional variable. For example, the reporting module 230 may receive a device identifier, a work order number, and the reporting module 230 will return a list of all certifications, tests, or specifications for that device identifier according to the tests performed under the received work order number. On the other hand, a reporting module 230 may receive a device identifier and a part number, and the reporting module 213 will return a list of all certifications, tests, or specifications for either the selected well device 101 or all well devices tested having the selected the part number.

[0078] Embodiments of the present invention employing the reporting module 230 are beneficial in that they transform the task of testing and certification—once a costly operational hurdle—into a robust data-point in business and operational management decisions. For example, manufacturers may use embodiments of the reporting module in research and development to better understand wear patterns and rates in real-world applications, to build a better product, and to manage customer relations. As those skilled in the art will appreciate, the reporting module 230 can be a powerful tool in achieving management-level value from systematic testing and certifications, which provides a comprehensive and reliable (*i.e.*, consistent) pool of data pertaining to asset management, inventory management, purchasing, risk management, and other business analytics. Exemplary reports generated by the reporting module 13 are shown in FIGS. 24-25.

[0079] Furthermore, embodiments of the present invention can employ an ERP (Enterprise Resource Planning) interface (not pictured) connected to the I/O of the central management server 100 to provide the foregoing benefits realized by the reporting module, but in a manner that is more fully integrated into enterprise-wide information systems and providing high levels of cross-functional integration, network scalability, and real-time data synchronization. In particular, embodiments of the present invention employ an ERP interface for the purposes of invoicing the testing and certification operations, for example, responsive to work order information entered by a testing user 151 to the testing interface 150 as shown in FIG. 6.

RFID 130, 135, 140

[0080] Furthermore, embodiments of the present invention can achieve some or all of the foregoing objectives by providing a central management server 200 that can communicate with one or more well equipment devices 101. For example, the central management server 200 can be in communication with the one or more well equipment devices using wireless communication technologies, for example, radio frequency identification (RFID) technologies. The one or more well equipment devices 101 can include an RFID tag 135, and the central management server 200 can communicate with the RFID tag 135 on the one or more well equipment devices using an RFID reader 130 in communication with the central management server 200 through the I/O 252. In an embodiment, the RFID tag is a UHF Gen-2 RFID tag that

is attached to the frac iron using a clamp designed to be sufficiently robust so that the RFID tag is not affected by the harsh operating conditions of the downhole environment.

[0081] In an embodiment, the RFID reader 130 and RFID 140 are peripherals to the testing interface 150, attaching thereto by known connection means in the art, such as a USB cable or cables. In certain embodiments, the RFID reader and RFID writer may be one unit, such as an RFID reader/writer device.

[0082] The RFID reader 130 can read a device identifier from the RFID tag on a selected well equipment device 101 through radio frequency communication and transmit the device identifier to the central management server 200. The central management server is positioned to receive the device identifier from the RFID reader 130. Any of the computer program products discussed herein, such as the testing module 210, can receive a device identifier responsive to the central management server 200 receiving a device identifier from the RFID reader 130. An embodiment of a computer-implemented method for using the RFID reader 130 includes the testing user 151 having a handheld and/or remote RFID reader 130 in physical proximity to the selected well equipment device 101 and the RFID tag 135 thereon so that the testing user can interrogate the RFID tag 135 and so that the RFID tag can transmit the device identifier to the RFID reader 130.

[0083] The RFID writer 140 can write an RFID certificate to the RFID tag on a selected well equipment device 101 through radio frequency communication and transmit the device identifier to the central management server 200. The RFID certificate can have the qualities and properties as described herein, preferably including at least a serial number. The central management server is positioned to transmit the RFID certificate or any data included therein to the RFID writer 140 responsive to any of the computer program products discussed herein, such as the certification module 220. An embodiment of a computer-implemented method for using the RFID writer 140 includes the testing user 151 having a handheld or remote RFID writer 140 in physical proximity to the selected well equipment device 101 and the RFID tag 135 thereon so that the testing user can establish a communication link with the RFID tag 135 and so that the RFID writer can transmit and store the RFID certificate or the information therein to the RFID tag 135.

[0084] This application claims priority and is related to U.S. Provisional Patent Application No. 61/330,248 filed April 30, 2010 titled "Machines, Systems, Computer-Implemented Methods, And Computer Program Products To Test And Certify Oil And Gas Equipment," which is incorporated by reference in its entirety herein.

[0085] The foregoing has broadly outlined certain features, and technical advantages of the present invention and a detailed description of the invention so that embodiments of the invention may be better understood in light of features and advantages of the invention as described herein, which form the subject of certain claims of the invention. It should be appreciated that the conception and specific embodiments disclosed may be readily utilized as a basis for modifying or designing other structures for carrying out the same purposes of the present invention. It should also be realized that such equivalent constructions do not depart from the invention as set forth in the appended claims. The novel features which are believed to be characteristic of the invention, both as to its organization and method of operation, together with further advantages are better understood from the description when considered in connection with the accompanying figures. It is to be expressly understood, however, that such description and figures are provided for the purpose of illustration and description only and are not intended as a definition of the limits of the present invention. For example, although the example embodiments discussed herein are directed to oil and gas hydraulic fracturing operations, it should be specifically noted that the systems, machines, methods, and computer program products to test and certify well equipment devices may be employed to carry out similar functions for other equipment or devices requiring routine testing and certification, including without limitation, aircraft maintenance and construction, ship maintenance and construction, facilities maintenance and construction, and so on.

That Claimed Is:

1. A machine to manage periodic testing and certification of well equipment devices, the testing and certification being facilitated by a plurality of testing apparatus performing one or more testing operations upon the well equipment devices, the machine comprising:

a processor;

a non-transitory memory;

an input/output unit to communicate with the plurality of testing apparatus;

a database positioned to match a device identifier to a well equipment device, a test specification, and a plurality of testing sequences;

a testing module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the testing module being operable by the processor, the testing module comprising a set of instructions that, when executed by the processor, cause the testing module to perform the following operations:

identifying a selected well equipment device, a device test specification, and a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations,

selecting a testing sequence of the plurality of testing sequences, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device,

controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing

operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification,

generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations, and

linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in the database so that a certificate can be generated responsive thereto; and

a certification module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the certification module being operable by the processor, the certification module comprising a set of instructions that, when executed by the processor, cause the certification module to perform the following operations:

identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device,

generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been performed upon the selected well equipment device responsive to the device test specification, and

linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

2. A machine as defined in Claim 1, wherein the input/output unit is further positioned to communicate with a testing interface, the testing module further performing the following operation:

calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification responsive to receiving a selection of a test sequence from the testing interface.

3. A machine as defined in Claim 2, the testing module further performing the following operations:

delivering to the testing interface the device test specification and instructions for performing the sequence of testing operations so that a local user may view the device test specification on a graphical display of the testing interface and so that the local user may perform the sequence of testing operations upon the selected well equipment device responsive to the device test specification;

generating testing data for the selected testing sequence responsive to receiving user data from the testing interface, the user data having been input to the testing interface responsive to the user performing the sequence of testing operations upon the selected well equipment device.

4. A machine as defined in Claim 1, wherein the input/output unit is further positioned to communicate with a remote user interface, the machine further comprising:

a reporting module stored in the memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the reporting module being operable by the processor, the reporting module comprising a set of instructions that, when executed by the processor, cause the reporting module to perform the following operations:

identifying a selected well equipment device, a device test specification, testing data for a plurality of testing sequences, and a certificate, the identifying operation responsive to receiving a device identifier for the selected well equipment device from the remote user interface,

delivering to the remote user interface at least one of the testing data, the device test specification, and the certificate responsive to the identifying operation.

5. A machine as defined in Claim 1, wherein:

the input/output unit is further positioned to communicate with an RFID reader; and

the receiving a device identifier for the selected well equipment device is responsive to interrogating a device RFID tag using the RFID reader, the device RFID tag being attached to the selected well equipment device and having the device identifier encoded thereon.

6. A machine as defined in Claim 5, wherein the input/output unit is further positioned to communicate with an RFID writer, the certification module further performing the following operations:

generating an RFID certificate responsive to the certificate, the RFID certificate being formatted so that the RFID certificate is recognizable by a remote interrogation device having an RFID reader; and

delivering an RFID certificate to the device RFID tag using the RFID writer so that the RFID certificate can be readily accessed by the remote interrogation device.

