Remote Operation of Cementing Head

Methods and systems are provided for remotely operating a cementing head. Remotely operating a cementing head may allow for continued rotation as well as up or down movements (e.g., of a top drive).
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REMOTE OPERATION OF CEMENTING HEAD

CROSS-REFERENCE TO RELATED APPLICATIONS


BACKGROUND OF THE INVENTION

Field of the Invention

[0002] Embodiments of the present invention generally relate to remote operation of a cementing head.

Description of the Related Art

[0003] A wellbore is formed to access hydrocarbon bearing formations, e.g., crude oil and/or natural gas, by the use of drilling. Drilling is accomplished by utilizing a drill bit that is mounted on the end of a tubular string, such as a drill string. To drill within the wellbore to a predetermined depth, the drill string is often rotated by a top drive or rotary table on a surface platform or rig, and/or by a downhole motor mounted towards the lower end of the drill string. After drilling to a predetermined depth, the drill string and drill bit are removed and a section of casing is lowered into the wellbore. An annulus is thus formed between the string of casing and the formation. The casing string is temporarily hung from the surface of the well. The casing string is cemented into the wellbore by circulating cement into the annulus defined between the outer wall of the casing and the borehole. The combination of cement and casing strengthens the wellbore and facilitates the isolation of certain areas of the formation behind the casing for the production of hydrocarbons.

[0004] It is common to employ more than one string of casing in a wellbore. In this respect, the well is drilled to a first designated depth with a drill bit on a drill string. The drill string is removed. A first string of casing is then run into the wellbore and set in the drilled out portion of the wellbore, and cement is circulated into the annulus behind the casing string. Next, the well is drilled to a second designated depth, and a second string of casing or liner, is run into the drilled out portion of the wellbore. If the second string is a liner string, the liner is set at a depth such that the upper portion of the second string of casing overlaps the lower portion of the first string of casing. The
liner string may then be fixed, or "hung" off of the existing casing by the use of slips that utilize slip members and cones to frictionally affix the new string of liner in the wellbore. The second casing or liner string is then cemented. This process is typically repeated with additional casing or liner strings until the well has been drilled to total depth. In this manner, wells are typically formed with two or more strings of casing/liner of an ever-decreasing diameter.

[0005] Cementing operations have involved the use of plugs as a way of correctly positioning the cement when setting the casing. Some mechanisms have employed the use of pressure or vacuum to initiate plug movement downhole for proper displacement of the cement to its appropriate location for securing the casing properly. In addition, confirmation of the plug movement was by line-of-sight (e.g., flag at the cementing head indicating ball drop). The early designs were manual operations so that when it was time to release a plug for the cementing operation, a lever was manually operated to accomplish the dropping of the plug. This created several problems because the plug-dropping head would not always be within easy access of the rig floor. Frequently, depending upon the configuration of the particular well being drilled, the dropping head could be as much as 100 feet or more in the derrick (i.e., 100 feet from the rig floor). In order to properly actuate the plug to drop, rig personnel would have to go up on some lift mechanism to reach the manual handle. This process would have to be repeated if the plug-dropping head had facilities for dropping more than one plug. In those instances, each time another plug was to be dropped, the operator of the handle would have to be hoisted to the proper elevation for the operation. In situations involving foul weather, such as high winds or low visibility, the manual operation had numerous safety risks.

[0006] Hydraulic systems involving a stationary control panel mounted on the rig floor, with the ability to remotely operate valves in conjunction with cementing plugs, have also been used in the past. Some of the drawbacks of such systems are that for unusual applications where the plug-dropping head turned out to be a substantial distance from the rig floor, the hoses provided with the hydraulic system would not be long enough to reach the control panel meant to be mounted on the rig floor. Instead, in order to make the hoses deal with these unusual placement situations, the actual control panel itself had to be hoisted off the rig floor. This, of course, defeated the whole purpose of remote operation. Additionally, the portions of the dropping head to
which the hydraulic lines were connected would necessarily have to remain stationary. This proved somewhat undesirable to operators who wanted the flexibility to continue rotation as well as up or down movements during the cementing operation.

Accordingly, what is needed are techniques and apparatus for remotely operating the cementing head.

