Abstract: A filter cake deposited by a drilling fluid, drill-in fluid or fluid loss control pill may be removed from a wellbore by introducing into the wellbore a dispersing agent of an organic amino phosphonic acid, ester or salt. The dispersing agent forms a dispersion containing at least a portion of the drilled solids. The dispersing agent may be introduced into the wellbore as a component of a filter cake removal treatment fluid or either prior to or after introduction of the filter cake removal treatment fluid.
APPLICATION FOR PATENT

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TITLE: METHOD OF REMOVING FILTER CAKE

SPECIFICATION

Field of the Invention

The invention relates to a method of removing the filter cake deposited by a drilling fluid, drill-in fluid, fluid loss control pill or other filter-cake producing wellbore activities by use of a dispersant.

Background of the Invention

In a typical drilling operation, a drill bit, located on the lower end of a drill pipe, penetrates the formation and creates a wellbore. A drilling fluid, or drilling mud, is circulated down the drill pipe, exits the drill bit and flows back to the surface through an annulus between the drill pipe and the wall of the wellbore. In addition to cooling the drill bit, the drilling fluid further serves to flush out rock particles that are sheared off by the drill bit during operation.

A drill-in fluid or drill-in mud, is a specific type of drilling fluid, which is pumped through the drill pipe while drilling through the producing, or payzone, area or the injection zone of the formation. The amount of drilled solids which contaminate the drilling fluid increases as the fluid continues to drill into the payzone or injection zone.

The optimum drill-in fluid provides constant lubricity under high shear conditions generated by the rotating drill bit and is sufficiently viscous to prevent fluid loss into the formation while at the time suspending solids and floating up debris from the wellbore.

Drill-in fluids are principally composed of a high density base-brine, such as sodium chloride, sodium bromide, calcium chloride, calcium bromide, zinc bromide, sodium formate, potassium formate, cesium formate or a mixture thereof. Drill-in fluids can also be oil or synthetic oil based.
In addition, drill-in fluids typically contain additives to impart desired physical and/or chemical characteristics to the fluid. For instance, the drill-in fluid typically contains a viscosifying agent to thicken the base fluid. This, in turn, increases the ability of the fluid to suspend or flush out the rock particles.

Drill-in fluids further typically contain other types of rheological additives, fluid loss control additives and weighting agents (either dissolved or suspended solids). In addition to viscosifying agents, drill-in fluids may include clay materials and lubricants to lubricate the drill bit. Such additives further serve to suspend solids and help "float" cutting debris out of the wellbore.

The drill-in fluid may further contain fluid loss control additives which include bridging agents and/or sized particles to prevent loss of the fluid to the neighboring formation. When used, fluid loss control agents further provide the fluid with sufficient viscosity to inhibit seepage of the fluid into the subterranean strata.

The drill-in fluid serves further to deposit a low-permeable filter cake on the walls of the wellbore to seal the permeable formation exposed by the drilling bit. The filter cake further limits the loss of fluid from the wellbore during cementing operations. In addition, it can protect the formation from possible damage by fluids which are capable of permeating into the formation.

Since many drill-in fluids used today are brine-based, often with liquid densities greater than 12 pounds per gallon (ppg), the finely dispersed solids within the drilling fluid are virtually impossible to remove mechanically and economically. As a result, drill-in fluids normally used in the field today carry elevated concentrations of finely divided drilled solids. Such solids are incorporated into the deposited filter cake.

Conventional drilling fluids perform similar functions as drill-in fluids but typically contain significantly more solids, including drilled solids, weighting solids and bridging solids, than drill-in fluids. At times, these fluids are also used to drill payzones or injection zones and also deposit solids laden filter cakes.

During normal wellbore operations, especially during the completion operations, fluid loss control pills are sometimes pumped into the wellbore to aid in the control of fluid lost to the formation. These pills often contain bridging agents to augment fluid loss control. A filter cake is typically deposited directly against the formation and may become embedded in the formation.
In order to produce the hydrocarbons from the wellbore or inject into the wellbore, the deposited filter cake must be removed. Complete removal of the filter cake is necessary for maximum hydrocarbon production or injection rates. In a typical well completion process, the deposited filter cake is removed by chemical treatments. Such chemicals attack the viscosifying and/or fluid loss control polymer or agent and dissolvable materials formulated into the drilling fluid, drill-in fluid or fluid loss control pill.

