METHOD FOR EFFICIENT PRESSURE AND INFLOW TESTING OF A FLUID CONTAINMENT SYSTEM THROUGH REAL TIME LEAK DETECTION WITH QUANTIFICATION OF PVT EFFECTS

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ABSTRACT
A method for testing a well system comprising providing fluid into a chamber of the system, measuring a change in fluid pressure within the chamber and measuring a temperature change of fluid within the closeable chamber.
METHOD FOR EFFICIENT PRESSURE AND INFLOW TESTING OF A FLUID CONTAINMENT SYSTEM THROUGH REAL TIME LEAK DETECTION WITH QUANTIFICATION OF PVT EFFECTS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the benefit of U.S. Provisional Application No. 61/556,781, filed Nov. 7, 2011 entitled “Method For Efficient Leak Testing With Real Time Measurement of PVT Effects”, which is hereby incorporated herein by reference.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

[0002] Not applicable.

BACKGROUND


[0004] The disclosure relates generally to systems and methods for conducting a pressure test of well system equipment. More particularly, the disclosure relates to systems and methods for reliably and efficiently testing wellbore fluid containment system (FCS) equipment, such as blowout preventers (BOPs), choke and kill lines, wellhead hangers, casing, liner and liner hangers, tubing hangers, completion, mechanical barriers such as packers, cement plugs and other equipment. Further, the disclosure relates to both high pressure testing and low pressure testing of FCS equipment.

[0005] 2. Background of the Technology

[0006] In drilling for oil and gas from an offshore hydrocarbon producing well, a well or well system is provided that includes a drilling rig with a riser section and a drill string used to convey drilling fluid down the drill string and through a wellhead to a drill bit disposed within a wellbore of a formation. During drilling, the walls of the wellbore are sometimes encased via the installation of tubular casing strings in the wellbore. Cement may be displaced into the wellbore so as to secure the individual casing strings to the wall of the wellbore. Drilling fluid and circulation material (i.e., cuttings from the formation) recirculate from the drill bit back to the drilling rig via an annulus formed between the drill string and the cased wall of the wellbore, and via the annulus formed between the drill string and the riser section that encircles it.

[0007] A FCS of the well system is configured to provide a fluid tight barrier between fluid within the well system (e.g., drilling fluid, circulation material, formation fluid, etc.) and the surrounding environment. The FCS includes all critical sealing points, including the BOP itself and each of its individual rams, the choke manifold and kill manifolds, an internal blowout preventer (IBOP), as well as other components. The FCS may be stressed in situations where a fluid pressure differential results between the well system and the surrounding environment. For instance, a wellbore or formation fluid influx, also called a “kick”, can cause an unstable and unsafe condition at the drilling rig. When a kick is detected, a FCS of the well system may be used to prevent formation fluid from breaching the well system by “chocking” or “killing” the well and regain control. In another example, the fluid pressure within the well system may rapidly decrease in the event of a low pressure kick, for instance, when a low pressure cavity within the formation is breached during drilling. Some of the seals and sealing points within the well system may be pressure assisted, and thus rely on the pressure of the fluid around it to help seal. Thus, these pressure assisted seals may be jeopardized in the event of a low pressure kick. In another example, at a certain point in time it may be desirable to abandon the well by removing the riser and rig, and sealing the well via the casing, wellhead a cement plug installed in the wellbore. Upon removal of the riser, the fluid pressure within the wellbore may decrease substantially as the hydrostatic head of the fluid within the marine riser (e.g., high density drilling fluid, etc.) is typically larger than the hydrostatic head by the seawater.

[0008] In order to ensure the correct functioning of the FCS during the life of the well system, the FCS is subject to a variety of testing regimens. For instance, components of the FCS undergoes periodic positive testing that includes low pressure testing, which may be performed at approximately 350 pounds per square inch (psi) and high pressure testing which may be conducted at approximately 10,000-15,000 psi, to ensure the FCS is capable of withstanding a pressurization due to an uncontrolled influx of formation fluid or in the event of a low pressure kick that may jeopardize pressure assisted seals. Also, the FCS undergoes inflow or negative pressure testing to ensure the integrity of the casing and cement installed in the wellbore, the wellhead assembly, as well as other components of the FCS, prior to un installing the marine riser.

[0009] As part of the FCS high pressure testing procedure, a FCS test plug may be landed against a sealing surface within the FCS, followed by subsequent pressurization of the FCS. Per current federal regulations, pressure testing of the FCS must be conducted upon installation and before 14 days have elapsed since the last BOP pressure test. Low and high pressure tests must be conducted for each individual component, and each component must demonstrate that it holds a reasonably stable pressure. For instance, in practice a pressure decay rate of 4 pounds per square inch (psi) per minute or less is seen as reasonably stable.

[0010] Even though components of a FCS need only demonstrate pressure holding capability for five minutes to pass a presently-required pressure test, conducting the individual tests often take much longer due to PVT effects that take place due to the pressurizing of the test fluid. Specifically, friction generated by the action of pumping a fluid (e.g., via a reciprocating pump) increases the temperature as the fluid is pressurized. Referring to FIG. 1, graph 100 illustrates fluid pressures in relation to time at different positions along a vertically-oriented subsea drill string during a high pressure test. Pressure curve 110 illustrates the fluid pressure at a point within the drill string near the sea floor, with curves 120, 130 and 140 illustrating fluid pressure at progressively shallower points along the drill string, with curve 140 illustrating fluid pressure at the shallowest point, near the surface. Due to being located at different vertical depths along the drill string, curve 110 is at the highest pressure, while curve 140 is at the lowest pressure of the curves.

[0011] As shown in FIG. 1, the high pressure test can be divided into three phases: a pumping phase (112, 122, 132 and 142), a shut-in phase (114, 124, 134 and 144) and a depressurization phase (116, 126, 136 and 146). The pumping phase takes place when the test fluid is pumped into the well system in order to pressurize the FCS. Testing fluid may be pumped into the drill string by a cement unit or mud pump...
disposed at the drilling rig of the well system. Once the FCS of the well system has been pressurized to the appropriate testing pressure, pumping ceases and the well system is shut-in, such that a portion of the well system containing the system components to be tested is isolated from the outside environment. Shut-in phases 114, 124, 134 and 144 have a beginning (114a, 124a, 134a and 144a) and an ending (114b, 124b, 134b and 144b). As shown by FIG. 1, the pressure at the beginning 114a, 124a, 134a and 144a exceeds the pressure at the end 114b, 124b, 134b and 144b of the shut-in phase. Also, in this pressure test, each shut-in phase includes a pressurization point (114c, 124c, 134c and 144c) where additional testing fluid is pumped into the well system to slightly increase fluid pressure within the FCS, known in the field as “bumping up the pressure.” This additional fluid may be pumped in at the pressurization point during the shut-in phase in order to return the fluid pressure within the FCS to the appropriate test pressure, a level similar to that existing near the beginning of the tests, at points 114a, 124a, 134a and 144a.

