METHOD AND SYSTEM FOR PERFORMING AN ELECTRICALLY OPERATED FUNCTION WITH A RUNNING TOOL IN A SUBSEA WELLHEAD

BACKGROUND OF THE INVENTION

1. Field of the Invention

[0001] This invention relates in general to communication with downhole apparatuses and, in particular, to a method and system for performing an electrically operated function with a running tool in a subsea wellhead.

2. Brief Description of Related Art

[0002] In both subsea and land based oil and gas exploration operations, operators are drilling and producing wells at greater and greater depths. Consequently, the total weight of the materials placed in the well is increasing. In addition, the casing loads landed in the well are increasing. Due to these loads, many operators now use dedicated landing strings to run and land the casing hanger in the wellhead. This is done to ensure that the landing string can support the weight of the casing string in the wellhead while the casing hanger is landed and set. These landing strings may be specialty strings designed specifically to support such weight and have increased tube wall thickness to provide increased tensile strength and increased resistance to slip crushing.

[0003] Operators have long desired to know what actions are transpiring within the well. As a result of this desire, many tools and apparatuses have been developed to transmit information from subsea locations to the operator at the surface. For example, during measurement while drilling operations (MWD), mud pulse technologies may be used to sonically transmit data through the drill string to an operator at the surface. Still other MWD operations may transmit data from subsea transmitters through electromagnetic pulses through the drill string. In this manner, operators may receive information about what is transpiring within the wellbore during drilling operations. However, these transmission methods only provide a means to transmit basic information about downhole activities back to the surface. These transmission technologies do not currently allow for real time transmission of data, nor do they allow for communication with, or control of, the tool from the surface.

[0004] Operators may also wish to know what is transpiring within the wellhead as the casing string is run, landed, locked, and cemented within the wellbore. This is particularly true in subsea environments where the wellhead and casing landing locations may be thousands of feet below the surface of the ocean. In one example, to determine if the tubing hanger has landed and locked, prior art embodiments will run the tubing hanger to the expected location within the wellhead. Then, the prior art embodiments perform the necessary procedures to lock the tubing hanger to the wellhead. The embodiments then conduct an overpull, i.e. pulling up on the running string suspending the tubing hanger running tool and the tubing hanger in the wellhead, to confirm that the tubing hanger has landed and locked within the wellhead. However, this is an imprecise measurement, and may provide a false indication of proper landing and locking. This is possible where the tubing hanger dogs did not properly engage the wellhead, causing the dogs to initially indicate proper locking through overpull, but the dogs then moving from the properly engaged position following execution of the test.

[0005] Another prior art method to confirm downhole operations, i.e. tubing hanger landing and tubing hanger locking, involves monitoring well fluids returning from the well to the operating rig. The tubing hanger will include an actuation sleeve that engages tubing hanger dogs with a profile in the wellhead. The actuation sleeve is actuated hydraulically, and when fluid returns through the running string following performance of the land and lock operations, it is assumed that the tubing hanger has properly locked in the wellhead. However, the return of fluid through the tubing string only means that the actions have been performed, not that they operated properly or that the tubing hanger properly locked in the wellhead.

[0006] Unfortunately, these prior art embodiments fail to provide direct confirmation of downhole operations, such as landing and locking. Often, the tool must be pulled to verify that the desired downhole operation has taken place. This can often take an entire day to run the tool to the location, perform an operation, and then pull the tool to verify landing and locking. If the tool did not perform properly, then only after pulling the tool does the operator know and become able to take corrective action. Therefore a system that could provide direct communication of downhole subsea operations, such as casing hanger landing and locking, is desirable.

[0007] Many casing hanger running and setting tools use torque applied to the landing string at the surface to perform functions at the wellhead. Due to the length of many landing strings, the applied torque at the wellhead may be significantly less than that applied at the surface. Thus, casing hanger running and setting tools using torque applied at the surface may not perform the functions desired. As a result, hydraulically powered casing hanger running and setting tools were developed. These tools receive operational power through hydraulic lines that run from the surface operating platform to the subsea tool thousands of feet beneath the ocean. Generally, the hydraulic lines are run from reels and descend to the well alongside the landing string. This adds considerably to the complexity of the casing running landing and setting operations as the additional lines must be run through the platform openings with the landing string without binding in the landing string running equipment, or potentially becoming pinched by the landing string running equipment, preventing operation of the running tool when it reaches the subsea location. In addition, hydraulic pressure is applied by applying pressure to the hydraulic line at the surface, there may be a lag time of several minutes before that pressure is felt at the running tool. This is an unacceptable delay. Therefore a system that could power a running tool without the use of hydraulic lines is also desirable. In addition, a system that can power the running tool and receive confirmation of landing and locking is desirable.

