SUBSEA COMPLETION APPARATUS

Field of the Invention

This invention relates to apparatus for drilling and completion of subsea wells for controlling fluid flow from and within such wells and for subsea fluid processing operations.

Background of the Invention

Conventionally, subsea completions are carried out from a drilling vessel or platform primarily designed for well drilling and installation of the subsea wellhead. These vessels are highly specialised and expensive to operate. They have usually been used to perform the entire installation sequence of the wellhead and completion.

The key components of known wellhead and completion designs must be installed or removed in a set sequence, as the installation/removal of one component is dependent on the prior installation/removal of another. For example, in a completion including a conventional Christmas tree, removal of the tubing hanger and production tubing requires the prior removal of the tree. With horizontal tree designs, the tubing hanger and its tubing has to be pulled prior to tree removal. This is a time consuming procedure that may be necessary for maintenance or repair of the valves and other equipment incorporated in the subsea completion, including the tree.

A subsea completion will almost always contain service lines extending downhole for controlling, monitoring and powering downhole equipment. The type of equipment and hence the required service lines may vary considerably between completion projects. Hitherto it has been usual for these service lines to exit the well through a tree attached to the wellhead. This has often necessitated detailed wellhead design changes from one well development to another. During installation of a tubing hanger and an associated tubing string into the wellhead, or during its removal, it may also be desirable to maintain

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communication with the downhole equipment via the service lines. Completion designs currently in use allow such communication for up to five service lines. It is desirable to increase the number of service lines available for such communication whilst the tubing string is being run/retrieved.

GB 2320937 concerns a horizontal subsea christmas tree in which a separate tree block is located on and surrounds a substantially cylindrical wellhead housing. Hydraulic control lines run through a corrosion cap at the housing upper end and an internal cap provided in the housing. These lines pass through a tubing hanger to a downhole safety valve.

There are several known solutions for the production of oil and gas from the bottom of the sea. One favoured solution is where several single wells are drilled and completed and flowlines are extended from each well along the seabed to a centrally located manifold unit placed on the seabed. The subsea manifold thus collects fluids from several wells, equalising the pressure differential between be wells and pumps the combined fluids to a production platform. It has been suggested that a subsea manifold also may have processing equipment, e.g. Troll Pilot. Manifolds are very heavy and complex and are usually installed using special crane barges. In addition, a large number of flowlines and connections are needed.

Process, e.g. separation equipment is commonly placed on fixed or floating production platforms, such that well fluids are brought to the surface to be processed, e.g. the separation of water from the hydrocarbons and gas from oil. Processing can also include equipment for sand removal, chemical additives removal, water or gas injection, "artificial lift" technology or chemical injection.

Fixed or floating platforms are of necessity very large in order to carry necessary processing, storage and utility features. With increasing depths the size of the platform must be increased correspondingly. For fixed platforms there is a limit to the water depth where they can be used. Floating platforms can be used at any depth, but they need to be held in position by anchor chains, tension legs or dynamic positioning against the heavy

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wind and wave forces experienced. All this equipment increases the platform weight and complexity, which in turns means, increased costs.

Another element which makes it more expensive to explore and develop subsea oil and gas fields at greater depths are the costs connected with the running and retrieval of equipment between the surface and the seabed. It takes longer time to make a "trip " and the lifting equipment must be larger.

There is therefore a need to develop more efficient systems for the exploitation of hydrocarbons from great depths, e.g. down to 4000 meters. Along with this there is also a need to be able to place more processing equipment on the seabed, so that the size of the platform can be reduced.

From GB 2285274 is known a subsea system comprising a template with a square centre section with a number of outwardly projected arms, which can he folded up during installation, so that the template can be installed through a rig's moonpool. The arms include means for supporting a well while a manifold placed on the centre section can process well fluids from all the wells. One problem with this arrangement is that there will be dimensional mismatches for example because a well is slightly askew. The pipes between well and manifold must therefore be flexible and have connectors at both ends. Such an arrangement then means that a number of subsea operations must be performed in order to complete the system.

Summary of the Invention

We have developed wellhead and completion components providing greater flexibility as regards installation and retrieval and which reduce the interdependence between key components during such procedures. We have also developed apparatus for linking downhole service lines to an external control / monitoring / supply point which permits greater standardisation of the wellhead design and allows operation, whilst the tubing hanger is being installed or removed, of downhole equipment attached to the service lines. The apparatus also allows one or more wells to be connected to subsea flow control and

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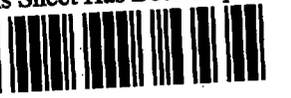


processing equipment. This may be provided in modular form. permitting greater standardisation between individual components. A given module may also he readily supplemented or replaced by another when appropriate, as control and processing needs change throughout the lifecycle of the associated well.

In a first aspect, the present invention provides a subsea completion comprising a wellhead from which extends a production fluid conduit; the completion comprising a flow control package removably located externally of the wellhead and containing at least one production flow control valve; characterised in that a continuation of the production fluid conduit extending away from the wellhead is releasably coupled to the flow control package by a subsea matable connector whereby the flow control package and components within the wellhead respectively may be installed and retrieved independently of each other .

The flow control package performs at least some of the functions of the Christmas tree in prior art completions, in that it provides control of fluid flows from and /or to the well, but it may be assembled from individual components, eliminating the need for large and complex forgings. At the same time this permits great flexibility in design to suit the requirements of a particular completion project. The relocation of flow control components from a christmas tree forming part of the main wellhead structure to a flow control package located remote to the wellhead leads to a design which nevertheless is suitable for use in a wide variety of operating environments. The flow control package may be installed or retrieved independently of completion components located within the wellhead. Moreover use of a drilling vessel or platform is unnecessary for such installation and retrieval. For example a smaller and less costly to operate diving support vessel can be used, freeing up the drilling vessel for use elsewhere. Casing hangers and completion tubing and a tubing hanger may be consecutively installed in the wellhead without having to remove the BOP stack and install other components. The flow control package may be located at the wellhead, or nearby. Horizontal and conventional christmas trees have to be positioned on the centre line of the wellhead; the flow control

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package does not. One conventional or horizontal tree serves one wellhead; a single flow control package according to the invention may serve one or more wellheads.