[0012] The pressure decay occurring during the shut-in phases (e.g., 114, 124, 134 and 144) for each pressure curve (e.g., 110, 120, 130 and 140) is due to heat transfer from pressurized fluid within the FCS to fluid in the surrounding environment. As will be discussed in greater detail herein, heat transfer is greater for testing fluid near the surface, as opposed to testing fluid within the FCS that is disposed farther downhole. The greater amount of heat transfer near the surface is due to friction generated during the process of pumping the testing fluid into the well system (e.g., via a cement unit or mud pump) for the purpose of pressurizing testing fluid within the FCS. This heat transfer leads to a greater relative difference in temperature between the testing fluid disposed within the marine riser and ambient water surrounding the drill string at that same vertical depth, resulting in a relatively large amount of heat transfer from the testing fluid disposed near the surface and the ambient water surrounding the drill string at that depth. The total or aggregate pressure decay within the FCS, when there is no fluid leak between the FCS and the surrounding environment, corresponds with the total or net heat transfer out of the fluid disposed within the FCS to the surrounding environment.

[0013] During the performance of the FCS low pressure and high pressure test, an analog, low resolution circular chart recorder may be used by drilling personnel on the drilling rig to observe a continuous pressure reading of the FCS. Even in cases where the tested FCS component is not leaking, the pressure test may often last over half an hour or longer before the pressure within the FCS begins to stabilize enough such that a continuous five minute period of successful pressure stabilization may be recorded. Further, due to pressure decay caused by PVT effects (e.g., pumping effects) and the low resolution of the analog chart recorder, FCS pressure tests are sometimes judged as successful before full stabilization (e.g., decay of 4 psi/min or less), thus allowing for the risk that remaining pressure decay may be due to a leak within the FCS, in addition to PVT effects. In practice, this phenomenon is especially impactful at higher testing pressures, as are required in deeper, hot wells and where oil based mud (OBM) or synthetic oil based mud (SOBM) is used as the testing fluid in offshore wells with a subsea BOP in deepwater.

[0014] Regarding negative pressure tests, once the drilling, completion and production phases of a well system have been completed, the well may be abandoned by uninstalling the riser, BOP and other components of the well system, and sealing the wellhead to prevent fluid communication between the wellbore and the surrounding environment. Therefore, prior to removing the marine riser, the negative pressure test is conducted to simulate the reduced hydrostatic well pressure that exist if the riser is removed or during abandonment by substituting seawater in the fluid column from the wellhead to surface. Thus, once the subsea wellhead or wellbore has been sealed, the reduced fluid pressure during the inflow or negative pressure testing operation creates a negative pressure differential across the wellbore and/or sealed wellhead. The process for simulating the negative pressure environment is created within the wellbore prior to abandoning the well via either the mechanical stab-in plug (MSP) method or the choke and kill line (CKL) method.

[0015] In the MSP method, a temporary or permanently installed tool is disposed within the wellbore configured to act as a barrier preventing inflow into the wellbore. In this method, a special mechanical stab-in plug, which may be either permanent or retrievable, is disposed within the wellbore that is configured to seal off the lower section of wellbore while also providing the ability of allowing the drill string or other conduit to be stabbed through it, once relatively low density fluids (e.g., base oil, water, etc.) was pumped into the lower, sealed portion of the wellbore, creating a negative pressure differential across the MSP plug. In the CKL method, a ram or other sealable mechanism of the BOP is actuated to fluidically isolate the wellbore and wellhead from the riser disposed above the BOP. Following the actuation of the BOP, relatively low density fluid is pumped into the wellbore via the choke and/or kill lines in order to create a negative pressure differential across the sealed ram of the BOP.

[0016] As with the high pressure tests, in judging the success or failure of the negative pressure test using either the MSP or CKL methods pressures are measured at the surface on the offshore rig. Because surface measurements are relied upon in determining the success of a negative pressure test, the plugging of the drill string by lost circulation material (LCM), the incorrect lining up of valves in performing either the MSP or CKL methods, or other causes may jeopardize the accuracy of the test. Moreover, those ordinarily skilled in the art will readily appreciate that supplementing data from surface measurements with real time downhole information aids in the administering and interpretation of pressure tests, including high, low and negative pressure tests of components of the well system.

[0017] Accordingly, there remains a need in the art for systems and methods that allow for timely and effective high and low pressure testing of well system equipment, such as a fluid containment system. Further, it would be advantageous if such systems and methods would calibrate against PVT effects during a pressure test of well system equipment. Still further, it would be advantageous to provide a system that includes a means providing a continuous pressure signal with a relatively improved resolution and higher efficiency.

BRIEF SUMMARY OF THE DISCLOSURE

[0018] In an embodiment, a method for pressure testing a well system comprises providing fluid into a closeable chamber of the well system, measuring in real time a change in fluid pressure within the closeable chamber using a sensor disposed within the well system and measuring in real time a temperature change of fluid within the closeable chamber.
using a sensor disposed within the well system. In an embodiment, the closeable chamber is provided with a fluid having a higher density than water. In some embodiments, the closeable chamber is provided with a fluid having a density substantially equal to water. In an embodiment, the closeable chamber comprises at least a portion of a drill string. In an embodiment, the closeable chamber comprises at least a portion of a choke line. In an embodiment, the closeable chamber comprises at least a portion of a kill line.

[0019] In an embodiment, the method may further comprise using real time pressure and temperature measurements to calculate real time pressure decay of fluid within the closeable chamber, wherein the pressure decay arises from changes in the volume of fluid within the closeable chamber over time. In an embodiment, the method may further comprise stubbing into a plug of the well system with the drill string to allow for fluid communication between the drill string and a volume of fluid disposed below the plug. In an embodiment, the closeable chamber comprises at least a portion of a blowout preventer. In an embodiment, the method may further comprise sealing the blowout preventer to prevent fluid communication between a drill string of the well system and an annulus adjacent to the blowout preventer. In an embodiment, the method may further comprise measuring in real time a pressure change in the closeable chamber using a sensor disposed within the well system. In an embodiment, the closeable chamber comprises a component of a completion system. In an embodiment, the component of the completion system comprises a tubing hanger. In an embodiment, the method may further comprise communicating a signal from the sensor using a wired pipe communication network.