**SUMMARY OF THE INVENTION**

One embodiment of the present invention provides a method. The method generally includes exchanging signals between a first device and a second device via a medium in connection with the cementing head, wherein the second device is adjacent to the cementing head, and performing cementing head operations corresponding to the exchanged signals.

Another embodiment of the present invention is a system. The system generally includes a first device located at a rig floor of the wellbore, a second device located adjacent to the cementing head, and a control unit for remotely operating the cementing head. The control unit is typically configured to exchange signals between the first device and the second device via a medium in connection with the cementing head and perform cementing head operations corresponding to the exchanged signals.

**BRIEF DESCRIPTION OF THE DRAWINGS**

So that the manner in which the above recited features of the present invention can be understood in detail, a more particular description of the invention, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this invention and are therefore not to be considered limiting of its scope, for the invention may admit to other equally effective embodiments.

Figure 1 illustrates a drilling system, according to an embodiment of the present invention.
Figure 2 illustrates example cementing operations that may be performed in the drilling system after installation of an outer casing string, according to an embodiment of the present invention.

Figure 3 illustrates a system for remotely operating a cementing head, according to an embodiment of the present invention.

Figures 4A-C illustrate different views of a lower device for remotely operating a cementing head, according to certain embodiments of the present invention.

Figure 5 is a flow diagram of exemplary operations for remotely operating a cementing head, according to an embodiment of the present invention.

Figures 6A-B illustrate a series of schematics that show how spacer and cement slurry may displace drilling fluid in a wellbore, according to embodiments of the present invention.

Figure 7 illustrates example cementing operations that may be performed for subsea operations, according to an embodiment of the present invention.

**DETAILED DESCRIPTION**

Figure 1 illustrates a drilling system 100, according to an embodiment of the present invention. The drilling system 100 may include a derrick 110. The drilling system 100 may further include drawworks 124 for supporting, for example, a top drive 142. A workstring 102 may comprise joints of threaded drill pipe connected together, coiled tubing, or casing. For some embodiments, the top drive 142 may be omitted (e.g., if the workstring 102 is coiled tubing). A rig pump 118 may pump drilling fluid, such as mud 114, out of a pit 120, passing the mud through a stand pipe and Kelly hose to the top drive 142. The mud 114 may continue into the workstring 102. The drilling fluid and cuttings, collectively returns, may flow upward along an annulus formed between the workstring and one of the casings 119i,o, through a solids treatment system (not shown) where the cuttings may be separated. The treated drilling fluid may then be discharged to the mud pit 120 for recirculation. A surface controller 125 may be in data communication with the rig pump 118, pressure sensor 128, and top drive 142.
After a first section of a wellbore 116 has been drilled, an outer casing string 119o may be installed in the wellbore 116 and cemented 111o in place. The outer casing string 119o may isolate a fluid bearing formation, such as aquifer 130a, from further drilling and later production. Alternatively, fluid bearing formation 130a may instead be hydrocarbon bearing and may have been previously produced to depletion or ignored due to lack of adequate capacity. After a second section of the wellbore 116 has been drilled, an inner casing string 119i may be installed in the wellbore 116 and cemented 111i in place. The inner casing string 119i may be perforated and hydrocarbon bearing formation 130b may be produced, such as by installation of production tubing (not shown) and a production packer.

Figure 2 illustrates example cementing operations that may be performed in the drilling system 100, for example, after installation of the outer casing string 119o, according to an embodiment of the present invention. For example, after running a casing string (e.g., outer casing string 119o) into the wellbore 116, the cementing of the casing string 119o may be carried out so that producible oil and gas, or saltwater may not escape from the producing formation to another formation, or pollute freshwater sands at shallower depth. In addition to the cementing of a casing string, the example cementing operations illustrated in Figure 2 may also apply at least for the cementing of liners.

The casing string 119o may be run into the wellbore 116 with a guide shoe 212. A float collar 210 may be located one to four joints above the guide shoe 212, wherein the float collar 210 may function as a back flow valve that may prevent the heavier cement slurry 204 from flowing back into the casing string 119o after the slurry has been placed into the annulus between the outside of the casing string 119o and the borehole wall. Centralizers 208 may be placed along the length of the casing string 119o, wherein the centralizers 208 may ensure that the casing string 119o is nearly centered in the borehole, thus allowing a more uniform distribution of cement slurry flow around the casing string 119o. This nearly uniform flow around the casing may be necessary to remove drilling mud in the annulus and provide an effective seal.

