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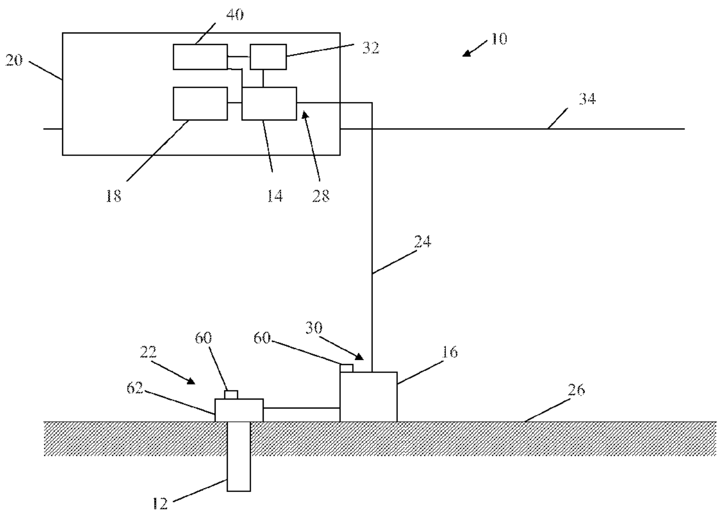

FIG. 1

(57) Abstract: A system and method for delivering a material from a vessel at a surface facility to a subsea location and into a subsea well are provided. The system generally includes a first-stage pump that is located at the surface facility and is configured to receive the material from the vessel. A tubular member extends from the first-stage pump to the subsea location. A second-stage pump is located at the subsea location and connected to the tubular member. The first-stage pump is configured to deliver the material through the tubular member to the second-stage pump at a first pressure, and the second-stage pump being configured to receive the material from the tubular member and inject the material into the well at a second pressure higher than the first pressure.

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SYSTEM AND METHOD FOR DELIVERING MATERIAL TO A SUBSEA WELL

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the benefit of U.S. Provisional Application No. 61/138,044, filed December 16, 2008.

BACKGROUND OF THE INVENTION

[0002] 1. Field of the Invention

[0003] This invention relates to the delivery of materials, such as scale inhibitor chemicals, from a vessel at a surface facility to a subsea location and into a subsea well, for example, to perform a subsea scale squeeze treatment in a subsea hydrocarbon well.

[0004] 2. Description of Related Art

[0005] The formation of scale, inorganic crystalline deposits, can occur throughout the equipment used in a hydrocarbon production operation. For example, in one typical situation, the formation of scale can occur as a result of waterflooding, such as when sea water is injected into a well and mixed with formation water in the well. Scale can also form upon changes in the supersaturation of solubility of minerals in the formation or produced waters that are caused by pressure and/or temperature changes. Scale formation can also be increased by nucleation sites, e.g., sand and corrosion. The scale-forming precipitates can include various minerals such as calcium carbonate, calcium sulfate, barium sulfate, magnesium carbonate, magnesium sulfate, and strontium sulfate. For example, sulfate scale deposition is likely to occur when seawater injection is used to recover deposited hydrocarbons.

[0006] Such scaling can occur inside and outside the well, e.g., within tubings or other equipment through which the production fluids flow from the well, and represents an important flow assurance problem in the oil and gas industry. In some cases, the scale formation can reduce or prevent flow through bores and tubings, prevent proper operation of valves and pumps, and otherwise interfere with the operation of the equipment associated with the well.

[0007] There are several techniques available to control scale deposition. For example, the fluid modification technique includes injecting water of different composition (e.g. aquifer water or desulfated water) to the reservoir and separating the water from the production stream. The most common technique to prevent and treat scale precipitation is the application of chemicals that function as scale inhibitors. Such chemical inhibitors, or scale inhibitors, may be aqueous based, oil based, emulsions, micro-encapsulated, porous impregnated pellets, and multifunctional products (e.g. corrosion/scale inhibitor, asphaltene/scale inhibitor, etc.). Scale inhibitors generally work by preventing nucleation and crystal growth. Many scale inhibitors can be applied into the production stream by continuous injection or into the wellbore by a scale squeeze treatment. A typical scale squeeze treatment for treating a well with a scale inhibitor includes interrupting the flow of production fluid from the well and injecting the scale inhibitor through the well into the reservoir so that the scale inhibitor interacts with the rock matrix in the reservoir to be adsorbed into the formation and then precipitated onto mineral surfaces. Typically, the squeeze treatment involves the injection of a preflush solution, followed by the injection of the chemical inhibitor (mainflush), and finally the injection of an overflush solution. Thereafter, the well is returned to operation and the scale inhibitor in the reservoir desorbs or dissolves into the fluid in the reservoir, such that the production fluid contains some scale inhibitor. The scale inhibitor generally prevents or reduces the deposition of scale from the production fluid in the tubings and other equipment through which the fluid flows.

[0008] Scale inhibitor can be injected into a subsea well from a surface facility such as an offshore platform or a floating production and storage and offloading (FPSO) vessel via production pipelines or flowline (which may include a riser) and associated manifolds that normally carry the production fluid upward from the subsea well to the surface facility. In this case, the flow of production through the riser is stopped. Then, the scale inhibitor is pumped into the top of the riser at the surface facility and through the riser to the subsea well and into the subsea reservoir. Low pump rates for the scale inhibitor are typically required due to a relatively high friction associated with the production flowline and/or the viscosity of the scale inhibitor, which may increase at the lower temperatures found close to the seabed. In some cases, a large volume of scale inhibitor may be used. For example, a typical 15 km-segment of production flowline may have a volume of 5,000 barrels, depending on the diameter, with the entire volume of the flowline being filled before the scale inhibitor begins to flow into the reservoir. Further, in some cases, the flowline need to be emptied and cleaned by a pigging operation before the chemical inhibitor is pumped into the wellbore in order to avoid pumping debris that exists in the flowline, such as scale, wax, and/or sand, into the formation.

