

TITLE: SUBSEA BOOSTING CAP SYSTEM
RELATED APPLICATIONS

[0001] This application claims priority to U.S. Provisional Patent Application 61/122,001, filed December 12, 2008, and entitled SUBSEA BOOSTING CAP SYSTEM, the disclosure of which is hereby incorporated by reference in its entirety.

BACKGROUND

Field of the Disclosure

[0002] The present disclosure relates generally to a subsea system, and in particular, to a subsea boosting cap system.

Description of the Related Art

[0003] In fluid production subsea systems, it is common to adopt an artificial lift method as a means to achieve economic viable levels of crude oil production and/or improve the reservoir oil recovery. A common method of artificial lift is the use of pumps, such as, for example, Coaxial Centrifugal Pumps (CCPs), which enable increased production rate results. However, current solutions often employ CCPs made to be installed inside subsea wellheads or similar constructions, which imposes a dimensional constraint in diameter. This can result in completion hardware that is excessively tall / large with more complex stack up construction, which could reduce the system reliability and consequentially add some environmental risks.

[0004] From a performance view point, this complexity in construction can also result in a long and winding plumbing arrangement, which can cause significant pressure losses with potential detrimental consequences for the production flowrate, resulting in negative financial implications for the oilfield lifetime sustainability. Likewise, taking into

consideration the required space on offshore vessels, a heavy, long and/or large pump arrangement adds more difficulties and risks for the installation and intervention activities as well as for onboard repairs. This can result in larger deployment vessels and thus more expensive offshore operations. It can also result in increased risk to the environment due to increased potential leakage paths. These concerns can be especially problematic in deep water fields where the extreme underwater environment can complicate installation and/or repair of subsea equipment, thus resulting in longer shutdown periods and higher costs.

SUMMARY

[0005] The present disclosure is directed to overcoming, or at least reducing the effects of, one or more of the issues set forth above. For example, the present disclosure can provide one or more of the following advantages: reduced installation costs; reduced operating or equipment costs; increased production rates by reducing the pressure losses across the flow path; reduced equipment size and/or weight; and reduced environmental risks.

[0006] An embodiment of the present disclosure is directed to an offshore fluid production system. The system comprises a subsea wellbore at a first position on an ocean floor. A subsea boosting cap system is positioned in a second position on the ocean floor that is different from the first position. The subsea boosting cap system comprises an anchor assembly capable of attaching to the sea floor, the anchor assembly comprising a pump cavity capable of receiving a removable pump assembly. The boosting cap system further comprises a valve system attached to the anchor assembly. The valve system comprises an inlet flow path and an outlet flow path, the inlet flow path being in fluid communication with the subsea wellbore. The boosting cap system further comprises a boosting cap covering the pump cavity. The boosting cap comprises a first flow path configured to provide fluid

communication between an inlet flow path and the removable pump assembly when the removable pump assembly is positioned in the pump cavity. A second flow path provides fluid communication between the removable pump assembly and the outlet flow path when the removable pump assembly is positioned in the pump cavity. The boosting cap system also comprises a crossover flow path providing fluid communication between the inlet flow path and the outlet flow path. The crossover flow path bypasses the pump cavity. The valve system is capable of directing fluid flow to the first flow path and the crossover flow path. A downflow production line can be in fluid communication with the outlet flow path of the boosting cap system.

[0007] Another embodiment of the present disclosure is directed to a subsea boosting cap system. The system comprises an anchor assembly capable of attaching to the sea floor. The anchor assembly comprises a pump cavity capable of receiving a removable pump assembly. A valve system is attached to the anchor assembly. The valve system comprises an inlet flow path and an outlet flow path, the inlet flow path being capable of fluidly communicating with a subsea wellbore. A boosting cap covers the pump cavity. The boosting cap comprises a first flow path configured to provide fluid communication between the inlet flow path and the removable pump assembly when the removable pump assembly is positioned in the pump cavity. A second flow path provides fluid communication between the removable pump assembly and the outlet when the removable pump assembly is positioned in the pump cavity. A crossover flow path provides fluid communication between the inlet flow path and the outlet flow path, the crossover flow path bypassing the pump cavity. The valve system is capable of directing fluid flow to the first flow path and to the crossover flow path.

