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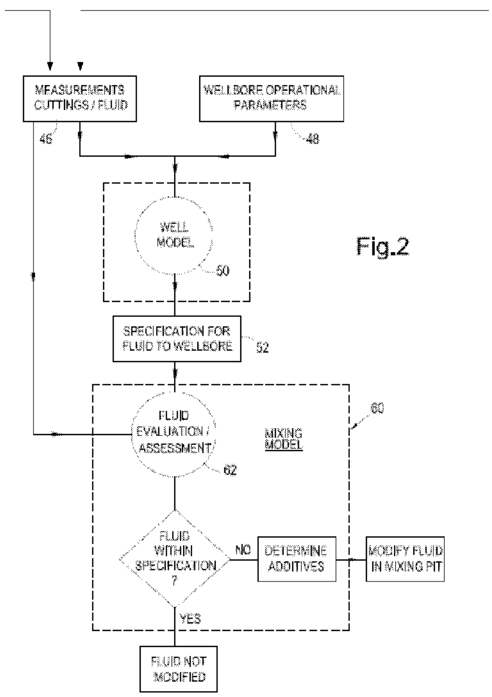

Fig.2

(57) Abstract: A method and system for controlling the properties of a drilling fluid provided to a wellbore operation and/or for conducting a well operation. The method steps including: a. performing a wellbore operation using wellbore apparatus located in a wellbore; b. providing a fluid to the wellbore for facilitating the wellbore operation; c. measuring at least one property of the fluid or of cuttings carried by the fluid during performance of the wellbore operation; d. determining whether the measured fluid fulfils predetermined criteria, e. determining an alteration to the fluid provided to the wellbore using a fluid mixing model when said measured fluid does not fulfil the predetermined criteria and f. modifying the fluid provided to the wellbore using said determined alteration.

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METHOD OF CONDUCTING WELL OPERATIONS

The present invention relates to methods of conducting well operations, and in particular, to methods of conducting drilling operations. The invention also relates to methods of controlling drilling fluids and to apparatus and systems for performing the methods.

Background

Various wellbore operations are carried out during the life cycle of a well, which naturally starts with the operation of drilling of the well itself. Drilling may be followed by running a casing or liner into the wellbore. At other stages, various intervention operations may be performed, for example, milling out a section of casing in an abandoned well before drilling a new well trajectory from the old wellbore. Various completion and cleaning processes may also be carried out to prepare a well for production.

In such operations, and especially in drilling operations, long strings of equipment such as drill pipe or the like, are run into the well, often in a rotary mode headed by a suitable bit for penetrating the geological formation of the subsurface. In order to assist the process, a drilling fluid is typically pumped into the well through a central conduit in the drilling string and is passed into the wellbore through an outlet connecting the conduit with the wellbore near the drill bit. The fluid is forced upwards under pressure back along the string toward the surface in the annular space defined between an outer surface of the drilling string and the casing or formation wall. The circuit from the drilling platform to wellbore and back to drilling platform may take the fluid several hours to complete.

The drilling fluid facilitates the well operation in a number of ways. A primary reason for circulating fluid in this way is to remove cuttings (i.e. particles of crushed or cut formation or rock produced by drilling) from the wellbore as it is drilled. The drilling fluid is designed to suspend or carry the cuttings. Therefore, the cuttings are removed from the wellbore when the fluid is forced under pressure back to the surface. The drilling fluid is then typically filtered or screened using shakers or other devices installed in a fluid handling apparatus on the drilling platform. Such devices remove the cuttings from the drilling fluid. The fluid is then typically re-used, i.e. circulated back to the wellbore.

If cuttings are not removed effectively from the wellbore, they can interfere with the proper operation of the drill bit and can significantly hamper the progress of the drilling operation, e.g. the rate of penetration of the formation. In come cases, where cuttings removal has been inefficient, it can become necessary to carry out a cleaning operation prior to completing the well. Improving the ability of a drilling fluid to remove cuttings from a wellbore therefore has a huge potential impact on the cost efficiency of a drilling operation.

In terms of other functions, the drilling fluid pumped into a wellbore also helps to drive the drill bit into the wellbore and to cool and lubricate the drill bit. Further, it may be applied to counterbalance hydrostatic pressure in the wellbore thereby preventing blow out. The drilling fluid also functions to maintain borehole stability by generating a pressure against the wellbore wall and thereby prevent it from collapsing. It also provides fluid loss control, i.e. it prevents loss of fluid into the formation, and it provides chemical stability to the formation thereby preventing chemically induced instability of the wellbore.

These functions should ideally be achieved whilst minimising formation damage. Damage may be caused by drilling fluids entering the formation, by the drilling fluids swelling clays present in the formation and/or by leading to precipitation of insoluble solids in the formation. Additionally the generation of emulsions in the formation should also be avoided.

The particular composition of the drilling fluid can impact significantly on its ability to perform these various functions whilst minimising formation damage. At the same time, downhole conditions such as wellbore mineralogy, temperature and pressure, drilling rates and trajectory, well length and volume etc, can affect fluid effectiveness. It is clearly desirable to use a drilling fluid that is suitable for given downhole conditions and achieves one or more of the functions above.

Drilling fluids are typically water or oil based compositions comprising a mixture of chemicals designed to achieve a variety of functions. Fluids may be formed, for example, with certain viscosities, densities, fluid loss control properties and chemical contents in order to try to provide the desired performance.

However, well and wellbore conditions continuously change during the performance of a wellbore operation as, for example, drilling progresses and different geological intervals are entered. Cuttings from the formation may also become mixed into and suspended in the fluid and re-circulated back into the borehole if they are not effectively removed at the surface. Wellbore pressure and temperature also impact on the fluid as well as the nature of the formation. Accordingly the properties, e.g. viscosity, of the drilling fluid may change significantly during the drilling operation affecting its subsequent performance when it is recirculated back into a wellbore.

As a result, it can be difficult for operators to select an appropriate fluid for a well operation such as drilling, and once a particular fluid is chosen by an operator, it is uncertain whether it is going to continue to be an appropriate fluid once subjected to the wellbore environment. As a result, the productivity of the drilling or other wellbore operation can be detrimentally affected.

It is conventional for samples of returning drilling fluid to be taken and subjected to a range of tests, usually in a laboratory, to determine values for their properties, i.e. viscosity, density etc. Based on the results of these tests, the drilling fluid may then be treated, e.g. by altering the proportion of components or by the addition of various compounds, so as to bring the properties back to appropriate ranges.

The subjection of fluids to a range of tests, the interpretation of the results obtained from the tests and the subsequent manual adjustment of the drilling fluid is, however, time consuming and labour intensive. Critically it does not enable rapid response or intervention to changes in the properties of a drilling fluid.

Various systems and methods for drilling systems are described in US 6176323, US2009/0188718, US2009/0293605, GB2441069, US2004/0236513, US6443001, WO01/67068 and US2008/0099241. The applicant has recognised the need for an improved automated method and system.

Summary of Invention

Accordingly the present invention provides a method of conducting a well operation, the method comprising the steps of:

a. performing a wellbore operation using wellbore apparatus located in a wellbore;

b. providing a fluid to the wellbore for facilitating the wellbore operation;

c. measuring at least one property of the fluid or of cuttings carried by the fluid during performance of the wellbore operation;

d. determining whether the measured fluid fulfils certain predetermined criteria;

e. determining an alteration to the fluid provided to the wellbore using a fluid mixing model when said measured fluid does not fulfil the predetermined criteria and

f. optionally modifying the fluid provided to the wellbore in response to the at least one measured property of the fluid or the cuttings.

Preferred methods of the invention comprise determining whether the fluid fulfils predetermined criteria by determining whether the at least one measured property has at least one characteristic in a predetermined range. Preferred methods of the invention are automated.

In preferred methods the fluid is recirculated during performance of the well operation.

Alternatively viewed the present invention provides a method, e.g. an automated method, of controlling the properties of a drilling fluid, the method including the steps of:

a. measuring at least one property of a fluid, or cuttings carried by a fluid, circulated in a wellbore for facilitating a drilling operation;

b. using the measured property to determine whether the fluid fulfils at least one predetermined fluid characteristic; and

c. optionally (e.g. if necessary) modifying the fluid provided to the wellbore based on said determination.

Viewed from a further aspect the present invention provides an apparatus for performing the methods herein described.

Viewed from another aspect the present invention provides a system for performing a well operation, the system comprising:

- wellbore apparatus provided in a wellbore through which a fluid is circulated for facilitating the wellbore operation;
- fluid measurement apparatus arranged to measure at least one property of the fluid, or cuttings carried by the fluid, during performance of the well operation; and
- fluid handling apparatus for modifying the fluid in response to the at least one measured property of the fluid or cuttings.

Viewed from another aspect the present invention provides a system for controlling the properties of a drilling fluid comprising:

- drill fluid measurement apparatus arranged to measure at least one property of the fluid or cuttings carried by the fluid during performance of the well operation; and
- fluid handling apparatus for modifying the fluid in response to the at least one measured property of the fluid or cuttings.

In preferred systems of the invention the fluid handling apparatus is adapted to form a fluid fulfilling predetermined criteria, e.g. having at least one characteristic in a predetermined range.

