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(54) Title: METHODS OF DRILLING AND CONSOLIDATING SUBTERRANEAN FORMATION PARTICULATES

(57) Abstract: The present invention relates to improved methods for drilling well bores penetrating producing zones while controlling formation particulates. Some embodiments of the present invention provide methods of drilling a well bore into a subterranean formation comprising the steps of providing a drilling composition comprising a drilling fluid and a consolidating material; and, using the drilling composition while drilling the well bore and allowing the consolidating material in the drilling composition to penetrate into the walls of the well bore.

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METHODS OF DRILLING AND CONSOLIDATING SUBTERRANEAN FORMATION PARTICULATES

5 **Field of the Invention.**

The present invention describes improved methods for drilling and treating well bores. More particularly, the present invention relates to improved methods for drilling well bores penetrating producing zones while controlling formation particulates.

Description of the Prior Art.

10 Often, well bores are drilled into weakly consolidated formations wherein the walls of the well bore may be sensitive to degradation by the force of mobile fluids within the formation. Often, such well bores are subjected to some form of sand control operation such as gravel packing to reduce the migration of unconsolidated formation particulates. One common gravel packing operation involves placing a gravel pack screen in the well bore and
15 packing the surrounding annulus between the screen and the well bore with particulates referred to as "gravel" that have a specific size designed to prevent the passage of formation sand. The gravel pack screen is generally a filter assembly used, *inter alia*, to support and retain the gravel placed during gravel pack operations. A wide range of sizes and screen configurations are available to suit the characteristics of the gravel pack sand used. Similarly,
20 a wide range of sizes of gravel is available to suit the characteristics of the unconsolidated or poorly consolidated particulates in the subterranean formation. The resulting structure presents a barrier to migrating sand from the formation while still permitting fluid flow. When installing the gravel pack, the gravel is carried to the formation in the form of a slurry by mixing the gravel with a transport fluid. Gravel packs act, *inter alia*, to stabilize the
25 formation while causing minimal impairment to well productivity. The gravel, *inter alia*, acts to prevent the particulates from occluding the screen or migrating with the produced fluids, and the screen, *inter alia*, acts to prevent the gravel from entering the production tubing. While gravel packs have been successfully used to control the migration of formation sands,

their placement generally reduces the available diameter of a well bore due to the physical size of the screen and the resulting gravel annulus.

The screen assembly referred to in the gravel packing operation may also be used as an independent sand control means. Some of the early screen technology dictated that the screens had to be small enough to pass through the smallest diameter of the well bore on the way to its desired placement location where the diameter of the well bore may actually be larger. Developments in technology have lead to deformable and expandable screens such that a relatively small size or small diameter screen may be placed in a desired location along the well bore and then expanded to accommodate the actual size of the well bore at the point of placement.

While the sand control methods mentioned above are routinely used in the completion of well bores, particularly those drilled into weakly consolidated formations, they increase the expense of installing a well bore by requiring separate steps to drill the well bore and then to control the formation sands.

SUMMARY OF THE INVENTION

The present invention describes improved methods for drilling and treating well bores. More particularly, the present invention relates to improved methods for drilling well bores penetrating producing zones while controlling formation particulates.

Some embodiments of the present invention provide methods of drilling a well bore into a subterranean formation comprising the steps of providing a drilling composition comprising a drilling fluid and a consolidating material; and, using the drilling composition while drilling the well bore and allowing the consolidating material in the drilling composition to penetrate into the walls of the well bore.

Other embodiments of the present invention provide methods of consolidating a subterranean formation surrounding a well bore comprising the steps of providing a drilling composition comprising a drilling fluid and a consolidating material; and, using the drilling composition while drilling the well bore and allowing the consolidating material in the drilling composition to penetrate into the walls of the well bore as it is formed.

Other and further objects, features and advantages of the present invention will be readily apparent to those skilled in the art upon a reading of the description of preferred embodiments which follows.

DESCRIPTION OF PREFERRED EMBODIMENTS

5 The present invention describes improved methods for drilling and treating well bores. More particularly, the present invention relates to improved methods for drilling well bores penetrating producing zones while controlling formation particulates.