[0008] Yet another embodiment of the present disclosure is directed to a method for removing a pump assembly positioned in a pump cavity of a subsea boosting cap system having a crossover flow path that bypasses the pump cavity. The method comprises flowing a production fluid through a boosting cap flow path to a pump assembly. The flow of fluid through the pump assembly is stopped. The boosting cap positioned over the pump assembly can be removed. The pump assembly can be removed from the pump cavity. The boosting cap can be replaced over the pump cavity. The fluid can be flowed through the crossover flow path while the pump assembly is removed from the pump cavity.

BRIEF DESCRIPTION OF THE DRAWINGS

[0009] FIG. 1 illustrates an offshore fluid production system, according to an embodiment of the present disclosure.

[0010] FIG. 2 illustrates the offshore fluid production system of FIG. 1 where the pump assembly has been removed, according to an embodiment of the present disclosure.

[0011] FIGS. 3A and 3B illustrate a directional valve for directing fluid, according to an embodiment of the present disclosure.

[0012] FIG. 4 illustrates an offshore fluid production system comprising a subsea boosting cap system, according to an embodiment of the present disclosure.

[0013] FIG. 5 illustrates an offshore fluid production system in which the subsea boosting cap system is configured to have a flow line connection via a double locking connection system, according to an embodiment of the present disclosure.

[0014] FIG. 6 illustrates an embodiment of an offshore fluid production system in which the subsea boosting cap system is configured to have a flow line connection via a post connection system, according to an embodiment of the present disclosure.

[0015] FIG. 7 illustrates a flowchart of a method for removing a pump assembly, according to an embodiment of the present disclosure.

[0016] While the disclosure is susceptible to various modifications and alternative forms, specific embodiments have been shown by way of example in the drawings and will be described in detail herein. However, it should be understood that the disclosure is not intended to be limited to the particular forms disclosed. Rather, the intention is to cover all modifications, equivalents and alternatives falling within the spirit and scope of the invention as defined by the appended claims.

DETAILED DESCRIPTION

[0017] FIG. 1 illustrates an offshore fluid production system 100, according to an embodiment of the present disclosure. Offshore fluid production system 100 includes a subsea wellbore 102 positioned on the ocean floor 104. A subsea boosting cap system 106 is in a different position on the ocean floor 104, such as adjacent to, or some distance away from, the subsea wellbore 102. Subsea boosting cap system 106 can be attached to a downflow production line 108, through which oil can flow to any suitable desired downstream location, such as an oil platform at the surface.

[0018] The subsea boosting cap system 106 can include an anchor assembly 110 capable of securing the system to the sea floor. Anchor assembly 110 can be the structural foundation of the system, providing the mechanical support and stability on the mudline sea floor. Anchor assembly 110 can also provide the system vital interlinks and structural basis to receive the inlet and outlet flowline connections, power connections and hydraulic connections for system monitoring and operability.

[0019] The anchor assembly 110 can be any suitable type of anchor assembly known in the art. In an embodiment of FIG. 1, anchor assembly 110 can include an upper frame 112 that can comprise operational interfaces, such as a pump cavity 114 that is capable of engaging a removable pump assembly 116. Anchor assembly 110 can also include a lower frame 118.

[0020] In an embodiment, lower frame 118 can be shaped in a manner so as to provide the ability to form a hydro cushion effect when the frame starts to embed into the sea bed. Lower frame 118 can further provide differential pressure when the suction process is started, causing the hydrostatic head to push down the structure into the sea bed until a desired depth is achieved. In an embodiment, the shape of lower frame 118 can be, for example, an upside-down cupped shape forming an enclosed space 120. An opening 122 is formed by lower frame 118 at an end of enclosed space 120, which is designed to allow lower frame 118 to be embedded in the sea floor via a suction force. A suction anchoring tube 124 can be connected to a stab or other conduit (not shown) that can provide a fluid pathway for providing the desired suction to the enclosed space 120 through lower frame 118.

[0021] While the above described embodiment employs suction to provide a desired anchor to the sea floor, any other suitable technique for anchoring a structure to the sea floor can be employed in place of or in addition to the anchoring structure of FIG. 1. One of ordinary skill in the art would readily be able to design and implement alternative anchoring structures.

[0022] Subsea boosting cap system 106 can include a valve system 126 attached to the anchor assembly 110 and to a boosting cap 162. Valve system 126 comprises an inlet 128 and an outlet 130. Inlet 128 can be in fluid communication with the subsea wellbore 102 via a production jumper 132. Outlet 130 can be in fluid communication with the downflow production line 108 via a production jumper 134.

