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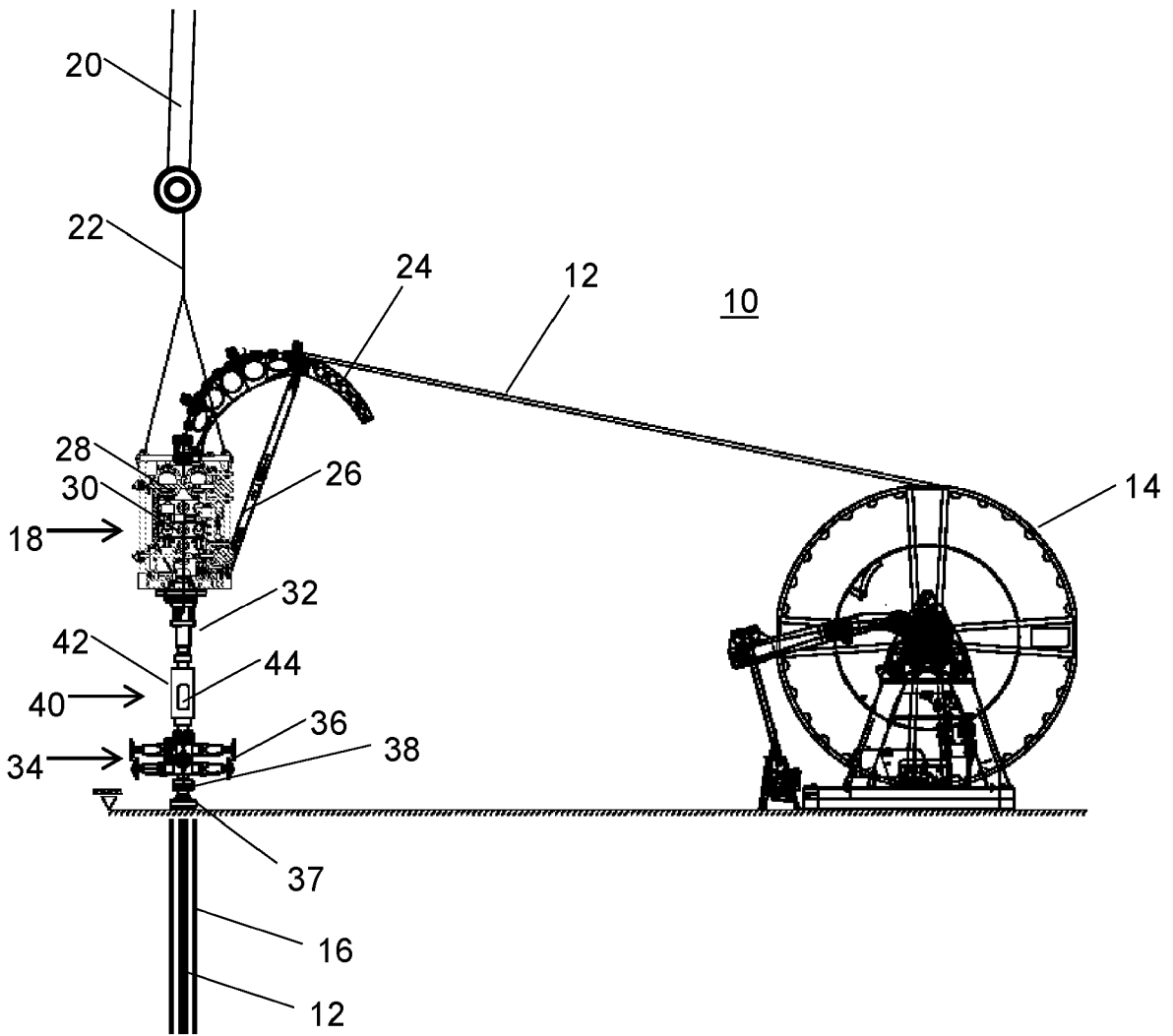


