(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
20 September 2012 (20.09.2012)

WIPO | PCT

(10) International Publication Number
WO 2012/125917 A1

(51) International Patent Classification:
E21B 17/00 (2006.01) *E21B 29/00* (2006.01)
E21B 10/64 (2006.01)

(21) International Application Number:
PCT/US2012/029415

(22) International Filing Date:
16 March 2012 (16.03.2012)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
61/453,387 16 March 2011 (16.03.2011) US
13/421,302 15 March 2012 (15.03.2012) US

(71) Applicant *(for all designated States except US)*: **BAKER HUGHES INCORPORATED** [US/US]; P.O. Box 4740, Houston, TX 77210 (US).

(72) Inventor; and

(75) Inventor/Applicant *(for US only)*: **MCFALL, Alan, L.** [US/US]; 17211 Northbridge Court, Spring, TX 77379 (US).

(74) Agent: **BYNUM, Todd, A.**; Baker Hughes Incorporated, P.O. Box 4740, Houston, TX 44210-4740 (US).

(81) Designated States *(unless otherwise indicated, for every kind of national protection available)*: AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IS, JP, KE, KG, KM, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LT, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

Declarations under Rule 4.17:

— *as to applicant's entitlement to apply for and be granted a patent (Rule 4.17(ii))*

[Continued on next page]

(54) Title: METHOD AND SYSTEMS TO SEVER WELLBORE DEVICES AND ELEMENTS

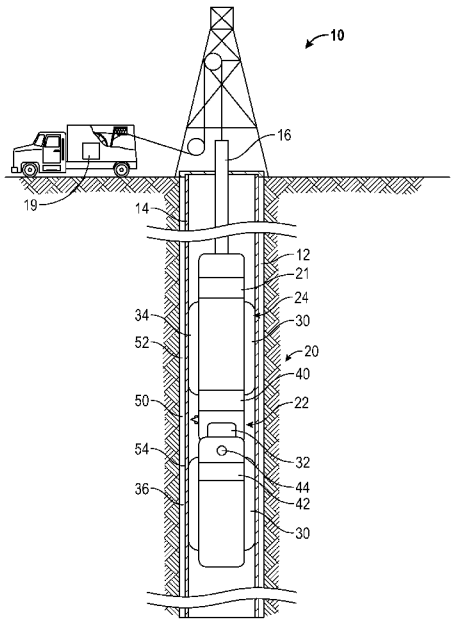


FIG. 1

(57) Abstract: A method for performing an operation in the wellbore may include at least partially separating a wellbore tubular while reducing a compression in a section of the wellbore tubular using a force applicator in the wellbore. An apparatus for performing the downhole operation may include a cutter configured to at least partially sever a wellbore tubular; and a force applicator configured to reduce a compression in a section of a wellbore tubular proximate to the cutter.

WO 2012/125917 A1

— *as to the applicant's entitlement to claim the priority of the earlier application (Rule 4.17(iii))*

Published:

— *with international search report (Art. 21(3))*

TITLE: **METHOD AND SYSTEMS TO SEVER WELLBORE DEVICES AND ELEMENTS**

INVENTOR: **MCFALL, Alan L.**

BACKGROUND OF THE DISCLOSURE

1. Field of the Disclosure

[0001] The disclosure herein relates generally to the field of severing a tubular member or other tools.

2. Background of the Art

[0002] During the construction of hydrocarbon producing wells and other subsurface structures, one or more tubular elements may be used. Common tubular elements include casings, liners, jointed drill pipe, and coiled tubing. Other devices that may include tubular components may include packers. Often, it may be desirable or necessary to remove such a tubular element from the well. If a portion of the tubular element becomes stuck in the well for some reason, then the tubular element may have to be severed. By severing the tubular element, the stuck portion may be left in the well while retrieving the remainder of the tubular element.

[0003] In some aspects, the present disclosure addresses the need for cutting tubulars and other items.

SUMMARY OF THE DISCLOSURE

[0004] In aspects, the present disclosure provides a method for performing an operation in the wellbore. The method may include at least partially separating a wellbore tubular while reducing a compression in a section of the wellbore tubular using a force applicator in the wellbore.

[0005] In aspects, the present disclosure provides an apparatus for performing a downhole operation. The apparatus may include a cutter configured to at least partially sever a wellbore tubular; and a force applicator configured to reduce a compression in a section of a wellbore tubular proximate to the cutter.

[0006] Examples of certain features of the disclosure have been summarized rather broadly in order that the detailed description thereof that follows may be better understood and in order that the contributions they represent to the art may be appreciated. There are, of course, additional features of the disclosure that will be described hereinafter and which will form the subject of the claims appended hereto.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] For a detailed understanding of the present disclosure, reference should be made to the following detailed description of the embodiments, taken in conjunction with the accompanying drawings, in which like elements have been given like numerals, wherein:

FIG. 1 illustrates one embodiment of a cutting tool made in accordance with the present disclosure; and

FIG. 2 schematically illustrates another embodiment of a cutting tool made in accordance with the present disclosure.