10 In some embodiments of the methods of the present invention, a well bore is drilled with a drilling composition comprising a drilling fluid and a consolidating material. The consolidating material is allowed to penetrate into the formation and substantially cure, thus consolidating the formation sands along the wall of the well bore. The methods of the present invention provide, *inter alia*, a means for stabilizing weakly consolidated formations surrounding a well bore during drilling, preventing the formation from collapsing during production, and producing through the treated interval.

15 Drilling fluids suitable or use in the present invention may be water-based fluids or oil-based invert emulsion fluids. Essentially any drilling fluid suitable for a drilling application may be used in accordance with the present invention, including aqueous gels, emulsions, and other suitable fluids. Suitable aqueous gels are generally comprised of water and one or more gelling agents and may further comprise weighting agents. Suitable
20 emulsions may be comprised of two immiscible liquids such as an aqueous gelled liquid and a liquefied, normally gaseous fluid, such as nitrogen. In some embodiments of the present invention where the well bore is drilled into a producing zone, the drilling fluid may comprise a drill-in fluid, which is a fluid designed specifically for drilling through the reservoir section of a well bore. Drill-in fluids are often used, *inter alia*, to minimize damage and maximize
25 production of exposed zones and to facilitate later well completion procedures. Often, additives essential for fluid loss control and cuttings carrying are present in a drill-in fluid. It is within the ability of one skilled in the art, with the benefit of this disclosure, to select a drilling fluid suitable for use in the drilling compositions of the present invention.

Traditional drilling operations add solid particulate matter to the drilling fluid to help control fluid loss to the surrounding formation. In the methods of the present invention, use of such additives can be greatly reduced or eliminated due to the fact that the consolidation material added to the drilling fluid may act as a fluid loss control agent. Thus, drilling compositions suitable for use in the present invention preferably comprise only a small amount of particulate fluid loss control material. In some embodiments of the present invention, particularly in those applications where the formation being drilled has a low permeability, *e.g.* a chalk formation, the drilling fluid composition may contain little if any particulate fluid loss control material. In other embodiments of the present invention, a fluid loss control material is present in the drilling fluid composition in an amount ranging from 0.1% to about 10% by weight of the overall drilling fluid composition. When used, the particulate fluid loss control material is preferably a material that will degrade in the well bore. Suitable such degradable fluid loss control material's include, but are not limited to, aliphatic polyesters, polylactic acid, poly(lactides), poly(orthoesters) and combinations thereof.

Consolidation materials suitable for use in the present invention include, but are not limited to, low-temperature epoxy-based resins, furan-based resins, phenolic-based resins, high-temperature (HT) epoxy-based resins, and phenol/phenol formaldehyde/furfuryl alcohol resins.

The temperature of the subterranean formation being drilled may affect selection of a consolidation material. By way of example, for subterranean formations exhibiting a temperature ranging from about 60°F to about 250°F, low-temperature epoxy-based resins comprising a hardenable resin component and a hardening agent component containing specific hardening agents may be preferred. For subterranean formations exhibiting a temperature ranging from about 300°F to about 600°F, a furan-based resin may be preferred. For subterranean formations exhibiting a temperature ranging from about 200°F to about 400°F, either a phenolic-based resin or a HT epoxy-based resin may be suitable. For subterranean formations exhibiting a temperature of at least about 175°F, a phenol/phenol formaldehyde/furfuryl alcohol resin may also be suitable.

