

1 APPARATUS, SYSTEMS AND METHODS FOR OIL AND GAS OPERATIONS

2

3 The present invention relates to apparatus, systems and methods for oil and gas
4 operations, in particular to apparatus, systems and methods for hydrocarbon production,
5 and/or for providing fluid control, and/or performing measurement and/or intervention in oil
6 and gas production or injection systems. The invention has particular application to
7 subsea oil and gas operations, and aspects of the invention relate specifically to
8 apparatus, systems and methods for hydrocarbon production which may include fluid
9 control, measurement and/or intervention in subsea oil and gas production and injection
10 infrastructure.

11

12 Background to the invention

13

14 In the field of subsea engineering for the hydrocarbon production industry, subsea
15 manifolds may be connected to one or more flowlines coming from or going to other flow
16 infrastructure within the flow system.

17

18 One type of subsea manifold is a well gathering manifold. This can accommodate
19 numerous subsea wells at once to receive production flow from one or more subsea wells
20 and often also has additional functionality. An alternative type of subsea manifold is an in-
21 line tee. An in-line tee is a piece of infrastructure which can be incorporated into a pipeline
22 or a flowline to create a branched tie-in point for one or more additional pipelines or
23 flowlines. For example, an in-line tee may provide a tie-in point to a main production
24 flowline for a flowline carrying production fluids from a subsea well. The term "subsea
25 manifold" may also be used more generally to refer to a subsea well gathering system.

26

27 During the development of subsea hydrocarbon fields, it is often the case that further tie-
28 ins to the flow system infrastructure are required, for example as new hydrocarbon
29 discoveries are made and additional wells are drilled. As such, one or more in-line tees
30 may be provided on the flow system to accommodate future tie-in requirements. If an in-
31 line tee tie-in point is not immediately required, the branched tie-in point may be provided
32 with a flow cap to shut it off, such that the pipeline can function as normal until such time
33 that the tie-in point is required. Providing in-line tees on the flow system to meet current
34 and future well tie-in requirements will bring initial expenditure down, because in-line tees
35 are generally less expensive than the typical well-gathering manifolds that can

1 accommodate numerous wells at once. However, a number of benefits which are realised
2 by the use of more traditional subsea infrastructure – such as typical well gathering
3 manifolds – are not translated into a disjointed system utilising individual branched tie in
4 points from in-line tees.

5
6 In addition, in-line tees are fully equipped with all of the equipment, instrumentation and
7 valving needed to facilitate their intended use. Whatever the type of subsea manifold, if the
8 internal equipment, instrumentation and/or valving within the manifold is to fail, the entire
9 manifold must be recovered in order to repair or replace these parts. This typically requires
10 large vessels, is expensive, disruptive and potentially damaging to the surrounding subsea
11 infrastructure, and is disruptive to production operations.

12
13 WO2013/121212 describes an apparatus and system for accessing a flow system such as
14 a subsea tree or a subsea manifold by providing a flow access apparatus which can be
15 used at a variety of access points. The apparatus and methods of WO2013/121212 enable
16 a range of fluid intervention operations, including fluid sampling, fluid diversion, fluid
17 recovery, fluid injection, fluid circulation, fluid measurement and/or fluid metering.

18
19 WO2016/097717 also describes an apparatus and system for accessing a flow system. In
20 particular, WO2016/097717 provides a multi-bore apparatus which facilitates fluid
21 communication between one or more subsea process apparatus and the flow system in
22 use.

23

24 Summary of the invention

25

26 There is generally a need for a method and apparatus which addresses one or more of the
27 problems identified above.

28

29 It is amongst the aims and objects of the invention to provide a subsea distributed manifold
30 system which mitigates drawbacks of prior art subsea manifolds and methods of use.

31

32 It is amongst the aims and objects of the invention to provide an improved subsea
33 distributed manifold system.

34

1 An object of the invention is to provide a flexible system and method of use suitable for
2 use with and/or retrofitting to industry standard or proprietary oil and gas system
3 infrastructure.
4

5 According to a first aspect of the invention, there is provided a subsea oil and gas
6 production installation, the installation comprising:
7 a subsea production system comprising a first production pipeline and a second
8 production pipeline;
9 a first subsea manifold in fluid communication with the first production pipeline comprising
10 a fluid access interface and a flowline connector;
11 a removable module fluidly connected to the fluid access interface of the first subsea
12 manifold and configured to receive production fluid from one or more subsea wells; and
13 a second subsea manifold in fluid communication with the second production pipeline;
14 wherein the first subsea manifold defines a first flow path between the fluid access
15 interface and the first production pipeline and a second bypass flow path between the fluid
16 access interface and the flowline connector;
17 wherein the first and the second subsea manifolds are fluidly coupled to one another by a
18 connecting flowline connected at a first end to the flowline connector of the first subsea
19 manifold; and
20 wherein the removable module comprises a flow control means operable to selectively
21 route the production fluid from one or more subsea wells into the first production pipeline
22 via the first flow path defined by the manifold, and/or into the second production pipeline
23 via the second bypass flow path, the connecting flowline and the second subsea manifold.
24

25 The connecting flowline may be a jumper flowline. The connecting flowline may be
26 connected at a second end to a flowline connector of the second subsea manifold.
27 Alternatively, the connecting flowline may be connected at a second end to a second
28 removable module fluidly connected to a fluid access interface of the second subsea
29 manifold.
30

31 The removable module may be a flow access hub, which may be a simple flow access hub
32 for connection of flow components, with no additional valves, controls, instrumentation, or
33 metering functionality. Alternatively, or in addition, the removable module may be a
34 functional module, which may comprise valves, controls, instrumentation, and/or metering
35 functionality, and which may be configured to be connected to the manifold via a flow

1 access hub. The flow control means operable to selectively route the production fluid from
2 one or more subsea wells into the first production pipeline via the first flow path defined by
3 the manifold, and/or into the second production pipeline via the second bypass flow path,
4 the connecting flowline and the second subsea manifold may be provided in a flow access
5 hub removable module and/or may be provides in a functional removable module.

6

7 The removable module (for example, a flow access hub) may be directly connected to the
8 fluid access interface of the first subsea manifold. Alternatively, the removable module (for
9 example, a functional module) may be connected to the fluid access interface of the first
10 subsea manifold via a flow access hub.

11

12 The removable module (for example, a flow access hub and/or a functional module) may
13 be configured to receive production fluid from one or more subsea trees directly.
14 Alternatively, the removable module (for example, a functional module) may be configured
15 to receive production fluid from one or more subsea trees via a flow access hub.

16

17 A flow access hub, which may be a flow access hub removeable module and/or a flow
18 access hub for connecting a functional removable module to a manifold, may comprise a
19 flowline inlet bore for connection to a flowline configured to carry fluid from a subsea well.
20 The flowline inlet bore may comprise a flowline connector for a flowline configured to carry
21 fluid from a subsea well. Alternatively, or in addition, the flowline inlet bore of the flow
22 access hub may be integrally formed with a flowline configured to carry fluid from a subsea
23 well. The flow access hub may therefore be a part of a flowline jumper system, and
24 therefore may be within the jumper envelope. The flow access hub may therefore be a flow
25 access hub that can be deployed with the jumper system and/or retrieved from a manifold
26 and subsea flow system with the jumper system, without causing disruption to the manifold
27 or the wider flow system.

28

29 The flow access hub may comprise a first interface (a manifold interface) connected to the
30 fluid access interface of the first subsea manifold. The fluid access interface of the first
31 subsea manifold may be a single bore interface and the first interface of the flow access
32 hub may be a single bore interface. Alternatively, the fluid access interface of the first
33 subsea manifold may be a dual bore interface and the first interface of the flow access hub
34 may be a dual bore interface.

35

1 The flow access hub may comprise a second interface (a module interface) connected to
2 an interface of a functional module, which may be a functional removable module. The
3 functional module interface may be a dual bore interface and the second interface of the
4 flow access hub may be a dual bore interface. Alternatively, the functional module
5 interface may be a triple bore interface and the second interface of the flow access hub
6 may be a dual bore interface.

7

8 The first interface (the manifold interface) of the flow access hub may have a lesser
9 number of bores than the second interface (the module interface) of the flow access hub.

10

11 The flow access hub may define a first flow path between the flowline inlet bore and the
12 second interface to fluidly connect a flowline configured to carry fluid from a subsea well to
13 the functional module. The flow access hub may define a second flow path between the
14 second interface and the first interface to fluidly connect the functional module to the first
15 subsea manifold.

16

17 The second subsea manifold may comprise a flowline connector. A second end of the
18 connecting flowline may be connected to the flowline connector. The connecting flowline
19 may be a jumper flowline and the flowline connector may be a flowline connector for a
20 jumper flowline.

21

22 The second subsea manifold may comprise a fluid access interface. The installation may
23 comprise a removable module fluidly connected to the fluid access interface of the second
24 subsea manifold. The removable module may be a flow access hub. Alternatively, or in
25 addition the removable module may be a functional module which may be configured to be
26 connected to the manifold via a flow access hub. The connecting flowline may be fluidly
27 connected to the functional module. Alternatively, or in addition, the functional module may
28 be configured to receive production fluid from one or more subsea wells. The functional
29 module may be directly connected to a fluid access interface of the second subsea
30 manifold. Alternatively, the functional module may be connected to a fluid access interface
31 of the second subsea manifold via a flow access hub. The functional module may be
32 configured to receive production fluid from the connecting flowline or from one or more
33 subsea wells directly. Alternatively, the functional module may be configured to receive
34 production fluid from the connecting flowline or from one or more subsea wells via a flow
35 access hub. The flow access hub may therefore be a part of a flowline jumper system, and

1 therefore may be within the jumper envelope. The flow access hub may therefore be a flow
2 access hub that can be deployed with the jumper system and/or retrieved from a manifold
3 and subsea flow system with the jumper system, without causing disruption to the manifold
4 or the wider flow system.

5
6 The flow control means may be one or more valves and/or an arrangement of valves
7 which may include flow control valves, isolation valves, check valves, ball valves, gate
8 valves and/or a combination thereof. The one or more valves may be electrically actuated
9 valves, manually actuated valves, hydraulically actuated valves, other types of valves or a
10 combination thereof. The one or more valves may be operable to selectively allow or
11 prevent flow of fluid through one or more flow paths defined by the removable module (i.e.
12 the flow access hub and/or the functional module). The one or more valves may be
13 operable by any suitable means, for example from the surface and/or from a subsea
14 control module (SCM) and/or by an ROV and/or by a diver.

15
16 The functional module may comprise further components, including but not limited to flow
17 control elements, flowlines, fluid access points, instrumentation (such as pressure and
18 temperature sensors) and/or valves, pumps or other suitable flow boosting means, filters,
19 flow measurement equipment or instruments, solid or phase separation equipment, and/or
20 sampling equipment, which may be operable by any suitable means, for example from the
21 surface and/or from a subsea control module (SCM) and/or by an ROV and/or by a diver.
22 The installation may be configured to perform distributed water injection or boosted water
23 injection operations. The installation may be configured to perform artificial lift operations,
24 including gas lift operations for displacing fluids which may otherwise impede production
25 flow or production restarts.

26
27 Controls for the flow control means and/or the further flow components may optionally be
28 integrated into the functional modules, the first and/or second manifolds, the production
29 jumper flowlines, connecting jumper flowlines or their respective connectors.

30
31 According to a second aspect of the invention, there is provided a subsea oil and gas
32 production installation, the installation comprising:
33 a subsea production system comprising a first production pipeline and a second
34 production pipeline;

1 a first subsea manifold configured to receive production fluid from one or more subsea
2 wells and in fluid communication with the first production pipeline; and
3 a second subsea manifold in fluid communication with the second production pipeline;
4 wherein the first and the second subsea manifolds are fluidly coupled to one another by a
5 connecting flowline; and
6 wherein the installation is operable to selectively route production fluid into the first
7 production pipeline via the first subsea manifold and/or into the second production pipeline
8 via the first subsea manifold, the connecting flowline and the second subsea manifold.

9
10 The first subsea manifold and/or the second subsea manifold may be (but are not limited
11 to being) a subsea manifold from the group comprising: a subsea collection manifold
12 system, a subsea well gathering manifold, a subsea in-line tee (ILT), a subsea Pipe Line
13 End Manifold (PLEM), a subsea Pipe Line End Termination (PLET) and a subsea Flow
14 Line End Termination (FLET). Preferably, the first subsea manifold and/or the second
15 subsea manifold are an ILT, a PLET and/or a combination of the two.

16
17 The first subsea manifold may be integrated into the first production pipeline and may
18 comprise a flow bore which is continuous with the first production pipeline. The first subsea
19 manifold may be in communication with the first production pipeline via an inlet connector
20 and an outlet connector of the first subsea manifold, which may be configured to effectively
21 integrate the first subsea manifold into the first production pipeline.