DETAILED DESCRIPTION OF THE DISCLOSURE

[0008] In aspects, the present disclosure provides devices and related methods for severing a wellbore tubular. In one embodiment, a localized portion of the tubular, e.g., one to four meters, may be mechanically isolated from a larger portion of the tubular. By mechanically isolated, it is meant that a force applying device may subject the isolated section to a force that reduces compressive forces in walls or physical structure at that isolated section. The force applying device may use hydraulic, electric, pneumatic and / or mechanical action. A suitable cutter is then used to at least partially sever the tubular at the isolated section. For instance, by applying a force equal or exceeding the compressive force acting on tube or pipe, a cutting element may make a continuous and non interrupted cut into the wall of the tubular without having compressive forces pinch the cutting element between the two sections being cut. As used herein, the compressive force or compression force is

the force that urges the cut or partially cut sections into contact with one another.

[0009] **FIG. 1** is a schematic diagram showing a rig **10** positioned over a wellbore **12**. The wellbore **12** may include a wellbore tubular **14**, such as a casing. It should be understood, however, casing is merely illustrative of a wellbore item that may be severed. Other wellbore items include liners, jointed drill pipe, coiled tubing, screens, production tubing, packers, etc. In one embodiment, a cutting device **20** may be used to separate the wellbore tubular **14** into two sections. A carrier **16**, which may be wireline, e-line, slickline, jointed tubulars or coiled tubing, may include power and/or data conductors such as wires for providing bidirectional communication and power transmission between the surface and the cutting device **20**. For example, a controller **19** may be placed at the surface for receiving data from the cutting device **20** and transmitting instructions to the cutting device **20**. The controller **19** may include a processor, a storage device, such as memory, for storing data and computer programs. The processor accesses the data and programs from the storage device and executes the instructions contained in the programs to control the cutting operation. Also, a downhole controller **21** may be used to control the cutting device **20**. The controllers **19**, **21** may work independently or cooperatively.

[0010] In one embodiment, the cutting device **20** may include a cutter **22** and a force applicator **24**. The cutter **22** may be configured to progressively cut into the wall of the tubular **14** to form two sections while the force applicator **24** applies an appropriately oriented force (*e.g.*, a force countering the compression force) to the tubular **14**. This tension force may minimize or prevent compressive forces from either pinching a cutting element between the two sections and / or allowing the compressive forces from rejoining the two sections. The tension force is applied close enough to the cutter **22** in order to counteract the compressive forces to a degree that the cutter **22** can operate to efficiently cut the tubular **14**, .*e.g.*, the tension force is sufficiently proximate to the cutter **22**.

[0011] The force applicator **24** is configured to apply a force to the tubular **14** that at least reduces a compression in the tubular **14**. In one embodiment, the force

applicator **24** may include anchors **30** and a force generator **32**. The anchors **30** engage the tubular **14** at upper and lower engagement points **34**, **36**, respectively. An axial region between the points **34**, **36** may hereafter be referred to as an isolated region or a controlled region. The force generator **32** applies a longitudinal or axially oriented force that urges the anchors **30** in opposing directions. As used herein, the term longitudinal or axial means co-axial with the long axis of the tubular **14**, e.g., the direction of fluid flow in either an uphole or downhole direction. In one embodiment, the anchors **30** may be a device that centers and / or stabilizes the cutting tool **20** in the tubular **14**. Centralizers and stabilizers generally include one or more radially extendable fins or pads that position a tool in a desired orientation in a bore and may maintain that orientation as the tool is operated. For example, the anchors **30** may include radially extendable slips having gripping elements (*e.g.*, serrated edges). Devices such as a piston (not shown) may extend the slips radially outward when supplied with the pressurized fluid (*e.g.*, gas or liquid) from a suitable source, *e.g.*, a hydraulic circuit **40**. The anchors **30** may include elements pads, inflatable members that expand to press the pads or gripping elements against a surface of the tubular **14**. In certain embodiments, the pads may be configured to partially or fully penetrate into a wall of the tubular **14**. In some embodiments, the anchors **30** may be configured to form a fluid seal with the surface that is engaged (*e.g.*, a gas-tight seal, a liquid-tight seal, etc.). Also, in certain embodiments, one or more of the anchors **30** may be pre-existing in the well. For example, the anchor(s) **30** may be a packer, a bridge plug, or other well tool.

[0012] The force generator **32** may be a hydraulically actuated ram (*e.g*, telescopic tubulars that expand), an electro-mechanical device (*e.g.*, an electric motor coupled to a worm gear), a hydraulic device (*e.g.*, a hydraulic motor coupled to a drive train),or any other device configured to generate a force. The force generator **32** may be energized by the power source for the anchors **30** or a separate power source. Also, it should be understood that the force applicator **24** is shown in schematic form only in **Fig. 1**. That is, while the force generator **32** is shown as a separate component from the anchors **30**, in some embodiments, a force generating

device may be incorporated into one or both of the anchors **30**. For instance, slips (not shown) may be driven axial upward/downward and also radially outward. That is, the force generator **32** may be integrated into the anchor(s) **30** to generate the tension force in the isolated region.