Figure 1

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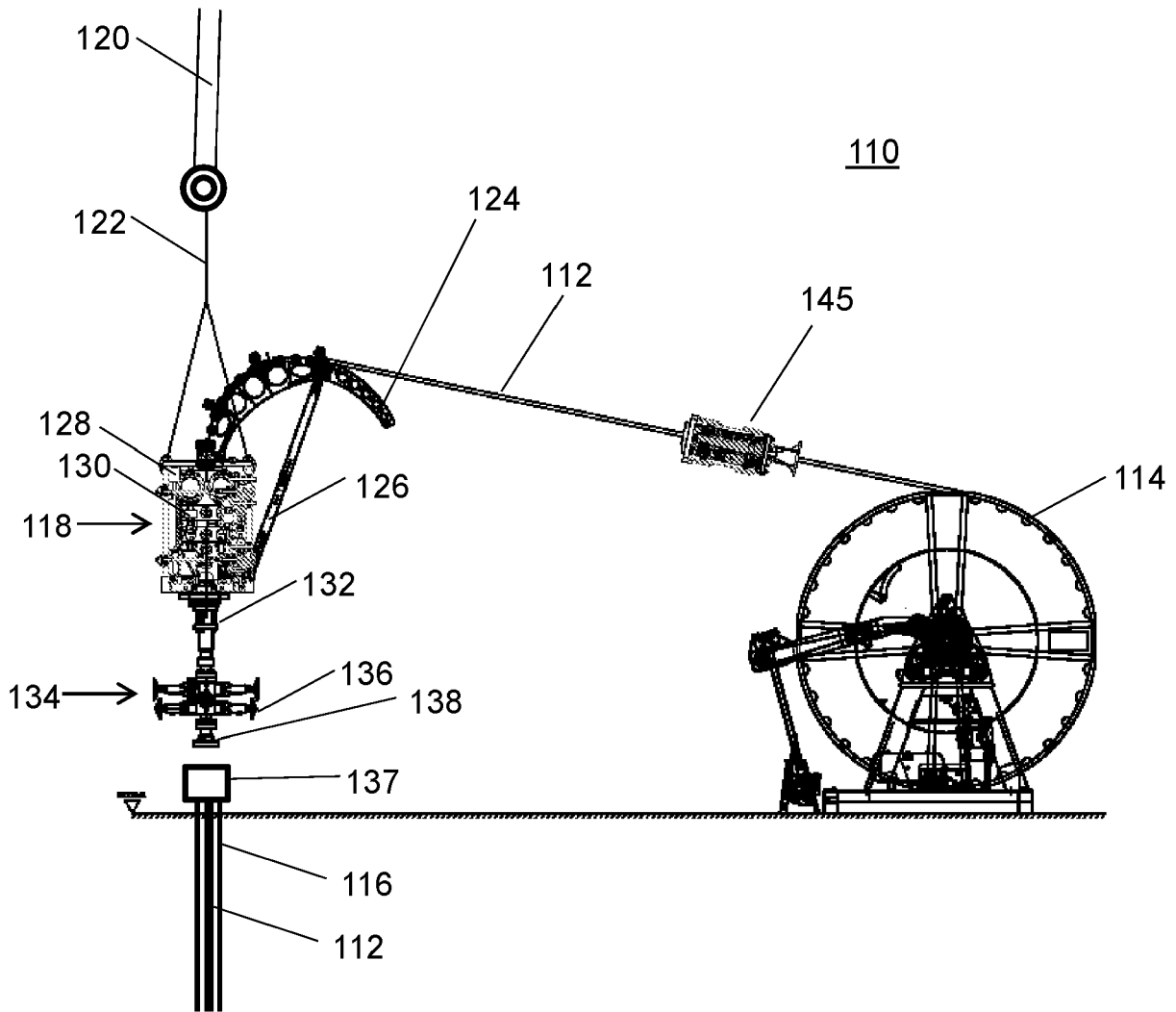


Figure 2

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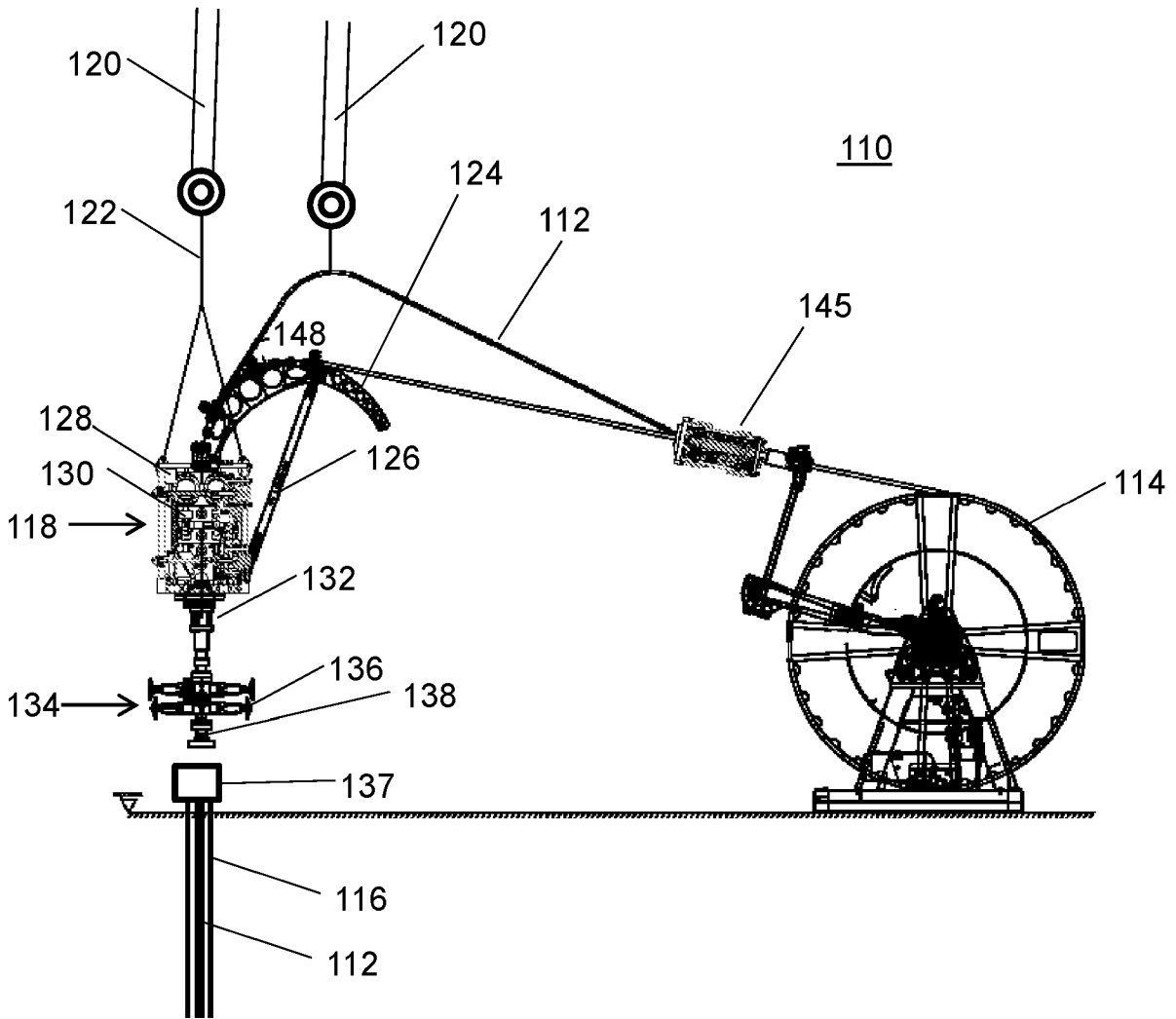


