

1 Well Control System and Method of Use

2

3 The present invention relates to drilling well control systems and method of use, and in
4 particular to managed pressure drilling for subsea applications. A particular aspect of the
5 invention relates to converting existing drilling systems to enable managed pressure
6 drilling operations.

7

8 Background to the invention

9

10 Drilling operations typically use a rotating drill bit on the end of a drill string. Mud is
11 pumped down the drill string from a rig mud pumping system and returned to the surface
12 flowing in the annulus between the drill string and the well. The returning mud exits the
13 annulus above a blow-out preventer (BOP) into a mud return line where it freely flows into
14 solids control equipment to allow sand and cuttings to be removed from the well. The mud
15 is stored in holding tanks until it is pumped back down the well.

16

17 The mud which is pumped down the drill string performs multiple functions, including
18 providing hydraulic power to drilling tools at the end of the drill string, stabilising the well,
19 and cooling the drill bit. The mud provides pressure in the well which prevents an influx of
20 pressurised gas or oil from any hydrocarbon bearing formations. The pressure is a function
21 of the mud density, friction in the wellbore caused by the flowing mud, and the vertical
22 depth of the well. The density of the mud must be controlled to provide a pressure at the
23 bottom of the well which is above the pore pressure (the pressure at which the well may
24 collapse or allow a hydrocarbon influx) but below the fracture pressure (the pressure
25 where the well structure could fracture).

26

27 Managed Pressure Drilling (MPD) is a form of drilling where the pressure at the bottom of
28 the well is more precisely controlled using various methods apart from controlling the mud
29 density. MPD is used to drill wells in conditions where the local geology makes
30 conventional drilling difficult or impossible.

31

32 For MPD operations the mud circulation system becomes a closed loop with returning mud
33 from the wellbore flowing into an arrangement of valves or manifolds that can apply
34 backpressure or route the flow to other processing systems. The annulus is capped above
35 the BOP using a seal, typically a rotating control device (RCD).

1 Offshore drilling relies on the use of a tubular, known as a drilling riser, which allows the
2 annulus to extend from the seabed to the surface. For floating drilling vessels, a riser
3 section known as a slip joint or telescopic joint is used to allow the free movement of the
4 drilling vessel caused by wave motion.

5
6 Managed pressure drilling systems are known which utilise a managed pressure drilling
7 manifold comprising metering, distribution and choke manifolds mounted on a skip on the
8 rig at surface. However, these manifolds are bulky and take up considerable space on a
9 rig or drill ship. The manifolds also require numerous hoses and control lines to be run
10 from the riser to the manifold.

11
12 Summary of the invention

13
14 It is an object of an aspect of the present invention to obviate or at least mitigate the
15 foregoing disadvantages of prior art well control and managed pressure drilling systems.

16
17 It is another object of an aspect of the present invention to provide a robust, reliable and
18 compact well control system suitable for deployment on riser assemblies used in a variety
19 of drilling.

20
21 It is a further object of an aspect of the present invention to provide marine risers with a
22 managed pressure drilling system with improved reliability and accessibility.

23
24 It is another object of an aspect of the present invention to provide a marine riser
25 conversion system for managed pressure drilling operations.

26
27 Further aims of the invention will become apparent from the following description.

28
29 According to a first aspect of the invention there is provided a well control system for a
30 riser comprising:

31 a riser assembly; and
32 at least one flow meter;

33 wherein the at least one flow meter is configured to be mounted on the riser.

34

35

1 The at least one flow meter may be configured to be mounted on or located on an outer
2 surface of the riser above or below a tension ring.

3

4 The at least one flow meter may be a differential pressure flow meter. The at least one
5 flow meter may be selected from the group comprising orifice plate, wedge, venturi,
6 Coriolis, Pitot tubes and/or variable area flow meters.

7

8 The system may comprise a control unit. The control unit may be configured to receive at
9 least one measurement signal from the at least one flow meter and analyse the
10 measurement signal in the control unit to monitor drilling fluid flow in the riser and/or in a
11 least one mud return line.

12

13 The control unit may be configured to analyse the measurement signal to monitor at least
14 one parameter or at least one property of the drilling fluid or drilling fluid flow in the riser
15 and/or in a least one mud return line.

16

17 The control unit may determine or calculate a Reynolds number for the drilling fluid flow.

18 The control unit may be configured to correct the Reynolds number as the properties of the
19 drilling fluid change. The properties of the fluid change may change due to contaminants
20 from debris, hydrocarbons, cuttings, sand, water etc.

21

22 The control unit may be configured to compare the at least one parameter with a desired
23 range of operating parameters. The control unit may be configured to generate a control
24 signal when the at least one parameter is determined to be outside of the desired range of
25 operating parameters.

26

27 The control unit may be configured to calculate, estimate or predict the density and/or
28 viscosity of the flowing drill fluid. The control unit may be configured for gas determination.

29

30 The at least one flow meter may have a flow measurement range of 10 to 2000 USG/min.

31 The system may comprise two or more flow meters. Each flow meter may have different
32 fluid flow range and/or fluid density range.

33

34 Preferably the system has two or more flow meters. The two or more meters may be
35 arranged in series or parallel. The two or more meters may be mounted in a meter

1 manifold. A first flow meter may have a flow measurement range of 10 to 400 USG/min. A
2 second flow meter may have a flow measurement range of 100 to 2000 USG/min.

3

4 The internal diameters of the flow meters may be selected to determine a flow
5 measurement range. A 2 inch diameter may be selected to have a flow measurement
6 range of 10 to 400 USG/min. A 5 inch diameter may be selected for a flow measurement
7 range of 100 to 2000 USG/min.

8

9 Preferably the riser assembly comprises a riser isolation device. The at least one flow
10 meter may be mounted in at least one meter manifold. The riser isolation device and/or the
11 at least one flow meter manifold may be located on a riser above a riser tension ring. The
12 riser isolation device and/or at least one flow meter manifold may be located on a riser
13 below a riser tension ring.

14

15 The riser assembly may comprise at least one choke assembly. The at least one choke
16 assembly may be mounted on the riser. The at least one choke assembly may be a choke
17 manifold. The at least one choke assembly may be located on a riser above or below a
18 riser tension ring. The at least one choke assembly may be mounted on or located on the
19 outer surface of a riser above or below a riser tension ring.

20

21 The riser assembly may comprise a rotating control device. The rotating control device
22 may be located on a riser above or below a riser tension ring.

23

24 The at least one choke assembly and/or at least one flow meter assembly may form part of
25 a managed pressure drilling manifold. The managed pressure drilling manifold may be
26 mounted on the riser. The managed pressure drilling manifold may be mounted on or
27 located on the outer surface of a riser above or below a riser tension ring.

28

29 The at least one flow meter may be integrated with a flow spool and/or the at least one
30 choke assembly. The riser assembly may comprise an integrated flow spool, choke
31 manifold and/or flow meter manifold on a riser joint or a riser slip joint. The riser slip joint
32 may be a retrievable riser slip joint. The riser assembly may comprise an upper riser
33 disconnect assembly. The upper riser disconnect assembly may be located above the riser
34 tension ring.