One consolidation material suitable for use in the methods of the present invention is a low-temperature epoxy based resin comprising a hardenable resin component and a hardening agent component. The hardenable resin component is comprised of a hardenable resin and an optional solvent. The solvent may be added to the resin to reduce its viscosity for ease of handling, mixing and transferring. It is within the ability of one skilled in the art with the benefit of this disclosure to determine if and how much solvent may be needed to achieve a viscosity suitable to the subterranean conditions, *e.g.* a low enough viscosity to permeate into the formation being drilled. Factors that may affect this decision include geographic location of the well and the surrounding weather conditions. An alternate way to reduce the viscosity of the liquid hardenable resin is to heat it. This method avoids the use of a solvent altogether, which may be desirable in certain circumstances. The second component is the liquid hardening agent component, which is comprised of a hardening agent, a silane coupling agent, a surfactant, an optional hydrolyzable ester for, *inter alia*, breaking gelled fracturing fluid films on the proppant particles, and an optional liquid carrier fluid for, *inter alia*, reducing the viscosity of the liquid hardening agent component. It is within the ability of one skilled in the art with the benefit of this disclosure to determine if and how much liquid carrier fluid is needed to achieve a viscosity suitable to the subterranean conditions.

Examples of hardenable resins that can be utilized in the liquid hardenable resin component include, but are not limited to, organic resins such as bisphenol A-epichlorohydrin resins, polyepoxide resins, novolak resins, polyester resins, phenol-aldehyde resins, urea-aldehyde resins, furan resins, urethane resins, glycidyl ethers and mixtures thereof. The resin utilized is included in the liquid hardenable resin component in an amount sufficient to consolidate the coated particulates. In some embodiments of the present invention, the resin utilized is included in the liquid hardenable resin component in the range of from about 70% to about 100% by weight of the liquid hardenable resin component.

Any solvent that is compatible with the hardenable resin and achieves the desired viscosity effect is suitable for use in the present invention. Preferred solvents are those having high flash points (most preferably about 125°F) because of, *inter alia*, environmental factors. As described above, use of a solvent in the hardenable resin composition is optional

but may be desirable to reduce the viscosity of the hardenable resin component for a variety of reasons including ease of handling, mixing, and transferring. It is within the ability of one skilled in the art with the benefit of this disclosure to determine if and how much solvent is needed to achieve a suitable viscosity. Solvents suitable for use in the present invention
5 include, but are not limited to, butylglycidyl ethers, dipropylene glycol methyl ethers, dipropylene glycol dimethyl ethers, dimethyl formamides, diethyleneglycol methyl ethers, ethyleneglycol butyl ethers, diethyleneglycol butyl ethers, propylene carbonates, methanols, butyl alcohols, d'limonene and fatty acid methyl esters.

Examples of the hardening agents that can be utilized in the liquid hardening agent
10 component of the low-temperature epoxy-based resins include, but are not limited to, amines, aromatic amines, polyamines, aliphatic amines, cyclo-aliphatic amines, amides, polyamides, 2-ethyl-4-methyl imidazole and 1,1,3-trichlorotrifluoroacetone. Selection of a preferred hardening agent depends, in part, on the temperature of the formation in which the hardening agent will be used. By way of example and not of limitation, in subterranean formations
15 having a temperature from about 60°F to about 250°F, amines and cyclo-aliphatic amines such as piperidine, triethylamine, N,N-dimethylaminopyridine, benzyldimethylamine, tris(dimethylaminomethyl) phenol, and 2-(N₂N-dimethylaminomethyl)phenol are preferred with N,N-dimethylaminopyridine most preferred. In subterranean formations having higher temperatures, 4,4-diaminodiphenyl sulfone may be a suitable hardening agent. The
20 hardening agent utilized is included in the liquid hardening agent component in an amount sufficient to consolidate the coated particulates. In some embodiments of the present invention, the hardening agent used is included in the liquid hardenable resin component in the range of from about 40% to about 60% by weight of the liquid hardening agent component.

25 The silane coupling agent may be used, *inter alia*, to act as a mediator to help bond the resin to the formation particulate surfaces. Examples of silane coupling agents that can be utilized in the liquid hardening agent component of the low-temperature epoxy-based resins include, but are not limited to, n-2-(aminoethyl)-3-aminopropyltrimethoxysilane, 3-glycidoxypropyltrimethoxysilane, and n-beta-(aminoethyl)-gamma-aminopropyl
30 trimethoxysilane. The silane coupling agent used is included in the liquid hardening agent

component in an amount capable of sufficiently bonding the resin to the formation particulates. In some embodiments of the present invention, the silane coupling agent used is included in the liquid hardenable resin component in the range of from about 0.1% to about 3% by weight of the liquid hardening agent component.

