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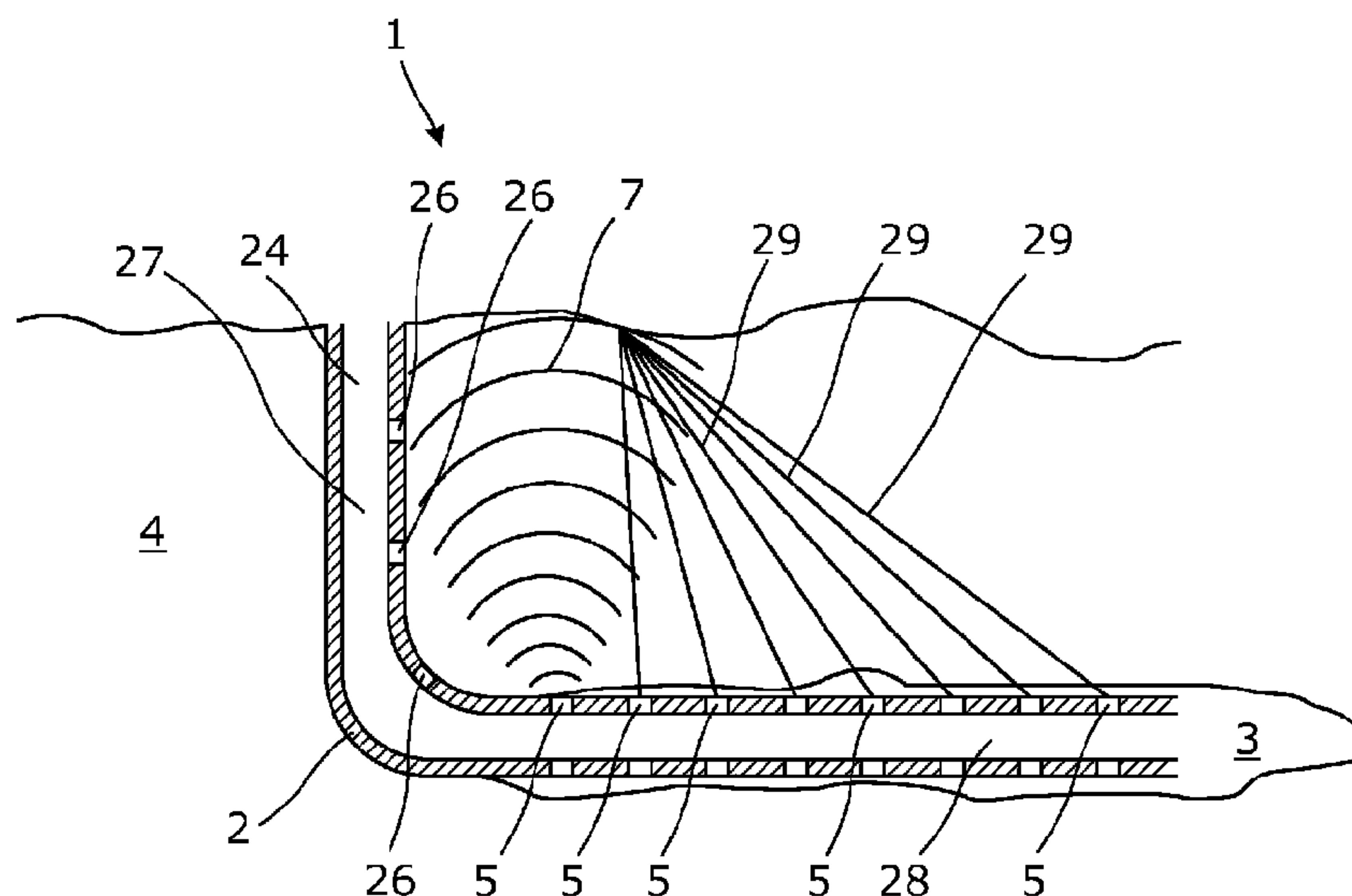
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(54) Title: A WELLBORE SURVEILLANCE SYSTEM



(57) **Abrégé/Abstract:**

The present invention relates to wellbore surveillance system for obtaining fluid reservoir information data, such as the position and amount of gas, oil and/or water, while draining hydrocarbons from an oil or gas field via a casing in a wellbore in a formation, the casing having a vertical part near a top of the casing and an inner face, the system comprising a first sensor for measuring a content of gas, oil and/or water in the formation, and a second sensor for measuring a content of gas, oil and/or water in the formation.

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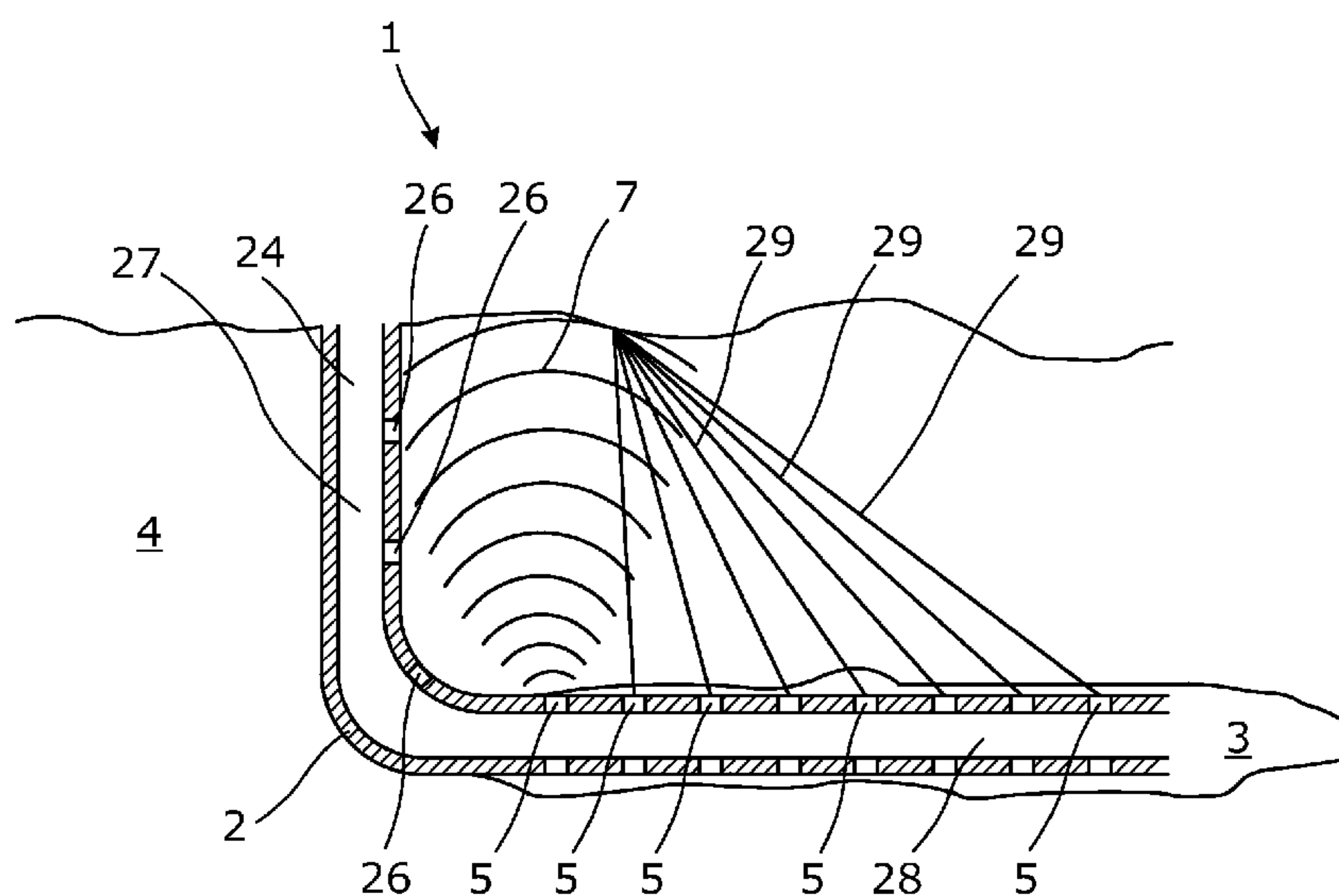


Fig. 9

(57) Abstract: The present invention relates to wellbore surveillance system for obtaining fluid reservoir information data, such as the position and amount of gas, oil and/or water, while draining hydrocarbons from an oil or gas field via a casing in a wellbore in a formation, the casing having a vertical part

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near a top of the casing and an inner face, the system comprising a first sensor for measuring a content of gas, oil and/or water in the formation, and a second sensor for measuring a content of gas, oil and/or water in the formation.

A WELLBORE SURVEILLANCE SYSTEM

Field of the invention

The present invention relates to a wellbore surveillance system for obtaining fluid reservoir information data, such as the position and quantity of gas, oil and/or water, while draining hydrocarbons from an oil or gas field via a casing in a well-bore in a formation, the casing having a vertical part near a top of the casing and an inner face, the system comprising a first sensor for measuring a content of gas, oil and/or water in the formation, and a second sensor for measuring a content of gas, oil and/or water in the formation.

Background art

Conventional reflection seismology uses surface sources and receivers to detect reflections from subsurface impedance contrasts in order to obtain data of fluid reservoir information. The obtained image often suffers in spatial accuracy, resolution and coherence due to the long travel paths between source, reflector, and receiver. To overcome this difficulty, a technique commonly known as vertical seismic profiling was developed to image the subsurface in the vicinity of a bore-hole. By this method, a surface seismic source is placed in the drilling tool, and signals are received by a single downhole receiver or an array of downhole receivers within the same drilling tool. This step is repeated for different depths of the receiver (or receiver array). This method is used for drilling but is also suitable for obtaining fluid reservoir information data in the subsequent production optimising process.

Another known method is to arrange an array of seismic sensors distributed along jointed tubulars (e.g. drill pipe or coiled tubing) to determine the physical condition of the drill string and whether drilling may be optimised. The seismic sensors are configured to detect seismic energy imparted into the adjacent formation by a wellbore source or surface source. This method is used for drilling but is also suitable for obtaining fluid reservoir information data in the subsequent production optimising process.

In addition, an optical fibre can be arranged in the well in order to obtain temperature data of the fluid in the vicinity of the well but not fluid reservoir information data, such as the position and quantity.

5 Description of the invention

It is an object of the present invention to wholly or partly overcome the above disadvantages and drawbacks of the prior art. More specifically, it is an object to provide a method and a system for obtaining fluid reservoir information data,
10 such as the position and the amount of gas, oil and water, while draining hydrocarbons from an oil or gas field.

The above objects, together with numerous other objects, advantages, and features, which will become evident from the below description, are accomplished by
15 a solution in accordance with the present invention by a wellbore surveillance system for obtaining fluid reservoir information data, such as the position and amount of gas, oil and/or water, while draining hydrocarbons from an oil or gas field via a casing in a wellbore in a formation, the casing having a vertical part near a top of the casing and an inner face, the system comprising:
20 - a first sensor for measuring a content of gas, oil and/or water in the formation, and
- a second sensor for measuring a content of gas, oil and/or water in the formation,
wherein the first and the second sensors are arranged at least partly in a casing
25 wall of the casing, and the second sensor is arranged at a distance from the first sensor.

Having two sensors at a distance from one another makes it possible for one sensor to send out a signal in the formation and for the other sensor to detect the
30 response from that signal. In this way, fluid reservoir information data can be obtained.

The wellbore surveillance system according to the invention may further comprise a second casing arranged in a second wellbore and comprising a first sensor for
35 measuring a content of gas, oil and/or water in the formation, and a second sensor for measuring a content of gas, oil and/or water in the formation, wherein the first and the second sensors are arranged at least partly in a casing wall of the

second casing, and the second sensor is arranged at a distance from the first sensor.

5 In one embodiment of the invention, the casing may have a second part more horizontal than the first part, and the sensors may be arranged in this second part.