35

1 The riser isolation device, at least one flow meter, at least one choke assembly, rotating
2 control device and/or the managed pressure drilling manifold may be located on a riser
3 and/or slip joint above the upper riser disconnect assembly.

4

5 By providing at least flow meter on the riser allows improved well control as properties of
6 the drilling fluid and returns can be accurately measured and/or monitored. It also provides
7 improved hose management as hoses and control lines are not required to be run from the
8 riser to flow meters located at surface. Providing a flow meter directly on the riser also
9 avoids locating bulky metering manifolds on the rig.

10

11 By providing components of a riser assembly above an upper riser disconnect assembly
12 above the tension ring may enable the components to be installed, removed or replaced
13 easily.

14

15 The upper riser assembly comprising slip joint, at least one flow meter, at least one choke
16 assembly, rotating control device and/or the managed pressure drilling manifold may be
17 installed on the riser and the RCD and/or other MPD equipment kept offline during
18 conventional drilling and only brought online for a required MPD operation.

19

20 The at least one choke assembly may receive drilling fluid from the riser annulus below the
21 RCD. The at least one choke assembly may be an MPD choke.

22

23 The upper riser disconnect assembly, riser isolation device, at least one flow meter, at
24 least one choke assembly, rotating control device and/or the managed pressure drilling
25 manifold may be controlled remotely.

26

27 The at least one flow meter may be an in-line flow meter. The at least one flow meter may
28 be configured to be connected to a distribution assembly comprising at least one valve
29 assembly. The distribution assembly may be located on the riser. The at least one flow
30 meter and/or the distribution assembly may be connected to the at least one choke
31 assembly mounted on the riser. The distribution assembly may comprise at least one
32 spool or hose connecting the at least one flow meter and/or the at least one choke
33 assembly.

34

1 The at least one valve assembly on the riser may be configured to open a pathway
2 between the riser annulus and the distribution assembly, at least one flow meter and/or at
3 least one choke assembly.

4

5 The tension ring may be disposed circumferentially about a portion of the riser, a portion of
6 the RID, a portion of slip joint, an outer barrel of a slip joint, a portion of the upper riser
7 disconnect assembly and/or a tension joint.

8

9 The upper riser disconnect assembly may comprise an upper connector and a lower
10 connector. The upper and lower connectors may be configured to disconnect from one
11 another. The separated upper and lower connectors may be configured to connect to one
12 another.

13

14 The slip joint may be a two-part slip joint. Alternatively, the slip joint may be a three or
15 more part slip joint. The slip joint may comprise at least one sealing assembly. The slip
16 joint may be a telescopic joint. The slip joint may comprise two telescopic members. The
17 slip joint may comprise more than two telescopic members.

18

19 According to a second aspect of the invention there is provided a riser assembly
20 comprising:

21 a riser; and

22 a managed pressure drilling manifold mounted on the riser.

23

24 The managed pressure drilling manifold may comprise at least one flow meter module, at
25 least one choke module and/or at least one valve assembly.

26

27 The managed pressure drilling manifold may comprise an integrated flow spool, choke
28 manifold and/or metering manifold. The managed pressure drilling manifold may be
29 mounted on a retrievable riser slip joint.

30

31 The least one flow meter module may comprise at least one flow meter. The at least one
32 flow meter may be an inline flow meter. The at least one flow meter may be configured to
33 be connected to a distribution assembly comprising at least one valve assembly. The
34 distribution assembly may be located on the riser. The at least one flow meter and/or the
35 distribution assembly may be connected to the at least one choke assembly mounted on

1 the riser. The distribution assembly may comprise at least one spool or hose connecting
2 the at least one flow meter and/or the at least one choke assembly.

3

4 The at least one valve assembly on the riser may be configured to open a pathway
5 between the riser annulus and the distribution assembly, at least one flow meter and/or at
6 least one choke assembly.

7

8 The riser assembly may be connected to or installed onto a riser system to allow a
9 managed pressure drilling operation without requiring structural modifications to riser. The
10 upper riser assembly comprising a riser isolation device and a managed pressure drilling
11 manifold may be connected to the upper riser disconnect assembly located above the
12 tension ring.

13

14 Embodiments of the second aspect of the invention may include one or more features of
15 the first aspect of the invention or its embodiments, or vice versa.

16

17 According to a third aspect of the invention there is provided a system for well control
18 comprising:

19 an upper riser assembly comprising

20 an upper riser disconnect assembly; and

21 at least one flow meter assembly, wherein the at least one flow meter assembly is
22 mounted on the upper riser assembly.

23

24 The at least one flow meter assembly may be mounted on an outer surface of the upper
25 riser assembly. The upper riser assembly may comprise a riser isolation device. The upper
26 riser assembly may comprise a slip joint. The at least one flow meter assembly may be
27 mounted on an outer surface of the slip joint.

28

29 The slip joint and/or the riser isolation device may be mounted to the upper riser
30 disconnect assembly above the upper riser disconnect assembly.

31 The upper riser assembly may be connectable to a lower riser. The upper riser assembly
32 may be connected to a lower riser by connecting the upper riser disconnect assembly to
33 the riser. The upper riser assembly may be connected to a riser above a riser tension ring.

34

1 The system may comprise at least one choke assembly. The at least one choke assembly
2 may be mounted on the upper riser assembly. The at least one choke assembly may be
3 mounted on the slip joint. The upper riser assembly may be a self-contained well control
4 system.

5

6 The at least one flow meter and/or at least one choke assembly may be integrated with a
7 flow spool. The integrated at least one flow meter, at least one choke assembly and
8 integrated flow spool system may be mounted on a retrievable slip joint.

9

10 The riser assembly may comprise a rotating control device. The rotating control device
11 may be located in the system between the slip joint and the RID.

12

13 The at least one choke assembly and/or at least one flow meter assembly may form part of
14 a managed pressure drilling manifold. The managed pressure drilling manifold may be
15 mounted on the upper riser assembly and/or slip joint.

16

17 Embodiments of the third aspect of the invention may include one or more features of the
18 first or second aspects of the invention or its embodiments, or vice versa.

19

20 According to a fourth aspect of the invention there is provided a system for managed
21 pressure drilling in a riser comprising:
22 an upper riser assembly comprising:
23 an upper riser disconnect assembly;
24 a rotating control device; and
25 at least one flow meter assembly, wherein the at least one flow meter assembly is
26 mounted on the upper riser assembly.

27

28 The upper riser assembly may comprise a slip joint. The upper riser assembly may
29 comprise riser isolation device. The riser isolation device may be mounted to the upper
30 riser disconnect assembly above the upper riser disconnect assembly.

31

32 The upper riser assembly may be connectable to a lower riser. The upper riser assembly
33 may be connected to a lower riser by connecting the upper riser disconnect assembly to a
34 riser. The upper riser assembly may be connected to a riser above a riser tension ring.

35

1 The system may comprise at least one choke assembly. The at least one choke assembly
2 may be mounted on the upper riser assembly. The at least one choke assembly may be
3 mounted on the slip joint.

