United States Patent Application Publication	20250264001
Kind Code	A1
Publication Date	August 21, 2025
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DOWNHOLE INJECTION TOOL AND METHOD FOR INJECTING A FLUID IN AN ANNULUS SURROUNDING A DOWNHOLE TUBULAR

Abstract

A downhole injection tool for injecting a treatment fluid in a space surrounding a downhole tubular installed in a borehole in the Earth is based on an elongate tool housing extending around a central longitudinal tool axis. At least two stings are provided, each having a fluid channel. At least two treatment fluid cannisters are provided in the downhole injection tool, for holding the treatment fluid that is to be injected. A first cannister of the at least two treatment fluid cannisters is fluidly connected with the exterior of the tool housing via a first sting of the at least two stings, but not via a second sting of the at least two stings. A second cannister of the at least two treatment fluid cannisters is fluidly connected with the exterior of the tool housing via the second sting, but not via the first sting.

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Family ID:	**1000008600285**
Appl. No.:	**18/702468**
Filed (or PCT Filed):	**November 10, 2022**
PCT No.:	**PCT/EP2022/081438**

Foreign Application Priority Data

EP	21207925.5	Nov. 12, 2021

Publication Classification

Int. Cl.: **E21B33/138** (20060101)

U.S. Cl.:

CPC **E21B33/138** (20130101);

Background/Summary

FIELD OF THE INVENTION

[0001] In a first aspect, the present invention relates to a downhole injection tool for downhole injecting a treatment fluid in a space surrounding a downhole tubular installed in a borehole in the Earth. In another aspect, the invention relates to method for injecting a treatment fluid in an annulus surrounding a downhole tubular installed within a borehole in the Earth.

BACKGROUND TO THE INVENTION

[0002] In the operation of oil/gas wells or other cased boreholes in the Earth, it can often become necessary or beneficial to punch one or more holes through, or otherwise perforate, the casing which lines the well bore, or a production tubing within the casing. Downhole tools have been proposed to perforate the casing, and to subsequently inject sealing material into the space between the Earth formation around the bore hole and the casing through the perforation or perforations formed therein. U.S. Pat. No. 2,381,929, for example discloses a system in which punches are forced outwardly, and radially against the casing, by a pressurized fluid. The application of pressure is continued until the punches are forced through the casing. Each punch is accompanied by a fluid passage through which a sealing material can be injected from the system into the annular space around the casing.

[0003] The system of U.S. Pat. No. 2,381,929 further comprises one or more reservoirs for holding a sealing material, or ingredients of sealing material still to be mixed. The reservoir(s) each contain a piston, which can push the contents of the reservoir through the fluid passages into the annular space. Each of the fluid passages is in fluid communication with each reservoir, so that the contents from each reservoir is be conveyed to each of the fluid passages with the aim to inject the sealing material into the annular space at multiple locations simultaneously.

[0004] It has been suggested that the sealing material having been injected with the system of U.S. Pat. No. 2,381,929 is not always evenly distributed around the full circumference of the annular space. This may lead to leak paths or weak spots along the longitudinal direction within the annulus.

SUMMARY OF THE INVENTION

[0005] In accordance with the invention there is provided a downhole injection tool for injecting a treatment fluid in a space surrounding a downhole tubular installed in a borehole in the Earth, comprising: [0006] an elongate tool housing extending around a central longitudinal tool axis; [0007] at least two stings, each of the stings comprising a fluid channel to establish fluid communication from within the tool housing to an exterior of the tool housing through the fluid channel, wherein each said sting is movable in a radially outward direction, away from the central longitudinal tool axis, from a retracted position to an extended position whereby each sting extends to outside the elongate tool housing; and [0008] at least two treatment fluid cannisters, for holding the treatment fluid that is to be injected, wherein a first cannister of the at least two treatment fluid cannisters is fluidly connected with the exterior of the tool housing via a first sting of the at least two stings, but not via a second sting of the at least two stings, and wherein a second cannister of the at least two treatment fluid cannisters is fluidly connected with the exterior of the tool housing via the second sting, but not via the first sting.