Figure 3

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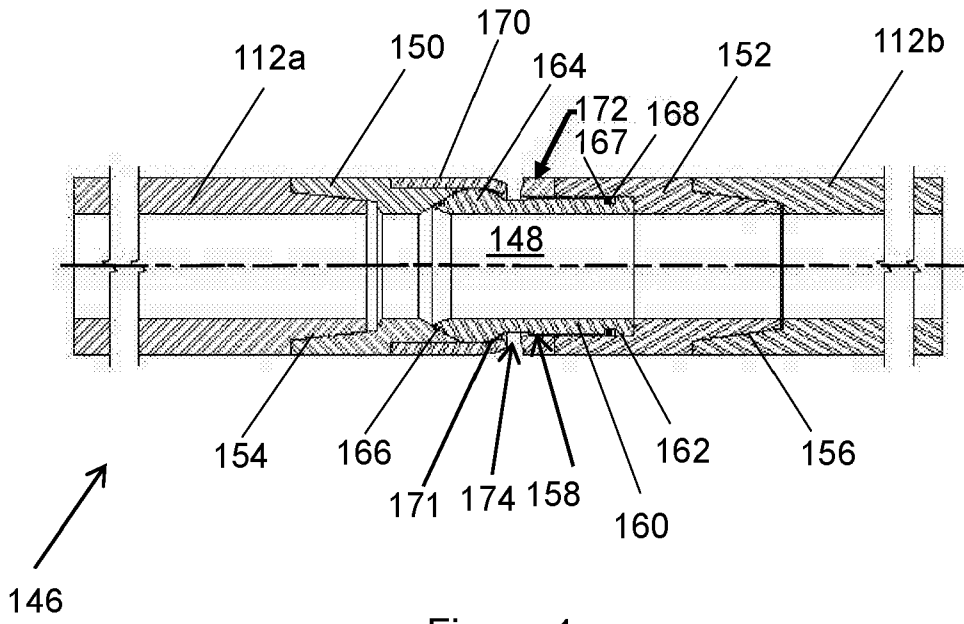


Figure 4

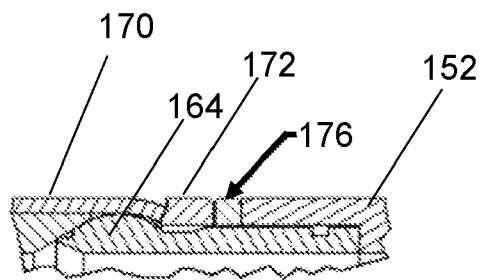


Figure 5

SYSTEMS AND METHODS FOR CONVEYING COILED TUBING INTO A FLUID CONDUIT

FIELD

5 This relates to systems and methods for conveying coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons.

BACKGROUND

10 In the oil & gas exploration and production industry, in order to access hydrocarbons from a formation, a well borehole ("wellbore") is drilled from surface. The wellbore is then lined with sections of bore-lining metal tubulars, known as casing, and production infrastructure installed to facilitate the ingress of hydrocarbons into the wellbore and transport them to surface.

15 The development of directional drilling techniques has facilitated the creation of high angle and horizontal wellbores (referred to below collectively as horizontal wellbores) which deviate from vertical and thus permit the wellbore to follow the hydrocarbon bearing formation to a greater extent. Amongst other things, horizontal wellbores beneficially facilitate increased production rates due to the greater length of the wellbore which is exposed to the reservoir.