4

5 The at least one choke assembly and/or at least one flow meter assembly may form part of
6 a managed pressure drilling manifold. The managed pressure drilling manifold may be
7 mounted on the upper riser assembly and/or slip joint.

8

9 The upper riser assembly and/or the slip joint may comprise a self-contained well control
10 system. The self-contained well control system may comprise at least one flow meter, at
11 least one choke assembly and/or an integrated flow spool.

12

13 The riser isolation device, at least one flow meter, at least one choke assembly, rotating
14 control device and/or the managed pressure drilling manifold may be located above the
15 upper riser disconnect assembly.

16

17 Providing at least flow meter and/or at least one choke assembly and RCD on the upper
18 riser assembly avoids the requirement for surface MPD flow meter and choke manifolds.

19

20 The at least one flow meter assembly may form part of a managed pressure drilling
21 manifold. The managed pressure drilling manifold may comprise at least one flow meter
22 module, at least one choke module and/or at least one valve assembly. The at least one
23 flow meter module, at least one choke module and/or at least one valve assembly are
24 mounted on the upper riser assembly.

25

26 The at least one flow meter assembly, valve manifold and/or at least one valve may be
27 mounted on an outer surface of the slip joint on the upper riser assembly.

28

29 Embodiments of the fourth aspect of the invention may include one or more features of the
30 first, second or third aspects of the invention or their embodiments, or vice versa.

31

32 According to a fifth aspect of the invention there is provided a system for managed
33 pressure drilling in a riser comprising:

34 a riser assembly comprising

35 a rotating control device; and

1 at least one flow meter assembly, wherein the at least one flow meter assembly is
2 mounted on the riser.

3
4 The riser assembly may comprise a slip joint. The at least one flow meter may be mounted
5 on the slip joint. The riser assembly may comprise riser isolation device. The riser may
6 comprise an upper riser disconnect assembly. The slip joint may be a retrievable slip joint.

7
8 The system may comprise at least one choke assembly. The at least one choke assembly
9 may be mounted on the riser. The at least one choke assembly may be mounted on the
10 slip joint.

11
12 The system may comprise an integrated flow spool, choke manifold and/or metering
13 manifold on the slip joint.

14
15 The at least one choke assembly and/or at least one flow meter assembly may form part of
16 a managed pressure drilling manifold. The managed pressure drilling manifold may be
17 mounted on the upper riser assembly and/or slip joint.

18
19 The at least one flow meter assembly, valve manifold and/or at least one valve may be
20 mounted on an outer surface of the slip joint on the riser .

21
22 The riser isolation device, rotating control device and/or the managed pressure drilling
23 manifold may be located on a riser above a riser tension ring.

24
25 The upper riser disconnect assembly may be configured to be connected to a tension joint
26 above the tension ring.

27
28 Preferably the upper riser assembly which comprise the riser isolation device, rotating
29 control device and the managed pressure drilling manifold may be releasably connected to
30 the lower riser assembly via the upper riser disconnect assembly.

31
32 Embodiments of the fifth aspect of the invention may include one or more features of the
33 first to fourth aspects of the invention or their embodiments, or vice versa.

34

1 According to a sixth aspect of the invention there is provided a metering manifold for use
2 on a riser comprising:
3 at least one flow meter;
4 wherein the metering manifold is mountable on the riser.

5
6 The metering manifold may be mountable on the slip joint. The metering manifold may be
7 connected to at least one choke assembly which is mountable on the riser and/or slip joint.
8 The metering manifold may be connected to at least one flow spool. The metering
9 manifold, at least one choke assembly and at least one flow spool may be an integrated
10 unit. The integrated unit mountable on the riser and/or slip joint.

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

14
15 According to a seventh aspect of the invention there is provided a managed pressure
16 manifold for managed pressure drilling comprising:
17 at least one flow meter;
18 wherein the managed pressure manifold is mounted on the riser.

19
20 The managed pressure manifold may comprise at least one choke assembly. The
21 managed pressure manifold may comprise least one flow spool. The at least one choke
22 assembly, at least one flow meter and at least one flow spool may be an integrated unit.

23
24 The managed pressure manifold may be mounted on the slip joint. The integrated flow
25 spool, choke assembly and flow meter manifold may be mounted on a slip joint.

26
27 Embodiments of the seventh aspect of the invention may include one or more features of
28 the first to sixth aspects of the invention or their embodiments, or vice versa.

29
30 According to an eighth aspect of the invention there is provided a method of installing a
31 riser well control system in a subsea riser comprising:
32 providing a riser assembly and
33 installing at least one flow meter assembly on the riser.

34 The method may comprise installing at least one choke assembly on the riser.

1 The method may comprise installing a riser isolation device above a tension ring on the
2 riser. The method may comprise installing a riser isolation device on the riser string above
3 the tension ring.

4

5 The method may comprise providing a valve assembly and/or a distribution assembly.

6 The method may comprise making up a tension ring. The method may comprise
7 connecting the tension ring to the riser, riser isolation device, slip joint and/or the upper
8 riser disconnect assembly.

9

10 The method may comprise mounting the at least one flow meter assembly and the at least
11 one choke assembly on at least one component of the upper riser assembly. The method
12 may comprise installing the upper riser assembly with connected at least one flow meter
13 assembly and/or at least one choke assembly on the riser.

14

15 The method may comprise mounting the at least one flow meter assembly and the at least
16 one choke assembly on the slip joint.

17

18 The method may comprise installing the upper riser disconnect assembly on the riser
19 string above the tension ring.

20

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

23

24 According to a ninth aspect of the invention there is provided a method of installing a
25 managed pressure drilling system on a subsea riser comprising:

26 providing a riser assembly;

27 installing a rotary control device; and

28 installing at least one flow meter assembly on the riser.

29

30 The method may comprise installing an upper riser disconnect assembly above the
31 tension ring. The method may comprise installing the rotary control device and the at least
32 one flow meter assembly above the upper riser disconnect assembly.

33 The method may comprise installing a riser isolation device above the tension ring.

34

1 The method may comprise installing at least one a choke assembly, at least one valve
2 assembly and/or a distribution assembly. The method may comprise installing an
3 integrated at least one flow meter, at least one a choke assembly and a flow spool on the
4 riser or slip joint. The method may comprise making up the tension ring. The method may
5 comprise connecting the tension ring to the riser below the upper riser disconnect
6 assembly.

7
8 The method may comprise installing the upper riser disconnect assembly on the riser
9 string and then installing the rotary control device onto the upper riser disconnect
10 assembly.

11
12 The upper riser assembly including slip joint, managed pressure drilling manifold, RCD
13 and RID may be installed on the lower riser by releasably latching onto the upper riser
14 disconnect assembly.

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

18
19 According to a tenth aspect of the invention there is provided a method of converting a
20 marine riser for well control operations comprising:
21 providing a riser assembly and installing at least one flow meter assembly on the riser.

22
23 The method may comprise installing at least one choke assembly on the riser. The method
24 may comprise installing an upper riser assembly on the riser with the at least one flow
25 meter assembly and/or the at least one choke assembly mounted on upper riser assembly.

