The invention relates to a method, apparatus and components for adding a riser to an offshore platform. The method may include positioning an L-shaped conduit in the water near the seabed and connecting an upward leg of the conduit to a riser located within the platform jacket through the use of a remotely-operated vehicle (ROV). A standard deepwater connector is used so the ROV can remotely connect the riser to the L-shaped conduit. A horizontal leg of the L-shaped conduit is connected to a pipeline located on the outside of the jacket. The method may be performed without ceasing production operations of the platform, thereby resulting in significant cost savings. The riser may be located in a column of conductor guides on the platform jacket. The riser may be stabilized within the guides, and/or electrically isolated from the platform jacket, through the use of generally semi-circular shaped segmented centralizers or by positioning a bladder between the riser and each guide and then filling the bladder with a material, such as grout or epoxy. The L-shaped conduit may be attached to a skid having one or more inflatable balloons for use in positioning the upward leg of the conduit beneath the riser. Various video, sonar and lighting equipment is disclosed to facilitate the remote connection of the L-shaped conduit to the riser. An assembly station is disclosed on the platform deck for constructing the riser in sections. The riser sections may be welded together in a positive-pressure welding habitat.
Fig. 1
(Prior Art)
Fig. 20

Fig. 21

Fig. 22

Fig. 23
OFFSHORE RISER RETROFITTING METHOD AND APPARATUS

BACKGROUND OF THE INVENTION

1. Field of the Invention

The present invention generally pertains to offshore platforms, and more particularly to offshore oil or gas platforms in need of being retrofitted with a riser.

2. Description Of The Related Art

It is known within the oil and gas industry that in certain applications, depending on the characteristics of a given offshore field and the desires of the operator, it may be desirable to retrofit an existing offshore platform with what is known in the industry as a “riser”. A riser is simply a long pipe or conduit that runs from the deck of the platform down to the sea floor, where it is connected to a pipeline. Oil and gas extracted from beneath the sea floor that is produced up to the deck of the platform may then be routed down through the riser and into the pipeline, which transports the oil and gas to another location (e.g., another platform or land) for further processing.

The current method of retrofitting a riser to an existing platform is to attach the riser in sections to the outside of the platform jacket. This is done using divers who bolt the pipe sections together to form the riser and attach it to the platform jacket. As shown in FIG. 1, a platform 10 generally includes a deck 12 and a jacket 14. The jacket 14 is the support structure for the deck 12. The jacket 14 rests on the ocean floor 16. FIG. 1 illustrates a riser 18 that has been attached to the exterior of the jacket 14. The riser 18 is connected to a pipe line 20 running along the ocean floor 16.

One problem with the current approach to retrofitting a riser 18 to an existing platform 10 is that safety concerns require that production be stopped during the time that the riser 18 is being attached to the jacket 14. One reason for this is because divers are used to bolt and attach the riser 18 to the outside of the jacket 14. Another reason for shutting down production is the potential for a section of the riser to be dropped on an existing pipeline, thereby rupturing it and creating a hazardous environment. The production downtime is extremely costly to the oil field operator. For example, it would not be uncommon for the operator to lose millions of dollars for each day of downtime.

Another problem with the current retrofitting method is that the number of days of downtime depends on site conditions, such as weather and wave activity. For example, these site conditions may require the crew to halt the retrofitting operation until the conditions improve. In these situations, the operator is at the mercy of the weather, for example, until the weather clears. Not only is millions of dollars of production being lost for each day of inactivity, but leased equipment must be paid for while waiting for the site conditions to improve. This equipment lease cost can easily add hundreds of thousands of dollars per day to the retrofitting tab.

As explained more fully below, the present invention is directed to a new and improved approach to installing a riser to an offshore platform. The present invention does not require termination of production during the installation operation. As such, it is believed that the use of the present invention will result in millions of dollars of cost savings to the operator.

SUMMARY OF THE INVENTION

In one aspect, the present invention may be a method of establishing a fluid flow path from a deck of an offshore platform supported by a jacket to a pipeline located in a body of water beneath the deck, comprising: positioning a conduit in the body of water below the deck, the conduit having a first end located within the jacket and a second end located outside of the jacket; constructing a riser having an upper end and a lower end; positioning the riser within the jacket with the upper end located at the deck; and connecting the lower end of the riser to the first end of the conduit. Another feature of this aspect of the invention may be that the method further includes performing each of the steps without ceasing production operations of the platform. Another feature of this aspect of the invention maybe that the method further includes connecting the second end of the conduit to the pipeline. Another feature of this aspect of the invention may be that the method further includes establishing fluid communication between the upper end of the riser and a source of hydrocarbons below the body of water. Another feature of this aspect of the invention may be that the method further includes positioning the riser within a plurality of conductor guides on the jacket. Another feature of this aspect of the invention may be that the method further includes stabilizing the riser within the conductor guides. Another feature of this aspect of the invention may be that the method further includes positioning a pair of generally semi-circular shaped centralizer members in an annulus formed between the riser and each conductor guide. Another feature of this aspect of the invention may be that the method further includes filling an annulus between the riser and each conductor guide with a material and allowing the material to set. Another feature of this aspect of the invention may be that the material is at least one of a grout and an epoxy. Another feature of this aspect of the invention may be that the method further includes electrically isolating the riser from the jacket. Another feature of this aspect of the invention may be that connecting the lower end of the riser to the first end of the conduit is performed without the use of a diver. Another feature of this aspect of the invention may be that connecting the lower end of the riser to the first end of the conduit is performed with a remotely operated vehicle. Another feature of this aspect of the invention may be that the method further includes connecting at least one inflatable bladder to the conduit and remotely controlling the pressure in the bladder to assist in positioning the first end of the conduit adjacent the lower end of the riser conduit. Another feature of this aspect of the invention may be that the method further includes using a diverless connector to connect the lower end of the riser to the first end of the conduit. Another feature of this aspect of the invention may be that the method further includes using a light source to align the lower end of the riser with the first end of the conduit.