[0020] In an embodiment, a method for pressure testing a well system comprises providing fluid into a closeable chamber of the well system and determining in real time a change in fluid pressure in the closeable chamber, wherein the change in pressure arises from a change in the volume of fluid within the closeable chamber. In an embodiment, the method further comprises determining in real time a change in fluid pressure within the closeable chamber arising from a change in temperature of the fluid. In an embodiment, determining in real time a change in fluid pressure within the closeable chamber arising from a change in the volume of fluid within the closeable chamber comprises measuring in real time a change in fluid pressure within the closeable chamber using a sensor disposed within the well system. In an embodiment, determining in real time a change in fluid pressure within the closeable chamber arising from a change in temperature of the fluid comprises calculating the change in temperature over time for a section of a wired pipe communication network. In an embodiment, the method further comprises summing the pressure decay arising from changes in temperature over time for the section of the wired pipe communication network. In an embodiment, the method further comprises subtracting the summed pressure decay arising from changes in temperature over time from the total fluid pressure decay within the closeable chamber. In an embodiment, the closeable chamber comprises at least a portion of a blowout preventer. In an embodiment, the closeable chamber comprises at least a portion of a wellhead.

[0021] In an embodiment, a method for pressure testing a well system comprises providing fluid into a closeable chamber of the well system, measuring in real time a change in fluid pressure within the closeable chamber using a sensor of a wired pipe communication network disposed within the well system, measuring in real time a temperature change of fluid within the closeable chamber using a sensor of the wired pipe communication network disposed within the well system and calculating in real time the pressure decay arising from a change in the volume of fluid disposed within the closeable chamber using the pressure and temperature measurements. In an embodiment, the closeable chamber comprises at least a portion of a blowout preventer. In an embodiment, the closeable chamber comprises at least a portion of a component of an upper completion system.

[0022] Embodiments described herein comprise a combination of features and characteristics intended to address various shortcomings associated with certain prior devices, systems, and methods. The various features and characteristics described above, as well as others, will be readily apparent to those skilled in the art upon reading the following detailed description, and by referring to the accompanying drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

[0023] For a detailed description of the exemplary embodiments of the invention disclosed herein, reference will now be made to the accompanying drawings in which:

[0024] FIG. 1 is a graph illustrating pressure curves generated during a pressure test of a drilling system;

[0025] FIG. 2 is a schematic representation of an embodiment of a well system configured to conduct a fluid containment system pressure test in accordance with principles described herein in accordance with principles described herein;

[0026] FIGS. 3A-3D are perspective views, some in cross-section, showing components of the wired pipe communication network shown in FIG. 2;

[0027] FIG. 4A is a graph illustrating pressure curves generated during a pressure test of a well system, such as the well system shown in FIG. 2;

[0028] FIG. 4B is a graph illustrating temperature curves generated during a pressure test of a well system, such as the well system shown in FIG. 2;

[0029] FIG. 5 is a graph illustrating temperature curves generated during a pressure test of a drilling system, such as the well system shown in FIG. 2;

[0030] FIG. 6 is a schematic representation showing the well system shown in FIG. 2 configured to conduct a completion system pressure test in accordance with principles described herein;

[0031] FIGS. 7A-7B are schematic representations of the well system shown in FIG. 2 configured to conduct a negative pressure test using an MSP method in accordance with principles described herein; and

[0032] FIGS. 8A and 8B are schematic representations of the well system shown in FIG. 2 configured to conduct a negative pressure test using a CKL method in accordance with principles described herein.

DETAILED DESCRIPTION

[0033] The following discussion is directed to various exemplary embodiments. However, one skilled in the art will
understand that the examples disclosed herein have broad application, and that the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to suggest that the scope of the disclosure, including the claims, is limited to that embodiment. The drawing figures are not necessarily to scale. Certain features and components herein may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in interest of clarity and conciseness.

[0034] In the following discussion and in the claims, the terms “including” and “comprising” are used in an open-ended fashion, and thus should be interpreted to mean “including, but not limited to . . . .” Also, the term “couple” or “couples” is intended to mean either an indirect or direct connection. Thus, if a first device couples to a second device, that connection may be through a direct connection, or through an indirect connection via other devices, components, and connections. In addition, as used herein, the terms “axial” and “axially” generally mean along or parallel to a given axis (e.g., given axis of a body or a port), while the terms “radial” and “radially” generally mean perpendicular to the given axis. For instance, an axial distance refers to a distance measured along or parallel to the given axis, and a radial distance means a distance measured perpendicular to the given axis. Still further, as used herein, the phrase “communication coupler” refers to a device or structure that communicates a signal across the respective ends of two adjacent tubular members, such as the threaded box-pin ends of adjacent pipe joints; and the phrase “wired drill pipe” or “WDP” refers to one or more tubular members, including drill pipe, drill collars, casing, tubing, sub, and other conduits, that are configured for use in a drill string and include a wired link. As used herein, the phrase “wired link” refers to a pathway that is at least partially wired along or through a WDP joint for conducting signals, and “communication link” refers to a plurality of communicatively-connected tubular members, such as interconnected WDP joints for conducting signals over a distance.

[0035] Systems and methods for reliably and efficiently testing components of a well system are disclosed herein. More particularly, systems and methods for detecting leaks within a well system during a pressure or inflow test via accounting for PVT effects are described herein. In some embodiments the disclosure, pressure, temperature, and pressure measurements of fluid of the well system is taken in real time via a wired pipe communication network.

[0036] A system and method for pressure testing components of a well system is disclosed herein. Embodiments described herein may be employed in various drilling and production applications; however, it has particular application as a system and method for detecting leaks during a test of well system via accounting for and calibrating against PVT effects during the pressure testing of pressure containing components of the well system, such as a fluid containment system (FCS). Further, it has particular application with regard to offshore well drilling and production systems.

[0037] Referring now to FIG. 2, an offshore well drilling system 10 generally includes an offshore semi-submersible drilling rig 20 disposed at the water line 12 with a derrick 24 and deck 22 having a testing fluid system (TFS) 21 disposed thereon. System 10 further includes a riser 30 that extends between the rig 20 and a wellhead 60 disposed at the sea floor 14, a FCS 40, a drill string 50 disposed within a marine riser 30 and having a central axis 55 and internal passageway 50b. Well system 10 further includes casing 70 that extends downward from a casing hanger 61 of wellhead 60 and is secured in place via cement 72.

