US008783357B2

(12) **United States Patent**
Coppedge et al.

(10) **Patent No.: US 8,783,357 B2**
(45) **Date of Patent: Jul. 22, 2014**

(54) **SUBSEA WELL SAFING SYSTEM**

(75) Inventors: **Charles Don Coppedge**, Houston, TX (US); **Dana Karl Kelley**, Friendswood, TX (US); **Charles C. Porter**, Houston, TX (US); **Hildebrand Argie Rumann**, League City, TX (US)

(73) Assignee: **Bastion Technologies, Inc.**, Houston, TX (US)

(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 108 days.

(21) Appl. No.: **13/220,593**

(22) Filed: **Aug. 29, 2011**

(65) **Prior Publication Data**

US 2012/0048566 A1 Mar. 1, 2012

Related U.S. Application Data

(60) Provisional application No. 61/377,851, filed on Aug. 27, 2010.

(51) **Int. Cl.**
E21B 29/12 (2006.01)

(52) **U.S. Cl.**
USPC **166/340**; 166/361; 166/365

(58) **Field of Classification Search**
CPC E21B 33/038; E21B 29/12
USPC 166/338, 340, 352, 359, 361, 363, 364, 166/365, 297, 298, 377, 55, 85.1
See application file for complete search history.

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Primary Examiner — Matthew Buck
Assistant Examiner — Stacy Warren
(74) *Attorney, Agent, or Firm* — Winstead PC

(57) **ABSTRACT**

A subsea well safing method and apparatus adapted to secure a subsea well in the event of a perceived blowout in a manner to mitigate the environmental damage and the physical damage to the subsea wellhead equipment to promote the ability to reconnect and recover control of the well. The safing assembly is adapted to connect the marine riser to the BOP stack. Pursuant to a safing sequence, the well tubular is secured in the upper and lower safing assemblies and the tubular is then sheared between the locations at which it has been secured. Subsequently, an ejection device is actuated to physically separate the upper safing assembly and connected marine riser from the lower safing assembly that is connected to the BOP stack.

20 Claims, 20 Drawing Sheets

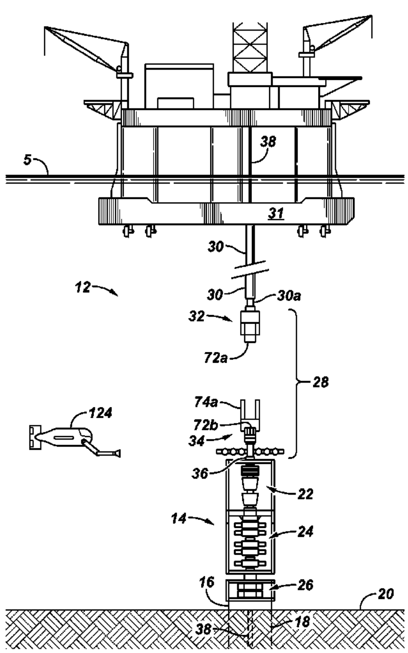


FIG. 1

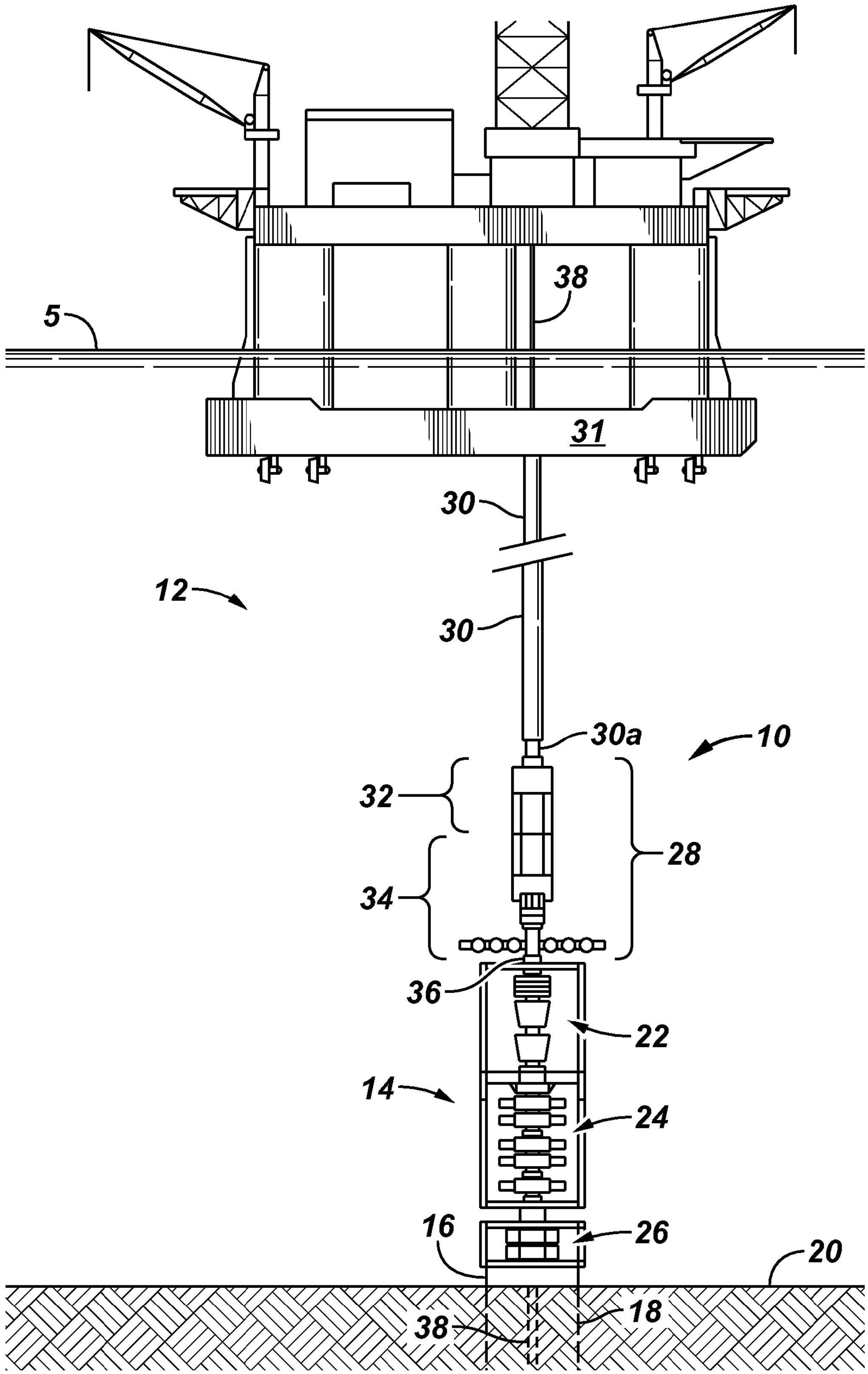


FIG. 2

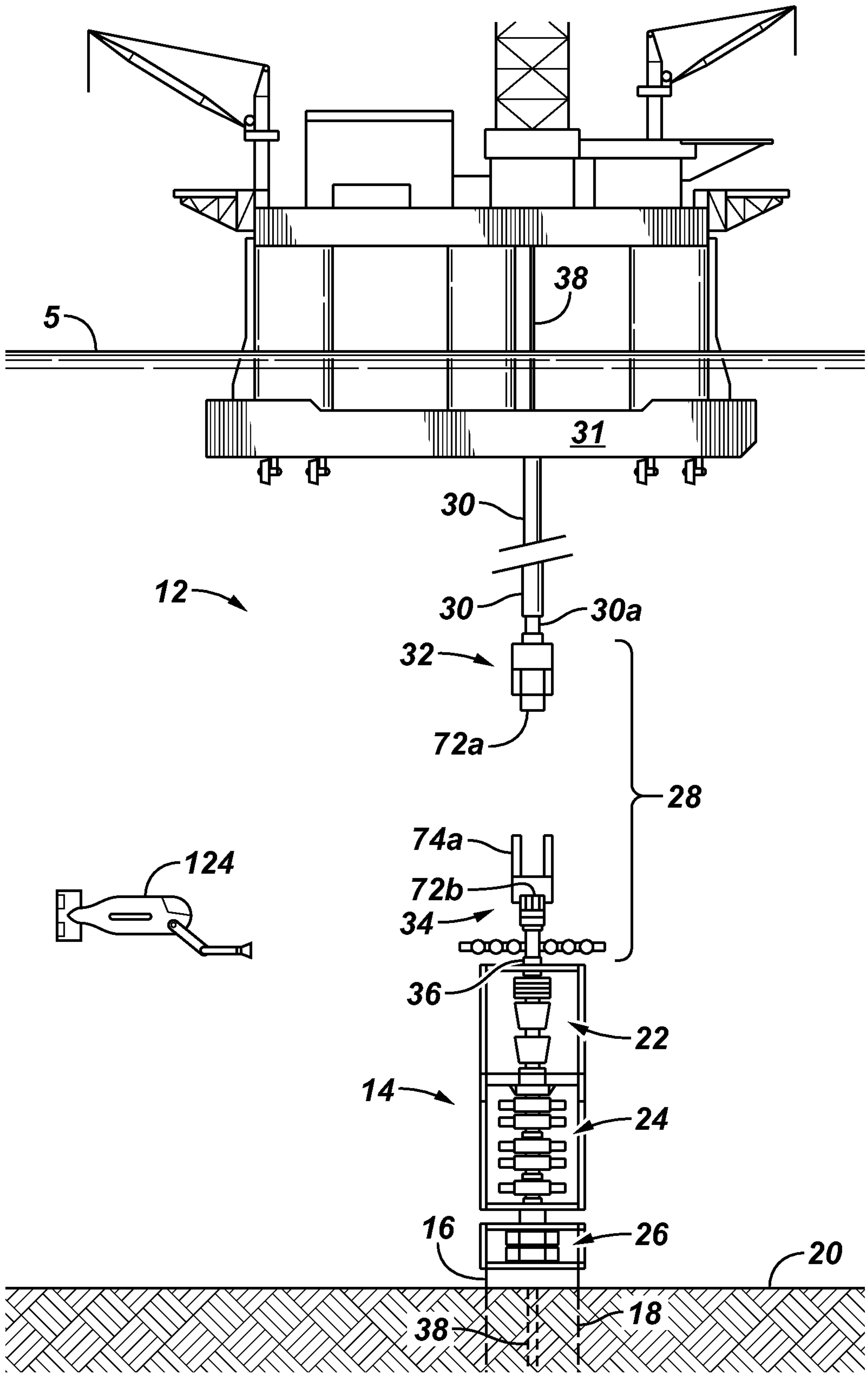

38
5
31
30
12
30
30a
32
72a
28
74a
124
72b
34
36
22
14
24
16
26
20
38
18

FIG. 3

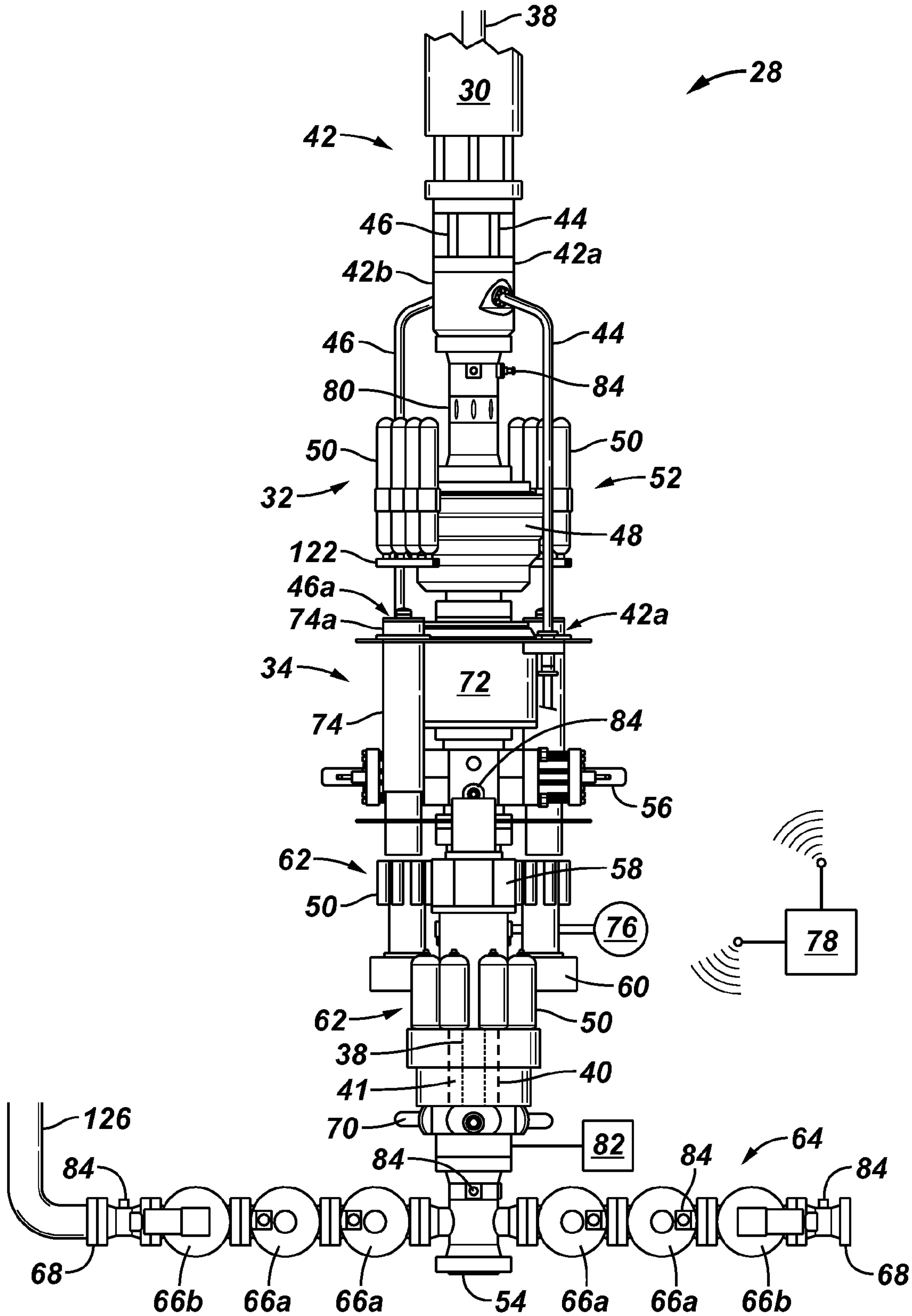

38
28
30
42
46
44
42a
42b
46
44
84
80
50
50
32
52
48
122
46a
74a
42a
34
72
74
84
56
62
58
50
76
78
60
62
50
38
40
41
70
126
82
84
84
84
64
84
68
66b
66a
66a
54
66a
66a
66b
68