26
27 The method may comprise installing a slip joint on the riser with the at least one flow meter
28 assembly, the at least one choke assembly and/or an integrated flow spool mounted on
29 the outer surface of the slip joint. The method may comprise removing an existing slip joint
30 and/or an existing slip joint inner barrel on the subsea riser.

31
32 Embodiments of the tenth aspect of the invention may include one or more features of the
33 first to ninth aspects of the invention or their embodiments, or vice versa.

34

1 According to an eleventh aspect of the invention there is provided a method of converting
2 a marine riser for MPD operations which enables managed pressure subsea drilling
3 operations comprising:
4 installing a rotary control device; and
5 at least one flow meter assembly on the riser.

6

7 The method may comprise installing at least one choke assembly on the riser and/or the
8 slip joint.

9

10 The method may comprise installing at least one choke assembly on the riser. The method
11 may comprise installing an upper riser assembly on the riser with the at least one flow
12 meter assembly and/or the at least one choke assembly mounted on upper riser assembly.

13

14 The method may comprise installing a slip joint on the riser with the at least one flow meter
15 assembly, the at least one choke assembly and/or an integrated flow spool mounted on
16 the outer surface of the slip joint.

17

18 The method may comprise removing an existing slip joint and/or an existing slip joint inner
19 barrel on the subsea riser.

20

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

23

24 According to a twelfth aspect of the invention there is provided a method of measuring at
25 least one parameter or property of drill fluid in subsea riser comprising:

26 providing a riser assembly comprising:

27 at least one flow meter assembly;

28 wherein the at least one flow meter assembly is mounted on the riser;

29 measuring at least one parameter or at least one property of the drill fluid in the riser.

30 The method may comprise generating a measurement signal to a control unit. The method
31 may comprise analysing the measurement signal in the control unit to compare the at least
32 one parameter with a desired range of operating parameters.

33 The method may comprise generating a control signal from the control unit when the at
34 least one parameter is determined to be outside of the desired range of operating
35 parameters.

1 The method may comprise analysing the measurement signal in the control unit to monitor
2 drilling fluid flow in the riser and/or in a least one mud return line.

3

4 The method may comprise monitoring at least one parameter or at least one property of
5 the drilling fluid or drilling fluid flow in the riser and/or in a least one mud return line.

6

7 The at least one flow meter may be a differential pressure flow meter.

8

9 The method may comprise measuring a pressure differential across a differential pressure
10 flow meter ΔP . The method may comprise measuring a line pressure drop due to friction
11 AP_f along a length L of pipe.

12

13 The method may comprise and calculating the quantity $AP_f / \Delta P$ and thereby calculating
14 one or more properties of the flow of drilling fluid.

15

16 The method may comprise determining or calculating a friction factor. The method may
17 comprise calculating the discharge coefficient of the flow, Reynolds number, density,
18 viscosity and/or flow rate of the drilling fluid.

19

20 The method may comprise calculating an operational corrected value of the calculated
21 Reynolds number. The method may comprise calculating the discharge coefficient from
22 the Reynolds number, where the Reynolds number is determined from the calculated
23 friction factor.

24

25 The method may comprises determining or calculating a Reynolds number for the drilling
26 fluid flow. The method may comprise taking further measurements to monitor a change in
27 the drilling fluid. The method may comprise correcting the correcting Reynolds number as
28 the properties of the fluid changes. The method may comprise correcting the correcting
29 Reynolds number based on the least further measurements taken.

30

31 The method may comprise comparing the at least one parameter with a desired range of
32 operating parameters.

33

34 The method may comprise calculating, estimating or predicting the density and/or viscosity
35 of the flowing drill fluid.

1 The method may comprise measuring at least one parameter or at least one property of
2 the fluid using two or more flow meters. The method may comprise switching between a
3 first flow meter having a first flow measurement range to a second flow meter having a
4 second flow measurement range.

5
6 The method may comprise using knowledge of the geometry of the riser, geometry of the
7 at least one flow meter, geometry of pipes or tubing, previous knowledge discharge
8 coefficient as function of friction factor and/or Reynolds number to calculate or estimate
9 information on the drilling fluid. The method may include estimating or calculating the
10 friction factor, Reynolds number, Discharge coefficient, density, viscosity and corrected
11 flowrate.

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

15
16 According to a thirteenth aspect of the invention there is provided a method of measuring a
17 property of the drill fluid in a subsea drilling operation comprising:
18 providing a riser assembly comprising;
19 a riser isolation device;
20 a rotary control device;
21 at least one flow meter mounted on the riser; and
22 diverting drill fluid from the riser to the at least one flow meter.

23
24 The method may comprise diverting drill fluid from the riser beneath the rotary control
25 device. The method may comprise diverting, measuring and/or choking drilling fluid returns
26 from the riser beneath the rotary control device back into the riser via the at least one flow
27 meter.

28
29 The method may comprise utilising existing mud return system. The method may comprise
30 using the existing divert system and flow lines to reach the shakers.

31
32 Embodiments of the thirteenth aspect of the invention may include one or more features of
33 any of the first to twelfth aspects of the invention or their embodiments, or vice versa.

34

1 According to a fourteenth aspect of the invention there is provided a method of managed
2 pressure drilling in a subsea drilling operation comprising:
3 providing a riser assembly comprising;
4 a riser isolation device;
5 a rotary control device;
6 at least one flow meter mounted on the riser;
7 at least one choke assembly mounted on the riser;
8 measuring properties of the flow and
9 actuating the choke to control flow.

10

11 The method may comprise diverting drill fluid from beneath the rotary control device. The
12 method may comprise diverting, measuring and/or choking the drill fluid returns from the
13 riser beneath the rotary control device and back into the riser (low pressure) via external
14 low lines including the at least one flow meter and the at least one choke assembly.

15

16 The method may comprise utilising existing mud return system. The method may comprise
17 using the existing divert system and flow lines to reach the shakers. The method may
18 comprise diverting high pressure MPD returns from beneath the RCD back into the riser
19 (low pressure) via flow lines including the at least one flow meter and at least one choke
20 assemblies. The method may utilise existing mud return lines to shakers.

21

22 Embodiments of the fourteenth aspect of the invention may include one or more features
23 of any of the first to thirteenth aspects of the invention or their embodiments, or vice versa.

24

25 According to a fifteenth aspect of the invention there is provided a method of measuring at
26 least one parameter or property of drilling fluid in a subsea riser comprising:
27 providing a well control system for a riser comprising a riser assembly;
28 at least one flow meter;
29 wherein the at least one flow meter is located on an outer surface of the riser assembly
30 above a riser tension ring; and
31 measuring at least one parameter or at least one property of the drilling fluid in the riser.

32

33 Embodiments of the fifteenth aspect of the invention may include one or more features of
34 any of the first to fourteenth aspects of the invention or their embodiments, or vice versa.