7. A system to certify oil and gas well equipment, the system comprising:

a plurality of devices to be used in well equipment to define a plurality of well equipment devices, each well equipment device of the plurality of well equipment devices having a device identifier associated therewith;

a central management server positioned to identify a device test specification and a plurality of testing sequences for a selected well equipment device responsive to receiving a device identifier for the selected well equipment device, the device test specification and the plurality of testing sequences defining certification criteria for the well equipment device;

a plurality of testing apparatus, each testing apparatus positioned to perform a testing sequence upon the well equipment device, the testing sequence being a sequence of testing operations, the sequence of testing operations being performed responsive to the device test specification;

a plurality of controllers, each controller positioned to receive commands responsive to the certification criteria from the central management server and to control the plurality of testing apparatus performing the sequence of testing operations upon the selected well equipment device responsive to the device test specification; and

a certificate generated responsive to the plurality of testing apparatus performing the plurality of testing sequences upon the well equipment device, the certificate indicating whether selected well equipment device has been tested according to the certification criteria within a pre-selected period of time.

8. A system as defined in Claim 7, the system further comprising:

a plurality of device RFID tags, each device RFID tag of the plurality of device RFID tags being attached to a well equipment device of the plurality of well equipment devices and having a device identifier for the well equipment device encoded thereon; and

an RFID reader in communication with the central management server and the plurality of device RFID tags, wherein the central management server is positioned to receive the device identifier for a well equipment device having a device RFID tag attached thereto responsive to the RFID reader interrogating the device RFID tag.

9. A system as defined in Claim 8, the system further comprising an RFID writer in communication with the central management server and the plurality of device RFID tags, wherein the central management server is positioned to generate an RFID certificate responsive to the certificate and deliver the RFID certificate to a device RFID tag using the RFID writer.

10. A system as defined in Claim 7, the system further comprising database positioned to match a device identifier to a well equipment device, a device test specification, and a plurality of testing sequences, wherein the central management server identifies a device test specification and a plurality of testing sequences for a selected well equipment device responsive to matching the device identifier in the database.

11. A system as defined in Claim 7, the system further comprising a testing interface in communication with the central management server, wherein:

each testing apparatus of the plurality of testing apparatus is positioned to perform a testing sequence responsive to receiving a selection of the testing sequence from the testing interface; and

the certificate is also generated responsive to user data received from the testing interface, the user data having been input to the testing interface responsive to the user performing the sequence of testing operations upon the selected well equipment device responsive to the device test specification.

12. A computer-implemented method to manage periodic testing of a plurality of well equipment devices, the testing being facilitated by a plurality of testing apparatus performing one or more testing operations upon the plurality of well equipment devices, the computer-implemented method comprising the following operations:

receiving a device identifier for a selected well equipment device of the plurality of well equipment devices;

identifying the selected well equipment device, a device test specification, and plurality of testing sequences, the identifying operation being responsive to the receiving operation, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations;

selecting a testing sequence of the plurality of testing sequences to define a selected testing sequence, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device;

calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification;

controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the

selected well equipment device, the sequence of testing operations being performed responsive to the device test specification;

generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations; and

linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in a database so that a certificate can be generated responsive thereto.

13. A computer-implemented method as defined in Claim 12 wherein the selecting operation is responsive to receiving a selection of the test sequence from a testing interface.

14. A computer-implemented method as defined in Claim 12, further performing the following operation:

calibrating the corresponding testing apparatus for the selected testing sequence responsive to the device test specification responsive to receiving a selection of a test sequence from the testing interface.

15. The computer-implemented method as defined in Claim 13, the computer-implemented method further comprising the following operations:

delivering to the testing interface the device test specification and instructions for performing the sequence of testing operations so that a local user may view the device test specification on a graphical display of the testing interface and so that the local user may perform the sequence of testing operations upon the selected well equipment device responsive to the device test specification;

generating testing data for the selected testing sequence responsive to receiving user data from the testing interface, the user data having been input to the testing interface responsive to the user performing the sequence of testing operations upon the selected well equipment device.

16. A computer-implemented method as defined in Claim 12 wherein receiving a device identifier for the selected well equipment device is responsive to interrogating a device RFID tag using a RFID reader, the device RFID tag being attached to the selected well equipment device and having the device identifier encoded thereon.

17. A computer-implemented method to manage periodic certification of a plurality of well equipment devices, the certification based upon testing data generated responsive to a plurality of testing apparatus performing one or more testing operations upon the plurality of well equipment devices, the computer-implemented method comprising the following operations:

identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device;

generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been performed upon the selected well equipment device responsive to the device test specification; and

linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in a database so that the certificate can be readily recalled from the database responsive to the device identifier.

18. A computer-implemented method as defined in Claim 16, the computer-implemented method further comprising the following operations:

delivering an RFID certificate to a device RFID tag using an RFID writer so that the RFID certificate can be readily accessed by the remote interrogation device, the device RFID tag being attached to the selected well equipment device and having the device identifier encoded thereon.

19. A computer program product stored in a memory, the memory being a tangible, non-transitory, computer-readable storage medium, and the computer program product being

operable by a processor, the computer program product comprising a set of instructions that, when executed by the processor, cause the testing module to perform the following operations:

identifying a selected well equipment device, a device test specification, and a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device, each testing sequence of the plurality of testing sequences to be performed by a corresponding testing apparatus of the plurality of testing apparatus, each testing sequence defining a sequence of testing operations;

selecting a testing sequence of the plurality of testing sequences, the selecting operation responsive to the selected well equipment device being positioned so that the corresponding testing apparatus for the selected testing sequence can perform testing operations upon the selected well equipment device;

controlling the corresponding testing apparatus for the selected testing sequence so that the corresponding testing apparatus performs the sequence of testing operations upon the selected well equipment device, the sequence of testing operations being performed responsive to the device test specification;

generating testing data for the selected testing sequence responsive to receiving output from the corresponding testing apparatus for selected testing sequence performing the sequence of testing operations;

linking the testing data for the selected testing sequence to the device identifier for the selected well equipment device in the database so that a certificate can be generated responsive thereto;

identifying a selected well equipment device, a device test specification, and testing data for a plurality of testing sequences, the identifying operation responsive to receiving a device identifier for the selected well equipment device;

generating a certificate for the selected well equipment device responsive to the testing data for the plurality of testing sequences, the plurality of testing sequences having been

performed upon the selected well equipment device responsive to the device test specification; and

linking the certificate for the selected well equipment device to the device identifier for the selected well equipment device in the database so that the certificate can be readily recalled from the database responsive to the device identifier.

FIG. 1

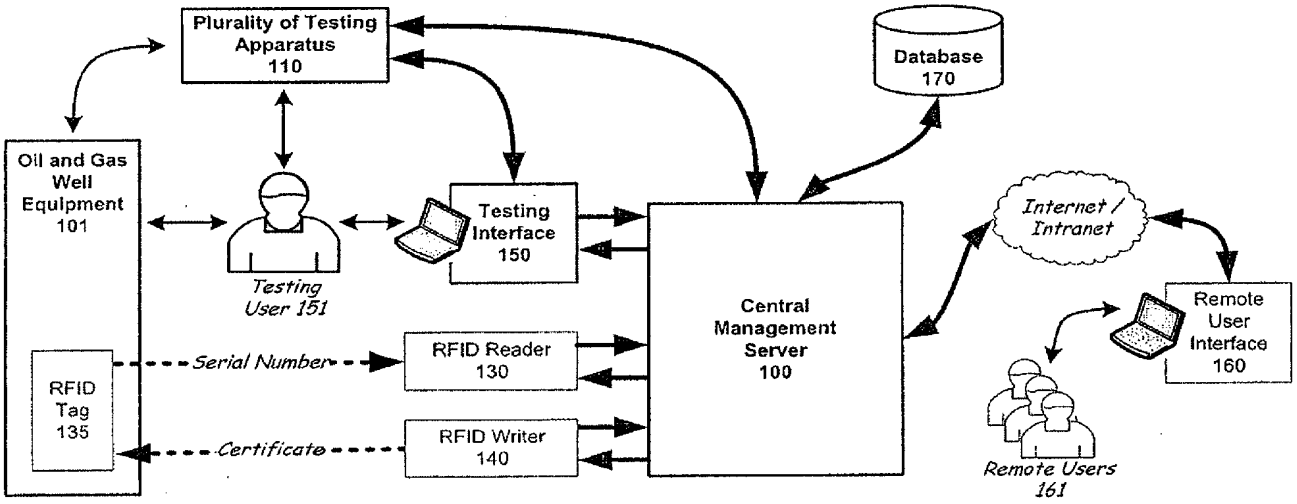

Plurality of Testing Apparatus 110
Database 170
Oil and Gas Well Equipment 101
Testing Interface 150
Testing User 151
Central Management Server 100
Internet / Intranet
Remote User Interface 160
RFID Tag 135
Serial Number
RFID Reader 130
RFID Writer 140
Certificate
Remote Users 161