Preferably a further conduit extends from the wellhead, having one end in communication with a tubing annulus and its other end releasably coupled to the flow control package by a subsea matable connector external to the wellhead. A yet further conduit may extend from the wellhead, having one end communicating with a region above or below a tubing hanger received within the wellhead, and its other end releasably coupled to the flow control package by a subsea matable connector external to the wellhead. These various conduits thus permit fluid circulation within the completion via the flow control package, equivalent to the circulation possible using a conventional or horizontal christmas tree. The various connectors may be separate, but preferably are combined to form a unitary hub connector.

When the or each connector is disconnected, a part of the or each connector associated with the wellhead is preferably sealed by a valve, plug or cap.

The tubing hanger may contain an annulus flow passage connected to the tubing annulus conduit and containing a flow control valve of equivalent function to an annulus master valve. Alternatively this valve may be positioned in the tubing annulus conduit or in the wellhead. The tubing hanger may also contain a flow control valve positioned in a production fluid flow passage connected to a tubing string; this valve having a function equivalent to the production master valve of a conventional or horizontal completion.

Alternatively this valve may be positioned in the production fluid conduit or in the wellhead. The wellhead may be of unitary construction or may comprise a flow spool connected to a separate lower wellhead part and containing the tubing hanger.

The flow control package may contain valves of equivalent function to the production wing valve, annulus wing valve, annulus valve, crossover valve and other flow control valves normally found in a conventional or horizontal subsea christmas tree and even

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manifolds. These valves may be separate subassemblies or grouped to form a service valve block and a production flow valve block. Where required, the flow control package may also contain a production choke having an inlet connected to the production master valve or wing valve equivalent, and an outlet coupled to an isolation valve, a manifold connector or flow line connector.

The flow control package may conveniently be used to house any other equipment needed to control or monitor the production phase of a given well development, such as flow meters, detectors, sensors and chemical injection ports.

In accordance with a second independent aspect of the invention, there is provided a controls cap secured at the top of a wellhead, characterised in that a plurality of service lines are led downhole through the controls cap from outside the wellhead, a jumper connecting the service lines in the controls cap to an external controls interface. Where the completion includes an internal tree cap and a tubing hanger below the controls cap, the necessary electrical and hydraulic connections may be led from the controls cap, through the tree cap and tubing hanger and into the tubing annulus. Alternatively, the completion may comprise a tubing hanger located below the controls cap and having a through bore; a first plug being positionable in the through bore for diversion of production fluid into a tubing hanger side outlet; a second plug positionable in the through bore above the first plug; the service line(s) being led from the controls cap, through the tubing hanger and into the tubing annulus. A test port preferably communicates with the space defined between the first and second plugs. Primary and secondary annulus seals may be positioned between the tubing hanger and the wellhead, with a test port communicating with the void defined between the primary and secondary seals.

During installation and workover/maintenance, when the controls cap is removed, communication with the service lines may be provided via a running tool engaged with the tree cap or tubing hanger. The external controls interface, may be situated for example nearby on the seabed, on an adjacent flow manifold, or attached to the wellhead. The physical link between the downhole service lines and the external controls interface

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can thus be entirely independent of the christmas tree or flow control package. This differs from prior conventional or horizontal tree designs, where part or all of the service lines link has to be incorporated into the body of the tree. Where desired, the controls interface may be provided by a subsea control module located in the flow control package of a subsea completion according to the first aspect of the invention. This subsea control module may also control elements of the flow control package, such as valves and/or chokes. The controls cap of the invention enables a greater number of service lines to be connected to downhole equipment than has been possible hitherto, which connection can be maintained during installation or removal of the completion.

A further independent aspect of the invention provides a subsea drilling and production system, comprising a framework, a well housing and a flow control module removably located externally of the well housing and containing at least one production flow control valve, characterised in that the flow control module is located on the framework and the well housing is rigidly connected to the framework. The connection can therefore be established during the construction of the framework. In that way, the later subsea installation of a pipe spool and appropriate fluid flow connectors is unnecessary. The required fluid flow channels, lines, pipes and the like may be integrated into the framework to form structural components thereof; so simplifying the framework construction, and saving weight and materials. Where two or more well housings are provided, the framework may advantageously be used as a template for multiple well drilling operations. Fluid flow connections can he established to all the wellheads and with fluid flow control and processing equipment, via the framework or template, with a very much reduced need to make up subsea flow connections. The template also performs the usual function of establishing the correct spacing between the wellheads.

A yet further independent aspect of the invention provides a subsea drilling and production system comprising a many-sided framework comprising structural members arranged to support well fluid flow control and/or processing modules, characterised in that well housings are located in the corners of the framework and rigidly connected to the structural members.

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In GB 2202561 is shown a standard template frame. Several templates can be joined together into a larger unit. In the template are locations for various modules and interconnecting pipework. Since the modules must he installed at predetermined locations in the template, an exchange of modules will at times make it necessary to remove other modules, to gain access.

According to a still further independent aspect of the invention, a subsea drilling and production system comprising a framework, a well housing and a plurality of modules for the control and/or processing of well fluids, is characterised in that the frame includes a plurality of connecting locations for the modules and all modules and connecting locations have a common connecting interface such that modules can be exchanged with each other and secured at any connecting location on the framework. This system achieves a greater degree of standardisation than in prior systems. Preferably modules can be connected together in a stacked configuration, in arbitrary order, as well as capable of being located anywhere on the framework, or being easily exchanged with other modules. For a given well completion, using the present invention, fewer and smaller modules may be required, so that modules can be handled by smaller vessels.

Further preferred features are described below with reference to the drawings which show illustrative embodiments of the invention.

Brief Description of the Drawings

Fig. 1 is a schematic sectional view of a wellhead forming a first embodiment of the present invention, without the flow control package installed;

Figs. 2a and 2b are similar views of respective alternative embodiments, Fig. 2a being a partial view of the wellhead on a slightly larger scale;

Fig. 3 is a diagrammatic plan view of the flow control package installed on the wellhead of Fig. 1,

Fig. 4 is a side view of the flow control package and wellhead of Fig. 3, in partial section;

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Figs. 5 - 10 diagrammatically illustrate various stages of a well drilling and completion operation using the apparatus of the invention;

Fig. 11 shows apparatus of the invention undergoing a workover via a BOP;

Figs. 12a and 12b illustrate two alternative configurations of the apparatus of the invention, undergoing tubing entry workover via a dedicated intervention package and riser;

Fig. 13 shows a modification of the apparatus of Fig. 1, providing disaster recovery in the event of bore damage to the wellhead;

Fig. 14 shows an alternative connector hub which may be used in the present invention;

Fig. 15 is a top view illustrating a flow control package of the invention for use with multiple wells;