[0009] When subsea production of different satellite wells is brought together in a manifold or flowline, scale squeeze treatment can become expensive. In this case, it may be necessary to shut down all of the wells even if only one well is to be treated since the flowline is to be used to deliver the scale inhibitor. This inconvenience can be avoided by providing a separate line from each well to a surface production facility; however, using dedicated lines may not always be possible due to engineering restrictions or capital expenditure limitations. In some cases, subsea squeeze treatments are sometimes performed using surface vessels, e.g., a Diving Support Vessel (DSV) and a flexible line attached to the subsea manifold. Subsea squeeze treatments have also been performed by placing encapsulated inhibitors into the wellhead. In that case, a Diving Support Vessel can transport the capsules, which fall down by their own weight through a flexible riser, into the sump. Diffusion of the scale inhibitor takes place due to difference in concentration gradients.

[0010] While such operations have been successfully used for subsea scale squeeze treatments, there exists a continued need for improved systems and methods for delivering materials, such as chemicals for a scale squeeze treatment, to a subsea well. The system and method should be capable of being used with a passage that is not defined by a riser, e.g., so that a subsea scale squeeze treatment can be performed without emptying the production fluid from the riser or reversing the flow of fluid in the riser, and should be capable of use in systems that include several wells and/or trees attached to a common production flowline.

SUMMARY OF THE INVENTION

[0011] The embodiments of the present invention generally provide systems and methods for delivering a material from a vessel at a surface facility to a subsea location and into a subsea well, such as for delivering one or more scale squeeze treatment chemicals adapted to inhibit scaling via an umbilical or other tubular member to a subsea well for a subsea scale squeeze treatment of the well. According to one embodiment, the system includes a first-stage pump located at the surface facility and configured to receive the material from the vessel. A tubular member extends from the first-stage pump to the subsea location. A second-stage pump is located at the subsea location and connected to the tubular member. For example, the second-stage pump can be disposed on the seafloor and/or as part of a tree at a head of the subsea well. The first-stage pump is configured to deliver the material through the tubular member to the second-stage pump at a first pressure, and the second-stage pump is configured to receive the material from the tubular member and inject the material into the well at a second pressure higher than the first pressure.

[0012] In some cases, the tubular member can be a flexible tube formed of a thermoplastic material and/or a flexible umbilical that defines a first tubular passage for receiving and delivering the material, and a second tubular passage having at least one conductive cable for communicating between the surface facility and the subsea location. The conductive cable can be configured to provide at least one of an electrical signal for controlling the operation of the second-stage pump and electrical power for powering the operation of the second-stage pump.

[0013] According to another embodiment, the present invention provides a method of delivering a material from a vessel at a surface facility to a subsea location and into a subsea well. The method includes operating a first-stage pump located at the surface facility to pump the material from the vessel through a tubular member extending from the first-stage pump to the subsea location, and operating a second-stage pump at the subsea location and connected to the tubular member to inject the material from the tubular member into the well. For example, the method can include providing the second-stage pump at the seafloor and/or as part of a tree at a head of the subsea well. The operation of the first-stage pump and the second-stage pump can include injecting a scale squeeze treatment chemical into the well to thereby perform a scale squeeze treatment of the well and inhibit scaling in the well and/or the riser, production pipeline, flowlines, or other equipment downstream of the well.

[0014] In some cases, a flexible tube formed of a thermoplastic material or a flexible umbilical can be provided as the tubular member, and the first-stage pump can be operated to pump the material through a first tubular passage of the umbilical. The umbilical can be provided with at least one conductive cable in the umbilical in communication with the surface facility and the subsea location. An electrical signal can be communicated from the surface facility to the subsea location via the conductive cable to control the operation of the second-stage pump, and/or electrical power can be provided from the surface facility to the subsea location via the electrically conductive cable to power the operation of the second-stage pump.

BRIEF DESCRIPTION OF THE DRAWINGS

[0015] Having thus described the invention in general terms, reference will now be made to the accompanying drawings, which are not necessarily drawn to scale, and wherein:

[0016] FIG. 1 is an elevation view schematically illustrating a system for delivering material from a surface facility to a subsea location and into a subsea well according to one embodiment of the present invention;

[0017] FIG. 2 is a cross-sectional view schematically illustrating an umbilical according to one embodiment of the present invention;

[0018] FIG. 3 is an elevation view illustrating a system for delivering material from a floating production facility to a subsea location and into a subsea well according to one embodiment of the present invention;

[0019] FIG. 4 is an elevation view illustrating a system for delivering material from a service vessel to a subsea location and into a subsea well according to another embodiment of the present invention; and

[0020] FIG. 5 is an elevation view illustrating a system for delivering material from a service vessel to a subsea location and into a subsea well according to another embodiment of the present invention.

DETAILED DESCRIPTION OF THE INVENTION

[0021] The present invention now will be described more fully hereinafter with reference to the accompanying drawings, in which some, but not all embodiments of the invention are shown. Indeed, this invention may be embodied in many different forms and should not be construed as limited to the embodiments set forth herein; rather, these embodiments are provided so that this disclosure will satisfy applicable legal requirements. Like numbers refer to like elements throughout.

[0022] Referring now to the drawings and, in particular, to FIG. 1, there is schematically shown a system **10** for delivering a material, such as chemicals for performing a scale squeeze treatment to a subsea well **12**. The system **10** generally includes a plurality of pumping units **14**, **16** in a multi-stage pumping arrangement for delivering the material from one or more vessels **18** located at a surface facility **20** to a subsea location **22** via a tubular member **24** and injecting the material into the well **12**.

[0023] The surface facility **20** can be any type of surface unit, such as an offshore platform or oil rig of any type. The vessel **18** can include one or more storage tanks mounted on the surface facility **20** or containers that are brought by ship or otherwise to the facility **20** and fluidly connected to the facility **20** so that the material in the vessel **18** can be received by a first-stage pumping unit **14** located at the surface facility **20**.