Viewed from yet another aspect the present invention provides a method of determining a fluid characteristic for a wellbore operation, the method comprising the steps of:

a. measuring at least one property of the fluid or of cuttings carried by the fluid during performance of the wellbore operation; and

b. measuring at least one wellbore operational parameter during performance of the wellbore operation; and

c. estimating a fluid characteristic of the fluid to be provided to the wellbore based on said measurements.

Viewed from still another aspect the present invention provides a method of assessing a drilling fluid for a drilling operation, the method comprising the steps of:

a. assessing the particle size distribution and/or particle content of the drilling fluid and/or the cutting size distribution, cutting mineralogy, cutting morphology and/or amount of cuttings present in said drilling fluid when in use; and

b. determining whether the drilling fluid is suitable to be provided to the wellbore.

The invention further provides processor control code to implement the above-described methods, in particular on a data carrier such as a disk, CD- or DVD-ROM, programmed memory such as read-only memory (Firmware), or on a data carrier such as an optical or electrical signal carrier. Code (and/or data) to implement embodiments of the invention may comprise source, object or executable code in a conventional programming language (interpreted or compiled) such as C, or assembly code, code for setting up or controlling an ASIC (Application Specific Integrated Circuit) or FPGA (Field Programmable Gate Array), or code for a hardware description language such as Verilog (Trade Mark) or VHDL (Very high speed integrated circuit Hardware Description Language). As the skilled person will appreciate such code and/or data may be distributed between a plurality of coupled components in communication with one another

Description

The well operation may be any operation, but is preferably an operation wherein cuttings or debris are produced and which are desirably removed from the wellbore. The well operation may be, for example, drilling, completion, milling or hole cleaning. The fluid is then drilling, completion, milling or cleaning fluid respectively. Preferably, however, the well operation is drilling and the fluid is a drilling fluid. The drilling operation may be drilling of an oil or gas well or drilling of an exploration well. More frequently, the methods of the invention are utilised in the drilling of oil and gas wells.

Drilling fluid is sometimes referred to as drilling mud. Drilling fluids are also sometimes referred in the art as being gel forming. As used herein, the term drilling fluid encompasses drilling muds and drilling fluids capable of forming gels. The drilling fluid is preferably used to suspend and transport cuttings produced during drilling out of the wellbore.

In preferred well operations the fluid provided to the wellbore is recirculated, preferably recirculated continuously. Thus preferably the fluid is provided to the wellbore, it is produced therefrom, optionally purified (e.g. filtered) and reintroduced into the wellbore. Well operations based on such recirculation techniques are advantageous as they are cost efficient compared to techniques using only fresh supplies of fluids. The typical drawback of recirculating fluid is that its properties may change during use and no longer be ideal for the purpose it is supposed to serve. A major advantage of the methods of the present invention is that they enable the properties of the fluid to be regularly or continuously monitored and if necessary regularly or continuously adjusted or modified to ensure the characteristics of the fluid are optimised even when recirculated.

An important feature of the methods of the invention is that the measuring of at least one property of the fluid or of cuttings is carried out during performance of the wellbore operation. Thus the at least one property is measured and the measurement obtained whilst the wellbore operation is ongoing. Preferably therefore the measuring of at least one property of the fluid or of the cuttings is in real time. This is in contrast to methods wherein a sample of fluid is taken and a measurement is taken at some later point in time, e.g. after the fluid has been transported to a laboratory.

Thus in a preferred method of the present invention the measuring step comprises measuring the at least one property of the fluid or the cuttings at intervals, e.g. regular, intervals during the performance of the operation. The interval may be, for example, 5 seconds-2 hours, 1 minute-1.5 hour, 5 minutes-1 hour or about 15-30 minutes, depending for example, on the property being measured and the measuring equipment being used. Preferably, however, the interval is less than 20 minutes, still more preferably less than 10 minutes, e.g. less than 5 minutes. In methods of the invention wherein step c. comprises measuring more than one property of the fluid or the cuttings, the interval between measurements of the properties may be the same or different depending on the equipment being used.

Particularly preferably the measuring step comprises measuring the at least one property of the fluid or the cuttings substantially continuously (e.g. continuously) during performance of the wellbore operation. To enable such measuring it is preferably automated.

In preferred methods of the invention, the step of measuring at least one property of the fluid or the cuttings is not carried out by detecting a nuclear magnetic resonance signal, i.e. it is not carried out by a technique utilising NMR.

The step of measuring the at least one property of the fluid or the cuttings may be performed after the fluid leaves the wellbore and/or before the fluid enters the wellbore. A sample of fluid leaving the wellbore may, for example, be taken prior to its entry to filtration apparatus to remove cuttings and/or after the filtration apparatus. When the sample is taken prior to the filtration step, the property measured may be a property of the fluid or the cuttings, but is preferably a property of the fluid. When the sample is taken after filtration, the property measured may also be a property of the fluid or of the cuttings. When measuring a property before the fluid enters the wellbore, the sample may be taken from the tank of the fluid handling (e.g. mixing) apparatus or from the pipe providing it to the formation. Conventional sampling equipment may be used in both cases. Optionally a bypass may be formed in one or more supply lines to facilitate sampling.

When the step of measuring the at least one property of the fluid or cuttings is performed after the fluid leaves the wellbore, a direct measure of how the operation affects its properties is obtained. In this way, the measurements contain the response of the fluid to being subjected to the wellbore. When the step of measuring the at least one property is carried out before the fluid enters the wellbore, a measurement of whether an appropriate fluid is being used is obtained. In the latter case a measurement of how the operation affects its properties is also obtained. This measurement is, however, typically less informative than the measurement on the fluid as it leaves the wellbore since the fluid will have been mixed with fluid from the tank of the fluid handling apparatus and the affect of changes diluted.

In preferred methods the step of measuring the at least one property of the fluid or the cuttings is performed before the fluid enters the wellbore. Particularly preferably a step of measuring at least one property is performed after the fluid leaves the wellbore (e.g. after filtration) and a step of measuring at least one property is carried out before the fluid enters the wellbore. The measured properties may be the same or different.

In preferred methods of the invention the at least one measured property is selected from the group consisting of:

- viscosity of fluid;
- density of fluid;

- fluid loss control properties;
- acidity of fluid;
- H_2S content of fluid;
- oil content of fluid;
- water content of fluid;
- emulsion stability of fluid;
- sand content and/or barite content of fluid;
- Cl^- , K^+ and/or lime content of fluid;
- size distribution of particles in the fluid;
- particle size distribution of cuttings;
- morphology of cuttings;
- mineralogy of cuttings; and/or
- amount of cuttings.

These properties may be measured according to methods known in the art and using commercially available equipment. For instance, viscosity of fluid may be measured using a viscometer, density of fluid using a densiometer, fluid loss using a fluid loss system, acidity using a pH meter, oil and water content as well as solids content may be measured using a retorte test (e.g. the API 13B-1 standard for water based drill fluids and the API 13B-2 standard for oil based fluids), emulsion stability using an electrical stability meter, chemical content (including H_2S content) using specific probes and tests (e.g. methylene blue test), size distribution of particles in the fluid using laser diffraction, particle size distribution of cuttings using laser diffraction or ultrasonics, morphology of cuttings using a morphology analyser, mineralogy of cuttings using a raman spectroscope or xray diffraction; and/or amount of cuttings using a weight sensor.

In a preferred method of the invention, the at least one measured property may be measured using nuclear magnetic resonance as described in UK patent application no. 0903580.9, the entire contents of which are hereby incorporated by reference. In this method a property of a drilling fluid is determined during performance of a drilling operation by detecting a nuclear magnetic resonance signal from out-of-hole drilling fluid. By out-of-hole drilling fluid is meant that the determination is on the drilling fluid before it enters the bore hole or after it has left the bore hole. The section of the line at which NMR measurement is effected should be made of non-magnetic material. Optionally a bypass line may be used.

The NMR signal detector may be any NMR apparatus capable of causing a drilling fluid to emit a detectable NMR signal and capable of detecting that signal. In general it will comprise a magnet, a radiofrequency detector and a radiofrequency emitter. The apparatus may also be provided with radiofrequency coils that impose spatially dependent, static or pulsed magnetic field gradients in any direction, strength, shape or duration. The magnet may have any of the formats conventional in NMR or MRI apparatus, e.g. hollow cylindrical or open (e.g. horseshoe), and the magnetic field may be permanent or may be created by electric current, e.g. in superconducting or non-superconducting coils. The use of open magnets is especially preferred as they may be readily positioned at desired locations along a line to detect signals from drilling fluid therein. Typically the magnetic strength will be in the range 1 to 100 MHz, preferably 2 to 20 MHz. The signal detector will typically be a magnetic resonance imager or an NMR apparatus capable of detecting a relaxation time dependent signal or a radio frequency dependent signal, either in one spatial dimension or spatially resolved (e.g. two or three dimensional) such as an NMR spectrometer or a magnetic resonance imager.

The NMR parameters that are measured will generally be the water proton relaxation times, i.e. T_1, T_2 and T_2*, signal amplitudes/intensities and the translational diffusion coefficient. Chemical shift and peak broadening may also be measured. The NMR signals from other active nuclei may of course also be detected.