10 By arranging the sensors in the second, more horizontal part, fluid reservoir information data can be obtained from a larger distance than with known measuring tools lowered into a well.

Furthermore, the system may have more than five sensors, preferably more than ten sensors, and more preferably more than twenty sensors.

15 In one embodiment, the first sensor may comprise at least one transmitter of a first signal, at least one receiver receiving the first signal and/or a second signal, and at least one transferring device, and the second sensor may comprise at least one transmitter of the second signal, at least one receiver of the first signal and/or the second signal, and at least one transferring device.

20

When each sensor has a transmitter and a receiver, the system may still function if one transmitter or receiver in a sensor breaks down.

25 In another embodiment, the sensors may be arranged in an opening in the inner face of the wall of the casing or a through-hole in the wall of the casing.

Moreover, the sensors may be arranged in the wall of the casing, forming part of an outer face of the casing and in contiguity with the well fluid and/or the formation.

30

Also, the sensors may extend from the inner face of the casing and into the formation surrounding the casing.

Further, the transmitter may be an acoustic transmitter.

35

In one embodiment, the acoustic transmitter may comprise a hammer or a weight.

Additionally, the acoustic transmitter may comprise a motor for pulling the weight in one direction and releasing the weight which, by means of a spring means, is forced in a second direction opposite the first direction towards the formation to abut the formation.

5

Furthermore, the receiver may comprise an acoustic receiver.

In one embodiment, the acoustic receiver may be an accelerometer.

10 In another embodiment, the receiver may comprise a motor for pulling the acoustic receiver in one direction and subsequently forcing the acoustic receiver, by means of a spring means, in a second direction opposite the first direction towards the formation to abut the formation.

15 In addition, the motor may pull the weight or the acoustic receiver in one direction by means of a rotating shaft.

Also, the acoustic receiver may be a microphone.

20 Furthermore, the first sensor may comprise a first and a second electrode for providing a current flowing from the first electrode to the second electrode to conduct a resistivity measurement or a conductivity measurement of the formation in order to determine the content of gas, oil and/or water in the formation.

25 Moreover, the sensor may comprise a microchip for transforming the signal or the resistivity or conductivity measurement into data and/or for storing and/or transferring the data, or for storing a representation of the data.

The present invention as described above may further comprise at least one tool
30 comprising a communication device for receiving data from the transferring devices when the tool is in the casing.

Also, the present invention may comprise at least one tool comprising an acoustic transmitter having a weight connected with a rotatable shaft rotated by a motor
35 in the tool.

Further, the tool may comprise an anchor section for anchoring the tool within the casing.

5 In one embodiment, the anchor section may comprise at least a first anchor extending in a first radial direction of the tool and a second anchor extending in a second direction opposite the first direction, the extension of the anchors from an outer face of a tool housing varying so that the tool is anchored in an eccentric relationship to the casing.

10 Furthermore, the tool may comprise a driving unit, such as a downhole tractor.

In one embodiment, the tool may comprise means for making a cavity in the casing. The means for making a cavity may be a drilling unit.

15 Moreover, the tool may comprise means for arranging a sensor in the cavity.

In one embodiment, the means for arranging the sensor in the cavity may be a rotating arm for rotating the sensor so that a thread of the sensor engages a thread in the cavity.

20

In addition, the transferring device and the communication device in the tool may use radio frequency for transferring data to the tool.

25 Moreover, the transmitter and the receiver of the sensor may be integrated as one unit.

Additionally, the transferring device may comprise a radio frequency identification tag, and the communication device may comprise a radio frequency identification reader.

30

In an embodiment of the invention, the sensor may comprise a battery for powering at least the transmitter and the receiver.

35 Furthermore, the tool may be connected with a wireline for powering the tool and for transmitting data to above the wellbore.

In addition, the tool may comprise a battery for powering the tool.

Moreover, the tool or the communication device may comprise a powering device for powering the sensor.

5 In another embodiment, the powering device and the sensor may comprise an inductive coupling for transferring power from the tool to the sensor through induction.

10 Furthermore, the inductive coupling may be used for transferring data from the sensor to the tool.

Additionally, the sensor may comprise a processor for transforming the signal or the resistivity or conductivity measurement into data and/or for storing and/or transferring the data, or for storing a representation of the data.

15 In an embodiment, these signals may be generated by acoustics.

In yet another embodiment, the transferring unit in one sensor may have a wireless communication means for communicating wirelessly with another wireless communication means in another sensor or with a wireless communication means in a communication device arranged closer to the top of the casing.

20

Moreover, the system may comprise several communication devices arranged at a predetermined mutual distance along the casing to the top of the casing, the distance being determined by the distance over which two devices are capable of communicating wirelessly with each other.

25

In addition, the system may comprise several sensors with wireless communication means arranged at a predetermined mutual distance along the casing to the top of the casing, the distance being determined by the distance over which two devices are capable of communicating wirelessly with each other.

30

Also, the system may comprise a hammering device arranged at surface or seabed for transmitting acoustic waves into the formation.

35 Additionally, the signal may be a low frequency acoustic or sonic signal at a frequency of 1 Hz-100 kHz, preferably 10-50 kHz, and more preferably 15-35 kHz.

Furthermore, the invention relates to a downhole tool for reading the data of the sensors in the downhole system as described above, wherein the tool may comprise driving means, such as wheels, for driving the tool forward in the casing, and a communication device as described above.

5

The present invention further relates to a method for installing the system as described above, comprising the steps of:

- providing a number of cavities at a distance from one another in the casing in the wellbore, and
- 10 - arranging the sensors in the wellbore surveillance system according to the invention in the cavities.

The method may further comprise the step of positioning a tool downhole outside a sensor in order to transfer fluid reservoir information data from the sensor to the tool.

15

In addition, the method may further comprise the steps of loading power from the tool to the sensor, transmitting a signal by means of the transmitter or providing a current from the first electrode, receiving the signal by means of the receiver or receiving the current by means of the second electrode, transforming the signal or current into data, and transferring data from the sensor to the tool.

20

Furthermore, the present invention relates to a production optimising method, comprising the steps of:

25

- transmitting a first signal by means of a first transmitter of the sensors in the wellbore surveillance system according to the invention,
- receiving the first signal by means of several receivers,
- transforming the first signal into data,
- 30 - transferring data from the sensor to a neighbouring sensor and to communication devices all the way to surface,
- transmitting a second signal by means of a second transmitter of the sensors at a predetermined period of time from the transmission of the first signal,
- receiving the second signal by means of several receivers,
- 35 - transforming the second signal into data, and
- transferring data from the sensor to a neighbouring sensor and to communication devices all the way to surface.

Said production optimising method may further comprise the steps of:

- exciting the formation by transmitting acoustic waves into the formation by means of several sensors at a time to enhance production of fluid into the well-bore,
- 5 - measure an impact of the exciting of the formation by transmitting a signal by means of one transmitter of the sensors,
- receiving the signal by means of several receivers,
- transforming the signal into data,
- transferring data from the sensor to a neighbouring sensor and to communica-
10 tion devices all the way to surface.

Also, the production optimising method according to invention may further comprise the steps of lowering a logging tool into the casing and logging the content of gas, oil and/or water in the fluid in the casing.

15

Finally, the production optimising method according to the invention may further comprise the steps of storing data from the sensors of several wells and processing the data into a three-dimensional model of the formation with regard to the content of gas, oil and/or water in the formation.

20

Brief description of the drawings

The invention and its many advantages will be described in further detail below with reference to the accompanying schematic drawings, which for the purpose of
25 illustration show some non-limiting embodiments and in which

Fig. 1 shows a wellbore surveillance system arranged in a casing downhole,

Fig. 2 shows a sensor according to the invention,

30

Fig. 3 shows another embodiment of the sensor,

Fig. 4 shows yet another embodiment of the sensor,

35 Fig. 5 shows yet another embodiment of the sensor,

Fig. 6 shows yet another embodiment of the sensor,

Fig. 7 shows a partial view of the system,

Fig. 8 shows a partial view of another embodiment of the system, and

5

Fig. 9 shows yet another embodiment of the system.

All the figures are highly schematic and not necessarily to scale, and they show only those parts which are necessary in order to elucidate the invention, other parts being omitted or merely suggested.

10

Detailed description of the invention

Fig. 1 shows a wellbore surveillance system 1 for obtaining fluid reservoir information data. When the formation 4 is drained of oil, the oil layer decreases, and the water becomes dominating. The oil runs up through a production casing 2, and eventually, the water will enter into the production casing and disturb the production of oil. In order to prevent the water from destroying the oil production, it is desirable to obtain information about the fluid reservoir and the amount and position of gas, oil and water while draining hydrocarbons from an oil or gas field. In order to be able to obtain such data, the system comprises at least two sensors 5. One sensor 5 sends out a signal 7 in the formation 4, and the response 29 is received by the other sensor or the same sensor. Having several sensors 5 makes it possible to obtain more detailed information about the reservoir by comparing the data from one sensor 5 with the data from another sensor. The system shown in Fig 1 comprises eight sensors 5 arranged with a mutual distance between them and spread out along the substantially horizontal part of the casing 2.

When the signal 7 passes the different layers of oil, gas and water, it changes, and these are the changes detected by the sensors 5 as a response. In order to analyse the data obtained by the sensors 5, a downhole tool 13 is lowered into the casing 2. The data is transferred from the sensors 5 to the tool 13, and when the tool reaches the surface, the data is analysed to obtain a profile of the layers of water, gas and oil.

35

The signal 7 transmitted is an acoustic signal, such as the signal used in seismic analysis. Seismic analysis pertains to waves of elastic energy, such as that

transmitted by P-waves and S-waves, in the frequency range of approximately 1 to 100 Hz. Seismic energy is studied to interpret the composition, fluid content, extent and geometry of rocks in the subsurface.

- 5 The seismic data is analysed when it has been transferred from the tool 13 to an analysis system subsurface. The seismic data can be used for modelling geophysical attributes and shapes or a geologic causal model of all rock properties, such as temperature, pressure, velocity, viscosity, etc. Furthermore, the data can be used for determining petrophysical effects and for indentifying fluid traps, re-
10 serves, recovery and risk.

The tool 13 may also be connected with a wireline 16 by means of which the data is transferred to the surface. In this way, the tool can stay in the casing over a longer period of time, even during production, and the data is sent to the surface
15 almost immediately after it has been transferred to the tool 13. The tool 13 is powered by the wireline, but may also be powered by a battery 17.

As can be seen in Fig. 1, the tool 13 has wheels 23 for driving the tool forward in the casing 2, and when the tool reaches a position opposite a sensor 5, the data
20 is unloaded. Subsequently, the tool 13 moves on to the next sensor 5 to unload data from that sensor and so forth.

The sensor 5 has a transmitter 6 for transmitting a first signal 7 and a receiver 8 for receiving the first signal. The receiver 8 in a first sensor 5 receives both the
25 response of a signal 7 sent from the transmitter 6 of the first sensor 5 and the response of a signal sent from the transmitter of a second sensor. Furthermore, the sensor 5 comprises a transferring device 9 to be able to transfer data away from the sensor. The sensor 5 is arranged in the casing wall 30 in a bore. The sensor 5 is fastened in the bore by means of threads or snap-fit fasteners.

30

The sensor 5 of Fig. 2 is powered by the tool 13 when it is positioned opposite the sensor in the casing 2. While the tool 13 powers the sensor 5, the sensor is able to transmit and receive signals 7 to obtain fluid reservoir information, and the information received from the receiver 8 is transferred to the tool 13 as it is
35 received by the receiver. Then, the tool 13 moves to the next sensor 5, and the operation is repeated.