The casing string 119o may be lowered into the drilling mud in the wellbore 116 using the rig drawworks 124 and elevators. The displaced drilling mud may flow to the mud tanks 120 and be stored there for later use. Once the entire casing string 119o is in place in the wellbore 116, the casing string 119o may be left hanging in the
elevators through the cementing operation. This may allow the casing string 119o to be reciprocated (i.e., moved up and down) and possibly rotated as the cement is placed in the annulus. This movement may assist the removal of the drilling mud. While the casing string 119o is hanging in the elevators, a cementing head 202 may be placed along an upper end of the workstring 102.

[0023] The cementing head 202 may be connected with flow lines that come from, for example, a pump truck 214. A blender 216 may mix dry cement and additives with water. A cement pump on the pump truck 214 may pump cement slurry 204 to the cementing head 202, which will eventually form the cementing 111o. For some embodiments, a preflush or spacer may initially be pumped ahead of the cement slurry 204, wherein the spacer may be preceded by a bottom wiper plug 206. The spacer may be used to assist in removing the drilling mud from the annular space between the outside of the casing string 119o and the borehole wall.

[0024] Cementing operations have involved the use of plugs as a way of correctly positioning the cement when setting the casing. Some mechanisms have employed the use of pressure or vacuum to initiate plug movement downhole for proper displacement of the cement to its appropriate location for securing the casing properly. Traditionally, when it was time to release a plug for the cementing operation, manual operations and hydraulic systems have been involved in operating valves in conjunction with the cementing plugs. However, manual operations and operations involving hydraulic systems, as described above, may become infeasible when the cementing head could be over 100 feet above the rig floor. This may prove somewhat undesirable to operators who want the flexibility to continue rotation as well as up or down movements (e.g., of the top drive 142) during the cementing operation. Accordingly, what is needed are techniques and apparatus for remotely operating the cementing head while continuing rotation as well as up or down movements.

[0025] Figure 3 illustrates a system 300 for remotely operating a cementing head 202, according to an embodiment of the present invention. The system 300 generally includes a lower device 304 and an upper device 302 for exchanging signals (indicated by arrows) via a medium in connection with the cementing head 202. An example of a medium generally includes a metal pipe, such as the workstring 102 or the flow lines that come from the pump truck 214. As illustrated, the upper device 302 may be adjacent to the cementing head 202 and the lower device 304 may be located
at the rig floor 306. The devices 302, 304 may include a control unit 308 and a battery pack 310, although the devices 302, 304 may be powered by other various sources. The lower device 304 may be controlled by a handheld device (not shown), for example, from within a dog house 316 (i.e., a safe distance from the wellbore; outside zone zero). The handheld device may be wired to the control unit 308i of the lower device 304. In order to use pneumatic lines (umbilicals) that may be available on the cementing head 202, solenoid valves 314 may be used and controlled by the system. In addition, the pressure for the system 300 may be provided by air cylinders 312 (e.g., pressurized gas).

[0026] For some embodiments, the system 300 may be a single-wire line transmission system, wherein the cementing head 202 may be used as the conductor, while both ends of the system 300 use a common path for the return current (e.g., earth return). For example, the cementing head 202 may be connected on the upper side to ground through the top drive (or grounded to the derricks ground). In addition, the lower side of the system 300, for example, below the lower device 304, may be connected to ground through slips, which make electrical contact with the mechanical rig structure, ensuring another path to earth's ground.