[0023] Production jumpers 132 and 134 can be attached to the inlet 128 and outlet 130 by any suitable connectors 133, which can be, for example, guide and hinge over connecting devices. An example of a suitable guide and hinge over connecting device is disclosed in WO2008/063080 A1, entitled A CONNECTOR MEANS, by MOGEDAL, Knut et al. and published on May 29, 2008, the disclosure of which is hereby incorporated by reference in its entirety. Other suitable connectors 133 include clamp type devices that can be locked by ROV with a torque tool, hydraulically actuated devices, mechanically actuated devices and/or electrically actuated devices.

[0024] Valve system 126 can comprise one or more valves for controlling the flow of fluid through the subsea boosting cap system 106. Any suitable type of valves can be employed. In an embodiment, isolation valves 136 and directional valves 138 can be employed. Isolation valves 136 can be capable of stopping or starting fluid flow through a given flow path. The function of the isolation valves 136 can generally be classified as the tertiary barrier of the overall offshore fluid production system 100, because they are often located in the intermediary position of the subsea field lay out.

[0025] Directional gate valves 138 are capable of switching flow from one flow path to another, as discussed in detail below. FIGS. 3A and 3B illustrate a directional valve 138, according to an embodiment of the present disclosure. Directional valve 138 comprises a gate 140 set in a valve body 142 comprising upper valve seats 144 and lower valve seats 146. The gate 140 is the on/off element of the system and can seal against the seats 144 and 146. Gate 140 can be any suitable gate, such as a slab gate, a cylindrically shaped gate or any other suitable gate that can function to direct the flow of water through the desired flow path. In an embodiment, the gate 140 can be a slab with flat sides and having a rectangular or

square cross-section. A bore 147 can be positioned in the gate 140 to allow fluid flow therethrough. The gate 140 can traverse back and forth in gate chamber 159 so as to position bore 147 to provide the ability to select a desired flow direction.

[0026] In an embodiment, the valve body 142 can be the main structural member of the system. For example, valve body 142 can integrate all components to provide structural capacity, flow path integrity, and pressure containing capability. In an embodiment, valve body 142 has a dual bore passage configuration which provides the ability to divert the flow according to the position of gate 140. In other embodiments, valve body 142 can have three or more passages. Examples of such embodiments are disclosed in Co-pending U.S. Patent Application No. [Atty Docket No. AKER.022U], the disclosure of which is hereby incorporated by reference in its entirety.

[0027] The upper valve seats 144 and the lower valve seats 146 physically engage the gate 140 and the valve body 142 so as to provide sealing capability on both sides of gate 140 around both flow paths 155 and 157. In this design concept, the valve seats 144 and 146 can provide isolation between the dual flow paths 155 and 157.

[0028] A bonnet assembly 154 can enclose a stem 150 and stem seal packing 152. The stem 150 can be the physical link between an actuator 151 and the gate 140. Actuator 151 can be any suitable actuation system. Such actuations systems are well known in the art. The stem 150 can act as a dynamic barrier of the system, connecting the gate 140 to the actuator 151 to provide the valve functional motion. While the bonnet assembly 154 is illustrated with a single stem 150, any suitable number and type of actuators can be employed, such as one or more hydraulic, manual, electrical and ROV operated actuators. Bonnet 154 can provide

structural retention for the dynamic sealing around the stem 150, as well as structural strength to mount an actuation system of any type.

[0029] In an embodiment, directional valve 138 can comprise a single gate 140 activated by a single actuator. In other embodiments, multiple gates and/or multiple actuators can be employed. The gate 140 can either be made as one integral piece or as an assembly of multiple parts, as desired. A sealing system (not shown) between gate 140 and valve seats 144 and 146, as well as between the valve seats and valve body 142, can include any suitable type of sealing mechanism. For example, the sealing mechanism can comprise a metal to metal type seal, or any other suitable type of seal made of any suitable material.

[0030] Directional valve 138 can include a single inlet, illustrated as flow path 153, and two outlets, flow paths 155 and 157, as illustrated in the embodiment of FIGS. 3A and 3B. Flow paths 155 and 157 can fluidly communicate with the flow path 153 through a connecting flow configuration 161. The connecting flow configuration 161 is positioned within gate valve 138 at a location separate from gate 140. Other potential gate configurations can also be employed. Examples of suitable gate configurations are disclosed in Co-pending U.S. Patent Application No. [Atty docket No: AKER.022U], the disclosure of which is hereby incorporated by reference in its entirety.