FIG. 4A

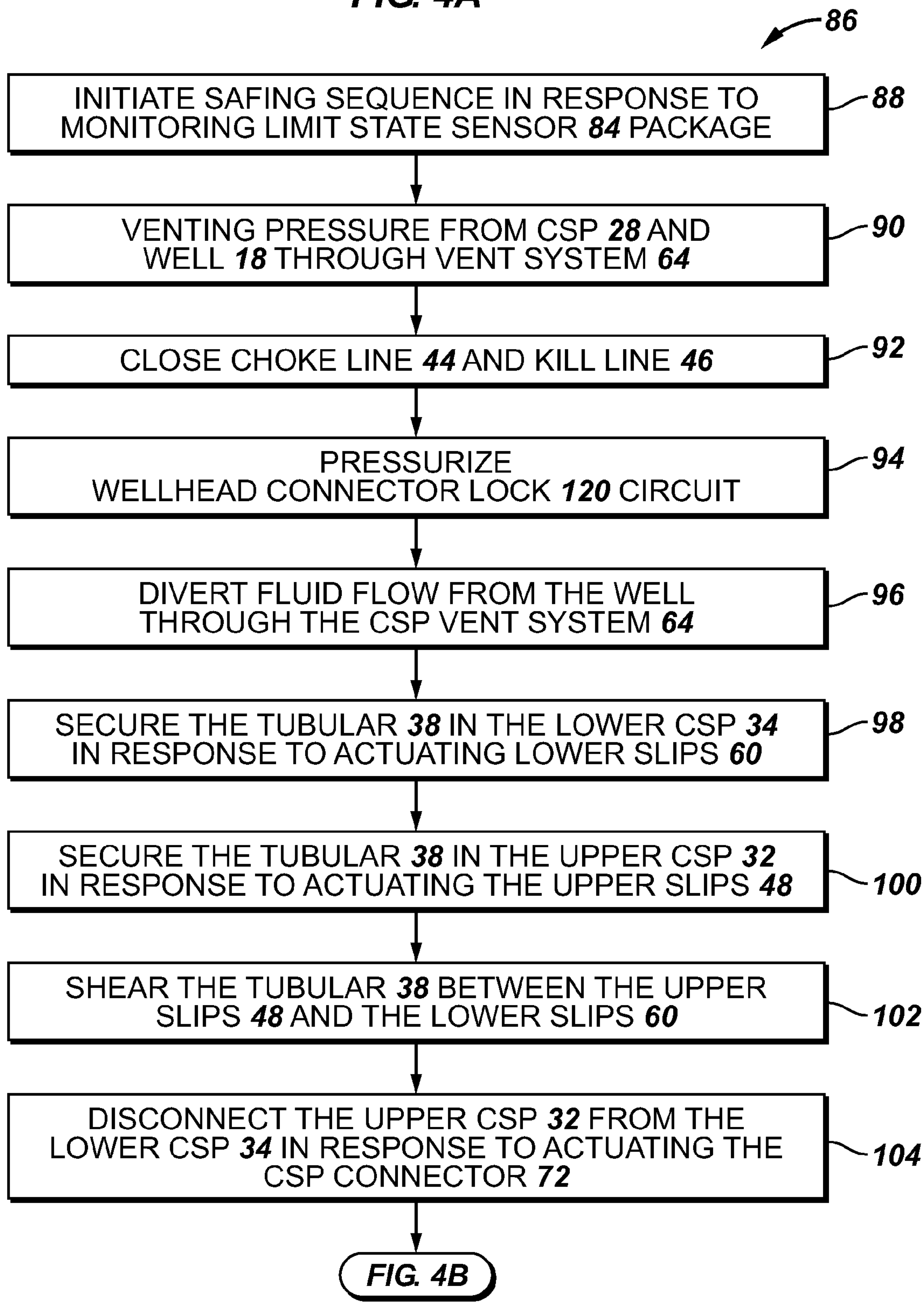

86
INITIATE SAFING SEQUENCE IN RESPONSE TO MONITORING LIMIT STATE SENSOR 84 PACKAGE
88
VENTING PRESSURE FROM CSP 28 AND WELL 18 THROUGH VENT SYSTEM 64
90
CLOSE CHOKE LINE 44 AND KILL LINE 46
92
PRESSURIZE WELLHEAD CONNECTOR LOCK 120 CIRCUIT
94
DIVERT FLUID FLOW FROM THE WELL THROUGH THE CSP VENT SYSTEM 64
96
SECURE THE TUBULAR 38 IN THE LOWER CSP 34 IN RESPONSE TO ACTUATING LOWER SLIPS 60
98
SECURE THE TUBULAR 38 IN THE UPPER CSP 32 IN RESPONSE TO ACTUATING THE UPPER SLIPS 48
100
SHEAR THE TUBULAR 38 BETWEEN THE UPPER SLIPS 48 AND THE LOWER SLIPS 60
102
DISCONNECT THE UPPER CSP 32 FROM THE LOWER CSP 34 IN RESPONSE TO ACTUATING THE CSP CONNECTOR 72
104
FIG. 4B

FIG. 4B

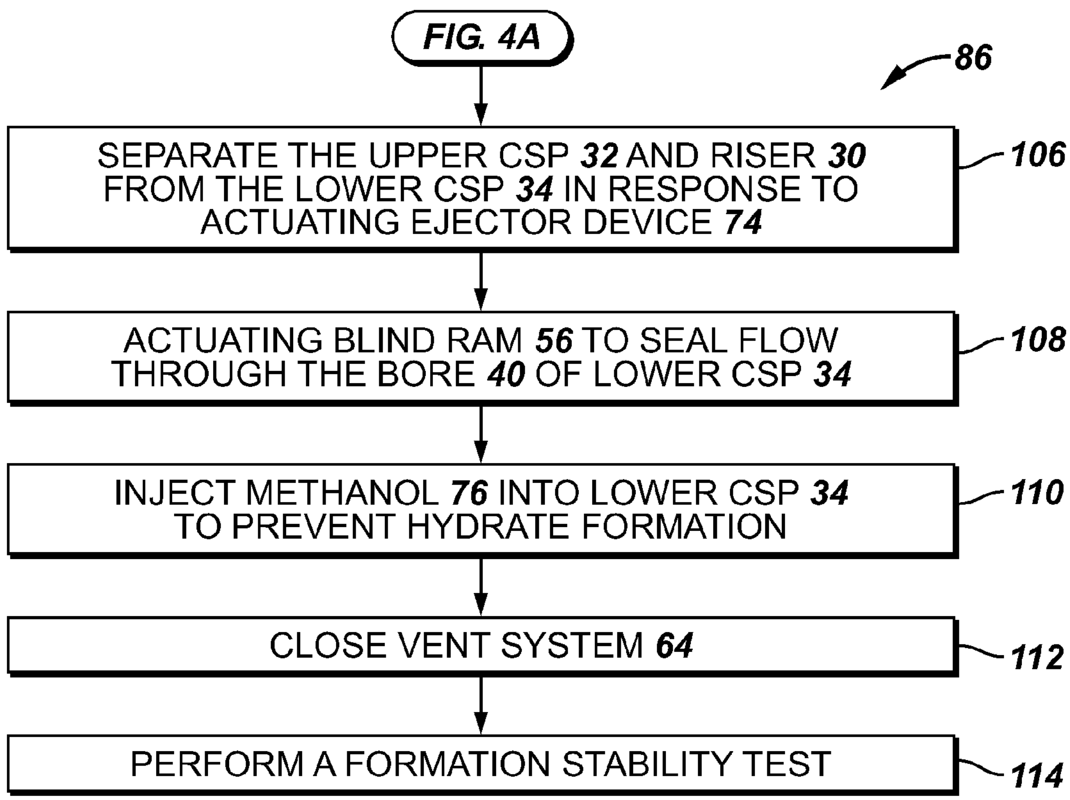


FIG. 4A
86
SEPARATE THE UPPER CSP 32 AND RISER 30 FROM THE LOWER CSP 34 IN RESPONSE TO ACTUATING EJECTOR DEVICE 74
106
ACTUATING BLIND RAM 56 TO SEAL FLOW THROUGH THE BORE 40 OF LOWER CSP 34
108
INJECT METHANOL 76 INTO LOWER CSP 34 TO PREVENT HYDRATE FORMATION
110
CLOSE VENT SYSTEM 64
112
PERFORM A FORMATION STABILITY TEST
114

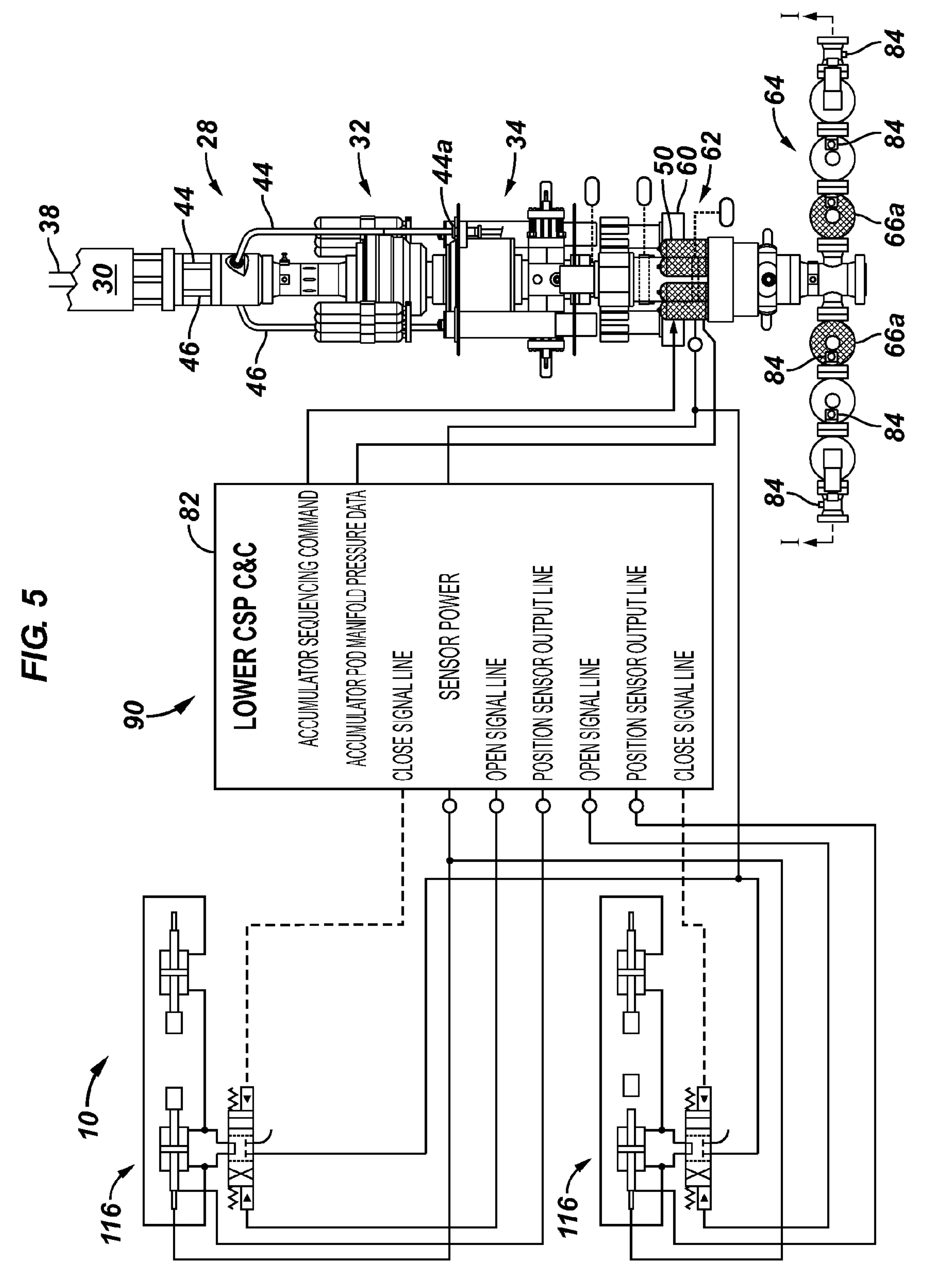

38
30
44
46
28
32
44a
34
50
60
62
64
84
66a
I
82
90
10
116
LOWER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
CLOSE SIGNAL LINE
SENSOR POWER
OPEN SIGNAL LINE
POSITION SENSOR OUTPUT LINE
OPEN SIGNAL LINE
POSITION SENSOR OUTPUT LINE
CLOSE SIGNAL LINE

FIG. 5

FIG. 5A

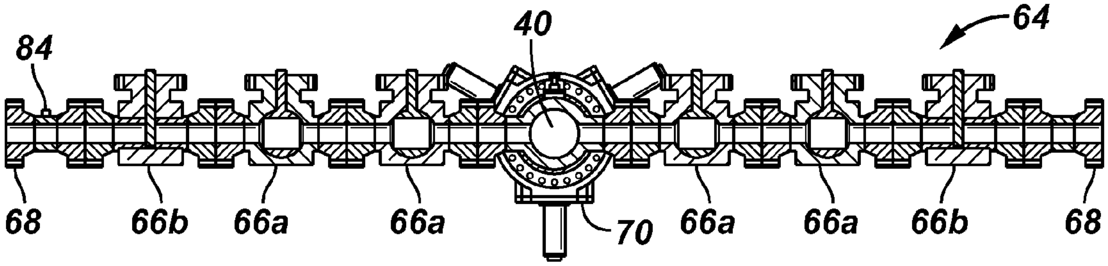


FIG. 8A

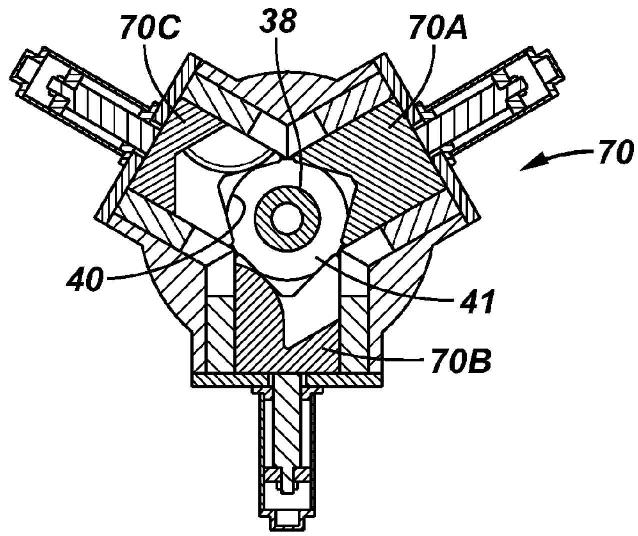


FIG. 8B

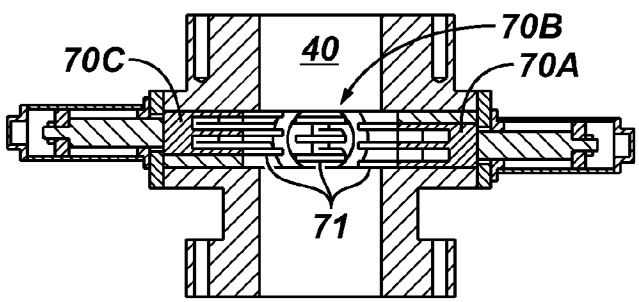
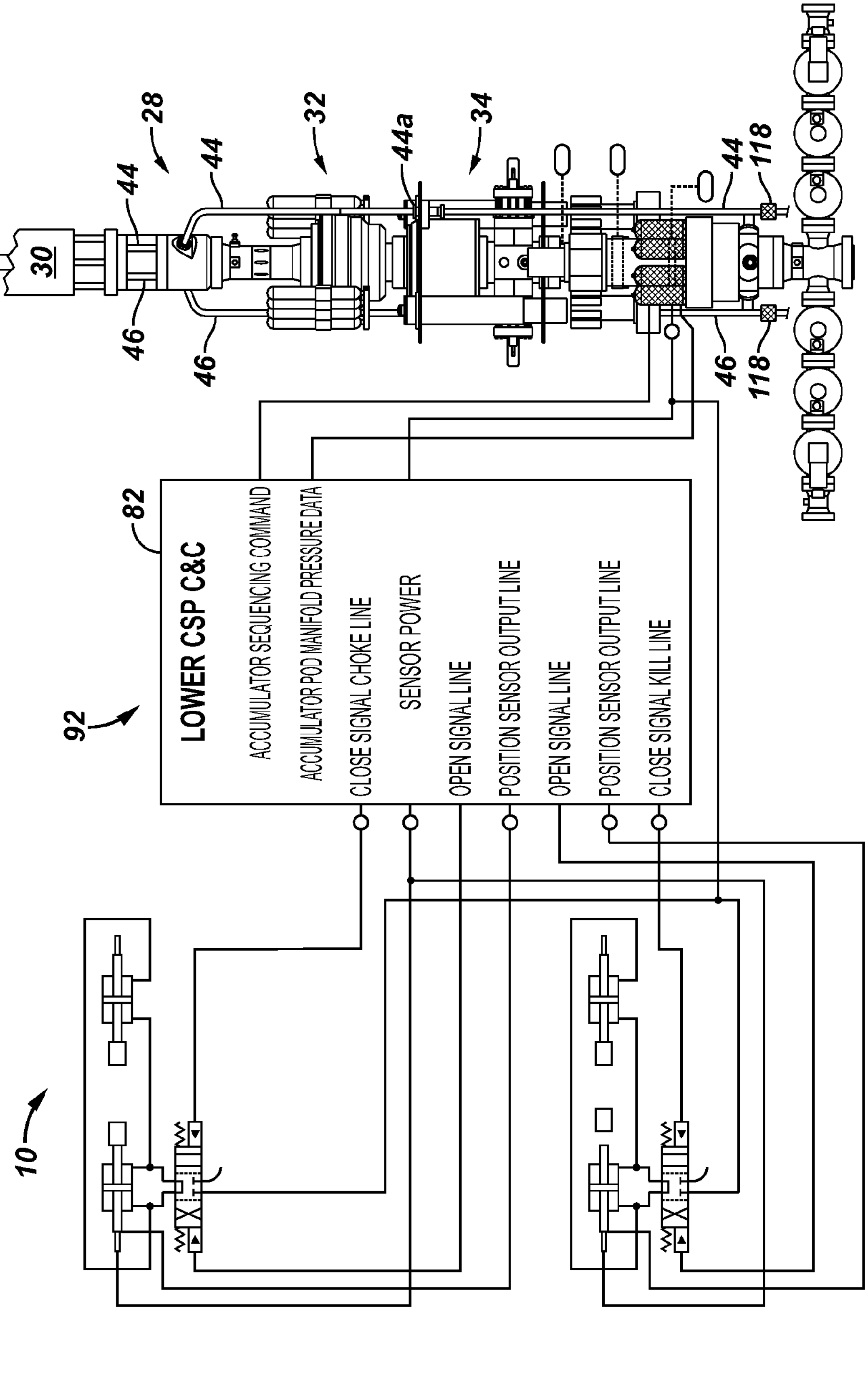