The sensor 5 in Fig. 3 comprises a microchip 12, such as a microcontroller, for transforming the response received by the receiver 8 into digital data. The microcontroller comprises static RAM for storing the data. The sensor 5 comprises a transferring device 9 for transferring the data to the tool 13, which in this embodiment comprises an inductive coupling 19 matching an inductive coupling 20 of the tool 13 for transferring the data by means of inductance. The sensor 5 also has a battery 15 for powering the sensor over a period of time. In this way, the sensor 5 is able to perform measurements on the fluid reservoir without the tool 13 being present. The sensor 5 is programmed, e.g. by means of a timer, to conduct a measurement each time a predetermined period of time has passed and to store the data until it can be transferred to the tool 13 or another device.

As shown in Fig. 4, the sensor 5 comprises a wireless communication means 25 for communicating wirelessly with another sensor, the tool 13 or another communication device. The sensor 5 in Fig. 4 has two electrodes 10, 11 instead of a transmitter 6 and a receiver 8. The electrodes 10, 11 are used for resistivity or conductivity logging or measurements. When measuring the resistivity, a current is passed between the two electrodes, and the potential drops between them provide the resistivity of the fluid present in the formation 4. When measuring the conductivity, a current is induced in the formation, and the capacity to carry the current is observed. By resistivity or conductivity measurement is meant the response measured by the sensor 5, e.g. the capacity or the potential drop.

In Figs. 2-4, the sensor 5 is arranged in a through-hole in the casing 2, but the sensor may also be positioned in a cavity in the casing, as shown in Fig. 5. When the sensor 5 is arranged in only part of the casing 2, the sensor itself does not have to withstand the pressure difference between the annulus and the inside of the casing.

The sensor 5 of Fig. 5 comprises a battery 15, an inductive coupling 19 and a processor 21 in which the memory and a communication means in the form of an input/output interface are arranged. The inductive coupling 19 and the battery 15 may be arranged in one unit. The processor 21 may also comprise a radio frequency identification device (RFID) to be read by a radio frequency identification reader in the communication device 26 of the tool 13.

In Fig. 6, the system also comprises a valve 31, such as an inflow control valve, arranged adjacent to the sensor 5, enabling signals 7 from the sensor to close the valve if measurements show that the water layer is too close to the sensor and thereby the valve. In this way, the valve 31 is shut off before letting water
5 into the casing 2. The tool 13 of the system 1 moves inside the casing 2 in order to read data from the sensors 5 and subsequently transfer the data to the surface. The tool 13 in Fig. 7 comprises wheels 23 for moving within the casing 2, but may as well comprise other driving means, such as a caterpillar track, legs or similar means. The tool 13 is powered through a wireline 16 for powering a motor
10 driving a pump and thereby the wheels 23. The tool 13 comprises a communication device 14 for transferring data from the sensor 5. When the communication device 14 is positioned opposite the sensor 5, the data can be transferred.

The tool of Fig. 7 also comprises a powering device 18 for powering the sensor, if
15 needed. If the sensor 5 does not have its own power, the tool 13 can transfer power to the sensor, which then performs a measurement, and the data is thus transferred to the tool 13 without being stored in the sensor first. In this way, the sensor 5 can be a very simple sensor with very few components. One way of transferring power to the sensor 5 is to use an inductive coupling 20 interacting
20 with an inductive coupling 19 in the sensor 5. The power may also be transferred to the sensor 5 in another suitable way, such as by mean of microwaves, infrared light or lasers.

The tool 13 may also hold its own power by comprising a battery 17, as shown in
25 Fig. 8. In this event, the tool 13 may stay in the casing 2 for a period of time when all the sensors 5 have been read several times and then emerge to the surface for data unloading. The legs holding the wheels 23 have been retracted in the tool of Fig. 8, enabling the tool to rest against the inner surface of the casing 2 and thus against the outer surface of the sensor 5. This facilitates more efficient transferral of data from the sensor 5 and/or power to the sensor. If needed,
30 the tool 13 may have a connection means for providing a direct electrical connection with the sensor 5.

In Fig. 9, the system 1 comprises several communication devices 26 distributed
35 along the casing 2 from the last sensor 5 to the top of the well. In this way, the wireless communication means 25 of the sensors 5 can transfer data to the next sensor or to the communication device 26 if the communication device is next in

line. The communication device 26 then communicates the data to the next communication device and so forth until the data reaches to top of the casing 24 or well. By having the communication devices 26, a tool 13 is not needed for obtaining the data in each sensor 5.

5

The wireless communication may occur by means of radio frequency communication, electromagnetic communication, WIFI, or by acoustic waves transmitted through the casing wall.

10 As can be seen in Fig. 10, the wellbore surveillance system may further comprise a second casing 50 arranged in a second wellbore and comprising a plurality of sensors for measuring a content of gas, oil and/or water in the formation, which are arranged at least partly in the casing wall of the second casing at a distance from each other. In this way, a first signal 7 transmitted by one transmitter 6 in a
15 sensor 5 in the first casing 2 can be received by a receiver in a sensor in the second casing 50. The signal has thus passed through the formation about which knowledge of the content of gas, oil and/or water is desired, and a system having sensors in two neighbouring casings provides more accurate data than a system having only one casing 2. The second casing 50 also comprises several communication devices 26 distributed along the casing 2 from the last sensor 5 to the top
20 of the well.

In the event that the transmitter in the sensors is not sufficient to transmit a strong enough signal for the receivers to receive, a tool 13 may be submerged
25 into a casing 2 as shown in Fig. 11. In order to generate a strong signal, the tool comprises an acoustic transmitter 53 comprising a weight 41 which is rotated by means of a rotatable shaft 54 to abut the casing wall and in this way transmit acoustic waves into the formation. The shaft is rotated by means of a motor 55 arranged in the tool housing. The tool comprises an anchor section 40 having an-
30 chors projecting radially from the tool housing to anchor the tool in an eccentric manner in the casing so that the distance from the tool housing to the casing wall in one direction is smaller than the distance from the tool housing to the casing wall in another direction opposite the one direction. In this way, the centre axis of the tool is offset in relation to the centre axis of the casing.

35

When the weight is rotated by the shaft, the weight hammers into the casing wall once along the inner circumference of the casing, generating one acoustic signal

per revolution of the shaft. In this way, a pattern of acoustic signals is generated which is recognisable by the sensors in the first casing and/or in the second casing 50. In another embodiment, the tool comprises a hammer generating the acoustic signal by means of a motor.

5

The signals are low frequency acoustic or sonic signals at a frequency of 1 Hz-100 kHz, preferably 10-50 kHz, and more preferably 15-35 kHz.

10 In Fig. 12, the signal transmitted into the formation is provided by a hammering device arranged at the surface or the seabed. The hammering device 51 may be arranged partly in the ground or in the formation. The signal of the hammering device is thus received by sensors in both casings or in one casing alone. The signal received in the receivers of the sensors is thus not a signal which has travelled to the surface or seabed before being received in the sensors. Before being
15 received in the receivers, the signal has only travelled more or less directly through the formation, resulting in a more accurate result.

As shown in Figs. 2-6, the sensors are arranged in an opening in the inner face of the wall of the casing or a through-hole in the wall of the casing. The sensors are
20 easily installed after completing the well by making a hole in the casing wall and inserting the sensor in that hole. The sensors may thus be arranged in the wall of the casing, forming part of an outer face of the casing and in contiguity with the well fluid and/or the formation. If the casing is cemented in, the sensors do not have to extend beyond the outer face of the casing, but if the casing is sur-
25 rounded by an annulus, the sensors may have to extend from the inner face of the casing and into the formation surrounding the casing, and thus the axial extension of the sensors are longer than the smallest thickness of the casing wall.

When the signal is an acoustic signal, the transmitter is an acoustic transmitter
30 and the receiver is an acoustic receiver 43. The acoustic transmitter 53 comprises a hammer or a weight 41. In Fig. 13, the acoustic transmitter comprises a motor 44 for pulling the weight 41 in one direction and releasing the weight which, by means of a spring means 45, is forced in a second direction opposite the first direction towards the formation to abut the formation. The weight is forced out
35 through an opening 48 in a housing 59 of the transmitter and can thus hammer against the formation, generating an acoustic signal.

The acoustic receiver 43 may be any suitable receiver such as an accelerometer, a microphone or similar acoustic receiver 43. The receiver may be a low frequency receiver of between 10-100 Hz. Not all acoustic receivers are capable of withstanding a hammering motion from a nearby transmitter without getting seriously damaged, and in such event, the receiver comprises a motor 44 for pulling the acoustic receiver 43 in one direction to ensure that the acoustic receiver is out of contact with a receiver housing 58 and that the acoustic receiver is surrounded by fluid while the weight has hammered against the formation or the casing. When the transmitter has transmitted its signal, the acoustic receiver is then forced, by means of a spring means 57, in a second direction opposite the first direction towards the formation to abut the formation and is consequently capable of receiving the signal, which is as illustrated by a dotted line in Fig. 13.

The motors of the transmitters or the receivers pull the weight or the acoustic receiver in one direction by means of a rotating shaft 46 which is rotated into the motor for pulling the weight or the acoustic receiver and forced in the opposite direction by a spring means 57 arranged between the weight or the acoustic receiver and the respective motor. The receiver comprises a tapering opening 47 to guide the acoustic receiver when forced towards the formation. Instead of a motor, an electromagnet may be arranged so when activated, the electromagnet pulls in the acoustic receiver or the weight.

The transmitter and the receiver are electronically connected via an electronic control 49 and they are in turn electronically connected via an electronic control 49 to a transferring device 9 for transferring data from this sensor to a neighbouring sensor in order to get the data upwards to the communication devices 26 and thus up to surface. As can be seen in Fig. 13, the sensor extends into the formation through the casing wall and the annulus or wellbore 3.

The communication devices 26 distributed along the casing can thus also be used for sending control signals down to the sensors in order to control which transmitter is transmitting a signal. In another embodiment, the sensors comprise a timer for controlling when a transmitter is to send a signal and when the receivers are to receive that signal. The sensors may be equipped with timers with programmed, predetermined intervals prescribing when to activate the sensor and when to also activate the transmitter of that sensor. The sensors may thus be pre-programmed prior to installation following a surveillance plan according to

which the sensors are activated once a year, half a year or whatever is appropriate. In this way, it is not necessary to submerge a tool in order to activate the sensors. Instead, the sensors activate themselves according to their programming and then send their data up to surface.

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In Fig. 1, the sensors 5 are arranged in the casing wall 30 so that only one sensor is arranged in the same circumferential plane of the casing. The sensors 5 may also be arranged in the same circumferential plane of the casing 2 and have a circumferential distance to one another, as shown in Fig. 9.

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The wellbore surveillance system may furthermore be used as formation logging method comprising the steps of transmitting a first signal by means of a first transmitter of one sensor, receiving the first signal sent by that sensor by means of several receivers in other sensors. Subsequently, the first signal is transformed into data and the data is transferred from the sensor to a neighbouring sensor. This step of transferring data is repeated until the data reaches the sensor closest to the top of the well, and then that sensor transfers the data to a communication device which again transfers the data to the next communication device all the way to surface. While doing so, a second signal is transmitted by means of a second transmitter of the sensors at a predetermined period of time from the transmission of the first signal, which is received by means of several receivers, and subsequently the data is transformed and sent to the surface in the same way as the first signal. By receiving the same signal in several receivers, the data can be processed so that a representation of how the oil, gas and water lie in layers or zones in the formation can be made.

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If the representation of how the oil, gas and water lie in layers or zones in the formation shows that a zone close to the production zone has an elevated concentration of water, a production optimising method can be executed. The production optimisation method comprises the steps of exciting the formation by transmitting acoustic waves into the formation by means of several sensors simultaneously, thereby enhancing production of fluid into the wellbore. In this way, the formation and the fluid comprised therein are oscillated so that the water is partially levelled out, if not fully levelled out, thereby aiding the oil in entering the production zone of the casing, thereby displacing the water locally outside the casing. Subsequently, the impact of the exciting of the formation is measured by transmitting a signal by means of one transmitter of the sensors, the signal is

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received by means of several receivers, and so forth as explained above, to provide a representation of the oil, water and gas layers or zones.