FIG. 2

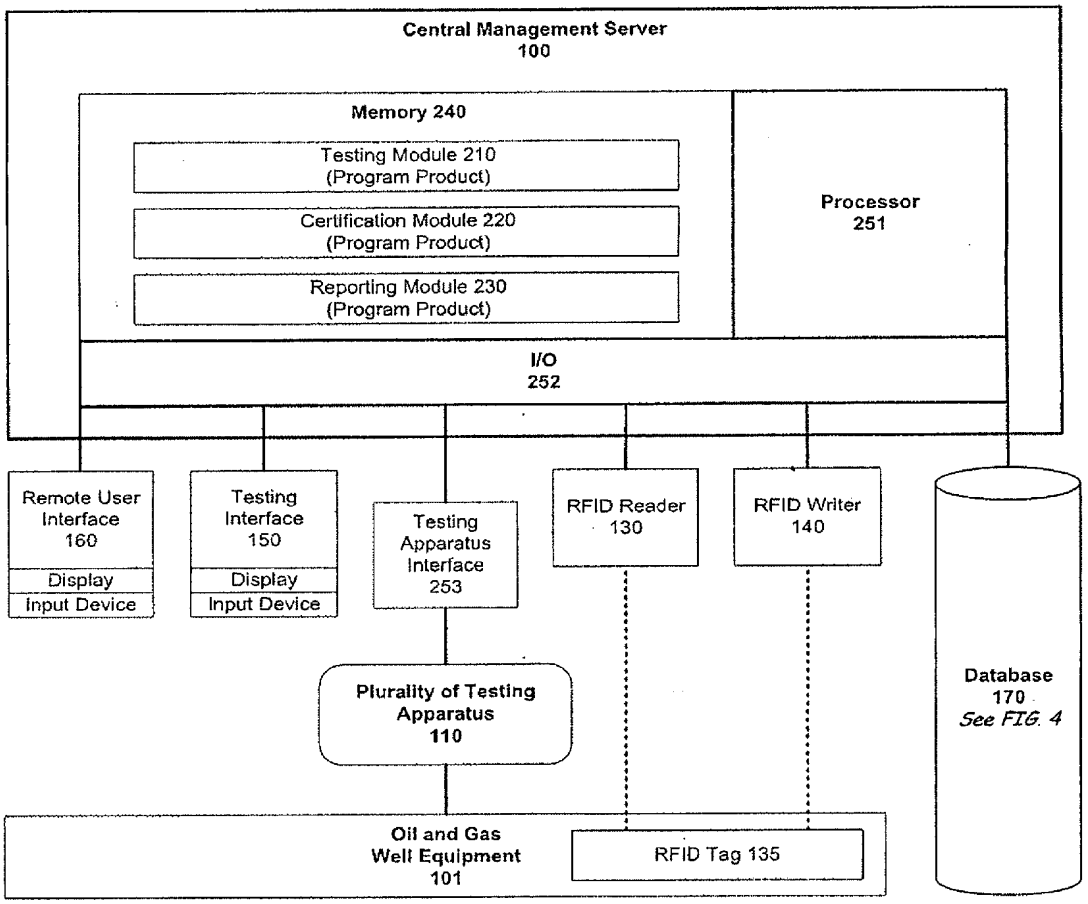

Central Management Server 100
Memory 240
Testing Module 210 (Program Product)
Certification Module 220 (Program Product)
Reporting Module 230 (Program Product)
Processor 251
I/O 252
Remote User Interface 160
Display
Input Device
Testing Interface 150
Display
Input Device
Testing Apparatus Interface 253
RFID Reader 130
RFID Writer 140
Database 170 See FIG. 4
Plurality of Testing Apparatus 110
Oil and Gas Well Equipment 101
RFID Tag 135

FIG. 3

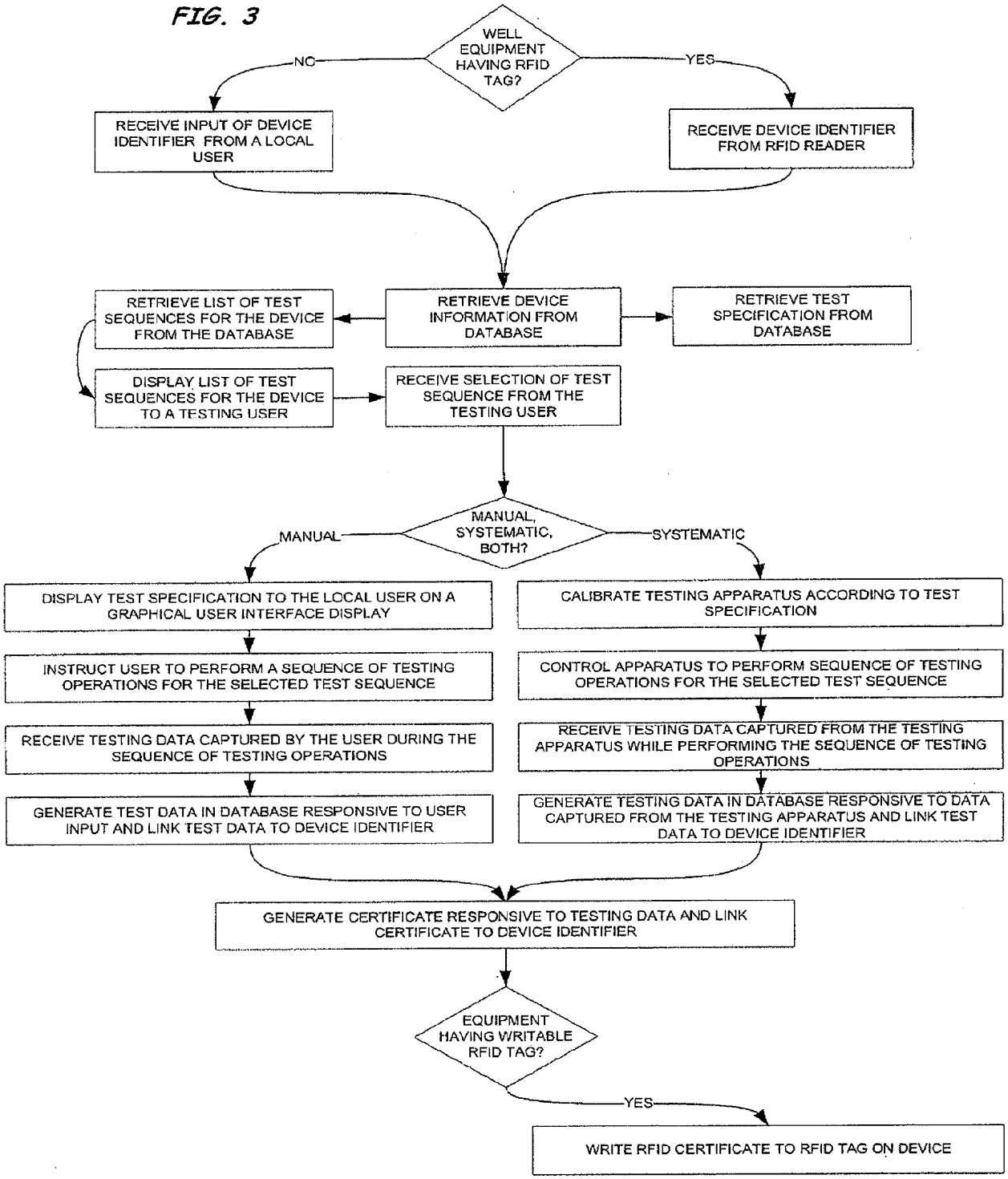
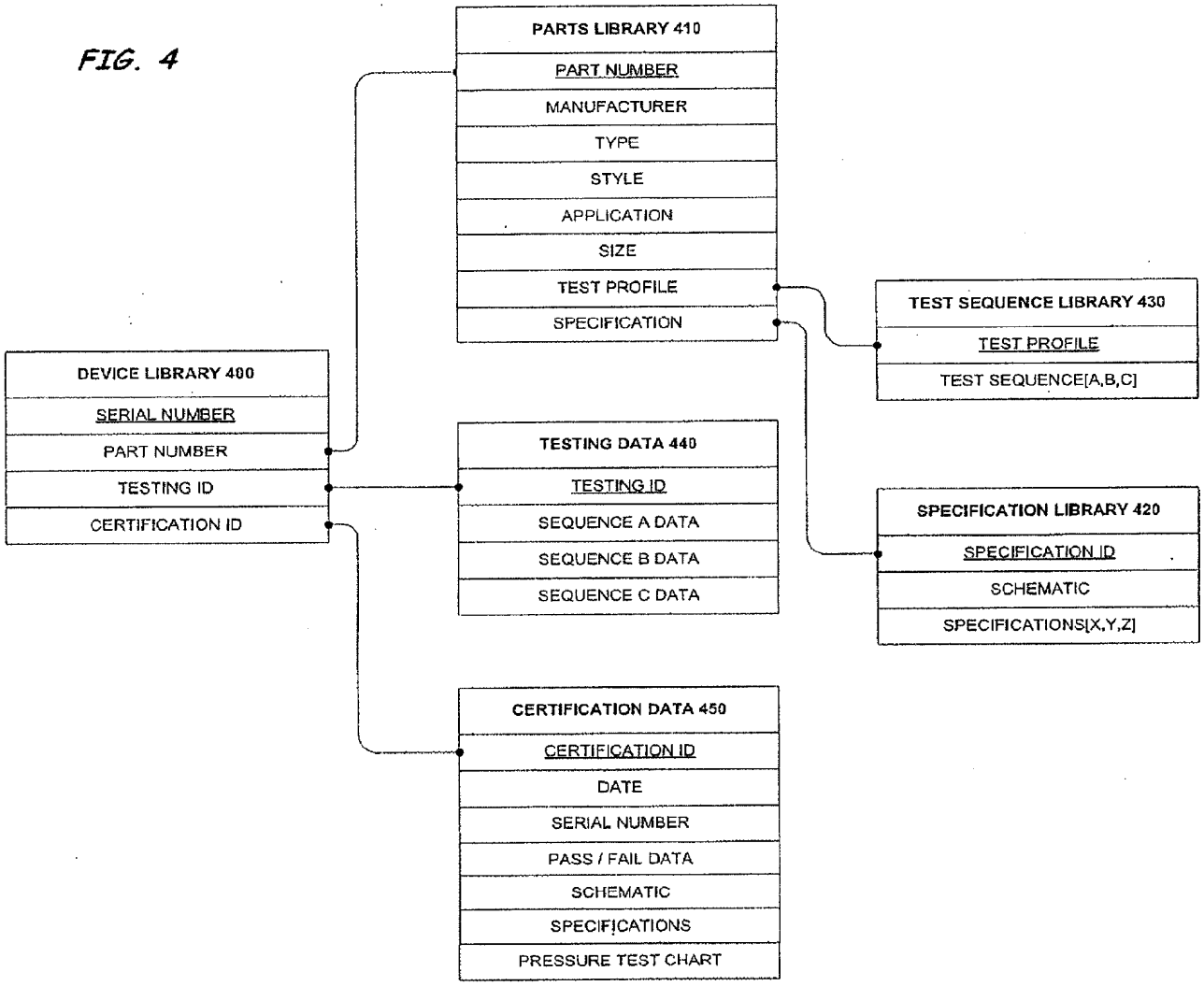