Removal of the deposited filter cake is relatively easy when the fluid or pill is freshly prepared. Newly prepared fluids or pills do not contain any significant amount of drilled clay or solids. Unfortunately, such chemical treatments have little or no effect in the removal of drilled clays and solids. As the treatment chemicals digest and remove the viscosifying or fluid loss control agents and soluble materials, the drilled clays and solids concentrate at the interface of the filter cake. As fluid is increasingly lost to the formation due to digestion and removal of the viscosifying or fluid loss control agent, the exposed drilled and other solids are pushed into and concentrate in the remaining filter cake, thereby hindering or blocking further removal of the filter cake.

A substantial need exists for a treatment chemical that can assist in maximizing the removal of drilled and other solids, thereby maximizing the removal of the deposited filter cake.

**Summary of the Invention**

A method of removing a filter cake deposited from drilling fluid, drill-in fluid and/or fluid loss pill containing drilled and/or deposited solids from a wellbore includes the use of a dispersing agent of an organic amino phosphonic acid, ester or salt thereof which forms a dispersion containing at least a portion of the drilled and/or deposited solids.

The dispersing agent may be introduced into the wellbore as a component of the filter cake removal treatment fluid or either prior to or after introduction of the filter cake removal treatment fluid. After introduction into the wellbore, the dispersing agent contacts the filter cake. At least a portion of the drilled or deposited solids is removed from the filter cake into the dispersion. Contacting of the fluid containing the dispersing agent with the filter cake typically results in soaking of the filter cake. As a result of contacting, digestion or degradation of at least a portion of
the filter cake occurs. Thus, the dispersion containing the dispersing agent and solids may further contain at least a portion of digested filter cake. Thus, the dispersion containing the dispersing agent assists in removal of the filter cake from the wall.

When introduced prior to the filter cake removal treatment fluid, the dispersing agent acts as a filter cake pre-soaking agent, though preferably the dispersing agent is a component of the filter cake removal treatment fluid.

The treatment fluid may include enzymes, acids, oxidizers, etc. which are effective in the removal and/or degradation of filter cakes.

The dispersing agent is an aminoalkyl phosphonic acid, ester or salt thereof. Preferably, the dispersing agent is a polyaminomethylene phosphonate having from 2 to about 10 nitrogen atoms, at least one methylene phosphonic group being attached to at least one nitrogen atom. In a preferred embodiment, at least one methylene phosphonic group of the phosphonate is attached to each nitrogen atom. Suitable species include ethylenediamine tetra(methylene phosphonate), diethylenetriamine penta(methylene phosphonate) and triamine- and tetraamine-polymethylene phosphonates having between from about 2 to about 10, preferably between from about 2 to about 6, methylene groups between each N atom. In a preferred embodiment, the dispersing agent is either bis-aminoethyl ether phosphonate or a mixture of monoethanol amine phosphonate and bis-hexamethylene triamine phosphonate and/or bis-hexamethylene triamine pentaphosphonate.

**Detailed Description of the Preferred Embodiments**

A filter cake deposited from drilling fluid, drill-in fluid and/or fluid loss pill may be more effectively removed from a subterranean formation surrounding a wellbore by use of an organic amino phosphonic acid, ester or salt thereof. The organic amino phosphonic acid, ester or salt acts as a dispersing agent and assists in the digestion of the filter cake. In light of its presence, drilled or deposited solids are dispersed within the dispersion and moved away from the vicinity of the filter cake. The filter cake removal fluid can therefore more efficiently digest the filter cake with less hindrance from the solids.

While at least some of the drilled or deposited solids are removed by the action of the dispersing agent, in some cases all of the solids are removed. Further, the dispersing agent is typically capable of degrading at least a portion of the filter
cake. In some cases, the filter cake is completely degraded by the action of the dispersing agent.