FIG. 6



LOWER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
CLOSE SIGNAL CHOKE LINE
SENSOR POWER
OPEN SIGNAL LINE
POSITION SENSOR OUTPUT LINE
OPEN SIGNAL LINE
POSITION SENSOR OUTPUT LINE
CLOSE SIGNAL KILL LINE
10
92
82
30
38
28
32
34
44
44a
46
118

FIG. 7

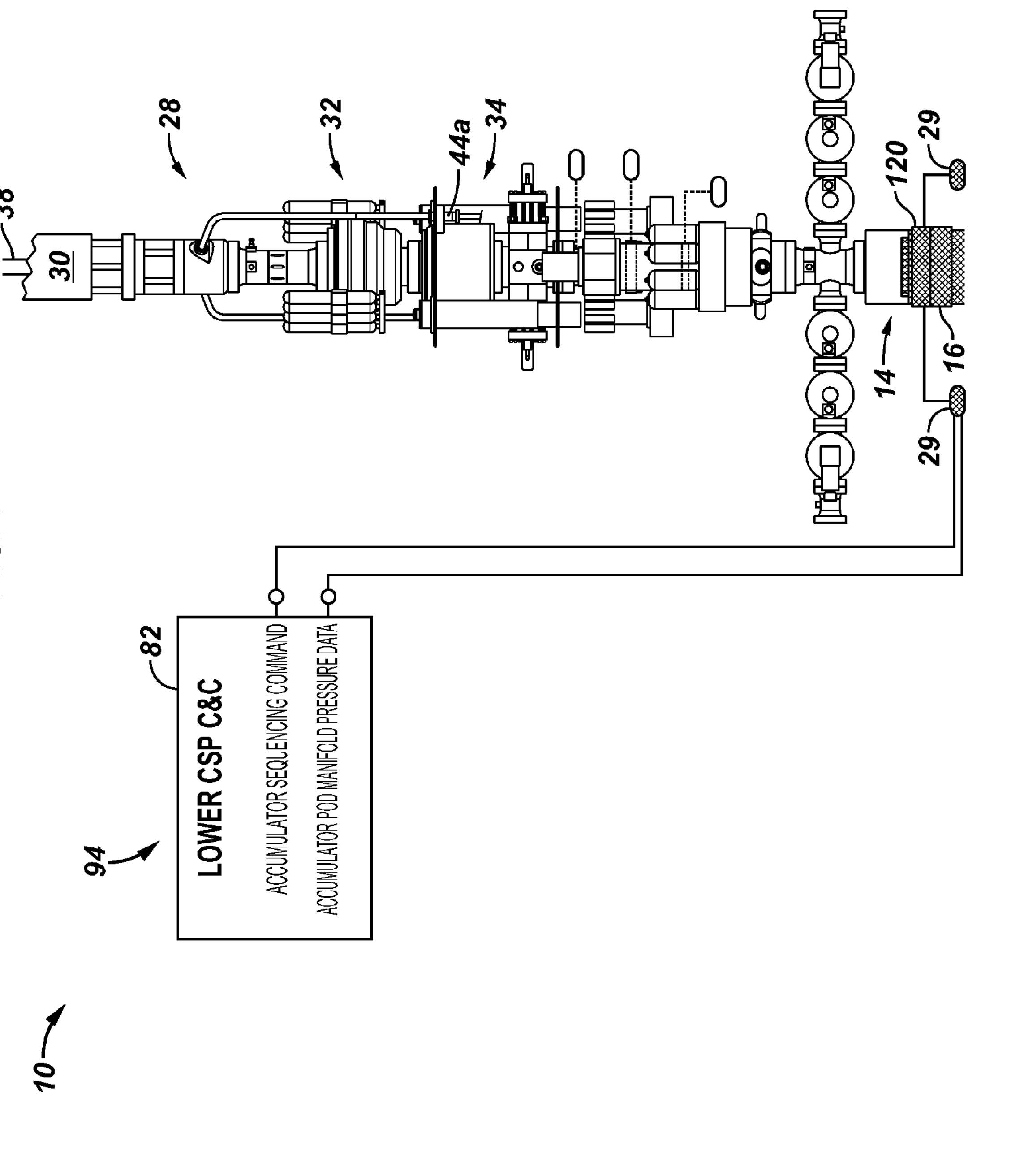
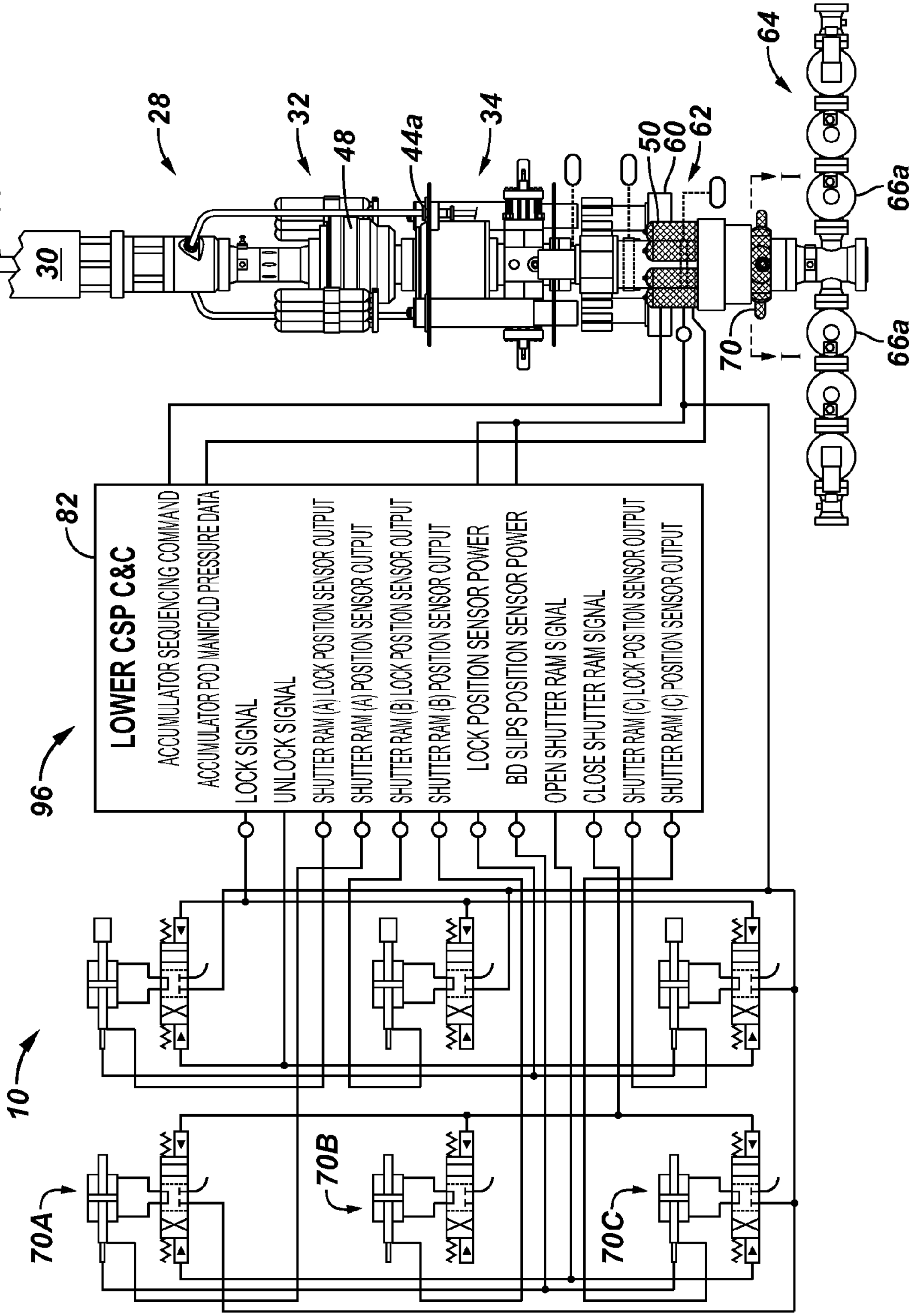

28
32
44a
34
38
30
29
120
16
14
29
82
LOWER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
94
10

FIG. 8


LOWER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
LOCK SIGNAL
UNLOCK SIGNAL
SHUTTER RAM (A) LOCK POSITION SENSOR OUTPUT
SHUTTER RAM (A) POSITION SENSOR OUTPUT
SHUTTER RAM (B) LOCK POSITION SENSOR OUTPUT
SHUTTER RAM (B) POSITION SENSOR OUTPUT
LOCK POSITION SENSOR POWER
BD SLIPS POSITION SENSOR POWER
OPEN SHUTTER RAM SIGNAL
CLOSE SHUTTER RAM SIGNAL
SHUTTER RAM (C) LOCK POSITION SENSOR OUTPUT
SHUTTER RAM (C) POSITION SENSOR OUTPUT
10
96
82
70A
70B
70C
38
30
28
32
48
44a
34
50
60
62
64
66a
66a
70

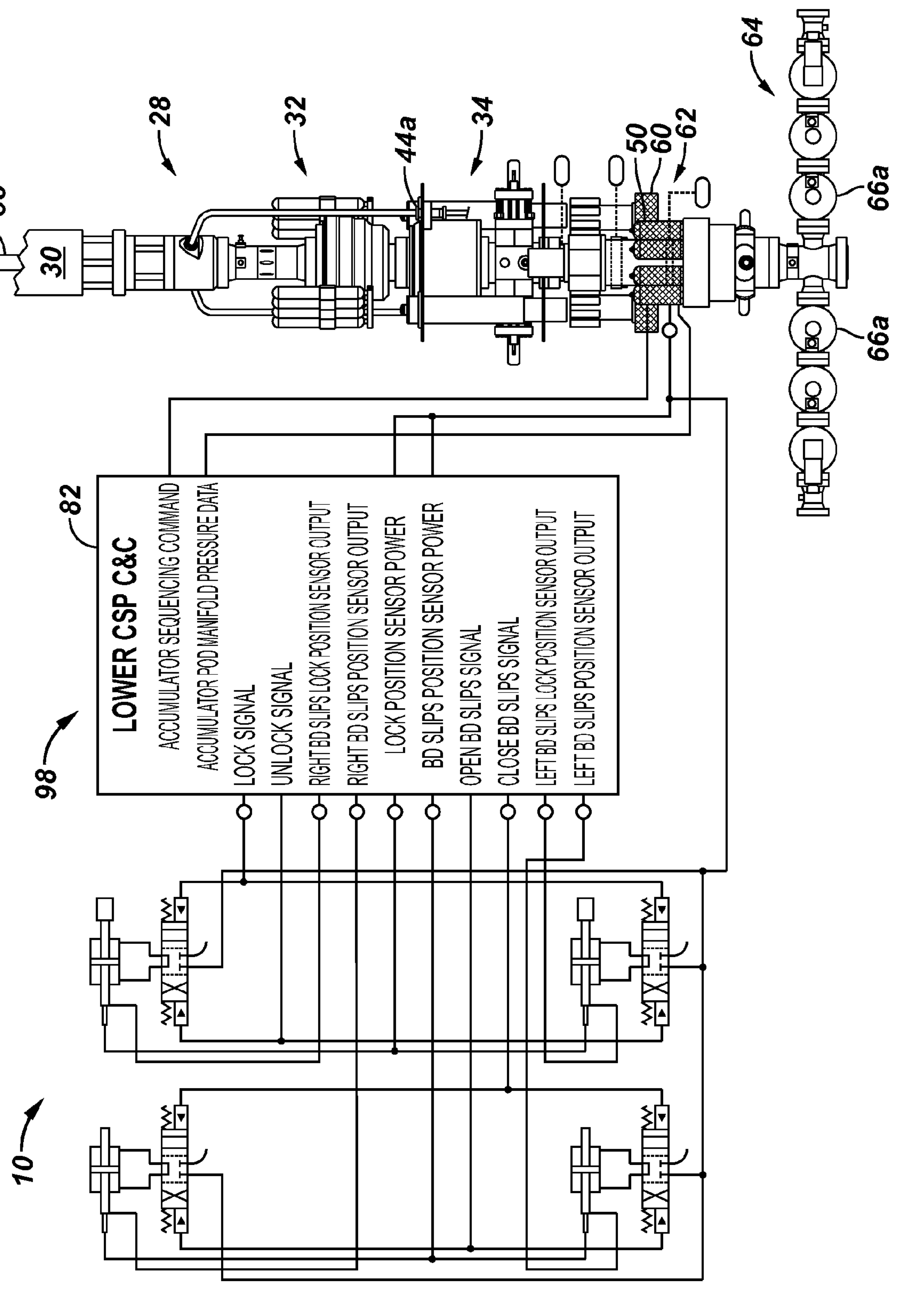
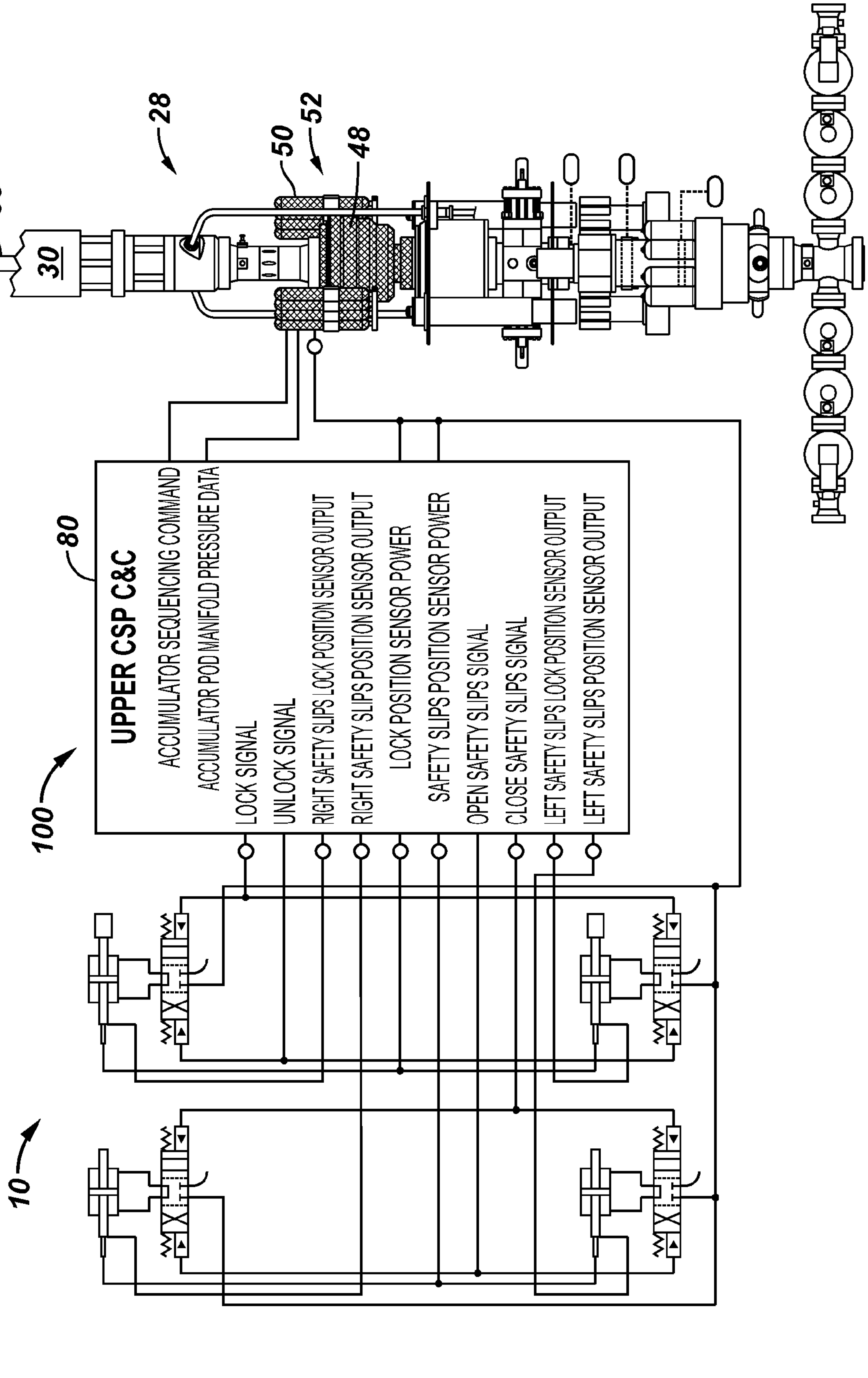