[0027] The signals received by the upper device 302 may be processed by the local control unit 3082 (dedicated microcontroller) and actuate operations of the cementing head 202 (e.g., dropping plugs, darts, tool activation, and/or confirmation devices - such as balls, RFID tags, etc. - into the wellbore). The signals may be acoustic or electromagnetic (EM) signals. For some embodiments, when the signals transmitted by the lower device 304 are acoustic signals (e.g., transmitted by a piezoelectric stack or a solenoid), the upper device 302 may include piezoelectric sensors (e.g., accelerometer) for detecting acoustic vibrations generated along an acoustic throughpipe (e.g., workstring 102). For acoustic signals, the devices 302, 304 may be in physical contact with the medium (e.g., rigid contact with workstring 102). However, for EM signals, the devices 302, 304 may not be in physical contact with the workstring 102, allowing the workstring to rotate as well during a cementing job. Although Figure 3 illustrates a cementing head, balls and/or darts may be dropped to actuate other downhole devices (e.g., setting tool for liner hanger; packer). For some embodiments, the devices 302, 304 may be removed, and cementing head operations may be performed wirelessly (e.g., by radio waves).
[0028] When the signals exchanged between the devices 302, 304 are EM signals, the devices 302, 304 may include toroidal coils, as will be discussed further herein. Various parameters of the toroidal coils may be adjusted, such as the coil size, magnetic core permeability, wire size, and the number of windings. More specifically, each device 302, 304 may include two toroidal coils: one for transmitting and another for receiving. A transmission between the devices 302, 304 may be achieved by energizing the winding of a transmission coil (e.g., the transmitting toroidal coil of the lower device 304). As described above, the transmission may be initiated by the handheld device. The current that flows through the winding may produce a magnetic flux in the core, which than induces a current in a conductor positioned in the center of the toroid (e.g., workstring 102), which can represent various signals. The current generated has to be high enough to overcome potential noise, yet low enough to conserve power. If a string of voltage pulses is applied to the coil, a corresponding string of current pulses may be induced in the workstring 102.

[0029] The transmission may be received at the upper device 302 (e.g., by the receiving toroidal coil of the upper device 302) by converting the current pulses flowing through the workstring 102 into voltage pulses. Confirmation of the operation may be indicated by a signal transmitted from the upper device 302 to the lower device 304. The handheld device may receive an indication of the confirmation. For some embodiments, multiple confirmations may be received. For example, acknowledgment of receipt of the command transmitted from the lower device 304 may be received. As another example, successful execution of the command or an error may be indicated on the handheld device, which can lead to the ability to troubleshoot the issue.

[0030] For some embodiments, each device 302, 304 may include a single toroidal coil with a first winding for transmitting signals, and a second winding for receiving signals, wherein the windings may have different configurations. Examples of configurations that may differ between the windings generally include a different number of windings and a different diameter of wiring for the winding. The receiver may require increased sensitivity to compensate for noise that may be received (signal-to-noise ratio (SNR)).
Figures 4A-C illustrate different views of the lower device 304, according to certain embodiments of the present invention. As described above, the lower device 304 may include two toroidal coils 610, 612 (e.g., one transmitter and one receiver). The toroidal coils 610, 612 may be mounted on a frame 602 comprising one or more hinges 604, where the ferromagnetic cores of the toroidal coils 610, 612 may be physically interrupted (e.g., open frame toroidal coils) but the magnetic flux generated may be continuous due to the inductive coupling at the ends of the individual core sections (i.e., the individual core sections substantially complete a toroidal coil due to inductive coupling at the ends of the core sections). Although there may be varied amounts of spacing between the different core sections, as long as there is inductive coupling at the ends of the individual core sections, the individual core sections may substantially complete a toroidal coil. Therefore, the toroidal coil sections 614, 616 may be mounted on a frame 602, as illustrated in Figure 4C, and the toroidal coil sections 614, 616 may move (e.g., closer and further to the workstring 102) in the same time with the frame 602. For some embodiments, the lower device 304 may have wheels, or other means of displacement, as illustrated in Figure 4C, to allow for mobility on the rig.

The toroidal coils 610, 612 may be formed by latching the partial toroidal coil sections 614, 616 that are mounted on the frame by a latching mechanism 606. The hinged frame 602 may have to be along a certain diameter of the tubular member (e.g., workstring 102) to properly latch. For some embodiments, the hinged frame 602 may comprise stands 618 for moving the frame along the workstring 102 until an outer diameter of the workstring 102 causes the partial toroidal coil sections 614, 616 to properly latch and form the toroidal coils 610, 612. The hinged frame 602 may further comprise centering guides (e.g., rollers) for centralizing the frame around the workstring 102. For example, in order to ensure concentricity of the toroidal coils 610, 612 around the workstring 102, a set of four equally spaced rollers 608 may be utilized in order to maintain a preset gap between the coils 610, 612 and the workstring 102, as illustrated in Figure 4B.