[0009] In a further aspect of the invention, there is provided a method of injecting a treatment fluid in an annulus surrounding a downhole tubular arranged within a borehole in the Earth, said method

comprising: [0010] providing a downhole injection tool as defined above; [0011] lowering the downhole injection tool into the borehole through the downhole tubular to a selected depth; [0012] at the selected depth, extending the first sting and the second sting through a wall of the downhole tubular, to establish fluid communication between downhole injection tool and the annulus surrounding the downhole tubular; [0013] injecting the treatment fluid from the downhole injection tool from the at least two treatment fluid cannisters through the first sting into the annulus surrounding the downhole tubular and through the second sting into the annulus; and [0014] retrieving the downhole injection tool from the downhole tubular.
[0015] These and other features, embodiments and advantages of the method, and of suitable expansion devices, are described in the accompanying claims, abstract and the following detailed description of non-limiting embodiments depicted in the accompanying drawings, in which description reference numerals are used which refer to corresponding reference numerals that are depicted in the drawings.

Description

BRIEF DESCRIPTION OF THE DRAWINGS
[0016] The drawing figures depict one or more implementations in accord with the present teachings, by way of example only, not by way of limitation. In the figures, like reference numerals refer to the same or similar elements.
[0017] FIG. **1** is schematic cross sectional view along line B-B indicated in FIG. **2**, of a section of a downhole injection tool for perforating and injecting;
[0018] FIG. **2** is a plan view along a longitudinal direction from above on the tool of FIG. **1**;
[0019] FIG. **3** is a detailed cross sectional view of the stings of the tool of FIG. **1**;
[0020] FIG. **4** is a plan view along line C-C indicated in FIG. **1**;
[0021] FIG. **5** is a detailed cross sectional view of the tool along line D-D as indicated in FIG. **2**;
[0022] FIG. **6** is a detailed cross sectional view of the cannisters that can connected to the tool of FIG. **1**; and
[0023] FIG. **7** is an example hydraulic circuit.
[0024] Similar reference numerals in different figures denote the same or similar objects. Objects and other features depicted in the figures and/or described in this specification, abstract and/or claims may be combined in different ways by a person skilled in the art. Unless otherwise indicated, the term longitudinal is used herein to express the direction parallel to the central longitudinal tool axis, and the term transverse is used to express any direction normal (perpendicular) to the central longitudinal tool axis.
DETAILED DESCRIPTION OF THE INVENTION
[0025] Disclosed is a downhole injection tool for injecting a treatment fluid in a space surrounding a downhole tubular installed in a borehole in the Earth. The tool may be run longitudinally in a bore of the downhole tubular. At least two stings are provided with the tool, each provided with a fluid channel. Each sting can protrude through a wall of the downhole tubular, and thereby establish a fluid communication channel between the downhole injection tool within the tubular and the space surrounding the tubular. At least two treatment fluid cannisters are provided in the downhole injection tool, for holding the treatment fluid that is to be injected. A first cannister of the at least two treatment fluid cannisters is fluidly connected with the exterior of the tool housing via a first sting of the at least two stings, but not via a second sting of the at least two stings. A second cannister of the at least two treatment fluid cannisters is fluidly connected with the exterior of the tool housing via the second sting, but not via the first sting.
[0026] By providing a dedicated cannister (or dedicated set of cannisters) for each of the stings, it is achieved that the treatment fluid is injected through each sting in predetermined quantities,

preferably in mutually equal quantities. The invention is based on an insight that in case of multiple stings being fed by a shared cannister, an imbalance may cause the treatment fluid to pass preferentially through one of the stings, thereby filling the space surrounding the tubular less homogenously. The imbalance may be caused, for example, by one of the stings experiencing a higher flow resistance than the other. The present invention is believed to facilitate a more controllable and homogenous distribution of the treatment fluid around the tool or the tubular.

[0027] In use, the downhole injection tool may be lowered into a borehole through the bore of the downhole tubular, to a selected depth. At the selected depth, the tool may be kept stationary, while extending the stings through a wall of the downhole tubular, to establish fluid communication between downhole injection tool and the annulus surrounding the downhole tubular. The treatment fluid is then injected, from the at least two treatment fluid cannisters through both stings into the annulus surrounding the downhole tubular. At least part of the stings may be subsequently retracted, and the downhole tool may then be retrieved from the downhole tubular.

[0028] Typical downhole tubulars include wellbore tubulars, such as, for example, casing, liner, or production tubing.

[0029] The invention can be applied with any type of downhole injection tool which has multiple injection stings. As one example, FIG. **1** shows a cross sectional view of a section of a downhole injection tool that can be used. In this example, the downhole injection tool is a perforating and injection tool, wherein the functionality of injecting is advantageously combined with the functionality of perforating. Notwithstanding, combining perforating and injection functionality in one tool is not a requirement of the invention. The cross section is taken along line B-B as indicated in FIG. **2**. For reason of clarity, some of the parts that are not essential to the present invention have been omitted or simplified.