5 In order to evaluate the impact of the exciting of the formation inside the casing, a logging tool is lowered into the casing and the content of gas, oil and/or water in the fluid in the casing is logged or measured, e.g. by means of a capacitance.

10 In order to present the data, the data from the sensors of several wells are stored and processed into a three-dimensional model of the formation with regard to the content of gas, oil and/or water in the formation. All data have a time stamp indicating at which time the signal was received, and from that time stamp, the data can be mapped and a three-dimensional modal can be made showing a representation of all the data from all the sensors of one or more wells.

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By fluid or well fluid is meant any kind of fluid which may be present in oil or gas wells downhole, such as natural gas, oil, oil mud, crude oil, water, etc. By gas is meant any kind of gas composition present in a well, completion, or open hole, and by oil is meant any kind of oil composition, such as crude oil, an oil-containing fluid, etc. Gas, oil, and water fluids may thus all comprise other elements or substances than gas, oil, and/or water, respectively.

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By a casing is meant any kind of pipe, tubing, tubular, liner, string, etc. used downhole in relation to oil or natural gas production.

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In the event that the system is not submergible all the way into the casing, a downhole tractor can be used to push the system all the way into position in the well. A downhole tractor is any kind of driving tool capable of pushing or pulling tools in a well downhole, such as a Well Tractor®.

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Although the invention has been described in the above in connection with preferred embodiments of the invention, it will be evident for a person skilled in the art that several modifications are conceivable without departing from the invention as defined by the following claims.

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Claims

1. A wellbore surveillance system for obtaining fluid reservoir information data while draining hydrocarbons from an oil or gas field via a first casing in a wellbore in a formation, the first casing having a vertical part near a top of the first casing and an inner face, the system comprising:
 - a first sensor for measuring a content of gas, oil and/or water in the formation, and
 - a second sensor for measuring a content of gas, oil and/or water in the formation,
 wherein the first and the second sensors are arranged at least partly in a casing wall of the first casing, and the second sensor is arranged at a distance from the first sensor, wherein the system further comprises a second casing arranged in a second wellbore and comprising:
 - a first sensor for measuring a content of gas, oil and/or water in the formation, and
 - a second sensor for measuring a content of gas, oil and/or water in the formation,
 wherein the first and the second sensors are arranged at least partly in a casing wall of the second casing, and the second sensor is arranged at a distance from the first sensor, wherein the first and second sensors of each of the first and second casings each comprise:
 - at least one transmitter of a first signal
 - at least one receiver receiving the first signal and/or a second signal, and
 - at least one transferring device
 wherein the system comprises wireless communication devices arranged at a predetermined mutual distance along the first casing and the second casing to the top of the casing, the distance being determined by the distance over which two devices are capable of communicating wirelessly with each other, wherein the second casing is arranged at a distance from the first casing so that a first signal transmitted by one transmitter in one of the first and second sensors in the first casing can be received by the receiver in one of the first and second sensors in the second casing.
2. A wellbore surveillance system according to claim 1, wherein the sensors are arranged in an opening in the inner face of the wall of the casing or a through-hole in the wall of the casing.

3. A wellbore surveillance system according to claim 1 or 2, wherein the sensors are arranged in the wall of the casing forming part of an outer face of the casing and in contiguity with the well fluid and/or the formation.
- 5 4. A wellbore surveillance system according to claim 1 or 2, wherein the sensors extend from the inner face of the casing and into the formation surrounding the casing.
- 10 5. A wellbore surveillance system according to any one of claims 1-4, wherein the transmitter is an acoustic transmitter.
6. A wellbore surveillance system according to claim 5, wherein the acoustic transmitter comprises a hammer or a weight.
- 15 7. A wellbore surveillance system according to claim 5, wherein the acoustic transmitter comprises a motor for pulling the weight in one direction and releasing the weight which, by means of a spring means, is forced in a second direction opposite the first direction towards the formation to abut the formation.
- 20 8. A wellbore surveillance system according to any one of claims 1-7, wherein the receiver comprises an acoustic receiver.
9. A wellbore surveillance system according to any one of claims 1-8, wherein
- 25 the acoustic receiver is an accelerometer.
10. A wellbore surveillance system according to any one of claims 1-9, wherein the receiver comprises a motor for pulling the acoustic receiver in one direction and subsequently forcing the acoustic receiver, by means of a spring means, in a
- 30 second direction opposite the first direction towards the formation to abut the formation.
11. A wellbore surveillance system according to any one of claims 1-4, wherein the first sensor comprises a first and a second electrode for providing a current
- 35 flowing from the first electrode to the second electrode to conduct a resistivity measurement or a conductivity measurement of the formation in order to determine the content of gas, oil and/or water in the formation.

12. A wellbore surveillance system according to any one of claims 1 or 2, wherein the sensor comprises a microchip for transforming the signal or the resistivity or conductivity measurement into data and/or for storing and/or transferring the data, or for storing a representation of the data.

13. A wellbore surveillance system according to any one of claims 1-12, further comprising at least one tool comprising a communication device for receiving data from the transferring devices when the tool is in the casing.

14. A wellbore surveillance system according to claim 13, wherein the tool or the communication device comprises a powering device for powering the sensor, and the powering device and the sensor comprise an inductive coupling for transferring power from the tool to the sensor through induction, the inductive coupling being used for transferring data from the sensor to the tool.

15. A wellbore surveillance system according to any one of claims 1-14, wherein the sensor comprises a processor for transforming the signal into data and/or for storing and/or transferring the data, or for storing a representation of the data.

16. A wellbore surveillance system according to claim 14, wherein the inductive coupling is used for transferring data from the sensor to the tool.

17. A wellbore surveillance system according to any one of claims 1-16, wherein the sensor comprises a processor for transforming the signal or the resistivity or conductivity measurement into data and/or for storing and/or transferring the data, or for storing a representation of the data.

18. A wellbore surveillance system according to any one of claims 1-17, wherein the signals are generated by acoustics.

19. A wellbore surveillance system according to any one of claims 1-18, wherein the system comprises several communication devices arranged at a predetermined mutual distance along the casing to the top of the casing, the distance being determined by the distance over which two devices are capable of communicating wirelessly with each other.

20. A wellbore surveillance system according to any one of claims 1-19,
 wherein the system comprises several sensors with wireless communication
 means arranged at a predetermined mutual distance along the casing to the top
 5 of the casing, the distance being determined by the distance over which two de-
 vices are capable of communicating wirelessly with each other.

21. A wellbore surveillance system according to any one of claims 1-20,
 wherein the system comprises a hammering device arranged at surface or sea-
 10 bed for transmitting acoustic waves into the formation.

22. A wellbore surveillance system according to any one of claims 1-21,
 wherein the signal is a low frequency acoustic or sonic signal at a frequency of
 1 Hz-100 kHz, preferably 10-50 kHz, and more preferably 15-35 kHz.

15 23. A downhole tool for reading the data of the sensors in the wellbore sur-
 veillance system according to any one of claims 1-22, wherein the tool comprises
 driving means, such as wheels, for driving the tool forward in the casing, and a
 communication device according to any one of claims 1-22.

20 24. A method for installing the system according to any one of claims 1-22,
 comprising the steps of:
 - providing a number of cavities at a distance from one another in the casing in
 the wellbore, and
 25 - arranging the sensors in the wellbore surveillance system according to any one
 of claims 1-22 in the cavities.

25. A method according to claim 24, further comprising the steps of:
 - positioning a tool downhole outside a sensor in order to transfer fluid reservoir
 30 information data from the sensor to the tool
 - loading power from the tool to the sensor,
 - transmitting a signal by means of the transmitter or providing a current from
 the first electrode,
 - receiving the signal by means of the receiver or receiving the current by means
 35 of the second electrode,
 - transforming the signal or current into data, and
 - transferring data from the sensor to the tool.

26. A production optimising method, comprising the steps of:
- transmitting a first signal by means of a first transmitter of the sensors in the wellbore surveillance system according to any one of claims 1-22,
 - 5 - receiving the first signal by means of several receivers,
 - transforming the first signal into data,
 - transferring data from the sensor to a neighbouring sensor and to communication devices all the way to surface,
 - transmitting a second signal by means of a second transmitter of the sensors at
 - 10 a predetermined period of time from the transmission of the first signal,
 - receiving the second signal by means of several receivers,
 - transforming the second signal into data, and
 - transferring data from the sensor to a neighbouring sensor and to communication devices all the way to surface.
 - 15
27. A production optimising method according to claim 26, further comprising the step of:
- exciting the formation by transmitting acoustic waves into the formation by means of several sensors at a time to enhance production of fluid into the well-
 - 20 bore,
 - measuring an impact of the exciting of the formation by transmitting a signal by means of one transmitter of the sensors,
 - receiving the signal by means of several receivers,
 - transforming the signal into data,
 - 25 - transferring data from the sensor to a neighbouring sensor and to communication devices all the way to surface.
28. A production optimising method according to claim 26 or 27, further comprising the steps of lowering a logging tool into the casing and logging the
- 30 content of gas, oil and/or water in the fluid in the casing.
29. A production optimising method according to any one of claims 26-28, further comprising the steps storing data from the sensors of several wells and processing the data into a three-dimensional model of the formation with regard
- 35 to the content of gas, oil and/or water in the formation.

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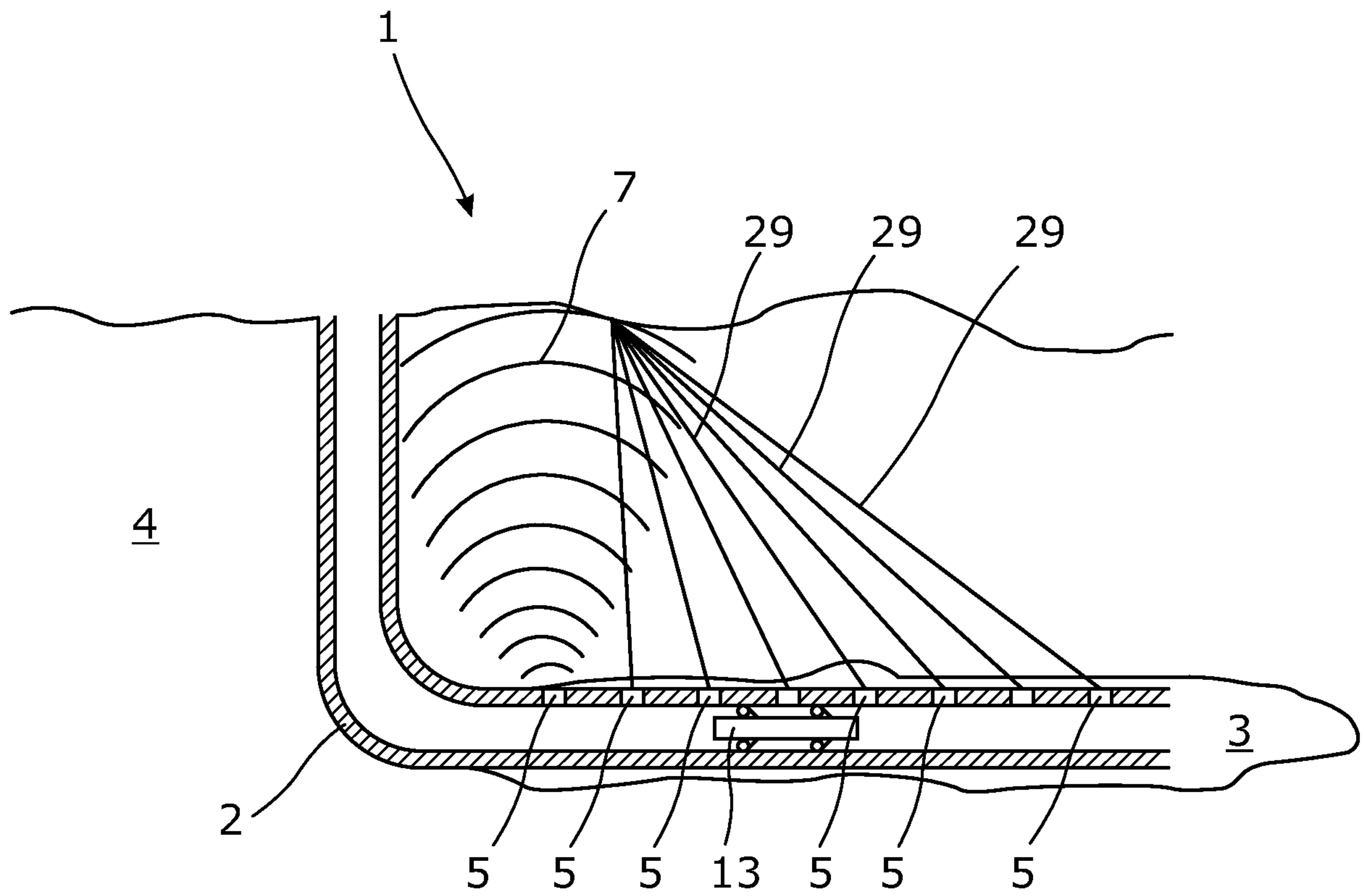