[0024] The first-stage pumping unit **14** receives the material and pumps the material through the tubular member **24**, such as an umbilical, that extends from the surface facility **20** to a subsea location **22**. In particular, as shown in FIG. 1, the tubular member **24** can extend to a second-stage pumping unit **16** located at the subsea location **22**, e.g., at or proximate to the seafloor **26**. The tubular member **24** defines one or more passages for the flow of the material. The first-stage pumping unit **14** delivers the material through the tubular member **24** and to the second-stage pumping unit **16** at a first pressure, typically higher than atmospheric pressure but insufficient for delivering the material into the well **12** and reservoir. It is appreciated that the pressure of the material may decrease from the inlet **28** of the tubular member **24** at the first-stage pumping unit **14** to the outlet **30** of the tubular member **24** at the second-stage pumping unit **16**. For example, the material can be stored in the vessel **18** at approximately atmospheric pressure, the first-stage pumping unit **14** can raise the pressure to a higher pressure to deliver the material through the tubular member

24, and the material can be provided to the second-stage pumping unit **16** at an even higher pressure.

[0025] The first-stage pumping unit **14** can be powered by a power source **32**, e.g., an electric or hydraulic power source. The operation of the power source **32** and the first-stage pumping unit **14** can be controlled by a controller **40**, e.g., a computer device configured to receive manual inputs from a human operator and/or operate according to a program of predetermined and defined commands and parameters. The controller **40** and the power source **32** can also be used to control and/or power the other components of the system **10**, including the second-stage pumping unit **16**. In some cases, the controller **40** can be a high pressure intervention control system unit.

[0026] The second-stage pumping unit **16** at the subsea location **22** is connected to the tubular member **24** and receives the material from the first-stage pumping unit **14** via the tubular member **24**. The second-stage pumping unit **16** raises the pressure of the material and injects the material into the well **12** at a second pressure that is higher than the first pressure achieved by the first-stage pumping unit **14**.

[0027] The multi-stage pumping system **10** of the present invention can provide the material to the well **12** with sufficient pressure for injection, while providing a relatively limited pressure of the material throughout the rest of the system **10**. For example, if the first-stage pumping unit **14** were operated without the second-stage pumping unit **16**, a greater pressure would be required in the tubular member **24** to provide sufficient pressure at the subsea location **22** for injection of the material into the well **12**. Typically, the first-stage pumping unit **14** would be required to provide the material with a pressure that is at least as great as the sum of the pressure drop that occurs in the tubular member **24** between the inlet **28** and outlet **30** and the pressure required for injection into the subsea well **12**. In some cases, e.g., where the tubular member **24** is an umbilical or a low-pressure hose or tube with a relatively narrow diameter, and/or the tubular member **24** is a long member for deepwater applications or otherwise, the pressure drop along the length of the tubular member **24** can be relatively great. In such cases, the required pressure at the inlet **28** of the tubular member **24** for overcoming both the pressure drop through the tubular member **24** and the pressure required at the subsea location **22** for injection into the well **12** can exceed the strength of the tubular member **24**. Thus, for a single-stage pump system, it may be required to provide a tubular member **24** with a high strength to withstand the high pressures required and/or to provide a tubular member **24** with a relatively large diameter so that the pressure drop therethrough is not excessively high.

[0028] On the other hand, the second-stage pumping unit **16**, which is provided at the subsea location **22** and downstream of the tubular member **24**, can be used to raise the pressure to a level sufficient for injection into the well **12** so that the pressure in the tubular member **24** can be limited to a level that is within the operating limits of the tubular member **24**. In this way, the pressure of the material provided by the first-stage pumping unit **14** to the tubular member **24** can be sufficient to overcome the pressure drop through the tubular member **24** but less than the sum of the pressure drop through the tubular member **24** and the pressure required at the subsea location **22** for injection into the well **12**. Thus, it may be sufficient to use a tubular member **24** with a relatively lower strength and/or a relatively small diameter. Even in deepwater applications where the tubular member **24** is long, an umbilical can have the sufficient strength and size to accommodate the flow of the material and the pressure required for maintaining the flow of the material therethrough. For example, the tubular member **24** can be structured to have a strength that is greater than the pressure drop that occurs in the tubular member **24** so that the tubular member **24** can withstand the pressure required to deliver the material therethrough; however, the tubular member **24** can be structured to have a strength that is less than the sum of the pressure drop that occurs in the tubular member and the pressure required for injection into the subsea well **12**. In particular, in some cases, the tubular member **24** can be structured to provide a burst strength of 15,000 psi or less, and the material can be provided at a maximum pressure in the tubular member **24** that is between 3,000 psi and 5,000 psi.

[0029] For example, the tubular member **24** of FIG. 1 is a flexible umbilical, and the cross-section of the umbilical is further illustrated in FIG. 2. The umbilical is a composite cable that includes an outer sheath **42** that contains a plurality of longitudinal members or functional components, such as tubes or hoses formed of thermoplastics or steel or other metals, electrically or optically conductive cables, strength members, and the like. For example, as shown in FIG. 2, the umbilical includes hollow, cylindrical tubes **44a, 44b, 44c** that define tubular passages **46** for the delivery of chemicals or other materials between the surface facility **20** and the subsea location **22**. For example, one or more of the tubular passages **44a, 44b, 44c** can be used for the delivery of the scale inhibitors during a subsea scale squeeze operation or for the delivery of hydraulic fluids or the like for other operations. The umbilical also includes conductive communication cables **48** that can be formed of electrical or optical conductors, such as solid or twisted copper or aluminum cables or fiber optic cables. The communication cables can be used for communication of control signals, for transmission of electrical power, and/or for the communication of information, such as information collected by sensors or other devices at the subsea location **22**. The cables can be contained in sheaths **50** of plastic or other protective materials. Strength members **52** can be formed of steel, composite materials, or the like and used to increase the strength and/or stiffness of the umbilical. In addition, other members or materials can be provided within the outer sheath **42**. For example, in some cases, the space **54** between the various members in the sheath **42** can be filled with plastic or other materials to increase the strength, buoyancy, rigidity, or seal of the umbilical.