20 In order to perform an intervention or workover operation in a wellbore, the intervention tools and equipment must be capable of being conveyed into and advanced along the wellbore, which may define a tortuous path over several kilometres. In the case of subsea wellbores, the wellbore may be accessed by a flexible marine riser tied back to a surface vessel.

25 Coiled tubing intervention systems – which employ a long continuous length of metal piping wound on a spool - provide the advantage over mechanical intervention tools in that coiled tubing facilitates the transportation of fluid downhole, for example as a cleaning or jetting fluid in a wellbore cleaning operation, as a power fluid to operate fluid-powered downhole tools, or as a treatment fluid, e.g. fracturing fluid, chemical wash operations, or the like. Coiled tubing systems are also particularly, but not
30 exclusively, suited to offshore operations where it is necessary to direct intervention equipment through the flexible marine riser. However, while coiled tubing intervention systems are used effectively in numerous applications, there are drawbacks with conventional coiled tubing systems which typically limit the extent to which coiled
35 tubing can be utilised in longer extended reach wellbores.

SUMMARY

According to a first aspect, there is provided a system for conveying coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons, according to the appended claims.

5 Beneficially, the system permits access to the coiled tubing, for example to facilitate connection and/or disconnection of sections of coiled tubing without having to trip the coiled tubing through the injector and around the tubing guide.

10 The fluid conduit may comprise one or more of: a wellbore, e.g. an extended reach horizontal wellbore; a pipeline, e.g. a hydrocarbon production or transportation pipeline; a riser, e.g. a marine riser; and an umbilical.

The system may comprise, may be coupled to, or operatively associated with a reel used to store the coiled tubing to be conveyed.

The injector may be configured to convey the coiled tubing from the reel into and/or from the fluid conduit.

15 The injector may comprise or take the form of an injector head.

The injector may be suspended from a crane.

The injector may be suspended from the crane by a sling or other suitable mechanism.

The injector may comprise a drive arrangement.

20 The drive arrangement may comprise an arrangement of gripping members.

In use, the gripping members may grip the coiled tubing so that the drive mechanism can push and/or pull the coiled tubing into and/or out of the fluid conduit.

The system may comprise a tubing guide.

The tubing guide may take the form of a gooseneck tubing guide.

25 The tubing guide may be disposed on top of the injector.

In use, the injector may receive the coiled tubing from the reel, the tubing guide being disposed on top of the injector head to guide the coiled tubing into the injector.

The system may comprise a lift bail.

30 The lift bail may support and position the tubing guide, the lift bail defining the angle at which the coiled tubing enters the injector.

The system may comprise a stripper.

The stripper may be disposed below the injector.

The stripper may comprise internal pack off elements which define a portion of an internal bore through the system. The pack-off elements may be formed from an

elastomeric material, arranged to provide a fluid seal with the outer surface of the coiled tubing as it passes through the system.

In use, the pack-off elements may be operable to be actuated against the outer surface of the coiled tubing.

5 The pack-off elements may be actuated by introducing hydraulic pressure into a chamber outside of the pack off elements.

Alternatively, the pack off elements may be mechanically actuated.

Beneficially, the stripper allows the coiled tubing to pass through the system while retaining pressure in the fluid conduit below the stripper.

10 The system may further comprise a pressure control assembly.

The pressure control assembly may comprise or take the form of one or more of: a well control stack; pipe ram; blow out preventer (BOP) arrangement or the like.

The pressure control assembly may be coupled to a wellhead, e.g. by a wellhead crossover flange or the like.

15 As described above, the system is configured to convey coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons.

The coiled tubing may comprise a first tubing portion and a second tubing portion configured for coupling to a proximal end of the first tubing portion, the first tubing portion comprising composite coiled tubing and the second tubing portion comprising metallic coiled tubing.

20 The composite coiled tubing has a lower coefficient of static friction than conventional metallic coiled tubing, e.g. 0.15 compared to 0.25, such that for the same input force the reach of the coiled tubing can be extended. As described above, the coiled tubing includes a first tubing portion comprising composite coiled tubing and a second tubing portion comprising metallic coiled tubing.

25 The first tubing portion may define a distal portion of the coiled tubing. Thus, on locating the system in the conduit, the first tubing portion may define a downhole or downstream portion of the coiled tubing.

30 The second tubing portion may define a proximal portion of the coiled tubing. Thus, on locating the system in the conduit, the second tubing portion may define an uphole or upstream portion of the coiled tubing.

It will be understood that the term proximal means closer to surface and that the term distal means further from surface.

35 In instances where the conduit comprises a horizontal wellbore, the system may be configured for deployment into the wellbore, with the first tubing portion disposed in

the horizontal section of the wellbore and the second tubing portion disposed in the vertical section of the wellbore. The second tubing portion may also be disposed partially in the horizontal section of the wellbore. For example, the system may be deployed into the wellbore until the second tubing portion is disposed around the heel of the wellbore and into the horizontal section of the wellbore.

As described above, the coiled tubing is configured for deployment into the conduit.