Correlation between the NMR measurements and the properties of the drilling fluid (e.g. viscosity, density etc) may be readily achieved by comparison with standards, i.e. samples having a range of values of these properties as measured by other means. Preferably the NMR parameters for a large range of standards is measured and then, using multivariate analysis, a prediction matrix is generated. This may then be used to generate values for the desired parameters of the “unknown” sample.

To differentiate between different drilling fluid properties, the method of NMR measurement and the measured data values may be manipulated to extract the correct correlation. Thus for example different T_1 or T_2 measurement techniques may be used and different set-up parameters, e.g. magnetization, echo-spacing or pulse gradient direction, shape and strength may be used. With signals measured by two or more such techniques, evaluation algorithms may then be used to calculate the value of the desired drilling fluid property.

In preferred methods of the invention a plurality of properties of the fluid or the cuttings are measured. When a plurality of properties are measured, one or more measurement techniques may be used. Particularly preferably at least 2, more preferably at least 3, e.g. 2 or 3, properties of the fluid or the cuttings are measured.

In particularly preferred methods the at least one measured property is a property of the fluid. Thus preferably the at least one measured property is selected from viscosity of fluid, density of fluid, fluid loss control properties, acidity of fluid, H_2S content of fluid, oil content of fluid, water content of fluid, emulsion stability of fluid, sand and/or barite content of fluid, K^+, Cl^- and/or lime content of fluid, size distribution of particles in the fluid and amount of particles in the fluid. The particles present in the fluid comprise cuttings as well as other particulate material, e.g. solids added to achieve a particular size distribution. Particularly preferably the at least one measured property is selected from viscosity of fluid, density of fluid, fluid loss control properties and chemical content, especially viscosity of fluid and density of fluid.

In some preferred methods, the at least one measured property is not the density of the fluid.

In methods wherein the at least one measured property is a property of the cuttings, it is preferably particle size distribution of cuttings or amount of cuttings. When the at least one measured property is a property of the cuttings, the measurement may be performed on the cuttings suspended in, or carried by, the fluid or may be made after separation of the cuttings from the fluid. Separation may be carried out by any method conventional in the art, e.g. by filtration.

The method of assessing the particle size distribution and/or particle content of the drilling fluid and/or the cutting size distribution, cutting mineralogy, cutting morphology and/or amount of cuttings present in said drilling fluid when in use to determine the effectiveness of a drilling fluid is new and forms an aspect of the invention.

In preferred methods of the invention the at least one property of the fluid or cuttings measured during performance of the well operation is converted into a fluid characteristic. In other words, a fluid characteristic is calculated from the measured property. A fluid characteristic is a property of the fluid *per se* at standard conditions, e.g. ambient temperature, such as 20 ^{o}C, and pressure. The standard conditions may vary between different fluid characteristics. Typically fluid characteristics are used by suppliers to describe their fluid products, e.g. drilling fluid, and are listed in the specification of a fluid. Representative examples of fluid characteristics include viscosity, density, acidity (pH), fluid loss control, chemical content, oil/water ratio, emulsion stability, solids content, particle size distribution and particle content.

Thus preferred methods of the invention comprise the further step of estimating or calculating the at least one fluid characteristic based on the measured property of the fluid or the cuttings. In some cases this is a straightforward conversion. For instance, if the measured property is fluid viscosity or density, then they can be converted into the fluid characteristics of viscosity and density respectively by applying a factor taking into account the temperature and pressure at which is the measurement is made. In other cases the conversion is more complex. For instance, when a property of the cuttings is measured, the conversion may be to any of, e.g. viscosity, density or oil/water ratio. Thus particularly preferred methods of the invention comprise a step of using a model of the behaviour of fluid in a wellbore to estimate the at least one fluid characteristic of the fluid entering or exiting the wellbore based on the measured property.

The following measured properties are typically used to estimate the fluid characteristics listed in the table below:

Measured Fluid Property	Fluid characteristic
Viscosity	Viscosity
Density	Density
Fluid loss	Fluid loss control
Acidity (pH)	Acidity
H_2S content	H_2S content
Oil content of fluid	Oil/water ratio

Water content of fluid	Oil/water ratio
Emulsion stability	Oil/water ratio Emulsion stability
K^+ content Cl^- content Lime content	Chemical content
Sand content Barite content	Solids content
Amount of particles	Particle content
Particle size distribution of fluid	Particle size distribution of fluid
Measured cutting property	Fluid Characteristic
Particle size distribution of cuttings	Viscosity
Morphology of cuttings	Density
Mineralogy of cuttings	Chemical content
Amount of cuttings	Viscosity

When operators are initially deciding which fluid to use in a particular well operation, they will typically have an “ideal” fluid specification in mind. Thus for each fluid characteristic (e.g. viscosity, density, acidity etc) there will exist a range within which they would like that characteristic of the fluid used to fall. Operators may develop this specification, for example, as a result of prior experience of performing the well operation, or similar operations, or derive it from laboratory testing.

An example specification for a water-based drilling fluid might be:

Viscosity:	Shear stress of 80-100 lb/100ft^2 at 1021 s^{-1}
Density:	1450 kg/m^3
Oil/water ratio:	78/22-82/18
Emulsion stability:	>500 mvolt
Particle size distribution:	d_{90} 280-350 μm
Solids content:	20-25 vol%

Thus in preferred methods of the invention, in step b the fluid provided to the wellbore has at least one (e.g. 1) fluid characteristic in a predetermined range. In more preferred methods of the invention, in step b the fluid provided to the wellbore has 2-6, more preferably 2, 3, 4 or 5 fluid characteristics in a predetermined range.

Preferred methods of the invention comprise the further step of assessing whether the estimated fluid characteristic falls within the predetermined range. Thus once the at least one property of the fluid or cuttings is measured during performance of the operation and it is used to estimate or calculate a fluid characteristic, this estimate is compared against the predetermined range. This assessment step may be carried out by the equipment used to perform the measurement. More preferably the assessment step may be carried out by a computer arranged to receive signals (i.e. data) from the measurement apparatus. In instances where the assessment is that the fluid characteristic falls inside the predetermined range, there is no need to modify the fluid provided to the wellbore. On the other hand, when the assessment is that the fluid characteristic does not fall inside the predetermined range, the fluid provided to the wellbore is preferably modified. Preferably the modified fluid has fluid characteristics inside the predetermined range. In other words the step of modifying the fluid comprises changing the fluid characteristic.

Thus a preferred method of the invention comprises the step of assessing whether the fluid to be provided to the wellbore has at least one fluid characteristic within the predetermined range, and the modifying step includes optionally changing the at least one fluid characteristic such that it falls within the predetermined range.

In preferred methods of the invention the step of modifying the fluid is carried out during performance of the wellbore operation. This is highly advantageous as it means that the fluid provided to the wellbore is optimised (i.e. is within the predetermined range) throughout the operation regardless of, for example, changes in the well or wellbore conditions and the presence of cuttings in the fluid. This enables rapid intervention to counteract, for example, the affects of chemical reactions between the fluid and the formation and loss of fluid or components of the fluid to the formation.

Thus in particularly preferred methods of the invention the modifying step is carried out at (e.g. regular) intervals between 5 seconds-6 hours, more preferably 1 minute-2 hours, still more preferably between intervals of 5 minutes-1 hour, e.g. intervals between 10 minutes-30 minutes during the performance of the operation. Still more preferably the modifying step is carried out substantially continuously. This may be achieved, for example, when the step of modifying the fluid is automated.

In particularly preferred methods of the present invention the measuring and modifying steps are both automated. Thus preferably at least one property of the fluid or cuttings is measured at intervals or more preferably continuously and the fluid provided to the wellbore is modified as necessary.

A preferred method, e.g. an automated method, of the present invention therefore comprises the steps of:

a. performing a wellbore operation using wellbore apparatus located in a wellbore;

b. providing a fluid to the wellbore for facilitating the wellbore operation wherein said fluid has at least one fluid characteristic in a predetermined range;

c1. measuring at least one property of the fluid or of cuttings carried by the fluid during performance of the wellbore operation;

c2. estimating the at least one fluid characteristic based on the measured property of the fluid or the cuttings;

c3. assessing whether the estimated fluid characteristic falls within the predetermined range;

d. optionally (e.g. if necessary) modifying the fluid provided to the wellbore in response to the at least one measured property of the fluid or the cuttings.

The step of modifying the fluid provided to the wellbore in response to the at least one measured property may, for example, involve altering the proportions of the components of the fluid, adding one or more additional components to the fluid or removing (e.g. stopping the supply of one or more components). Preferably the response is alteration of the proportions of the components of the fluid.

Representative examples of modifications that may be made in response to various measured properties are listed below:

Viscosity is too low:	Amount of clay mineral increased or clay mineral added
Density is too low:	Amount of weighting agent increased or weighting agent added
Acidity (pH) is too high:	Amount of acid (e.g. citric acid) increased and/or amount of alkali decreased

Oil/water ratio is too high: Water (brine) content is increased

Emulsion stability is too low: Shear energy or specific solids e.g. clay minerals, are added

Particle size distribution of fluid is not appropriate: Amount of particulate materials, e.g. calcium carbonate, graphites etc. is altered or such materials are added. Alternative the screens present in the shaker may be altered.