SUMMARY OF THE INVENTION

[0008] These and other problems are generally solved or circumvented, and technical advantages are generally achieved, by preferred embodiments of the present invention that provide a method and system for performing an electrically operated function with a running tool in a subsea wellhead.

[0009] In accordance with an embodiment of the present invention, a method for performing a remote operation of a subsea wellhead is disclosed. The method provides a running tool having at least one electrically operated function and couples a subsea wellhead component to the running tool. The method then couples the running tool to a tubular string having at lease one electrically conductive wire mounted within a tubular wall of the tubular string for transmitting electric potential to the running tool. Next, the running tool and subsea wellhead component are run on the tubular string from a surface platform to a location within the subsea wellhead. Then,

the method performs the electrically operated function of the running tool using the transmission of electric potential through the tubular string at least one electrically conductive wire.

[0010] In accordance with another embodiment of the present invention, a subsea tool system for performing a remote operation in a subsea wellhead is disclosed. The system includes a running tool having at least one electrically operated function for setting a subsea wellhead component coupled to the running tool. A tubular string is coupled to the running tool. The tubular string has at least one electrically conductive transmission line formed in a tubular wall of the tubular string. The system also includes a control unit located on a surface platform. The control unit is communicatively coupled to the transmission line to control the electric potential applied to the transmission line. The transmission line communicatively couples to the running tool to transmit electric potential between the running tool and the control unit to operate the electrically operated function of the running tool to set the subsea wellhead component.

[0011] In accordance with yet another embodiment of the present invention, a subsea tool system for performing a remote operation in a subsea wellhead is disclosed. The system includes a running tool having at least one electrically operated function for setting a subsea wellhead component coupled to the running tool. A tubular string is coupled to the running tool. The tubular string has at least one transmission line formed in a tubular wall of the tubular string. The system also includes a control unit located on a surface platform, wherein the control unit is communicatively coupled to the transmission line to control an electric potential applied to the transmission line. The transmission line communicatively couples to the running tool to transmit the electric potential between the running tool and the control unit, and the running tool has at least one electric servo motor adapted to operate a tool function. The transmission line further communicatively couples to the electric servo motor, and the control unit controls the flow of electric potential to the electric servo motor through the transmission line to operate the electric servo motor and set the subsea wellhead component.

[0012] An advantage of a preferred embodiment is that it provides a method for establishing a communication line with a drill pipe landing string. The disclosed embodiments accomplish this in a manner that quickly and easily establishes an electrically powered communication connection without use of external umbilicals. The disclosed embodiments also provide one or

more electric circuits extending between the tool and the surface through the landing string without requiring the use of specialty tools or equipment to run the landing string. In so doing, the disclosed embodiments provide a mechanism for the use of electric sensors to transmit downhole data to the surface in real time while performing subsea wellhead operations. The disclosed embodiments also provide for use of an electrically powered running tool for more precise control and an increased likelihood of correct and timely running tool performance. Still further, the disclosed embodiments may provide for both use of electric sensors and an electrically powered running tool.

BRIEF DESCRIPTION OF THE DRAWINGS

[0013] So that the manner in which the features, advantages and objects of the invention, as well as others which will become apparent, are attained, and can be understood in more detail, more particular description of the invention briefly summarized above may be had by reference to the embodiments thereof which are illustrated in the appended drawings that form a part of this specification. It is to be noted, however, that the drawings illustrate only a preferred embodiment of the invention and are therefore not to be considered limiting of its scope as the invention may admit to other equally effective embodiments.

[0014] Figure 1A is a schematic representation of an electrically powered running tool suspended within a wellbore in accordance with an embodiment of the present invention.

[0015] Figures 1B-1C are schematic representations illustrating operation of locking dogs of the electrically powered running tool of Figure 1A.