Figs. 16-21 show various alternative flow package configurations and arrangements for their connection to the wellhead and a manifold;

Fig. 22 is a schematic side view (not to scale) of a framework or template embodying the invention,

Fig. 23 shows an adaptation of the figure 23 embodiment for use with a conventional tree and also contains a key to symbols used in figs. 22, 23, 24, 29, 30, 31, 32, 33 and 34;

Fig. 24 schematically shows flow connections possible using the arrangement of fig. 22;

Figs. 25 and 26 are side and plan views respectively of a further embodiment;

Figs. 27a-d illustrate various possible template configurations;

Fig. 28 is a schematic plan view of a preferred template;

Fig. 29 is a view similar to fig. 25 showing further details;

Fig. 30 is a side view corresponding to fig. 26;

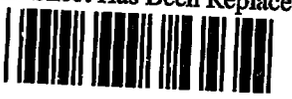
Figs. 31-33 are schematic side views showing combinations of modules;

Fig. 34 shows an alternative template for use with a permanent guide base;

Fig. 35 shows various different modules used to form embodiments of the invention, and combinations of such modules with various templates;

Fig. 36 illustrates comparative installation and workover times for a completion including a flow package and controls cap according to the present invention, and various known completion types.

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Description of the Preferred Embodiments

Referring to Fig. 1 there is shown a wellhead 10 supported in an outer housing and a permanent guide base 12, both attached to a conductor casing 14. Casing strings 16 are suspended within the wellhead 10 by hangers 18. A tubing string 20 is suspended from a tubing hanger 22 landed within the wellhead 10. The tubing hanger 22 has a vertical through bore 24 permitting full bore access to the tubing string during workovers. In production mode, production fluid is diverted to a tubing hanger side outlet 26, by a plug 28 in the through bore 24.

The side outlet communicates with a production fluid conduit 30 having one end extending through a side wall 32 of the wellhead 10 and its other end (not shown in Fig. 1) terminating at one part of a subsea matable connector, contained within a connector hub 34. Chain dotted line 36 indicates the flow path provided by the conduit 30 to the hub 34.

A further conduit 38 extends through the wellhead side wall 32 to a subsea matable connector part in the hub 34, as indicated by chain dotted line 40. The end of conduit 38 within the wellhead communicates with the production annulus via a flow passage 42 formed in the tubing hanger 22. The junction between the conduit 38 and the flow passage 42 is sealed by a pair of sealing elements 44, 46 carried by the tubing hanger 22. The production fluid conduit 30 and the tubing hanger side outlet are similarly sealed together by the sealing element 46 and a further sealing element 48.

A yet further conduit 50 extends through the wellhead side wall 32 from a location above the tubing hanger 22, to a subsea matable connector part in the hub 34, as indicated by the chain dotted line 52. The end of the conduit 50 within the wellhead 10 communicates with a flow passage 54 extending above an internal tree cap 56. For completion installation and workovers, if desired, fluid can be circulated through the flow passage 54 and conduit 50, either with or without the tree cap 56 in place. The tree cap 56 is sealed to the wellhead by a sealing element 58.

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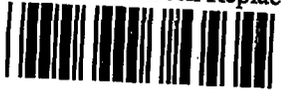
Electrical, optical and/or hydraulic service lines 60 for communication with downhole equipment are routed through the tubing hanger 22 and tree cap 56. Communication from there to a workover/production controls system is achieved by installing suitable linking controls connections. As shown in Fig. 1, for production, a controls cap 62 is installed above the tree cap 56, and includes a stab connector 64 which mates with the various lines in the tree cap 56. During workover and installation, a similar stab connector is provided on the various running tools. From the controls cap a suitable jumper extends to a controls/communication interface provided at or near the subsea well, for example a subsea control module in the flow control package.

To provide isolation of the well required as part of the completion operation, the tubing hanger through bore 24 is closable by a remotely operable valve 66. When open, valve 66 provides unobstructed access to the tubing 20. Likewise, the annulus flow passage 42 in the tubing hanger is closable by a valve 68. The valves 66, 68 may be electrically or hydraulically actuated valves of known kind, e.g. ball valves, and respectively fulfil functions equivalent to the production master valve and annulus master valve in prior completion designs.

When the hub 34 is disconnected from the flow control package as shown in Fig. 1, the flow connection parts in it are sealed by a pressure cap 70.

Fig. 2a shows an alternative embodiment in which the tree cap 56 is replaced by a plug 57 received in the tubing hanger through bore 24, above the plug 28. A test port 29 may be provided, having one end communicating with the space between the plugs 28 and 57, e.g. for monitoring possible leakage past plug 28. The other end of test port 29 (not shown) may terminate at the upper surface of the controls cap 62 or at some other convenient location for connection to an umbilical or monitoring equipment. Optionally, a tubing hanger secondary lockdown mechanism 23 may be provided above the tubing hanger 22. Conduit 50 may be connected to a port or like flow passages schematically illustrated at 51, to provide fluid communication with the wellhead interior above the tubing hanger 22.

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wellhead after removal of the pressure cap 70. However, many other connector configurations will also be suitable to provide fluid communication between the wellhead and flow control package. Hub connector 84 contains complementary connector parts providing fluid tight couplings with the connector parts of the wellhead hub 34. Production conduit 30 is thereby connected via pipe 85 to a production flow block 86 containing flow control valves. Some or all of these valves may provide well fluid isolation and pressure containment, serving as a barrier between the producing formation and the environment. These valves may have functions equivalent to the production master and/or wing valves in a christmas tree. The hub connectors 34 and 84 likewise interconnect the annulus conduit 38 and the BOP circulation conduit 50 with respective conduits 88 and 90 leading to a service block 92 containing valves for example functionally equivalent to an annulus wing valve, annulus access valve and crossover valve, and/or others having any additional service control functions required for a given completion project. The service valve block shown in Fig. 3 contains two such valves. A crossover conduit 94 extends between the service valve block 92 and the production flow block 86. The various valves in the flow control package include associated actuators 96, 98, 100 which are hydraulically powered and/or may have operating shafts 102, 104, 106 coupled to ROV receptacles 108, 110, 112 in ROV panel 114. Production flow is directed from block 86 through a production choke 116 and from there to a flow line or manifold connector 118, coupled to a flowline 119 as shown. The production choke is optional, depending on project requirements.