WELL EQUIPMENT HAVING RFID TAG?
NO
YES
RECEIVE INPUT OF DEVICE IDENTIFIER FROM A LOCAL USER
RECEIVE DEVICE IDENTIFIER FROM RFID READER
RETRIEVE LIST OF TEST SEQUENCES FOR THE DEVICE FROM THE DATABASE
RETRIEVE DEVICE INFORMATION FROM DATABASE
RETRIEVE TEST SPECIFICATION FROM DATABASE
DISPLAY LIST OF TEST SEQUENCES FOR THE DEVICE TO A TESTING USER
RECEIVE SELECTION OF TEST SEQUENCE FROM THE TESTING USER
MANUAL, SYSTEMATIC, BOTH?
MANUAL
SYSTEMATIC
DISPLAY TEST SPECIFICATION TO THE LOCAL USER ON A GRAPHICAL USER INTERFACE DISPLAY
INSTRUCT USER TO PERFORM A SEQUENCE OF TESTING OPERATIONS FOR THE SELECTED TEST SEQUENCE
RECEIVE TESTING DATA CAPTURED BY THE USER DURING THE SEQUENCE OF TESTING OPERATIONS
GENERATE TEST DATA IN DATABASE RESPONSIVE TO USER INPUT AND LINK TEST DATA TO DEVICE IDENTIFIER
CALIBRATE TESTING APPARATUS ACCORDING TO TEST SPECIFICATION
CONTROL APPARATUS TO PERFORM SEQUENCE OF TESTING OPERATIONS FOR THE SELECTED TEST SEQUENCE
RECEIVE TESTING DATA CAPTURED FROM THE TESTING APPARATUS WHILE PERFORMING THE SEQUENCE OF TESTING OPERATIONS
GENERATE TESTING DATA IN DATABASE RESPONSIVE TO DATA CAPTURED FROM THE TESTING APPARATUS AND LINK TEST DATA TO DEVICE IDENTIFIER
GENERATE CERTIFICATE RESPONSIVE TO TESTING DATA AND LINK CERTIFICATE TO DEVICE IDENTIFIER
EQUIPMENT HAVING WRITABLE RFID TAG?
YES
WRITE RFID CERTIFICATE TO RFID TAG ON DEVICE

FIG. 4


PARTS LIBRARY 410
PART NUMBER
MANUFACTURER
TYPE
STYLE
APPLICATION
SIZE
TEST PROFILE
SPECIFICATION
TEST SEQUENCE LIBRARY 430
TEST PROFILE
TEST SEQUENCE[A,B,C]
DEVICE LIBRARY 400
SERIAL NUMBER
PART NUMBER
TESTING ID
CERTIFICATION ID
TESTING DATA 440
TESTING ID
SEQUENCE A DATA
SEQUENCE B DATA
SEQUENCE C DATA
SPECIFICATION LIBRARY 420
SPECIFICATION ID
SCHEMATIC
SPECIFICATIONS[X,Y,Z]
CERTIFICATION DATA 450
CERTIFICATION ID
DATE
SERIAL NUMBER
PASS / FAIL DATA
SCHEMATIC
SPECIFICATIONS
PRESSURE TEST CHART