Fig. 1

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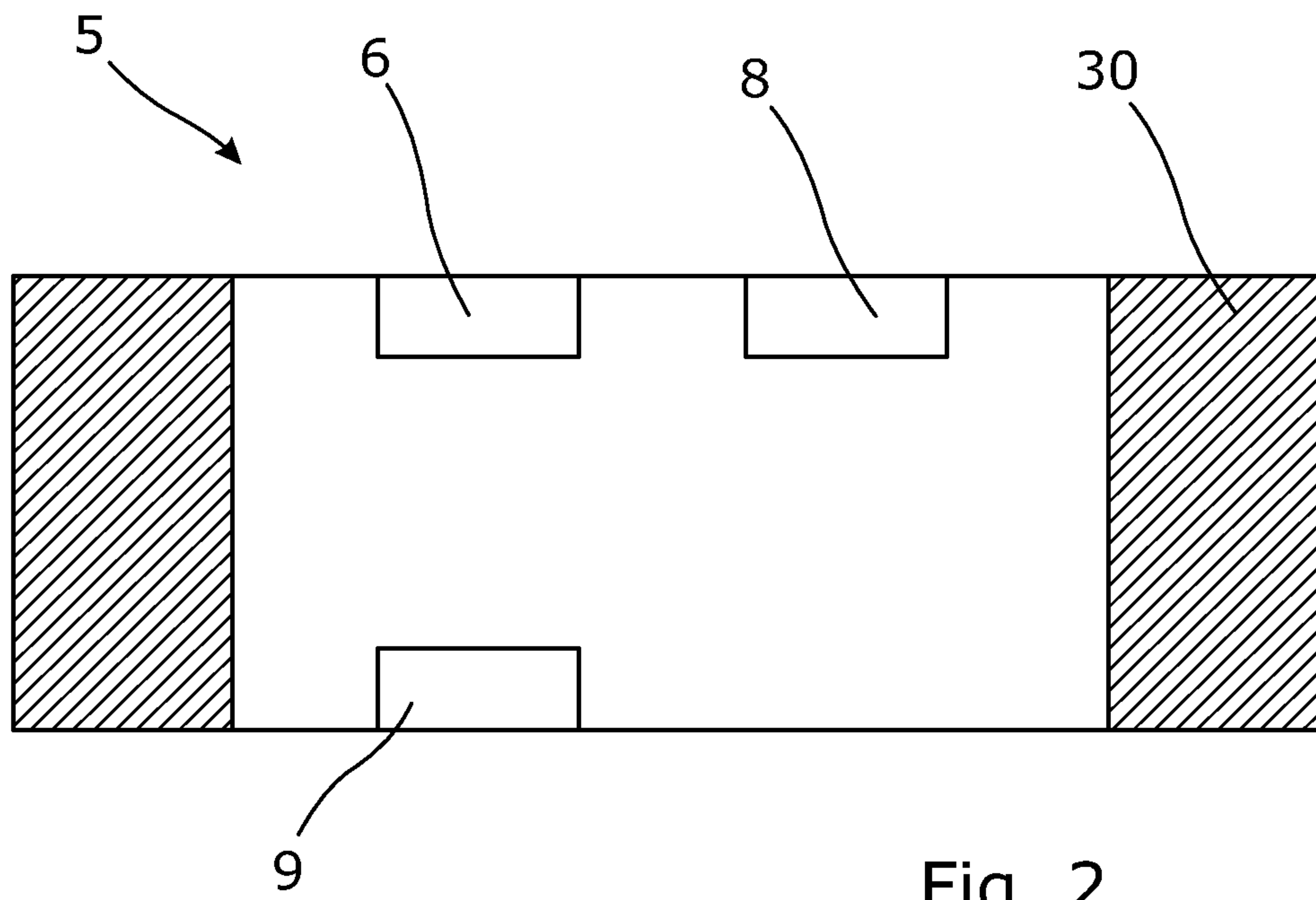


Fig. 2

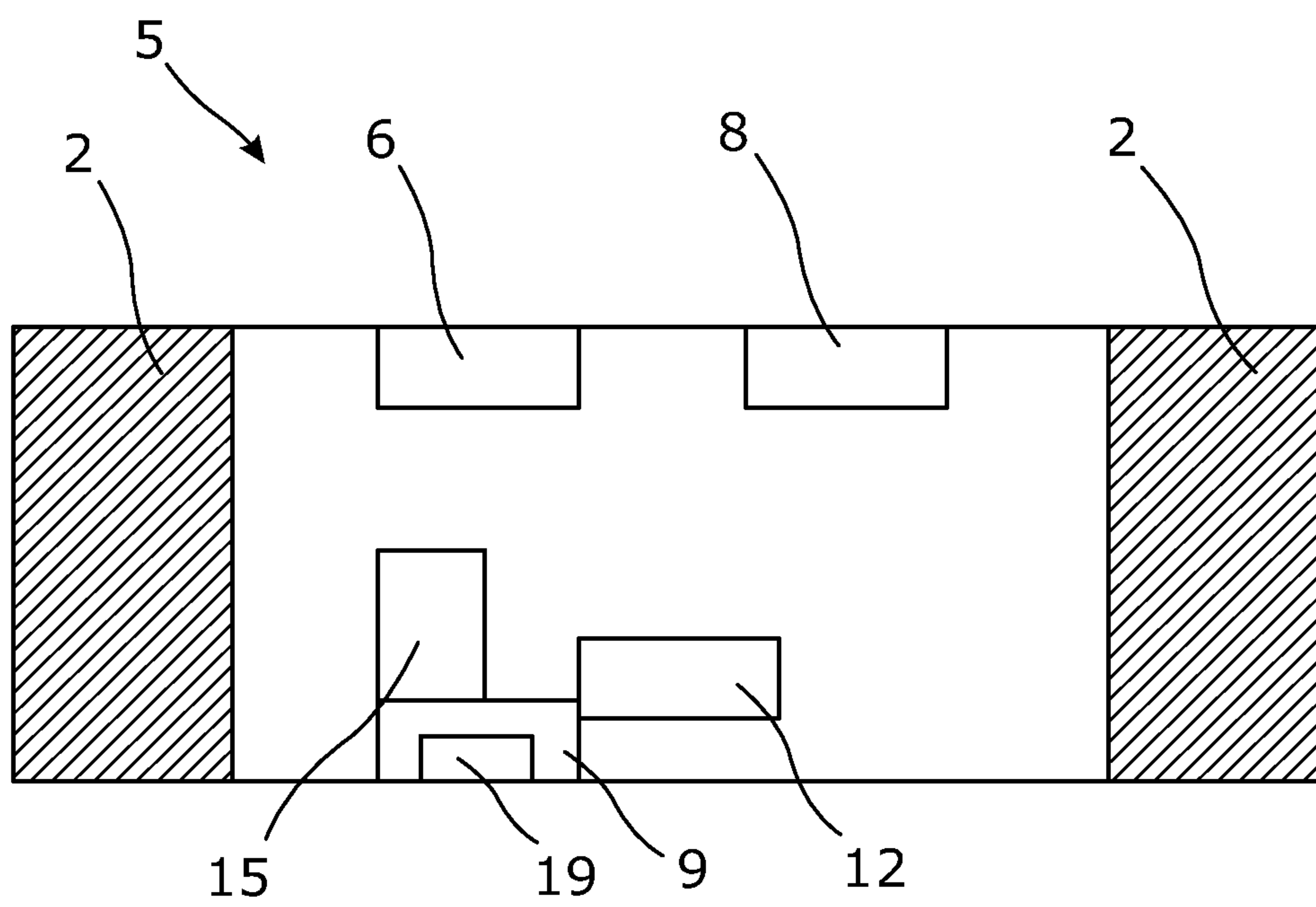


Fig. 3

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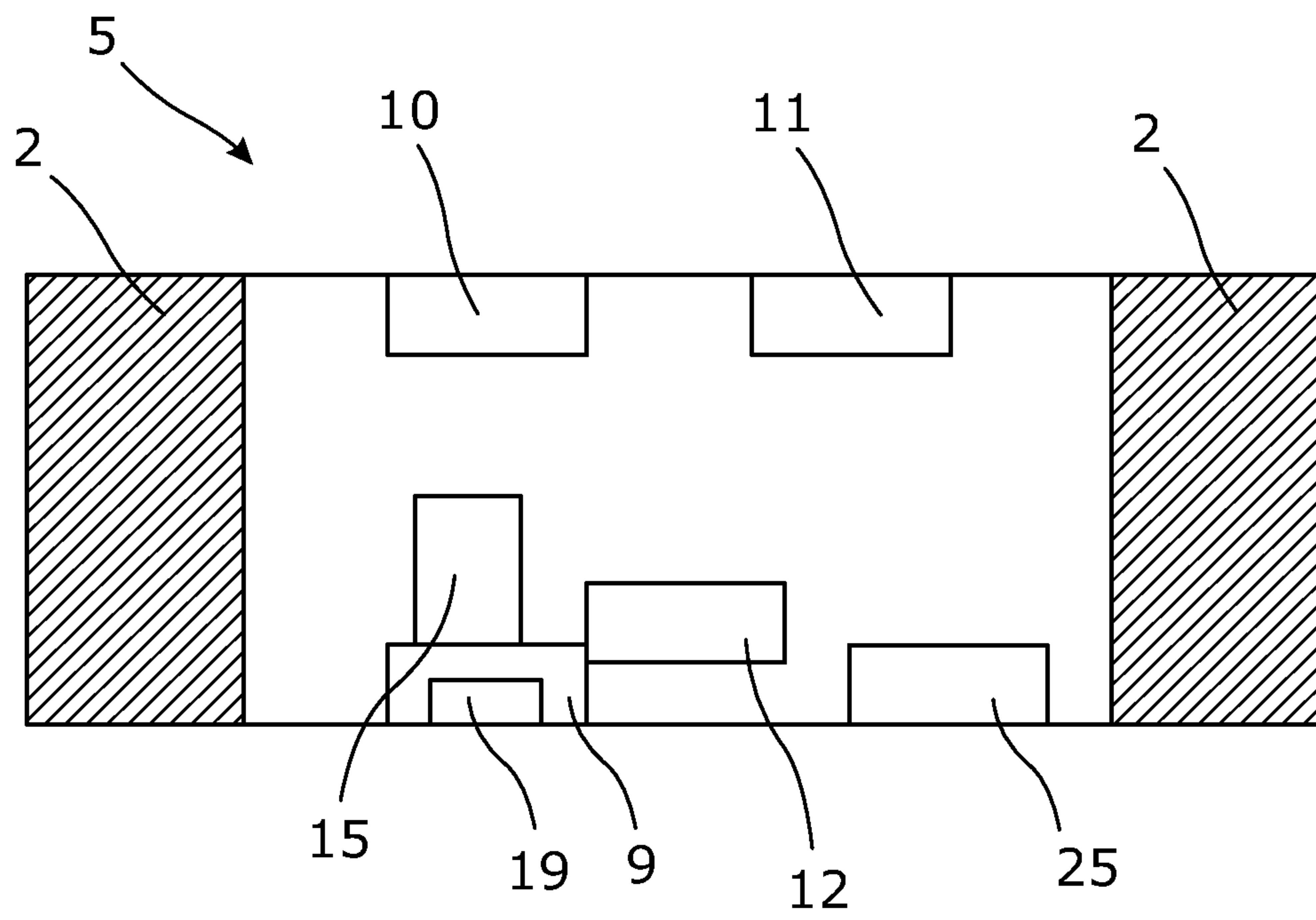