[0030] It is appreciated that the umbilical shown in FIG. 2 is an exemplary tubular member **24** that can be used in the system **10** of the present invention, and other tubular members can also be used, including umbilicals of various sizes, configurations, and materials. For example, in some cases, the tubular member **24** can be a flexible tube formed of a polymer, a thermoplastic material, a reinforced composite material, or the like. The tubular member can be a dedicated device (or a dedicated fluid passage in a composite umbilical or other device) that is used for delivery of the material to the well but that is not used for delivery of production fluids from the well, and the tubular member (or the dedicated passage) can be sized accordingly, e.g., smaller than a typical riser that delivers production fluids from a subsea well to a floating production facility. For example, in some cases, the internal diameter of the fluid passage of the tubular member that is used for delivering the material to the well can be between about 1/4 inch and 4 inches, such as about such as about 1/2 inch, 1 inch, or 2 inches, 3 inches, or 4 inches. For example, the first tubular passage **44a** of the umbilical shown in FIG. 2 can have a diameter of about 1/4 inch or 1/2 inch and can be used for delivering the material to the well **12**. For situations where a greater volume of material is to be delivered to the well **12**, the tubular member **24** can be a larger hose, such as a 3- or 4-inch diameter hose formed of a composite material, such as a thermoplastic matrix material with a synthetic aramid or other reinforcement material.

[0031] The multi-stage pump system **10** of the present invention is illustrated with two pumping units **14**, **16** in FIG. 1, and each pumping unit **14**, **16** typically includes one pump, but additional pumps or pumping units **14**, **16** can be provided in other embodiments. For example, additional pumps can be located at the surface facility **20**, subsea location **22**, or therebetween. Additional pumps can be configured in parallel with the illustrated pumping units **14**, **16** to provide increased pumping capacity or redundancy, and/or additional pumps can be provided in series with the illustrated pumping units **14**, **16** to successively raise the pressure of the material along the flow path of the material. Some or all of the pumping units **14**, **16** can include filters to prevent the delivery of solids and particles and thereby prevent the injection of such solids and particles into the well **12** and the reservoir formation. Further, each pumping unit **14**, **16** can be adapted to selectively pump chemicals and/or to mix chemicals if necessary.

[0032] Sensors **60** can be provided for monitoring relevant operational parameters, such as pressure, temperature, flow, viscosity, or the like. Such sensors **60** can be provided in the vessel **18**, pumping units **14**, **16**, tubular member **24**, or elsewhere throughout the system **10**. Signals from the sensors **60** can be communicated to a central control device, such as the controller **40**, which can then adjust the system parameters according to the conditions sensed by the sensors **60**, e.g., by adjusting valves throughout the system **10**, by controlling the operational state and speed of the pumping units **14**, **16**, and by controlling the operation of heaters or other equipment throughout the system **10**. The controller **40** can also receive other signals from sensors installed inside the tree or within the wellbore. Sensors at the subsea location **22** are typically configured to communicate with a surface location, e.g., by sending signals to the controller **40** via the umbilical. If the controller **40** is not located at the same surface facility **20** where the umbilical is connected, then an additional communication link, such as a wired or wireless connection, can be provided between the surface facility **20** and the controller **40**.

[0033] FIG. 3 illustrates a system **10** according to another embodiment of the present invention in which the second-stage pumping unit **16** is provided as an integral part of a subsea tree **62**. As illustrated, the surface facility **20** is a floating production facility, such as an offshore platform at the ocean surface **34**. The first-stage pumping unit **14** is located in the floating production facility **20**. The tubular member **24** is an umbilical and connects the first-stage pumping unit **14** to the second-stage pumping unit **16**, which is located on the seafloor **26** as part of a subsea tree **62**, which generally controls the flow of fluids into and out of the well **12**. The second-stage pumping unit **16** can be located proximate to, but separate from, the tree **62**. Alternatively, as shown in FIG. 3, the second-stage pumping unit **16** can be an integral part of the tree **62**, i.e., part of a single piece of equipment that is deployed as one unit. In either case, the umbilical can be connected to the second-stage pumping unit **16** via a subsea umbilical termination assembly **68**. Further, as illustrated, the umbilical can be fluidly connected to additional segments that extend to other wells or the like.

[0034] In another embodiment, shown in FIG. 4, the surface facility **20** is a service vessel such as an FPSO. The service vessel can include the first-stage pumping unit **14**, the vessel **18** for providing the scale inhibitor or other materials for injection, the controller **40**, and the power source **32**, so that the service vessel can provide the material for the injection operation. In addition, the service vessel can be used to deploy the umbilical or other tubular member **24**. In this regard, a winch apparatus **64** can be used to control the unreeling of a cable **66** attached to the umbilical termination assembly **68** that is connected to the umbilical. As the cable **66** is unreeled from the service vessel, the umbilical termination assembly **68** can be lowered to the subsea location **22**, thereby deploying the umbilical, which can also be unreeled from the service vessel, e.g., from reel **70**. A remote-operated vehicle (ROV) or other submersible control device can be used to assist in connecting the umbilical termination assembly **68** to the second-stage pumping unit **16** that is attached to, or part of, the subsea tree **62**. Alternatively, the umbilical termination assembly **68** can be adapted to attach itself to the second-stage pumping unit **16** and/or the tree **62**, e.g., autonomously or under operator control. In some embodiments, the umbilical termination assembly **68** can include additional equipment to assist in attaching the umbilical termination assembly **68** to the second-stage pumping unit **16** and/or the tree **62**, such as a global position system (GPS) device, one or more cameras, thrusters for controlling the location and orientation of the umbilical termination assembly **68**, electric and/or hydraulic systems, and the like. As shown in FIG. 4, buoyancy devices **72** can be attached at a plurality of positions along the length of the tubular member **24** so that the buoyancy devices **72** are deployed to different depths when the tubular member **24** is generally vertically oriented. The buoyancy devices **72** generally reduce the forces exerted throughout the tubular member **24** and on the connections of the tubular member **24** due to the weight of the tubular member **24**.