The first tubing portion may be configured for storage on and deployment from the reel. By constructing the first tubing portion from composite coiled tubing, the first tubing portion may be configured to be stored on and deployed from the reel.

The second tubing portion may be configured for storage on and deployment from a reel. By constructing the second tubing portion from metallic coiled tubing, the second tubing portion may be configured to be stored on and deployed from the reel.

In use, a fluid discharge apparatus may be disposed at a distal end of the first tubing portion at surface, the first tubing portion and the fluid discharge apparatus then being deployed into the conduit by unreeling the first tubing portion from the reel. In instances where the conduit comprises a horizontal wellbore, for example, the system may be configured to deploy the fluid discharge apparatus and the first tubing portion into the horizontal section of the wellbore. The first tubing portion may comprise a single run of composite coiled tubing. Alternatively, where required the first tubing portion may comprise a plurality of runs of composite coiled tubing coupled together. The first tubing portion may thus be deployed into the conduit to an initial deployment location, at which the distal end of the coiled tubing is disposed in the conduit and the proximal end of the first tubing portion is at surface. The second tubing portion may then be coupled to the proximal portion of the first tubing portion, the second tubing portion then being unreeled from the reel.

Alternatively, the first and second tubing portions may be coupled together at surface and deployed into the conduit together.

The first tubing portion may take a number of different forms.

The first tubing portion may comprise a base pipe.

The base pipe may be constructed or formed from a polymeric material.

The polymeric material may be a thermoplastic material.

The thermoplastic material may be at least one of: polyaryletherketone (PAEK); polyarylketone (PAK); polyetherketone (PEK); polyetheretherketone (PEEK); polycarbonate (PC) or the like.

In particular embodiments, the base pipe is constructed or formed from polyetheretherketone (PEEK).

The composite coiled tubing may comprise a composite laminate disposed around the base pipe.

5 The composite laminate may comprise a matrix.

The matrix may comprise a polymeric material.

The matrix may, for example, comprise a thermoplastic material.

10 The matrix may comprise at least one of: polyaryletherketone (PAEK); polyarylketone (PAK); polyetherketone (PEK); polyetheretherketone (PEEK); polycarbonate (PC) or the like.

The composite laminate may comprise a plurality of reinforcing elements disposed within the matrix.

The reinforcing elements may be embedded in the matrix.

15 The reinforcing elements may comprise fibres, strands, filaments, nanotubes or the like.

For example, the reinforcing elements may comprise glass fibres, carbon fibres or the like.

In particular embodiments, the reinforcing elements comprise carbon fibres.

20 The first tubing portion may have a diameter of between 25 mm (1inch) and 83 mm (3.25 inches).

The second tubing portion may take a number of different forms.

The second tubing portion may be constructed or formed from steel.

The second tubing portion may have a diameter of between 25 mm (1inch) and 83 mm (3.25 inches).

25

According to a second aspect, there is provided a method for conveying coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons using the system of the first aspect.

30 The system may be run into the fluid conduit in order to perform, or as part of an intervention operation, in the fluid conduit.

The system may be run into the fluid conduit during operation of the fluid conduit, for example while fluid is flowing in the fluid conduit.

Also described is a system for conveying coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons, the system comprising:

an injector configured to convey the coiled tubing into and/or from the fluid conduit; and

a line tensioner configured to apply a tensile force to the coiled tubing.

Beneficially, the line tensioner is configured to apply a tensile force to the coiled tubing to provide enhanced control over the positioning of the coiled tubing and/or prevent damage thereto.

The system may further comprise a tubing connector for coupling portions of coiled tubing.

Also described is a method for conveying coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons using a system for conveying coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons, the system comprising: an injector configured to convey the coiled tubing into and/or from the fluid conduit; and a line tensioner configured to apply a tensile force to the coiled tubing.

The system may be run into the fluid conduit in order to perform, or as part of an intervention operation, in the fluid conduit.

The system may be run into the fluid conduit during operation of the fluid conduit, for example while fluid is flowing in the fluid conduit.

Also described is a tubing connector for coiled tubing, wherein the tubing connector is configured to couple a first coiled tubing section and a second tubing section, the tubing connector reconfigurable between a first, unlocked, configuration which permits the first and second coiled tubing section to pivot relative to each and a second, locked configuration in which relative pivoting of the first and second coiled tubing sections is prevented.

The tubing connector may take the form of a knuckle joint assembly.

The tubing connector may be generally tubular in construction, having an axial flow passage, e.g. in the form of a throughbore, extending therethrough.

The throughbore may be contiguous with axial throughbores of the coiled tubing sections.

The tubing connector may comprise a first end ring.

The first end ring may be configured for coupling to an end of a first coiled tubing section.

A coupling arrangement may be provided for coupling the first end ring to the first coiled tubing section.

The coupling arrangement may comprise a fastener, a threaded connection, such as threaded box and pin connection, or other suitable coupling.

The tubing connector may comprise a second end ring.

5 The second end ring may be configured for coupling to an end of a second coiled tubing section.

A coupling arrangement may be provided for coupling the second end ring to the second coiled tubing section.