[0016] Figure 2A is a schematic representation of a running tool having a battery powered sensor package suspended within a wellbore in accordance with an embodiment of the present invention.

[0017] Figures 2B-2C are schematic representations illustrating operation of locking dogs of the running tool of Figure 2A.

[0018] Figure 3A is a schematic representation of a running tool having an electrically activated hydraulic accumulator suspended within a wellbore in accordance with an embodiment of the present invention.

[0019] Figures 3A-3C are schematic representations illustrating operation of locking dogs of the running tool of Figure 3A.

[0020] Figure 4 is a schematic representation of a landing string in accordance with the embodiments of Figures 1, 2, and 3.

[0021] Figure 5 is a detail view of a portion of the schematic representation of Figure 4.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

[0022] The present invention will now be described more fully hereinafter with reference to the accompanying drawings which illustrate embodiments of the invention. This invention may, however, be embodied in many different forms and should not be construed as limited to the illustrated embodiments set forth herein. Rather, these embodiments are provided so that this disclosure will be thorough and complete, and will fully convey the scope of the invention to those skilled in the art. Like numbers refer to like elements throughout, and the prime notation, if used, indicates similar elements in alternative embodiments.

[0023] In the following discussion, numerous specific details are set forth to provide a thorough understanding of the present invention. However, it will be obvious to those skilled in the art that the present invention may be practiced without such specific details. Additionally, for the most part, details concerning rig operations, wellbore drilling, wellhead placement, and the like have been omitted inasmuch as such details are not considered necessary to obtain a complete understanding of the present invention, and are considered to be within the skills of persons skilled in the relevant art.

[0024] Referring to Figure 1A, a subsea tool system 11 is shown. Subsea tool system 11 includes a subsea wellhead 13 disposed at a sea floor 15. A running tool 17 is suspended within wellhead 13 on a wired landing string 19. A subsea wellhead member 18, such as a tubing hanger, casing hanger, or the like, is coupled to a lower end of running tool 17. Running tool 17

may operate to set subsea wellhead member 18 within wellhead 13 using a packer 16. Landing string 19 extends from running tool 17 suspended within wellhead 13 up to and through a platform 21. Platform 21 is an operational platform located on a surface of a body of water and provides a working area for operators to conduct drilling and production activities through wellhead 13. In some embodiments, a riser string (not shown) may extend between the platform and the wellhead to provide a conduit for landing string 19 and other devices and/or substances to travel between wellhead 13 and platform 21. A specialty sub 23 may be coupled inline with landing string 19 at platform 21. Specialty sub 23 will be coupled inline with landing string 19 following arrival of running tool 17 at a desired location with wellhead 13.

[0025] In the illustrated embodiment, specialty sub 23 may comprise a sub designed to transmit electric potential from an electrical power unit 25 located on platform 21 to wires (Figure 4) of landing string 19. Electrical power unit 25 may be located proximate to landing string 19 and specialty sub 23 as illustrated or may be located further from landing string 19 and specialty sub 23. Electrical power unit 25 may be coupled to specialty sub 23 in a manner that allows transmission of electric potential from electrical power unit 25 to specialty sub 23 while still allowing for rotation of landing string 19. In other embodiments, landing string 19 may not rotate. Specialty sub 23 will transmit the electric potential received from electrical power unit 25 through wires in landing string 19 in a manner described in more detail below with respect to Figure 4 and Figure 5.

[0026] Running tool 17 may be an electrically powered running tool. Running tool 17 may include at least one electric servo motor 27. Running tool 17 may couple to landing string 19 in a manner that allows for the wires of landing string 19 to transmit electrical potential from specialty sub 23 to running tool 17. This electric potential will then be transmitted to electric servo motor 27 via wires 79 (Figure 4) so that electric servo motor 27 may operate a function of the tool to set subsea wellhead member 18. As shown in Figure 1B, electric servo motor 27 may couple to a cam member 26 via a linkage 24. Cam member 27 interfaces with a locking dog 22 positioned within an opening 20 of tubular wall 14 of running tool 17. When actuated, electro servo motor 27 will drive linkage 24 downward, which, in turn, drives cam member 26 downward causing mating ramped surfaces of locking dog 22 and cam member 26 to slide past one another. This motion drives locking dog 22 into engagement with an inner diameter of

wellhead 13 through mating profiles as shown in Figure 1C. Electric servo motor 27 may operate to lock and unlock the locking dogs 26 of running tool 17 to and from subsea wellhead 13 for setting of subsea component 18.