[0030] The tool can be of modular design, having several sections (or: modules) which can be assembled in a string using connectors. Shown in FIG. **1** are an expander section **30** and a piston section **50**. The piston section **50** is connected to the expander section **30** at connector **52**. The expander section **30** comprises a base **37**, to which, in turn, an elongate tool housing **3** is connected at connector **32**. The tool housing **3** is extending around a central longitudinal tool axis **2**. The tool can be run downhole in a downhole tubular, such as a wellbore tubular. Connectors, such as for example screw connectors **34** in the base **37**, may be provided to attach an optional external centralizer, such as a (flexible) spring blade (not shown).

[0031] The expander section **30** comprises two stings, first sting **7** and second sting **7′**, both positioned in one transverse plane, but at mutually opposing azimuths. More than two stings may be provided, preferably in said one transverse plane and/or preferably equally distributed around the circumference of the tool, to facilitate equal distribution of the treatment fluid in all directions. Each sting **7**,**7′** is movable in a radially outward direction **18**,**18′**, away from the central longitudinal tool axis **2**, from a retracted position (as shown) to an extended position (not shown), whereby each sting **7**,**7** partly extends to outside the elongate tool housing **3**. Windows, for example window **13**, may suitably be provided in the elongate tool housing **13** to allow passage of each sting.

[0032] A hydraulic drive mechanism is provided to drive each sting **7**,**7′** from its respective retracted position to extended position. The hydraulic drive mechanisms may comprise a press device for each of the stings **7**,**71**. Each press device may comprise a wedge segment **33**,**33′** respectively acting the sting **7**,**7′** to force each sting **7**,**7′** in the radially outward direction **18**, **18′** from the tool housing **3**. The movement of the first sting **7** is driven by movement of the first wedge segment **33** in longitudinal direction with respect to elongate housing **3** and the first sting **7**, whereas the movement of the second sting **7′** is driven by movement of the second wedge segment **33′** in said longitudinal direction with respect to elongate housing **3** and the second sting **7′**.

[0033] The radially outward directions **18**,**18′** are in essence transverse to the longitudinal axis **2**. Each sting **7**,**7′** is rigidly mounted on a distal end of a bending arm **35**,**35′**. At a proximal end thereof, each bending arm **35**,**35′** is fixed longitudinally stationary relative to the elongate tool housing **3**. In the embodiment as shown, each bending arm **35**,**35′** is monolithic to the base **37**. This can be made by machining. Each sting **7**,**7′**, is movable in unison with the distal end of its own respective bending arm **35**,**35′**, each in a longitudinal-radial plane from the central longitudinal tool axis **2**. As a result, each sting **7**,**7′** can move in said radial outward direction **18**,**18′**, essentially without experiencing any friction in the transverse direction. Each bending arm **35**,**35′** effectively acts as a spring blade, which is elastically loaded as the press device forces the sting **7**,**7′** in the radially outward direction **18**,**18′**.

[0034] Thus, the expander section **30** of the present example employs multiple sting-arm combinations, each with their own press device. For example, in the embodiment of FIG. **1**, the already mentioned sting **7** and bending arm **35** together form a first sting-arm combination, whereby the tool further comprises a second sting-arm combination comprising a second sting **7′** and a second bending arm **35′**. The second sting comprises, wherein said second sting is movable in a second radially outward direction **18′** opposite to the first radially outward direction **18** and also away from the central longitudinal tool axis **2**. The first sting-arm combination and second sting-arm combination are arranged side-by-side whereby the first sting and the second sting are positioned in one transverse plane, but at mutually differing azimuths around the central longitudinal tool axis **2**.

[0035] Both press devices act on both sting-arm combinations simultaneously, to force the first sting and second sting in mutually differing radially outward directions from the tool housing, transversely to the longitudinal axis.

[0036] Each press device includes its own wedge segment. Two such wedge segments are shown in FIG. **1**: the first wedge segment **33** and a second wedge segment **33′**. The first wedge segment **33** and second wedge segment **33′** are slidingly abutted against each other in a longitudinal-radial abutment plane **38**, whereby the first wedge segment **33** is in sliding contact with the first sting-arm combination (**7**,**35**) and whereby the second segment **33′** is in sliding contact with the second sting-arm combination (**7′**,**35′**). When being forced into relative movement, in longitudinal direction, with respect to the first sting **7** and second sting **7′**, the first wedge segment **33** and the second wedge segment **33′** are also free to slidingly move, relative to each other, in the longitudinal direction.