22
23 The second subsea manifold may be integrated into the second production pipeline and
24 may comprise a flow bore which is continuous with the second production pipeline. The
25 second subsea manifold may be in communication with the second production pipeline via
26 an inlet connector and an outlet connector of the second subsea manifold, which may be
27 configured to effectively integrate the second subsea manifold into the second production
28 pipeline.

29
30 The connecting flowline may be a jumper flowline and may be a flexible jumper flowline or
31 a rigid jumper flowline. Combinations of flexible and rigid jumper flowlines may be used
32 within the system. The connecting flowline may be connected to the first and/or second
33 subsea manifolds directly. The connecting flowline may be connected to an external
34 flowline connector, such as a jumper flowline connector, of the first and/or second subsea

1 manifolds. Alternatively, or in addition, one or both ends of the connecting flowline may be
2 coupled to the first and or second subsea manifolds via an intermediate structure.

3

4 The first subsea manifold may be operable to route the production fluid received from one
5 or more subsea wells into the first production pipeline or the second production pipeline via
6 the connecting flowline and the second subsea manifold.

7

8 Either or both of the first and second subsea manifolds may comprise at least one fluid
9 access point which may be configured to receive (i.e. be connected to) one or more
10 removable modules. The one or more removable modules may comprise one or more flow
11 access hubs. Alternatively, or in addition, the one or more removable modules may be one
12 or more functional modules which may be configured to be connected to the manifold via
13 one or more flow access hubs. The at least one fluid access point may be a single bore
14 access point. Alternatively, or in addition, the at least one access point may be a dual bore
15 and/or a multi-bore access point. The at least one removable module may be a single
16 bore, dual bore and/or multi bore module.

17

18 The first subsea manifold may be configured to receive the production fluid from the one or
19 more subsea wells via the one or more removable modules connected to the first subsea
20 manifold. The one or more removable modules connected to the first subsea manifold may
21 be configured to receive the production fluid from the one or more subsea wells, route the
22 production fluid into the first subsea manifold and selectively route the production fluid into
23 the first and/or the second production pipelines via the first subsea manifold. The one or
24 more removable modules may comprise at least one valve which may be operable to
25 selectively route production fluid into the into the first and/or the second production
26 pipelines.

27

28 The second subsea manifold may be configured to receive the production fluid from the
29 one or more subsea wells coupled to the first subsea manifold via the one or more
30 removable modules connected to the second subsea manifold. The connecting flowline
31 may be fluidly connected to the one or more removable modules connected to the second
32 subsea manifold. A first end of the connecting flowline may be coupled to an external
33 flowline connector of the first subsea manifold and a second end of the connecting flowline
34 may be coupled to an external flowline connector of the one or more removable modules
35 connected to the second subsea manifold. The one or more removable modules

1 connected to the second subsea manifold may be configured to: receive the production
2 fluid from the one or more subsea wells via the one or more removable modules
3 connected to the first subsea manifold, the first subsea manifold and the connecting
4 flowline and route the production fluid into the second subsea manifold and into the
5 second production pipeline via the second subsea manifold. The one or more removable
6 modules may comprise at least one valve which may be operable to permit flow of the
7 production fluid into the into the second subsea manifold and consequently the second
8 production pipeline.

9
10 Like the first subsea manifold, the second subsea manifold may also be configured to
11 receive production fluid from one or more subsea wells. The second subsea manifold may
12 be configured to receive the production fluid from the one or more subsea wells coupled to
13 it via the one or more removable modules connected to the second subsea manifold. The
14 one or more removable modules connected to the second subsea manifold may be
15 configured to receive the production fluid from the one or more subsea wells, route the
16 production fluid into the second subsea manifold and selectively route the production fluid
17 into the first and/or the second production pipelines via the second subsea manifold. The
18 one or more removable modules may comprise at least one valve which may be operable
19 to selectively route production fluid into the into the first and/or the second production
20 pipelines.

21
22 The first production pipeline and the second production pipeline may operate at the same
23 and/or different working pressures. The installation may be configured to route production
24 fluid into the first production pipeline and/or the second production pipeline depending
25 upon the pressure of the well from which the production fluid originates.

26
27 Embodiments of the second aspect of the invention may include one or more features of
28 the first aspect of the invention or its embodiments, or vice versa.

29
30 According to a third aspect of the invention, there is provided a subsea oil and gas
31 production installation, the installation comprising:
32 a subsea production system comprising a first production pipeline and a second
33 production pipeline;
34 at first subsea manifold configured to receive production fluid from one or more subsea
35 wells and in fluid communication with the first production pipeline; and

1 a second subsea manifold configured to receive production fluid from one or more subsea
2 wells and in fluid communication with the second production pipeline;
3 wherein the first and the second subsea manifolds are fluidly coupled to one another.

4

5 The first subsea manifold and/or the second subsea manifold may be (but is not limited to
6 being) a subsea manifold from the group comprising: a subsea collection manifold system,
7 a subsea well gathering manifold, a subsea in-line tee (ILT), a subsea Pipe Line End
8 Manifold (PLEM), a subsea Pipe Line End Termination (PLET) and a subsea Flow Line
9 End Termination (FLET). Preferably, the first subsea manifold and/or the second subsea
10 manifold are an ILT, a PLET and/or a combination of the two.

11

12 The first subsea manifold may be operable to route the production fluid received from one
13 or more subsea wells into the first production pipeline or the second production pipeline via
14 the second subsea manifold.

15

16 The second subsea manifold may be operable to route production fluid received from one
17 or more subsea wells into the second production pipeline, or the first production pipeline
18 via the first subsea manifold, or both.

19

20 The first and second subsea manifolds may comprise at least one fluid access point which
21 may be configured to receive one or more removable modules. The at least one fluid
22 access point may be a single bore access point. Alternatively, or in addition, the at least
23 one access point may be a dual bore and/or a multi-bore access point. The at least one
24 removable module may be a single bore, dual bore and/or multi bore module.

25

26 The one or more removable modules may comprise one or more flow access hubs.
27 Alternatively, or in addition, the one or more removable modules may comprise one or
28 more functional modules which may be configured to be connected to the manifold via one
29 or more flow access hubs. The one or more removable modules may be configured to
30 receive the production fluid from the one or more subsea wells, route the production fluid
31 into the first and second subsea manifolds, respectively, and selectively route the
32 production fluid into the first and/or the second production pipeline. The one or more
33 removable module may comprise valves which are operable to selectively route production
34 fluid into the into the first and/or the second production pipeline, via the first and/or second
35 subsea manifolds. The first and second subsea manifolds may each be configured to

1 receive production fluid from one or more subsea wells, respectively, via the one or more
2 removable modules.

3

4 The first production pipeline and the second production pipeline may operate at the same
5 and/or different working pressures. The installation may be configured to route production
6 fluid into the first production pipeline and/or the second production pipeline depending
7 upon the pressure of the well from which the production fluid originates.

8

9 Embodiments of the third aspect of the invention may include one or more features of the
10 first to second aspects of the invention or their embodiments, or vice versa.

11

12 According to a fourth aspect of the invention, there is provided a subsea manifold for a
13 subsea oil and gas production installation, the manifold comprising:

14 at least one fluid access point for a subsea well configured to be fluidly connected to a
15 subsea well to receive production fluid therefrom;

16 a main flow bore configured to be in fluid communication with a subsea production
17 pipeline; and

18 a flowline connector for a jumper flowline, configured to be fluidly connected to a jumper
19 flowline;

20 wherein the manifold defines a first flow path between the at least one fluid access point
21 and the main flow bore and a second bypass flow path between the at least one fluid
22 access point and the flowline connector for a jumper flowline, bypassing the main flow
23 bore.

24

25 The first flow path and the second flow path may be fluidly connected and may be
26 selectively separated by a flow barrier such as a valve.

27

28 The subsea manifold may be configured to be integrated into the production pipeline and
29 the main flow bore may be configured to be continuous with the production pipeline. The
30 subsea manifold may be in communication with the production pipeline via an inlet
31 connector and an outlet connector of the subsea manifold, which may be configured to
32 effectively integrate the subsea manifold into the production pipeline.

33

34 The at least one fluid access point may be configured to receive (i.e. be connected to) one
35 or more removable modules. The at least one fluid access point may be a single bore

1 access point. Alternatively, or in addition, the at least one access point may be a dual bore
2 and/or a multi-bore access point. The at least one removable module may be a single
3 bore, dual bore and/or multi bore module.

4

5 The one or more removable modules may comprise one or more flow access hubs.
6 Alternatively, or in addition, the one or more removable modules may be one or more
7 functional modules which may be configured to be connected to the manifold via one or
8 more flow access hubs. The subsea manifold may be configured to be fluidly connected to
9 at least one subsea well to receive production fluid therefrom via one or more removable
10 modules connected to the at least one fluid access point. The one or more removable may
11 be configured to receive the production fluid from the subsea well and route the production
12 fluid into the subsea manifold. The one or more removable modules may be configured to
13 and selectively route the production fluid into the first flow path and/or the second flow path
14 of the subsea manifold. The one or more removable modules may comprise at least one
15 valve which may be operable to selectively flow paths.

16

17 The subsea manifold may comprise one or more valves which may be provided to control
18 the direction and route of flow and/or for flow assurance purposes (for example, to shut off
19 a flowline or inlet/outlet when not in use).

20

21 Embodiments of the fourth aspect of the invention may include one or more features of the
22 first to third aspects of the invention or their embodiments, or vice versa.

23

24 According to a fifth aspect of the invention, there is provided a subsea manifold for a
25 subsea oil and gas production installation, the manifold comprising:
26 at least one fluid access point configured for connection to a connecting flowline carrying
27 production fluid coming from another subsea manifold; and
28 a main flow bore configured to be in fluid communication with a subsea production
29 pipeline;
30 wherein the manifold defines a flow path between the at least one fluid access point and
31 the main flow bore for routing the production fluid coming from the other subsea manifold
32 into the production pipeline.

33

34 The at least one fluid access point may be a flowline connector for a jumper flowline. The
35 at least one fluid access point may be configured to be fluidly connected to a further

1 subsea manifold, wherein the further subsea manifold is connected to one or more subsea
2 wells, to receive production fluid from the one or more subsea wells connected to the
3 further subsea manifold.

4

5 The at least one fluid access point may be a fluid interface and may be configured to
6 receive (i.e. be connected to) at least one removable module. The at least one removable
7 module may comprise one or more flow access hubs. Alternatively, or in addition, the at
8 least one removable module may be one or more functional modules which may be
9 configured to be connected to the manifold via one or more flow access hubs. The at least
10 one removable module may be configured to be fluidly connected to the further subsea
11 manifold, wherein the further subsea manifold is connected to one or more subsea wells,
12 to receive production fluid from the one or more subsea wells connected to the further
13 subsea manifold and route the production fluid into the subsea manifold via the fluid
14 access point. The removable module may be connected to the at least one fluid access
15 point via a flow access hub. The flow access hub may comprise a flowline inlet bore for
16 connection to the connecting flowline. The flowline inlet bore may comprise a flowline
17 connector for the connecting flowline. Alternatively, or in addition, the flowline inlet bore of
18 the flow access hub may be integrally formed with the connecting flowline. The connecting
19 flowline may be a jumper flowline. The flow access hub may therefore be a part of a
20 flowline jumper system, and therefore may be within the jumper envelope. The flow access
21 hub may therefore be a flow access hub that can be deployed with the jumper system
22 and/or retrieved from the manifold and subsea flow system with the jumper system,
23 without causing disruption to the manifold or the wider flow system.

24

25 Alternatively, or in addition, the at least one fluid access point may be for a subsea well
26 configured to be fluidly connected to a subsea well to receive production fluid therefrom.

27

28 Embodiments of the fifth aspect of the invention may include one or more features of the
29 first to fourth aspects of the invention or their embodiments, or vice versa.

30

31 According to a sixth aspect of the invention, there is provided a method of controlling
32 production flow from one or more subsea wells, the method comprising:
33 providing a subsea production system comprising:

1 at least one subsea well, a first production pipeline in fluid communication with a
2 first subsea manifold and a second production pipeline in fluid communication with
3 a second subsea manifold;
4 wherein at least one subsea well is connected to the first subsea manifold;
5 wherein the first subsea manifold and the second subsea manifold are fluidly
6 coupled to one another by a connecting flowline; and
7 wherein the first subsea manifold is provided with a flow control means operable to
8 route the production fluid from the at least one subsea well into the first production
9 pipeline via the first subsea manifold and/or into the second production pipeline via
10 the second first manifold, the connecting flowline and the second subsea manifold.

11

12 The first production pipeline may have a first working pressure and the second production
13 pipeline may have a second working pressure. The first working pressure and the second
14 working pressure may be the same. The first working pressure and the second working
15 pressure may be different. The method may comprise directing production flow from the at
16 least one subsea well into the first or the second production pipeline depending on the
17 pressure of the fluid produced from the well.

18

19 The method may comprise operating valves to select whether the production flow is
20 directed into the first or the second production pipeline.