[0027] In alternative embodiments, electric servo motor 27 may couple to porting valves of running tool 17. Electric servo motor 27 may then operate to open and close the porting valves. In still other embodiments, Electric servo motor 27 may comprise multiple electric servo motors 27 coupled to various functions. Electric power unit 25 may include a mechanism to control operation of electric servo motor 27, such as a switch to supply and remove electric potential from electric servo motor 27. Electric power unit 25 may also include any suitable mechanism to operate electric servo motor 27 in a variable condition so as to partially open or close a valve within running tool 17. In still other embodiments, electric power unit 25 may include any suitable mechanism to allow an operator to select for operation of a particular electric servo motor 27 of a plurality of electric servo motors 27, thereby allowing the operator to select the operation of a particular running tool 17 function to set subsea wellhead member 18. In this manner, running tool 17 may use electric power to operate locking dogs and porting valves of running tool 17 to land and set subsea wellhead member 18, such as a casing hanger, within subsea wellhead 13.

[0028] Referring now to Figure 2A, a subsea tool system 29 is shown. Subsea tool system 29 includes a subsea wellhead 31 disposed at a sea floor 33. A running tool 35 is suspended within wellhead 31 on a wired landing string 37. A subsea wellhead member 32, such as a tubing hanger, casing hanger, or the like, is coupled to a lower end of running tool 35. Running tool 35 may operate to set subsea wellhead member 32 within wellhead 31 using a packer 30. Landing string 37 extends from running tool 35 suspended within wellhead 31 up to and through a platform 39. Platform 39 is an operational platform located on a surface of a body of water and provides a working area for operators to conduct drilling and production activities through wellhead 31. In some embodiments, a riser string (not shown) may extend between the platform and the wellhead to provide a conduit for landing string 37 and other devices and/or substances to travel between wellhead 31 and platform 39. A specialty sub 41 may be coupled inline with landing string 37 at platform 39. Specialty sub 41 will be coupled inline with landing string 37 following arrival of running tool 35 at a desired location with wellhead 31.

[0029] In the illustrated embodiment, specialty sub 41 may comprise a sub designed to transmit a data signal between a data acquisition system 43 located on platform 39 and wires (Figure 4) of landing string 37. Data acquisition system 43 may be located proximate to landing string 37 and specialty sub 41 as illustrated or may be located further from landing string 37 and specialty sub 41. Data acquisition system 43 may be coupled to specialty sub 41 in a manner that allows transmission of the data signal from data acquisition system 43 to specialty sub 41 while still allowing for rotation of landing string 37. In other embodiments, landing string 37 may not rotate. Specialty sub 41 will transmit the data signal through wires in landing string 37 in a manner described in more detail below with respect to Figure 4 and Figure 5.

[0030] Running tool 35 may include a battery powered sensor package 45. Sensor package 45 may couple to one or more sensors 34 (Figure 2B) located on running tool 35. In an embodiment, sensors 34 will generate a data signal in response to operation of running tool 35 within wellhead 31. For example, sensors 34 may generate a signal in response to the position of running tool 35 within wellhead 31, the torque applied at a tool joint of running tool 35, and the weight suspended from running tool 35. In addition, sensors 34 may generate a signal in response to operation of a function of running tool 35. As shown in Figure 2B, running tool 35 may include a rotatable stem 36. A cam member 38 may be threaded to an outer diameter of stem 36 so that rotation of stem 36 will cause axial movement of cam member 38 through mating threads of stem 36 and cam member 38. Cam member 38 interfaces with a locking dog 40 positioned within an opening 42 of tubular wall 44 of running tool 35. Rotation of stem 36 will cause cam member 38 to move axially downward, which, in turn, causes mating ramped surfaces of locking dog 40 and cam member 38 to slide past one another. This motion drives locking dog 40 into engagement with an inner diameter of wellhead 31 through mating profiles as shown in Figure 2C. Locking dog 38 is communicatively coupled to sensors 34. As locking dog 38 moves axially in response to rotation of stem 36, sensors 34 will generate a signal that is transmitted to sensor package 45 that is, in turn, communicated to the surface through wires 79 (Figure 4).