In another aspect, the present invention may be an apparatus for connecting a generally vertical riser within a jacket of an offshore platform to a pipeline located outside of the jacket, comprising: a frame; and a generally L-shaped conduit attached to the frame, the L-shaped conduit having a first end adapted for connection to a lower end of the riser.
conduit and a second end adapted for connection to the pipeline. Another feature of this aspect of the invention may be that the apparatus further includes at least one remotely-controllable inflatable bladder adapted to assist in positioning the first end of the conduit adjacent the lower end of the riser. Another feature of this aspect of the invention may be that the apparatus further includes a diverless connector connected to the first end of the L-shaped conduit and a mating connector connected to the lower end of the riser.

In still another aspect, the present invention may be an apparatus for constructing a riser comprising: a support base; a tower rotatably attached to the base and moveable between a lower position and an upper position; a top clamp movably attached to the tower; a bottom clamp attached to the support base, and aligned with the top clamp when the tower is in its upper position; and an enclosure having an open position and closed position, the enclosure being positioned between the bottom clamp and the top clamp when the enclosure is in its closed position.

The above summary of the invention is not intended to, nor does it, attempt to summarize all aspects of the present invention. Other features, aspects and advantages of the present invention will become apparent from the following discussion and detailed description.

BRIEF DESCRIPTION OF THE DRAWINGS

Fig. 1 is a side view of a prior art offshore platform showing that a riser that has been retrofitted to the outside of the platform. Fig. 2 is a side view showing one embodiment of the present invention. Fig. 3 is an end view of a specific embodiment of a tube turn skid of the present invention. Fig. 4 is a side view in cross section illustrating how a riser of the present invention may be centrally stabilized in a conductor guide and/or electrically isolated from an offshore platform jacket. Fig. 5 is side view in partial cross-section showing another embodiment of the present invention. Fig. 6 is a side view showing another embodiment of a tube turn skid of the present invention. Fig. 7 is a top view of the tube turn skid shown in Fig. 6. Fig. 8 is an end view of the tube turn skid shown in Figs. 6 and 7. Fig. 9 is a side view in partial cross section of an offshore platform with the tube turn skid being lowered into position. Fig. 10 is another similar to Fig. 9 showing the tube turn skid attached to a number of winches and being moved into position.

Fig. 11 is another similar to Figs. 9 and 10, showing additional cables located adjacent a column of conductor guides and connected to the tube turn skid to assist in locating the skid in its desired position for connection to the jacket and the riser. Fig. 12 is a top view showing the tube turn skid in position as illustrated in Fig. 11. Fig. 13 is a side view showing a platform crane and a vertical stalking station located on an upper deck of the offshore platform, with the vertical stalking station in its upright position. Fig. 14 is a side view similar to Fig. 13, except that the vertical stalking station is shown in a lowered or horizon-
to be used to hold a hardenable material such as grout or epoxy to stabilize the riser within the guide.

[0050] FIG. 38 is a top view of the configuration shown in FIG. 37.

[0051] FIG. 39 is a side view similar to FIG. 37, only showing the bladder after it has been filled.

[0052] FIG. 40 is a top view of the configuration as shown in FIG. 39.

[0053] While the invention will be described in connection with the preferred embodiments, it will be understood that it is not intended to limit the invention to those embodiments. On the contrary, it is intended to cover all alternatives, modifications, and equivalents as may be included within the spirit and scope of the invention as defined by the appended claims.

DETAILED DESCRIPTION OF THE INVENTION

First Embodiment

[0054] Referring to the drawings in detail, wherein like numerals denote identical elements throughout the several views, there is shown in FIG. 2 an offshore platform 11 and one embodiment of the present invention wherein a riser 19 is installed, without terminating production, inside or down the interior of a jacket 21 of the platform 11 utilizing an existing unused drilling conductor "slot". FIG. 2 further shows a pipeline connection assembly or tube turn skid 22 (see dashed lines) that is provided to connect the bottom of the riser 19 (located inside the jacket 14) to a pipe line 23 (located outside the jacket 21).

[0055] In one embodiment, the present invention may rely on or make use of existing structure located on the platform 11. As is well known to those of skill in the industry, drilling and production platforms are typically constructed with a number of "routes" or "channels" through which drilling string and production tubing (not shown) may be directed down inside the jacket 21 and into the ocean floor 17. If it is desired to use one of the routes in a drilling or production operation, a "conductor" (which is a pipe, not shown) is fed from a deck 13 of the platform 11 (in sections) down through conductor guides 24 (which are sometimes like funnels) corresponding to the particular slot selected. The conductor (not shown) is fed (in sections) down to and driven into the ocean floor 17. Drilling string (not shown) is then passed down through the conductor to drill the well. After the well has been drilled and the drilling string is removed, production tubing (not shown) is installed through the conductor to complete the well and produce the hydrocarbons to the platform 11. This background on conductors is merely provided for a background understanding of the purpose of the conductor guides 24.