[0035] In another embodiment, shown in FIG. 5, the second-stage pumping unit **16** is connected to the tubular member **24** and is deployed from the surface facility **20** with the tubular member **24**. For example, as illustrated, the tubular member **24** can be an umbilical, and the umbilical and the cable **66** can be connected to the second-stage pumping unit **16** before being deployed. The second-stage pumping unit **16** can be deployed with the umbilical by using the winch apparatus **64** to control the unreeling of the cable **66**. As the cable **66** is unreeled from the service vessel, the second-stage pumping unit **16** can be lowered to the subsea location **22**, thereby deploying the umbilical, which is also unreeled from the service vessel. The location and configuration of the second-stage pumping unit **16** can be controlled using a remote-operated vehicle (ROV) or other submersible control device or by using additional equipment provided with the second-stage pumping unit **16**, such as a global position system (GPS) device, one or more cameras, thrusters for controlling the location and orientation of the umbilical termination assembly **68**, electric and/or hydraulic systems, and the like.

[0036] With the tubular member **24** configured to connect the first- and second-stage pumping units **14**, **16**, the system **10** can be used to selectively inject materials into the subsea well **12**. In a typical injection operation, the first-stage pumping unit **14** operates at a relatively lower pressure, and the second-stage pumping unit **16** operates at a relatively higher pressure. The pumping units **14**, **16** can provide a variable rate of flow of the materials into the well **12**, and the system **10** can selectively pump a series of materials into the well **12**. For example, different chemicals for performing a preflush, mainflush, and overflush operation can be stored in the vessel(s) **18**. The different chemicals can be delivered by the system **10** to the well **12** successively or simultaneously. In some cases, the vessel(s) **18** can include heating devices, such as resistance heaters or heat exchangers, to adjust the temperature of the chemicals, e.g., to heat the chemicals and thereby increase the flow rate of the chemicals through the tubular member **24**.

[0037] The tubular member **24** can be configured to communicate between the pumping units **14**, **16**, e.g., in cases where the tubular member **24** is an umbilical. Thus, the umbilical can transport chemicals for a scale squeeze treatment operation as well as communicating signals from sensors at each end of the umbilical, communicating control signals, e.g., for controlling the operation of the pumping units **14**, **16**, and/or communicating power, e.g., for operating the pumping units **14**, **16**. More particularly, signals from sensors **60** at the subsea location **22** can be communicated via the umbilical to the controller **40** at the surface facility **20**, and the controller **40** can provide via the umbilical either or both of operating power for operating the second-stage pumping unit **16** and operating commands for controlling the operation of the second-stage pumping unit **16** and thereby controlling the injection of materials for the subsea scale squeeze treatment. Communication of such signals through the tubular member **24** can be performed using electrical signals through electrically conductive elements (e.g., copper wires) of the tubular member **24** or using optical signals through optically conductive elements (e.g., fiber optics) of the tubular member **24**. In some cases, the second-stage pumping unit **16** can be powered by the subsea tree **62** or via a flying lead that is connected to the subsea umbilical termination assembly **68**.

[0038] In some cases, the amount of material, such as chemical scale inhibitor, that is used is relatively less than that which would otherwise be required in a conventional method of delivering the material to the subsea well **12** via a production pipeline or flowline, e.g., because the diameter and the volume of the tubular member **24** can generally be less than a production pipeline by virtue of the multiple-stage pumping arrangement of the present invention. Further, if the tubular member **24** is an umbilical or other relatively low-pressure, low-diameter member that is not used for delivering production fluids from the well **12**, the amount of debris and solids that are pumped into the wellbore during injection into the well **12** can be reduced. That is, while a pipeline or flowline typically contains such debris and solids, which may be injected into the well **12** if the pipeline or flowline is used for injecting fluids into the well **12**, such injection of debris and solids can generally be avoided by using a separate tubular member **24** for injecting the scale inhibitor or other materials into the well **12**. It is also appreciated that, by using a separate tubular member **24** for injection of the material, downtime associated with the injection of materials through the production pipeline or flowline can generally be avoided or reduced.

[0039] Many modifications and other embodiments of the invention set forth herein will come to mind to one skilled in the art to which this invention pertains having the benefit of the teachings presented in the foregoing descriptions and the associated drawings. Therefore, it is to be understood that the invention is not to be limited to the specific embodiments disclosed and that modifications and other embodiments are intended to be included within the scope of the appended claims. Although specific terms are employed herein, they are used in a generic and descriptive sense only and not for purposes of limitation.

WHAT IS CLAIMED IS:

1. A system for delivering a material from a vessel at a surface facility to a subsea location and into a subsea well, the system comprising:

a first-stage pump located at the surface facility and configured to receive the material from the vessel;

a tubular member extending from the first-stage pump to the subsea location; and

a second-stage pump at the subsea location and connected to the tubular member, the first-stage pump being configured to deliver the material through the tubular member to the second-stage pump at a first pressure, and the second-stage pump being configured to receive the material from the tubular member and inject the material into the well at a second pressure higher than the first pressure.

2. A system according to Claim 1 wherein the tubular member is a flexible umbilical, the umbilical defining a first tubular passage for receiving and delivering the material, and a second tubular passage having at least one conductive cable for communicating between the surface facility and the subsea location.

3. A system according to Claim 2 wherein the conductive cable is configured to provide at least one of an electrical signal for controlling the operation of the second-stage pump and electrical power for powering the operation of the second-stage pump.

4. A system according to Claim 1 wherein the second-stage pump is disposed on the seafloor.

5. A system according to Claim 1 wherein the second-stage pump is disposed as part of a tree at a head of the subsea well.