[0031] FIG. 3A illustrates directional valve 138 in a first position for allowing fluid to flow through a flow path 155 and simultaneously blocking fluid flow through a flow path 157. FIG. 3B illustrates directional valve 138 in a second position, which allows fluid to flow through flow path 157, while simultaneously blocking fluid flow through the flow path 155. During operation, the stem 150, which can be connected to an actuator 151, can force gate 140 from the first position, shown in FIG. 3A, to the second position shown in FIG. 3B,

thereby simultaneously beginning fluid flow through flow path 157 and stopping fluid flow through the flow path 155.

[0032] Referring again to FIG. 1, the boosting cap 162 can be positioned to cover the pump cavity 114. As mentioned above, pump cavity 114 can contain a removable pump assembly 116. In an embodiment, boosting cap 162 is attached directly to the removable pump assembly 116 via any suitable manner, such as, for example, via a hydraulic, mechanical, electrical, or ROV operated connector. As will be discussed in greater detail below, the boosting cap 162, removable pump assembly 116 and optionally some or all of the valve system 126 can be configured to be removable from anchor assembly 110.

[0033] The boosting cap 162 is configured to allow fluid connection with the valve system 126. In an embodiment, at least a portion of the valve system 126 of FIG. 1 is attached to the boosting cap 162 so as to be removable from the anchor assembly 110 when the boosting cap 162 is removed. For example, valve system 126 can comprise a boosting cap flowbore connector 186 that is connected to the boosting cap 162. Valve system 126 can also comprise a portion 137 that can be connected to the anchor assembly 110. The boosting cap flowbore connector 186 and valve system portion 137 can be coupled together and configured so as to be separable one from the other. Thus, boosting cap flowbore connector 186 can be attached to boosting cap 162 in a manner that allows it to be removed from the anchor assembly 110 with the boosting cap 162, while valve system portion 137 remains coupled to the anchor assembly 110. When boosting cap 162 is positioned on anchor assembly 110, boosting cap flowbore connector 186 and valve system portion 137 can be held together by any suitable means, such as clamping device 139.

[0034] Boosting cap 162 comprises the first flow path 158, which can be configured to provide fluid communication between the inlet flow path 188 and the removable pump assembly 116 when removable pump assembly 116 is positioned in pump cavity 114.

Boosting cap 162 further comprises a second flow path 160, which is configured to provide fluid communication between the removable pump assembly 116 and outlet flow path 189 when removable pump assembly 116 is positioned in pump cavity 114.

[0035] In an embodiment, boosting cap 162 further comprises a crossover flow path 156 configured to provide fluid communication between the inlet flow path 188 and outlet flow path 189. This configuration allows fluid flow from the subsea wellbore to bypass the pump cavity 114 when desired, such as when removable pump assembly 116 is removed from the pump cavity 114 for maintenance and/or repair.

[0036] In an alternative embodiment, illustrated in FIG. 4 and described in greater detail below, crossover flow path 156 is positioned outside of the boosting cap 162, as indicated by the dashed portion of the crossover flow path 156. This alternative configuration allows flow through crossover flow path 156 when boosting cap 162 is removed from the boosting cap system.

[0037] Referring again to FIG. 1, the removable pump assembly 116 of subsea boosting cap system 106 comprises one or more pumps 164 supported by a spool adapter 166. Pumps 164 can be any suitable pump that can be employed for pumping fluids from a wellbore. One example of a suitable pump is a coaxial centrifugal pump (CCP). One or more pumps can be employed. Where pump assembly 116 includes multiple pumps, the pumps can be arranged in series or parallel. Although pumps 164 are shown in a side-by-side arrangement in FIG. 1, they can also be positioned on top of each other in a straight aligned arrangement, similarly

as shown in FIG. 4; or any other suitable arrangement, depending on installation vessel, pump type and available space.

[0038] The pumps 164 can be enclosed inside a suitable enclosure, such as, for example, a canister 165. Canister 165 can provide physical protection for the pumps 164 by providing structural integrity and physical capability to withstand installation and operational loads. Canister 165 can also act as a pressure barrier to the environment.