[0056] In one aspect of the present invention, the guides 24 maybe utilized for a different purpose. With reference to FIG. 2, it can be seen that the riser 19 is fed down through the guides 24, and then connected to the tube turn skid 22 via a connection 26. As will be discussed further below, the connection 26 may be any type of connection in which two sections of pipe or conduit may be remotely connected through the use of a Remotely Operated Vehicle ("ROV"). One example of an industry-standard connection, which has been used in ultra-deepwater diverless applications, may be a collet connection assembly of the type available from Cameron International Corporation, of Houston, Tex. Other known connectors may be of the type available from FMC Corporation, of Houston, Tex., or Oil States Industries, of Arlington, Tex., for ultra-deepwater/ROV applications.

[0057] The tube turn skid 22 is preferably placed into its position before the riser 19 is lowered down through the guides 24. The skid 22 can be lowered into position through the use of a platform crane and winches (not shown), as more fully discussed below. The tube turn skid 22 may include a generally L-shaped section of pipe 28 mounted to a support frame 30. The L-shaped section 28 preferably includes a bend of sufficient diameter to allow traditional rigging equipment to pass therethrough, as will be understood by those of skill in the art. Part of the connection 26 (denoted as 26a) may be connected to the upstanding vertical portion of the L-shaped member 28. The other end of the L-shaped member (i.e., the end of the horizontal section of the L-shaped member 28) may be provided with a flange 36 and positioned outside of the jacket 21. The flange 36 is of any known type used for connecting a riser to the pipe line 23. Attached to the frame 30 may be a downwardly extending stabbing connector 32 adapted for engagement with a lowermost guide 34 on the jacket 21 at the mudline level, if available. The stabbing connector 32 may be a pipe that is disposed in co-axial relationship with the vertical end (i.e., where the connection part 26a is located) of the L-shaped member 28.

[0058] As best seen in FIG. 3, which is an end view of one sample embodiment of the tube turn skid 22, it can be seen that the frame 30 may include upstanding side members 38 adapted to contain inflatable balloons or bladders 40 that may be secured to the side members 38. As more fully discussed below in connection with another embodiment of the present invention, a mesh covering may be provided to contain the balloons 40 to control their volume and assist in controlling the buoyancy of the skid 22, as more fully discussed below.

[0059] The installation process is preferably commenced by lowering the tube turn skid 22 from the deck 13 down to or near the ocean floor 17. At that point, the balloons 40 are inflated, through the use of an ROV, until neutral buoyancy is achieved. (In actuality, as is known in the industry, neutral buoyancy actually means slightly negative buoyancy, so the part to which the balloons are attached will not rise to the water surface.) Rigging cables (not shown in FIG. 2) are also preferably passed downwardly and connected to the top of the curved portion of the L-shaped member 28. The ROV (not shown) can then grasp the tube turn skid 22 and maneuver it, assisted by the rigging cables, from outside the jacket 21, through an opening in the jacket 21, to its desired position inside the jacket 21. As shown in FIG. 2, the stabbing connector 32 on the bottom of the frame 30 when available may be stabbed into engagement with the lowermost guide 34. It is noted that if the site conditions worsen (e.g., unexpected strong water currents) during the process of moving the tube turn skid 22 from outside the jacket 21 to inside the jacket 21, the balloons 40 may be deflated to lower the skid 22 to the ocean floor 17 until conditions improve. As more fully discussed below in connection with another embodiment, an umbilical containing various hoses and cables is provided to remotely operate various items of equipment preferably provided to connect the riser 19 to the skid 22 (e.g., sonar, video, hydraulic, load cells, green laser fan alignment lights, etc.).

[0060] Next, after the skid 22 is properly positioned, the rigging cables are removed, and the riser sections are then serially welded and lowered downwardly through the use of an assembly station 42 located on the deck 12. The station 42 may include, for example, structure similar to a J-Lay tower.
of the type that has been proven for use on barges, and a positive-pressure welding station or habitat. The riser sections are serially held in place by the station 42 and welded inside the welding habitat to the riser 19, which is gradually lowered downwardly through the guides 24. The lower end of the riser 19 may include a part 266 of the connection 26, which may be remotely engaged, through the use of the ROV and various video and sonar feeds with the umbilical, to the part 266 of the connection 26, which is attached to the top of the L-shaped pipe 28. The flange 36 on the end of the horizontal portion of the L-shaped member 28 may then be connected to the pipe line 23 in a known manner.

[0061] It is also preferable that the riser 19 be stabilized within the conductor slots 24 and/or electrically isolated from the jacket 21. As shown, for example, in FIG. 4, this may be accomplished by positioning accurate wedge sections 44 in the annulus formed between the riser 19 and the guides 24. It is noted that the size of the annulus will depend on the size of the pipe used for the riser 19 and the size of the conductor slots 24. The wedge sections 44 are preferably provided with a suitable material 46 (e.g., neoprene) to engage the riser 19 to electrically isolate the riser from the jacket 21. In another embodiment, as more fully discussed below, a hardenable filler material, such as grout or epoxy, for example, may be positioned through the use of an annular bladder in each annulus between the riser 19 and the guides 24.

Second Embodiment

[0062] Another embodiment of the present invention will now be described with reference to FIGS. 5-40. Referring to FIG. 5, an offshore platform 50 includes a jacket 52 resting on the ocean floor 54. The platform 50 may further include an upper deck 56 and a lower deck 58, both positioned above the ocean water surface 60. The platform 50 is provided with a platform crane 62. A vertical stalking station 64 is shown mounted on the upper deck 56, which will be described in more detail below in connection with FIGS. 9-16. The platform 50 may be provided with one or more conductors 66 positioned within guides 67 for use in drilling a well in and/or producing hydrocarbons from beneath the ocean floor 54.