35

1 According to a sixteenth aspect of the invention there is provided method of managed
2 pressure drilling in a subsea drilling operation
3 comprising providing a well control system for a riser assembly comprising
4 a riser assembly;
5 at least one flow meter;
6 wherein the at least one flow meter is located on an outer surface of the riser assembly
7 above a riser tension ring; and
8 providing a rotating control device; and
9 measuring at least one property of drilling fluid flow using the at least one flow meter.

10

11 Embodiments of the sixteenth aspect of the invention may include one or more features of
12 any of the first to fifteenth 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 representation of a managed pressure drilling (MPD) riser assembly
20 according to the prior art;

21

22 Figure 2 is a schematic representation of a riser system for MPD according to a first
23 embodiment of the invention;

24

25 Figure 3A to 3F are schematic representations of an upper riser assembly for the riser
26 system shown in Figure 2;

27

28 Figure 4 is a cross-sectional schematic view of a flow meter used in the riser assembly of
29 Figure 2;

30

31 Figure 5 is a flow diagram of the process of measuring and monitoring mud flow according
32 to an embodiment of the invention; and

33

34 Figure 6 is a flow diagram of the process of measuring different parameters of mud flow
35 according to an embodiment of the invention.

1 Detailed description of preferred embodiments

2

3 Figure 1 shows a schematic representation of a drilling system for managed pressure
4 drilling of a subsea reservoir known in the prior art.

5

6 The drilling system 10 comprises a riser assembly 12 located between a rig platform 13
7 and a wellhead. The system 10 has a riser flow spool (RFS) 16, a riser isolation device
8 (RID) 18, a rotating control device (RCD) 20 mounted on the riser.

9

10 The riser 12 is connected to a slip joint 14. The slip joint 14 is configured to respond to
11 heave movement of the platform during dynamic sea conditions.

12

13 A portion of platform 13 is shown, which may be a floating rig or drillship. The platform
14 supports the drilling system 10. A plurality of tensioning cylinders 19 are secured to the
15 platform and exert an upward force on rods or cables 22. The lower end of each rod or
16 cable 22 is connected to a riser tensioning ring 24 which is connected to maintain the
17 stability of the drilling system 10 in the offshore environment.

18

19 External auxiliary lines 26 are connected to the BOP (not shown) and circulate fluids and
20 provide control lines to the BOP. A termination ring 28 is disposed circumferentially about
21 a portion of the slip joint 14. The auxiliary lines 26 terminate at the termination ring.

22 Flexible hoses 30 are connected to the termination ring 28 and extend upward coupling to
23 the platform. The hoses 30 have been truncated in these drawings for clarity. The
24 termination joint 28 provides fluid communication between the auxiliary lines 26 and the
25 flexible hoses 30.

26

27 The RFS 16 has two drilling fluid return flowlines 32 and 34 in fluid communication with a
28 distribution manifold 40 which directs flow to an MPD manifold 41 located at surface to
29 allow applied drilling fluid back pressure.

30

31 The MPD manifold 41 includes a junk catcher 42 to catch and trap debris in the fluid, a
32 metering manifold 44 to measure fluid flow rates and density and a choke manifold 46 to
33 control for balanced and underbalanced fluid return rates and wellhead pressure during
34 MPD operations.

35

1 Fluid returns are processed through a mud gas separator (MGS) or the rig's mud gas
2 separator which separates the gas from the drilling fluid. The gas is vented to be burned or
3 stored in a subterranean formation.

4

5 The fluid is then returned to the drill string in the riser assembly via a mud pump (not
6 shown) to be recirculated in the drilling apparatus.

7

8 During a managed pressure drilling operation, the RCD 20 provides a rotating internal
9 sealing element that seals against the drill string to create a pressure-tight barrier to
10 establish a closed system and divert riser flow to the surface MPD manifold. The closed
11 system enables dynamic adjustments to wellbore pressure, accurate flow rate
12 measurement and safer mud gas separation. The metering manifold 44 measures the fluid
13 flow rates and the choke manifold 46 enables control of the annular pressure by increasing
14 or decreasing the annual flow.

15

16 Figure 2 schematically shows features of a manage pressure drilling system 100 according
17 to a first embodiment of the present invention. It will be appreciated that the drilling system
18 can adopt different configurations depending on the type of riser system on which it is
19 being installed and the type of drilling operation. Figure 2 represents one possible
20 configuration that the MPD system may adopt.

21

22 The drilling system 100 comprises a riser assembly 112. The system 100 has a riser
23 isolation device (RID) 118, a rotating control device (RCD) 120 and an upper riser
24 disconnect assembly (URD) 150 mounted on the riser below a slip joint 114. The slip joint
25 114 is configured to respond to heave movement of the platform during dynamic sea
26 conditions.

27

28 The upper riser disconnect assembly 150 allows for a quick separation of the upper riser
29 section 112a including RID, RCD and slip joint from the lower riser section 112b.

30

31 Tension ring 124 is disposed circumferentially about a tension joint 125 located between
32 the quick disconnect assembly 150 and the lower riser section 112b. Although in this
33 example the tension ring 124 is connected to tension joint 125, it may alternatively be
34 connected to an existing rig outer barrel located between the quick disconnect assembly

1 150 and the riser 112. In this example the riser isolation device, a rotating control device
2 120 and an upper riser disconnect assembly 150 are disposed above the tension ring 124.

3

4 Tensioning cylinders are secured to the platform and exert an upward force on rods or
5 cables 122. The lower end of each rod or cable 122 is connected to a riser tensioning ring
6 124 which is connected to maintain the stability of the riser string. For clarity the cables
7 122 are truncated and the platform has not been shown in Figure 2.

8

9 In this example the slip joint is a telescopic three-part slip joint. However, it is appreciated
10 that other types of slip joint may be used. The slip joint enables the riser system to adjust
11 in length as the platform heaves in response to motion of the waves.

12

13 External auxiliary lines 126 are connected to the BOP (not shown) and circulate fluids and
14 provide control lines to the BOP. A termination ring 128 is disposed circumferentially about
15 a portion of the lower riser section 112b. The auxiliary lines 126 terminate at the
16 termination ring 128. Flexible hoses 130 are connected to the termination ring 28 and
17 extend upward coupling to the platform. The hoses 130 have been truncated in these
18 drawings for clarity. The termination joint 128 provides fluid communication between the
19 auxiliary lines 126 and the flexible hoses 130.

20

21 An MPD manifold system 141 is located on an outer surface of the riser string above the
22 quick disconnect assembly 150 as best shown in Figures 3A to 3E. In this example the
23 managed pressure manifold 141 is located on the outer surface of part of the slip joint 114.
24 The MPD manifold system is a well control system.

25

26 MPD manifold system comprises flow lines 132 and 134. Flow line 132 comprises spool
27 162a, dual isolation valve 164a, an in-line flow meter 166a, choke 168a and return spool
28 170a into the riser bore. Flow line 132 comprise spool 162b, dual isolation valve 164b, an
29 in-line flow meter 166b and choke 168b and return spool 170b into the riser bore.

30

31 During MPD, the MPD manifold system 141 routes drilling fluid from the riser bore beneath
32 the RID and the RCD (High pressure upstream of RCD) in the MPD flow lines 132 and 134
33 respectively.