Particle content of fluid is not appropriate: Amount of particulate materials, e.g. calcium carbonate, graphites etc. is altered or such materials are added

In preferred methods of the invention, a fluid mixing model is used to determine the alteration necessary to modify the at least one fluid characteristic. Preferred fluid mixing models are therefore able to calculate the compositional change necessary to cause the necessary change in a fluid characteristic, e.g. viscosity and density.

A simple example of how this may work is as follows. A drilling fluid may initially comprise components A, B and C in amounts of 10, 10 and 80 % wt respectively and have a viscosity of X and a density of Y. During use in a drilling operation, however, the viscosity of the fluid increases to X+10 and the density increases to Y+20. The change in the fluid properties is measured and the corresponding change in the fluid characteristics estimated. If the viscosity of X+10 and density of Y+20 is outside the pre-determined viscosity and density range the step of assessing whether the fluid characteristics fall within their predetermined ranges therefore gives rise to a negative result. The computer carrying out the assessment therefore uses a fluid mixing model to calculate what compositional change is necessary to reduce viscosity and density by the required amount. Optionally the model or algorithm doing this can take into account factors including the volume of fluid held in the tank of the fluid handling apparatus, the flow rate of fluid into the wellbore, the flow rate of fluid out of the wellbore, the total volume of fluid in circulation etc. The output of the model might be, for example, that the proportion of A should be increased to 15% and the proportion of B correspondingly decreased to 5%. This information is sent by the computer to the fluid handling apparatus and in particular the feed lines supplying the tank of the fluid handling apparatus and the flow of A and B into the mixing tank can be adjusted accordingly. The information may be sent continuously. Alternatively the model may average the input over a period of time, e.g. 10 minutes-1 hour, and send averaged output to the fluid handling apparatus.

The fluid mixing models may be prepared on the basis of tests carried out in the laboratory and/or prior work carried out in the formation. The man skilled in the art can readily generate suitable algorithms to function as the model. Multivariate models are preferred since they enable the simultaneous optimisation of a number of fluid characteristics.

The methods of the present invention therefore ensure that the fluids provided to the wellbore are optimised for a significant proportion of the time the operation runs. In particularly preferred methods wherein the steps of measuring and modifying are automated, the fluid may be optimised for the entirety of the well operation. This ensures that cuttings are removed efficiently so the wellbore is clean, the wellbore is stable, the wellbore is drilled efficiently and at the same time the formation is not damaged. The duration of a typical wellbore operation may be 12 hours-7 days, e.g. 24 hours-5 days.

In especially preferred methods of the invention, the at least one measured property of the fluid or cuttings is used to feedback information as to the effectiveness of the fluid and/or operation. Such a method may be described as a self-improving or self-learning method because the measured property of the fluid or cuttings is used to determine the optimal fluid specification for use in the operation. In such methods, an initial fluid specification is used at the start of the operation, then as data is generated and fed back, the specification may be modified. This in turn induces changes to the fluid provided to the wellbore by the method of measurements, assessments and modifications described above. The process is thus iterative.

For example, if a measured viscosity is low and cuttings mineralogy measurements indicate that a transition from sand into a shale formation has taken place, the feedback system may estimate a desired fluid specification having a higher viscosity than the fluid from earlier stages of the operation.

The self-improving or self-learning method may also be applied to continuously update the fluid mixing model.

Such methods may also be adapted to optimise the fluid to suit the operational parameters of the operation, e.g. to maximise the rate of penetration. Alternatively, or additionally, the methods may optimise the fluid to achieve specific well conditions. Examples of well conditions include wellbore stability, wellbore cleanliness, wellbore pressure and level of formation damage. This may include geological condition. The method may include estimating the well condition e.g. based on the measurements of the fluid property or the cuttings.

Thus in preferred methods of the invention, the range of at least one characteristic of the fluid to be provided to the wellbore is determined using the measurement of at least one property of the fluid or cuttings carried by the fluid during the performance of the wellbore operation. In particularly preferred methods, at least one wellbore operational parameter is also measured. In such cases the at least one measured property of the fluid or cuttings and the at least one measured wellbore operational parameter are used to determine the range of at least one fluid characteristic of the fluid to be provided to the wellbore.

In such methods the at least one wellbore operational parameter is preferably selected from the group consisting of:

- rate of penetration;
- hole diameter;
- well path;
- wellbore pressure;
- wellbore temperature;
- wellbore mineralogy;
- wellbore length;
- drilling fluid pumping rate; and
- drill string rotational speed.

Preferably the wellbore operational parameter is selected from wellbore pressure and wellbore temperature. These operational parameters, and the others listed above, can all be determined using conventional apparatus and methods known in the art. Such parameters are conventionally monitored by the system controlling a well operation, e.g. drilling. In the methods of the invention these parameters are preferably measured continuously.

More preferably the well condition is selected from wellbore stability and wellbore cleanliness, especially wellbore cleanliness. Wellbore cleanliness provides a measure of the effectiveness of a fluid such as a drilling fluid to remove cuttings from a wellbore and produce them on the drilling platform. Wellbore cleanliness may be estimated from the level of cuttings that are removed from the fluid, e.g. by the filtration apparatus. Thus the weight of cuttings removed from the fluid may be determined to gain a measure of the efficiency of their removal. Similarly well stability may be estimated from cuttings morphology. The calliper log typically kept during an operation may alternatively provide an estimation of well stability. Additionally formation damage may be estimated from filter loss.

Preferably a model of the behaviour of fluid in a wellbore is used to estimate or determine the range of at least one characteristic of the fluid to be provided to the wellbore, based on the measured property of the fluid or the cuttings and/or the at least one measured wellbore operational parameter. A model may be generated on the basis of data generated during prior operations in the formation, during operations in similar formations and/or during earlier stages of the well operation in progress. The later is preferred. The self-improving or self-learning method described above may also be applied to continuously update the fluid mixing model.

The model may be a real time hydraulic model which is initialized with wellbore objects which describes the geometry, geology and other properties of the well. Real time drilling fluid data may also be input to model. More than one real-time hydraulic model/simulator may be used. The models may be stepped forward in time, and the properties (e.g. pressure, flow, depth or drilling fluid parameters) may thus be predicted from the models. There is thus the advantage of being able to look ahead and prepare performance optimisation. The results from different models (data set) may be shown and may be related to each other. This has the advantage that there uncertainty of relying on only a single real time hydraulic model is reduced with the overall benefit of reducing the drilling operation risk.

Particularly preferred models are able to determine the range of one or more fluid characteristics that optimise one or more well condition. When such a model is utilised, step d. of the methods herein described then comprise the step of optimising the fluid to achieve that well condition. Thus when the model optimises the well condition of wellbore stability, step d. comprises optimising the fluid to maintain stability of the wellbore. Similarly when the model optimises well cleanliness, step d. comprises optimising the fluid to increase efficiency of removal of cuttings from the wellbore. Naturally simultaneous optimisation of more than one well condition may be carried out.

Preferred methods of the invention comprise the additional step of selecting a plurality of the measured properties of the drill fluid or cuttings that are together indicative of a condition of the wellbore and processing said plurality of measured properties for user interpretation/visualisation.

Preferred methods, apparatus and systems of the invention utilise a control system comprising a computer arranged to receive signals from drill fluid measurement apparatus, to calculate whether the fluid fulfils at least one predetermined criterion and to send signals to fluid handling apparatus to modify the fluid.

The fluid handling apparatus preferably comprises a holding or mixing tank, means to mix the contents of said tank and feed lines connected to supplies of fluid components. The fluid handling apparatus also preferably comprises filtering apparatus, e.g. shakers.

The shaker may optionally comprise screens of different “Cutt” points or hole openings. Screens with different Cutt points generally function to remove cuttings that are greater in size than a varying minimum, from the fluid, whilst allowing cuttings in the fluid below that minimum size to pass through the shaker and re-enter the well. The screens may be automatically controllable and selectable so that cuttings having a particular size or particle size distribution (PSD) can be retained in the drilling fluid. In this way, the particle size distribution, e.g. of cuttings, in the fluid can be controlled and modified.

Based on the measurements of PSD, an automatic recommendation for screen selection can be given. For example, if the PSD measurement that the proportion of larger particles is not sufficient, this would lead to an automatic recommendation to change the screen for a coarser shaker screen.

Description of preferred embodiments

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

Figure 1 is schematic representation of a drilling system showing the circulation of drilling fluid;

Figure 2 is a flow chart representation of a modelling sequence for the drilling process of Figure 1;

Figures 3a and 3b show the variation of a property of a drilling fluid with time, and

Figure 4 shows a schematic block diagram of the computer calculating the modelling sequence.

With reference firstly to Figure 1, there is shown a drilling system 1 in use during drilling of a well. A drill string 3 extending from a drilling platform (not shown) is fitted with a drill bit 3b and is located in a wellbore 5 where the string and drill bit are rotated to drill into the subsurface 9. The wellbore 5 is typically drilled through a number of different geological formations of the subsurface 9. A drill fluid is circulated under pressure into the wellbore through a conduit 3c in the drill string. For the purpose of this example, the drill fluid is oil based, but it can also be water-based. The fluid exits the drill string near the drill bit 3b, and is moved back up toward the surface in an annular space 5a of the wellbore 5 defined between an outer surface of the drill string and the wall 5w of the wellbore. Cuttings and other solid particulates 7 which are produced as a result of drilling are suspended in the drill fluid and carried in the fluid toward the surface and out of the wellbore.