[0013] In certain embodiments, the cutting tool **20** may include an information processing device **42**, one or more sensors **44**, and other electronics to monitor and control the cutting operation. Illustrative sensors include, but are not limited to, position sensors, temperature sensors, pressure sensors, and strain gages. The information processing device **42** may be a microprocessor having preprogrammed instructions that receives information from the sensors **44** and has bi-directional communication (*i.e.*, uplink and downlink capability) with the surface (e.g., surface processor **19**).

[0014] In some embodiments, the cutter **22** may include one or more spinning blades that precess such the spinning blades move gradually radially outward. The blades may be rotated using a hydraulically actuated motor. Devices such as gear drives may be used to transmit power from the motor to the blades. Other embodiments may use electric motors to rotate the blades. Also, in some embodiments, the cutter **22** may be a chemical cutter that dispenses a corrosive agent that removes the material making up the wellbore tubular **14**. In other embodiments, the cutter **22** may include an energetic beam, such as a laser, that forms a weakened area in the tubular **14**.

[0015] In an illustrative use, the cutting tool **20** is positioned in the wellbore **12** at a target location **50** at which the wellbore tubular **14** is to be severed. The tubular **14** at the location **50** may be subjected to compressive loadings that could impair or prevent the cutting operation. For example, the weight of the tubular **14** uphole of the location **50** could generate the compressive loading. In some situations, a surface structure as a rig may bear some of the weight of the tubing **14**. In other situations, the tubular **14** is not actively supported by any surface structure. In either case, the anchors **30** are actuated to engage an inner surface of the tubing **14** at two points **34**, **36**. Next, the force generator **32** may be actuated to urge the anchors **30**

in opposing directions. The axial force generated by the force generator **32** causes a localized reduction in the compressive force at the location **50**, which is between the two points. That is, the compressive forces along the tubing **14** may be greater uphole of point **34** and / or downhole of point **36** than at the location **50**.

[0016] Depending on the situation, the force generator **32** may generate an axial force that partially offsets the compression in the isolated region, balances the compression in the isolated region, or even cause the isolated region to be in tension. For example, the force generator **32** may be controlled to provide a tension force that reduces the compression in the portion of the tubular **14** at the location **50** to a value that allows the cutter **22** to cut progressively into the tubular **14** to form an upper section **52** and a lower section **54**. The compression may be reduced to a value that prevents the sections **52**, **54** from applying a force (e.g., a normal force) that substantially impedes movement of the cutter **22**. Thus, where the cutter **22** includes a blade or blades, the compression is reduced to a point where the blades may at least partially sever the tubular **14** without having the blade(s) frictionally locked between the two sections **52**, **54**.

[0017] The cutter **22** is operated until the tubular **14** is separated into the sections **52**, **54** or is sufficiently weakened such that an applied force or manipulation of the tubular **14** separates the sections **52**, **54**. That is, the cutter **22** may remove sufficient material such that the remaining material connecting the sections **52**, **54** can be snapped, sheared, fractured, shattered or otherwise broken. If partially severed, the sections **52**, **54** may be separated using the force applicator **24**, a fishing tool (not shown) that may be used to retrieve the section **52**, or some other method.

[0018] **FIG. 2** illustrates another embodiment of the cutting tool **20** shown in a rig **10** positioned over a wellbore **12**. In this embodiment, a tubular **14** does not extend to the surface. Thus, the tubular **14** cannot be supported by a rig or other structure at the surface. In some embodiments, the cutting device **20** may have been used to remove a section of tubular and / or other devices (e.g., packers) that connected the tubular **14** to the surface. In a sense, the tubular **14** may be

considered "free-standing," but it should be understood that the tubular **14** may lie against or contact objects in the wellbore **12**. In this embodiment, the cutting tool **20** includes a force applicator **70** that includes anchors **72** and a force generator **74**. The anchors **72** may be similar to those shown in **Fig. 1** and are not discussed in further detail. The force generator **74** in this embodiment uses a non-mechanical force generating mechanism. For example, the force generator **74** may include a pump **76** that pressurizes an interior volume **78** with a pressurized fluid. The fluid may be a resident wellbore fluid received via a line **80**, a fluid from a downhole source **82**, and / or supplied from the surface. The pressurized fluid applies pressure to the anchors **72** to generate a tension in a region in which the tubular **14** is to be severed. In another arrangement, the force generator **74** may include magnetic elements that apply opposing magnetic fields that repel the anchors **72** apart.

[0019] In an illustrative use, the cutting tool **20** is positioned in the wellbore **12** at a target location **50** at which the wellbore tubular **14** is to be severed. In a prior operation, the cutting tool **20** may have been used to remove a section of the wellbore tubular **14**. For example, the cutter **20** may have been used to cut through slips of a packer (not shown). The removal of such a section prevents the tubular **14** from being supported at the surface. Thus, the tubular **14** at the location **50** may be subjected to compressive loadings that could impair or prevent the cutting operation. As before, the anchors **72** are actuated to engage the tubular **14**. Next, the force generator **72** may be actuated to urge the anchors **72** in opposing directions. The axial force generated by the force generator **74** causes a localized reduction in the compressive force at the location **50**.