[0063] The platform 50 further includes a welded vertical riser string (or riser) 68 that has been installed through the use of the vertical stalking station 64. The riser 68 is positioned down through the interior of the jacket 52, as opposed to on the outside of the jacket 52. Again, the riser 68 may be installed without ceasing production in order to eliminate downtime costs. Attached to the lower end of the riser 68 is a tube turn skid 70, which will be described in more detail below in connection with FIGS. 6-8. The tube turn skid 70 is shown connected to the lower end of the riser 68 via a diverless connection 106 (e.g., a proven industry-standard collet connector of the type discussed above). The platform 50 is preferably provided with segmented centralizers 74 within each guide 67 through which the riser 68 is passed to centrally stabilize the riser 68 within the guides 67 and/or electrically isolate the riser 68 from the jacket 52. The centralizers 74 are more discussed below in connection with FIGS. 33-36. Alternatively, as explained above and discussed more fully below in connection with FIGS. 37-40, the riser 68 may be stabilized and electrically isolated within the guides 67 through use of an annular bladder filled with a material such as grout or epoxy, for example.

[0064] The platform 50 is also preferably provided with a fusion bonded epoxy (FBE) application habitat 76 below the vertical stalking station 64 (e.g., between the upper deck 56 and lower deck 58) to apply FBE or any other suitable field joint corrosion coating to the welded joints of the riser 68. After the riser 68 has been welded and installed into position, the upper end of the riser 68 is preferably engaged with a temporary support friction clamp 78 of a type known in the industry to hold the riser 68 in place after it is disconnected from the stalking station 64 until it can be tied-in to a production manifold by a mechanical contractor.

[0065] The platform 50 may also be provided with a number of winches 82 (e.g., air and/or hydraulic winches), each having a cable 84 that may be used in positioning the tube turn skid 70. A platform-based work-class remotely-operated vehicle (ROV) 86 of the type known in the industry (e.g., a 100 horse power ROV) is also provided to assist in positioning the tube turn skid 70 and make the necessary connections at the skid 70. The size of the ROV 86 should be selected in light of the capacity of the crane 62 so that the crane 62 is able to lift the ROV 86 to deck level from a supply boat. The platform 50 may also be provided with a sonar/video system 88 to enable surveillance of the positioning and connecting of the skid 70. The skid 70 is also provided with an umbilical 90 running from the upper or lower deck 56 or 58 to the skid 70. The umbilical 90 may include a variety of cables or conductors, such as for air, hydraulics, light power, load cell and video feeds, for example. The umbilical 90 is preferably connected to a control panel located, for example, on one of the decks 56 or 58, to enable an operator, such as at deck level, to remotely operate the necessary equipment to position and make the necessary connections to the skid 70.

The Tube Turn Skid

[0066] The tube turn skid 70 shown in FIG. 5 will now be described in more detail in connection with FIGS. 6-8. Referring to FIG. 6, the tube turn skid 70 may include a support frame 92 and a conduit 94 having a riser end 96 and a flange end 98. The frame 92 is preferably configured to rest on a brace positioned in the jacket 52. Depending on the desired placement of the skid 70 on the jacket bracing, it may be necessary to use the ROV 86 to remove anodes attached to the jacket bracing for later relocation by pipeline divers. The frame 92 may be secured to structural members 93 on the jacket 52 through the use of any appropriate connecting mechanism, such as U-clamps 95, for example, as shown in FIG. 6. The skid frame 92 is preferably clamped to the jacket bracing 93 by pipeline divers when the skid 70 is connected to the pipeline. The conduit 94 may be a section of pipe having a generally straight or horizontal section 100 and a curved section 102. In a specific embodiment, the conduit 94 may be a 3D or 5D induction bend. The particular curvature and dimensions of the conduit 94 will be dictated by the specific design and configuration of the platform 50 and jacket structure (e.g., grid layout of conductor slots 67), and may, for example, bend only in one plane. In a specific embodiment, the induction bend may be configured for three-dimensional reach to the desired conductor slot 67. The flange end 98 may include a flange 104 suitable for connection to a pipe line (not shown here) as will be understood by those of ordinary skill in the art. The riser end 96 of the conduit 94 is preferably provided with a diverless connector 106.

[0067] The connector 106 may be any type of diverless connector known in the art that can be used to remotely connect two sections of conduit located underwater through the use of an ROV, some examples of which were previously
provided above. In a specific embodiment, the connector 106 may be a collet connector that includes hydraulic activation cylinders 108 that are connected to one or more hydraulic fluid conduits 110 contained within the umbilical 90. A video camera 112 may also be mounted adjacent the connector 106 (and/or on the skid 70 and/or jacket 52) and connected to a video cable 114 contained within the umbilical 90. The connector 106 may also be provided with a green fan laser 116, as will be understood by those of skill in the industry, atop the connector 106 to assist in coaxial alignment of the connector 106 with the conductor guides 67 through which the riser 68 is to be positioned, as more fully discussed below. In a specific embodiment, the green fan laser 116 may be of the type available from Imenco AG of Haugesund, Norway, known as The Imenco Underwater Green Laser.

In this specific embodiment, the skid 70 is further preferably provided with at least one air blader or balloon, such as a first air blader or balloon 118 and a second air blader or balloon 120. The first blader 118 is preferably contained within a first enclosure 122 and the second blader 120 is preferably contained within a second enclosure 124. In a specific embodiment, the enclosures 122 and 124 may be cages made with rigid or flexible steel mesh. The use of the enclosures 122/124 is preferred to assist in avoiding the possibility of uncontrolled positive buoyancy. As discussed above and as will be readily understood by those of skill in the art, the air bladders 118/120 may be remotely inflated via an air hose 126 contained within the umbilical 90. This allows for remote control from the deck of the in-water weight of the skid 70 to maintain negative buoyancy (i.e., avoid the possibility of run-away positive buoyancy). In a specific embodiment, for example, the in-water weight of the skid 70 may be adjusted to approximately 500 pounds or determined to correspond to the ROV capacity.