The coupling arrangement may comprise a fastener, a threaded connection, such as threaded box and pin connection, or other suitable coupling.

10 The tubing connector may comprise a joint member.

The joint member may comprise a shank portion.

The shank portion may be configured to seat within a recess in the second end ring.

The joint member may comprise a ball-shaped end portion.

15 The ball-shaped portion may at least partially seat within a corresponding seat in the first end ring.

The tubing connector comprises a sleeve.

The sleeve may be disposed around at least part of the first end ring and ball-shaped end portion of the joint member.

20 An inner surface of the sleeve may form a seat for part of the ball-shaped end portion.

The tubing connector comprises a locking collar.

The locking collar may be disposed around the joint member.

25 The locking collar may be axially interposed between the first and second end rings.

In the unlocked configuration, the tubing connector is arranged so that there is an axial gap between the sleeve and the locking collar. In use, the tubing connector couples the first and second coiled tubing sections, the tubing connector permitting - via the engagement between the ball-shaped portion and the seats – the coiled tubing sections to pivot or flex about the tubing connector.

30

In the locked configuration, the locking collar is axially displaced relative to the unlocked configuration to engage the sleeve.

The tubing connector may comprise a split collar.

In the locked configuration, the split collar may be disposed between the locking collar and the end ring. In this configuration, pivoting or flexing of the tubing connector may be prevented.

Also described is a system for conveying coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons, comprising a tubing connector for coiled tubing, wherein the tubing connector is configured to couple a first coiled tubing section and a second tubing section, the tubing connector reconfigurable between a first, unlocked, configuration which permits the first and second coiled tubing section to pivot relative to each and a second, locked configuration in which relative pivoting of the first and second coiled tubing sections is prevented.

The fluid conduit may comprise one or more of: a wellbore, e.g. an extended reach horizontal wellbore; a pipeline, e.g. a hydrocarbon production or transportation pipeline; a riser, e.g. a marine riser; and an umbilical.

The system may comprise, may be coupled to, or operatively associated with a reel used to store the coiled tubing to be conveyed.

The injector may be configured to convey the coiled tubing from the reel into and/or from the fluid conduit.

The injector may comprise or take the form of an injector head.

The injector may be suspended from a crane.

The injector may be suspended from the crane by a sling or other suitable mechanism.

The injector may comprise a drive arrangement.

The drive arrangement may comprise an arrangement of gripping members.

In use, the gripping members may grip the coiled tubing so that the drive mechanism can push and/or pull the coiled tubing into and/or out of the fluid conduit.

The system may comprise a tubing guide.

The tubing guide may take the form of a gooseneck tubing guide.

The tubing guide may be disposed on top of the injector.

In use, the injector may receive the coiled tubing from the reel, the tubing guide being disposed on top of the injector head to guide the coiled tubing into the injector.

The system may comprise a lift bail.

The lift bail may support and position the tubing guide, the lift bail defining the angle at which the coiled tubing enters the injector.

The system may comprise a stripper.

The stripper may be disposed below the injector.

The stripper may comprise internal pack off elements which define a portion of an internal bore through the system. The pack-off elements may be formed from an elastomeric material, arranged to provide a fluid seal with the outer surface of the coiled tubing as it passes through the system.

5 In use, the pack-off elements may be operable to be actuated against the outer surface of the coiled tubing.

The pack-off elements may be actuated by introducing hydraulic pressure into a chamber outside of the pack off elements.

Alternatively, the pack off elements may be mechanically actuated.

10 Beneficially, the stripper allows the coiled tubing to pass through the system while retaining pressure in the fluid conduit below the stripper.

The system may further comprise a pressure control assembly.

The pressure control assembly may comprise or take the form of one or more of: a well control stack; pipe ram; blow out preventer (BOP) arrangement or the like.

15 The pressure control assembly may be coupled to a wellhead, e.g. by a wellhead crossover flange or the like.

Also described is a method for conveying coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons using a system for conveying coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons, comprising a tubing connector for coiled tubing, wherein the tubing connector is configured to couple a first coiled tubing section and a second tubing section, the tubing connector reconfigurable between a first, unlocked, configuration which permits the first and second coiled tubing section to pivot relative to each and a second, locked configuration in which relative pivoting of the first and second coiled tubing sections is prevented.

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The system may be run into the fluid conduit in order to perform, or as part of an intervention operation, in the fluid conduit.

The system may be run into the fluid conduit during operation of the fluid conduit, for example while fluid is flowing in the fluid conduit.

30

It will be understood that the features defined above or described below may be utilised in isolation or in combination with any other defined feature.