[0031] In an alternate embodiment, sensors 34 may generate a signal in response to operation of porting valves of running tool 35. The generated signal may comprise any suitable signal. In an embodiment, sensors 34 may send the generated signals to a receiver of sensor package 45.

Sensor package 45 may be communicatively coupled to the wires of landing string 37. In and embodiment, the wires (Figure 4) of landing string 37 will directly couple to sensor package 45 so that the generated signals may be transmitted electrically from sensor package 45 through the wires of landing string 37. The signals may then be transmitted through the wires of landing string 37 to specialty sub 41 and then to data acquisition unit 43. There, data acquisition unit 43 may display the signals in a manner understandable to an operator located on platform 31, store the signals in a media that allows for later retrieval, or both display and store the signals. In an embodiment, the data signals are transmitted through landing string 37 in real time allowing for information regarding operation of running tool 35 to be received and utilized as the events generating the signals occur.

[0032] Referring to Figure 3A, a subsea tool system 47 is shown. Subsea tool system 47 includes a subsea wellhead 49 disposed at a sea floor 51. A running tool 53 is suspended within wellhead 49 on a wired landing string 55. A subsea wellhead member 54, such as a tubing hanger, casing hanger, or the like, is coupled to a lower end of running tool 53. Running tool 53 may operate to set subsea wellhead member 54 within wellhead 49 using a packer 50. Landing string 55 extends from running tool 53 suspended within wellhead 49 up to and through a platform 57. Platform 57 is an operational platform located on a surface of a body of water and provides a working area for operators to conduct drilling and production activities through wellhead 49. In some embodiments, a riser string (not shown) may extend between the platform and the wellhead to provide a conduit for landing string 55 and other devices and/or substances to travel between wellhead 49 and platform 57. A specialty sub 59 may be coupled inline with landing string 55 at platform 57. Specialty sub 59 will be coupled inline with landing string 55 following arrival of running tool 53 at a desired location with wellhead 49.

[0033] In the illustrated embodiment, specialty sub 59 may comprise a sub designed to transmit a control signal between a control panel 61 located on platform 57 and wires (Figure 4) of landing string 55. Control panel 61 may be located proximate to landing string 55 and specialty sub 59 as illustrated or may be located further from landing string 55 and specialty sub 41. Control panel 61 may be coupled to specialty sub 59 in a manner that allows transmission of the control signal from control panel 61 to specialty sub 59 while still allowing for rotation of landing string 55. In other embodiments, landing string 55 may not rotate. Specialty sub 59 will

transmit the control signal through wires in landing string 55 in a manner described in more detail below with respect to Figure 4 and Figure 5.

[0034] Running tool 53 may be a hydraulically operated running tool. In the illustrated embodiment, running tool 53 includes a tool control pod 63 and an accumulator bank 65. Accumulator bank 65 may be a hydraulic storage tank capable of receiving and storing hydraulic fluid pressure. Accumulator bank 65 may be communicatively coupled with operational functions of running tool 53 so that fluid pressure may be transmitted from accumulator bank 65 to hydraulically actuated functions of running tool 53 to set subsea wellhead member 54. In an embodiment, tool control pod 63 will communicatively couple to accumulator bank 65 so that tool control pod 63 may actuate hydraulic valves to divert hydraulic pressure stored in accumulator bank 65 to desired hydraulic functions of running tool 53 to set subsea wellhead member 54. In an embodiment, tool control pod 63 diverts hydraulic pressure in response to an electrical signal from control panel 61. In the illustrated embodiment, control panel 61 comprises a device that allows an operator to select a desired functional operation of running tool 53 for actuation. For example, an operator may select to lock a set of locking dogs on running tool 53 through control panel 61. As shown in Figure 3B, control pod 63 may be linked to a hydraulic cylinder 56 formed as a part of a body 58 of running tool 53. Hydraulic cylinder 56 may be coupled to a cam member 60 that may move axially in response to operation of cylinder 56. Cam member 56 may interface with a locking dog 62 positioned within an opening 64 in body 58 of running tool 53. In response to a signal through wires 79 (Figure 4) to control pod 63, control pod 63 may operate valves to allow flow of hydraulic pressure through hydraulic lines to hydraulic cylinder 56. In response, a piston of hydraulic cylinder 56 will move axially downward, in turn moving cam member 60 axially downward. This will cause mating ramped surfaces of cam member 60 and locking dog 62 to slide past one another. As mating surfaces of cam member 60 and locking dog 62 move past one another, locking dog 62 will move radially outward, engaging mating profiles of locking dog 62 and wellhead 49 as shown in Figure 3C.