The flow control package 82 may also include the controls/communication interface in the form of a subsea control module 120 containing equipment for monitoring and controlling the operation of downhole equipment such as a DHSV and pressure and temperature sensors, as well as for controlling the valves 66, 68 or 78, 80 associated with the tubing hanger 22, wellhead 10 or flow spool 72. Module 120 may also control the valves in the flow control package 82 itself, as well as the production choke 116 and any other equipment which may be included in the flow control package for a given completion project. As shown in Fig. 4, a jumper 122 provides the necessary electrical and hydraulic connections between the control module 120 and the controls cap 62.

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Figs. 5 to 10 illustrate a typical installation sequence for a completion including the wellhead 10 and flow control package 82. As shown in Fig. 5, first the conductor casing and PGB are installed. Next, the wellhead is installed with the pressure cap 70 in place on the hub 34. A bore protector 124 is preinstalled in the wellhead 10. As shown in Fig. 6, next a BOP 125 is installed on the wellhead 10 and the casing strings 16 are drilled, run and cemented. The bore protector 124 is then removed and the tubing string 20 and its hanger 22 are run and landed in the wellhead 10 using a running tool 126 (Fig. 7). A service line connection 61 is provided in the running tool 126, which mates with the service lines 60 extending downhole into the tubing annulus, for example strapped to the outside of the tubing. The plug 28 is then set in the tubing hanger 22 and the tree cap installed in the wellhead 10 in the position shown in Fig. 1. (Or the plugs 28, 57 are set in the tubing hanger: Fig. 2a.). The BOP is then removed. The pressure cap 70 can now be removed, for example using ROV 127, Fig 8. The flow control package 82 is then installed on the wellhead 10 with the hub connectors 34, 84 in mating engagement (see Fig. 10). As shown in Fig. 8, the flow control package may be wire deployed, for example from a DSV, using ROV hooks 128. Alternatively, as shown in Fig. 9, the flow control package 82 may be drill pipe deployed. Control during installation of the flow control package 82 can be achieved by umbilical 129, ROV 127 or other means. Finally, the controls cap 62 and jumper 1 12 are installed, for example using an ROV, to arrive at the configuration depicted in Fig. 4. The present invention however allows considerable flexibility in the installation sequence. For example, the flow control package can be preconnected to the wellhead; the wellhead and flow package assembly then being landed in the outer housing and PGB 12. Alternatively, the flow package may be separately installed either before or after tubing hanger installation.

Fig. 11 schematically illustrates a workover operation requiring full bore access, conducted using BOP 125. The wellhead 10 projects sufficiently far above the flow control package 82 to allow the BOP 125 to engage the top of the wellhead 10 with the flow control package installed. However, if desired, workover may be carried out without the flow control package in place. Prior to installation of the BOP, the controls cap 62 is

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removed using an ROV. The tree cap 56 is removed using a landing string run within the BOP to initiate the well entry, and may be installed likewise. The internal configuration of the wellhead with the BOP in place is then similar to that shown in Fig. 7 (tubing hanger installation)

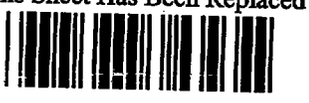
Figs. 12a and 12b illustrate a tubing entry workover ("lightweight intervention"). Fig. 12a shows a dedicated workover apparatus 130 and riser 132 engaging the top of the wellhead 10 with the flow control package 82 still in place. To permit such engagement, the controls cap 62 is again removed. Tubing entry access is gained by removing a plug 134 in the tree cap 56 (Fig. 1), removing plug 28 and opening the valve 66. The resulting configuration is as shown in Fig. 12b, except that in that figure the flow control package 82 is shown removed and the pressure cap 70 installed on the hub 34.

In the event that the bore of the wellhead is damaged and incapable of receiving the tubing hanger, Fig. 13 illustrates use of a flow spool 136, somewhat similar to flow spool 72 in Fig. 2, as an adapter to recover the wellhead. The hub 34 associated with the wellhead 10 is permanently capped and a new hub 138 of the flow spool 136 is used to connect to the flow control package 82 (not fully shown). The flow control package includes a modified flow loop 140 for connection to the manifold/flow line. If the flange connectors of the conduits 30, 38, 50 leak, an isolation sleeve 142 can be installed and sealed in the wellhead, between the casing hangers 18 and the flow spool 136.

Fig. 14 shows an alternative hub 144 for the wellhead 10, including a ROV/diver replaceable section, used to eliminate the risk of losing the well due to hub damage.

Fig. 15 shows a flow control package 149 capable of connection to multiple wells. To that end, it includes a pair of hub connectors 146, 148 for connection to respective wellheads 150 and 152. Again a flowline/manifold connector 118 is provided, through which the production flow is led to a flowline 119 or a manifold.

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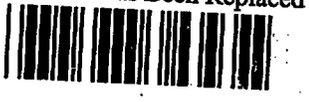
Although the previously illustrated flow control packages are shown surrounding the wellhead 10 when installed, as shown in Fig. 16 the flow control package 82 could equally well be modified for installation to one side of the wellhead, connected to it using a vertical stab, horizontal stab or a differently orientated connector schematically illustrated as 160. A production flow outlet from the flow control package 82 can be connected via a jumper 166 and connector 168 to a nearby manifold 162, supported on a foundation 164. The horizontal distance between the connectors 160 and 168 may be for example, 10-30 m.

Fig. 17 shows a flow control package 83 positioned to one side of the wellhead 10 and having a hub connector portion 84 that interfaces directly with the wellhead hub connector 34. Flow control package 83 contains a valve block 170, valve actuators 172, a production flow choke 116, and additional production fluid processing equipment 174. Such equipment may comprise for example gas/water separator stages, gas to liquid conversion plant, pumps and the like, that would ordinarily be positioned further down the production flow stream rather than directly adjacent to the wellhead. Production fluid is led from the flow package 83 via an isolation valve 176, connector 180 and flowline 178.

Fig. 18 shows in plan, and Fig. 19 in elevation, a template installation comprising multiple wells 182 (only two shown). A template 184 supported on a foundation 186 contains and locates the wells 182 and also supports a manifold 188. Multiple flow control packages 190, one associated with each well 182, are supported between hub connectors 192 on each well 182 and further hub connectors 194 on the manifold 188.

Figs. 20 and 21 generally correspond to Figs. 18 and 19 respectively, but show modified flow connections between the wells, flow control packages and manifold. Each well 182 is directly connected to the manifold 188 by a respective hub connector 196. The flow packages 190 are mounted solely on the manifold 188. Respective unitary hub connectors 198 conduct fluid flows in both directions between each flow control package 190 and the manifold. Other flow configurations can readily be envisaged: for example a flow package may serve several wells.