21

22 A first removable module may be connected to the first subsea manifold and a second
23 removable module may be connected to the second subsea manifold. The removable
24 module may be a flow access hub. Alternatively, or in addition, the removable module may
25 be a functional module which may be configured to be connected to the manifold via a flow
26 access hub. The first removable module may be fluidly connected to the at least one
27 subsea well, which may be via a flow access hub. The method may comprise flowing
28 production fluid from the at least one subsea well into the first removable module. The
29 method may comprise operating valves provided in flow path or paths within the first
30 removable module to select whether fluid is directed into the first or the second production
31 pipeline.

32

33 The method may comprise directing fluid into the first production pipeline via the first
34 subsea manifold. The method may comprise directing fluid into the second production
35 pipeline via the first subsea manifold, the connecting flowline, a removable module to

1 which the connecting flowline is coupled connected to the second subsea manifold and the
2 second subsea manifold.

3

4 Embodiments of the sixth aspect of the invention may include one or more features of the
5 first to fifth aspects of the invention or their embodiments, or vice versa.

6

7 According to a seventh aspect of the invention, there is provided a method of installing a
8 distributed manifold system, the method comprising:

9 installing a first production pipeline and a first subsea manifold in fluid communication with
10 the first subsea pipeline and installing a second subsea pipeline and a second subsea
11 manifold in fluid communication with the second subsea pipeline, wherein the first subsea
12 manifold comprises a fluid access interface and a flowline connector;

13 installing a connecting flowline between the first subsea manifold and the second subsea
14 manifold, wherein the connecting flowline is connected at a first end to the flowline
15 connector of the first subsea manifold;

16 fluidly connecting a removable module to the fluid access interface of the first subsea
17 manifold, wherein the removable module is fluidly connected to at least one subsea well,
18 such that production fluid from the at least one subsea well can be selectively routed into
19 the first production pipeline via the removable module and the first subsea manifold or the
20 second production pipeline via the removable module, the first subsea manifold, the
21 connecting flowline and the second subsea manifold.

22

23 The removable module may be a flow access hub. Alternatively, or in addition, the
24 removable module may be a functional module which may be configured to be connected
25 to the manifold via a flow access hub. The method may comprise installing a flow access
26 hub onto the fluid access point of the first subsea manifold. The subsea well may be
27 connected to the removable module via the flow access hub. The subsea well may be
28 fluidly connected to the flow access hub. The method may comprise installing the
29 removable module to the flow access hub located on the fluid access interface of the first
30 subsea manifold. The removable module may comprise flow control means operable to
31 selectively route production fluid into the first production pipeline and/or the second
32 production pipeline.

33

34 The installation method may be a staged installation method which may comprise
35 connecting one or more subsea wells to the distributed manifold system in the future.

1
2 Embodiments of the seventh aspect of the invention may include one or more features of
3 the first to sixth aspects of the invention or their embodiments, or vice versa.
4
5 According to an eighth aspect of the invention there is provided a flow access hub
6 comprising:
7 a first interface comprising at least three bores;
8 a second interface comprising at least two bores; and
9 a flowline inlet bore;
10 wherein the hub defines a first flow path between the flowline inlet bore and a first bore of
11 the first interface, a second flow path between a second bore of the first interface and a
12 first bore of the second interface and a third flow path between a third bore of the first
13 interface and a second bore of the second interface.
14
15 The first interface may be an interface for connection to a removable module (a module
16 interface). The second interface may be an interface for connection to a manifold (manifold
17 interface). The first and second interfaces of the hub may be configured to fluidly connect
18 with like interfaces of other components, equipment and/or structures.
19
20 The at least three bores of the first interface may be arranged adjacent to one another.
21 The at least three bores of the first interface may be parallel.
22
23 The at least two bores of the second interface may be arranged adjacent to one another.
24 The at least two bores of the second interface may be parallel.
25
26 Alternatively, the at least two bores of the second interface may be arranged
27 concentrically. The first bore of the second interface may be arranged concentrically inside
28 the second bore. Alternatively, the second bore of the second interface may be arranged
29 concentrically inside the first bore.
30
31 The first interface may comprise parallel bores and the second interface may comprise
32 concentric bores.
33
34 The hub may comprise a body. The body may be generally cylindrical. The first and
35 second interfaces may be disposed on substantially opposite sides of the hub. The first

1 and second interfaces may have their axes oriented substantially in a vertical plane. The
2 first and second interfaces may have their axes oriented substantially in a horizontal plane.
3 The flowline inlet bore may have its axis oriented substantially in the vertical plane. The
4 flowline inlet bore may have its axis oriented substantially in the horizontal plane. The
5 flowline inlet bore may have its axis radially oriented with respect to a main body of the
6 hub. The flowline inlet bore may have its axis radially oriented with respect to a direction of
7 the axis of a main body of the hub. The flowline inlet bore may have its axis radially
8 oriented with respect to an axis of the first interface and/or an axis of the second interface.

9
10 The flowline inlet bore may comprise a flowline connector for a jumper flowline. The
11 flowline inlet bore may be integrally connected to a jumper flowline.

12
13 Embodiments of the eighth aspect of the invention may include one or more features of the
14 first to seventh aspects of the invention or their embodiments, or vice versa.

15
16 According to ninth aspect of the invention there is provided a flow access hub comprising:
17 a first interface comprising at least two bores;
18 a second interface comprising at least two bores; and
19 a flowline inlet bore;
20 wherein the flowline inlet bore is configured to route flow into one or both of the at least
21 two bores of the second interface.

22
23 The hub may define a first flow path between the flowline inlet bore a first bore of the first
24 interface and a second flow path between a second bore of the first interface and a first
25 bore of the second interface.

26
27 The at least two bores of the first interface may be arranged adjacent to one another. The
28 at least two bores of the first interface may be parallel.

29
30 The first interface may comprise three bores and the second interface may comprise two
31 bores. The hub may define a third flow path between a third bore of the first interface and
32 a second bore of the second interface. The three bores of the first interface may be
33 arranged adjacent to one another. The three bores of the first interface may be parallel.

34 The two bores of the second interface may be arranged concentrically. The first bore of the

1 second interface may be arranged concentrically inside the second bore. Alternatively, the
2 second bore of the second interface may be arranged concentrically inside the first bore.

3

4 The first interface may comprise parallel bores and the second interface may comprise
5 concentric bores.

6

7 The first and second interfaces of the hub may be configured to fluidly connect with like
8 interfaces of other components, equipment and/or structures.

9

10 The flowline inlet bore may be configured to route flow into one or both of the at least two
11 bores of the second interface via one or more modules fluidly connected to the first
12 interface.

13

14 Embodiments of the ninth aspect of the invention may include one or more features of the
15 first to eighth aspects of the invention or their embodiments, or vice versa.

16

17 According to a tenth aspect of the invention there is provided a flow access hub
18 comprising:

19 an assembly comprising a first part comprising an interface, and a second part comprising
20 a flowline connector;

21 wherein the interface comprises one or more flow openings, at least one of said flow
22 openings oriented with a first longitudinal axis;

23 wherein the flowline connector has a second longitudinal axis inclined to the first
24 longitudinal axis of the at least one flow opening;

25 wherein the first part is configured to be connected to a subsea flow apparatus by locating
26 the interface at a first rotational orientation with respect the subsea flow apparatus; and

27 wherein the second part is configured to be assembled with the first part in one of a range
28 of azimuthal orientations about the first longitudinal axis such that the second longitudinal
29 axis of the flowline connector is oriented at a required azimuthal orientation with respect to
30 the subsea flow apparatus.

31

32 The flow access hub may be an indexed flow access hub in which the second longitudinal
33 axis of the flowline connector / the flowline connector may be indexable between a range
34 of azimuthal orientations.

35

1 The first rotational orientation between the interface of the first part and the subsea flow
2 apparatus may be a fixed rotational orientation. That is, interface of the first part may only
3 be connected to the subsea process apparatus in a certain rotational orientation (or in one
4 of a number of discrete radial orientations). The rotational orientation may be fixed due to
5 the position of the one or more flow openings of the interface and the requirement to fluidly
6 couple and align the one or more flow openings of the interface with one or more
7 corresponding flow openings of the subsea flow apparatus.

8 The second part may be assembled with the first part in a range of azimuthal orientations
9 about the first longitudinal axis. Before assembly, one of the orientations may be selected
10 before assembling the second part with the first part such that the second longitudinal axis
11 of the flowline connector may be oriented at an optimum, desired azimuthal orientation
12 with respect to the subsea flow apparatus. In this way, the flowline connector can be
13 positioned in an optimum location with respect to the subsea flow apparatus to facilitate
14 connection to a flowline.

15

16 The inventors have realised that, where the rotational orientation between part of a flow
17 access hub and a subsea flow apparatus is fixed – for example, due to reasons of bore
18 alignment between the two components – it is desirable to be able to adjust the position of
19 a flowline connector of the flow access hub. In this way, the flowline connector can be
20 optimally positioned with respect to the fixed flow access apparatus in a way which best
21 suits the layout of the subsea field infrastructure. As the position of the flowline connector
22 is flexible, it can be selected to facilitate a low stress, well-aligned connection between the
23 flowline connector and a flowline. This may also have beneficial implications on load
24 bearing, flow rates, flowline lengths and the complexity of the subsea field infrastructure.

25

26 The subsea flow apparatus may be a manifold. The subsea flow apparatus may be a
27 subsea manifold selected from the group comprising: a subsea collection manifold system,
28 a subsea well gathering manifold, a subsea in-line tee (ILT), a subsea Pipe Line End
29 Manifold (PLEM), a subsea Pipe Line End Termination (PLET) and a subsea Flow Line
30 End Termination (FLET).

31

32 The interface may be a first interface. The first part may further comprise a second
33 interface. The first part may define a first flow path between the flowline connector and the
34 first interface and/or the second interface of the first part. The at least one flow opening of
35 the first interface may be configured to be fluidly connected to at least one flow opening of

1 the subsea flow apparatus. The second interface of the first part may comprise at least two
2 flow openings. The first flow path may be defined between the flowline connector and one
3 of the at least two flow openings of the second interface of the first part. The first part may
4 define a second flow path between a second of the at least two flow openings of the
5 second interface and the at least one flow opening of the first interface.

6

7 The second interface of the first may be configured to be connected to a subsea process
8 apparatus, such as a functional module. The flow access hub may define one or more flow
9 paths between a subsea process apparatus and the subsea flow apparatus in use.

10

11 The first part of the flow access hub may be a body. The second part of the flow access
12 hub may be a conduit. A first end of the conduit may be coupled to the first part of the flow
13 access hub and a second end of the conduit may form the flowline connector.

14

15 The second part may be rigidly connected to the first part. The second part may be welded
16 to the first part.

17

18 The second part may be moveably and/or adjustably connected to the first part such that
19 the azimuthal orientation of the second longitudinal axis of the flowline connector with
20 respect to the subsea flow apparatus is adaptable, once the second part is assembled with
21 the first part. The second part may be coupled to the first part by a flanged connection.

22 The second part may be coupled to the first part by a threaded connection. The second
23 part may be coupled to the first part by a clip which facilitates relative movement between
24 the first part and the second part.

25

26 The first part may comprise a cut out section to accommodate the second part.

27

28 The flowline connector may be configured for connection to a flowline carrying fluid from a
29 subsea well. The flowline connector may comprise a flowline connector for a flowline
30 configured to carry fluid from a subsea well, which may be a jumper flowline. Alternatively,
31 or in addition, the flowline connector of the flow access hub may be integrally formed with
32 a flowline configured to carry fluid from a subsea well. The flow access hub may therefore
33 be a part of a flowline jumper system, and therefore may be within the jumper envelope.

34 The flow access hub may therefore be a flow access hub that can be deployed with the

1 jumper system and/or retrieved from a manifold and subsea flow system with the jumper
2 system, without causing disruption to the manifold or the wider flow system.

3

4 Embodiments of the tenth aspect of the invention may include one or more features of the
5 first to ninth aspects of the invention or their embodiments, or vice versa.

6

7 According to an eleventh aspect of the invention there is provided a flow access hub
8 comprising:

9 an assembly comprising:

10 a first part comprising a first interface; and

11 a second part comprising a flowline connector for a jumper flowline;

12 wherein the first interface comprises one or more flow openings, at least one of said flow
13 openings oriented with a first longitudinal axis;

14 wherein the flowline connector for a jumper flowline has a second longitudinal axis inclined
15 to the first longitudinal axis of the at least one flow opening;

16 wherein the first part is configured to be connected to a subsea manifold by locating the
17 first interface at a first rotational orientation with respect to the subsea manifold; and

18 wherein the second part is configured to be assembled with the first part in one of a range
19 of azimuthal orientations about the first longitudinal axis such that the second longitudinal
20 axis of the flowline connector for a jumper flowline is oriented at a required azimuthal
21 orientation with respect to the subsea manifold.