6. A system according to Claim 1 wherein the vessel is configured to provide a scale squeeze treatment chemical adapted to inhibit scaling and the second-stage pump is configured to inject the chemical into the well to perform a scale squeeze treatment of the well.

7. A system according to Claim 1 wherein the tubular member is a flexible tube formed of a thermoplastic material.

8. A method of delivering a material from a vessel at a surface facility to a subsea location and into a subsea well, the method comprising:

operating a first-stage pump located at the surface facility to pump the material from the vessel through a tubular member extending from the first-stage pump to the subsea location; and

operating a second-stage pump at the subsea location and connected to the tubular member to inject the material from the tubular member into the well.

9. A method according to Claim 8, further comprising providing a flexible umbilical as the tubular member, wherein operating the first-stage pump comprises pumping the material through a first tubular passage of the umbilical, and further comprising providing at least one conductive cable in the umbilical in communication with the surface facility and the subsea location.

10. A method according to Claim 9, further comprising communicating an electrical signal from the surface facility to the subsea location via the conductive cable to control the operation of the second-stage pump.

11. A method according to Claim 9, further comprising providing electrical power from the surface facility to the subsea location via the electrically conductive cable to power the operation of the second-stage pump.

12. A method according to Claim 8 wherein operating the first-stage pump comprises providing the material to the tubular member at a pressure that is greater than a pressure drop that occurs through the tubular member and less than a sum of the pressure drop that occurs through the tubular member and a pressure required for injecting the material into the well.

13. A method according to Claim 8, further comprising providing the second-stage pump at the seafloor.

14. A method according to Claim 8, further comprising providing the second-stage pump as part of a tree at a head of the subsea well.

15. A method according to Claim 8 wherein operating the first-stage pump and the second-stage pump comprises injecting a scale squeeze treatment chemical into the well to thereby perform a scale squeeze treatment of the well and inhibit scaling in the well.

16. A method according to Claim 8, further comprising providing a flexible tube as the tubular member, the flexible tube being formed of a thermoplastic material.