[0035] Referring now to Figure 4, landing strings 19, 37, and 55 of Figure 1A, Figure 2A, and Figure 3A, respectively, may all be alternative embodiments of landing string 67 of Figure 4. Landing string 67 includes a plurality of pipe joints 69. Each pipe joint 69 includes a pin end 71 and a box end 73. In the illustrated embodiment, landing string 67 is constructed by coupling a

pin end 71 of a first joint 69 to a box end 73 of a second joint 69, as shown in Figure 4; this is done by threading a thread 75 of pin end 71 through a matching thread 77 of box end 73. Joining of a first joint 69 to a second joint 69 will form string 67 having a central passage 68 having an axis 70. At least one wire 79 may be formed in each pipe joint 69 during manufacture of each pipe joint 69. In the illustrated embodiment, two wires 79 are shown in each pipe joint 69. A person skilled in the art will understand that multiple wires 79 may be formed in pipe joint 69, as permitted by a thickness of each wire 79 and a wall thickness of each pipe joint 69. Wire 79 may be formed of an electrically conductive material such as copper or the like. In other embodiments, wire 79 may be a fiber optic cable. Each wire 79 is formed within each pipe joint 69 in a manner that allows for a plurality of wires 79 to be placed radially from the inner diameter toward the outer diameter. Each wire 79 is insulated from pipe joint 69 and adjacent wires 79 to reduce interference between wires 70 and to allow for a different signal or electric potential to travel along each wire 79 in a separate electric circuit.

[0036] Referring to Figure 5, at each connection point between pipe joints 69, pin end 71 defines a downward facing shoulder 81 extending from an exterior diameter of pipe joint 69 radially inward. Each box end 73 defines an upward facing rim 83 having a width approximately equal to a width of downward facing shoulder 81. An annular channel 85 may be formed in downward facing shoulder 81. Annular channel 85 may be lined with an insulator 87, such as rubber. Annular channel 85 may then be filled with an electrically conductive material 89 between insulator 87 and a surface of downward facing shoulder 81. This forms an electrically conductive ring 91 within downward facing shoulder 81 having a surface that is exposed and flush with downward facing shoulder 81.

[0037] Similarly, an annular channel 93 may be formed in rim 83. Annular channel 93 may be lined with an insulator 95, such as rubber. Annular channel 93 may then be filled with an electrically conductive material 97 between insulator 95 and a surface of rim 83. This forms an electrically conductive ring 99 within rim 83 having a surface that is exposed and flush with rim 83. When pin end 71 is inserted into box end 73, and matching threads 75 and 77 are threaded together, downward facing shoulder 81 and rim 83 come into contact with and abut one another. In an embodiment, conductive ring 91 will be formed in an area of downward facing shoulder 81 such that it will be aligned with conductive ring 99. In this manner, the exposed surface of

conductive ring 91 will abut the exposed surface of conductive ring 99 and insulators 85, 95 will contact one another, shielding conductive rings 91, 99 from pipe joints 69 and adjacent wires 79. Thus, an electrical current or electric potential may pass from conductive ring 99 to conductive ring 91 and vice versa, allowing for transmission of electric potential across the boundary between pipe joints 69.

[0038] Each wire 79 will correspond to a separate pair of conductive rings 91, 99. Each wire 79 will electrically couple to a pair of conductive rings 91, 99 at opposite ends of wire 79. Thus, an electrical signal or electric potential may be transmitted through wire 79 of a first pipe joint 69, through conductive ring 91 to conductive ring 99, wherein wire 79 of a second pipe joint 69 will receive the signal or electric potential and transmit it to the next pipe joint 69. A pair of conductive rings 91, 99 may be formed in each pipe joint 69 and will be positioned so as to correspond to each wire 79 formed in each pipe joint 69, thus multiple electric circuits may be formed in each pipe joint 69, allowing landing string 67 to carry multiple electric circuits from a platform to a subsea location. Wire 79 and conductive rings 91, 99 are formed during the manufacturing process of each pipe joint 69 so that wire 79 and conductive rings 91, 99 will be appropriately aligned to correspond to the desire electric circuit. A person skilled in the art will understand that the inclusion and alignment of wire 79 and conductive rings 91, 99 in each pipe joint 69 during manufacturing of each pipe joint 69 will allow landing string 67 to be assembled at a rig platform without need of additional tools. Thus, rig operators may run in landing string 67 in a conventional manner without the added complexity of an external electric or hydraulic umbilical, decreasing run in time over tools utilizing external power. Other methods of placing wires in one pipe joint in continuity with wires in adjacent pipe joints are feasible. These alternative methods are contemplated and included in the disclosed embodiments.