22

23 The inventors have realised that, where the rotational orientation between part of a flow
24 access hub and a subsea manifold is fixed – for example, due to reasons of bore
25 alignment between the two components – it is desirable to be able to adjust the position of
26 a flowline connector for a jumper flowline. In this way, the flowline connector for a jumper
27 flowline can be optimally positioned with respect to the fixed flow access apparatus and
28 subsea manifold in a way which best suits the layout of the subsea field infrastructure. As
29 the position of the flowline connector for a jumper flowline is flexible, it can be selected to
30 provide an optimum jumper departure angle for a jumper flowline with respect to the
31 manifold to facilitate a low stress, well-aligned connection between the flowline connector
32 for a jumper flowline and a jumper flowline. This may also have beneficial implications on
33 load bearing, flow rates, flowline lengths and the complexity of the subsea field
34 infrastructure.

35

1 Embodiments of the eleventh aspect of the invention may include one or more features of
2 the first to tenth aspects of the invention or their embodiments, or vice versa.

3

4 According to a twelfth aspect of the invention there is provided a subsea flow system
5 comprising a subsea manifold, a jumper flowline and a flow access hub according to a
6 tenth or an eleventh aspect of the invention.

7

8 The interface of the first part of the hub may be connected to the subsea manifold. The
9 flowline connector of the second part of the hub may be connected to the jumper flowline.

10

11 Embodiments of the twelfth aspect of the invention may include one or more features of
12 the first to eleventh aspects of the invention or their embodiments, or vice versa.

13

14 Brief description of the drawings

15

16 There will now be described, by way of example only, various embodiments of the
17 invention with reference to the drawings, of which:

18

19 Figure 1 is a piping and instrumentation diagram of a subsea system useful for
20 understanding the invention;

21

22 Figure 2A is a schematic perspective view of a subsea system according to an
23 embodiment of the invention;

24

25 Figure 2B is a piping and instrumentation diagram of the system of Figure 2A;

26

27 Figure 2C is a piping and instrumentation diagram of the system of Figures 2A and 2B,
28 prior to population;

29

30 Figure 2D is a piping and instrumentation diagram of the system of Figures 2A, 2B and 2C,
31 partially populated;

32

33 Figures 3A to 3I are schematic perspective views of the installation process of a manifold
34 of the system according to an embodiment of the invention;

35

1 Figures 4 to 6 are schematic piping and instrumentation diagrams of removable modules
2 according to alternative embodiments of the invention;

3

4 Figure 7 is a piping and instrumentation diagram of a subsea system according to an
5 embodiment of the invention;

6

7 Figures 8A to 8E are schematic piping and instrumentation diagrams of alternatively
8 configured subsea systems according to embodiments of the invention;

9

10 Figures 9A to 9C are schematic piping and instrumentation diagrams of alternatively
11 configured subsea systems according to embodiments of the invention;

12

13 Figures 10A to 10C are schematic piping and instrumentation diagrams of alternatively
14 configured subsea systems according to embodiments of the invention;

15

16 Figure 11 is a piping and instrumentation diagram of a subsea system according to an
17 embodiment of the invention, configured with a single production pipeline and a gas lift or
18 service pipeline;

19

20 Figures 12A to 12D are respectively plan, exploded isometric, first exploded longitudinal
21 sectional and second exploded longitudinal sectional views of an assembly according to a
22 preferred embodiment of the invention;

23

24 Figure 13 is an exploded isometric view of an assembly according to an alternative
25 embodiment of the invention;

26

27 Figure 14A is an exploded isometric view of an assembly according to an alternative
28 embodiment of the invention;

29

30 Figure 14B is a perspective view of a hub of the assembly of Figure 14A;

31

32 Figure 15A is an exploded isometric view of an assembly according to an alternative
33 embodiment of the invention;

34

35 Figure 15B is a perspective view of a hub of the assembly of Figure 15A;

1
2 Figure 16A is an exploded isometric view of an assembly according to an alternative
3 embodiment of the invention; and

4
5 Figures 16B and 16C are perspective views of a hub of the assembly of Figure 16A.

6
7 Detailed description of preferred embodiments

8
9 The terms “upper”, “lower”, “above”, “below”, “up” and “down” are used herein to indicate
10 relative vertical positions in vertical orientations of flow system components. The invention
11 also has applications in horizontal orientations, and when these terms are applied to such
12 orientations they may indicate “left”, “right” or other relative positions in the context of the
13 orientation of flow system components.

14
15 Referring firstly to Figure 1, there is shown a subsea system comprising traditional subsea
16 components, which is useful for understanding the invention. The system contains two
17 four-slot manifolds 60, each capable of connecting to up to four subsea wells, X1, X2, X3,
18 X4, X5, X6, X7 and X8. The production fluid from the wells is routed through the manifolds
19 and into either production flowline A or production flowline B. These types of manifolds are
20 large and heavy. They require a large CAPEX investment for a reasonably low well count,
21 they require specialist installation using specialist vessels and equipment due to their
22 substantial size and weight and they restrict where the top-hole locations of subsea wells
23 can be drilled.

24
25 Referring to Figure 2A and 2B, there is shown, generally at 110, a distributed manifold
26 system according to an embodiment of the invention.

27
28 A distributed manifold system comprises a collection of manifolds, displaced from one
29 another and fluidly connected together. In the example shown in Figures 2A and 2B these
30 manifolds are in-line tees (ILTs) and Pipe Line End Terminations (PLETs). A distributed
31 manifold system can function in the same manner as a conventional well gathering
32 manifold, but instead its components and connection points are distributed over a pipeline
33 system. A distributed manifold can be selectively populated and utilised as and when
34 project requirements demand. This kind of system also provides utmost flexibility to
35 subsea architecture (for example, allowing a well top-hole to be drilled in an optimal

1 position and served by a specifically located manifold within the distributed system;
2 whereas typically, top-hole location is influenced by the fixed location of existing subsea
3 infrastructure).

4

5 The system of Figures 2A and 2B is made up of four drill centres, shown generally by the
6 shaded areas 112a, 112b, 112c and 112d, each bordered by dashed lines. Within each
7 drill centre, a number of subsea wells are connected to a manifold of the system. In drill
8 centre 112a, which is the outermost drill centre in the system, subsea Christmas trees
9 114a and 114b are fluidly connected to a PLET 116 by a pair of flexible jumper flowlines.
10 In drill centre 112b, two subsea Christmas trees 114c and 114d are connected to an ILT
11 118. In drill centre 112c, four subsea Christmas trees 114e to 114h are connected to a
12 four-slot ILT 120. Finally, in drill centre 112d, Christmas trees 114i and 114j are fluidly
13 connected to PLET 122.

14

15 The system has two main production flowlines: production flowline A and production
16 flowline B. Production flowlines A and B each lead comingled fluid produced from various
17 subsea wells to a separate production riser (not shown), in the direction indicated by the
18 arrows. The manifolds 116, 118, 120 and 122 are integrated into production flowline A,
19 and each comprise a main flow bore which is continuous with flowline A. Each of the
20 manifolds 116, 118, 120 and 122 is connected to a respective PLET or ILT 124, 126, 128,
21 130, which is similarly integrated into flowline B, by a flexible jumper flowline 132a, 132b,
22 132c, 132d. This arrangement allows for fluid coming from the subsea wells via any of the
23 Christmas trees 114a to 114j to be selectively routed into either production flowline A or
24 production flowline B. A production flowline may, for example, be selected based on the
25 pressure of the fluid originating from the well in question and the pressure of the
26 production flowlines.

27

28 Figure 2B shows in more detail how fluid connections are made to the manifolds 116, 118,
29 120, 122, 124, 126, 128, 130 in the system. For example, with reference to the ILT 118 in
30 drill centre 112b in communication with production flowline A, it can be seen that the ILT
31 118 comprises two fluid access points 134 and 136 having dual bore interfaces.
32 Connected to each of these access points 134, 136 there is a flowline connector hub 158.
33 The purpose of the hub 158 is to connect a subsea well to the manifold and provide a fluid
34 access interface for connection of the well and the ILT 118 with one or more functional
35 removable modules. The hub 158 is therefore a part of the flowline jumper system, and

1 therefore within the jumper envelope. The hub can therefore be deployed with the jumper
2 system and/or retrieved from the ILT 118 and subsea flow system with the jumper system,
3 without causing disruption to the ILT 118 or the wider flow system. The hub can therefore
4 provide a fluid access and intervention location within the jumper flowline envelope. The
5 flowline connector hub 158 comprises a dual bore interface lower which mates with the
6 dual bore interface of the fluid access points, a flowline inlet bore which is fluidly coupled
7 to the Christmas trees 114c and 114d via a flexible jumper flowline, and a triple bore upper
8 interface. The hub 158 defines two respective flow paths between the two bores of its
9 lower interface and two bores of its upper interface and a third flow path between the
10 flowline inlet bore and the third bore of its upper interface. The flowline inlet bore forms a
11 connection point for a flowline, to receive production fluid from a subsea well. In
12 embodiments of the invention, the hub could be integrally formed with the end of a
13 flowline, such as a jumper flowline connected to or configured to be connected to receive
14 fluid from a subsea well. Although in the presently described embodiment the hub 158
15 does not comprise any additional components, it will be appreciated that the hub 158 - or
16 any of the flowline connector / flow access hubs described throughout this specification –
17 may include one or more valves for selectively routing fluid in the system in substantially
18 the same manner as described in more detail below with reference to operation of
19 removable module 140.

20

21 In the embodiment of Figure 2B, each hub 158 provides a landing and connection point for
22 removable functional modules 138 and 140. Each of the removable modules 138 and 140
23 has a triple bore interface which is fluidly connected to the triple bore interface of the hub
24 158. In each case, two bores of the triple bore interface of the removable modules 138 and
25 140 are fluidly connected to two of the bores of the hubs 158 upper interface, whilst the
26 third bore is fluidly coupled to the third bore of the hub 158 which corresponds to the
27 flowline inlet bore and thus connected Christmas trees 114c and 114d via a flexible jumper
28 flowline. The Christmas trees 114c and 114d are not connected directly to the ILT 118 but
29 are instead fluidly connected to the ILT 118 via the removable modules 138 and 140 and
30 hubs 158. Without the removable modules present (for example, if the hubs 158 were to
31 have blind flow caps installed on their upper interfaces) there would be no way for fluid to
32 flow from the wells connected to the subsea trees 114c and 114d to the ILT 118.

33

34 The removable modules 138 and 140 are, in this case, identical. For conciseness, only the
35 function of module 140 is described. The module 140 receives fluid from the tree 114d via

1 an inlet bore and comprises a multiphase flow meter 142 through which all production fluid
2 from the tree is routed. The flow path within the module 138 then splits into two branches,
3 either of which can be selected by operation of valves 143a and 143b, to selectively route
4 fluid into either production flowline A or production flowline B, respectively. The ILT 118
5 comprises a flowline connector for a jumper flowline 144 to which flexible jumper flowline
6 132b is connected. From each of its fluid access points 134 and 136, the ILT defines a
7 flow path which connects one bore of the dual bore interface to its local flowline:
8 production flowline A. For flow assurance reasons, each of these flow paths comprise a
9 valve 145; however, it will be appreciated that this may be omitted or replaced with an
10 equivalent component in alternative embodiments. From each of its fluid access points 134
11 and 136, the ILT also defines a flow path connecting the other bore of the dual bore
12 interface directly to the jumper flowline connector 144, effectively bypassing the main
13 flowline A and therefore routing flow towards production flowline B via the jumper flowline
14 132b, a removable module 146 provided on the ILT 126 (described below), and the ILT
15 126.

16

17 ILT 126 is similar to the ILT 118; however, it has only a single fluid access point 148
18 having a single bore interface. Connected to the access point 148 there is a flowline
19 connector hub 159. The purpose of the hub 159 is to connect the flow originating from the
20 subsea wells 114c and 114d to the ILT 126, and to provide a fluid access interface to
21 facilitate connection of the subsea wells 114c and 114d and the ILT 126 to one or more
22 removable modules. The flowline connector hub 159 comprises a lower single bore
23 interface which mates with the fluid access point 148, a flowline inlet bore which is fluidly
24 coupled to the jumper flowline 132b, and a dual bore upper interface. The hub 159 defines
25 a first flow path between the bore of its lower interface and a bore of its upper interface
26 and a second flow path between the flowline inlet bore and the second bore of its upper
27 interface. The flowline inlet bore could form a connection point for a flowline, or the hub
28 could be integrally formed on the end of a flowline.

29

30 A removable module 146 having a dual bore interface is fluidly to the hub 159, and is
31 thereby operable to receive fluid produced from the wells corresponding to subsea
32 Christmas trees 114c and 114d. A valve 119 (which in alternative embodiments may be
33 omitted) is provided in the flow loop of the removable module 146 to selectively permit fluid
34 to enter production flowline B. A valve 150 is also provided in the ILT 126 for flow
35 assurance and connection purposes.

1
2 The description of the arrangement and operation of drill centre 112b generally applies to
3 each of the drill centres depicted in Figures 2A and 2B, with relatively minor differences.
4 For example, in drill centre 112c a 4-slot ILT 120 is provided, having an alternative flow
5 path configuration within the ILT.