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In another embodiment, the flow control package can be located on a framework, for example a template, and laterally displaced from the well axis and contained in a separate module, hereinafter referred to as a barrier module, as it will generally serve to shut in the well when required. However the barrier module itself may incorporate additional apparatus / functions such as a choke and/or subsea control module. The barrier module may be supplemented or replaced by other modules, as further described below.

In fig. 22 there is shown a subsea template that is made up of a framework 200. In its simplest form the framework can consist of a single horizontal beam or girder 202. Preferably the framework will be made up of two parallel beams with additional crossbeams as needed, similar to the template shown in fig. 25. The beams can be I-beams, U-beams, tubes or any other cross-sectional shape and are connected together e.g. by welding to give the framework the necessary strength and stiffness.

At the end of the framework is placed a cylindrical housing 204 (which later will be referred to as a wellhead housing). The cylinder defines a central passage 206. Internally the housing is equipped with means (profiles, not shown) for hanging casing from the wellhead, as is well known in the art. The top of the wellhead has a profile for a standard wellhead connector. In this way, equipment to he used during drilling and completion can he connected to the well, for example risers, BOP 's, and rotating heads. For the guiding of equipment into the well, the housing 204 can be equipped with a removable funnel or suchlike.

When casing is cemented into the well, this will act as a support for the framework. However the framework can also be supported by a separated foundation structure, e.g. a pile, mudmat or skirt, to form a template.

Within framework are located header pipes 208a, 208b for oil or gas or other fluids. The headers can he a structurally integrated part of the framework and act as beams. This will increase the framework's strength and also save weight. The headers are provided with

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connectors at at least one end, for connecting to external flowlines, for example to another well or to a riser.

In the framework is also fixed an upwardly protruding pipe stub 212 terminating in a facing connector hub. This includes a number of fluid flow conduits 214. The upper end of the hub terminates in a connector hub interface 216. The barrier modules 218 have a corresponding connector. At the hub's lower end, the conduits 214 are in communication with pipes in the framework. Some of the conduits are connected to the headers 208a, 208b. Other conduits or lines can also be led into the stub, for example electrical lines and lines for hydraulic or chemical fluids that can communicate with other pipes or lines in the framework 202.

The framework template may include orienting means to orient modules into correct angular position before they are connected.

The connector interfaces have a standardised layout, i.e. all the various conduits, lines etc, have their own predetermined location within the connector, although not all connectors will necessarily include all lines.

If a module slot or connection location defined by the hub and connector interface is unused, a pressure tight cap 220 (fig. 31), or a "dummy connector" can be fixed to the stub 212, to prevent hydrocarbons leaking into the environment and to avoid seawater coming into the pipe system. Also, in the conduits of the stub 212 there may be placedclosure devices, typically check valves, to prevent the same.

The geometry of the connector interface is fixed in relation to the pipes or lines in the framework. In the case of special-type modules with another type of connector, an adapter can be used. In that case, the check valves may he placed in the adapter.

The wellhead housing 204 has a side outlet 222. This outlet provides fluid communication between the wellhead and the stub 212. The outlet 222 may include a

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number of conduits for well fluids and possibly lines for fluids to be injected into the well or electrical lines for power to the well. In fig. 22 is shown, as an example, one conduit 224 for well fluids from the tubing and one conduit 226 that is connected to the annulus.

This fluid connection between the framework and the well is designed as a part of the framework's overall structure and is thus rigid. This arrangement avoids the problems of known "bridge" connectors where there may he tolerance problems because of dimensional differences between well and manifold.

In a conventional completion as shown in GB 2285274 a Christmas tree must be attached on top of the well head to act as a barrier to control well pressure. The manifold with chokes, pumps and so on is located away from the well, for example on the centre section shown in this patent.

With the presently described embodiments, the need for the known kinds of christmas trees is eliminated. Instead the flow control functionality of the tree is located laterally from the well axis and placed on the framework. One optional aspect of the present invention is thus to integrate the functions of the tree and the manifold into one single structure. This may, among other things, result in a simpler and faster access to the well. This arrangement avoids the need for removal of the christmas tree during some workover operations. Instead, the BOP can he connected directly to the wellhead.

The production tubing 228 is hung from the wellhead housing 204 by means of a tubing hanger 230 having a side outlet 232 that communicates with the conduit 224. A plug 234 closes off the vertical passage in the tubing hanger 230 above the side outlet 232. An internal tree cap or stopper 236 or any other type of closure means (e.g. valves) is placed in the housing 204 in its upper part to close off the housing's central passage to the environment. An outer cap (debris cap) 238 closes off the top of the wellhead. Well fluid will thus flow from the production tubing 228 into the conduit 224 and into the module 218. The module 218 in this embodiment is a combined barrier and manifold module.

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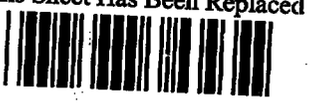


If it is found necessary to do work in the well, the valves in the barrier module will be closed to shut down the well. Next, a BOP 240 is connected to the well head (fig. 33) after removing the debris cap 238. A tool can now be run through the BOP to remove the internal cap 236 to give access to the well under controlled conditions. Afterwards, the cap 236 is again set and the BOP removed. Production can then be resumed.

Fig 23 schematically shows flow connections between the wellhead housing 204, hub connector interface 216 and a typical barrier module 218. Production fluid conduit 224 is connected via the interface 216 to a production master valve 255 in the barrier module 218. Valve 255 is connected via a choke 253 to three valves 255a, 255b, 255c, controlling/distributing production flow to each or any of three headers 208a, 208b, 208c provided in the framework. The flow to these headers passes back down through the hub connector interface 216.

Annulus fluid conduit 226 is connected via the interface 216 to an annulus master valve 355 and a crossover valve 259 in the barrier module 218. A two inch workover access conduit 227 runs from the connector interface 216 to a point in the wellhead housing 204 above the internal cap 236. A service line 229 passes up through the connector interface 216 and is connected to the workover access conduit 227 via an intervention valve 231 and annulus wing/workover valve 233. An interconnecting conduit 235 in the barrier module 218 runs from a point in the service line between valves 231, 233, to a point in the annulus fluid conduit 226, between the valves 355, 259. A small bore line, e.g. for chemical injection or annulus monitoring, is connected to the interconnecting conduit 235, via an external coupler 239 and a valve 241 in the barrier module 218. The axis of the coupler 239 is aligned with that of the connector hub interface 216, both preferably being substantially vertical, so that the module can be readily landed in or retrieved from its connecting location, with automatic makeup/disconnection of the various flow and service connections. If desired, the small bore coupler can also be integrated into the connector hub interface 216, as can any connections for electrical or hydraulic lines, and electrical/fibre optic signal transmission lines. Alternatively all these supplementary

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connections (e.g. 243) can be arranged externally around the connector hub interface 216, in the manner of coupler 239.