[0039] The removable pump assembly 116 can include any suitable means for providing power to the pumps 164, such as, for example, a high voltage penetrator 174. In an embodiment, as illustrated in FIG. 1, spool adapter 166 comprises high voltage penetrator 174, which provides power to the pumps and flow passage between the upstream and downstream sides of the pumping processing, thereby enabling means to isolate and divert fluid flow via directional valves (e.g., valve 138) and isolation valves (e.g., valves 136) during periods of maintenance on the removable pump assembly. This can keep the offshore fluid production system 100 in continuous or near continuous operation during pump malfunction or maintenance operations. The high voltage penetrator is capable of being electrically coupled to any suitable power source connection. In embodiments, the high voltage penetrator 174 can provide means for physical connection of the power supply directly to the pump assembly 116, thereby avoiding multiple power connections to minimize possibility of failure.

[0040] While the high voltage penetrator 174 is illustrated at a horizontal position by the side of the spool adapter 166, it can be installed at any suitable position and be configured in any suitable spatial arrangement with respect to the subsea boosting cap system 106. For

example, it can be positioned on an upper side of the boosting cap 162 in a horizontal or vertical arrangement via an ROV flying lead. ROV flying leads are well known in the art.

[0041] In an embodiment, pump assembly 116 can further include a settling cavity 168 to accommodate deposition of contaminants, such as debris and/or denser parts of the produced fluid. Fluid flow path 158 is in fluid communication with settling cavity 168 via a third fluid flow path 170. Fluid is pumped up from the settling cavity through a fourth flow path 172, through second flow path 160 in the boosting cap 162, and then through outlet flow path 189 to the outlet 130. Thus, settling cavity 168 can close the loop between the third fluid flow path 170 and the fourth flow path 172.

[0042] The various portions of the pump assembly 116 can be fastened together by any suitable manner that can provide the desired seal integrity and physical capability to withstand installation and operational loads. For example, clamps 175 can be used to fasten both the spool adapter 166 and the settling cavity 168 to the canister 165, as illustrated in the embodiment of FIG. 1. Any other suitable fastening means can also be used. In an alternative embodiment, two or more of the various portions of pump assembly 116 can be manufactured as a single integral part.

[0043] The pump assembly 116 can employ seals to provide desired protection from leakage into and out of the various connections between the different parts of pump assembly 116. For example, seals 178 can be employed for sealing the canister 165. Seals 180 can provide sealing around flow bores, such as the flow bore connections between the canister 165 and the settling cavity 168. Seals 178 and 180 can be any suitable type of seals, such as, for example, metal-to-metal seals.

[0044] Periodic maintenance or replacement of the pump assembly 116 can involve removing the pump assembly 116 from the subsea boosting cap system 106. If a spare pump assembly is available, the boosting cap 162 and pump assembly 116 can be retrieved to the surface, where the pump assembly 116 can be replaced by the spare pump assembly. Then the boosting cap 162 and spare pump assembly can be re-installed in the subsea boosting cap system 106.

[0045] FIG. 2 illustrates an embodiment employing a pressure cap 176 in the subsea boosting cap system 106 where the pump assembly 116 has been removed, according to an embodiment of the present disclosure. As illustrated in FIG. 2, the pressure cap 176 can be used to seal the pump cavity 114 in the absence of the removable pump assembly 116. In an embodiment, the pressure cap 176 can be attached to the boosting cap 162 by a connecting means 177. Any suitable connecting means can be employed, such as, for example, a hydraulic, mechanical, electrical or ROV operated connector. In an embodiment, the design of the boosting cap 162, pressure cap 176 and spool adapter 166 (FIG. 1) can include the same hub interface, thereby allowing the same running tool to be used to install all three.

[0046] Thus, in situations where the subsea boosting cap system 106 is in bypass mode for a relatively long period of time, such as where a spare pump assembly is not available, the boosting cap 162 can be attached to the pressure cap 176 to provide a double barrier while the fluid production system 100 is under production mode (e.g., while hydrocarbon fluids are flowing through crossover flow path 156). Alternatively, it may be desirable to employ the boosting cap system 106 in bypass mode for periods of time without the pressure cap 176.

[0047] FIG. 4 illustrates another embodiment of an offshore fluid production system 100 comprising a subsea boosting cap system 106, as mentioned above. The subsea boosting cap

system of FIG. 4 differs from the subsea boosting cap system of FIG. 1 in that the valve system and crossover flow path of the FIG. 4 embodiment allow retrieval of the boosting cap without stopping production during the time period that the boosting cap is removed.