The dispersing agent, which serves to disperse the solid particles, is an organic amino phosphonic acid, ester or salt. The dispersing agent may further function as a pH adjusting agent. Suitable dispersing agents include aminoalkyl phosphonic acids, ester or salts, like polyaminomethylene phosphonates having between from about 2 to about 10 nitrogen atoms. In a preferred embodiment, at least each nitrogen of the compound contains at least one methylene phosphonic group. Examples of suitable aminoalkyl phosphonic acids, esters and salts include ethylenediamine tetra(methylene phosphonate), diethylenetriamine penta(methylene phosphonate) and the triamine- and tetramine-polymethylene phosphonates with from about 2 to about ten, preferably from about 2 to about 6, methylene groups between each nitrogen atom. In a preferred embodiment, the dispersing agent is either bis-aminoalkyl ether phosphonate or a mixture of a monoalkanol amine phosphonate and a bis-hexalkylene triamine phosphonate.

Further, the dispersing agent may be a linear or branched polyphosphonic acid, ester or salt. Exemplary of such linear or branched polyphosphonic acids, esters, or salts are those of the formula:

\[
Z_2N-(CH_2)_n-N\left\{[(CH_2)_a-N]_x-(CH_2)_b-N\right\}(CH_2)_mNZ_2
\]

wherein:
- each Z is independently -CHR \( ^1 \)PO\(_3\)(R)(R) or H, provided that at least two Zs are -CHR \( ^1 \)PO\(_3\)(R)(R);
- each R\(^1\) is independently selected from -H, -CH\(_3\), -C(R\(^2\))(R\(^2\))(R\(^2\)), C\(_6\)H\(_5\), -C(R\(^2\))(R\(^2\))-, -SO\(_3\)H and -SO\(_3\)M\(_2\);
- each R\(^2\) is independently selected from -H, -CH\(_3\) and -C\(_2\)H\(_5\);
- each R is independently selected from -H, -CH\(_3\), -C\(_2\)H\(_5\) and M;
each M is independently selected from an alkali metal, A of an alkaline earth metal, 1/n of a transition metal with +n charge, an ammonium ion and hydrogen ion; n is between from about 1 to about 6, preferably from about 2 to about 4; m is between from about 1 to about 6, preferably from about 2 to about 4; a is between from about 1 to about 10, preferably from about 2 to about 4; b is between from about 1 to about 10, preferably from about 2 to about 4; x is between from 0 to about 6, preferably from 0 to about 3; and y is between from 0 to about 6, preferably from 0 to about 2.

Such compounds are disclosed in U.S. Patent No. 5,261,491.

Typically, the dispersing agent is added to the filter cake removal treatment fluid and such fluid is then introduced into the wellbore. Other than being a component of the filter cake removal treatment fluid, it is possible that the dispersing agent may be added to the wellbore either prior to introduction of the filter cake removal treatment fluid, subsequent to introduction of the filter cake removal treatment fluid or simultaneously with the introduction of the filter cake removal treatment fluid.

When introduced as a component of the filter cake removal treatment fluid, the amount of dispersing agent present in the fluid is an amount sufficient to maintain the dispersed drilled solids in dispersion. Typically the amount of dispersing agent to the fluid is between from about 0.1 to about 25 volume percent (based on the total volume of the composition). In some uses, the dispersant may be used up to full strength.

Typical drilling fluids, drill-in fluids and fluid loss pills include those basically comprised of water, a viscosifying agent, a particulate solid bridging agent, and when needed, a weighting agent. Viscosifying agents are typically water-soluble starches (such as corn based or potato based starches), water soluble polysaccharides (such as xanthan polysaccharides, wellan polysaccharides, scleroglucan polysaccharides, and guar polysaccharides), water soluble celluloses (such as hydroxyalkyl celluloses, like hydroxyethyl cellulose, as well as hydrophobically modified hydroxyalkyl celluloses and cellulose ethers), water soluble polyacrylamides and copolymers thereof (such as copolymers of acrylamide with acrylate monomers), modified starches, modified polysaccharides and chemically modified polysaccharides (such as hydroxyalkyl starches and polysaccharides; starch and polysaccharide esters, crosslinked starches and polysaccharides; hypochlorite oxidized starches and polysaccharides; starch and
polysaccharide phosphate monoesters; cationic starches and polysaccharides, starch and polysaccharide xanthates; and, dialdehyde starches and polysaccharides). Specific examples of suitable modified staiches and modified polysaccharides include, but are not necessarily limited to: carboxymethyl starches and polysaccharides; hydroxyethyl starches and polysaccharides; hydroxypropyl starches and polysaccharides; hydroxybutyl starches and polysaccharides; carboxymethylhydroxyethyl starches and polysaccharides; carboxymethylhydroxypropyl starches and polysaccharides; carboxymethylhydroxybutyl starches and polysaccharides; epichlorohydrin starches and polysaccharides; alkylene glycol modified starches and polysaccharides.