6
7 It will be appreciated that alternative removable modules may be used, and that the
8 alternative modules may be provided with additional flow components, flow control
9 elements, flowlines, fluid access points, instrumentation (such as pressure and
10 temperature sensors) and/or valves and/or they may be provided without these
11 components to provide a simple flow loop without obstruction. It will also be appreciated
12 that the manifolds 124, 126, 128, 130 in communication with production flowline B may be
13 replaced with different manifolds in alternative embodiments of the invention, which are
14 also capable of being connected to subsea wells (like manifolds 116, 118, 120 and 122).

15
16 The two PLETs 116 and 124 which are provided in drill centre 112a are the outermost
17 components in the distributed manifold system. The PLETs 116 and 124 are also
18 connected by a jumper flowline 132a. The PLET 116 comprises a valve 151 in the bore
19 continuous with production flowline A which can be operated to shut off the flowline – for
20 example, to facilitate the connection of a pigging device to the system. A pigging device
21 could be installed between the flowline 132a and connector 152 of the PLET 116. The flow
22 loop created by the distributed manifold system is able to support bi-directional pigging,
23 and/or round trip pigging from a platform or other remote facility via the production
24 flowlines A and B.

25
26 Drill centre 112d is the final drill centre in the distributed manifold system, before the
27 production fluid is recovered to the surface via production risers (not shown). Each
28 production pipeline A and B is routed through a riser base module 154a and 154b. Each
29 riser base module 154a and 154b also comprises a fluid access points 155a and 155b
30 having single bore interfaces, on which flowline connector hubs and dual bore interface
31 removable modules 156a and 156b are mounted. These are gas lift modules, which each
32 comprise a flow loop having a gas lift injection choke. Although in alternative embodiments
33 an orifice may be used in place of a choke valve. One bore of each of the modules 156a
34 and 156b is connected to the single bore interface of the riser base module whilst the other
35 is connected to a gas lift delivery line to receive gas for gas lift operations. The modules

1 156a and 156b can be operated to inject gas into the flow of production fluid from
2 production pipelines A and/or B at the base of the riser in order to reduce its density and to
3 make it easier to recover to the surface.

4

5 The flowline connector hubs 158 and 159 can transform a dual or single bore interface of a
6 fluid access point of a manifold into a triple or dual bore interface, respectively. An
7 example of a dual to triple bore flowline connector hub is described with reference to
8 Figures 12A to 12C. In addition, the flowline connector hubs are a part of the flowline
9 jumper system and are therefore within the jumper envelope. The flowline connector hubs
10 can be deployed with the jumper system and/or retrieved from the manifolds in the
11 distributed manifold system and the subsea flow system with the jumper system, without
12 causing disruption to the manifold(s) or the wider flow system.

13

14 Figure 2C shows the system of Figures 2A and 2B, before connection and completion. At
15 this stage, the system 210 is not connected to any subsea wells nor is it connected to the
16 wider production flow system including production risers. An advantage of the distributed
17 manifold system is that the fundamental core components of the system, including those
18 included in the incomplete system of Figure 2C, can be installed along with other subsea
19 infrastructure (for example, integrated with a pipeline during a pipelay operation). At a later
20 stage, additional components, including connecting flowlines and removable modules, can
21 be installed in the system if they are required. As these components are smaller and
22 lighter than a full-size traditional well gathering manifold, they can be installed using ROVs
23 and/or other suitable equipment and do not require the use of specialist installation
24 vessels. The distributed manifold system also provides flexibility with respect to subsea
25 field development, as the system provides multiple locations at which to connect subsea
26 wells to the system as and when they are developed, and can be easily adapted to provide
27 new connection points for wells at optimal locations on the seabed, with the provision of a
28 small number of connection components.

29

30 Figure 2D shows the system 110 in a partially populated state. The system of Figure 2D is
31 equipped with flowlines 132a, 132b, 132c, 132d connecting the manifolds of the system
32 together and flowlines 131 connecting production flowline headers A and B to the riser
33 base modules 155a and 155b, respectively, to enable flow to travel from subsea wells
34 connected to the manifolds of the system to either of production pipelines A or B.
35 However, in the absence of removable modules connected to the PLETs and ILTs of the

1 system (as well as to the riser base modules), there is no complete flow loop through
2 which flow can travel.

3

4 With reference to drill centre 112b for example, one subsea well Christmas tree is fluidly
5 connected to fluid access point 134 of the ILT 118 via the hub 158 and the removable
6 module 138. As such, flow from the associated subsea well can be routed into production
7 flowlines A or B by use of the module 138. As noted above, flow cannot be routed into the
8 production risers until a removable module is connected to the riser base modules 155a
9 and 155b to complete the flow path.

10

11 Multiple subsea wells have been connected to other manifolds within the system and
12 unconnected fluid access points (also referred to as slots) are available for the connection
13 to subsea wells in the future, should they be required.

14

15 Figures 3A to 3I show a connection sequence for connecting subsea wells to a manifold of
16 a distributed manifold system. The manifold is a subsea in-line tee 218 integrated into a
17 production pipeline A. The ILT 218 was laid on the sea bed along with the production
18 pipeline A by a pipelay vessel and has an integral mud mat 253 which has been folded out
19 to support the ILT on the seabed.

20

21 The ILT 218 has two fluid access points 234 and 236, each having a dual bore interface
22 (not shown). In Figure 3A the fluid access points 234 and 236 are closed with flow caps.
23 The ILT also has a flowline connector for a jumper flowline 244. Each of the fluid access
24 points 234 and 236 is fluidly connected to production flowline A by one or more flow paths
25 defined by the manifold (not shown) corresponding to one of the bores of each dual bore
26 interface, and the flowline connector 244 by one or more flow paths defined by the
27 manifold (not shown) corresponding to the other bore of each dual bore interface.

28

29 Figure 3B shows the process of a jumper flowline 232 being connected to the flowline
30 connected 244 of the ILT 218. Installation of the jumper can be performed using an ROV
31 or similar and does not require heavy-duty or specialist deployment vessels. The jumper
32 flowline 232 will connect the ILT to another manifold within the distributed manifold system,
33 or perhaps to a removable module connected to and mounted on another manifold.

34

1 In Figure 3C, the flow cap is removed from the fluid access point, exposing its dual bore
2 interface.

3

4 Figure 3D shows the step of connecting a subsea well to the fluid access interface 234 via
5 flowline 214a having an associated flowline connector hub 255 and Figure 3E shows the
6 completed connection. The flowline connector hub 255 has a lower dual bore interface (not
7 shown) which is aligned with the dual bore interface of the fluid access point 234 upon
8 connection. The flowline connector hub 255 also has a flowline inlet bore. The flowline
9 214a and the connector hub 255 may be integral components and/or may be detachable.
10 The upper interface of the flowline connector hub 255 is a triple-bore interface, having two
11 bores corresponding to the dual bore interface of the fluid access point 234 and a third
12 bore corresponding to the flowline 214a. The triple-bore upper interface cannot be seen in
13 Figure 3E, as a flow cap is positioned on the connector hub 255. As such, no flow can take
14 place between the well and the ILT.

15

16 In Figure 3F, the flow cap is removed to expose the triple-bore upper interface of the
17 flowline connector hub 255. A removable module is now able to be connected to the ILT,
18 as is shown in the step of Figure 3G. The removable module 238 has a triple-bore lower
19 interface to communicate with the triple-bore upper interface of the flowline connector hub
20 255. The removable module connection is complete in Figure 3H. The removable module
21 defines a flow path between the flowline inlet bore and one other bore of its triple-bore
22 lower interface, and a flow path between the flowline inlet bore and the other bore of its
23 triple-bore lower interface. As such, fluid can now flow from the well via the flowline 214a,
24 through the removable module and into either: (a) the flowline 232 (on route to a second
25 production flowline) via the flowline connector 244 or (b) into production flowline A,
26 depending upon how valves (not shown) within in the removable module are operated.

27

28 Figure 3I shows the ILT after the steps of Figures 3C to 3H have been repeated to install a
29 second removable module 239 upon the fluid access point 236 of the ILT 218. Like the
30 jumper flowlines, installation of the removable modules can be performed using an ROV or
31 similar and does not require heavy-duty or specialist deployment vessels. Advantageously,
32 if a component within the removable module fails – for example, a multiphase flow meter –
33 only the module needs to be recovered. Not the entire ILT.

34

1 Figures 4A, 4B, 5 and 6 are examples of removable modules that can be used with the
2 system.
3

4 The removable module 338 of Figure 4A has a triple-bore lower interface connected to a
5 triple bore upper interface of flowline connector hub 358. Two of the bores of the flowline
6 connector hub 358 are fluidly connected to the dual-bore interface 334 of a manifold, whilst
7 the third receives production fluid from a Christmas tree 314. The module 338 functions to
8 selectively route fluid received from the tree 314 into either one (or both) of the bores of
9 the dual bore interface of the manifold's fluid access point.
10

11 The removable module 388 of Figure 4B has an additional access point 356, which is
12 capable of being connected up by a line 357 for venting, chemical injection and/or well
13 control purposes and/or for the provision of pressure and/or temperature transducers.
14

15 The removable module 438 of Figure 5A contains a simple flow loop to connect fluid
16 entering the flowline connector hub 359 from a flowline 414 to a single bore fluid access
17 point interface 434 of a manifold. The flow loop contains a valve for flow assurance and/or
18 control purposes.
19

20 The removable module 488 of Figure 5B is similar to the module 438 of Figure 5A, and
21 contains a simple flow loop to create a flow path between respective bores of the flowline
22 connector hub 359, for example to enable a fluid flow from a flowline 464 to a single bore
23 fluid access point interface 484 of a manifold. The flow loop also contains a valve for flow
24 assurance and/or control purposes, but differs from the module 438 in that the flow loop is
25 piggable, to enable pigging of the flow path and/or round trip pigging around the system in
26 which it is installed.
27

28 The removable module 556 of Figure 6 is a gas lift module, like that described with
29 reference to Figure 2B, and variations may contain a gas lift venturi or a gas lift choke
30 valve, depending on operational requirements.
31

32 Referring to Figure 7, an alternative configuration of a flow system according to an
33 embodiment of the invention is shown. This system allows production fluid flowing from a
34 subsea well to be routed into either of production flowlines A or B. The system 610 is
35 similar to the system 110 of Figures 2A and 2B, with like features indicated by like

1 reference numerals, incremented by 500. The system 610 differs from the system 110 in
2 that subsea wells are connected to manifolds integrated in both production flowlines A and
3 B, as opposed to only being connected to the production flowline A side of the distributed
4 manifold system. In addition, there are only two drill centres 162a and 612b in the
5 embodiment of Figure 7.

6

7 In the embodiment shown, the flow system comprises four manifolds: two PLETs 616 and
8 624 in the outermost drill centre 612a and two ILTs 618 and 626 in the drill centre 612b.
9 Each manifold 616, 618, 624, 626 has two fluid access points 634 and 636 and is capable
10 of being connected to and receiving production fluid from up to two subsea wells.

11 However, in the embodiment shown, only a single subsea well Christmas tree 164a, 614b,
12 614c, 614d is connected to each manifold 616, 618, 624, 626.

13

14 The main differences in system configuration can be described with reference to drill
15 centre 612b, where it can be seen that the two ILTs 618 and 626 each have two jumper
16 flowline connectors 644a, 644b, 644c and 644d and are fluidly connected to one another
17 by two jumper flowlines 632c and 632d.

18

19 A removable flow-through module 638a is connected to the ILT via the fluid access point
20 interface 634 and flowline connector hub 658, providing flow routes between the well
21 connection point 647 and flow bores 649a and 649b of the ILT 618 which are in fluid
22 communication with production flowlines A and B, respectively. The flow paths within the
23 removable module 638 each has a valve. As such, fluid produced from the well and
24 entering the module 638 can be selectively routed through the flow paths 649a or 649b of
25 the ILT 618, and thus production flowlines A or B (via jumper flowline 632d) by operation of
26 the valves in the removable module. The opposite ILT 626 functions to direct flow in a
27 similar manner. A subsea Christmas tree 614d is connected to the ILT 626 via removable
28 module 638b and hub 658. By operating the valves within the removable module 638b
29 fluid produced from the well 614d and entering the module 638b can be selectively routed
30 through the flow paths of the ILT 626, and thus production flowlines B or A (via jumper
31 flowline 632c).

32

33 The ILT 618 also comprises a second interface 636, for the connection of a further subsea
34 well in the future. A flow cap is shown installed on the second interface 636 whilst it is not
35 currently in use.

1
2 It will be appreciated that although each manifold is described as having two interfaces -
3 and therefore being able to accommodate the connection of two subsea fluid sources
4 (subsea well Christmas trees in this embodiment) – manifolds within a distributed manifold
5 system may be provided with more or less interfaces to accommodate different numbers of
6 subsea wells and future subsea expansion plans.