The skid 70 is also preferably provided with a cable assembly 128 having a load cell 130 and a ring eye 132. The load cell 132 is connected to an electrical cable 134 contained within the umbilical 90 to provide a reading to an operator at the deck of the in-water weight of the skid 70 so that appropriate negative buoyancy can be maintained. The manner in which the skid 70 may be positioned will now be explained with reference to FIGS. 9-11.

Positioning of the Tube Turn Skid

Referring now to FIG. 9, a cable 87 from a winch 89 may be connected to the ring eye 132 on the cable assembly 128 on the skid 70. The winch 89 may be connected to and supported by a platform crane 63 on the upper deck 56 until the skid 70 is positioned near the point through which the skid 70 is to be passed through the platform jacket 52. As shown in FIG. 10, the skid 70 is then transferred from the crane 63 to a number of winch lines 84 connected to winches 82. The winch lines 84 may be routed through the use of pulleys (e.g., pulley 85) mounted to the jacket 52 and/or routed around jacket members. These lines are used to position the connector 106 on the tube turn skid 70 beneath the column of conductor guides 67 through which the riser 68 is to be positioned. The ROV 86 may also be used to grasp the skid 70 and assist in locating it in its desired position relative to the jacket 52. With reference to FIGS. 11 and 12, additional winch lines 97 may be routed downwardly adjacent to the selected column of conductor guides 67 and attached to the riser end 96 of the conduit 94 on the skid 70 to assist in positioning the skid 70. The green fan laser 116 (see, e.g., FIG. 6) on top of the diverless connector 106 is then used in a known manner to shine a beam of visible light upwardly through the column of conductor slots 67 through which the riser 68 is to be positioned. In this manner, the exact desired location of the skid 70 may be established and the skid 70 can be precisely positioned so that the skid 70 can be leveled and the connector 106 can be engaged with the riser 68. In a specific embodiment, two circular plates (not shown) may be provided to assist in use of the green fan laser 116. The plates are provided with a diameter to permit them to be placed by the ROV in the two conductor guides 67 located immediately above the connector 106. The plates are preferably painted white. The plate to be positioned in the guide 67 immediately above the connector 106 preferably has a hole cutout (e.g., having a diameter of approximately three inches) in the center of the plate. The plate to be positioned above the lower plate is preferably provided with a black or dark-colored crosshair marking. These plates thus cooperate to assist in using the green fan laser 116 to align the connector 106 beneath the guides 67 for engagement with the riser 68.

Once the tube turn skid 70 is properly positioned, the next step is to construct and lower the riser 68 into position so that it can be attached to the tube turn skid 70 by the diverless connector 106. This is done through the use of the vertical staking station 64, as will now be explained in connection with FIGS. 13-32. It is noted that, at this time, the ROV 86 and/or winches 82 may be used to temporarily hang the centralizers 74, for later installation, on the jacket bracing adjacent the conductor slots 67 through which the riser string 68 is to be located.

The Stacking Station

Referring to FIG. 13, in a specific embodiment, the stacking station 64 may include a support base 136 attached to drilling deck skid beams 138 on the upper deck 56. As will be described more fully below, the support base 136 may comprise a pair of generally parallel I-beams positioned on the deck skid-beams 138. The station 64 is positioned over the empty column of conductor slots 67 through which the riser 68 is to be lowered. The station 64 also includes a tower 140 that is hingedly connected to the support base 136 at a pivot point 142. The tower 140 is movable between a vertical position (as shown in FIG. 13) and a horizontal position (as shown in FIG. 14). A hinged support arm 144 is connected to the support base 136 and tower 140 to hold the tower in its vertical position, and is collapsible to allow the tower 140 to move to its horizontal position. The tower 140 also includes a winch 146 (e.g., a hydraulic winch) that controls a cable 148 that runs to the top of the tower 140 and over a pulley 150 and then down to a top clamp 152. The top clamp 152 includes rollers 186 and 187 to facilitate movement of the top clamp 152 up and down along the tower 140, as more fully discussed below in connection with FIG. 28. The structure and operation of the top clamp 152 is more fully described below in connection with FIGS. 24-25 and 28-32. The tower 140 also includes a horizontal joint support 154, the structure and operation of which is described more fully below in connection with FIGS. 20 and 21. The station 64 also includes a bottom clamp 156 disposed on the support base 136. The structure and operation of the bottom clamp 156 will be described more fully below in connection with FIGS. 26-32.

The station 64 also includes a positive pressure welding habitat 158 connected to a vertical support member 160 that is connected to the support base 136 and adapted for
rotatable movement, as will be further discussed below, including in connection with FIGS. 22-23. The use of pressurized enclosures and rooms is well known and customary on offshore platforms for safety reasons. The welding habitat 158 is supplied with a positive pressure air flow via an air duct connected to a remotely-located ventilator fan positioned a safe distance from any areas where a potential leak or hazard might arise on the platform. Attached to the top of the tower 140 is an x-ray spider davit 141 that is provided to lower an x-ray source inside the riser 68 to inspect each weld as the riser sections 162 are welded together within the welding habitat 158. As mentioned above in connection with the size of the ROV 86, the various components of the staking station 64 should be designed and sized within the capacity of the crane 62 so that the crane 62 will be able to lift the components to the deck surface from a supply boat for assembly.