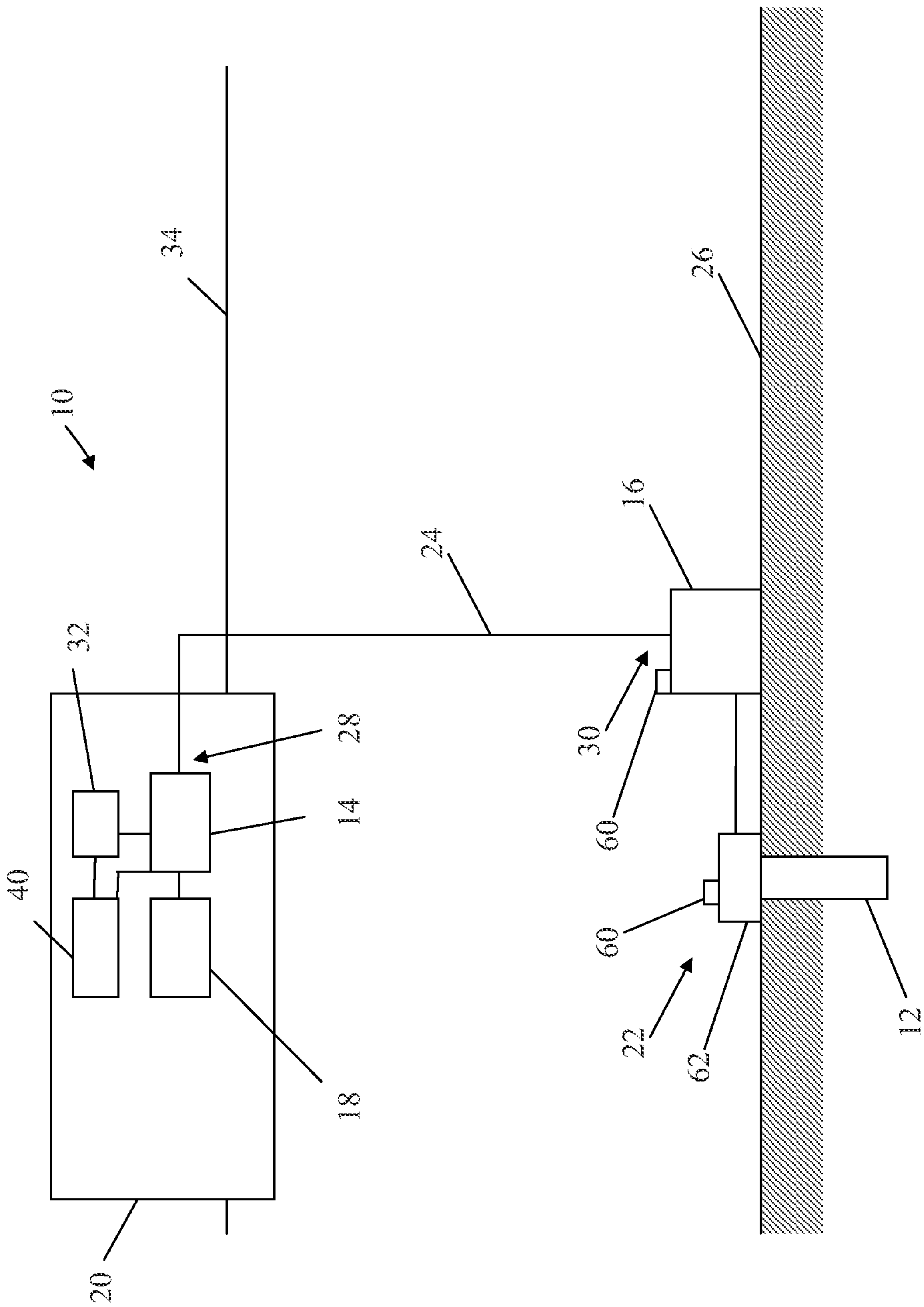

FIG. 1

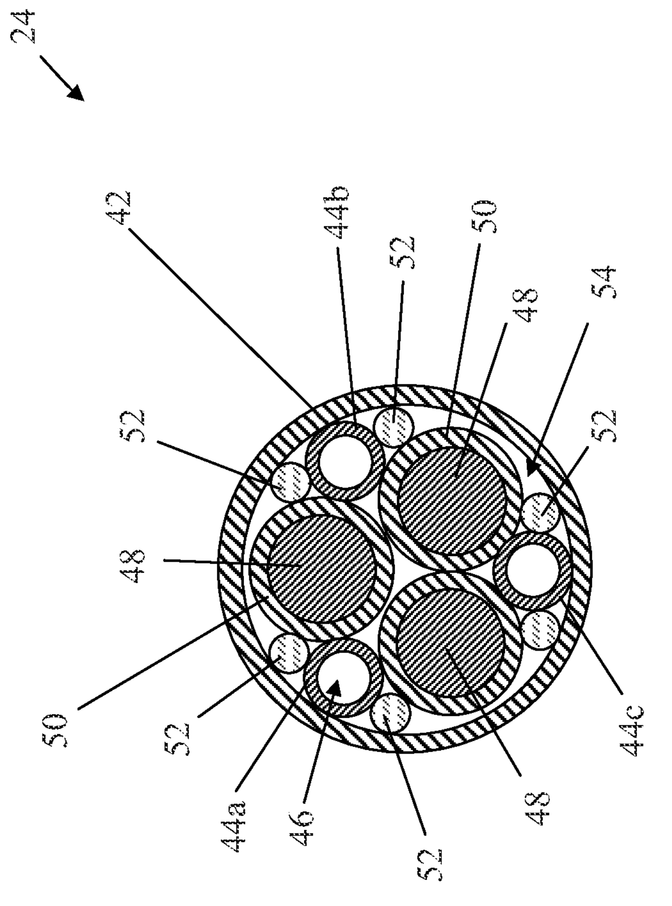

FIG. 2

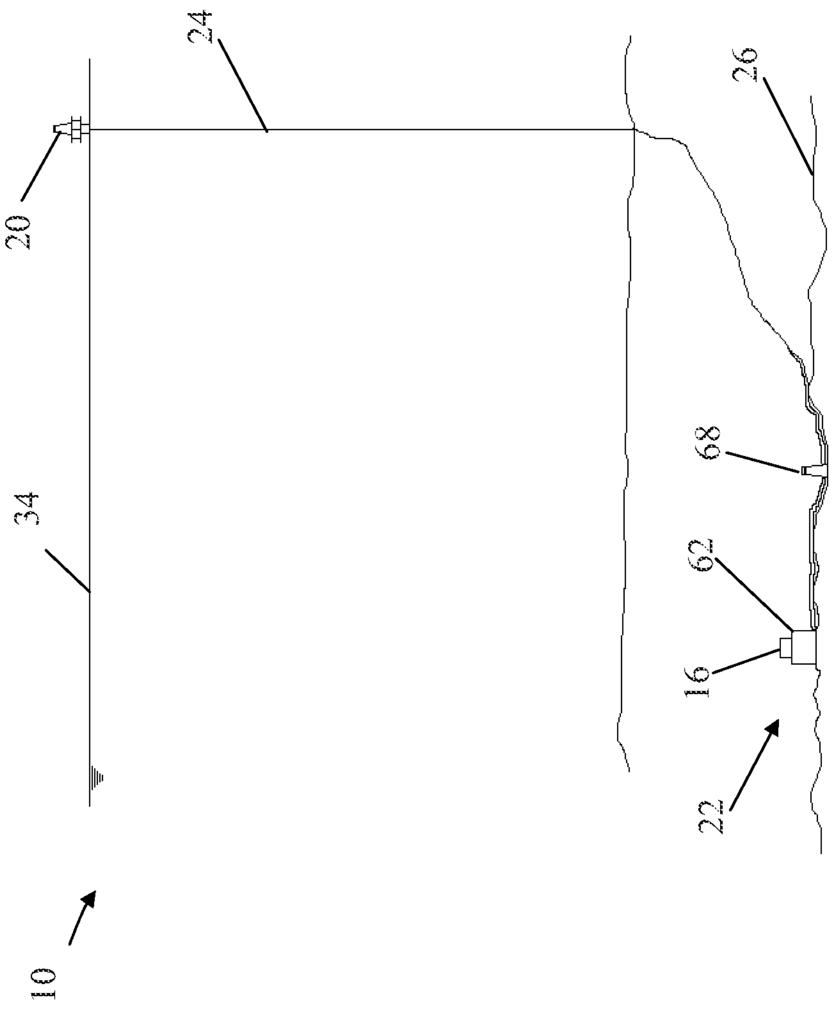