[0020] It should be understood that the **Figs. 1** and **2** embodiments are merely illustrative. For example, in certain embodiments, the anchors and force generators may be positioned external to the tubular member; *i.e.*, in the annulus.

[0021] Referring to **FIGS. 1** and **2**, several control methodologies may be used to control the cutting device **20**. In one illustrative operating mode, personnel at the surface may initiate and monitor the cutting operation by using the surface controller **19**. For instance, the downhole information processing device **42** may be

programmed to activate the cutting device **20** upon receiving a command signal via a suitable carrier (e.g., wireline) from the surface.

[0022] In another operating mode, the cutting operation may be automated such that surface control is not used to initiate, control, and / or terminate the cutting operation. For example, the information processing device **42** may be programmed to initiate the cutting operation using pre-programmed instructions and one or more signal inputs. In some arrangements, the information processing device **42** may receive signals from a timer (not shown) that initiates a cutting operation after a pre-set amount of time has expired (*e.g.*, thirty minutes). During such a time delay, the cutting device **20** may be lowered into the wellbore **12** and positioned at the proper depth. In another mode, a motion sensor (*e.g.*, an accelerometer) generate signals that may be used to determine when the cutting device **20** has come to a rest at the target location **50**. That is, a no detected motion period of a specified time duration may be indicative that the target location **50** has been reached. In still other embodiments, downhole parameters (*e.g.*, tool orientation, temperature, pressure, etc.) may be measured in connection with the initiation of the operation of the cutting device **20**. Thus, in some aspects, a memory of the information processing device **42** may include pre-programmed instructions that use one or more inputs (e.g., time, sensor measurements, etc.) in order to control the operation of the cutting device **20**. It should be appreciated that such embodiments may be useful for use with conveyance devices such as slick line or coiled tubing that do not include communication carriers that enable direct surface control of the cutting device **20**.

[0023] While the foregoing disclosure is directed to the one mode embodiments of the disclosure, various modifications will be apparent to those skilled in the art. It is intended that all variations within the scope of the appended claims be embraced by the foregoing disclosure.

THE CLAIMS

What is claimed is:

1. A method for performing an operation in the wellbore, comprising:

- at least partially separating a wellbore tubular into a first and a second section while reducing a compressive force acting on the wellbore tubular using a force applicator in the wellbore.

2. The method of claim 1, wherein the wellbore tubular is separated using one of: (i) at least one cutting element, (ii) a chemical reaction, (iii) a shaped charge, and (iv) an energetic beam.

3. The method of claim 1, further comprising: positioning the force applicator inside the wellbore tubular, gripping the wellbore tubular at two points, and wherein the wellbore tubular is at least partially separated at a location between the two points.

4. The method of claim 1, further comprising applying an axial force to an inner surface of the wellbore tubular using the force applicator.

5. The method of claim 1, wherein a force applicator applies an axial force using one of: (i) a pressurized fluid, (ii) a magnetic force, (iii) a hydraulically actuated ram, (iv) a hydraulic motor, and (v) an electric motor.

6. The method of claim 1, further comprising: engaging the wellbore tubular with a first and a second anchor associated with the force applicator; and urging the first and second anchors in opposing directions.

7. The method of claim 6, further comprising: (i) positioning a cutting device using at least one of: (i) the first anchor, and (ii) the second anchor.

8. The method of claim 1, wherein a tension force applied by the force generator results in one of: (i) substantially no compression in the wellbore tubular section, and (ii) a tension in the wellbore tubular section.

9. An apparatus for performing a downhole operation, comprising:

- a cutter configured to at least partially sever a wellbore tubular into a first and a second section; and
- a force applicator configured to reduce a compressive force acting on a section of a wellbore tubular proximate to the cutter.

10. The apparatus of claim 9, wherein the cutter includes one of: (i) at least one cutting element, (ii) a chemical reaction, and (iii) an energetic beam.

11. The apparatus of claim 9, wherein the force applicator is configured to urge the first and the second sections in opposite directions.

12. The apparatus of claim 9, wherein the force applicator is configured to apply an axial force to an inner surface of the wellbore tubular.

13. The apparatus of claim 9, wherein the force applicator includes at least one anchor configured to engage an inner surface of the wellbore tubular.

14. The apparatus of claim 9, wherein a force applicator includes one of: (i) a pressurized fluid, (ii) a hydraulically actuated ram, (iii) a hydraulic motor, and (iv) an electric motor.