38
30
28
32
44a
34
50
60
62
64
66a
66a
82
98
10
LOWER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
LOCK SIGNAL
UNLOCK SIGNAL
RIGHT BD SLIPS LOCK POSITION SENSOR OUTPUT
RIGHT BD SLIPS POSITION SENSOR OUTPUT
LOCK POSITION SENSOR POWER
BD SLIPS POSITION SENSOR POWER
OPEN BD SLIPS SIGNAL
CLOSE BD SLIPS SIGNAL
LEFT BD SLIPS LOCK POSITION SENSOR OUTPUT
LEFT BD SLIPS POSITION SENSOR OUTPUT

FIG. 9

FIG. 10



38
30
28
50
52
48
80
100
10
UPPER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
LOCK SIGNAL
UNLOCK SIGNAL
RIGHT SAFETY SLIPS LOCK POSITION SENSOR OUTPUT
RIGHT SAFETY SLIPS POSITION SENSOR OUTPUT
LOCK POSITION SENSOR POWER
SAFETY SLIPS POSITION SENSOR POWER
OPEN SAFETY SLIPS SIGNAL
CLOSE SAFETY SLIPS SIGNAL
LEFT SAFETY SLIPS LOCK POSITION SENSOR OUTPUT
LEFT SAFETY SLIPS POSITION SENSOR OUTPUT

FIG. 11

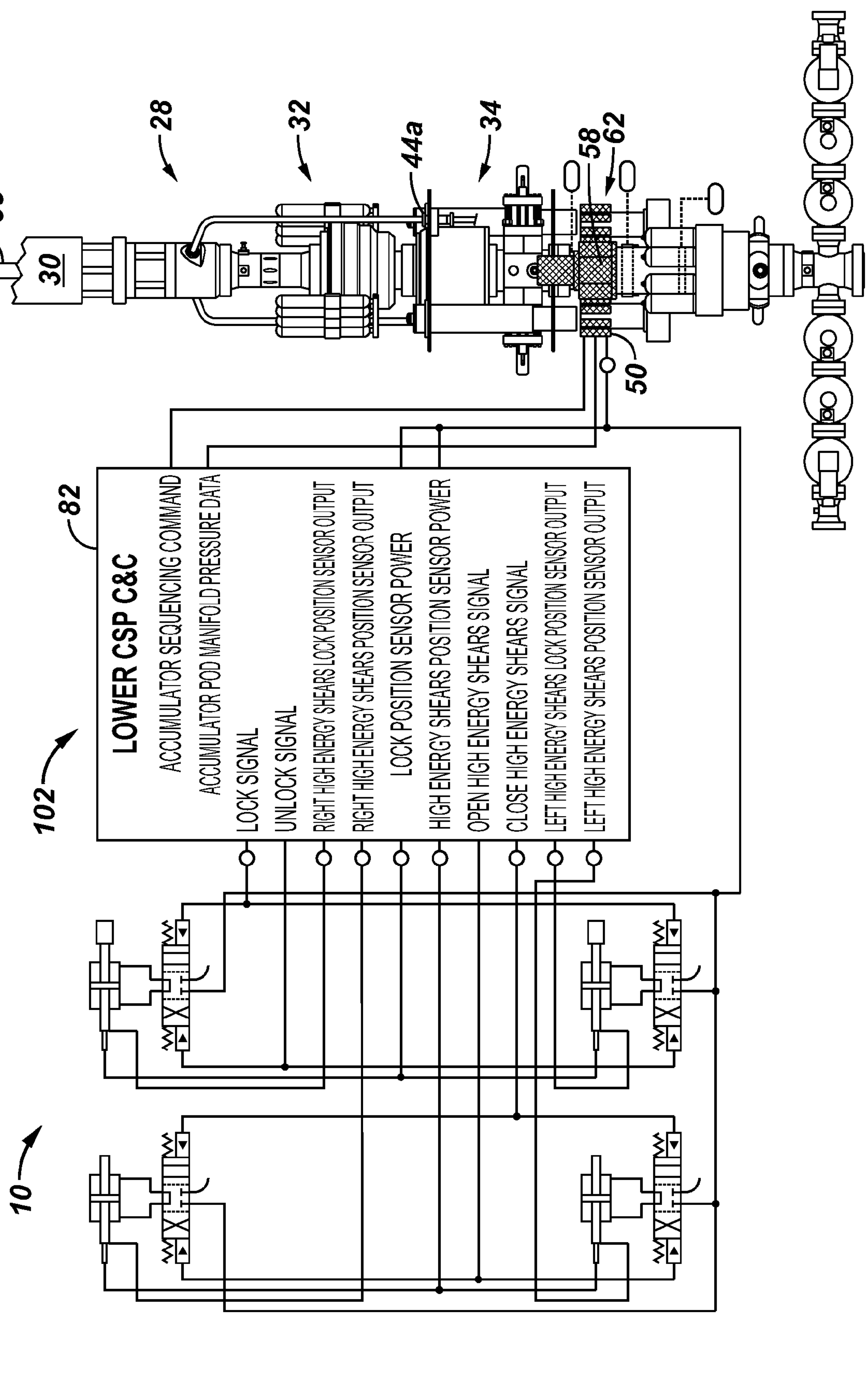
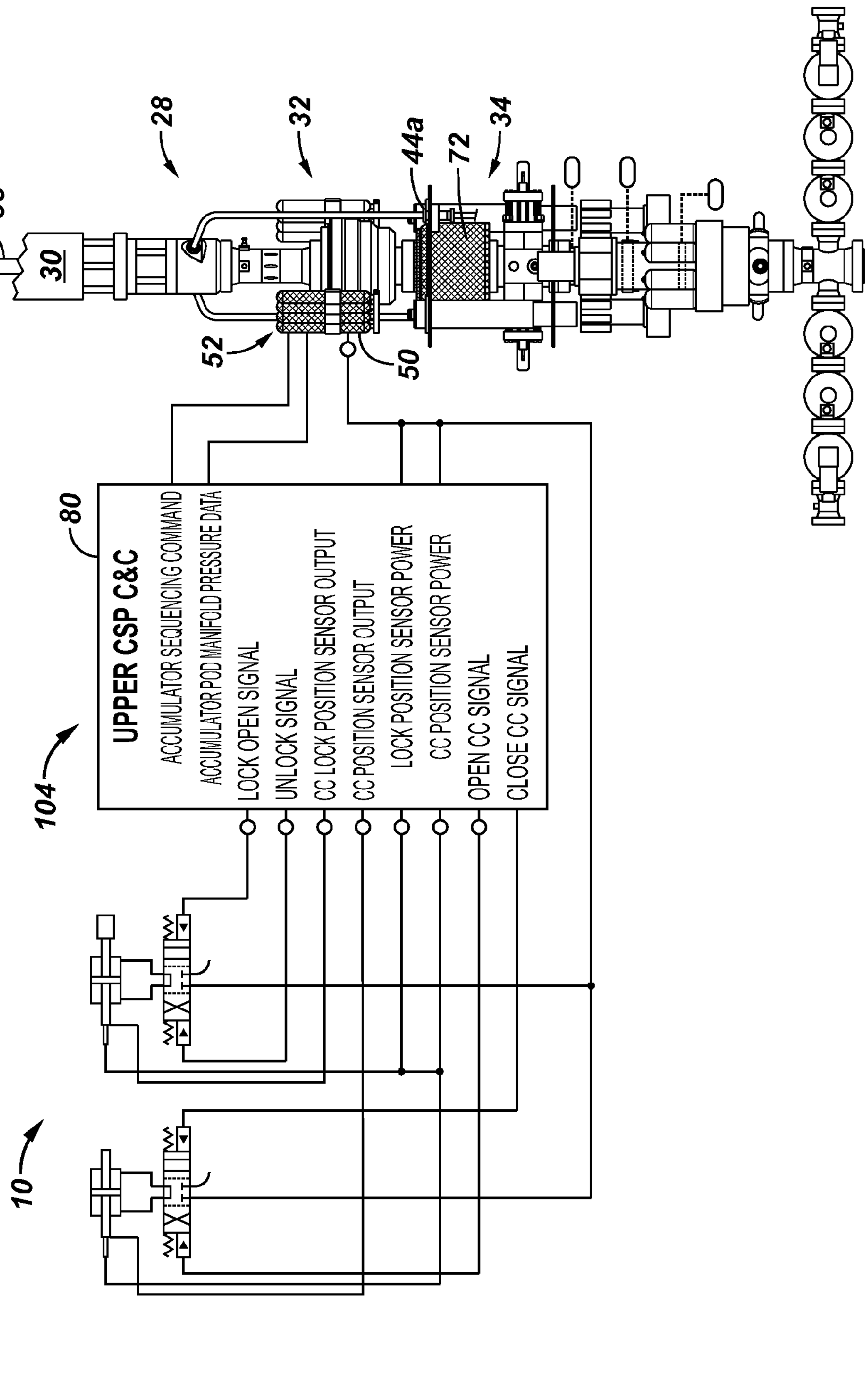

28
32
44a
34
58
62
38
30
50
82
102
10
LOWER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
LOCK SIGNAL
UNLOCK SIGNAL
RIGHT HIGH ENERGY SHEARS LOCK POSITION SENSOR OUTPUT
RIGHT HIGHENERGY SHEARS POSITION SENSOR OUTPUT
LOCK POSITION SENSOR POWER
HIGH ENERGY SHEARS POSITION SENSOR POWER
OPEN HIGH ENERGY SHEARS SIGNAL
CLOSE HIGH ENERGY SHEARS SIGNAL
LEFT HIGH ENERGY SHEARS LOCK POSITION SENSOR OUTPUT
LEFT HIGH ENERGY SHEARS POSITION SENSOR OUTPUT

FIG. 12


38
30
28
32
44a
72
34
52
50
80
104
10
UPPER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
LOCK OPEN SIGNAL
UNLOCK SIGNAL
CC LOCK POSITION SENSOR OUTPUT
CC POSITION SENSOR OUTPUT
LOCK POSITION SENSOR POWER
CC POSITION SENSOR POWER
OPEN CC SIGNAL
CLOSE CC SIGNAL

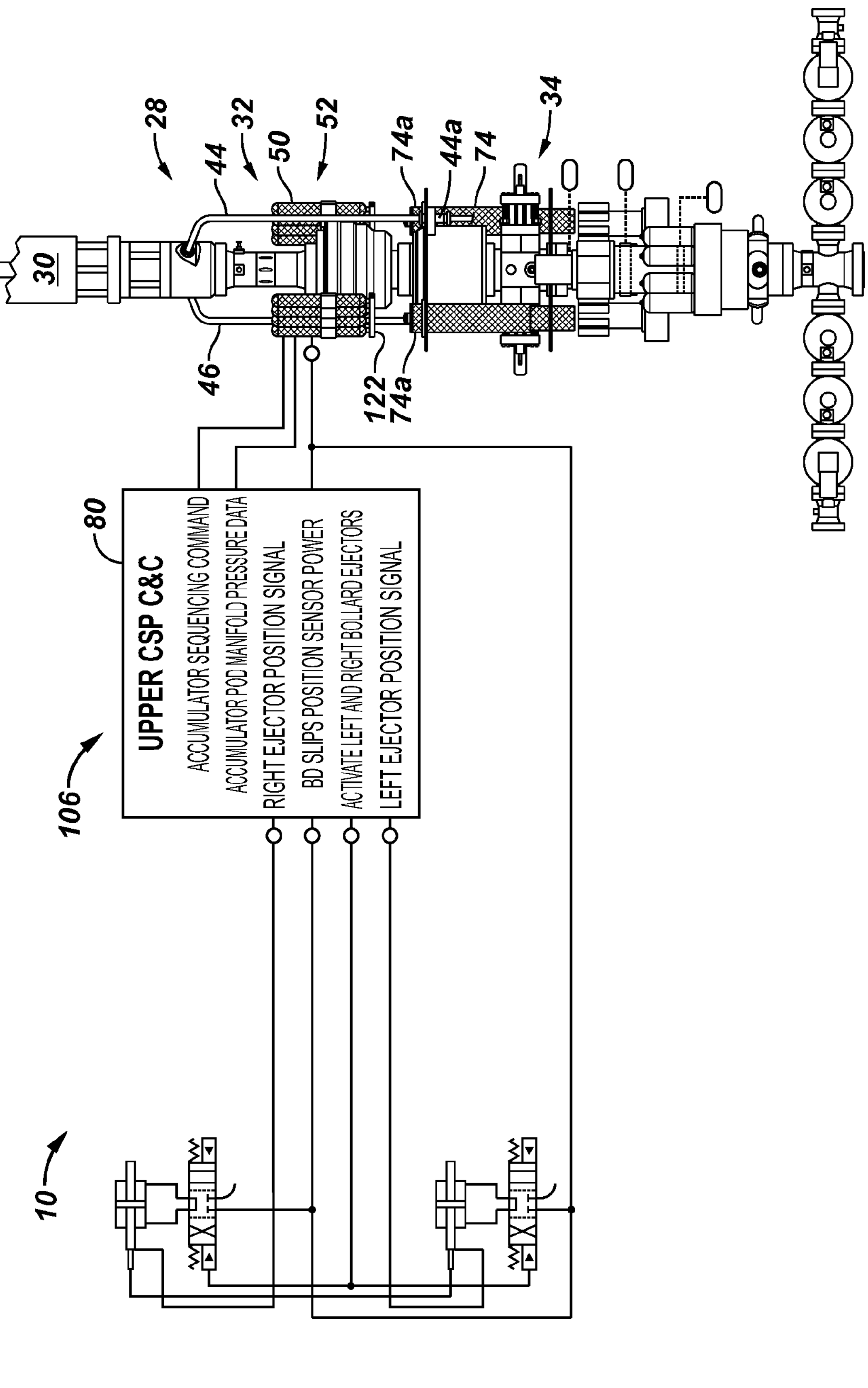

38
30
28
44
32
50
52
74a
44a
74
34
46
122
74a
80
UPPER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
RIGHT EJECTOR POSITION SIGNAL
BD SLIPS POSITION SENSOR POWER
ACTIVATE LEFT AND RIGHT BOLLARD EJECTORS
LEFT EJECTOR POSITION SIGNAL
106
10