[0048] In the embodiment of FIG. 4, crossover flow path 156 is positioned outside of the boosting cap 162. For example, the crossover flow path 156 can be a conduit that is attached to the outside of boosting cap 162 in a manner that will allow crossover flow path 156 to be run in and connected together with the boosting cap 162. Valve system 126 can be configured to direct fluid flow through either the crossover path 156, so that it bypasses the boosting cap 162, or through the first flow path 158.

[0049] In an embodiment of FIG. 4, the valves system 126 can be configured so that isolation valves 136 remain with the anchor assembly 110 to direct the flow when the boosting cap 162 is removed. Directional valves, such as those illustrated in FIG. 3, or any other suitable valves, can be employed in place of or in addition to isolation valves 136 to direct the flow.

[0050] A boosting cap flowbore connector 186 can be attached to boosting cap 162 in an embodiment of FIG. 4. The boosting cap flowbore connector 186 is capable of engaging and locking onto posts 167, thereby allowing the boosting cap 162 to attach to the valve system 126 and anchor assembly 110. Boosting cap flowbore connector 186 can be designed to unlock and disengage from posts 167 using, for example, a ROV or other suitable means, thereby allowing remote removal of the boosting cap 162 from the anchor assembly 110.

[0051] FIG. 5 illustrates an embodiment of the offshore fluid production system 100 in which the subsea boosting cap system 106 is configured to have a flow line connection via a double locking connection system 182. Double locking connection system 182 can be

deployed and locked onto the anchor assembly 110 via a guide post 184. The double locking connection system 182 can also be connected to boosting cap 162 via a boosting cap flowbore connector 186, which is capable of locking onto posts 167, similarly as described above in the embodiment of FIG. 4. Seals 180 can be employed to seal the flow bore connections. Any suitable type of seals can be employed, such as, for example, metal-to-metal seals. Isolation valves 136 can be used to close the flow paths 188 while the boosting cap 162 is not in place in order to protect against contamination of the environment by production fluid spills. Production jumpers 132 and 134 can be flexible or rigid and can be connected to the subsea wellbore 102, subsea boosting cap system 106 and downflow production line 108 via any suitable connector, such as swivel joints (not shown) for better landing flexibility.

[0052] FIG. 6 illustrates another embodiment of the offshore fluid production system 100 in which the subsea boosting cap system 106 is configured to have a flow line connection via a post connection system 190. Post connection system 190 can be deployed onto the anchor assembly 110 via a post 192 received by a receptacle 194. The post connection system 190 can also be connected to boosting cap 162 via a boosting cap flowbore connector 186. Seals 180 can be employed to seal the flow bore connections. Any suitable type of seals can be employed, such as, for example, metal-to-metal seals. Isolation valves 136 can be used to close the flow path 188 while the boosting cap 162 is not in place in order to protect against contamination of the environment by production fluid spills, as well as to control the flow of production fluid through the system. Production jumpers 132 and 134 can be flexible or rigid and can be connected to the subsea wellbore 102, subsea boosting cap system 106 and

downflow production line 108 via any suitable connector, such as swivel joints, mentioned above, for better landing flexibility.

[0053] As shown in the embodiment of FIG. 7, the present disclosure can also be directed to a method for removing a pump assembly positioned in a pump cavity of any of the subsea boosting cap systems of the present disclosure having a crossover flow path that bypasses the pump cavity. The method can include flowing a production fluid through a boosting cap flow path to a pump assembly, as shown at 202. Stopping the flow of fluid through the pump assembly and removing the boosting cap positioned over the pump assembly, as shown at 204,206. The pump assembly can also be removed from the pump cavity, as shown at 208, either simultaneously with or separately from the boosting cap. The boosting cap can then be replaced over the pump cavity, as shown at 210.

[0054] In an embodiment, production fluid can be flowed through the crossover flow path after the boosting cap is replaced, but while the pump assembly is removed from the pump cavity, as shown at 212. In another embodiment where a system such as that shown in the embodiment of FIG. 4 is employed, production fluid can be flowed through the crossover flow path even when the boosting cap is removed, thereby allowing continuous or substantially continuous flow of production fluid during servicing of the pump assembly.