5 Any surfactant compatible with the liquid hardening agent may be used with the low-temperature epoxy-based resins. Such surfactants include, but are not limited to, ethoxylated nonyl phenol phosphate esters, mixtures of one or more cationic surfactants, and one or more non-ionic surfactants and alkyl phosphonate surfactants. The mixtures of one or more cationic and nonionic surfactants are described in U.S. Patent No. 6,311,773, the relevant
10 disclosure of which is incorporated herein by reference. A $C_{12} - C_{22}$ alkyl phosphonate surfactant is preferred. The surfactant or surfactants utilized are included in the liquid hardening agent component in an amount in the range of from about 2% to about 15% by weight of the liquid hardening agent component.

 A diluent or liquid carrier fluid in the hardenable resin composition may be used to
15 reduce the viscosity of the hardenable resin component for ease of handling, mixing and transferring. It is within the ability of one skilled in the art, with the benefit of this disclosure, to determine if and how much liquid carrier fluid is needed to achieve a viscosity suitable to the subterranean conditions. Any suitable carrier fluid that is compatible with the hardenable resin and achieves the desired viscosity effects is suitable for use in the present
20 invention. The liquid carrier fluids that can be utilized in the liquid hardening agent component low-temperature epoxy-based resins preferably include those having high flash points (most preferably above about 125°F). Examples of liquid carrier fluids suitable for use in the present invention include, but are not limited to, dipropylene glycol methyl ethers, dipropylene glycol dimethyl ethers, dimethyl formamides, diethyleneglycol methyl ethers,
25 ethyleneglycol butyl ethers, diethyleneglycol butyl ethers, propylene carbonates, d'limonene and fatty acid methyl esters.

 Another consolidation material suitable for use in the methods of the present invention is a furan-based resin. Suitable furan-based resins include, but are not limited to, furfuryl alcohol resins, mixtures furfuryl alcohol resins and aldehydes, and a mixture of furan
30 resins and phenolic resins. A furan-based resin may be combined with a solvent to control

viscosity, if desired. Suitable solvents for use in the furan-based consolidation fluids of the present invention include, but are not limited to 2-butoxy ethanol, butyl acetate, and furfuryl acetate.

Another consolidation material suitable for use in the methods of the present invention is a phenolic-based resin. Suitable phenolic-based resins include, but are not limited to, terpolymers of phenol, phenolic formaldehyde resins, and a mixture of phenolic and furan resins. A phenolic-based resin may be combined with a solvent to control viscosity if desired. Suitable solvents for use in the phenolic-based consolidation fluids of the present invention include, but are not limited to butyl acetate, butyl lactate, furfuryl acetate, and 2-butoxy ethanol.

Another consolidation material suitable for use in the methods of the present invention is a HT epoxy-based resin. Suitable HT epoxy-based components include, but are not limited to, bisphenol A-epichlorohydrin resins, polyepoxide resins, novolac resins, polyester resins, glycidyl ethers and mixtures thereof. An HT epoxy-based resin may be combined with a solvent to control viscosity if desired. Suitable solvents for use with the HT epoxy-based resins of the present invention are those solvents capable of substantially dissolving the HT epoxy-resin chosen for use in the consolidation fluid. Such solvents include, but are not limited to, dimethyl sulfoxide, dimethyl formamide, dipropylene glycol methyl ether, dipropylene glycol dimethyl ether, diethylene glycol methyl ether, ethylene glycol butyl ether, diethylene glycol butyl ether, propylene carbonate, d'limonene, and fatty acid methyl esters.