Particulate solid bridging agents include, but are not limited to, barite (barium sulfate), calcium carbonate, and soluble salts such as sodium chloride when used in a salt saturated system.

Weighting agents typically include salts such as barite (barium sulfate), sodium bromide, sodium chloride, potassium chloride, calcium chloride, calcium bromide, zinc bromide and mixtures of these salts. The weighting agents provide the fluid with sufficient density so the hydrostatic pressure of the dense fluid in the wellbore counterbalances pressure exerted by the fluid in the strata.

The following examples are illustrative of some of the embodiments of the present invention. Other embodiments within the scope of the claims herein will be apparent to one skilled in the art from consideration of the description set forth herein. It is intended that the specification, together with the examples, be considered exemplary only, with the scope and spirit of the invention being indicated by the claims which follow.

All percentages set forth in the Examples are given in terms of weight units except as may otherwise be indicated.

**EXAMPLES**

Examples 1-3. A drill-in fluid or mud (DIF) was used to verify the effectiveness of a dispersant. The DIF contained 1 barrel of a 2 weight percent KCl brine, 8 pounds per barrel (ppb) of polymeric starch as fluid loss control additive, 2.5 ppb of a viscosifying xanthan XC-type polymer, 0.1 ppb of KOH, for pH control, 30 ppb of calcium carbonate as fluid loss control additive and about 40 ppb of simulated drilling solids (RevDust™ clay, a product of Milwhite, Inc.). The presence of the RevDust™
mimics the presence of very fine-particle drilled-solids, which accumulates during drilling operations. It is anticipated that DIF would be difficult to remove since it contains 8 ppb starch for fluid loss control, the normal level being typically around 4 ppb. While the presence of excess starch controls fluid loss more effectively, filter cakes deposited with excess starch are typically more difficult to remove. Furthermore, DIF contained 2.5 ppb xanthan polymer while the typical amount is around 1 ppb. This further adds to the anticipated difficulty of removing a deposited filter cake.

DIF was then heat-aged for 16 hours at 190°F before conducting fluid loss experiments. The fluid loss cell was fitted with a 400 md Aloxite disk and the permeability values were determined in the production and injection directions by flowing water through the disk at constant pressure. The heat-aged DIF was added to a fluid loss cell, heated to 190°F, and then filtrate was collected dynamically at 300 RPM for one hour and then statically for 15 hours through a 400 md Aloxite disk with a differential pressure of 800 psi. Residual DIF was then poured off the deposited filter cake.

A filter cake removal treatment fluid was prepared based upon an enzyme package designed to remove both starch and xanthan polymer. This treatment fluid was composed of a 3% acetic acid solution to which 50 pounds per thousand gallons (pptg) Ferrotrol-300 (an iron control additive, a product of BJ Services Company), 2.0 gallons per thousand gallons (gpt) CI-I1 (except for Example 3) (a corrosion inhibitor, a product of BJ Services Company), 5.0 gpt NE-118 (a nonionic surfactant, a product of BJ Services Company), 5.0 gpt dispersing agent when used, and 80 pptg sodium acetate to create a buffer at pH 4. 50 gpt GBW-14C and 10 gpt GBW-16C (both enzymes available from BJ Services Company) were then added. Example 2 and Comparative Example 1 further contained about 50 gpt of 30-35% hydrogen peroxide added first to the acetic acid solution, which is sometimes referred to as peroxyacetic acid.

A dispersing agent was added to the filter cake removal fluid in Examples 2-3. The dispersing agent A of Example 2 and 3 was an aqueous acid solution of bis-aminoalkyl ether phosphonate containing less than 2 weight percent methanol. The fluid was then added to the deposited DIF filter cake at 190°F. The cell was then pressurized and about 5 ml of filtrate was then removed. The cell was then shut for about 16 hours, after which the filtrate was collected. The resulting production and
injection permeabilities were then determined and compared with the initial permeability values. The results are set forth in Table 1.