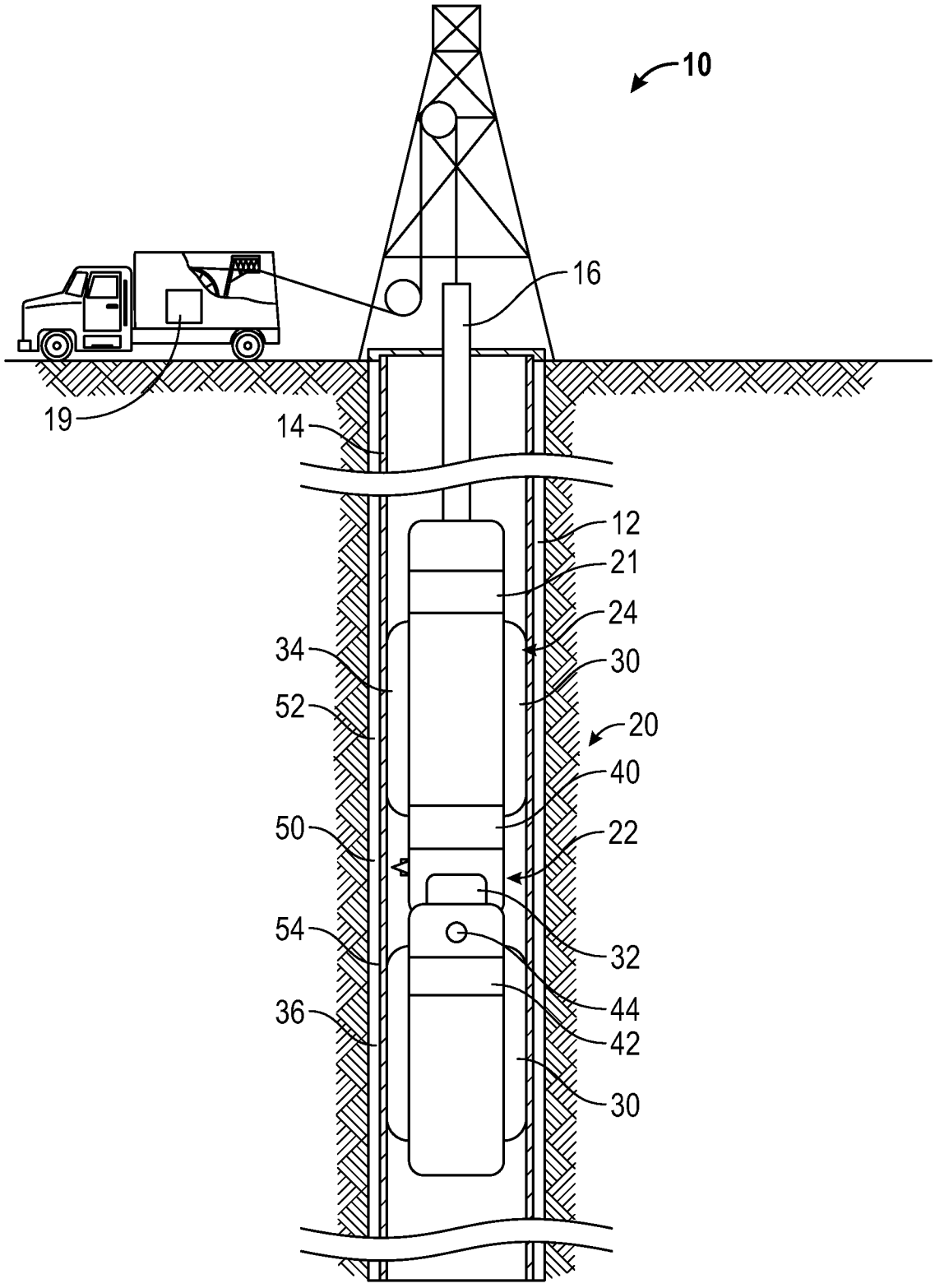


FIG. 1

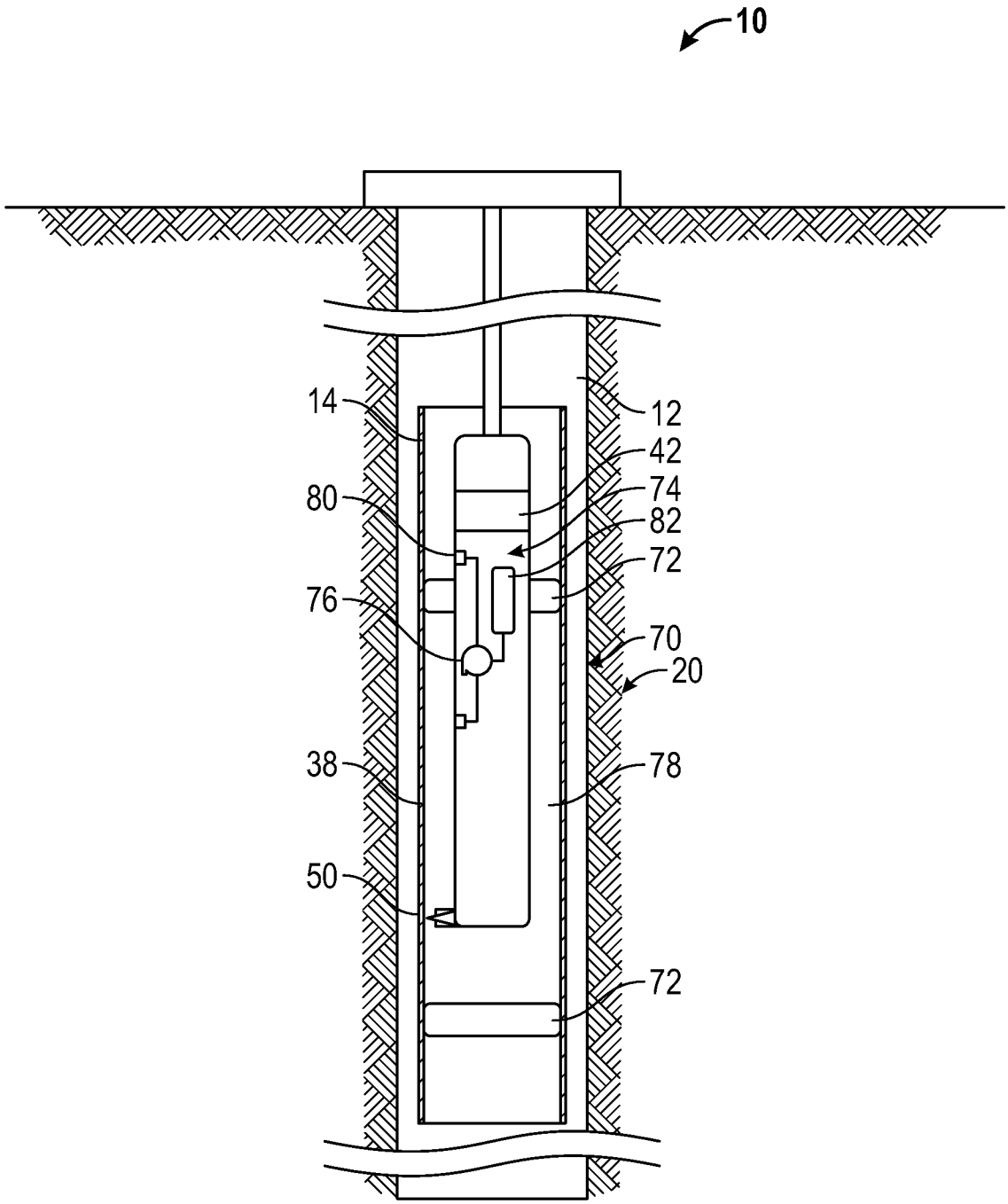


FIG. 2

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2012/029415

A. CLASSIFICATION OF SUBJECT MATTER

E21B 17/00(2006.01)i, E21B 10/64(2006.01)i, E21B 29/00(2006.01)i

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)

E21B 17/00; E21B 10/60; E21B 23/00; E21B 29/00; E21B 10/42; E21B 34/10

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

Korean utility models and applications for utility models

Japanese utility models and applications for utility models

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

eKOMPASS(KIPO internal) & Keywords: cutter, wellbore, tubular

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2003-0188868 A1 (NEIL A.A. SIMPSON et al.) 09 October 2003 See abstract, paragraphs 11-15 and figures 1,6	1-14
A	US 2002-0144817 A1 (JAMES C. DOANE et al.) 10 October 2002 See abstract, claims 1,17 and figure 3	1-14
A	US 2010-0206637 A1 (HARRISON STUART et al.) 19 August 2010 See abstract and figure 1	1-14
A	US 2003-0217850 A1 (JOEL, D. SHAW et al.) 27 November 2003 See See abstract and figures 1,2,3A	1-14

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

☒ See patent family 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 application or patent but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of citation or other special reason (as specified)

"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

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
13 JUNE 2012 (13.06.2012)	**14 JUNE 2012 (14.06.2012)**
Name and mailing address of the ISA/KR Korean Intellectual Property Office 189 Cheongsa-ro, Seo-gu, Daejeon Metropolitan City, 302-701, Republic of Korea Facsimile No. 82-42-472-7140	Authorized officer LEE, Won Jae Telephone No. 82-42-481-5512

Form PCT/ISA/210 (second sheet) (July 2009)