FIG. 13

FIG. 13A

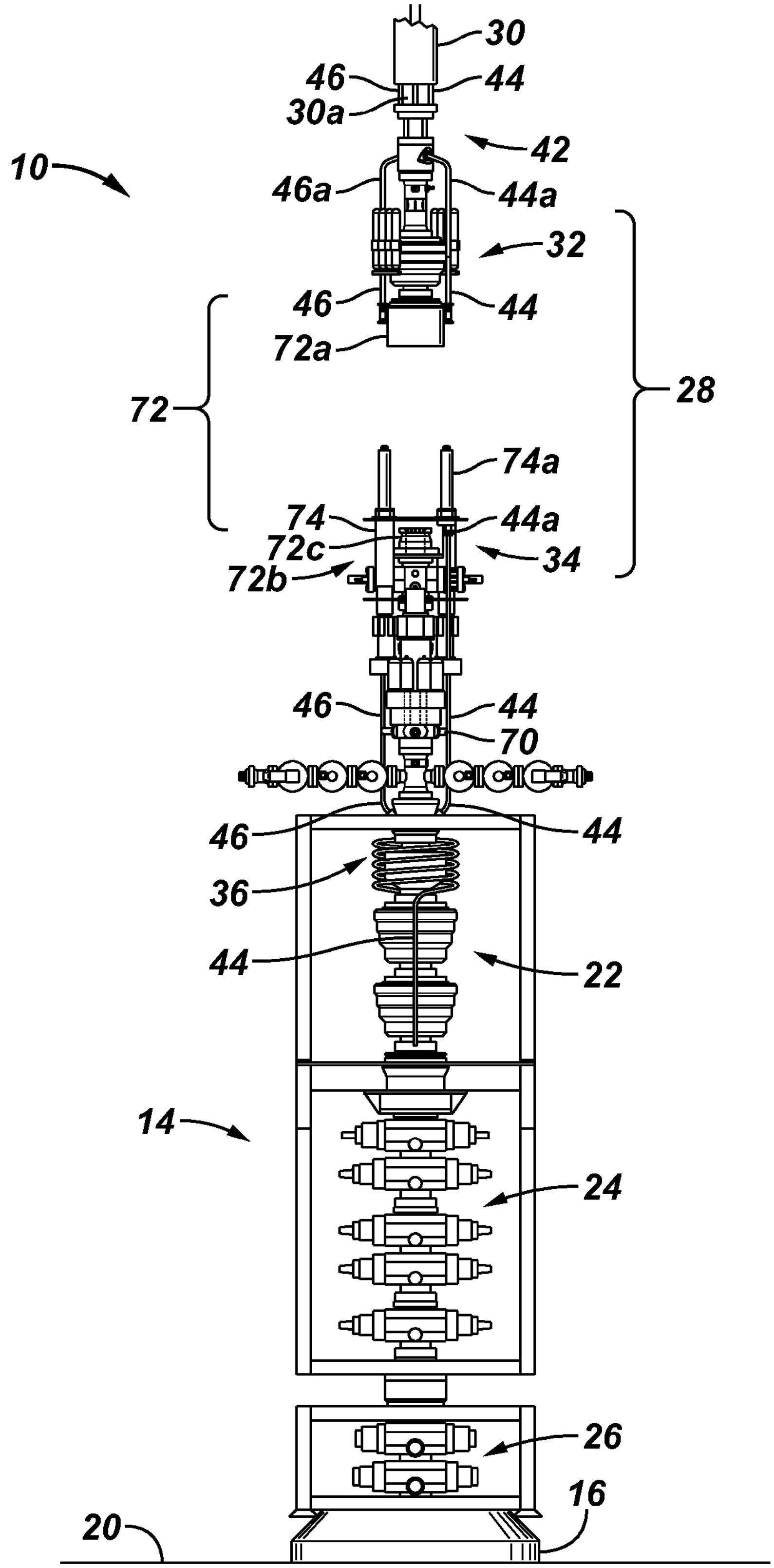
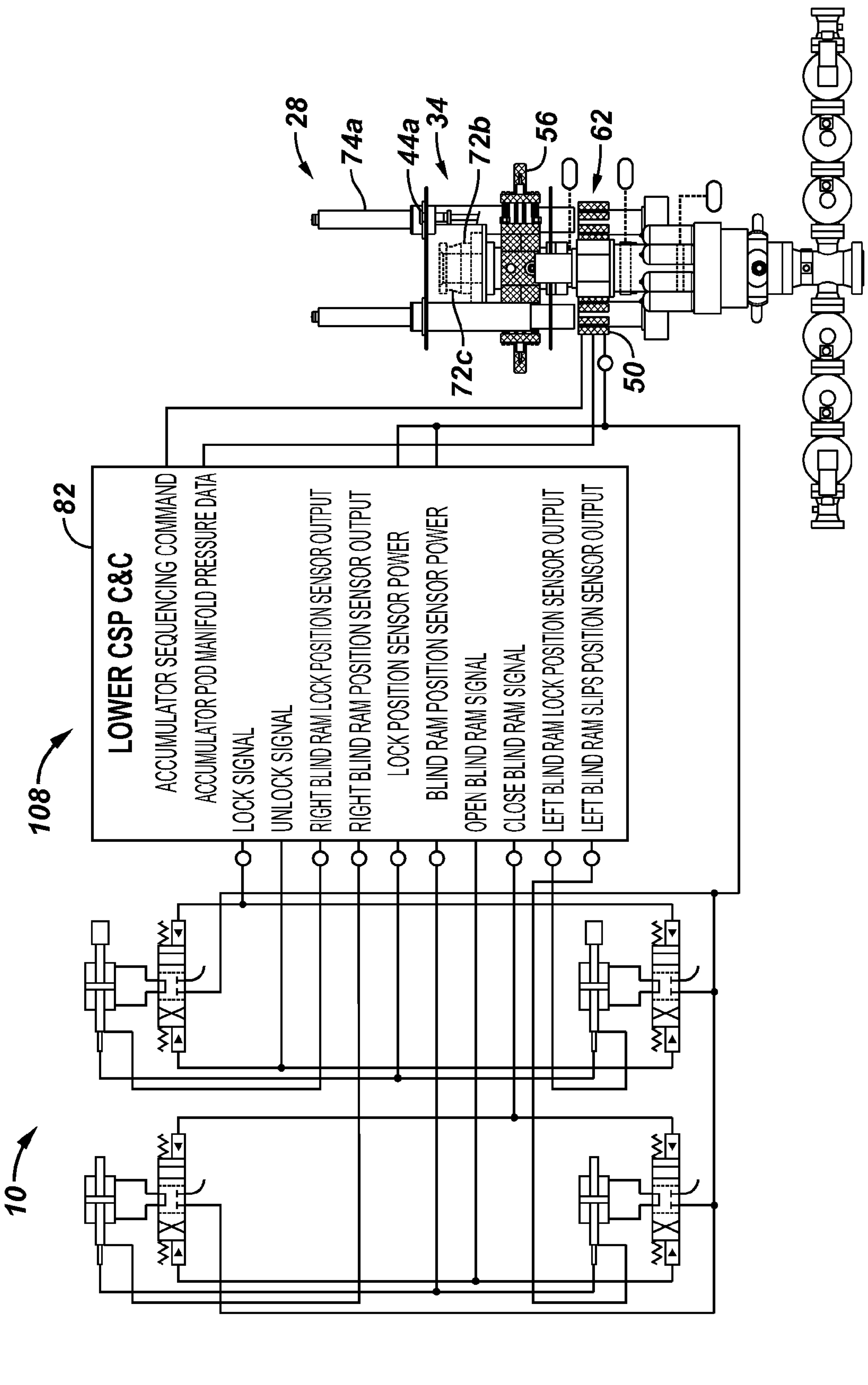

30
46
44
30a
42
10
46a
44a
32
46
44
72a
28
72
74a
74
44a
72c
34
72b
46
44
70
46
44
36
44
22
14
24
26
16
20

FIG. 14



28
74a
44a
34
72b
56
62
72c
50
82
108
10
LOWER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
LOCK SIGNAL
UNLOCK SIGNAL
RIGHT BLIND RAM LOCK POSITION SENSOR OUTPUT
RIGHT BLIND RAM POSITION SENSOR OUTPUT
LOCK POSITION SENSOR POWER
BLIND RAM POSITION SENSOR POWER
OPEN BLIND RAM SIGNAL
CLOSE BLIND RAM SIGNAL
LEFT BLIND RAM LOCK POSITION SENSOR OUTPUT
LEFT BLIND RAM SLIPS POSITION SENSOR OUTPUT

FIG. 15

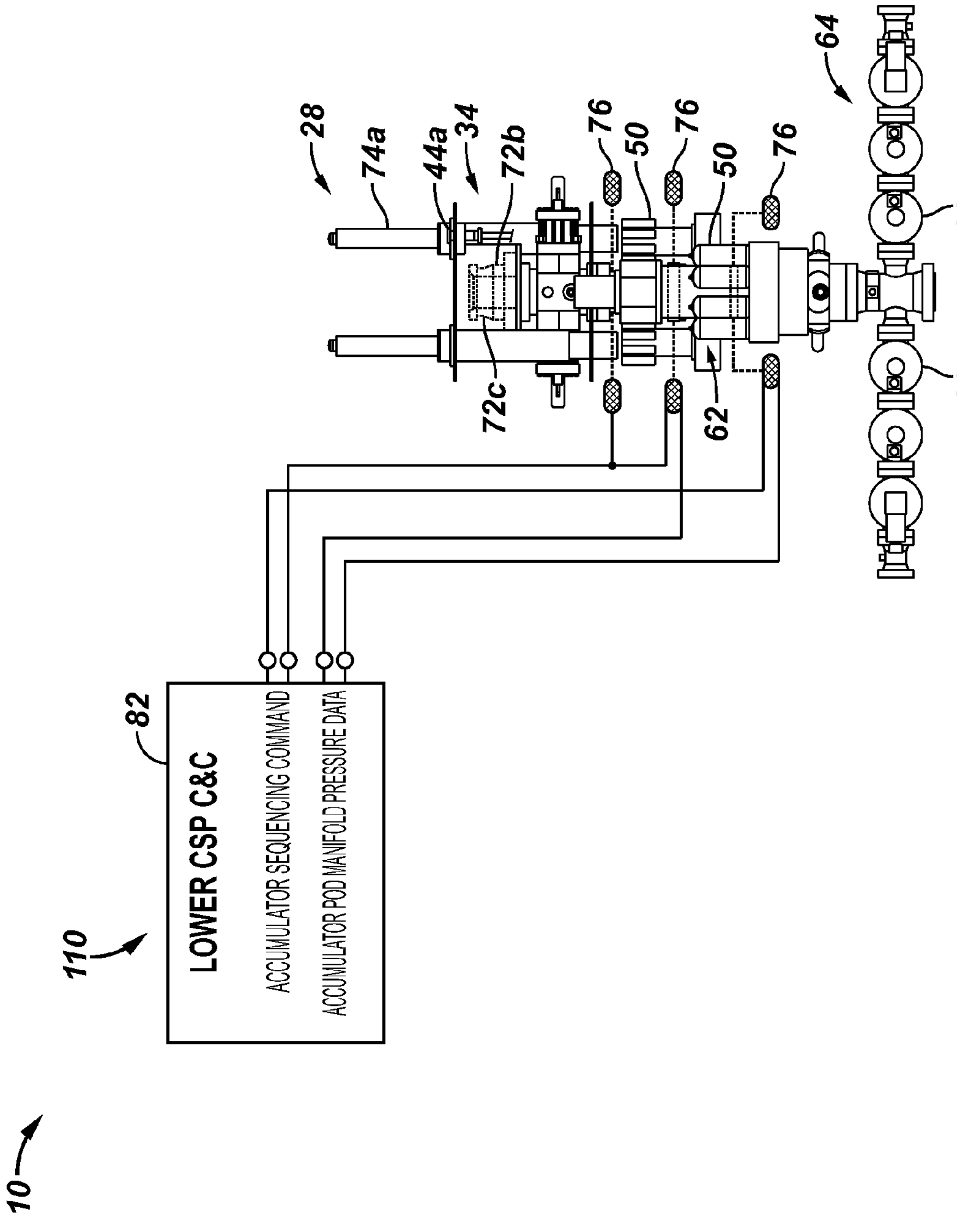

LOWER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
82
110
10
28
74a
44a
34
72b
72c
76
50
76
50
76
62
64
66a
66a