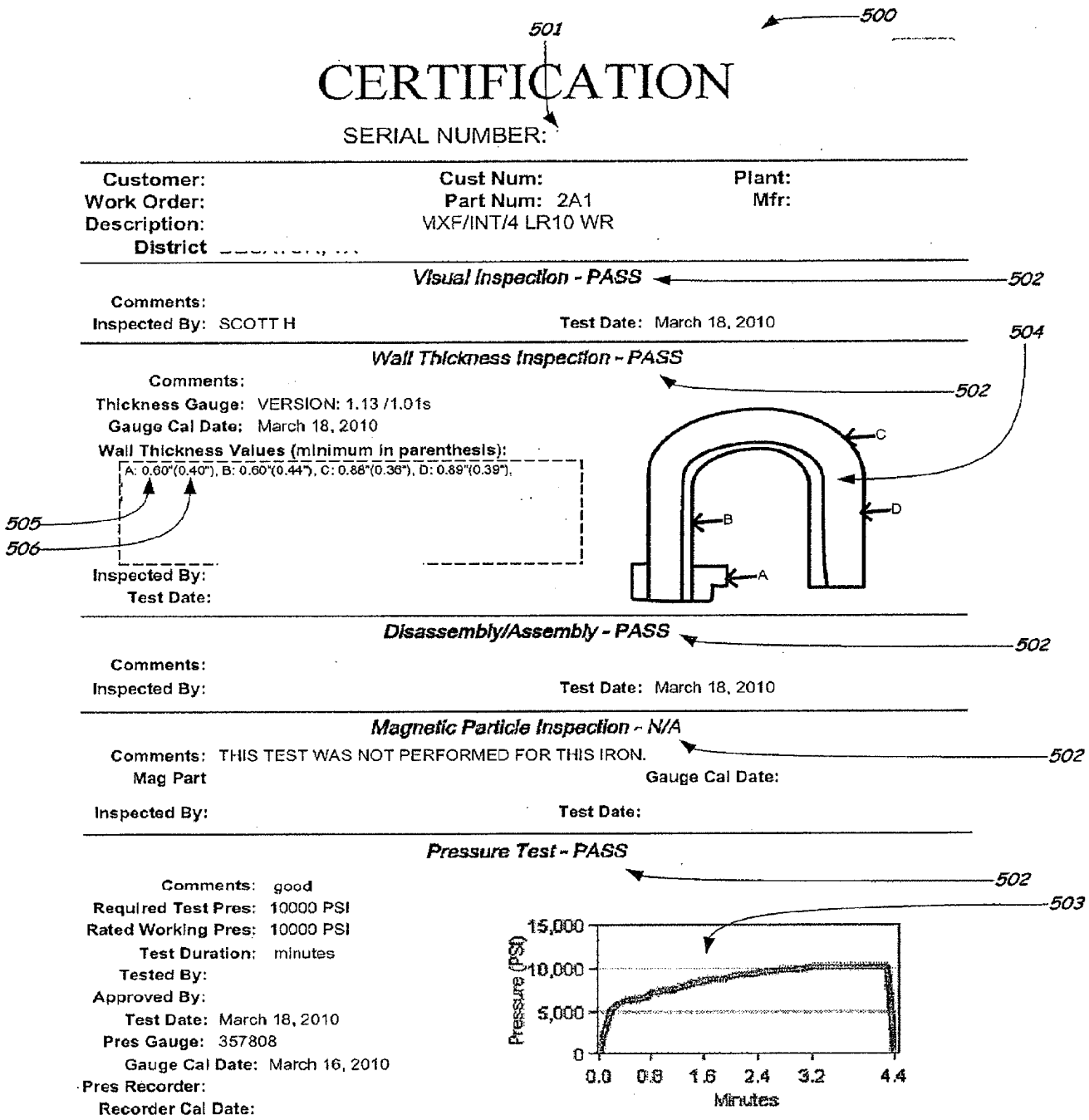

500
501
CERTIFICATION
SERIAL NUMBER:
Customer:
Cust Num:
Plant:
Work Order:
Part Num: 2A1
Mfr:
Description:
MXF/INT/4 LR10 WR
District
Visual Inspection - PASS
502
Comments:
Inspected By: SCOTT H
Test Date: March 18, 2010
504
Wall Thickness Inspection - PASS
Comments:
502
Thickness Gauge: VERSION: 1.13 /1.01s
Gauge Cal Date: March 18, 2010
Wall Thickness Values (minimum in parenthesis):
A: 0.60"(0.40"), B: 0.60"(0.44"), C: 0.88"(0.36"), D: 0.89"(0.39").
505
506
C
D
B
A
Inspected By:
Test Date:
Disassembly/Assembly - PASS
502
Comments:
Inspected By:
Test Date: March 18, 2010
Magnetic Particle Inspection - N/A
Comments: THIS TEST WAS NOT PERFORMED FOR THIS IRON.
502
Mag Part
Gauge Cal Date:
Inspected By:
Test Date:
Pressure Test - PASS
502
503
Comments: good
Required Test Pres: 10000 PSI
Rated Working Pres: 10000 PSI
Test Duration: minutes
Tested By:
Approved By:
Test Date: March 18, 2010
Pres Gauge: 357808
Gauge Cal Date: March 16, 2010
Pres Recorder:
Recorder Cal Date:
15,000
10,000
5,000
0
Pressure (PSI)
0.0
0.8
1.6
2.4
3.2
4.4
Minutes

FIG. 5

FIG. 6

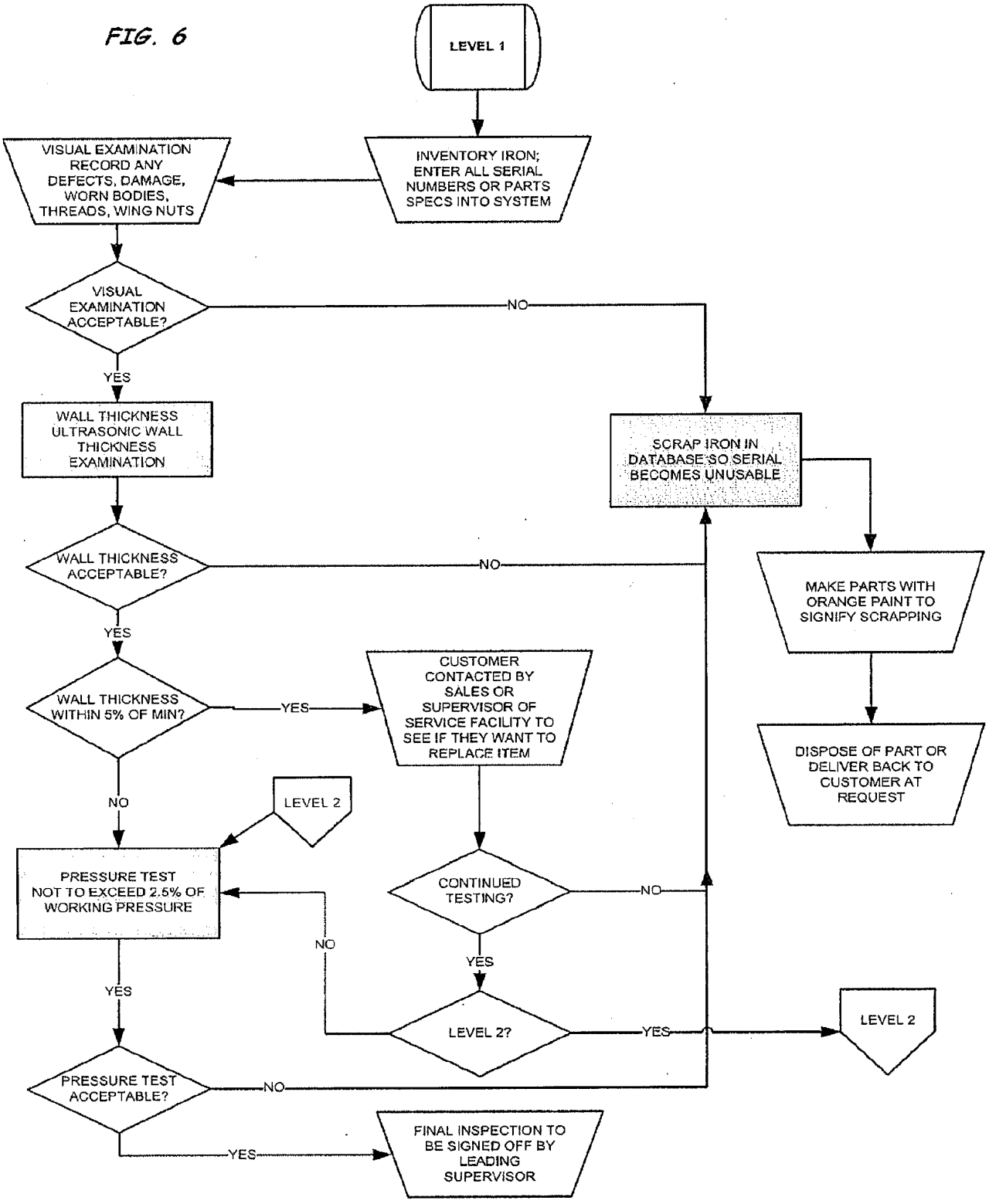
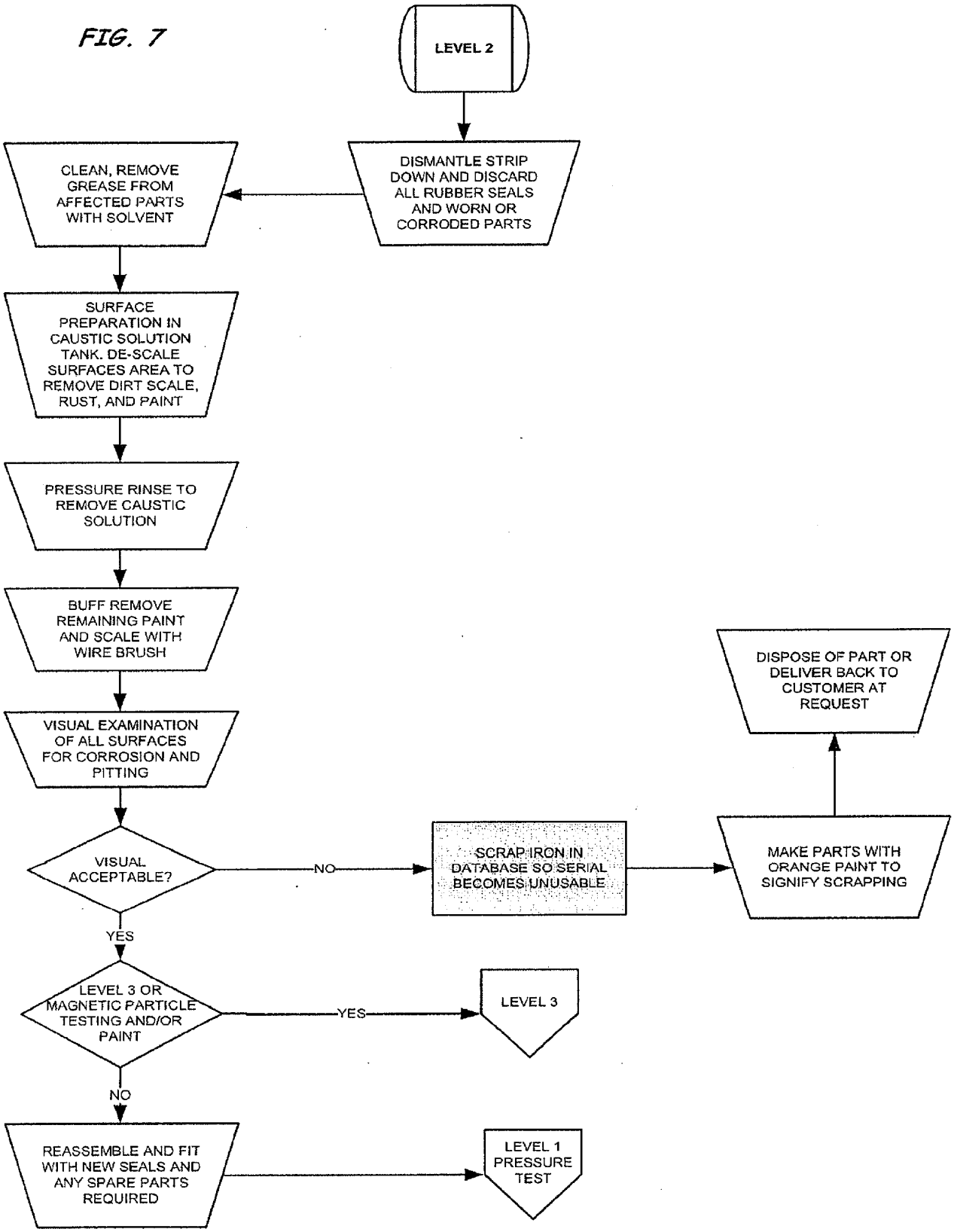