[0037] An inlay **36**, consisting of sheet or platelet of a wear resistant contact material, may be provided in a recess in one of the wedge segments at the abutment plane **38**. The inlay **36** may be best visible in the detailed cross sectional view of FIG. **3**. The inlay may be made of a material having a high degree of wear resistance and/or a low coefficient of friction. Other beneficial properties for this material include one or more of a high mechanical strength, stiffness, and hardness. Furthermore, it may have high temperature resistance and a good creep resistance at high temperatures. Examples of preferred materials include PEEK (a polyetheretherketone material), preferably bearing grade (BG) PEEK, which may be reinforced with carbon fiber.

[0038] The bending arms **35**,**35′** are flexible, such that upon movement of the respective wedge segments **33**,**33′** the bending arms **35**,**35′** flex or pivot outward, such that each sting **7**,**7′** is movable in unison with the distal ends of the bending arms in a longitudinal-radial plane from the longitudinal tool axis **2**. The bending arms **35**,**35′** may flex fully elastically, or the flexing may be assisted by a pivot. Elastic bending has the advantage that the bending arms will automatically retract when the wedge segments **33**,**33′** are returned to their starting positions.

[0039] With the tool ran concentrically inside a downhole tubular installed in a borehole in the Earth, the stings will first engage with the inside of the wall of the tubular and after continued forcing the wedge segments the stings will ultimately, one after the other, perforate the wall of the tubular and protrude through the tubular into the annular space surrounding the tubular.

[0040] As can also be seen in FIG. **3**, in this particular example, a major part of the sting **7** is cylindrical and extends along a longitudinal sting axis **8**. The longitudinal sting axis **8** is in essence perpendicular to the central longitudinal tool axis **2**, and extending radially outward therefrom in the transverse plane **28**. The sting **7** may comprise an end cap **41**, which might be slightly tapered at the radially outward facing surface. The end cap **41** may comprise an orifice, a nozzle, and/or house a non-return valve. The sting **7** is held in place by a sting foot **49**, which may, for example, be bolted to the distal end of the bending arm **35**.

[0041] FIG. **4** shows a side view of the tool from the direction indicated by C-C in FIG. **1**. Both the end cap **41** of the sting **7**, and the sting foot **49** can be seen through window **13** in tool housing **3**. The window **13** is preferably sufficiently large to receive the sting foot **49** when the sting is in the extended position. Bolts **40** may be employed to mount the sting **7** to the bending arm.

[0042] The wedge segments **33**,**33′** each engage with a hydraulic piston, which may be housed within the piston section **50**. The hydraulic piston can be actuated by a hydraulic fluid that is displaced by a pump, to impart the relative movement of the wedge segments, in longitudinal direction, with respect to each of the stings **7**,**7′**. Advantageously, each of the wedge segments **33**,**33′** engages with a plurality of hydraulic pistons.

[0043] Focusing now on FIG. **5**, there is illustrated a cross-section of the piston section **50** shown in FIG. **1** but along the line D-D as indicated in FIG. **2**. The cross-section view also shows part of the base **37**. The piston section **50** comprises a piston housing **57** provided with one or more piston bores **56***a*, **56***b*. Piston rods **53***a* and **53***b* traverse the base **37**, and both piston rods engage with the wedge segment **33**. Hydraulic pistons **54***a* and **54***b* are respectively formed at the other ends of the piston rods **53***a* and **53***b*. The hydraulic pistons **54***a*,**54***b* are slidingly arranged in the piston bores **56***a*,**56***b*. The piston bores are sealed off by piston plugs **51***a* and **51***b* sealed in place with O-rings or the like. The pistons **54***a* and **54***b*, are actuated by a hydraulic fluid which can be introduced in the piston bores between the piston plugs **51***a*, **51***b* and the hydraulic pistons **54***a*, **54***b*. The hydraulic fluid is displaced by a pump. The wedge segments can be retracted by hydraulically actuating pistons **54***a* and **54***b* to move towards the piston plugs (**51***a*,**51***b*), by pumping hydraulic fluid in the piston rod annuli (**58***a*,**58***b*) that exist between the piston rods (**53***a*,**53***b*) and the piston bore walls. Valves to direct the hydraulic fluid flow may be provided in a separate tool section (not shown). The hydraulic pump may also be provided in a separate tool section (not shown).