Yet another consolidation material suitable for use in the methods of the present invention is a phenol/phenol formaldehyde/furfuryl alcohol resin comprising from about 5% to about 30% phenol, from about 40% to about 70% phenol formaldehyde, from about 10 to about 40% furfuryl alcohol, from about 0.1% to about 3% of a silane coupling agent, and from about 1% to about 15% of a surfactant. In the phenol/phenol formaldehyde/furfuryl alcohol resins suitable for use in the methods of the present invention, suitable silane coupling agents include, but are not limited to, N-2-(aminoethyl)-3-aminopropyltrimethoxysilane, 3-glycidoxypropyltrimethoxysilane, and n-beta-(aminoethyl)-gamma-aminopropyl trimethoxysilane. Suitable surfactants include, but are not limited to, an

ethoxylated nonyl phenol phosphate ester, mixtures of one or more cationic surfactants, and one or more non-ionic surfactants and an alkyl phosphonate surfactant. Suitable solvents for use with phenol/phenol formaldehyde/furfuryl alcohol resins include, but are not limited to, 2-butoxy ethanol, butyl acetate, furfuryl acetate, and combinations thereof

5 Regardless of the consolidation material chosen, its viscosity should preferably be controlled to ensure that it is able to sufficiently penetrate the subterranean formation. A preferred depth of treatment may be from about one to about three well bore diameters; however, the laminate and/or non-uniform makeup of the formation, *i.e.* shale-sandstone-shale-sandstone, *etc.*, may make reaching such a depth unrealistic. In some embodiments of
10 the present invention, the consolidation fluid penetrates at least about 0.5 inches into the walls of the well bore.

 One embodiment of a method of the present invention provides a method of drilling a well bore with a drilling composition comprising a drilling fluid component and a consolidating material component, and allowing the consolidating material to penetrate into
15 the walls of the well bore.

 Another embodiment of a method of the present invention provides a method of consolidating a subterranean formation surrounding a well bore comprising the steps of drilling a well bore with a drilling composition comprising a drilling fluid component and a consolidating material component, and allowing the consolidating material to penetrate into
20 the subterranean formation surrounding the well bore.

 Therefore, the present invention is well adapted to carry out the objects and attain the ends and advantages mentioned as well as those that are inherent therein. While numerous changes may be made by those skilled in the art, such changes are encompassed within the spirit and scope of this invention as defined by the appended claims.

What is claimed is:

1. A method of drilling a well bore comprising the steps of:
providing a drilling composition comprising a drilling fluid and a
consolidating material; and,
5 using the drilling composition while drilling the well bore and allowing the
consolidating material in the drilling composition to penetrate into the walls of the well bore.
2. The method of claim 1 wherein the consolidation material has a viscosity of
less than about 100 cP.
3. The method of claim 1 wherein the consolidation material comprises a
10 hardenable resin component, the hardenable resin component comprising a hardenable resin
and a hardening agent component, a liquid hardening agent, a silane coupling agent, and a
surfactant.
4. The method of claim 3 wherein the hardenable resin in the liquid hardenable
resin component is an organic resin comprising bisphenol A-epichlorohydrin resin,
15 polyepoxide resin, novolak resin, polyester resin, phenol-aldehyde resin, urea-aldehyde resin,
furan resin, urethane resin, glycidyl ethers, or mixtures thereof.
5. The method of claim 3 wherein the liquid hardening agent in the liquid
hardening agent component comprises amines, aromatic amines, aliphatic amines, cyclo-
aliphatic amines, piperidine, triethylamine, benzyldimethylamine, N,N-
20 dimethylaminopyridine, 2-(N,N-dimethylaminomethyl)phenol,
tris(dimethylaminomethyl)phenol, or mixtures thereof.
6. The method of claim 3 wherein the silane coupling agent in the liquid
hardening agent component comprises N-2-(aminoethyl)-3-aminopropyltrimethoxysilane, 3-
glycidoxypropyltrimethoxysilane, n-beta- (aminoethyl)-gamma-aminopropyl
25 trimethoxysilane or mixtures thereof.
7. The method of claim 3 wherein the surfactant in the liquid hardening agent
component comprises ethoxylated nonyl phenol phosphate ester, mixtures of one or more
cationic surfactants, a C₁₂ – C₂₂ alkyl phosphonate surfactant, one or more non-ionic
surfactants and an alkyl phosphonate surfactant, or mixtures thereof.