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2012/029415

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 2003-0188868 A1	09.10.2003	AU 2000-18679 A1	12.07.2000
		AU 2000-18679 B2	22.04.2004
		AU 2000-18687 A1	12.07.2000
		AU 2000-18687 B2	29.04.2004
		AU 2000-18688 A1	12.07.2000
		AU 2000-18688 B2	11.09.2003
		AU 2000-18689 A1	12.07.2000
		AU 2000-18689 B2	23.10.2003
		AU 2000-18766 A1	12.07.2000
		AU 2000-18766 B2	29.04.2004
		AU 2000-18768 A1	12.07.2000
		AU 2000-18768 B2	16.10.2003
		AU 2001-10442 A1	03.07.2001
		AU 2001-10442 B2	06.05.2004
		AU 2002-14137 A1	21.05.2002
		AU 2002-212537 B2	05.04.2007
		AU 2002-214137 B2	04.01.2007
		AU 2002-339101 A1	10.06.2003
		AU 2003-255716 A1	02.02.2004
		AU 2003-255716 A8	02.02.2004
		CA 2356130 A1	29.06.2000
		CA 2356130 C	02.03.2010
		CA 2356131 A1	29.06.2000
		CA 2356131 C	29.01.2008
		CA 2356144 A1	29.06.2000
		CA 2356144 C	12.12.2006
		CA 2356148 A1	29.06.2000
		CA 2356148 C	04.10.2005
		CA 2356184 A1	29.06.2000
		CA 2356184 C	26.05.2009
		CA 2356194 A1	29.06.2000
		CA 2356194 C	27.02.2007
		CA 2393744 A1	28.06.2001
		CA 2393744 C	27.05.2008
		CA 2428479 A1	16.05.2002
		CA 2428479 C	04.07.2006
		CA 2441814 A1	26.09.2002
		CA 2441814 C	04.01.2011
		CA 2445033 A1	17.10.2002
		CA 2445033 C	07.07.2009
		CA 2446675 C	25.03.2008
		CA 2452857 A1	05.06.2003
		CA 2452857 C	28.07.2009
		CA 2459053 A1	26.08.2004
		CA 2459053 C	10.07.2007
		CA 2460829 A1	22.01.2004
		CA 2460829 C	09.09.2008
		CA 2461851 A1	25.09.2004
		CA 2461851 C	27.11.2007

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2012/029415

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
		CA 2461855 A1	25.09.2004
		CA 2461855 C	20.05.2008
		CA 2462031 A1	25.09.2004
		CA 2462031 C	27.11.2007
		CA 2462115 C	22.12.2009
		CA 2473216 A1	09.01.2005
		CA 2473216 C	20.11.2007
		CA 2497854 A1	29.06.2000
		CA 2497854 C	15.08.2006
		CA 2509317 A1	08.12.2005
		CA 2509317 C	04.08.2009
		CA 2511628 A1	27.01.2006
		CA 2511628 C	01.09.2009
		CA 2519325 A1	30.03.2006
		CA 2519325 C	03.06.2008
		CA 2529016 A1	23.12.2004
		CA 2537867 A1	16.05.2002
		CA 2537867 C	20.03.2007
		CA 2557965 A1	29.06.2000
		CA 2557965 C	19.08.2008
		CA 2560501 A1	29.06.2000
		CA 2560501 C	25.03.2008
		CA 2564290 A1	29.06.2000
		CA 2564290 C	29.01.2008
		CA 2565202 A1	29.06.2000
		CA 2603100 A1	29.06.2000
		CA 2603100 C	15.02.2011
		CA 2622596 A1	30.03.2006
		CA 2622596 C	24.11.2009
		CA 2663922 A1	17.10.2002
		CA 2663922 C	16.08.2011
		CA 2683103 A1	10.04.2003
		CA 2686423 A1	29.06.2000
		EP 1141515 A1	10.10.2001
		EP 1141517 A1	10.10.2001
		EP 1141517 B1	08.12.2004
		EP 1141518 A1	10.10.2001
		EP 1141518 B1	26.10.2005
		EP 1144802 A2	17.10.2001
		EP 1144802 B1	08.12.2004
		EP 1147287 A2	24.10.2001
		EP 1147287 B1	17.08.2005
		EP 1151180 A1	07.11.2001
		EP 1242714 A1	25.09.2002
		EP 1333963 A2	13.08.2003
		EP 1333963 B1	10.01.2007
		EP 1413709 A2	28.04.2004
		EP 1413709 A3	29.09.2004
		EP 1413709 B1	28.07.2010
		EP 1505251 A2	09.02.2005

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2012/029415

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
		EP 1505251 A3	14.02.2007
		EP 1505251 B1	13.05.2009
		EP 1510651 A2	02.03.2005
		EP 1510651 A3	09.05.2007
		EP 1510651 B1	02.07.2008
		EP 1582274 A2	05.10.2005
		EP 1582274 A3	08.02.2006
		EP 1654346 A2	10.05.2006
		EP 1659259 A1	24.05.2006
		EP 2273064 A1	12.01.2011
		GB 2345308 A	05.07.2000
		GB 2346400 A	09.08.2000
		GB 2346632 A	16.08.2000
		GB 2346909 A	23.08.2000
		GB 2347445 A	06.09.2000
		GB 2382832 A	11.06.2003
		GB 2383065 A	18.06.2003
		GB 2383361 A	25.06.2003
		GB 2403749 A	12.01.2005
		GB 2415001 A	14.12.2005
		GB 2415453 A	28.12.2005
		GB 2416551 A	01.02.2006
		GB 2418683 A	05.04.2006
		GB 2428717 A	07.02.2007
		GB 2463400 A	17.03.2010
		GB 2463588 A	24.03.2010
		US 2001-040054 A1	15.11.2001
		US 2001-045284 A1	29.11.2001
		US 2002-060079 A1	23.05.2002
		US 2002-079100 A1	27.06.2002
		US 2002-079106 A1	27.06.2002
		US 2002-112338 A1	22.08.2002
		US 2002-145281 A1	10.10.2002
		US 2002-166664 A1	14.11.2002
		US 2002-166668 A1	14.11.2002
		US 2002-175474 A1	28.11.2002
		US 2002-185274 A1	12.12.2002
		US 2002-195256 A1	26.12.2002
		US 2003-019638 A1	30.01.2003
		US 2003-024711 A1	06.02.2003
		US 2003-042022 A1	06.03.2003
		US 2003-042028 A1	06.03.2003
		US 2003-062171 A1	03.04.2003
		US 2003-106698 A1	12.06.2003
		US 2003-132032 A1	17.07.2003
		US 2003-136561 A1	24.07.2003
		US 2004-055756 A1	25.03.2004
		US 2004-079528 A1	29.04.2004
		US 2004-131812 A1	08.07.2004
		US 2004-149454 A1	05.08.2004