[0038] TFS 21 is disposed at rig floor 22 and comprises a mud pit 25, a cement unit 27 and a fluid conduit 28. Conduit 28 provides a fluid flowpath 29 for the passage of testing fluid 29a from mud pit 25, through cement unit 27, and to the passageway 50b of drill string 50. Cement unit 27 comprises a high pressure, reciprocating fluid pump. However, in other embodiments cement unit 27 may comprise other components configured to pressurize a fluid. Testing fluid 29 comprises a drilling fluid that may be at a high density or high weight (e.g., drilling fluid, SOBM, completion fluid, etc.) relative to the ambient water 13 disposed below water line 12. For instance, fluid 29 typically has a high enough density to overcome the pressure of fluid within the adjacent formation 16. Alternatively, testing fluid may also comprise a relatively lower density fluid, such as water.

[0039] An annulus 35 is formed between drill string 50 and riser 30 and allows for the recirculation of drilling fluid between rig 20 and a wellbore 62 that extends into subterranean formation 16 from the sea floor 14. FCS 40 generally includes components configured to retain and manage fluid pressure within well system 10 (e.g., drill string 50, FCS 40 and annulus 35). In the embodiment of well system 10, FCS 40 includes BOP 41, choke line 44, kill line 46 and an internal blowout preventer (IBOP) 48, wellhead and the casing and or liner and float valves. Rams 42 of IBOP 41 are configured to provide an annular seal 43 about drill string 50 upon actuation, dividing annulus 35 into a first or upper section 35a extending between rig 20 and seal 43 and a second or middle section 35b extending from seal 43 downward to a FCS testing plug 49 coupled to drill string 50.

[0040] A third or lower section 35c extends from wellhead 60 into the wellbore 62. Testing plug 49 is configured to prevent fluid flow between middle portion 35b of annulus 35 and a lower portion 35c extending into wellbore 62. Testing plug 49 forms an annular seal 49a against an annular surface 61a of hanger 61 disposed within wellhead 60. Testing plug 49 is coupled to an end of two adjacent tubular joints or sections 52 that extend between nodes 51 and physically engages upper annular surface 61a of hanger 61 via lower annular surface 49a. A radial port or opening 45 is provided in the drillstring 50 to act as a route of fluid communication between drillstring 50 and the annulus 35 above testing plug 49. During drilling, a volume of formation fluid or a kick of fluid from the formation 16 that has a relatively higher pressure than drilling fluid disposed within wellbore 62 may flow into wellbore 62 and travel upward through lower section 35c of annulus 35 (testing plug 49 is not installed in well system 10 during the act of drilling). The formation kick may be trapped or isolated within lower section 35c of annulus 35 via actuating one or more rams 42 of BOP 41 to provide the annular seal 43. Choke line 44 and kill line 46 may be configured to provide for alternate routes of fluid communication between rig 20 and annulus 35 such that the kill fluid (e.g., water, weighted drilling mud, etc.) is pumped into FCS 40 to prevent further upward flow of fluid from formation 16.

[0041] During a formation kick, an influx of fluid from the formation may be circulated upward through choke line 44 to the rig 20, in an effort to regain control and stabilize the flow of formation fluid into annulus 35 by introducing a fluid at sufficient density to provide the minimum required hydrostatic head to balance the formation pressure such that fluid
pressure within FCS 40 may stabilize. Choke line 44 generally includes a lower valve 44a, a manifold 44b and an upper valve 44c. Fluid flow through choke line 44 may be restricted by closing lower valve 44a or upper valve 44c. Further, choke manifold 44b includes a plurality of valves, chokes and other equipment, and as such is configured to manage and regulate flow through choke line 44. Because successful control of a formation kick may depend on the effective operation of choke line 44 and its components, valves 44a, 44c and manifold 44b are individually pressure tested during the pressure testing of FCS 40. Kill line 46 is also used to manage a formation kick by allowing for circulation between annulus 35 and rig 20. For instance, kill line 46 is used as a route of fluid communication to pump high density drilling mud or other fluid downward from rig 20 to the annulus 35 to forcibly maintain the fluid from the formation kick or influx within the wellbore 62. Thus, a kill line such as kill line 46 may be used to “kill” the well by reversing, stopping or at least substantially restricting the flow of fluid from the formation into the wellbore 62 by pumping heavy fluid into the entire fluid circulation system (e.g., annulus 35, choke line 44, kill line 46, etc.) from the rig 20. Kill line 46 comprises a lower valve 46a, a kill manifold 46b and an upper valve 46c. As with choke line 44, flow through kill line 46 may be substantially restricted or controlled via valves 46a, 46c and manifold 46b. Thus, during pressure testing of FCS 40, valves 46a, 46c and manifold 46b are pressure tested as well.

Another component of FCS 40, IBOP 48, is disposed at an upper end 50a of drill string 50 at the rig 20 and is configured to manage fluid pressure within drill string 50. For instance, during a formation kick, high pressure formation fluid may begin flowing upward through string 50 via an opening or port of the string 50 disposed within wellbore 62 (e.g., at the drill bit). For instance, IBOP 48 includes a valve that allows for the passage of fluid into string 50 but may be closed to restrict fluid from flowing out of string 50 through IBOP 48 in the event of a formation kick. Thus, because IBOP 48 may be used in effectively controlling a formation kick, IBOP 48 is pressure tested during the pressure testing of FCS 40.

Referring now to FIGS. 2 and 3A-3D, drill string 50 comprises a plurality of nodes 51 (e.g., 51a-51e) coupled between a plurality of tubular joints 52. Wired or networked drill pipe incorporating distributed sensors can transmit data from anywhere along the drill string 50 to the rig 20 for analysis. Nodes 51 are provided at desired intervals along the drill string 50. Network nodes 51 essentially function as signal repeaters to regenerate and/or boost data signals and mitigate signal attenuation as data is transmitted up and down the drill string. The nodes 51 may also include measurement assemblies. The nodes 51 may be integrated into an existing section of drill string or a downhole tool along the drill string 50. For purposes of this disclosure, the term “sensors” is understood to comprise sources (to emit/transmit energy/signals), receivers (to receive/detect energy/signals), and transducers (to operate as either source/receiver). Tubular joints 52 include a first pipe end 53 having, for example, a first induction coil 53a and a second pipe end 54 having, for example, a second induction coil 54a.