Assembling the Riser String

[0074] The vertical staking station 64 is used to create the welded vertical riser string 68 (see FIG. 5) by welding together sections of riser pipe or conduit 162, such as shown in FIG. 15. The riser pipe sections 162 are preferably coated with FBE or other suitable corrosion inhibiting coating before the riser string 68 is constructed. With reference to FIG. 15, the conduit is depicted with a mating member 164 that corresponds to the diverless connector 106 on the tube turn skid 70 (see, e.g., FIG. 6). Again, the present invention is not limited to any particular brand or style of diverless connector. Thus, the section of conduit 162 shown in FIG. 15, with the mating member 164, is the lowermost section of the riser 68. This first, or lowermost, riser section shall be referred to by the numeral 162a. All subsequent conduit sections 162b will be as shown in FIG. 15 except without the mating member 164, and referred to by the numeral 162b etc. The upper end of each conduit section 162 is provided with a collar 166 adapted for mating engagement with the top clamp 152 on the tower 140 and the bottom clamp 156, as will be more fully discussed below. The lower end of the bottom riser section 162c is temporarily capped so as to prevent ocean water from flowing up into the riser 68 as it is being lowered into position, thereby eliminating the possibility of air flow at the welding habitat 158 that could be caused by water surge or wave action. Temporarily capping the bottom of the riser string 68 also allows the riser string 68 to be partially filled with water from the deck level in order to ballast the riser string 68 during the installation process, which may be more desirable with larger riser pipe diameters. The lower cap will be removed at a later stage after the riser 68 is positioned, preferably just prior to making the connection between the riser 68 and the diverless connector 106.

[0075] As shown in FIG. 14, the tower 140 is shown in a lowered or generally horizontal position. The crane 62 is being used to position a section of riser conduit 162 on the tower 140. The collar 166 on the riser pipe 162 is engaged with the top clamp 152 and the horizontal joint support 154 on the tower 140 is engaged with an opposite end of the riser pipe 162. FIG. 16 illustrates the crane 62 being used to lift the tower 140 from its lowered position to its upright or generally vertical position. FIG. 17 illustrates the tower in its upright position and the top clamp 152 being lowered by the winch 146 to lower the riser pipe section 162 relative to the bottom clamp 156. Note that after the lower end of the riser pipe 162 has passed through and is laterally supported by the bottom clamp 156, the horizontal joint support 154 is disengaged from the riser pipe 162 and moved out of the way into an open or retracted position so as to allow the top clamp 152 to move downwardly past the joint support 154. FIG. 20 illustrates the horizontal joint support 154 in its closed or clamped position, and FIG. 21 illustrates the horizontal joint support 154 in its open or retracted position. FIG. 18 shows the top clamp 152 lowered all the way down adjacent the bottom clamp 156. The top clamp 152 is unclamped from the riser pipe 162a and moved back to the top of the tower 140 once the collar 166 on the section of riser pipe 162a is resting on the bottom clamp 156 in a mechanically fail-safe position, as will be discussed and shown in more detail below.

[0076] The next step is to load the next section of riser pipe 162b onto the tower 140, in the manner explained above. The top of each section of riser pipe 162b etc. is preferably temporarily capped so as to prevent the loss of positive pressure in the welding habitat 158 during the welding process, as more fully discussed below. Referring now to FIG. 19, once the tower 140 is loaded with the next section of riser pipe 162b and moved into its upright position, the lower end of the riser section 162b is positioned into coaxial alignment and contact with the upper end of the riser section 162a being held by the bottom clamp 156 to form a joint to be welded together. The manner in which the riser sections 162a and 162b are coaxially aligned by the bottom clamp 156 will be discussed and illustrated in more detail below. The welding habitat 158 is then rotated into a closed position so as to form a positive-pressure enclosure around the joint so that the two sections of riser pipe 162a and 162b can be safely welded in a known manner. A top view of the welding habitat 158 in its closed position is shown in FIG. 22. Once the weld is completed, the welding habitat is moved into an open position (see, e.g., FIGS. 18 and 23), and the x-ray spider davit 141 is used to inspect the welded joint. Assuming the weld passes inspection, the bottom clamp 156 is released, and the top clamp 152 is lowered as explained above to lower the riser string 68 until the collar 166 on the riser section 162c is positioned into engagement with the bottom clamp 156. This process is repeated until the entire riser string 68 has been constructed and the lowermost riser section 162c is positioned with the diverless mating connector 164 (see FIG. 15) positioned adjacent the diverless connector 106 on the skid 70 for engagement thereto through the use of the ROV and above-described surveillance equipment. As the riser string 68 is gradually constructed and lowered down through the conductor slots 67, it is preferred that temporary wooden centralizers be positioned in the annulus between the riser 68 and at least some of the conductor guides 67 (preferably at least the guides 67 just above and below the water line 60) to maintain stability of the riser string 68 during the installation process, and to especially avoid excessive movement of the riser string 68 due to wave action during the welding process.

[0077] Once the riser string 68 is connected to the connector 106, the next step is to conduct an industry standard hydrotest of the riser assembly while the riser string 68 is still being held in by the staking station 64. The top of the riser string 68 is capped and the riser is filled with water and pressurized by a pump to a hydrostatic test pressure to confirm no leaks in the assembly of the riser 68 and the skid 70. The centralizers 74 or hardenable filler material is then installed at each conductor guide 67 using the ROV 86. The temporary friction clamp 78 is then clamped to the riser 68 at the lower or production deck level 58 to secure the riser 68 until a mechanical contractor executes the final tie-in to the
production manifold. At a later time, pipeline installation divers may secure the skid 70 to the jacket 52, such as with U-clamps 95, as shown in FIG. 6, and reinstall any jacket anodes at the same time the flange 104 on the skid 70 is attached to the pipeline on the ocean floor 54.