As shown in broken lines, the production conduit 224, its corresponding connections to the headers 208a, 208b, 208c, the workover access conduit 227, or any other flow connection as desired, may be extended upwardly through the barrier module 218 to an upper connection interface 216a, preferably substantially identical to the interface 216. Thus, if required, further modules may be connected to the module 218 in stacked configuration, and workover access may also be via the upper connection interface instead of line 229..

The barrier module 218 may also contain an independently retrievable subsea controls module 254, connectable for example to a controls cap such as 62, Fig 1, via jumper. Alternatively, service line connections may be via the wellhead housing side outlet 222.

In fig. 24 is shown an embodiment that combines the present invention with a "conventional" completion. At times it may be desirable to use a conventional christmas tree. As shown a conventional christmas tree 242 can be fixed to the well head. Also as shown the well is in this case completed with a dual tubing hanger 244. Produced well fluid will flow into the tree and from there into the module 218 via a bypass pipe 246.

In an alternative to the above described embodiment, shown in figs 25 and 26, the framework 200 can be extended to the other side of the wellhead housing 204 and provided with a second pipe stub (not shown) with hub 216b. The two hubs are interconnected via conduits 271, 272 to provide fluid communication between the hubs. In addition, there are conduits 222, 224 from the well to the barrier module and headers 208a, 208b, as described above. It should he noted that one of the headers can be connected to an umbilical that will provide electrical and hydraulic power to the modules.

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In one module position, at the hub 216, is located a barrier module 218. In the other module position, defined by the hub 216b, is located a process module 318. The module 318 can for example contain a separator, a booster or an injection pump.

Advantageously, several templates can he positioned parallel to each other a daisychain arrangement, with the corresponding headers 208a, 208b interconnected by suitable flowlines and connectors.

In figs. 23 -26 are shown embodiments for a single well. However, systems embodying the present invention can be developed for any number of wells. For example, in a two-well implementation the frame beams can be extended to form a template with room for two modules and with the wellhead housings located at each end. Further, the system can be used with three, four, five or more wells. The wells may be located in the corners of the template structure and the modules located just inboard of each well. As earlier explained, the connections between well and module may be rigid and are preferably part of the frame structure.

In figs. 27a-d are shown some examples of alternative template structures with more than one well. The layout of the templates is preferably a regular geometric shape, e.g. triangle (fig. 27a), pentagon (fig. 27b), hexagon (fig. 27c) or octagon (fig. 27d), with integral wellhead housings located at the framework corners. However, the number of wells accommodated is limited only by the size of the template and what can conveniently he transported and lowered to the seabed.

As earlier stated and shown in the drawings, the wellhead housings 204 are rigidly interconnected by beams 202 that make up the outer frame structure of the template. The hubs 216 are located just inboard of each wellhead. Headers can be located anywhere, but are preferably located such that they pass underneath all hubs 216.

In figs. 28 to 30 are shown a preferred embodiment of the invention. In this case there are four wellheads or well housings 204a, 204b, 204c, 204d located in the corners of a

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rectangularly shaped template 300. Beams and girders connect the four well housings. Every well housing has a side outlet 222 orientated inwards towards a stub 212. As can be seen from fig. 29, the side outlets can be part of, or contained in, diagonal beams.

Horizontal beams 202a, 202b, 202c, 202d are arranged in a rectangular pattern. They are fixed to the well housings 204a, 204b, 204c, 204d. There also may be upper horizontal beams 248a, 248b, 248c, 248d if necessary (figs 29 and 30). In addition there may be fixed any number of tie bars, struts, fillets etc. that may be necessary to obtain the desired stiffness and strength.

Headers 208a, 208b, 208c are fixed to the template frame. As shown they are parallel in one direction and these headers may be continuous across the length of the template. Other headers 208d, 208e, 208f (figs 29 and 30) are arranged parallel to each other and perpendicular to the first set. Each header terminates in a hub so that they can be connected to flowlines 250. Flowlines 250 can extend to another template or to a riser base. Two header hubs can for example be connected with a pig loop. As shown, this embodiment may have up to twelve header hubs. Each header may communicate with any or all of the module hub interfaces 16, depending upon the requirements of a particular installation.

On the template 300 there are in addition provided pipes or lines for hydraulic fluid and/or electrical power. These terminate at a hub arranged for connection to an umbilical 252. Alternatively, these pipes and lines may be integrated into the header hubs.

The headers can be an integrated part of the template frame structure. In this way they can be made a part of the load-carrying frame of the template structure.

In fig. 29 is shown header 208b that is placed approximately along the centre axis of the template. Headers 208a, 208c are shown to be about midway between the centre and side. The headers 208a, 208c thus run underneath the pipe stubs 212. In stub 212 there are

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arranged several conduits 214, as earlier described. Any of the conduits can be made to communicate with any header. This gives added flexibility to the system.

Even if there are shown two sets of three headers in the drawings, it must be understood that there can be several or a lesser number of headers and correspondingly, a different number of conduits in the stub 212.

The modules can also have an independent fluid communication with each other. As shown in fig. 29, conduits 209a, 209b, 209c that are independent of the headers run between stubs 212. Only two sets of conduits are shown in the drawings, but each module can be linked with its closest neighbour this way.

This arrangement makes possible a large degree of flexibility, both in the equipment accommodated and in the sequence of installation operations. All modules are, in one way or another, in fluid communication with each other, either through the headers or through the conduits 209a, b, c. This design makes it possible to use several different types of modules at different locations. For example, a separator module 218a, fig. 28 can be set in one module slot and well fluid from all or any well can be routed to this module. One module 218b, fig. 28, can be an injection module, placed in connection with one wellhead 204a, fig. 28, used for an injection well.

In fig. 31 there is shown another possible configuration. The well shown on the left hand side is in the process of being drilled. Drilling is carried out using a drill string 260 and drill bit 262. Drilling can be conducted through a drilling riser 264 or possibly as riserless drilling with mud return hose 266. The template 300 has no modules at this stage. The well shown on the right hand side has been completed and an integrated master valve/manifold module 218c is about to be connected to the template 300.