Nodes 51 comprise a portion of a wired pipe communication network 56 that provides an electromagnetic signal path that is used to transmit information along the drill string 50. The communication network 56, or broadband network telemetry, may thus include multiple nodes 51 based along the drill string 50. Communication links or wired conductors 52a may be used to connect the nodes 51 to one another, and may comprise cables or other transmission media integrated directly into sections of the drill string 50. The cable may be routed through the central wellbore of the drill string 50, or routed externally to the drill string 50, or mounted within a groove, slot or passageway in the drill string 50. Signals from the plurality of sensors 51 along the drill string 50 are transmitted to the rig 20 through wire conductors 52a along the drill string 50. Communication links 52a between the nodes 51 may also use wireless connections. A plurality of packets may be used to transmit information along the nodes 51. Further detail with respect to suitable nodes, a network, and data packets is disclosed in U.S. Pat. No. 7,207,396 (Hall et al., 2007), hereby incorporated in its entirety by reference. Various types of sensors 57 may be employed along the drill string 50 in various embodiments, including without limitation, axially spaced pressure sensors, temperature sensors, and others. The sensors 57 may be disposed on the nodes 51 positioned along the drill string, disposed on tools incorporated into the drill string, or a combination thereof. Thus, sensors 57 of nodes 51 may measure temperature, pressure, etc., of fluid within string 50 or annulus 35 of well system 10.

Network nodes 51 are disposed along the drill string 50 between joints 52. In some embodiments, the booster assemblies are spaced at 1,500 ft. (500 m) intervals to boost the data signal as it travels the length of the drill string 50 to prevent signal degradation. Network nodes 51 are also located at these intervals to allow measurements to be taken along the length of the drill string 50. The distributed network nodes 51 provide measurements that give the driller additional insight into what is happening along the potentially miles-long stretch of the drill string 50.

Rig 20 includes a well site computer 58 that may display information for the drilling operator. The wired pipe communication network 56 transmits information from each of a plurality of sensors 57 to a surface computer 58. Information may also be transmitted from computer 58 to another computer 59, located at a site remote from the well, with this computer 59 allowing an individual in the office remote from the well to review the data output by the sensors 57. Although only a few sensors 57 are shown in the figures, those skilled in the art will understand that a larger number of sensors may be disposed along a drill string (e.g., drill string 50) when drilling, and that all sensors associated with any particular node may be housed within or annexed to the node 51, so that a variety of sensors rather than a single sensor will be associated with that particular node.

Due to the risk of losing control of well system 10 (i.e., the uncontrolled flow of combustible or flammable formation fluids into well system 10) caused by an uncontrolled wellbore influx of fluid from the formation, it is important to detect the influx as soon as possible. In some circumstances, a BOP (e.g., BOP 41) of the FCS (e.g., FCS 40) is actuated to close off the well above the wellbore influx. In some cases, for example in deepwater wells, the wellbore influx may migrate above the BOP before a ram of the BOP fully closes to seal off the wellbore. In the embodiments disclosed herein, the wired pipe communication network 56 allows wellsite personnel to identify potential remedial actions for the migrated wellbore influx. In some embodiments, the measurements used are independent from surface measurements.
One or more embodiments of a well drilling system 10 comprising a fluid containment system 40 and a testing fluid system 21 having been disclosed, one or more embodiments of a method of pressure testing components of the FCS 40 are also disclosed herein. Further, one or more embodiments of a method for evaluating or troubleshooting the results of a failed pressure test of components of FCS 40 are disclosed herein. In an embodiment, a FCS pressure testing method generally includes the steps of engaging a testing plug of the FCS against a sealing surface within the FCS (e.g., a casing hanger), disposing a quantity of testing fluid (e.g., drilling fluid, etc.) within the FCS, isolating a component of the FCS (e.g., actuating a ram of the BOP, closing a valve of the choke line, etc.), displacing an additional quantity of testing fluid into the FCS to increase the fluid pressure within the FCS to a predetermined testing pressure, shut-in the FCS by ceasing the displacement of testing fluid into the FCS, continuously in real-time monitor fluid pressure within the FCS via a wired pipe communication network for a period of time.

In an embodiment, ram 42 of BOP 41 may be pressure tested as part of the regime for pressure testing each individual component of FCS 40. In this embodiment, testing plug 49 is coupled to drill string 50 and displaced downward through marine riser 30 until annular surface 49a of tool 49 engages annular surface 61a of tubing hanger 61 to create annular seal 49c, which divides annulus 35 into upper section 35a and lower section 35c. Before, during or after sealing engagement has been achieved between tool 49 and hanger 61, high density testing fluid 29 (e.g., drilling fluid, SOBM, competition fluid, etc.) is disposed within drill string 50 and riser 30 at a relatively low pressure (e.g., approximately 300-350 psi) using cement unit 27 and flowpath 29a. Also, prior to commencement of the pressure testing of FCS 40, ram 42 of BOP 41 is actuated to form an annular seal 43 against an outer surface of drill string 50, substantially preventing testing fluid from a port 45 of string 50 from flowing upward into the upper section 35a of annulus 35. Thus, annular seals 49c and 43 form middle section or closable chamber 35b within marine riser 30. During the course of the pressure testing of ram 42, pressure and temperature of fluid within annulus 35 and drill string 50 is continuously measured at different vertical depths along string 50 via nodes 51a, 51b, 51c, etc. For instance, pressure and temperature of fluid within chamber 35b is continuously measured via node 51c while pressure and temperature in upper portion 35a are measured via nodes 51a and 51b and the temperature and pressure of lower portion 35c are measured by nodes 51a and 51c. Measurements taken by sensors 57 at nodes 51 (e.g., nodes 51a-51c) are continuously transmitted to computers 58 or 59 at rig 20 via wired pipe communication network 56.

Following the engagement of annular seals 49c and 43, fluid pressure within drillstring 50 and chamber 35b of annulus 35 is increased to a predetermined testing pressure by displacing a volume of testing fluid 29 into chamber 35b via port 45. Testing fluid 29 is pumped using cement unit 27 into drill string 50 via fluid flowpath 29a, which comprises mud pit 25, cement unit 27 and passageway 50b of string 50. Testing fluid 29 within chamber 35b is subsequently pressurized to approximately between 5,000-15,000 psi by cement unit 27. During the process of pressurizing testing fluid within chamber 35b, testing fluid 29 is disposed within choke line 44 and kill line 46, preventing fluid within chamber 35b from flowing up lines 44, 46 via the weight of the fluid 29 disposed within lines 44, 46.