34

1 The MPD manifold system 141 includes in-line flow meters 166a , 166b and choke
2 assemblies 168a, 168b in flow lines 132, 134 respectively which are mounted on the riser
3 and connected to the riser bore below the RCD 120. The in-line flow meters 166a , 166b
4 measure drilling fluid flow rates and density. The choke assemblies 168a, 168b enables
5 control of the annular pressure by increasing or decreasing the annual flow. The MPD
6 manifold system 141 diverts flow below the RCD 120, measures and chokes the MPD
7 returns back into the riser via external MPD flow lines 132 and 134. This allows the fluid
8 returns to utilise existing mud return systems in an upper riser section 112a including
9 diverter system and flow lines to shakers.
10
11 The flow meter and choke assemblies are dimensioned such that they can be mounted on
12 the slip joint without impacting the functioning of the slip joint.
13
14 Components of the MPD manifold system including the flow meters and choke assemblies
15 are controlled remotely. The flow meters and choke assemblies may be controlled
16 automatically by electronic or hydraulic monitoring equipment and/or slimline actuators.
17
18 The drilling fluid re-enters the riser bore at the bottom of the slip joint 114 and flows in the
19 riser return system including the diverter.
20
21 The MPD manifold system 141 has a third return flow line 180 with a bypass facility shown
22 in Figure 3E. The flow line 180 is safety system to operate as a riser over pressure
23 protection (PRV) line with automated choke controls. This flow line enables the flow meter
24 and choke assembly in flow lines 132 and 134 to be isolated and bypassed when not
25 required such as when drilling out shoe.
26
27 During a managed pressure drilling operation, the RCD 20 provides a rotating internal
28 sealing element that seals against the drill string to create a pressure-tight barrier to
29 establish a closed system and divert riser flow to the surface MPD manifold. The closed
30 system enables dynamic adjustments to wellbore pressure, accurate flowrate
31 measurement and safer mud gas separation.
32
33 Fluid returns are processed through a mud gas separator (MGS) or the rigs mud gas
34 separator which separates the gas from the drilling fluid. The gas is vented ,flared, or

1 stored in a subterranean formation. The fluid is then returned to the drill string via the mud
2 pump to be recirculated in the drilling apparatus.

3

4 In the event of a gas kick the annular BOP (not shown) located on the lower riser is closed
5 to seal around the drill string. The RID 118 is closed around the drill string to isolate the
6 upper riser system and allow any gas in the riser to be contained.

7

8 Any isolated gas may be circulated through flowlines 132 and 134 via the choke manifold
9 to maintain a back pressure in the riser allowing the gas to be circulated out in a controlled
10 manor to the MGS to capture and separate large volume of free gas from the mud. The
11 gas once separated from the mud is then safely vented.

12

13 As best shown in Figure 3D, a flow line 172 is routed from the annular body and vents into
14 lower end of slip joint 114 outer barrel 114a to allow bleed and equalisation of RCD 120.
15 Figure 3F shows an optional booster line inlet manifold 190 with valves 192 and 194 for
16 booster line 196 on a riser joint (or telescopic joint outer barrel). The booster line inlet
17 manifold enables the non-intrusive pumping in 'across top' of riser column for Pressurized
18 Mud Cap Drilling (PMCD) using existing booster pump and booster line. The booster line
19 inlet manifold 190 enable the flushing of RCD and upper end of riser during connections.
20 This manifold does not require an additional booster Coflexip hose (for MPD or PMCD).

21

22 Although in the above example the MPD manifold including the flow meters and choke
23 assemblies are described as being located or mounted on an outer surface of the riser
24 telescopic joint it will be appreciated that the MPD manifold, flow meters and/or choke
25 assemblies may be located or mounted, located or attached to a riser joint.

26

27 Figure 4 shows a cross-sectional schematic view of an in-line flow meter for use in the
28 MPD manifold mounted or located on the riser assembly. The flow meter is a differential
29 pressure flow meter which is based around the use of flow adjustment members such as
30 an obstruction or an expansion in the pipe to create a pressure drop for measurement of
31 the volume of fluid passing through a flow meter. The flow adjustment may be created by
32 an orifice plate, wedges, venturi, Coriolis, cones and/or a reduction in bores such as in
33 process equipment. By measuring the differential pressure between a point immediately
34 upstream of the obstruction/expansion and at a point downstream of the

1 obstruction/expansion where the pressure has changed due to obstruction/expansion, the
2 volumetric or mass flow rate can be determined.

3

4 In this example the flow meter is a venturi flow meter. However, it will be appreciated that
5 other types of flow meter may be used.

6

7 The volumetric or mass flow rate can be derived from the differential pressure using
8 Bernoulli's theorem which is based on the conservation of energy within a flowing fluid and
9 a discharge coefficient. The flow meter has a reduced cross-sectional area in the flow-path
10 of the fluid thereby creating a pressure differential on opposite sides of the flow adjustment
11 member i.e. venturi member.

12

13 The pressure differential created on opposite sides of the flow adjustment member has a
14 known mathematical relationship to the flow rate of the fluid passing there through, and as
15 long as the cross-sectional area at the opening of the venturi is constant, the fluid flow
16 measurements are very accurate.

17

18 For all differential pressure flow meter types, the density of the fluid being measured is
19 also required to complete the calculation of mass or volumetric flow rate.

20

21 The flow adjustment member is mounted to an inner surface of the pipe for restricting the
22 flow of fluid through the pipe and process a pressure drop in the fluid as it flows past the
23 flow restriction member.

24

25 Figure 4 shows a cross-sectional schematic view of flow meter 200 for use in the MPD
26 drilling system. The flow meter 200 has a tubular housing 210 having an internal bore
27 212 extending longitudinally therethrough providing a fluid passageway 213 in which a flow
28 adjustment member 214 is mounted to the inner surface 211a of the wall 211 of the
29 housing 210. In this example the flow adjustment member is a venturi member 214
30 comprising a venturi section 220.

31

32 The venturi section 220 has an upstream section 222 which converges into a coaxial
33 reduced diameter venturi throat section 224 which expands into a coaxial divergent
34 downstream section 226.

35

1 The flow meter 200 has four ports 228a, 228b, 228c and 228d in the housing wall 211
2 which are in fluid communication with the flow through passageway 213. Port 220a is
3 located in the wall 211 at a position 227 upstream of the venturi section 220, port 228b is
4 located in the wall 211 of the venturi upstream section 222, port 228c is located in the wall
5 211 of the throat section and port 228d is located in the wall 211 of the downstream
6 section.

7

8 The ports 228a, 228b, 228c and 228d are pressure ports for receiving a pressure sensing
9 device to measure the pressure of the fluid flowing through the venturi which permits the
10 detection and measurement of a pressure differential induced by fluid flow through the
11 reduced diameter venturi throat section 224.

12

13 A temperature measurement device 230 is mounted on the housing wall 211 in fluid
14 communication with the flow through passageway 213. In the example shown the
15 temperature measurement device is located downstream of the venturi, but it will be
16 appreciated that the temperature measurement device may be located upstream of the
17 venturi. The temperature measurement device may be located in the upstream,
18 downstream or throat section of the flow meter. The flow meter may have multiple
19 temperature measurement devices located a different section of the flowmeter.