[0044] When two wedge segments **33** and **33′** have to be actuated, the above described hydraulic pistons **54***a*,**54***b* together act as a first piston engaging with the first wedge segment **33**, while similar hydraulic pistons together form a second piston engaging with the second wedge segment **33′**. The hydraulic fluid, which is displaced by the hydraulic pump, can be distributed over all available piston bores. Referring now, to FIG. **2**, it can be geometrically understood that the total combined area available for the two piston bores **56***a* and **56***b* for the “first piston” (i.e. two times two piston bores, for two wedge segments of the tool) is larger than the area available for a single circular piston bore per wedge segment would be (i.e. two times one single piston bore). This allows for more available force on the stings. Moreover, each being held by two piston rods instead of one, the wedge segments will be more rigid and stable against force components in the direction perpendicular to the cross section cut plane of FIG. **1**. On the other hand, some relative flexibility is provided on the wedge segments to react to net force components in one of the radially outward directions **18**,**18′**. Under normal conditions, the forces in the radially outward directions **18**,**18′** counter each other, but when one of the stings **7**,**7′** starts to advance into the wall of a wellbore tubular then temporarily a net force may present itself. By providing wedge segments **33**,**33′** that slide relatively to each other, instead of a solid single wedge, strains that would be caused by the resulting net force can be more easily accommodated.

[0045] Also visible in FIG. **2** are screw holes **24** to facilitate positioning of another tool section (e.g. a hydraulic section with a pump and/or valves), and three hydraulic fluid connectors **25**, which can be used to convey pressurized hydraulic fluid from a reservoir, using a pump and/or valve segment of the tool (not shown), to the piston bore(s) and to convey a return stream from the piston rod annulus or annuli back to a return reservoir, or vice versa. A third hydraulic fluid connector **25** is optional, and may be used to convey pressurized hydraulic fluid from the reservoir to one or more treatment fluid cannisters, as will be further elaborated on below. The hydraulic fluid connectors **25** engage with hydraulic fluid channels (e.g. bores) provided within the piston housing.

[0046] Referring, again, to FIG. **3**, each of the stings **7**,**7′** (but illustrated only for sting **7**) comprise an injection tube **43** comprising a fluid channel **47**, to establish fluid communication from within the tool housing **3** to an exterior of the tool housing through the fluid channel **47**. The fluid channel **47** within the injection tube **43** may suitably connect to a discharge nozzle **45** via check valve (suitably a biased ball valve, not shown), which may be provided, for example, within the end cap **41**. The fluid channel can be connected to a treatment fluid cannister via flexible line (not shown) that can be plugged into a socket **31**. Such socket **31** may suitably comprise a compression fitting in which a ferrule **21** is compressed around an end of the flexible line as a nut **22** is tightened. The injection tube **43** may be held in place by the sting foot **49**, which may, for example, be bolted to the distal end of the bending arm **35**. An O-ring seal **44** may be provided to avoid leakage of treatment fluid which is passed from the socket **31** into the fluid channel **47**. This is only one example of how the sting can be mounted onto the bending arm, and alternative constructions to rigidly mount the sting to the bending arm are assumed to be in reach of the skilled person based on the present teaching. A frangible zone **46** may comprise reinforcement rings **48** stacked around the injection tube **43**, in mutual abutment with each other. The sting of FIG. **3** is modelled after the sting shown disclosed in WO2020/229440A1, and modified to fit in the tool as described herein.

[0047] Cannisters **60**,**60′** are provided for storing the treatment fluid. The cannisters may be in selective fluid communication with a hydraulic pump, via a selectable valve which selectively isolates the cannisters from the pump or opens the cannisters to the pump. The hydraulic fluid may push the treatment fluid from the cannisters to the stings **7**,**7′**, by displacing and replacing the treatment fluid inside the cannisters. A piston separator may be provided within each cannister to separate the treatment fluid from the hydraulic fluid and to avoid contamination of the treatment fluid by the hydraulic fluid. The pump may be the same pump as the one utilized for actuating the press device, as the pump's duty for actuating the press device will not be necessary when the sting is in its extended position.