8. The method of claim 3 wherein the resin-type coating material is a furan-based resin comprising furfuryl alcohol, a mixture furfuryl alcohol with an aldehyde, a mixture of furan resin and phenolic resin or mixtures thereof.

9. The method of claim 3 further comprising a solvent comprising 2-butoxy
5 ethanol, butyl acetate, furfuryl acetate, or mixtures thereof.

10. The method of claim 1 wherein the consolidation material is a phenolic-based resin comprising terpolymer of phenol, phenolic formaldehyde resin, a mixture of phenolic and furan resin, or mixtures thereof.

11. The method of claim 10 further comprising a solvent comprising butyl acetate,
10 butyl lactate, furfuryl acetate, 2-butoxy ethanol, or mixtures thereof.

12. The method of claim 1 wherein the consolidation material is a HT epoxy-based resin comprising bisphenol A-epichlorohydrin resin, polyepoxide resin, novolac resin, polyester resin, glycidyl ethers, or mixtures thereof.

13. The method of claim 12 further comprising a solvent comprising dimethyl
15 sulfoxide, dimethyl formamide, dipropylene glycol methyl ether, dipropylene glycol dimethyl ether, dimethyl formamide, diethylene glycol methyl ether, ethylene glycol butyl ether, diethylene glycol butyl ether, propylene carbonate, d'limonene, fatty acid methyl esters, or mixtures thereof.

14. The method of claim 1 wherein the resin consolidation material is a
20 phenol/phenol formaldehyde/furfuryl alcohol resin comprising from about 5% to about 30% phenol, from about 40% to about 70% phenol formaldehyde, from about 10 to about 40% furfuryl alcohol, from about 0.1% to about 3% of a silane coupling agent, and from about 1% to about 15% of a surfactant.

15. The method of claim 14 further comprising a solvent comprising 2-butoxy
25 ethanol, butyl acetate, furfuryl acetate, or combinations thereof.

16. The method of claim 1 wherein the fluid component of the drilling fluid comprises an aqueous gel or an emulsion.

17. The method of claim 1 wherein the consolidating material penetrate into the walls of the well bore from about 0.1 to about 3 inches.

18. The method of claim 1 wherein the drilling composition further comprises a fluid loss control material.

19. The method of claim 18 wherein the fluid loss control material comprises a aliphatic polyester, a polylactic acid, a poly(lactide), or a combination thereof.

5 20. A method of consolidating formation particulates surrounding a well bore comprising the steps of:

providing a drilling composition comprising a drilling fluid and a consolidating material; and,

10 using the drilling composition while drilling the well bore and allowing the consolidating material in the drilling composition to penetrate into the walls of the well bore.

21. The method of claim 20 wherein the consolidation material has a viscosity of less than about 100 cP.

15 22. The method of claim 20 wherein the consolidation material comprises a hardenable resin component comprising a hardenable resin and a hardening agent component comprising a liquid hardening agent, a silane coupling agent, and a surfactant.

23. The method of claim 22 wherein the hardenable resin in the liquid hardenable resin component is an organic resin comprising bisphenol A-epichlorohydrin resin, polyepoxide resin, novolak resin, polyester resin, phenol-aldehyde resin, urea-aldehyde resin, furan resin, urethane resin, glycidyl ethers, or mixtures thereof.

20 24. The method of claim 22 wherein the liquid hardening agent in the liquid hardening agent component comprises amines, aromatic amines, aliphatic amines, cyclo-aliphatic amines, piperidine, triethylamine, benzyldimethylamine, N,N-dimethylaminopyridine, 2-(N₂N-dimethylaminomethyl)phenol, tris(dimethylaminomethyl)phenol, or mixtures thereof.

25 25. The method of claim 22 wherein the silane coupling agent in the liquid hardening agent component comprises N-2-(aminoethyl)-3-aminopropyltrimethoxysilane, 3-glycidoxypropyltrimethoxysilane, n-beta- (aminoethyl)-gamma-aminopropyl trimethoxysilane or mixtures thereof.