FIGS. 4A and 4B illustrate graphs of data that may be generated by nodes 51 (e.g., 51a, 51b and 51c) during a high pressure test of components of FCS 40. Curves 502 and 508 illustrate the temperature and pressure curves, respectively, captured in real time by top node 51a. Curves 504 and 510 illustrate the temperature and pressure curves, respectively, captured in real time by middle node 51b. Curves 506 and 512 illustrate the temperature and pressure curves, respectively, captured in real time by bottom node 51c. Nodes 51a, 51b and 51c are each within fluid communication with one another, and thus expansion of fluid disposed proximal to one node will result in a measured fluid pressure increase by all three nodes. A pumping phase 207 is followed by a shut-in phase 208, having a beginning 208a and an ending 208b, marks the period of time after pumping has finished and before FCS 40 has been depressurized, which is then followed by a depressurization phase 209. Specifically, during pumping phase 207, testing fluid 29 is pumped into drillstring 50 via cement unit 27, which in turn displaces a volume of fluid into chamber 35c, pressurizing the chamber 35c to the BOP testing pressure. Once pressure within chamber 35c has reached the BOP testing pressure, the beginning 208a of shut-in phase 208 initiates with the cessation of pumping from cement unit 27, stopping the flow of testing fluid 29 into drillstring 50 at rig 20. As part of the BOP pressure test shown in FIG. 2, ram 42 must successfully hold the BOP test pressure for a specified period of time. In one example, ram 42 must hold 15,000 psi for a period of five minutes. Friction from pumping results in an increase in temperature of the additional testing fluid 29 pumped into FCS 40 and string 50 from mud pit 25. During shut-in phase 208 heat generated within the pumped-in testing fluid 29 begins to transfer out into fluid occupying riser 30 and/or the ambient seawater surrounding riser 30. Thus, at least partially arising from the transfer of heat from testing fluid 29, fluid pressure within chamber 35c steadily decreases in response to the decreasing temperature of fluid within FCS 40, especially with regard to the additional testing fluid 29 pumped into FCS 40 from mud pit 25.

As opposed to traditional surface measurements (e.g., on a circular chart), the data captured by nodes 51a, 51b and 51c of FIG. 2 quantify both pressure and temperature of the fluid within FCS 40, allowing the computers 58, 59, to correct against PVT effects in order to determine the amount of pressure decay during the shut-in phase 208 that is arises from the decay in temperature, and not due to a possible leak. Due to the relationship between pressure, volume, and temperature, a pressure decrease may only be caused by decay in temperature. A leak within a FCS results in a decrease in the volume of fluid present in the FCS and in turn a decrease in fluid pressure within the FCS. The ability to extract the amount of pressure decay due to the decay in temperature allows for a more time efficient shut-in phase for non-leaking FCSs as the pressure decay due to decay in fluid temperature will be quantified and extracted, leaving a near-zero change in pressure over time, illustrating that the system is holding pressure and has successfully passed the pressure test.

The total or net pressure decay within the FCS arising from temperature decay(dP/T) is calculated from the node data using the equation:
\[ dP_T = \sum_i \frac{dT_r}{dt} \]

where \( i \) denotes the section between nodes (e.g., nodes 51a-51e), with the number of sections being a function of the number of nodes (number of sections = (number of nodes));

denotes the change in temperature for a given section \((dT_r)\) divided by the change in time \((dt)\). FIG. 5 illustrates the relationship between the total pressure decay \((dP)\) 602, the pressure decay arising from a decay in temperature \((dP_T)\) 604 and the pressure decay arising from a decrease in the volume of fluid \((dP_v)\) 606 disposed in a non-leaking FCS, where the total pressure decay is substantially arising from the decay in temperature and thus the decay in pressure arising from a change in volume is near zero. This illustrates that when the decay in pressure arising from a decay in temperature is known, it may be accounted for or removed (i.e., subtracted) from the pressure decay measured by the nodes, leaving only the pressure decay to a change in volume. Given that in a non-leaking FCS the volume will remain constant such that the change in temperature due to a change in volume will be approximately zero, if the measured pressure decay and the pressure decay due to temperature are not substantially equal then a leak in the measured system will be indicated. Because the decay in pressure due to temperature has been filtered out, a drilling operator will not have to wait for the temperature within the measured system to stabilize before receiving an indication of whether the system has passed or failed the pressure test, shortening the total time for a given test.

Referring back to FIG. 2, in order to test the sealing integrity of ram 42, the pressure and temperature of sections of the drill string 50 are measured in real time in order to determine the \(dP_T\) for each section, and after the \(dP_T\) is observed from the computers 58, 59, as holding substantially constant pressure for approximately five minutes, the pressure test would be successful. In addition to ram 42 of BOP 41, other components of FCS 40 may be pressure tested in a similar manner. For instance, other individual rams of BOP 41 may be actuated to create an annular seal within annulus 35, forming a cavity defined by the ram’s annular seal and the seal 49a produced by BOP testing plug 49. Likewise, lower valves 44a, 46a, manifolds 44b, 46b, and upper valves 44c, 46c, of choke line 44 and kill line 46, respectively, may be pressure tested. In order to test the components of choke line 44 and kill line 46, high density testing fluid 29 is pumped into drillstring 50 via cement unit 27. Ram 42 of BOP 41 may be actuated to create annular seal 43. However, instead of allowing fluid communication between choke line 44 and kill line 46 with chamber 35c, a component of lines 44, 46, may be sealed (e.g., lower valve 44a). In this embodiment, the sealed component (e.g., valve 44a) may be pressure tested to see if it holds the BOP test pressure for a requisite period of time (e.g., five minutes). In another embodiment, nodes are placed (e.g., nodes similar to nodes 51) within choke line 44 or kill line 46 in order to continuously measure and transmit pressure and temperature readings from lines 44, 46 and quantify any pressure decay within lines 44, 46, due to temperature decay so as to determine if there has been a decay in pressure due to a decrease in the volume of fluid disposed within lines 44, 46. In this embodiment, other components of network 56 would be incorporated into lines 44 and 46 (e.g., wired conductors 52a, etc.) to allow for the transference of signals or data from nodes of lines 44 and 46 to computers 58, 59. Further, while pressure would be measured in real time from nodes disposed in lines 44, 46, temperature measurements would be read from nodes disposed within drill string 50, as heated fluid would be pumped into string 50 from cement unit 27.