Fig. 4

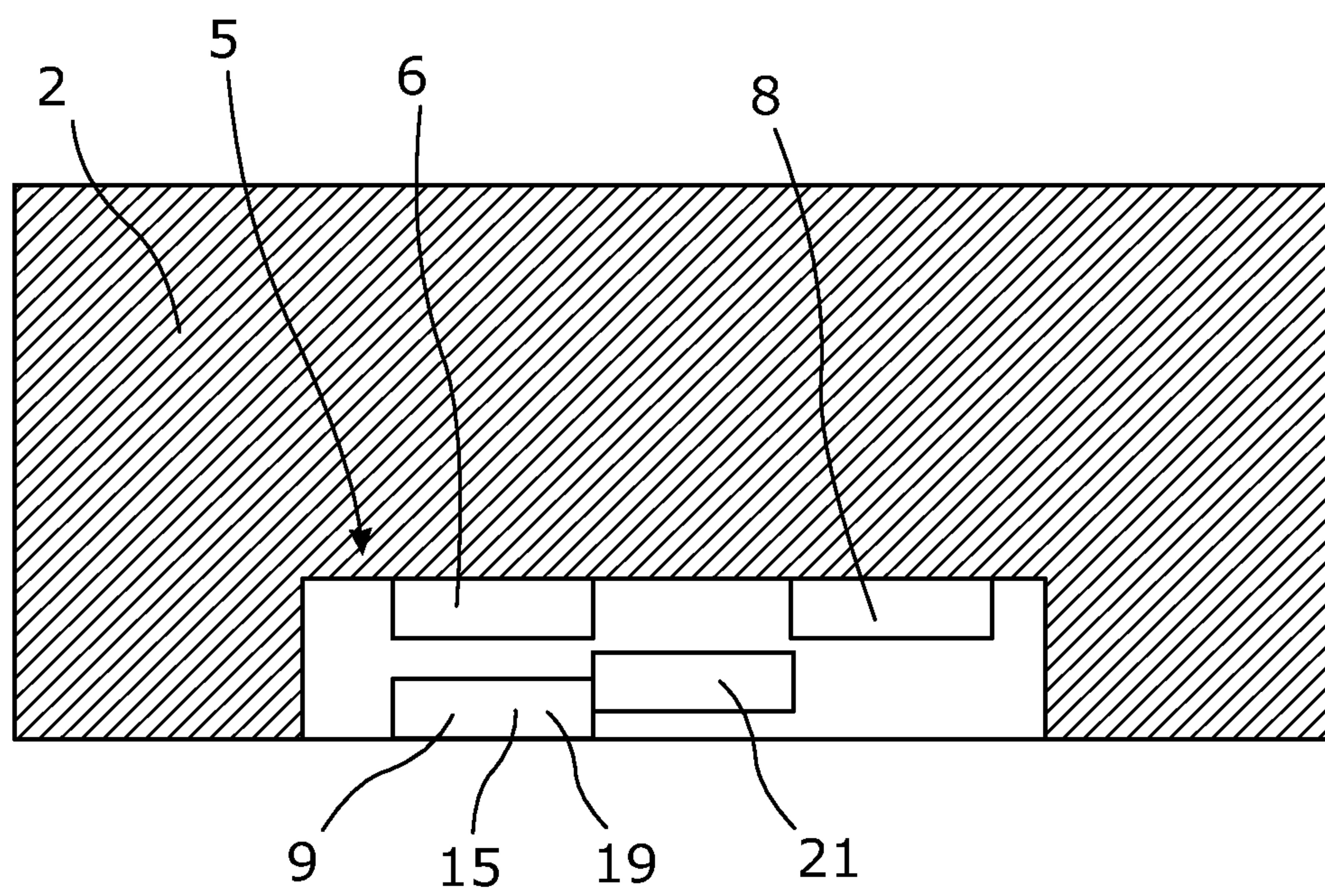


Fig. 5

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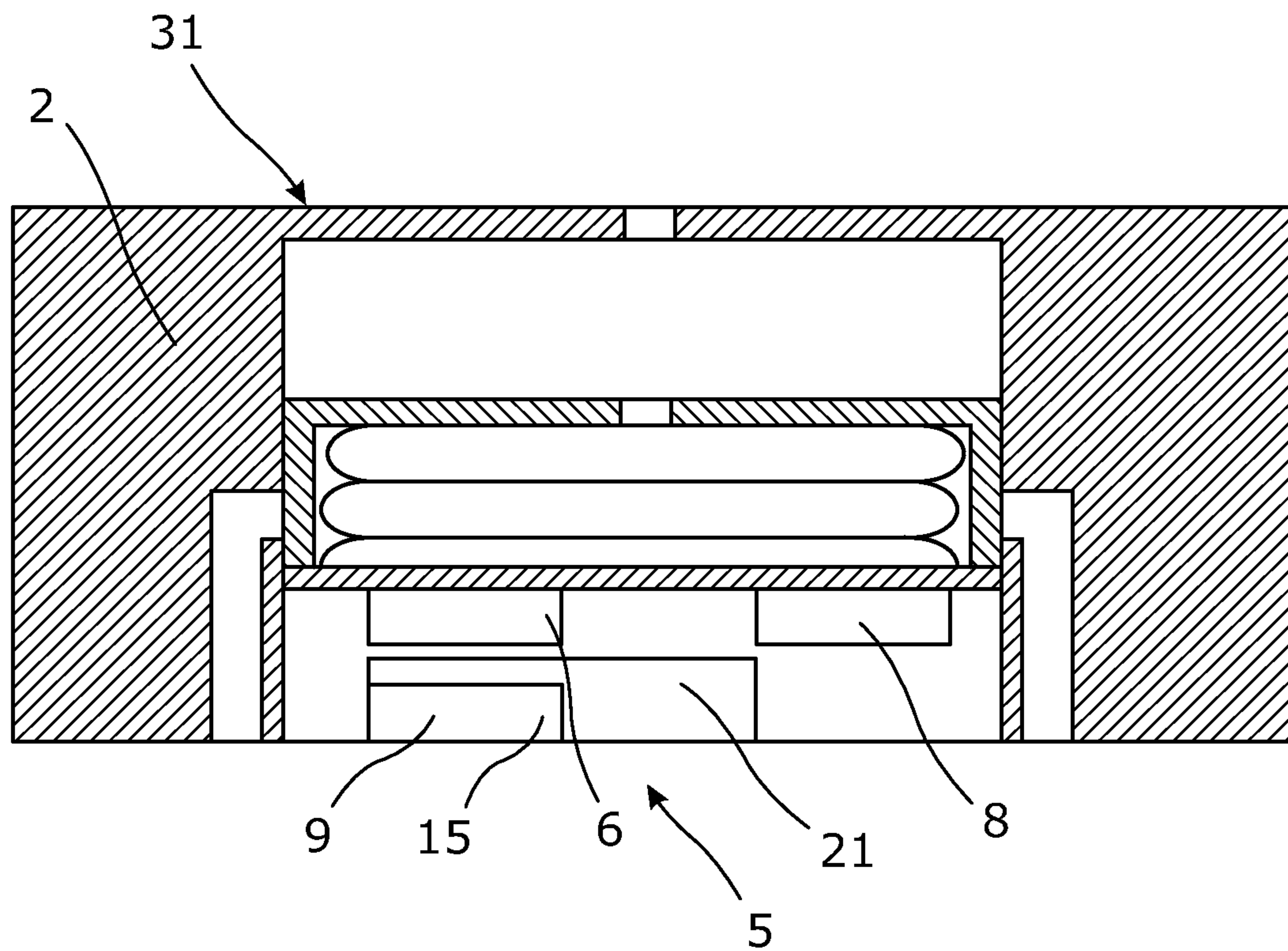


Fig. 6

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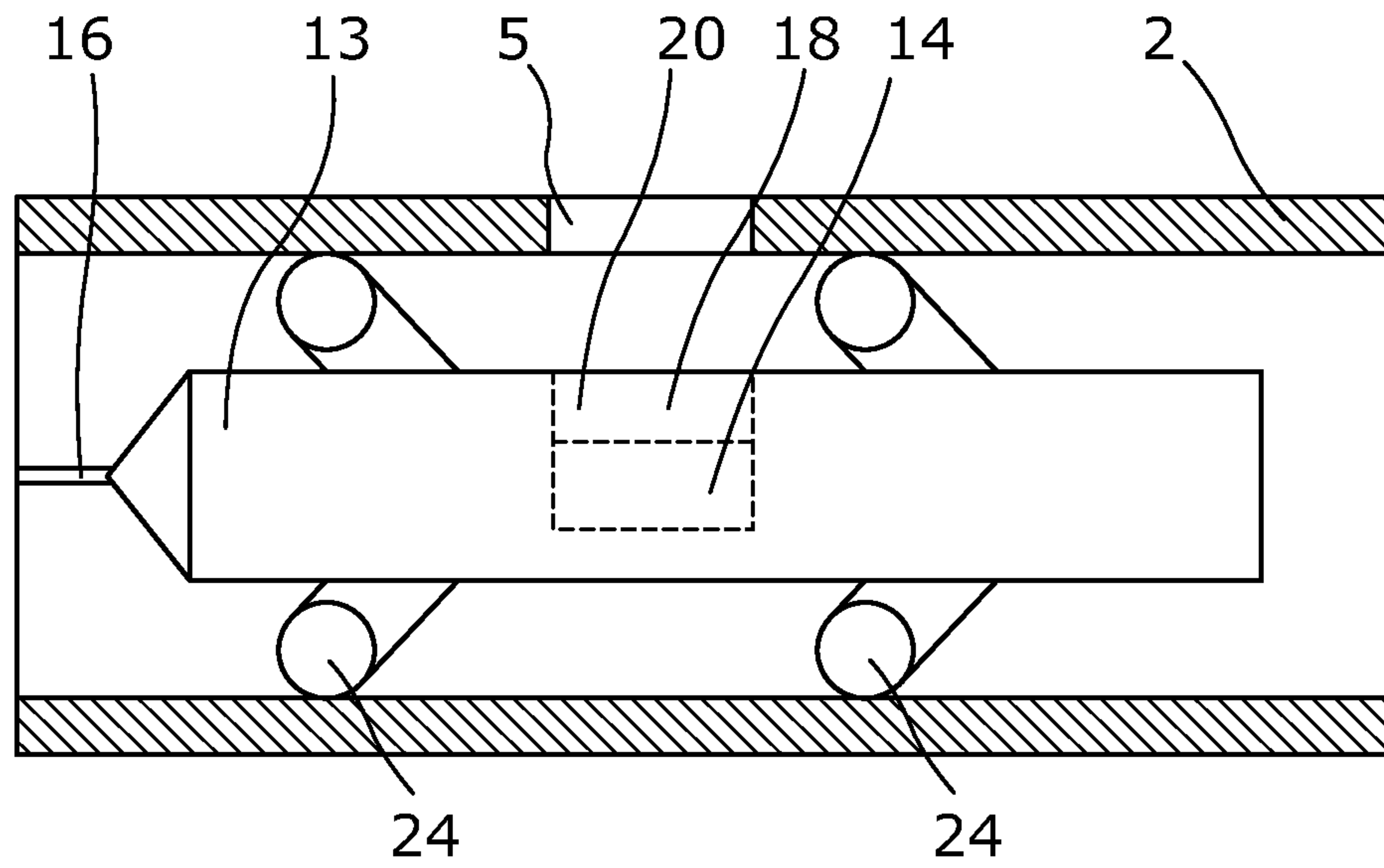