Fluid handling apparatus 10 are provided on the platform for treating the drill fluid that has passed through the wellbore 5 before it is re-used. The handling apparatus 10 includes a shaker pit 12 into which fluid carrying cuttings and solids is received from the wellbore annulus 5a. The shaker pit 12 includes various shakers fitted with screens,(not shown) including a shale shaker, which remove solid particles and cuttings from the wellbore fluid. From the shaker pit, the drilling fluid is passed into a mixing pit 14 where the fluid is prepared and may be modified for re-use in the well. The mixing pit 14 may comprise a mixing tank for holding fluid drill fluid during mixing. Such a tank may typically have a capacity of 30-40 m^3. Fluid then exits the mixing pit 14 and back into the drill string conduit 5c.

It may also be desirable to configure the one or more shakers 30 with screens of different “Cutt” points or hole openings to apply to the fluid for removing cuttings above a certain size from the fluid, whilst allowing cuttings in the fluid below that size to pass through the shaker and re-enter the well. The different screens may be automatically controllable and selectable so that the cuttings have a particular size or particle size distribution (PSD). In this way, the particle size distribution, e.g. of cuttings in the fluid can be controlled and modified. It is useful often to have particles of a certain size present in the drill fluid in order to plug micro-fractures in the formation and prevent circulation loss incidents.

A number of measurements are performed on the drilling fluid as it passes through the shaker 12 and before entering the mixing pit 14, using measurement apparatus 20. Properties of both the drilling fluid and the cuttings carried by the drilling fluid are measured. The measurements are automated and carried out in real time, during drilling, and are performed substantially continuously, subject only to the sampling rate limits of the measurement tools. The measured properties are used to determine how the fluid may need to be modified in order to ensure that the fluid is suitable for the drilling operation being undertaken. Thus, the fluid in the mixing pit 14 may be modified in response to the measured properties for example by changing the amounts of the components supplied from one or more chemical storage tanks 30a-c fluidly connected to the mixing pit 14. These tanks may have a capacity of around 20 m3. The modification of fluid is similarly an automated process, which takes place in real time and on a continuous basis during the drilling of the well.

The measured properties in this example include viscosity and temperature of the fluid, density, emulsion stability, particle size distribution, fluid loss, pH, H_2S content, cuttings morphology, mineralogy, oil/water ratio and solids content. All of these characteristics of the fluid may be altered.

In order to make such measurements, the measurement apparatus 20 includes a viscometer 20v coupled to the line 22, which connects the shaker and the mixing pit. The viscometer 20v may, for example, take the form of an inline automated Couette viscometer providing measurements at different shear rates, covering the API standard shear rate span of $5{:}1022s^{-1}$. Such a viscometer is currently manufactured by Brookfield, Coriolis and others. The viscometer includes a temperature probe in order that the viscosity measurements, which depend strongly on temperature, can be used to derive an appropriate viscosity curve for other prescribed temperatures.

A densiometer 20d is provided which is used to measure the density of the fluid. A Coriolis mass flow meter can, for instance, be used to do this by measuring the natural frequency of the filled Coriolis tube.

Fluid loss is measured using an automated fluid loss system (AFLS) 20f designed to autonomously measure the High-Pressure High-Temperature (HPHT) fluid loss properties of water and oil-based fluids at discrete real-time intervals. As an alternative to measuring fluid loss, the fluid loss may be estimated or simulated using other real-time measurements. The fluid loss can be simulated (not measured) by measuring other fluid properties such as PSD, viscosity etc. and using the measurements of these properties to provide an estimate of the fluid loss.

An automated self-cleaning instrument is selected, allowing it to be controlled and used for continuous repeat measurement. The AFLS can, for example, be controlled via a SCADA system and a Mitsubishi Q series PLC with Modbus TCP interface.

The particle size distribution of the fluid is measured using a particle size distribution measurement device 20p. Such a device may take the form of a liquid particle analyser where a sampling system samples a constant volume of drilling fluid. The sample is diluted and fed down to a flow cell, where images of the particles are captured with a camera. Image elements are counted in different directions to determine the length scales of the particles. Other techniques that may be used to determine particle size distribution include laser diffraction and ultrasonics.

The measurement apparatus 20 further includes an electrical stability meter 20e that is used to measure the emulsion stability of the drilling fluid. An automated version of a Fann Model 23D Electrical Stability Tester may, for instance, be used where an automated wiper for cleaning electrodes is fitted, and control electronics are provided for continuous measurement. Further, such a tester is modified to output readings automatically and transmit them in real time.

At the shaker 12, a cuttings flow meter 20c is installed. This device collects cuttings at an output of a shale shaker. Weight sensors connected to a mud logging acquisition system of the platform allows the weight of the cuttings to be determined. The amount of cuttings in terms of mass can then be determined by combining the weight with cuttings bulk density measurements performed on the cuttings.

The shape of cuttings removed from the fluid by the shakers is evaluated using a cuttings morphology analyser 20m. Length-to-thickness (L/T-ratio) ratio of cuttings provides information about the downhole processes. Samples for this purpose are collected in a cup from various decks of shakers in the shaker pit 14 and emptied into a liquid particle analyser where images of the cuttings are taken by a camera, and analysed in a similar way to the particle size distribution device 20p.

Analysis of oil, water and solids content can be performed by a retorte test according to the API 13B-1 standard for water based drill fluids and API 13B-2 for oil based fluids. From this, the proportion of oil, water and solids content can be derived and used to provide measures of oil/water ratio and solids content. The sampling of the drill fluid for the retorte test is automated in this system so that regular sampling and measurement of these properties is performed throughout the drilling process.

Cuttings flow may also be measured, e.g. using ultrasonics.

The mineralogy of particles is analysed using a Raman spectroscope 20r. Cuttings are moved from the morphology analyser to the Raman spectroscope, which analyses the cuttings directly with little or no preparation. An alternative method for determining mineralogy is XRF.

It will be appreciated that other properties may also be measured. For example, pH may be measured in water based drilling fluids. For such measurements, an Ion Specific Field Effect Transistor may be used. The presence of H_2S may also be measured using probes equipped with ceramic oxides and fluorides. Alternatively the fluid or cuttings properties may be determined using methods such as nuclear magnetic resonance (NMR) or ultrasonics.

The measured properties are transmitted from the instruments of the measurement apparatus 20 to a control system where the measured parameters can be monitored remotely, on a continuous basis and in real-time. The measurements may also be stored as data for later use, although in the present process, they are used in real time to determine how the fluid provided into the wellbore conduit 5c might need to be changed to ensure that the fluid has a suitable composition at all times.

To this end, the control system is arranged to monitor and to process the measurements to determine what needs to be done in the mixing pit 14, for example to determine whether to change the proportions of components, inject an additional component or to stop supplying a component and to determine how much should be added/removed. Alternatively, or additionally, the measurements may be used to alter the screens present in the shaker.

The method for processing the measurements and determining how to modify the fluid can be seen with further reference to Figure 2. This part of the system is implemented by using two models, firstly a “well model” 50 and thereafter a “mixing model” 60. The measurements made by the measurement apparatus 20 provide a first input 46 to the well model. In addition, various physical wellbore operational parameters provide a second input 48 to the well model. The physical wellbore operational parameters are measured and monitored by the control system during the drilling operation and include for example the rate of penetration, hole diameter, well path trajectory, pressure, and temperature. Changes in such parameters can impact significantly on the drilling process. Accordingly, both the measured properties 46 and the operational parameters 48 provide information about conditions in the well, which are important to take into account in the well model 50 for determining a suitable fluid.

Based on the input 48 of physical wellbore operational parameters and the input 46 of measurements of the drilling fluid and cuttings, an estimation is carried out by the well model 50 to determine and then output a desired fluid specification or characteristic 52 for the drilling fluid to be provided into the well, given the well conditions derived from the input parameters 46, 48 and/or a given desired condition. Thus, the well condition may be estimated based on the measurements. The well model 50 may, for example, be utilised to optimise the density of the drilling fluid to maximise the rate of penetration of the formation. Alternatively the well model 50 may be adapted to estimate a specification for the fluid that will give for example best possible hole cleaning performance or minimum fluid loss, given the measured wellbore operational parameters. The desired condition for optimisation using the well model may be specified by an operator as an additional input to the well model, for example set via a control panel, and may be changed during the drilling operation. The well model may also optimise for a plurality of desired conditions.

Wellbore stability can, for instance, be closely controlled using the drilling fluid. For example, a density of the fluid can be specified to increase borehole pressure so as to maintain overpressure conditions, prevent formation collapse into the annulus, and restrict fluid loss into the formation. It is clear, however, that a particular specification should therefore also take account of the geological conditions, because the different formations may for example be more receptive to fluids than others, and so in this example it is useful in the present system to use measured properties such as mineralogy as a guide for example to the fluid receptiveness of the formation which in turn guides the estimation of a suitable fluid.