[0048] FIG. **6** shows a cross section of how such cannisters may be implemented on the tool of FIG. **1**, which has two stings. A first cannister **60** comprises a treatment fluid first reservoir **61**, a hydraulic fluid first reservoir **62**, a first piston separator **63**, a first cannister head **66**, and a first cannister base **67**. A second cannister **60′** comprises a treatment fluid second reservoir **61′**, a hydraulic fluid second reservoir **62′**, a second separator piston **63′**, a second cannister head **66′**, and a second cannister base **67′**. The first piston separator **63** is slidable in longitudinal direction over a first central hydraulic fluid tube **65** and the second piston separator **63′** is slidable in the longitudinal direction over a second central hydraulic fluid tube **65′**.

[0049] The first cannister base **67** is provided with a hydraulic fluid connector **72** for supply of pressurized hydraulic fluid from the pump, and with a treatment fluid first connector **71** and a treatment fluid second connector **71′**. The latter two may respectively be fluidly connected to sockets **31** and **31′** via treatment fluid connection lines (not shown). These treatment fluid connection lines are suitably flexible, to allow for the transition of the stings **7**,**7′** from their respective retracted position to extended position.

[0050] The treatment fluid first connector **71** communicates via a bore **73** through the first cannister base **67** to the treatment fluid first reservoir **61**. Inside the first central hydraulic fluid tube **65**, an inner tube **75** extends from the treatment fluid second connector **71′** to connector **76** provided in the second cannister base **67′**. This communicates via a bore **77** through the second cannister base **67′** to the treatment fluid second reservoir **61′**. The hydraulic fluid connector **72** communicates via bore **74** and the first central hydraulic fluid tube **65** to a hydraulic fluid first annulus **82** in the first cannister head **66** which extends between the first central hydraulic fluid tube **65** and the first cannister head **66**. From there, the hydraulic fluid can pass via the hydraulic fluid first annulus **82** into the hydraulic fluid first reservoir **62**. The bore **74** is suitably sealed off, for example by means of O-ring **85**, from the treatment fluid first reservoir **61** to avoid contamination of the treatment fluid inside the treatment fluid first reservoir **61** with the hydraulic fluid passing through bore **74**.

[0051] The hydraulic fluid first reservoir **62** is fluidly connected to the hydraulic fluid second reservoir **62′** as follows. Via bore **78** though the first cannister head **66** and liner **79** a hydraulic fluid connection is established to bore **84** in the second cannister base **67′** and the second central hydraulic fluid tube **65′**. Bore **84** is suitably sealed off from the treatment fluid second reservoir **61′**, for example with O-ring **87** or other type of seal. From the second central hydraulic fluid tube **65′**, the hydraulic fluid can enter into the hydraulic fluid second reservoir **62′** via annulus **82′** extending between the second central hydraulic fluid tube **65′** and the second cannister head **66′**.

[0052] Both the first cannister **60** and the second cannister **60′** are in selective fluid communication with the hydraulic fluid pump. During use, a selectable valve selectively isolates both the first cannister **60** and second cannister **60′** from the pump or opens both the first cannister **60** and the second cannister **60′** to the pump. When selectively opened to the pump, both the hydraulic fluid first reservoir **62** and the hydraulic fluid second reservoir **62′** fill with the hydraulic fluid when the cannister is opened to the pump. The first cannister **60** is in fluid communication with the first sting **7** with a first treatment fluid connection line (not shown) extending between the treatment fluid first connector **71** and socket **31**. The second cannister **60′** is in fluid communication with the second sting **7′** with a second treatment fluid connection line (not shown) extending between the treatment fluid second connector **71′** and socket **31′**. The second treatment fluid connection line bypasses the first treatment fluid connection line and the first sting **7**, and the first treatment fluid connection line bypasses the second treatment fluid connection line and the second sting **7′**.

[0053] An advantage of providing a dedicated cannister (or dedicated set of cannisters) for each of the stings, it is achieved that the treatment fluid is injected through each sting in predetermined quantities, preferably in mutually equal quantities. If multiple stings would be fed by a shared cannister, imbalances may cause the treatment fluid to pass preferentially through one of the stings, thereby filling the annulus surrounding the downhole tubular less homogenously. Imbalances may be caused, for example, by one of the stings experiencing a higher flow resistance than the other. By feeding each sting from a different cannister, it is believed a more controllable and homogenous distribution of the treatment fluid around the tubular can be feasible.