7
8 The fluid access interfaces provided formed by the hubs 658 provide a convenient
9 interface upon which to land and connect one or more removable flow modules to the
10 system. The flow modules may merely facilitate the provision of a flow path between a
11 subsea well and the first and/or second production flowlines, or they can provide the
12 system with additional functionality. For example, an alternative flow module might
13 comprise pressure and temperature transducers to obtain measurements of the production
14 fluid flowing from the well.

15
16 As the modules 638 are removably connected to the hub interfaces – the hubs being
17 located on the manifold – they are conveniently located in the jumper flowline envelope
18 and can be recovered with minimal disruption to the flow system. As such, active flow
19 components located within the modules are also easily removable and recoverable. It is
20 therefore beneficial to provide certain flow components within the modules, instead of
21 providing them within the ILT or PLET itself, as removal and retrieval of a module alone is
22 simpler, cheaper and less disruptive than retrieval of the entire PLET or ILT if repair or
23 replacement of the flow components is required.

24
25 The selection as to whether to route production fluid through production flowline A or
26 flowline B may be influenced by factors such as the pressure and/or flow rate of production
27 fluid from the subsea well and the pressure and/or flow rate of fluid in the production
28 flowline.

29
30 The interfaces 634 and 636 and are triple-bore interfaces, providing triple bore access for:
31 receiving production fluid from a well, routing production fluid to a first production flowline
32 and/or routing production fluid to a second production flowline.

33
34 Alternatively configured flow systems are shown in Figures 8A to 8E. These embodiments
35 illustrate the adaptability of the principles of the invention to include different levels of flow

1 isolation, which can be required by certain projects, operators and/or in certain operating
2 regions. These Figures also demonstrate flexibility with respect to the provision and
3 placement of flow components.

4

5 Figure 8A shows a flow system 810 which is similar to the flow system 610 of Figure 7 and
6 functions in substantially the same manner as the flow system 610, with like features
7 indicated by like reference numerals, incremented by 200. Like the system 610, the
8 system 810 allows production fluid flowing from a subsea well to be routed into either of
9 production flowlines A or B.

10

11 The system 810 differs from the system 610 in several ways. In particular, the system 810
12 offers different levels of flow isolation. For example, the pair of flow bores shown generally
13 at 864 in the PLET 816 which are associated with Christmas tree XT1 are not provided
14 with any valves to isolate the bores 864. Isolation is provided by a removable module
15 (such as a flow access hub and/or a functional module) or by a flow cap (not shown) when
16 no well is connected to the flow access interface. By removing the isolation valves from the
17 PLET in this way, and providing them elsewhere in the flow system, the PLET can be
18 made smaller and lighter. This is beneficial when pipeline and equipment size and weight
19 constraints apply to the flow system, for example, size and weight constraints of the
20 pipelay installation equipment.

21

22 Another way in which the flow system 810 differs from that 610 of Figure 7 is that the ILT
23 818 is provided with additional flow isolation valves for both of its flow access interfaces
24 834, 836, which are located in the associated flow bores to provide double isolation
25 between the headers A and B and the interfaces 834 and 836. For example, the
26 production flowline header A can be isolated from the flow access interface 834 using the
27 arrangement of valves 865c and 865d and the production flowline header B can be
28 isolated from the flow access interface 834 using the arrangement of valves 865a and
29 865b. Double isolation, multiple isolation levels greater than two, and/or a combination of
30 isolation levels, can be provided for one or more of the bores forming flow access
31 interfaces in alternatively arranged flow systems by providing isolation valves in removable
32 modules (including flow access hubs and removable functional modules), in one or more
33 of the flow bores of the manifold (such as the ILT 818 or other manifold type) and/or in an
34 associated, fluidly connected manifold (such as the ILT 828 or other manifold).

35

1 To tie in a well – for example, the well associated with subsea tree XT4 – in a system
2 without isolation, the well of XT3 would typically be shut in and the production flowline
3 header A would be depressurised. This process is costly and time consuming as it halts
4 production from other wells connected to the flow system. However, the arrangement
5 shown in Figure 8A negates this requirement. Instead, the four valves shown generally at
6 871 in the ILT 818 can be closed until the tree XT4 is fluidly connected to the flow system
7 without impacting production from any of the other subsea wells connected to the flow
8 system 810.

9
10 Although not shown, it will also be appreciated that ROV hot stabs may be provided in any
11 of the manifolds, flow access hubs and/or removable functional modules for facilitating the
12 performance of seal assurance testing of the seals between these components.

13
14 Figure 8B shows an alternative flow system 910. In this arrangement, single isolation is
15 provided between each of the flow access interfaces 933, 935, 934 and 936 and the
16 production flowline headers A and B. Figure 8B demonstrates the flexibility allowed by
17 embodiments of the invention, specifically relating to the provision of flow components,
18 such as flow meters 966a, 966b and 966c.

19
20 The removable functional module 931 installed on the flow access hub 958 on the flow
21 access interface 933 of PLET 916 comprises a lower dual bore interface for fluidly
22 coupling to the dual bore interface of the hub 958 and an upper single bore interface. The
23 removable module 931 receives fluid from a subsea Christmas tree XT1 via the single
24 bore interface and routes the production fluid through a flow meter 966a provided in fluid
25 communication with the single bore interface, before selectively splitting the flow using
26 valves provided in the module 931 in combination with valves in the PLET 916 to route it
27 into either, or both, of production headers A and B.

28
29 The flow meter 966b has an alternative placement. In this arrangement, the removable
30 module 968 similarly comprises a lower dual bore interface for fluidly coupling to the dual
31 bore interface of the hub on flow access interface 935 and an upper single bore interface.
32 However, this removable module does not contain a flow meter. Instead, a further flow
33 access hub 967 is provided on the upper single bore interface of the removable module
34 968 between the subsea tree XT2 and the removable module 968, providing a dual bore
35 access interface 969. A flow meter module comprising flow meter 966b is fluidly connected

1 to the interface 969 for metering fluid flow from the tree XT2. This configuration is
2 advantageous because the flow meter 966b can be retrieved to the surface – for example,
3 for repair or replacement or to be swapped out completely for a different flow component -
4 without disturbing any of the wider flow system, including the connection between the
5 subsea tree XT2 and the flow system via the flow access hub 967. In contrast, to retrieve
6 the flow meter 966a associate with the production from Christmas tree XT1 the entire
7 removable module 931 must be recovered. This operation would be more complex,
8 requiring disconnection from the tree XT1 as well as the hub 958.

9
10 Like the flow meter 966b, the flow meter 966c can also be recovered individually without
11 disturbing the wider flow system. In this arrangement, the flow meter 966c is provided in a
12 flow meter module coupled to a flow access hub 970 provided on an external flowline
13 connector of the tree XT3.

14
15 It will be appreciated that in any of the foregoing embodiments, if and where flow access
16 hubs are provided, the flow access hubs can comprise any number of bores and define
17 single or multi-bore interfaces depending upon the layout and requirements of the flow
18 system. The hubs can be provided with valves and/or additional components, where
19 required. Likewise, removable functional modules can define one or more flow access
20 interfaces which may be single or multi-bore interfaces, or a combination of the two, and
21 may comprise isolation valves or other flow components, equipment, instrumentation or
22 access points as required.

23
24 In Figure 8C, a level of isolation has been removed by removing a number of the valves
25 from the PLET 1016 (i.e. when compared with the PLET 916 shown in Figure 2B). The
26 PLET 1016 has been further simplified by providing an electrically actuated valve 1072
27 instead of a hydraulically actuated valve. By doing so, hydraulic supply components and
28 connections can be removed from the PLET 1016. Replacing hydraulic valves with
29 electrically actuated valves in this manner can be performed throughout the distributed
30 manifold flow system 1010, if desired. For example, electrically actuated valves 1073a,
31 1073b, 1073c and 1073d can be provided in place of hydraulic valves.

32
33 Like the foregoing embodiments, the flow system of Figure 8D utilises removable modules
34 1131, 1168 and 1138 which each define a lower dual bore interface for fluidly coupling to
35 the dual bore interface of flow access hubs 958, for connecting them to the PLET and ILT.

1 Production fluid from the wells associated with trees XT1, XT2 and XT3 flow into a single
2 bore interface and through a single flowline of the modules 1131, 1168 and 1138,
3 respectively, before being selectively split in two. By providing an isolation valve 1174a,
4 1174b and 1174c in the single flowline section of the modules 1131, 1168 and 1138,
5 respectively, double isolation can be achieved for each of the flow bores in each module,
6 by using three valves instead of the usual four. Reducing the number of valves required to
7 provide double isolation has beneficial cost, weight and space saving implications, which
8 will appeal to some operators, particularly when operating within strict project constraints.
9 Again, in any of the configurations shown an electrically actuated valve can be provided in
10 place of a manual or a hydraulic valve, or vice versa.

11

12 Figure 8E shows a flow system 1210 having an ROV test pressure cap 1280 installed on a
13 flow access interface of the ILT 1218 via a flow access hub. Before production from the
14 well via Christmas tree XT4 commences, ROV test pressure cap 1280 allows for seal
15 assurance testing of the seal between the flow system components – known as a backseat
16 test – to be conducted. The module 1280 can be removed and replaced with an alternative
17 or preferred removable module following completion of the test to facilitate production.

18

19 Embodiments of the invention can also be used to support flow boosting configurations,
20 such as those shown in Figures 9A, 9B and 9C.

21

22 Figure 9A shows a pumping arrangement 1410, in which each of the flowline headers A
23 and B are production flowline headers. This arrangement is similar to that of the flow
24 system 110 of Figures 2A and 2B. However, instead of being connected by a single
25 flowline, the PLETS 1416 and 1424 are connected by two flexible jumper flowlines 1432a
26 and 1432b provided on either side of a pumping module 1482. The flexible jumper
27 flowlines 1432a and 1432b are connected to flowline connectors 1488a and 1488b on the
28 module 1482.

29

30 By operating valves within the flow system to selectively route production fluid, the
31 pumping module 1482 is operable to receive production fluid flowing from Christmas trees
32 XT1, XT2 and/or XT3 via the PLETS 1416 and 1424 and jumper flowlines 1432a and
33 1432a, which each form inlet flowlines to the pumping module 1482. The pumping module
34 boosts the flow rate of the production flow from trees XT1, XT2 and/or XT3 and discharges
35 the boosted flow via an outlet flowline connector 1489 which is connected to a flow access

1 interface 1418 of the PLET 1424 by a flexible jumper flowline 1490. The boosted
2 production flow is therefore recovered to the surface via production flowline header B. It
3 will be appreciated that a similar arrangement could be employed to boost flow in
4 production flowline header A.

5
6 An alternative pumping arrangement is shown in Figure 9B as 1510. Here, the flow system
7 functions in a manner which is similar to the flow systems 610, 810, 910, 1010 and 1110 of
8 Figures 7 and 8A to 8D, and will be generally understood with reference to the description
9 accompanying those drawings. In this embodiment, the pumping module 1582 has two
10 dual bore interfaces 1591a and 1591b, each interface having inlet bores 1592a and 1592b
11 for receiving production fluid from respective subsea trees, and export bores 1593a and
12 1593b for discharging the boosted production fluid to production flowline headers A or B
13 respectively. The system 1510 enables boosted production in flowline A, flowline B, or
14 both of flowlines A and B simultaneously (for example to benefit from a 50% reduction in
15 back pressure compared with a single flowline).

16
17 In the configuration shown, the valves have been opened/closed to provide boosted flow
18 from all four wells XT1 to XT4 through both flowlines simultaneously. However, by
19 opening and closing the valves in different combinations, production from wells XT1 and
20 XT2 could be boosted through flowline A while production is allowed to flow naturally
21 (unboosted) from wells XT3 and XT4 through flowline B. Alternatively, the valves can be
22 operated to allow production from wells XT1 and XT2 to flow naturally through flowline A
23 while production is boosted from wells XT3 and XT4 through flowline B. The valves can
24 also be operated to bypass the pumping module and allow production from any of the
25 wells to flow naturally through flowline A or flowline B selectively.

26
27 Figure 9C is a schematic P&ID of an alternatively configured subsea system, 2610. The
28 system 2610 functions similarly to the flow system 1510 and will be generally understood
29 with reference to the description accompanying Figure 9B. Like the system 1510, system
30 2610 comprises a pumping module 2682 having two dual bore interfaces 2691a and
31 2691b. Interface 2691a is fluidly connected to manifold 2616, and interface 2691b is
32 fluidly connected to manifold 2624. Flow paths connecting the interfaces 2691a and
33 2691b enable production fluid from the subsea trees to the pump inlet or to bypass the
34 pumping module to flow to the other of the manifolds. The system 2610 includes
35 additional flow routing and valves to enable fully selectable boosted production flow or

1 natural (unboosted) flow from any of the connected wells to either of the production
2 flowlines.

3

4 Manifold 2616 is similar to manifold 1516, but includes a second isolation valve 2683a
5 located on the downstream side of the manifold between the branch lines to the trees and
6 the production flowline A, to enable independent isolation of trees XT1 and XT2 from
7 flowline A without preventing flow to the manifold 2624 from either tree.