BRIEF DESCRIPTION OF THE DRAWINGS

These and other aspects will now be described, by way of example, with reference to the accompanying drawings, of which:

5 Figure 1 shows a system for conveying coiled tubing into a fluid conduit suitable for transporting hydrocarbons;

Figures 2 and 3 show another system for injecting coiled tubing into a fluid conduit suitable for transporting hydrocarbons;

Figure 4 shows a tubing connector for coiled tubing, in a first configuration;

10 Figure 5 shows part of the tubing connector shown in Figure 3 in a second configuration.

DETAILED DESCRIPTION OF THE DRAWINGS

Referring first to Figure 1 of the accompanying drawings, there is shown a system, generally depicted at 10, for conveying coiled tubing 12 from a reel 14 into and/or from a fluid conduit 16 suitable for transporting hydrocarbons.

As shown in Figure 1, the system 10 comprises an injector in the form of injector head 18. In the illustrated system 10 shown in Figure 1, the injector head 18 is suspended from a crane, generally depicted at 20, by a sling 22.

20 The injector head 18 receives the coiled tubing 12 from the reel 14, a gooseneck tubing guide 24 being disposed on top of the injector head 18 to guide the coiled tubing 12 into the injector head 18. A lift bail 26 supports and positions the tubing guide 24, the lift bail 26 defining the angle at which the coiled tubing 12 enters the injector head 18.

25 The injector head 18 comprises a drive arrangement 28 comprising an arrangement of gripping members 30, with the gripping members 30 mounted on corresponding chains driven by corresponding cogs. The gripping members 30 grip the coiled tubing 12 so that the drive mechanism 28 can push and/or pull the coiled tubing 12 into and/or out of the fluid conduit 14.

30 As shown in Figure 1, a stripper 32 is provided below the injector head 18. The stripper 32 comprises internal pack off elements (not shown) which define a portion of an internal bore through the system 10. The pack-off elements are formed from an elastomeric material, arranged to provide a fluid seal with the outer surface of the coiled tubing 12 as it passes through the system 10. The pack-off elements are operable to be actuated against the outer surface of the coiled tubing 12, and in this case are actuated by introducing hydraulic pressure into a chamber outside of the pack

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off elements. Alternatively, the pack off elements may be mechanically actuated. The stripper 32 allows the coiled tubing 12 to pass through the system 10 while retaining pressure in the fluid conduit 12 below the stripper 32.

5 The system 10 further comprises a pressure control assembly 34. In the illustrated system 10, the pressure control assembly 34 includes a well control stack, pipe ram, blow out preventer (bop) arrangement 36 or the like.

The pressure control assembly 34 is coupled to wellhead 37 by a wellhead crossover flange 38 or the like.

10 As described above, the system 10 comprises an access module, generally depicted at 40, having a body 42 and an access window 44.

Beneficially, the system 10 permits access to the coiled tubing 12 via the access window 44, for example to facilitate connection and/or disconnection of sections of coiled tubing 12 without having to trip the coiled tubing 12 through the injector head 18 and around the tubing guide 24.

15 Referring now to Figures 2 and 3 of the accompanying drawings, there is shown an alternative system, generally depicted at 110, for conveying coiled tubing 112 from a reel 114 into and/or from a fluid conduit 116 suitable for transporting hydrocarbons.

20 As shown in Figure 2, the system 110 comprises an injector in the form of injector head 118. In the illustrated system 110 shown in Figure 2, the injector head 118 is suspended from a crane, generally depicted at 120, by a sling 122.

25 The injector head 118 receives the coiled tubing 112 from the reel 114, a gooseneck tubing guide 124 being disposed on top of the injector head 118 to guide the coiled tubing 112 into the injector head 118. A lift bail 126 supports and positions the tubing guide 124, extension and/or retraction of the lift bail 126 altering the angle at which the coiled tubing 112 enters the injector head 118.

30 The injector head 118 comprises a drive arrangement 128 comprising an arrangement of gripping members 130, with the gripping members 130 mounted on corresponding chains driven by corresponding cogs. The gripping members 130 grip the coiled tubing 112 so that the drive mechanism 128 can push and/or pull the coiled tubing 112 into and/or out of the fluid conduit 114.

35 As shown in Figures 2 and 3, a stripper 132 is provided below the injector head 118. The stripper 132 comprises internal pack off elements (not shown) which define a portion of an internal bore through the system 110. The pack-off elements are formed from an elastomeric material, arranged to provide a fluid seal with the outer surface of the coiled tubing 112 as it passes through the system 110. The pack-off elements are

operable to be actuated against the outer surface of the coiled tubing 112, and in this case are actuated by introducing hydraulic pressure into a chamber outside of the pack off elements. Alternatively, the pack off elements may be mechanically actuated. The stripper 132 allows the coiled tubing 112 to pass through the system 110 while retaining pressure in the fluid conduit 112 below the stripper 132.

The system 110 further comprises a pressure control assembly 134. In the illustrated system 110, the pressure control assembly 134 includes a well control stack, pipe ram, blow out preventer (bop) arrangement 136 or the like.

The pressure control assembly 134 is coupled to wellhead 137 by a wellhead crossover flange 138 or the like.

As shown in Figures 2 and 3, the system 110 further comprises a line tensioner 145. The line tensioner 145 is configured to apply a tensile force on the coiled tubing 112.

The system 110 further comprises a tubing connector 146 (shown in Figure 4) for coupling portions of coiled tubing 112.