20

21 Temperature and/or pressure changes of the fluid being measured may cause the inner
22 diameter of the passageway to expand or contract. Changes in the size of the inner
23 diameter of the passageway through the flow meter can have a substantial change on the
24 pressure drop of the fluid flowing past the venturi. This can result in inaccurate
25 measurements.

26

27 In use, fluid flows in a direction indicated by arrow "A". Although the fluid in Figure 4 is
28 shown as flowing in direction "A", it will be appreciated the flow meter may also function in
29 an opposing direction. The flow meter may be installed on a riser tubular or hose in either
30 orientation with no effect on the operation or the accuracy of the measurement readings.

31 The tubular body 210 has a flange 213 at either longitudinal end 210b of the body 210.

32 The flanges 213 have connection means such as holes to connect the flow meter 200 to a
33 pipeline tubulars or pipeline hoses.

34

1 The diameter of the throat section is smaller than the diameter of upstream section or
 2 downstream section, thereby restricting the fluid flow through the passageway. In use, the
 3 flow meter is connected to a hose to measure the drill fluid flow therethrough.

4

5 It will be appreciated that different flow adjustments devices may be used as an alternative
 6 to a venturi. It will also be appreciated that different restrictor shapes, sizes and
 7 configurations may be used to adjust and optimize the fluid flow meter conditions and
 8 performance.

9

10 Pressure measurements are taken at pressure ports 228a and 228b to calculate the line
 11 pressure drop due to friction ΔP_f along a length L of pipe. Pressure measurements taken
 12 at pressure ports 228b and 228c enable a pressure differential ΔP_t to be measured.
 13 Pressure measurements taken at pressure ports 228c and 228d enable a pressure
 14 differential ΔP_r to be measured.

15

16 The quantity $\Delta P_f / \Delta P_t$ can be subsequently calculated enabling the inline calculation of
 17 multiple properties of the flow. The pressure drop due to friction in the pipe can be
 18 expressed as equation 1 and is valid for all Reynolds numbers.

19

$$\Delta P_f = \frac{\lambda \rho u^2 L}{2D}$$

20 Equation 1

where λ is friction factor, ρ is density in kg/m³

21

μ is pipe velocity, D is pipe diameter

22

23 By combining Equation 1 with the Hagen- Poiseuille equation and rearranging for velocity
 24 in terms of a pressure drop it is possible to derive friction factor in laminar flow as

25

$$\lambda = \frac{64}{Re}$$

26 Equation 2

where Re is Reynolds number

27

28 Equation 2 shows that in laminar flow, the friction factor is inversely proportional to
 29 Reynolds number only. This suggests that measuring friction factor in the laminar flow
 30 region will allow a direct calculation of Reynolds number. It follows that if the discharge
 31 coefficient is repeatable in laminar flow it can accurately be correlated with Reynolds
 32 number or indeed friction factor itself to provide inline corrections.

It is not only laminar flow where friction factor is dependent on Reynolds number. There are several well known correlations for friction factor in turbulent flows e.g. Colebrook-White equation that would perform a similar role to equation 2. In these cases the dependence on Reynolds number is not linear but the same process can be used to calculate discharge coefficient. .

Friction factor and differential pressure flow measurement are important contributors to the invention.

The beta β ratio of the flow meter is the ratio of the pipe diameter to the throat diameter. The inclusion a parameter known as the Discharge Coefficient helps remove errors associated with location of pressure measurements.

Finally, a term to correct for the expansibility of the fluid ϵ is included with ϵ equal to 1 for incompressible fluids.

The volume flow through the flow meter venturi (in this case) is therefore

$$Q = C_d \epsilon \frac{\pi d^2}{4 \sqrt{(1-\beta^4)}} \sqrt{\frac{2(\Delta P_t)}{\rho}}$$

Equation 3

Where Q is Volume flow, Cd is Discharge coefficient

By providing a flow meter measurement system that combines the differential pressure flow rate equation (equation 3) with the friction factor equation (equation 2) allows properties of the fluid to be calculated.

The pressure measurement reading is used to measure a pressure drop, ΔP_t , across the differential pressure meter. Additionally, the pressure drop, ΔP_f , due to friction across a straight length of pipe is measured. Using these two measurements can facilitate the calculation of various fluid properties.

By measuring the pressure drop ΔP_X across the differential pressure meter and the pressure drop ΔP_f along a length of pipe, and with knowledge of the pipe and meter geometry, it is possible to calculate friction factor in line using equations 4 and 5

$$\lambda = \frac{\Delta P_f}{\Delta P_s} C_M$$

1 Equation 4

2

3 Equation 4 shows two terms one a ratio of two differential pressure measurements and
4 two a constant relating to meter geometry, pipe length and discharge coefficient.

$$C_M = \frac{D(1-\beta^4)}{C_d^2 L \beta^5}$$

5 Equation 5

6

7 Equation 5 provides a repeatable correlation for friction factor which is independent of
8 physical properties of the fluid.

9

10 In practice, this calculation method can be accomplished by two real-time differential
11 pressure measurements only. Low uncertainty of these measurements is subject to regular
12 calibrations and maintenance procedures.

13 This can be accomplished by a calibration and characterisation of the flow meter and
14 measurement system.

15

16 Knowledge is also required of the geometry of pipe work and flow adjustment member as
17 well as an indication of the systems performance i.e. discharge coefficient over the
18 useable Reynolds number range and hence friction factor range.

19

20 Characterisation and calibration allows the establishment of an equation or similar to relate
21 discharge coefficient as a function of friction factor or to relate discharge coefficient (Cd)
22 as a function of Reynolds number (Re).

23

24 Using the established relation between discharge coefficient with friction factor or
25 Reynolds number with equation 4 it is possible to determine the friction factor, Reynolds
26 number and discharge coefficient for the measurement system.

27

28 This can be achieved using an iterative approach. Alternatively, this may be achieved
29 using calculated friction factor or Reynolds number value with the theoretical or reference
30 value.

31

1 A simple ratio of the calculated to reference values allows for the calculation of a corrected
 2 friction factor and corrected Reynolds number as shown in equations 6 and 7 respectively.
 3 This enables the alignment or matching of measured values with calculated values.

4

$$\lambda_{cor} = \frac{\lambda_{the}}{\lambda_{calib}} \lambda_{calc}$$

5 Equation 6

6

7 Where λ_{calib} is the calculated friction factor value during calibration, λ_{calc} is calculated
 8 friction factor during operation, λ_{the} is the theoretical friction factor for the reference
 9 Reynolds number.

$$Re_{cor} = \frac{Re_{ref}}{Re_{calib}} Re_{calc}$$

10 Equation 7

11

12 Re_{calib} is the calculated Reynolds number during calibration, Re_{calc} is the calculated
 13 Reynolds number during calibration and Re_{ref} is the reference Reynolds number during
 14 calibration.