[0054] The treatment fluid may for example be a two-component resin, the components of which being mixed during the injection of the treatment fluid. In this case, multiple cannisters may be provided for each of the stings. Alternatively, a resin may be employed which hardens in contact with a wellbore fluid, such as water. Examples are described in International publication No. WO2021/170588A1. In such cases, a single cannister per string could suffice.

[0055] FIG. **7** shows one non-limiting example of how the hydraulic circuit can be designed. The associated pump and valves may be packaged in a separate tool section. The hydraulic fluid is provided in a pressure-compensated reservoir **90** where the pressure is kept equal to the pressure outside of the elongate tool housing **3**. Pump **91** is provided to displace the hydraulic fluid. In this example, the pump **91** is a unidirectional pump. The outlet of pump **91** is split to two three-way valves **92**,**93** and a selectable valve **94**. Two other connections of the three-way valves **92**,**93** are respectively connected directly to the pressure-compensated reservoir **90** (bypassing the pump **91**), and the third connectors of the three-way valves are in connection with respectively connectors **95** and **96**. These may be joined with two of the hydraulic fluid connectors **25**. For example, connector **95** may be joined with the hydraulic fluid connector **25** which is in fluid communication with piston bores **56***a*, **56***b*, while connector **96** is joined with the hydraulic fluid connector **25** which is in fluid communication with the piston rod annuli **58***a*,**58***b*, as shown in FIG. **5** (and similar other piston bores and piston rod annuli of other press devices provided in the tool). The outlet of the selectable valve **94** may be in communication with connector **96**, which in turn may be connected to the third of the hydraulic fluid connectors **25**, and from there to a hydraulic fluid first and second reservoirs **62**,**62′** to actuate the treatment fluid cannisters in so far as provided in the tool.

[0056] The valves may be controlled electrically. To activate the press device(s), three-way valve **92** is selected to open pump **91** to connector **95** and block the connection to the pressure-compensated reservoir **90**. At the same time, three-way valve **93** is in opposite position, blocking the connection with the pump **91** but opening the connection to the pressure-compensated reservoir **90**. This allows circulation of the hydraulic fluid from the pressure-compensated reservoir **90** to the piston bores **56***a*, **56***b* and from the piston rod annuli **58***a*,**58***b* back into the pressure-compensated reservoir **90**. When the piston rods **53***a*, **53***b* are in their end positions, the selectable valve **94** may be opened to open the cannister(s) to the pressure of the pump **91** and thereby start the injection of the treatment fluid. The stings may be restored to their retracted positions by reversing the positions of both three-way valves **92** and **93** whereby allowing circulation of the hydraulic fluid from the pressure-compensated reservoir **90** to the piston rod annuli **58***a*,**58***b* and from the piston bores **56***a*,**56***b* back into the pressure-compensated reservoir **90**.

[0057] Many variations are possible for the hydraulic circuitry. For example, three-way valves **92** and **93** may be mechanically interlinked so that they mechanically switch in unison. Other variants may include use of a bi-directional pump.

[0058] The downhole tool may be used as follows. First, the downhole tool as described above is lowered into the borehole, through the downhole tubular, to a selected depth. Then, at the selected depth, the press device acting on the sting is activated. Thereby the sting is forced in the radially outward direction from the tool housing, through a wall of the downhole tubular, whereby in certain embodiments the wall of said downhole tubular is perforated. Subsequently, the downhole tool may be retrieved from the downhole tubular by pulling the downhole tool in upward direction through to borehole towards surface. Prior to retrieving the tool, the treatment fluid may be injected from the downhole tool through the sting into an annulus surrounding the downhole tubular.

[0059] At least part of the sting may be retracted prior to retrieving. This can be done by reversing the relative movement of the press device, in longitudinal direction, with respect to the sting. A distal end of the sting, for instance the end cap **41**, may stay behind in the wall of the downhole tubular after retrieving the downhole tool. This practice has been proposed in e.g. WO2020/229440A1.

[0060] The present disclosure is not limited to the embodiments as described above and the appended claims. Many modifications are conceivable, and features of respective embodiments may be combined. The particular embodiments disclosed above are illustrative only, as the present invention may be modified, combined and/or practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein.