The well model “simulates” down hole conditions and how certain fluid characteristics affect the downhole conditions. It comprises an algorithm for determining an appropriate fluid, which in this example may contain the theoretical relationships between: 1) well fluid properties (e.g. viscosity and density) and wellbore pressure for a given operational parameters; 2) wellbore pressure and stability of geological formation; 3) stability of geological formation and formation type; 4) formation type and cuttings measurements. Moreover, it may incorporate a number of other relationships or correlations linking the well fluid parameters with the measured properties 26 and/or wellbore operational conditions 48. The fluid specifications determined from the well model are such as to ensure safe and efficient drilling can be performed. The fluid specification 52 typically specifies a range of desired values for fluid characteristics. During drilling the operational parameters 48 and requirements for safe drilling will change, and accordingly the fluid specifications 52 needed for safe drilling also change automatically.

The fluid specification 52 output from the well model 5 is used as an input to the mixing model 60. In addition, the measurements 46 are input to the mixing model.
An assessment step 62 is firstly carried out to assess whether the fluid as measured is within the specification 52. The measurements 46 input to the model 60 provides the information about the “starting” condition of the drill fluid. The measured properties of the fluid are compared with the predetermined ranges defined in the fluid specification 52. If the fluid is within the fluid specification, no modification of the fluid is required. If the fluid does not meet the fluid specification, it is necessary to determine how the fluid may be changed to bring it within specification before it is sent into the wellbore 5. The mixing model provides a “sensitivity map” of how chemical changes to drill fluids of different types and compositions control the fluid characteristics. In particular, the model may incorporate links in the form of specific correlations that describe the effect of a chemical additive on a characteristic of the fluid. For example, a polymer such as a xanthan polymer can be correlated to the viscosity of a water based mud. In such an example, the addition of xanthan polymer may have the following effect on 3 rpm and 600 rpm viscosimeter readings in the fluid: addition of 1 kg/m^3 increases 3 rpm by 1 and 600 rpm by 8. This relationship can be tabulated and programmed to form a “viscosity increasing” or “viscosifying” correlation in the mixing model.

To provide a further example, a correlation between the addition of a polymer and the fluid characteristic of fluid loss control may be specified in the mixing model. Supposing a fluid property measurement for fluid loss is 8 ml, then addition of 3 kg/m^3 PAC ELV may reduce fluid loss by half (i.e. addition of 3 kg/m^3 gives fluid loss of 4 ml, addition of 6 kg/m^3 gives fluid loss of 2 ml). This relationship between quantity of PAC ELV additive and reduction fluid loss can similarly be tabulated and programmed into the mixing model so that the fluid can be modified by the appropriate addition of polymer to bring it within the required specification.

Accordingly, on being presented with the drill fluid measurements, the mixing model can determine what additives require to be added, in what quantity and under what conditions in order to modify the fluid such that it is brought within the specification. These additives includes both solid materials such as weighting materials e.g. in powder form, and fluid chemicals. Once this is determined, a corresponding control signal is sent to the flow valves 16 on the injection line 18 to open them as required and add an additive to the fluid in the mixing pit 14. The flow valves are remotely controllable and adjustable so that additives can be added at a certain flow rate.

Where the specification of fluid from the well model requires there to be a certain particle size distribution or amount of particles in the fluid (e.g. if morphology measurements such as size and shape and content/size distribution of particles input to the mixing model indicate that the fluid is out of specification), the control system may transmit control signals to control the shakers and select suitable screens to modify the particle content of fluid appropriately. The mixing model may be programmed to decide whether to control particle size distribution by using screens and/or by addition of solids in the mixing pit.

In other embodiments, a premix may be used and added to the fluid in order to modify it and bring it within the specification. Such a premix is a fluid mixture with constituent chemicals present in pre-determined proportions. It is a “ready made” additive that may have been tested and is known to provide a particular effect on a drilling fluid or the drill fluid characteristics. In typical embodiments, the premix consists of a fluid blend of the chemicals normally present in a drill fluid, but without weighting materials such as barite. The viscosity of the premix can be higher than the drilling fluid specification or lower, e.g. to increase or decrease the viscosity of the drill fluid. In this way, the premix can be applied in accordance with the mixing model to control properties such as viscosity and density of the drilling fluid, and at the same time control the chemical composition. Control of viscosity can for example be performed by adding a suitable amount of either high or low viscosity premix from a storage tank 30a-c. Control of density may be performed by using a particular premix in combination with addition of dry weighting material such as barite to the fluid. Different types of premixes can be used, which may be prepared away from the fluid processing system and transported to the processing facility as required.

The implementation of the well model and mixing model may be as programmed microprocessors in part of the control system or part of the control system software.

The measurements of the fluid are sent to the control system, and monitored throughout the process. They are fed directly into the well model algorithm in the software or programmed microprocessors to determine the desired fluid specification, which in turn is fed directly to the mixing model algorithms control system following the logic described above and control signals are then sent to the mixing apparatus to change the characteristics of the drill fluid as appropriate.

The drilling fluid is a complex system with interdependencies between the various measurable properties. Accordingly, the behaviour of the fluid following its modification with the additives may be unpredictable. As shown in Figure 2, the process may be iterative. In other words, after the mixing model has determined whether or not to modify the fluid, another measurement is taken and the process begins again. Thus, the additives may be added over a period of time until the predetermined criteria desired for the measured fluid is achieved.

During the iterative process, the dynamics of the fluid property may behave as shown in either Figure 3a or 3b. In Figure 3a, the property of the fluid being measured is gradually brought down towards the predetermined criterion or set point over time. In Figure 3b, a quick adjustment is sought and the property initially dips below the desired set point. Thereafter, the behaviour of the property becomes oscillatory as it approaches the set point. The set points may be set by an engineer operating the system. The set points may be constant values or varying curves or sequences which are pre-programmed. Alternatively, appropriate curves may be calculated by the control system taking into account the overall system stability. The curves may be updated based on measured values, e.g. adjustments may be made to the curves if measured properties differ from predicted values.

The iterative process may be used to continuously update the models, namely the well and mixing models. These models may be optimised with regards to response, enabling good control of property transients, and reducing such typical oscillatory behaviour. These iterative processes may involve application of several additives simultaneously, and may require monitoring of several properties to achieve an ideal fluid and optimize use of additives.

A schematic block diagram of a computer for processing the data is shown in Figure 4. As will be appreciated, the term computer is intended generically and may cover a server, standalone computer or other processing devices. The computer comprises a processor 602 connected to working memory 604, a data store 608 and permanent program memory 606. The data store 608 contains information on the fluid characteristics, for example, the different properties and the suitable ranges of their values. The program memory 606 stores the various elements of the code which cause the processor to perform the required steps. For example, there is program code for the well and mixing models which may be adaptive to respond to changes programmed by a user or self-learning to respond to information learnt from the real-time measurements. Using these models, the processor is configured to calculate whether the fluid fulfils at least one predetermined criterion, i.e. whether or not one of the measured properties lies within a target range or approaches a set point. If the fluid does not fulfil the criterion, the processor is configured to determine an alteration to the fluid using the models.

There is also data communications control code by which the processor which is connected to a communications link 600 communicates with other parts of the system. The processor is thus configured to receive signals from the various measuring devices of the drill fluid measurement apparatus via the communications link. The processor is also configured to send signals to the fluid handling apparatus to modify the fluid. In this way, control of the fluid is automated. The communications link also allows the system to be monitored locally or remotely, for example by accessing one or more live databases containing real time data streamed from the measurement apparatus.

The computer also comprises a user interface 612 which may also be accessed from one or more locations. The interface may provide an overview of the system and the various measurements and an indication of the alterations which have been calculated and are to be applied. The interface may allow user-input for example to specify a condition of the well for optimization of the well fluid, updates to the model, and/or the properties to be measured. Drilling data might be accessed in the same way and could be used in combination with the measurements of fluid measurements to determine the well condition for optimization.

Some or all of the contents of the permanent program memory and working memory may also be provided on portable storage media such as floppy disk 607.

Automating the processes above provide significant improvements to the drilling process. In particular, better decisions about the appropriate drill fluid can be made, and the fluid can be automatically and continuously optimized for a required performance as the process proceeds. It also provides significant efficiency improvements.

There are also logistical improvements. For example, the quantities of additives used can be monitored and used to predict when additional supplies are required. In this way, the quantity of additives stored on site may be minimised which is particularly important in marine operations where storage is limited. There may be an automated link to the additive suppliers to order additional additives when required to ensure that the additives are received when required. By having full control of all volumes and chemicals sent to and from the rig, it will be possible to link this directly to invoicing and thus the automated link may provide for automatic invoicing. For example, if all volumes and chemicals are “tagged”, the ordering and invoicing could be made automated.

Having full control of all volumes available at base facilities and at the drilling rigs, also allows additional logistical optimisations. For example, a specific volume of fluid with certain properties can be allocated to the rig requiring this volume. Equally by handling of waste, improved control of waste composition will optimise logistics by giving automated recommendations for where the waste is ideally to be sent.

Various modifications and improvements may be made without departing from the scope of the invention herein described.

CLAIMS:

1. A method of conducting a well operation, the method comprising the steps of:

a. performing a wellbore operation using wellbore apparatus located in a wellbore;

b. providing a fluid to the wellbore for facilitating the wellbore operation;

c. measuring at least one property of the fluid or of cuttings carried by the fluid during performance of the wellbore operation;

d. determining whether the measured fluid fulfils predetermined criteria,

e. determining an alteration to the fluid provided to the wellbore using a fluid mixing model when said measured fluid does not fulfil the predetermined criteria and

f. modifying the fluid provided to the wellbore using said determined alteration.