Figure 5 illustrates example operations 500 for remotely operating a cementing head in a wellbore, according to certain embodiments of the present invention. Examples of cementing head operations generally include dropping plugs, darts, tool activation, and/or confirmation devices - such as balls, radio-frequency
identification (RFID) tags, etc. into the wellbore. The operations may begin at 502 by exchanging signals between a first device (e.g., located at a rig floor) and a second device via a medium (e.g., a metal pipe) in connection with the cementing head, wherein the second device may be adjacent to the cementing head. At 504, cementing head operations may be performed that correspond to the exchanged signals. Exchanging the signals generally includes transmitting a signal (e.g., acoustic or EM) for actuating operations of the cementing head, wherein the signal may be transmitted from the first device to the second device. When using acoustic signals, the signals may be transmitted longitudinally, transversely, or a combination of both with respect to the medium. A signal may be received at the first device, originating from the second device, confirming the operations of the cementing head. For some embodiments, proximity sensors may confirm the operations of the cementing head, for example, after a plug has reached a pre-defined location in the wellbore.

Figures 6A-B illustrate a series of schematics that show how spacer and cement slurry may displace drilling fluid in a wellbore, according to embodiments of the present invention. Two wiper plugs 702, 704 may be used to separate the spacer and the cement slurry from the drilling fluid in the wellbore. For some embodiments, a different number of plugs may be used (e.g., one plug or three plugs). The cementing head 202 may have two retainer valves that hold the wiper plugs 702, 704 in place. When the spacer and cement slurry are to be pumped to the inside of the casing string through the cementing head 202, the retainer valve for the bottom wiper plug 702 may be activated. This may release the bottom wiper plug 702 into the initial portion of the spacer flow to the well, as illustrated in Figure 6B. This bottom wiper plug 702 may keep the drilling fluid from contaminating the spacer and the cement slurry while they pass through the inside of the casing string.

As described above, activation of the retainer valve for the bottom wiper plug 702 may be initiated by transmitting a signal via a lower toroidal coil 706 located on the rig floor (or at the cement pump or a convenient location) through a medium (e.g., workstring 102) in connection with the cementing head 202. Control electronics associated with the upper toroidal coil 708, located adjacent to the cementing head 202, may receive and decode the signal, then activate the retainer valve for releasing
the bottom wiper plug 702. For some embodiments, activating the retainer valve may involve utilizing compressed gas (e.g., air, nitrogen, etc.) to control the retainer valve.

[0036] Upon transmitting the signal via the lower toroidal coil 706, an operator (e.g., located on the rig floor and/or at the pump truck) may receive several confirmations. For example, the operator may receive a first confirmation indicating that the upper toroidal coil 708 has received and decoded the signal transmitted by the lower toroidal coil 706. Further, the operator may receive a second confirmation indicating that the retainer valve for the bottom wiper plug 702 has been activated. Moreover, the operator may receive a third confirmation indicating that the bottom wiper plug 702 has actually been released after the retainer valve has been activated. For example, a proximity sensor 710 may be used for indicating that the bottom wiper plug 702 has been released (as indicated by the downward arrow in Figure 6B after the plug 702 has passed the sensor 710). For some embodiments, the confirmations may be visual or audible signals (e.g., separate lights or audible signals indicating each confirmation). For some embodiments, the confirmations may be signals transmitted through mediums in connection with the cementing head 202, via the upper toroidal coil 708. For example, if there are operators located at both the rig floor and the pump truck, each operator may receive the confirmations independently via different mediums (e.g., via the workstring 102 and the flow lines at the pump truck 214). Also, as described above, confirmations may be received by a handheld device.

[0037] When a predetermined volume of cement slurry has passed through the cementing head 202, the retainer valve for the top wiper plug 704 may be activated, releasing the top wiper plug 704 into the flow to the well (not illustrated). Activation of the retainer valve for the top wiper plug 704 and the confirmations may be performed as described above. For some embodiments, parameters of the signal transmitted by the lower toroidal coil 706 (e.g., frequency) may be modified in accordance with the fluid traveling through the medium (e.g., workstring 102).

REMOTE OPERATION OF CEMENTING HEAD FOR SUBSEA OPERATIONS

[0038] Figure 7 illustrates example cementing operations that may be performed for subsea operations, according to an embodiment of the present invention. Communications between a vessel 824 and a well 836 that is separated by a body of
water 818 may be performed by coupling at least two means of communication. For example, to confirm the location of a plug in the well 836, a first signal may be transmitted through a well casing 819 of the well 836 up to the floor 816 of the sea (i.e., mudline). From the floor 816, a second signal may be transmitted to the surface 822 of the sea by using sonar, as will be described further herein.