<table>
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<th>Example No.</th>
<th>Comp. Ex. 1</th>
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<tr>
<td>Treating Fluid Composition</td>
<td>Oxidizing Formulation (Without Dispersing Agent)</td>
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<tr>
<td>Return Perm, %, Inject</td>
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<td>90</td>
<td>87</td>
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Table 1 illustrates that treatment of the filter cake with a dispersing agent (Example 2) in accordance with the invention is more effective than a similar treatment which did not contain a dispersing agent (Comparative Example 1). A treatment fluid containing the dispersing agent within the invention but not hydrogen peroxide (Example 3) was still significantly more effective in removal of the deposited filter cake than Comparative Example 1.

Examples 4-5. The procedure of Examples 1-3. Example 4 uses the same drill-in mud as set forth in Examples 1-3 above. In Example 5, the drill-in mud (DIF-2) was prepared from 0.88 barrels of water, 9.5 ppb KCl, 55 ppb of a commercially available polymeric drill-in fluid additive which further contains calcium carbonate, starch and a viscosifying xanthan XC-type polymer, 11.3 ppb of calcium carbonate as fluid loss control additive and about 36 ppb of RevDust.

Further, the filter cake removal treatment fluid in Examples 4 and 5 was prepared from the same enzyme package described above. The dispersing agent B was a mixture comprising an aqueous acid solution of about 11 weight percent of bis-hexamethylene triamine phosphonate, 13 weight percent of bis-hexamethylene triamine pentaphosphonate and about 60 weight percent of monoethanol amine.
phosphonate. Because the polymer system used in the DIF-2 was known to be more difficult to break than xanthan polymer especially with added drilled solids, the filter cake is more difficult to remove. The results of the testing is set forth in Table II below:

<table>
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<tr>
<td><strong>Treating Fluid Composition</strong></td>
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<td>Dispersing Agent, gpt</td>
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<td>Return Perm, %, Prod</td>
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<tr>
<td>Return Perm, %, Inject</td>
<td>86</td>
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From the foregoing, it will be observed that numerous variations and modifications may be effected without departing from the true spirit and scope of the novel concepts of the invention.
CLAIMS

What is claimed is:

1. In a method of removing a filter cake containing drilled and deposited solids from a wellbore by introducing into the wellbore a treatment fluid capable of degrading the filter cake, the improvement comprising further introducing into the wellbore and/or treatment fluid a dispersing agent and forming a dispersion containing at least a portion of the drilled and/or deposited solids, the dispersing agent being an organic amino phosphonic acid, ester or salt thereof.

2. The method of Claim 1, wherein the dispersing agent is an aminoalkyl phosphonic acid, ester or salt thereof.

3. The method of Claim 2, wherein the dispersing agent is a polyaminomethylene phosphonate having from 2 to about 10 nitrogen atoms.

4. The method of Claim 3, wherein the dispersing agent is selected from the group consisting of ethylenediamine tetra(methylene phosphonate), diethylenetriamine penta(methylene phosphonate) and triamine- and tetraamine-polymethylene phosphonates having between from about 2 to about 8 methylene groups between each N atom.

5. The method of Claim 3, wherein the dispersing agent is either bis-aminoalkyl ether phosphonate or a mixture of a monoalkanol amine phosphonate and a bis-hexalkylene triamine phosphonate.

6. The method of Claim 1, wherein the dispersing agent is a polyphosphonic acid, ester or salt of the formula:
Z₂N - (CH₂)ₙ - N \left[ (CH₂)ₐ - N \right]ₓ - (CH₂)ₛ - N \right] (CH₂)ₘNZ₂

wherein:

each Z is independently -CHR¹PO₃(R)(R) or H, provided that at least two Zs are -CHR¹PO₃(R)(R);
each R¹ is independently selected from -H, -CH₃, -C(R²)(R²)(R²), C₆H₅, -C(R²)(R²), -SO₃H₂ and -SO₃M₂;
each R² is independently selected from -H, -CH₃ and -C₂H₅;
each R is independently selected from -H, -CH₃, -C₂H₅ and M;
each M is independently selected from an alkali metal, A of an alkaline earth metal, 1/n of a transition metal with +n charge, an ammonium ion and hydrogen ion;
n is between from about 1 to about 6, preferably from about 2 to about 4;
m is between from about 1 to about 6, preferably from about 2 to about 4;
a is between from about 1 to about 10, preferably from about 2 to about 4;
b is between from about 1 to about 10, preferably from about 2 to about 4;
x is between from 0 to about 6, preferably from 0 to about 3; and
y is between from 0 to about 6, preferably from 0 to about 2.