2. A method as claimed in claim 1, comprising determining whether the fluid fulfils predetermined criteria by determining whether said fluid has at least one characteristic in a predetermined range.

3. A method as claimed in claim 1 or claim 2, wherein said fluid is recirculated during performance of the well operation.

4. A method as claimed in any one of claims 1 to 3, wherein step c. comprises measuring the at least one property of the fluid or the cuttings substantially continuously during performance of the wellbore operation.

5. A method as claimed in any one of claims 1 to 4, wherein the step of modifying the fluid is carried out during performance of the wellbore operation.

6. A method as claimed in any one of claims 1 to 5, wherein the step of measuring and/or modifying the fluid is automated.

7. A method as claimed in any one of claims 1 to 6, wherein the at least one measured property is selected from the group consisting of:

- viscosity of fluid;
- density of fluid;
- fluid loss control properties;
- acidity of fluid;

- H_2S content of fluid;
- oil content of fluid;
- water content of fluid;
- emulsion stability of fluid;
- sand and/or barite content of fluid;
- K^+, Cl^- and/or lime content of fluid;
- particle size distribution of fluid;
- particle size distribution of cuttings;
- morphology of cuttings;
- mineralogy of cuttings; and/or
- amount of cuttings.

8. A method as claimed in any one of claims 1 to 7, wherein step d comprises the steps of:

estimating at least one fluid characteristic of the fluid based on the measured property of the fluid or the cuttings; and

assessing whether the estimated fluid characteristic falls within a predetermined range.

9. A method as claimed in any one of claims 1 to 8, wherein the range of at least one characteristic of the fluid to be provided to the wellbore is determined using the measurement of the at least one property of the fluid or cuttings carried by the fluid during the performance of the wellbore operation.

10. A method as claimed in claim 9, wherein at least one wellbore operational parameter is measured and the at least one measured property of the fluid or cuttings and the at least one measured wellbore operational parameter are used to determine the range of at least one fluid characteristic of the fluid to be provided to the wellbore.

11. A method as claimed in claim 9 or claim 10, wherein a model of the behaviour of the fluid in a wellbore is used to estimate or determine the range of at least one characteristic of the fluid to be provided to the wellbore.

12. A method as claimed in any one of claims 1 to 11, wherein said method is automated.

13. A method as claimed in any one of claims 1 to 12, wherein steps c to f are iteratively repeated.

14. Apparatus for performing the method as claimed in any one of the preceding claims.

15. A system for controlling the properties of a drilling fluid for facilitating a well bore operation, the system comprising:

drill fluid measurement apparatus arranged to measure at least one property of the fluid or cuttings carried by the fluid during performance of the well operation;

fluid handling apparatus for modifying the fluid in response to the at least one measured property of the fluid or cuttings; and

a computer which is configured to

receive signals from said drill fluid measurement apparatus,

calculate whether the fluid fulfils at least one predetermined criterion,

determine an alteration to the fluid using a fluid mixing model when said measured fluid does not fulfil the predetermined criterion and

send signals to said fluid handling apparatus to modify the fluid.

16. A system for performing a well operation, the system comprising:

wellbore apparatus provided in a wellbore through which a fluid is circulated for facilitating the wellbore operation; and

a system for controlling the properties of a drilling fluid as claimed in claim 15.

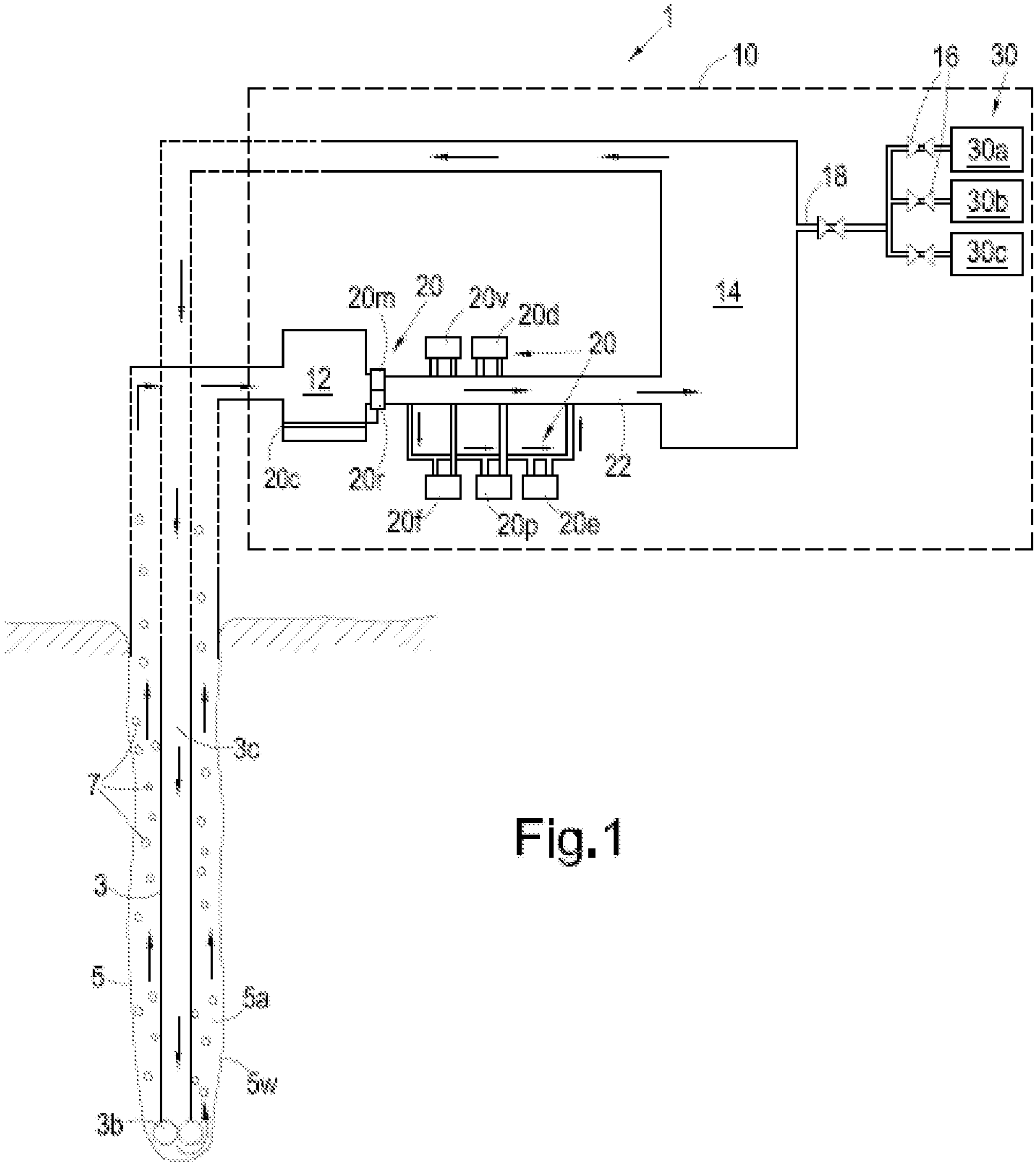
17. Program code for a computer which when running on a computer causes the computer to

receive signals from drill fluid measurement apparatus arranged to measure at least one property of the fluid or cuttings carried by the fluid during performance of the well operation,

calculate whether the fluid fulfils at least one predetermined criterion,

determine an alteration to the fluid using a fluid mixing model when said measured fluid does not fulfil the predetermined criterion and

send signals to a fluid handling apparatus to modify the fluid.


1
10
16
30
30a
30b
30c
18
14
20m
20
20v
20d
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12
20c
20r
22
20f
20p
20e
3c
7
3
5
5a
5w
3b