LEVEL 1
INVENTORY IRON; ENTER ALL SERIAL NUMBERS OR PARTS SPECS INTO SYSTEM
VISUAL EXAMINATION RECORD ANY DEFECTS, DAMAGE, WORN BODIES, THREADS, WING NUTS
VISUAL EXAMINATION ACCEPTABLE?
NO
YES
WALL THICKNESS ULTRASONIC WALL THICKNESS EXAMINATION
SCRAP IRON IN DATABASE SO SERIAL BECOMES UNUSABLE
WALL THICKNESS ACCEPTABLE?
NO
MAKE PARTS WITH ORANGE PAINT TO SIGNIFY SCRAPPING
YES
WALL THICKNESS WITHIN 5% OF MIN?
YES
CUSTOMER CONTACTED BY SALES OR SUPERVISOR OF SERVICE FACILITY TO SEE IF THEY WANT TO REPLACE ITEM
DISPOSE OF PART OR DELIVER BACK TO CUSTOMER AT REQUEST
NO
LEVEL 2
PRESSURE TEST NOT TO EXCEED 2.5% OF WORKING PRESSURE
CONTINUED TESTING?
NO
NO
YES
YES
LEVEL 2?
YES
LEVEL 2
PRESSURE TEST ACCEPTABLE?
NO
YES
FINAL INSPECTION TO BE SIGNED OFF BY LEADING SUPERVISOR

FIG. 7


LEVEL 2
DISMANTLE STRIP DOWN AND DISCARD ALL RUBBER SEALS AND WORN OR CORRODED PARTS
CLEAN, REMOVE GREASE FROM AFFECTED PARTS WITH SOLVENT
SURFACE PREPARATION IN CAUSTIC SOLUTION TANK. DE-SCALE SURFACES AREA TO REMOVE DIRT SCALE, RUST, AND PAINT
PRESSURE RINSE TO REMOVE CAUSTIC SOLUTION
BUFF REMOVE REMAINING PAINT AND SCALE WITH WIRE BRUSH
VISUAL EXAMINATION OF ALL SURFACES FOR CORROSION AND PITTING
VISUAL ACCEPTABLE?
NO
SCRAP IRON IN DATABASE SO SERIAL BECOMES UNUSABLE
MAKE PARTS WITH ORANGE PAINT TO SIGNIFY SCRAPPING
DISPOSE OF PART OR DELIVER BACK TO CUSTOMER AT REQUEST
YES
LEVEL 3 OR MAGNETIC PARTICLE TESTING AND/OR PAINT
YES
LEVEL 3
NO
REASSEMBLE AND FIT WITH NEW SEALS AND ANY SPARE PARTS REQUIRED
LEVEL 1 PRESSURE TEST