[0055] In an embodiment, the method can include positioning a pressure cap 176 over the pump cavity, in addition to replacing the boosting cap, after the pump assembly is removed. As discussed above, the pressure cap can provide a second barrier to help prevent fluid spills while the pump assembly is removed.

[0056] For the offshore contingency where the pressure cap 176 is used, the pressure cap 176 can be installed on the ocean surface, such as onboard an intervention vessel. Alternatively,

pressure cap 176 can be installed in a subsea operation. An example of a subsea installation employing the pressure cap 176 can include the following main steps: First, the pressure cap 176 can be run via a running tool and deployed on a subsea boosting cap system intervention receptacle (not shown), which can be used for holding the cap 176 while the running tool removes the pump assembly 116. The running tool can then lock and lift the boosting cap 162 and removable pump assembly 116 to deploy it in a mudmatt receptacle (also not shown), where the running tool releases the boosting cap 162 from the spool adapter 166 of the removable pump assembly 116. At this point in time, new seals can be placed by an ROV on flowline connection porches, as is well known in the art. After that, the running tool can move and lock the boosting cap 162 onto the pressure cap 176. The boosting cap / pressure cap assembly is then positioned back into the pump cavity 114. The connection system is then locked to the inlet and outlet connectors. The running tool can then be locked onto the spool adapter 166 of the pump assembly 116 that was removed from the pump cavity, and the pump assembly 116 can be transported to the surface.

[0057] The systems of the present disclosure can be installed using any suitable method. The following method provides one illustrated example for anchoring the Suction Anchoring Structure. First, the Suction Anchoring Structure can be prepared with a vent hatch opened, as is well known in the art. Slings can be attached from the Suction Anchoring to the vessel crane master, with a heave compensator at a non-active mode. The suction anchoring system can be lowered through the splash zone with the vent hatch open. Run down toward the seabed can occur at any suitable speed, such as at speeds of about 0.5 m/s. The suction anchoring system can be stopped around 3 meters above the seabed and the heave compensator can be placed at active mode. Run in speed can then be reduced as desired (e.g.,

as slow as possible) when entering into the seabed, while watching for correct alignment. After entering the seabed, lowering can be continued until slack is produced in the slings. Then an ROV can close the vent hatch and hook up a suction stab into the suction anchoring tube. Suction can then be started to force the frame down into the seabed until the final desired depth is achieved.

[0058] While the systems of the present disclosure have generally been shown as having a vertical configuration, one of ordinary skill in the art would readily understand that the systems can also be configured in any other direction, such as to have a horizontal or angular configuration.

[0059] Although various embodiments have been shown and described, the disclosure is not so limited and will be understood to include all such modifications and variations as would be apparent to one skilled in the art.

WHAT IS CLAIMED IS:

1. An offshore fluid production system, comprising:
 - a subsea wellbore at a first position on an ocean floor;
 - a subsea boosting cap system positioned in a second position on the ocean floor that is different from the first position, the subsea boosting cap system comprising:
 - an anchor assembly capable of attaching to the sea floor, the anchor assembly comprising a pump cavity capable of receiving a removable pump assembly;
 - a valve system attached to the anchor assembly, the valve system comprising an inlet flow path and an outlet flow path, the inlet flow path being in fluid communication with the subsea wellbore;
 - a boosting cap covering the pump cavity, the boosting cap comprising a first flow path configured to provide fluid communication between an inlet flow path and the removable pump assembly when the removable pump assembly is positioned in the pump cavity, and a second flow path providing fluid communication between the removable pump assembly and the outlet flow path when the removable pump assembly is positioned in the pump cavity; and
 - a crossover flow path providing fluid communication between the inlet flow path and the outlet flow path, the crossover flow path bypassing the pump cavity, the valve system being capable of directing fluid flow to the first flow path and the crossover flow path; and
 - a downflow production line in fluid communication with the outlet.

2. The system of claim 1, further comprising the removable pump assembly engaging the pump cavity, the boosting cap being positioned over the removable pump assembly.

3. The system of claim 2, wherein the pump assembly comprises a spool adapter and one or more pumps supported by the spool adapter.

4. The system of claim 3, wherein the pump assembly further comprises a lower cavity for collecting contaminants, the lower cavity being in fluid communication with the one or more pumps.

5. The system of claim 4, wherein a third flow path provides fluid communication from the first flow path of the boosting cap to the lower cavity and a fourth flow path provides fluid communication from the lower cavity to the second flow path of the boosting cap.