FIG. 16

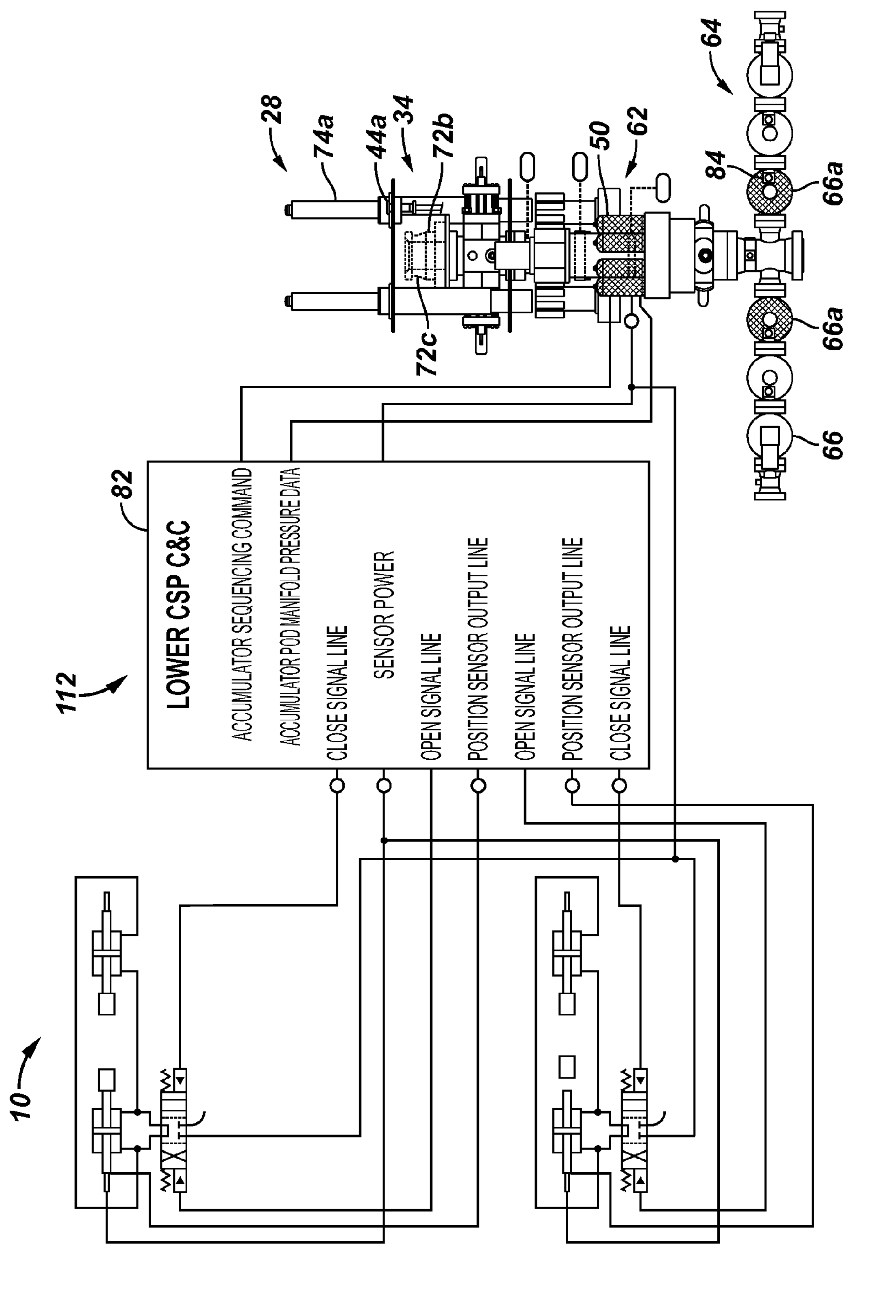
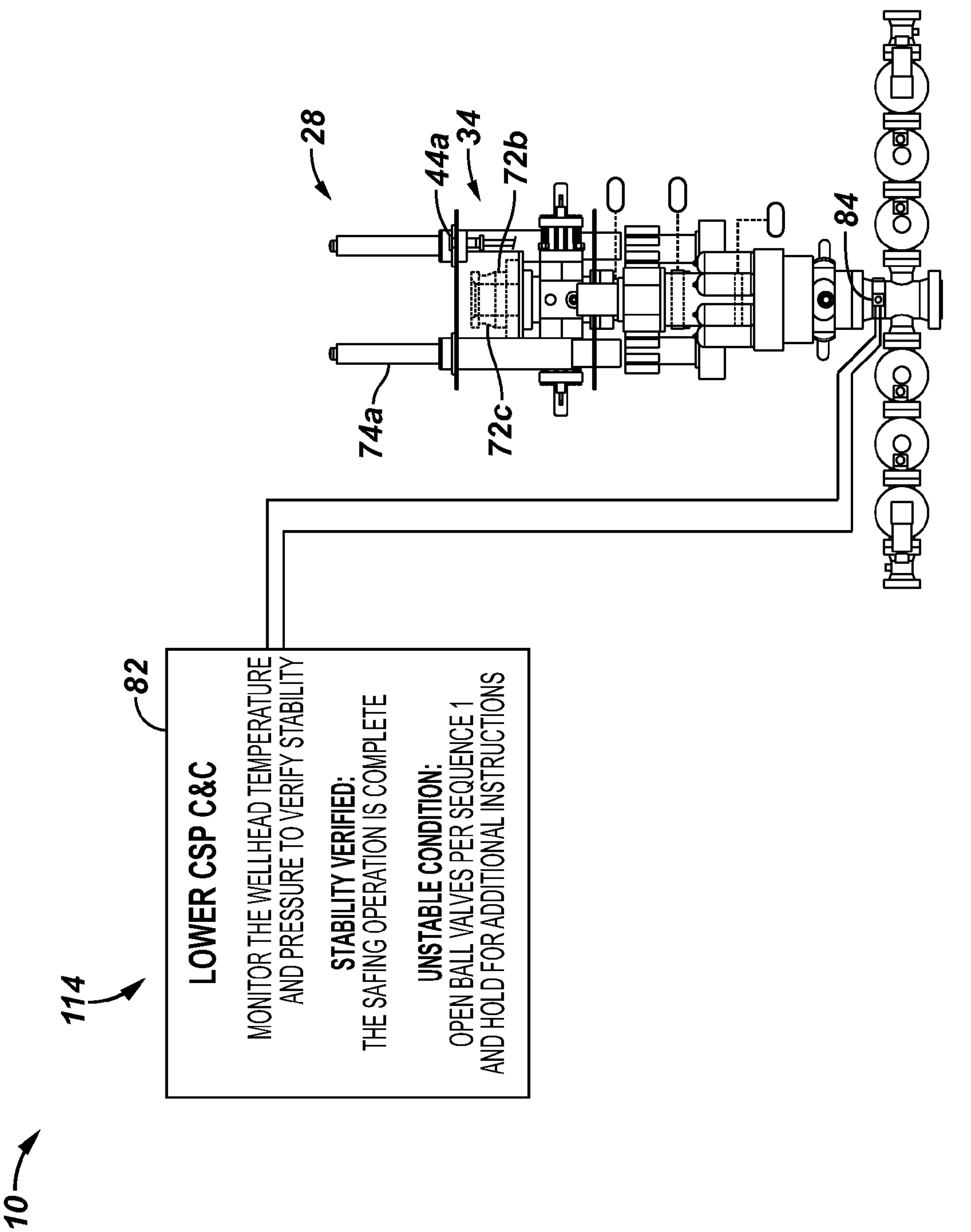

28
74a
44a
34
72b
50
62
64
84
66a
66a
66
72c
82
112
10
LOWER CSP C&C
ACCUMULATOR SEQUENCING COMMAND
ACCUMULATOR POD MANIFOLD PRESSURE DATA
CLOSE SIGNAL LINE
SENSOR POWER
OPEN SIGNAL LINE
POSITION SENSOR OUTPUT LINE
OPEN SIGNAL LINE
POSITION SENSOR OUTPUT LINE
CLOSE SIGNAL LINE

FIG. 17


28
44a
34
72b
84
74a
72c
82
114
10
LOWER CSP C&C
MONITOR THE WELLHEAD TEMPERATURE AND PRESSURE TO VERIFY STABILITY
STABILITY VERIFIED:
THE SAFING OPERATION IS COMPLETE
UNSTABLE CONDITION:
OPEN BALL VALVES PER SEQUENCE 1 AND HOLD FOR ADDITIONAL INSTRUCTIONS

SUBSEA WELL SAFING SYSTEM

RELATED APPLICATIONS

This application claims the benefit of U.S. provisional patent application No. 61/377,851 which was filed on Aug. 27, 2010.

BACKGROUND

This section provides background information to facilitate a better understanding of the various aspects of the invention. It should be understood that the statements in this section of this document are to be read in this light, and not as admissions of prior art.

The invention relates in general to wellbore operations and more particular to safety devices and methods to seal, control and monitor subsea oil and gas wells. A blowout preventer is a large, specialized valve used to seal, control and monitor oil and gas wells. Blowout preventers are designed to cope with extreme erratic pressures and uncontrolled flow (formation kick) emanating from a well reservoir during drilling. Kicks can lead to the uncontrolled release of oil and/or gas from a well resulting in a potentially subsea well event known as a blowout. Blowout preventers are critical to the safety of crew, rig (the equipment system used to drill a wellbore) and environment, and to the monitoring and maintenance of well integrity. While blowout preventers are intended to be fail-safe devices, accidents may still occur if the blowout preventer fails to properly operate. For example, during the Apr. 20, 2010, Deepwater Horizon drilling rig explosion, it is believed that the blowout preventers may not have properly operated and/or were not activated in a timely fashion. In addition, due to the failure the wellhead equipment was damaged creating additional obstacles to recovering control of the well.

SUMMARY

According to one or more aspects of the invention, a subsea well safing package for installing on a blowout preventer stack on a subsea well comprises a safing assembly connector interconnecting a lower assembly and an upper safing assembly, the safing assembly connector operable to a disconnected position, wherein the lower safing assembly is adapted to be connected to a blowout preventer stack on a subsea well and the upper safing assembly is adapted to be connected to a marine riser; the lower assembly comprising lower slips to engage a tubular suspended in a bore formed through the lower and the upper safing assemblies; the upper safing package comprising upper slips operable to engage the tubular; and a shear positioned between the upper slips and the lower slips, the shear operable to shear the tubular.

A subsea well safing system according to one or more aspects of the invention comprises a safing assembly comprising a lower safing assembly connected to a blowout preventer stack connected to a subsea well and an upper safing assembly connected to a marine riser; a safing assembly connector interconnecting the lower safing assembly and the upper safing assembly providing a bore therethrough in communication with the marine riser and the well; and an ejector device connected between the upper safing assembly and the lower safing assembly, the ejector device operable to physically separate the upper assembly and connected marine riser from the lower safing assembly.

According to one or more aspects of the invention, a subsea well safing sequence comprises utilizing a safing assembly installed between a blowout preventer stack of a subsea well and a marine riser, the safing assembly comprising a lower safing assembly connected to the blowout preventer stack and an upper safing assembly connected to the marine riser forming a bore between the riser and the blowout preventer stack; securing a tubular suspended in the bore at a position in the lower safing assembly; securing the tubular at a position in the upper safing assembly; shearing the tubular in the bore between the position in the lower safing assembly and the position in the upper safing assembly at which the tubular has been secured; and physically separating the upper safing assembly and the connected marine riser from the lower safing assembly connected to the blowout preventer stack.

The foregoing has outlined some of the features and technical advantages of the invention in order that the detailed description of the invention that follows may be better understood. Additional features and advantages of the invention will be described hereinafter which form the subject of the claims of the invention.

BRIEF DESCRIPTION OF THE DRAWINGS

The disclosure is best understood from the following detailed description when read with the accompanying figures. It is emphasized that, in accordance with standard practice in the industry, various features are not drawn to scale. In fact, the dimensions of various features may be arbitrarily increased or reduced for clarity of discussion.

FIG. **1** a schematic illustration of a subsea safing system according to one or more aspects of the invention utilized in a subsea well drilling system.

FIG. **2** depicts a subsea safing system according to one or more aspects of the invention, wherein the safing sequence has been initiated and the riser and upper safing package are physically and hydraulically disconnected from the lower safing package, the BOP stack, and the well.

FIG. **3** illustrates a subsea well safing assembly according to one or more aspects of the invention in isolation.

FIG. **4A-4B** is a flow chart of a subsea well safing sequence according to one or more embodiments of the subsea well safing system.

FIGS. **5-17** are schematic diagrams of safing sequence steps according to one or more embodiments of the subsea well safing system.

FIG. **5A** is a sectional view of a vent system according to one or more embodiments of the well safing package shown along the line I-I of FIG. **5**.

FIG. **8A** is a sectional view of an embodiment of a deflector device shown along the line I-I of FIG. **8**.

FIG. **8B** is a sectional, side view of an embodiment of the impingement device of FIG. **8A** in isolation.

FIG. **13A** illustrates the riser and upper safing package disconnected and separated from the lower safing package and the wellhead in response to progression of the subsea well safing sequence.

DETAILED DESCRIPTION

It is to be understood that the following disclosure provides many different embodiments, or examples, for implementing different features of various embodiments. Specific examples of components and arrangements are described below to simplify the disclosure. These are, of course, merely examples and are not intended to be limiting. In addition, the disclosure may repeat reference numerals and/or letters in the various examples. This repetition is for the purpose of simplicity and clarity and does not in itself dictate a relationship between the various embodiments and/or configurations discussed. More-over, the formation of a first feature over or on a second feature in the description that follows may include embodiments in which the first and second features are formed in direct contact, and may also include embodiments in which additional features may be formed interposing the first and second features, such that the first and second features may not be in direct contact.

As used herein, the terms "up" and "down"; "upper" and "lower"; "top" and "bottom"; and other like terms indicating relative positions to a given point or element are utilized to more clearly describe some elements. Commonly, these terms relate to a reference point as the surface from which drilling operations are initiated as being the top point and the total depth of the well being the lowest point, wherein the well (e.g., wellbore, borehole) is vertical, horizontal or slanted relative to the surface.

In this disclosure, "hydraulically coupled" or "hydraulically connected" and similar terms, may be used to describe bodies that are connected in such a way that fluid pressure may be transmitted between and among the connected items. The term "in fluid communication" is used to describe bodies that are connected in such a way that fluid can flow between and among the connected items. It is noted that hydraulically coupled may include certain arrangements where fluid may not flow between the items, but the fluid pressure may nonetheless be transmitted. Thus, fluid communication is a subset of hydraulically coupled.

A subsea well safing system is disclosed to provide a means for mitigating the environmental and economic damage that can result from the loss of control of a well, such as occurred in the Macondo well being drilled from the Deepwater Horizon on 20 Apr. 2010. According to one or more aspects of the invention, the subsea well safing system provides a mechanism to separate the riser from the blowout preventer stack and the well in a manner intended to limit the physical damage to the well drilling system and to enhance the potential for successfully reconnecting to the well, for example via BOP stack, to regain control of the well.

FIG. **1** is a schematic illustration of a subsea well safing system, generally denoted by the numeral **10**, being utilized in a subsea well drilling system **12**. In the depicted embodiment drilling system **12** includes a BOP stack **14** which is landed on a subsea wellhead **16** of a well **18** (i.e., wellbore) penetrating seafloor **20**. BOP stack **14** conventionally includes a lower marine riser package ("LMRP") **22** and blowout preventers ("BOP") **24**. The depicted BOP stack **14** also includes subsea test valves ("SSTV") **26**. As will be understood by those skilled in the art with benefit of this disclosure, BOP stack **14** is not limited to the devices depicted.

Subsea well safing system **10** comprises safing package, or assembly, referred to herein as a catastrophic safing package ("CSP") **28** that is landed on BOP system **14** and operationally connects a riser **30** extending from platform **31** (e.g., vessel, rig, ship, etc.) to BOP stack **14** and thus well **18**. CSP **28** comprises an upper CSP **32** and a lower CSP **34** that are adapted to separate from one another in response to initiation of a safing sequence thereby disconnecting riser **30** from the BOP stack **14** and well **18**, for example as illustrated in FIG. **2**. The safing sequence is initiated in response to parameters indicating the occurrence of a failure in well **18** with the potential of leading to a blowout of the well. According to one or more embodiments of the invention, subsea well safing system **10** may automatically initiate the safing sequence in response to the correspondence of monitored parameters to selected safing triggers. According to one or more embodiments of the invention CSP **28** may include an accumulator **29**, see FIGS. **3** and **7**, hydraulically connected to wellhead **16** to operate the wellhead connector lock as further described below. In the embodiment of depicted in FIG. **7**, wellhead accumulator **29** is depicted as a standalone, accumulator located proximate to seafloor **20** and wellhead **16**.

Wellhead **16** is a termination of the wellbore at the seafloor and generally has the necessary components (e.g., connectors, locks, etc.) to connect components such as BOPs **24**, valves (e.g., test valves, production trees, etc.) to the wellbore. The wellhead also incorporates the necessary components for hanging casing, production tubing, and subsurface flow-control and production devices in the wellbore.

BOP stack **14** commonly includes a set of two or more BOPs **24** utilized to ensure pressure control of well **18**. A typical stack might consist of one to six ram-type preventers and, optionally, one or two annular-type preventers. A typical stack configuration has the ram preventers on the bottom and the annular preventers at the top. The configuration of the stack preventers is optimized to provide maximum pressure integrity, safety and flexibility in the event of a well control incident. For example, one set of rams may be fitted to close on the drillpipe, blind rams to close on the open hole, and another set of shear rams to cut and hang-off the drillpipe. It is also common to have an annular preventer at the top of the stack to close over a wide range of tubular (e.g., drillpipe) sizes and the open hole. BOP stack **14** also includes various spools, adapters, and piping ports to permit circulation of wellbore fluids under pressure in the event of a well control incident.

LMRP **22** and BOP stack **14** are coupled together by a wellbore connector that is engaged with a corresponding mandrel on the upper end of BOP stack **24**. LMRP **22** typically provides the interface (i.e., connection) of the BOPs **24** and the bottom end **30***a* of marine riser **30** via a riser connector **36** (i.e., riser adapter). Riser connector **36** commonly comprises a riser adapter for connecting the lowest end **30***a* of riser **30** (e.g., bolts, welding, hydraulic connector) and a flex joint that provides for a range of angular movement of riser **30** (e.g., 10 degrees) relative to BOP stack **14**, for example to compensate for vessel **31** offset and current effects on along the length of riser **30**. Riser connector **36** may further comprise one or more ports for connecting fluid (i.e., hydraulic) and electrical conductors, i.e., communication umbilical, which may extend along (exterior or interior) riser **30** from the drilling platform located at surface **5** to subsea drilling system **12**. For example, it is common for a hydraulic choke line **44** and a hydraulic kill line **46** to extend from the surface for connection to BOP stack **14**.