8

9 Manifold 2624 is similar to manifold 1524, but includes a connector 2684 for an outlet from
10 the pumping module 2682 on the downstream side of the manifold between the branch
11 lines to the trees and the production flowline, enabling pumping of boosted production flow
12 into production flowline B. Manifold 2624 also includes an isolation valve 2683b located
13 on the downstream side of the manifold between the branch lines to the trees and the
14 production flowline B, to enable isolation of trees XT3 and XT4 from flowline B without
15 preventing flow to the manifold 2616 from either tree.

16

17 The system 2610 enables flow from any of the connected wells to a naturally flowing
18 production flowline (flowline A) or a boosted production flowline (flowline B). In the
19 configuration shown, the valves have been opened/closed to enable natural flow from
20 wells XT1 and XT3 to flowline A, and boosted flow from wells XT2 and XT4 to flowline B
21 via the pump module 2682. However, by opening and closing the valves in different
22 combinations, production from any combination of the wells could be boosted through
23 flowline B while production is allowed to flow naturally (unboosted) from the other wells.
24 Alternatively, all the wells can be allowed to flow naturally through both or either flowline,
25 or all the wells can be boosted through flowline B.

26

27 Another feature of system 2610 is that it enables double isolation of the production
28 pipelines from the subsea tree interfaces utilising combinations of valves from the pair of
29 manifolds 2616 and 2624, without relying on arrangements of double inline isolation valves
30 that would increase bulk and weight of the system. This facilitates later tie-ins or other
31 operations that would otherwise require depressurisation of the pipeline system.

32

33 By providing flexible and adaptable subsea infrastructure solutions, embodiments of the
34 invention support future subsea field expansion. As such, the system can be adapted to

1 accommodate additional subsea wells in the future. Figures 10A, 10B and 10C show
2 examples of subsea field expansion configurations.

3

4 Figure 10A shows an expanded distributed manifold system generally at 1610. This
5 arrangement is similar to that of the flow system 110 of Figures 2A and 2B. However,
6 instead of being connected by a single flowline, the PLETS 1616 and 1624 are connected
7 by two flexible jumper flowlines 1632a and 1632b provided on either side of an additional
8 ILT 1695. As such, the flow system 1610 has been adapted to provide additional tie-in
9 points for subsea Christmas trees XT5 and XT6. By providing further manifolds and further
10 connecting flowlines, the principles of the invention can be employed to support further
11 expansion of the subsea field.

12

13 Figure 10B shows an expanded distributed manifold system 1710 which is similar to the
14 flow system 610 of Figure 7 and should be generally understood with reference to the
15 description accompanying Figure 7. The PLETS 1716 and 1724 are connected by two
16 pairs of flexible jumper flowlines 1732a, 1732b, 1732c and 1732d provided on either side
17 of a manifold 1796. The manifold comprises two main flowlines 1798 and 1799 which
18 fluidly communicate with production header flowlines A and B, as well as connecting
19 flowlines which fluidly couple a single bore of each dual bore interface to a respective main
20 flowline, for selective production to flowline headers A and/or B in the same manner as
21 described with reference to Figure 7. As such, the flow system 1710 is adapted to provide
22 additional tie-in points for subsea Christmas trees XT5 and XT6. By providing further
23 manifolds and further connecting flowlines, the principles of the invention can be employed
24 to support further expansion of subsea fields.

25

26 Figure 10C is similar to the arrangement shown in Figure 10B. However, the additional
27 manifold 1896 comprises four flow access interfaces to accommodate the connection of
28 four subsea wells: XT5, XT6, XT7 and XT8. In addition, a pumping module 1882 is
29 provided, which comprises a single dual bore interface 1897 fluidly connected to a
30 corresponding interface of the additional manifold 1896 via two flexible flowlines. The
31 pumping module functions in a similar manner to the pumping modules 1582 and 2682 of
32 Figures 9B and 9C, but differs in that it comprises a single dual bore interface 1897. The
33 interface comprises an inlet bore 1892 for receiving production fluid from the subsea trees
34 and an export bore 1893 for discharging the boosted production fluid to either of
35 production flowline headers A or B.

1
2 The foregoing embodiments relate to flow systems including two production pipelines, and
3 configurations of spatially distributed manifolds and flow components which enable
4 selective flow of production fluid from wells into the chosen pipelines. However, the
5 principles of the invention extend to the connection of flow components and manifolds in
6 flow systems that utilise a single production pipeline. An example is illustrated in Figure
7 11, which shows a flow system 1310 including a single production pipeline B, and a
8 second pipeline A in the form of a gas lift or service pipeline. The gas lift pipeline enables
9 gas injection into the wells, and flowline header B is a production flowline header for
10 exporting production flow from the wells to the surface.

11
12 In this configuration, subsea Christmas trees XT1 and XT2 are located between subsea
13 PLETs 1316 and 1324. Each tree is connected to each respective PLET 1316 and 1324
14 by a flexible jumper flowline, a flow access hub and a removable functional module.

15
16 Taking XT1 as an example, the flowline 1381a couples XT1 to a flow access hub 1383a
17 located on a flow access interface 1384a of PLET 1316 and the flowline 1381b couples
18 XT1 to a flow access hub 1383b located on a flow access interface 1384b of PLET 1324.
19 Removable functional modules 1385a and 1385b complete the fluid connection between
20 the tree XT1 and the PLETs 1316 and 1324 which are integrated into flowline headers A
21 and B, respectively. XT2 has a similar flow arrangement. XT3 is also similarly connected to
22 the flow system 1310, but instead via ILTs 1318 and 1326. In use, the gas lift pipeline is
23 able to feed gas from surface to each of the wells at XT1, XT2, and XT3 via the respective
24 removable functional modules, which can control and meter the gas flow into the wells.

25
26 The gas lift injection lines, removable modules, or indeed the gas lift pipeline itself can be
27 installed when needed to support the production from the wells in the system. In some
28 fields, installation of one or more of the gas lift components may be later than the time of
29 installation of the production flowline, which may initially produce without gas lift
30 operations.

31
32 The ILT 1326 to which Christmas tree XT3 is coupled for production comprises an
33 additional dual bore access interface 1386 which is not connected to a well. Instead, a
34 pump module 1382 is connected to the access interface 1386 by a pair of flexible jumper
35 flowlines and a flow access hub 1387. In use, the pump module 1382 can be used to boost

1 the production flow rate of production header B. It will be appreciated that a pump module
2 could also be provided in fluid communication with flowline header A, or in a second
3 production header of a system comprising two production headers. More than one pump
4 module can also be provided for additional boosting. Although the pump module is fluidly
5 coupled to the header B via the ILT 1326, it will be appreciated that the module could be
6 connected to the header B in alternative ways. For example, it could be directly connected
7 to or integrated with the header and/or could be connected to a different manifold or
8 manifold access point in communication with the flowline header. The pump module may
9 be installed later than the time of installation of the production flowline, which may initially
10 produce without pumping capability.

11

12 Figures 12A to 12D are respectively plan, exploded isometric, first exploded longitudinal
13 sectional and second exploded longitudinal sectional views of an assembly according to a
14 preferred embodiment of the invention. Figure 12C is a section through line A-A of Figure
15 12A, and Figure 12D is a section through line B-B of Figure 12D. The assembly, generally
16 shown at 700, comprises a connector hub 755, a manifold interface sub-assembly 744,
17 and a module interface sub-assembly 738 of a removable module (the majority of the
18 removable module is omitted for clarity, with only the lower interface sub-assembly 738
19 being shown).

20

21 The manifold interface sub-assembly 744 is fluidly connected to two flow bores 745, 746 of
22 a manifold (not shown), which may be an ILT, PLET or alternative manifold, described with
23 reference to Figures 2A to 7. In this embodiment, the interface sub-assembly 744 has a
24 concentric dual bore interface, comprising a central bore 747 in communication with bore
25 745, and annulus bore 748 in communication with bore 746.

26

27 The connector hub 755 has a body 756, which has a lower dual bore interface in the same
28 concentric configuration as the flowline connector 744, comprising a central bore 757 and
29 an annulus bore 758. The bores 757 and 758 extend generally axially through the body
30 756 to respective openings 759A, 759B in a module interface at the upper end of the hub.

31

32 In addition, the hub 755 comprises a flowline connector bore 759 for connection to a
33 jumper flowline 714, which typically functions as a fluid inlet for fluid from the jumper
34 flowline 714, for example from a connected production well. The flowline connector bore
35 753 is substantially radially oriented with respect to the body 756 (whereas the bores 757,

1 758 are substantially axially oriented in the body). The jumper flowline 714 may be
2 connected to the flowline connector bore by any suitable industry connector, but in
3 preferred embodiments the jumper flowline 714 and the hub 755 are integrally formed so
4 that the hub 755 is a part of the jumper system (or jumper envelope) and can be installed
5 or retrieved with the jumper flowline itself.

6

7 The flowline connector bore 759 redirects within the body 756 to be in fluid communication
8 with a third opening 759C on an upper module interface on the hub. The upper module
9 interface therefore comprises three separated and parallel axial bores.

10

11 The removable module has a triple-bore lower interface 738 corresponding to the triple-
12 bore upper interface of the hub 755.

13

14 The assembly and in particular the hub 755 enable a three-way connector incorporating a
15 flowline inlet to be created on a dual bore interface. The assembly 700 has general
16 application to the provision of a three-way connection on a manifold, but in addition is a
17 preferred configuration of installations according to embodiments of the invention
18 described herein. In particular, the assembly 700 can be used with Branch FAM modules
19 described with reference to Figures 4A and 4B, as the hub 338. The openings 759A and
20 759B are configured to be coupled to the outlets of the flow control means of the module
21 and connect the module to the first and second flow paths within the manifold (to the first
22 and second production headers respectively). The flowline bore 753 receives production
23 fluid from the production jumper flowline from a connected subsea well, and the production
24 fluid flows through the hub to exit through the opening 759C to the module. In the module,
25 the fluid flows through the flowmeter to the flow control means, where it is selectively
26 flowed to one or other production header.

27

28 The parallel triple-bore connection between the hub 755 and the module 738 requires
29 precise alignment and azimuthal orientation in order for the bores to be properly coupled,
30 and therefore can only be made in one angular orientation. In contrast, the connection
31 between the concentric bores of the hub 755 and the connector 744 can be made at any
32 angular orientation without risking the pairing of incompatible flowlines. This allows for
33 quicker and easier installation of the parts, and a range of possible azimuthal departure
34 angles for the jumper flowline 714. The assembly may be used with flexible jumper
35 flowlines or rigid jumper flowlines depending on system requirements. The flexibility of the

1 azimuthal departure angles for the jumper flowline 714 means that the assembly is
2 particularly suited for use with M-shaped rigid jumper flowlines.
3
4 In alternative embodiments, for example where the installation is not sensitive to departure
5 angles, the manifold interface and the lower interface on the hub may be of a non-
6 concentric dual bore configuration. Configurations in which the dual bore manifold
7 interface for the hub is integrated into the manifold, as well as configurations in which the
8 dual bore interface is formed on the manifold by the installation of a sub-assembly on the
9 manifold, are within the scope of the invention. In a further alternative configuration, the
10 triple bore interface of the hub is a triple concentric bore interface, rather than the parallel
11 axial bore interface shown in Figure 12B. The removable module would then have a
12 concentric triple-bore lower interface corresponding to the concentric triple-bore upper
13 interface of the hub, so that coupling of the module and the hub is not sensitive to precise
14 alignment and azimuthal orientation.
15
16 Figures 13 to 16C show alternative assemblies to the concentric flow bore arrangement of
17 Figures 12A to 12D, having hubs with parallel flow bore arrangements. In some concentric
18 arrangements, a collapsing force can be created between the annulus bore and the central
19 bore, due to the pressure differential between the bores. Where this is likely to happen,
20 parallel bore arrangements may be preferred.
21
22 The assemblies function generally in the same way as that of Figures 12A to 12D and their
23 operation will be understood with reference to Figures 12A to 12D and the accompanying
24 description.
25
26 The assembly of Figure 13, generally shown at 1900, comprises a connector hub 1955, a
27 manifold interface sub-assembly 1944, and a module interface sub-assembly 1938 of a
28 removable module (the majority of the removable module is omitted for clarity, with only
29 the lower interface sub-assembly 1938 being shown). The module interface sub-assembly
30 1938 comprises three upper bore openings and three lower bore openings, one
31 corresponding to each of the bores 1959A, B and C of the connector hub 1955.
32
33 The manifold interface sub-assembly 1944 is fluidly connected to two flow bores 1945,
34 1946 of a manifold (not shown), which may be an ILT, PLET or alternative manifold,
35 described with reference to Figures 2A to 7. In this embodiment, the interface sub-

1 assembly 1944 has an off-centre parallel dual bore interface, comprising a first bore 1947
2 in communication with bore 1945, and a second bore 1948 in communication with bore
3 1946. The interface sub-assembly 1944 therefore acts as an adaptor. It shifts the axially
4 symmetrical configuration of the flow bores 1945, 1946 of the manifold (not shown) to an
5 off-centre parallel dual bore arrangement, to present an interface complimentary to the
6 lower interface of the connector hub 1955 and thereby facilitate connection of the
7 connector hub 1955 to the manifold (not shown).