In fig. 32 is shown a further possible configuration. The well shown on the left is completed. A master or "manifold" module 218d is connected into the template. This module comprises barrier valves (master and wing), pipework and a choke. On the well

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shown on the right it is expected that more equipment will he needed. The module 218e shown here has therefore also an upper hub part or interface 268 so that another module, for example a separation module, can be added later. The hub is protected by a cap 220.

Fig. 33 shows the situation with several modules stacked on top of each other. The drawing shows a master module 218e with a separation module 218f on top.

The template can be placed on a foundation if necessary for added support. If necessary, the template can be equipped with a centre hole 256 for a pile 258 (fig. 32). The template can also have means for levelling (not shown).

As shown in fig. 34, such a foundation could be a PGB (Permanent Guide Base) with the same layout and dimensions as a four well template and placed on the seabed. Holes are drilled through funnels (not shown) in the PGB and 30" conductor pipes 312 are cemented in the holes. The template is then lowered to the seabed and secured to the PGB for further drilling. A pile 258a attachable to the template 300 may be driven into the seabed through a centre hole or collar 256a in the PGB 310.

One advantage of the invention is thus that the system makes possible a greater degree of finishing on land or on the platform prior to lowering the frame or template to the seabed. For example, the modules may be pre-attached (cf. fig. 34) and all necessary pipes, lines, hubs and so on are also pre-attached in that they are fabricated as part of the structure. A large degree of flexibility is also provided if it becomes necessary to change or upgrade parts.

Another possibility is to attach conductors to the well housing before lowering. These may be of the telescopic type (to save space) and, after placing the template on the seabed, the conductor pipes can be extended using hydraulic jacks or the like (not shown). This will provide a better foundation before drilling. The template can have a surrounding protection structure to protect against overtrawling, as is well known in the art.

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As earlier described, the mateable connectors of the modules have a standard interface. This makes it possible to make standard building blocks. Preferably, modules can, during the life time of the field, be extended upwards by adding new modules. Modules can also be exchanged, for example a simple type of module can be exchanged for a more complex type. This makes it possible to accommodate changes to the well flow during the field's life time, but will also make possible a simpler and cheaper initial phase development.

There are many functions for processing a well flow and the modules can be built to combine (or stacked to combine) any of these functions. The functions may be:

Master and wing valve
Choke
Pumps
Injection
Drilling mud separation
Oil/gas separation
Oil/water separation
Desanding
Sensors or other instruments

Fig. 35 shows an overview of the different modules 218 that can be used and some possible combinations with each other and with the template.

Many other arrangements are of course possible. As an example, a four well template can have three producing wells with three corresponding barrier modules. The fourth module slot is used for an oil/gas separation module and the gas separated out is reinjected into the fourth well to maintain formation pressure, as is well known.

The common interface for the connectors and the flexible communication with the headers makes it possible to tailor the system to a wide variety of needs. For example, it can be seen from the drawings (e.g. fig. 33) a separation module can receive a multiphase

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flow (from wellheads 204a and/or 204d and/or header 208f, say), and separate out the constituents to separate headers (208d, 208e, say).

The system makes for great flexibility. In the first phase of field development the system can be completed with only the basic barrier modules. This makes for smaller start-up costs. Later, if necessary, these simple modules can he exchanged for other modules. The system can of course be equipped with modules with all necessary functions pre-installed. This makes for an initially move expensive development, but may be cheaper in the long run.

When modules are standardised like this, they can be readily exchanged and therefore also be reused elsewhere.

The present invention has a much larger degree of flexibility than systems known hitherto. The modules can be very simple and intended to be stacked together. Other modules can be of a different type so when needed a simple module is exchanged for a more complex one. A module can have one or several functions.

The basic module is of course the barrier module, which according to regulations, must have valves to control the well, both the tubing and the annulus passages. The modules are preferably retrievable using guidelineless techniques. The valves in the barrier module are typically like the conventional christmas tree valves, usually electrohydraulic gate valves with failsafe close function and ROV override. The basic module will normally also include a choke 253 (see fig. 33) and a subsea control module 254. Advantageously both of these parts can be retrievable independently of the module.

The hub pressure cap 70 or connector interface pressure cap 220 and the plug 57 and controls cap 62 could be diver installed/removed, or installed/removed by a suitable tooling package. Further variations and modifications of the described embodiments are readily possible, within the scope of the claims.

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Finally, Fig. 36 shows estimated times for installation (including well drilling time), christmas tree workover, tubing workover, light intervention (tubing access) and heavy intervention (full bore access) for a completion including the flow package and controls cap of the invention, in 1400m water depth. For comparison, equivalent times for conventional, tubing head and horizontal completions are also given. The present invention offers reduced installation and tubing workover times and markedly reduced tree workover times compared to the other designs. Light and heavy intervention times are comparable with those for a horizontal completion.

The invention permits greater flexibility in wellhead component manufacture, well completion, workover and maintenance operations, improved resource usage and reduced costs. Preferred embodiments of the wellhead and flow control package of the invention are particularly suitable for deep water applications.

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CLAIMS

1. A subsea completion comprising a wellhead (10, 182, 204) from which extends a production fluid conduit (30, 224); the completion comprising a flow control package (82, 190, 218) removably located externally of the wellhead and containing at least one production flow control valve; characterised in that a continuation of the production fluid conduit (30, 224) extending away from the wellhead is releasably coupled to the flow control package (82, 194, 218) by a subsea matable connector (34, 84, 216), whereby the flow control package (82, 190, 218) and components within the wellhead (10, 182, 204) respectively may be installed and retrieved independently of each other .

2. A subsea completion as defined in claim 1 characterised in that a further conduit (38, 226) extends from the wellhead (10, 204), having one end in communication with a tubing annulus and its other end releasably coupled to the flow control package (82, 218) by a subsea matable connector (34, 84, 216) external to the wellhead.

3. A subsea completion as defined in claim 1 or 2 characterised in that a further conduit (50, 254) extends from the wellhead (10, 204), having one end communicating with a region above a tubing hanger received within the wellhead, and its other end releasably coupled to the flow control package (82, 218) by a subsea matable connector (34, 84, 216) external to the wellhead.

4. A subsea completion as defined in claim 2 or 3 characterised in that the connectors (34, 84, 216) are combined to form a unitary hub connector.

5. A subsea completion as defined in any of claims 1-4 characterised in that, when the or each connector (34, 84, 216) is disconnected, a part of the or each connector associated with the wellhead is sealed by a valve, plug or cap (70, 220).