The Top and Bottom Clamps

Specific embodiments of the top clamp 152 and the bottom clamp 156 on the vertical stacking station will now be described. Referring to FIG. 24, a specific embodiment of the top clamp 152 is shown in an open position. The top clamp 152 may include a frame 170 with a pair of clamping arms 172 and 174 hingedly attached thereto. Each clamping arm 172/174 includes a curved clamping surface 176/178 sized for mating engagement with the riser pipe 162. The top clamp 152 further includes any suitable mechanism for moving the arms 172/174 between open and closed positions. For example, in the specific embodiment shown in FIG. 24, the top clamp 152 may be provided with a jack screw 180 attached to the arms 172/174 via threaded flange members 182 and 184, in a known manner. The top clamp 152 is also preferably configured for rolling engagement with the tower 140 of the vertical stacking station 64. As shown in FIG. 24, the tower 140 may be an l-beam. The top clamp 152 may include an outer roller 186 disposed between the frame 170 and the tower 140. The top clamp 152 may further include one or more inner rollers 188 positioned to engage an inner surface of the tower 140 such that the top clamp 152 is engaged with or connected to the tower 140 to permit rolling movement of the top clamp 152 up and down the tower 140. As shown in FIG. 28, discussed further below, the top clamp 152 is preferably provided with a set of upper rollers 186/188 and a set of lower rollers 187/189. FIG. 25 is similar to FIG. 24, except that FIG. 25 shows the top clamp 152 in its closed or clamped position, with the clamping surfaces 176/178 clamped around the riser pipe 162.

Referring now to FIG. 26, the bottom clamp 156 may include a pair of clamping arms 190 and 192 configured for slidable engagement with the support base 136 of the stacking station 64. With reference to FIG. 31, the clamping arm 190 is shown in cross-section, and it can be seen from this view that the support base 136 may comprise a pair of generally parallel l-beams 194 and 196. It can further be seen from FIG. 31 that the clamping arms 190/192 each includes a lower lip 198 that defines a slot 200 to allow for sliding engagement of the arms 190/192 with the l-beams 194 and 196. The slots 200 are further preferably sized to allow for sufficient lateral movement of the arms 190/192 relative to the beams 194/196 for purposes of co-axial alignment of sections of riser pipe 162 to be welded together, as discussed in more detail below.

Referring again to FIG. 26, corresponding opposed ends of the arms 190/192 are connected to screw jacks 202/204 and configured to move between an open position (as shown in FIG. 26) and a closed position (as shown in FIG. 27). Each arm 190/192 further includes an arcuate ledge 206/208. In operation, as shown in FIG. 29, when the top clamp 152 lowers a section of riser pipe 162 down through the bottom clamp 156, the arms 190/192 are moved towards each other by the screws jacks 202/204 into a position such that the collar 166 on the riser pipe section 162 will rest on the arcuate ledges 206/208. The purpose of the clamping arms is not to clamp and hold the riser string 68, but instead to position the arcuate ledges 206/208 so as to support the collar 166. In this way, a mechanical fail safe connection is provided to hold the riser string 68. In other words, the riser string 68 is not susceptible to being dropped due to failure of a transverse clamping mechanism. Once the riser pipe collar 166 is securely resting on the arcuate ledges 206/208, and the top clamp 152 has been withdrawn to retrieve another section of riser pipe 162, the riser pipe 162 hanging in the arms 190/192 can be moved around as needed to position it in co-axial alignment with the next section of riser pipe to which it is to be welded. Side-to-side, or lateral, movement is accomplished through the use of a lateral positioning mechanism, such as a lateral hydraulic cylinder 210 that may be connected to the support base 136 and the arm 192. The bottom clamp 156 may further be provided with one or more transverse or rotational positioning mechanisms, such as hydraulic cylinders 212 and 214, which are connected to the support base 136 and the arms 192 and 190, respectively. If both cylinders 212 and 214 are actuated in unison, then both arms 190/192 will move transversely together along with the pipe 162. But if only one of the cylinders 212/214 is actuated or if they are actuated in different directions then rotational movement will be imparted to the riser pipe 162.

Stabilizing the Riser in the Guides

Details of a specific embodiment of the centralizers 74 will now be described with reference to FIGS. 33-36. Referring to FIG. 33, a side view of a pair of centralizer segments 74a and 74b is shown in a spaced apart position. FIG. 34 is a top view of the segments 74a/74b as shown in FIG. 33. Each segment 74a/74b includes a curved surface 216a/216b adapted for engagement around the riser string 68. Each curved surface 216a/216b is preferably lined with a suitable material (e.g., neoprene) to electrically isolate the riser 68 from the jacket 52. FIGS. 35 and 36 illustrate the centralizer segments 74a and 74b installed in a conductor slot 67 with the riser 68 positioned therethrough. It can be seen from the side profile shown for example in FIG. 36 that the segments 74a/74b may form a funnel and be adapted for mating engagement with the conductor slot 67.