[0061] In particular, the concept disclosed herein of providing dedicated treatment fluid cannisters for each sting can be applied to other types of injection stings and expansion mechanisms, including perforating tools as disclosed in e.g.: U.S. Pat. No. 2,381,929, WO2020/229440A1, a Kinley perforator tool (U.S. Pat. No. 3,199,287); drilling tools (WO2018/115053A1), and more. Furthermore, the downhole tubular may already have been perforated prior to running the downhole injection tool, such as is the case in above-mentioned WO2018/115053A1 wherein the drilling device may be pulled to surface after which a sealant injection device is positioned at the depth where the sealant injection channels had been drilled.

[0062] Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative embodiments disclosed above may be altered, combined and/or modified and all such variations are considered within the scope of the present invention as defined in the accompanying claims.

Claims

1. A downhole injection tool for injecting a treatment fluid in a space surrounding a downhole tubular installed in a borehole in the Earth, comprising: an elongate tool housing extending around a central longitudinal tool axis; at least two stings, each of the stings comprising a fluid channel to establish fluid communication from within the tool housing to an exterior of the tool housing through the fluid channel, wherein each said sting is movable in a radially outward direction, away from the central longitudinal tool axis, from a retracted position to an extended position whereby each sting extends to outside the elongate tool housing; at least two treatment fluid cannisters, for holding the treatment fluid that is to be injected, wherein a first cannister of the at least two treatment fluid cannisters is fluidly connected with the exterior of the tool housing via a first sting of the at least two stings, but not via a second sting of the at least two stings, and wherein a second cannister of the at least two treatment fluid cannisters is fluidly connected with the exterior of the tool housing via the second sting, but not via the first sting.
2. The downhole injection tool of claim 1, further comprising a hydraulic drive mechanism functionally connected to the at least two stings to move each of the at least two stings from the retraced position to the extended position, said hydraulic drive mechanism comprising a piston and pump, which piston is actuated by a hydraulic fluid that is displaced by said pump.
3. The downhole injection tool of claim 2, wherein both the first cannister and the second cannister are in selective fluid communication with said pump.
4. The downhole injection tool of claim 3, wherein the pump is in selective fluid communication with both the first cannister and the second cannister via a selectable valve which selectively isolates both the first cannister and the second cannister from the pump or opens both the first cannister and the second cannister to the pump.
5. The downhole injection tool of claim 1, wherein the first sting and the second sting are movable in mutually differing directions.
6. The downhole injection tool of claim 1, wherein the first sting and the second sting are movable in mutually opposing directions.
7. A method of injecting a treatment fluid in an annulus surrounding a downhole tubular arranged within a borehole in the Earth, said method comprising: providing a downhole injection tool comprising: an elongate tool housing extending around a central longitudinal tool axis; at least two stings, each of the stings comprising a fluid channel to establish fluid communication from within the tool housing to an exterior of the tool housing through the fluid channel, wherein each said sting is movable in a radially outward direction, away from the central longitudinal tool axis, from a retracted position to an extended position whereby each sting extends to outside the elongate tool housing, at least two treatment fluid cannisters, for holding the treatment fluid that is to be injected, wherein a first cannister of the at least two treatment fluid cannisters is fluidly connected with the exterior of the tool housing via a first string of the at least two stings, but not via a second sting of the at least two stings, and wherein a second cannister of the at least two treatment fluid cannisters is fluidly connected with the exterior of the tool housing via the second sting, but not via the first sting; lowering the downhole injection tool into the borehole through the downhole tubular to a selected depth; at the selected depth, extending the first sting and the second sting through a wall of the downhole tubular, to establish fluid communication between downhole injection tool and the annulus surrounding the downhole tubular; injecting the treatment fluid from the downhole injection tool from the at least two treatment fluid cannisters through the first sting into the annulus surrounding the downhole tubular and through the second sting into the annulus; retrieving the downhole injection tool from the downhole tubular.
8. The method of claim 7, further comprising moving each of the at least two stings from the retraced position to the extended position by means of a hydraulic drive mechanism.
9. The method of claim 8, further comprising actuating a piston comprised in said hydraulic drive mechanism by a hydraulic fluid that is displaced by a pump.

10. The method of claim 9, wherein both the first cannister and the second cannister are in selective fluid communication with said pump.
11. The method of claim 10, wherein the pump is in selective fluid communication with both the first cannister and the second cannister via a selectable valve which selectively isolates both the first cannister and the second cannister from the pump or opens both the first cannister and the second cannister to the pump.
12. The method of claim 8, wherein the first sting and the second sting are moved in mutually differing directions.
13. The method of claim 8, wherein the first sting and the second sting are moved in mutually opposing directions.