FIG. 3

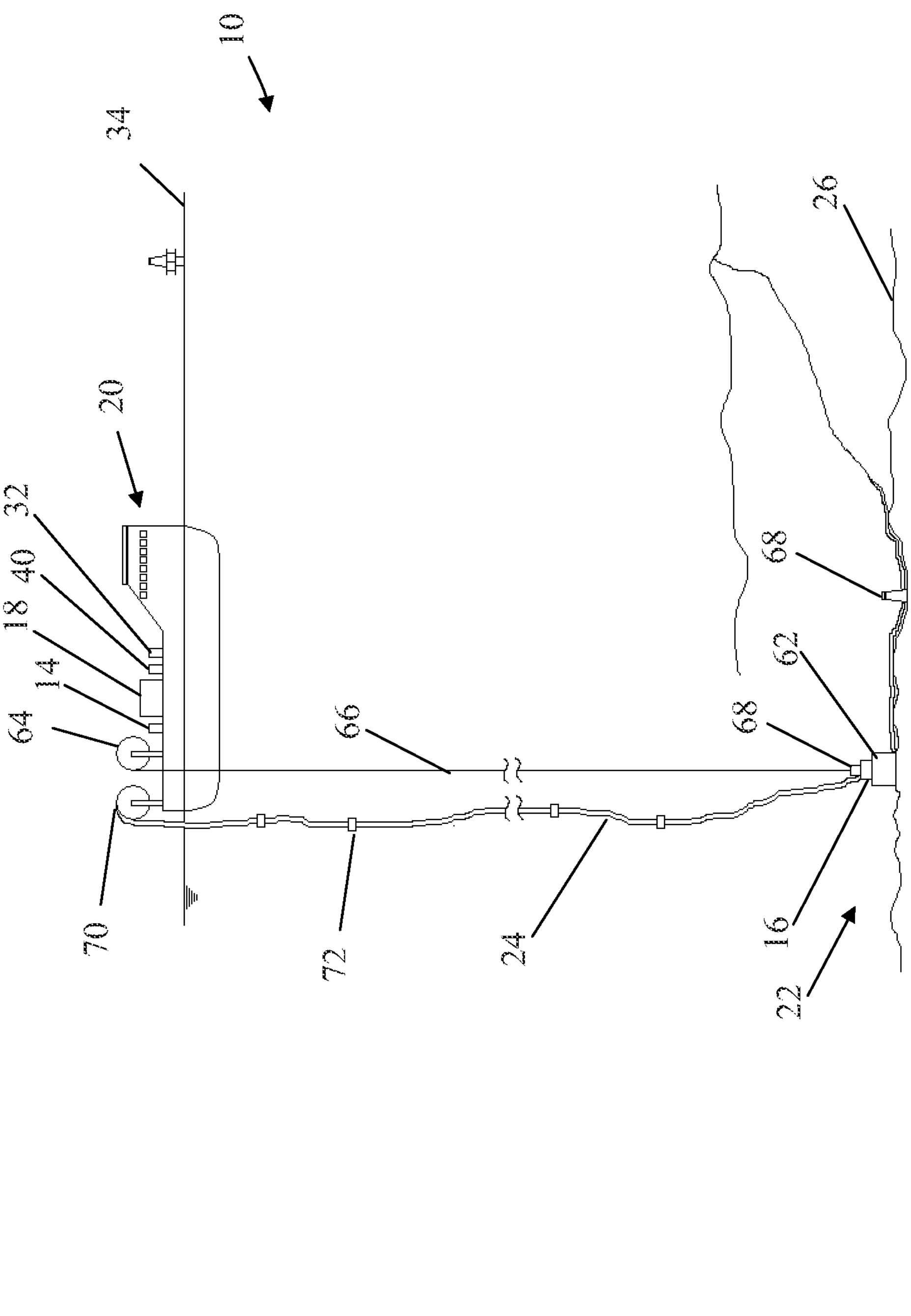

FIG. 4

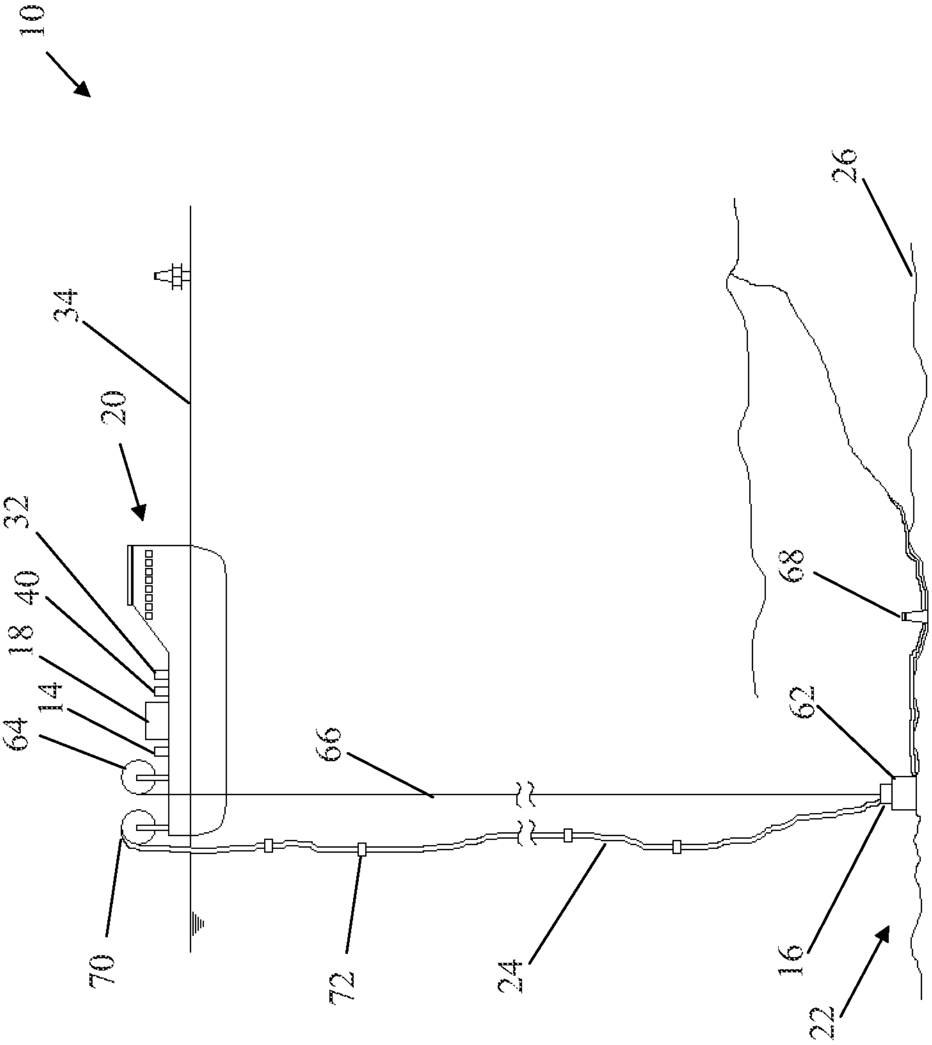

FIG. 5