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2012/029415

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
		US 2004-159466 A1	19.08.2004
		US 2004-163823 A1	26.08.2004
		US 2004-173355 A1	09.09.2004
		US 2004-177974 A1	16.09.2004
		US 2004-216506 A1	04.11.2004
		US 2004-216878 A1	04.11.2004
		US 2004-216925 A1	04.11.2004
		US 2004-226723 A1	18.11.2004
		US 2004-251035 A1	16.12.2004
		US 2005-003458 A1	06.01.2005
		US 2005-005668 A1	13.01.2005
		US 2005-011650 A1	20.01.2005
		US 2005-016738 A1	27.01.2005
		US 2005-077046 A1	14.04.2005
		US 2005-121232 A1	09.06.2005
		US 2005-127673 A1	16.06.2005
		US 2005-155771 A1	21.07.2005
		US 2005-161222 A1	28.07.2005
		US 2005-252662 A1	17.11.2005
		US 2006-065408 A1	30.03.2006
		US 2008-017387 A1	24.01.2008
		US 2008-202753 A1	28.08.2008
		US 2009-223680 A1	10.09.2009
		US 2010-218582 A1	02.09.2010
		US 2010-273680 A1	28.10.2010
		US 6325148 B1	04.12.2001
		US 6425444 B1	30.07.2002
		US 6446323 B1	10.09.2002
		US 6457532 B1	01.10.2002
		US 6527049 B2	04.03.2003
		US 6543552 B1	08.04.2003
		US 6578630 B2	17.06.2003
		US 6598678 B1	29.07.2003
		US 6688400 B2	10.02.2004
		US 6695063 B2	24.02.2004
		US 6698517 B2	02.03.2004
		US 6702029 B2	09.03.2004
		US 6702030 B2	09.03.2004
		US 6708769 B2	23.03.2004
		US 6712142 B2	30.03.2004
		US 6712151 B2	30.03.2004
		US 6742606 B2	01.06.2004
		US 6752215 B2	22.06.2004
		US 6851475 B2	08.02.2005
		US 6899181 B2	31.05.2005
		US 6902000 B2	07.06.2005
		US 6923261 B2	02.08.2005
		US 6976536 B2	20.12.2005
		US 6976539 B2	20.12.2005
		US 7004257 B2	28.02.2006

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2012/029415

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
		US 7086478 B2	08.08.2006
		US 7093653 B2	22.08.2006
		US 7117957 B2	10.10.2006
		US 7124821 B2	24.10.2006
		US 7124826 B2	24.10.2006
		US 7168497 B2	30.01.2007
		US 7188687 B2	13.03.2007
		US 7234532 B2	26.06.2007
		US 7267175 B2	11.09.2007
		US 7275602 B2	02.10.2007
		US 7322420 B2	29.01.2008
		US 7367404 B2	06.05.2008
		US 7373990 B2	20.05.2008
		US 7754439 B2	13.07.2010
		US 7921925 B2	12.04.2011
		US 8006771 B2	30.08.2011
US 2002-0144817 A1	10.10.2002	US 6702031 B2	09.03.2004
US 2010-0206637 A1	19.08.2010	US 2010-0206635 A1	19.08.2010
		US 2010-0206636 A1	19.08.2010
		US 2010-0230171 A1	16.09.2010
		WO 2010-093775 A2	19.08.2010
		WO 2010-093775 A3	02.12.2010
		WO 2010-093775 A3	19.08.2010
US 2003-0217850 A1	27.11.2003	AU 2003-231795 A1	12.12.2003
		AU 2003-231795 A1	12.12.2003
		AU 2003-231795 B2	04.01.2007
		AU 2003-231795 B2	04.01.2007
		CA 2486682 A1	04.12.2003
		CA 2486682 C	15.09.2009
		DE 60302569 D1	05.01.2006
		DE 60302569 T2	14.06.2006
		DK1507954T3	20.02.2006
		EP 1507954 A1	23.02.2005
		EP 1507954 B1	30.11.2005
		US 6827148 B2	07.12.2004
		WO 03-100210 A1	04.12.2003
		WO 0310-0210A1	04.12.2003