6. The system of claim 1, further comprising a pressure cap sealing the pump cavity, the boosting cap being positioned over the pump cavity and attached to the pressure cap, wherein the pump cavity does not contain the removable pump assembly.

7. The system of claim 1, wherein the crossover flow path allows fluid communication between the inlet flow path and the outlet flow path when the boosting cap is removed from the pump cavity.

8. The system of claim 1, wherein the fluid communication between the inlet flow path and the subsea wellbore is provided by a conduit attached to the inlet flow path with a guide and hinge over connecting device.

9. The system of claim 8, wherein the downflow production line is attached to the outlet flow path with a guide and hinge over connecting device.

10. A subsea boosting cap system, comprising:

- an anchor assembly capable of attaching to the sea floor, the anchor assembly comprising a pump cavity capable of receiving a removable pump assembly;
- a valve system attached to the anchor assembly, the valve system comprising an inlet flow path and an outlet flow path, the inlet flow path being capable of fluidly communicating with a subsea wellbore;
- a boosting cap covering the pump cavity, the boosting cap comprising a first flow path configured to provide fluid communication between the inlet flow path and the removable pump assembly when the removable pump assembly is positioned in the pump cavity, and a second flow path providing fluid communication between the removable pump assembly and the outlet when the removable pump assembly is positioned in the pump cavity; and
- a crossover flow path providing fluid communication between the inlet flow path and the outlet flow path, the crossover flow path bypassing the pump cavity, the valve system being capable of directing fluid flow to the first flow path and to the crossover flow path.

11. The system of claim 10, wherein the cross over flow path allows fluid communication between the inlet flow path and the outlet flow path when the boosting cap is removed from the pump assembly.

12. The system of claim 10, further comprising the removable pump assembly engaging the pump cavity, the boosting cap being positioned over the removable pump assembly.

13. The system of claim 12, wherein the pump assembly comprises a spool adapter and one or more pumps supported by the spool adapter.

14. The system of claim 13, wherein the pump assembly further comprises a lower cavity for collecting contaminants, the lower cavity being in fluid communication with the one or more pumps.

15. The system of claim 14, wherein a third flow path provides fluid communication from the first flow path of the boosting cap to the lower cavity and a fourth flow path provides fluid communication from the lower cavity to the second flow path of the boosting cap.

16. The system of claim 10, further comprising a pressure cap sealing the pump cavity, the boosting cap being positioned over the pump cavity and attached to the pressure cap, wherein the pump cavity does not contain the removable pump assembly.

17. The system of claim 10, wherein the valve system comprises a directional gate valve capable of directing fluid flow to the first flow path and to the crossover flow path, the directional gate valve comprising a slab gate capable of stopping fluid flow through one of the crossover flow path and the first flow path while simultaneously opening one of the first flow path and crossover flow path.

18. The system of claim 10, wherein the boosting cap is attached to a boosting cap flowbore connector, the boosting cap flowbore connector providing fluid communication between the boosting cap and the valve system.

19. The system of claim 18, wherein the boosting cap flowbore connector comprises a portion of the valve system.

20. A method for removing a pump assembly positioned in a pump cavity of a subsea boosting cap system having a crossover flow path that bypasses the pump cavity, the method comprising:

- flowing a production fluid through a boosting cap flow path to a pump assembly;
- stopping the flow of fluid through the pump assembly;
- removing the boosting cap positioned over the pump assembly;
- removing the pump assembly from the pump cavity;
- replacing the boosting cap over the pump cavity; and
- flowing the fluid through the crossover flow path while the pump assembly is removed from the pump cavity.

21. The method of claim 20, further comprising directing the flow of fluid through the crossover flow path while the boosting cap is removed.

22. The method of claim 20, further comprising positioning a pressure cap over the pump cavity, in addition to replacing the boosting cap, after the pump assembly is removed.

23. The method of claim 20, further comprising engaging a second pump assembly in the pump cavity after the first pump assembly is removed.

24. The method of claim 23, further comprising diverting the flow of fluid through the second pump assembly after engaging the second pump assembly, the fluid in the pump assembly flowing down into a settling cavity for removing contaminants and then flowing back up through the second pump assembly and into the boosting cap.

25. The method of claim 20, wherein the removing the pump assembly and the removing the boosting cap occur simultaneously.