[0039] Referring to Figure 7, there is shown a well 836 that has been drilled into the earth beneath the sea 818 or other body of water. A subsea wellhead structure 804 may be emplaced on the floor 816 of the sea at the top of the well 836. Suspended in the well 836 from the wellhead 804 may be a string of well casing 819. A riser pipe 814 may be connected to the wellhead 804 and may communicate with the casing string 819 through passages in the wellhead 804. The riser pipe 814 may extend up through the water to a drilling ship or vessel 824 floating on the surface 822 of the sea directly over the wellhead 804. The riser pipe 814 may extend up through an opening in the ship 824, and the top of the riser pipe 814 may be exposed above the waterline and within the vessel 824. A string of drill pipe 802 may extend within the riser pipe 814 upwardly from the wellhead 804 and may terminate at the top in a cementing head 820. The drilling vessel 824 may be equipped with a derrick structure 834.

[0040] The cementing head 820 may have an upper set of toroidal coils 832 located adjacent to the cementing head 820. The upper set of toroidal coils 832 may receive signals from a lower set of toroidal coils 830 located on the deck 826 of the vessel 824, wherein the lower set of toroidal coils 830 may transmit the signals through a medium in connection with the cementing head 820. The signals received by the upper set of toroidal coils 832 may actuate operations of the cementing head 820 (e.g., dropping darts). For some embodiments, the lower set of toroidal coils 830 may be attached to or wrapped around a metal pipe (e.g., drill pipe 802) and may transmit signals through the metal pipe (i.e., a metal pipe in connection with the upper set of toroidal coils 832 attached to the cementing head 820). The signals may be acoustic or electromagnetic signals, as described above.

[0041] When spacer fluid and cement slurry are ready to be pumped to the inside of the drill pipe 802 through the cementing head 202 (and eventually into the well casing 819), a retainer valve for a bottom wiper dart may be activated. This bottom
wiper dart may keep drilling fluid from contaminating the spacer fluid and the cement slurry while they pass through the inside of the drill pipe 802.

[0042] Activation of the retainer valve for the bottom wiper dart may be initiated by transmitting a signal via the lower set of toroidal coils 830 located on the deck 826 through the drill pipe 802 in connection with the cementing head 820. The upper set of toroidal coils 832, located adjacent to the cementing head 820, may receive and decode the signal, then activate the retainer valve for releasing the bottom wiper dart. For some embodiments, activating the retainer valve may involve utilizing compressed gas to control the retainer valve. After the bottom wiper dart has been released, confirmation of the release may be indicated to an operator on the deck 826. For some embodiments, one or more proximity sensors that detect when the bottom wiper dart has been released may trigger on a light to notify the operator that the bottom wiper dart has been released. In addition, the operator may be notified in other ways, as described above.

[0043] When a predetermined volume of cement slurry has passed through the cementing head 820, a retainer valve for a top wiper dart may be activated, releasing the top wiper dart into the flow to the well 836. Activation of the retainer valve for the top wiper dart and confirmation of the release may be performed as described above. For some embodiments, parameters of the signal transmitted by the lower set of toroidal coils 830 (e.g., frequency) may be modified in accordance with the fluid traveling through the medium (e.g., drill pipe 802).

[0044] After a dart has been dropped into the well 836, and seated into a corresponding plug, confirmation of the location of the dart and plug in the well 836 may be useful in determining successful operation of the cementing head 820 using any of the above-described methods. For example, it may be useful to determine whether the bottom wiper dart and corresponding plug has reached a pre-defined location, such a float collar (e.g., by a pressure sensor or load cell). For some embodiments, a first signal may be transmitted through the well casing 819 up to the floor 816 of the sea. A device 806 may receive the first signal and transmit a second signal 808 up to the surface 822 of the sea using sonar or an acoustic modem.