[0039] Accordingly, the disclosed embodiments provide numerous advantages. For example, the disclosed embodiments provide a means to allow real time data transmission from a running tool to a working platform located on the surface. In addition, it allows for real time operation of the tool without needing to rely on a complicated mechanical manipulation process. These features are accomplished without adding extra time or handling equipment to run the landing string and running tool from the surface to the subsea location or wellhead. Because the wire is formed within the pipe joints and can be made up without requiring rig workers to properly align

wires, tie wraps, or umbilicals, the running process is not hindered or slowed in any manner traditionally associated with use of electric or hydraulic umbilicals. Still further, the disclosed systems provide for development of an array of smart tools that can perform a plethora of functions while receiving real time feedback from the tool, allowing operators to be more confident that well completion operations have been successfully performed.

[0040] It is understood that the present invention may take many forms and embodiments. Accordingly, several variations may be made in the foregoing without departing from the spirit or scope of the invention. Having thus described the present invention by reference to certain of its preferred embodiments, it is noted that the embodiments disclosed are illustrative rather than limiting in nature and that a wide range of variations, modifications, changes, and substitutions are contemplated in the foregoing disclosure and, in some instances, some features of the present invention may be employed without a corresponding use of the other features. Many such variations and modifications may be considered obvious and desirable by those skilled in the art based upon a review of the foregoing description of preferred embodiments. Accordingly, it is appropriate that the appended claims be construed broadly and in a manner consistent with the scope of the invention.

What is claimed is:

1. A method for performing a remote operation of a subsea wellhead (13, 31, 49), the method comprising:

(a) providing a running tool (17, 35, 53) having at least one electrically operated function and coupling a subsea wellhead component (18, 32, 54) to the running tool (17, 35, 53);

(b) coupling the running tool (17, 35, 53) to a tubular string (19, 37, 55, 67) having at least one electrically conductive wire (79) mounted within a tubular wall of the tubular string (67) for transmitting electric potential to the running tool (17, 35, 53);

(c) running the running tool (17, 35, 53) and subsea wellhead component (18, 32, 54) on the tubular string (19, 37, 55, 67) from a surface platform (21, 39, 57) to a location within the subsea wellhead (13, 31, 49); then

(d) performing the electrically operated function of the running tool (17, 35, 53) using the transmission of electric potential through the at least one electrically conductive wire (79) of the tubing string (19, 37, 55, 67).

2. The method of Claim 1, wherein:

the at least one electrically conductive wire (79) mounted within a tubular wall of the tubular string (19, 37, 55, 67) comprises a first electrically conductive wire (79), and a second electrically conductive wire (79); and

step (d) comprises transmitting an electrical potential along the first electrically conductive wire (79) from the surface platform (21, 39, 57) to the running tool (17, 35, 53) while receiving an electrical potential along the second electrically conductive wire (79) from the running tool (17, 35, 53) to the surface platform (21, 39, 57).

3. The method of Claim 1, wherein step (b) comprises further coupling the tubular string (19) to a source of electrical potential (25).

4. The method of Claim 1,wherein step (b) comprises further coupling the tubular string (37) to a data receiver (43).

5. The method of Claim 1, wherein step (d) comprises:

providing electric potential to at least one electric servo motor (27) of the running tool (17) through the at least one electrically conductive wire (79) of the tubular string (19); and

operating the electric servo motor (27) of the running tool (17) in response to the electric potential to set the subsea wellhead component (18).

6. The method of Claim 5, wherein performing at least one tool function comprises operating at least one of a set of locking dogs of the running tool (17) and porting valves of the running tool (17).