FIG. 6 illustrates well system 10 configured to conduct a high pressure test of an upper completion system of the FCS 40, including tubing 81 and casing 70. Upon completion of the drilling phase, a lower completion and an upper completion may be installed within wellbore 62 prior to the beginning of the production phase of well system 10. For instance, in the embodiment illustrated in FIG. 6, upper completion 80 generally includes tubing 81 coupled to a tubing hanger 82 to serve as the main support for production tubing and to act as a sealing point of the riser 30 at the wellhead 60, and casing 70 which is installed and cemented in place via cement 72 to seal the wellbore 62 from the formation, thus making wellbore 62 a closeable chamber configured to prevent formation fluid from leaking into the wellbore 62.

Tubing 81 includes a port 86 that provides fluid communication between wellbore or chamber 62 and the internal passageway 50b of string 50. Tubing hanger 82, upon installation in wellhead 60, creates an annular seal 28a that prevents fluid communication between wellbore 62 and the annulus 35 within marine riser 30. Tubing 81 and tubing hanger 82 are installed via a tubing hanger running tool 83 that is coupled to the downhole terminal end 50 of drill pipe 50. Specifically, tubing hanger 82 and running tool 83 are coupled together as tubing 81 is displaced downward into wellbore 62. Following the installation of upper completion 80, a lower completion may be installed within wellbore 62 that includes production packers to isolate particular zones of wellbore 62, plugs, circulating devices, etc. Once the lower and upper completions have been installed, running tool 83 may be decoupled from tubing hanger 82, allowing for the removal of drill pipe 50 and running tool 83 from the marine riser 30.

Testing of seal 82a includes inflow or negative pressure testing and positive pressure testing at both high (e.g., approximately 70% of maximum capacity) and low pressures. To test the seal integrity of seal 82a of hanger 61 and/or the casings 70, as well as other components of upper completion 90, high density fluid (e.g., drilling fluid, completion fluid, etc.) is pumped from a cement unit 27, down through the drill string 50, out through a port 86 (as indicated by the arrows shown in FIG. 6) and into the wellbore 62. Nodes 51 (e.g., 51a-51e, etc.) disposed within annulus 35 are used to indicate real time pressure and temperature of the fluid in both passageway 50b of string 50 and wellbore to determine the real time decay in pressure due to an increase in volume caused by a leak in the upper completion 90, \(dP_T\). If seal 82a of tubing hanger 82 and the seal between casing 70 and formation 16 are properly sealed, the pressure and temperature data transmitted from nodes 51 (e.g., 51a-51e, etc.) will indicate a nearly constant \(dP_T\), thus indicating successful a positive pressure test of upper completion 90.

While the embodiment illustrated in FIG. 6 describes the use of nodes 51 and network 56 in pressure testing an upper completion 90, nodes 51 and network 56 may
also be used for performing a pressure test of an installed lower completion. For instance, nodes 51 of tubing 82 may be disposed within individual production zones that are sealed via a plurality of production packers. The annular seal created by each installed production packer may be tested by pressurizing each individual sealed production zone and measuring in real time the fluid pressure and temperature within the particular tested zone.

Besides the positive pressure testing, also inflow or negative pressure testing is commonly required for wells with a subsea BOP or a mudline suspension system to verify barriers and well integrity for those instances that the wellbore may be exposed to a reduced hydrostatic pressure as may be the case once the marine riser is eliminated or during abandonment. Wellbores of well systems, such as system 10, may be subjected to negative pressures upon abandonment (e.g., pressure within wellbore 62 may be lower than in the surrounding environment 13), when wellhead 60 is sealed and BOP 41 and riser 30 have been removed. Formation fluid within the wellbore may be of a higher pressure than the seawater surrounding the wellhead, creating a negative pressure across wellhead 60 that may lead to an inflow of fluid from formation 16 into the wellbore 62 if FCS 40 fails to seal wellbore 62. As discussed previously, inflow or negative pressure testing involves creating a negative pressure environment within the wellbore (e.g., wellbore 62) through the use of low density fluids, possibly seawater.

FIGS. 9A and 9B illustrate a negative pressure testing setup using the MSP method. In this embodiment, a mechanical packer or plug 804 is installed in wellbore 62. In some embodiments, barrier plug 804 may be a temporary or removable plug such as the RTTS (Hulliburton tool) (3000 N, Sam Houston Pkwy E, Houston, Tex., 77032 U.S.A.) which is a retrievable mechanical sub-in packer. Alternatively, barrier plug 804 may also be a permanently installed MSP. The plug or barrier plug 804 having a valve 804a is installed within the wellbore 62, providing an annular seal 804b, isolating an upper section 62a from a lower section or closeable chamber 62b of wellbore 62. The wellbore 62 is sealed from the surrounding formation using a barrier 806 installed at the downhole end of the casing 70. The plug 804 seals the wellbore 62 from annulus 35 of riser 30 when the drill string 50 is not stabbed (protruding) into it (as shown in FIG. 7A). However, string 50 may be displaced downward into wellbore 62 and “stabbed” into the plug 804 such that valve 804a of plug 804 opens, allowing fluid disposed within string 50 to be pumped into the lower portion or chamber 62b of the wellbore 62.

In order to conduct the negative pressure test of wellbore 62 and wellhead 60, drill string 50 is partially or completely filled with a relatively less dense fluid 829 compared to the heavier drilling or completion fluid. In this example the negative pressure testing fluid is water. However, in other embodiments fluid 829 may be base oil or other relatively less dense fluids. Following the filling of drill string 50, the string 50 is stabbed into the plug 804 (as shown in FIG. 7B) by displacing string 50 farther into wellbore 62, which allows for fluid communication between the water 829 in drill string 50 and the lower portion 62b of wellbore 62. If wellbore 62 is not isolated by the barrier 806 and/or casing 70, or other subsurface components of FCS 40, then relatively higher pressure formation fluid may flow upward into the downhole end of drill string 50, displacing the relatively less dense water 829 upward toward rig. The real time pressure and temperature within the drill string 50 may be measured using nodes 51 (e.g., 51a-51d), which may be used to measure a possible decay in fluid pressure due to an increase in volume caused by a leak, dPv. Thus, if the dPv indicated by nodes 51a-51d remains substantially zero then this indicates a successful negative or low pressure test of the integrity of the wellbore 62.