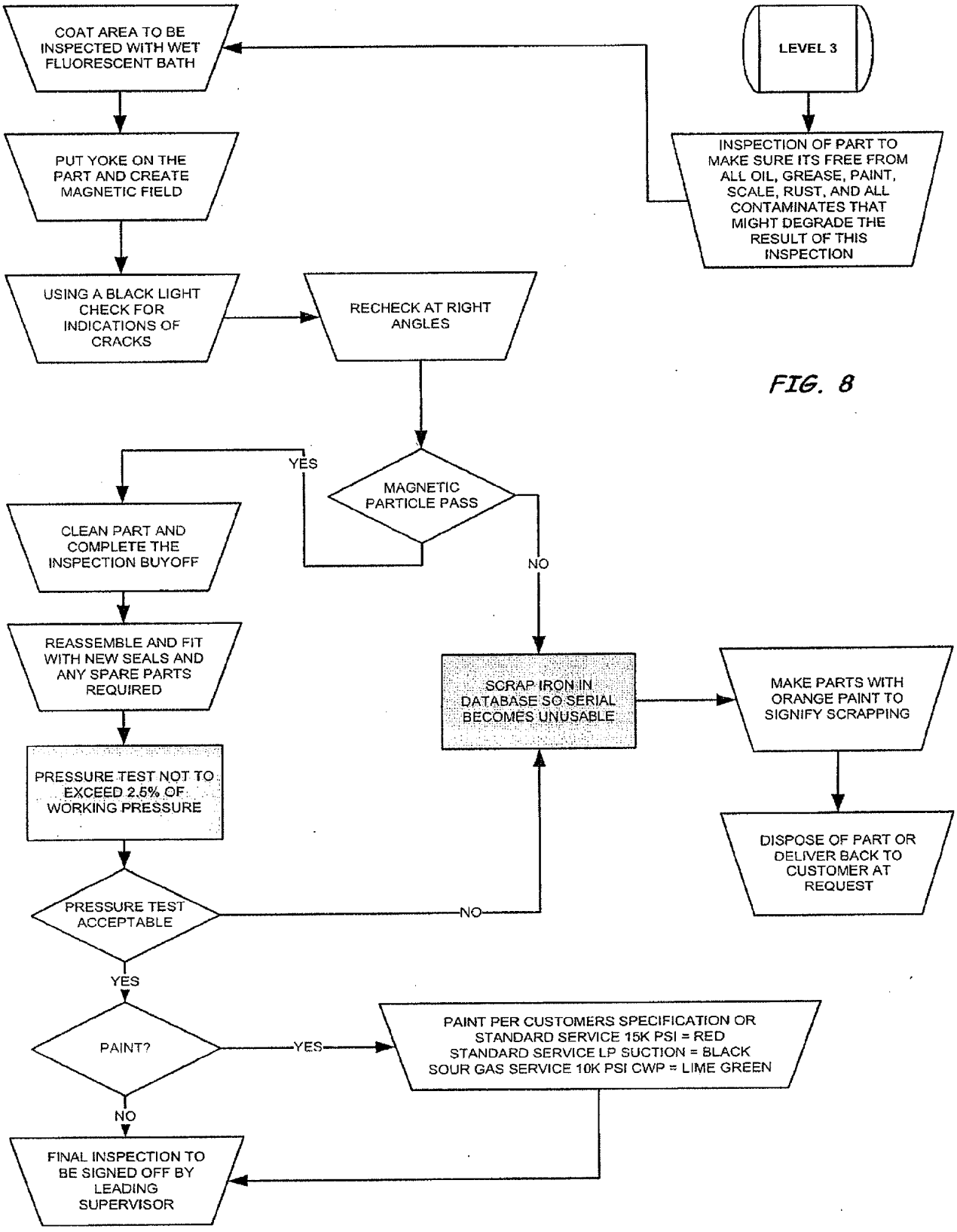

COAT AREA TO BE INSPECTED WITH WET FLUORESCENT BATH
PUT YOKE ON THE PART AND CREATE MAGNETIC FIELD
USING A BLACK LIGHT CHECK FOR INDICATIONS OF CRACKS
RECHECK AT RIGHT ANGLES
MAGNETIC PARTICLE PASS
YES
NO
CLEAN PART AND COMPLETE THE INSPECTION BUYOFF
REASSEMBLE AND FIT WITH NEW SEALS AND ANY SPARE PARTS REQUIRED
PRESSURE TEST NOT TO EXCEED 2.5% OF WORKING PRESSURE
PRESSURE TEST ACCEPTABLE
NO
YES
PAINT?
YES
NO
PAINT PER CUSTOMERS SPECIFICATION OR
STANDARD SERVICE 15K PSI = RED
STANDARD SERVICE LP SUCTION = BLACK
SOUR GAS SERVICE 10K PSI CWP = LIME GREEN
FINAL INSPECTION TO BE SIGNED OFF BY LEADING SUPERVISOR
SCRAP IRON IN DATABASE SO SERIAL BECOMES UNUSABLE
MAKE PARTS WITH ORANGE PAINT TO SIGNIFY SCRAPPING
DISPOSE OF PART OR DELIVER BACK TO CUSTOMER AT REQUEST
LEVEL 3
INSPECTION OF PART TO MAKE SURE ITS FREE FROM ALL OIL, GREASE, PAINT, SCALE, RUST, AND ALL CONTAMINATES THAT MIGHT DEGRADE THE RESULT OF THIS INSPECTION

FIG. 8

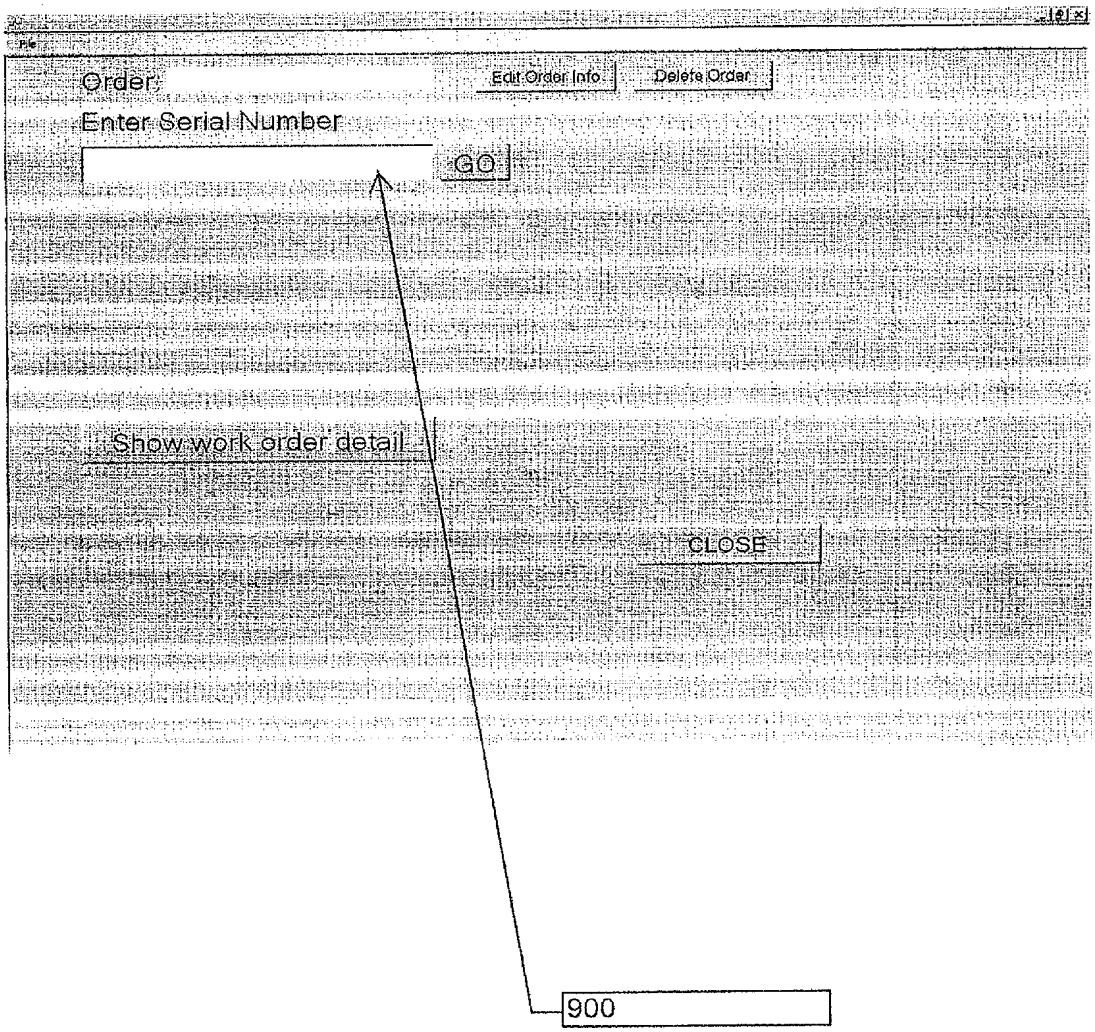

Order:
Edit Order Info
Delete Order
Enter Serial Number
GO
Show work order detail
CLOSE
900

FIG. 9

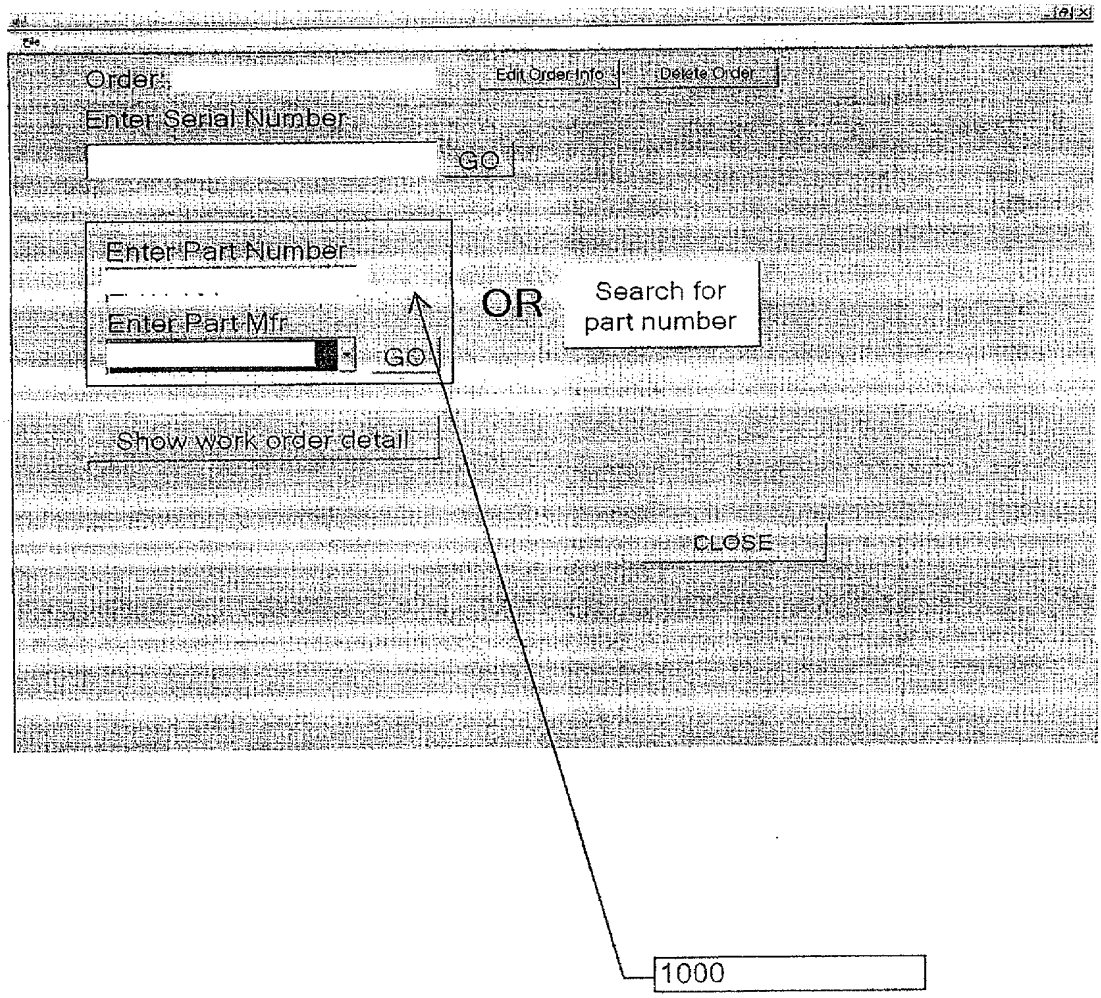

Order:
Edit Order Info
Delete Order
Enter Serial Number
GO
Enter Part Number
Enter Part Mfr
GO
OR
Search for part number
Show work order detail
CLOSE
1000