An alternative approach to stabilizing the riser 68 in the guides 74 and/or electrically isolating the riser 68 from the platform 52 will now be discussed in connection with FIGS. 37-40. Referring initially to FIGS. 37 and 38, an annular blander 218, such as an elastic latex blander, shown here in an empty or collapsed form, maybe attached to a metal deployment ring 220. The ring 220 should be of sufficient weight to pull the blander 218 down through the water. The annular blander 218 is sized to fit around the riser 68. A pair of polypropylene ropes 222 are attached to the ring 220 and used to lower the blander 218 into position adjacent the conductor guide 67. The ROV 86 is used to monitor proper positioning of the blander 218 relative to the guide 67. Once in position, an injection hose 224 running from deck level is inserted into an aperture 219 in the blander 218 and used to inject a hardenable or settable material into the blander 218 so as to fill up with annulus between the guide 67 and the riser 68, as shown in FIGS. 39 and 40. The filler material may be of any type (e.g., grout, epoxy, etc.) that could be used to fill the blander and stabilize the riser 68 within the guides 67. At least the inner diameter of the ring 220 is preferably covered with an insulating material (e.g., neoprene) so that the riser 68 is electrically isolated from the guides 67. The blander 218 is also preferably made of a material (e.g., latex) that will electrically isolate the riser 68 from the guides 67. Once the
bladder 218 is filled to the desired level, the ROV 86 may be used to cut the ropes 222 and hose 224, the loose ends of which may then be retrieved to deck level. A bladder 218 for each guide 67 is preferably positioned over the riser string 68 just before the uppermost riser section 162 is welded to the riser string 68, and then the bladders 218 are preferably lowered into position and filled after the hydrostatic pressure test is successfully completed.

From the above description it can be seen that by employing the present invention a riser can be installed on an existing operational offshore platform without terminating production, thereby avoiding economic loss associated with production downtime. Use of the present invention further eliminates expensive delays with marine equipment and diver operations due to unpredictable strong ocean currents and rough sea states. Use of the present invention further results in better control of interfacing schedules of offshore contractors, and expensive mobilization of marine equipment is also avoided. In addition, with the present invention, the riser can be installed and tested before pipeline installation equipment is mobilized. There are also safety benefits provided by the present invention insofar as it is not necessary to unduly subject divers and marine support vessels to potentially adverse currents or sea states. It can also be seen that the present invention is implemented pursuant to industry standard safe and high quality procedures for hydrocarbon producing environments. Another advantage of the present invention is that the riser sections are welded, as opposed to bolted, together, thereby resulting in better connections between the riser sections such that the joints are less susceptible to leakage.

It is to be understood that the invention is not limited to the exact details of construction, operation, exact materials or embodiments shown and described, as obvious modifications and equivalents will be apparent to one skilled in the art. It is also noted that although one benefit of the invention is the ability to install a riser to a platform without ceasing production, the invention is not limited to riser installations where production is not terminated during the installation process. Accordingly, the invention is therefore to be limited only by the scope of the appended claims.

1. A method of establishing a fluid path from a deck of an offshore platform supported by a jacket to a pipeline located in a body of water beneath the deck, comprising: positioning a conduit in the body of water below the deck, the conduit having a first end located within the jacket and a second end located outside of the jacket; constructing a riser having an upper end and a lower end; positioning the riser within the jacket with the upper end located at the deck; and connecting the lower end of the riser to the first end of the conduit.

2. The method of claim 1, further including performing each of the steps without ceasing production operations of the platform.

3. The method of claim 1, further including connecting the second end of the conduit to the pipeline.

4. The method of claim 1, further including establishing fluid communication between the upper end of the riser and a source of hydrocarbons below the body of water.

5. The method of claim 1, further including positioning the riser within a plurality of conductor guides on the jacket.

6. The method of claim 5, further including stabilizing the riser within the conductor guides.

7. The method of claim 5, further including positioning a pair of generally semi-circular shaped centralizer members in an annulus formed between the riser and each conductor guide.

8. The method of claim 5, further including filling an annulus between the riser and each conductor guide with a material and allowing the material to set.

9. The method of claim 8, wherein the material is at least one of a grout and an epoxy.

10. The method of claim 1, further including electrically isolating the riser from the jacket.

11. The method of claim 1, wherein connecting the lower end of the riser to the first end of the conduit is performed without the use of a diver.

12. The method of claim 1, wherein connecting the lower end of the riser to the first end of the conduit is performed with a remotely operated vehicle.

13. The method of claim 1, further including connecting at least one inflatable bladder to the conduit and remotely controlling the pressure in the bladder to assist in positioning the first end of the conduit adjacent the lower end of the riser conduit.

14. The method of claim 13, further including an enclosure containing the inflatable bladder.

15. The method of claim 1, further including using a diverless connector to connect the lower end of the riser to the first end of the conduit.

16. The method of claim 1, further including using a light source to align the lower end of the riser with the first end of the conduit.

17. An apparatus for connecting a generally vertical riser within a jacket of an offshore platform to a pipeline located outside of the jacket, comprising: a frame; and a generally L-shaped conduit attached to the frame, the L-shaped conduit having a first end adapted for connection to a lower end of the riser conduit and a second end adapted for connection to the pipeline.

18. The apparatus of claim 17, further including at least one remotely-controllable inflatable bladder adapted to assist in positioning the first end of the conduit adjacent the lower end of the riser.

19. The apparatus of claim 17, further including a diverless connector connected to the first end of the L-shaped conduit and a mating connector connected to the lower end of the riser.

20. An apparatus for constructing a riser comprising: a support base; a tower rotatably attached to the base and moveable between a lower position and an upper position; a top clamp movably attached to the tower; a bottom clamp attached to the support base, and aligned with the top clamp when the tower is in its upper position; and an enclosure having an open position and closed position, the enclosure being positioned between the bottom clamp and the top clamp when the enclosure is in its closed position.

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