8

9 The connector hub 1955 has a body 1956, which has a lower dual bore interface (not
10 shown) in the same parallel configuration as the manifold interface sub-assembly 1944,
11 comprising parallel bores. The bores extend generally axially through the body 1956 to
12 respective parallel openings 1959A, 1959B in a module interface at the upper end of the
13 hub.

14

15 In addition, the hub 1955 comprises a flowline connector bore 1953 for connection to a
16 jumper flowline (not shown), which typically functions as a fluid inlet for fluid from the
17 jumper flowline, for example from a connected production well. The flowline connector
18 bore 1953 is substantially radially oriented with respect to the body 1956 (whereas the
19 bores of the lower dual bore interface (not shown) of the hub 1955 are substantially axially
20 oriented in the body). The jumper flowline may be connected to the flowline connector
21 1953 bore by any suitable industry connector. In arrangements of the invention the jumper
22 flowline and the hub 1955 are integrally formed so that the hub 1955 is a part of the jumper
23 system (or jumper envelope) and can be installed or retrieved with the jumper flowline
24 itself.

25

26 The flowline connector bore 1953 redirects within the body 1956 to be in fluid
27 communication with a third opening 1959C on an upper module interface on the hub 1955.
28 The upper module interface therefore comprises three separated and parallel axial bores.

29

30 The removable module has a triple-bore lower interface 1938 corresponding to the triple-
31 bore upper interface of the hub 1955.

32

33 The parallel triple-bore connection between the hub 1955 and the interface sub-assembly
34 1944 requires precise alignment and azimuthal orientation in order for the bores to be
35 properly coupled, and therefore can only be made in one angular orientation. Therefore, in

1 the assembly 1900 the azimuthal departure angle for the jumper flowline (not shown) is set
2 by the location of the flowline connector bore 1953. The hub 1955 can be machined to
3 orient the flowline connector bore 1953 in the required location.

4

5 The assembly of Figure 14A is similar to that shown in Figure 13 and will be understood
6 with reference to the description accompanying Figure 13, with like features indicated by
7 like reference numerals incremented by 100. The assembly 2000 differs from the
8 assembly 1900, in that it includes an alternatively configured flowline connector hub 2055
9 (shown in Figures 14A and 14B).

10

11 The connector hub 2055 has a body 2056, which has a lower dual bore interface (not
12 shown) in the same parallel configuration presented by the manifold interface sub-
13 assembly 2044, comprising parallel bores. The bores extend generally axially through the
14 body 2056 to respective parallel openings 2059A, 2059B in a module interface at the
15 upper end of the hub.

16

17 In addition, the hub 2055 comprises a flowline connector bore 2053 for connection to a
18 jumper flowline (not shown). In the embodiment shown in Figures 14A and 14B, the body
19 2056 of the hub 2055 has been cut away, to accommodate an elbow piece 2063 which
20 forms the flowline connector bore 2053. The elbow piece 2063 is fluidly coupled to a bore
21 2061 on a cut-away surface of the hub 2055 which is in fluid communication with the third
22 opening 2059C on an upper module interface on the hub 2055.

23

24 The elbow piece 2063 is welded to the bore 2061 in a selected orientation to provide a
25 flowline connector bore 2053 having a chosen azimuthal departure angle for the jumper
26 flowline (not shown). The orientation of the flowline connector bore 2053 and thus the
27 departure angle offered to a jumper flowline by the hub differs between Figures 14A and
28 14B, as the elbow piece 2063 is welded (i.e. fixed) in a different manner in each figure.

29

30 By providing a cut-away hub body 2056 in this way, the machining required to produce a
31 hub 2055 having an optimum azimuthal departure angle for a jumper flowline is
32 substantially reduced.

33

34 The assembly of Figure 15A is similar to that shown in Figures 14A and 14B and will be
35 understood with reference to the description accompanying those figures, with like

1 features indicated by like reference numerals incremented by 100. The assembly 2100
2 differs from the assembly 2000, in that it includes an alternatively configured flowline
3 connector hub 2155 (shown in Figures 15A and 15B).

4

5 Instead of being welded to the hub, the flowline connector bore 2053 is formed by an
6 elbow piece 2163 having an integral end flange 2165 comprising various apertures for
7 receiving bolts. The elbow piece 2163 is fluidly coupled to a bore 2161 on a cut-away
8 surface of the hub 2155 via the bolted flange 2165, the cut-away surface comprising
9 complimentary apertures for receiving the bolts and coupling the elbow piece 2163 to the
10 hub 2155.

11

12 By rotating the flange 2165 with respect to the bore 2161 and bolting it in place, the
13 orientation of the elbow piece 2163 can be adjusted. Therefore, the elbow piece 2163 can
14 be selectively coupled to the bore 2161 in to provide a flowline connector bore 2153
15 having a chosen azimuthal departure angle for the jumper flowline (not shown). As the
16 elbow piece 2163 and the bolted flange 2165 are one, integral piece, the elbow piece 2163
17 will have a number of rotational positions depending upon the number of bolts on the
18 flange 2165 and corresponding apertures in the cut-away surface of the hub 2155.

19

20 The orientation of the flowline connector bore 2153 and thus the departure angle offered to
21 a jumper flowline by the hub differs between Figures 15A and 15B, as the elbow piece
22 2063 is bolted in a different manner in each figure.

23

24 By providing a flanged elbow piece in this way, the hub 2155 is adaptable. The azimuthal
25 departure angle for a jumper flowline can be changed, in future, by adjusting the position
26 of the flange 2165 with respect to the hub 2155.

27

28 It will be appreciated that alternative flanged arrangements could also be provided. For
29 example, the elbow piece may be rotatably with respect to the flange, so that the radial
30 position of the flowline connector bore 2153 can be indexed whilst the flange 2165 remains
31 in place, fixed to the hub 2155.

32

33 The assembly of Figure 16A is similar to that shown in Figures 15A and 15B and will be
34 understood with reference to the description accompanying those figures, with like
35 features indicated by like reference numerals incremented by 100. The assembly 2200

1 differs from the assembly 2200, in that it includes an alternatively configured flowline
2 connector hub 2255 (shown in Figures 16A and 16C).

3

4 Instead of being bolted to the hub by a flange, the flowline connector bore 2253 is formed
5 by an elbow piece 2263 having a straight extension portion 2267. The elbow piece 2263 is
6 a removable insert, the extension portion 2267 of which is inserted into the hub bore 2261
7 (as shown by the arrow in Figure 16B) in any desired orientation to provide a flowline
8 connector bore 2253 having a chosen azimuthal departure angle for a jumper flowline (not
9 shown). The insert is fixed in place by in the hub, for example by a clip (such as a circlip)
10 or a clamp. The elbow piece 2263 insert is freely rotatable with respect to the axis of the
11 hub body 2256. This configuration is advantageous as the orientation of the elbow 2263
12 with respect to the hub 2255 and, as a result, the flowline connector bore 2153, is not
13 restricted by the number and the position of bolts, like that of the elbow piece of Figures
14 15A and 15B. The assembly may comprise a fixing means to fix the insert in place,
15 temporarily or permanently.

16

17 In the embodiments shown in Figures 14A to 16C, the elbow section may have a different
18 shape, size or orientation. Likewise, the cut-out section of the hubs may be configured
19 differently.

20

21 In the embodiments shown in Figures 12 to 16C, the manifold interface sub assembly may
22 be omitted, and the connector hub may be connected directly to the bore of a manifold
23 interface. Alternatively, the connector hub and the manifold interface sub assembly may be
24 combined to as a single component. In further alternative configurations, the triple bore
25 interfaces of the hub may be triple concentric bore interface, rather than the parallel axial
26 bore interfaces shown. The removable modules would then have a concentric triple-bore
27 lower interface corresponding to the concentric triple-bore upper interface of the hubs, so
28 that coupling of the module and the hub is not sensitive to precise alignment and azimuthal
29 orientation.

30

31 Although the terms upper and lower have been used to describe the configuration of fluid
32 interfaces and connections throughout this specification, these are relative terms, and may
33 be interchangeable with horizontal interfaces where a horizontal connection is made
34 between components instead of a vertical connection.

35

1 Although the figures and the forgoing description describe fluid entering the distributed
2 manifold system from a subsea Christmas tree, it will be appreciated that production fluid
3 from alternative types of manifold (such as a well gathering manifold) or source may be
4 routed into the distributed manifold system. For example, a well gathering manifold may
5 comeingle the production fluid from a number of subsea wells, which may then be routed
6 into and through a manifold of the subsea distributed manifold system in the same manner
7 as described above with reference to a subsea Christmas tree.

8

9 It will also be appreciated that, although one flow of production fluid is described as
10 coming from each subsea well, additional and/or parallel flowlines may be provided which
11 may carry, for example, gas to and from a well for gas lift operations.

12

13 It will be appreciated that although the distributed manifold systems described above are
14 said to comprise ILTs and PLETs, they may instead (or also) comprise alternative types of
15 manifold.

16

17 It will also be appreciated that the various manifolds and removable modules described
18 throughout can be adapted to have vertical and/or horizontal connection points depending
19 on system requirements.

20

21 The distributed manifold system functions in a similar way to that of a conventional twin
22 header manifold. However, due to the nature of the distributed manifold system – which is
23 made up of various manifolds (such as ILTs and PLETs) displaced from one another and
24 connected by jumper flowlines, as opposed to a single, rigid manifold structure – the
25 subsea field development has increased flexibility. A conventional twin header manifold
26 sets fixed connection points for subsea wells on the manifold structure, whereas the
27 distributed manifold configuration of the present invention allows manifolds to be placed at
28 optimal positions on the seabed, to suit field development and reservoir geometry. This
29 also allows for flexibility in top hole locations and, in some cases, negates the need for
30 side-tracked wells.

31

32 Where future field development is expected, a large conventional manifold with surplus
33 well connection points might be provided to accommodate any additional wells that are
34 developed in the future. This will require large capital expenditure. In addition,

1 conventional and/or modified manifolds for this use tend to have long lead times and
2 require specialist vessels to deploy and install.

3

4 In contrast, the distributed manifold system of the present invention can be retrofitted into
5 an existing subsea system to facilitate production from additional wells. The system can be
6 provided to suit current field needs and further extended with the addition of smaller
7 manifolds and flowlines when and if it becomes necessary to connect further subsea wells
8 to the system. As the manifolds used in the distributed system are more compact and
9 more readily available (as use can be made of standard components), lead times and
10 capital expenditure are reduced.

11

12 Conventional manifolds for the connection of multiple wells require foundation piles to
13 provide the necessary support. Such manifolds also have specific installation requirements
14 which might include the use of specialist vessels. The flow components which form the
15 distributed manifold are, in contrast, smaller and lighter; requiring less seabed support and
16 removing the need for specialist installation vessels.

17

18 The comparatively compact nature of the manifolds utilised by the distributed manifold
19 system of the present invention, along with the provision of additional instrumentation,
20 valving and equipment in removable modules, makes the system easier to deploy and
21 install. The manifolds are small and light enough to be integrated into the production
22 pipeline and handled by the pipelay mechanisms on a conventional pipelay vessel. The
23 removable modules can also be deployed and fitted using smaller vessels such as
24 remotely operated vehicles (ROVs) at a later date (if not initially required).

25

26 It will be appreciated that variations to flow routing, valve configuration and placement, and
27 combinations of features and functions from different described embodiments are within
28 the scope of invention, and additional pressure test valves and chemical injection points
29 may be incorporated into the systems at various locations to facilitate testing and flow
30 assurance operations.

31

32 The invention provides a subsea oil and gas production installation, methods of installing
33 the installation and methods of use. The installation comprises a subsea production
34 system comprising a first production pipeline and a second production pipeline, a first
35 subsea manifold in fluid communication with the first production pipeline comprising a fluid

1 access interface and a flowline connector, a removable module fluidly connected to the
2 fluid access interface of the first subsea manifold and configured to receive production fluid
3 from one or more subsea wells and a second subsea manifold in fluid communication with
4 the second production pipeline. The first subsea manifold defines a first flow path between
5 the fluid access interface and the first production pipeline and a second bypass flow path
6 between the fluid access interface and the flowline connector. The first and the second
7 subsea manifolds are fluidly coupled to one another by a connecting flowline which is
8 connected at a first end to the flowline connector of the first subsea manifold. The
9 removable module comprises a flow control means operable to selectively route the
10 production fluid from one or more subsea wells into the first production pipeline via the first
11 flow path defined by the manifold, and/or into the second production pipeline via the
12 second bypass flow path, the connecting flowline and the second subsea manifold.
13
14 Various modifications to the above-described embodiments may be made within the scope
15 of the invention, and the invention extends to combinations of features other than those
16 expressly claimed herein.
17