FIG. 10

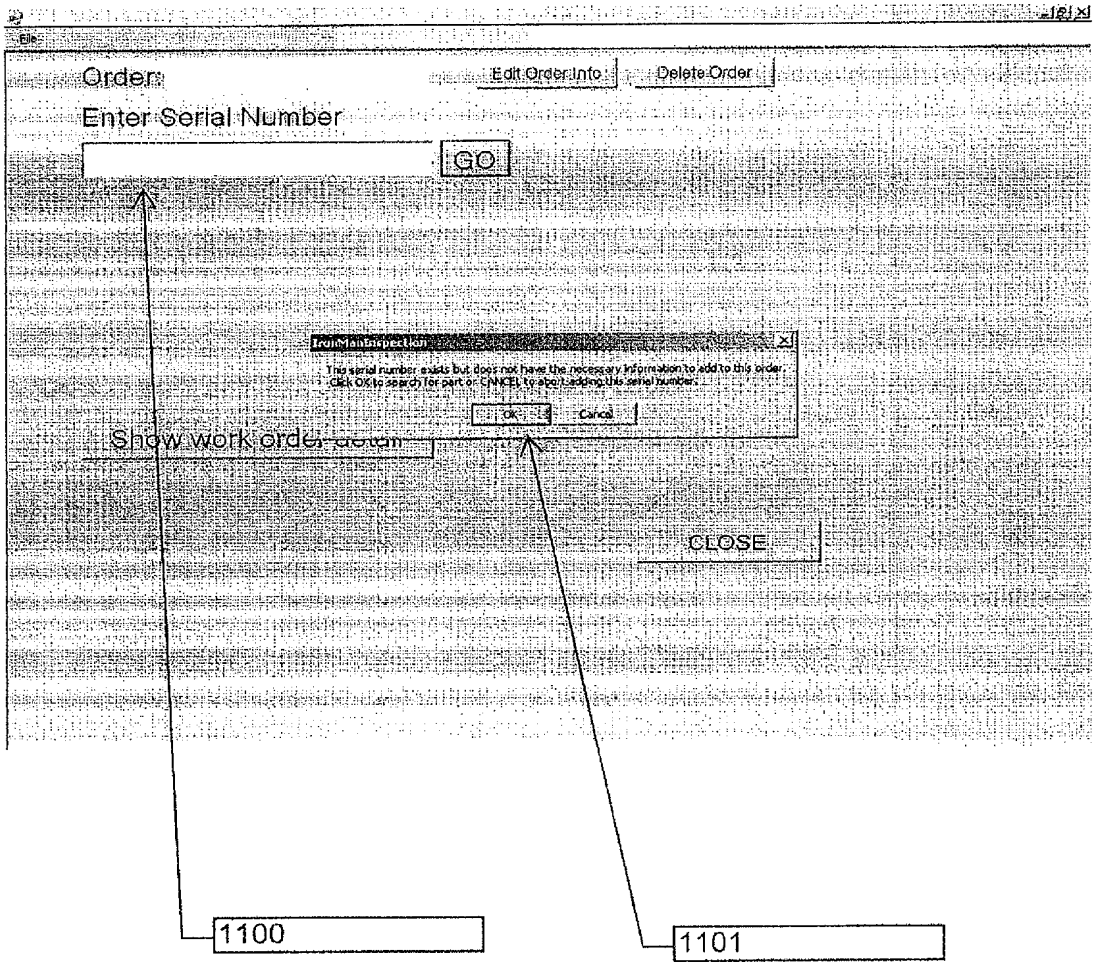

Order:
Edit Order Info
Delete Order
Enter Serial Number
GO
Show work orders
CLOSE
1100
1101

FIG. 11

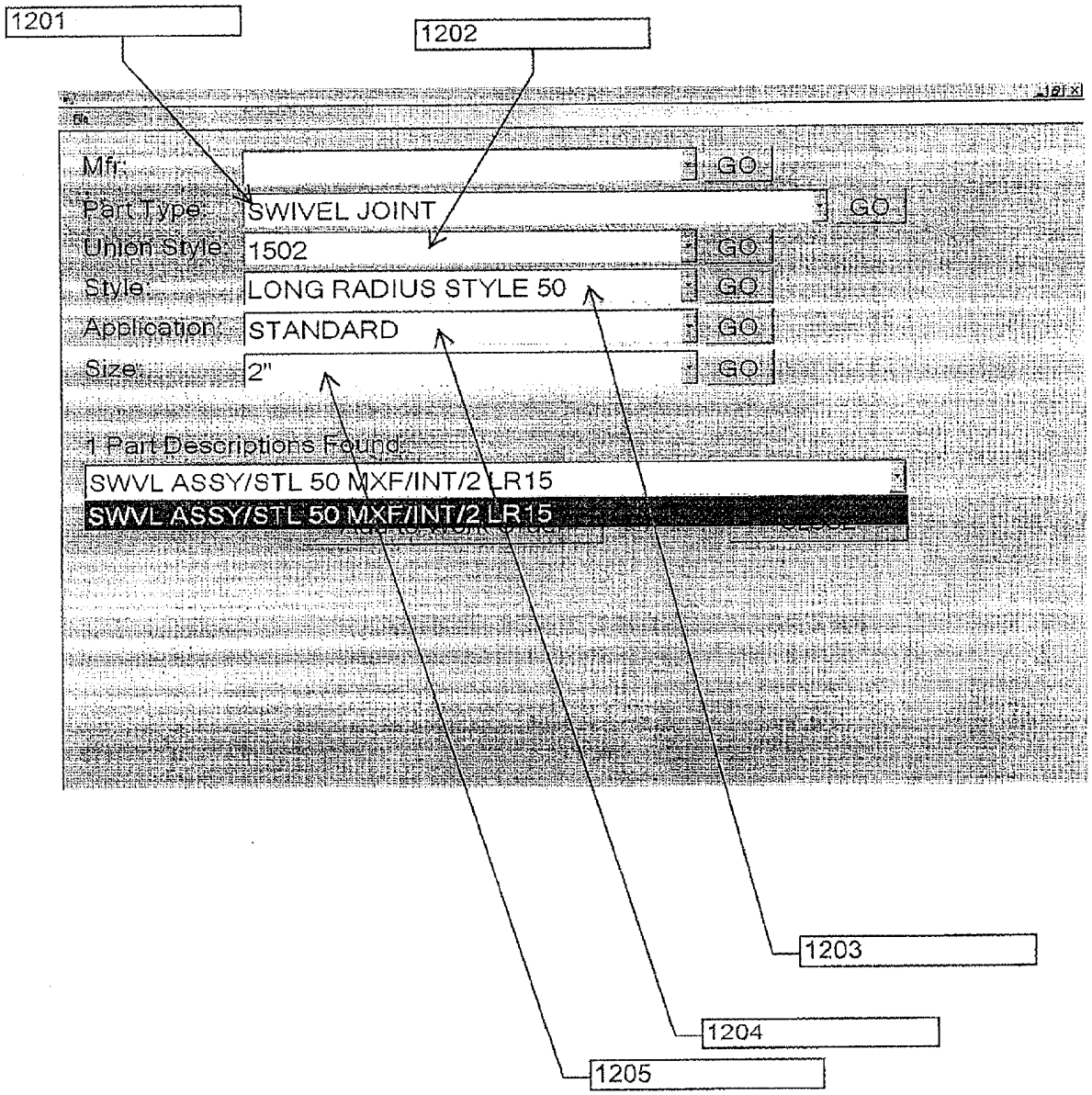

1201
1202
Mfr:
GO
Part Type:
SWIVEL JOINT
GO
Union Style:
1502
GO
Style:
LONG RADIUS STYLE 50
GO
Application:
STANDARD
GO
Size:
2"
GO
1 Part Descriptions Found:
SWVL ASSY/STL 50 MXF/INT/2 LR15
SWVL ASSY/STL 50 MXF/INT/2 LR15
1203
1204
1205

FIG. 12