7. The method of Claim 1, wherein the agent is bis-aminoethyl ether phosphonate or a mixture of bis-hexamethylene triamine phosphonate and monoethanol amine phosphonate and, optionally, bis-hexamethylene triamine pentaphosphonate.

8. The method of Claim 1, wherein the dispersing agent is a component of the treatment fluid.

9. A method of removing a filter cake containing drilled and deposited solids from a wellbore comprising:
(a) introducing into the wellbore a treatment fluid comprising a dispersing agent of an organic amino phosphonic acid, ester or salt thereof;
(b) digesting at least a portion of the filter cake with the treatment fluid;
(c) forming a dispersion of drilled and deposited solids wherein at least a portion of the drilled and deposited solids separate from the filter cake; and
(d) removing the dispersion and at least a portion of the filter cake from the wellbore.

10. The method of Claim 9, wherein the dispersing agent is selected from the group consisting of a bis-aminoalkyl ether phosphonate; and a mixture of a monoalkanol amine phosphonate and a bis-hexalkylene triamine phosphonate;

11. The method of Claim 10, wherein the dispersing agent is bis-aminoethyl ether phosphonate or a mixture of monoethanol amine phosphonate and bis-hexamethylene triamine phosphonate and, optionally, bis-hexamethylene triamine pentaphosphonate.

12. The method of Claim 11, wherein the dispersing agent is bis-aminoethyl ether phosphonate.

13. The method of Claim 11, wherein the dispersing agent is a mixture of bis-hexamethylene triamine phosphonate and monoethanol amine phosphonate and, optionally, bis-hexamethylene triamine pentaphosphonate.

14. A method of increasing the flow of production fluids from or injection fluids into a subterranean formation by removing a filter cake having fine particulates from the wellbore, the method comprising:
(a) introducing into the wellbore a treatment fluid and a dispersing agent, wherein the dispersing agent is introduced into the wellbore either before or after introduction of the treatment fluid or as a component of the treatment fluid;
(b) digesting or degrading at least a portion of the filter cake with the treatment fluid; and
(c) forming a dispersion of fine particulates and dispersing agent; and
(d) removing the dispersion and at least a portion of the filter cake from the wellbore

wherein the dispersing agent is an organic amino phosphonic acid, ester or salt thereof.

15. The method of Claim 14, wherein the dispersing agent is selected from the group consisting of a bis-aminoalkyl ether phosphonate; and a mixture of a monoalkanol amine phosphonate and a bis-hexalkylene triamine phosphonate;

16. The method of Claim 15, wherein the dispersing agent is bis-aminoethyl ether phosphonate or a mixture of monoethanol amine phosphonate and bis-hexamethylene triamine phosphonate and, optionally, bis-hexamethylene triamine pentaphosphonate.

17. The method of Claim 15, wherein the dispersing agent is bis-aminoethyl ether phosphonate.

18. The method of Claim 15, wherein the dispersing agent is a mixture of bis-hexamethylene triamine phosphonate and monoethanol amine phosphonate and, optionally, bis-hexamethylene triamine pentaphosphonate.
INTERNATIONAL SEARCH REPORT

A. CLASSIFICATION OF SUBJECT MATTER

INV. C09K8/52

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):
C09K C02F

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


A WO 2005/073130 A (BOZZETTO GIOVANNI SPA [IT]; PALADINI MASSIMO [IT]; SPINI FRANCESCO [IT]) 11 August 2005 (2005-08-11) page 2 - page 6 1-18

A EP 0 479 462 A (BRIToil PLC [GB]) 8 April 1992 (1992-04-08) cited in the application page 2, line 18 - line 50 1-18

Further documents are listed in the continuation of Box C.

X See patent family annex

* Special categories of cited documents

'X' 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.

'Y' 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.

'S' document member of the same patent family.

Date of the actual completion of the international search: 18 July 2008

Date of mailing of the international search report: 29/07/2008

Name and mailing address of the ISA:
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Tel (+31-70) 340-2040 Tx 31 651 epo nl
Fax (+31-70) 340-3016

Authorized officer: Zimpfer, Emmanuel
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