Riser **30** is a tubular string that extends from the drilling platform **31** down to well **18**. The riser is in effect an extension of the wellbore extending through the water column to drilling vessel **31**. The riser diameter is large enough to allow for drillpipe, casing strings, logging tools and the like to pass through. For example, in FIGS. **1** and **2**, a tubular **38** (e.g., drillpipe) is illustrated deployed from drilling platform **31** into riser **30**. Drilling mud and drill cuttings can be returned to surface **5** through riser **30**. Communication umbilical (e.g., hydraulic, electric, optic, etc.) can be deployed exterior to or through riser **30** to CSP **28** and BOP stack **14**. A remote operated vehicle ("ROV") **124** is depicted in FIG. **2** and may be utilized for various tasks.

Refer now to FIG. **3** which illustrates a subsea well safing package **28** according to one or more aspects of the invention in isolation. CSP **28** depicted in FIG. **3** is further described with reference to FIGS. **1** and **2**. In the depicted embodiment, CSP **28** comprises upper CSP **32** and lower CSP **34**. Upper CSP **32** comprises a riser connector **42** which may include a riser flange connection **42***a*, and a riser adapter **42***b* which may provide for connection of communication umbilicals and extension of the communication umbilicals to various CSP **28** devices and/or BOP stack **14** devices. For example, a choke line **44** and a kill line **46** are depicted extending from the surface with riser **30** and extending through riser adapter **42***b* for connection to the choke and kill lines of BOP stack **14**. CSP **28** comprises a choke stab **44***a* and a kill line stab **46***a* for interconnecting the upper portion of choke line **44** and kill line **46** with the lower portion of choke line **44** and kill line **46**. As will be further described below with reference to safing sequence **86**, stabs **44***a*, **46***a* also provide for disconnecting from the stab and kill lines during a safing operations; and during subsequent recovery and reentry operations reconnecting to the choke and kill lines via stabs **44***a*, **46***a*. In some embodiments, riser connector **42** may also comprise a flex joint.

CSP **28** comprises an internal longitudinal bore **40**, depicted in FIG. **3** by the dashed line through lower CSP **34**, for passing tubular **38**. Annulus **41** is formed between the outside diameter of tubular **38** and the diameter of bore **40**.

Upper CSP **32** further comprises a slips **48** (i.e., safety slips) adapted to close on tubular **38**. Slips **48** are actuated in the depicted embodiment by hydraulic pressure from an accumulator **50**. In the depicted embodiment, CSP **28** comprises a plurality of hydraulic accumulators **50** which may be interconnected in pods, such as upper accumulator pod **52**. As will be understood by those skilled in the art with benefit of the present disclosure, accumulators **50** may be provided in various configurations. In the depicted embodiment, accumulators **50** are hydraulically charged and do not require connection to a hydraulic source at the surface. It will also be recognized by those skilled in the art that hydraulic pressure may be provided from the surface. In this embodiment, accumulators **50** located in the upper accumulator pod **52** are at least hydraulic connected to slips **48**. In one or more embodiments of the invention, the pressure in accumulators **50** are monitored and accumulators **50** may be actuated in sequence and as needed to ensure that adequate hydraulic pressure is available and provided for actuation of CSP devices such as slips **48**.

Lower CSP **34** comprises a connector **54** to connect to BOP stack **14**, for example, via riser connector **36**, rams **56** (e.g., blind rams), high energy shears **58**, lower slips **60** (e.g., bi-directional slips), and a vent system **64** (e.g., valve manifold). Vent system **64** comprises one or more valves **66**. In this embodiment, vent system **64** comprise vent valves (e.g., ball valves) **66***a*, choke valves **66***b*, and one or more connection mandrels **68**. Valves **66***b* can be utilized to control fluid flow through connection mandrels **68**. For example, a recovery riser **126** is depicted connected to one of mandrels **68** for flowing effluent from the well and/or circulating a kill fluid (e.g., drilling mud) into the well as further described below. Vent system **64** is further described below with reference to FIGS. **5** and **5**A.

In the depicted embodiment, lower CSP **34** further comprises a deflector device **70** (e.g., impingement device, shutter ram) disposed above vent system **64** and below lower slips **60**, shears **58**, and blind rams **56**. Lower CSP **34** includes a plurality of hydraulic accumulators **50** that are arranged and connected in one or more lower hydraulic pods **62** for operations of various devices of CSP **28**. As will be further described below, CSP **28**, in particular lower CSP **34**, may include methanol, or other chemical, source **76** operationally connected for injecting into lower CSP **34**, for example to prevent hydrate formation.

Upper CSP **32** and lower CSP **34** are detachably connected to one another by a connector **72**. CSP connector **72** is depicted in the illustrated embodiments as a collet connector, comprising a first connector portion **72***a* and a second mandrel connector portion **72***b* which are illustrated for example in FIG. **13**A. An ejector device **74** (e.g., ejector bollards) is operationally connected between upper CSP **32** and lower CSP **34** to separate upper CSP **32** and riser **30** from lower CSP **34** and BOP stack **14** after connector **72** has been actuated to the unlocked position. CSP **28** also includes a plurality of sensors **84** which can sense various parameters, such as and without limitation, temperature, pressure, strain (tensile, compression, torque), vibration, and fluid flow rate. Sensors **84** further includes, without limitation, erosion sensors, position sensors, and accelerometers and the like. Sensors **84** can be in communication with one or more control and monitoring systems, for example as further described below, forming a limit state sensor package.

According to one or more embodiments of the invention, CSP **28** comprises a control system **78** which may be located subsea, for example at CSP **28** or at a remote location such as at the surface. Control system **78** may comprise one or more controllers which are located at different locations. For example, in at least one embodiment, control system **78** comprise an upper controller **80** (e.g., upper command and control data bus) and a lower controller **82** (e.g., lower command and controller bus). Control system **78** may be connected via conductors (e.g., wire, cable, optic fibers, hydraulic lines) and/or wirelessly (e.g., acoustic transmission) to various subsea devices and to surface (i.e., drilling platform **31**) control systems.

With reference to the embodiments depicted in FIGS. **3** to **17**, control system **78** includes upper controller **80** and a lower controller **82**. Each of upper and lower controllers **80**, **82** may comprise a collection of real-time computer circuitry, field programmable gate arrays (FPGA), I/O modules, power circuitry, power storage circuitry, software, and communications circuitry. One or both of upper and lower controller **80**, **82** may comprise control valves.

According to at least one embodiment, one of the controllers, for example lower controller **82**, serves as the primary controller and provides command and control sequencing to various subsystems of safing package **28** and/or communicates commands from a regulatory authority for example located at the surface. The primary controller, e.g., lower controller **82**, contains communications functions, and health and status parameters (e.g., riser strain, riser pressure, riser temperature, wellhead pressure, wellhead temperature, etc.). One or more of the controllers may have black-box capability (e.g., a continuous-write storage device that does not require power for data recovery).

Upper controller **80** is described herein as operationally connected with a plurality of sensors **84** positioned throughout CSP **28** and may include sensors connected to other portions of the drilling system, including along riser **30**, at wellhead **16**, and in well **18**. Upper controller **80**, using data communicated from sensors **84**, continuously monitors limit state conditions of drilling system **12**. According to one or more embodiments, upper controller **80**, may be programmed and reprogrammed to adapt to the personality of the well system based on data sensed during operations. If a defined limit state is exceeded an activation signal (e.g., alarm) can be transmitted to the surface and/or lower controller **82**. A safing sequence may be initiated automatically by control system **78** and/or manually in response to the activation signal.

With reference to FIGS. **4**A and **4**B, a safing sequence **86** according to one or more embodiments of subsea well safing system **10** is disclosed. In sequence step **88**, the safing sequence is initiated in response to monitoring the limit state sensor **84** package by upper controller **80**. In sequence step **90**, pressure is vented from CSP **28** by opening a valve **66***a* in vent system **64**, see, e.g., FIGS. **1**, **3**, **5** and **5**A. In sequence step **92**, the choke and kill lines are closed to prevent combustibles from flowing up from the well and to the surface through the kill and choke lines, see, e.g., FIGS. **1**, **3** and **6**. In sequence step **94**, the wellhead **16** connector lock is pressurized to prevent accidental ejection of BOP stack **14** from wellhead **16**, see, e.g., FIGS. **3** and **7**. In sequence step **96**, fluid flowing up from the well is diverted, e.g., partially diverted, to the open vents to prevent erosion of CSP elements such as the slips **48**, **60**, see, e.g., FIGS. **1**, **3**, **8**, **8**A and **8**B. For example, fluid flow may be diverted by operating a deflector device **70** to a closed position. In sequence step **98**, tubular **38** is secured in lower CSP **34** by closing lower slips **60** (e.g., bi-directional slips), see, e.g., FIGS. **1**, **3** and **9**. In sequence step **100**, tubular **38** is secured in upper CSP **32** by closing upper slips **48** (e.g., safety slips), see, e.g., FIGS. **1**, **3** and **10**. In sequence step **102**, tubular **38** is sheared in lower CSP **34** by activating shears **58**, see, e.g., FIGS. **1**, **3** and **11**. In sequence step **104**, upper CSP **32** and lower CSP **34** are disconnected from one another by operating CSP connector **72** to a disconnected position, see, e.g., FIGS. **1**, **3**, **12** and **13**A. In sequence step **106**, riser **30** and upper CSP **32** are separated (e.g., ejected) from lower CSP **34** and BOP stack **14** by activating ejector device **74** (i.e., ejector bollards), see, e.g., FIGS. **1-3**, **13**, and **13**A. In sequence step **108**, (see, e.g., FIGS. **1-3** and **14**) blind rams **56** are closed to shut-off fluid flow from BOP stack **14** through bore **40** (see FIG. **3**) and escaping to the environment. In sequence step **110**, treating hydrate formation in lower CSP **34** by injecting methanol, see, e.g., FIGS. **1-3** and **15**. In sequence step **112**, closing the vents **66***a* opened in vent system **64** in sequence step **90**, see, e.g., FIGS. **1-3** and **16**. In sequence step **114**, performing a formation stability test, see, e.g., FIGS. **1-3** and **17**.

FIG. **5** is a schematic diagram of sequence step **90**, according to one or more embodiments of subsea well safing system **10** which is described with further reference to FIGS. **1** and **3**. In response to initiating safing sequence **86**, one or more vent valves **66***a* of vent system **64** are opened. Valves **66***a* are opened to reduce the flow of fluid through the annulus **41** between tubular **38** and the CSP **28** walls forming bore **40** through CSP **28** (see FIG. **3**, the dashed lines in lower CSP **34**) and lowering the backpressure on lower slips **60**. The open and closed position of vent valves **66***a* can be verified by a control signal from each valve position sensor **84**. An accumulator **50** located in the assigned accumulator pod **62** is activated to provide hydraulic power to the valve actuators **116** of controller **82**. Lower controller **82** continuously monitors the accumulator pod **62** pressure and activates additional accumulators **50** as may be required to maintain working pressure. With reference to FIGS. **5-17**, the active device (e.g., accumulators, valves, slips, shears) of the depicted sequence step are emphasized by hatching.

FIG. **5**A is a sectional view of an embodiment of vent system **64** shown along the line I-I of FIG. **5**. FIG. **5**A depicts two vent valves **66***a* on each side of vent system **64**, which are depicted in the closed position. Valves **66***b* are positioned to control flow through connection mandrels **68**. In the depicted embodiment, the sensor **84** located proximate to the connection mandrel **84** is an accelerometer.

FIG. **6** is a schematic diagram of sequence step **92**, according to one or more embodiments of subsea well safing system **10** which is described with further reference to FIGS. **1** and **3**. In sequence step **92**, valves **118** positioned in each of choke line **44** and kill line **46** are actuated from the open to the closed position to prevent combustibles from flowing up the choke line **44** and the kill line **46**.

FIG. **7** is a schematic diagram of sequence step **94**, according to one or more embodiments of subsea well safing system **10** which is described with further reference to FIGS. **1** and **3**. Controller **82** initiates the pressurization of wellhead connector lock **120** to prevent the accidental ejection of BOP stack **14** from wellhead **16** due to the high back pressure encountered in subsequent sequence steps, e.g., when deflector device **70** is closed, slips **48**, **60** are closed; and due to the loss of hydraulic pressure to wellhead connector lock **120** when riser **30** is disconnected from BOP stack **14** disconnecting any hydraulic sources extending along riser **30** to CSP **28**.

FIG. **8** is a schematic diagram of sequence step **96**, according to one or more embodiments of subsea well safing system **10** which is described with further reference to FIGS. **1**, **3**, **8**A and **8**B. In sequence step **96**, controller **82** actuates deflector device **70**, described in the embodiments of FIG. **8**, **8**A and **8**B as shutter ram **70**, to a closed position (see FIG. **8**A) in response to applying hydraulic pressure in the embodiment of FIG. **8** from a hydraulic accumulator **50** of lower accumulator pod **62**. In the closed position, deflector device **70** diverts fluid flow from passing through annulus **41** of CSP **28** to vent system **64** and open vent valves **66***a*. The closed shutter ram **70**, depicted in FIG. **8**A, protects CSP **28** from the high flow rates and entrained solids that are encountered thereby limiting erosion of devices of CSP **28**, such as upper safety slips **48** and lower slips **60**. Shutter ram **70** may be provided in various manners and configurations. Referring to FIG. **8**A, tubular **38** is depicted substantially centered within bore **40** of shutter ram **70** which is coaxial with bore **40** of CSP **28** by rams **70**A, **70**B, and **70**C. According to at least one embodiment, closure of rams **70**A, **70**B, **70**C does not seal annulus **41**. In the embodiment as depicted in FIG. **8**B, each of rams **70**A, **70**B and **70**C comprises stacked and spaced apart plates **71** which interleave portions of the plates **71** of the adjacent rams.

FIG. **9** is a schematic diagram of sequence step **98**, according to one or more embodiments of subsea well safing system **10** which is described with further reference to FIGS. **1** and **3**. In sequence step **98**, controller **82** actuates lower slips **60** (e.g., bi-directional slips) securing tubular **38** within lower CSP **34** in preparation for sequence step **102**. In some embodiments, lower slips **60** may comprise deflector armor to divert fluid flow toward vent system **64** instead of, or in addition to, shutter ram **70** described and disclosed with reference to sequence step **96** and FIGS. **8**, **8**A, and **8**B.

FIG. **10** is a schematic diagram of sequence step **100**, according to one or more embodiments of subsea well safing system **10** which is described with further reference to FIGS. **1** and **3**. In sequence step **100**, upper slips **48** are actuated to engage tubular **38** within upper CSP **32**. In this embodiment, sequence step **100** is actuated by upper controller **80**. As with other sequence steps, the controller monitors the pressure status of accumulators **50** and if a low pressure is detected, a subsequent accumulator in a pod is activated to actuate the sequence step device (i.e., slips **48** in sequence step **100**).

FIG. **11** is a schematic diagram of sequence step **102**, according to one or more embodiments of subsea well safing system **10** which is described with further reference to FIGS. **1** and **3**. After tubular **38** is engaged and secured respectively in upper CSP **32** (i.e., by slips **48**) and lower CSP **34** (i.e., slips **60**), lower controller **82** actuates shears **58** thereby shearing tubular **38** between upper slips **48** and lower slips **60**.

FIG. **12** is a schematic diagram of sequence step **104**, according to one or more embodiments of subsea well safing system **10** which is described with further reference to FIGS.

1, 2, 3 and 13A. In sequence step 104, CSP connector 72 is actuated to the open, or disconnected, position permitting separation of upper CSP 32 from lower CSP 34 in sequence step 106. In this embodiment, CSP connector 72 is actuated via upper controller 80 and hydraulic accumulators 50 located in upper accumulator pod 52. In the depicted embodiment, CSP connector 72 is a collet comprising a first connector portion 72a and a second connector portion 72b, depicted for example in FIG. 13A. Second connector portion 72b is disposed with lower CSP 34 and comprises a mandrel, identified individually by the numeral 72c (see, FIGS. 13A, 14-17). The mandrel 72c provides a mechanism for reconnecting, for example with a riser, for re-entry into well 18.