15

16 Using the friction factor method, the correct discharge coefficient can be calculated
 17 independently of the physical properties of the drilling fluid. Equation 3 can now be used to
 18 calculate the corrected volumetric flow rate of the fluid.

19

20 Figure 5 is a flow diagram of the process steps in determining flow properties of drilling
 21 fluid using a flow meter in accordance with an embodiment of the invention.

22

23 Referring the Figure 5, first of all, a known relation between the discharge coefficient and
 24 the Reynolds number is obtained for the meter geometry (Step 1). Using the flow meter,
 25 the pressure differential, ΔP_t , across the differential pressure meter and the pressure drop
 26 ΔP_f along a length of pipe are measured (Step 2).

27

28 The friction factor is calculated using equation 4 (Step 3). In some implementations, this
 29 can involve calculating a corrected value of the friction factor as set out in equation 6.

30

31 The friction factor is used to calculate a value for the Reynolds number of the flow, for
 32 instance using equation 2. In some implementations, this can involve calculating a

1 corrected value of the Reynolds number as set out in equation 7 (Step 4).

2

3 The discharge coefficient is calculated using the calculated or corrected value of the
4 Reynolds number (Step 5). Step 6 shows an iterative process of calculating the value of
5 the discharge coefficient, using the friction factor at stage 3 in some embodiments.

6

7 The density of the fluid is established by sampling, looking up tables or other appropriate
8 method (Step 7). The established density value is used to calculate a flowrate of the fluid
9 using equation 3 (Step 8).

10

11 If the friction factor and discharge coefficient are known then it is possible to infer the
12 density of the drilling fluid in real-time by using equation 1. In this equation, the unknowns
13 are density and velocity of the drilling fluid the equation may be rearranged in terms of
14 density. The velocity may be measured using a known measurement device such as an
15 ultrasonic meter. The measured velocity may then be used to calculate the density.

16

17 Alternatively, combining equations 1 and 3, there are two equations with two unknowns. It
18 is possible to iterate these two values to provide a density and a corrected volumetric
19 flowrate. This may be applicable where indications of a target density are known.

20

21 As with friction factor, correction of the density can be made on initial meter calibration by
22 using equation 9.

$$\rho_{cor} = \frac{\rho_{ref}}{\rho_{calib}} \rho_{calc}$$

23 Equation 9

24

25 where ρ_{cor} is the corrected density, ρ_{ref} is the reference density during calibration, ρ_{calib} is the
26 calculated density during calibration and ρ_{calc} is the calculated density during operation.

27 When the density of the drill fluid is known, it is further possible to calculate the viscosity of
28 the drilling fluid (μ). Knowledge of the density, pipe diameter, velocity and Reynolds
29 number (derived from friction factor) allows viscosity to be calculated using the standard
30 Reynolds number (Re) calculation equation as shown in equation 10.

31

$$\mu = \frac{\rho Du}{Re}$$

32 Equation 10

1
2 Figure 6 shows a flow diagram of the calculation of additional flow properties of drilling
3 fluid using the above techniques is shown.
4
5 Steps 1 to 6 and 8 of Figure 6 will be understood from the description of Figure 5 above.
6 However, Step 7 differs in that the density is calculated either from knowledge of a target
7 density or from a velocity measurement using equation 1 (Step 9). In some embodiments,
8 the value of the flowrate calculated at Step 8 may be iterated back to the calculation of the
9 density at Step 7.
10
11 At Step 10, the viscosity is calculated using equation 10. This calculation can use a
12 measured velocity or the velocity equivalent of the flowrate calculated at Step 8. Typically,
13 the calculation would also use the Reynolds number calculated at Step 4 and density
14 value at Step 7.
15 The knowledge of meter and pipe geometry and previous knowledge of discharge
16 coefficient as a function of friction factor or Reynolds number, it is possible to calculate
17 information including friction factor, Reynolds number, Discharge coefficient, density,
18 viscosity and/or a corrected flowrate about flowing fluid from two differential pressure
19 measurements and an indicative pipe velocity only.
20
21 The system may comprise two or more flow meters. Each flow meter may have different
22 fluid flow range and/or fluid density range. The system may have a flow measurement
23 range of 10 to 2000 USG/min. The system may have a switch mechanism to switch
24 between different flow meters having different measurement ranges.
25
26 Throughout the specification, unless the context demands otherwise, the terms 'comprise'
27 or 'include', or variations such as 'comprises' or 'comprising', 'includes' or 'including' will be
28 understood to imply the inclusion of a stated integer or group of integers, but not the
29 exclusion of any other integer or group of integers.
30
31 Furthermore, relative terms such as "lower", "upper", "up", "down", above, below and the
32 like are used herein to indicate directions and locations as they apply to the appended
33 drawings and will not be construed as limiting the invention and features thereof to
34 particular arrangements or orientations. The term mounted may include installed in,

1 installed on, attached to or located on a surface thereof. The terms “manifold” and
2 “assembly” may be interchangeable.

3

4 The invention provides a well control system for a riser comprising a riser assembly and
5 at least one flow meter, wherein the flow meter manifold is mounted on the riser.

6

7 The invention may facilitate the conversion of marine riser assemblies for MPD operations
8 which enable conventional and/or managed pressure drilling operations.

9

10 The invention provides a complete self-contained managed pressure drilling system for
11 connection on the riser. It avoids the requirement for MPD surface equipment and major
12 drilling riser equipment modifications. It also mitigates the requirement for any flow return
13 hoses from riser back to the rig/surface.

14

15 The invention mitigates the requirement for independent pipework upgrades for MPD
16 mudflow and utilises existing rig mud return / fluid circulation system and well control
17 procedures.

18

19 By providing a self-contained MPD system on an upper riser string and an upper riser
20 disconnect assembly above the tension ring, components of the MPD drilling, flow meter,
21 choke and distribution manifolds may quickly, safely and easily installed and/or removed
22 from the riser assembly without requiring the BOP to be disconnected and the riser string
23 pulled to surface. This configuration may allow components of a riser assembly and MPD
24 drilling system to be installed only when they are required.

25

26 The invention enables a convention drilling riser to be converted for managed pressure
27 drilling without requiring significant modification to rigs choke and kill and standpipe
28 manifolds. It also avoids installing additional return hoses and numerous control lines in
29 the moonpool or locating bulky distribution, choke and metering manifolds on the rig. The
30 system also enables high pressure MPD returns to be diverted from beneath an RCD back
31 into the riser (low pressure) via flow lines and the flow meter and choke assembly.

32

33 The invention provides an integrated flow spool, choke manifold and metering manifold on
34 a retrievable riser slip joint which can be easily installed and/or removed from a riser
35 assembly

1 The foregoing description of the invention has been presented for the purposes of
2 illustration and description and is not intended to be exhaustive or to limit the invention to
3 the precise form disclosed. The described embodiments were chosen and described in
4 order to best explain the principles of the invention and its practical application to thereby
5 enable others skilled in the art to best utilise the invention in various embodiments and
6 with various modifications as are suited to the particular use contemplated. Therefore,
7 further modifications or improvements may be incorporated without departing from the
8 scope of the invention herein intended.

9
10
11
12
13