26. The method of claim 22 wherein the surfactant in the liquid hardening agent component comprises ethoxylated nonyl phenol phosphate ester, mixtures of one or more cationic surfactants, a C₁₂ – C₂₂ alkyl phosphonate surfactant, one or more non-ionic surfactants and an alkyl phosphonate surfactant, or mixtures thereof.

5 27. The method of claim 22 wherein the resin-type coating material is a furan-based resin comprising furfuryl alcohol, a mixture furfuryl alcohol with an aldehyde, a mixture of furan resin and phenolic resin or mixtures thereof.

28. The method of claim 22 further comprising a solvent comprising 2-butoxy ethanol, butyl acetate, furfuryl acetate, or mixtures thereof.

10 29. The method of claim 20 wherein the consolidation material is a phenolic-based resin comprising terpolymer of phenol, phenolic formaldehyde resin, a mixture of phenolic and furan resin, or mixtures thereof.

30. The method of claim 29 further comprising a solvent comprising butyl acetate, butyl lactate, furfuryl acetate, 2-butoxy ethanol, or mixtures thereof.

15 31. The method of claim 20 wherein the consolidation material is a HT epoxy-based resin comprising bisphenol A-epichlorohydrin resin, polyepoxide resin, novolac resin, polyester resin, glycidyl ethers, or mixtures thereof.

20 32. The method of claim 31 further comprising a solvent comprising dimethyl sulfoxide, dimethyl formamide, dipropylene glycol methyl ether, dipropylene glycol dimethyl ether, dimethyl formamide, diethylene glycol methyl ether, ethylene glycol butyl ether, diethylene glycol butyl ether, propylene carbonate, d'limonene, fatty acid methyl esters, or mixtures thereof.

25 33. The method of claim 20 wherein the resin consolidation material is a phenol/phenol formaldehyde/furfuryl alcohol resin comprising from about 5% to about 30% phenol, from about 40% to about 70% phenol formaldehyde, from about 10 to about 40% furfuryl alcohol, from about 0.1% to about 3% of a silane coupling agent, and from about 1% to about 15% of a surfactant.

34. The method of claim 33 further comprising a solvent comprising 2-butoxy ethanol, butyl acetate, furfuryl acetate, or combinations thereof.

35. The method of claim 20 wherein the fluid component of the drilling fluid comprises an aqueous gel or an emulsion.

36. The method of claim 20 wherein the consolidating material penetrate into the walls of the well bore from about 0.1 to about 3 inches.

5 37. The method of claim 20 wherein the drilling composition further comprises a fluid loss control material.

38. The method of claim 37 wherein the fluid loss control material comprises a aliphatic polyester, a polylactic acid, a poly(lactide), or a combination thereof.

INTERNATIONAL SEARCH REPORT

International Application No
PCT/US2004/027736

A. CLASSIFICATION OF SUBJECT MATTER

IPC 7 E21B43/02

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

IPC 7 C09K E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 4 042 032 A (BOWLES BOBBY K ET AL) 16 August 1977 (1977-08-16) column 2, line 31 - column 7, line 30	1-38
X	EP 1 326 003 A (HALLIBURTON ENERGY SERV INC) 9 July 2003 (2003-07-09)	1-19
A	paragraph '0005! paragraph '0015! - paragraph '0029!	20-38
X	US 2003/131999 A1 (BARTON JOHNNY A ET AL) 17 July 2003 (2003-07-17)	1-19
A	paragraph '0009! paragraph '0029! - paragraph '0050!	20-38
X,P	US 2003/188872 A1 (BARTON JOHNNY A ET AL) 9 October 2003 (2003-10-09)	1-19
A,P	paragraph '0009! paragraph '0029! - paragraph '0042!	20-38

☐ Further documents are listed in the continuation of box C.

☒ Patent family members are listed in annex.

* Special categories of cited documents:

A document defining the general state of the art which is not considered to be of particular relevance

E earlier document but published on or after the international filing date

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O document referring to an oral disclosure, use, exhibition or other means

P document published prior to the international filing date but later than the priority date claimed

T later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

X document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

Y document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.

Z document member of the same patent family

Date of the actual completion of the international search

16 December 2004

Date of mailing of the international search report

13/01/2005

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