FIG. 13 is a schematic diagram of sequence step 106, according to one or more embodiments of subsea well safing system 10 which is described with further reference to FIGS. 1-3 and 13A. In sequence step 106, ejector devices 74 (i.e., ejector bollards) are actuated to physically separate upper CSP 32 and riser 30 from lower CSP 34 as depicted in FIGS. 2 and 13A. For example, ejector devices 74 may include piston rods 74a which extend to push the upper CSP 32 away from lower CSP 34 in the depicted embodiment. FIGS. 2, 13A, and 14-17 illustrate piston rod 74a in an extended position. In the embodiment of FIG. 13, actuation of ejector devices 74 is provided by upper controller 80 and accumulator(s) 50 located in upper accumulator pod 52.

Typically, riser 30 will be in tension which will assist in pulling the disconnected upper CSP 32 vertically away from lower CSP 34. In addition, the water currents and deflection in riser 30 (e.g., offset from platform 31) will assist in moving riser 30 and separated upper CSP 32 laterally away from lower CSP 34 and the well. Choke line 44 and kill line 46 are disconnected respectively at choke stab 44a and kill stab 46a (FIG. 3). Stabs 44a and 46b provide a means for reconnection to surface sources during recovery operations.

In the depicted embodiments, ejector device 74 is attached to lower CSP 34 and piston rods 74a push against a portion of upper CSP 32, for example a portion of the frame 122 of upper CSP 32 shown generally in FIG. 13. It will be understood by those skilled in the art with benefit of this disclosure that ejector device 74 may be arranged in different configurations without departing from the scope of the invention. For example, ejector device 74 may be reversed so as to be attached with upper CSP 32 wherein piston rod 74a acts against lower CSP 34.

FIG. 14 is a schematic diagram of sequence step 108, according to one or more embodiments of subsea well safing system 10 which is described with further reference to FIGS. 1, 2 and 3. In sequence step 108, blind rams 56 are actuated to the closed position sealing bore 40 (see FIGS. 3 and 8A, 8B) to block any fluid that may be flowing up from well 18 through BOP stack 14. In the depicted embodiment, actuation of blind rams 56 is provided by lower controller 82 and accumulator(s) 50 located in lower accumulator pod(s) 62.

FIG. 15 is a schematic diagram of sequence step 110, according to one or more embodiments of subsea well safing system 10 which is described with further reference to FIGS. 1, 2 and 3. In sequence step 110, methanol 76 may be injected into lower CSP 34 to prevent hydrate formation CSP 28, in particular in the vents (e.g., vent valves 66a) of vent system 64. In the depicted embodiment, the injection of methanol 76 is provided by lower controller 82 and may be powered by accumulator(s) 50 located in lower accumulator pod(s) 62.

FIG. 16 is a schematic diagram of sequence step 112, according to one or more embodiments of subsea well safing system 10 which is described with further reference to FIGS. 1, 2 and 3. In sequence step 112, lower controller 82 actuates hydraulic power (e.g., accumulator 50) to actuate the open vent valves 66a from the open to the closed position.

FIG. 17 is a schematic diagram of sequence step 114, according to one or more embodiments of subsea well safing system 10 which is described with further reference to FIGS. 1-3. Subsequent to closing vent valves 66a in sequence step 112, lower controller 82 can initiate and perform a formation stability test for example by monitoring wellhead temperature and pressure via one or more sensors 84.

If stable formation conditions are indicated, safing system 10 may be placed in a standby condition until recovery operations can be initiated and completed. If unstable formation conditions are indicated, vent valves 66a may be opened to relieve pressure in an effort to prevent a subsurface blowout of well 18, which will result in loss of the well and require more difficult and time consuming processes to plug well 18. With effluent venting to the environment, a recovery riser 126 extending, for example from a vessel at surface 5, may be connected to connection mandrel 68 of vent system 64 as depicted in FIG. 3. ROV 124 (FIG. 2) may be utilized to connect flexible riser 126. A valve, such as valve 68b, may be operated to the open position permitting flow of effluent through mandrel 68 of vent system 64 into riser 126 and to the surface; and the open vent valves 66a are operated to the closed position, thus providing a means to limit environmental damage until control of well 18 can be recovered.

According to one embodiment, a method of recovery of well 18 comprises closing in well 18 via lower CSP 34 and/or venting effluent from well 18 through vent system 64 and a recovery riser 126 to the surface. A riser 30 and choke line 44 and/or kill line 46 hydraulics are extended from the surface to lower CSP 34. Choke and kill lines 44, 46 can be connected to BOP stack 14 and well 18 via choke stab 44a and kill stab 46a which are located on lower CSP 34 which is still connected to well 18. Riser 30 in some circumstances may be connected to connector mandrel 72b of CSP connector 72 to reestablish hydraulic communication with well 18 through BOP stack 14. Depending on the status of BOP stack 14 and formation stability, drilling mud may be circulated down one of riser 30, kill line 46, choke line 44, and/or flexible riser 126 to kill well 18.

According to one or more aspects of the invention, a subsea well safing package for installing on a blowout preventer stack on a subsea well comprises a safing assembly connector interconnecting a lower safing assembly and an upper safing assembly, the safing assembly connector operable to a disconnected position, wherein the lower safing assembly is adapted to be connected to a blowout preventer stack on a subsea well and the upper safing assembly is adapted to be connected to a marine riser; the lower assembly comprising lower slips to engage a tubular suspended in a bore formed through the lower and the upper safing assemblies; the upper safing assembly comprising upper slips operable to engage the tubular; and a shear positioned between the upper slips and the lower slips, the shear operable to shear the tubular.

According to one or more aspects of the invention a subsea well safing package is provided for installing on a blowout preventer stack on a subsea well comprises a safing assembly connector interconnecting a lower safing assembly and an upper safing assembly, the safing assembly connector operable to a disconnected position, wherein the lower safing assembly is adapted to be connected to a blowout preventer stack on a subsea well and the upper safing assembly is adapted to be connected to a marine riser; the lower assembly comprising lower slips to engage a tubular suspended in a bore formed through the lower and the upper safing assemblies; the upper safing assembly comprising upper slips operable to engage the tubular; a shear positioned between the upper slips and the lower slips, the shear operable to shear the tubular; and an ejector device connected between lower safing assembly and the upper safing assembly, the ejector device operable to physically separate the upper safing assembly from the lower safing assembly.

The package may include a vent carried by the lower safing assembly, the vent operable between an open and a closed position. In at least one embodiment the package further includes a vent carried by the lower safing assembly and positioned below the lower slip when connected to the well, wherein the vent is operable between an open and a closed position.

According to one or more embodiments of the invention, the ejector device includes an extendable piston rod. The piston rod may be extendable in response to the application of hydraulic pressure.

According to one or more embodiments of the invention, the safing package comprises a hydraulic accumulator disposed with the safing assembly and in hydraulic communication with the lower slips. In some embodiments, a plurality of hydraulic accumulators are arranged in an upper accumulator pod, wherein the upper accumulator pod is in hydraulic communication with the upper slips. According to at least one embodiment the shear is in hydraulic communication with at least one of a lower hydraulic accumulator pod and an upper hydraulic accumulator pod. Similarly, the ejector device is in hydraulic communication with at least one of a lower hydraulic accumulator pod and an upper hydraulic accumulator pod in some embodiments.

According to one or more embodiments, a vent is carried by the lower safing assembly and positioned below the lower slip when connected to the well, wherein the vent is operable between an open and a closed position; and a deflector device is positioned between the lower slips and the vent, wherein the deflector device is operable to a closed position to divert fluid flow toward the vent. In some embodiments, the deflector device does not seal against the tubular suspended in the lower safing assembly when in the closed position.

A subsea well safing system according to one or more aspects of the invention comprises a safing assembly comprising a lower safing assembly connected to a blowout preventer stack connected to a subsea well and an upper safing assembly connected to a marine riser; a safing assembly connector interconnecting the lower safing assembly and the upper safing assembly providing a bore therethrough in communication with the marine riser and the well; and an ejector device connected between the upper safing assembly and the lower safing assembly, the ejector device operable to physically separate the upper assembly and connected marine riser from the lower safing assembly.

The safing assembly can further comprise, for example, lower slips operable to engage a tubular suspended in the bore of the lower safing assembly; upper slips operable to engage the tubular suspend in the bore of the upper safing assembly; a shear located between the lower slips and the upper slips operable to shear the tubular; and a vent in communication with the bore, the vent operable between a closed position and an open position. In some embodiments, the safing system further comprises a deflector device located in the lower safing assembly between the lower slips and the vent, the deflector device operable to a closed position to divert fluid flow toward the vent.

According to one or more aspects of the invention, a subsea well safing sequence comprises utilizing a safing assembly installed between a blowout preventer stack of a subsea well and a marine riser, the safing assembly comprising a lower safing assembly connected to the blowout preventer stack and an upper safing assembly connected to the marine riser forming a bore between the riser and the blowout preventer stack; securing a tubular suspended in the bore at a position in the lower safing assembly; securing the tubular at a position in the upper safing assembly; shearing the tubular in the bore between the position in the lower safing assembly and the position in the upper safing assembly at which the tubular has been secured; and physically separating the upper safing assembly and the connected marine riser from the lower safing assembly connected to the blowout preventer stack.

The foregoing outlines features of several embodiments so that those skilled in the art may better understand the aspects of the disclosure. Those skilled in the art should appreciate that they may readily use the disclosure as a basis for designing or modifying other processes and structures for carrying out the same purposes and/or achieving the same advantages of the embodiments introduced herein. Those skilled in the art should also realize that such equivalent constructions do not depart from the spirit and scope of the disclosure, and that they may make various changes, substitutions and alterations herein without departing from the spirit and scope of the disclosure. The scope of the invention should be determined only by the language of the claims that follow. The term "comprising" within the claims is intended to mean "including at least" such that the recited listing of elements in a claim are an open group. The terms "a," "an" and other singular terms are intended to include the plural forms thereof unless specifically excluded.

What is claimed is:

1. A subsea well safing package for installing on a blowout preventer stack on a subsea well, the package comprising:

a safing assembly connector interconnecting a lower safing assembly and an upper safing assembly, the safing assembly connector operable to a disconnected position, wherein the lower safing assembly is to be connected to a blowout preventer stack on a subsea well and the upper safing assembly is to be connected to a marine riser;

the lower safing assembly comprising lower slips to engage and secure a tubular suspended in a bore formed through the lower and the upper safing assemblies;

the upper safing assembly comprising upper slips operable to engage and secure the tubular; and

a shear positioned between the upper slips and the lower slips, the shear operable to shear the tubular.

2. The package of claim **1**, further comprising a vent carried by the lower safing assembly, the vent operable between an open and a closed position.

3. The package of claim **1**, further comprising a vent carried by the lower safing assembly and positioned below the lower slips when connected to the well, wherein the vent is operable between an open and a closed position.

4. The package of claim **1**, further comprising an ejector device connected between the lower safing assembly and the upper safing assembly, the ejector device operable to push the upper safing assembly and the lower safing assembly apart and thereby physically separate the upper safing assembly from the lower safing assembly.

5. The package of claim **4**, wherein the ejector device comprises a piston rod operable to an extended position in response to the application of hydraulic pressure.

6. The package of claim **1**, further comprising a hydraulic accumulator in hydraulic communication with one selected from the lower slips and the upper slips.

7. The package of claim **1**, further comprising:

a plurality of hydraulic accumulators arranged in a lower accumulator pod, wherein the lower accumulator pod is in hydraulic communication with the lower slips; and

a plurality of hydraulic accumulators arranged in an upper accumulator pod, wherein the upper accumulator pod is in hydraulic communication with the upper slips.

8. The package of claim 4, further comprising:

a plurality of hydraulic accumulators arranged in a lower accumulator pod, wherein the lower accumulator pod is in hydraulic communication with the lower slips;

a plurality of hydraulic accumulators arranged in an upper accumulator pod, wherein the upper accumulator pod is in hydraulic communication with the upper slips;

the shear in hydraulic communication with at least one of the lower accumulator pod and the upper accumulator pod; and

the ejector device in hydraulic communication with at least one of the lower accumulator pod and the upper accumulator pod.

9. The package of claim 1, further comprising:

a vent carried by the lower safing assembly and positioned below the lower slips when connected to the well, wherein the vent is operable between an open and a closed position; and

a deflector device positioned between the lower slips and the vent, wherein the deflector device is operable to a closed position to divert fluid flow toward the vent.

10. The package of claim 9, wherein the deflector device does not seal against the tubular suspended in the lower safing assembly when in the closed position.

11. The package of claim 1, further comprising:

a vent carried by the lower safing assembly and positioned below the lower slips when connected to the well, wherein the vent is operable between an open and a closed position; and

a deflector device positioned between the lower slips and the vent, the deflector device operable to a closed position to divert fluid flow from the well to the vent, wherein the deflector device comprises three rams.

12. A subsea well safing system, comprising:

a safing assembly comprising a lower safing assembly connected to a blowout preventer stack connected to a subsea well and an upper safing assembly connected to a marine riser;

a safing assembly connector in a latched position interconnecting the lower safing assembly and the upper safing assembly providing a bore therethrough in communication with the marine riser and the well, the safing assembly connector operable to an unlatched position thereby disconnecting the upper safing assembly from the lower safing assembly; and

an ejector device connected between the upper safing assembly and the lower safing assembly, the ejector device operable to push the upper safing assembly and the lower safing assembly apart and thereby physically separate the upper safing assembly and connected marine riser from the lower safing assembly.

13. The system of claim 12, wherein the safing assembly further comprises:

lower slips operable to engage a tubular suspended in the bore of the lower safing assembly;

upper slips operable to engage the tubular suspended in the bore of the upper safing assembly;

a shear located between the lower slips and the upper slips operable to shear the tubular; and

a vent in communication with the bore, the vent operable between a closed position and an open position.

14. The system of claim 12, wherein the safing assembly further comprises:

lower slips operable to engage a tubular suspended in the bore of the lower safing assembly;

upper slips operable to engage the tubular suspended in the bore of the upper safing assembly;

a shear located between the lower slips and the upper slips operable to shear the tubular;

a vent in communication with the bore and located between the lower slips and the blowout preventer stack, the vent operable between a closed position and an open position; and

a deflector device located in the lower safing assembly between the lower slips and the vent, the deflector device operable to a closed position to divert fluid flow toward the vent.

15. A subsea well safing sequence, the method comprising:

utilizing a safing assembly installed between a blowout preventer stack of a subsea well and a marine riser, the safing assembly comprising a lower safing assembly connected to the blowout preventer stack and an upper safing assembly connected to the marine riser forming a bore between the riser and the blowout preventer stack, wherein the lower safing assembly comprises lower slips and the upper safing assembly comprises upper slips;

securing a tubular suspended in the bore with the lower slips at a position in the lower safing assembly;

securing the tubular with the upper slips at a position in the upper safing assembly;

shearing the tubular in the bore between the position in the lower safing assembly and the position in the upper safing assembly at which the tubular has been secured; and

after shearing the tubular, physically separating the upper safing assembly and the connected marine riser from the lower safing assembly connected to the blowout preventer stack.

16. The method of claim 15, wherein physically separating the upper safing assembly from the lower safing assembly comprises actuating an ejector device connected between the upper safing assembly and the lower safing assembly thereby pushing the upper safing assembly and the lower safing assembly apart.

17. The method of claim 15, further comprising disconnecting, prior to physically separating, the upper safing assembly from the lower safing assembly in response to actuating an assembly connector to an open position.

18. The method of claim 15, further comprising prior to securing the tubular, venting pressure from the bore through a vent located in the lower safing assembly between the blowout preventer stack and the position at which the tubular is to be secured in the lower safing assembly.

19. The method of claim 15, further comprising prior to securing the tubular:

venting pressure from the bore through a vent located in the lower safing assembly between the blowout preventer stack and the position at which the tubular is to be secured in the lower safing assembly; and

diverting fluid flow from the bore to the vent prior to securing the tubular.

20. The method of claim 19, wherein the diverting fluid flow comprises actuating a shutter ram to a closed position, wherein the shutter ram is located in the lower safing assembly between the vent and the position at which the tubular is to be secured in the lower safing assembly.

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