Fig. 7

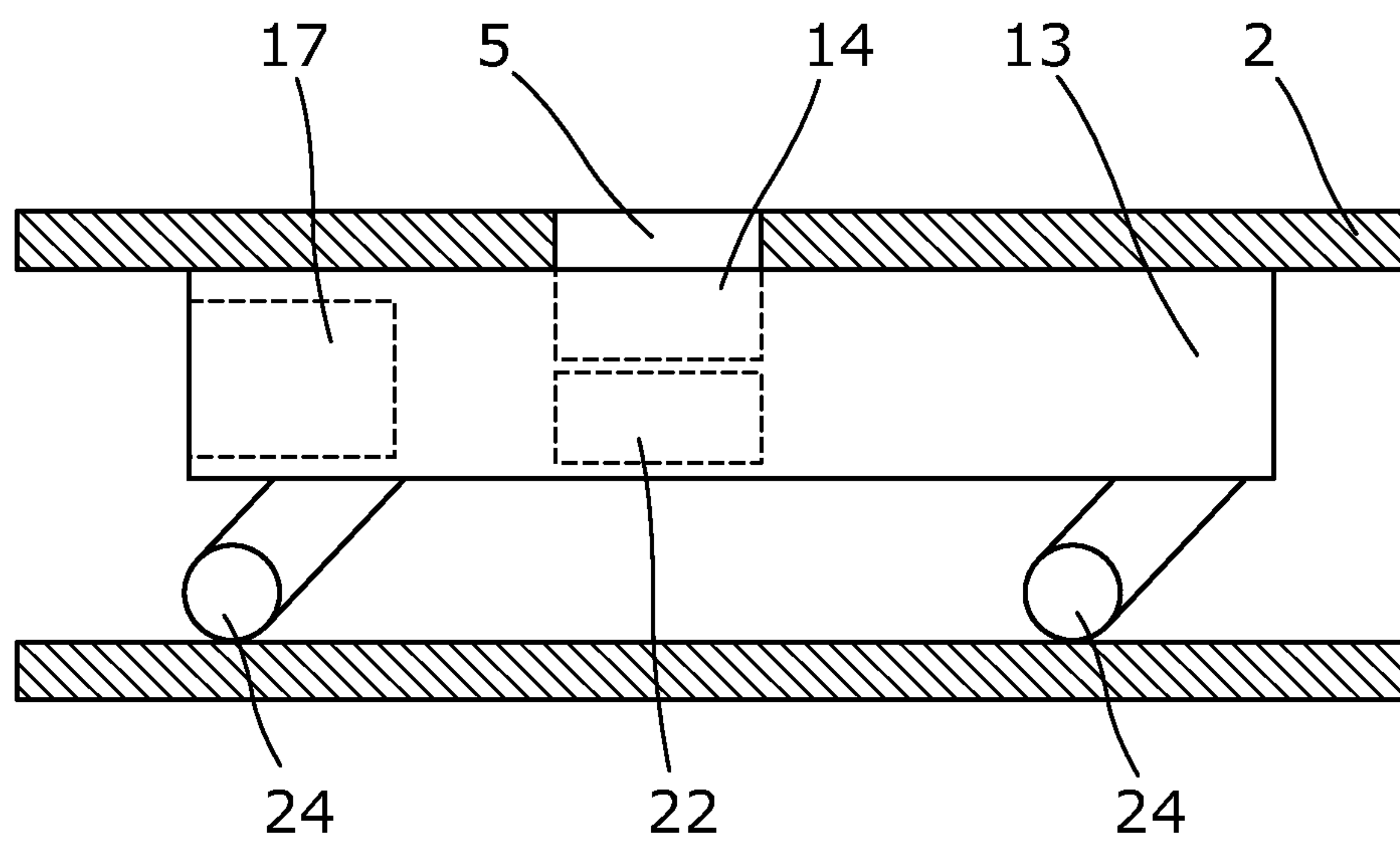


Fig. 8

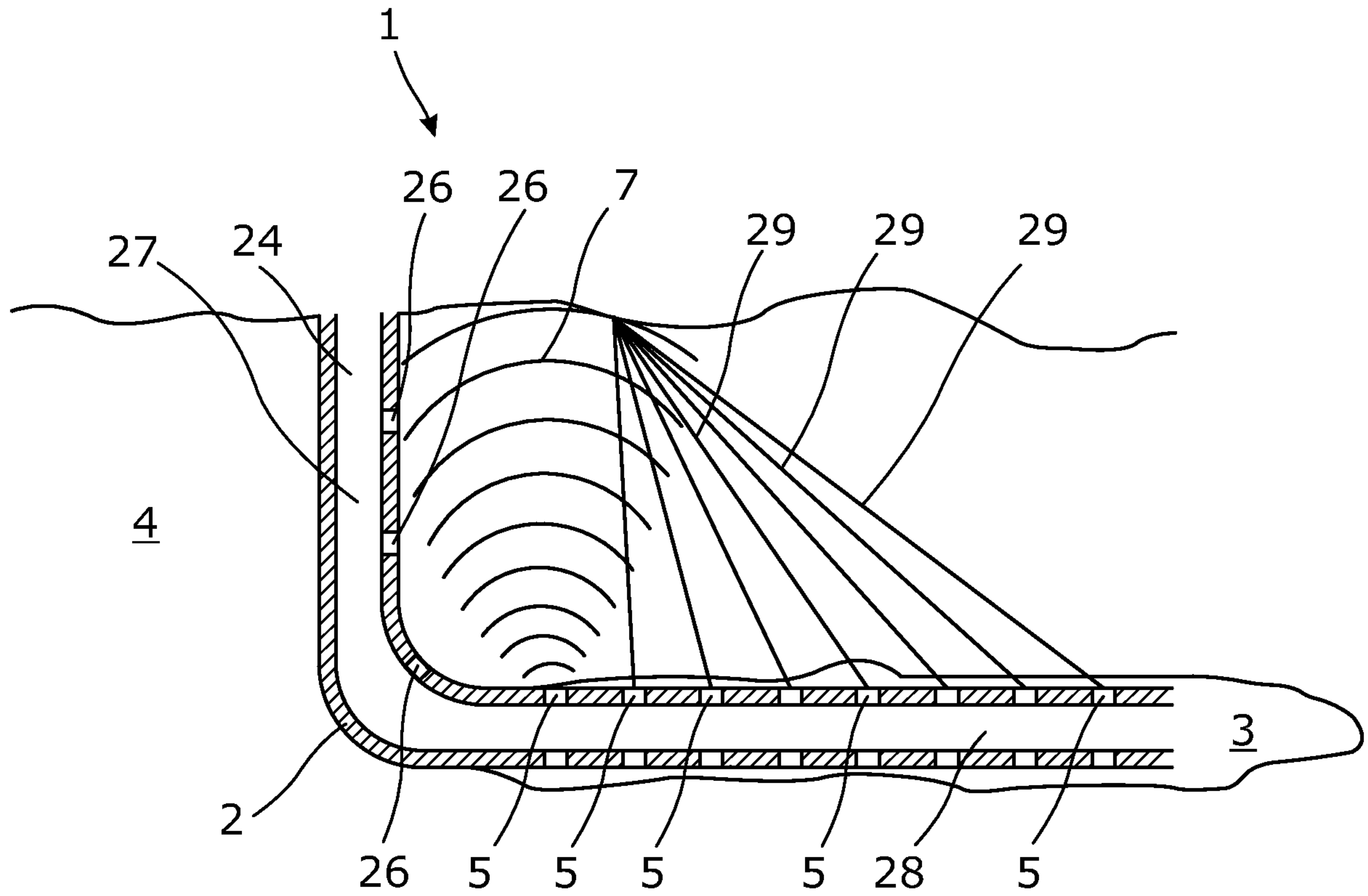


Fig. 9

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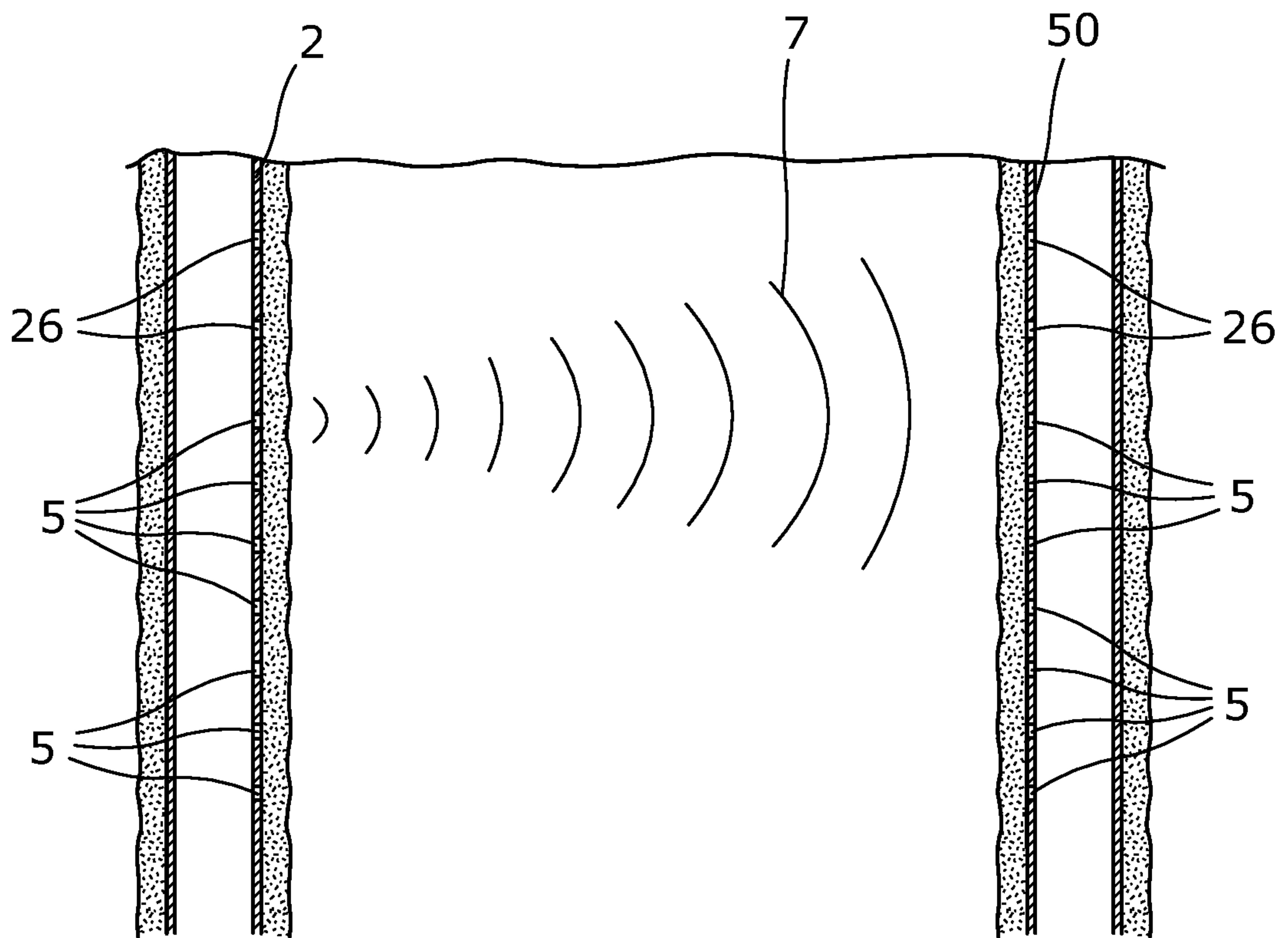