[0045] Due to transmitting between multiple mediums (e.g., seawater and within the wellbore), coupling of the first signal with the second signal may be required for
successfully determining whether the bottom wiper dart and plug have reached the pre-defined location. For some embodiments, the second signal may be transmitted by a remotely operated vehicle (ROV) that is plugged in at a convenient location (e.g., at the blowout preventer or wellhead 804). For some embodiments, a buoy 810 may receive the second signal 808 transmitted through the sea 818 and transmit a signal via a transmission line 812 to a receiver located on the deck 826. The receiver located on the deck 826 may process the signal to confirm the location of the dart and corresponding plug. For some embodiments, the direction of signal transmission between the buoy 810 and the device 806 may be downwards when a signal is transmitted from the vessel 824 to the well 836.

[0046] While the foregoing is directed to embodiments of the present invention, other and further embodiments of the invention may be devised without departing from the basic scope thereof, and the scope thereof is determined by the claims that follow.
Claims:

1. A method for remotely operating a cementing head in a wellbore, the method comprising:
   exchanging signals between a first device and a second device via a medium in connection with the cementing head, wherein the second device is adjacent to the cementing head; and
   performing cementing head operations corresponding to the exchanged signals.

2. The method of claim 1, wherein the medium is a metal pipe.

3. The method of claim 1, wherein the first device is located at a rig floor of the wellbore.

4. The method of claim 1, wherein exchanging the signals comprises transmitting a signal for actuating operations of the cementing head, wherein the signal is transmitted from the first device to the second device.

5. The method of claim 4, further comprising receiving a signal confirming the operations of the cementing head, wherein the signal is received at the first device, originating from the second device.

6. The method of claim 5, wherein sensors confirm the operations of the cementing head.

7. The method of claim 1, wherein the signals comprise acoustic signals and electromagnetic (EM) signals.

8. The method of claim 7, wherein the acoustic signals are transmitted by an acoustic transmitter that is in physical contact with the medium.

9. The method of claim 7, wherein the acoustic signals are transmitted longitudinally, transversely, or a combination of both with respect to the medium.

10. The method of claim 7, wherein the EM signals are exchanged by toroidal coils that are not in physical contact with the medium.
11. The method of claim 10, wherein at least one toroidal coil of the first device comprises partial toroidal coil sections mounted to form a complete toroidal coil.

12. The method of claim 11, wherein the complete toroidal coil is formed by disposing the partial toroidal coil sections on a hinged frame around the medium.

13. The method of claim 7, wherein the EM signals are exchanged by a single-wire line transmission system.

14. The method of claim 1, wherein the operations comprise dropping plugs, darts, tool activation, and confirmation devices into the wellbore.

15. The method of claim 1, wherein exchanging the signals comprises exchanging signals through a body of water using sonar or an acoustic modem.

16. A system for remotely operating a cementing head in a wellbore, the system comprising:
   a first device located at a rig floor of the wellbore;
   a second device located adjacent to the cementing head; and
   a control unit for remotely operating the cementing head, wherein the control unit is configured to:
      exchange signals between the first device and the second device via a medium in connection with the cementing head; and
      perform cementing head operations corresponding to the exchanged signals.

17. The system of claim 16, wherein the control unit is attached to the second device.

18. The system of claim 17, further comprising another control unit attached to the first device for processing the signals exchanged between the first device and the second device.

19. The system of claim 16, further comprising sensors for confirming the operations of the cementing head.

20. The system of claim 19, further comprising a handheld device for controlling the first device and receiving confirmations for the operations of the cementing head.
21. The system of claim 16, wherein the signals comprise acoustic signals and electromagnetic (EM) signals.

22. The system of claim 21, wherein the EM signals are exchanged by toroidal coils that are not in physical contact with the medium.

23. The system of claim 22, wherein at least one toroidal coil of the first device comprises partial toroidal coil sections mounted to form a complete toroidal coil.

24. The system of claim 23, wherein the complete toroidal coil is formed by disposing the partial toroidal coil sections on a hinged frame around the medium.
EXCHANGE SIGNALS BETWEEN A FIRST AND A SECOND DEVICE VIA A MEDIUM IN CONNECTION WITH A CEMENTING HEAD, WHEREIN THE SECOND DEVICE IS ADJACENT TO THE CEMENTING HEAD.

PERFORMING CEMENTING HEAD OPERATIONS CORRESPONDING TO THE EXCHANGED SIGNALS.

FIG. 5
FIG. 6B