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6. A subsea completion as defined in any of claims 1-5 characterised in that a tubing hanger (22) containing an annulus flow passage (42) is connected to the tubing annulus conduit and contains a flow control valve (66,68).

7. A subsea completion as defined in any of claims 1-5, characterised in that a flow control valve (80) is positioned in the tubing annulus conduit.

8. A subsea completion as defined in any of claims 1-7, characterised in that a tubing hanger (22) containing a flow control valve (66) is positioned in a production fluid flow passage connected to a tubing string (20).

9. A subsea completion as defined in any of claims 1-7, characterised in that a flow control valve (78) is positioned in the production fluid conduit (30).

10. A subsea completion as defined in any of claims 1-9, characterised in that the wellhead (10) comprises a flow spool (72) connected to a separate lower wellhead part (74) and containing a tubing hanger (22).

11. A subsea completion as defined in any of claims 1-10 characterised in that the flow control package (82, 190, 218) contains one or more valves of equivalent function to a production wing valve, annulus wing valve, annulus valve or crossover valve.

12. A subsea completion as defined in claim 11 characterised in that the valves in the flow control package (218) are assembled into a unitary module.

13. A subsea completion as defined in claim 11 characterised in that the valves in the flow control package (82, 190, 218) are formed as separate subassemblies.

14. A subsea completion as defined in claim 11 characterised in that the valves in the flow control package (82, 190, 218) are grouped to form a service valve block (92) and a production flow valve block (86).

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15. A subsea completion as defined in any of claims 1-13 characterised in that the flow control package (82, 190, 218) contains a production choke (116, 253).

16. A subsea completion as defined in claim 15 characterised in that the production choke (253) is releasably connected to the flow control package (218).

17. A subsea completion as defined in any of claims 1-16 characterised in that the flow control package (190, 218) is supported on a well template (184, 200, 300).

18. A subsea completion as defined in claim 17 characterised in that the flow control package (190, 218) is located on the template (200, 300) externally of the wellhead (204) and that the wellhead is rigidly connected to the template.

19. A subsea completion as defined in any of claims 17-18 characterised in that the subsea matable connector (216) is integrated into the template (200, 300).

20. A subsea completion as defined in any of claims 17-19 characterised in that the production fluid conduit (224, 226) is integrated into the template (200, 300).

21. A subsea completion as defined in any of claims 17-20 characterised in that the template (300) includes more than one wellhead (200a, 200b, 200c, 200d).

22. A subsea completion as defined in any of claims 17-21 characterised in that the template (300) supports more than one module (218d, 218e).

23. A subsea completion as defined in any of claims 17-22 characterised in that the template supports a separation module.

24. A subsea completion as defined in any of claims 1-16 characterised in that the flow control package (190) is supported on a manifold (188).

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25. A subsea completion comprising a controls cap (62) secured at the top of a wellhead, characterised in that a plurality of service lines (60) are led downhole through the controls cap from outside the wellhead, a jumper (122) connecting the service lines in the controls cap (60) to an external controls interface.

26. A completion as defined in claim 25 characterised in that an internal tree cap (56) and a tubing hanger (22) are located below the controls cap (62), the service lines (60) being led from the controls cap (62), through the tree cap (56) and tubing hanger (22) and into the tubing annulus.

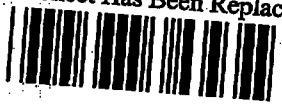
27. A completion as defined in claim 25 characterised in that a tubing hanger (22) having a through bore is located below the controls cap (62); a first plug (28) being positionable in the through bore for diversion of production fluid into a tubing hanger side outlet (26); a second plug (57) positionable in the through bore above the first plug (28); the service lines (60) being led from the controls cap (62), through the tubing hanger (22) and into the tubing annulus.

28. A completion as defined in claim 27 characterised in that a test port (29) communicates with the space defined between the first and second plugs.

29. A completion as defined in any of claims 26-28, characterised in that communication with the service lines (60) is alternatively provided via a running tool engaged with the tree cap (56) (where present) or tubing hanger (22) when the controls cap (162) is removed.

30. A completion as defined in any of claims 26-29 characterised in that primary and secondary annulus seals (44, 45) are positioned between the tubing hanger and the wellhead; a test port (47) communicating with the void defined between the primary and secondary seals.

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31. A completion as defined in any of claims 1-24 and any of claims 25-30, characterised in that the controls interface comprises a subsea controls module (120, 254) located in the flow control package (82, 218).

32. A completion as defined in claim 31, characterised in that the subsea controls module (254) is retrievable independently of the flow control package (218).

33. A subsea drilling and production system, comprising a framework (184, 202, 300), a well housing (182, 204) and a flow control module (190, 218) removably located externally of the well housing and containing at least one production flow control valve, characterised in that the flow control module (190, 218) is located on the framework (184, 202, 300) and that the well housing is rigidly connected to the framework.

34. A subsea drilling and production system comprising a many-sided framework (300) comprising structural members arranged to support well fluid flow control and/or processing modules (218), characterised in that well housings (204a, 204b, 204c, 204d) are located in the corners of the framework and rigidly connected to the structural members.

35. A subsea drilling and production system as defined in claim 34 characterised in that the structural members are arranged in a regular pattern.

36. A subsea drilling and production system as defined claim 35, characterised in that the framework is arranged to form a rectangle or a square.

37. A subsea drilling and production system as defined in claim 35, characterised in that the framework is arranged to form a triangle.

38. A subsea drilling and production system as defined in claim 35, characterised in that the framework has five or more sides.

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39. A subsea drilling and production system comprising a framework (300), a well housing (204) and a plurality of modules (218) for the control and/or processing of well fluids, characterised in that the framework (300) includes a plurality of connecting locations (216) for the modules (218) and all modules and connecting locations have a common connecting interface such that modules (218) can be exchanged with each other and secured at any connecting location on the framework.

40. A system as defined in any of claims 33-39 characterised in that a fluid conducting pipe comprises a structural part of the framework (300).

41. A system as defined in any of claims 33-40, characterised in that a said module (218) is releasably connected to the framework (300).

42. A system as defined in any of claims 33-41, characterised in that the framework comprises a hub for connecting to the module.

43. A system as defined in any of claims 33-42, characterised in that at least some of said modules (218e, 218f) can be operatively interconnected in a stacked configuration.

44. A system as defined in any of claims 33-43 characterised in that the framework (300) is a template.

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