FIGS. 8A and 8B illustrate an alternative method for negative or low pressure testing wellbore 62 before abandoning a well using the CLF method. Referring first to FIG. 8A, the downhole end of wellbore 62 is sealed by barrier 806, casing 70 and wellhead 60, and lower valves 44a, 46a, are in a closed position, forming a closeable chamber 831 generally including wellbore 62, string 50 and annulus 35. In this method, kill line 46 is then partially or completely filled with negative testing fluid 829 via being pumped from cement unit 27 while a ram or annular (e.g., ram 42) of BOP 41 is actuated to create annular seal 43, isolating wellbore 62 from annulus 45 of marine riser 30. Also, lower valves 44a, 46a, are opened to provide fluid communication between wellbore 62 and lines 44 and 46. Nodes 51a-51d measure real time pressure and temperature values within the drill string 50 and wellbore 62, indicating a real time pressure decay within wellbore 62 due to a leak between wellbore 62 and either the formation 16 or the ambient water 13. If the wellbore 62 is sealed from formation 16, then the low density fluid 829 disposed within the choke and kill lines 44, 46, will not be displaced by the relatively higher density and pressure formation fluid, and the dPv measured by nodes 51a-51d within drill string 50 will remain substantially zero, indicating a successful negative pressure test of the wellbore 62. Thus, by using nodes 51 to monitor fluid pressure downhole in real time, personnel at the rig 20 need not choke manifold 44b for a fluid flow from wellbore 62, in order to determine if there was a leak in FCS 40. This may eliminate some issues with current testing procedures. For instance, by using nodes 51, even if lower valve 44a malfunctioned and remained closed, fluid pressure within wellbore 62 could still be monitored in real time to determine the presence of a leak.

Referring back to FIG. 6, an inflow or negative pressure test on a completion of well system 10, such as upper completion 80. For example, relatively low density fluid such as water or base oil may be disposed within passage 50b of string 50 and put into fluid communication with wellbore 62 via port 86. Due to the lower density of the fluid disposed within string 50, the amount of static fluid pressure or head applied to wellbore 62 from passage 50b is substantially reduced, thus the upper completion 80’s ability to withstand inflow or negative pressure between wellbore 62 and formation 16.

While embodiments have been shown and described, modifications thereof can be made by one skilled in the art without departing from the scope or teachings herein. The embodiments described herein are exemplary only and are not limiting. Many variations and modifications of the systems, apparatus, and processes described herein are possible and are within the scope of the invention. Accordingly, the scope of protection is not limited to the embodiments described herein, but is only limited by the claims that follow, the scope of which shall include all equivalents of the subject matter of the claims. Unless expressly stated otherwise, the steps in a method claim may be performed in any order. The recitation of identifiers such as (a), (b), (c) or (1), (2), (3) before steps in a method claim are not intended to and
do not specify a particular order to the steps, but rather are used to simplify subsequent reference to such steps.

What is claimed is:

1. A method for pressure testing a well system comprising:
   providing fluid into a closeable chamber of the well system;
   measuring in real time a change in fluid pressure within the closeable chamber using a sensor disposed within the well system; and
   determining in real time a temperature change of fluid within the closeable chamber using a sensor disposed within the well system;

2. The method of claim 1, wherein the closeable chamber is provided with a fluid having a higher density than water.

3. The method of claim 1, wherein the closeable chamber is provided with a fluid having a density substantially equal to water.

4. The method of claim 1, wherein the closeable chamber comprises at least a portion of a drill string.

5. The method of claim 1, wherein the closeable chamber comprises at least a portion of a choke line.

6. The method of claim 1, wherein the closeable chamber comprises at least a portion of a kill line.

7. The method of claim 1, further comprising using real time pressure and temperature measurements to calculate real time pressure decay of fluid within the closeable chamber; the calculated pressure decay arising from changes in the volume of fluid within the closeable chamber over time.

8. The method of claim 4, further comprising stabbing into a plug of the well system with the drill string to allow for fluid communication between the drill string and a volume of fluid disposed below the plug.

9. The method of claim 1, wherein the closeable chamber comprises at least a portion of a blowout preventer.

10. The method of claim 9, further comprising sealing the blowout preventer to prevent fluid communication between a drill string of the well system and an annulus adjacent to the blowout preventer.

11. The method of claim 1, further comprising measuring in real time a pressure change in the closeable chamber using a sensor disposed within the well system.

12. The method of claim 1, wherein the closeable chamber comprises a component of a completion system.

13. The method of claim 11, wherein the component of the completion system comprises a tubing hanger.

14. The method of claim 1, further comprising communicating a signal from the sensor using a wired pipe communication network.

15. A method for pressure testing a well system comprising:
   providing fluid into a closeable chamber of the well system; and
   determining in real time a change in fluid pressure in the closeable chamber, the determined change in pressure arising from a change in the volume of fluid within the closeable chamber.

16. The method of claim 15, further comprising determining in real time a change in fluid pressure within the closeable chamber arising from a change in temperature of the fluid.

17. The method of claim 15, wherein determining in real time a change in fluid pressure within the closeable chamber arising from a change in the volume of fluid within the closeable chamber comprises measuring in real time a change in fluid pressure within the closeable chamber using a sensor disposed within the well system.

18. The method of claim 16, wherein determining in real time a change in fluid pressure within the closeable chamber arising from a change in temperature of the fluid comprises measuring in real time a temperature change of fluid within the closeable chamber using a sensor disposed within the well system.

19. The method of claim 16, wherein determining in real time a change in fluid pressure within the closeable chamber arising from a change in temperature of the fluid comprises calculating the change in temperature over time for a section of a wired pipe communication network.

20. The method of claim 19, further comprising summing the pressure decay arising from changes in temperature over time for the section of the wired pipe communication network.

21. The method of claim 20, further comprising subtracting the summed pressure decay arising from changes in temperature over time from the total fluid pressure decay within the closeable chamber.

22. The method of claim 15, wherein the closeable chamber comprises at least a portion of a blowout preventer.

23. The method of claim 15, wherein the closeable chamber comprises at least a portion of a wellhead.

24. A method for pressure testing a well system comprising:
   providing fluid into a closeable chamber of the well system;
   measuring in real time a change in fluid pressure within the closeable chamber using a sensor of a wired pipe communication network disposed within the well system;
   measuring in real time a temperature change of fluid within the closeable chamber using a sensor of the wired pipe communication network disposed within the well system; and
   calculating in real time the pressure decay arising from a change in the volume of fluid disposed within the closeable chamber using the pressure and temperature measurements.

25. The method of claim 24, wherein the closeable chamber comprises at least a portion of a blowout preventer.

26. The method of claim 24, wherein the closeable chamber comprises at least a portion of a component of an upper completion system.