Fig.1

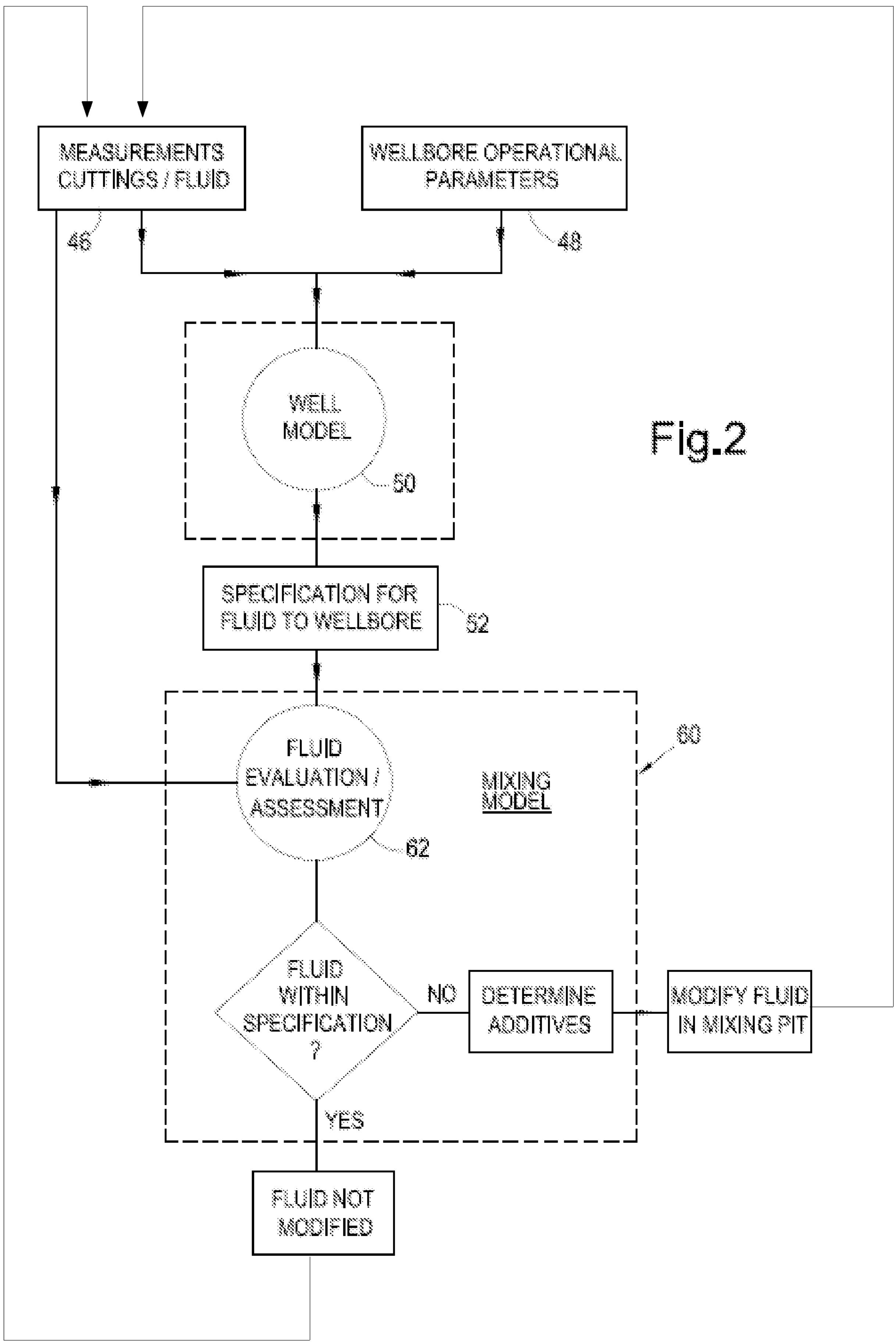
MEASUREMENTS
CUTTINGS / FLUID
46
WELLBORE OPERATIONAL
PARAMETERS
48
WELL
MODEL
50
SPECIFICATION FOR
FLUID TO WELLBORE
52
60
FLUID
EVALUATION /
ASSESSMENT
62
MIXING
MODEL
FLUID
WITHIN
SPECIFICATION
?
NO
DETERMINE
ADDITIVES
MODIFY FLUID
IN MIXING PIT
YES
FLUID NOT
MODIFIED

Fig.2

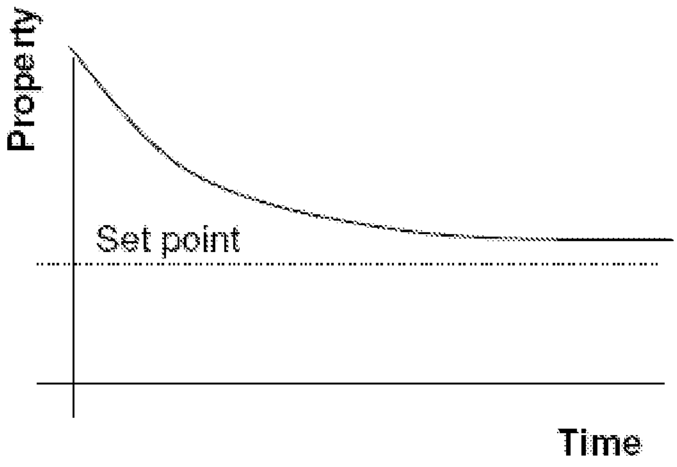

Fig 3a

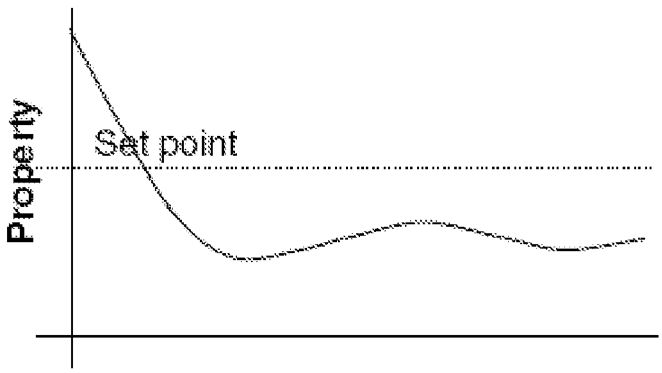

Fig 3b

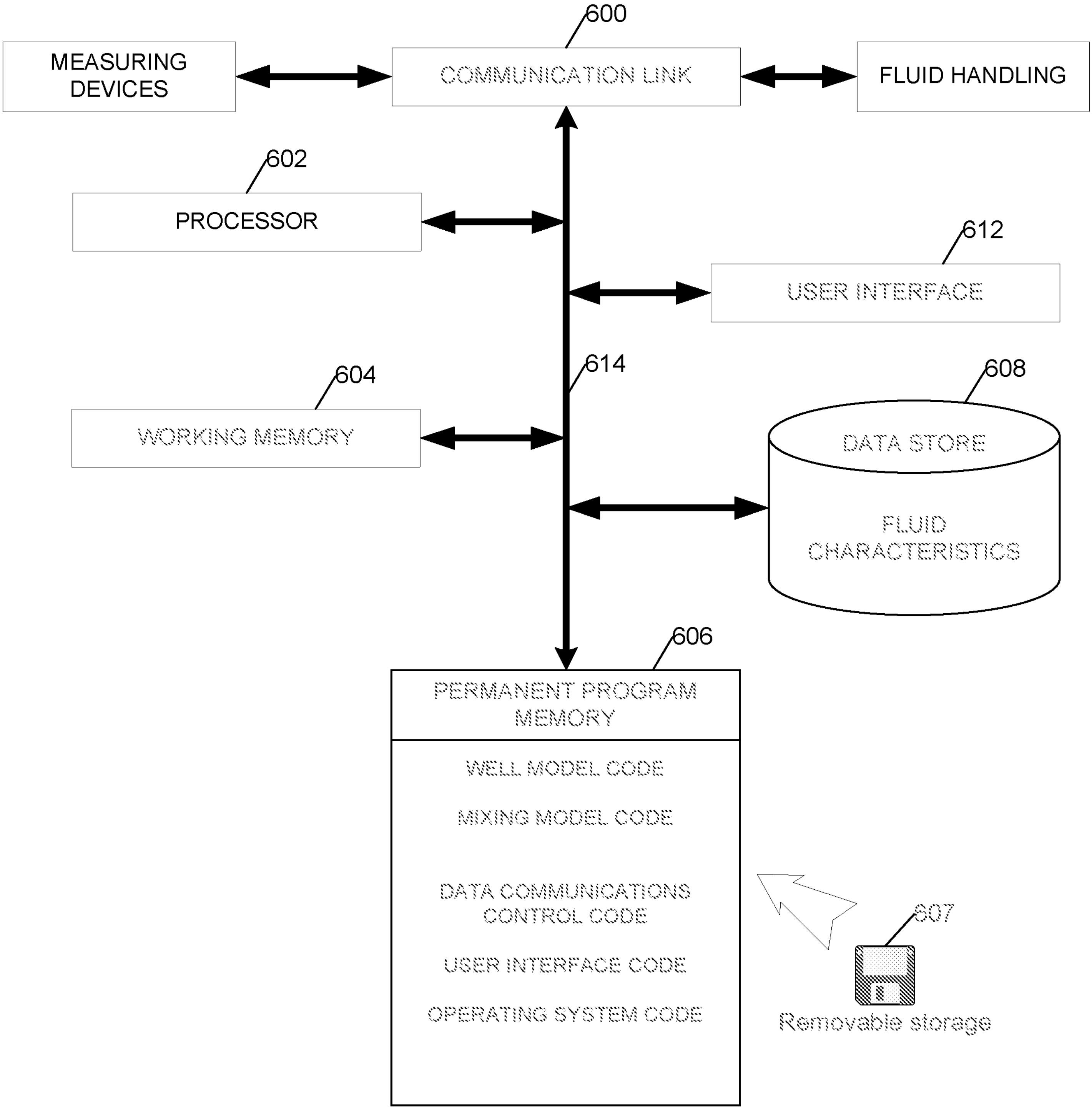
600
MEASURING DEVICES
COMMUNICATION LINK
FLUID HANDLING
602
PROCESSOR
612
USER INTERFACE
614
604
WORKING MEMORY
608
DATA STORE
FLUID CHARACTERISTICS
606
PERMANENT PROGRAM MEMORY
WELL MODEL CODE
MIXING MODEL CODE
DATA COMMUNICATIONS CONTROL CODE
USER INTERFACE CODE
OPERATING SYSTEM CODE
607
Removable storage

Figure 4