7. The method of Claim 1, wherein step (d) comprises:

providing at least one sensor package (45) on the running tool (35), wherein the sensor package (45) generates an electrical signal in response to at least one of the tool position, the tool torque at the tool joint, and the weight suspended from the tool; then

transmitting the generated electrical signal through the at least one electrically conductive wire (79) to the surface platform (39).

8. The method of Claim 1, wherein step (d) comprises:

providing a tool control pod (63) communicatively coupled to the running tool (53), wherein the tool control pod (63) communicates with hydraulic valves that divert pressure from a hydraulic accumulator (65) of the running tool (53);

providing an electrical potential through the at least one electrically conductive wire (79) to the tool control pod (63); then

diverting stored pressure in the hydraulic accumulator (65) to set the subsea wellhead component (54) in response to the electrical potential applied to the tool control pod (63).

9. A subsea tool system (11, 29, 47) for performing a remote operation in a subsea wellhead (13, 31, 49), the system comprising:

a running tool (17, 35, 53) having at least one electrically operated function for setting a subsea wellhead component (18, 32, 54) coupled to the running tool (17, 35, 53);

a tubular string (19, 37, 55, 67) coupled to the running tool (17, 35, 53), wherein the tubular string (19, 37, 55, 67) has at least one electrically conductive transmission line (79) formed in a tubular wall of the tubular string (19, 37, 55, 67);

a control unit (25, 43, 61) located on a surface platform (21, 39, 57), wherein the control unit (25, 43, 61) is communicatively coupled to the transmission line (79) to control the electric potential applied to the transmission line (79); and

wherein the transmission line (79) communicatively couples to the running tool (17, 35, 53) to transmit electric potential between the running tool (17, 35, 53) and the control unit (25, 43, 61) to operate the electrically operated function of the running tool (17, 35, 53) to set the subsea wellhead component (18, 32, 54).

10. The subsea tool system (47) of Claim 9, further comprising:

the running tool (53) having a hydraulic accumulator (65) for storing hydraulic pressure, the accumulator (65) communicatively coupled to at least one hydraulic function of the running tool (53) for setting of the subsea wellhead component (54);

the running tool (53) having a tool control pod (63) communicatively coupled to the hydraulic accumulator (65) and further communicatively coupled to the control unit (61) through the at least one transmission line (79); and

wherein the control unit (61) modulates an electric potential signal sent through the transmission line (79) to the tool control pod (63) so that the tool control pod (63) actuates control valves of the accumulator (65) to divert fluid pressure in the accumulator (65) to the at least one hydraulic function of the running tool (53) to set the subsea wellhead component (54).

11. The subsea tool system (29) of Claim 9, wherein:

the running tool (35) has a battery powered sensor package (45) coupled to the running tool (35), wherein the sensor package (45) generates an electrical signal in response to at least one of the tool position within the wellhead (31) , the torque applied at the tool joint, and the weight suspended from the tool;

the sensor package (45) further communicatively coupled to the control unit (43) through the transmission line (79); and

wherein the sensor package (45) transmits the electrical signal through the transmission line (79) to the control unit (43), and the control unit (43) presents the electrical signal in a manner understandable by an operator located on the platform (39).

12. The subsea tool system of Claim 11, wherein the control unit (43) records and stores the electrical signal.

13. The subsea tool system of Claim 11, wherein the transmission line (79) comprises a fiber optic cable.

14. The subsea tool system (11) of Claim 9, wherein:

the running tool (17) has at least one electric servo motor (27) adapted to operate a tool function for setting the subsea wellhead component (18);

the at least one transmission line (79) couples to the electric servo motor (27); and

the control unit (25) controls the flow of electric potential to the electric servo motor (27) through the transmission line (79) to operate the electric servo motor (27) to set the subsea wellhead component (18).

15. The subsea tool system (11) of Claim 14, wherein:

the at least one transmission line (79) comprises a plurality of transmission lines (79);

the at least one electric servo motor (27) comprises a plurality of electric servo motors (27) adapted to operate separate functions of the running tool (17) for setting the subsea wellhead component (18);

each at least one transmission line (79) couples to a separate electric servo motor (27) and further couples to the control unit (25); and

the control unit (25) controls the flow of electric potential to each transmission line (79) and electric servo motor (27) to set the subsea wellhead component (18).