Fig. 10

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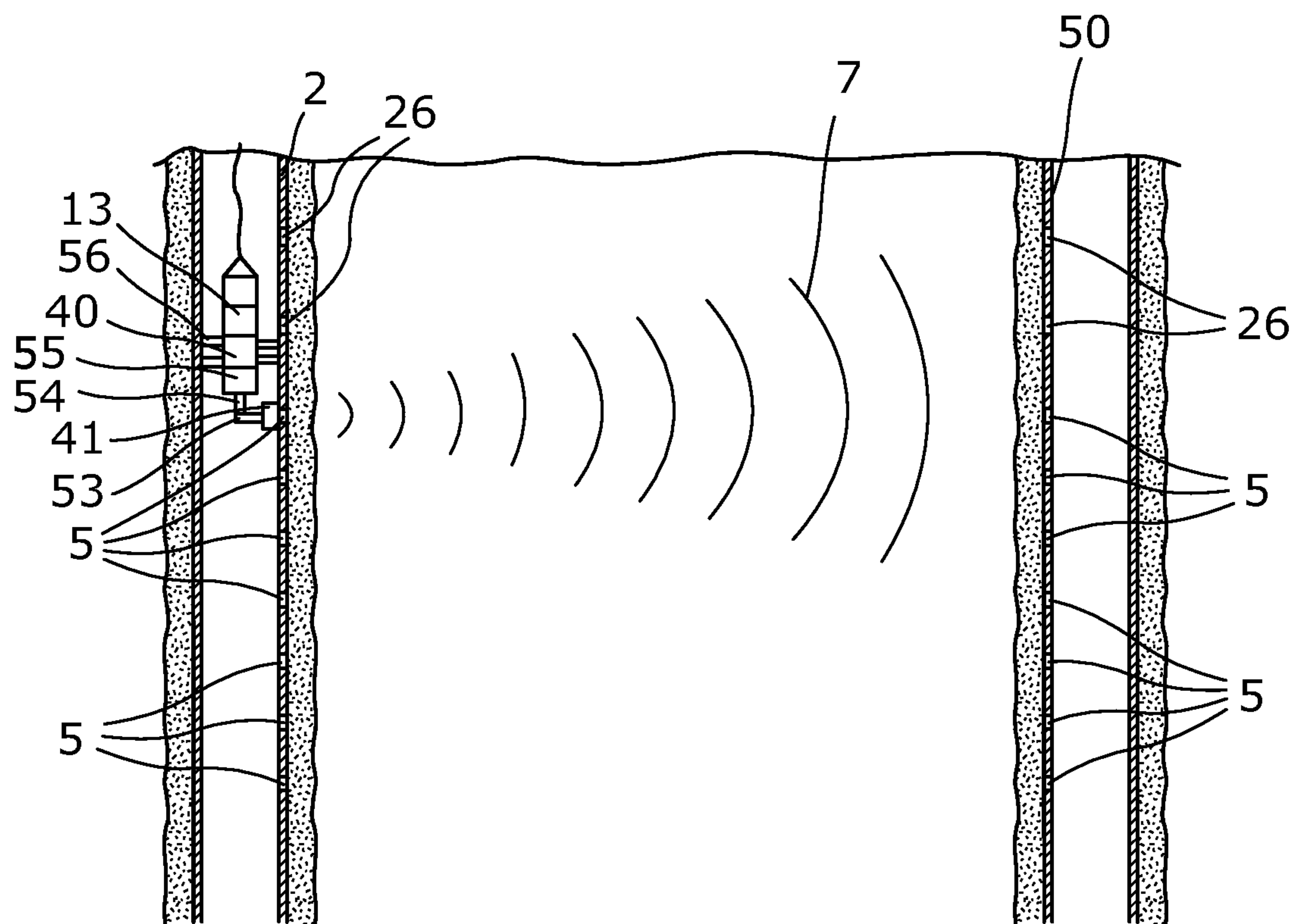


Fig. 11

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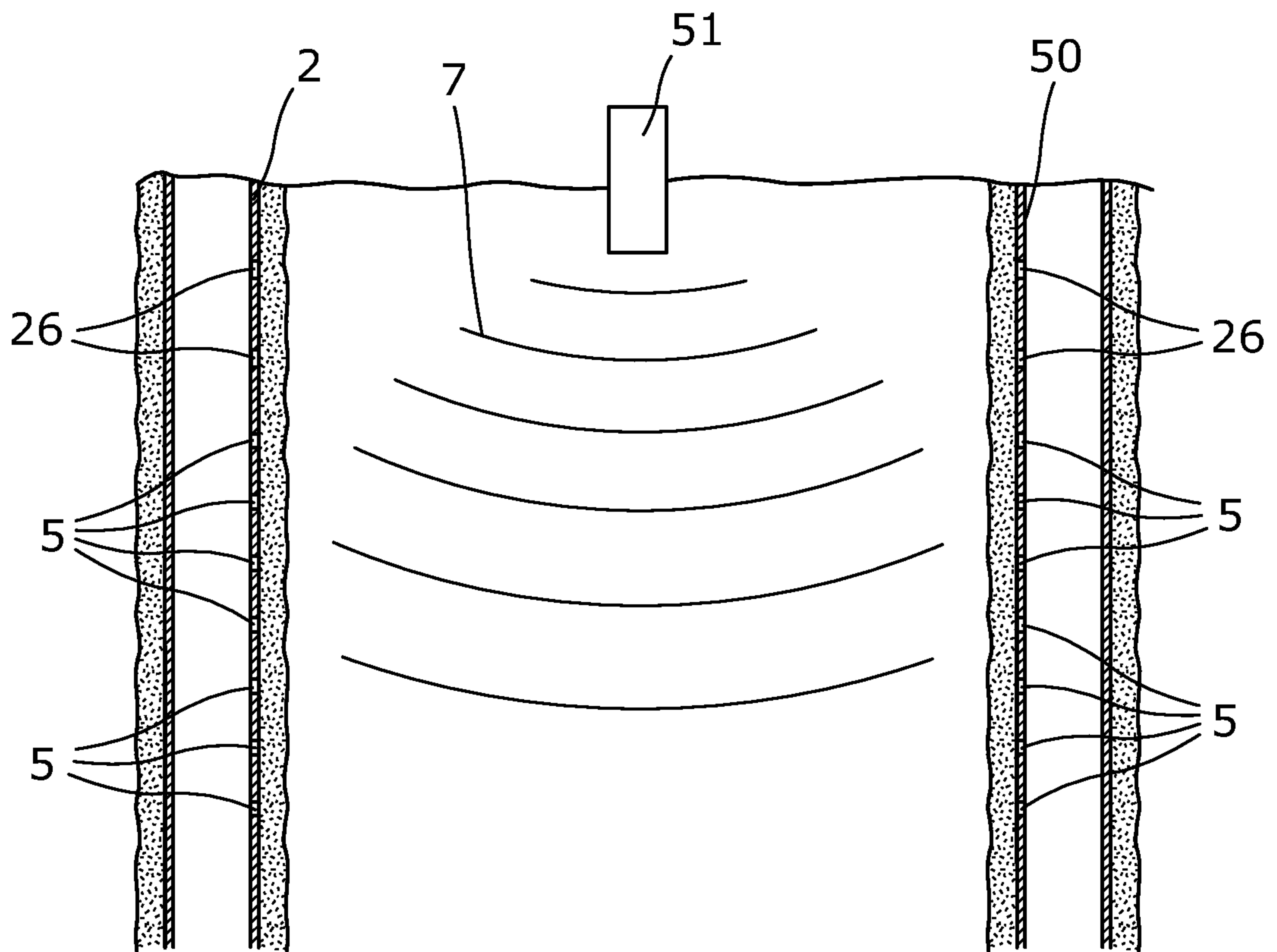


Fig. 12

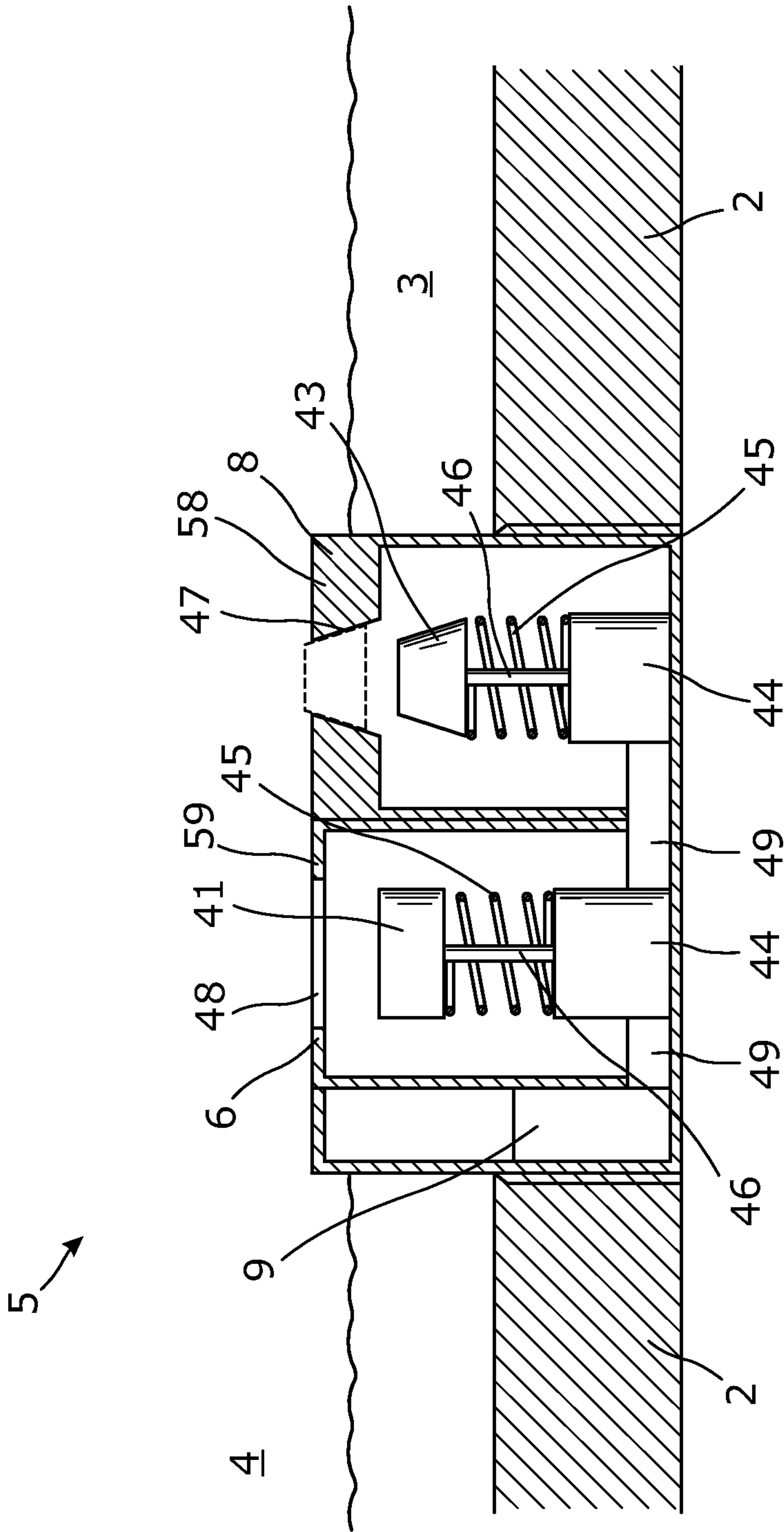


Fig. 13