As shown in Figure 3, in order to position the coiled tubing 112, the crane 120 (or another crane) is provided to lift the coiled tubing 112 as shown, permitting access to the coiled tubing 112 and the tubing connector 146. The normal position of the coiled tubing 112 is shown for reference.

Referring now also to Figures 4 and 5 of the accompanying drawings, there is shown a longitudinal sectional view of the connector 146. Figure 4 shows the tubing connector 146 in a first, unlocked, configuration. Figure 5 shows the tubing connector 146 in a second, locked, configuration.

The tubing connector 146 takes the form of a knuckle joint assembly for coupling sections of coiled tubing, represented by 112a, 112b in Figures 4 and 5.

As shown, the tubing connector 146 is generally tubular in construction, having throughbore 148 extending therethrough. The throughbore 148 is contiguous with axial throughbores of the tubing sections 112a, 112b.

The tubing connector 146 comprises end rings 150, 152 configured for coupling to respective ends of the coiled tubing sections 112a, 112b. In the illustrated tubing connector 146, the end ring 150 is coupled to the tubing section 112a by a threaded box and pin connection 154 and the end ring 152 is coupled to the tubing section 112b by a threaded box and pin type connection 156. However, it will be recognised that any suitable coupling may be used.

Interposed between the end rings 150,152 is a joint member 158 having a shank portion 160 which seats within a recess 162 in end ring 152 and a ball-shaped end portion 164 part of which seats within a corresponding seat 166 in end ring 150. As shown in Figure 4, a groove 167 is formed in the shank portion 160, the groove 167 receiving an annular seal element 168. The seal element 168 prevents fluid leakage around the joint member 158.

A sleeve 170 is disposed around the end ring 150 and ball-shaped end portion 164 of the joint member 158, an inner surface of the sleeve 170 forming a seat 171 for part of the ball-shaped end portion 164.

As shown in Figure 4, the tubing connector 146 comprises a locking collar 172. The locking collar 172 is disposed around the joint member 158 (in the illustrated connector 146 around the shank portion 160). The locking collar 172 is axially interposed between the end rings 150, 152

In the unlocked configuration shown in Figure 4, the tubing connector 146 is arranged so that there is an axial gap 174 between the sleeve 170 and the locking collar 172. In use, the tubing connector 146 couples the first and second coiled tubing sections 112a, 112b, the tubing connector 146 permitting - via the engagement between the ball-shaped portion 164 and the seats 166,171 - the coiled tubing sections 112a,112b to pivot or flex about the tubing connector 146.

Referring now in particular to Figure 5 of the accompanying drawings, which shows the tubing connector 146 in a locked configuration, in order to lock the tubing connector 146 the locking collar 172 is axially displaced (to the left as shown in Figures 4 and 5) to engage the sleeve 170. As shown, a split collar 176 is disposed between the locking collar 172 and the end ring 152. In this configuration, pivoting or flexing of the tubing connector 146 is prevented.

It will be recognised that the systems and methods described above are merely exemplary and that various modifications may be made without departing from the scope of the claimed invention as defined by the appended claims.

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CLAIMS

1. A system for conveying coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons, the system comprising:

5 an injector configured to convey the coiled tubing into and/or from the fluid conduit;

an access module comprising a body and a window to permit access to the coiled tubing, wherein the access module is disposed between the injector and the fluid conduit; and

10 a tubing connector configured to couple a first coiled tubing section of the coiled tubing to a second coiled tubing section of the coiled tubing,

wherein the tubing connector comprises:

a sleeve; and

a locking collar,

15 wherein the tubing connector is reconfigurable via axial displacement of the locking collar between a first, unlocked, configuration in which an axial gap is provided between the sleeve and the locking collar and which permits the first and second coiled tubing sections to pivot relative to each other and a second, locked, configuration in which the locking collar engages the sleeve and in which relative pivoting of the first and second coiled tubing sections is prevented.

2. The system of claim 1, wherein the fluid conduit comprises one or more of: a wellbore; a pipeline; a riser; and an umbilical, the system configured to convey the coiled tubing into the fluid conduit.

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3. The system of claim 1 or 2, wherein the injector comprises:

a drive arrangement; and

an arrangement of gripping members.

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4. The system of claim 1, 2 or 3, wherein the tubing connector takes the form of a knuckle joint assembly.

5. The system of any preceding claim, wherein the tubing connector comprises a joint member.

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6. The system of claim 5, wherein the joint member comprises a ball-shaped end portion.

5 7. The system of claim 6, wherein the ball-shaped end portion permits the first and second coiled tubing sections to pivot or flex about the tubing connector.

8. The system of claim 5, 6 or 7, comprising a split collar.

10 9. The system of claim 8, wherein in the second configuration the split collar is disposed adjacent to the locking collar to prevent pivoting or flexing of the tubing connector, and thus prevent relative pivoting of the first and second coiled tubing sections.

15 10. A method for conveying coiled tubing into and/or from a fluid conduit suitable for transporting hydrocarbons using the system of any preceding claim.

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